การทดลองใช้การแทนที่ด้วยน้ำร้อนในห้องปฏิบัติการของน้ำมันดิบ
จากแหล่งสุพรรณบุรีโดยใช้แท่งตัวอย่างหินจำลอง

Hot-water Flooding, A Laboratory Experiment of Suphan Buri Crude Using Reinstalled Cores

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ชื่อวิทยานิพนธ์	การทดลองใช้การแทนที่ด้วยน้ำร้อนในห้องปฏิบัติการของน้ำมันดิบจากแหล่งสุพรรณบุรีโดยใช้แท่งตัวอย่างหินจำลอง
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บทคัดย่อ

วัตถุประสงค์ของงานวิจัยนี้เป็นการศึกษาแนวทางเพื่อประยุกต์ใช้ ในการเพิ่มผลผลิตน้ำมันดิบของแหล่งสุพรรณบุรี โดยการทดลองในห้องปฏิบัติการศึกษาการแทนที่ด้วยน้ำร้อนในแท่งตัวอย่างหินน้ำมันจำลอง ที่สร้างขึ้นมาให้มีคุณสมบัติหลัก เช่น เนื้อหิน การอัดแน่นและการประสานของเม็ดทราย ความพรุนและความสามารถให้ของไหลผ่านได้ เหมือนกันกับชั้นหินในแหล่งผลิตของแหล่งสุพรรณบุรีจริงๆ ในการศึกษาได้ทำการอัดแทนที่ด้วยน้ำร้อนที่อุณหภูมิ 90 องศาเซลเซียส เปรียบเทียบกับการอัดแทนที่ด้วยน้ำที่อุณหภูมิเท่ากับในแหล่งชั้นหิน พบว่าอัตราการไหลเฉลี่ยเพิ่มขึ้น 13.9% จาก 27.3% ไปเป็น 41.2% โดยใช้ปริมาณการอัดแทนที่ 2 เท่าของปริมาตรพื้นที่ว่างของแท่งตัวอย่างหิน จากผลสรุปของการศึกษานี้ จะสามารถนำไปพิจารณาเป็นแนวทางประยุกต์ และประกอบการศึกษาเพิ่มเติมเพื่อเพิ่มอัตราการผลิตน้ำมันดิบในแหล่งสุพรรณบุรีได้

Thesis Title	Hot-water Flooding, A Laboratory Experiment of Suphan Buri Crude Using Reinstalled Cores
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Abstract

The purpose of this study is to carry out the laboratory water flooding experiment to investigate the production improvement for Suphan Buri Oil Field. Core plug samples were reconstructed resembling the original reservoir conditions to experiment the water flooding. The reinstalled plug samples were flooded at reservoir temperature 76°C comparing to that of a desire temperature 90°C. This hot-water flooding laboratory experiment proves a successful recovery improvement of an average 13.9% additional recovery, from 27.3% to 41.2%, when 2 pore volumes of injected hot-water flooded.

The study proves that the hot-water injection results in improving recovery through decreasing crude oil viscosity in consequence reduce flow resistance and thermal expansion throughout the core plugs. The additional heat also swells up the crude in which adds expulsion energy to the system and consequently increase its production operations. Eventhough this hot-water flooding method shows optimistic results however it could not practically be applied direct to the field without other related property studies.

Acknowledgement

I would like to express my deepest gratitude appreciation to my advisor, Assistant Professor Dr. Pitsanu Bunnual, of Mining Engineering Department, Prince of Songkhla University and Dr. Vinit Harnsamuit, Senior Reservoir Engineer of PTT Exploration and Production Public Company Limited for all their valuable advice, encourgement and guidance throughout this thesis study. It is with their continuous efforts that this thesis has reached its final shape.

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Finally, I would like to express my deepest appreciation to my family, my wife Kulacha and my daugther Suchaya Chunlasen for their love and supporting.

Sombat Chunlasen

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Chapter 1

Introduction

1.1 Introduction

In year 2000, Thailand's petroleum demand totaled 895,000 barrel per day (STBD), a rise of 0.9% from previous year (PTTEP, Annual Report 2000). The expansion of petroleum consumption was attributed by the economic growth. The further consumption, the required activities in petroleum exploration and production. Since the beginning of petroleum exploration in Thailand in 1921, at Fang Basin, northern Thailand where oil seeps were found, nowadays, the petroleum exploration and production are both onshore and offshore throughout the country including the Gulf of Thailand and Andaman sea. In the Central Region, oil explorations and productions are in Phitsanulok, Suphan Buri, Kamphaeng Saen and Petchabun basins.

The Suphan Buri oil field, a combined area of 20,000 square kilometers with two small oil pools, was discovered in 1988 and production commenced in 1991 by BP Exploration Operating Co. Ltd., and now under PTT Exploration and Production Thailand. The crude oil production for the field during the first year 1991 was targetted at 800 STBD but it had exceeded expectation of average 1,200 STBD. Soon after the first few years of production, the flow rate has gradually dropped (Figure 1-1). The production rate in year 2000 was sustained at 550 STBD (PTTEP Annual Report, 2000). The production decreasing suspected problems in rapid production operations because of low reservoir pressure, problem in reservoir drive mechanism and low gas-oil ratios. (Bidston & Daniels, 1992).

Despite the high ambient temperature, an in-line process heater was installed to assist in degassing the crude in preparation for tanker loading and prevent wax deposition in the surface pipework and tanks. From the field production and operations report of PTTEP1, March 1996, the well UT1-7/D1 was shut down for some days due to build up of water level near pump depth (Figure1-1).

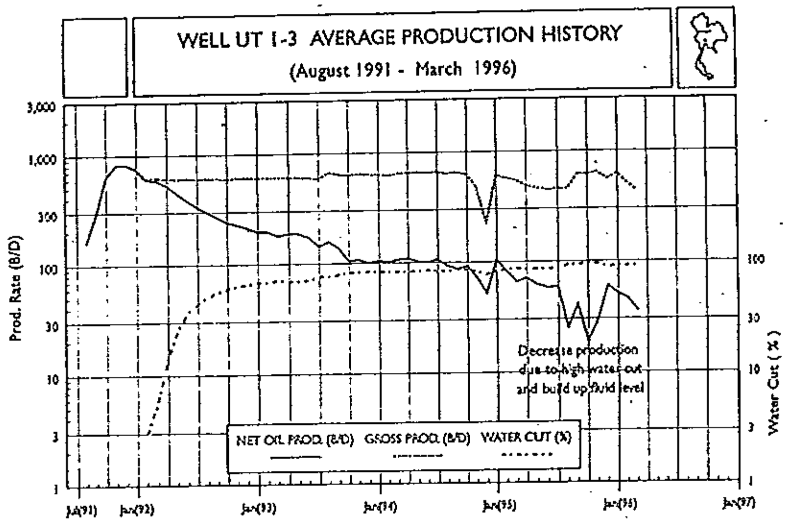

Figure 1-1 Suphan Buri UT-1-3 Production Rate (PTTEP, 1997)

The Suphan Buri crude oil analysis was carried out and found that the crude oil is likely viscous oil of 9.6 centipoises, high paraffin wax content of 15% and low gravity@60°F at 23.5°API (BP Petroleum, 1987). This data information is particularly encouraging further studies to enhanced further recovery. The enhanced secondary recovery process following primary production operations refers to all additional production from the reservoir resulting from the use of artificial energy added to the reservoir system (Craft, Hawkins, 1991). Reduction of the present oil viscosity 9.6 cP is the main key to this laboratory experiment by applying heat to the flooding system improving the displacement and production recovery efficiencies.

Hot-water flooding is one of the efficient recovery processes for heavy crude oil and medium oil (Prats, 1986). Hot water reduces the viscosity of the crude and of the formation water and hence will reduce the flow resistance (Chapter 2). It is also used to clean up the well bore surrounding i.e. organic solids near well bore, clay materials or fine materials that could be inhibiting pore throat (Prats, 1986).

1.2 Review of Literatures

1.2.1 Suphan Buri Oil Field

The Suphan Buri basin, 800 sq. km. is a Tertiary half graben with over 3 km thick of sediments (Figure 1-2) (Hill G.S., 1987). The Suphan Buri oil field is situated on the western fault controlled basin flank of Suphan Buri Basin. The basin is elongated in shape and bounded by an active margin on the west and a passive margin on the east.

The reservoir interval is Oligocene-Miocene fluvio-lacustrine sediments. These sediments were deposited on an alluvial braided plain fringing lake cut and filled by channel conglomeratic sandstones. The Suphan Buri oil field structure formed as a rollover on a low angle north south trending fault during the deposition. The structure closure relies on three-way dip closure and up-dip fault seal of the west.

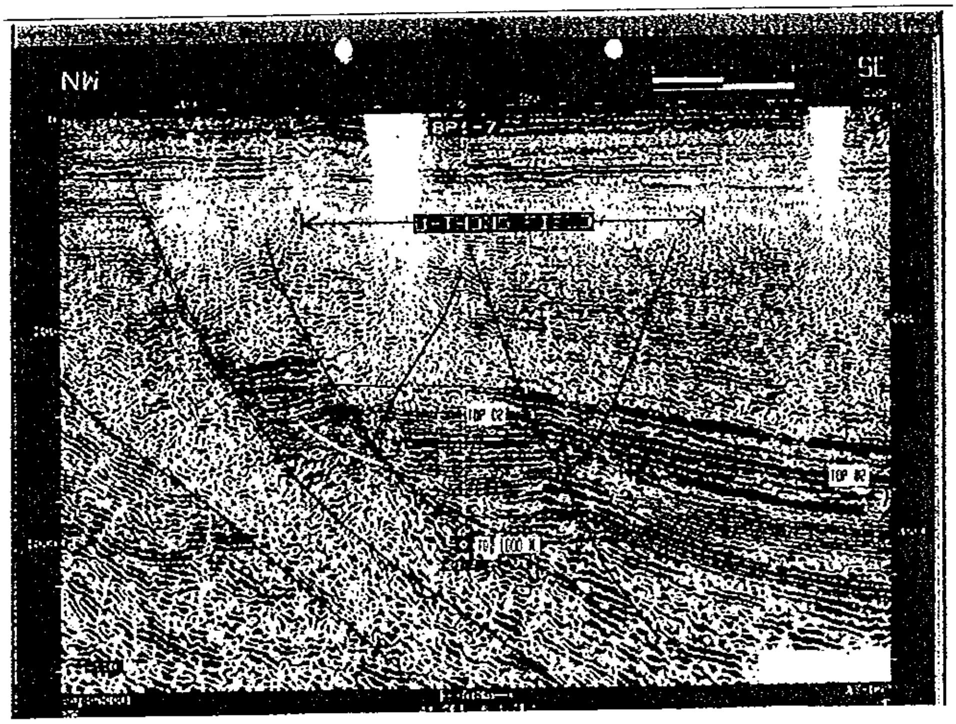

Figure 1-2 Seismic Interpretation: Suphan Buri Basin Structure (Swiecicki A. & Hill G.S. 1987)

1.2.2 Petrography and Diagenesis

The basin sequences are characterized by sandstones and conglomerates, display high degree of textural and chemical immaturity. They are generally poorly sorted muddy sandstones with packstone texture and are composed of subangular to sub-rounded grains and lithoclasts. The matrix of sandstones and conglomerates consists mainly of quartz silt, possible feldspar silt, micas and detrital clay minerals (Hill, 1987).

The main diagenetic processes that affect the sandstones and conglomerates occurred during burial through out the basins. Due to the high matrix and lithic content, mechanical compaction is the main process responsible for the reduction of deposition porosity and permeability. Carbonate phases, nodular calcite, and ferroan calcite are also reducing poroperm. Visible porosity within the sandstones and conglomerates ranges from 0% to 20% is mainly present as primary intergranular porosity (Hill, 1987).

The generalized depositional models of Suphan Buri are described and divided into 3 broad layers; (Figure 1-3)

- Upper Reservoir (UR): Alluvial fan-delta sediments, improving in quality to the south and east in the lower part. Better quality in the north and west of the closure in the upper part of the unit, reflecting retreat of the fan.
- Middle Reservoir (MR): A lacustrine interval dominated by mudstones across the field, probably a barrier to vertical flow between the Lower and Upper reservoir if not fault-breached.
- Lower Reservoir (LR): Alluvial braidplain sediments, good quality reservoir sands deposited in channel sand bodies across the area.

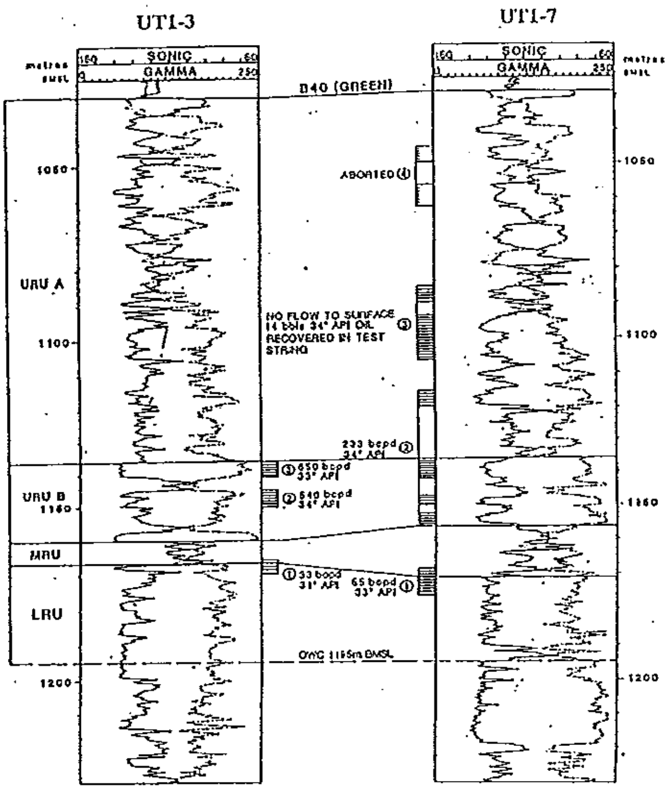

Figure 1-3 U-Thong Wells Correlation (Swiecicki A. & Hill G.S., 1987)

1.2.3 Suphan Buri Oil Source

Suphan Buri oil field has a known significant oil source provided by mudstones which accumulated in deep permanent lakes during Oligocene to Miocene (Swiecicki A. & Hill G.S., 1987). In 1988, geochemical studies of well BP-2, W-6, by BP Research Centre (Davis 1988), were carried out of lacustrine mudstones together with thermal modelling for five wells in the westerly basins suggested that the generated crude oil has very little gas generation and high wax content of 45% by weight. The viscosities were found to be dependent on heat and increased sharply below 37°C on colling due to wax crystallisation. The wax appearance temperature was at 51°C (Coombes, Maile, 1987).

In 1993, the PVT and crude oil analyses of well BP 1-1, DST 1 & DST 3A were carried out by BP Petroleum. The composition of the crude oil at wellhead samples were determined as heptanes plus residue fraction. The viscosity values at 175 °F at reservoir pressures at 1804, and 1549 psig were at 7.443 and 6.193 cP respectively. The calculated API gravity @60°F were at 25.5 and 28.2 respectively. The Suphan Buri crude oil sample viscosities and API gravity which are being used in this experiment are extrapolated using plot graphs in Appendix O (Core lab, 1993).

1.2.4 Suphan Buri Field Exploration

Early reconnaissance seismic revealed five Tertiary basins and the regional constructed cross section illustrates relatively small basinal areas showing similar asymmetric half-graben structural styles of the western and eastern basins. Stratigraphic wells show that the basins have different seismic characteristics, the easterly basins are filled by poorly sorted fluvial sands, gravel mudstones with high energy, discontinuous, banded seismic appearance. The westerly basins are well-layered with some low-energy sections showing good continuity which generally related to lacustrine mudstone sections in subsequent wells. The stratigraphic well data and quality reconnaissance seismic proved the westerly basins to be prospective with a well developed lacustrine sequence at adequate depths for oil generation.

1.2.4.1 Type of Reservoirs

The lacustrine basins have dominantly low energy depositional environments providing limited reservoir developments providing limited reservoir development especially in the basin center. Around the margins of the lake river delta, channels and alluvial fans offer generally poorly sorted interbedded reservoirs, typically exhibiting a rapid decrease of poroperm with depth. The reservoir is interpreted to comprise both fan delta and alluvial fan sediments as the lake shoreline advanced and retreated. The reservoir lithofacies are poorly sorted and highly variable ranging from conglomerates and pebbles to sandstones, silts and mudstones. The oil reservoirs are interpreted as fan delta channel and turbidite sands within a dominantly mudstone section.

1.2.4.2 Field Development

A geological model for reservoir deposition and four reservoir zones, had been established from detailed evaluation of the cores and log from both wells. Total net pay within the four reservoir zones, 2-5 m thin stacked sands, was 30 meters in both wells. The reservoir formation tester (RFT), and drill stem test (DST) pressure data collected from the major wells indicated that the oil zones were in contact with a common oil/water contact (Bidston and Daniels, 1992). The well exhibited good productivity during drill stem test of the primary sands, with measured permeabilities of up to one darcy. A well flowed at 1,190 BOPD from two test zones, whist another flowed at 300 BOPD, from the three test zones. The wellsite facilities were designed for an oil through put of 1200 BOPD from 6 production wells, KS1-1, UT1-3, UT1-3/D1, UT1-7, UT1-7/D1and UT1-7/D2 (Production and Operations report, 1996).

1.3 Statement of Objectives, Scope of the Study, and Possible Achievement

1.3.1 Statement of Objectives

The main aim of this study is to carry out a laboratory experiment for any significant improvement to improving the Suphan Buri oil recovery. The current primary recovery method has been producing cumulative amount of oil in places at 1,930,087 bbl, (Production and Operation monthly report, 1996). The expansion of oil production, it responds to further recovery efforts, enhanced secondary recovery, to produce additional remaining crude oil.

For such a high viscosity crude oil of Suphan Buri, 9.6cP, the crude has a much higher flow resistance than does the water. The water moves faster than the crude, leaving some mobile crude behind. Therefore, a reduction of crude viscosity by introducing substantial amount of heat into the reservoir and consequently more crude oil will be produced (Prats, 1986). Choosing thermal process by hot-water flooding technique for such particular condition is rather preferential only for recovery study in laboratory. The operation process is considered simple, available supply water, appropriate petrophysical properties and most importantly low in operating costs.

The objective of this study is :

- to carry out laboratory Hot-water Flooding technique applied on reinstalled Suphan Buri core plug samples at reservoir temperature condition 76°C and at a desire warmer condition, 90°C.
- to compare the study results whether its application at higher reservoir temperature, 90°C would prove increasing in oil recovery to that of the normal reservoir condition, 76°C.

1.3.2 Scope of Study

The study of water flooding is performed using original core samples of Suphan Buri UT1-7/D3 well, reinstalled to laboratory equipment standard core plug samples and being flooded by the Suphan Buri crude oil sample. The experiment is carried out at ACS Laboratories, Songkhla, Thailand. The water flooding recovery results of the two thermal conditions are compared to see if any significant recovery production improvement when higher water flooding temperature applied. More importantly, it is to prove a successive remarkable recovery after a certain number temperature increased in the reservoir conditions.

1.3.3 Possible Achievement

The possible achievement of this study to understand the samples behavior both core plug samples and crude oil behavior when water flooding at different temperatures are applied. The results of the two-temperature water flooding are monitored and compared to a significant level of recovery improvement. The knowledge achievement from this study can be recommended motivation for practical procedure to increase a certain level of the Suphan Buri oil field production. It is also can be used as fundamental information for future development in petroleum exploration and production industries.

1.4 Hot-water Flooding Applications

There are a number of hot-water flooding applications in the USA, USSR and in Europe. At the Loco, Oklahoma, USA, where crude oil viscosity is 600 cp, the total recovery of 156 bbl/acre-ft after 1-year hot-water flood in a thin sand formation. Heat losses from this thin reservoir were reported to be about 60% of the injected heat. Also in Oklahoma at Northeast Butterly Oil Creek Unit, oil viscosity 2,000 cp, the hot-water drive phase of the project lasted about 4 years, produced 375,000 bbl of oil from cyclic hot-water simulation. At Kern River, California, USA, viscosity 4,060 cp, injection of 2.23×10^6 bbl of hot water in a year at average of 300°F resulted in an oil recovery of 40,260 bbl. The Schoonebeek hot-water drive, in Holland, where the viscosity is 175 cp, attained an injection capacity of 95,000 BPD and after 10 years operation, the oil recovery attributable to the hot-water drive was nearly 1.25×10^6 bbl and still expected further recovery (Prats, 1986).

