Cementation exponent in carbonate reservoir of the Wahoo Formation (i.e., its relationship to permeability, pore geometry, and hydrocarbon production) as determined from core of the Husky Oil NPR Operations Inc. (U. S. Geological Survey) Lisburne Test Well No. 1 (8,052.0' - 8,066.5'), ARCO Alaska Inc. Prudhoe Bay Unit L2-26 (11,145.5' - 11,165.5'), and ARCO Alaska Inc. Prudhoe Bay Unit L5-24 (11,170.4' - 11,494.5').

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CEMENTATION EXPONENT IN CARBONATE RESERVOIRS:

ITS RELATIONSHIP TO PERMEABILITY, PORE GEOMETRY, AND HYDROCARBON PRODUCTION

by

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ABSTRACT

Formation evaluation of carbonate reservoirs is more complex than that of sandstone reservoirs. For example, the core analysis of carbonate samples containing open vugs on their surfaces is not the same as analyzing sandstone core samples.

This study shows that the well log-derived cementation exponents are as accurate as laboratory derived cementation exponents. Comparison of cementation exponent data derived from both laboratory and well logs shows a very strong correlation (correlation coefficient 0.94).

The well log based Nugent (1984) technique is more accurate than the Pickett Plot technique in determining cementation exponent (m). This is due to the significant weaknesses of the Pickett Plot method (e.g., this technique averages m for the entire logged interval, the interval must be water wet, porosity values of the interval have to have a wide range).

The measured permeability values of most of the samples studied are very low; only a few samples show high to very high values. Permeability ranges widely from 0.04 to 1501.31 md. The Mission Canyon Formation has almost all of the highest values, while the Wahoo Formation has the lowest values.

Diagenesis played a very important role in forming the pore geometries and rock textures of the formations. The tightly interlocking dolomite-crystal fabric formed the lowest permeability values, whereas dissolution caused permeability to be high.

The porosity versus formation resistivity factor data show excellent relationship with a correlation coefficient of about 0.90. This indicates that m decreases with decreasing porosity.

Cementation exponents in this study range from 1.54 to 3.0. In order to establish a meaningful relationship between cementation exponent and hydrocarbon production, m must have values greater than 3.0.

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STRATIGRAPHY

Formations used in this study are from three different basins: The Wahoo Formation of the Lisburne Group is part of the North Slope Basin, (Fig. 3); the Charles Salt, Duperow, Mission Canyon, and Red River Formations are part of the Williston Basin (Fig. 4); the Phosphoria Formation is part of the Big Horn Basin (Fig. 4).

Wahoo Formation:

The Lisburne Group (Mississippian-Pennsylvanian) is divided into two formations on the west end of the Sadlerochit Mountains of the Eastern Brooks Range: the Wahoo (Pennsylvanian) from which the samples for this study were gathered and Alapah (Fig. 3, Okland, et al., 1987). The stratigraphic boundary between the Wahoo and Alapah Formations is commonly characterized by a sharp contact (Mamet and Armstrong, 1972).

The marine Wahoo Formation/Limestone shows different lithological characteristics in the lower and upper parts (Wood and Armstrong, 1975). The lower part of the Wahoo consists of medium-grained bryozoan crinoid wackestones and packstones. Coarse-grained bryozoan crinoid grainstones and a 45-foot-thick oolitic grainstone interval form the uppermost rocks of the Wahoo Formation. This portion is thought to have been deposited in a strongly agitated open-shoal environment containing oolite banks (Wood and Armstrong, 1975). The predominant porosity types are vuggy, intercrystalline, and fracture (Okland, et al., 1987).

RESULTS

Data was obtained from laboratory, well log, and petrographic analyses. Lab analysis included permeability, porosity, formation resistivity factor, and cementation exponent measurements. Well log analysis consisted of obtaining porosity readings from sonic, neutron, and density logs. Cementation exponents were calculated based on these porosity values. Petrographic analysis included determination of porosity types and diagenetic history for all formations.

Permeability and Porosity:

The measured permeability values of most samples are poor to fair (i.e., < 10 md) and only a few samples show good to very good values (i.e., > 10 md, Table 1). Permeability values range from 0.04 to 1501.31 md. The highest permeability samples are from the Mission Canyon Formation, the lowest from the Wahoo Formation.

Porosity values of most samples are fair to very good (i.e., > 10 %) and only a few samples have negligible values (i.e., < 5 %). Porosity values range from 1.2 to 30.8 %.

Cementation Exponent:

As mentioned in the methods section, m was derived by various techniques. These methods were standard lab, special lab, and well logs. Plots were made to show the degree of correlation between these techniques. The majority of standard lab-derived m values are below 2.0 and the highest is 2.31(Fig. 9). The majority of special lab-derived m values are above 2.0 and the highest value is 2.91 (Fig. 9). The well log-derived m data shows very high

Table 1. Porosities derived from both lab and well logs and measured permeabilities of samples used in this study.

SAMPLE	FORMATION NAME	WELL NAME	POROSITY (%, Lab.)	POROSITY (%, Logs)	PERM. (md)
7	CHARLES SALT	33-1 NP	19.6	20.6	11.19
8	CHARLES SALT	33-1 NP	10.0	10.9	2.86
49	CHARLES SALT	33-1 NP	13.7	14.4	1.80
87	CHARLES SALT	33-1 NP	-	-	-
88	CHARLES SALT	33-1 NP	-	-	-
89	CHARLES SALT	33-1 NP	-	-	-
6	DUPEROW	33-1 NP	13.5	14.0	33.12
11	DUPEROW	3D-9 LUTTS	11.6	11.0	31.99
13	DUPEROW	33-1 NP	9.5	9.5	6.67
14	DUPEROW	3D-9 LUTTS	7.9	11.0	0.68
45	DUPEROW	3D-9 LUTTS	12.4	15.7	32.46
51	DUPEROW	33-1 NP	8.2	8.2	19.75
55	DUPEROW	3D-9 LUTTS	22.7	17.2	829.81
58	DUPEROW	3D-9 LUTTS	-	-	-
61	DUPEROW	33-1 NP	16.9	16.9	1.02
90	DUPEROW	33-1 NP	-	-	-
91	DUPEROW	33-1 NP	-	-	-
92	DUPEROW	33-1 NP	-	-	-
93	DUPEROW	33-1 NP	-	-	-
62	WAHOO	LISBURNE L5-24	12.0	11.0	1.66
63	WAHOO	LISBURNE L5-24	4.3	7.0	0.08
64	WAHOO	LISBURNE L5-24	3.4	4.5	0.04
65	WAHOO	LISBURNE L5-24	4.0	5.0	0.05
66	WAHOO	LISBURNE L5-24	3.4	9.6	0.30
67	WAHOO	LISBURNE L5-24	7.5	14.6	0.25
68	WAHOO	LISBURNE L5-24	4.4	9.8	0.13
69	WAHOO	LISBURNE L5-24	11.8	16.1	1.61
70	WAHOO	LISBURNE L5-24	3.6	4.5	0.07
94	WAHOO	LISBURNE L2-26	10.1	8.0	1.02
95	WAHOO	LISBURNE L2-26	11.1	7.8	1.25
96	WAHOO	LISBURNE L2-26	11.1	13.5	1.40
97	WAHOO	LISBURNE L2-26	5.6	6.9	0.38
98	WAHOO	LISBURNE L2-26	-	-	-
99	WAHOO	LISBURNE L2-26	4.4	4.5	0.12
71	WAHOO	LISBURNE TEST WELL #1	4.5	5.0	0.22
72	WAHOO	LISBURNE TEST WELL #1	4.6	5.0	0.25
73	WAHOO	LISBURNE TEST WELL #1	2.8	9.0	0.14
74	WAHOO	LISBURNE TEST WELL #1	2.5	10.0	0.15
75	WAHOO	LISBURNE TEST WELL #1	5.0	5.0	0.17
76	WAHOO	LISBURNE TEST WELL #1	-	-	-
2	M.CANYON	1-28 DONALD PETERSON	10.2	14.8	0.06
9	M.CANYON	1-28 DONALD PETERSON	3.3	20.0	0.30
15	M.CANYON	1-28 DONALD PETERSON	20.1	10.3	1415.75
16	M.CANYON	1-28 DONALD PETERSON	12.4	9.8	1501.31
17	M.CANYON	1-28 DONALD PETERSON	4.6	2.3	0.06
18	M.CANYON	1-28 DONALD PETERSON	-	-	-
22	M.CANYON	1-28 DONALD PETERSON	4.6	1.8	0.08
24	M.CANYON	1-28 DONALD PETERSON	8.2	2.0	1.34
25	M.CANYON	1-28 DONALD PETERSON	-	-	-
36	M.CANYON	1-28 DONALD PETERSON	5.0	7.0	0.07
37	M.CANYON	1-28 DONALD PETERSON	-	-	-
41	M.CANYON	1-28 DONALD PETERSON	2.6	1.2	0.07
44	M.CANYON	1-28 DONALD PETERSON	4.0	1.5	0.08
47	M.CANYON	1-28 DONALD PETERSON	15.4	7.1	55.86
60	M.CANYON	1-28 DONALD PETERSON	-	-	-
100	M.CANYON	1-28 DONALD PETERSON	-	-	-
10	M.CANYON	#1-8 RUSCH	19.5	20.0	573.49
20	M.CANYON	#1-8 RUSCH	22.7	23.0	139.27
21	M.CANYON	#1-8 RUSCH	21.2	19.0	68.58

Figure 10. Four different types of plots based on the data taken from all samples. The graphs at the top of the pages represent lab-derived data, whereas, the graphs at the bottom of the pages represent well-log derived data.

Correlation coefficients are as follows:

A. R = 0.88

B. R = 0.92

C. R = 0.80

D. R = 0.64

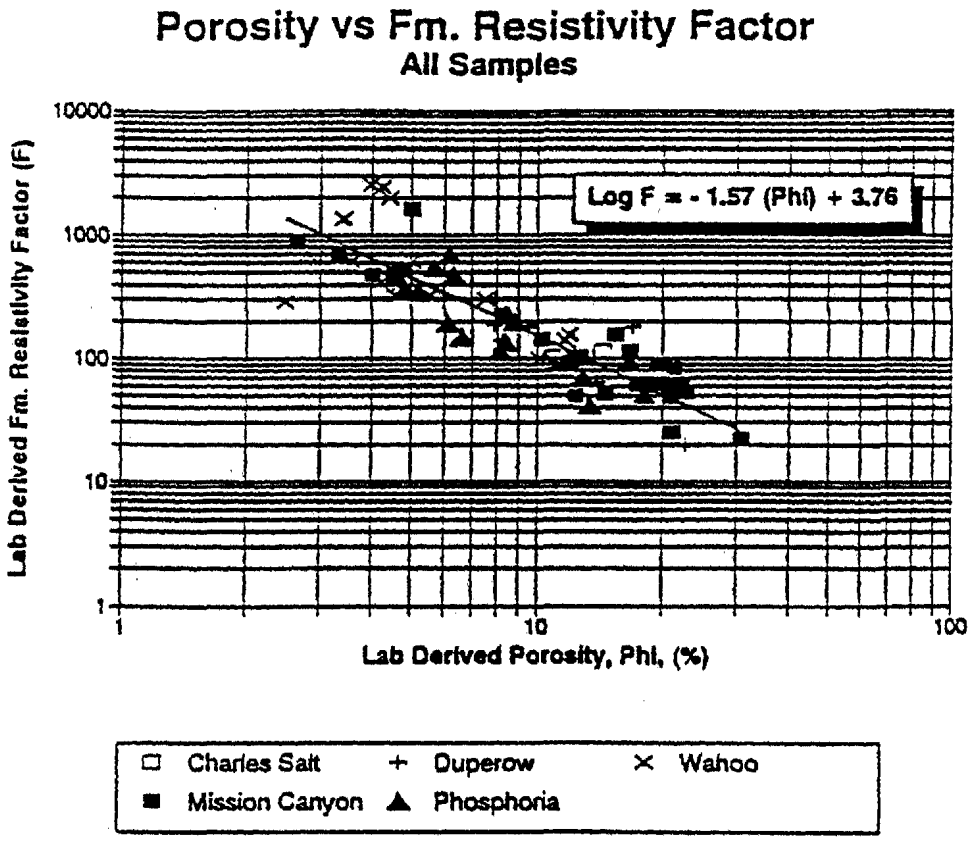
E. Power function equation is on the graph.

