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Idaho National Engineering and Environmental Laboratory
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ABSTRACT

Crude oil/brine/rock interactions can lead to large variations in the displacement efficiency of waterflooding, by far the most widely applied method of improved oil recovery. Laboratory waterflood tests show that injection of dilute brine can increase oil recovery. Numerous fields in the Powder River basin have been waterflooded using low salinity brine (about 500 ppm) from the Madison limestone or Fox Hills sandstone. Although many uncertainties arise in the interpretation and comparison of field production data, injection of low salinity brine appears to give higher recovery compared to brine of moderate salinity (about 7,000 ppm). Laboratory studies of the effect of brine composition on oil recovery cover a wide range of rock types and crude oils. Oil recovery increases using low salinity brine as the injection water ranged from a low of no notable increase to as much as 37.0% depending on the system being studied. Recovery increases using low salinity brine after establishing residual oil saturation (tertiary mode) ranged from no significant increase to 6.0%. Tests with two sets of reservoir cores and crude oil indicated slight improvement in recovery for low salinity brine. Crude oil type and rock type (particularly the presence and distribution of kaolinite) both play a dominant role in the effect that brine composition has on waterflood oil recovery.

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1. INTRODUCTION

Waterflooding is by far the most widely used method to increase oil recovery. It has been shown that different wetting states of crude oil, brine, and rock ensembles can yield widely different oil recoveries during laboratory waterflood tests. The wetting state, or wettability, of a rock and fluids system can be altered in a number of ways: for example, changing crude oil composition, changing the aging temperature of the rock with crude oil, or the temperature of displacement (Jadhunandan and Morrow 1995). The initial water saturation has a dominant effect on the wettability states induced by adsorption from crude oil because the distribution of water determines which parts of the rock surface are contacted by the oil (Salathiel 1973, Jadhunandan and Morrow 1995, Xie and Morrow 2001, Tong, Xie and Morrow 2002). It was also observed that brine composition could have a significant impact on oil recovery (Jadhunandan and Morrow 1995, Yildiz and Morrow 1996, Yildiz, Valat and Morrow 1999, Tang and Morrow 1997). It follows that there may be cases where attention to brine composition could lead to increased recovery and likely increase in the economic profitability of a waterflood.

Almost without exception, at the start of a waterflood, water from the cheapest source (usually different in composition to the formation water) is used as the injection water, provided injectivity is not adversely affected by formation damage. Historically, little consideration has been given in reservoir engineering practice to the effect of injection brine composition on waterflood displacement efficiency or to the possibility of increased oil recovery through manipulation of the composition of the injected water. Most laboratory relative permeability tests and displacement tests are done using synthetic formation water as both the connate and injected brine rather than using formation connate brine and the actual field injection water.

There may sometimes be an optimal brine composition that could involve many variables with respect to ionic composition and concentration but current knowledge of how and when brine composition can be manipulated to advantage is very limited. Several examples of improved recovery by injection of low ionic strength brine have been reported for both outcrop and field core samples (Tang and Morrow 1997, 2002). Of the many possibilities that need to be further explored, laboratory results on the increased recovery given by injection of dilute brine appeared the most promising with respect to near term field application. Tang and Morrow showed that oil recovery increased markedly with dilution for recovery of several types of crude oil and Berea sandstone with permeability to gas of about 800md (hereafter referred to as Berea 800). Even when the connate water was of relatively high salinity, injection of dilute brine gave economically significant increase in oil recovery. Systematic studies based mainly on Berea 800 showed three conditions were necessary for increased recovery. These were adsorption from crude oil onto the rock surface, the presence of clay (most likely kaolinite) in the rock, and the presence of an initial water saturation. Sufficient conditions for improved recovery, such as the type of crude oil and rock, composition of the connate and injected brine, and the initial brine saturation are still far from understood. The crude oil/brine/rock interactions that determine displacement efficiency are highly complex. Nevertheless laboratory observations were sufficiently encouraging to justify further studies aimed at field application.

In 1997, the Idaho National Engineering and Environmental Laboratory (INEEL), in conjunction with BP and the University of Wyoming, gained funding from the U.S. DOE National Laboratory Partnership Program to expand work begun at the University of Wyoming. BP provided funding to the University of Wyoming as well as in-kind contributions to the project such as laboratory equipment and technical assistance. University of Wyoming researchers were involved with laboratory investigations of the improved recovery phenomenon. The two main objectives were to test for improved recovery for a wider range of crude oil/brine/rock systems, identify targets for field testing, and develop an improved understanding of the displacement mechanisms that cause sensitivity of oil recovery to brine composition. The INEEL was tasked initially with the comparison of past production history in fields for which the injected brine was of much lower salinity than the formation brine with results for injection of brines of more usual (higher) salinity. The INEEL later added a significant portion of the laboratory work aimed at scaling of laboratory data and potential field application. This final report provides a detailed account of the work accomplished at the INEEL and the University of Wyoming.

An unexpected but significant problem in the conduct of the project arose in attempting to obtain additional blocks of the Berea 800 sandstone that had served as a model rock in earlier studies. Berea 800, supplied by Cleveland Quarries in Ohio, has been used a model sandstone by production research laboratories for almost 50 years. Results for this sandstone were to be used as a reference when evaluating other factors such as the types of crude oil and rocks and variation in brine composition or connate water saturation. When new supplies of Berea 800 were ordered at the beginning of the project, the supplied rock turned out to be many times lower permeability than Berea 800, and was typically in the range of 60 to 90 md (hereafter referred to as Berea 60). Berea 60 did not show the large response to variation in salinity exhibited by Berea 800. Instances of sudden change in properties of the as-supplied Berea sandstone have occurred previously but the more usual type of Berea sandstone could be obtained once the problem was pointed out to the suppliers. Considerable discussions were held with personnel at Cleveland quarries and additional batches of Berea sandstone were purchased but all were of much lower permeability than specified by the supplier and recovery behavior was consistent with the first batch of Berea 60. While it is of great interest to investigate rock type as a parameter, results obtained for the Berea 60 showed that this rock was not suitable for use as a substitute model rock. Possible causes of the difference in behavior between Berea 800 and Berea 60 are addressed in this report.

Parametric studies were continued using both Berea 60 and higher permeability samples of Berea sandstone, some of which had been supplied by other research laboratories and had been in storage for many years. In adopting this compromise, the consistency in properties from one batch of rock to another was much less than that given by working exclusively with a well-characterized rock sample. Distinct differences in the original location of the rock in the quarry and the history of storage after the rock has been cut can be expected. Results obtained to date point to the rock properties as being the most critical factor in increased oil recovery by injection of dilute brine. In presenting the results, details of the source and the history of individual cores with respect to the blocks from which they were cut are provided. Encouraging results for a number of target-reservoir core samples showed that the observed effects of brine composition on oil recovery for Berea 800 were definitely not peculiar to this particular rock type.

Results obtained at INEEL are presented in the first part of this report and those obtained at the University of Wyoming in the second part. The close interaction between INEEL and the University of Wyoming maintained throughout the project is clear from the discussion of how the results from one group influenced the course of investigation by the other. The main objective of this report is to provide detailed documentation of all observations made during the course of this project. Further contributions to the public domain will be made through publications on specific aspects of the work covered in this report.

2. STUDIES AT INEEL

2.1 Historical Field Waterflood Comparison

Work at the INEEL initially focused on field-scale historical data from the Powder River Basin, a major petroleum-producing basin in Wyoming that is conveniently close to both the INEEL and the University of Wyoming. Waterfloods, both large and small, have been applied extensively within the basin. A brief study of the waterflooding practices in the basin revealed that the vast majority of waterfloods used fresh water either exclusively throughout the life of the waterflood or at least initially but later re-injected produced water as it broke through in the producing wells. Fresh source-water formations were either the Fox Hills sandstone or the Madison limestone. The historical record of this basin was searched to find waterfloods using fresh injection water and others using more saline injection water and then compare results to determine if the historical record substantiates the laboratory observation that waterfloods with fresh water can give higher recovery than obtained by injection of a more saline brine.

The Powder River basin of the United States is located largely in northeastern Wyoming with a small portion extending into southeastern Montana. The basin is a deep, northerly trending, asymmetric, mildly deformed trough, approximately 250 mi long and 100 mi wide. Its axis is close to its western margin, which is defined by Bighorn Mountains uplift and the Casper arch. It is bordered on the south by the Laramie and Hartville uplifts, and on the east by the Black Hills uplift. The northern margin is defined by the subtle northwest-trending Miles City arch.

The basin is one of the richest petroleum provinces in the Rocky Mountains. More than 2.5 billion barrels of recoverable oil have been discovered in reservoirs ranging in age from Late Paleozoic to Upper Cretaceous (Dolton, Fox, and Clayton 1990).

The Muddy-Newcastle is the most prolific oil-producing formation in the basin, but the sand is often poorly sorted with substantial clays present. Clays within the pores are sensitive to fresh water and can migrate and cause plugging of rock pores. Generally, injection waters used in this formation were modified by the addition of potassium chloride and/or potassium hydroxide for clay stabilization. The effect of such modifications of the injection brine on waterflood displacement efficiency were not studied in laboratory corefloods and because of that and the problems associated with injecting fresh water into the Muddy-Newcastle, fields in this formation were excluded as candidates for comparison of low-salinity-water versus high-salinity-brine oil recovery.

2.1.1 Minnelusa Formation

Reservoirs in the Minnelusa formation are generally small, but lend themselves to waterfloods because of the typically clean, well-sorted sand. The Minnelusa formation is of Pennsylvanian and Lower Permian age. Sandstones of the Minnelusa formation are major oil-producing reservoirs within the basin and are productive in both structural and stratigraphic settings. The Minnelusa formation lies in the northeastern portion of the Powder River basin east of the city of Gillette, Wyoming. The formation outcrops in the Black Hills above Rapid City, South Dakota.

The first well in the Minnelusa having commercial significance was completed in 1957. Exploration for additional Minnelusa discoveries has continued into the 1990's with an extremely high increase in exploration activities with the higher oil prices of the early 1980's. Most of the larger Minnelusa reservoirs were discovered in the earlier phase of Minnelusa exploration, during the 1960's, but numerous smaller discoveries have continued into the present. The original oil-in-place for the Minnelusa in the Powder River basin has been estimated at 629 million barrels. (Van West 1972)

The Minnelusa formation is comprised predominantly of white crystalline sandstone containing little clay and is loosely cemented by carbonate and anhydrite. The formation appears to have been deposited in a marine environment, but an eolian origin, in part is not excluded. The upper portion of the Minnelusa formation (Upper Minnelusa) usually contains two producing zones ("A" and "B") and a third major sand ("C") which is usually nonproductive (Foster 1958). In a study of thirty-five Minnelusa reservoirs, average values were determined for the reservoir characteristics of these fields and are listed in Table 1.1 (Hochanadel, Lunceford and Farmer 1990).

2.1.2 Minnelusa Field Comparisons

In laboratory waterfloods, oil recovery was plotted against pore volumes of fluid produced. Oil recovery is the ratio of cumulative volume of produced oil to the volume of oil originally in place in the core. A pore volume of fluid produced is the ratio of the sum of the produced oil and water volume to the pore volume of the core. The following sections discuss how field waterflood data were obtained and plotted in order to compare field results to laboratory results.

West Semlek. The West Semlek unit was formed in 1973 and water injection began in June of that year. The engineering study on the proposed West Semlek unit was done in 1971. (Wyoming Oil and Gas Conservation Commission 1986) Production is from the upper Minnelusa “B” sand of Pennsylvanian age, which occurs at an average depth of 7240 ft. The reservoir is a stratigraphic trap with truncation of the sand defining the reservoir limits except in the west, where an oil-water contact limits the oil reservoir. The upper Minnelusa “B” sand is a well-developed, fine-to-medium-grained anhydritic sandstone with occasional interbedding of dense shaly dolomite. Field porosity averages 19.4%, the permeability averaged 647 md for three cored wells, and connate water saturation is estimated to be 25%. Crude oil at West Semlek is 22° to 24° API. The original reservoir pressure was 2847 psig, and the reservoir temperature is 144°F. The GOR is 10 SCF/STB and the original FVF was 1.049 bbl/STB.

Water produced from a different portion of the formation, the lower Minnelusa “B” sand, was used as the injection water for this waterflood and averaged 7165 ppm TDS.

The original engineering study included an area that has since been removed from the unit boundaries. Therefore, the unit bulk volume and other values calculated in the engineering study are invalid for the unit as it stands today. New unit-volumes were calculated using the following equations assuming no free gas in the reservoir.

$$PV = V_b\phi \quad or \quad PV[bbl] = 7758 V_b[AF]\phi. \qquad \textbf{(1)}$$

where PV is pore volume, V_b is the bulk volume, and ϕ is porosity.

$$OOIP + OWIP = PV. \qquad \textbf{(2)}$$

where $OOIP$ is original oil in place and $OWIP$ is original water in place. Dividing Eq (2) by PV yields

$$\frac{OOIP}{PV} + \frac{OWIP}{PV} = \frac{PV}{PV} = 1. \qquad \textbf{(3)}$$

Assuming no gas saturation,

$$S_o + S_w = 1. \quad \textbf{(4)}$$

where S_o is oil saturation and S_w is water saturation. Also, by definition,

$$\frac{OOIP}{PV} = S_o \quad and \quad \frac{OWIP}{PV} = S_w. \quad \textbf{(5)}$$

Rearranging Eq (5) and dividing by the bulk reservoir volume, we get an equation for the calculation of OOIP as a function of PV, S_o, and V_b (and B_o).

$$OOIP\left[\frac{bbl_{res}}{AF}\right] = \frac{PV \cdot S_o}{V_b} \quad or \quad OOIP\left[\frac{STB}{AF}\right] = \frac{PV \cdot S_o}{V_b B_o}. \quad \textbf{(6)}$$

where B_o is the formation volume factor in bbl/STB.

Bulk volume, V_b, of the reservoir was calculated to be 8764 AF for the productive portion of the unit as it stood during production. From Eq (1), the pore volume of the unit was calculated to be 13,597,736 bbl using the average porosity for the unit of 19.4%. From Eq (5), given an average initial-oil-saturation of 75% and a formation volume factor of 1.049 bbl/STB, the OOIP becomes 1109 STB/AF.

By summing the cumulative oil production and dividing by the OOIP the oil recovery can be calculated. The pore volume of liquid produced is calculated by summing the oil and water production and dividing by the reservoir pore volume.

The following wells were active producers in the West Semlek unit: 28-2, 28-4, 28-4b, 28-7, 28-9, 28-11, and 29-1 (Wyoming Oil and Gas Conservation Commission 1986). The production data from the unit wells, which is in STB, was converted to reservoir barrels before calculating pore volumes produced. Figure 1.1 is a plot of the cumulative recovery versus pore volumes produced fluid from the West Semlek unit.

Reservoir Connate Brine Composition – The produced water was analyzed in 1986 for total dissolved solids and averaged 15,500 ppm. However, according to the unit engineering study, the connate water concentration ranged from 50,000 to 70,000 ppm. To explain the difference, we must consider the timing of the water analyses. Water injection began in 1973 and water breakthrough occurred in 1974; therefore, the produced water analyzed was almost certainly mixed and diluted with the injected water.

Injection Brine Composition – At the beginning of the waterflood of the West Semlek unit, all of the injection water came from the Minnelusa lower "B" from two off-unit water wells (28-1 and 28-6). The composition of the injection water at the onset of the waterflood, therefore, was about 7000 ppm TDS (see Table 1.2 for details of the water analysis). As the waterflood progressed, the produced water from the oil reservoir (the Minnelusa upper "B", about 60,000 ppm TDS) was commingled with the lower salinity water from the Minnelusa lower "B" increasing the injection water salinity with time, such that by 1986 it had risen to 15,000 ppm. The average injection water TDS throughout the waterflood is assumed to be 10,000 ppm.

North Semlek. The North Semlek Unit is a freshwater waterflood, obtaining its injection water from the Fox Hills formation (TDS = 1095 ppm). The waterflood feasibility study for the North Semlek field was prepared in 1987 (Terra Resources 1987). Wells in this field produce from the Lower "B" sand member of the Minnelusa formation and reside primarily in sections 16 and 21 of T52N, R68W. The field was discovered in 1963 with the completion of the Heath Government 21-1. The next well to be completed in the field was the Terra State No. 1, 12 years later, in 1975. In 1983, the Semlek Federal No. 1 was completed and the unit development was finished in 1984 with the completion of the Heath Government 21-5.

The reservoir is divided into an upper section and a lower section. Above the transition zone, the initial oil saturation was 80%, while below the transition zone the initial oil saturation was 60%. Original oil in place is taken from the waterflood feasibility study and calculated volumetrically to be 3,620,926 STB, with 3,088,271 STB above the transition zone and the remainder below the transition zone. By knowing the OOIP, FVF, porosity, and initial oil saturations, the bulk volume and pore volume can be calculated using Eq (1) and Eq (5). Bulk volume is calculated to be 31,523,758 bbl and the pore volume is 4,980,754 bbl.

Total dissolved solids of the initial reservoir (connate) brine averaged 42,000 ppm, with approximately 80% NaCl equivalent by weight.

Figure 1.2 is a plot showing the oil production from the North Semlek unit. Note that there was a significant primary production period before the field was developed and water injection began.

Injection Water – Water injection in the North Semlek unit began in January 1988 using the Semlek Federal #1 well. In October 1995, this well was shut in and injection continued using the Heath Government 21-5 well at the same injection rate as before. The water supply well, completed in the fresh water Fox Hills formation, is the Muñoz Government 28-5. The injection water analysis is shown in Table 1.3.

Moran. The Moran field is located in the northeastern portion of the Powder River Basin, approximately fifteen miles east of the town of Gillette, WY. The field is composed of two units: the East Moran (Minnelusa) unit and the West Moran Minnelusa unit. ARCO developed the eastern portion of the field and Sun developed the western portion; thus, the two units within the same field. ARCO originally proposed to unitize the entire field. However, this was not accomplished; instead the east and west units were organized separately, probably due to political or company policy reasons. The two units were combined in this analysis because they were developed concurrently and produced from the same reservoir.

The original oil in place for the Moran Minnelusa reservoir is estimated to be 1,783,000 STB. (ARCO 1986, ARCO 1987, Sun Exploration 1987) The average field porosity is estimated to be 14.4%, the bulk volume of the reservoir is 17,942 ac-ft, initial water saturation is 37.1%, and the formation volume factor is 1.07 bbl/STB. The total dissolved solids in the reservoir brine were very high, ranging from 89,000 ppm to 158,000 ppm. Before the initiation of the waterflood, the total dissolved solids concentration in the water produced from the Czapanskiy A-4 well was 128,000 ppm, with sodium chloride accounting for 97%.

The E. Moran No. 2 was recompleted as a water source well in the Fox Hills formation. Water injection began in December 1987 into wells E. Moran No. 1 and Czapanskiy A-4. See Table 1.3 for an analysis of fresh water from the shallow Fox Hills sand.

Figure 1.3 shows the oil recovery for the Moran field. There was a short primary production period before commencing the waterflood.

Comparison of Three Minnelusa Waterfloods. The three waterfloods described above are all in fields producing from the Minnelusa formation; one using higher salinity Minnelusa injection water and two using fresh Fox Hills water. The purpose of the historical field data was to determine if any trend in oil recovery with injection brine composition could be identified.

The comparison of the three waterfloods shown in Figure 1.4 indicates that the two fields waterflooded with fresh water resulted in higher oil recoveries. This significant finding is consistent with laboratory results that will be discussed in the following sections.

2.2 Laboratory Corefloods at INEEL

The University of Wyoming has done a large amount of laboratory research aimed at improved oil recovery by waterflooding through manipulation of the injection brine chemistry. The INEEL began a series of waterflood experiments to augment University of Wyoming results and to assist in generating results related to scale-up. Most of the original laboratory work done at the U. of Wyoming was done using Berea 800 sandstone and cores from the CS reservoir (Europe) and Dagang (China), and a variety of crude oils including CS crude, Moutray crude, A95 (Prudhoe Bay) crude, Dagang crude, and Minnelusa crude. Experimental work at INEEL was begun using Berea sandstone and Minnelusa crude oil from a target reservoir.

2.2.1 General laboratory procedures

Most of the corefloods were done using Berea sandstone obtained from Cleveland Quarries of Amherst, Ohio. The cores were coated with epoxy[1] with inlet and outlet ports permanently embedded into the epoxy as shown in Figure 1.5. The epoxy is a non-sag paste and penetrates the core to a depth of no more than one or two sand grains. Epoxy was applied to a thickness of about ¼ inch around the sandstone cores. By this method, the cores were effectively sealed and no flow around the outside of the core was possible. Tests at the University of Wyoming have shown that while epoxy resin sometimes affects imbibition and wetting phenomena, no change in wetting behavior was detected for this particular epoxy. Blocks of Berea sandstone were drilled so that the resulting cores were cut parallel to the bedding plane. Cores prepared at INEEL were cut from three blocks designated as INL-A, INL-B, and INL-C. Cores from block INL-B had been cut 10 years previous to use and had been stored in an oven for 10 years at 55°C prior to use. All other cores were dried at 55°C for about two to three days, except two cores from block INL-A (cores INL9 and INL 10 which were stored at 55°C for 7 months before use).