1.5 Samples Preparation and Analytical Procedure

Prior to the hot-water flooding experiment, certain petrophysical properties of the core samples i.e. porosity, permeability, grain density, grain size distributions, and mineralogy are required. The cloud point temperature of the crude oil is as well required for the experiment. The available cores were crushed and reinstalled as close as its original conditions to run hot-water flooding successfully.

1.5.1 Suphan Buri Crude Oil Sample

Prior to the hot-water flooding approaching, various laboratory analyses were carried out to determine a cloud point, a pour point, paraffin contents, and viscosity values of the crude oil (Appendix O). The cloud point determination was conducted as an information to indicate whether wax problems can be expected. The analysis information is a basis of selecting and helping out calculating fluids displacement in the experiment to improving crude oil recovery (Appendix N & O).

The cloud point is determined by injecting crude oil sample (Figure 1-4) into standard core plugs at various different temperatures. The cloud point is estimated from measurement and observation of the inflection point on the cooling curve (Appendix K).

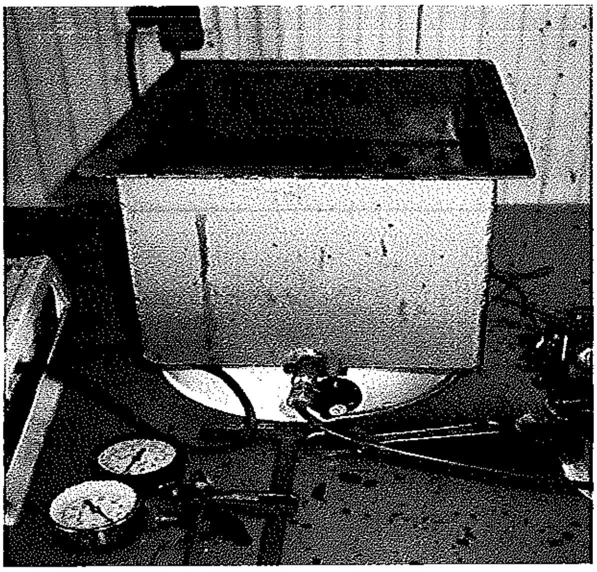

Figure 1-4 Suphan Buri Crude Oil

1.5.2 Suphan Buri Core Sample

The retrieved core sample to perform the experiment was in poor conditions, crumbly and highly weathered. It was kept in wooden boxes wrapped in tarpaulin and left being exposed to the air for a number of years.

The available core sample was unsuitable to perform the experiment directly but to reconstruct new core plugs using original material, that convenient and controllable to hold in overburden pressure cell for hot-water flooding experiment.

Thin section analysis (Appendix B), X-ray diffraction analysis (Appendix C), and grain size distribution from sieve analysis (Appendix D), were carried out on the retrieved core samples for data information to assist reinstall the core material as close to original properties i.e. porosity, permeability and grain density (Appendix E). The core plugs were then brined and oil saturated (Appendixes H & I) to represent the actual Suphan Buri formation.

Water Flooding experiment preparations are as follows (details in Appendices):

- Core sample retrieved from PTT Explo. & Prod. Public Company Limited, Bangkok to ACS Laboratories (Thailand) Pty.Ltd. Songkhla, Thailand.
- Core sample sections were selected for thin section and X-ray diffraction analyses (Appendices B and C). The rest of core sample was then gently crushed to study its grain size distribution using standard sieve analysis method (Appendix D).
- Standard core plug samples, 1.5" diameter and 2" long, were constructed out from the crushed materials using information from grain size distribution, thin section and X-ray diffraction analysis results and true average petrophysical properties of the Suphan Buri reservoir formation i.e. porosity, permeability and grain density (Appendix E).
- Core plug samples were then individually determined for their ambient and reservoir conditions porosity, permeability and grain density (Appendices F,G and H) for fluid saturation purposes (Appendices J and K).
- Core plug samples were selected to determine fluid flow rate at single phase condition, in order to calculate the relative permeability at unsteady state condition (Appendix L).

- Three (3) core plug samples were selected to normal water flood at reservoir temperature 76°C using relative permeability calculation at unsteady state condition.
- Eight (8) core plug samples were eventually flooded by hot water at a chosen temperature 90°C to find any improvement of oil recovery compare to that of the flooding at normal reservoir thermal condition.

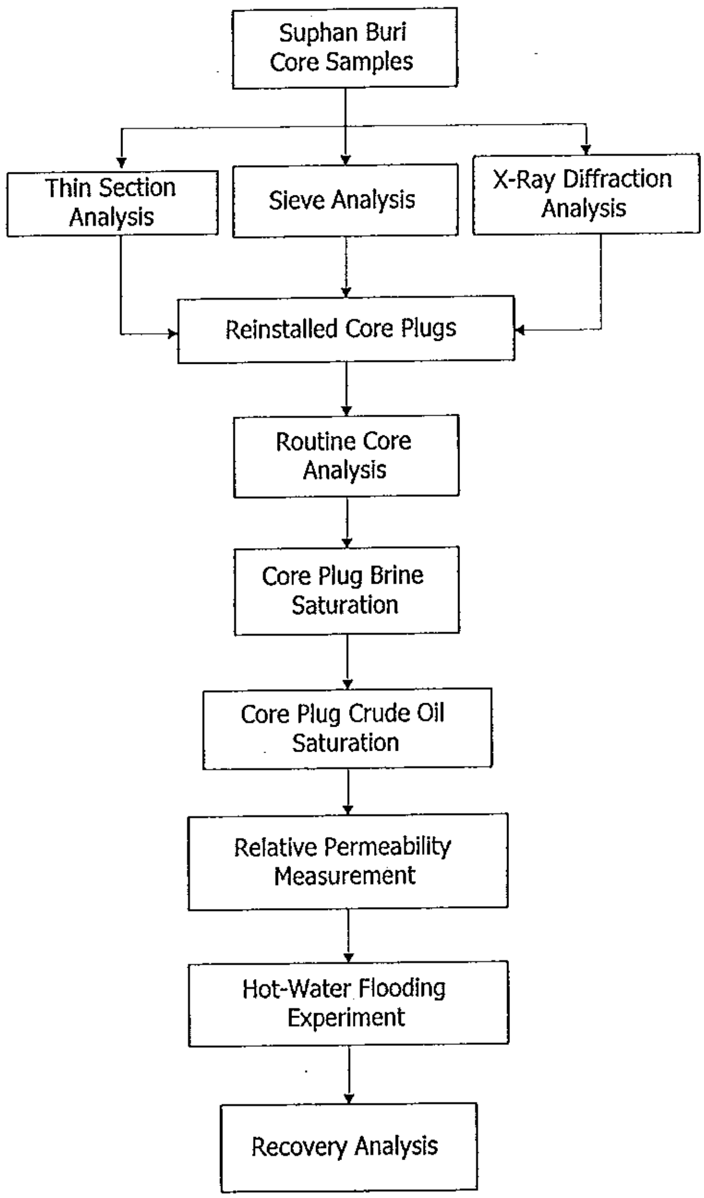

Figure 1-5 Sample Preparation and Hot-water Flooding Analysis Procedure

Chapter 2

Hot-water Flooding Experiment

2.1 Introduction

2.1.1 Thermal Recovery Method

Thermal recovery processes tend to reduce the reservoir flow resistance by reducing the viscosity of the crude. Consider two reservoirs that are entirely similar except for the viscosity of the crude (Figure 2-1). Linear displacement of oil by a specified volume of water will result in an oil saturation in the water-swept zone that is larger for the one having the higher viscosity. At sufficiently low crude viscosities, the oil saturation upstream of the displacement front is essentially irreducible, leading to what is known as piston-like displacement. The oil saturation drops across the displacement front by an amount of equal to 1-Sor-Swi.

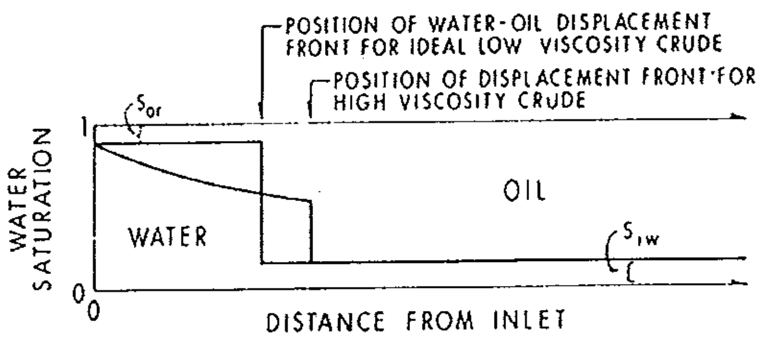

Figure 2-1 Qualitative effect of crude viscosity on the oil saturation distribution (Prats, 1986).

For high viscosity crude, the drop in oil saturation at the displacement front is much smaller, and a substantial amount of mobile crude is bypassed by leading edge of the displacement front. Because of its high viscosity, the crude has a much higher flow resistance than does the water. The water simply moves faster than the crude, leaving some mobile crude behind. This means that for the more viscous crudes, at the same water injection rate and injected volume, water will break through at the producer earlier (Prats, 1986).

There are a number of basic physical ways to reduce the viscosity of the crude, for example mixing the crude with a low-viscosity solvent, or increasing its temperature (Prats, 1986). As to the nature of the Suphan Buri crude oil and geological structures of the area, various thermal recovery methods for example: hot-fluid injection, hot-water flooding, steam flooding, and in-situ combustion, can be considered apply to enhanced recovery of the field. These flooding processes tend to reduce the reservoir flow resistance by reducing the viscosity of the crude.

2.1.2 Mechanisms of Displacement

The improvement in recovery of viscous crude by means of hot-water floods relative to normal waterfloods is primary due to (Prats, 1986):

- the improved oil mobility resulting from the reduction in oil viscosity. Reducing the viscosities of the crude and of the water, it tends to reduce the flow resistance as well. (Appendix O).
- the reduction in residual oil at high temperature. It is also to clean up the wellbore surrounding. There might have some organic solids near wellbore, which may be melted or dissolved. The clay material may be stabilized, the absolute permeability may be increased by the high temperature, or fine materials that could be inhibiting flow in gravel packs may be flushed away.

The effective mathematically of recovery flow rate is depending on the following ratio parameters (Johnson, Bossler, Naumann, 1959):

The ratio of gravity to applied pressure forces: $\frac{Lg\Delta\rho}{\Delta p}$,

The ratio of capillary pressure forces to applied pressure forces: $\frac{\sigma}{\sqrt{k}\Delta p}$, and the ratio of applied pressure forces to viscous forces : $\frac{k\Delta p}{\mu L u}$

Where

k = permeability of the sample

Δp = pressure drop between injector and producer

(no pressure dropped in this experiment)

μ = crude viscosity,

L = distance between injection and production, which is core plug length,

u = volumetric flow velocity,

σ = interfacial tension between crude and water,

g = acceleration constant due to gravity,

$\Delta\rho$ = density difference between water and crude.

In the ratio of the gravity forces to applied pressure forces, the only controllable crude property is the density difference between the crude and the displacing water. But the density of the crude does not change significantly during the course of flooding recovery process. The factor interfacial tension between crude and water is depending on the capillary pressure forces in the pore network. Since capillary pressure forces tend to hold the crude in the pore network, for this reinstalled core samples it would be desirable to make the interfacial tension essentially zero. This has the potential of allowing the crude to be extracted from the network. In the ratio of applied forces to viscous forces, the viscosity is the only crude property. The crude volumetric flow velocity increases as the viscosity increases (Jones, Roszelle, 1978).

2.1.3 Mobility Ratio Measurement

Mobility is a relative measure of how easily fluid moves through porous media. The principal fluid characteristic is the viscosity of the crude compared to that of the injected hot water. The mobility ratio is calculated from values of the water/oil relative permeability ratio at selected saturations and the given fluid viscosities at the initial reservoir temperature.

$$\text{Mobility Ratio} = \frac{Krw / \mu w}{Kro / \mu o}$$

A good water flood has a mobility ratio around 1. If the reservoir crude oil is extremely viscous, the the mobility ratio will be likely be much greater than 1. When this is the case, the water will "finger" through the reservoir and bypass much of the crude oil. (Craft and Hawkins, 1991) Calculated results of mobility ratio at each saturation point reported in data calculation sheet of each sample.

2.2 Hot-water Flooding Temperature Selection

The design and operation of hot-water flooding temperature in this laboratory experiment has been considered and selected at 90°C according to:

- the limitation and capability of the available laboratory equipment,
- the effectiveness of viscosity and temperature correlation.

The effect of decreasing crude oil viscosity to improving the oil recovery in laboratory performance of sample containing viscous crude is depending on the generation of additional heat. The heat produced by temperature is directly proportional to the viscosity and indirectly to the mobility ratio. Therefore, a selection of an appropriate applied hot-water temperature is important to the hot-water flooding technique (Craft & Hawkins, 1991).

Prior to the experiment, firstly, the equipment was tested for optimal capability to withstanding the highest controllable temperature and at constant flooding duration. At ACS Laboratories, where the experiment is carried out, the equipment used are designed and modified from the equipment, which normally used for conventional core analysis. The result from the test shows that maximum temperature that can withstand the heat from the experiment is at 90°C. Secondly, in Appendix O, the Suphan Buri crude oil viscosity values as function of temperatures are in Figure O-2. The crude oil viscosities are ranging from 9.64cP to 6.48cP correlating to the reservoir temperature 76°C and selected temperature 90°C. They are elevating in a linear function and are not in great discrepancies. For other temperature selections required, they can be measured by extrapolation from plot out in Figure O-2.

A selection of one temperature point at 90°C, where optimal controllable of available equipment collaborated to the minimal available extrapolated viscosity value (Appendix O), is considered suitable and acceptable for the hot-water flooding experiment.

2.3 Equipment and Apparatus

- Overburden Triaxial Pressure Cell with hydrostatic pressure holder
- Pressure pump with control regulator
- Electrical mantle with temperature controller
- Glass receiving tube, with a calibrated scale
- Digital thermometer
- Stop watch
- Laboratory data sheet

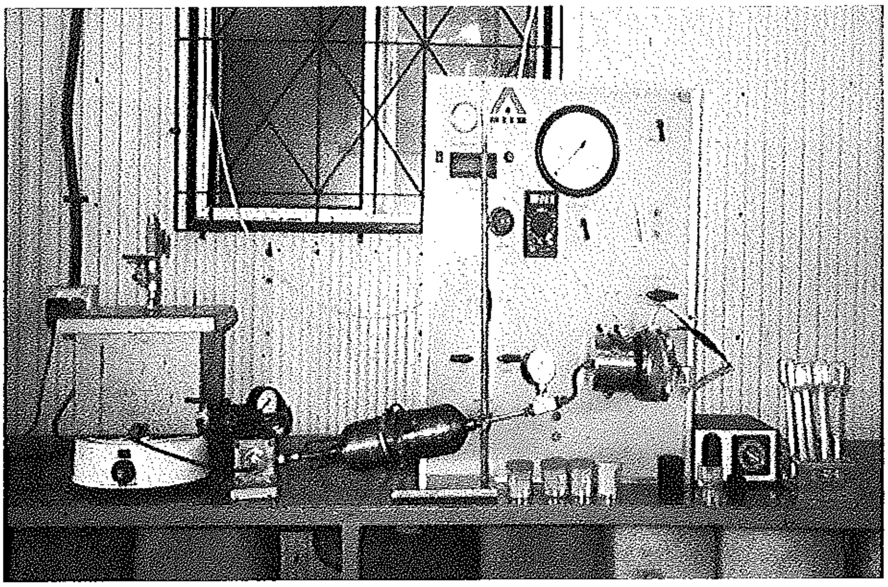

Figure 2-2 Overburden Triaxial Pressure Cell

2.4 Method

A hot-water flooding involves the flow of only two phases: water and oil. The elements of hot-water flooding are relatively simple. It is basically a displacement process in which oil is displaced immiscibly by hot water. A number of laboratory flooding has been experimented, and found of good correlations between the two different temperature applications, 76°C and 90°C. The results of analysis laboratory performances are interpreting and evaluating using basic calculations of unsteady-state relative permeability in Table 3-1and in Appendix M.

2.5 Procedure

A standard fully oil-brine saturated core plug sample is inserted into a thick walled rubber sleeve and loaded into a stainless steel hydrostatic holder. The cell is filled with water and the hydraulic pump is used to obtain the confining pressure. The reservoir pressure of 2000psi is slowly applied to seal and conform the sample to the original conditions. The system cell is heat up to stable 90°C, then hot brine is then injected at 20psi upstream pressure into the core plug. The amounts of injected hot brine and crude oil recovery are recorded in the receiving tube (Figure 2-3).

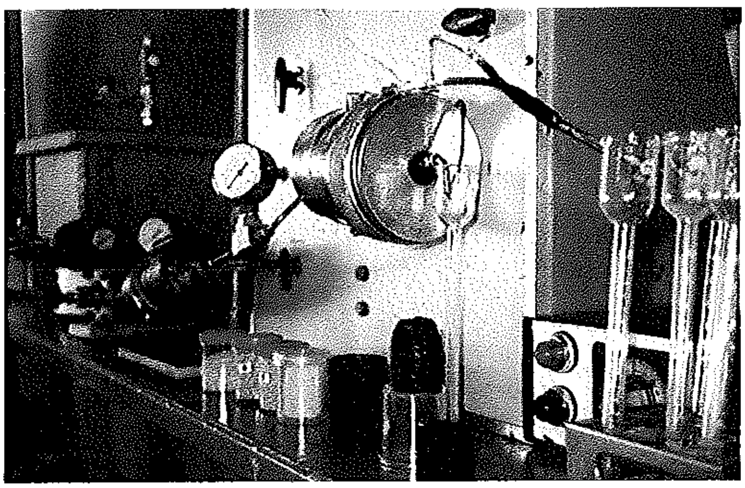

Figure 2-3 Retrieved Water and Crude Oil Recovery in Receiving Tube

2.6 Calculation

Oil and water relative permeability under un-steady-state is considered the method in fluids displacement (Figure 2-4). The core plug is saturated with brine and then oil flooded to irreducible water saturation (Appendix K). The flooding pressure used was 20 psi across the entire core plug and no pressure drop during the flooding process. The overburden porosity and permeability, pore volume of the core plug, fluid saturations and crude oil properties, these data are significant and sufficient to develop the oil & brine relative permeability to obtain oil recovery.

The percentage of recovery is estimated from the relationship between cumulative oil recovery and residual oil, when injected water applied to the reinstalled core plugs at 0.5, 1, 2, 3 and 4 pore volumes.

Data entry requirement

- Overburden air permeability (mD) derived from gas permeability measurement – Appendix G
- Overburden Porosity derived from porosity measurement – Appendix F
- Core plug sample pore volume (cm^3) from porosity measurement – Appendix F
- Oil permeability derived from Klinkenberg gas slippage calculation, Ko @ Swi (mD) – Appendix G
- Initial water saturation Swi (%) – Appendix K
- Core plug length (cm) – Appendix E
- Core plug diameter (cm) – Appendix E
- Oil viscosity @ 90°C – Crude oil determination Appendix O
- Liquid flow rate at single phase condition calculation, Q @ Swir (cm^3/s) – Appendix L
- Injected pressure 20 psi

In this experiment, the core plug sample's wettability, operating system temperature, and injected pressure are held at constant.