F. Power function equation is on the graph.

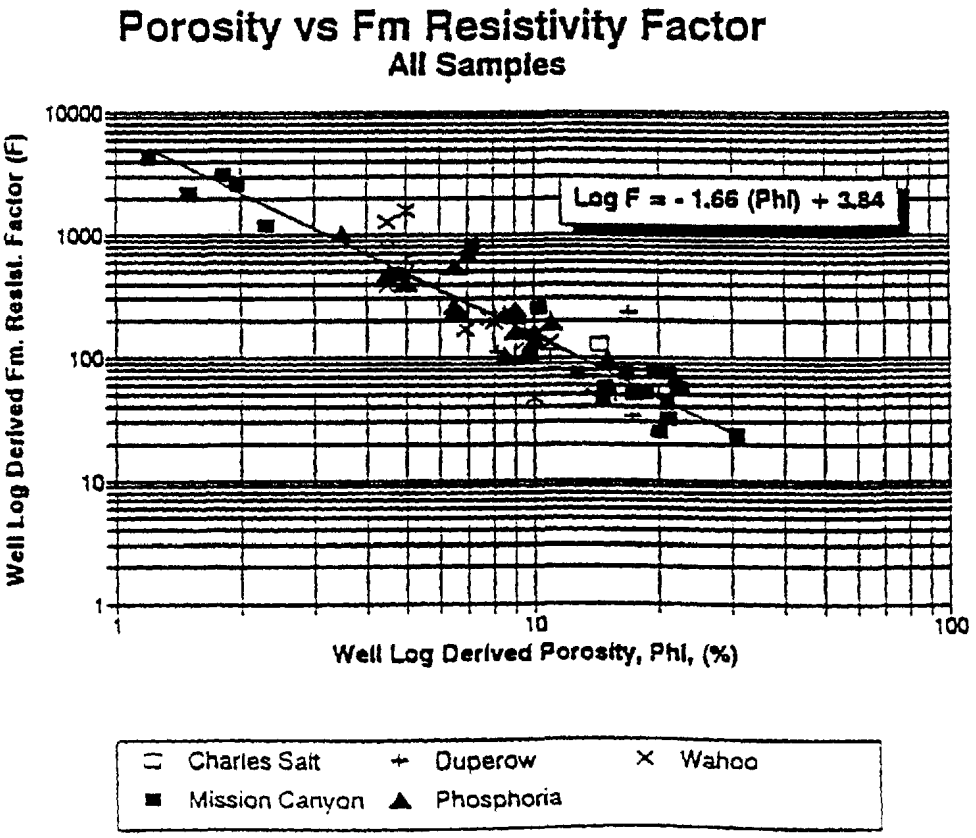
G. R = 0.50

H. R = 0.45

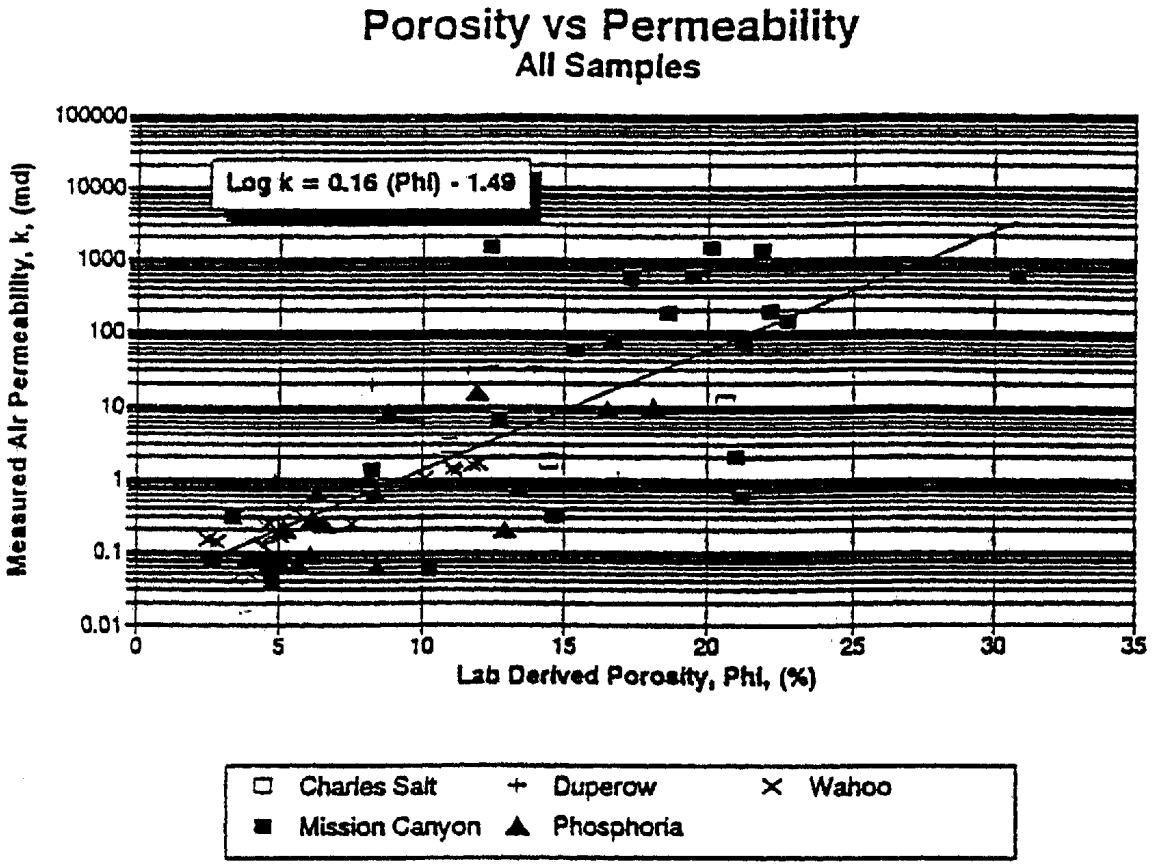
A


Porosity vs Fm. Resistivity Factor
All Samples
Log F = - 1.57 (Phi) + 3.76
Lab Derived Fm. Resistivity Factor (F)
Lab Derived Porosity, Phi, (%)
10000
1000
100
10
1
1
10
100
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

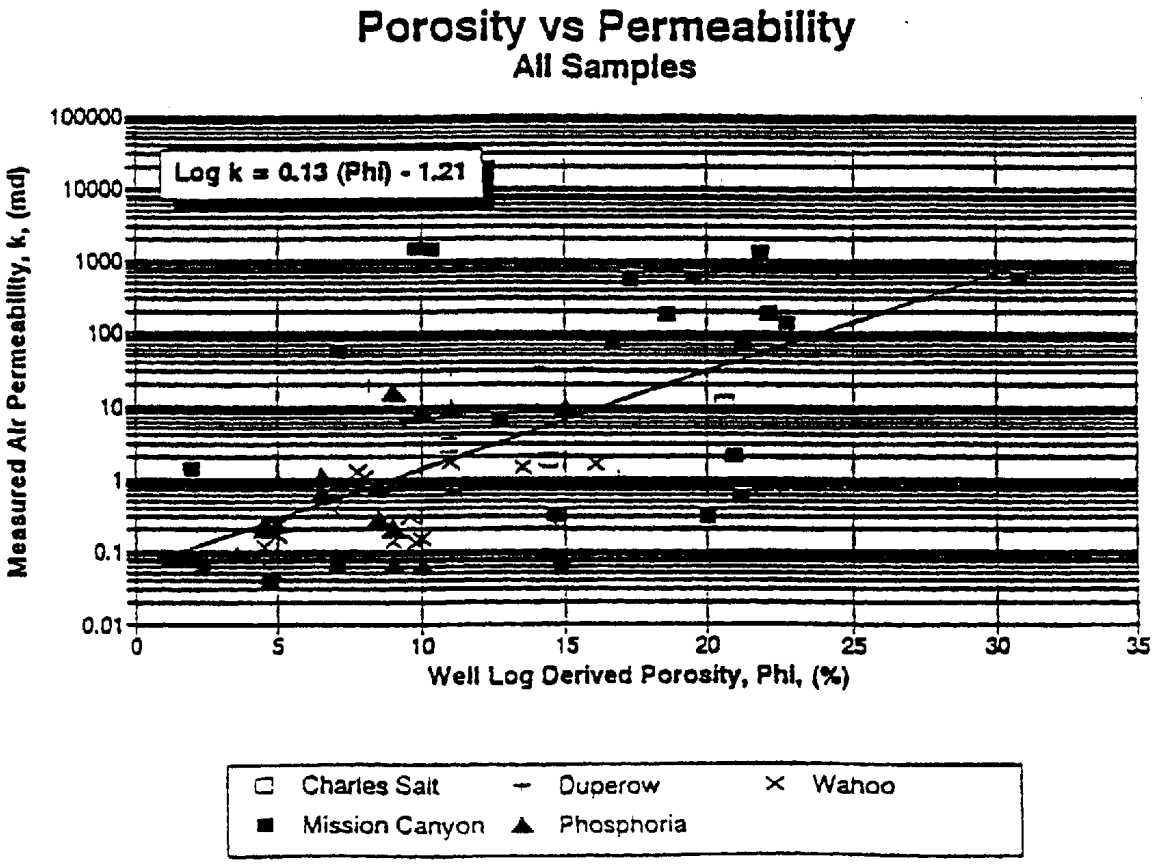
B


Porosity vs Fm Resistivity Factor
All Samples
Log F = - 1.66 (Phi) + 3.84
Well Log Derived Fm. Resist. Factor (F)
Well Log Derived Porosity, Phi, (%)
10000
1000
100
10
1
1
10
100
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