With the core dried and coated in epoxy, a dry weight is recorded and gas permeability is measured using carbon dioxide.

Epoxy-coated cores were placed in a chamber under vacuum for ½ hour prior to submersion in degassed brine. The vacuum was held on the submerged core for two hours and then released. The cores remained submerged at atmospheric pressure overnight and were then removed and capped. A minimum of five pore-volumes of water was then injected through the cores while applying a backpressure of 60 psi. Then the mass of the water-saturated core was measured.

The pore volume was calculated from the dry mass of the core, the water saturated mass of the core, the water density, and the core geometry.

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[1] Hysol brand epoxy 1C purchased from Krayden Inc. Denver, CO

$$V_p = \frac{wet\ mass - dry\ mass}{\rho_w} - dead\ volume\ at\ ends\ of\ core, \quad \textbf{(7)}$$

where V_p is the core pore volume and ρ_w is the density of the saturating water. The dead volume at the ends of core, illustrated in Figure 1.5, is a measured, constant value for each core. If this volume were not taken into account, the pore volume value would be erroneously high. Porosity is calculated by dividing the pore volume by the measured bulk volume.

Water permeability was measured during the high-pressure water injection described in the water saturation section of the core saturation procedures.

Crude oil used in laboratory corefloods was filtered to remove any particulate matter and then placed under a vacuum and stirred for one hour at room temperature to remove soluble gasses from the oil. All cores were oil-flooded at a differential pressure drop of 50 psi. Five pore volumes of oil were injected in each direction while collecting the produced water. The volume of the produced water was quantified and used to determine the oil and water saturations after the oil flood by the following equation (assuming gas saturation equals zero).

$$S_w = 1 - \left(\frac{produced\ water\ volume - dead\ volume}{V_p} \right). \quad \textbf{(8)}$$

After the oil flood, the cores were considered to be at initial conditions. The cores were then aged at the desired temperature for 10 to 18 days.

2.2.2 Scale-up experiments

A series of corefloods was done to investigate the effect of changing core size on oil recovery during waterfloods (see Table 1.4). For these experiments, crude oil from the Prudhoe Bay field, A95, was used, along with simulated formation brine and Berea sandstone cores cut from INL-A. Four cores were prepared and brought to initial conditions. Two of the cores were 4 inches in length and the other two were 8 inches in length. The connate brine in all four cores was the simulated formation field brine. The injection water was the same as the connate brine for one 4-inch core and one 8-inch core, but was diluted 100 times for the other two cores. Waterflood injection rate was set at 3 ft/D and the aging temperature and flooding temperature were both 70°C.

Results of the four waterfloods are plotted in Figure 1.6. Based on previous work at the University of Wyoming, the ensemble of Berea sandstone, A95 crude oil, and simulated Prudhoe Bay formation water was selected because it was anticipated that it would give a positive response to dilute waterflooding. However, as can be seen from Figure 1.6, no increase in oil recovery was seen in the diluted waterfloods. Neither the 8-inch diluted flood nor the 4-inch diluted flood recovered more oil than its undiluted paired flood; these results were unexpected

The intent of this group of corefloods was to investigate the effect of core size on the increased recovery process associated with dilute water flooding. Because an increase in recovery was not seen, the effect of core size on the process could not be clearly demonstrated. Nevertheless, there was increase in recovery for the 8-inch floods compared to the 4-inch floods. The apparent difference in recovery using different core sizes, possibly related to end effects, suggests that further investigation is needed of the effect of core size on oil recovery from mixed wettability cores generated by adsorption from crude oil.

2.3 Experiments with CS crude oil

The experiments with A95 crude oil and Berea sandstone clearly indicated that achieving an increase in oil recovery due to fresh water injection was not as straight forward as indicated by previous experience and that not every crude-oil/brine/rock system would be amenable to such a process. In order to establish a system and procedures with which a substantial increase in oil recovery due to fresh water injection could be routinely repeated, experiments with CS crude oil and Berea sandstone were undertaken.

2.3.1 Manipulation of invading brine, holding connate brine constant

Four Berea sandstone cores from Block INL-B (these cores had been stored at 55°C for ten years) were prepared for waterflooding by saturating with simulated CS formation brine and then flooding with CS crude oil to arrive at initial conditions (see Table 1.5). The TDS of the CS formation brine was 15,139 ppm. The cores were aged, as well as waterflooded, at a temperature of 55°C for a period of between 10 and 14 days. After aging the cores were waterflooded. The invading brine of two of the cores was CS reservoir brine (CSRB), while the invading brine of the other two cores was a 100-fold dilution of CSRB (0.01 CSRB). The results are plotted in Figure 1.7. The initial water saturation of the four cores ranged from 23.3% to 25.5%. The average recovery from the diluted floods was slightly lower than the average recovery from the undiluted floods, but by an insignificant amount, and was within the usual experimental variance (about + or – 1.5%). Oil recovery from mixed-wet cores is highly sensitive to initial water saturation (Xie and Morrow, 2001) and the almost 2% difference in initial water saturation could have contributed to the difference in recovery between results for cores INL-5 and INL-6. The range of recoveries for this data set indicate that the core samples may have been strongly water wet. Storing these cores for 10 years at 55°C may have altered their wettability from mixed wet to strongly water wet, thus causing the poor response to dilute brine flooding.

2.3.2 Manipulation of both connate and invading brine

In a further attempt to demonstrate the improved recovery relationship for fresh or diluted waterfloods, an additional set of six Berea sandstone cores were prepared and brought to initial conditions using CS crude oil (see Table 1.6). In this case, the connate brine for three of the cores was undiluted CSRB and the connate brine for the other three cores was 0.01 CSRB.

There was some concern that the Berea sandstone at the University of Wyoming and at the INEEL was not producing equivalent results at the two laboratories. Four cores (B1100a 1 through 4) were sent from the University of Wyoming, while two were from the stock of Berea sandstone stored at the INEEL (INL9 and INL10) as indicated in Figure 1.8. The INL cores had been stored at 55°C for 7 months prior to use. The cores were aged and flooded at 55°C. Results are shown in Figure 1.8.

Results for all the cores used in this set are plotted in Figure 1.8, but since they were not all from the same block of Berea sandstone, they should be discussed separately. Considering only the cores obtained from the University of Wyoming, the average recovery from the diluted CSRB cores was significantly higher than that for the cores with full strength CSRB – 61.5% OOIP versus 52.5% OOIP respectively.

The two Berea sandstone cores cut from Block INL-A yielded different results. The full strength CSRB core recovered more oil as a percentage of original oil in place during the waterflood than the diluted CSRB core – 50% versus 46%.

The UW cores showed a positive result to diluting the reservoir brine, while the INEEL cores showed no response to diluted reservoir brine. There also appeared to be a significant difference in the magnitude of the oil recovery between the UW and INEEL cores.

2.4 Corefloods with Minnelusa Oil

Laboratory corefloods to study the effects of injection brine dilution on the Minnelusa formation were performed in tandem at the INEEL and the University of Wyoming.

2.4.1 Minnelusa Corefloods at Room Temperature

The objective of this series of corefloods was to establish a baseline for increased oil recovery using diluted formation brine as the injection brine as opposed to undiluted formation brine. Future experiments would then be compared to this baseline for increased recovery.

Because of these unexpected differences in recoveries, the INEEL ordered a new block of Berea sandstone and used it exclusively for all subsequent coreflooding tests. The gas permeability of Block INL-C cores was relatively low compared to previously tested cores, and showed considerable variation, ranging from 88 to 239 md (see Tables 1.7 and 1.9).

Experimental Setup. Eight Berea sandstone cores were cut from Block INL-C for waterflood tests (see Table 1.7). Core length was 3.0 inches and core diameter was 1.5 inches. The block had been stored at ambient conditions. After the cores were cut from the block, they were dried at 55°C for 3 days, then cooled and coated with epoxy. All the cores were initially saturated with synthetic Minnelusa brine. The brine composition is shown in Table 1.8. The brine has a total dissolved solids content of 38,653 ppm and the pH of the solution is 6.85. The cores were then flooded and aged at 55°C in a sealed pressure vessel. After aging, the cores were removed from the oven. With the cores at ambient temperature, one pore volume of fresh crude oil was injected through the core before the waterflood.

Half the cores were waterflooded with full strength Minnelusa brine and the others were waterflooded with diluted (100 fold) Minnelusa brine, all at ambient temperature without any backpressure and at a constant flow rate of 3 ft/D.

Results of Room Temperature Corefloods and Discussion. Oil recovery, differential pressure drop, and pore volumes injected were recorded for each waterflood. Oil recoveries versus pore volumes injected are shown in Figure 1.9.

Recoveries ranged from a low of 38.6% OOIP to a high of 45.4% OOIP. No significant differences in recovery can be noted between the two sets of waterfloods (diluted versus undiluted). Differential pressure, however, was significantly higher during the diluted waterfloods compared to the undiluted floods. Higher differential pressures did not result in higher oil recoveries.

Averaging the oil recovery curves for the two sets resulted in an average recovery (at 10 PV) for the dilute floods of 42.0% OOIP with a standard deviation of 2.8. The average recovery for the undiluted floods was 41.1 OOIP ± 1.5. These average recovery curves are shown in Figure 1.10. From these ambient conditions waterfloods, no significant increase in oil recovery was seen for injection of diluted MRB as opposed to full strength MRB. In addition, there was no correlation between oil recovery and porosity, permeability, or original-oil-in-place.

Room Temperature Minnelusa Corefloods: Conclusions and Recommendations. Several factors could have contributed to the lack of higher oil recoveries for the diluted waterfloods. It is possible that the aging temperature of 55°C was not high enough to effectively establish the wetting state before the start of the waterflood. By the same token, the room temperature waterflood may have been too cold to facilitate any wetting change caused by the dilution of the injection brine. In addition, the high mobility ratio of the waterflood caused by the relatively low temperature (ambient) may have masked the expected increase in oil recovery from the diluted waterfloods.

For the reasons stated above, it was decided that additional testing should be done for the same crude oil-brine-rock ensemble except the displacement would be run at elevated temperature. The higher temperature should promote greater wetting changes during the aging process and lessen the possibility of viscous fingering during waterflooding.

2.4.2 Minnelusa Corefloods at 75°C

Core Preparation Procedures. Seven cores were cut 3 inches in length by 1.5 inches in diameter from Berea sandstone Block INL-C. Gas permeabilities ranged from 88 to 151md for this block of Berea sandstone (see Table 1.9). The cores were brought to initial water saturations in the same manner as previously described using Minnelusa reservoir brine and Minnelusa crude oil and aged at 75°C.

Waterflood Procedures. Prior to beginning the waterfloods, one pore volume of fresh Minnelusa crude oil was injected through the core. No produced water was detected from any of the cores during this step.

Either full strength MRB or diluted MRB (100-fold dilution) was injected into the cores at 75°C at 3 ft/D. The water reservoir was located outside the oven, the core was inside the oven, and the collection tubes were located outside the oven. The production line (from the core to the collection tubes outside the oven) was as short as possible and made out of 1/16-inch stainless steel tubing in order to minimize fluid hold-up in the line. After the waterflood was finished, the production line was flushed with water and any oil held up there was recorded. (Note: no oil was found in the production line after the waterflood for any of the cores in this set of corefloods.)

No backpressure was used during the waterfloods. A transducer connected to a computer provided a record of the differential pressure across the core. The oil and water produced during the waterflood was collected in 15-mL tubes in a fraction collector outside the oven. The waterflood was continued until 10 pore volumes were produced. The dead-volume oil was subtracted from the oil produced in the first collection tube.

Because the core was at the reservoir temperature (T_R) of 75°C during the waterflood, the fluid densities used to quantify initial oil in place and production volumes were calculated at T_R. Both oil density and water density were corrected from room temperature to T_R (Pratts 1982).

Results of Minnelusa Floods at 75 C. Results from the waterfloods are listed in Table 1.9 and are shown graphically in Figure 1.11.

Discussion of Results of Minnelusa Corefloods at 75°C. All the cores flooded with diluted MRB had higher recovery factors than the cores flooded with full strength MRB. Figure 1.12 shows the average oil recovery curves for the diluted waterfloods versus the undiluted waterfloods. The average recovery factor for the diluted waterfloods was 55.7% compared to an average recovery factor of 49.0% for the non-diluted waterfloods. Earlier tests with this crude oil and sandstone aged at 55°C and flooded at room temperature were inconclusive as to the effect of brine composition. However, results of cores aged and waterflooded at 75°C clearly show that the diluted waterfloods give more efficient oil recovery.

Aging temperature of 75°C was used in this set of experiments to promote wetting change during the aging process. Past research has shown that a higher aging temperature increases the change in wetting state from very strongly water wet. Fingering of the water through the oil during the 20°C waterfloods could have masked a possible increase in recovery due to dilute water injection. Flooding at the higher temperature, 75°C lessened the impact of possible viscous fingering.

Flooding of Core INL-19 with dilute brine gave very significant increase in oil recovery compared to the undiluted waterfloods; 66% OOIP versus 49% OOIP, a 35% increase. Core A18 also had the lowest initial water saturation of all the cores in this data set (see Table 1.9). Figure 1.13 is a plot showing the relationship between oil recovery and initial water saturation for the five cores in the diluted waterflood set. As can be seen, there is a weak correlation with oil recovery increasing with decrease in initial water saturation.

Conclusions Drawn from Minnelusa Corefloods at 75°C. Oil recovery was increased from 49.0% to 55.6% of OOIP on average – a percent increase of 13.7% – by injecting diluted reservoir brine compared to undiluted waterfloods using Berea sandstone, Minnelusa crude oil, and synthetic Minnelusa reservoir brine. Aging temperature and flooding temperature were both 75°C (167°F).

2.5 Monument Butte Field

Earlier work at the University of Wyoming indicated that paraffinic crude oils were more amenable than asphaltic crudes to increased oil recovery by injection of fresh water. The Monument Butte field in the Uinta Basin produces a high wax content crude oil and is currently expanding a small waterflood pilot to the field. Potable water is available as a source of injection water and Inland Resources Inc., operators of the field, were interested in the applicability of dilute waterflooding to the Monument Butte field to increase oil recovery during waterflood operations.

2.5.1 Depositional Environment and Reservoir Description

The Monument Butte field is located in the Uinta Basin. The Uinta Basin is a topographic and structural trough encompassing an area of more than 9300 mi^2 in northeast Utah (Utah Geological Survey 2000). The basin is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank. The Uinta Basin formed in Paleocene to Eocene time, creating a large area of internal drainage that was filled by ancestral Lake Uinta. Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine sediments that make up the Green River Formation. Alluvial red-bed deposits, which are laterally equivalent to and intertongue with the Green River Formation, make up the Colton Formation (Wasatch).

More than 450 million barrels of oil have been produce from the Green River and Colton Formations in the Uinta Basin. The Cedar Rim, Altamont, Bluebell, and Red Wash fields produce from the northern shoreline deposits of Lake Uinta, while the fields in the Monument Butte area produce from southern deltaic shoreline deposits as preserved in the Middle and Lower Members of the Green River. The southern shore of Lake Uinta was very broad and flat, which allowed large transgressive and regressive shifts in the shoreline in response to climatic- and tectonic-induced rise and fall of the lake. The cyclic nature of Green River deposition in the Monument butte area resulted in numerous stacked deltaic deposits. Distributary-mouth bars, distributary channels, and nearshore bars are the primary producing sandstone reservoirs in the area. The Lower Douglas Creek sandstone and the D sandstone of the Green River formation are the more important reservoir units in the greater Monument Butte field.

2.5.2 Formation water analysis

In the fall of 2000, produced water was collected from a number of wells in the field. The total dissolved solids (TDS) of these water samples ranged from 9116 ppm to 14532 ppm; the average being 11780 ppm. An analysis of the formation water is shown it Table 1.10.

The simulated formation water recipe used in the laboratory corefloods is based on an average of seven produced water analyses. The calculated composition is shown in Table 1.11.

2.5.3 Injection water analysis

Three different field injection water analyses were also obtained. The injection water for the waterflood ongoing in the field is obtained from a surface source. The TDS of the injection water ranges from 402 ppm to 729 ppm with the average being 583 ppm. The average injection water analysis is shown in Table 1.12, while the calculated composition is shown in Table 1.13.

2.5.4 Crude oil preparation

Crude oil and water samples were collected simultaneously from a number of wells from the Monument Butte field at the same time as the water samples were collected. However, all oil used in the corefloods was collected from the same well: Monument Butte 3A-35. The oil was heated to the reservoir temperature of 140°F, filtered to remove any particulates, and placed under vacuum for one hour to remove light ends and reduce the possibility of gas coming out of solution during coreflooding. The filtered and degassed oil was then placed in a capped bottle and stored in an oven at 140°F.

2.5.5 Laboratory corefloods

A series of laboratory corefloods were done to evaluate the process of dilute water injection to improve waterflood recovery for the Monument Butte field. Because this crude oil has a high pour point (95°F), all oil handling and corefloods were done in an oven at the reservoir temperature of 140° F. Before using field core, waterfloods were first done using Berea sandstone cores in order to be sure the experimental procedures were adequate to handle the new methodology at higher temperatures in the oven.

The cores' dimensions were measured and the cores were then coated in epoxy as described earlier for the Minnelusa cores. After the cores were saturated with Monument Butte formation brine, Monument Butte crude oil from well 3A-35 was injected through the cores to establish the initial oil saturation (S_{oi}) and connate water saturation (S_{wc}). The cores were then stored in the 140°F oven at these conditions ($S_{oi} + S_{wc} = 1$) for at least two weeks to allow the wetting state to stabilize. Figure 1.14 is a schematic diagram showing the laboratory setup used when waterflooding the cores using Monument Butte formation fluids.

Initial and produced volumes of oil and water were calculated at flooding conditions (T = 140°F). Waterfloods were run at a maximum of 3 ft/D or 60 psid. Produced oil was quantified by measuring the volume collected in the produced oil trap, and the water was back-calculated from the weight of the produced water collected outside the oven (to prevent or reduce evaporation). Produced water volume was calculated from the produced weight and the density at 140°F.

Berea sandstone. Two cores, INL-26 and INL-27, were prepared from the Berea sandstone block INL-C. Permeabilities and porosities of the two cores are shown in Table 1.14.

The purpose of waterfloods was to determine if waterfloods using fresh water would recover more oil than waterfloods using formation water. Results using Berea sandstone, Monument Butte field core, and simulated reservoir and injection brine were primarily meant to work out waterflooding procedures to be sure field cores would not be wasted because of procedural inadequacies. Nevertheless, nothing abnormal occurred and no problems were encountered during the Berea sandstone corefloods that would preclude the results from being used and reported. Injection rate was set at 3 ft/D. The results of the Berea sandstone corefloods are shown in Figure 1.15. Data weren't collected for the fresh water flood between one and four pore volumes, so care should be taken when comparing shape of the recovery curves of the two floods. The oil recovery at 7.5 pore volumes (the termination point for core INL-27) was 32.7% OOIP for INL-26 and 34.9% OOIP for core INL-27. The percent difference in recovery between the two floods was 6.8%.

Field core. Field core was collected from 5 different wells from the Monument Butte field: Paiute 34-8, Monument Butte 3A-35, Allen 34-5, Federal 6-35, and Mon Fed 33-11J. The cores were obtained from the State of Utah Department of Natural Resources – Utah Geological Survey in August of 2000. The cores were then taken to TerraTek at University Research Park in Salt Lake City, where plugs were cut and cleaned and put through routine core analysis. Results of the analyses are shown in Table 1.15.

One half of the core plugs collected were sent to the University of Wyoming and the other half was kept at the INEEL for waterflood experiments. Three sets of core pairs were selected from the plugs kept at the INEEL for waterflooding studies. One pair (samples 3 and 4) was from well Paiute 34-8, another (samples 7 and 8) was from well 3A-35, and the other pair (samples 17 and 18) was from well Federal 6-35. Porosity and permeability (using CO_2) were calculated for these six core plugs at the INEEL. Table 1.16 lists these results as well as the values for porosity and permeability obtained from TerraTek for comparison.

The rock properties measured at the INEEL compare quite closely to those obtained by TerraTek on the same core plugs. This comparison is shown here to demonstrate that core preparation techniques at the INEEL, although they are somewhat different from those at TerraTek (and other laboratories), yield substantially the same values. The INEEL-calculated properties were done after the core plugs were encapsulated in epoxy, which changes the way the cores can be handled in the laboratory. This favorable comparison adds credence to the waterflood results obtained at the INEEL.

Even though Berea sandstone was used first, to work out difficulties encountered during the coreflooding procedures, problems did arise during the first pair of Monument Butte field cores. The field cores were significantly lower in permeability than the Berea sandstone cores. Because the field cores had such low permeability, the waterflood flow rate was quite slow at the maximum differential pressure of 60 psi. The first coreflood (core 3 from Table 1.16) was shut down after only four pore volumes were injected because the oil recovery curve appeared to have ceased to increase and because of the long duration of the flood. However, the next flood (core 4) was extended to over 10 pore volumes and oil recovery continued to increase throughout the duration of the flood. This suggests that the recovery from core 3 could have also increased were the waterflood allowed to continue. Because of the procedural inconsistency between the two floods, a comparison between them was not made.