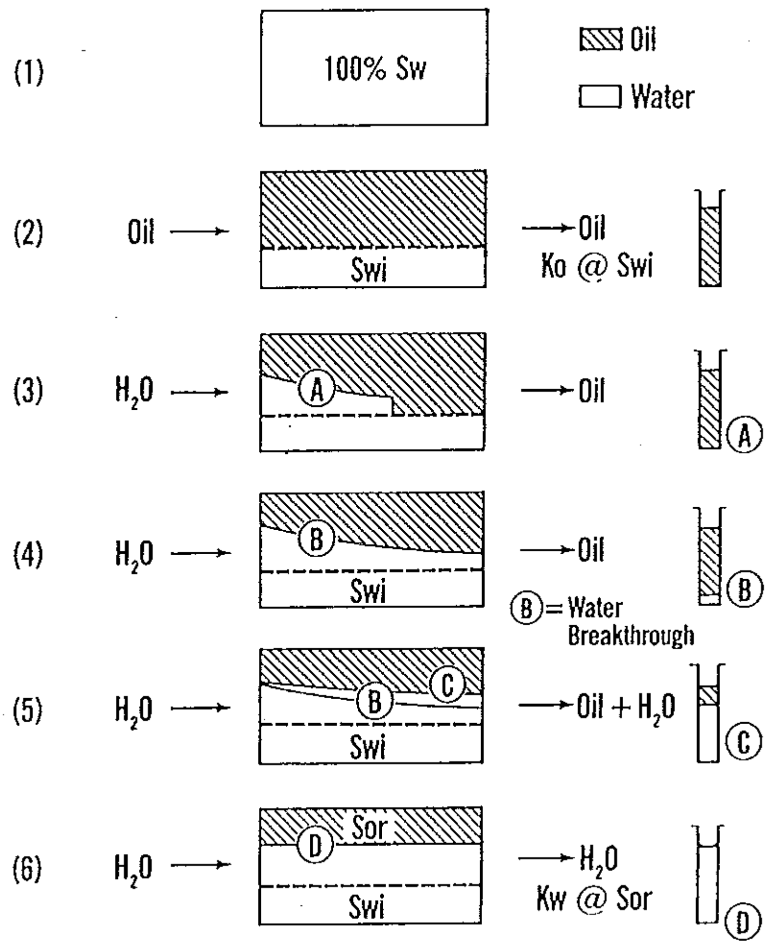

Figure 2-4 Unsteady State Water-Oil Relative Permeability
(Core Labs, 1982)

Chapter 3

Results

3.1 Test Results

The summary of analytical data calculations of the core plug samples are reported in Table 3-1. The individual analytical data entry and calculations including plots out of core plug samples no.1 and no.4 are reported below, and other core plug samples no. 2 to 3 and 5 to 11 are reported in Appendix M.

Total of 3 (Samples no. 1 to 3) and 8 (Samples no. 4 to no.11) reinstalled and fully oil saturated core plug samples were flooded using water at 76°C and 90°C respectively. The results from the water flooding are in linearly scale. The oil and water saturations of each core plug are well functioned with the pore volumes of injected water. The water flooding ceased after six hours flooding resulting maximum pore volumes of around 2.9 and 4.3 pore volumes respectively. The unsteady state oil and water relative permeability curves are dependent on the reduced saturation. Calculated mobility ratios from the relationship of water and oil relative permeability at selected saturations of each sample are shown in Tables 3-2 & 3-3.

Table 3-1 shows summary of unsteady state conventional water flooding recovery results. The average flooding results of plug samples no.1 to 3 are 16.33, 20.33 and 27.33 percent when flooded at 0.5, 1 and 2 pore volumes and final recovery 28.07 percent at 2.9 pore volume. For plug samples no.4 to 11, the average recoveries are 18.63, 27.88, 41.19 and 45.25 and 42.33 percent when flooded with 0.5, 1, 2, 3 and 4 pore volumes and final recovery 47.17 percent at 4.3 pore volume.

Unsteady State Conventional Water Flooding Recovery Results

Water Flooding Analysis	Analyst : Sombat Chunlasen
Suphan Buri Oil Field	Date :
	File :

Water Flooding at Reservoir Condition (76 degree C)

Sample No.	Crude Oil Recovery at Pore Violume Injected Water					
	0.5 PV	1.0 PV	2.0 PV	3.0 PV	4.0 PV	Final
1	20.00	22.00	27.50			28.30
2	14.00	19.00	27.00			28.10
3	15.00	20.00	27.50			27.80
Average Recovery	**16.33**	**20.33**	**27.33**	**0.00**	**0.00**	**28.07**

Water Flooding at 90 degree C

Sample No.	Crude Oil Recovery at Pore Violume Injected Water					
	0.5 PV	1.0 PV	2.0 PV	3.0 PV	4.0 PV	Final
4	20.00	33.00	41.50	44.00	45.00	45.26
5	19.00	29.00	45.00	49.50		50.00
6	20.00	28.00	42.00	46.00		47.40
7	22.00	34.00	48.50	55.00	55.50	55.80
8	20.00	30.00	53.00	56.50		57.90
9	13.00	20.00	32.00	38.00		39.60
10	20.00	30.00	45.00	48.00		53.60
11	15.00	19.00	22.50	25.00	26.50	27.80
Average Recovery	**18.63**	**27.88**	**41.19**	**45.25**	**42.33**	**47.17**

Table 3-1 Result Water Flooding Recovery

The following data entry and calculation results are of sample no.1 being water flooded at reservoir temperature 76°C shown in Table 3-2, and Figures 3-1 to 3-4 comparing to sample no.4 being water flooded at a selected temperature 90°C in Table 3-3, Figures 3-5 to 3-8.

Sample no. 1: Core plug sample being flooded at reservoir temperature 76°C.

Table 3-2 Unsteady-state Water Oil Relative Permeability Data Entry and Calculation: The table shows data entry for calculating of water flooding and test results correlating to the percentage of recovery, temperature and amount of injected hot water. The other variables are functions of cumulative injection, time taken, fluid viscosities, cumulative crude oil & water in receiving tubes and the relative permeability to the total fluids.

Figure 3-1: Unsteady-state Water Oil Relative Permeability: The plot shows a typical oil-wet relative permeability plot against a function of water saturation. The unsteady-state relative permeability determination methodology describes in Appendix M. In the beginning of the flooding, the oil and water relative permeability values gradually changed while water saturation remained a little change because the elasticity of the core plug when high confining pressure applied. At the initially water saturation, or a non-movable water saturation characteristic of the sample, a water-free production zone which is normally above the transition zone in production well, see Figure 3-2. The plot curves are directional, starting with the Krw, the relative permeability to water, lowest brine saturation at 0.101 or 10% and proceeding to the top-right.

With an active water flooding drive to maintain the pressure, it increases in water saturation as the water flooded in to expel crude oil. The relative permeability to oil (Kro) is reduced, hence the Kro value proceeds toward the lower right into the transition zone. The next higher water-saturation point

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	1			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Temperature	76 C	Ko @ Swi (mD)	147.6	*m =*	
				Swi (%)	10.102	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	178			Oil Viscosity @ 76C	9.644
Date	5 Apr 98	Porosity (%)	20.4	Length (cm)	4.8		
		Sat. Pore Volume (cc)	14.02	Diameter (cm)	3.8		
		Residual Oil Saturation (cc)	7.6	X-Sectional Area (cm^2)	11.341	Q @ Swir (cm^3/s)	0.049

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil Recovery Percent	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.40	0.90	90	1.00	9.64	0.50	0.50	4.72	0.40	0.90
7200.00	20.00	2.00	3.50	90	1.00	9.64	1.50	1.00	14.15	1.60	2.60
10800.00	20.00	6.10	8.20	90	1.00	9.64	2.10	0.60	19.81	4.10	4.70
14400.00	20.00	12.50	15.00	90	1.00	9.64	2.50	0.40	23.58	6.40	6.80
18000.00	20.00	20.20	23.00	90	1.00	9.64	2.80	0.30	26.42	7.70	8.00
21600.00	20.00	26.00	29.00	90	1.00	9.64	3.00	0.20	28.30	5.80	6.00

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.556	0.000	0.005	0.0	10.102	0.101	1.000	0.000	1.000	0.000	0.06	0.0
0.385	0.615	0.015	1.1	11.199	0.112	0.006	0.001	0.007	0.166	0.25	1.6
0.128	0.872	0.027	7.5	17.614	0.176	0.003	0.002	0.006	0.709	0.58	6.8
0.059	0.941	0.038	11.5	21.640	0.216	0.002	0.004	0.006	1.659	1.07	16.0
0.038	0.963	0.045	13.8	23.922	0.239	0.002	0.005	0.006	2.661	1.64	25.7
0.033	0.967	0.034	14.5	24.605	0.246	0.001	0.003	0.005	3.007	2.07	29.0

Table 3-2 Relative Permeability Data Calculation, Plug Sample no.1

shown, 0.112 (Table 3-2), corresponds to water breakthrough, relative permeability to water (Krw) 0.001, at 0.25 Pore Volume injection, and mobility ration at 1.6. At the intersection of Kro and Krw best fit curves, is where the Oil and Water flow at equal ease. The water cut is 50% at this point.

The plot shows a simple uniformly permeable layer of oil and water permeability. The flooding results in producing total of 3.0 cc crude oil and 26.0 cc of water and water saturation of 24.6%, before the operation stopped after six hours flooding. For further injection water applied, the relative permeability to oil best fit curve would be reduced to nearly zero at 40% water saturation and hence hardly further crude oil flows out of the core plug.

Figure 3-2: Effective of fractional flow of water (fw) on water saturation: The plot shows the relationship between water saturation versus fractional flow of flooding hot-water. The curve shows the interstitial water saturation and the end point, saturation at flood front. At the interstitial water saturation point, 0.101 or Sw 10%, the reservoir values or core plug saturation conditions are at rest. When the flooding takes place, along A, the straight line indicates a steady saturation conditions until the water breakthrough at B, 0.616 fraction flow of water. The water saturation increases gradually along C and stops at D where the crude oil flowage stops.

Figure 3-3: Effective of fractional flow of water (fw) on oil recovery: The plot shows the crude oil recovery versus flow of the water. The oil recovery curve has no effect of loosen off materials or fine particles in the core plug. The maximum recovery of core plug sample is 28.3% crude oil recovery, of the pore space.

Figure 3-4: shows the crude oil recovery against the injected water at reservoir temperature 76°C. The percentage of crude oil recovery is approximately 20%, 25%, 27.5% and final 28.3% at the 0.5, 1, 2 and maximum of 2.07 pore volumes of injected hot-water respectively. The curve shows no matter how much more

WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**1**
Porosity	**20.4 percent**
Initial Water Saturation	**10.1 percent**
Permeability to Air	**178 milliDarcy's**
Effective Oil Permeability	**147.6 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability

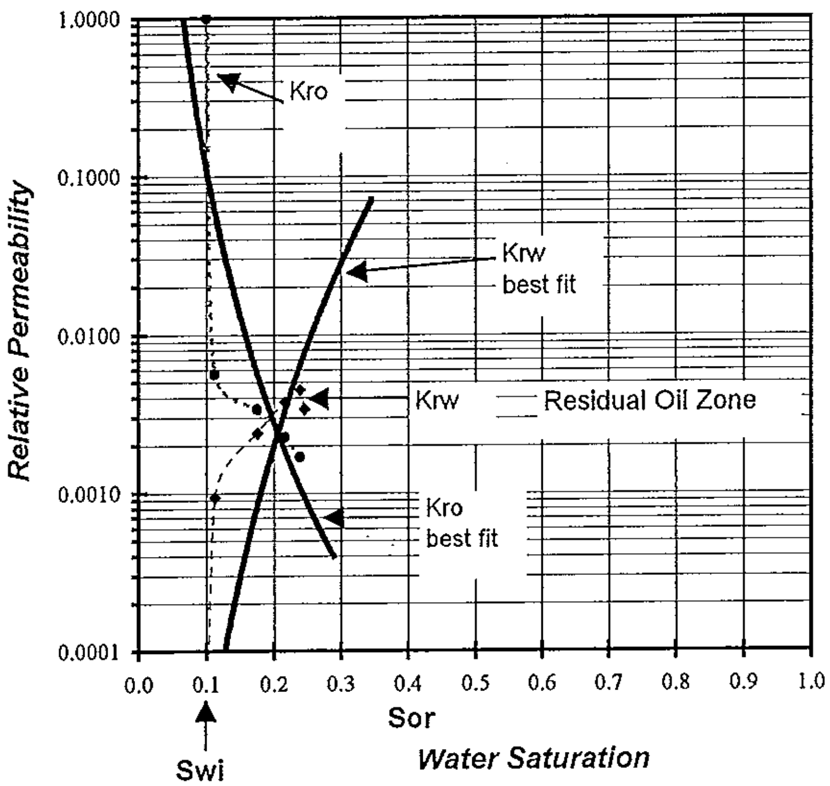

Figure 3-1 Core plug sample no.1: Relative Permeability and Water Saturation Relationship

Kro is Realtive Permeability to Oil
Krw is Relative Permeability to Water

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis** **Suphan Buri Oil Field**
Sample Number	**1**
Porosity	**20.4 percent**
Initial Water Saturation	**10.1 percent**
Permeability to Air	**178 milliDarcy's**
Effective Oil Permeability	**147.6 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

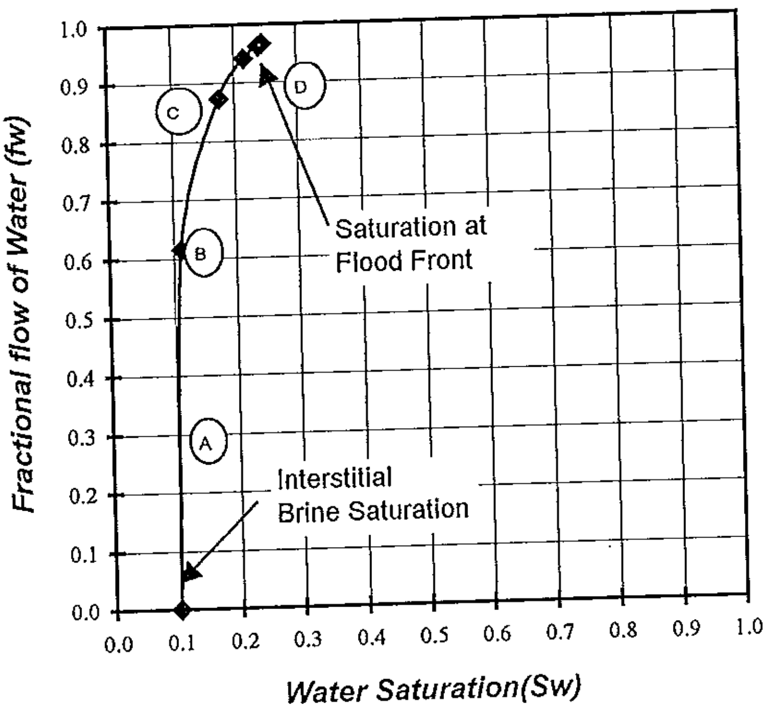

Figure 3-2 Core plug sample no. 1: Flow of Water and Water Saturation Relationship

Effect of water saturation of core plug 1 on the Fractional flow of water (fw) at reservoir temperature

WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**1**
Porosity	**20.4 percent**
Initial Water Saturation	**10.1 percent**
Permeability to Air	**178 milliDarcy's**
Effective Oil Permeability	**147.6 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

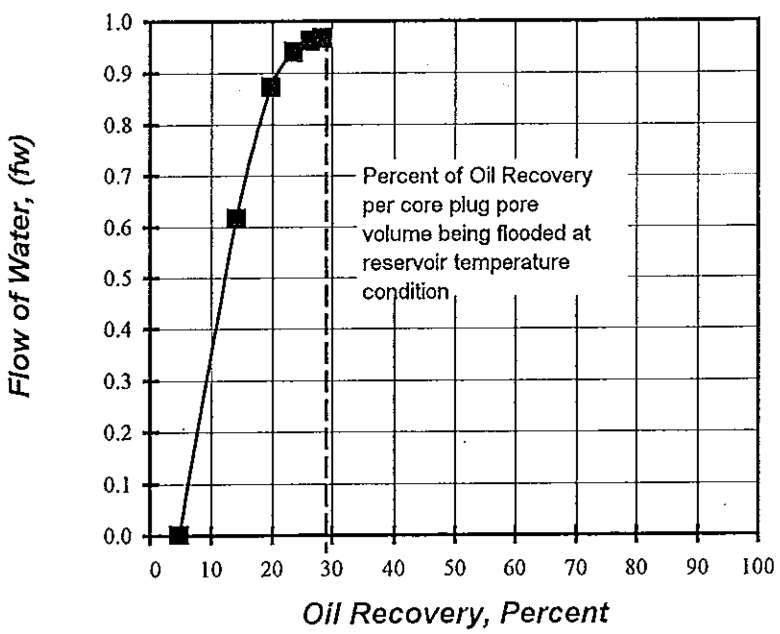

Figure 3-3 Core plug sample no.1 : Effect of Crude Oil Recovery and Flow of Water

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**1**
Porosity	**20.4 percent**
Initial Water Saturation	**10.1 percent**
Permeability to Air	**178 milliDarcy's**
Effective Oil Permeability	**147.6 milliDarcy's**

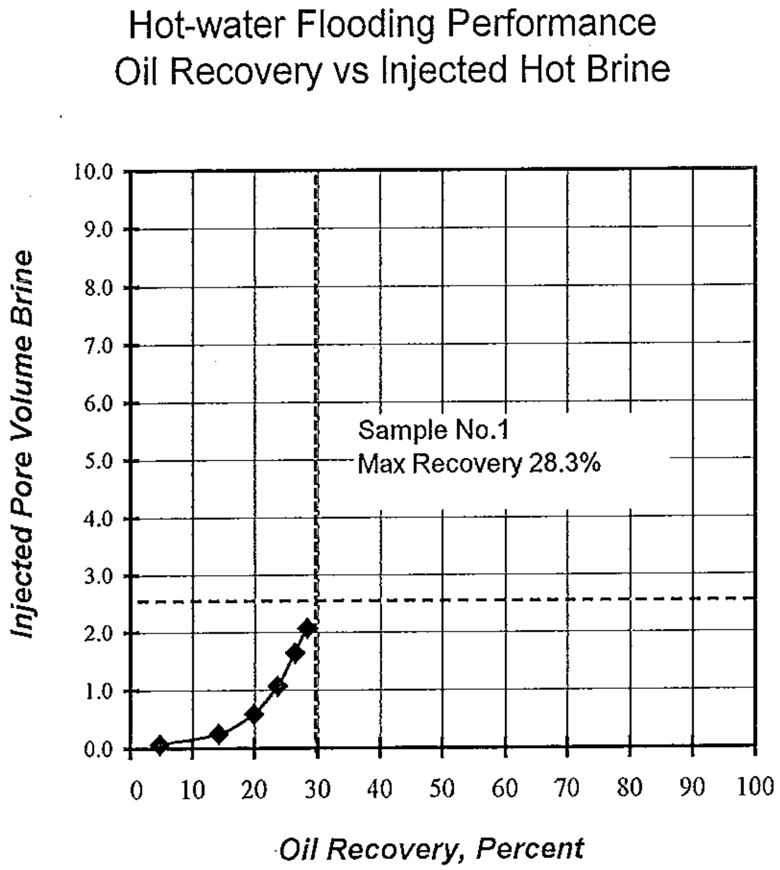

Figure 3-4 Core plug sample no.1 : Oil Recovery and Injected Water Relationship

of injected hot water and time taken, there will be only small amount of crude oil come out of the core plug.

Sample 4: Core plug sample being hot-water flooded at 90°C

Table 3-3: Unsteady-state Water Oil Relative Permeability Data Entry and Calculation. The table shows data entry for calculating of Hot-Water Flooding and test results. The data entry and calculations are on the percentage of recovery, amount of injected hot water (brine) and calculated mobility ratio. The other variables are functions of cumulative injection, time taken, fluid viscosities, cumulative crude oil & brine in receiving tubes and the relative permeability to the total fluids.

Figure 3-5: Unsteady-state Water Oil Relative Permeability: The plot shows a typical oil-wet relative permeability plot against a function of water saturation. The unsteady-state relative permeability determination methodology describes in Appendix M. In the beginning of the flooding, the oil and water relative permeability values gradually changed while water saturation remained a little change because the elasticity of the core plug when high confining pressure applied. At C, initially water saturation, or a nonmovable water saturation characteristic of the sample. At this point, it is a water-free production zone which is normally above the transition zone in production well, see Figure 3-6. The plot curves are directional, starting with the Krw, the relative permeability to water, lowest brine saturation at 0.071 or 8% and proceeding to the top-right.