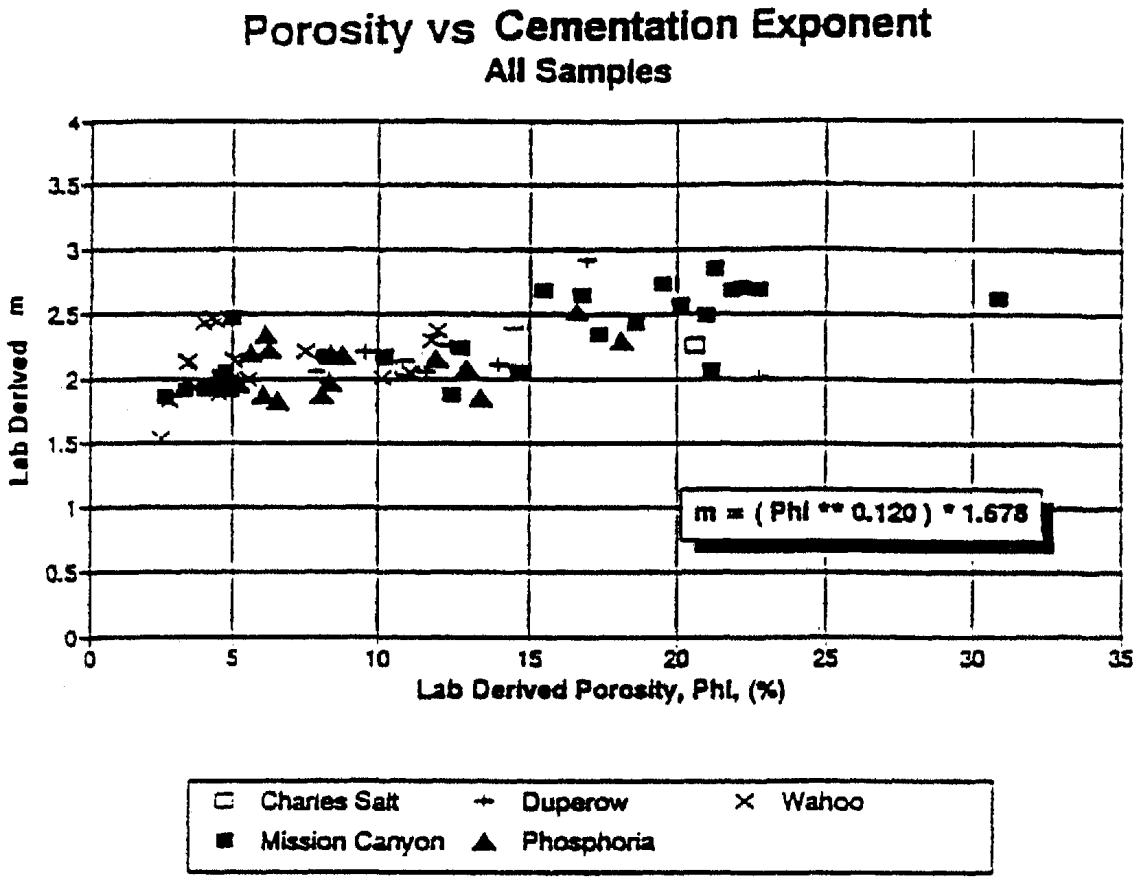
C


Porosity vs Permeability
All Samples
Log k = 0.16 (Phi) - 1.49
Measured Air Permeability, k, (md)
100000
10000
1000
100
10
1
0.1
0.01
0
5
10
15
20
25
30
35
Lab Derived Porosity, Phi, (%)
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

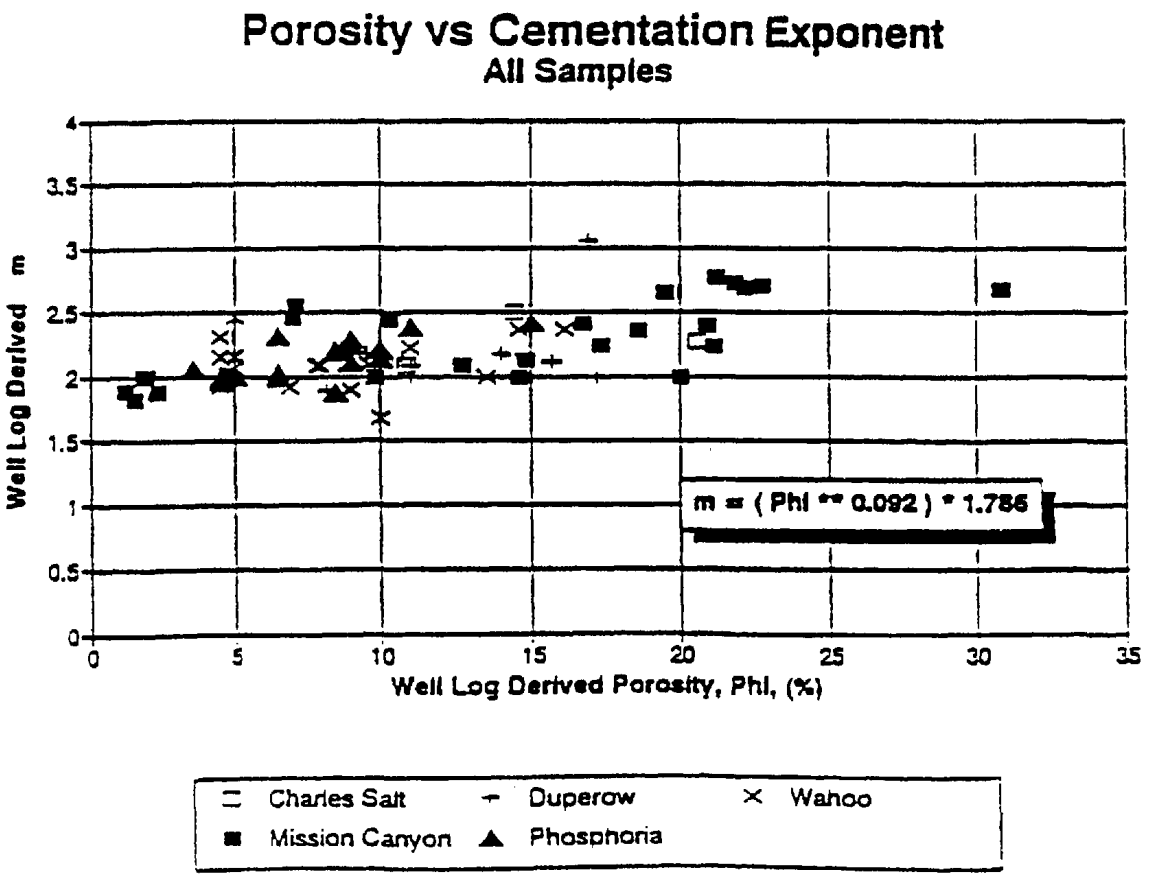
D


Porosity vs Permeability
All Samples
Log k = 0.13 (Phi) - 1.21
Measured Air Permeability, k, (md)
100000
10000
1000
100
10
1
0.1
0.01
0
5
10
15
20
25
30
35
Well Log Derived Porosity, Phi, (%)
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

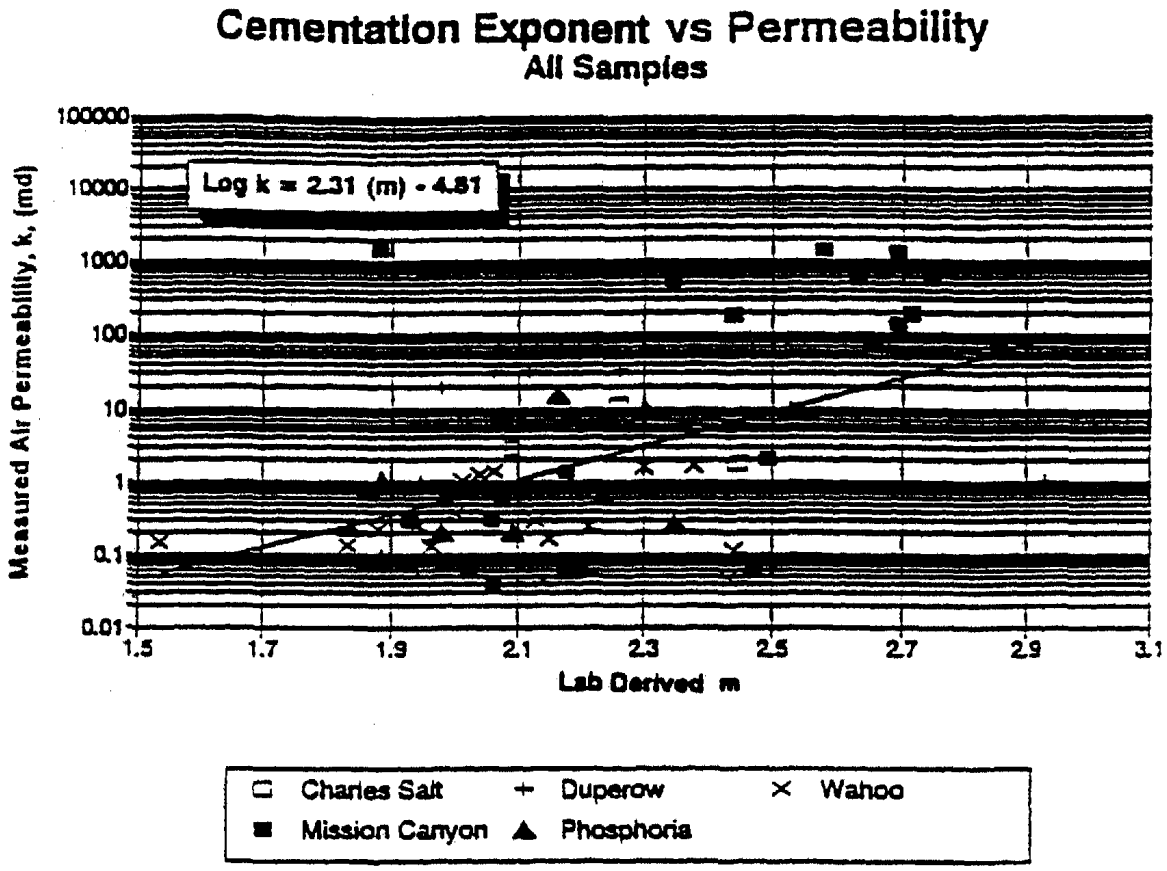
E


Porosity vs Cementation Exponent
All Samples
Lab Derived m
Lab Derived Porosity, Phi, (%)
m = (Phi ** 0.120) * 1.678
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

F


Porosity vs Cementation Exponent
All Samples
Well Log Derived m
Well Log Derived Porosity, Phi, (%)
m = (Phi ** 0.092) * 1.786
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

G


Cementation Exponent vs Permeability
All Samples
Log k = 2.31 (m) - 4.81
Measured Air Permeability, k, (md)
100000
10000
1000
100
10
1
0.1
0.01
1.5
1.7
1.9
2.1
2.3
2.5
2.7
2.9
3.1
Lab Derived m
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

