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An Experimental Study of Water Imbibition in Chalk From the Ekofisk Field

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ABSTRACT

The Ekofisk Field in the North Sea produces from two lithologically similar, low permeability fractured chalk formations. The Ekofisk Formation of Danian age is separated from the lower Tor Formation of Maastrichtian age by a tight zone of about 15 m thickness. With a projected primary recovery factor of only 18%, the secondary recovery target is substantial. A pilot waterflood has been conducted in the Tor Formation and expansion of waterflooding to a large area of the Tor is planned. For waterflooding to recover substantial oil in a highly fractured rock large saturation changes in the matrix rock must be achieved through water imbibition.

Water imbibition in Tor samples is high and variable and the imbibition in Ekofisk samples is low and also variable. The first objective of the laboratory investigation reported here was to establish correlations between imbibition and rock parameters in the highly water wet Tor samples. The second objective was to determine the reasons for differences in Ekofisk and Tor water imbibition.

The volume of water imbibed and the initial water saturation in Tor samples correlated very well with porosity for the two wells examined. The water saturation after imbibition was constant at about 60 percent of pore volume, independent of porosity. Imbibition in the Ekofisk samples from the one well examined varied widely and did not correlate with any of the rock parameters examined. Pore structure studies and extraction experiments with strong solvents indicate that the difference between Tor and Ekofisk samples is due to rock surface chemistry differences.

The correlation developed here with the Tor samples provides a sound basis for comparing data from different wells, for examining the effect of various handling and laboratory procedures, and for data input in models. The indication of rock surface chemistry differences provides direction for further research aimed at explaining in greater detail differences between the Ekofisk and Tor rocks with respect to imbibition.

References and illustrations at end of paper.

INTRODUCTION

The Ekofisk Field is located near the center of the North Sea on a relatively simple anticlinal feature (Figure 1). The reservoir rock is chalk, and the productive zones are confined to the Ekofisk and Tor Formations, which are Danian and Maastrichtian in age, respectively. The field was discovered in 1969 and initial production began in 1971. The estimated original oil in place is $0{,}8 \cdot 10^6$ stock tank m^3 and the projected primary recovery is about 18 percent. About two thirds of the original oil in place is in the Ekofisk Formation and one third in the Tor Formation.[1]

The chalk sediments in the Ekofisk area have rather unique characteristics. The main constituent in this rock is skeletons of coccolithophores, which are unicellular algae. Usually the whole skeleton, the coccosphere is disaggregated into the distinctive coccoliths and further disaggregation produces the plate shaped crystals termed coccolith platelets. Geological studies have shown that the rates of sedimentation are significantly different for the Ekofisk and Tor Formation. The Danian age was dominated by moderately organic productivity and high carbonate dissolution rate, while the Maastrichtian age had high organic productivity and low carbonate dissolution rate. The thin layer of about 15 m between the Ekofisk and Tor Formation has a very high clay content.

In cores the chalk is moderately soft to hard, burrowed with stylolites and solution seams. Some intervals are highly fractured, only rubble is recovered from many productive intervals. Both porosity and permeability are determined by three interdependent factors: Primary depositional features, diagenesis and deformation style and history. The Ekofisk Field chalks have mainly interparticle porosity with fractures, and the porosity is in the range of 20 to 40%. Due to the extremely small pore throats in these chalks the matrix permeability is very low. Actual measurements of permeability on core plugs show values from 0.1 md to as high as 8 md. Data from well tests indicate that the more fractured intervals in the Ekofisk Field chalks have a formation permeability of about 100 md. It should be noted that fractures in the chalk remain among the least understood aspects of the Ekofisk area reservoirs.

The substantial secondary recovery target in the Ekofisk Field initiated a water injection pilot test, extensive computer model studies and laboratory experiments to investigate the effects of water injection in the Ekofisk Field. The purpose of the pilot test was to determine if water breakthrough was consistent with laboratory measured water imbibition values and if water could be injected at the desired rates without problems.

The main model concept used in the Ekofisk waterflood project is the dual-porosity model, where one porosity is associated with the matrix blocks and the other represents that of the fractures. When the water flow is controlled by the capillary pressure gradient, water imbibes into the matrix and displaces oil to the fracture system. Due to the complexity of the imbibition process, no simple law or equation is available for description of the process and prediction of recovery efficiency. Therefore, the laboratory water imbibition experiments on Ekofisk chalk sampels were an essential part of the waterflood evaluation program. The topic of this paper is a segment of this laboratory work conducted to evaluate the potential of waterflooding in Ekofisk.

Two primary concerns about laboratory imbibition results are that they are representative of what will occur in the reservoir and that correlations can be developed which permit proper input into the reservoir simulator. Variations in imbibition are the results of differences in pore structure and/or wettability. The first objective of this study was to develop a correlation between imbibition and rock parameters in Tor Formation samples known to be highly water wet. The second objective was to determine if differences in Tor and Ekofisk Formation imbibition behavior were due to pore structure or wettability effects. Once these objectives were met, then additional experimentation was done to establish the effects of other factors, such as core preservation procedures and the temperature used in the laboratory test. It is hoped these later studies will be covered in a future paper.

LITERATURE REVIEW

Most experimental work on imbibition behavior has been concerned with the scaling aspects of the process. The basis for this work was in fact these scaling investigations so a short review of some papers in this sector are presented here.

The first field related imbibition experiments were initiated by the rapid decline of oil productivity in the Spraberry Field. The work was performed by Brownscombe and Dyes[2] and showed that the oil recovery was dependent on the boundary conditions. The rate of imbibition was suggested to be proportional to the square root of permeability, since permeability is proportional with the square of the pore size. Their experimental data do not confirm this statement.