With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot water flooded in to expel crude oil. This starts to reduce the relative permeability to oil (Kro), hence the Kro values proceed toward the lower right into the transition zone. The next higher water-saturation point shown, 0.078 (Table 3-3), corresponds to water breakthrough, relative permeability to water (Krw) 0.002, at 0.66 Pore Volume injection, and mobility

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study :	Hot-water Flooding Analysis	Sample No	4			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Temperature	90C	Ko @ Swi (mD)	155.3	*m =*	
				Swi (%)	7.087	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	187			Oil Viscosity @ 90C	6.477
Date	5 Apr 98	Porosity (%)	15.9	Length (cm)	4.82		
		Sat. Pore Volume (cm^3)	9.84	Diameter (cm)	3.76		
		Residual Oil Saturation (cc)	5.2	X-Sectional Area (cm^2)	11.104	Q @ Swir (cm^3/s)	0.075

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil *Recovery Percent*	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.80	1.30	90	1.00	6.48	0.50	0.50	5.26	0.80	1.30
7200.00	20.00	4.30	6.50	90	1.00	6.48	2.20	1.70	23.16	3.50	5.20
10800.00	20.00	9.80	13.50	90	1.00	6.48	3.70	1.50	38.95	5.50	7.00
14400.00	20.00	21.00	25.00	90	1.00	6.48	4.00	0.30	42.11	11.20	11.50
18000.00	20.00	27.25	31.50	90	1.00	6.48	4.25	0.25	44.74	6.25	6.50
21600.00	20.00	36.75	41.05	90	1.00	6.48	4.30	0.05	45.26	9.50	9.55

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2 (percent)*	Water Saturation *Sw (percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.385	0.000	0.005	0.0	7.087	0.071	1.000	0.000	1.000	0.000	0.13	0.00
0.327	0.673	0.019	0.8	7.849	0.078	0.006	0.002	0.008	0.318	0.66	2.06
0.214	0.786	0.026	8.2	15.290	0.153	0.006	0.003	0.009	0.566	1.37	3.67
0.026	0.974	0.042	34.0	41.110	0.411	0.001	0.006	0.007	5.764	2.54	37.33
0.038	0.962	0.024	30.9	37.966	0.380	0.001	0.004	0.004	3.860	3.20	25.00
0.005	0.995	0.035	41.5	48.602	0.486	0.000	0.005	0.006	29.335	4.17	190.00

Table 3-3 Relative Permeability Data Calculation, Plug Sample no.4

ratio at 2.06. At "A" the intersection of Kro and Krw best fit curves, is where the Oil and Water flow at equal ease. The water cut is 50% at this point.

To the right, the points represent crude oil increasing throughputs until it reaches the point 0.411 water saturation and 2.54 pore volume injection where the curve downward turns. For this sample no.4, the decreasing downwards at the point in relative permeability to brine is probable the effect of swelling clays or mobile fine particles blocking off the pore throats in the core plug. If not the formation damage blocking off, the production would have carried along to the B, residual oil saturation (nonmovable oil) point where crude oil can not be recovered by this hot-water flooding. Providing further injection hot-water applied, the relative permeability to oil best fit curve would be reduced to nearly zero at 80% water saturation and hence hardly further crude oil flows out of the core plug.

Figure 3-6: Effective of fractional flow of water (fw) on water saturation: The plot shows the relationship between water saturation versus fractional flow of flooding hot-water. The curve shows the interstitial water saturation and the end point, saturation at flood front. At the interstitial water saturation point, 0.071 or Sw 7%, the reservoir values or core plug saturation conditions are at rest. When the flooding takes place, along A, the straight line indicates a steady saturation conditions until the water breakthrough at B, 0.67 fraction flow of water. Suddenly the brine saturation increases abruptly along C and stops at D where the crude oil flowage stops.

Figure 3-7: Effective of fractional flow of water (fw) on oil recovery: The plot shows the crude oil recovery versus flow of the water. The oil recovery curve slows down at around 25% percent pore volume (75% flow of water) and stays high throughput at 40%. From there upwards, 0.7 to 0.8, the fractional flow of water (fw) abruptly flushed to the right indicates some fine materials loosen off causing larger flow paths and abrupt flushing through. When crude oil recovery is getting over 42%, it starts to decrease. This is probably due to the

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**4**
Porosity	**15.9 percent**
Initial Water Saturation	**7.1 percent**
Permeability to Air	**187 milliDarcy's**
Effective Oil Permeability	**155.3 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Effect of Permeable Layer on Oil and Brine
Permeability

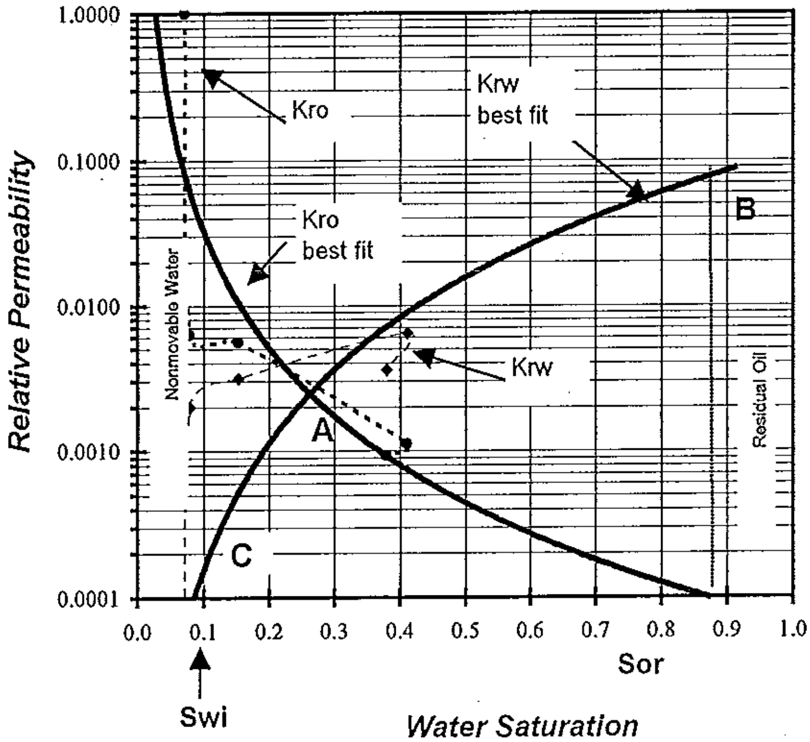

Figure 3-5 Core plug sample no.4: Relative permeabilities plotted as functions of water saturation.

Kro is Relative Permeability to Oil
Krw is Relative Permeability to Water

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis** **Suphan Buri Oil Field**
Sample Number	**4**
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Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

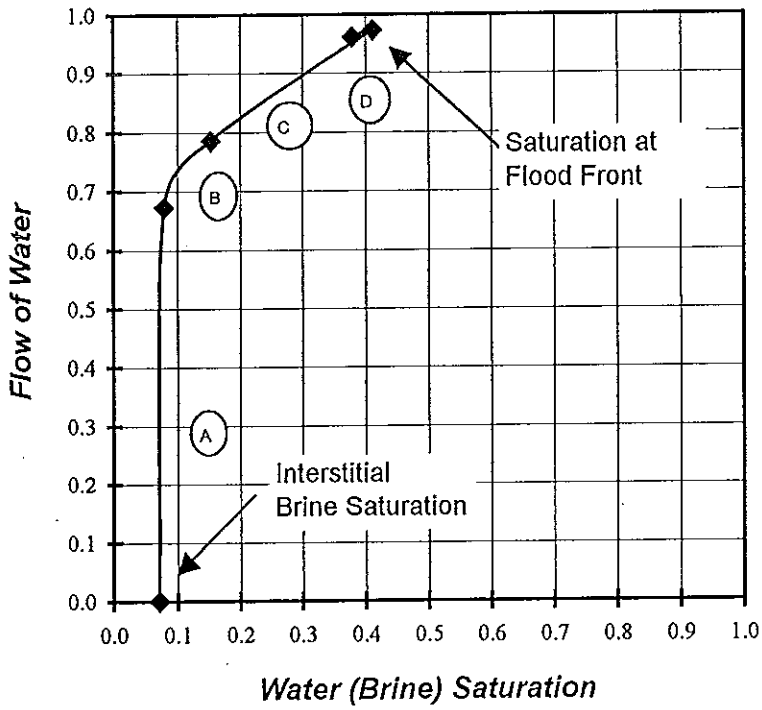

Figure 3-6 Core plug sample no.4: Flow of Water and Water Saturation Relationship

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**4**
Porosity	**15.9 percent**
Initial Water Saturation	**7.1 percent**
Permeability to Air	**187 milliDarcy's**
Effective Oil Permeability	**155.3 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

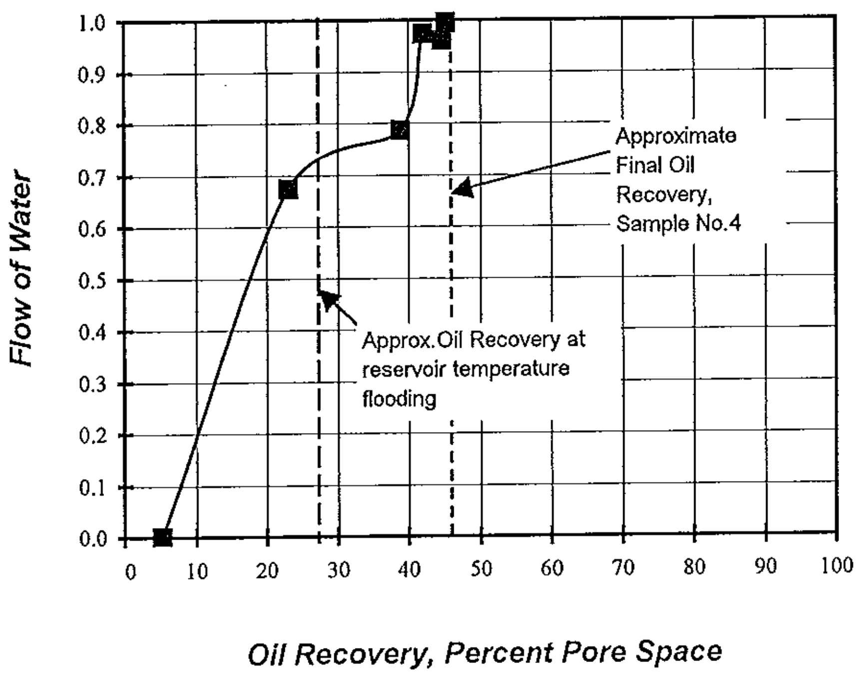

Figure 3-7 Core plug sample no.4 : Crude Oil Recovery and Flow of Water Relationship

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**4**
Porosity	**15.9 percent**
Initial Water Saturation	**7.1 percent**
Permeability to Air	**187 milliDarcy's**
Effective Oil Permeability	**155.3 milliDarcy's**

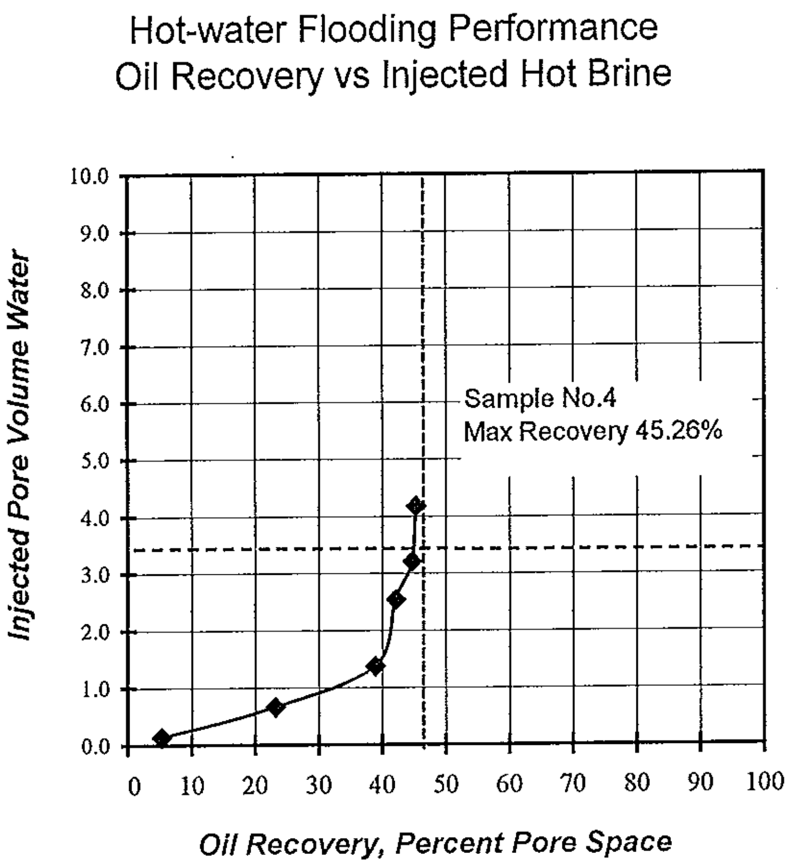

Figure 3-8 Core plug sample no.4 : Oil Recovery and Injected Hot-water Relationship

suspending fine materials are starting to block off pore throats of the core plug. The maximum recovery of core plug sample no.4 is at 45.26% crude oil recovery, of the pore space, after 6 hours flooding.

The crude oil recovery of 45.26% is plot in comparison to the average recovery 28.07% when core plug samples are water-flooded at reservoir temperature 76°C. In this particular core plug sample no.4, there are further improvement of 7.55% and 13.86% oil recovery produced at 1 and 2 pore volumes when hot-water flooding method at 90°C introduced compare to that of the normal reservoir temperature flooding.

Figure 3-8: shows the crude oil recovery against the injected hot water. The percentage of crude oil recovery is approximately 20%, 33%, 41.50%, 44.0%, 45.0% and final 45.26% at the 0.5, 1, 2, 3, 4 and 4.17 pore volumes of injected hot-water. After six hours of flooding, the curve shows no further crude oil flow and if so, would be only a little for a long period of injection time.

Comparison of the Flooding Recoveries

The flooding recovery process in the experiments fall into two classes:

- one is the water which is injected into the core plug and,
- another is the heat which is generated within the core plug itself.

Comparison of the two-condition floodings in Table 3.4, within the first half pore volume flooding after 2 to 3 hours flooding, an average recovery of water flooding gives enhanced crude oil recovery of 2.30 %. After 4 to 5 hour of flooding at 1, and 2 pore volumes, the average enhanced recovery are at 7.55% and 13.86%. An additional effective enhanced recovery is almost twice as much when further two pore volumes are flooded. At normal water flooding, the flow stopped at around 2.90 pore volumes compare to that of 4.31 pore volumes when higher temperature of 90°C applied. This corresponds to the calculated mobility ratio values where the viscosity characteristics are in difference (Tables

3-2 & 3-3). The average percentage crude oil recovery when 0.5, 1, 2, 3, 4 and maximum pore volumes of injected water applied to the reinstalled core plugs are as follows:

Pore Volume Injection	Percent Average Crude Oil Recovery 76°C	90°C	Percent Recovery Improvement
0.5	16.33	18.63	2.30
1	20.33	27.88	7.55
2	27.33	41.19	13.86
3		45.25	
4		42.33	
Final Recovery	28.07	47.17	19.10

Table 3-4 Average Percentage Crude Oil Recovery at Different Pore Volume Flooding

From the above result tables and data plots, the hot-water flooding at higher temperature reduces greater saturated core plug flow resistance by reducing the viscosity of the crude and consequently yields higher flow recovery compares to core plug samples flooded at reservoir temperature. The difference in flooding temperature of 14°C (76°C to 90°C), the additional thermal in the core plug decreases its viscosity thereby improving flowrage and resulting in improving its oil recovery (Table 3-4).

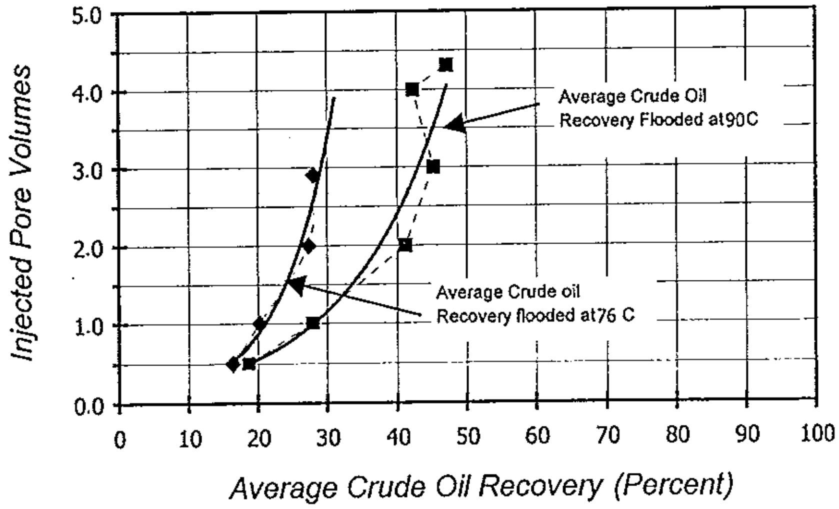

Figure 3-9 Average Crude Oil Recovery vs Pore Volume Water Flooding

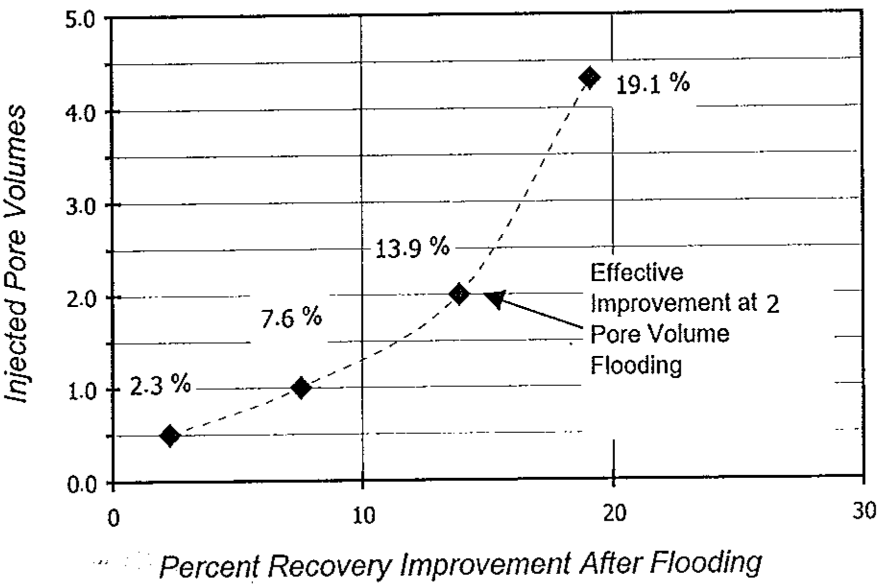

Figure 3-10 Recovery Improvement

The use of hot-water flooding, however is rather an effective production improvement of 7.55 percent when an approximately 2 pore volumes of injected hot-water applied to the system. However, the average maximum crude oil recovery, after six hours flooding, derived from receiving tubes of 28.07% and 47.17% when flooded at maximum 2.90, and 4.31 pore volumes, produces an enhanced recovery of 19.1%.

Chapter 4

Critique and Conclusion

Critique

The crude oil sample used in this water flooding experiment was retrieved from the Suphan Buri oil production at well site, directly from an oil tank before it was transported out for refining process. The crude oil sample was analyzed for its cloud point property (Appendix N), and viscosity-temperature correlations (Appendix O). The experimented core plugs were using core material collected from Suphan Buri field. Prior to the flooding experiment, the core plug had to be reinstalled to its original property conditions because it was too highly weathered and too crumbled to use directly. The core sample was also determined for its physical properties i.e. mineralogy, and petrography, described in Appendices, to assist core plug reinstallation.

A number of 3 and 8 reinstalled core plug samples were chosen for water flooding experiment at normal reservoir temperature 76°C, compare to a selected desire temperature at 90°C. The laboratory water flooding method shows significant enhanced recoveries when flooded at 0.5, 1, 2, 3, 4 pore volumes of each core plug. The percentage recovery was calculated from the crude oil output receiving from the overburden pressure cell and residual oil saturation of the core plugs. The crude oil recoveries were stopped after six hours flooding, because there were only small amount of crude oil outflow.

The flooding temperature difference of 14°C, from 76°C to 90°C, reduces the crude oil viscosities from 9.64cP at reservoir temperature to 6.48cP at 90°C. The reduction in crude oil viscosity will allow the oil to flow freely, and consequently increases an average of 19.1% crude oil recovery. This experiment, there are limitation and capability of the available laboratory equipment, otherwise the hot-water temperature used would then be higher and the effective viscosity value would have been reduced a lot lower and ended up resulting in higher crude oil recovery.

In the beginning of the experiment, the oil and water relative permeability values gradually changed, while water saturation remained little changes, because of the elasticity of the core plug while high confining pressure applied. After the second hour of flooding the core plug grain particles are starting to fall off causing large pore space and consequently rapid fluid flowage. At the latter hours, the loosen and suspended grain particles are starting to block off the pore throat of the rock. This was suspected as a formation-damaged case, where grained materials compaction and the cure age in laboratory were not well indurated compare to that of the natural compaction and cementation.

