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DISPERSIVITY AS AN OIL RESERVOIR ROCK CHARACTERISTIC

Annual Report for the Period
October 1, 1985 - September 30, 1986

By
Donald E. Menzie
Subijoy Dutta

March 1987

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Performed Under Contract No. AC19-85BC10851

University of Oklahoma
Norman, Oklahoma

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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**Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy**

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PREFACE

During the past year this research has clarified several fundamental concepts about dispersivity, and has established significant evidence of dispersivity as an oil reservoir rock characteristic. A composite picture of the results obtained and correlations developed this far is presented in this report.

ACKNOWLEDGMENTS

The support of this project by the US Department Of Energy has been essential in developing the standard experimental technique for determination of dispersivity as a new reservoir rock characteristic. The cooperation and encouragement of our research effort by colleagues in the Petroleum & Geological Engineering Department and administrators of the University of Oklahoma are gratefully appreciated.

We would like to acknowledge the invaluable contribution of Reza S. Shadizadeh in obtaining a progressively better experimental data. The sincere help and integrated effort of Mark J. Warner, another graduate assistant, in this project is also appreciated. A significant input has also been made by a visiting scholar, Dr. Multar A. El-Ageli, who is now back in his parent country, but who is expected to work in this project again sometime next year.

Special appreciation is expressed to Mr. Bryan L. Watts for providing a computer for the wordprocessing of this report. We would like to thank Karen D. Hinkle for her sincere effort in preparing the manuscript for this report and all other reports submitted to DOE during the past year.

OBJECTIVE

The ultimate goal of this project is to establish dispersivity, α_d , as an oil reservoir rock property. The following investigations are being made at the University of Oklahoma as intermediary steps towards the final goal of this project:

1. To determine a standard technique for evaluating the dispersion characteristics of an oil reservoir rock.
2. To establish a correlation of dispersivity, α_d , with other core characteristics.
3. To evaluate the impact of physical properties of miscible and immiscible fluids on the dispersion characteristics of reservoir rocks.
4. To establish a relationship between the dispersivity α_d , of a reservoir rock and its relative permeability and capillary pressure curves.
5. To evaluate the effect of dispersivity, α_d , on the sweep efficiency of an EOR flood.

SCOPE OF WORK

In the second year of the project we plan to run more tests on cores with high permeability, and also use the conductivity method to determine the effluent concentrations. The correlations developed so far between dispersivity and other core characteristics will be verified and modified, if necessary, in this year. A relationship between dispersivity, α_d , of a reservoir rock and its relative permeability and capillary pressure characteristics are also scheduled to be investigated.

PERSONNEL INVOLVED

Principal Investigator:	Donald E. Menzie
Research Associate:	Subijoy Dutta
Graduate Assistants:	Reza S. Shadizadeh Mark J. Warner
Visiting Scholar:	Muttar A. El-Ageli

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ABSTRACT

The main objective of this research project is to establish dispersivity, α_d , as an oil reservoir rock characteristic and to use this reservoir rock property to aid in enhancing crude oil recovery. A second objective is to compare the dispersion coefficient and the dispersivity of various reservoir rocks with other rock characteristics such as: porosity, permeability, capillary pressure, and relative permeability. The dispersivity of a rock was identified as one of its physical property by measuring the mixing of two miscible fluids, one displacing the other in a porous medium.

A core was 100% saturated with a liquid oil product (resident fluid) which was displaced by injecting a miscible liquid (displacing fluid). Samples of fluid produced from the outlet end of the core were analyzed for determining the percentage of the resident and the displacing fluid in the producing end. The extent of the spread of the concentration front (mixing) was measured from these samples by use of a refractometer after calibration with the specific fluids. The miscible liquids consisted of crude oil, naphtha and various mixtures of oil products. Mixtures of miscible liquids were used in order to obtain equal viscosity fluids.

Several physical and flow characteristics were measured on the same core in order to investigate the correlation with dispersivity.

A standard technique for measuring the dispersion coefficient, k , and the dispersivity, α_d , of an oil reservoir rock has been proposed. While conducting this research, a new low-cost, and rapid method of coating cores for laboratory flow studies has been developed.

Dispersion coefficients and dispersivities for several Berea sandstone cores were determined and attempts were made to correlate with other standard oil reservoir rock characteristics. A direct relationship between dispersivity and total permeability was observed from the laboratory data. A correlation was also developed to correct for the difference in the viscosities of the two miscible fluids. A new method of calculating the relative permeability ratio of a miscible system was also proposed. Other correlations for dispersivity being attempted were Koal's heterogeneity factor (H-factor) and Peclet number.

1.0 SUMMARY OF FISCAL YEAR-1986 STUDIES

1.1 Introduction:

The unsteady mixing of two miscible fluids displacing one another in a porous medium is governed by the dispersion phenomenon. In a microscopically disordered porous medium, two basic mechanisms drive the dispersion process. They rise from the chaotic nature of the porelevel velocity field forced on the flowing fluid by the irregularity of the porespace.¹¹ In a disordered porous medium streamtubes get disrupted and continually break-up and rejoin at the junctions of flow passages. This leads to a wide variation in length of streamlines traversing the system, which is considered to be the kinematic mechanism of dispersion. As a result of changing pore geometry, orientation, and local pressure gradient of a streamline, the speed along the streamline varies considerably in traversing the medium. These two basic mechanisms cause a concentration front of fluid particles to spread as it advances through the system. The extent of the spread of the concentration front of the fluid particles depends upon the dispersivity of the medium. This experimental study is designed to investigate the correlation of dispersivity with other reservoir rock characteristics.

The first step in this project was to establish a standard technique for measuring dispersivity, α_d , of an oil reservoir rock. Different techniques were tried both on sandpacks and core samples of actual reservoir rocks. A new core-mounting method, using liquid metal, was developed which is also simple, economic and safe.