Cores 7 and 8 were deemed too tight (permeability of 2.3 md) to waterflood without applying excessive pressure. The pressure was limited because of concern that the epoxy coating could crack causing loss of fluid containment and core loss.

Cores 15 and 16 were successfully flooded with formation water and fresh water respectively. Both were flooded at an injection rate of 0.3 ft/D with a differential pressure of 60 psi across the core.

The initial water saturation of core 15 was 19.0% and the initial water saturation of core 16 was 22.5%. If the same trend for oil recovery and initial water saturation applies to the Monument Butte cores as was seen with the Berea/Minnelusa cores, then a higher oil recovery would be expected for core 15. Core 15 was flooded with formation water and core 16 was flooded with fresh water. Results for the two waterfloods are shown in Figure 1.16.

As can be seen from Figure 1.16, the fresh water flood recovered significantly more oil than the formation water flood. At 10 pore volumes, the formation water flood recovered 37.5% of the OOIP, while the fresh water flood recovered 42.1% of the OOIP, which is a percent increase of 12.4%

Discussion of Monument Butte Corefloods. Both pairs of waterfloods done with Monument Butte reservoir fluids resulted in higher recovery from the fresh water flood compared to the formation waterflood. This is a significant finding, but should be tempered because this is the result of only four corefloods (two done with Berea sandstone and two done with Monument Butte field core). Additional testing on field cores is being done at the University of Wyoming. If similar results are obtained with additional testing, field operators of the Monument Butte field can use these results as an aid to development as the waterflood is expanded to other parts of the field.

2.6 Discussion

2.6.1 Historical field waterflood

A search of historical waterfloods from publications from the WOGCC indicated that there were a number of waterfloods that used Minnelusa formation water as the water source as well as a number of fresh water floods. However, upon detailed analysis and searches only one flood with brine of moderate salinity was located, while many fresh water floods were found. Even in this case the primary water source was a Minnelusa sand, with salinity of 11,780 ppm compared to the reservoir formation water salinity of about 60,000 ppm. When the formation water flood was compared to the two fresh water floods recovery was about 16% (4.5% OOIP) greater for the fresh waterfloods than for the 11,780-ppm West Semlek flood.

State and public records indicate that some polymer was used in all three field-floods, but there was not enough information to determine how much polymer was used. The use of polymer to augment the waterfloods could limit the accuracy of the comparison of the three floods. Questions that arise because of this could include: Was the polymer treatment as effective in the 11,780-ppm flood as it was in the fresh water floods? How much polymer was used in each of the three floods? How does the use of polymer affect the wettability? Without answers to these and other questions pertaining to the use of polymer to augment waterflood recovery, data from these three fields, should be treated with caution.

2.6.2 Laboratory investigations of improved waterflooding

Laboratory work at the INEEL began using Berea sandstone cores that were cut and stored for five or more years at a temperature of 55°C and at ambient pressure. Comparative salinity tests showed no differences in oil recovery. This behavior might be related to changes in the clay properties that could have occurred during storage at elevated temperature. Waterfloods using cores cut from the new block of Berea sandstone showed increased oil recovery for dilution of both the connate and the injection brine. The rock appears to be a critical component of the improved oil recovery system. The amount and type of clay present within the pores of the rock has been identified by work at the University of Wyoming as a critical element in the application of this process. After firing Berea sandstone at 800°C to destroy the clay structures increased recovery was no longer observed for injection of dilute brine. More work needs to be done, however, to determine the relationships between clay quantity, species, and geometry and the changes in clay/brine/crude oil interactions and wettability and the improved oil recovery that results from dilute brine waterflooding.

Corefloods using Minnelusa reservoir fluids. In the first tests of recovery for Minnelusa crude by waterflooding with dilute brine, no increase in recovery was observed for cores that were aged at 55°C followed by flooding at room temperature.

In the second series of tests, when cores were aged and then flooded at 75°C, oil recovery was significantly increased (from 49.0% to 55.6% of OOIP) by injecting diluted reservoir brine compared to undiluted waterfloods. Based on these results, it appears that there was a greater effect when the waterflood was run at reservoir temperature.

2.6.3 Monument Butte field evaluation

The evaluation of the Monument Butte field was fairly straightforward. Some good quality cores were collected from the core library at the Utah Geological Survey. The preliminary corefloods using Berea sandstone indicated that the reservoir fluids had potential to recover more oil when fresh injection water was used. Waterfloods using field cores and reservoir fluids substantiated preliminary results were also obtained using Berea sandstone. Oil recovery was increased by 12.4% when fresh water was used as the injection water as opposed to the injection of formation brine.

These findings can be useful when planning the expansion of the current waterflood in the Monument Butte field. It is suggested that, provided formation damage is not an issue, the operators use fresh water when expanding the waterflood to new areas of the field and re-inject produced water into areas of the field that are already under waterflood.

2.7 Conclusions

- Analysis of the historical field record of waterfloods in the Powder River Basin indicated that injection of fresh water (583ppm) gave increased oil recovery compared to injection of a 11,780-ppm brine.

- Rock properties appear to play an important role in improved oil recovery from waterfloods using diluted injection water.

- Temperature of displacement appears to play a major role in wettability alteration associated with improved oil recovery by injection of low salinity water.

- At a temperature of 75°C and using an ensemble of Berea sandstone, Minnelusa crude oil, and Minnelusa reservoir brine, oil recovery increased from 49.0% to 55.6% when using a 100-fold dilution of the reservoir brine as the injection brine increased oil recovery when compared to that for injection of the reservoir brine.

- Waterflood tests done in the laboratory using Monument Butte field core, crude oil, and formation water indicate that production from this field may benefit from a strategy that takes advantage of the availability of fresh injection water.

- During expansion of the waterflood in the Monument Butte field, fresh water should be used in all new areas and produced water should only be used as a source for injection water in areas of the field where the waterflood has been operating for longer periods.

3. LABORATORY STUDIES AT THE UNIVERSITY OF WYOMING

3.1 Introduction

Numerous examples of the dependency of the efficiency oil recovery by waterflooding and spontaneous imbibition on brine composition have been reported (Jadhunandan and Morrow 1991, Yildiz and Morrow 1996, Yildiz, Valat and Morrow 1999, Tang and Morrow 1997, 1999a, 1999b, 2002, Morrow et al. 1998). Increases in oil recovery of over 50% OOIP have been observed with change in brine composition. There are many possible scenarios for improved recovery that have yet to be explored. Studies aimed at field application have focused on the observation that injection of dilute brine, relative to the composition of the connate (initial brine) gave higher recovery than injection of brine of the same composition as the connate brine (Tang and Morrow 1997, 1999a, 1999b, 2002). The mechanism by which improved recovery is obtained is not well understood. The strategy of the project was to confirm observations for a wider variety of crude oil and rock types, and to identify field situations where improved recovery by injection of dilute brine is likely to give improved recovery.

A major problem in the development of this work is the large number of variables that can only be defined in broad terms. Rocks, usually characterized by permeability and porosity, have complex pore structure and mineralogy. Crude oils are characterized by chemical properties such as asphaltene content, acid and base numbers, and physical properties such as viscosity and density. Reservoir connate brines and waterflood injection brines are generally solutions of mainly monovalent and divalent ions that vary widely in salinity. For the brines, at least, their compositions can be determined in detail and synthetic brines of desired composition can be prepared. The outcome of a waterflood depends on the interplay of crude oil/brine/rock (COBR) interactions that determine wetting properties and displacement efficiency. Numerous other conditions must be considered in the design of displacement tests. Tests are broadly divided into those aimed at improved understanding of the displacement mechanism and those mainly designed for screening individual reservoirs for field application. The factors involved in testing and the considerations that guided the course of the investigation are given below.

3.2 Rock

Many early studies of oil recovery were made on unconsolidated sands and bead packs. Most reservoir rocks are consolidated. However, attempts to prepare a model consolidated-rock were only partially successful. In the 1950s, a quarry that produced building stone from an outcrop Berea sandstone was identified as a convenient source of large blocks of uniform sandstone needed for research purposes. Since then, about 90% of laboratory production research studies of oil recovery have been made with rock from this source.

The mostly commonly used form of Berea sandstone had permeability of about 500 to 800 md to gas and porosity of about 22%. This rock (referred to as Berea 800) was mainly used in earlier studies of the effect of brine composition on recovery, and was to be used in the present work for comparison of the recovery behavior of different types of crude oil. Tang and Morrow (1999a) showed that injection of dilute brine gave improved recovery of crude oil from Berea 800 sandstone but if the rock was fired, the recovery was independent of brine composition. This, and other observations, suggested that the presence of potentially mobile clay, in all likelihood kaolinite, in Berea 800, played a key role in the recovery mechanism.

About three years ago, ordered supplies of Berea sandstone were found to have unexpectedly low permeability (about 60 to 90 md to brine). Extended discussions were held with the quarry operators. However, all further batches of the supplied rock were found to have low permeability and porosity and mineralogical features that differed from Berea 800. While it is of interest to test rocks with different properties, the loss of Berea 800 as a model rock for parametric studies was a serious setback to this and other projects. Some Berea sandstone was supplied in cubic foot blocks from storage by courtesy of Philips Petroleum. Screening tests sometimes involved use of reservoir core samples as identified in the text.

In addition to permeability and porosity, several of the rock samples were characterized by a suite of measurements that consisted of BET surface areas, cation exchange capacities, and x-ray diffraction. Results obtained to date for the rock samples used in this study are shown in Table 2.1. Petrographic thin sections and SEM micrographs were also prepared.

3.3 Crude Oil

Initial observations of sensitivity of oil recovery to salinity were for a strongly acidic Moutray crude oil (Yildiz and Morrow 1996). The difference in recovery for the tested pair of brines was about 6%. Subsequently, larger changes (about 15% OOIP) for the same pair of brines were observed for an asphaltic crude oil of high base number. Observations of improved recovery for dilute brines were made on an Alaskan crude oil and two other crudes from reservoirs being considered for field application (Tang and Morrow 1997, 1999a). Comparative tests of results for different crude oils within the past few years have been hindered by the loss of the Berea 800 as the model rock for which distinct brine composition effects had been observed.

In obtaining crude oil samples, it is important that they be obtained from wells that are free of surface active contaminants such as corrosion inhibitors or other well treatment chemicals. Oil samples used in this and past studies were obtained from new wells that had not been treated with surface-active chemicals, or from wells that had been flowing for a long period, of the order of years, since chemical treatment. Whenever possible, the oil is obtained at one time as a single sample of sufficient volume to complete the relevant series of tests. For oils selected as standard test crude oils, one-barrel samples were usually obtained. This ensured a sufficient supply of oil for both the experimental program and for meeting requests for samples from other laboratories. For reservoir screening, samples of about 10 liters were usually obtained. Crude oil properties used in the present work are given in Table 2.2.

Many of the displacement tests reported below were run at elevated (reservoir) temperature as indicated with the results. Two approaches were taken to avoid evolution of gas during waterflooding. The first was to elevate the mean pressure of the displacement through use of a backpressure regulator. (Cases where backpressure, P_b, was applied are indicated with the results. Otherwise, the backpressure was zero.) However, recovery curves obtained using backpressure regulators sometimes featured inconsistencies (including early breakthrough) that presented unexpected uncertainty in the interpretation of results. This behavior may have been related to pressure pulses but was not investigated in detail. The second approach was to degas the oil by evacuation. This gave more consistent displacement results and maintained the basic simplicity of the experimentation that was essential to running a large number of tests. As with loss of solution gas, further removal of light ends from the crude oil will tend to increase the oil viscosity and also increase the solvency of the oil for its heavy polar components (Buckley et al. 1998). As a consequence, the wettability alteration properties of the crude oil may be somewhat modified. However, in general, this is not likely to be a dominant factor with respect to the wettability states induced by the different crude oils.

3.4 Initial water saturation

The amount and distribution of brine in a rock is a key variable with respect to development of mixed wettability (MXW) states generated by adsorption from crude oil. Synthetic reservoir brine compositions used in the present work are given in Table 2.3. Initial saturations of selected brine composition were usually established by flow of oil with pressure drop and volume throughput carefully controlled when aiming for the target initial water saturation. Low initial-water saturations were established by displacement of water by air using a porous plate. The core was subsequently saturated with crude oil under vacuum. The initial brine is referred to as connate brine by analogy with reservoir connate brine in discussion of displacement experiments.

3.5 Time and temperature of aging cores in crude oil.

Cores containing crude oil at initial water saturation were aged in sealed stainless steel pressure vessels for 10 days at reservoir temperature or at a selected compromise temperature in comparative studies of crude oils from different reservoirs.

3.6 Waterfloods

Cores were set in viton rubber sleeves and mounted in specially designed core holders. Details of the procedure are available (Tang 1998, Zhang 2000). Brine used in waterflooding the prepared cores is referred to as the injection brine (IB). The injection rate in all experiments corresponded to a frontal advance rate of about 3ft/day. Although reservoirs are seldom flooded with more than up to one pore volume of brine, the laboratory measurements are compared over a much wider range of volume throughput. The results are still considered relevant to recovery from the swept zones of a reservoir.

3.7 Results

3.7.1 Effect of Initial Water Saturation on Oil Recovery from Berea Sandstone

The effect of initial brine saturation was investigated for several classes of Berea sandstone distinguished by permeabilities of about 60md, 500md, and 1100md. In all cases, Minnelusa reservoir brine (see Table 2.3) was the initial (connate) brine.

3.7.2 Cores with Air Permeability of 60 md (B60)

A summary of B60 core properties is given in Table 2.4. The cores were saturated with Minnelusa reservoir brine (MRB) prior to establishing initial water saturation. Waterflood recovery curves with the injection brine of same composition as the connate brine are shown in Figure 2.1. Recovery as % OOIP increased with increase in initial water saturation. This trend is clear from the plots shown in Figure 2.2 of recovery versus connate water at 2 and 10 PV injected. Plots of residual versus initial oil saturation for this MXW data set are shown in Figure 2.3.

Water flood recovery curves for injection of dilute brine are shown in Figure 2.4. There was a tendency for recovery (% OOIP) to increase with initial water saturation as illustrated by plots of recovery at 2PV injection and at 10 PV injection of dilute brine (Figure 2.5). Plots of residual versus initial saturation are shown in Figure 2.6 for dilute brine injection.

Comparisons of recovery for injection of RB and 0.01 RB are presented in Figure 2.7 for 2 PV injection and in Figure 2.8 for 10 PV injection. At 2 PV injection recovery for injection of dilute brine was slightly higher than for RB brine at all levels of initial saturation. However, after injection of 10 PV, recoveries were essentially the same for the two types of brine except for a small difference at an initial water saturation of about 17%.

It is concluded that Berea 60 is only slightly sensitive to injection brine salinity and that B60 is of limited value as a model rock for systematic investigation of the effect of brine composition on oil recovery.

3.7.3 Cores with Air Permeability of 500 md (B500)

A series of tests of the effect of connate water on oil recovery were run on Berea sandstone cores with permeabilities to air of about 500 md. Core properties are presented in Table 2.5.

Recovery curves for injection of reservoir brine for cores with initial water saturation ranging from 11 to 28% are presented in Figure 2.9. Recovery versus S_{wi} at 2 PV and 10 PV injected are shown in Figure 2.10. At 2 PV injected, the % OOIP recovered increased gradually with initial water saturation. At 10 PV injected, the % OOIP recoveries for the two cores with the lower initial water saturations were about equal and for the core with the highest initial water saturation there was only slight increase in recovery from 2 PV to 10 PV injected. Plots of residual versus initial saturation for this MXW data set are shown in Figure 2.11.

Recovery curves for injection of 0.01 RB are presented in Figure 2.12. Comparison of recoveries for injection of dilute brine at 2PV and 10PV injected is shown in Figure 2.13. The results showed a minimum in recovery at about 18% S_{wi}.

Figure 2.14 shows a comparison of waterflood recovery versus initial water saturation at 2PV injected for both MRB and 0.01 MRB injection. Corresponding plots for 10 PV injected are shown in Figure 2.15. In all cases, the recovery for injection of dilute brine was significantly higher than for RB, the minimum difference being almost 10% OOIP. At high initial water saturation (27%), the increase in recovery over that for MRB flooding was about 30% OOIP. This trend is counter-intuitive in that it might be anticipated that, the higher the initial RB brine saturation, the lesser the effect of injecting low salinity brine. These results have implications with respect to recovery from transition zones and zones of higher water saturation.

Plots of residual versus initial oil saturation for injection of MRB and 0.01 MRB are shown in Figure 2.16 for 2 PV and 10 PV injection.

3.7.4 Cores with Air Permeability of 1100 md (B1100a)

A third series of tests of the effect of initial water saturation was made using Berea sandstone of about 1100md permeability (see Table 2.6). Recovery curves for injection of reservoir brine for two levels of initial water saturation (15% and 23%) are shown in Figure 2.17. Recovery, expressed as % OOIP, increased with increase in initial brine saturation. Recoveries at 2PV and 10 PV injection versus initial water saturation are shown in Figure 2.18.

Recovery curves for injection of dilute brine into cores with connate water saturation ranging from 8 to 24% are shown Figure 2.19. Recovery versus initial water saturation for 2 and 10PV injected is presented in Figure 2.20.

Oil recovery by dilute brine flooding for the 1100md sandstone decreased with decrease in initial water saturation from 27% to 17% but was essentially constant for further reduction in initial water saturation down to 8%. Residual versus initial oil saturation is plotted in Figure 2.21.

Comparison of recovery versus initial water saturation for reservoir and dilute brine flooding is presented in Figure 2.22. For the two saturations for which recovery by RB flooding was measured, the dilute brine flooding clearly gives increased recovery. Residual versus initial oil saturation for MRB and 0.01 MRB flooding at 2 and 10 PV injected are shown in Figure 2.23.

3.7.5 Connate and Injection Brine Salinity

Connate brine salinity - B60. Large increases in waterflood recoveries were observed from Berea 800 when the connate water was changed from synthetic reservoir brine to a dilution of this brine (Tang and Morrow 1997). The effect of the connate water composition was tested in the present work for the 60md Berea sandstone (see Table 2.7). The two cores had almost the same S_{wi}. The waterflood results are shown in Figure 2.24. Final oil recoveries for B60-8 and B60-9 at 10 PV injected were 69% and 67%, respectively, but the recovery for B60-9, especially in the range of 1 to 3 PV injection, was significantly lower than for B60-8. This behavior is unusual; very high recoveries have been observed previously for cores containing dilute connate brine no matter what brine was injected (Tang and Morrow 1997). Further tests would be needed to confirm the observed behavior. Overall, these results are consistent with the conclusion drawn from the results for the effect of initial water saturation on recovery from B60, that this rock is relatively insensitive to brine composition.

X-ray refraction results for the low permeability Berea showed that chlorite was present in about equal or greater amount than kaolinite.

3.7.5.1 Connate and injected brine salinity - heterogeneous Berea (450 to1000md) – Bhet.

Cores cut from a 1 cu. ft. block of Berea sandstone obtained from Philips Petroleum Company were found to range in permeability from 450 to 1000md. The properties of cores used in displacement tests are listed in Table 2.8.

Three cores, with permeabilities close to 450 md, were selected for testing. Initial water saturations of about 26% were established by flow of Minnelusa crude oil. Waterflood recoveries were measured for three conditions: MRB as both the connate and injection brine (Bhet-450-1); MRB as the connate brine and 0.01 MRB as the injection brine (Bhet-450-2); 0.01 as both the connate and injection brine (Bhet-450-3). The results are shown in Figure 2.25.

With MRB as the connate brine, injection of dilute brine gave about 5% less recovery than injection of reservoir brine (Bhet-450-3). This result was counter to most previous observations and may be related to differences in individual core properties. With dilute brine as both the connate and the injection brine, break-through recovery was about the same as for Core Bhet-450-2, but recovery continued to increase after break-through. After 10 PV injection, the recovery for Bhet-450-3 was about 20% OOIP higher than for Bhet-450-2 and about 15% higher than for Bhet-450-1. These large differences demonstrate that, even though unexpected behavior was observed for Bhet-450-2, oil recovery from Bhet-450 can be distinctly sensitive to brine composition. The major clay constituents for this rock were kaolinite and illite.

Injection brine salinity - 350/440 md (Berea- B350/440). Two core plugs were cut from the same block of Berea sandstone. Permeabilities were 350 and 440 md and the cores were designated as B350 and B440 respectively (see Table 2.9). Both cores had initial reservoir brine (MRB) saturations of about 25% established by flow of Minnelusa crude oil. The cores were aged and flooded at 75°C. Core B440 was flooded with MRB and core B350 with 0.01MRB. Experiments were run at 40 psi backpressure to prevent evolution of gas from the oil.