H

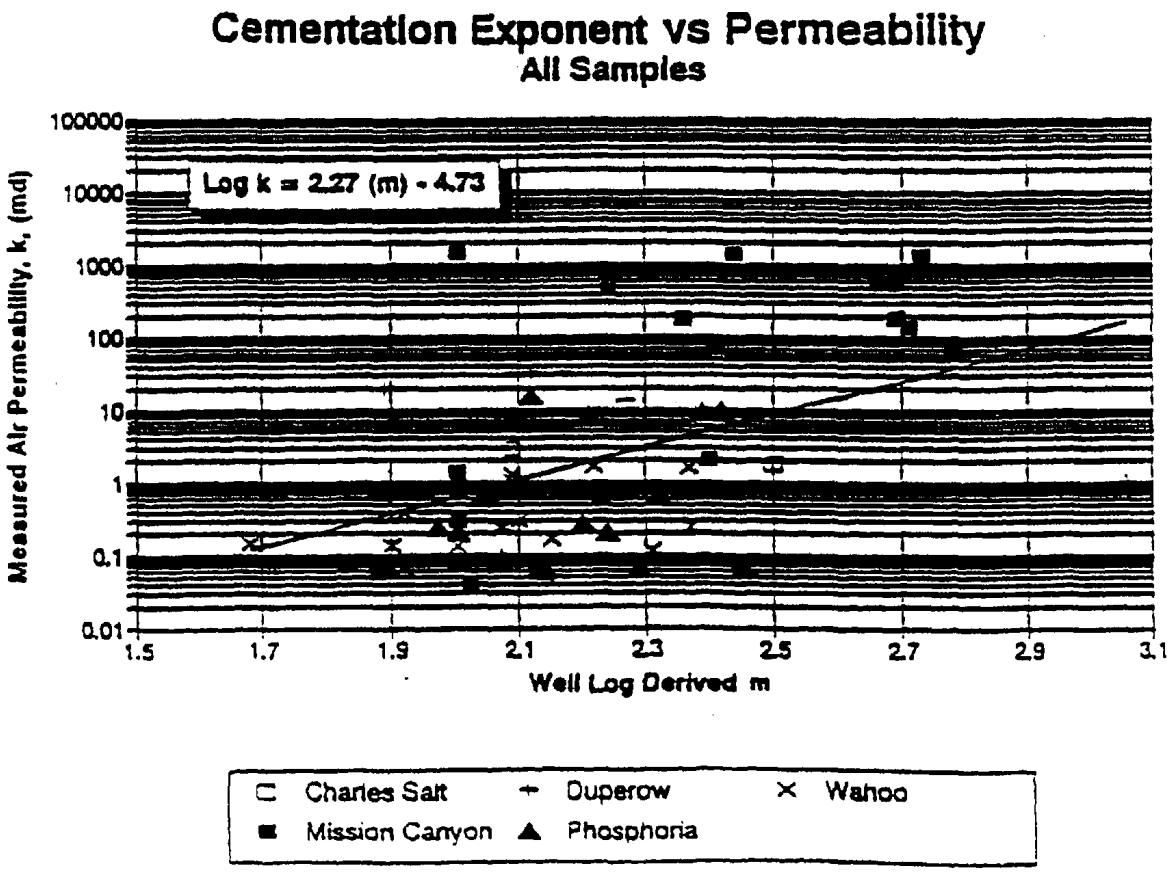

Cementation Exponent vs Permeability
All Samples
Log k = 2.27 (m) - 4.73
Measured Air Permeability, k, (md)
100000
10000
1000
100
10
1
0.1
0.01
1.5
1.7
1.9
2.1
2.3
2.5
2.7
2.9
3.1
Well Log Derived m
Charles Salt
Duperow
Wahoo
Mission Canyon
Phosphoria

Figure 11. Plots for samples containing predominantly vuggy porosity. The graphs at the top of the pages represent lab-derived data, whereas, the graphs at the bottom of the pages represent well-log derived data.

Correlation coefficients are as follows:

A. R = 0.80

B. R = 0.69

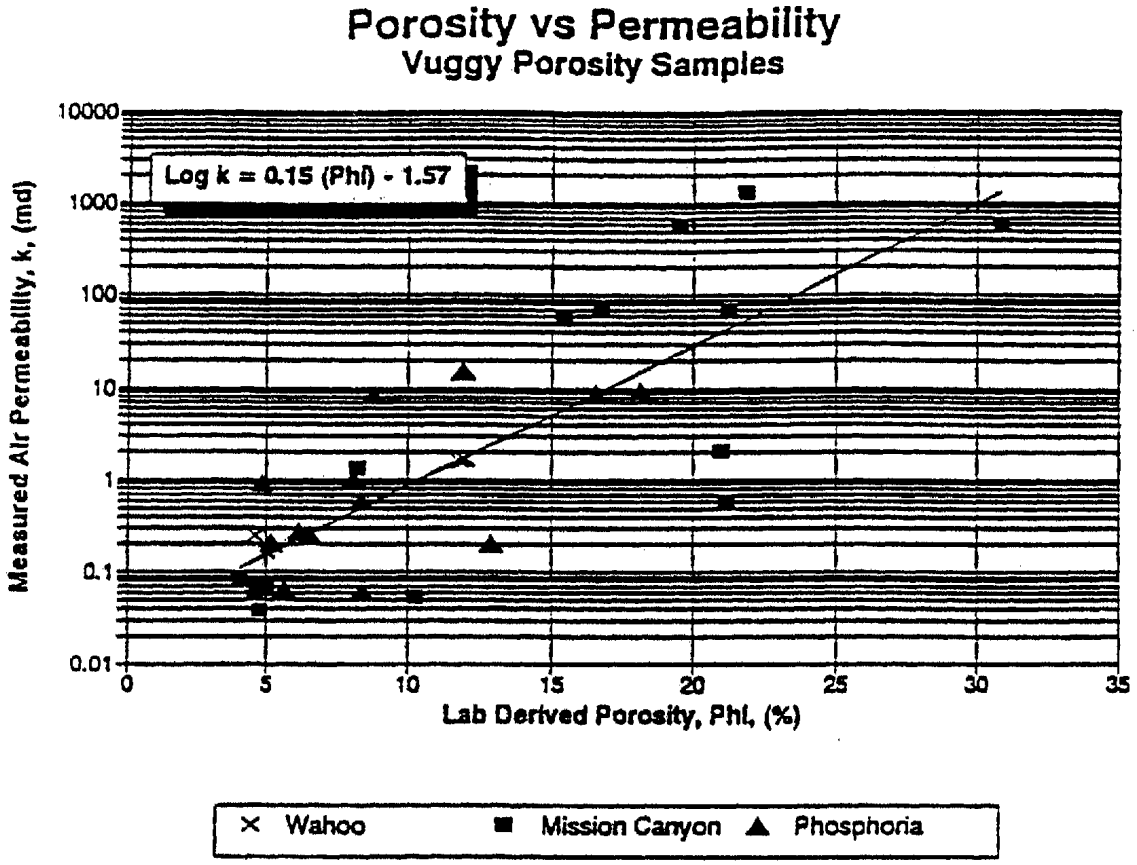
C. Power function equation is on the graph.