In petroleum engineering laboratory, there are glass beads, not available for this experiment, at various sizes to reconstruct a core sample if no original core material available. The formation damage case would have been avoided if only these glass beads were used instead of the original core material. The total results would have also been different.

Conclusion

This laboratory experiment, hot-water flooding using Suphan Buri crude oil and reinstalled core plug samples, proves an average 13.9% additional recovery when 2 pore volumes of injected hot-water were used and up to 19.1% additional recovery when flooding until there were hardly any outflow. The hot-water flooding method practices to produce additional remaining crude oil from reinstalled core samples. The analytical results from this study can be used as fundamental data information and further appropriate studies required prior to actual practical application. These significant studies are including other crude oil properties, reservoir size and characteristic, available water supply and more importantly an economic wise.

It is concluded that the result from this hot-water flooding experiment performed on core plug samples proves useful and is reasonably considered an appropriate methods suitable to improving Suphan Buri oil production. However, proper studies are necessary to prove of above strategy prior to practical application.

Recommendation for Further Study

1. There was a formation damage occurred during the flooding experiment because grained materials compaction and the cure age of the reinstalled core plugs were not well indurated and well cemented. To avoid such formation damaged and make more useful laboratory experiment, it is recommended using glass or heat proof plastic beads at various sizes to construct core plugs instead of using poor original core material.

2. This strategic flooding technique cannot be applied directly to the field without other appropriate reservoir characteristic studies. The natural forces, which are controlling the reservoir for oil recovery, must as well be considered in the practical design such as the gravity, capillary pressure and viscous tension (Prats, 1986). In this laboratory experiment, the gravity, the solution gas driving forces in the core plug samples were too small to take consideration.

3. To apply hot-water flooding to the Suphan Buri field, there are other geological engineering properties required includes: reservoir characteristics, heterogeneity including size, shape, continuity, natural fractures, chemical composition of the rocks including impurities and type of clays, reservoir dip, thickness and depth. The depth of the reservoir affects the hot-water flooding in two ways, firstly, investment and operating costs which generally increase as the depth increases.

Secondly, the reservoir must be deep enough to maintain the injection pressure and reservoir pressure (Helander, 1990).

4. In the Suphan Buri reservoir, it has a dipped structure towards south-east, Figure 1-2 (Swiecicki & hill,1987) a proper study design of injection well arrays down the line drive dip must be well considered to drive crude oil to producing well. The homogeneity of a reservoir plays an important role in the effectiveness of a water flood (Prats, 1986). The present of faults permeability trends, and the good correlation is required between new injection wells and production well. If however a serious channeling exists, then much of the reservoir oil will be bypassed and the hot-water injection will be rendered useless.

5. As further studies recommended above, there are as well more complicated flooding investigation involving fluids with varying viscosities and surface tension, which will be affected by dispersion. There are also floods involving heat and phase changes at the bubble or dew point and also chemical reactions.

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Appendix A

Core Sample

Introduction

The core samples (Figures A-1, A-2) scheduled for testing were collected from UT1-7/D3 well, Suphan Buri. The core was cut in 1996 and it is now in poor condition, easily crumbled and highly weathered. The core sample was cut approximately 45 degrees to the bedding and it was also primarily slabbed half for conventional core analysis. Prior to hot-water flooding experiment, various physical properties of the core samples are required. Having observed the original core sample, it is hardly possible to measure any physical properties upon its existent conditions. The core plugs to be used are then reinstalled to resemble the original properties.

Material

The retrieved cores are from two depth intervals:

Well: UT1-7/D3 Core-2

Depth intervals : 1199.00-1200.00 m (1 meter) and
1331.00-1331.40 m (0.40 meter)

The top depth core section is generally light gray, very fine to fine grain shaly sands, argillaceous, calcareous, fine lamination, crumbly and highly weathered. The core is low to poor visible porosity. The bottom section, 40 cm, is pebbly grained conglomerate and heterogeneous sandstone with uneven distribution of large and small pores. This is one of the sections where the hydrocarbon was discovered.

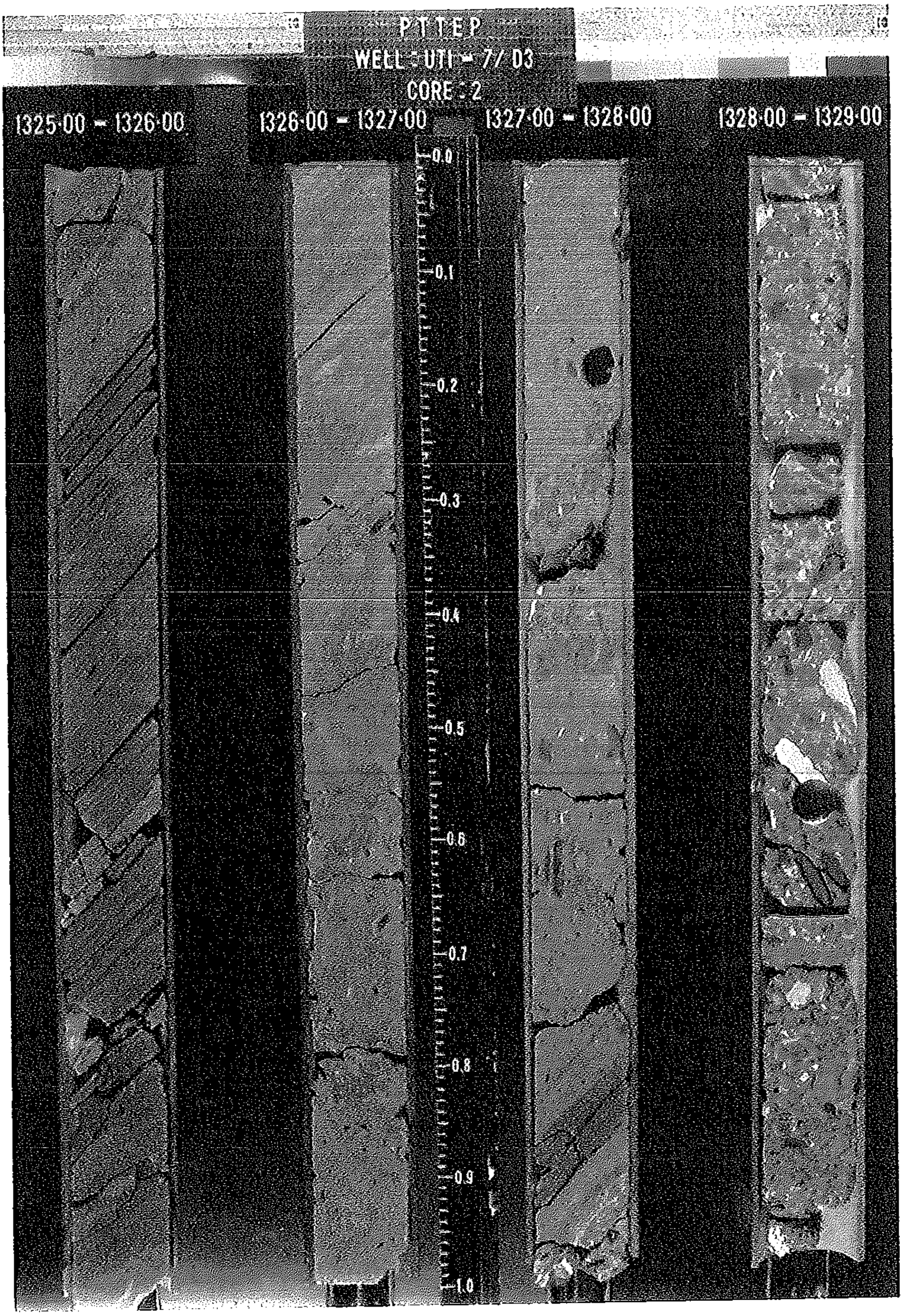

Figure A-1 : Core photograph taken under white light, depth interval 1325.00-1329.00 m.

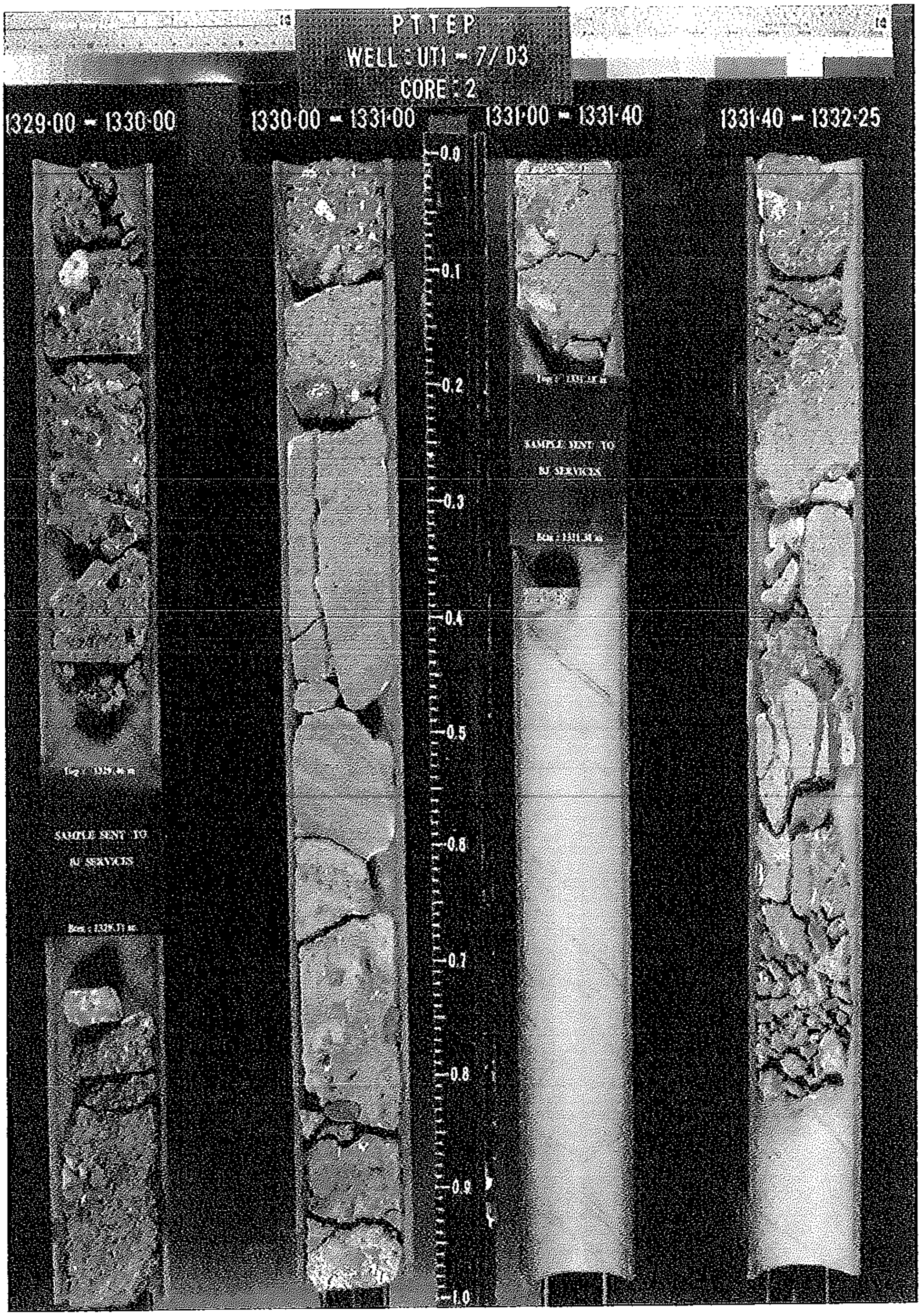

Figure A-2 : Core photograph taken under white light, depth interval 1329.00-1332.25 m.

Appendix B

Thin Section Analysis on Core Sample

Introduction

Thin section analysis was carried out on the original core sample retrieved from Suphan Buri to describe the classification, texture, mineralogy and environment of deposition. The analytical data results will assist in core plug reinstallation procedure.

Material

Core chips were cut and five thin sections were made up from UT1-7/D3 core section: 1199.00-1200.00 m. see Figures B-1,& B-2.

Method

The sample was supplied impregnated with epoxy. Thin section was impregnated with blue-stained araldite prior to thin section preparation in order to facilitate porosity recognition. The thin section was stained with Alizarin Red-S and potassium ferricyanide to aid different carbonate assemblages identification and was stained with sodium cobaltinitrite to differentiate potassium feldspar from plagioclase.

Results

The core sample from UT1-7/D3 well is composed mostly of siliclastic and carbonate materials. It is pebbly to conglomeratic with grain size range from few hundred microns to 25 millimeter. The sample is poorly to moderately sorted, matrix supported with high lithic fragments content. Lithic fragments and detrital grains are floating in siliclastic and carbonate matrices. Most detrital grains are subrounded to rounded with few angular to subangular. Lithic fragments are predominantly carbonate with minor metamorphic quartzite, mica schist, slate and phillite), altered and chlorotised volcanic lithic fragments and rounded sedimentary chert.

Few detrital quartz and feldspar grains are present. Quartz is mainly monocrystalline and exhibits strongly undulose extinction, suggesting a metamorphic or plutonic origin. Monocrystalline quartz grains with straight undulose extinction are trace components. Polycrystalline quartz is less common and occurs as rounded to subrounded grains with high undulose extinction. Feldspar grains are stained yellow upon staining with sodium cobaltinitrite. They are mainly potassic with few cross-hatched twinning grains, suggesting orthoclase and microcline. A few mica, probable muscovite, grains are also present and disseminated throughout the sample.

The sample has poor reservoir quality. The porosity is present in trace amounts most of which occurs as vuggy, moldic and fracture. Diagenesis is this sample is limited. Some sort of recrystallisation has occurred to the micrite of carbonate matrix. Alteration is minor with volcanic lithic fragments altered to chlorite.

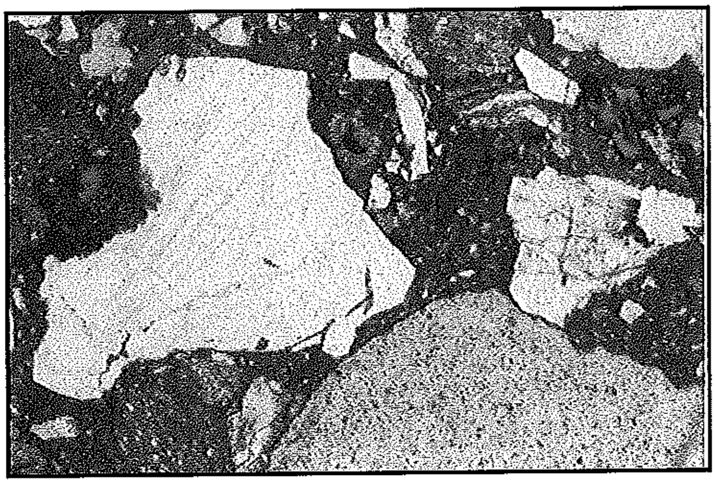

Figure B-1 Thin section photomicrograph showing general view, plane polarised light

Figures B-2 and B-3 Thin section photomicrographs showing general view of the sample. Porosity occurs along natural fracture, blue stained.

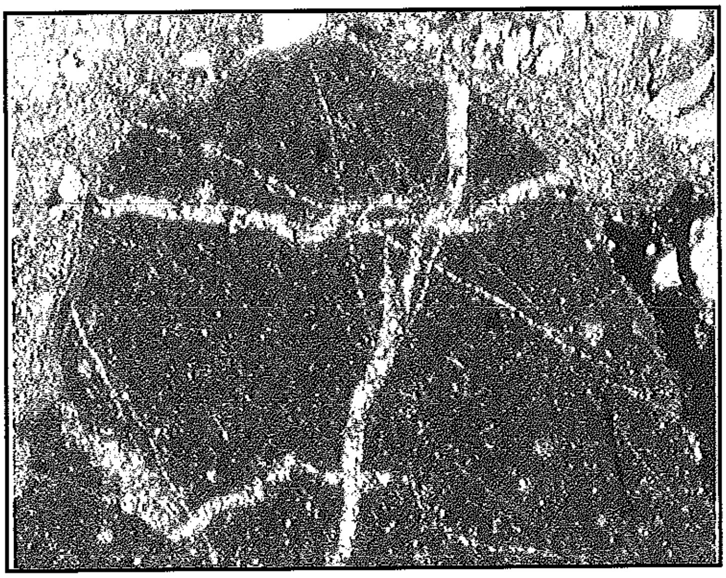

Figure B-4 Thin section photomicrograph showing rounded sedimentary chert lithic fragment. Crossed polars.

Figure B-5 Thin section photomicrograph showing metamorphic (mica schist) and carbonate lithic grains. Large pore space between grains. Plane polarised light.

Figure B-6 Thin section photomicrograph showing chloritised volcanic lithic grain (pale green). Plane polarised light.

Figure B-7 Thin section photomicrograph showing vuggy and moldic porosity between micritic carbonate materials. Plane polarised light.

Appendix C

X-ray Diffraction Analysis on Core Sample

Introduction

X-ray diffraction analysis method is well known to petrographic studies in petroleum and mining industries. It is defined as the scientific description and study of rocks. A variety of techniques and instrumentation have been devised to assist petroleum geologists. The XRD method is to detect every crystalline material on core sample that has a unique x-ray diffraction pattern comparable to a fingerprint.

$$I_x = \frac{KV}{\mu(XRD)}$$

Where I_x is the measured intensity of a diffraction line of any crystalline component (x) in the rock sample.
K is a constant that depends on the incident X-ray intensity and goniometer geometry.
V is the volume fraction of that component.
$\mu_{(XRD)}$ is the line absorption coefficient of the specimen.

The core plug samples, which cut for thin section analysis, were as well performed XRD to determine qualitative bulk mineralogy including relative abundance of major phases.

Material

Samples were take from UT1-7/D3 core at section: 1199.00-1200.00 m.

Procedure

The core sample was ground to a fine–grain size, cleaned, dried, and then immersed in a dispersive solution. This solution is subsequently centrifuged for a selected time to separate clay and sand size particles. The material remaining in suspension is decanted and filtered through an unglazed porcelain plate to yield oriented slides for clay analysis.

Result

The sample is also a mixture of siliclastic and carbonate. Minor amounts of mica probably illite or muscovite, feldspar (microcline), kaolinite and chlorite. The following phases were detected in the samples.

Quartz	abundant, more than 40wt.%
Calcite	abundant, more than 40wt.%
Mica	minor, nominally>1%,<10%
Microcline	minor, nominally>1%,<10%
Kaolinite	minor, nominally>1%,<10%
Chlorite	minor, nominally>1%,<10%

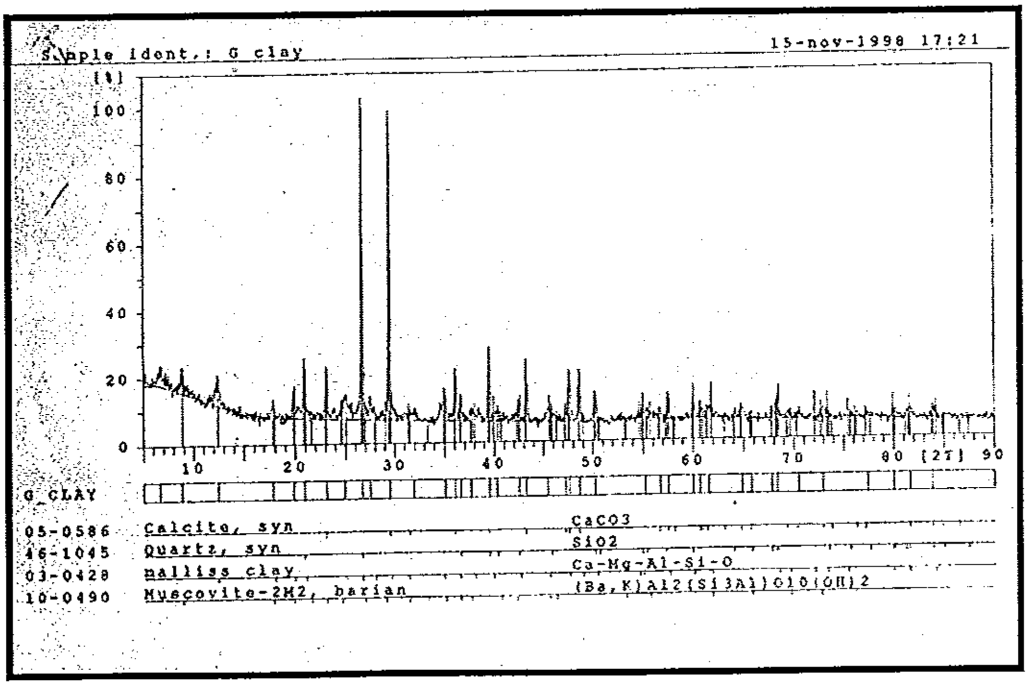

Figure C-1 X-ray Diffraction Peaks Analysis

Appendix D

Core Sample Grain Size Distributions Using Sieve Analysis

Introduction

Petrographic characterization is an important part of basic core analysis. Its data are useful in understanding and interpreting the core analysis results. Petrographic information and basic core analysis measurements provide an integrated framework for reservoir evaluations. Sieve analysis data is used primarily for determining a grain size distribution for core plug reinstallation design. A known mass of crushed core sample is mechanically vibrated through stacked screens with progressively smaller openings. The partial sample weights retained on individual screens are used to provide a sieve analysis report of screen opening size versus percent sample retained. Grain size is classified using Wentworth grain size scale, which also defines the common terms used in rock descriptions.

