

TECHNICAL NOTE

Determination of Archie Parameters from Omani Carbonate Cores

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(Received 18/10/1992; accepted for publication 17/5/1993)

Abstract. This paper presents a data analysis approach to determine Archie parameter a , m and n from standard resistivity measurements on carbonate rocks core samples from Omani oil fields. The constants a and m were determined from core derived porosity data and the corresponding formation resistivity factor under different overburden pressures. Saturation exponent n of Archie's formula was estimated by measuring resistivity index for different brine saturations. The exact determination of Archie parameters is of paramount importance for the evaluation of oil reservoir rocks. Small change of a , m and n could produce a dramatic difference in the hydrocarbon reserve estimation processes.

The core analysis presented in this study for carbonate rocks showed that a is in the range of 0.74 to 1.81 with an average of 1.12 and m varies from 1.41 to 2.79 and giving an average of 2.03. Saturation exponent n has a range of 1.83 to 2.59, with an average of n 2.08, indicating that the studied reservoir is predominantly water wet. Cementation factor m and formation factor coefficient a were tested under different overburden pressure conditions. It is found that m and a are sensitive to the change of the applied overburden pressure.

Nomenclature

- F = formation resistivity factor
- a = formation factor coefficient
- ϕ = core porosity, %
- m = cementation factor
- n = saturation exponent
- S_w = water saturation
- P = net overburden pressure
- R_w = brine resistivity, $\Omega \cdot m$.
- R_0 = resistivity of rock fully saturated with brine, $\Omega \cdot m$.

- R_1 = formation resistivity, $\Omega.m$.
 I = resistivity index
 δ = incremental change

Introduction

Due to variation in pore geometry in carbonate reservoir rocks, it is primordial to examine Archie parameters, saturation exponent n , cementation factor m and formation factor coefficient a . Because carbonate reservoirs are not universally water wet, saturation exponent n often differs from the standard value of 2. This difference is ascribed mainly to rock wettability in addition to other rock/fluid characters. Therefore to determine an accurate water saturation, Archie parameters have to be very carefully defined. The implication for log interpretation is alarming. Suppose a zone had been interpreted conventionally using $n = 2$ and found to have a water saturation 40 percent, making it a candidate for producing hydrocarbon. Using the same logs but assuming the rock is oil wet and n was around 10, water saturation could alternatively take a value of 83 percent, making it water producing zone.

It is known that the matrix of a rock is, for all practical purposes non conducting, the only conductor being the salt water solution contained in the pore space. Natural rock system, however, especially precludes a mathematical development for the thorough definition of $F = f(\phi)$ relationship. The first definitive work was done by Archie [1] in which he observed that the formation resistivity factor F was related to the formation porosity ϕ in the form

$$F = a/\phi^m = R_0/R_w \quad (1)$$

and rock resistivity R_1 to water saturation S_w in the form

$$S_w^n = F R_w / R_1 \quad (2)$$

Archie's equation is considered as an ultimate base of the formation evaluation processes. Archie did not use the coefficient a in his equation and was taken as 1.0. In practice, the values of a , m and n are varying with the rock type, the nature of the saturating fluids and desaturation processes. A correct choice is sometimes very difficult, particularly in carbonate rocks. Some authors [2,3; pp. 110-129, 4-6] have pointed out that if a is a constant it should be equal to 1.0. Our purpose in this study is mainly to propose a relationship for the choice of these parameters a , m , and n for carbonate reservoir rock by testing limestone core sample collected from the pay zones of carbonate reservoirs in the northern part of Oman.

Determination of Cementation Factor m and Formation Factor Coefficient a

The practical application of the relationship $F = f(\phi)$ for a particular rock type is best accomplished by evaluating the cementation factor m and formation factor coefficient a using laboratory measured values of the formation resistivity factor and porosity. Each rock type has its characteristic formation factor versus porosity relation. Core measurements to determine this relationship required a range of especially preserved core samples, this is to keep the core under the same reservoir fluid distribution conditions, having different porosities. Table 1 summarizes the porosity and formation factor values at different overburden pressures (14,28,50,110,200 and 210 Kg/cm²). The data shown in the table have been obtained from the laboratory analysis of core samples collected from two wells. For every core sample, the porosity has been determined. The resistivity R_0 of the core 100 percent brine saturated was measured. The resistivity of simulated formation brine was 0.05 ohm-meter at