Displacement with reservoir brine (B440) showed only small increase in recovery after breakthrough. Final oil recovery at 10PV injected was 56.8% OOIP. As seen from Figure 2.26, oil recovery for B350 increased slowly after breakthrough until 2.9 PV of 0.01 MRB had been injected and the oil recovery was 55.6% OOIP. Then, the effluent became cloudy and production of an emulsion caused difficulty in defining the interface in the oil/brine separator. With further injection of dilute brine, oil production increased rapidly. After injection of 4 PV of dilute brine, oil recovery had increased to 67.9% OOIP. Thus, within injection of 1.2 PV, oil recovery increased by more than 12% OOIP and was consistent with release of clay particles. The recorded pH of the effluent brine during the B350 waterflood rose from 8.1 to 8.9. Detailed characteristics of these rocks have not yet been measured.

3.7.5.2 Connate and injection brine salinity - B1100b.

Waterfloods - Cores identified as the B1100b series were cut from a block of Berea sandstone with an average air permeability of about 1100 md. Properties of the cores are summarized in Table 2.10. Initial water saturations of 26±1% were established by flow of Minnelusa crude. The cores were then aged in Minnelusa oil for 10 days at 75°C. Four waterfloods were then run at 75 °C for the following connate water /injection water salinities: MRB/MRB (B1100b-1); MRB/0.01MRB (B1100b-2); 0.01MRB/MRB (B1100b-3); 0.01MRB/0.01MRB (B1100-4). The results are presented in Figure 2.27. All four recovery-curves had approximately the same shape.

With MRB as the connate brine as well as the injection brine, final oil recovery after injection of 10 PV was 64% OOIP. For the duplicate core plug B1100b-2 with MRB as the connate brine, injection of 0.01MRB gave 62% OOIP oil recovery. Within the limits of experimental error (±2% OOIP) these two recoveries are equal. All of the recoveries are significantly lower than those obtained for corresponding displacements with B1100a cores. For B1100-4 with MRB as the connate brine, the recovery for injection of reservoir brine was 78% OOIP (B1100a-2), and 90% OOIP for injection of 0.01 MRB.

Cores B1100b-3 and B1100b-4 both initially contained 0.01 MRB as the connate brine and were flooded with MRB and 0.01 MRB, respectively. Final oil recoveries at 10 PV injection for B1100b-3 and B1100b-4 were 78% and 76%, respectively. Thus the presence of 0.01 MRB as the connate brine resulted in about a 15% OOIP increase in recovery in both cases.

Kaolinite and illite were the main clay constituents for both rock types. The surface area for B1100a was 0.348 sq m/gm. For B1100b (two samples) the areas were 0.834 and 0.551 sq m/gm, which on average is about twice as high as for B1100a. Ion exchange capacities were also higher for B1100b (see Table 2.1).

3.7.6 Spontaneous imbibition – B1100b

Measurements of oil recovery by spontaneous imbibition were made in order to aid in identifying the wetting state of the cores. These measurements also provide comparison with previously reported companion sets of waterflood and spontaneous imbibition data (Tang and Morrow 1997).

Four cores, designated as B1100b-(5 to 8) were cut from the B1100b block and then prepared under conditions that gave a duplicate set of plugs with respect to the B1100b-(1 to 4) core series. The invading brine in the imbibition tests corresponded to that used in the waterflood tests (Figure 2.27 and Figure 2.28). All cores showed significant imbibition with oil recoveries ranging from 43 to 74% OOIP. Core properties and initial and final water saturations achieved by spontaneous imbibition are included in Table 2.10.

With MRB as the connate brine, the final recovery for invasion of the 0.01MRB was 5% lower than for invasion of MRB. With dilute brine as the connate brine, imbibition of reservoir brine gave about 74% OOIP recovery. With 0.01MRB as the connate brine, imbibition of 0.01MRB gave about 64% recovery.

The average oil recovery for the cores initially saturated with 0.01 MRB was 69%, which was 24% higher than that obtained from the cores originally saturated with MRB (45%), indicating that the efficiency of oil recovery by imbibition was dominated by the salinity of the connate brine. For these tests, the invading brine did not have much effect on final oil recovery.

3.7.7 Change in salinity for tertiary mode flooding – B360.

CS Crude oil. Two cores were taken from a block of Berea sandstone with nominal permeability of 360md. This sandstone is designated as B360 and the cores as B360-1 and B360-2 (see Table 2.11). Waterfloods were run with a backpressure of 40 psi on CS crude oil/CS brine/Berea sandstone mainly to avoid the possibility of gas evolution during displacement at elevated temperature.

Core B360-1 was initially saturated with CS RB. An initial water saturation of 21% was established by flow of CS crude oil. The core was aged at 55 °C for 10 days. 10 PV of CS RB was then injected followed by 10 PV of distilled water, the extreme case of dilute brine flooding. After injection of 1.7 PV of distilled water, cloudy effluent was observed, and after injection of 2.5 PV, an additional 3.8% of OOIP was produced (see Figure 2.29). Recovery after injection of distilled water eventually increased the recovery from 43.4%, at 10 PV CS RB injected, to 49.6% OOIP.

For Core B360-2 the connate brine was double the concentration of the CSRB. After injection of 10PV CSRB the recovery was 40.6% OOIP. After injection of 10 PV 0.01 CS RB, an additional 7.8% OOIP was recovered (see Figure 2.29). However, for this core, the recovery given by injection of CS RB up to 10 PV indicates that comparable recovery would have resulted from continued flooding with CS RB. An increase in measured pressure drop from stable values of about 2 up to 5.6 psi indicated that increase in resistance to flow had accompanied the change in injection brine composition.

Detailed rock properties are not available for this rock.

Minnelusa crude oil. Tertiary-mode recovery of Minnelusa oil was also tested. A core plug, B360-3 (see Table 2.11), was saturated with MRB and initial water saturation was established by drainage using a porous plate. The core was then evacuated for 5 minutes before filling the remaining pore space with Minnelusa crude oil. Other preparation and displacement conditions are given in Figure 2.30. After establishing a well-defined residual by flow of MRB up to 10 PV, the injection brine was switched to 0.01 MRB. Only very slight increase in recovery was observed for 5 PV injection of the dilute brine.

3.7.8 A95 crude oil – *B1100a*

Recovery of A95 crude oil in tertiary mode was tested for three core plugs taken from the same block of Berea sandstone. The cores had gas permeabilities of 844, 888, and 942 md (see Table 2.12). They were saturated with reservoir brine designated ARB (see Table 2.3) and flooded to initial water saturations of about 23%. The cores were then flooded with about 11 PV of ARB followed by 11 PV of 0.1ARB and then 11 PV of 0.01 ARB. The results presented in Figs. 2.31, 2.32, and 2.33, show that the increase in recovery that followed reduction in salinity of the injection brine was usually much less than 2% OOIP.

3.7.9 Scaling of tertiary mode oil recovery from MXW rocks – B1100a

The effect of core length on recovery behavior was tested by comparison of waterflood behavior for 3 and 6-inch length cores (see Table 2.13). Four 3-inch length and two 6 inch B1100a cores were initially saturated with CS reservoir brine (see Table 2.3). Initial water saturations of about 21% were established by flow of CS crude oil. Cores were aged at 55°C for 10 days. In all cases, recovery after break through increased with PV injected up to about 8PV at which stage the recovery curve flattened off to give a well-defined residual oil saturation. Injection of CS RB was continued up to about 10 PV and then 0.01CS RB was injected for at least another 10 PV.

Results for the all four 3 inch cores were generally consistent (see Figure 2.34). Pressure drop across the core increased upon injection of dilute brine. Recovery from the core that exhibited the lowest pressure increase upon injection of dilute brine (B1100a-9) gave the least tertiary mode recovery. Recoveries at break through, after injection of CS RB, and after injection of 0.01 CS RB, are summarized in Table 2.13.

Waterflood recovery curves for the 6-inch cores are presented in Figure 2.35. Recovery behavior and pressure drop for the two cores were in very close agreement. Recovery increased by 6% OOIP upon injection of dilute brine.

Comparison of results for the short and long cores show some consistent differences with respect to oil recovery at break through, after injection of CS RB, and after injection of 0.01 CSRB. These differences are summarized in Table 2.13. Recoveries for the long cores were always about 6% less than corresponding recoveries for the short cores.

3.7.10 Waterfloods on Reservoir Rock

Minnelusa reservoir rock (MinRR). Core samples (MinRR-1 and MinRR-2) were cut from whole core taken from the Minnelusa formation. The cores were from oil-bearing zones. They were cleaned by extraction with 60/40 toluene/methanol. After establishing initial water saturation of about 25% with Minnelusa reservoir brine, the cores were aged at reservoir temperature (75°C) for 10 days. Waterfloods were run at the reservoir temperature with a backpressure of 80 psi. Test conditions and results are summarized in Table 2.14.

Waterflood results are shown in Figure 2.36. Cores MinRR-1 and MinRR-2 were waterflooded with MRB and 0.1 MRB, respectively. MinRR-1 gave a recovery of 67% of OOIP after injection of 10PV MRB. The oil recovery by 0.1 MRB flooding for MinRR-2 was only about 3% higher than that obtained from MinRR-1. However, as was often the case for floods performed using a backpressure regulator, the results featured early breakthrough.

Monument Butte reservoir rock

(MonBRR). Two clean cores, *MonBRR*-1 and *MonBRR-2* of about 9md permeability from the Monument Butte field were prepared for comparative waterflood tests. Initial water saturations of 22.1 and 21.3 were established by displacement of MonB reservoir brine with MonB crude oil at 60°C. (The crude oil was solid at room temperature.)

Core MonBRR-1 was flooded with MonB reservoir brine. Core MonBRR-2 was flooded with a 750-ppm brine that was representative of MonB source of brine used for water injection. As for the tests on Minnelusa reservoir cores, recovery for injection of dilute brine was slightly higher than for reservoir brine (see Figure 2.37). Oil production continued for both cores with continued injection of brine. After injection of 10 PV brine, the final oil recovery was 35% OOIP for core MonBRR-1 and 38% OOIP for core MonBRR-2. Test conditions and results are summarized in Table 2.14. Although this difference in recovery is small, the increase in recovery for injection of dilute brine is qualitatively consistent with the higher recoveries for the Monument Butte field observed by INEEL for cores of 26 and 30md permeability (See Figure 1.16).

X-ray diffraction showed that the clays in the Monument Butte rock tested by UW were mainly chlorite and illite with essentially no evidence of kaolinite. This may be the reason why only small increase in recovery was observed for injection of dilute brine for the cores tested by UW.

3.8 Conclusions

1. Sensitivity of oil recovery to decrease in salinity of invading brine was dependent on rock properties. The selection of Berea sandstones used in this study exhibited a variety of responses to injection of dilute brine. For two high permeability Berea sandstones (1100a and 1100b), B1100a, which had the lower BET surface area and lower cation exchange capacity, showed a distinctly higher number of instances of increased recovery for injection of dilute brine.

2. For injection of dilute brine, several instances of increased recovery of about 6% OOIP were measured for rocks in the permeability to gas range of 500 to 800 md.

3. For Berea 1100a and for B60, waterflood oil recovery increased with increase in initial water saturation. Decrease in salinity of the injection brine gave additional increase in recovery for Berea 1100. B 60 showed either no or very little increase in oil recovery with injection of dilute brine.

4. Tertiary mode dilute brine floods did not result in significant increase in recovery of Minnelusa and A95 crude oils from Berea sandstone (B360 and B1100a respectively). These oils are very similar in asphaltene content and acid and base number.

5. Injection of dilute brine resulted in slightly increased recovery of Monument Butte oil from Monument Butte rock.

6. For waterflood tests run on Minnelusa crude oil/Minnelusa brine/Berea rock, oil recovery is highly dependent on the brine concentration of the connate water. Oil recovery increases with decrease in salinity of connate brine.

7. Imbibition tests, run on Minnelusa crude oil/Minnelusa brine/Berea rock ensembles, showed that oil recovery increases with the decrease in salinity of the connate brine.

8. Large increase in oil recovery when both the connate and injected brine are dilute shows that salinity shock (resulting from a large difference in connate and injection brine composition) is not a necessary feature of the enhanced recovery mechanism.

9. Waterfloods, run on CS crude oil/CS brine/Berea sandstone ensembles, indicate that part of the residual oil left by reservoir brine flooding can be further produced by injecting dilute brine. (The CS oil is paraffinic with very low asphaltene content and low base number and causes less change in wettability of sandstone than asphaltic crude oils such as the Minnelusa.)

4. FUTURE WORK AND FIELD APPLICATION BASED ON RESULTS FROM INEEL AND UNIVERSITY OF WYOMING.

Overall the results obtained in the study were encouraging. The loss of Berea 800 as a model rock had a large impact on the study, even though some apparent inconsistencies in behavior were observed. This rock had been shown to give significant increase in recovery for injection of dilute brine, and was well suited for identifying trends in recovery with change in experimental parameters. The loss of availability of a brine-sensitive model rock was somewhat offset by the greatly extended range of rock types that were tested. Although few absolute conclusions can be drawn, results are generally consistent with the hypothesis that kaolinite, a potentially mobile clay, plays a key role in the recovery mechanism. Rocks containing mainly chlorite and illite showed only small response to injection of dilute brine. Laboratory results for rocks that had been subjected to extended drying at elevated temperatures showed little sensitivity to brine composition. Overall, the results indicate that the recovery mechanism may be dependent on the distribution and state of attachment of clays within a rock as much as their absolute amount.

Application of low salinity brine flooding will almost certainly be reservoir specific. Comparison of displacements at ambient and elevated temperature showed the importance of temperature and the need to run flooding tests at reservoir temperature. Further progress will depend on a combination of studies on core samples from target reservoirs and development of improved screening criteria through systematic study of selected crude oils and outcrop rocks. If future field tests were encouraging, a major research effort aimed mainly at developing an improved understanding of the mechanisms by which brine composition can affect oil recovery would certainly be justified.

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Figures

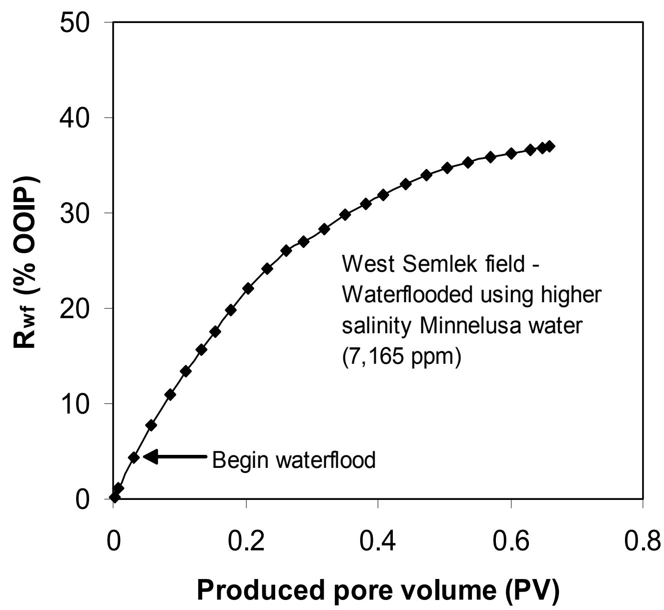

Figure 1.1. Oil recovery from the West Semlek unit.

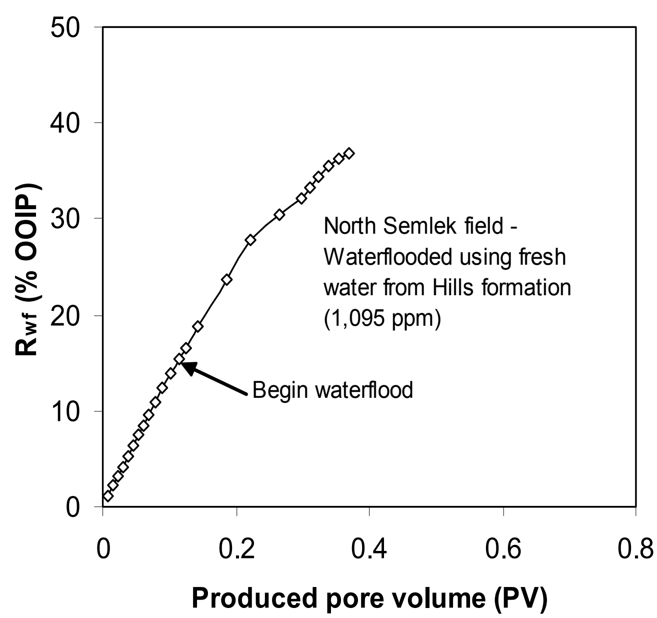

Figure 1.2. Oil production from the North Semlek unit.

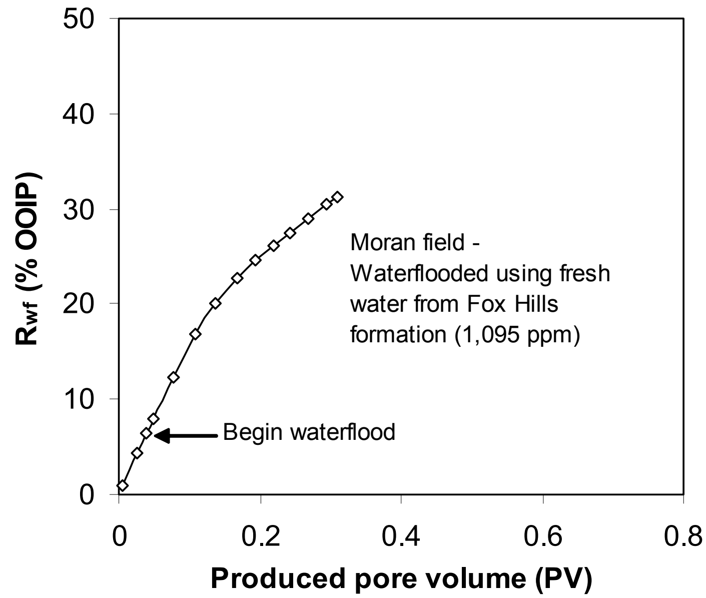

Figure 1.3. Oil production from the Moran field.

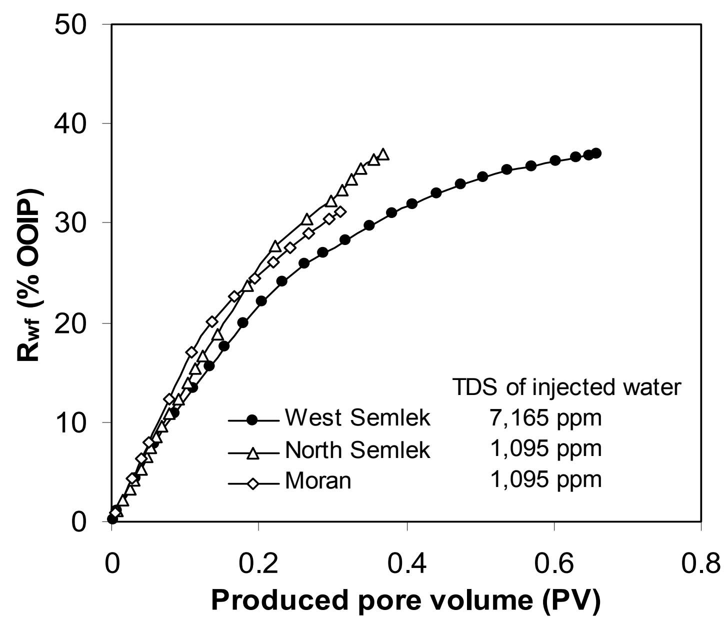

Figure 1.4. Comparison of three Minnelusa field waterfloods showing oil recovery versus produced pore volumes.

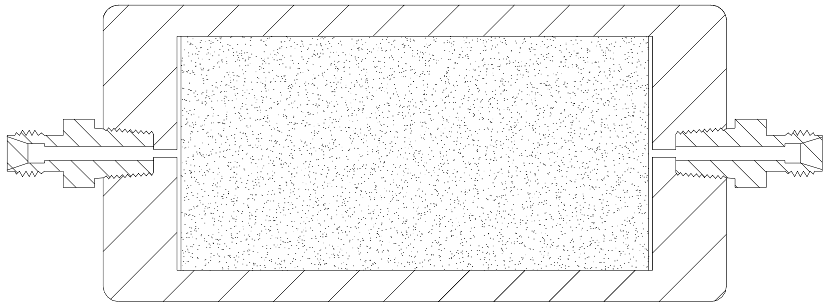

Figure 1.5. Berea sandstone core coated in epoxy with end fittings in place.