Graham and Richardson[3] performed a laboratory investigation of imbibition using a triangle block of fused quartz. They studied the scaling laws and the relation between the rate, the surface tension and the fracture permeability. The experiments demonstrated that the lower the injection rate into the fractures, the greater is the oil recovery for a given amount of water injected. By solving the basic flow equations they recognized that the rate of imbibition is proportional to σ, $\sqrt{k}$, $f(\Theta)$ (a function of the wettability) and depends on the fluid viscosities and the characteristics of the rocks. An equally important experimental work on imbibition was presented by Mattax and Kyte.[4] They discussed the experimental simulation of the imbibition phenomenon and verified the scaling laws of Rapoport.[5]

Iffly et.al.[6] investigated the effect of composition of the rock and fluids on the water imbibition. They concluded that experiments carried out with fluids and/or cores different from those of the investigated field are meaningless, except in very particular cases. The imbibition experiments on siltstone also indicated that oil recovery decreases as the carbonate and organic matter content increases.

The role of capillary-gravity ratio was discussed by Iffly et.al.[6] based on experimental results from imbibition tests on cores with different size and properties. The basic conclusion is that recovery time decreases with decreasing capillary-gravity ratio. Du Prey[7] performed similar experiments as Iffly which confirm this conclusion. Du Prey also compared centrifugal and conventional imbibition results for various ratios of capillarity and gravity. His results indicate that centrifuge tests on small samples are not reliable for reproducing the recovery curve of a big matrix block. Du Prey explains this from the fact that above a certain gravity level, the local properties of two phase flow change.

The important ideas found in the different studies can be summarized as follows:

1) Imbibition is usually the most important mechanism in the displacement of oil by water in fractured reservoirs. The gravity forces and viscous forces can be very important depending on the characteristics of the matrix blocks and the fluids.
2) The boundary conditions existing at the surface of the matrix blocks are important.
3) Recovery versus dimensionless time has shown interesting similarity between theoretical analysis and experimental results. But due to rock heterogeneity and unknown effects of lithology and fluid characteristics, laboratory experiments on the reservoir system are the only valid method for predicting imbibition recovery.
4) The present theory on imbibition states that the imbibition rate is proporitonal to $k^{\frac{1}{2}}$, $\phi^{-\frac{1}{2}}$, exposed matrix area, fluid characteristics and rock-fluid interaction relationships.
5) The scaling laws used to obtain recovery curves for reservoir matrix blocks based on laboratory tests on small rock samples are not generally accepted.
6) The development of a general relationship between fluid-, rock-, rock-fluid interacting parameters and imbibition is considered nearly impossible. This task will require a correct micro description of the rock and the nature of the physico-chemical relations between rock and fluids.
7) Both experimental and numerical techniques should be further developed through comprehensive studies on various reservoir systems combined with basic research on capillary behavior, wettability, pore structures and multiphase flow.

EXPERIMENTAL METHODS

The experimental work is composed of wettability and imbibition tests, rock property measurements and special extraction methods.

Wettability and imbibition tests

The objective of this work was to investigate the capillary imbibition in cleaned Ekofisk Field chalks. A standard cleaning procedure was used for all core plugs. The plugs were extracted by alternating xylene and methanol until no more contamination (colour) was observed in the solvents. The cores were then dried, evacuated and saturated with simulated formation water. The water saturated plugs were loaded into the ultra-centrifuge cells (Figure 2), and centrifuged at room temperature for 2 hours at 20 000 rpm. This speed results in an irreducible water saturation in the cores, since no more water was displaced by increasing the speed. The water saturation obtained at 20 000 rpm will be denoted initial water saturation in the following, since this is the water present at the start of the imbibition experiments.

The majority of the cores tested in this project was investigated with respect to wettability. The basis for the wettability study was Amott's[8] wettability test modified by Cuiec[9] and Harvey[10]. A complete test was performed as follows:

1) The cores were saturated with simulated formation water.
2) The core plugs were centrifuged for 2 hours at 20 000 rpm under formation oil.
3) The plugs were placed in imbibition cells (Figure 3) surrounded by simulated North Sea water, and allowed to imbibe to equilibrium. The volume of water imbibed was measured, A.
4) Forced displacement was performed by centrifuging the plugs for 2 hours at 20 000 rpm under simulated formation water. The volume of oil displaced was determined by weight measurements, B.
5) The plugs were placed in imbibition cells surrounded by formation oil and the imbibition process was allowed to proceed to equilibrium. The water displaced was measured (equal to the volume of oil imbibed), C.
6) The plugs were centrifuged for 2 hours at 20 000 rpm under formation oil and the volume of water displaced was measured, D.
7) The wettability index, RDI (relative displacement index) was determined as follows:

$$RDI = A/(A+B)-C/(C+D) \quad \text{.........} \quad (1)$$

This procedure allowed the water imbibition behavior to be determined along with the wettability index.

Rock property analysis and extraction tests

The rock property evaluation was primarily involved with pore structure analysis based on mercury porosimetry, sorption isotherms, scanning electron microscopy (SEM) and mineralogical studies. Pore size distribution and specific surface area were determined from standard mercury porosimetry with a pressure limit of 400 MPa. Surface area data was also obtained from nitrogen sorption isotherms by using BET-analysis. Pore sizes, pore throat sizes and pore shape were examined on photomicrographs from scanning electron microscopy of chalk or pore cast of chalk. A detailed description of the microscopic study is given in reference 11.

The wettability and imbibition studies revealed major differences between Ekofisk and Tor Formation. To investigate possible causes for these differences several rock samples were examined in greater detail. The work was concentrated on the quantification of clay and organic material in the chalk and the effect of these parameters on imbibition. The amount of non carbonate impurities in the chalk was determined by dissolving the carbonate with HCl. In addition extraction tests were conducted on both Tor and Ekofisk core plugs. Harsh solvents like tetrahydrofuran (THF) were used for extraction of already xylene/methanol cleaned cores.