D. Power function equation is on the graph.

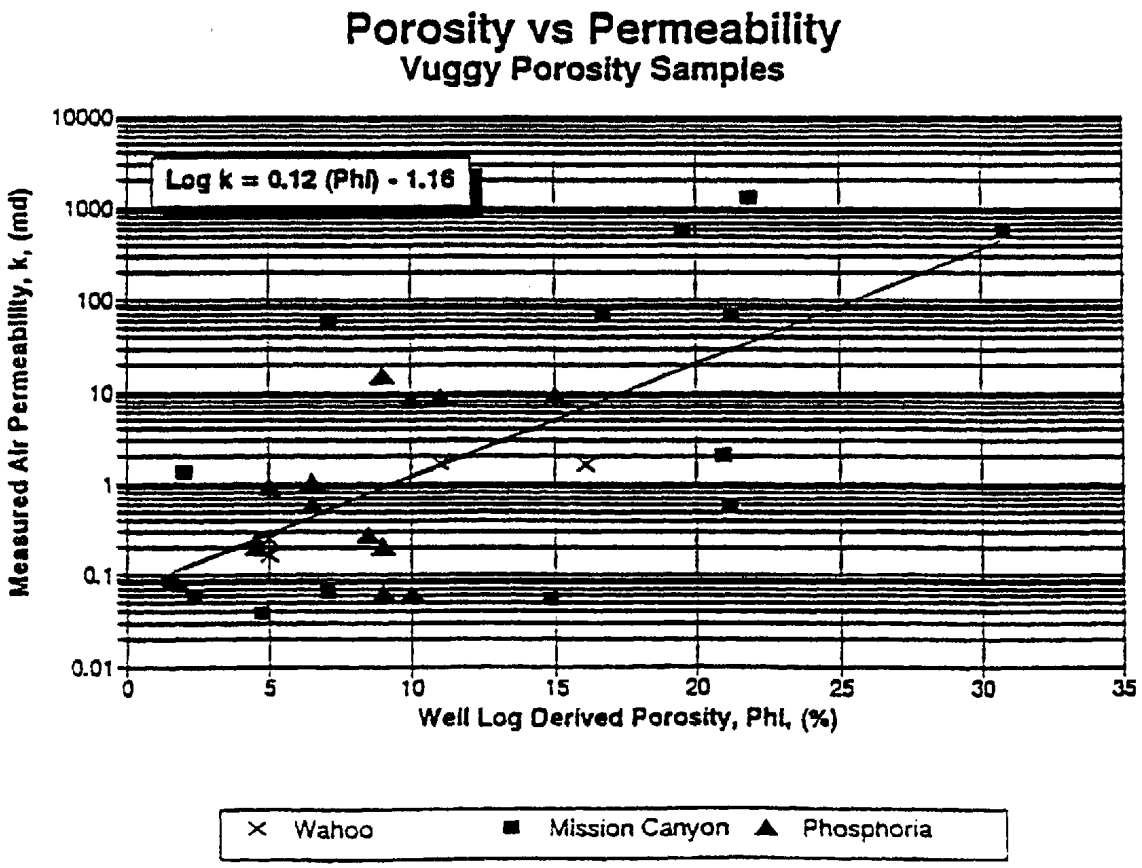
E. R = 0.75

F. R = 0.77

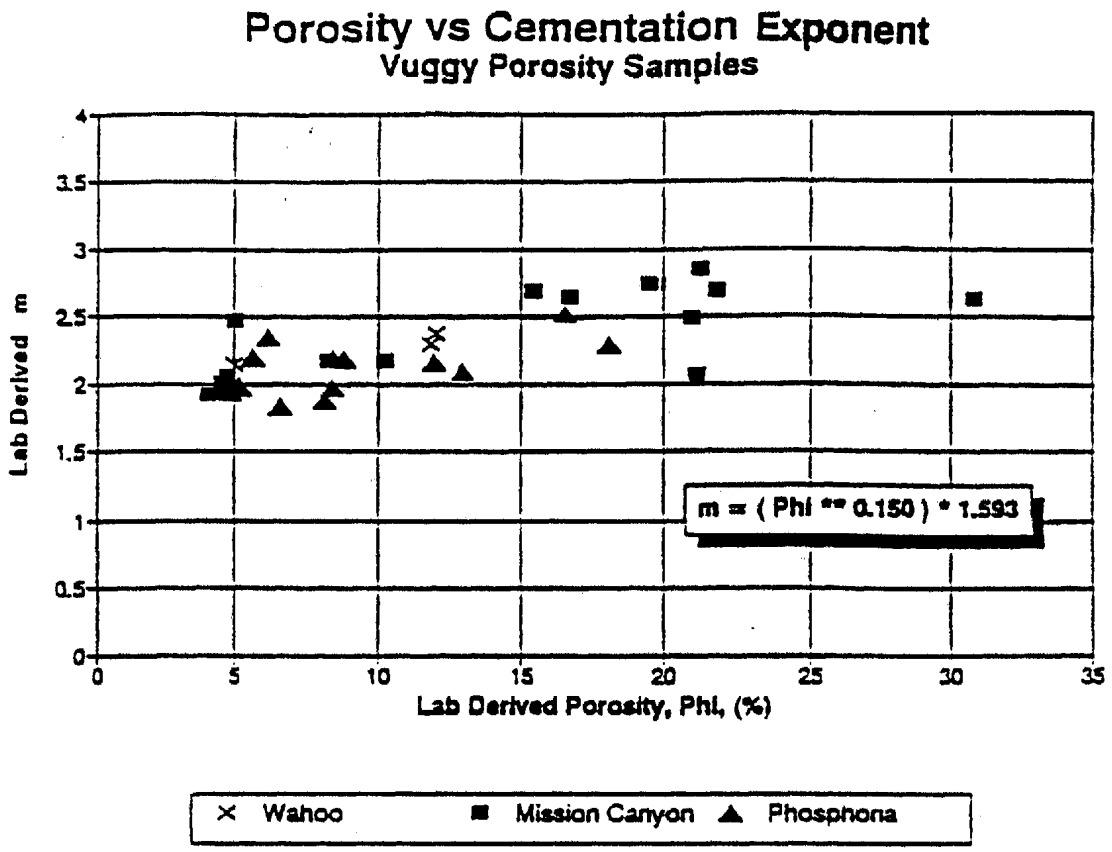
A


Porosity vs Permeability
Vuggy Porosity Samples
Log k = 0.15 (Phi) - 1.57
Measured Air Permeability, k, (md)
10000
1000
100
10
1
0.1
0.01
0
5
10
15
20
25
30
35
Lab Derived Porosity, Phi, (%)
Wahoo
Mission Canyon
Phosphoria

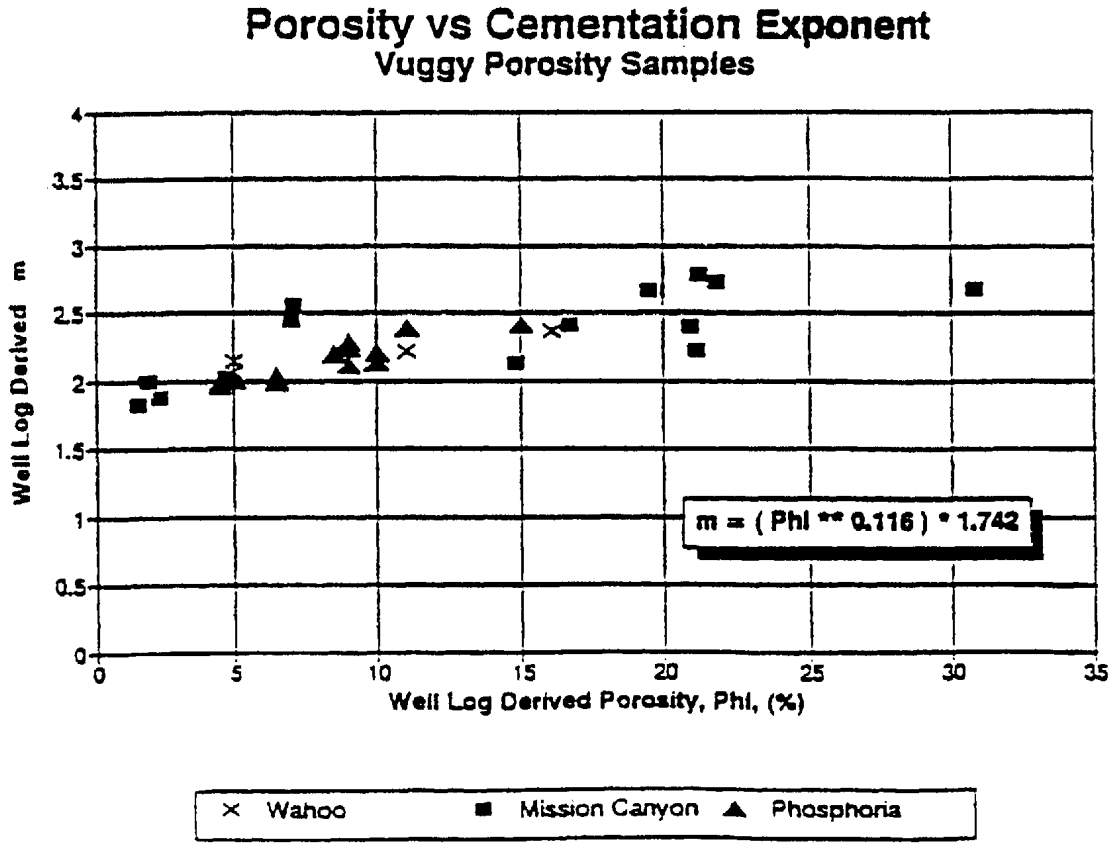
B


Porosity vs Permeability
Vuggy Porosity Samples
Log k = 0.12 (Phi) - 1.16
Measured Air Permeability, k, (md)
10000
1000
100
10
1
0.1
0.01
0
5
10
15
20
25
30
35
Well Log Derived Porosity, Phi, (%)
Wahoo
Mission Canyon
Phosphoria

C

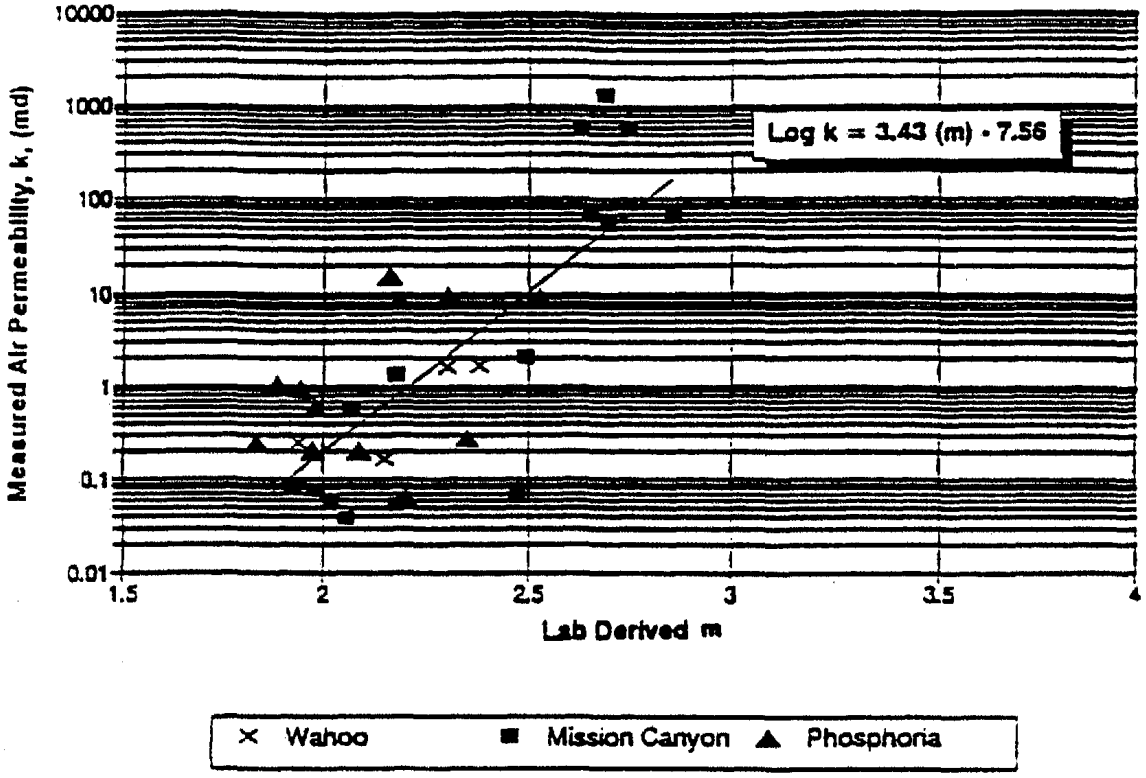

Porosity vs Cementation Exponent
Vuggy Porosity Samples
Lab Derived m
Lab Derived Porosity, Phi, (%)
m = (Phi ** 0.150) * 1.593
Wahoo
Mission Canyon
Phosphoria

D


Porosity vs Cementation Exponent
Vuggy Porosity Samples
Well Log Derived m
Well Log Derived Porosity, Phi, (%)
m = (Phi ** 0.116) * 1.742
Wahoo
Mission Canyon
Phosphoria

Cementation Exponent vs Permeability
Vuggy Porosity Samples

E



Cementation Exponent vs Permeability
Vuggy Porosity Samples

F

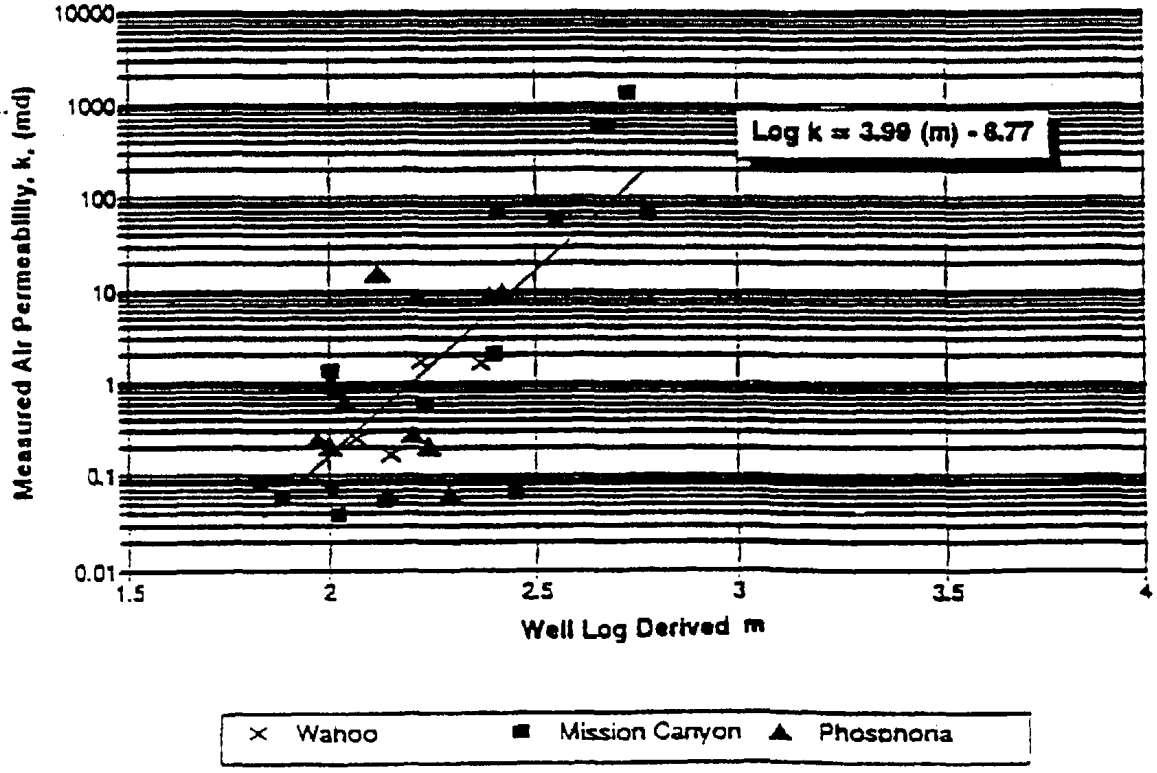


Figure 12. Plots prepared based on the data taken from samples containing predominantly intercrystalline porosity. All the graphs were made with only lab derived information. The last graph is a comparison of the data from this study with the Shell-TTU data.

