1 of 1

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Laboratory Methods for
Enhanced Oil Recovery Core Floods

Topical Report

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ABSTRACT

Current research at the Idaho National Engineering Laboratory (INEL) is investigating microbially enhanced oil recovery (MEOR) systems for application to oil reservoirs. Laboratory corefloods are invaluable in developing technology necessary for a field application of MEOR. Methods used to prepare sandstone cores for experimentation, coreflooding techniques, and quantification of coreflood effluent are discussed in detail. A technique to quantify the small volumes of oil associated with laboratory core floods is described.

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CONTENTS

ABSTRACT	iii
ACKNOWLEDGEMENTS	iv
NOMENCLATURE	vii
INTRODUCTION	1
CORE PREPARATION	1
Core Cutting and Storage	1
Porosity Determination	2
Core Encapsulation	2
Gas Permeability	5
Calculations	6
Core Saturations	7
Brine Saturation	7
Brine Permeability Measurements	8
Calculations	9
Oil Saturation of the Core	10
Calculations	10
WATERFLOOD	11
End Effects	11
Effluent Quantification	12
Waterflood Results	13
ENHANCED (MICROBIAL) FLOOD	15
Microbial Preparations	15
CONCLUSIONS	15
REFERENCES	15

LIST OF FIGURES

Figure 1.	Molded end plates (side and bottom views) used in coreflooding experiments.	3
Figure 2.	Rotating core and end plate holder used during epoxy application.	3
Figure 3.	Cross-section of epoxy coated core with end plates and port fittings attached.	4
Figure 4.	Gas permeameter configuration.	5
Figure 5.	Effect of temperature on viscosity of air and nitrogen.	6
Figure 6.	Schematic of epoxied core saturation device.	7
Figure 7.	Schematic of brine permeability and oil saturation system.	9
Figure 8.	Core flooding system.	11
Figure 9.	Experimental error associated with oil quantification procedure.	13
Figure 10.	Typical room temperature waterflood oil saturation reduction curve for Schuricht crude oil.	14

LIST OF TABLES

Table 1.	Comparison of extrapolated gas permeability and brine permeability.	8
Table 2.	Initial oil saturation values for typical cores.	10
Table 3.	Waterflood residual oil saturations (room temperature) for typical cores.	14

NOMENCLATURE

A	cross-sectional area, cm ²
k_a	absolute permeability or extrapolated gas permeability, mD
k_b	permeability using brine as the flowing fluid, mD
k_g	observed gas permeability at a particular average pressure, mD
L	core length, cm
m	slope, mD-atm
ΔP	differential flowing pressure across core, atm
P_{atm}	atmospheric pressure, atm absolute
P_{ave}	mean flowing pressure in core, atm
$(PQ)_{std}$	pressure and flowrate at standard conditions, atm-mL/s
PV	pore volume of core, mL
PV_{inj}	pore volumes injected, mL
P_1	flowing pressure upstream of core, atm gauge
P_2	flowing pressure downstream of core, atm gauge
Q	flowrate of saturating fluid, mL/s
Q_{ave}	mean gas flowrate through core, mL/s
S_{oi}	initial oil saturation, fraction
S_o^n	oil saturation after any point 'n' in a coreflood, fraction
S_o^{n-1}	oil saturation at the previous point in a coreflood, fraction
t	time, s
u_i	apparent velocity, flowrate/cross-sectional area, cm/s
V_a	aqueous phase volume collected in tube, mL
V_b	volume of brine displaced from core during oil saturation, mL
V_{bulk}	bulk volume of core, mL
V_{grain}	grain volume of core, mL
V_{inj}	volume injected, mL
V_o	oil phase volume collected in tube, mL
W_a	weight of tube plus aqueous phase, g
W_b	weight of brine collected during permeability measurements, g
W_c	weight of core including oil and brine, g
W_d	weight of dry core, g
W_f	weight of collection tube plus fluids, g
W_o	weight of oil in collection tube, g
W_i	weight of empty collection tube, g
W_w	weight of core saturated with 100% brine, g
μ	flowing fluid viscosity, cP
μ_w	water-phase viscosity, cP
ρ_a	aqueous phase density, g/mL
ρ_b	brine density, g/mL
ρ_o	oil density, g/mL
ϕ	porosity, fraction
ϕ_{eff}	effective porosity, fraction