RESULTS

Imbibition

Water imbibition results using cores from two wells, A8 and B16, in the Ekofisk Field are shown as correlations with porosity in Figures 4, 5 and 6. For all the core plugs from well A8 the RDI-value was greater than 0,9, so cleaned rock from the Tor Formation seemed to be completely water wet. RDI-value was not measured for the B16 samples. Figure 4 shows the initial water saturation, S_{wi}, as a function of porosity, where S_{wi} was determined after the ultra-centrifuging in oil. The water saturation change due to imbibition, ΔS_w, versus porosity is shown in Figure 5. The final water saturation after imbibition, S_{wf}, is the sum of ΔS_w and S_{wi}, and the plot is shown in Figure 6. This diagram shows that the residual oil saturation ($1-S_{wf}$) after water imbibition is essentially constant independent of porosity, averaging 37,3% of pore volume for the 40 plugs.

A supplementary experiment was performed to determine if S_{wf} could be increased by applying a positive displacement pressure. Centrifuge experiments with a capillary pressure of -70 kPa showed no additional oil production. These experiments indicate a general capillary behavior of the water wet Tor Formation samples as shown in Figure 7.

The RDI-values for cleaned Ekofisk Formation core plugs varied from 0 to 0.85. This variation in wettability has considerable effect on imbibition behavior. The imbibition of core plugs from Ekofisk Formation is therefore not only governed by the pore structure of the rock but also by the wetting properties. A partial confirmation of this statement is seen in Figure 8, 9 and 10. As observed in these figures the initial water saturation, imbibition saturation change, and final water saturation do not correlate with porosity the way the cores from the Tor Formation do. The average imbibition saturation change in the Ekofisk Formation based on data from 51 core plugs from well A8 (Figure 9) is 25,9%.

To obtain more data for analysis of the difference in imbibition between Ekofisk and Tor Formation the amount of clay and organic material in the chalk core plugs were determined. Figure 11 presents percent residue insoluble in HCl and water imbibed versus depth. In general the upper part of the Ekofisk Formation contains more residual matter than the lower part and the Tor Formation.

The imbibition results presented in Figures 8, 9 and 10 were determined using xylene and methanol extracted core plugs. Unlike samples from the Tor Formation, additional extraction with THF increased water imbibition in Ekofisk Formation samples. Figure 12 presents a comparison of imbibition behavior before and after THF extraction for an Ekofisk and Tor Formation core plug.

Rock parameters

SEM-micrographs at 5000 X (and greater) provide visual documentation of micropore space properties. But the micrographs may also be used to quantify pore parameters. The pore size distribution curve shown in Figure 13 was constructed by using a transparent overlay on the SEM-micrograph and tracing the pore configurations. A similar study of the pore throats resulted in curve B in Figure 13, and curve C is the pore throat size distribution obtained from mercury porosimetry. A pore size to throat size ratio of about 2-3 is observed from Figure 13. Investigation of this ratio from several SEM-micrographs of chalk from various intervals, indicates that the ratio is nearly constant. No quantitative data are obtained from SEM-micrographs on the degree of heterogeneity in the arrangement of pores and pore coordination number. However, SEM-micrographs of rock and epoxy pore casts indicate that both the Tor and Ekofisk Formation have sheet or plate like pores.

Examination of micrographs from 10 core plugs from Tor and Ekofisk Formation showed no significant mineralogic differences as far as visual structure is concerned. Occasional differences were noted, but these features could not be used to explain differences in imbibition between Tor and Ekofisk Formation.

Pore size distributions were determined on several core plugs using mercury porosimetry. From a pore size distribution curve of the type shown in Figure 13C, the 50% throat size (D_{50}) was determined. This is the throat size at which 50% of the actual pore volume of the sample is saturated with mercury. Based on the observations from SEM-micrographs about sheet-like pores, the pore throat size was calculated from the equation:

$$D = - \frac{2\ \sigma \cos\Theta}{p} \quad \text{..........} \quad (2)$$

Plotting D_{50} against porosity resulted in the correlations shown in Figure 14. Note that this correlation include data from both Tor and Ekofisk Formation.

DISCUSSION

Capillary imbibition data from approximately 100 core plugs from Ekofisk and Tor Formation, Ekofisk Field, were obtained in this project. The two most important aspects of this study, the porosity correlations in the Tor Formation and the wettability of the Ekofisk Formation are discussed in the following.

Tor Formation

The residual oil saturation was obtained by subtracting the initial water saturation and the imbibition saturation change from one. The initial water saturation was determined by the formula

$$S_{wi} = \frac{V_p - \Delta W/\Delta\rho}{V_p} \quad \text{..........} \quad (3)$$

where V_p is the pore volume, ΔW is the weight of the water saturated core minus the weight of the core after spinning under oil in the high speed centrifuge, and $\Delta\rho$ is the water density minus the oil density. An inspection of this formula shows that errors in the order of 0.03 g in weighing the plugs may result in errors in S_{wi} values in the order of ± 5% to 10% of the pore volume. Thus, the deviations about the S_{wi} versus ϕ line (Figure 4) are within the experimental errors which could be expected. In Figure 6 the deviation from a constant residual oil saturation is within ± 7% of V_p for 24 of 28 core plugs from A8. The cores from B16 are excluded from this evaluation due to undetermined wettability. This is remarkably narrow considering that both S_{wi} and ΔS_w errors are involved, and indicates that the residual oil saturation after imbibition is a constant for water wet chalk.

The experiments performed to determine if the S_{wf} values could be increased by applying a positive displacement pressure showed no additional oil production. This indicates that the imbibition capillary pressure curves are such that essentially all of the movable oil is recovered when a capillary pressure of zero is reached. We can establish that the water imbibition saturation change is equal to a constant minus the initial water saturation, i.e.,

$$\Delta S_w = C - S_{wi} \quad \text{...............} \quad (4)$$

An average value for the constant (or S_{wf}) is 61,4% of V_p for the extraced Tor Formation core plugs from well A8. Two questions arise from this correlation. Why is porosity the correlating parameter and what causes the residual oil saturation to be constant in the Tor Formation?

Permeability or permeability-porosity relationships did not give satisfactory correlations with residual oil saturation. This could be caused by errors in measuring the extremely low permeabilities in chalk and/or the effects of microheterogenities in the core plugs. Porosity alone was by far the best correlating parameter in the Tor Formation. However, Figure 14 shows a linear relationship between porosity and average pore throat size, so combined with Figure 4 the initial water saturation increases with decreasing pore throat size.