Material

Samples were take from UT1-7/D3 core at sections: 1199.00-1200.00 m and 1331.00-1331.40 m.

Method

The retrieved core samples were gently crushed and then sieved to standard grain-size scale. The crushed sample is weighed and then placed on the top coarsest sieve. The sieves are shaken manually for a period of not less than ten minutes. After shaking, each sieve is weighed to obtain the retained sample weight. The total cumulative weight of the sample should be within 5% of the initial dry sample weight. The data is tabulated and plotted as cumulative percent versus grain size distribution.

Result

Sample A – Fine laminated silty sand at depth 1199.10m

SIZE			WT. RETAINED			Cum. % pass
mm.		Average	g.	%	Cum.%ret.	
	+19.000		0.000	0.0000	0.0000	100.000
-19.000	+12.500	15.411	3.931	0.9100	0.9100	99.090
-12.500	+6.700	9.152	24.797	5.7600	6.6700	93.330
-6.700	+4.750	5.641	10.161	2.3600	9.0300	90.970
-4.750	+2.360	3.348	11.342	2.6300	11.6600	88.340
-2.360	+1.180	1.669	12.007	2.7900	14.4500	85.550
-1.180	+0.600	0.841	10.135	2.3500	16.8000	83.200
-0.600	+0.300	0.424	7.192	1.6700	18.4700	81.530
-0.300	+0.150	0.212	5.501	1.2800	19.7500	80.250
-0.150	+0.075	0.106	17.416	4.0400	23.7900	76.210
-0.075	+0.038	0.053	23.034	5.3500	29.1400	70.860
-0.038	+0.0188	0.0267	305.234	70.8600	100.0000	0.000
TOTAL			430.75		100.0000	

Table D-1 Grain Size Distribution

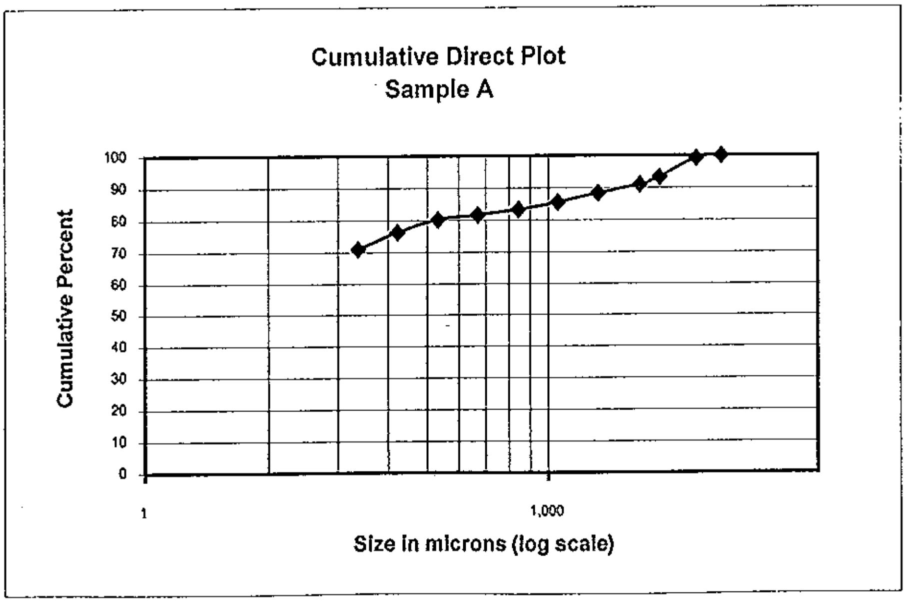

Figure D-1 Grain Size Distribution Sample A

Sample B – Fine grained sand including pebble at depth: 1331.20m

SIZE			WT. RETAINED			Cum. % pass
mm.		Average	WT. g.	%	Cum.%ret.	
	+12.500		0.000	0.0000	0.0000	100.000
-12.500	+6.700	9.152	21.078	8.0800	8.0800	91.920
-6.700	+4.750	5.641	2.562	0.9800	9.0600	90.940
-4.750	+2.360	3.348	5.530	2.1200	11.1800	88.820
-2.360	+1.180	1.669	5.614	2.1500	13.3300	86.670
-1.180	+0.600	0.841	5.110	1.9600	15.2900	84.710
-0.600	+0.300	0.424	6.394	2.4500	17.7400	82.260
-0.300	+0.150	0.212	6.828	2.6200	20.3600	79.640
-0.150	+0.075	0.106	4.552	1.7400	22.1000	77.900
-0.075	+0.038	0.053	8.683	3.3300	25.4300	74.570
-0.038	+0.0188	0.027	194.599	74.5700	100.0000	0.000
TOTAL			260.950		100.0000	

Table D-2 Grain Size Distribution

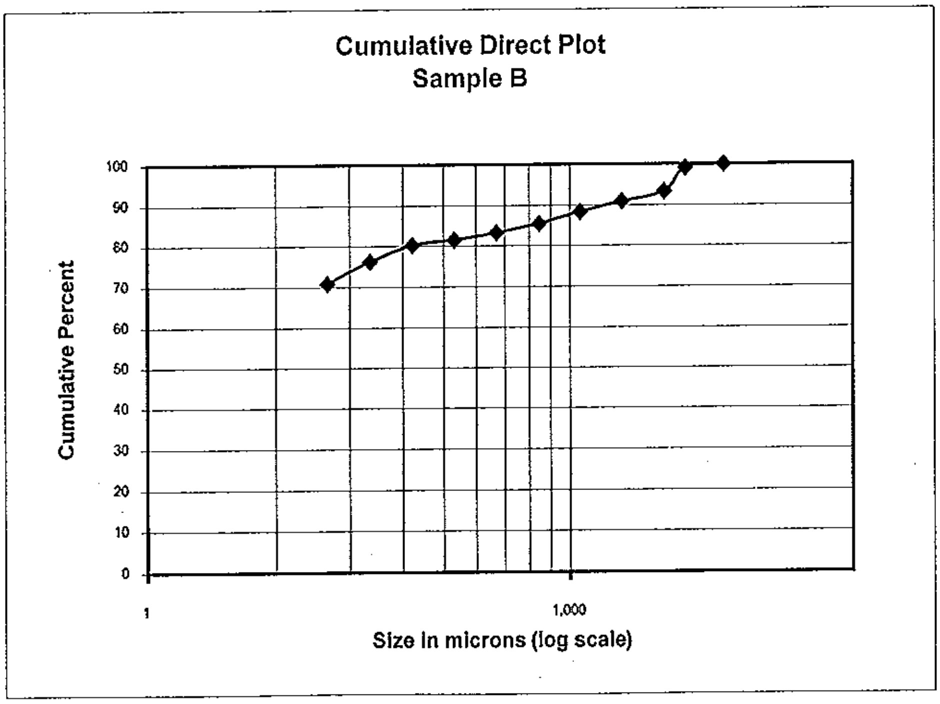

Figure D-2 Grain Size Distribution Sample B

Appendix E

Core Plug Sample Reinstallation to Original Reservoir Conditions

Introduction

The collected core sample materials are highly weathered and are not suitable to drill for standard core plugs, which needed in the test cell. Standard basic core analysis procedure is determined by type of required information. Generally a standard core plug sample is removed from sections of whole core sample oriented either vertically or horizontally with respect to the whole core axis or with respect to the normal bedding planes.

For standard routine core analysis, a standard plug size 1.5 inches in diameter and 2 inches long, is constructed as to the requirement in a test cell. A test plug is cut and trimmed to provide regularly shaped samples, right cylinders. The material used compiled from the results from thin section analysis, X-Ray diffraction analysis, sieve analysis grain size distributions and petrophysical properties from previous studies. The reinstalled core plug samples are constructed as close as to the original reservoir conditions. Petrophysical properties of the cores i.e. porosity, permeability, are as well critical to the reinstallation, therefore grain size materials used must be as close to the original core samples. Standard core plug sample can be constructed using various size glass beats if no original materials available.

Material

Samples were take from UT1-7/D3 core at sections: 1199.00-1200.00 m and 1331.00-1331.40 m.

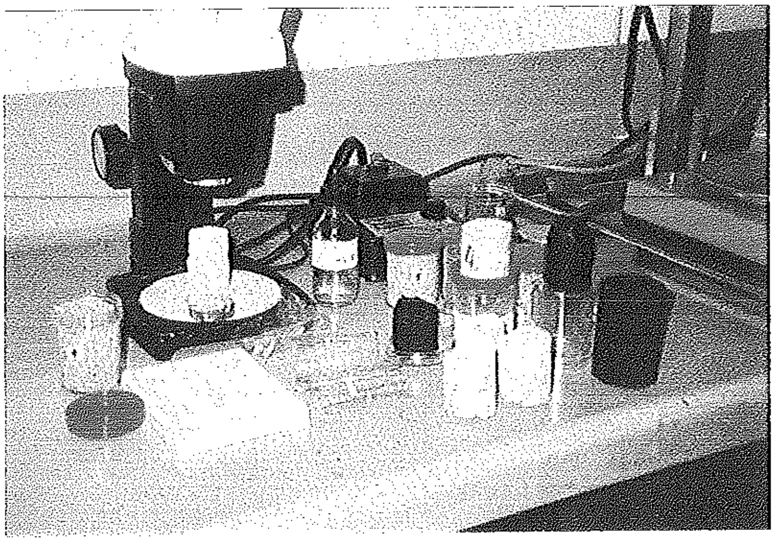

Figure E-1 Core Sample Preparation

Procedure

The core samples were gently crushed into individual grains using geological hammer. Core sample materials were separated into various size categories using the grain size distribution table results from sieve analysis. The sample materials are pebbly to conglomeratic with grain size range from very fine to 25 millimeter.

Grain materials used per weight for two core plugs:

Pebbles	25	g
Very coarse	15	g
Coarse	8	g
Medium	6	g
Fine	6	g
Very fine	15	g
Silty	5	g
Clay	180	g
Total	260	g
Clean water	50	cc

Various core material grains are collected in a plastic bucket. The samples are mixed thoroughly using clean water as intermixture. The mixture is then poured into a 2.5 inch diameter plastic tube which well lubricated on the side with grease. The mixture is well squeezed and compressed inside the plastic tube removing out any excess air bubbles.

The plastic tube containing mixture core sample is then kept in oven at 90°C for 48 hours to dry out excess water. Once dried, the core plug sample is pushed out, some cut along side the tube as plug gets stuck in, and is trimmed both ends to standard 2 inch long. Core plugs are then stored in an airtight desiccator and allowed to cool to room temperature before running porosity, permeability and fluid saturation purposes.

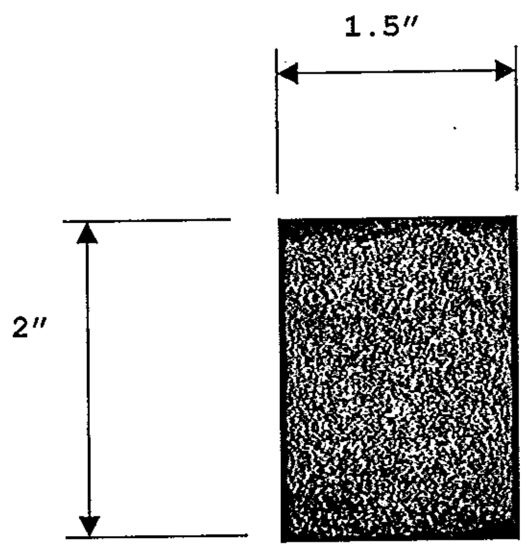

Figure E-2 Reinstalled Core Plug Sample

Appendix F

Core Plug Sample Petrophysical Properties
Porosity Measurement

Introduction

(Recommended Practices for Core Analysis), by API

Prior to hot water flooding process, a represent core plug is required in a test chamber. The core plug sample to which resembles the actual reservoir materials, general petrophysical properties of the plug i.e. porosity and permeability are required. The porosity of reservoir rocks needs to be determined in order to calculate the volume of hydrocarbons within the reservoir. The porosity and permeability determination of core samples is part of conventional core analysis.

Porosity is defined as the ratio of void space volume to bulk volume of a material. Porosity in core plug sample is determined by a combination of the following physical properties : Grain volume, Pore volume and Bulk volume using Porosimeter (Figure F-3).

$$\text{Pore volume (PV)} = \text{Bulk Volume (BV)} - \text{Grain Volume (GV)}$$

$$\text{Porosity \%} = \frac{\text{Pore Volume}}{\text{Bulk Volume}} \times 100$$

Grain Volume (GV) Measurement

Grain volume is determined by helium injection using principle of gas volume and gas pressure equilibrium, Boyle's Law ($P_1 V_1 = P_2 V_2$). To make the measurement, a core plug sample is sealed in the porosimeter using helium as gas reference volume. (Figure F-1)

HELIUM INJECTION POROSITY DATA SHEET

Hot-water Flooding A
Suphan Buri Oil Field

Ambient Data Entry

Sample No. =>	1	2	3	4	5	6	7	8	9	10	11
Direction	H	H	H	H	H	H	H	H	H	H	H
Volume Billet Removed	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46	14.46
PF (Volume Full Billets)	86.01	86.01	86.01	85.97	85.97	85.97	85.97	85.97	85.97	85.97	85.97
PB (Volume Billet#3 Out)	62.65	62.65	62.65	62.63	62.63	62.63	62.63	62.63	62.63	62.63	62.63
Dry Weight	114.8	114.5	115.0	118.7	117.0	116.8	116.9	118.9	118.7	118.3	117.9
Immersed Weight	724.0	722.0	726.5	732.6	733.0	731.0	733.1	731.9	733.9	730.7	732.0
POS (Applied Pressure)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
PS (Readout Pressure)	61.50	61.80	61.90	63.32	62.90	62.89	62.32	63.60	63.70	63.16	63.45
Volume Removed	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84	57.84
RV (Referrence Volume)	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36	33.36
GV (Grain Volume)	42.38	42.65	42.73	43.96	43.61	43.60	43.12	44.19	44.27	43.83	44.07
BV (Bulk Volume)	53.47	53.32	53.66	54.10	54.13	53.98	54.14	54.05	54.20	53.96	54.06
PV (Pore Volume)	11.09	10.68	10.92	10.14	10.52	10.38	11.02	9.86	9.92	10.13	9.99
Grain Density (g/cm3)	2.71	2.69	2.69	2.70	2.68	2.68	2.71	2.69	2.68	2.70	2.68
Ambient Porosity (%)	20.70	20.00	20.40	18.74	19.44	19.23	20.36	18.24	18.31	18.78	18.48

Overburden Data Entry

Sample No. =>	1	2	3	4	5	6	7	8	9	10	11
Direction	H	H	H	H	H	H	H	H	H	H	H
PF (Volume Full Billet)	87.88	87.88	87.88	87.88	87.88	87.88	87.88	87.88	87.88	87.88	87.88
PB (Volume Billet#3 Out)	63.07	63.07	63.07	63.07	63.07	63.07	63.07	63.07	63.07	63.07	63.07
400 PS	66.99	66.72	66.46	66.88	66.32	66.54	65.35	68.17	68.33	67.21	67.80
OB 1 PS (2000 psi)	69.66	69.39	69.11	69.56	68.97	69.20	67.96	70.90	71.06	69.90	70.51
OB RV (2000 psi)	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30
400 PV	11.47	11.66	11.85	11.54	11.95	11.79	12.67	10.63	10.52	11.31	10.89
OB 1 PV (2000 psi)	9.61	9.80	9.98	9.68	10.08	9.92	10.77	8.81	8.70	9.46	9.05
OB 1 BV (2000 psi)	51.62	51.46	51.79	52.24	52.26	52.12	52.24	52.23	52.38	52.11	52.22
Overburden Porosity (%)	17.90	17.10	17.50	15.90	16.60	16.30	17.50	15.40	15.50	15.90	15.60

Table F-1 Porosity Data Report

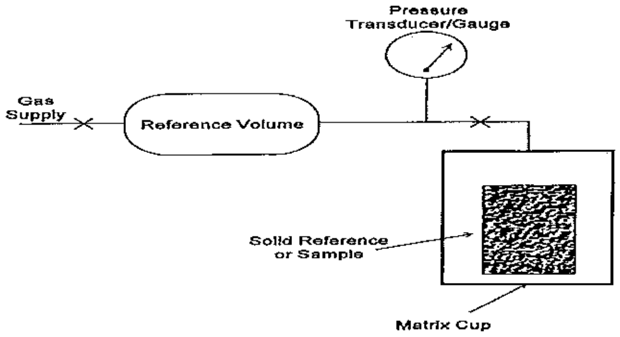

Figure F-1 Porosimeter Schematic

Material

Reinstalled core plug samples.

Apparatus

Helium injection porosimeter -

- valves to control and direct gas flow,
- regulator to adjust gas pressure,
- precision pressure transducer (0-100 psi), electronics and digital display to monitor gas pressure,
- matrix cup to hold the sample at atmospheric conditions,
- stainless steel billets of known volumes,
- a reference chamber to hold the helium at 100 psig before introduction to the matrix cup.

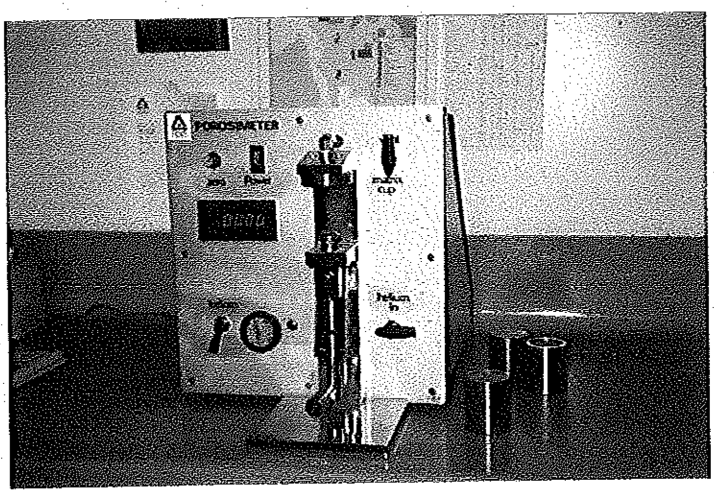

Figure F-2 Ambient Porosimeter

Supply of helium gas - helium is commonly used in petroleum engineering laboratory and is the suitable gas to use in this test because it is inert and does not react with or be adsorbed by the rock. Also, the small molecular size of helium allows it to penetrate micropores more readily than any other gas.

Procedure

The clean core plug sample is weighed and then sealed in the chamber at atmospheric pressure. A known volume of helium (Reference Volume RV) is held at 100 psi and then allowed to expand into the sample and stabilized. From the resultant pressure the grain volume is calculated using Boyle's Law.

Bulk Volume (BV) Measurement

Bulk volume is determined by mercury displacement. Archimedes (Buoyancy) principal states that the weight & volume of fluid displaced is equal to that of the subject immersed in the fluid that causes the displacement. The difference between the dry core plug weight and the immersed weight is the weight of mecury displaced by the core plug sample. The bulk volume of the core plug is the volume of the displaced liquid.

$$BV = \frac{\text{Mass of mercury displaced}}{\text{Density of mercury at measurement temperature}}$$

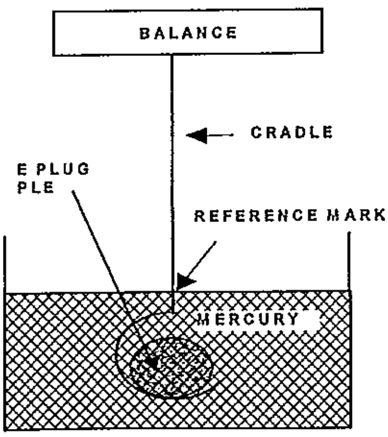

Figure F-3 Bulk Volume Measurement

Density of mercury at 22°C = 13.5413 Hg Density gm/cm^3

Grain Density (GD) Measurement

Grain density refers to the density of framework material in a rock, including sand grains, cement, pore filling matrix, etc. It is also used in a qualitative sense as an indicator of lithological changes, cement type and relative cement quantity. Grain density is measured the same way as grain volume measurement. The grain density is obtained by dividing the weight of the framework material by its volume.