INTRODUCTION

A carefully planned and consistent laboratory coreflooding procedure is an essential part of a successfully implemented field application for most enhanced oil recovery (EOR) projects. Microbially enhanced oil recovery (MEOR) processes are inherently more complex than other EOR processes because it is necessary to understand and control bacterial growth and metabolism in oil field environments in addition to the complexities associated with all EOR applications. To successfully apply MEOR technologies, an implicit understanding of biological and physical parameters and interactions controlling ultimate oil retention and release are necessary. Laboratory investigations involving reservoir rock (cores) are required to determine basic production mechanisms, to optimize the recovery process, to elucidate the complexities associated with MEOR, and to develop a field project design.

Although MEOR was first conceived in 1926¹ and has been actively pursued by numerous researchers since, a broad forum of investigation is still available today. Several historical reviews have been written on MEOR^{2,3,4,5} and recently the technology has been recognized as a "potentially significant process" by the U. S. Department of Energy (DOE).⁶ The application of MEOR has resulted in three dominant areas of activity: (a) use of microbially produced polymers and biomass for increased waterflood sweep efficiency;^{7,8} (b) single well stimulations and wellbore cleanup to recover near-wellbore oil;⁴ and (c) use of bacteria for the in situ generation of surfactants, acids, gasses, and alcohols for enhanced oil recovery.^{9,10,11} Work at the Idaho National Engineering Laboratory (INEL) has primarily been concerned with surfactant based MEOR.

Epoxy encased Berea sandstone cores, 15.24 cm (6 in.) in length and 2.54 cm (1 in.) in diameter, are used for laboratory experiments. The use of these relatively small cores and the method of fluid containment has many advantages in comparison to larger cores traditionally used in laboratory applications; e.g., the experimental system is inherently less costly due to reduced fluid volumes in experimentation, smaller volumes of waste are generated, and coreflood experiments can be run in shorter times. The use of smaller cores results in unique problems associated with effluent quantification. Traditional quantification techniques include the use of volumetrically graduated collection tubes for data collection. The use of small cores makes such quantification techniques difficult, if not impossible, because of the limited effluent volumes. A novel method of coreflood effluent quantification has been developed to quantify the limited effluent volumes associated with smaller cores.

This report describes in detail the procedures and methods for the preparation and flooding of cores used in MEOR research at the INEL. An effort has been made to include all equations, calculations, steps, and procedures used in the coreflooding processes.

CORE PREPARATION

Core Cutting and Storage

Berea sandstone cores used for core flooding experiments are cut from a 30.48 cm (12 in.) cubic block, with a reported permeability range of 400 to 500 mD (Cleveland Quarries Company, Amherst, Ohio). These blocks are halved perpendicular to the bedding plane to form two blocks. Cores 15.24 cm (6 in.) in length and 2.54 cm (1 in.) in diameter are then cut parallel to the bedding plane using a

standard diamond-core drill bit^a with distilled water as the lubricating fluid. The cores are then placed in a 55°C oven for drying and storage.

Porosity Determination

A Boyle's law-type nitrogen porosimeter is used to determine grain volume of core samples having a maximum size of 6 inches in length by 1 inch in diameter. Grain volume measurements are determined by knowing the volume of reference samples and initial and final pressures during measurement.