The second question is why the residual oil saturation is constant after water imbibition. Pore parameters are the key to the answer, since fluid parameters, wettability and boundary conditions were unchanged in the experiments. The main pore parameters affecting trapping of oil are: Pore to throat size ratio, the degree of heterogeneity in the arrangement of pores, throat to pore coordination number and the properties of the pore surfaces which include composition and degree of roughness. Heterogeneities in pore structure are not pronounced in chalk of the Ekofisk type, but microfractures are observed. These microfractures have a significant effect on the permeability, but their influence on the residual saturation after imbibition is not known. The coordination number, i.e. the number of channels connecting each pore, is affecting the trapping of oil. Wardlaw[12] suggests that a low coordination number results in high residual non-wetting phase saturation. But due to the difficulties in quantifying coordination number, the relative importance of the coordination number as one of several variables affecting recovery is not presently known. The surface roughness of pores in reservoir rock varies greatly from the smooth crystal surfaces of some dolomites to the pitted or clay coated surfaces of many sandstones. However, in the Ekofisk Field chalks the variation in surface properties is minor. This is also confirmed by the relatively constant specific surface area measured on this rock (1-2 m^2/g). This discussion has eliminated most pore parameters except the pore size to pore throat size ratio as an important factor in trapping mechanism in chalk.

There is relatively little work available on correlating residual saturations with pore structure, and especially with respect to the imbibition process. A few studies have dealt with waterflood microscopic recovery, and the following general observations have been made[13]:

- Rocks with large pores and correspondingly small specific surface areas have low irreducible water saturation, and a large saturation change may occur during the two phase flow.

- Breakthrough recovery may correlate with the group $\sigma\cos\Theta\sqrt{k}$, and ultimate recovery has been shown to correlate with the group $\sigma\cos\Theta\sqrt{\phi/k}$. In each case recovery decreased with increasing value of the correlating group.

- Both the group k/ϕ and D_p/D_{50} have been shown to correlate with residual oil after tertiary recovery processes. Here D_{50} and D_p are mean pore entry diameter and median bulge diameter, respectively.

- For strongly wetted systems in which capillary forces predominate over viscous and gravity forces, pore geometry is of first order importance in controlling trapping.

The few experimental results available in literature on residual oil versus pore parameters are not conclusive, and most correlations are obtained from tests on sandstone and glass models. The correlations obtained in this project are interesting due to the fact that the experiments were performed on chalk and that the residual oil saturation after imbibition was close to constant. Therefore, the chalk samples may have a common property, independent of porosity, that could explain the constant residual oil saturation. A combination of factors may be the reason, but it seems to be strong evidences for the D_p/D_{50} ratio as an essential parameter, since this ratio is found to be nearly constant in the investigated chalk.

The correlations between S_{wi}, ΔS_w, S_{wf} and porosity obtained in the present experimental work greatly increase our understanding of the imbibition process in Tor Formation. These results also revealed the significant differences in imbibition behavior between the Tor and the Ekofisk Formations. The data have been useful as a basis for further laboratory analysis in connection with the Ekofisk waterflood and may be useful in future reservoir evaluation problems in North Sea chalks. The correlations obtained for the Tor Formation could possibly be a characteristic property of water wet chalk in general, but this question cannot be answered until extensive experimental investigations of imbibition behavior in various chalk formations have been performed.

Ekofisk Formation

This work revealed that the imbibition behavior in the Ekofisk Formation is not mainly governed by pore characteristics. Since the pore structure is similar in the two formations, the difference in imbibition must be due to the wettability. The wetting properties of this rock seems to be very complex, and the imbibition recovery is unpredictable. The investigation program presented in this paper was the first attempt to determine some of the factors affecting the wettability of this rock.

As mentioned the rates of sedimentation were significantly different for the Ekofisk and Tor Formations, and the tight zone represent major changes in sedimentation. The insoluble residue analysis shows that the Ekofisk Formation contains higher amounts of residual matter than the Tor Formation.

Although the insoluble residue do not correlate directly with imbibition behavior, it is possible that they are indirectly related in some zones. The clay could be present as an overgrowth on the chalk, and could thus affect the imbibition behavior. Deposition of an additional organic component may change the wetting characteristics and alter the imbibition behavior. The key to these effects could appear to be the type and distribution of the organic components and other impurities in the pore system. Additional work will be required to further classify the impurities and their distribution in each sample.

The use of harsh solvents have been shown to increase the imbibition oil recovery in Ekofisk Formation core plugs. This behavior indicates that some of the material influencing the Ekofisk Formation imbibition is removable using harsh extraction procedures. A further problem will be to identify the extractable material, in order to understand the difference between Tor and Ekofisk Formation, as well as differences in Ekofisk.

CONCLUSIONS

The conclusions of this study are:

1. In Tor Formation the initial water saturation (S_{wi}), water imbibed (ΔS_w), and final water saturation (S_{wf}) correlate very well with porosity.

2. The saturation data (S_{wi}, ΔS_w and S_{wf}) from Ekofisk Formation did not correlate with porosity or any other rock property.

3. The pore structure of the Tor and Ekofisk Formation appears basically the same.

4. Extraction experiments indicate the difference in imbibition behavior of Tor and Ekofisk Formation is due to surface chemistry differences.