Table 1. Porosity (ϕ) and formation resistivity factor (F) for carbonate core samples

Well 1. Sample No.	50 Kg/cm ²		110 Kg/cm ²		210 Kg/cm ²	
	F	$\phi\%$	F	$\phi\%$	F	$\phi\%$
1	8.7	36.1	8.9	35.93	6.1	38.18
2	9.4	33.13	9.6	32.87	9.7	32.57
3	8.3	33.74	8.5	33.58	8.6	33.38
4	6.6	38.00	6.7	37.47	7.00	36.77
5	13.0	28.00	13.4	27.92	13.7	27.73
6	6.6	39.93	6.7	36.74	6.8	36.99
7	7.4	35.34	7.6	35.14	7.6	34.41

Well 2. Sample No.	14 Kg/cm ²		28 Kg/cm ²		200 Kg/cm ²	
	F	$\phi\%$	F	$\phi\%$	F	$\phi\%$
1	6.0	38.7	7.4	38.4	8.1	37.4
2	6.4	35.9	8.9	33.6	8.2	35.1
3	6.7	35.1	8.2	34.9	8.6	34.1
4	6.5	36.5	7.9	36.2	8.4	35.0
5	6.0	36.7	7.7	35.2	8.3	35.2
6	5.4	39.4	6.9	39.1	7.3	38.6
7	5.7	38.0	7.3	36.2	7.6	36.7
8	6.9	33.4	7.8	37.1	8.4	36.0
9	8.0	31.3	9.3	31.1	9.8	30.3
10	8.9	28.2	10.0	28.0	10.5	27.4

25°C. The formation resistivity factor F was determined for each sample using the definition $F = R_{\phi}/R_w$ at different overburden pressure conditions.

By taking the logarithm of both sides of equation 1. relating formation factor to porosity, the result is

$$\log F = \log a - m \log \phi \quad (3)$$

Thus a plot of $\log F$ versus $\log \phi$ should give a linear trend, where $-m$ represents the slope of this linear trend of F vs. ϕ and an intercept at $\phi = 1.0$ is giving the coefficient a . It appears that m has varied for different rock condition as a function of the degree of cementing of the rock. Figures 1-6 represent the $F = f(\phi)$ relations for the studied

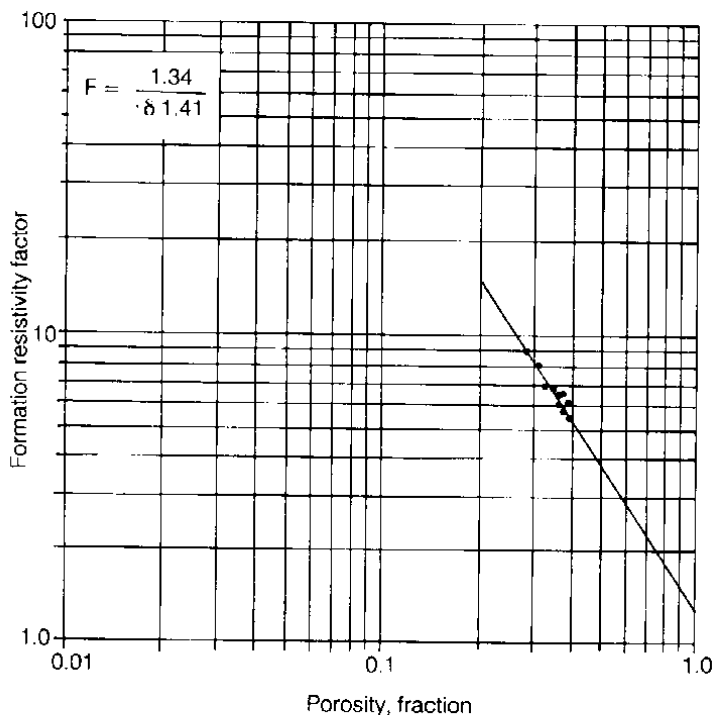


Fig. 1. Overburden pressure, 14 kg/cm².