Correlation coefficients are as follows:

A. R = 0.92

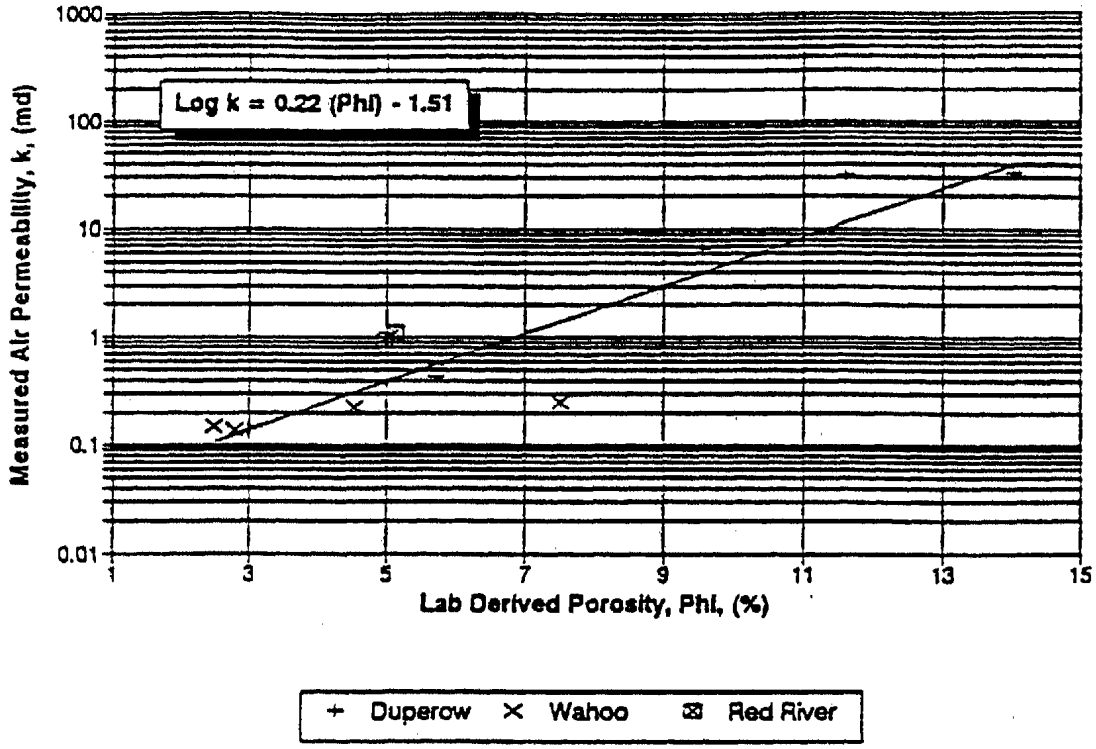
B. R = 0.87

C. Power function equation is on the graph.

D. Power function equation is on the graph.

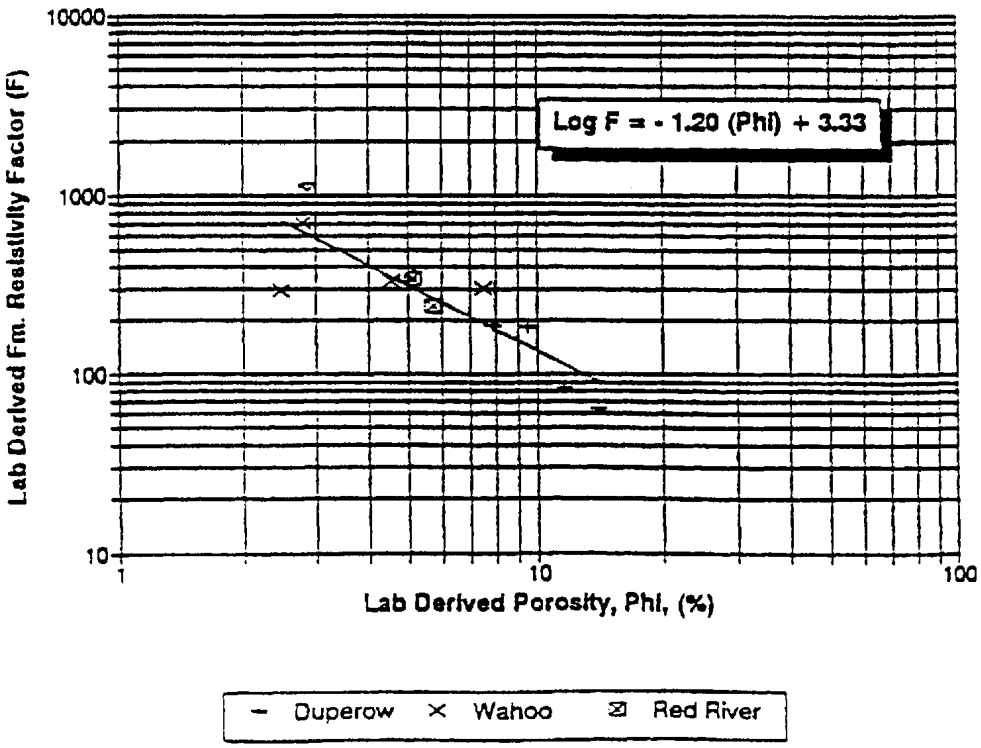
Porosity vs Permeability
Intercrystalline Porosity Samples

A

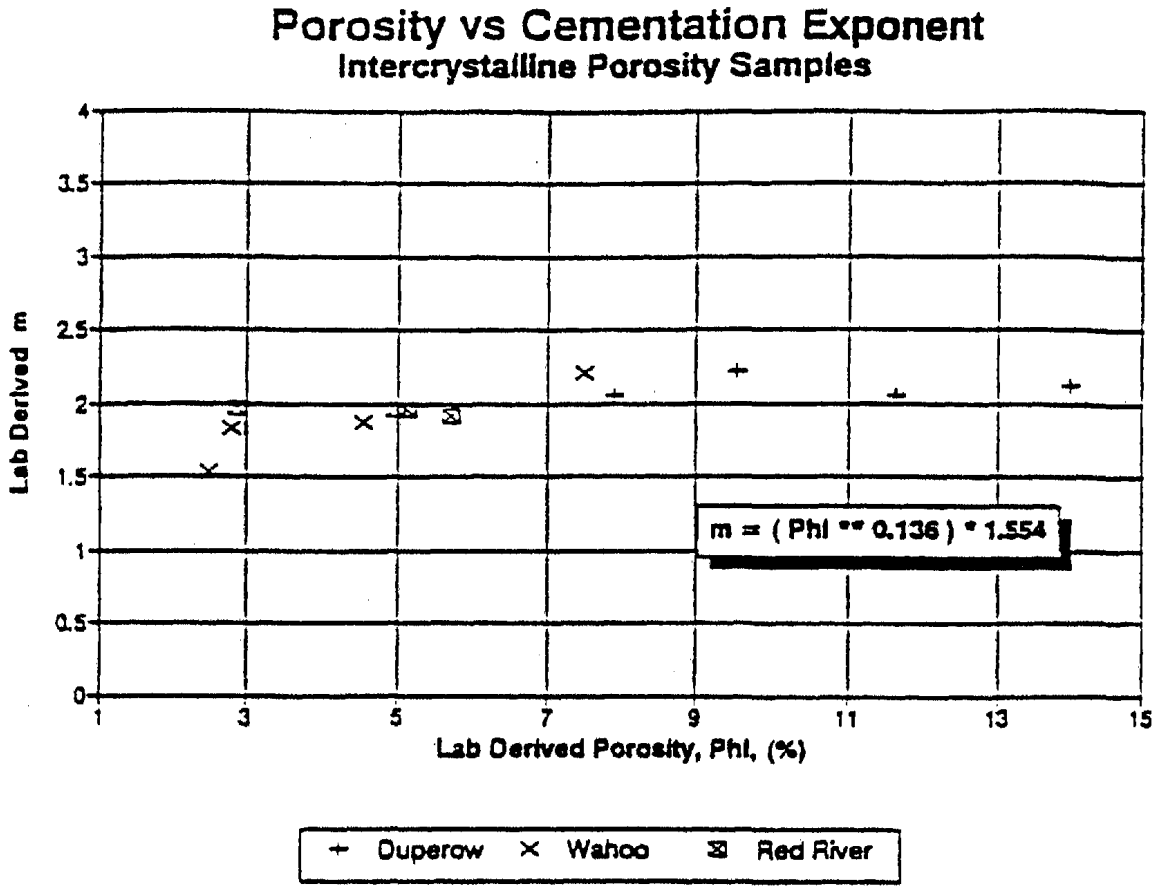


Porosity vs Fm. Resistivity Factor
Intercrystalline Porosity Samples

B



C


Porosity vs Cementation Exponent
Intercrystalline Porosity Samples
Lab Derived m
Lab Derived Porosity, Phi, (%)
m = (Phi ** 0.136) * 1.554
Duperow
Wahoo
Red River