Cores mounted with this new technique can be safely used against any leaks for high pressure displacements.

Two different techniques for measuring effluent concentrations were used- (i) using conductivity meter, (ii) using refractometer. More accurate and reliable results were obtained by the refractometer technique. Other techniques, such as distillation, tracers, and ion analyzer etc. were not used since they required different lab setups and the refractometric system yielded satisfactory results.

1.2 Correlation Of Dispersivity With Other Physical Characteristics

Of Rocks:

Core's heterogeneity factors (H-factors) for different experimental runs were determined. The H-factors were found to be higher for rocks with higher dispersivity. The method of determining the H-factor and the corresponding values for different experimental runs are shown in the latter part of this report.

The variation in permeability ratio of the displaced fluid (oil) to the displacing fluid (Naphtha), k_o/k_N vs. saturation was determined by using a new technique. The permeability ratio decreased with decreasing saturation of the displaced fluid. This observation matches with the established pattern of change in relative permeability with saturation. Details of this permeability ratio determination from the experimental data of dispersivity runs are shown in the latter part of this report.

An empirical equation for viscosity ratio correction has been developed for obtaining a standard dispersion coefficient. A standard dispersion coefficient (K_s) is defined as the dispersion coefficient obtained from a miscible flooding process with a viscosity ratio of resident fluid to the displacing fluid ($\mu_r/\mu_d = 1$) as one.

The dispersion coefficient, K , and the dispersivity α_d , of reservoir rocks were found to increase with the total permeability, k , of the rock.

The Peclet Number, Pe , has been determined for different experimental runs and correlated with the concentration profiles and washout Functions. Theoretical variations of concentration profiles and Washout Functions with dimensionless time were also plotted and compared with the experimental profile. The theoretical and the experimental profile match each other closely.

A brief description and illustrations of the laboratory observations and determinations are furnished in the latter part of this report.

1.3 Status and Accomplishments:

The following accomplishments have been made during the past year :

- (a) A standard technique has been developed for measuring the dispersion coefficient, K , and the dispersivity, α_d , by using a refractometer, and a positive displacement pump.
- (b) A new metallic method of coating oilfield cores for laboratory studies has also been developed in this study.
- (c) A correlation of dispersivity, α_d , with Koval's heterogeneity factor (H-factor) was made.
- (d) The variation in relative permeability ratio of the displaced fluid to the displacing fluid with saturation changes of the displaced fluid was determined, using a new technique. The relative permeability variation for a miscible flooding system was thus obtained from the dispersivity runs.
- (e) A direct relationship between the permeability of a reservoir rock and its dispersion coefficient, K , has been established for Berea sandstone.
- (f) A new correlation to correct the viscosity effect on the dispersion coefficient, K , has also been developed.

In the coming year experimental results will be obtained on several core samples in order to investigate the impact of the physical properties of the displacing and the displaced fluids on the dispersivity. The relative permeability, capillary pressure, Koval's heterogeneity factor, absolute permeability, porosity, and the grain size distribution data will be measured for the same core samples. It is planned to measure and correlate these rock properties with the measured dispersivity.

2.0 EXPERIMENTAL METHOD OF DETERMINATION OF DISPERSIVITY

A series of experimental runs were made on Berea sandstone cores in this phase of the study. The core samples had different porosities and permeabilities.

2.1 Experimental Setup:

A schematic diagram of the experimental setup is shown in Figure 1. From a block of Berea sandstone, 2" diameter cores were drilled by using a coring bit. The cores were then dried in an oven for 48 hours at a temperature of 230°F.

The Berea cores were coated with epoxy coating in the conventional manner for conducting the runs, but were found to be vulnerable to severe damage and leakage at pressures higher than 30 psig. Moreover, channeling of fluid through the coating and sandstone interface was evident. Also, penetration of epoxy into the core sample was another matter of concern.

A new core mounting technique developed to overcome the aforementioned problems involved coating a core with liquid weld, (which is commercially available as J-B Weld), and heavy duty aluminum foil. A coating of liquid weld was first applied on the core and then a coating of heavy duty aluminum foil was applied. The same coatings were repeated several times in the same sequence and the core was mildly heated for early solidification of the liquid weld. The core was uniformly rotated while being heated mildly for 2 hours and left for 24 hours for complete solidification of the coating. Three pressure-holding clamps were also used on the core for safety and better manageability of the core assembly.

FIGURE 1 SCHEMATIC DIAGRAM OF EXPERIMENTAL SETUP

The liquid-metal-coated core was then held at the ends by two aluminum end-plates. Two rubber gaskets were placed between the end plates and the core surface in order to prevent any leakage from the sides. The core assembly was then tested under water for leakage up to 90 psig by injecting air from one end into the core. When no leak was observed the core assembly was considered ready for experimentation. However, before beginning the actual experimental run the core was again oven-dried for 48 hours and the dry weight of the assembly was recorded first at the outset of the experimental run.

The complete experimental setup used for the miscible flooding process consisted of a high pressure, variable volumetric rate, positive displacement pump, graduated cylinders, 1/8" stainless steel tubing, pressure gauge, and a wet test meter (flowmeter).

2.2 Theory and Procedure:

The porosity and permeability of the core was first determined. Air was injected through the core and the flow rate at the outlet was measured by a wet test meter at a certain stable inlet pressure. Similarly, at different inlet pressures these values were recorded and the corresponding permeabilities were calculated by the equation:

$$k = \frac{2q\mu LP_2}{A(P_1^2 - P_2^2)}$$

where:

- q = flow rate in cc/sec
- μ = dynamic viscosity in cp
- L = length of the core, cm
- P₂ = Outlet pressure in atm.
- P₁ = Inlet pressure in atm.
- A = Cross-sectional area in cm²
- k = Permeability of the core in Darcy

These permeability values were plotted on coordinate paper against $1/\bar{P}$ where $\bar{P} = (P_1 + P_2)/2$. The line passing through these points was extrapolated to infinite pressure i.e. $1/\bar{P} = 0$ to get the total permeability of the core. The permeabilities obtained for different cores are listed under experimental results in the latter part of this report. The total permeabilities of the cores were also checked after initial Naphtha saturation by flowing Naphtha through the cores and determining their liquid permeabilities.