Grain density (GD) is calculated by dividing the sample weight by the grain volume (GV).

$$GD = \frac{\textit{Sample Dry Weight}}{\textit{Sample Grain Volume}} \quad (g/cm^3)$$

Appendix G

Core Plug Sample Petrophysical Properties
Gas Permeability Measurement

Introduction

(Recommended Practices for Core Analysis), by API

Determining the permeability of reservoir rocks is important to the development of a reservoir. As of this Suphan Buri oil production, permeability and porosity are the major roles to achieve the best possible performance of the reservoir. Permeability is a measure of the ability of a porous medium to conduct fluid. Measured permeability is expressed in milliDarcies (mD). A permeability of 1 Darcy is defined as that permeability which will allow the flow of 1cm^3/sec of fluid of 1 centipoise (cp) viscosity through a cross sectional area of 1cm^2 under a pressure gradient of 1 atmosphere (atm/sec).

The permeability of a rock depends on the porosity; the size and shape of the pores, pore throats and interconnecting channels including the degree of interconnection between pores and the roughness of pore walls. The permeability is also related to lithology, grain size, grain sorting, grain shape and angularity, and the degree of cementation and pore filling matrix. It is believed that the containing of carbonate materials in this reservoir would as well be the key to increase permeability if some acids were injected in the formation.

To determine the permeability of a core sample, air at a known initial pressure (upstream pressure) is made to flow through the length of the sample. The sample is sealed along its length so that no air may bypass the sample. The flow rate of air from the other end of the sample is measured. The permeability for that sample is then calculated using Darcy's Law through knowledge of the upstream pressure and flow rate during the test, the atmospheric pressure, the viscosity of air and the length and cross sectional area of the sample.

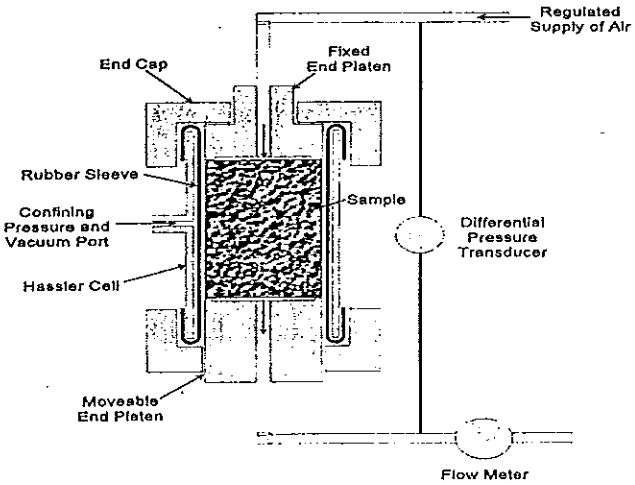

Figure G-1 Gas Permeameter Schematic (Hassler)

Material

Reinstalled core plug samples after porosity measurement.

Apparatus

Air Permeameter - :

- a Hassler cell to hold the sample during analysis and to prevent by passing of air around the sample.
- manual valves for controlling air flow direction.
- regulator to control the confining pressure on the sample in the Hassler cell.
- regulator to control air pressure and rate of air flow through the plug.
- pressure transducer, electronics and digital readout to monitor the upstream pressure.
- A series of calibrated bubble tubes of different volumes to monitor the flow rate of air through the sample.

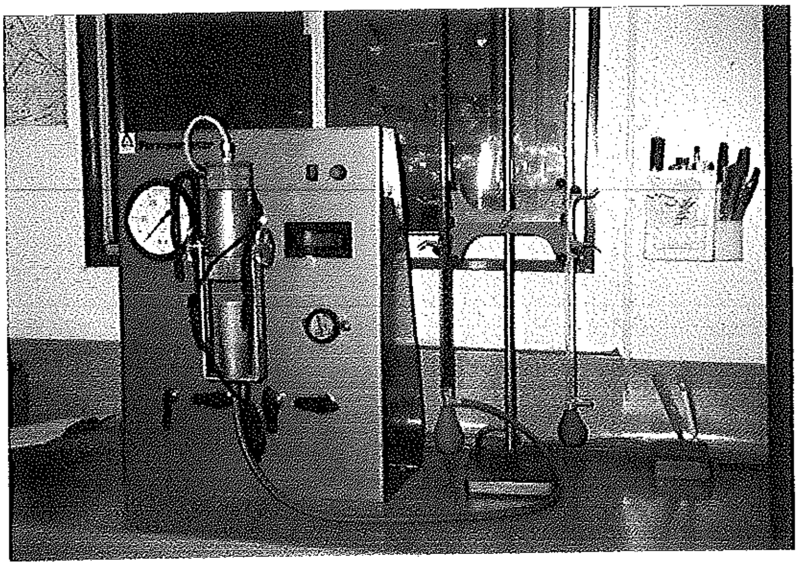

Figure G-2 Ambient Permeameter

Procedure

Measure the length and diameter of the plug with Vernier callipers to 2 decimal places (cm). Load the core plug in the Hassler cell which consists of a rigid cylindrical chamber fitted internally with a rubber sleeve. The cell is open at both ends to allow air to pass through. The rubber can be pressured up from an external air source. The rubber sleeve is then pressured up to 250 psig which seals the sides of the plug, preventing any bypass of air during the flow test.

Apply the upstream pressure to the top of the sample using a regulator to gradually increase the pressure. At the same time, use the bubble tube to check the flow rate of air through the sample. Adjust the upstream pressure to achieve a desirable flow rate. A very high flow rate causes turbulence in the air flow which leads to inaccurate results.

The following equation, a form of Darcy's Law is used to calculate permeability. All pressures need to be in units of atmospheres (atm):

$$\text{Kgas} = \frac{2000 \, x \, BP \, x \, \mu_{gas} \, x \, Q \, x \, L}{\left[(P_1 \, x \, 0.06805 + BP)^2 - (BP)^2\right] x \, A}$$

where:

BP	=	Barometric pressure in <u>atmospheres</u> (BP millibars x 0.0009869 = BP atmospheres)
μ_{air} or μ_{N2}	=	viscosity of gas (varies with temperature)* in centipoises
Q	=	flow rate $= \frac{\text{flow volume (cm}^3\text{)}}{\text{flow time (sec)}} = \frac{V}{T}$
L	=	length of plug in cm
P_1	=	upstream pressure in <u>psi</u>
0.6805	=	conversion factor for psi to atmospheres
A	=	cross sectional area of plug
A	=	width x breadth
* μ_{air}	=	$-8 \times 10^{-7} T^2 + 8 \times 10^{-5} T + 0.0171$
T	=	temperature in ^{o}C

Klinkenberg Gas Slippage

When gas is flowing through a capillary or a porous medium then the layers of gas adjacent to the solid surface exhibits a finite velocity. Gas slippage is a result of diffusion dominated by collisions between the gas molecules and the pore walls. The gas slippage causes measured gas permeability to be greater than liquid permeability on the same sample.

To avoid the problem of obtaining pore-pressure-dependent gas permeability, Klinkenberg, who pointed out the gas slippage to the oil industry, presented a method in which gas permeability measurements made at several different mean pore pressure can be extrapolated to infinite pore pressure. This extrapolated gas permeability, now called Klinkenberg permeability, is equal to the permeability obtained using a non-reactive liquid such as a clean liquid or refined hydrocarbon. Gas slippage causes measured gas permeability to be greater than liquid permeability on the same sample.

The below equations are some related relationships gas permeability to fluid permeability.

Ko : Ka	$Ko = 0.7254 * Ka^{1.0258}$
Kw : Ka	$Kw = 0.7643*Ka^{1.0165}$

Sample no. 1:

Ka	absolute permeability to air	= 187 mD
Ko	absolute permeability	
Ko	$= 0.7254 * Ka^{1.0258}$	= 155.25 mD

Where Ka : air permeability.
Kw : calculated water permeability.
Ko : calculated oil permeability.

PERMEABILITY DATA SHEET

Hot-water Flooding Analys
Suphan Buri Oil Field

Ambient Data Entry

Sample No. =>	1	2	3	4	5	6	7	8	1A	2A	3A
Direction	H	H	H	H	H	H	H	H	H	H	H
Temperature Degree C	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	22.0	22.0	22.0
BP (Barometric Pressure)	1010	1010	1010	1010	1010	1010	1010	1010	1010	1010	1010
P1 (Input Pressure)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Flow Volume (cc)	100	100	100	100	100	100	100	100	100	100	100
Time Taken (sec)	17.0	18.2	15.8	25.5	17.5	19.2	18.5	17.5	18.0	17.9	17.7
Core Plug Length (cm)	4.8	4.9	4.8	4.8	4.8	4.9	4.9	4.8	4.8	4.8	4.8
Core Plug Diameter (cm)	3.8	3.7	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Ambient Permeability (mD)	**203.0**	**196.0**	**219.0**	**209.0**	**199.0**	**182.0**	**189.0**	**198.0**	**193.0**	**195.0**	**196.0**

Overburden Data Entry

Sample No. =>	1	2	3	4	5	6	7	8	1A	2A	3A
Direction	H	H	H	H	H	H	H	H	H	H	H
Temperature Degree C	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	22.0	22.0	22.0
BP (Barometric Pressure)	1010	1010	1010	1010	1010	1010	1010	1010	1010	1010	1010
P1 (Upstream Pressure)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Flow Volume (cc)	100	100	100	100	100	100	100	100	100	100	100
OB1 Time Taken (sec)	18.5	19.6	19.8	18.3	19.3	19.7	20.7	19.3	19.3	19.0	18.8
Overburden Permeability (mD	**187.0**	**182.0**	**175.0**	**189.0**	**180.0**	**177.0**	**169.0**	**179.0**	**178.0**	**180.0**	**181.0**
Calculated Oil Permeability	**155.3**	**151.0**	**145.0**	**157.0**	**149.3**	**146.7**	**139.9**	**148.4**	**147.6**	**149.3**	**150.1**

Table G-1 Permeability Data Report

Appendix H

Core Plug Sample Petrophysical Properties
Gas Porosity and Permeability Measurement
At Overburden Pressure

Introduction

Porosity and permeability at Overburden Pressure

As a core is brought to the surface it will expand slightly due to the release of the overburden pressure. This will result in an increase in pore volume since the framework (i.e. grains ,cement, etc.) is relatively incompressible. The increase in pore volume causes a corresponding increase in bulk volume and consequently increasing the space available to transmit fluid. Therefore, the measured porosity and permeability are relatively greater than the actual permeability at reservoir pressure conditions.

To obtain porosity and permeability data which are representative of reservoir conditions the reduction in pore volume with increased pressure is measured in a hydrostatic cell. The confining pressure to be used on the sample is determined by the overburden and fluid pressures in the reservoir. In simple terms, the confining pressure is given by the overburden pressure (due to the overlying rock mass) minus the fluid pressure within the reservoir.

Procedure

Upon completion of porosity and permeability measurements under ambient condition, the core plugs were measured under overburden condition using Overburden Triaxial Pressure cell (Figure H-1). The Cell has been designed particularly to perform Porosity and Permeability measurements on rock samples under simulated reservoir overburden conditions. It uses an air actuated hydraulic pump to achieve a simulated reservoir confining pressure on the sample. Pressure transducers are used to accurately monitor the pressure of the gas mediums used to measure the parameters of a given sample. The procedures for these measurements are somewhat similar to the ambient porosity and permeability measurement.

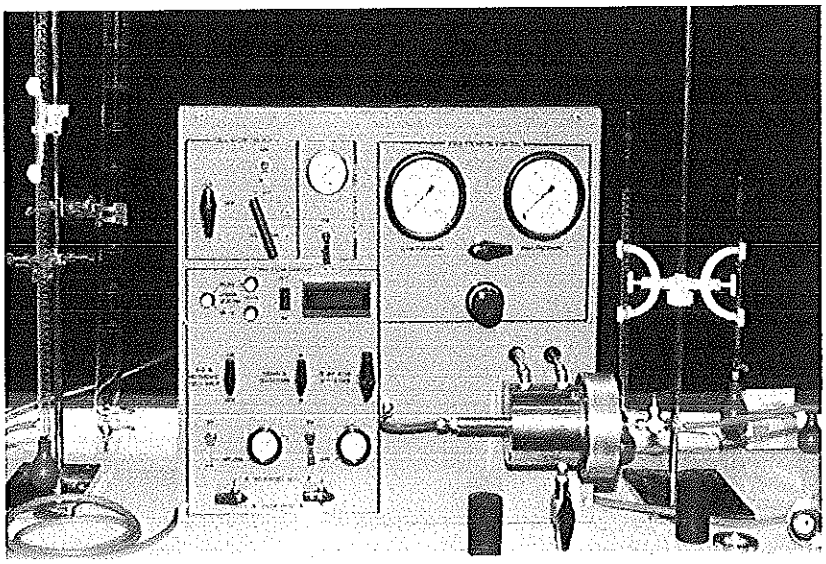

Figure H-1 Overburden Triaxial Pressure Cell

HOT-WATER FLOODING ANALYSIS

OVERBURDEN REINSTALLED CORE ANALYSIS

Sample Number	Dir	Ambient Porosity	OB1 Porosity	Ambient Permeability	OB1 Permeability
1	H	20.7	17.9	193	178
2	H	20.0	17.1	195	180
3	H	20.4	17.5	196	181
4	H	18.7	15.9	203	187
5	H	19.4	16.6	196	182
6	H	19.2	16.3	219	175
7	H	20.4	17.5	209	189
8	H	18.2	15.4	199	180
9	H	18.3	15.5	182	177
10	H	18.8	15.9	189	169
11	H	18.5	15.6	198	179

Table H-1 Ambient and Overburden Porosity and Permeability Data

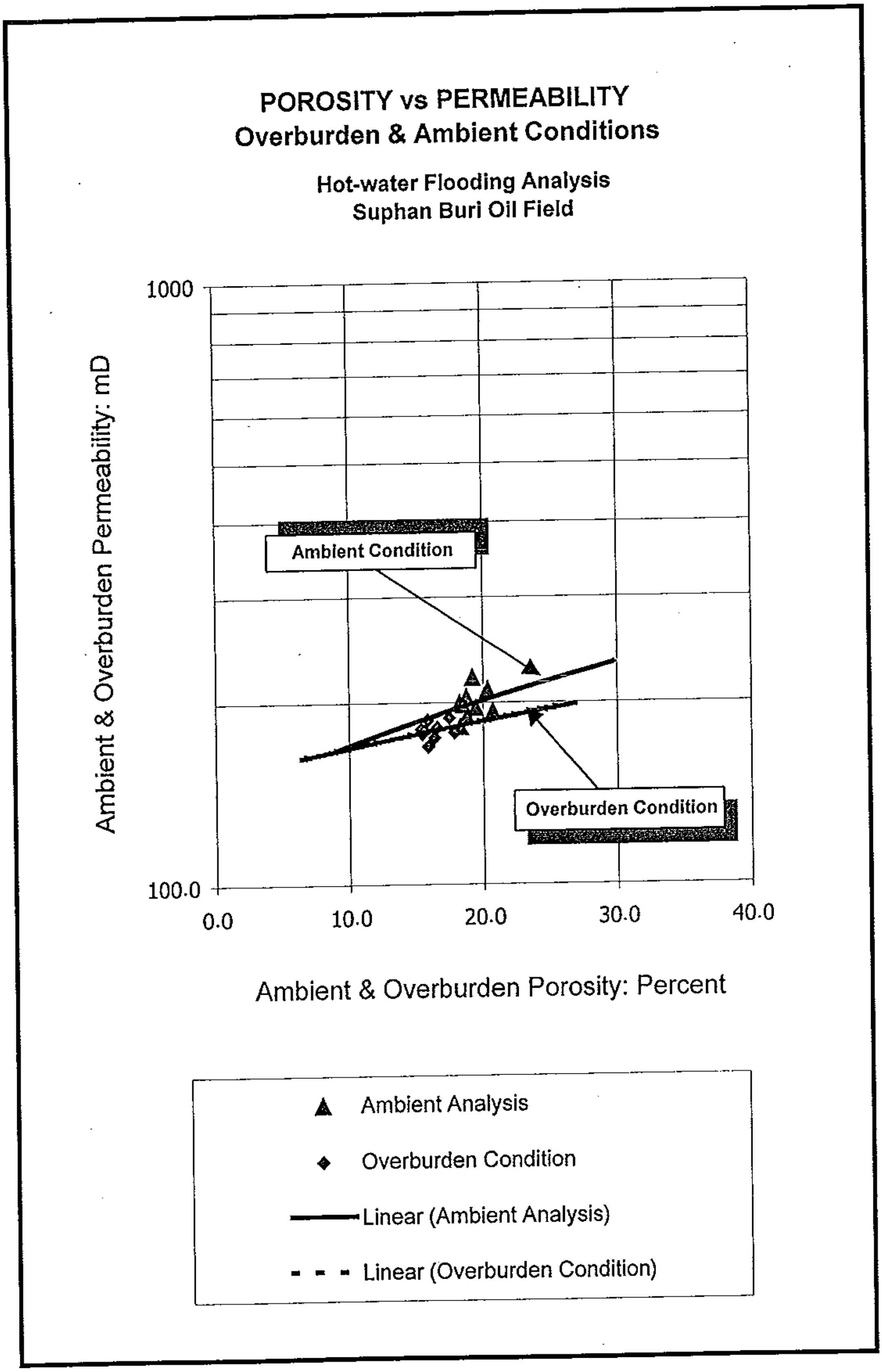

Figure H-2 Porosity and Permeability Relationship at Ambient and Overburden Conditions

Appendix I

Simple Brine Preparation for Core Plug Sample Saturation

Introduction

Prior to hot-water injection initiated, it is necessary to typically 100% fully saturate the core plug sample to formation water condition. Simple brine was selected as injection fluid.

Apparatus

- Volumetric flask
- Balance
- Buchner flask and funnel
- Vacuum pump
- Filter paper (normal size of 0.45μ)
- Beaker
- Spoon
- Funnel
- Wash bottle (containing distilled water)

Procedure

Brine used in this experiment is a common simple brines. The brine is made up using the conversion 1 g / L = 1000 ppm of sodium chloride, NaCl. A 30,000 ppm NaCl brine consists of 30g of sodium chloride in one litre of distilled water.

Dry and clean up the equipment. Place a clean and dry beaker on the balance and tare the balance. Using a clean and dry spoon, weigh the correct amount of the required sodium chloride one at a time. Use the funnel to pour the salt into the volumetric flask and the wash bottle to ensure no salt is left in the beaker.

Rinse and dry the beaker and spoon in between weighing each type of salt. Approximately half fill the volumetric flask with distilled water and shake end-over-end until all salts are dissolved into the solution. Fill volumetric flask to volume mark and shake end-over-end to attain uniform solution concentration.

Set up Buchner flask and funnel. Select appropriate filter paper. Wet filter paper using a small amount of distilled water. Vacuum filter the brine. When filtering is complete, stopper the Buchner flask and vacuum solution until it is degassed. Filtered and evacuated solution is stored in a clean and labelled container.

Appendix J

Core Plug Sample Brine Saturation

Introduction

Prior to hot-water injection, water (brine) saturation is needed on the core plugs as to the reservoir conditions. Brine was selected as injection fluid. This test procedure is to obtain core plug sample that is fully (100%) water saturated, typically to the reservoir formation.

Material

- Reinstalled core plug sample
- Simple brine

Apparatus :

- Balance
- Pressure chamber
- Vacuum pump
- Haskel pump
- Filtered fresh water

Procedure

The core plug is clean, dry and weight is determined. Place core plug sample into the pressure chamber and vacuum the cell for minimum of two hours and then record the vacuum pressure. Connect the chamber to the simple brine and allow the brine to enter the chamber using the vacuum as the negative drive pressure.

Connect the brine supply to the pressure pump to the chamber and pressurized to 2000 psi and leave for minimum 12 hours. Upon completion, release the pressure slowly, and unload the core plug sample from the chamber and immerse under fresh clean water. The sample to be kept in container before crude oil saturation.