D

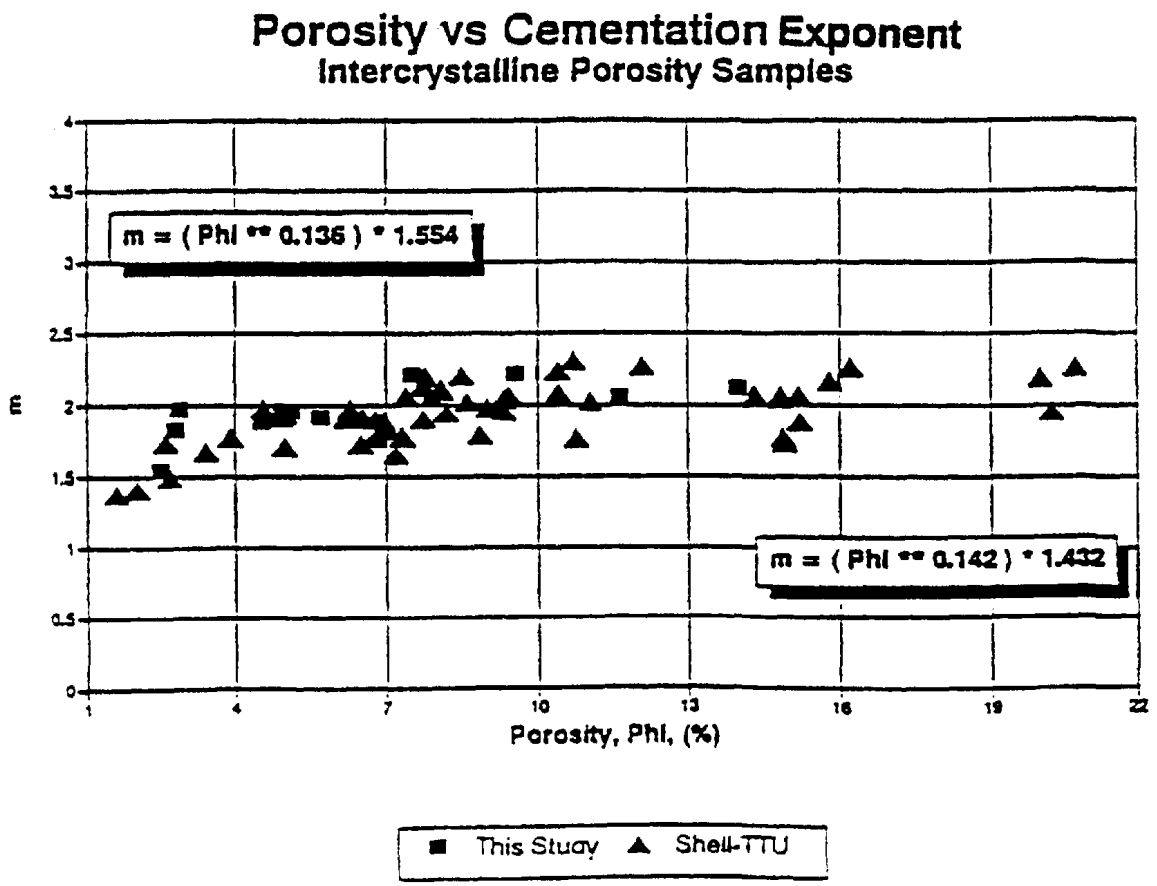

Porosity vs Cementation Exponent
Intercrystalline Porosity Samples
m
Porosity, Phi, (%)
m = (Phi ** 0.136) * 1.554
m = (Phi ** 0.142) * 1.432
This Study
Shell-TTU

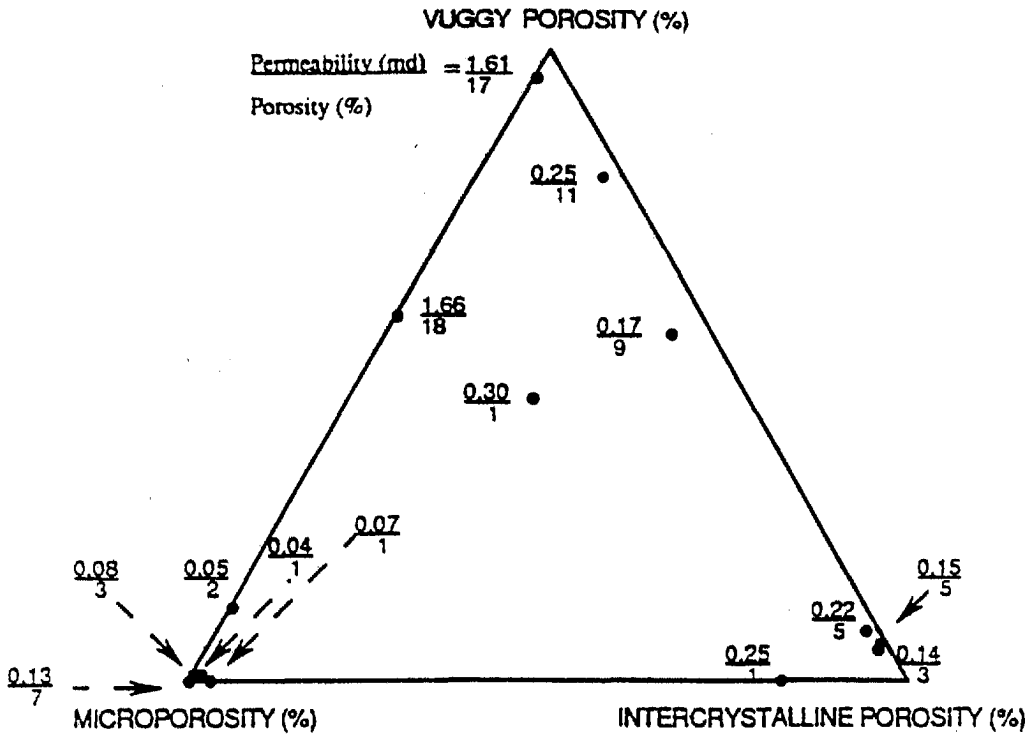
Table 2. Porosity types in the samples are shown in percent. This data is from a 300-point-count of the thin sections.

Sample No	Formation Name	Vuggy Por. (%)	Micropor. (%)	Intercrystal. Por.(%)	Channel Por.(%)
7	Charles Salt	71	0	29	0
8	Charles Salt	38	4	59	0
49	Charles Salt	51	17	31	0
87	Charles Salt	98	0	2	0
88	Charles Salt	32	10	58	0
89	Charles Salt	70	0	30	0
6	Duperow	35	0	58	7
11	Duperow	4	0	96	0
13	Duperow	15	0	80	5
14	Duperow	16	0	84	0
45	Duperow	58	0	24	18
51	Duperow	54	0	38	8
61	Duperow	58	0	38	4
90	Duperow	34	0	56	10
91	Duperow	33	0	60	7
92	Duperow	33	0	67	0
93	Duperow	34	0	64	2
62	Wahoo	58	42	0	0
63	Wahoo	1	99	0	0
64	Wahoo	1	98	1	0
65	Wahoo	12	88	0	0
66	Wahoo	45	30	25	0
67	Wahoo	0	18	82	0
68	Wahoo	0	100	0	0
69	Wahoo	96	4	0	0
70	Wahoo	0	97	3	0
71	Wahoo	8	2	90	0
72	Wahoo	80	3	17	0
73	Wahoo	5	2	93	0
74	Wahoo	6	1	93	0
75	Wahoo	55	6	39	0
24	M. Canyon	91	7	0	2
22	M. Canyon	67	33	0	0
2	M. Canyon	74	26	0	0
25	M. Canyon	88	8	0	4
41	M. Canyon	27	73	0	0
60	M. Canyon	97	2	0	1
9	M. Canyon	23	65	0	12

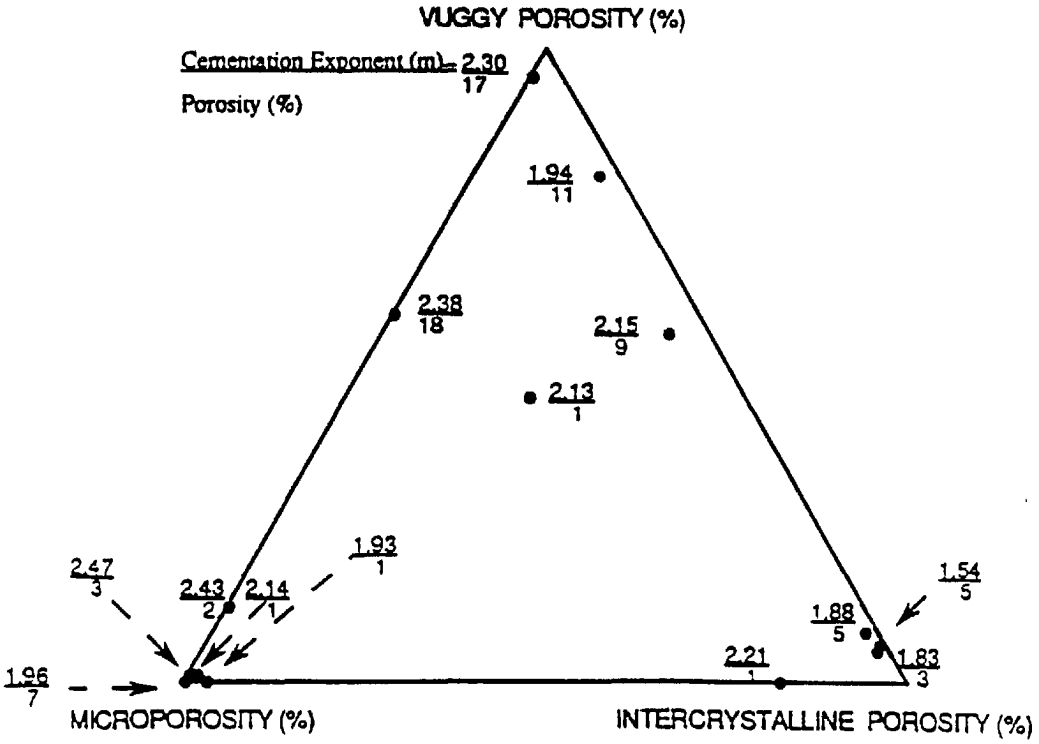
Figure 13. Ternary plots based on the porosity types provided from point counting of thin sections for all formations.

A. Porosity and permeability values for each sample.

B. Porosity and cementation exponent (m) values for each sample.



WAHOO FORMATION



WAHOO FORMATION

Wahoo Formation:

The Wahoo Formation, unlike the other formations shows more scattering on the ternary diagrams. There is no predominant porosity type (vuggy, intercrystalline, and microporosity), but rather the data points are distributed among the three poles. Most of the high permeability values are located in the vuggy porosity corner. The cementation exponent data are concentrated near the poles.

Charles Salt Formation:

The Charles Salt Formation is composed of a combination of vuggy and intercrystalline porosities. The plot shows a trend of higher permeability with higher vuggy porosity percentage. A similar trend can be seen in the cementation exponent toward vuggy porosity.

Duperow Formation:

The Duperow Formation consists predominantly of intercrystalline porosity with lesser amounts of vuggy porosity. With some exceptions, permeability values appear to increase with increasing vuggy porosity (more data is needed to document this relationship). Although the two highest cementation exponents are located closer to the vuggy porosity corner, there is not a clear trend in any direction. This might be due to the presence of channel porosity which probably lowered values of the cementation exponents.

Mission Canyon Formation:

The data points for the Mission Canyon Formation are clustered between vuggy and microporosity, but closer to the vuggy porosity corner. Except for a few data points, permeability values, overall, tend to be higher with increasing

vuggy porosity. The cementation exponents also tend to have higher values with increasing percentages of vuggy porosity.

Red River Formation:

Red River Formation is characterized by a combination of vuggy and intercrystalline porosities with minor amounts of microporosity. The permeability values are randomly distributed. This random distribution can be seen in the cementation exponents as well. Cementation exponents are generally less than 2.0.