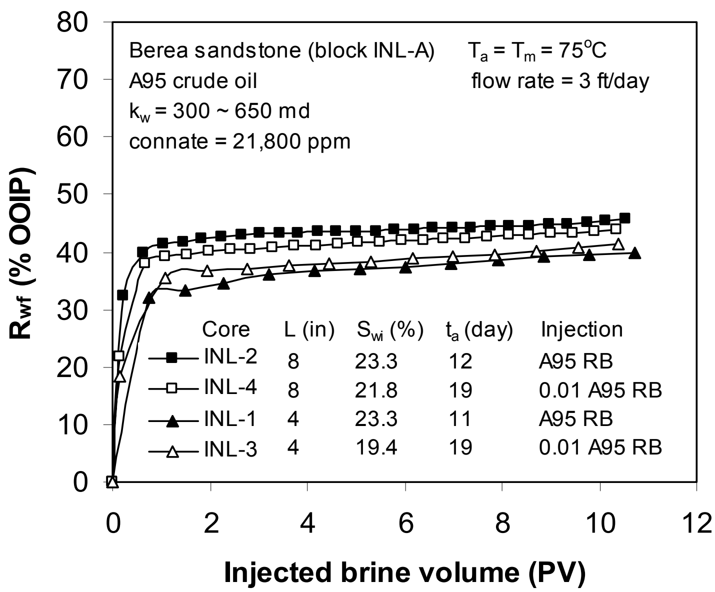

Figure 1.6. Results of experiments to determine effect of core size on waterflood oil recovery.

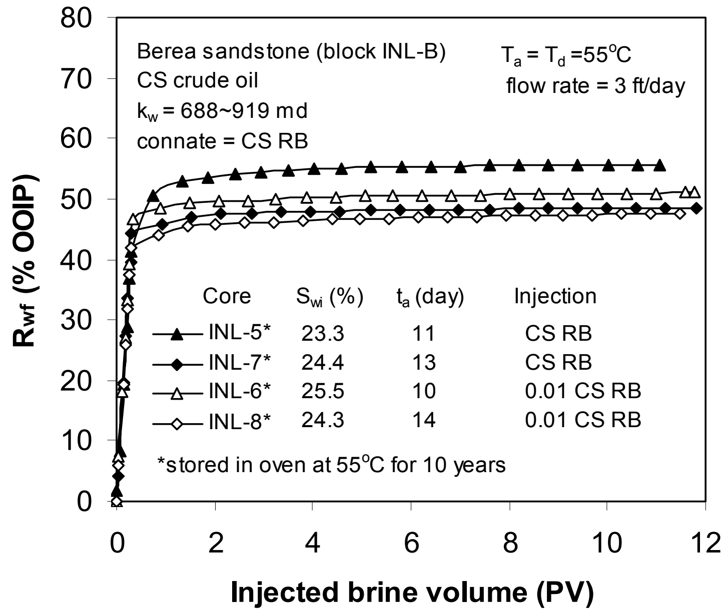

Figure 1.7. Effect of injection brine dilution on oil recovery from waterflooding Berea sandstone and CS crude oil.

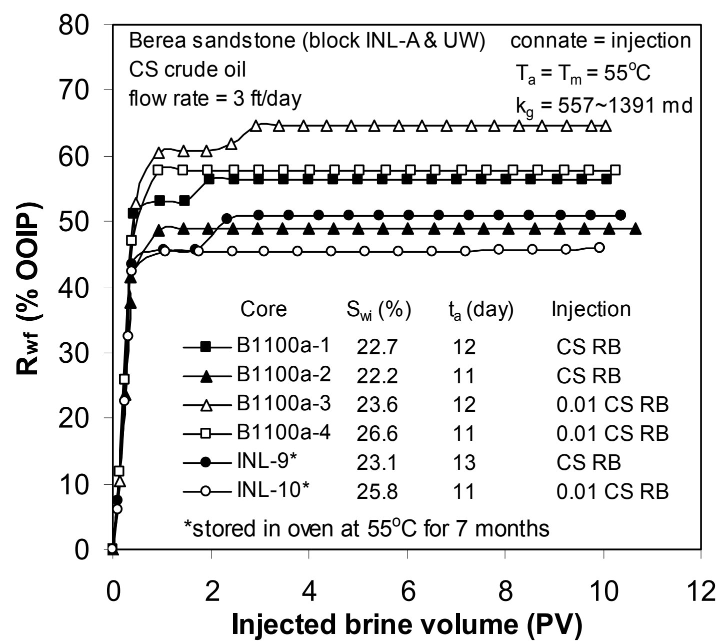

Figure 1.8. Corefloods with Berea sandstone and CS crude oil showing effect of brine dilution on waterflood oil recovery.

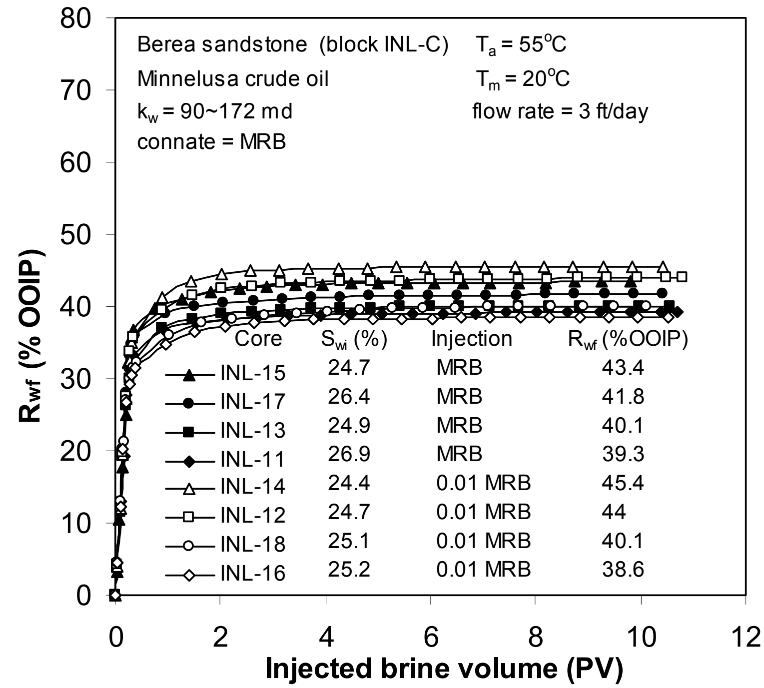

Figure 1.9. Oil recovery for eight corefloods using Berea sandstone and Minnelusa reservoir fluids at ambient temperature.

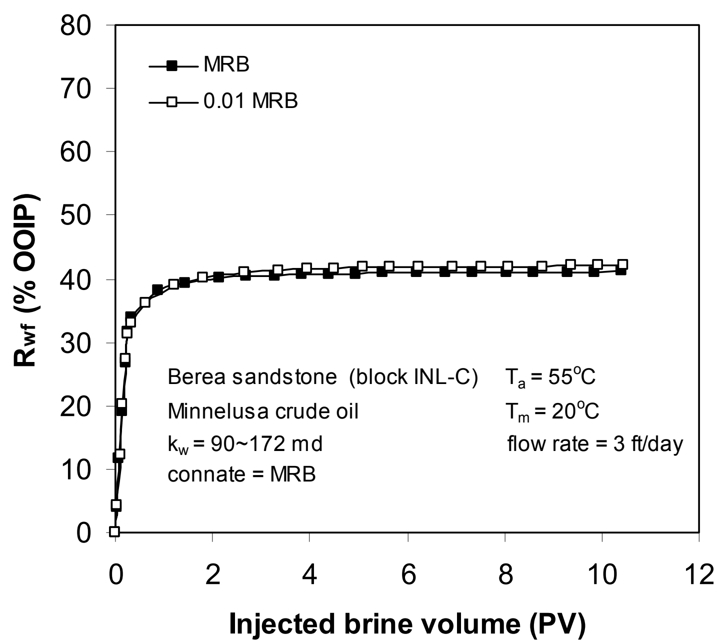

Figure 1.10. Average oil recovery curves for four waterfloods using full strength reservoir brine as the injection water and four waterfloods using a 100-fold dilution as the injection water.

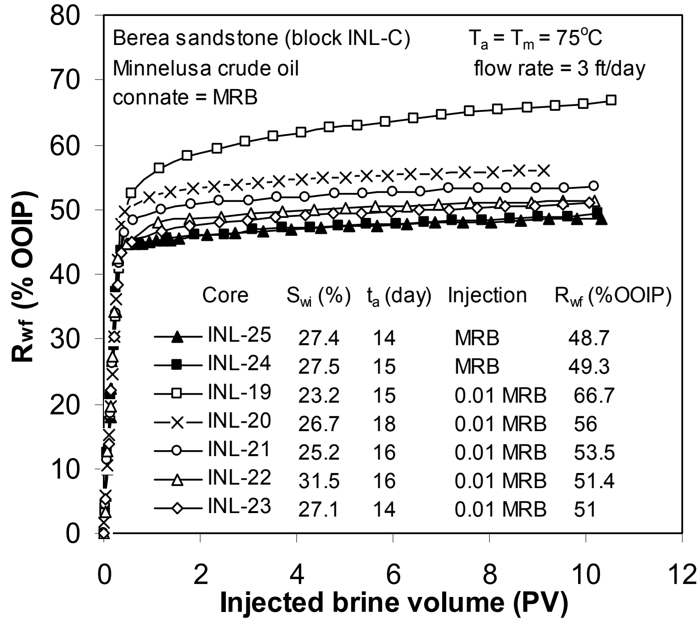

Figure 1.11. Production data for series of waterfloods using different injection water compositions at 75°C (kw = 88~151 md).

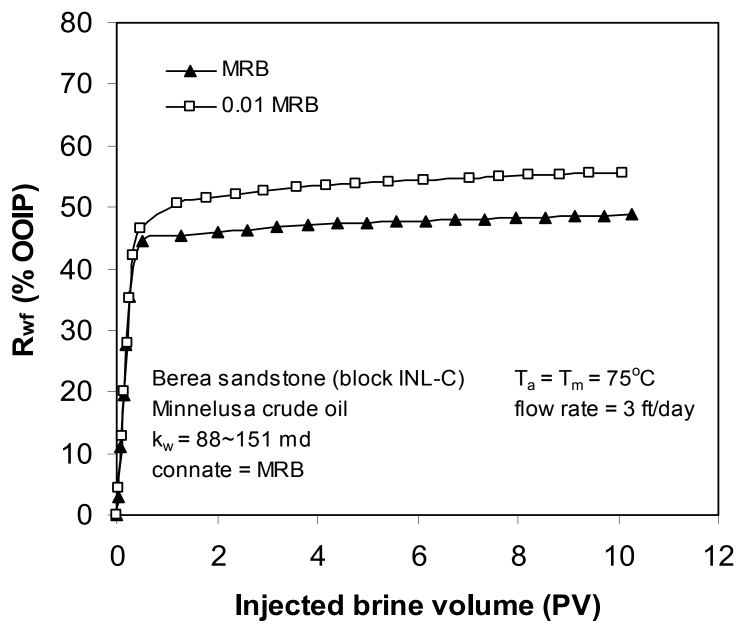

Figure 1.12. Average of oil recovery curves (see Fig. 1.11) for waterfloods of Berea sandstone cores using Minnelusa crude oil and with Minnelusa formation brine as the connate water.

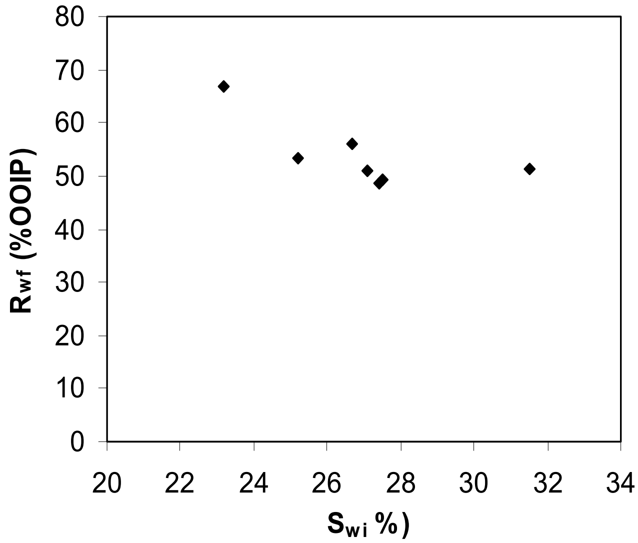

Figure 1.13. Oil recovery versus initial water saturation for five diluted waterfloods at 75°C using Berea sandstone, Minnelusa crude oil, and synthetic Minnelusa brine.

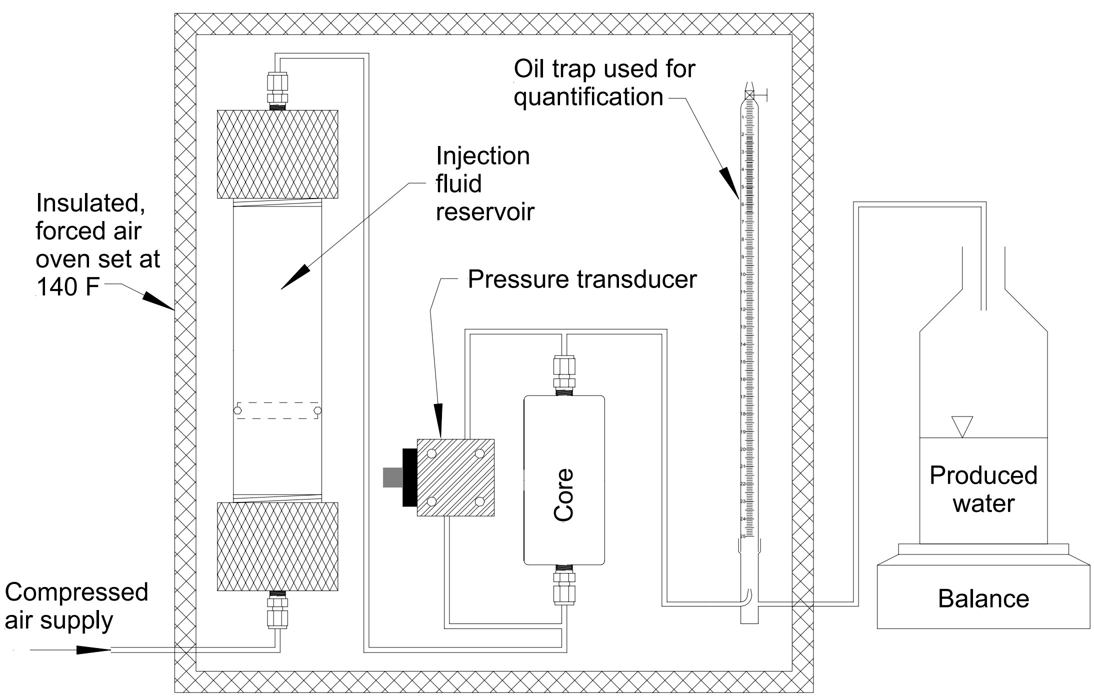

Figure 1.14. Laboratory setup used for waterflooding with Monument Butte formation fluids.

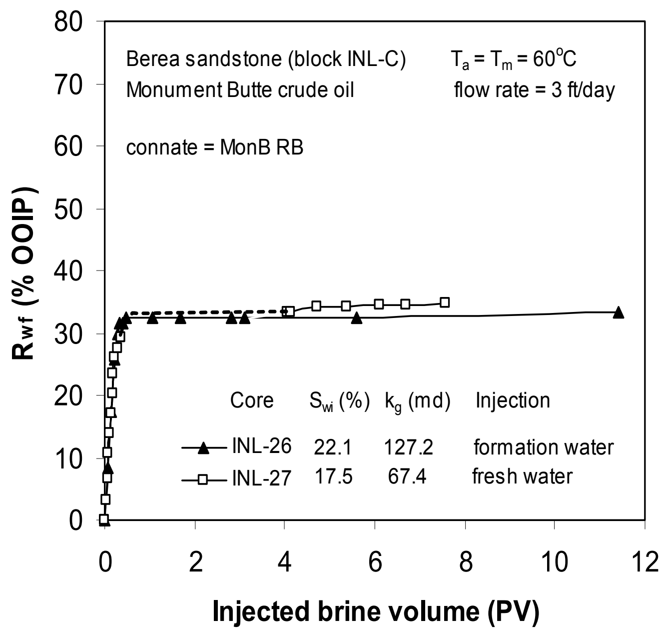

Figure 1.15. Oil recovery from Berea sandstone using field crude oil and field waters.

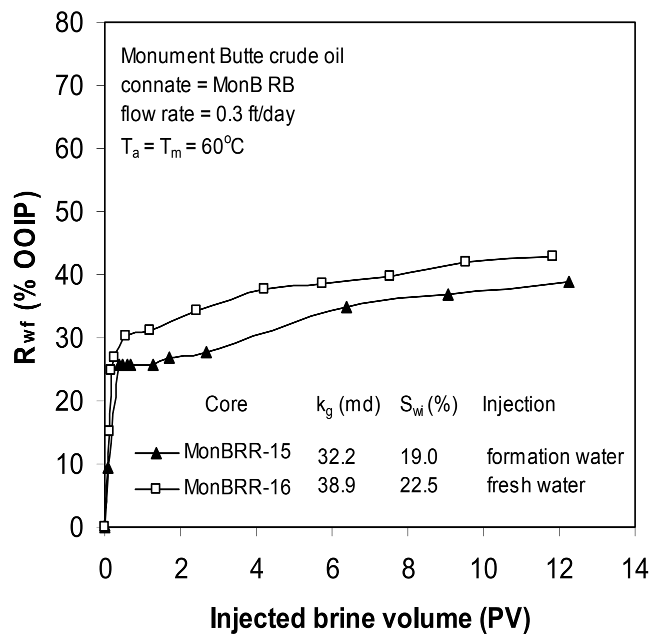

Figure 1.16. Comparative of Oil recovery curves for two Monument Butte field cores showing increase in recovery when fresh water is used as the injection water.

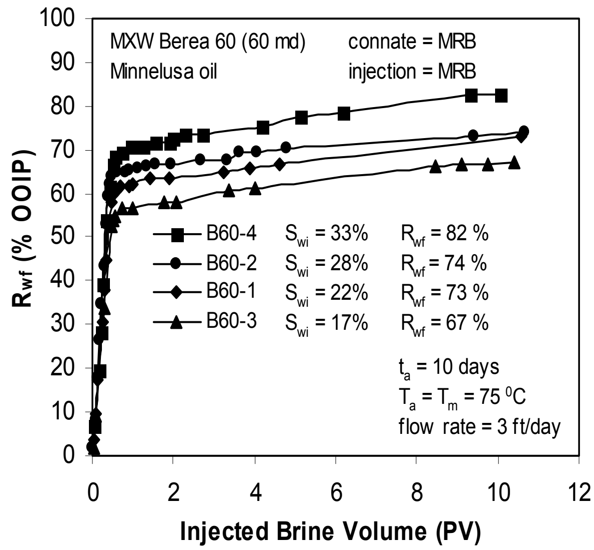

Figure 2.1. Effect of initial water saturation on oil recovery from Berea 60.

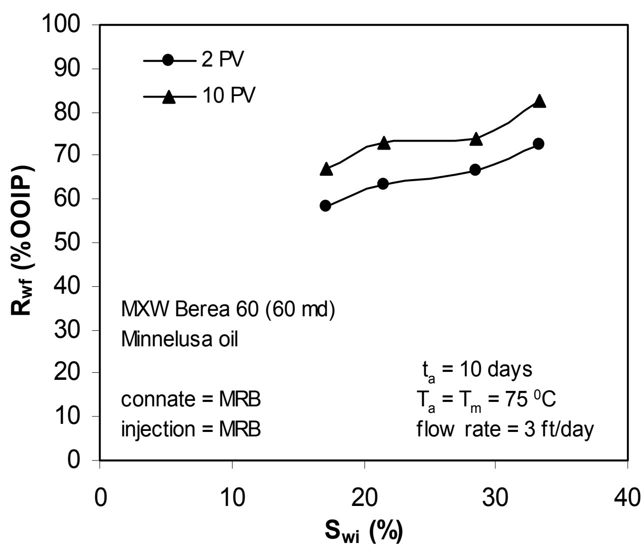

Figure 2.2. Oil recovery versus initial water saturation from Berea 60 after injection of 2 and 10 PV of Minnelusa reservoir brine.

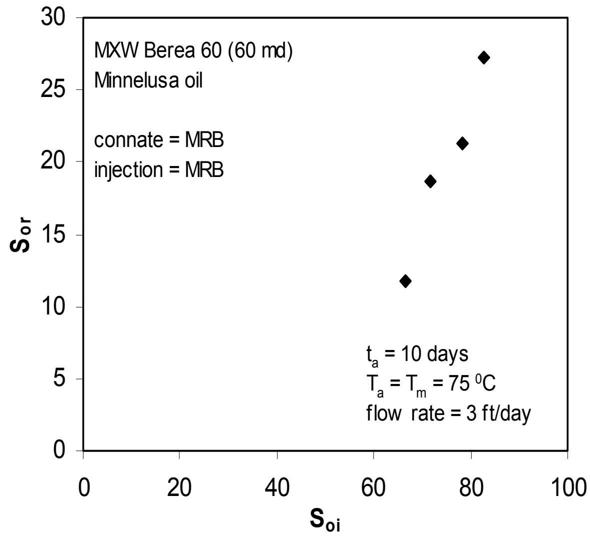

Figure 2.3. Residual oil saturation versus initial oil saturation for flooding with Minnelusa reservoir brine (10 PV) (Berea 60).