NOMENCLATURE

A = volume of water imbibed in the wettability test

B = volume of oil displaced during forced water displacement

C = constant (equation (4))

C = volume of oil imbibed in the wettability test

D = volume of water displaced during forced oil displacement

D = pore opening (distance between plates (equation (2))

D_p = mean bulge size of pore

D_{50} = average pore throat size

$f(\Theta)$ = dimensionless function of wettability

k = permeability

p = pressure

P_c = capillary pressure

RDI = relative displacement index from wettability test

S = saturation in % of pore volume

S_{or} = residual oil saturation

S_{wf} = final water saturation after imbibition

S_{wi} = initial water saturation

ΔS_w = water saturation change due to imbibition

V_p = pore volume

ΔW = weight difference

Θ = contact angle

ρ = density

σ = interfacial tension

ϕ = porosity

Subscripts

c - capillary
or - residual oil
p - pore
w - water
wi - initial water
wf - final water
50 - average

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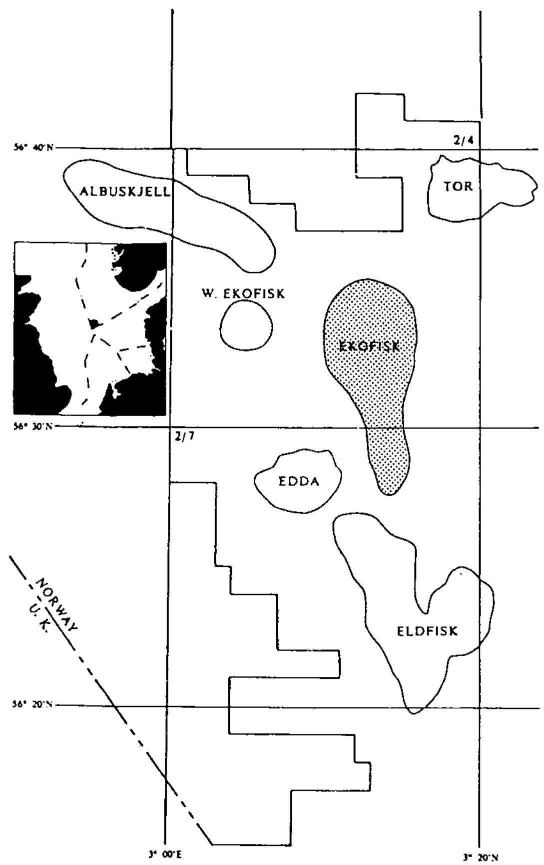

Fig. 1—The Ekofisk area in the North Sea.

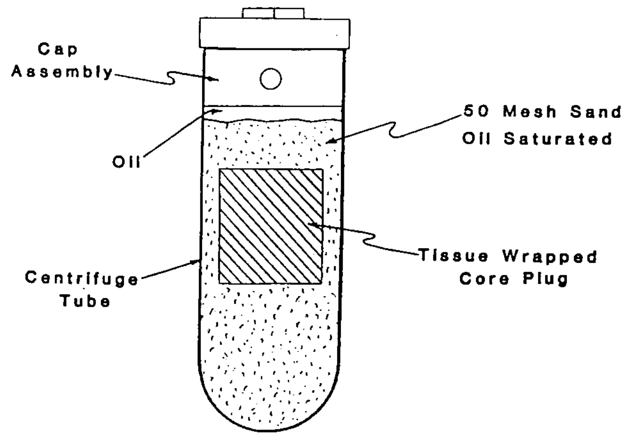

Fig. 2—Core plug loaded into the centrifuge cell for saturating with oil.

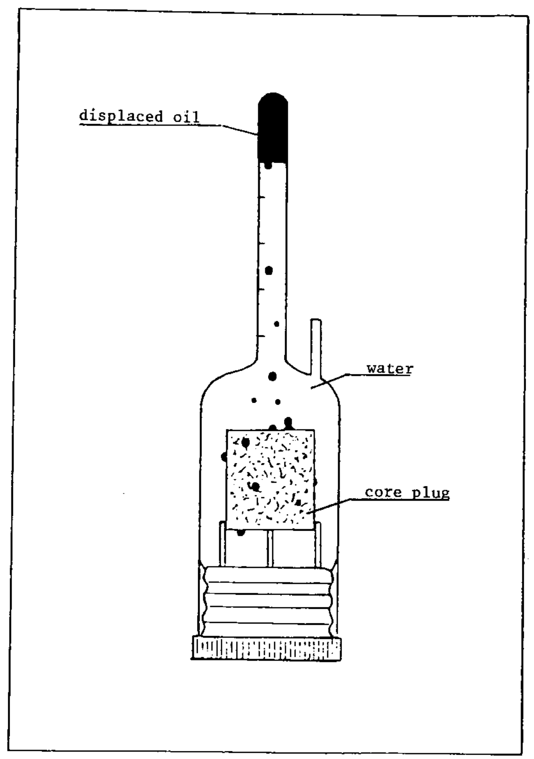

Fig. 3—Imbibition cell with oil-saturated core plug.

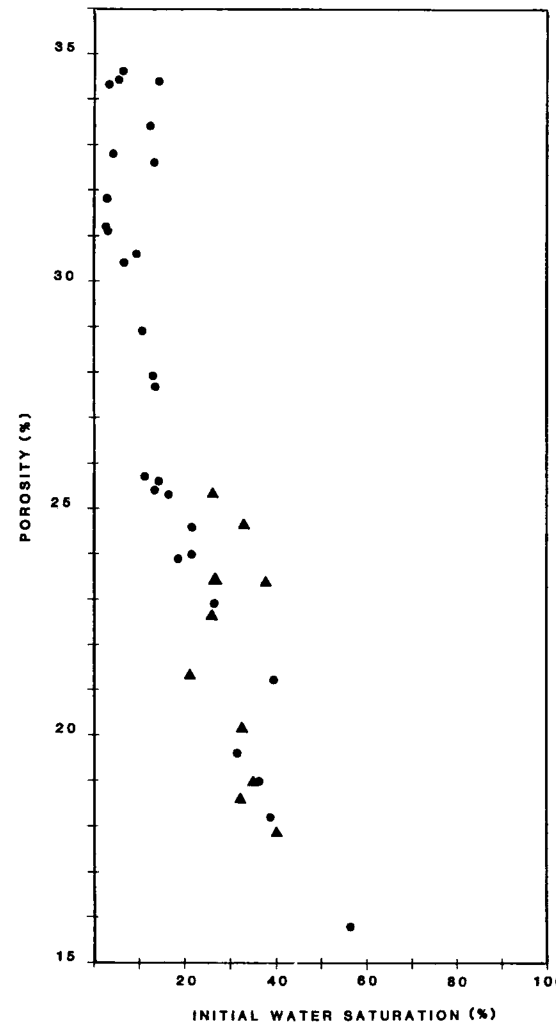

Fig. 4—Initial water saturation vs. porosity, Tor formation.