Effective porosity of the core sample may then be determined from the bulk volume and the grain volume of the sample. Bulk volume of the sample is determined by direct measurement. Pore volume is determined by subtracting the grain volume from the bulk volume. Effective porosity can then be determined by

$$\phi_{eff} = \frac{V_{bulk} - V_{grain}}{V_{bulk}} \quad (1)$$

Core Encapsulation

Dry cores are fitted with molded Insulthane 401^b end plates and encased with Hysol 1C^c epoxy. End plates are injected into teflon molds around male 1/8 in. NPT to 1/8 in. tubing connectors and are designed to eliminate liquid segregation in the core inlet and outlet¹² (see Figure 1). Stainless steel or nylon connectors are used to attach injection and production lines. End plates are not re-used because of their low cost and adherence of the epoxy. Technology used in core encasement is somewhat similar to that used by Phillips Petroleum Company.¹³

A concern for MEOR research is contamination of the system with unknown bacteria. Historically, mechanical core holding devices such as Hassler type core holders have been used to seal cores during corefloods. Removing cores from a holder during preparation and coreflooding procedures can introduce unknown bacteria because of the open core surface. Coating the cores with epoxy reduces the risk of contamination while handling the core during coreflooding procedures.

Berea sandstone cores are not sterilized prior to use. Several methods of sterilization were considered including chemical, radiological, and physical methods. Of the methods evaluated, gamma irradiation (radiological) and ethylene oxide (chemical) were considered advantageous because no residues are left, and changes in geochemical composition are considered negligible. Although attractive, facilities were not available for either treatment. Therefore, indigenous microbial populations of Berea sandstone following cutting and drying were evaluated. As used in coreflood experiments, the sandstone contains less than 600 aerobic colony forming units per gram of material. Anaerobic populations were not detectable following 20 days of incubation. The indigenous populations were cultured and evaluated for

a. Felker Operations, Torrance, CA.

b. Rudolf Bros. and Co., 960 Walnut St., Canal Winchester, OH.

c. The Dexter Company, distributed by Rudolf Bros. and Co., Canal Winchester, OH.

Figure 1. Molded end plates (side and bottom views) used in coreflooding experiments.

emulsification of crude oil (negative), adherence to hydrocarbons (negative), and production of exopolysaccharides (negative). Organisms used in coreflood experiments, such as *Bacillus licheniformis* JF-2, consistently out-competed the indigenous organisms in shake flask experiments.

Epoxy is applied by inserting the core and end plates into an open, rotating core holder (see Figure 2). Epoxy is used to encapsulate the core and secure the end plates to the core ends. Epoxy is prepared according to the manufacturer's instructions in small [120 mL ($\approx \frac{1}{2}$ cup)] plastic disposable

Figure 2. Rotating core and end plate holder used during epoxy application.

containers using disposable wooden tongue depressors as applicators. Working time after mixing the epoxy is about $\frac{1}{2}$ hour; it hardens in 2 hours; 1 day is required to cure; and ultimate hardness is obtained in 5 to 7 days at room temperature. Two or three epoxy applications resulting in a total thickness of $\frac{1}{4}$ inch are applied to both the core and the end plates. Tubing caps are tightened to the inlet and outlet to seal the core and it is then labeled for future identification. A cross-section of an epoxy-encased core with end plates and fittings in place is presented graphically in Figure 3.

Figure 3. Cross-section of epoxy-coated core with end plates and port fittings attached.

An important element of core encapsulation is epoxy thickness. Cores with insufficient epoxy coating may crack after brine saturation because of rock expansion from clay swelling. A coating thickness of ¼ inch has proven to be sufficient to mitigate cracking.

Gas Permeability

Absolute permeability of sandstone cores is determined using a gas permeameter designed and constructed at the INEL (see Figure 4). The permeameter can be easily configured to accommodate epoxied cores of any length or dimension, as well as cores held in other mechanical devices. Gas permeability calculations require five active measurements: (1) upstream flowing pressure, (2) downstream flowing pressure, (3) gas flowrate, (4) atmospheric pressure, and (5) flowing gas temperature. The upstream flowing pressure is measured with a high accuracy Heise (0 to 250 psi) pressure gauge. The downstream flowing pressure is measured with a Validyne DP15TL differential pressure transducer coupled to a Validyne CD223 digital transducer indicator. Nitrogen flowrates are measured using a mass flowmeter.^a Atmospheric pressure is read from a mercury manometer.