Phosphoria Formation:

The Phosphoria samples are clearly dominated by vuggy porosity. It is difficult to see any meaningful distribution in permeability values or cementation exponents. However, the cementation exponents are generally greater than 2.0.

Diagenesis:

This section describes the diagenetic history of each of the formations studied. One of the main purposes of this study is to determine the impact of diagenesis upon the pore geometry. For example, dissolution can either create pores or enlarge existing pores, whereas, cementation can destroy or modify the pore geometry.

Wahoo Formation:

The samples of the Wahoo Formation used in this study can be divided into two groups. The first group is characterized by dolomitized mudstone, and biosparite (bryozoans, echinoids, brachiopods). The second group is

pervasively dolomitized and is represented by mosaic or interlocking coarse dolomite crystals. Their paragenetic sequences differ slightly, however, there is a common paragenesis for the two groups:

1. Deposition of the original sediments.
2. Dissolution: minor for the first group of rocks, however, the second group of samples have undergone intensive dissolution creating vuggy porosity.
3. Dolomitization: in the first group, dolomitization is cryptocrystalline. The second class of rocks underwent pervasive dolomitization which formed a mosaic of coarse interlocking dolomite crystals. The interlocking nature of the crystals greatly reduced the permeability of the rocks.
4. Silicification: both carbonate grains and matrix underwent replacement by silica.
5. Cementation: precipitation of sparry calcite cement between carbonate grains in the first category samples greatly reduced their porosity and permeability.
6. Fracturing: some fracturing took place in both groups.
7. Precipitation of sparry calcite in void spaces and fractures; mostly in the second group samples.

Charles Salt Formation:

The samples of Charles Salt Formation used in this study are characterized by sucrosic dolomite. Porosity is a combination of both intercrystalline and vuggy. The diagenetic history is as follows:

DISCUSSION

The cementation exponent of the core samples was determined using a special technique. Most of the relationships among the various petrophysical values are as expected. However, the relationship of the cementation exponent to permeability and cumulative hydrocarbon production was not as expected: the relationship between m and permeability did not give a positive best-fit, and the m versus production plot failed to show any meaningful relationship.

Analytical Techniques:

Measurement of m in carbonate rocks containing vuggy porosity (especially those with open vugs on the surfaces of cores) requires a special core analysis technique (see methods section), unlike other carbonates and sandstones. Inaccurate measurements were produced when standard analytical techniques were applied to carbonate samples containing surface vugs. The open surface vugs do not hold the brine and therefore the weights of 100 percent brine saturated samples were not accurate. This caused the porosity and therefore the cementation exponent to be incorrect.

Permeability and Porosity:

The permeability and porosity data show a large range of values due to the heterogeneity of the carbonate formations studied. The combination of vuggy and channel porosities produced the highest permeability in the samples. This combination occurs in the Mission Canyon Formation, but not in the other formations studied. The lowest permeability values are observed in the Wahoo and Red River Formations, and result from the tightly interlocking dolomite-crystal fabric (Fig. 14) and anhydrite occluding void spaces in these rocks.

the cementation exponents are not high enough to be effective. In other words, the pore path (tortuosity) is not complex enough to influence permeability and production. In order for m to affect water saturation or hydrocarbon production, it must be at least 3 or over. This can be observed clearer in Figure 2. Also as mentioned in the results section, reservoir pressure, reservoir shape, and other parameters could affect the relationship between m and production.

Petrographic Analysis:

Diagenesis played a very significant role in forming the porosity types and rock textures of the formations. For example, vuggy porosity is a direct result of non-selective dissolution, whereas intercrystalline porosity is due to dolomitization. The predominant vuggy porosity in the Mission Canyon Formation produced relatively high cementation exponents. The Duperow Formation, which has mainly intercrystalline porosity, has cementation exponents around 2.0. Where there is great variation in porosity type, such as in the Wahoo Formation, cementation exponents show a broad range from 1.54 to 2.47.

CONCLUSIONS

The following conclusions were reached:

1. Determination of m in carbonate rocks is more complex than in sandstones and requires greater care and special core analysis techniques. For example, carbonate cores containing large openings or open vugs on their surfaces cannot be treated the same way as sandstones or erroneous values will be obtained.

2. The well log-derived formation evaluation data correlate strongly with the lab-derived results. This proves the utility of well logs (which are more economical than coring) in the determination of m.

3. The measured permeability data shows a broad range of values (0.04-1501.31 md). This results from depositional and diagenetic heterogeneities in the carbonate formations studied.

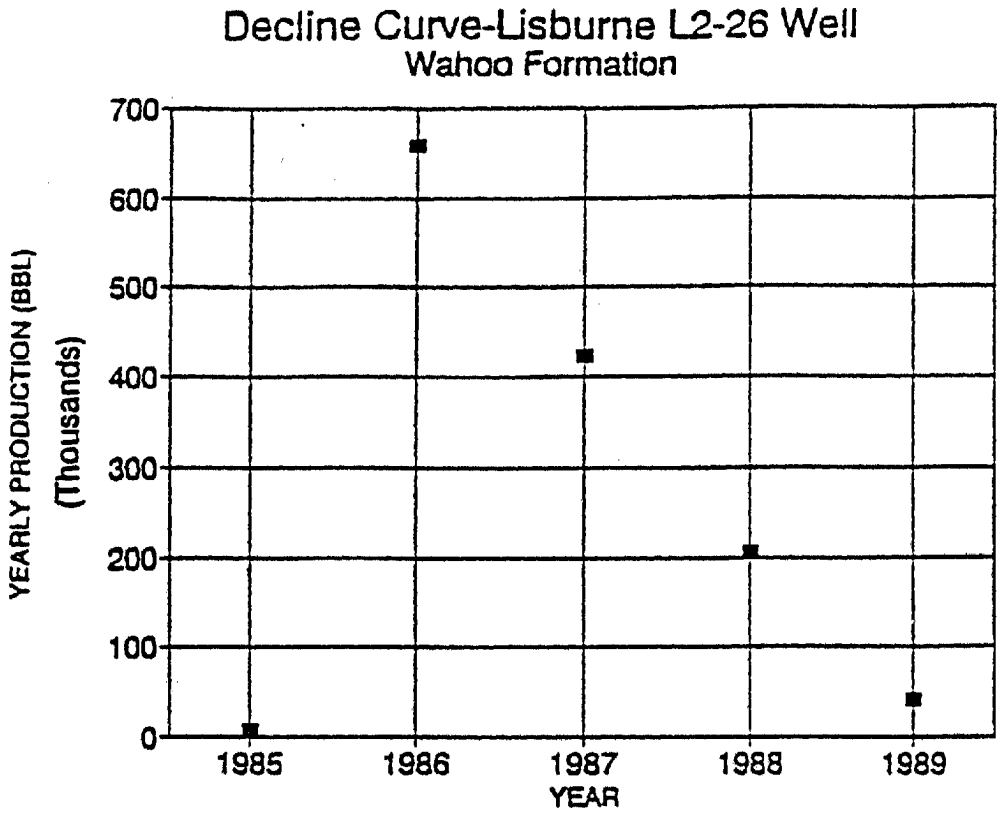
4. Samples characterized by a combination of vuggy and channel porosity have high permeability, whereas those characterized by tightly interlocking dolomite crystals have low permeability. Pore-filling anhydrite can also reduce permeability.

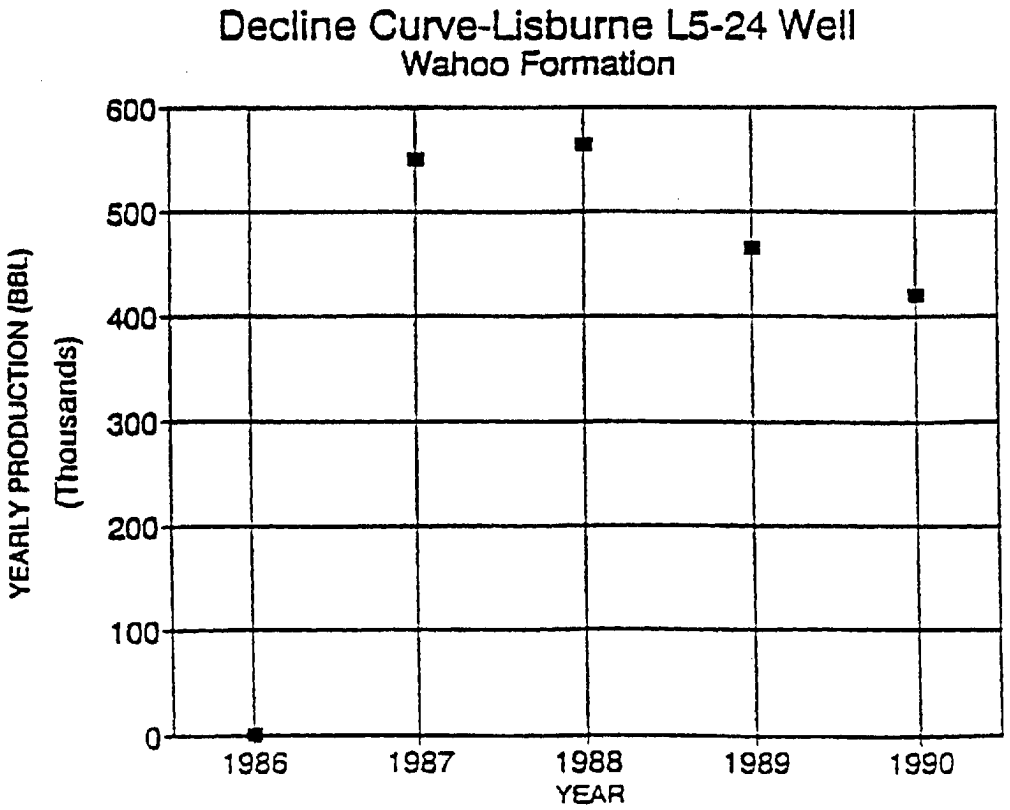
5. The cementation exponent decreases with decreasing porosity in low-porosity carbonates.

6. The correlation between porosity and permeability is almost identical

to the correlation between m and permeability. This indicates that porosity is themajor factor affecting permeability whereas m does not show an effect on permeability. The cementation exponent and permeability both show relationships with the surface area and other dimensions of void spaces. This relationship might not be strong enough because the flow of electrical current through water-filled capillaries in rocks is much more efficient than the flow of hydrocarbons through the same capillaries.

7. The expected relationship between the cementation exponent and production could not be established. This is probably due to the fact that the cementation exponents are below 3.0 and other variables could not be constrained (i.e., reservoir pressure, reservoir shape, etc.). The cementation exponent can affect both permeability and hydrocarbon production whenever it is over 3.0.


Decline Curve-Lisburne L2-26 Well
Wahoo Formation
YEARLY PRODUCTION (BBL)
(Thousands)
700
600
500
400
300
200
100
0
1985
1986
1987
1988
1989
YEAR


Decline Curve-Lisburne L5-24 Well
Wahoo Formation
YEARLY PRODUCTION (BBL)
(Thousands)
600
500
400
300
200
100
0
1986
1987
1988
1989
1990
YEAR