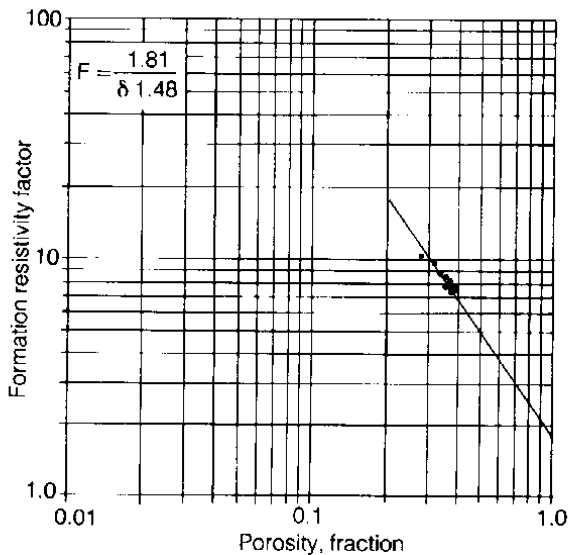


Fig. 2. Overburden pressure, 28 kg/cm².

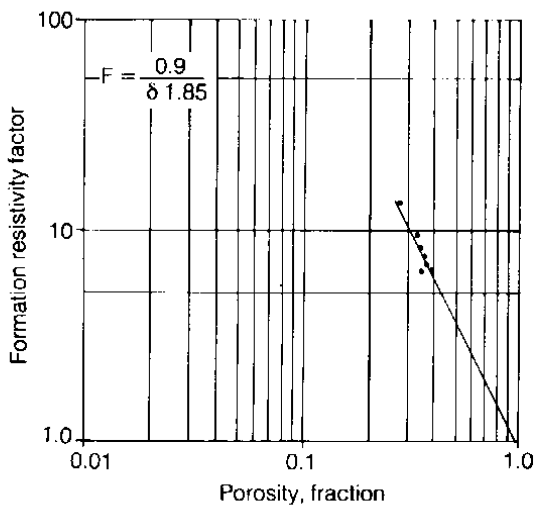


Fig. 3. Overburden pressure, 50 kg/cm².

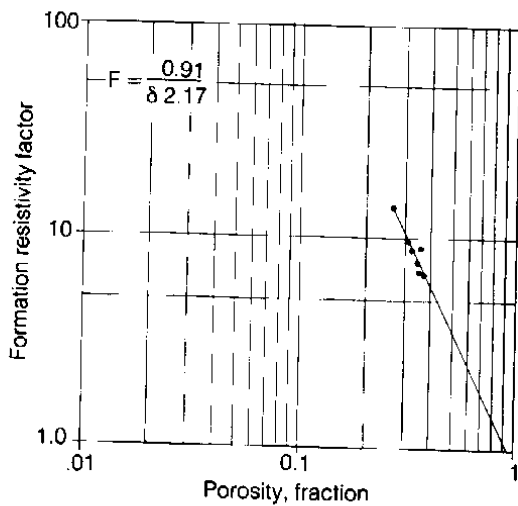


Fig. 4. Overburden pressure, 110 kg/cm².

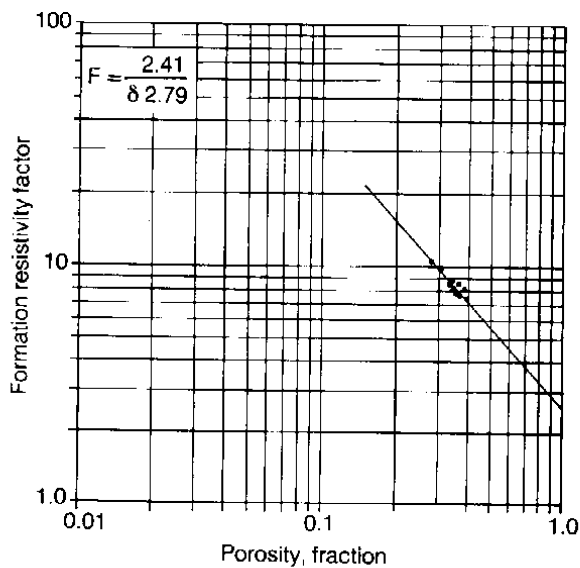


Fig. 5. Overburden pressure, 200 kg/cm².