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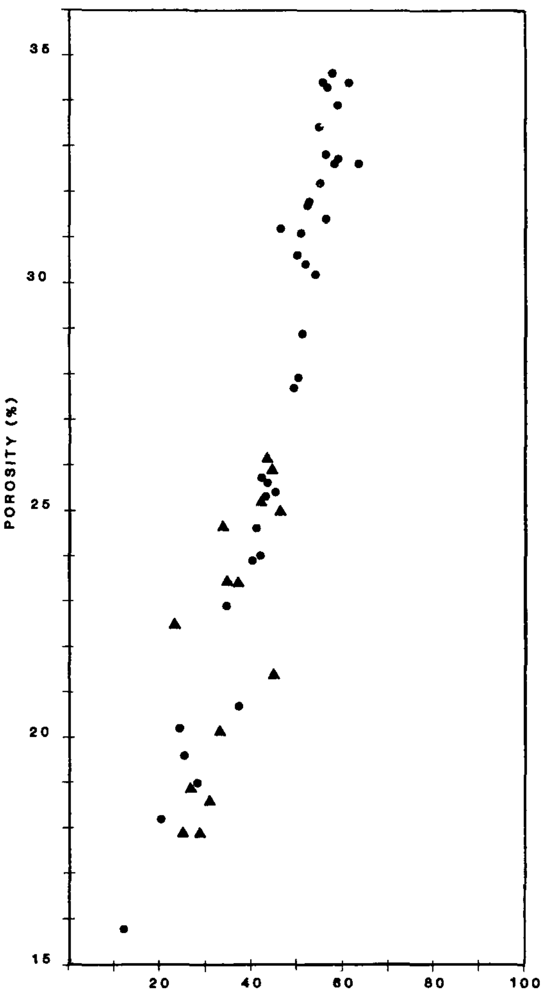

Fig. 5—Imbibition water saturation change vs. porosity, Tor formation.

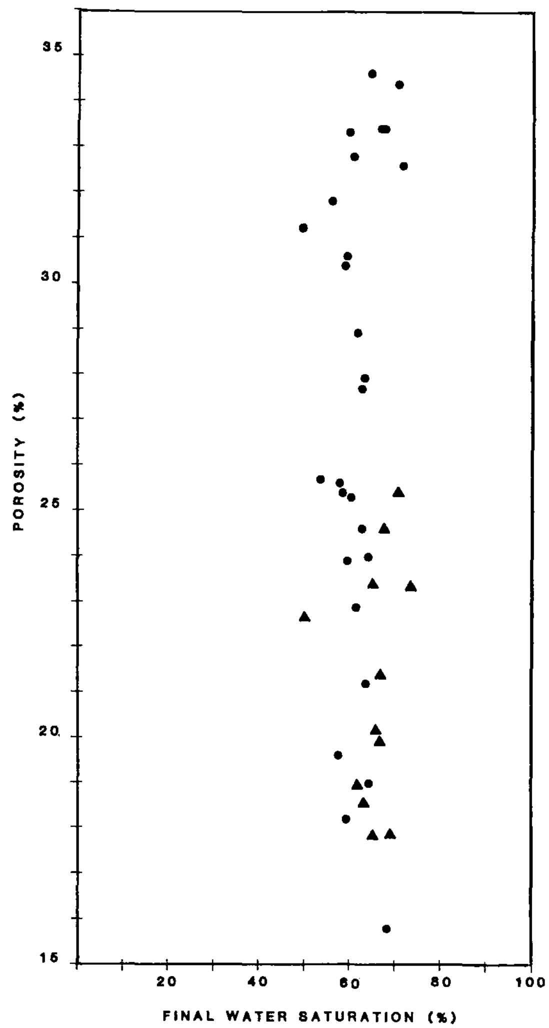

Fig. 6—Final water saturation vs. porosity, Tor formation.

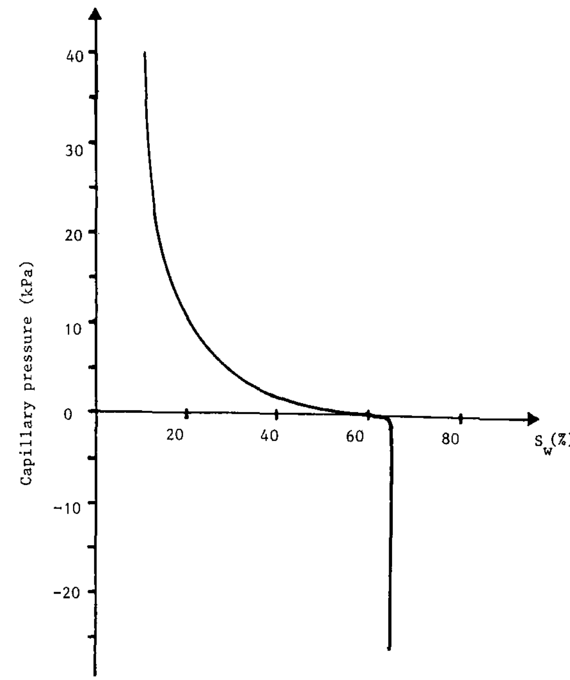

Fig. 7—Typical imbibition capillary pressure curve, Tor formation.