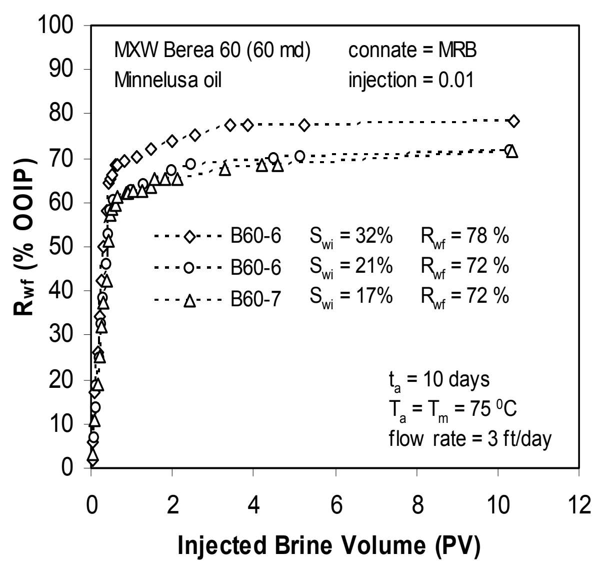

Figure 2.4. Oil recovery by flooding with dilute Minnelusa brine (0.01 Minnelusa reservoir brine) for different initial water saturations (Berea 60).

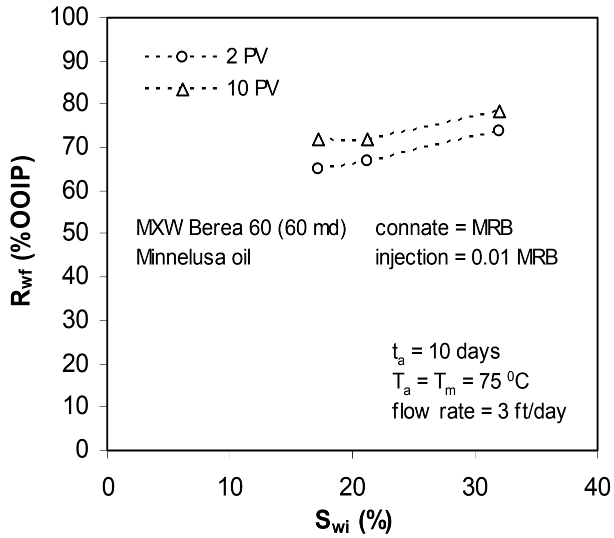

Figure 2.5. Oil recovery versus initial water saturation after injection of 2 and 10 PV of dilute brine (Berea 60).

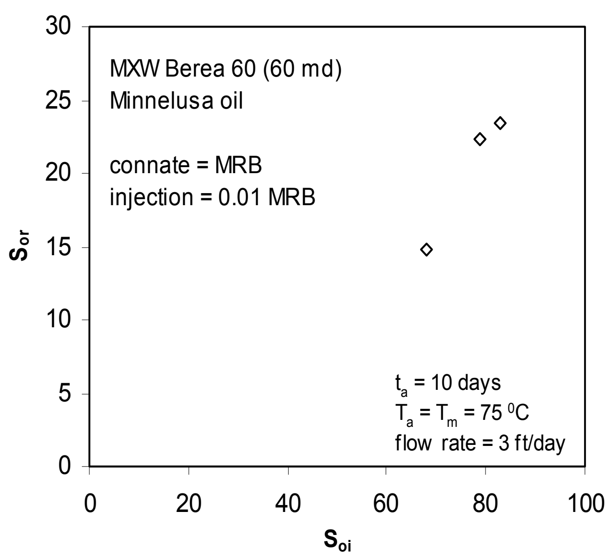

Figure 2.6. Residual oil saturation versus initial oil saturation for injection of 0.01 Minnelusa reservoir brine (10 PV) (Berea 60).

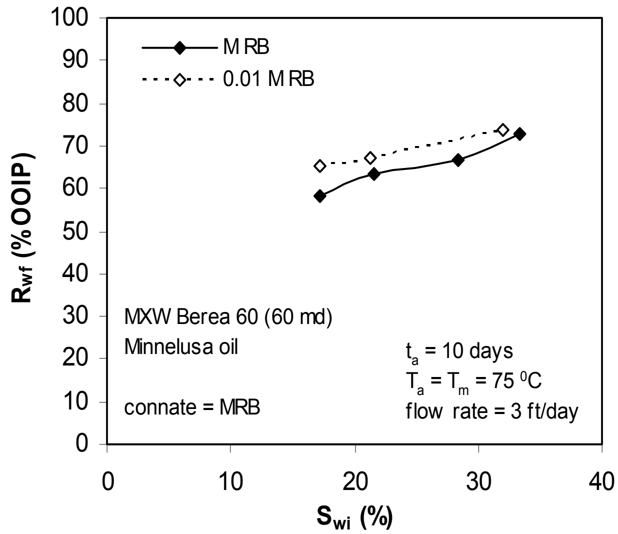

Figure 2.7. Comparison of oil recovery by Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine flooding for 2 PV injection (Berea 60).

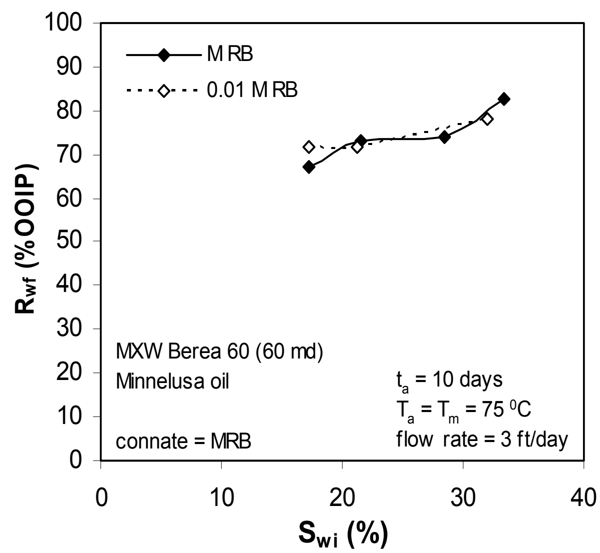

Figure 2.8. Comparison of oil recovery by Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine flooding versus initial water saturation for 10 PV injection (Berea 60).

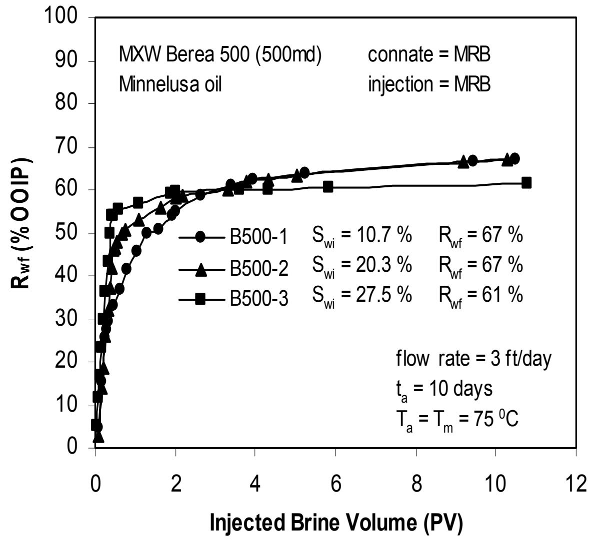

Figure 2.9. Oil recovery by flooding with Minnelusa reservoir brine for different initial water saturations (Berea 500)

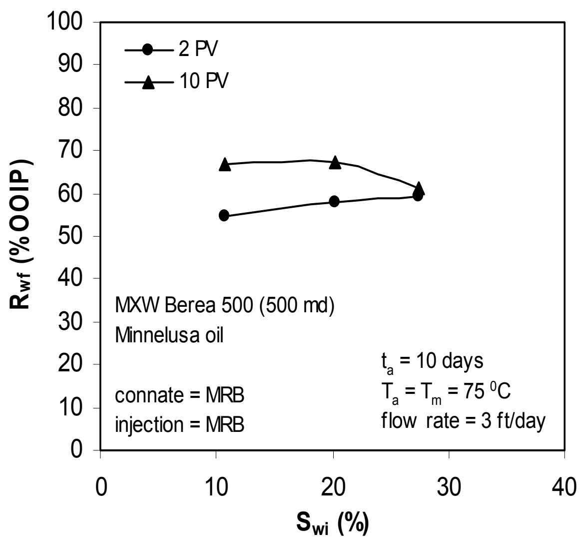

Figure 2.10. Oil recovery versus initial water saturation after injection of 2 and 10 PV of Minnelusa reservoir brine (Berea 500).

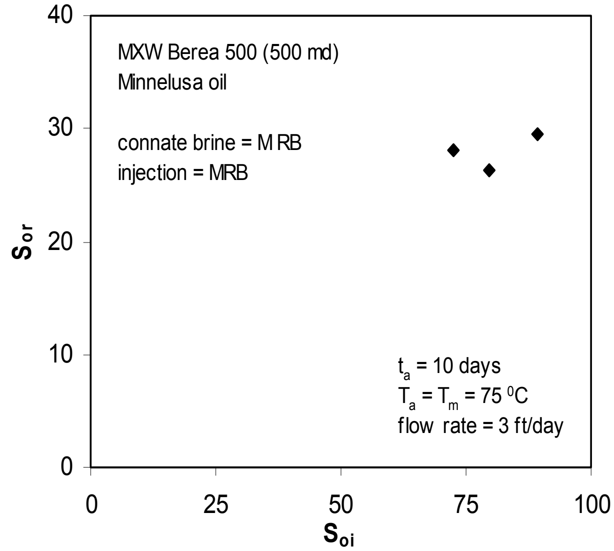

Figure 2.11. Residual oil saturation versus initial oil saturation for Minnelusa reservoir brine flooding (10 PV) (Berea 500).

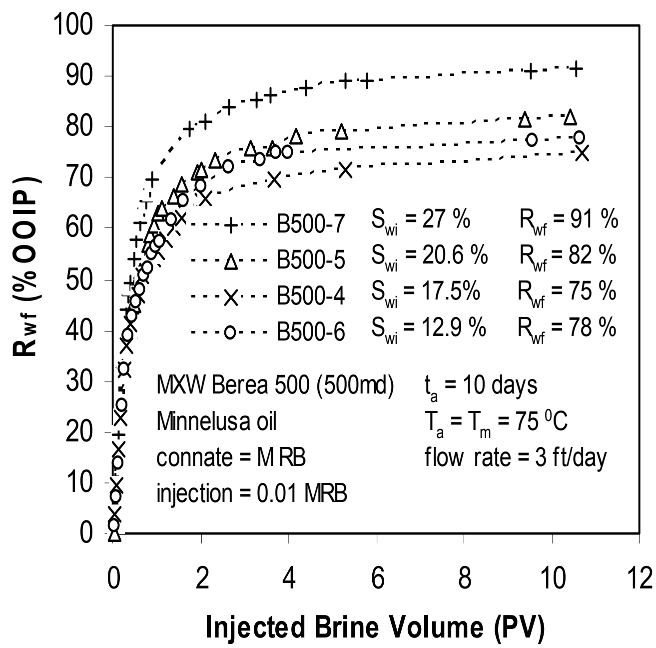

Figure 2.12. Oil recovery by flooding with dilute Minnelusa brine (0.01 Minnelusa reservoir brine) for different initial water saturations (Berea 500),

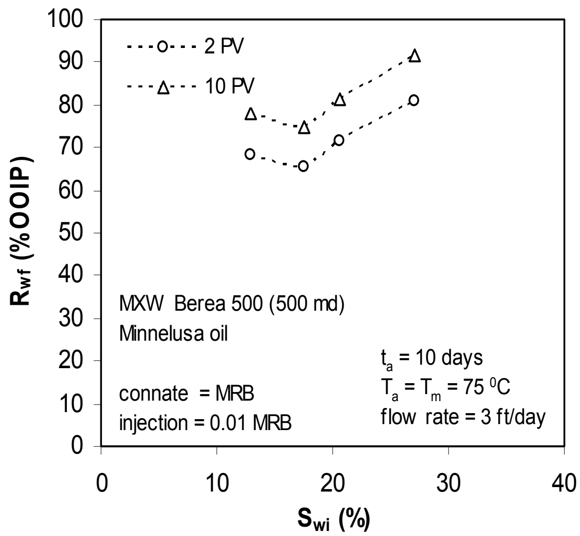

Figure 2.13. Oil recovery versus initial water saturation after injection of 2 and 10 PV of dilute Minnelusa brine (Berea 500).

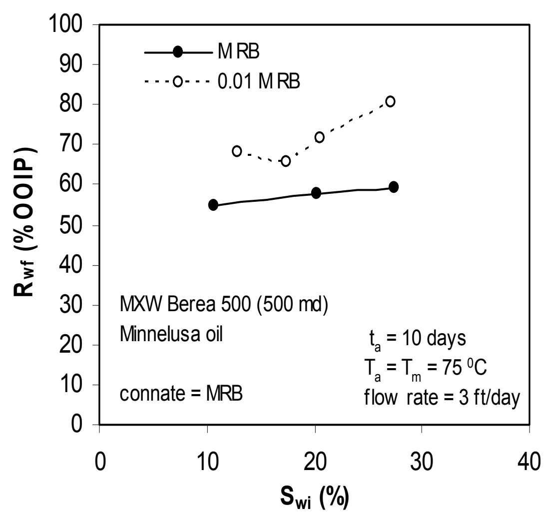

Figure 2.14. Oil recovery versus initial water saturation after injection of 2 PV of Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine (Berea 500).

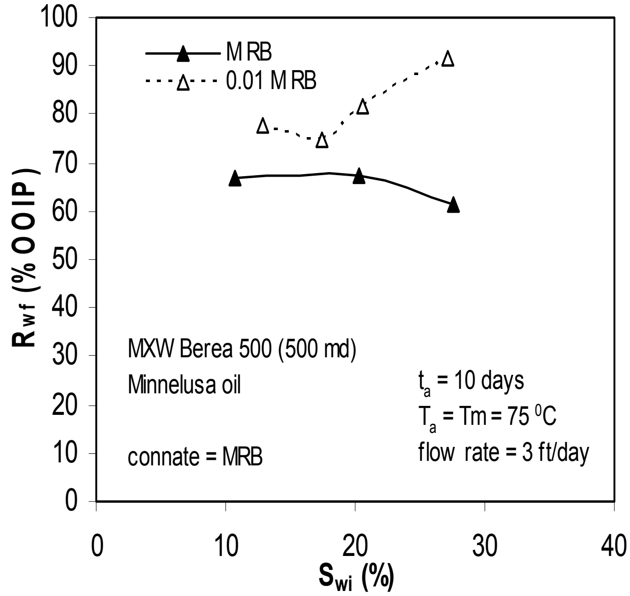

Figure 2.15. Oil recovery versus initial water saturation after injection of 10 PV of Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine (Berea 500).

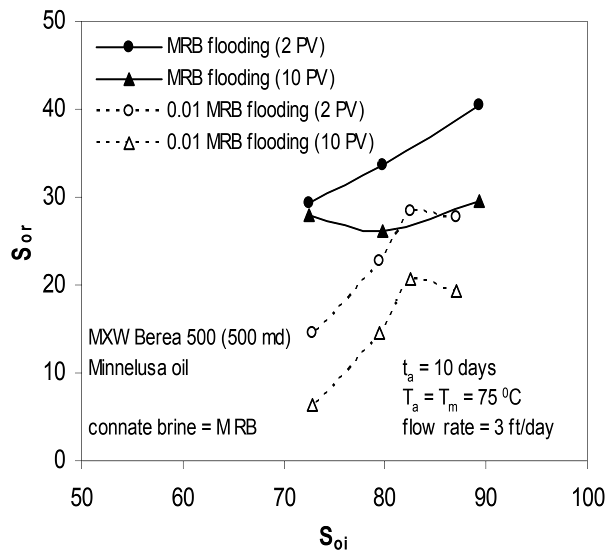

Figure 2.16. Residual oil saturation versus initial oil saturation for flooding with Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine (Berea 500).

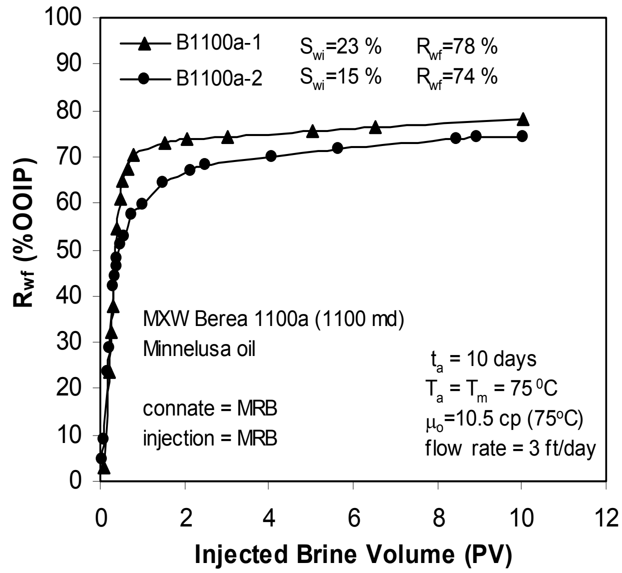

Figure 2.17. Oil recovery by flooding with Minnelusa reservoir brine for different initial water saturations (Berea 1100a).

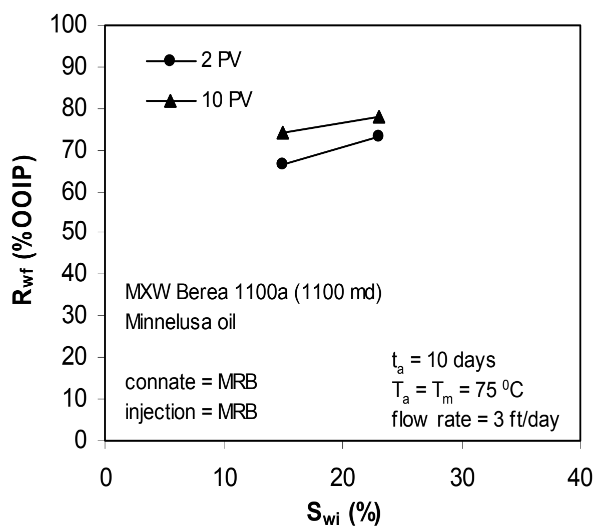

Figure 2.18. Oil recovery versus initial water saturation after injection of 2 and 10 PV of Minnelusa reservoir brine (Berea 1100a).

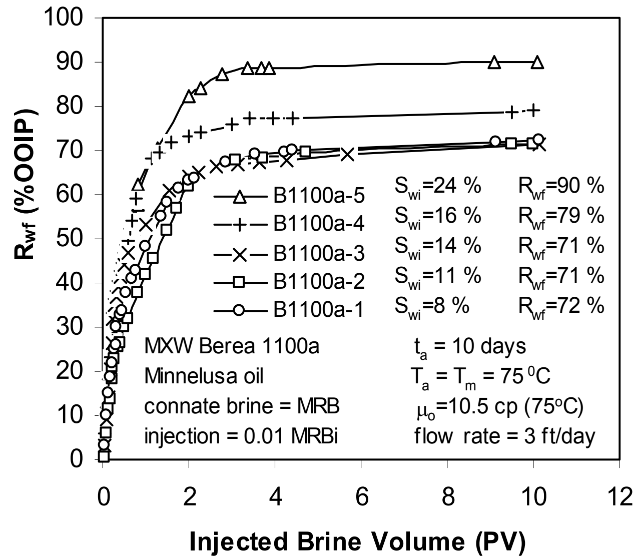

Figure 2.19. Oil recovery by flooding with dilute Minnelusa brine (0.01 Minnelusa reservoir brine) for different initial water saturations (Berea 1100a).

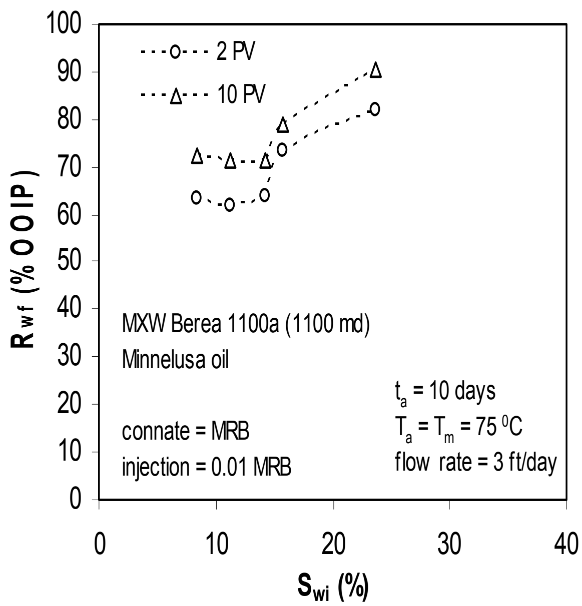

Figure 2.20. Oil recovery versus initial water saturation after injection of 2 and 10 PV of dilute Minnelusa brine (Berea 1100a).