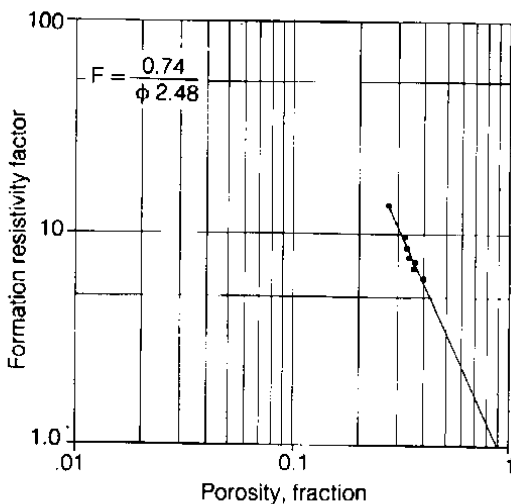


Fig. 6. Overburden pressure, 210 kg/cm².

limestone core samples. From these figures, it is seen that m has gone from 1.41 to 2.79, while a was covering the range of 0.74 to 1.81. An integrated analysis of the retained formation resistivity - porosity data led to generalized the $F = f(\phi)$ relationship for the acquired limestone core samples in the following form

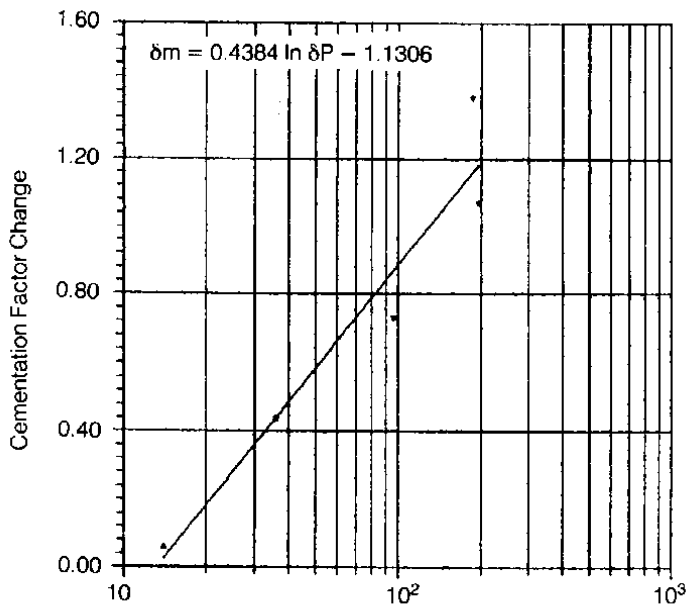
$$F = 1.12/\phi^{2.03} \quad (4)$$

Formation resistivity factor and overburden pressure

Knowledge of formation resistivity factor behavior with pressure change is important because of the stress distribution existing in the formations adjacent to the well bore. This is especially characterized, since the experimental observations indicated that the change of formation factor with pressure is more pronounced than that can be accounted on the basis of porosity change [7; p. 332, 8; p. 647]. The change of formation resistivity factor with pressure could be expressed in the change of cementation factor due to the change of applied overburden pressures. Table 2 presents cementation factor values and the corresponding overburden pressure. Providing that the pore fluid pressure was 14 Kg/cm², the rate of change of cementation factor has been calculated in relation to the net overburden pressure change with respect to this fluid pressure, Table 2. Fig. 7 illustrates the relationship between the incremental increase of cementation factor δm and net change of overburden pres-

Table 2. Change of cementation factor and formation resistivity coefficient with overburden pressure change

P Kg/cm ²	14	28	50	110	200	210
m	1.41	1.48	1.85	2.17	2.79	2.48
a	1.34	1.81	0.9	0.91	2.41	0.74
δP Kg/cm ²	zero	14	36	96	186	196
δm	zero	0.07	0.44	0.76	1.38	1.07
δa	0	0.47	-0.44	-0.43	1.07	-0.60

**Fig. 7. Pressure Change Kg/cm².**

sure δP . A relationship between δm and δP has been developed demonstrating an increasing trend of cementation factor as the applied overburden pressure becomes higher.

$$\delta m = 0.4384 \ln \delta p - 1.1306 \quad (5)$$

Equation (5) reflects the impact of the overburden pressure on formation resistivity factor. The values of formation factor coefficient a deduced from the logarithmic plot

of F against ϕ did not exhibit a significant function to the change of the overburden pressure. Table 2 illustrates a values for the net changes of overburden pressure. This confirms the limitations of ascribing the higher formation resistivity factor to tortuosity. In any pore system, tortuosity can be expected to be sensitive to change of applied pressure. Tortuosity values shown in Table 2 illustrate a heterogeneous pore system of the studied carbonate rock samples and nonuniform distribution of electrolyte within the pore system. On the other side the cementation factor proposed by Archie represents the effect of all interrelated parameters that characterize a natural rock. Not only the overburden pressure affecting the cementation factor but also pore geometry system, tortuosity and conductive solids should be considered in the study of cementation factor behavior.