The pore volumes of the cores were determined by saturating the cores completely with Naphtha and weighing the cores to get the weight

of Naphtha in the void volumes which, when divided by the specific gravity of Naphtha, yields the pore volumes of the cores. From the pore volumes and bulk volumes the porosities of the cores were determined.

After the determination of porosity and permeability, the cores were again cleaned by injecting air and drawing a vacuum on the outlet end of the cores. The cleaning process was continued until it matched the dry weight of the cores. The cores were then dried in the oven again and saturated completely with crude oil in Run #4, #5, and #7 for displacement with Naphtha. In Run #6, a mixture of Isooctane (96.75%) and Vegetable Oil (3.25%) was used to saturate the core and was displaced with a mixture of 90% Naphtha and 10% crude oil, termed as NC9010. The viscosity of the displaced fluid was matched with the viscosity of the displacing fluid in Run #6.

During the miscible displacements, the effluent concentrations of the displacing fluid were determined by measuring the refractive index of the effluent mixture and obtaining the concentration values from the calibration curves prepared before the displacement runs. The displacing fluid continued to be injected until the effluent concentration of the displacing fluid reached 95% or more.

The concentration profile against the pore volumes injected at different times during an experiment (Run #6) is shown in Figure 2.

DISPERSIVITY PROJECT
RUN 6
BEREA CORE NO. 3B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL K = 90 MD, POROSITY = 0.181
NC9010 DISPLACING ISOCTANE

FIGURE 2 EFFLUENT CONCENTRATION VS PV INJECTED

Calculations and interpretations of data were performed by plotting the concentration profile versus pore volumes injected and parameter λ vs. effluent concentration of the displacing fluid.

The parameter λ is defined as:

$$\lambda = \frac{\left(\frac{V}{V_p} - 1 \right)}{\sqrt{\left(\frac{V}{V_p} \right)}}$$

where:

V = effluent volume at any time during displacement in cc

V_p = pore volume of core in cc

A plot of λ against concentration is shown on Figure 3. From the resulting straight line of this figure the values of λ_{90} & λ_{10} corresponding to 90% and 10% displacing liquid concentrations were read. The dispersion coefficient, k , was then calculated from the following equation:

$$k = \frac{\bar{U}L}{3.625} \left(\lambda_{90} - \lambda_{10} \right)^2$$

where:

L = length of the core in cm

λ_{90} = λ at 90% concentration of the displacing fluid

λ_{10} = λ at 10% concentration of the displacing fluid

$\bar{U}$ = Average interstitial velocity in cm/sec.

= $q/A\phi$

q = Average injection flow rate in cc/sec.

A = Cross-sectional area of the core in cm^2

ϕ = Porosity of the core as a fraction of the pore volume

DISPERSIVITY PROJECT
RUN 6
BEREA CORE NO. 3B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL K = 90 MD, POROSITY = 0.181
NC9010 DISPLACING ISOCTANE

FIGURE 3 LAMBDA VS EFFLUENT CONC.

Dispersivity, α_d , was then calculated by using the following equation:

$$\alpha_d = K/\bar{U}$$

where:

α_d = Dispersivity, cm.

K = Dispersion Coefficient in cm^2 /sec.

This basic method for the determination of dispersivity remained the same for Run Nos. 4 through 12. A sample calculation of dispersivity for Run #6 is shown on the following page.

2.3 Sample Calculations:

DISPERSIVITY CALCULATIONS

For Core #3B

Run #6

Length of the core, L	=	15.24 cm.
Bulk volume, V	=	308.89 cc.
Cross-sectional area, A	=	20.268 cm ²
Reservoir model temperature, T	=	71° F
Total permeability of the core, K	=	90 mD
Porosity, ϕ	=	18.1%
Pore volume, Vp	=	56 cc
Displacing fluid	=	96.75% Isooctane and 3.25% Vegetable Oil
Displaced fluid	=	90% Naphtha + 10% Crude Oil (NC 9010)
Crude Oil	=	36° API
Average flow rate, $\bar{q}$	=	0.0218 cc/sec.
Average interstitial velocity, $\bar{U}$	=	$\frac{0.0218}{(20.268 \times 0.181)}$
	$\bar{U}$ =	0.0059568cm/sec.

From Figure 3

$$\lambda_{g_o} = 0.3$$

$$\lambda_{l_o} = -0.26$$

Dispersion Coefficient, K, is given by ⁹:

$$K = \frac{\bar{U}L (\lambda_{10} - \lambda_{10})^2}{(3.625)^2}$$

$$= \frac{0.0059568 \times 15.24 (0.3 + 0.26)^2}{(3.625)^2}$$

$$\text{or, } K = 0.0022 \text{ cm}^2 / \text{sec.}$$

Dispersivity,

$$\alpha_d = K/\bar{U} = \frac{0.0022}{0.0059568}$$

$$\text{or, } \alpha_d = 0.369 \text{ cm}$$

2.4 Alternative (Rumer's) Method:

An alternative method used by Rumer¹⁰ to calculate the dispersion coefficient was also used to calculate the values of dispersion coefficient for Run #6 in order to check the accuracy of the method used.