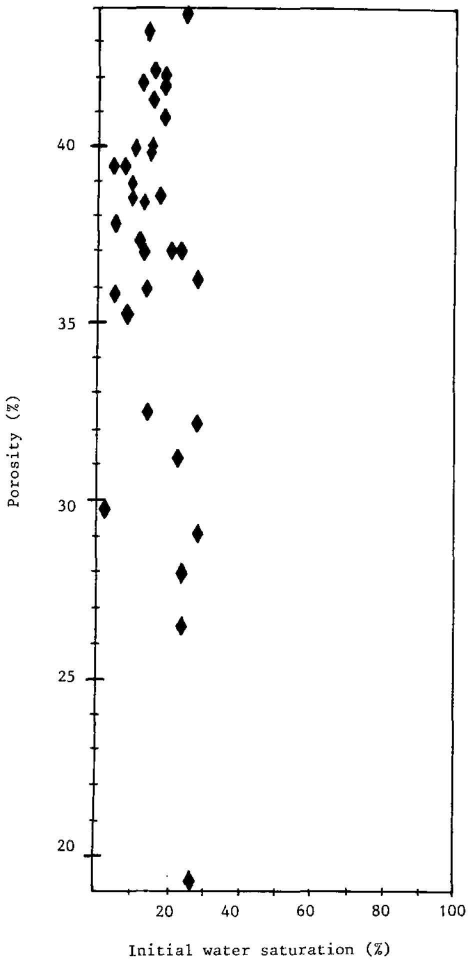

Fig. 8—Initial water saturation vs. porosity, Ekofisk formation.

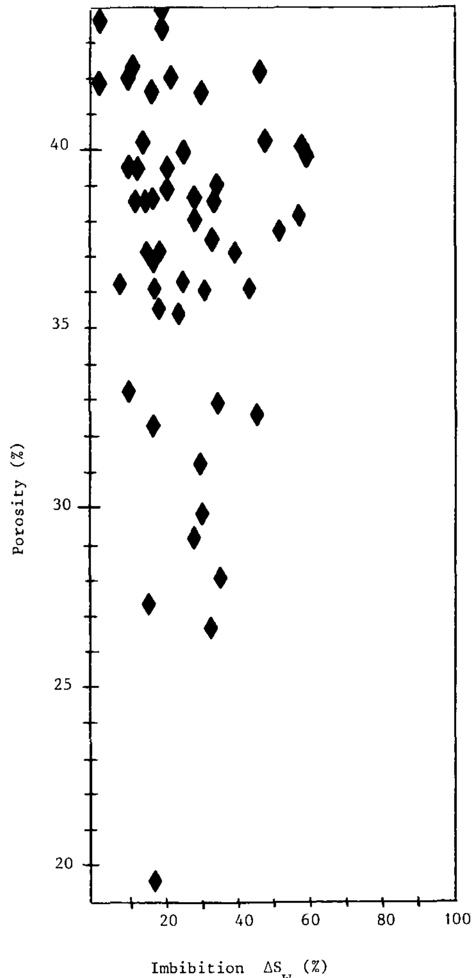

Fig. 9—Imbibition water saturation change vs. porosity, Ekofisk formation.

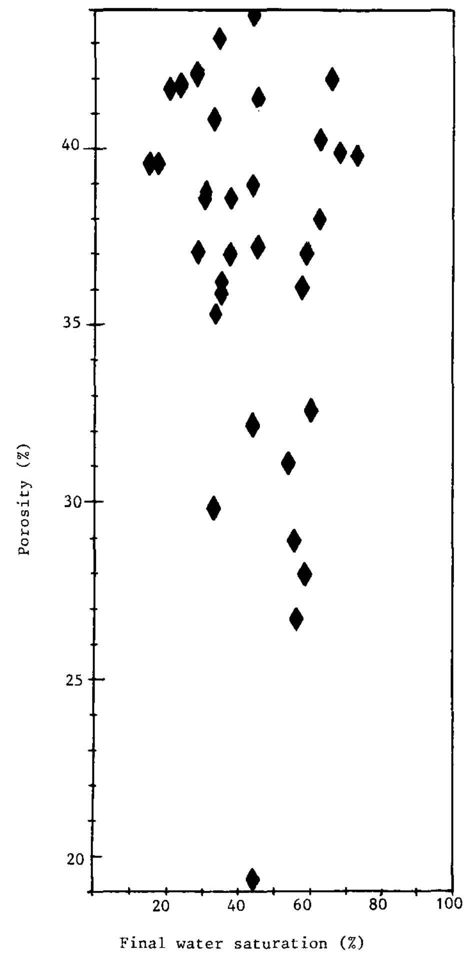

Fig. 10—Final water saturation vs. porosity, Ekofisk formation.

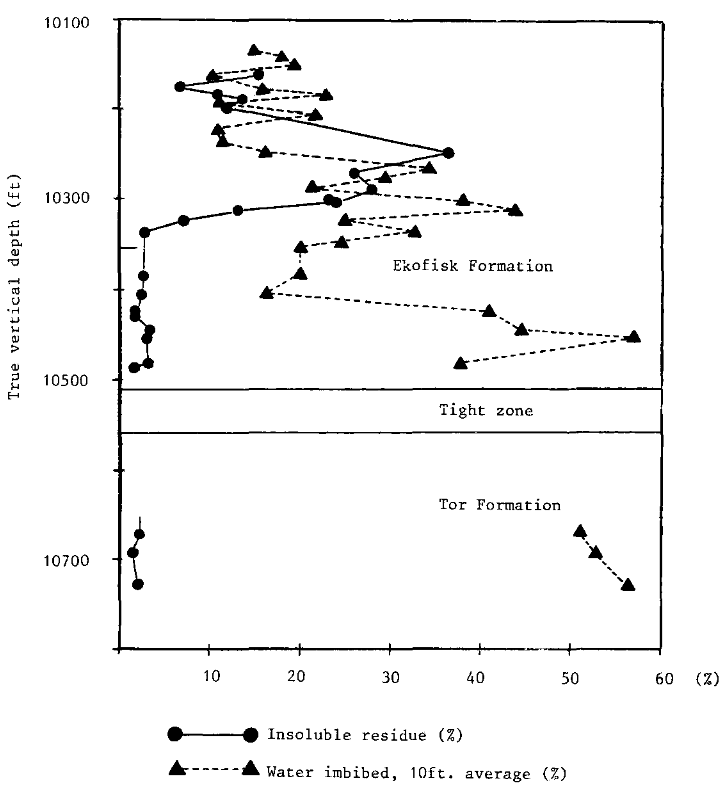

Fig. 11—Weight percent insoluble residue and imbibition saturation change vs. depth.