LEGEND:

A - pressure regulator	E - pressure transducer
B - thermometer	F - digital transducer indicator
C - pressure gauge	G - mass flow meter
D - epoxied core	

Figure 4. Gas permeameter configuration.

a. Omega Engineering, Model FMA-5610.

Bacterial metabolism is highly dependent on the presence or absence of O_2 ; and most field conditions are anaerobic. Mimicking field conditions as much as possible is important for laboratory core floods. Purging the core with nitrogen during absolute permeability measurements helps ensure anaerobicity by displacing the air (O_2) from the core.

Calculations

Observed gas permeability, k_g , is a function of the average pressure in the core, and is calculated from Darcy's law modified for gas,

$$k_g = \frac{Q_{ave} \mu L}{A \Delta P} \times 1000 . \quad (2)$$

Boyle's law is used to calculate the average flowrate, Q_{ave} , through the core,

$$Q_{ave} = \frac{(PQ)_{ad}}{P_{ave}} . \quad (3)$$

Mean pressure, P_{ave} , in the core during the flow measurement is calculated by

$$P_{ave} = \frac{P_1 + P_2}{2} + P_{atm} . \quad (4)$$

Because nitrogen viscosity is a function of temperature, corrections are applied (see Figure 5).¹⁴

Absolute permeability, k_a , is the linear extrapolation of observed gas permeability, k_g , at infinite pressure [see equation (5)].

$$k_g = k_a + m \left[\frac{1}{P_{ave}} \right] . \quad (5)$$

Roughly 15 flow tests are required to obtain enough data to accurately extrapolate permeability on small cores. Absolute permeability, k_a , using gas as the flowing fluid is commonly referred to as extrapolated gas permeability.

Figure 5. Effect of temperature on viscosity of air and nitrogen. (From Amyx et al.¹⁴)

Core Saturations

Selection of brine composition prior to saturation is important because of permeability and other considerations that will be discussed later. An actual sample of field brine may be used or a synthetic brine similar to field brine may also be used in the laboratory corefloods.

Brine Saturation

Completely saturating epoxy-coated cores for use in experimental corefloods is of paramount importance. A residual gas saturation in the core can affect later results and calculations. Partially sealed cores are inherently difficult to saturate because of the closed core surface. Current saturation procedure uses a vacuum to slowly saturate epoxy-coated cores fitted with open end ports. Figure 6 is a schematic of the saturation device showing an epoxied core enclosed in the vacuum tube.

Figure 6. Schematic of epoxied core saturation device.

By slowly introducing the saturating liquid into the vacuum tube through a needle valve, the liquid is degassed as it enters. By allowing the liquid to slowly enter the core only through the bottom port, the liquid levels inside and outside the core are equal. Thus, the core will be saturated when the liquid

level reaches the top of the core. The degassed liquid, as it drips into the vacuum tube, is prevented from entering the top of the epoxied core by a deflecting cup placed over the top of the core. As the liquid level slowly rises in the tube it enters the core through the raised bottom port. Total time for core submersion is about 2 hours. The core is left submerged under vacuum overnight and subsequently weighed (recorded as weight @ $S_w = 100\%$) and capped. The core is then stored for 1 week in order to achieve ionic equilibrium with the rock.

Brine Permeability Measurements

Core permeability using brine as the flowing fluid is referred to as brine permeability. Brine permeability (k_b) may be somewhat lower than the extrapolated gas permeability (k_a) because of clay swelling. Berea sandstone contains from 9 to 13% clay.¹⁵ While water is commonly considered to be nonreactive in the ordinary sense, the occurrence of swelling clays in many reservoir rock materials (including Berea sandstone) results in water being the most frequently occurring reactive liquid in connection with permeability determinations. Permeability changes of 50-fold or more may be noted between that determined with air and that determined with fresh water in oilfield reservoir cores.¹⁶ Because the degree of clay hydration is a function of brine salinity, care must be taken that brine permeability values are obtained with water whose salinity corresponds to formation water. Brine permeability is compared to extrapolated gas permeability to indicate plugging, fines migration, excessive clay swelling, and other problems that could result in atypical core performance. Table 1 shows typical values of extrapolated gas and brine permeabilities.