The basic solution of the dispersion equation

$$K \frac{d^2 c}{dx^2} - \bar{U} \frac{dc}{dx} = \frac{dc}{dt}$$

is expressed in a dimensionless form as follows:¹⁰

$$\frac{C}{C_0} = \frac{1/2 \operatorname{erfc} \left(\frac{1-a}{2\sqrt{an}} \right)}{2\sqrt{an}} \dots \dots \dots (1)$$

where 'a' and 'n' are dimensionless terms defined as follows:

$$a = \frac{\bar{U}t}{x} \quad \text{where: } t = \text{time, sec.}$$

$$x = \text{distance, cm.}$$

$$n = \frac{K}{\bar{U}x} \quad \text{where: } K = \text{Dispersion Coefficient, cm}^2/\text{sec.}$$

now, defining

$$P = \frac{(1-a)}{(\sqrt{an})^2} \dots\dots\dots (2)$$

from equation (1) we get:

$$\frac{C}{C_0} = 1/2 \operatorname{erfc}(P)$$

$$\text{or, } \operatorname{erf}(P) = 1 - 2 \left(\frac{C}{C_0} \right) \dots\dots\dots (3)$$

since, $\operatorname{erfc}(P) = 1 - \operatorname{erf}(P)$

The quantity $\left(1 - 2 \left(\frac{C}{C_0}\right)\right)$ was calculated from the

experimental results for each value of t, and the corresponding value of p was then calculated from equation (3).

Also, the term

$$P\sqrt{n} = \frac{(1-a)}{2\sqrt{a}} \dots\dots\dots (4)$$

from equation (2) and (4) P and $P\sqrt{n}$ is known for each value of t,

since, $a = \frac{\bar{U}t}{x} = \frac{\bar{U}t}{L}$

Thus, the slope of the line from a plot of P vs $P\sqrt{n}$ will

give us $\sqrt{n}$ which in turn gives us the value of K since $n = \frac{K}{UL}$

For Run #6 the values of C/C_0 , P , and $P\sqrt{n}$ were calculated as shown in Table 1. From the plot of P vs $P\sqrt{n}$ plotted in X and Y-directions respectively the slope ($\sqrt{n}$) was found to be 0.1589.

$$\text{or, } n = (0.1589)^2 = 0.025249$$

$$\text{or } K = \bar{U}Ln$$

$$= 0.0059568 \times 15.24 \times 0.025249$$

$$t = 0.00228 \text{ cm}^2/\text{sec.}$$

$$\text{Dispersivity, } \alpha_d = \frac{0.00228}{0.0059568} = 0.382 \text{ cm.}$$

TABLE 1 CONCENTRATION PROFILE WITH "p" VALUES FOR RUN #6

No. of Observations	T Seconds	C/Co	P	$P/\sqrt{n}$
1	1491.0	.02000	1.4600	.2733
2	1720.0	.04000	1.2423	.1995
3	1940.0	.08000	.9956	.1388
4	2170.0	.20000	.5959	.0824
5	2383.0	.38000	.2167	.0355
6	2614.0	.54000	-.0711	-.0107
7	2838.0	.68000	-.3309	-.0519
8	3071.0	.78000	-.5470	-.0914
9	3292.0	.87200	-.8041	-.1264
10	3527.0	.93200	-1.0565	-.1612
11	3761.0	.96000	-1.2423	-.1938
12	3993.0	.97200	-1.3571	-.2244
13	4227.0	.98400	-1.5267	-.2537
14	4454.0	.98800	-1.6095	-.2808
15	4716.0	.99200	-2.0741	-.3106
16	4946.0	1.00000	-10.0020	-.3356
17	5172.0	1.00000	-10.0020	-.3592

Note: These values were used to check the dispersivity by an alternative method used by Rumer¹⁰.

3.0 EXPERIMENTAL RESULTS

The experimental data and the results obtained for Run #4 through #7 are summarized in Table 2 and that of Run #8, #9, #10, #11 and #12 are summarized in Table 3.

The effluent concentration profiles for Run #6, #8, #9, #10 and #11 against pore volumes injected are shown in Figures 2, 4, 5, 6, and 7 respectively. The experimental data for each of these runs are also listed in the respective Figures.

Capillary pressure-saturation data were obtained from an experimental run on core #3B. Due to air breakthrough at 25 psig further desaturation was not possible in this run. The capillary pressure is given by the following equation:

$$P_c = P_{nw} - P_w$$

where:

P_c = capillary pressure, Psi

P_{nw} = Pressure of non-wetting phase (air), Psi

P_w = Pressure of wetting phase (oil), Psi

A curve showing the wetting phase saturation vs capillary pressure for this run is shown in Figure 8.

TABLE 2 Experimental Data and Results Obtained for Run #4,5,6, & 7

PARAMETER	RUN #4 (core #1B)	RUN #5 (core #2B)	RUN #6 (core #3B)	RUN #7 (core #3B)
Dispersivity, α_d (cm)	6.17	1.45	0.37	3.3
Dispersion Coeff., K_d (cm ² /sec)	0.023	0.0055	0.0022	0.0165
Porosity, ϕ (%)	22.60	22.60	18.10	18.1
Permeability, k (mD)	225.00	15.0	90.00	90.00
Core Length, L (cm)	13.97	13.97	15.24	15.24
Type of Core	Berea Sand- stone	Berea Sand- stone	Berea Sandstone	Berea Sandstone
Average inter- stitial velocity, $\bar{U}$ (cm/sec)	0.00373	0.00380	0.00595	0.0050
Pore Volume, V_p (cc)	64.05	64.05	56.0	56.0
Viscosity Ratio, $V, (\mu_r/\mu_d)$	17.12	17.12	1.0	17.12

TABLE 3 Experimental Data and Results Obtained for
Run #8, #9, #10, #11, and #12

PARAMETER	RUN #8 (core #3B)	RUN #9 (core #4B)	RUN #10 (core #4B)	RUN #11 (core #5B)
Dispersivity, α_d (cm)	0.072	0.079	3.39	0.12
Dispersion Coeff., k , (cm ² /sec)	0.00037	0.00037	0.0167	0.00564
Porosity, ϕ (%)	18.10	19.60	19.60	19.80
Permeability, k (mD)	90.00	98.00	98.00	143.00
Core Length, L (cm)	15.24	15.24	15.24	15.24
Type of Core	Berea Sand- stone	Berea Sand- stone	Berea Sandstone	Berea Sandstone
Average inter- stitial velocity, $\bar{U}$ (cm/sec)	0.005	0.0047	0.00493	0.00475
Pore Volume, V_p (cc)	56.05	60.45	60.0	61.0
Viscosity Ratio, $V, (\mu_r/\mu_d)$	0.058	0.058	17.12	0.063