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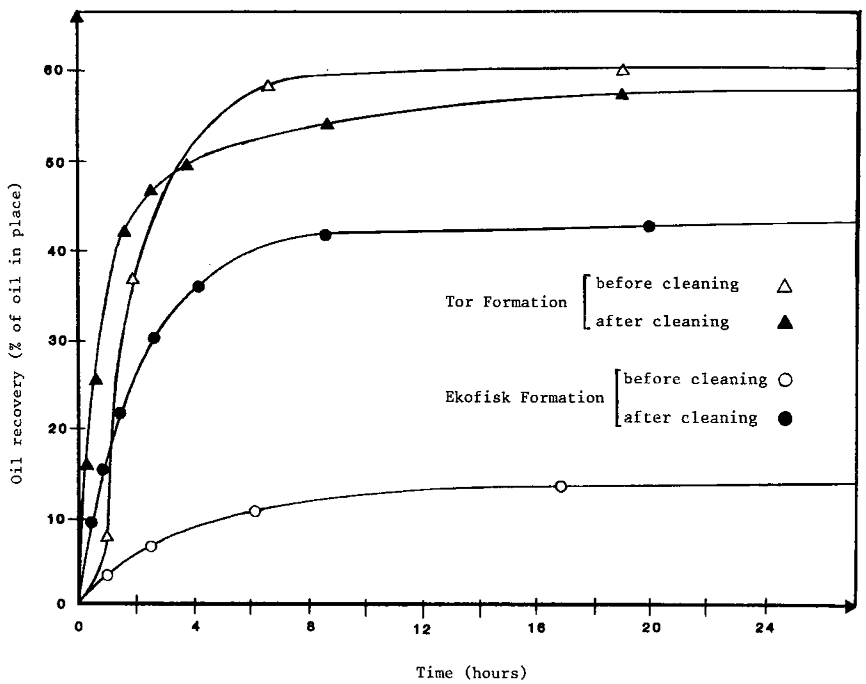

Fig. 12—Imbibition behavior before and after extraction with THF.

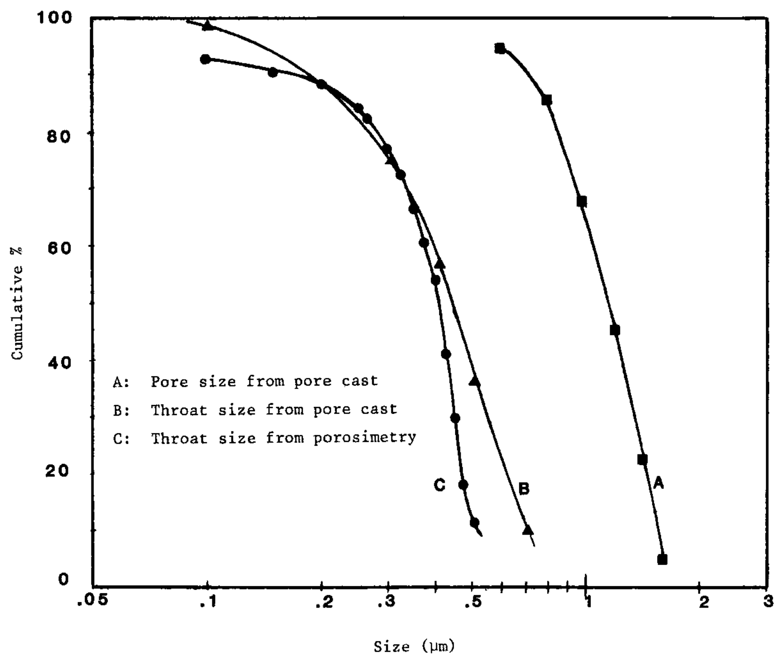

Fig. 13—Typical pore and throat size distribution.

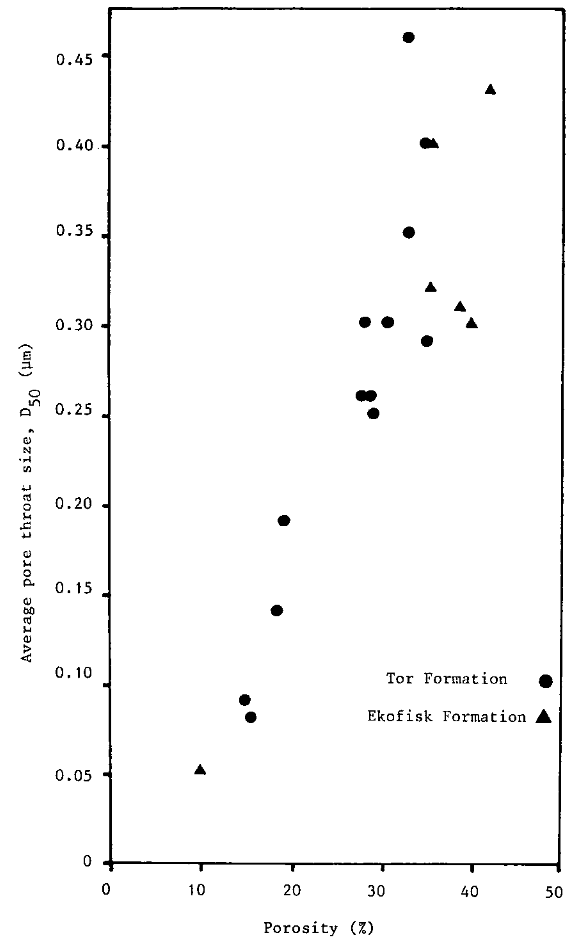

Fig. 14—Average pore and throat size vs. porosity.

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