Determination of Saturation Exponent n

The relationship between saturation and resistivity has been studied extensively by many authors. There are a number of factors affecting the value of the saturation exponent n ; wettability, rock structure, presence of clay, measurement technique and history of fluid displacement. It appears that wettability is the utmost controlling factor of the saturation exponent. The conducted researches of [9-11] had shown a clear trend of saturation exponent n going from $n = 2$ for water-wet pack to $n = 25$ in the case of oil-wet pack. It is found that wettability is an important factor in determining resistivity of partially saturated carbonate rocks. Why the saturation exponent n depends on wettability. In water-wet rock, brine coats each grain and provides a continuous path for ion flow at all saturation, n remains constant around 2. In oil-wet rock, brine is trapped in blobs in the middle of each pore. As water saturation decreases, paths between blobs get broken. Thereby resistivity increases dramatically and n increases to 10 or more [12].

The conventional determination of saturation exponent is based on Archie's formula

$$S_w = (aR_w/\phi^m R_t)^{1/n} \quad (6)$$

Originally Archie formula did not include a coefficient, but Winsauer *et al.* (1953) have added it to the equation. Since then, a is commonly used as part of Archie's equation. By taking the logarithm of equation 6, it is transposed into

$$\log R_t = \log (aR_w/\phi^m) - n \log S_w \quad (7)$$

If the terms on both sides of the same sign in equation 7 can be combined, the equation is rewritten in the form:

$$\log I = - n \log S_w \quad (8)$$

Where $I =$ resistivity index (R_t/R_0) and $R_0 = aR_w/\phi^m$. Therefore, plotting of $\log I$ versus $\log S_w$ should produce a straight line of a negative slope n .

Laboratory measurements of the saturation exponent n can be accomplished by a variety of techniques that can be generally defined as static or dynamic. The methods for measuring the saturation exponent are tedious. It is, however, very important to have these data measured in the laboratory on representative core samples. Ten core samples have been collected from oil bearing zones especially preserved and prepared to retain their wettability conditions have been tested. Using static technique, the samples were placed in a high speed centrifuge and spun at increasing incremental speed to an equivalent capillary pressure 35 Kg/cm^2 . Then, the samples were removed from the centrifuge cups. Brine saturations and electrical resistivities were determined. Resistivity index I values were calculated from R_0 , resistivity at 100 percent brine saturation and R_t , resistivity at partial brine saturation. Table 3 summarizes resistivity index, electrical resistivity, brine saturation and saturation exponent for the studied core samples (three samples failed during test) in addition to the corresponding porosity.

Saturation exponents n were determined from the logarithmic plot of resistivity index, I versus brine saturation, S_w for seven core samples. From these figures, it is found that saturation exponent, n values varied from 1.83 to 2.59, Table 3. The composite plot of the function $I = f(S_w)$ is depicted on Fig. 8. The data for this plot were

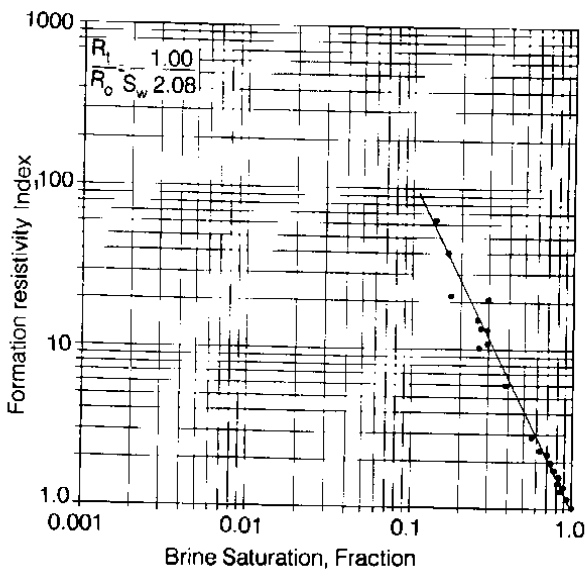


Fig. 8. Composite samples.