TABLE 3 Continued

PARAMETER	RUN #12 (core #5B)
Dispersivity, α_d (cm)	3.93
Dispersion Coeff., K_d (cm ² /sec)	0.0196
Porosity, ϕ (%)	19.80
Permeability, k (mD)	143.00
Core Length, L (cm)	15.24
Type of Core	Berea Sandstone
Average inter- stitial velocity, $\bar{U}$ (cm/sec)	0.005
Pore Volume, V_p (cc)	61.0
Viscosity Ratio, $V, (\mu_r/\mu_d)$	15.88

DISPERSIVITY PROJECT
BEREA CORE NO. 3B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL k = 90 MD, POROSITY = 18.1%
CRUDE DISPLACING NAPHTHA
RUN 8

FIGURE4 EFFLUENT CONCENTRATION VS.PV INJECTED

DISPERSIVITY PROJECT
BEREA CORE NO.4B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL κ = 98 MD, POROSITY = 19.6%
CRUDE DISPLACING NAPHTHA
RUN 9

FIGURE5 EFFLUENT CONCENTRATION VS,PV INJECTED

DISPERSIVITY PROJECT
BEREA CORE NO. 4B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL κ = 98 MD, POROSITY = 19.6 PCT.
NAPHTHA DISPLACING CRUDE
RUN 10

FIGURE6 EFFLUENT CONCENTRATION VS. PV INJECTED

DISPERSIVITY PROJECT
BEREA CORE NO. 5B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL K = 143 MD, POROSITY = 19.8 PCT.
CRUDE DISPLACING NAPHTHA
RUN 11

FIGURE 7 EFFLUENT CONCENTRATION VS. PV INJECTED

CAPILLARY PRESSURE CURVE

DISPERSIVITY PROJECT

CORE NO. 3B

AIR DISPLACING 10W MOTOR OIL

FIGURE 8 CAPILLARY PRESSURE CURVE

4.0 DISCUSSION AND CORRELATION OF DISPERSIVITY

4.1 Permeability Correlation:

The experimental results indicate that of all the relationships observed so far between the dispersion coefficient of a rock and its other physical properties, the most conspicuous relationship is found to exist between the permeability and the dispersion coefficient.

From the experimental results listed in Tables 2 and 3 it may be noted that for the Berea sandstone cores the dispersion coefficient, k , and the dispersivity, α_d , increased with the permeability, k , of the cores. This observation matches the findings of Dutta³ and Harleman et al⁴.

Miscible flooding experiments with Berea sandstone cores conducted by displacing crude oil with naphtha showed a definite linear relationship between dispersion coefficient, k , (cm²/sec.) and permeability k (mD) of the cores. A plot of permeability against dispersion coefficient for different experimental runs is shown in Figure 9.

A generalized equation governing this relationship can be written as:

$$k = a \log (K) + c$$

where:

K = Dispersion Coefficient, cm²/sec

k = Permeability, mD

a, c = constants

DISPERSIVITY PROJECT
PERMEABILITY VS DISPERSION COEFFICIENT
RUN NOS. 4,5, 7, 10, AND 12

FIG. 9 PERMEABILITY VS. DISPERSION COEFFICIENT

For Berea sandstone with Naphtha displacing crude oil having a viscosity ratio (μ_o / μ_n) of 17.12 this empirical equation can be written as:

$$K = 0.01487 \log (k) - 0.012.$$

Similarly, values of these constants for different rocks and different viscosity ratios of the displaced and the displacing fluids can also be determined.

4.2 Viscosity Correlation:

To obtain a standard dispersion coefficient (K_s) a viscosity ratio correction factor was introduced. A standard dispersion coefficient (K_s) is defined as the dispersion coefficient obtained from a miscible flooding process with a viscosity ratio of displacing fluid to the displaced fluid as one, i.e., when the displacing fluid and the displaced fluid has the same viscosity.

During the experimental runs in a Berea sandstone core using different viscosity ratios of fluids, different dispersion coefficients were obtained. Experimental Run #6 was conducted by using a viscosity ratio equal to one. From the results obtained the following empirical relationship was found to match the values of dispersion coefficients.

$$K_s = K \left(\frac{\mu_{\text{resident}}}{\mu_{\text{displacing}}} \right)^n \dots\dots\dots (5)$$

or,

$$k_{\text{a}} = k (V)^n$$

where: k_{a} = Standard dispersion coefficient,
cm²/sec.

k = Dispersion Coefficient at any given
viscosity ratio, cm²/sec.

V = Viscosity ratio of displaced fluid to
the displacing fluid

n = empirical constant exponent

For the Berea core having a permeability of 90.0 mD, the value of the exponent 'n' was determined to be -0.71. The change in the value of this exponent 'n', if any, with rocks of different permeabilities is under investigation.

Equation (5) can thus be written as:

$$k_{\text{a}} = k (V)^{-0.71} \dots\dots\dots(6)$$

Actual value of standard dispersion coefficient, k_{a} , for a Berea sandstone obtained by a viscosity ratio ($V = 1$) and the calculated values obtained by using equation (6) from different experimental runs are listed in Table 4.

In the same manner, if the standard dispersion coefficient, k_{a} , is known, the dispersion coefficient, k , for any given viscosity ratio can be calculated by using equation (6).

TABLE 4 Actual and Predicted Standard Dispersion Coefficient,
 k_s , for a Berea Sandstone Core.