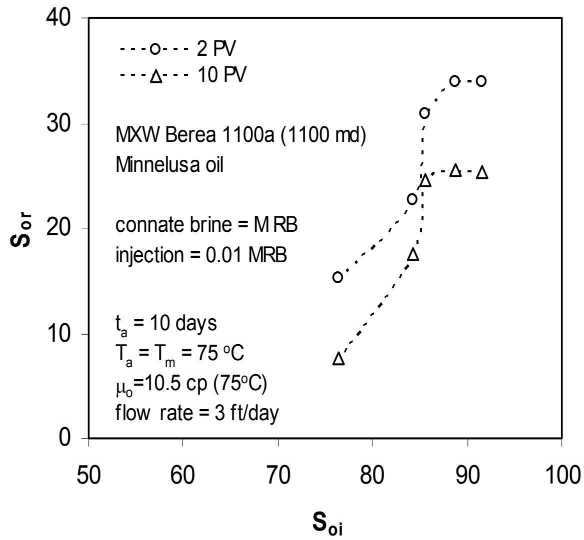

Figure 2.21. Residual oil versus initial oil saturation after 2 and 10 PV injection of 0.01 Minnelusa reservoir brine (Berea 1100a).

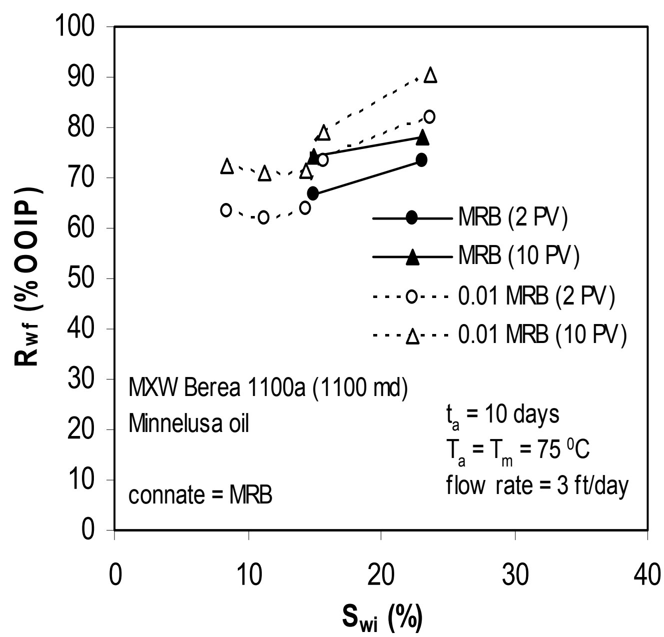

Figure 2.22. Oil recovery versus initial oil saturation after 2 and 10 PV injection of Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine (Berea 1100a).

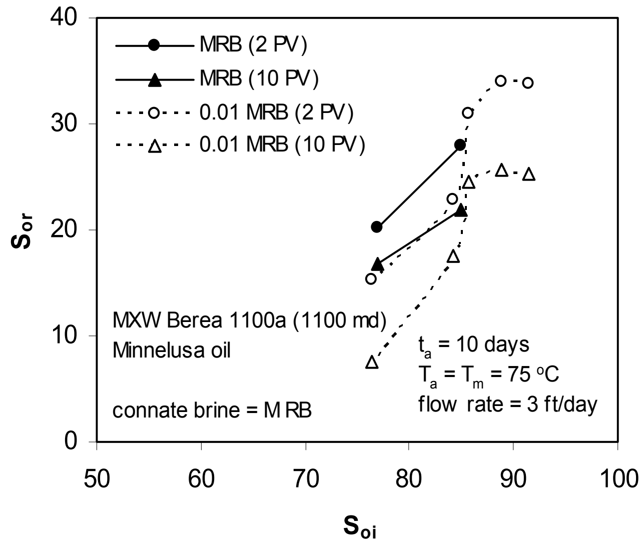

Figure 2.23. Residual oil versus initial oil saturation after 2 and 10 PV injection of Minnelusa reservoir brine and 0.01 Minnelusa reservoir brine (Berea 1100a).

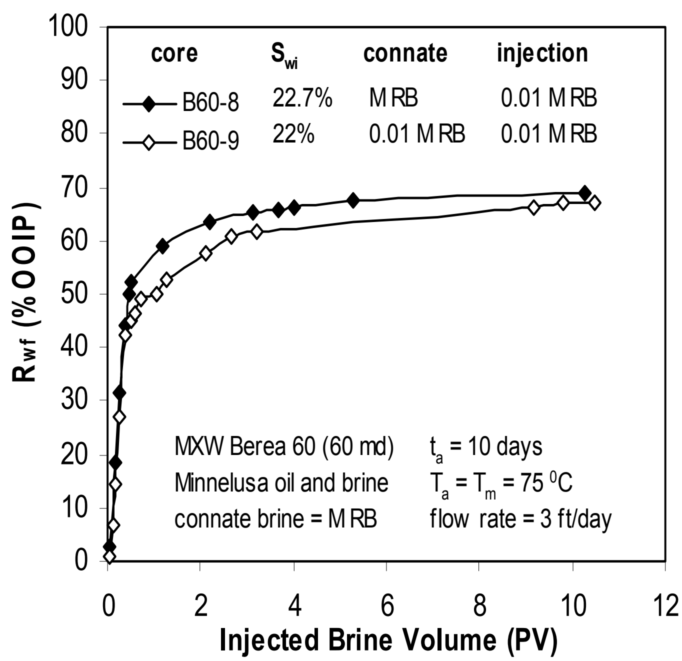

Figure 2.24. Effect of brine composition on oil recovery from Berea 60.

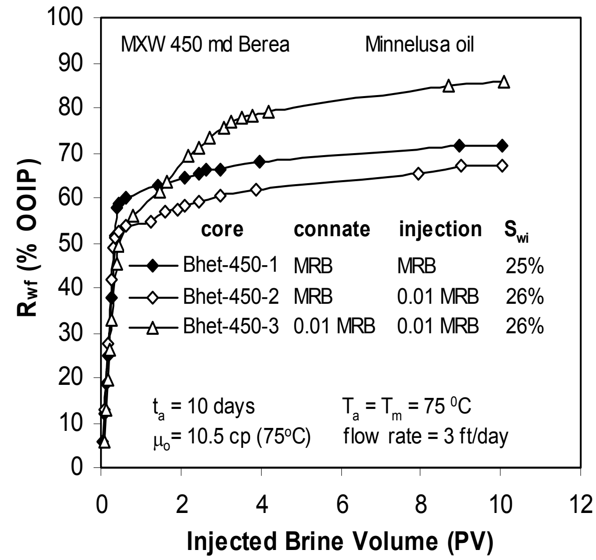

Figure 2.25. Effect of brine composition on oil recovery by waterflooding (Bhet450).

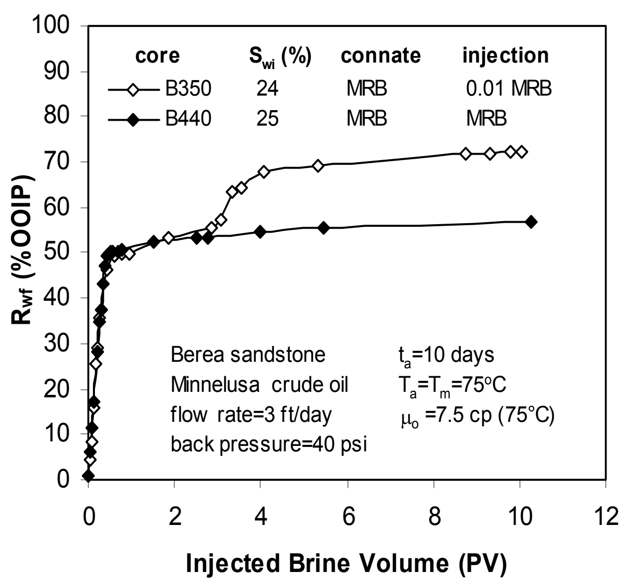

Figure 2.26. Example of delayed increase in oil recovery for injection of dilute Minnelusa brine (0.01 Minnelusa reservoir brine).

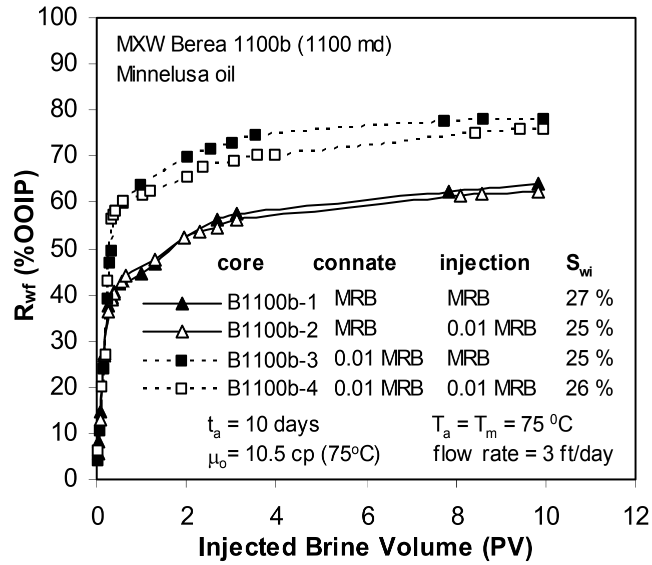

Figure 2.27. Change in oil recovery with salinity of connate brine for Minnelusa oil for B1100b.

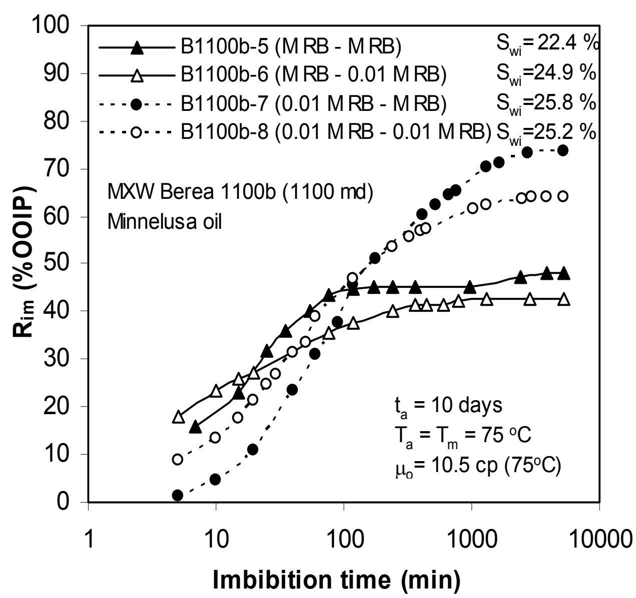

Figure 2.28. Effect of brine composition on spontaneous imbibition (Berea 1100b).

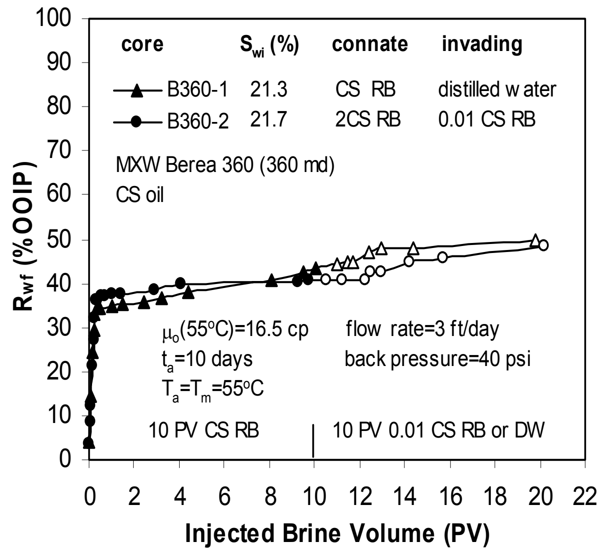

Figure 2.29. Increase in oil recovery and pressure drop after switching injected CS reservoir brine to 0.01 CS reservoir brine (Berea 360).

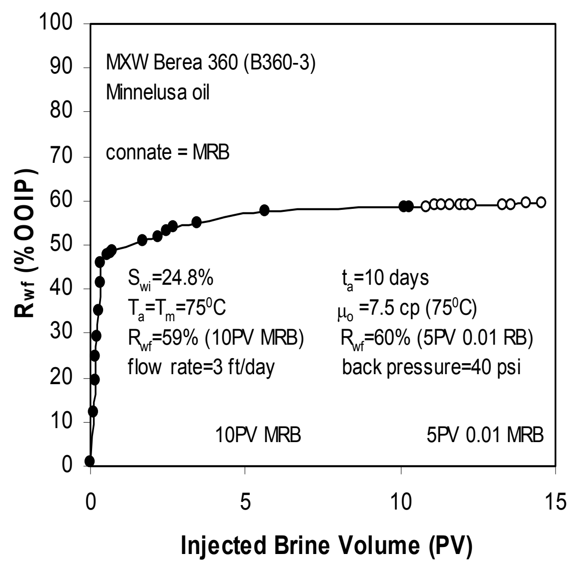

Figure 2.30. Effect of reduction in salinity on tertiary mode recovery of Minnelusa oil.

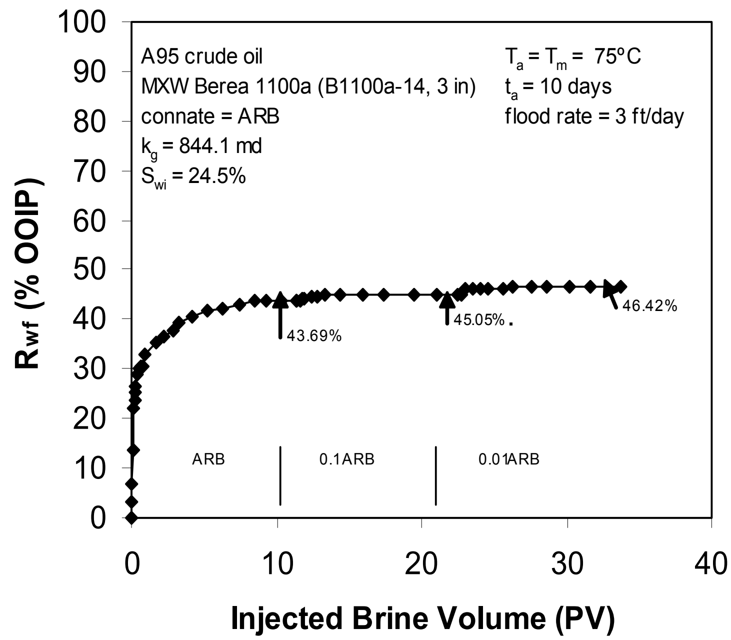

Figure 2.31. Effect of injection brine concentration on tertiary mode recovery of A95 crude oil.

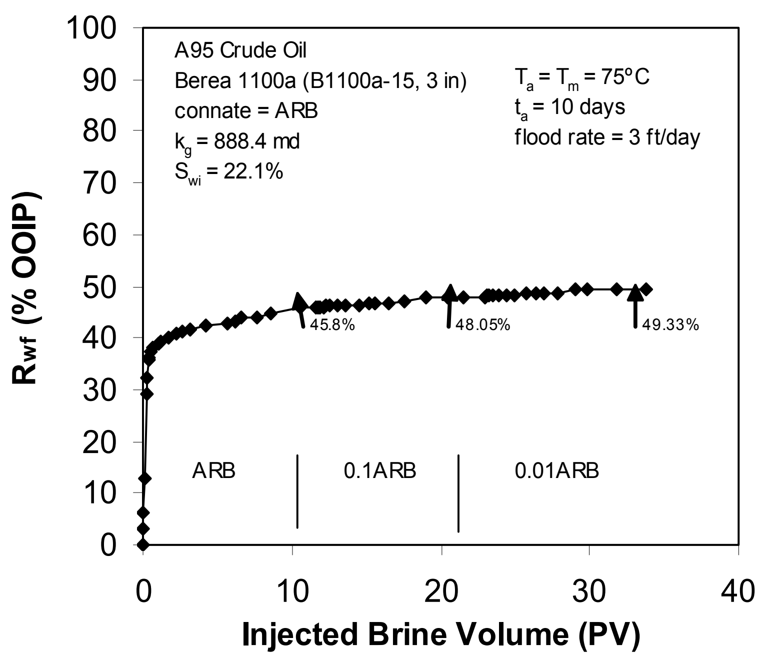

Figure 2.32. Effect of injection brine concentration on tertiary mode recovery of A95 crude oil.

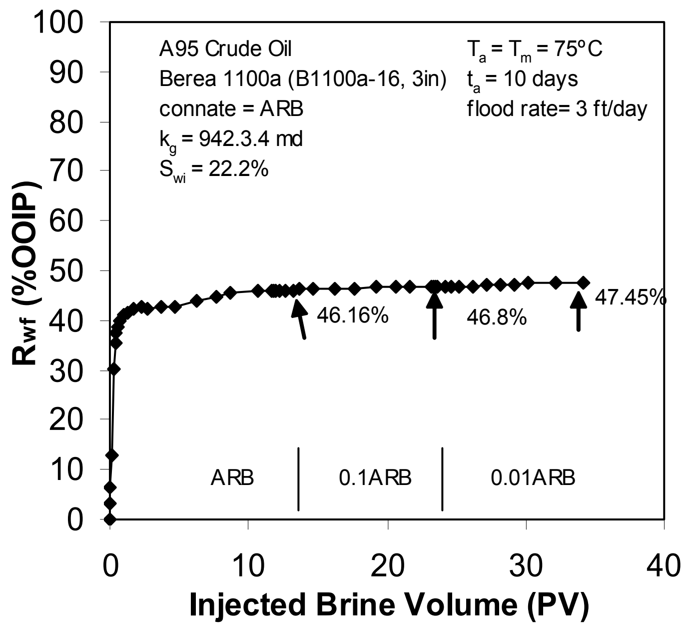

Figure 2.33. Effect of injection brine composition on tertiary mode recovery of A95 crude oil.

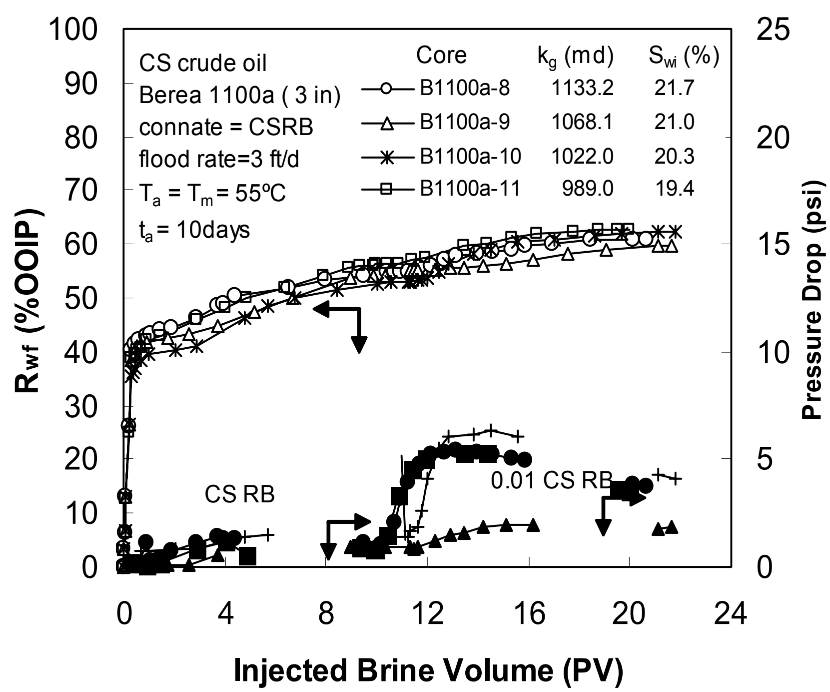

Figure 2.34. Effect of injection brine composition on tertiary mode recovery of CS crude oil.

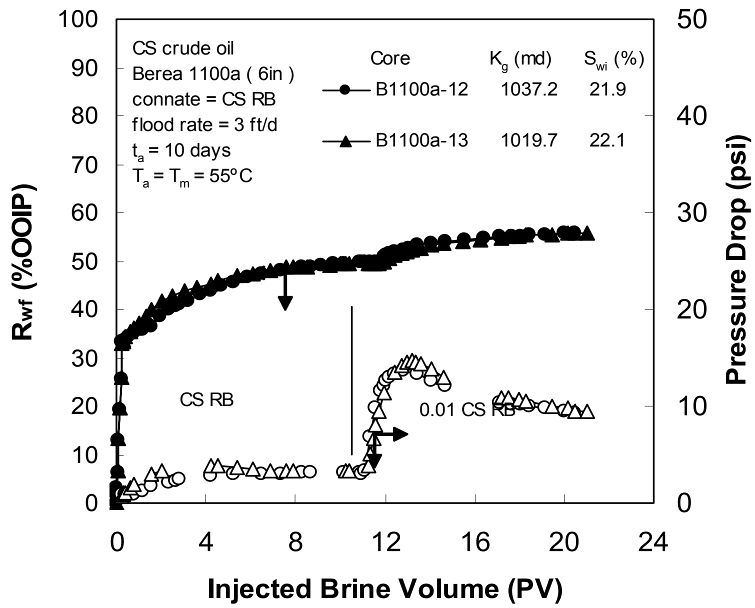

Figure 2.35. Effect of injection brine composition on oil recovery and pressure drop for tertiary mode recovery of CS crude oil.