Table 3. Brine saturation (S_w), electrical resistivity (R_t), resistivity index (I), saturation exponent (n) and core porosity (ϕ) for carbonate core samples, well 2

Sample No.	ϕ % at 50 Kg/cm ²	S_w %	R_t Ω .m.	I	n
2	35.9	100	0.380	1.0	2.06
		93.3	0.44	1.16	
		72.8	0.72	1.9	
		27.3	5.36	14.1	
		16.3	15.6	41.0	
3	35.1	100	0.41	1.0	2.14
		76.5	0.73	1.78	
		68.2	0.92	2.25	
		29.2	5.69	13.9	
		13.9	27.43	66.9	
4	36.5	100	0.375	1.00	1.83
		86	0.54	1.44	
		63.9	0.86	2.29	
		56.6	1.04	2.77	
		26.3	3.9	10.4	
7	38.0	100	0.345	1.00	2.59
		88.1	0.48	1.39	
		79.9	0.61	1.77	
		29.8	7.5	21.7	
8	37.4	100	0.355	1.00	2.08
		93.6	0.41	1.15	
		82.2	0.54	1.52	
		25.6	5.64	15.9	
9	31.3	100	0.518	1.00	2.04
		83.6	0.74	1.43	
		30	5.77	11.2	
10	28.2	100	0.64	1	1.83
		38.2	3.91	6.11	
		17.2	11.41	22.5	

taken from all core sample analysis. From the relationship plotted in Fig. 8, the average value of saturation exponent n was found 2.08. This saturation exponent n determined by the above procedure, using the retained limestone core samples equals to 2.08, is indicating that the studied reservoir is predominantly water wet carbonate reservoir.

Conclusions

The m and a values of Archie's formula ($F = 1.12/\phi^{2.03}$ determined by core derived porosity versus formation resistivity factor were 2.03 and 1.12 respectively. These values are recommended to substitute a , m parameters in the water saturation equation for the retained carbonate reservoir. Also, it is found that the parameters a and m respond to the overburden pressure change in a different fashion. While a did not demonstrate a definite relationship to the pressure change, δm showed an increasing function of the net overburden pressure increase δP . The average saturation exponent, n determined by the adopted procedure in this work, using limestone core samples was around 2.08. This n value means that the reservoir could be considered as water-wet. Because of the effect of the wettability conditions on the selection of n , it is very important to identify the rock wettability preference.

Acknowledgement. We thank Petroleum Development Oman for providing us core samples and logs data and Prof. Sushil Bhandari, Sultan Qaboos University, for reviewing the manuscript.

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تحديد معاملات أرشي لعينات من صخور كربونائية عُمانية

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ملخص البحث . تقدم الدراسة طريقة لتحديد معاملات أرشي (a, m, n) بوساطة قياس المقاومة الكهربائية لصخور كربونائية من حقول بترول عُمانية . تحددت كل من a, m, n بإستخدام المسامية المستنتجة من العينات الصخرية ومعامل المقاومة الطبقيّة وذلك تحت ظروف من الضغوط المختلفة . تحدد المعامل n بقياس مؤشر المقاومة الكهربائية تحت ظروف تشعبية مختلفة .

إن تحديد معاملات أرشي يحمل أهمية كبرى في دراسة وتقويم الطبقات الحاملة للزيت .

وقد أوضحت تحليلات عينات الصخور الكربونائية أن المعامل a تتراوح قيمته بين ٠,٧٤ ، ١,٨١ بمتوسط ١,١٢ بينما تتراوح قيمة المعامل m بين ١,٤١ ، ٢,٧٩ بمتوسط ٢,٠٣ . وتراوح قيمة المعامل n بين ١,٨٣ ، ٢,٥٩ بمتوسط ٢,٠٨ . هذه القيمة للمعامل n تثبت أن الصخور الخازنة تحت البحث من النوع المائية التبلل . كذلك أوضحت هذه الدراسة ، أن كل من المعاملين (a, m) يتغير مع تغير الضغط الفعلي على الصخور بطريقة مختلفة .