Parameter	Run #6	Run #7	Run #8	
$\mu_{\text{displacing}}$, cp	0.642	0.473	8.1	
$\mu_{\text{displaced}}$, cp	0.642	8.1	0.473	
Viscosity ratio, V	1.0	17.125	0.058	
Standard Dispersion Coefficient, K_s , cm ² /sec. (calculated)	0.0022	0.00218	0.0027	
Dispersion Coeff., k_s , cm ² /sec. (experimental)	0.0022	0.0165	0.00037	
	Run #9	Run #10	Run #11	Run #12
$\mu_{\text{displacing}}$, cp	8.1	0.473	8.1	0.51
$\mu_{\text{displaced}}$, cp	0.473	8.1	0.51	8.1
Viscosity ratio V	0.058	17.12	0.063	15.88
Standard Dispersion Coefficient, K_s , cm ² /sec. (calculated)	0.00278	0.0022	0.0039	0.0027
Dispersion Coeff., K_s , cm ² /sec. (experimental)	0.00037	0.0167	0.00056	0.01963

4.3 Koval's H-factor Correlation

A heterogeneous system is defined as one in which the recovery at one pore volume solvent injected in a matched viscosity flood is less than 99 percent⁵. The degree of heterogeneity of a system is measured by its H-factor. For a homogeneous system $H=1$. The H-factor is defined mathematically by E.J. Koval⁵ as:

$$H = \bar{k}/E$$

where:

$\bar{k}$ is a parameter characterizing the viscosity

effects

E = Effective viscosity ratio

In this study Koval's H-factor was determined for Run Nos. 1 thru 12 as listed in Table 5. A sample procedure for determination of H-factor is shown on the following page.

DETERMINATION OF KOVAL'S HETEROGENEITY FACTOR

$$\bar{K} = HE$$

where: $\bar{K}$ = A parameter characterizing the
viscosity effects

H = Heterogeneity factor

E = Effective viscosity ratio

$$E = (0.78 + 0.22 (V)^{1/4})^4$$

Where: $V = \mu_{\text{resident}} / \mu_{\text{displacing}}$

From Koval's paper⁵ (Eq. 10):

$$V_{PI} \text{ (complete)} = \bar{K} = HE$$

Sample H - Factor calculation:

Run #8

Core #3B

Crude oil displacing Naphtha

$$V = \frac{\mu_r}{\mu_d} = \frac{0.473}{8.1} = 0.058$$

$$E = (0.78 + 0.22 (V)^{1/4})^4$$

$$E = 0.622$$

Pore Volume Injected for complete (100% displacement)

$$V_{PI} = 2.3 \text{ (Figure 4)}$$

$$\text{or, } \bar{K} = 2.3 = H \times 0.622$$

$$\text{or, } H = \frac{2.3}{0.622} = 3.70$$

TABLE 5 DISPERSIVITY AND KOVAL'S H-FACTOR FOR DIFFERENT EXPERIMENTAL RUNS

Run no.	Core no. & type	Dispersion Coeff., λ	Dispersivity α_d	H-factor	Permeability k , (mD)	Length L , (cm)
1	3P Consolidated Sandpack in pipe	9.690	30.76	4.61	481	285.60
2	2p Unconsolidated sandpack in pipe	8.930	21.34	10.59	2466	280.52
3	4p Consolidated sandpack in pipe	6.045	14.97	5.64	325	285.60
4	1B Berea SS	0.0230	6.17	2.00	225	13.97
5	2B Berea SS	0.0055	1.45	2.37	15	13.97
6	3B Berea SS	0.0022	0.37	1.93	90	15.24
7	3B Berea SS	0.0165	3.30	2.20	90	15.24
8	3B Berea SS	0.00037	0.072	3.70	90	15.24
9	4B Berea SS	0.00037	0.079	3.41	98	15.24
10	4B Berea SS	0.0167	3.39	1.72	98	15.24
11	5B Berea SS	0.00056	0.12	5.57	143	15.24
12	5B Berea SS	0.0196	3.93	2.26	143	15.24

It may be noted from the values of the H-factor obtained for different experimental runs that for rocks with a low dispersion coefficient ($k < 0.5$) the H-Factors were also low. The length of the core and the viscosity ratio of the fluids were other important factors contributing to this effect. For Berea sandstone cores between 13-16 cm. length the H-factor values were found to lie around 2.0, whereas for consolidated sandpacks in pipes (slim tubes) between 280-286 cm. length, the H-factor values were found to lie around 5.0. Run #2 was conducted in an unconsolidated sandpack and has no other comparable or similar runs to establish a standard H-factor.

4.4 Permeability Ratio Correlation

Apparently the permeability variations of liquids in a miscible drive have never been calculated and no specific attempt has ever been made to measure the permeability of each liquid in a miscible flood. An attempt was made to calculate the variation in permeability ratio of oil to Naphtha with saturation using the following equations:

$$\frac{k_o}{k_n} = \frac{q_o \mu_o}{q_n \mu_n} = \frac{C q_o}{q_n}$$

where:

k_o, k_n = Permeability to oil and Naphtha respectively
in Darcy

q_o, q_n = Flow rate of oil and Naphtha respectively, in cc/sec

μ_o, μ_n = Viscosity of oil and Naphtha respectively in cp

C = Proportionality factor

DISPERSIVITY PROJECT

BEREA CORE NO. 3B
LENGTH = 15.24 CM, BV = 308.89 CC
TOTAL K = 90 MD, POROSITY = 18.1 PCT.
CRUDE OIL DISPLACING NAPHTHA

RUN NO. 8

FIGURE 10 K_O/K_N VS. OIL SATURATION

During the experiment the oil and Naphtha flow rate was recorded as total effluent and then calculated individually by refractometer analysis of each constituent. Thus, the permeability ratio k_o/k_n was calculated at increasing saturations of the displacing liquid in terms of the flow rate ratio for a certain proportionality factor depending upon the viscosity of the liquids involved. A sample plot of k_o/k_n vs. oil saturation, s_o , for Run #8 is plotted in Figure 10. This permeability ratio profile gives us a perspective of the change in permeabilities of the two liquids with respect to the change in their saturation. As evident from the figure, the permeability ratio (k_o/k_n) increased with the increase in oil saturation. This means either the Naphtha permeability (k_n) decreased with increase in oil saturation or the oil permeability, k_o , increased with oil saturation or both a decrease in k_n and an increase in k_o occurred simultaneously with an increase in oil saturation. This experimental observation matches the established pattern of variation in relative permeability with changes in wetting/non-wetting phase saturation.