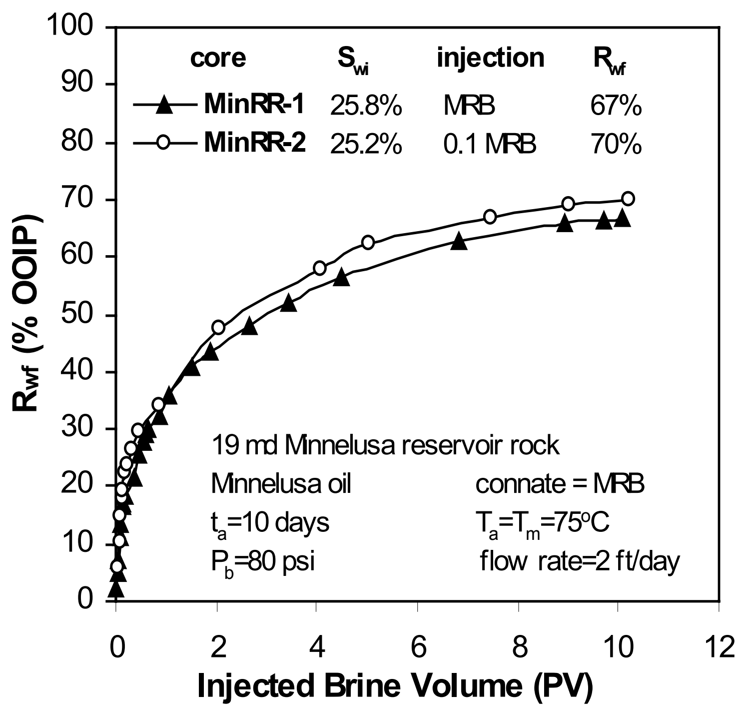

Figure 2.36. Comparison between oil recoveries by Minnelusa reservoir brine and dilute brine flooding for Minnelusa reservoir rock.

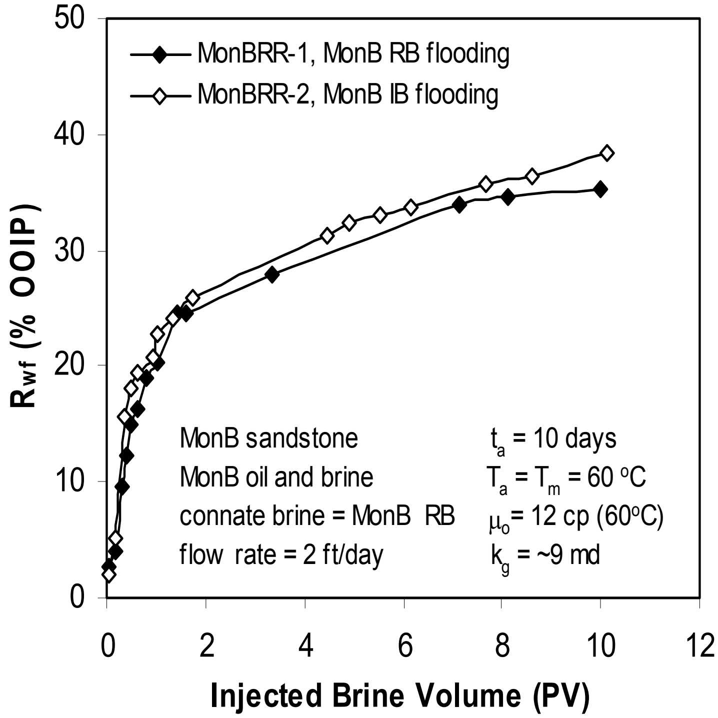

Figure 2.37. Comparison between oil recoveries by Monument Butte reservoir brine and injection brine flooding.

Tables

Table 1.1. Average reservoir characteristics of thirty-five Minnelusa reservoirs.

Average reservoir permeability, md	50 to 657
Porosity, %	16.2
Dykstra-Parsons permeability coefficient, dimensionless	0.75
Connate water saturation, %	25.5
Pay thickness, ft	29.3
API gravity, degree API	18 to 40
Initial formation volume factor, bbl/STB	1.087
Solution GOR, cu ft/bbl	61.5
Oil viscosity at reservoir temperature, cp	15.2
Produced water chloride content, ppm	2000 to 200,000

Table 1.2. Water analysis for the two off-unit source-water wells for the West Semlek unit.

Brine components	Concentration (mg/L)	
	Well 28-1	Well 28-6
Cations		
Potassium	79	122
Sodium	610	2580
Calcium	630	740
Magnesium	133	142
Anions		
Sulfate	2110	2550
Chloride	576	3470
Carbonate	0	0
Bicarbonate	495	688
Total dissolved solids	4380	9950

Table 1. 3. Water analysis for the North Semlek injection water – Muñoz Government 28-5 well (Fox Hills formation).

Brine components	Concentration (mg/L)
Cations	
Sodium	318
Calcium	5.8
Others	0
Anions	
Sulfate	199
Chloride	5.3
Carbonate	0
Bicarbonate	567
Total dissolved solids	1095

Table 1.4. Properties of Berea sandstone cores (from INL Block-A) used with A95 crude oil in scale-up experiments.

Core	Length, in	k_g, md	k_w, md	ϕ, %	S_{wi}, %
INL-1	3.94	801	525	23.1	23.3
INL-2	8.20	925	642	22.0	21.7
INL-3	3.98	845	300	22.9	19.4
INL-4	8.30	904	650	22.0	21.8

Table 1.5. Properties of Berea sandstone cores (from INL Block-B) used with CS crude oil to explore the effect of manipulating the invading brine while holding connate brine constant. These cores were stored in 55°C oven for ten years.

Core	Length, in	k_g, md	k_w, md	ϕ, %	S_{wi}, %
INL-5*	5.80	1020	917	25.2	23.3
INL-6*	5.80	1043	688	25.0	25.5
INL-7*	5.82	1108	919	25.0	24.4
INL-8*	5.99	977	717	24.5	24.3

Table 1.6. Properties of Berea sandstone cores (Block B1100a from UW and INL BlockA) used with CS crude oil to explore the effect of manipulating both the connate brine and the invading brine.

Core	Length, in	Diameter, in	k_g, md	ϕ, %	S_{wi}, %
B1100a-2	3.00	1.48	1391	24.4	22.2
B1100a-3	3.03	1.45	1185	24.3	23.6
B1100a-1	3.02	1.44	1188	24.2	22.7
B1100a-4	3.03	1.49	1068	23.6	26.6
INL-9*	2.98	1.42	898	21.9	23.1
INL-10*	2.99	1.45	557	20.1	25.8

*Stored in over at 55°C for 7 months.

Table 1.7. Properties of Berea sandstone cores (from INL Block-C) used with Minnelusa crude oil to explore the effects of manipulating connate and invading brine at room temperature (room temperature).

Core	Length, in	Diameter, in	k_g, md	k_w, md	ϕ, %	S_{wi}, %
INL-11	3	1.5	182	134	19.7	26.9
INL-12	3	1.5	141	105	20.3	24.7
INL-13	3	1.5	233	159	20.5	24.9
INL-14	3	1.5	185	154	20.4	24.4
INL-15	3	1.5	232	164	21.5	24.7
INL-16	3	1.5	239	155	20.4	25.2
INL-17	3	1.5	217	172	20.7	26.4
INL-18	3	1.5	125	90	18.7	25.1

Table 1.8. Synthetic Minnelusa brine composition used in corefloods (p11).

Component	gram/Liter
NaCl	29.803
$CaCl_2 * 2H_2O$	2.787
Na_2SO_4	5.903
$MgSO_4 * 7H_2O$	1.723

Table 1.9. Basic core information (INL Block-C) and data resulting from waterfloods (Minnelusa crude oil 75°C).

Core	ϕ (%)	K_g (md)	K_w (md)	S_{wi} (%)	OOIP (mL)	Produced oil (mL)	Oil recovery factor (%)	S_{or} (%)	Aging time (D)	Injection brine
INL-19	20.2	225	130	23.2	13.6	9.1	66.7	25.6	15	0.01 MRB
INL-20	18.5	132	88	26.7	11.8	6.6	56.0	32.2	18	0.01 MRB
INL-21	19.7	181	117	25.2	12.9	6.9	53.5	34.8	16	0.01 MRB
INL-22	18.3	132	92	31.5	10.8	5.5	51.4	32.9	16	0.01 MRB
INL-23	20.3	211	145	27.1	12.6	6.4	51.0	35.7	14	0.01 MRB
INL-24	19.9	218	151	27.5	12.6	6.2	49.3	36.8	15	MRB
INL-25	19.9	180	141	27.4	12.7	6.2	48.7	37.3	14	MRB

Table 1.10. Average formation water analysis for the Monument Butte field.

Dissolved Solids	mg/L
Sodium, Na^-	4425
Potassium, K^-	16
Calcium, Ca^{+2}	19
Magnesium, Mg^{+2}	4
Total cations	4464
Chloride, Cl^-	6282
Bicarbonate, HCO_3^-	1034
Sulfate, SO_4^{-2}	1
Total anions	7316
Total dissolved solids	11780

Table 1.11. Formation brine composition for Monument Butte field, Uinta Basin, Utah.

Reservoir brine constituents	g/L
NaCl	10.282
$NaHCO_3$	1.389
$KHCO_3$	0.041
$CaCl_2 \bullet 2H_2O$	0.070
$MgCl_2 \bullet 6H_2O$	0.031
$MgSO_4 \bullet 7H_2O$	0.003

Table 1.12. Average injection water analysis for the Monument Butte field.

Dissolved Solids	mg/L
Sodium, Na^-	95
Calcium, Ca^{+2}	49
Magnesium, Mg^{+2}	26
Total cations	170
Chloride, Cl^-	154
Bicarbonate, HCO_3^-	224
Sulfate, SO_4^{-2}	35
Total anions	413
Total dissolved solids	583

Table 1.13. Field injection water composition for Monument Butte field, Uinta Basin, Utah.

Injection water constituents	g/L
NaCl	0.029
$NaHCO_3$	0.308
$CaCl_2 * 2H_2O$	0.180
$MgCl_2 * 6H_2O$	0.143
$MgSO_4 * 7H_2O$	0.090

Table 1.14. Properties and dimensions of the two Berea sandstone cores used in waterfloods with Monument Butte field fluids.

	INL-26	INL-27
Length, in	3.01	2.98
Diameter, in	1.46	1.47
Porosity, %	19.9	19.3
Gas permeability, md	207	147
Brine permeability, md	127.2	67.4
Initial water saturation, %	22.1	17.5

Table 1.15. Routine core analysis test results for core plugs collected from the Monument Butte field.

Well name	Sample number	Approximate depth (feet)	Sample length (inches)	Sample diameter (inches)	ϕ (%)	k_g (md)
Paiute 34-8	1	4057.75	2.024	1.483	13.34	2.30
	2	4057.90	2.290	1.480	13.95	2.46
	3	4058.90	2.126	1.484	14.83	4.72
	4	4059.20	2.213	1.485	14.21	4.09
Mon Butte 3A-35	5	4997.50	2.985	1.484	15.62	6.22
	6	4997.70	2.980	1.483	15.02	5.19
	7	4998.55	2.694	1.482	13.62	2.59
	8	4998.70	2.458	1.482	14.32	2.61
	9	4998.85	2.469	1.482	13.42	1.44
	10	4999.00	2.671	1.483	12.61	0.60
	11	5004.30	2.556	1.482	13.75	1.33
	12	5004.45	2.550	1.482	14.85	3.14
	13	5004.60	2.650	1.482	14.21	2.53
	14	5004.75	2.603	1.483	14.05	2.27
Allen 34-5	15	5024.85	3.022	1.484	16.32	26.45
	16	5025.00	3.023	1.482	16.09	30.29
Federal 6-35	17	5026.45	2.651	1.482	14.22	3.50
	18	5026.60	2.625	1.483	10.68	1.06
Mon Fed 33-11J	19	5196.65	3.032	1.483	15.43	8.45
	20	5196.80	3.036	1.482	15.46	9.62

Table 1.16. Comparison of core plug properties calculated by TerraTek and INEEL.

	TerraTek		INEEL	
Core	**Porosity (%)**	**Permeability (md)**	**ϕ (%)**	**Permeability (md)**
3	14.83	4.72	15.5	4.3
4	14.21	4.09	14.2	3.6
7	13.62	2.59	13.9	2.4
8	14.32	2.61	13.8	2.2
15	16.32	26.45	16.0	32.2
16	16.09	30.29	16.0	38.9

Table 2.1. Rock Properties: Cation Exchange Capacity; BET Surface Area; Dominant Clay by x-ray Diffraction.

Core No	CEC	BET	Clay
MonBRR-1	0.00120	0.701	kaolinite>illite>chlorite
MonBRR-2	0.00220	1.290	kaolinite>illite>chlorite
B60	0.00299	1.150	kaolinite>illite>chlorite
Bhet450 (638md)	0.00197	0.838	kaolinite>illite>chlorite
Bhet450(1062md)	0.00140	0.673	kaolinite>illite>chlorite
B1100a	0.00130	0.348	kaolinite>illite>chlorite
B1100b	0.00148	0.834	kaolinite>illite>chlorite

Table 2.2. Properties of Crude Oils.

Oil Samples	T °C	μ cp	°API	nC_7-asph wt %	Wax wt %	Acid # mg KOH/g oil	Base # mg KOH/g oil
CS	23	58	25.1	0.78	12.5	0.33	1.16
	55	16.5					
CS*	23	81					
	55	17.2					
Minnelusa	23	47	24.6	8.06	-	0.17	2.29
	75	7.5					
MonB	23	solid	-	-	-	-	-
	60	12					
A95	25	33.8	25.2	8.67	-	0.24	2.20

*degassed CS oil

Table 2.3. Ionic Compositions of Synthetic Reservoir Brine and Injection Brine.

	Ionic Concentrations ppm							
Brine	K^+	Na^+	Ca^{2+}	Mg^{2+}	Cl^-	HCO_3^-	SO_4^{2-}	TDS
CS	56	5,626	58	24	8,249	1,110	18	15,140
Minnelusa	-	13,635	760	170	19,424	-	4,664	38,653
Monument Butte (RB)	16	4425	19	4	6282	1034	1	11,780
Monument Butte (IB)	-	95	49	26	154	224	35	583
A95	47.6	8,379	109.8	334	13,260	-	-	22,130

Table 2.4. Core Properties –Initial Water Saturation and Oil Recovery — B60.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
B60-1	52	16.7	14.5	21.5	MRB	MRB	72.9
B60-2	55	17.4	15.3	28.4	MRB	MRB	73.9
B60-3	54	16.8	14.8	17.2	MRB	MRB	67.2
B60-4	73	17.2	15.3	33.4	MRB	MRB	82.4
B60-5	56	16.6	14.7	32	MRB	0.01 MRB	78.3
B60-6	69	17	14.9	21.3	MRB	0.01 MRB	71.7
B60-7	61	16.7	14.8	17.3	MRB	0.01 MRB	71.7

Table 2.5. Core Properties –Initial Water Saturation and Oil Recovery — B500.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
B500-1	483	21.5	19.4	10.7	MRB	MRB	66.9
B500-2	470	21.4	18.9	20.3	MRB	MRB	67.1
B500-3	495	21.6	18.9	27.5	MRB	MRB	61.3
B500-4	491	21.7	19.1	17.5	MRB	0.01 MRB	75
B500-5	497	22.2	19.5	20.6	MRB	0.01 MRB	81.8
B500-6	531	21.8	19.2	12.9	MRB	0.01 MRB	77.8
B500-7	537	22	19.3	27.1	MRB	0.01 MRB	91.4

Table 2.6. Core Properties –Initial Water Saturation and Oil Recovery — B1100.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
B1100a-1	1112	23.3	20.5	15	MRB	MRB	74.3
B1100a-2	1081	23.3	20.3	23.1	MRB	MRB	78.1
B1100a-3	1123	23.1	20.1	8.4	MRB	0.01 MRB	72.3
B1100a-4	1126	23.4	20.4	11.2	MRB	0.01 MRB	71.2
B1100a-5	1156	23.5	20.6	14.3	MRB	0.01 MRB	71.3
B1100a-6	1064	22	19.3	16.3	MRB	0.01 MRB	79.1
B1100a-7	1152	23.2	20.2	23.7	MRB	0.01 MRB	90

Table 2.7. Core Properties –Connate Brine Salinity and Oil Recovery — B60.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
B60-8	68	16.7	14.9	22.7	MRB	0.01 MRB	68.7
B60-9	79	17.3	15.1	22	0.01 MRB	0.01 MRB	67

Table 2.8. Core Properties –Connate Brine Salinity and Oil Recovery — Bhet-450.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
Bhet-450-1	461	21.3	18.7	25.3	MRB	MRB	71.4
Bhet-450-2	464	21.3	18.7	25.8	MRB	0.01 MRB	66.9
Bhet-450-3	498	20.6	18.2	26.3	0.01 MRB	0.01 MRB	85.8

Table 2.9. Core Properties –Injection Brine Salinity and Oil Recovery — B440/350.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
B440	440	20.4	18	24.8	MRB	MRB	56.8
B350	347	20.5	17.7	24.1	MRB	0.01 MRB	72.4

Table 2.10. Core Properties –Connate Brine Salinity and Oil Recovery — B1100.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected/Invading Brine	R_{wf} or R_{im} % OOIP
Waterfloods							
B1100b-1	1181	23	20.77	25.9	MRB	MRB	64.3
B1100b-2	1170	23.4	20.76	24.9	MRB	0.01 MRB	62.2
B1100b-3	1039	22.5	19.97	25.2	0.01 MRB	MRB	78.1
B1100b-4	1139	22.7	20.12	27.4	0.01 MRB	0.01 MRB	75.6
Spontaneous Imbibition Tests							
B1100b-5	1157	23.3	20.7	22.4	MRB	MRB	47.9
B1100b-6	1067	23.1	20.6	24.9	MRB	0.01 MRB	42.5
B1100b-7	1174	22.7	20	25.8	0.01 MRB	MRB	73.8
B1100b-8	1139	22.7	20	25.2	0.01 MRB	0.01 MRB	64.2

Table 2.11. Core Properties –Tertiary Mode Flooding and Oil Recovery — B360.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
B360-1	362	19.9	17.8	21.5	CS RB	CS RB Distilled water	43.4 49.6
B360-2	363	20.4	17.9	21.3	2 CS RB	CS RB 0.01 CS RB	40.6 48.4
B360-3	362	20.2	17.7	24.8	MRB	MRB MRB(5PV)	58.6 59.7

Table 2.12. Tertiary Mode Recovery of A95 Crude Oil — B1100a.

Core No., length	K_g, md	S_{wi}, %	OOIP,%, at breakthrough	OOIP,%, at the end of ARB flood	OOIP,%, at the end of 0.01 ARB flood after ARB flood
B1100a-14	844.1	24.5	27.0	43.7	46.4
B1100a-15	888.0	22.1	36.2	45.8	49.3
B1100a-16	942.3	22.2	35.5	46.2	47.4
Average			**32.9**	**45.2**	**47.7**

Table 2.13. Scaling of Tertiary Mode Recovery – CS Crude Oil — B1100a.

Core No., length	K_g, md	S_{wi}, %	OOIP,%, at breakthrough	OOIP,%, at the end of 1.0 CS RB flood	OOIP,%, at the end of 0.01 CS RB flood after 1.0 CS RB flood
B1100a-8, 3in	1133.2	21.7	40.32	54.84	60.97
B1100a-9, 3in	1068.1	21.0	38.26	55.08	59.70
B1100a-10, 3in	1022.0	20.33	38.87	56.42	62.70
B1100a-11, 3in	989.0	19.4	35.43	53.36	62.25
Average, 3in			**38.22**	**54.91**	**61.40**
B1100a-12, 6in	1037.2	21.9	33.20	49.73	55.66
B1100a-13, 6in	1019.7	22.1	33.00	49.59	55.77
Average, 6in			**33.10**	**49.66**	**55.72**

Table 2.14. Core Properties –Injection Brine Salinity and Oil Recovery — Reservoir Rock.

Core	k_g md	ϕ %	V_p cm^3	S_{wi} %	Connate Brine	Injected Brine	R_{wf} % OOIP
Minnelusa Reservoir Rock							
MinRR-1	17.5	11	9.4	25.8	MRB	MRB	66.9
MinRR-2	19.3	10.6	9	25.2	MRB	0.1 MRB	70.1
Monument Butte Reservoir Rock							
MonBRR-1	8.5		9.4	22.1	MonB RB	MonB RB	35.4
MonBRR-2	9.6		9.8	21.3	MonB RB	MonB IB	38.3