Table 1. Comparison of extrapolated gas permeability and brine permeability for typical cores.

core	extrapolated gas permeability, k_a (mD)	brine permeability, k_b (mD)	permeability ratio, $\frac{k_b}{k_a}$
62	805	680	0.84
67	790	510	0.65
68	850	620	0.73
69	870	680	0.78
70	860	720	0.84

Core permeability using brine, k_b , as the flowing fluid is calculated from Darcy's law,

$$k_b = \frac{Q\mu L}{A\Delta P} \times 1000 . \quad (6)$$

Figure 7 is a schematic of the system used to determine brine permeability; the same apparatus is used for oil saturations. Milton Roy Slo Speed miniPumps are used for fluid delivery. De-ionized (D.I.) water is used as the pumping fluid in order to minimize pump corrosion. Tempco 250 cm³ floating piston accumulators are used to separate the pumping fluid from the corrosive injection brine and also function as injection fluid (brine, oil, etc.) reservoirs. Differential pressure across the core is measured using a Validyne DP15TL differential pressure transducer coupled to a Validyne CD223 dual channel, digital display, transducer indicator. 250 cm³ of brine is pumped through the core at 4 cm³/min during

LEGEND:

A - D.I. water reservoir	H - epoxied core
B - pump	I - collection and separatory cylinder
C - manifold	J - 0.2 micron filter
D - pressure relief valve	K - pressure gauge
E - floating piston accumulator	L - collection beaker
F - bleed-off line	M - balance
G - vacuum line	

Figure 7. Schematic of brine permeability and oil saturation system.

permeability measurements.

Calculations. The brine flowrate, Q , is given by

$$Q = \frac{W_b}{t\rho_b} \quad (7)$$

Brine viscosity is measured using a Wells-Brookfield cone and plate viscometer Model DV-II with a CP-40 spindle following the manufacture's protocol.

Pore volume of the core, PV , is given by

$$PV = \frac{W_w - W_d}{\rho_b} \quad (8)$$

and porosity, ϕ , is defined as

$$\phi = \frac{PV}{V_{bulk}} \quad (9)$$

The values obtained from equations (1) and (9) are compared. A significant difference indicates problems, such as incomplete brine saturation, that must be resolved before proceeding with the next step in core preparation

Oil Saturation of the Core

Initial oil saturation is achieved by pumping 7 PV (125 cm³) of de-gassed crude oil through the core at 20 cm³/h (see Figure 7) and then reversing the flow direction and pumping another 7 PV of oil through the core to ensure an even saturation distribution throughout the core. A Nupro pressure relief valve, set at 180 psi, is installed on the pump outlet to limit the maximum differential pressure across the core to 180 psi. Brine and oil are collected in a separatory cylinder and are allowed to separate. Brine displaced from the core is quantified volumetrically to calculate initial oil saturation. The core is weighed, sealed, and aged at flooding temperature for a minimum of 2 weeks prior to waterflooding to allow for the wetting state to stabilize at the flooding temperature.¹⁷ Table 2 shows initial oil saturation values for typical cores. The average initial oil saturation is 78.5% $\pm$ 1.7.

Table 2. Initial oil saturation for typical cores.

Core	Initial oil saturation (%)
42	79.97
43	78.03
45	77.27
46	78.95
47	76.50
48	81.97
49	76.03
52	78.98
53	77.27
54	78.73
56	79.42

Calculations. Initial oil saturation, S_{oi} , can be calculated from the volume of brine displaced from the core by

$$S_{oi} = 1 - \frac{V_b}{PV} \quad (10)$$

Initial oil saturation is also calculated gravimetrically using differences in core weights and fluid densities by

$$S_{oi} = 1 - \frac{W_c - W_d}{PV(\rho_b - \rho_o)} + \frac{\rho_o}{\rho_b - \rho_o} \quad (11)$$

Initial oil saturations calculated from equations (10) and (11) are compared. Any difference is due to errors in quantification or fluid densities, or to residual gas; and indicate problems with the core that need to be resolved.