4.5 Peclet Number Correlation:

Peclet number is a dimensionless ratio of the product of average interstitial velocity and length divided by the dispersion coefficient. Conceptually it is similar to the ratio of moments. The following equation mathematically defines the Peclet number:

$$Pe = \frac{\bar{U}L}{\epsilon}$$

where:

Pe = Peclet number

$\bar{U}$ = Average interstitial velocity of the
fluid mixtures during the miscible flood
cm/sec.

L = Length of the core, cm.

ϵ = Dispersion coefficient, cm²/sec

Sample calculations of Peclet numbers for different experimental runs are shown on the following page.

The dispersion coefficient, dispersivity, H-factor and Peclet numbers for all the experimental runs (Run #1-12) are listed in Table 6.

SAMPLE CALCULATIONS
OF
PECLET NUMBERS FOR
DIFFERENT RUNS

Run #1

$$Pe = \frac{\bar{U}L}{K} = \frac{0.315 \times 285.6}{9.69} = 9.28$$

RUN #2

$$Pe = \frac{\bar{U}L}{K} = \frac{0.4183 \times 280.52}{8.93} = 13.14$$

Run #3

$$Pe = \frac{\bar{U}L}{K} = \frac{0.4038 \times 285.6}{6.045} = 19.08$$

Run #4

$$Pe = \frac{\bar{U}L}{K} = \frac{0.00373 \times 13.97}{0.0230} = 2.27$$

Run #5

$$Pe = \frac{\bar{U}L}{K} = \frac{0.00380 \times 13.97}{0.0055} = 9.65$$

Run #6

$$Pe = \frac{\bar{U}L}{K} = \frac{0.00595 \times 15.24}{0.0022} = 41.22$$

RUN #7

$$Pe = \frac{\bar{U}L}{K} = \frac{0.0050 \times 15.24}{0.065} = 4.62$$

Run #8

$$Pe = \frac{\bar{U}L}{K} = \frac{0.005 \times 15.24}{0.00037} = 205.95$$

Run #9

$$Pe = \frac{\bar{U}L}{K} = \frac{0.0047 \times 15.24}{0.00037} = 193.59$$

Run #10

$$Pe = \frac{\bar{U}L}{K} = \frac{0.00493 \times 15.24}{0.0767} = 4.50$$

Run #11

$$Pe = \frac{\bar{U}L}{K} = \frac{0.00475 \times 15.24}{0.000564} = 12.84$$

Run #12

$$Pe = \frac{\bar{U}L}{K} = \frac{0.005 \times 15.24}{0.01963} = 3.88$$

TABLE 6 PECLET NUMBERS AND H-FACTORS FOR DIFFERENT
EXPERIMENTAL RUNS

Run No.	Dispersion Coefficient, D (cm ² /sec)	Dispersivity α_d (cm)	H-Factor*	Peclet No. Pe ($\bar{U}L/\kappa$)
1	9.690	30.76	4.61	9.28
2	8.930	21.34	10.59	13.14
3	6.045	14.97	5.64	19.08
4	0.0230	6.17	2.00	2.27
5	0.0055	1.45	2.37	9.65
6	0.0022	0.37	1.93	41.21
7	0.0165	3.30	2.20	4.62
8	0.00037	0.072	3.3	206.00
9	0.00037	0.079	3.4	193.59
10	0.0167	3.39	1.72	4.50
11	0.00475	0.12	5.57	12.84
12	0.01963	3.93	2.26	3.88

* H - Factor is Toval's heterogeneity factor

The partial differential equation governing the dispersion phenomena is commonly expressed as:

$$\frac{k}{dx^2} \frac{d^2c}{dx^2} - \frac{\bar{U}}{dx} \frac{dc}{dx} = \frac{dc}{dt} \dots\dots\dots (7)$$

where:

- k = Dispersion coefficient, cm^2/sec
- dc = Change in concentration
- t = Time in sec.
- dx = Change in distance in the flow directions, cm
- $\bar{U}$ = Average interstitial velocity, cm/sec

The above equation can be written in a dimensionless form in terms of the Peclet number, $Pe = \bar{U}L/k$, and dimensionless time, $\tau = t\bar{U}/L$ as follows:

$$\frac{1}{Pe} \frac{d^2c}{dx^2} - \frac{dc}{dx} = \frac{dc}{d\tau} \dots\dots\dots (8)$$

A simplified solution of the above equation is given by ^{1,7}:

$$\frac{C}{C_0} = \frac{1}{2} \text{erfc} \left(\frac{(1 - \tau)}{2\sqrt{\tau/Pe}} \right) \dots\dots\dots (9)$$

If we define the Washout function, W , as

$$W = \left(1 - \frac{C}{C_0} \right)$$

then:

$$W = 1 - \frac{1}{2} \text{erfc} \left(\frac{(1 - \tau)}{2\sqrt{\tau/Pe}} \right) \dots\dots\dots (10)$$

A plot of theoretical and experimental values of Washout Function, W vs. Dimensionless Time, τ ($\bar{U}t/L$) for the Peclet numbers obtained for Run Nos. 6 and 7 are shown in Figures 11 and 12 respectively.

It may be noticed that for Run No. 6 the theoretical curve very closely matched the experimental profile (Figure 11) due to the matched viscosity flood. The viscosity ratio of the displaced fluid (isooctane) to the displacing fluid (NC9010) was one in Run No. 6.

The viscosity ratio of the displaced fluid (crude Oil) to the displacing fluid (naphtha) was 17.12 in Run No. 7. This is considered to be very high and unfavorable viscosity ratio. The deviation of the experimental values (Figure 12) from the theoretical values in this Run may be attributed to the unfavorably high mobility ratio.

DISPERSIVITY PROJECT
 THEORETICAL AND EXPERIMENTAL VARIATION
 OF WASHOUT FUNCTION VS. DIMENSIONLESS TIME
 RUN NO. 6, PECLET NO. = 41.22

FIGURE 11 THEORETICAL AND EXPERIMENTAL
 WASHOUT FUNCTION VS DIMENSIONLESS TIME
 FOR RUN NO. 6

DISPERSIVITY PROJECT
 THEORETICAL AND EXPERIMENTAL VARIATION
 OF WASHOUT FUNCTION VS. DIMENSIONLESS TIME
 RUN NO. 7, PECLET NO. = 4.62

FIGURE 12 THEORETICAL AND EXPERIMENTAL
 WASHOUT FUNCTION VS DIMENSIONLESS TIME
 FOR RUN NO. 7

5.0 CONCLUSIONS

A standard technique for determining the dispersion coefficient and dispersivity has been developed in this study. By using the dispersion measurement techniques as described in this paper, the extent of unsteady mixing of a resident fluid with the injected fluid in an oil reservoir rock can be determined.

Dispersivities of several Berea sandstone cores were experimentally determined and attempts were made to correlate dispersivity and dispersion characteristics with other rock characteristics. The most significant and direct relationship of the dispersion characteristics was found to exist between the dispersion coefficient and the total permeability of a core.

A correlation has also been developed to correct the viscosity effect of the displacing and the displaced fluid on the dispersivity of a reservoir rock.

Koval's (Koval 1963) heterogeneity factor, H-factor, for the Berea sandstone cores showed some particular trend of variation with the corresponding dispersivities and dispersion coefficients.

The advantages of using the dispersion characteristics of an oil reservoir rock over some of the other characteristics are summarized below:

(i) The absolute permeability of a rock often varies with the types of fluids injected. Whereas the standard dispersion coefficient, K_s , of a core was found to be the same, even when different fluids were used to conduct the displacement experimentations.

(ii) The experimental determination of dispersivity is much simpler and easier than the measurement of absolute permeability of a rock.

While pursuing for a standard technique, a new method of coating the core samples for laboratory studies has been developed during this investigation.

Experimental results are also being obtained on several core samples in order to investigate the impact of other physical properties of the displacing and the resident fluids used in the miscible flooding experiments for determination of dispersivity, and the dispersion coefficient. Several physical characteristics are also being measured on the same core samples for testing other possible relationships with dispersivity. The ultimate goal of this investigation is to determine the dispersivities and standard dispersion coefficients of various reservoir rocks.

6.0 NOMENCLATURE

A = Cross sectional area, sq. cm
 d_p = Particle diameter, cm
 C = Concentration
 D = Diffusivity, $\text{cm}^2/\text{sec.}$
 D_m = Molecular diffusion coefficient, $\text{sq. cm}^2/\text{sec.}$
 H = Heterogeneity factor
 I = Dispersion coefficient, $\text{cm}^2 \text{ sec.}$
 k = Permeability, mD
 q = Volumetric flow rate, cc/sec.
 L = Length, cm
 S = Saturation, % of pore volume
 t = Time, sec.
 T = Temperature, °F
 U = Average Interstitial Velocity, cm/sec.
 V = Volume injected, cc/
 also used as Viscosity ratio.
 V_p = Pore Volume, cc

Greek Letters:

α_d = Dispersivity, cm
 ϕ = Porosity, %
 $\lambda = [(V/V_p) - 1]/(\sqrt{V \cdot V_p})$
 μ = Dynamic viscosity, cp

7.0 RELATED PRESENTATIONS AND PUBLICATIONS

1. S. Dutta, and D.E. Menzie "Dispersivity as an Oil Reservoir Rock Characteristic", paper presented at Montana Tech. Butte, Montana, September, 1984.
2. S. Dutta, and D.E. Menzie "Dispersivity as an Oil Reservoir Rock Characteristic", paper presented at the National Institute for Petroleum and Energy Research, Bartlesville, Oklahoma, August, 1984.
3. D.E. Menzie, S. Dutta, R. Shadizadeh, and M.A. El-Ageli, "Dispersivity as an Oil Reservoir Rock Characteristic", submitted for publication and presentation at the 1987 SPE Meeting.
4. D.E. Menzie, S. Dutta, R. Shadizadeh, "A New Metallic Method of Coating Oilfield Core for Laboratory Studies", submitted in July 1986 for publication in the JPT.
5. D.E. Menzie, S. Dutta, R. Shadizadeh, and M.A. El-Ageli, "Dispersivity as an Oil Reservoir Rock Characteristic", presented in the Southwest Regional Meeting of the American Chemical Society, Houston, Nov. 19-21, 1986.
6. S. Dutta, D.E. Menzie, and R. Shadizadeh, "Identification of a new Rock Characteristic For Economic Selection of Disposal sites for Toxic/Hazardous Waste", to be presented in the Fourth Annual Meeting of the American Society for Surface Mining and Reclamation, March 17-20, 1987, Billings, Montana.
7. R.S. Shadizadeh, and Mark J. Warner "Experimental Determination of Dispersivity as a Reservoir Rock Characteristic for Groundwater Aquifer", presented in the Annual Meeting of the Oklahoma Academy of Science, Tahlequah, Oklahoma, Nov. 14, 1986.

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