WATERFLOOD

Figure 8 is a schematic of the core flooding apparatus. Cores can be flooded at temperatures up to 82°C (180°F) as needed. The waterflood effluent is collected in approximately 10 cm³ aliquots in 16 by 100 mm borosilicate disposable culture tubes which have been pre-weighed and numbered and placed in a timed fraction collector.^a The tubes are capped with parafilm after effluent collection, to prevent evaporation, until quantified. Oil saturated and aged cores are waterflooded with a total of 250 cm³ (about 15 total core pore volumes) of degassed brine filtered to 0.45 μm.

End Effects

Waterflood breakthrough results can be dependent on rate and length if capillary end effects are not overcome. These end effects will become negligible when the numerical value of the scaling coefficient, $Lu\mu_w$, exceeds a value of $6.67(10^{-3})$ to $83.3(10^{-3})$ cm²-cP/s.¹⁸ This range of scaling coefficient values corresponds to a range of frontal advance rates of 5.4 to 67 ft/d respectively for the

LEGEND:

A - D.I. water reservoir	H - vacuum line
B - pump	I - epoxied core
C - pressure relief valve	J - fraction collector
D - pressure gauge	with tubes
E - floating piston accumulator	
F - bleed-off line	
G - 0.45 micron filter	

Figure 8. Core flooding system.

a. Buchler Instruments, model LC200.

Berea sandstone cores used in INEL projects. Waterfloods are run at a frontal advance rate of 5 ft/d (1.524 m/d) in order to minimize end effects and still remain close to typical field frontal advance rate values, which are 1 to 2 ft/d.

Effluent Quantification

Effluent quantification is based upon weight differences of the tubes and densities of the liquids. The parafilm cap is removed and the tube including content is weighed (W_f). Crude oil is removed by repetitive addition and removal of hexane until a clear organic phase ($\approx 100\%$ hexane) is present. Residual hexane is gently evaporated under nitrogen. The tube, containing only the aqueous phase, is then weighed (W_a).

Weight of the oil in the tube, W_o , can be calculated by

$$W_o = W_f - W_a . \quad (12)$$

The volume of the crude oil, V_o , is calculated from weight and density by

$$V_o = \frac{W_o}{\rho_o} . \quad (13)$$

Aqueous phase volume, V_a , is calculated by

$$V_a = \frac{W_a - W_t}{\rho_a} . \quad (14)$$

With no gas saturation, volume of liquid injected, V_{inj} , is assumed to be equal to effluent volume,

$$V_{inj} = V_a + V_o . \quad (15)$$

Core pore volumes injected, PV_{inj} , is calculated by

$$PV_{inj} = \frac{V_{inj}}{PV} . \quad (16)$$

Oil saturation of the core, where n is the tube number, is calculated by

$$S_o^n = S_o^{n-1} - \left[\frac{V_o^n}{PV} \right] . \quad (17)$$

Small errors involved in the procedure are attributed to water evaporation during quantification. The error is independent of the quantity of oil or brine in the tube as shown in Figure 9. The average error per oil tube during oil quantification is $0.0018 \text{ cm}^3 \pm 0.0027$. Multiplying this error by 20 tubes with oil in an average waterflood, the cumulative average error would be 0.036 cm^3 of oil. This amount represents 0.2% of the total pore volume (core $PV = 17.5 \text{ cm}^3$). Assuming a calculated waterflood residual oil saturation of 52.0% , the actual oil saturation would be $52.2\% \pm 0.3$, accounting for error in oil quantification.

All tubes are weighed on an analytical balance (Fisher XD400) connected to an IBM PC via a RS232 connector port. This enables recording the tube weights directly onto a computer disk. The resulting weight files are then loaded into a Lotus 1-2-3™ worksheet that is used for data reduction and manipulation.

Figure 9. Experimental error associated with oil quantification procedure.

All aqueous effluent resulting from microbial floods are autoclaved to kill viable microbes, and checked for neutral pH prior to disposal. The crude oil and hexane from the separation procedure is disposed of according to standard procedures. All guidelines and safety procedures are followed for handling, storage, and disposal of hazardous wastes.

Waterflood Results

Results are reported for analysis as a plot of oil saturation (S_o) versus pore volumes of brine injected (PV_{inj}). Analysis of these plots permits an accurate evaluation of the complete flood including flood dynamics; whereas, an evaluation based on endpoint analysis may result in future data skewed optimistically.

Figure 10 shows the results from a typical waterflood for Schuricht crude oil^a run at room temperature. Notice that for this core oil production has not completely ceased even after 15 PV of brine have been injected through the core. An extrapolation of the waterflood oil saturation decline or continued flooding is necessary in order to accurately analyze results of further floods.

a. Schuricht field, Powder River Basin, Crook County, Wyoming. Gravity is 25.4 °API at 60°F (15.6°C).

Figure 10. Typical room temperature waterflood oil saturation reduction curve for Schuricht crude oil.

Waterflood residual oil saturation for a given oil has been found to be fairly constant. Table 3 shows the waterflood residual oil saturation for a typical set of cores. The average oil saturation remaining in the cores after a 15 PV waterflood is $52.0\% \pm 3.1$. These data were obtained from room temperature waterfloods.

Table 3. Waterflood residual oil saturations (room temperature) for typical cores.

Core	Waterflood* Residual Oil† Saturation (%)
42	56.84
43	52.75
45	51.24
46	52.33
47	55.60
48	53.55
49	51.03
53	45.99
52	49.96
54	48.52
56	54.11

* Brine: 2.5% NaCl, 0.5% CaCl₂

† Oil: Schuricht Crude

ENHANCED (MICROBIAL) FLOODS

Enhanced floods, injection of microbes or microbial products to recover residual waterflood oil, are performed after residual waterflood conditions have been achieved. Microbial floods are performed similar to waterfloods with major exceptions being the bacterial inoculum and incubation periods. Bacterial injection rates (0.125 mL/min or 5 ft/d frontal advance rate) are the same as brine injection rates during previous and subsequent waterfloods.

Microbial Preparations

Many different organisms can be used in coreflood experimentation and each requires a careful selection of growth medium and conditions. Methodologies of microbial preparations depend on the purpose of the experiment. For example, to evaluate the effect of *Bacillus licheniformis* JF-2 in situ metabolism and the impacts of cell presence on oil recovery, cells would be grown aerobically at 30°C (86°F) in minimal Medium E 1502 for *Bacillus* with 1% sucrose as the carbon source and 2.5% NaCl. Cell suspensions would be prepared by centrifuging a culture grown to an optical density (O.D.) of 1.0 ± 0.15 , and then resuspending the pellet in fresh medium to the same O.D. This fresh cell suspension (1.0 pore volumes) would be immediately injected into cores waterflooded to residual oil saturation and then incubated for 2 weeks at 30°C (86°F) prior to resuming the waterflood. Resuspending the cells in fresh medium immediately prior to injection would ensure that recovery of residual oil was the result of either in situ metabolism or the physical presence of cells, or both. A complete description of microbial preparations, techniques, and results has been previously reported.^{19,20,21}

CONCLUSIONS

- 1) Multiple independent calculations of core properties such as porosity, permeability, and saturations help diagnose and correct problems encountered during future corefloods.
- 2) A standardized method was developed to prepare epoxy-coated cores for laboratory corefloods that includes a urethane end plate designed to eliminate fluid segregation in the end plate.
- 3) Reported block permeability of Berea sandstone can vary widely from actual permeability. Absolute permeabilities in the range of 800 to 900 mD were calculated from cores cut from blocks which were reported to be in the 400 to 500 mD range.
- 4) A new technique was developed to quantify small volumes of oil associated with instantaneous oil production in small-volume laboratory core floods.

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