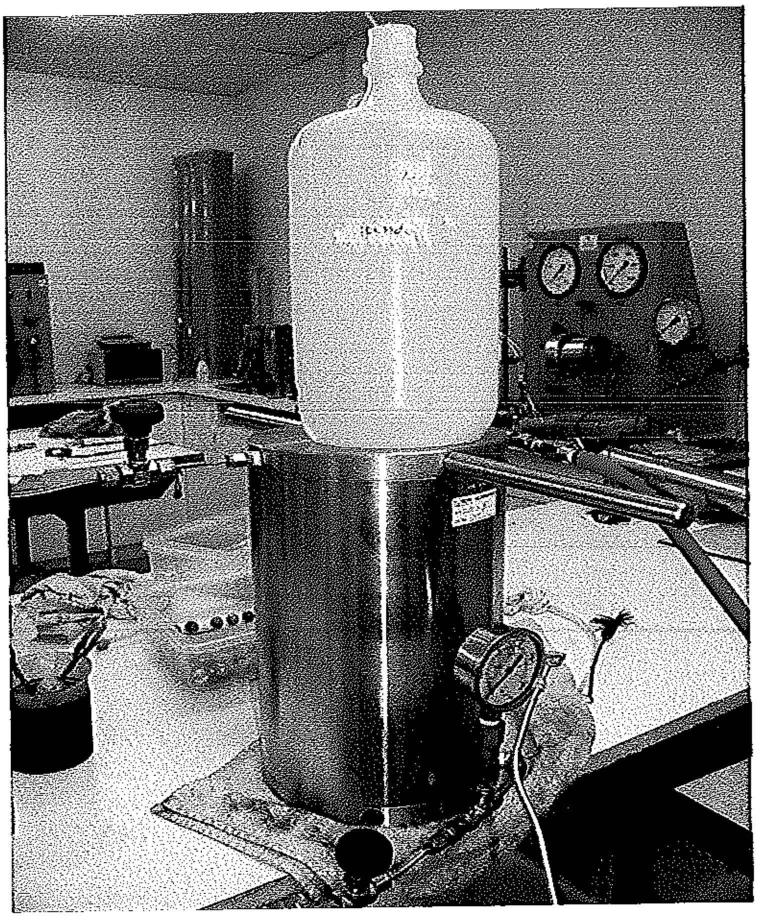

Figure J -1 Core Plug Sample Brine Saturation

WATER SATURATION DATA SHEET

Analysis Information
Hot-water Flooding Analysis
Suphan Buri Oil Field
Formation

Fluid Formation	
Saturan	Formation brine
Density	1.00
Analyst	

Data Entry

Sample No. =>	1	2	3	4	5	6	7	8	9	10	11
Dry Weight (g)	114.8	114.5	115.0	118.7	117.0	116.8	116.9	118.9	118.7	118.3	117.9
Bulk Volume (cm^3)	53.5	53.3	53.7	54.1	54.1	54.0	54.1	54.1	54.2	54.0	54.1
Pore Volume (cm^3)	11.09	10.68	10.92	10.14	10.52	10.38	11.02	9.86	9.92	10.13	9.99
Porosity (%)	20.7	20.0	20.4	18.7	19.4	19.2	20.4	18.2	18.3	18.8	18.5
Grain Volume (cm^3)	42.4	42.7	42.7	44.0	43.6	43.6	43.1	44.2	44.3	43.8	44.1
Grain Density (g/cm^3)	2.71	2.69	2.69	2.70	2.68	2.68	2.71	2.69	2.68	2.70	2.68
Calculated Saturated Weight (g)	125.9	125.2	125.9	128.8	127.5	127.2	127.9	128.8	128.6	128.4	127.9

Saturation Data (measured during saturation)

	1	2	3	4	5	6	7	8	9	10	11
Dry Weight (g)	114.8	114.5	115.0	118.7	117.0	116.8	116.9	118.9	118.7	118.3	117.9
Actual Saturated Weight (g)	125.5	124.6	125.4	128.4	127.2	126.6	127.4	128.3	128.3	128.3	127.6
Saturant Weight (g)	10.70	10.10	10.40	9.75	10.20	9.80	10.53	9.43	9.60	10.00	9.65
Saturated Pore Volume (cm^3)	10.70	10.10	10.40	9.75	10.20	9.80	10.53	9.43	9.60	10.00	9.65
Saturation (%) Pore Volume	96.5	94.6	95.2	96.2	97.0	94.4	95.6	95.6	96.8	98.7	96.6
Immersed Weight (g)											
Saturation Bulk Volume (cm^3)	125.5	124.6	125.4	128.4	127.2	126.6	127.4	128.3	128.3	128.3	127.6
Saturation Grain Volume (cm^3)	114.8	114.5	115.0	118.7	117.0	116.8	116.9	118.9	118.7	118.3	117.9
Saturation Grain Density (g/cm^3)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Saturation Porosity (%) Swi of BV	8.53	8.11	8.29	7.59	8.02	7.74	8.26	7.35	7.48	7.79	7.57

Table J-1 Water Saturation Data Sheet

Appendix K

Core Plug Sample Oil Saturation

Introduction

Prior to the final hot-water flooding, brine and oil saturations are required on the core plugs to the reservoir conditions. The Suphan Buri crude is needed for the procedure. Prior to this test the core plug was fully brine saturated, typically to the reservoir formation brine.

Material

- Reinstalled Core plug sample
- Suphan Buri crude oil

Apparatus :

- Balance
- Overburden Triaxial Pressure Cell
- Regulators to control water pressure and monitor cell pressure
- Suphan Buri crude oil
- Electrical mantel with temperature controller
- Core plug sample with fully brine saturation
- Glass receiving tube, with a calibrated scale
- Digital thermometer connected on the inlet and outlet tubes

Procedure

This test procedure is designed to obtain samples that are fully (ideally 100%) liquid saturated, typically with simulated formation brine and reservoir crude oil.

CRUDE OIL SATURATION DATA SHEET

Analysis Information	Fluid Formation	
Hot-water Flooding Analysis	Saturant	Formation brine
Suphan Buri Oil Field	Density@25C	0.9199
Formation		

Data Entry

Sample No. =>	1	2	3	4	5	6	7	8	9	10	11
Dry Weight (g)	114.8	114.5	115.0	118.7	117.0	116.8	116.9	118.9	118.7	118.3	117.9
Bulk Volume (cm^3)	53.5	53.3	53.7	54.1	54.1	54.0	54.1	54.1	54.2	54.0	54.1
Pore Volume (cm^3)	10.09	10.68	10.92	10.14	10.52	10.38	11.02	9.86	9.92	10.13	9.99
Porosity (%)	20.7	20.0	20.4	18.7	19.4	19.2	20.4	18.2	18.3	18.8	18.5
Grain Volume (cm^3)	42.38	42.65	42.73	43.96	43.61	43.60	43.12	44.19	44.28	43.83	44.07
Grain Density (g/cm^3)	2.71	2.69	2.69	2.70	2.68	2.68	2.71	2.69	2.68	2.70	2.68
Calculated Saturated Weight (g)	124.1	124.3	125.0	128.0	126.7	126.3	127.0	128.0	127.8	127.6	127.1

Saturation Data (measured during saturation)											
Dry Weight (g)	114.8	114.5	115.0	118.7	117.0	116.8	116.9	118.9	118.7	118.3	117.9
Actual Saturated Weight (g)	127.7	126.5	126.0	127.7	126.5	126.0	126.8	127.5	127.5	127.5	127.0
Saturant Weight (g)	12.90	12.00	11.00	9.05	9.50	9.20	9.90	8.60	8.80	9.20	9.10
Saturated Pore Volume (cm^3)	14.02	13.04	11.96	9.84	10.33	10.00	10.76	9.35	9.57	10.00	9.89
Saturation (%) Pore Volume	138.98	122.14	109.50	97.02	98.17	96.35	97.66	94.82	96.43	98.73	99.02
Immersed Weight (g)											
Saturation Bulk Volume (cm^3)	138.8	137.5	137.0	138.8	137.5	137.0	137.8	138.6	138.6	138.6	138.1
Saturation Grain Volume (cm^3)	124.8	124.5	125.0	129.0	127.2	127.0	127.1	129.3	129.0	128.6	128.2
Saturation Grain Density (g/cm^3)	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Saturation Porosity (%)	10.10	9.49	8.73	7.09	7.51	7.30	7.81	6.75	6.90	7.22	7.17
Initial Oil Saturation (%)	48.80	47.43	42.79	37.90	38.71	38.03	38.27	37.06	37.72	38.38	38.73

Note: Density of Crude oil 0.9199 gm/cc from PVT Analysis 1.3.2 Summary of Previous Study Results

Table K-1 : Crude Oil Saturation Data Sheet

The individual core plug sample was weighed and recorded on lab data sheet before placing into a thick walled rubber sleeve and loaded into a stainless steel hydrostatic cell. The cell is filled with water and the hydraulic pump is used to obtain the ambient confining pressure depending on the rubber sleeve thickness. In this measurement, an ambient pressure of 450 psi was used. Then the Suphan Buri crude of above cloud point temperature is then slowly injected at 2 psi upstream pressure into the core plug. It is to ensure that the liquid flow rate did not result in non laminar or turbulent conditions. The amounts of overflowed brine and crude oil were received in the receiving tube. The system was then allowed to stabilize, for a constant flow of up and down stream constant pressure and no further access brine came out of the core plug. The core plug was then taken out for final weight.

Residual Oil Saturation Determination using Summartion Fluids Retort Method

Fluid Saturations

Fluid saturation is defined as the ratio of the volume of a fluid in a core sample to the pore volume of the sample. Brine, oil and gas are distributed in porous media in a manner dictated primarily by gravity and capillary forces. Gravity forces separate reservoir fluids from top to bottom into free gas, oil and brine respectively.

Core plug sample once has been flooded by hot-water injection, then some nonremoval oil remained in small pore spaces. The oil and brine are generally held by capillary forces found as thin film left on the grain particles and in the small pore spaces.

This test procedure is required in order to find the residual oil saturation, Sor, which is being left in the core plug.

Apparatus

The retort Figure K-2 consists of an insulated oven made to accommodate up to 20 samples per run. The oven is heated with rod-type heating elements which are arranged so that each sample receives an equal amount of heat. The temperature of the oven can be controlled to any temperature up to

650°C. The outlet stem of each sample holder (termed the retort bomb) makes a vapour tight seal with the top of the condensing tube. The condensing tube runs down through a water bath beneath the oven.

Calibrated glass receiving tubes collect the condensed fluids at the outlet of the condensing tube.

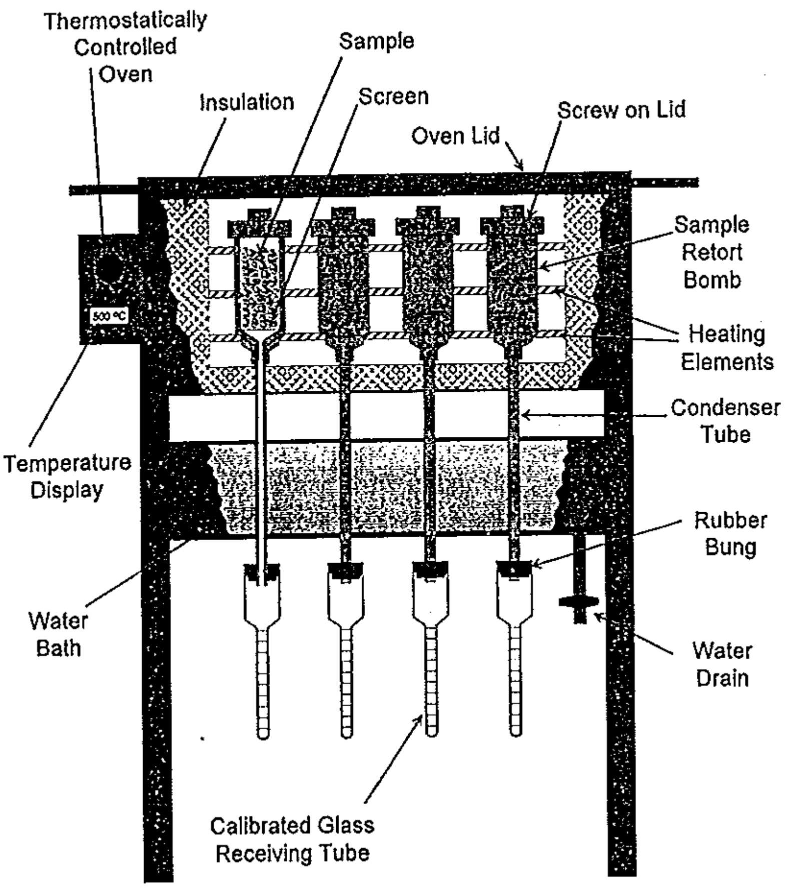

Figure K-1 Retort Oven

Procedure

Once the core plug removed from overburden triaxial pressure cell, the plug is broken into fingernail size pieces, weighed approximately to 100 grams and placed into the retort bomb. The water bath is filled, glass receiving tubes placed at the condensing tube outlets, the temperature controller set to 180°C and the retort switched on.

The resulting water volume collected in the calibrated glass receiving tubes is recorded as a function of time at, at least, 10 minute intervals. This record allows the initial pore water volume to be accurately assessed.

Once water production at 180°C is complete, oil and initial water volumes are recorded, the condensing bath is drained and the temperature raised to 650°C. At this temperature all remaining oil and clay bound water is removed from the sample and collected in the receiving tube.

Calculations

$$\text{Sg, Gas Porosity (\%)} = \frac{\text{Gas volume (cm}^3\text{)}}{\text{Volume gas bulk sample}} \times 100$$

$$\text{Sw, Water Porosity (\%)} = \frac{\text{Initial water (cm}^3\text{)}}{\text{Retort bulk volume (cm}^3\text{)}} \times 100$$

$$\text{So, Oil Porosity (\%)} = \frac{\text{Corrected oil volume (cm}^3\text{)}}{\text{Retort bulk volume (cm}^3\text{)}} \times 100$$

Summation of Fluids Porosity (%) = %Gas + %Oil + %Water

Or $Sw + So + Sg = 1$

RESIDUAL OIL SATURATION DATA SHEET

Analysis Information
Hot-water Flooding Analysis
Suphan Buri Oil Field
Formation

Summation of Fluids Data Sheet - Calculations

Sample No. =>	1	2	3	4	5	6	7	8	9	10	11
Wet weight (g)	127.7	126.5	126.0	127.7	126.5	126.0	126.8	127.5	127.5	127.5	127.0
Retort weight (g)	99.5	99.5	100.0	99.8	99.5	101.0	100.0	100.0	101.0	100.0	99.5
Oil collected (cm3)	7.60	6.90	7.80	5.20	5.00	5.00	4.60	3.70	5.50	4.50	7.00
Collected Initial water (cm3)	23.10	25.30	21.30	28.00	27.00	26.80	27.00	28.60	26.30	27.00	23.00
Collected Final water (cm3)	24.00	26.80	23.00	29.30	29.00	27.50	28.00	29.00	27.00	28.50	26.00
Grain density (g/cm3)	2.71	2.69	2.69	2.70	2.68	2.68	2.71	2.69	2.68	2.70	2.68
Saturated Bulk Volume (cm3)	36.73	37.06	37.16	36.98	37.09	37.70	36.89	37.16	37.67	37.05	37.20

Overburden Data Entry

Water Porosity (%)	62.89	68.27	57.32	75.72	72.81	71.09	73.20	76.96	69.81	72.87	61.83
Crude oil Porosity (%)	20.69	18.62	20.99	14.06	13.48	13.26	12.47	9.96	14.60	12.15	18.82
Gas Porosity (%)	16.42	13.11	21.69	10.21	13.71	15.65	14.33	13.08	15.59	14.98	19.35
Sum of Fluids Porosity (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Water Saturation (%)	62.89	68.27	57.32	75.72	72.81	71.09	73.20	76.96	69.81	72.87	61.83
Crude Oil Saturation (%)	20.69	18.62	20.99	14.06	13.48	13.26	12.47	9.96	14.60	12.15	18.82
(Residual Oil Saturation)											

Table K-2
Residual Oil Saturation

Appendix L

Hot-water Flooding Flow Rate Calculation
(Single Phase Condition)

Introduction

In order to calculate oil-brine relative permeability, the injection flow rate is required and is derived from Darcy's law of steady-state, horizonatl laminar flow. The theory of flow of homogeneous fluids through porous media is based on the work of Darcy, which indicates a direct relationship between velocity and pressure gradient.

$$K = \frac{\mu QL}{A(P1 - P2)}$$

where	μ	is the liquid viscosity (cP)
	Q	is the liquid flow rate(cm^3/sec)
	L	is the sample length (cm)
	A	is the sample cross sectional area (cm^2)
	P_l and P_2	are the inlet and outlet pressures (psi)
	K	is absolute permeability (D)

The absoloute permeability of a rock is the permeability of the rock to a non-reactive fluid when it is fully saturated with thet fluid. It is a property of the rock alone, not the fluid whioch flow through it.

In Appendix G, we have the overburden permeability to air and because of gas slippage and inertial effetcs it can be converted to permeability of oil at irreducible water saturation (see Appendix G, Klinkenberg Gas Slippage) :

Ko : Ka $\quad Ko = 0.7254 * Ka^{1.0258}$

Calculations

The usual practice for laboratory work is to use the special case of Darcy's for the steady state flow of incompressible fluids.

$$K = \frac{14696\mu QL}{A(P_1 - P_2)}$$

$$Q\ @\ Sw = \frac{Ko * A(P_1 - P_2)}{14696\mu L}$$

Sample no. 1:

μ	is the liquid viscosity (cP)	= 6.477 cP
L	is the sample length	= 4.82 cm
A	is the sample cross sectional area	= 11.014 cm^2
P_l and P_2	are the inlet and outlet pressures	= 20 psi
14696	conversion factor for psi to atmospheres and Darcy's to mD	
Ka	absolute permeability to air	= 187 mD
Ko	absolute permeability	
Ko	= 0.7254 * Ka $^{1.0258}$	= 155.25 mD
Q@ Sw	is the liquid flow rate	

$$Q\ @\ Sw = \frac{155.25 * 11.014 * 20}{14696 * 6.477 * 4.82}$$

$$= 0.0745\ cm^3/sec$$

Appendix M

Relative Permeability Determination
(Unsteady-State Condition)

Introduction

The permeability of a rock is a measure of the ease with which fluid can flow through it. If only one fluid is present in the rock, and the rock does not react with the fluid, the permeability of the rock to the fluid is known as “absolute” or “specific” permeability. If a formation contains two or more immiscible fluids, the effective permeability for a given medium in the present of the others must be considered. If a formation contains two or more immiscible fluids, and each fluid tends to interfere with the flow of the others. This reduction in ability of a fluid to flow through a permeable material is called a relative permeability effect (Walter, 1978).

Relative permeability is believed to be controlled by the following factors:

Pore geometry,
Wettability,
Fluid distribution,
Saturations and Saturation history.

This experiment describes the operations to be employed for a typical unsteady-state hot-water-oil relative permeability analysis.

Direct application of Darcy’s law to the flow of a fluid in a porous media requires that the flowing fluid completely saturates the medium. The concept of of effective permeability may be applied to simultaneous flow of one or more fluids in a rock, which is a function of its percentage saturation. The effective permeability of the rock to each fluid is considered to be independent of the other fluid phases.

Effective permeability obtained from laboratory measurements conducted on core plug sample are normalized by the absolute permeability of the core sample. The relative permeability is expressed as follows:

Kr = Ka/Ke

Where

Kr = Relative Permeability

Ka = Absolute Permeability

Ke = Effective Permeability between initial and Residual Saturation

Test Methodology

- Pressure gradient across the plug should be sufficient to minimize capillary end effects.
- The sample should be homogeneous and 100% liquid saturated.
- The drive pressure and fluid properties are constant during experimenting.
- The flow should be horizontal.
- Ignoring the gravity effects.

This theory published by Johnson, Bossler and Nauman (JBN) has been well used and is the basis for all Relative Permeability calculated in petroleum industry today.

Apparatus

- Overburden Triaxial Hydrostatic Pressure Cell
- Receiving tubes with calibration
- Pressure measurement apparatus : inlet pressure gauges, and transducers)
- Stop watch
- Sample balance
- Pressure Pump

- Pump for the application of overburden pressure
- Digital thermometer
- Electrical mantle
- Crude oil container
- Heating system
- Laboratory data sheet

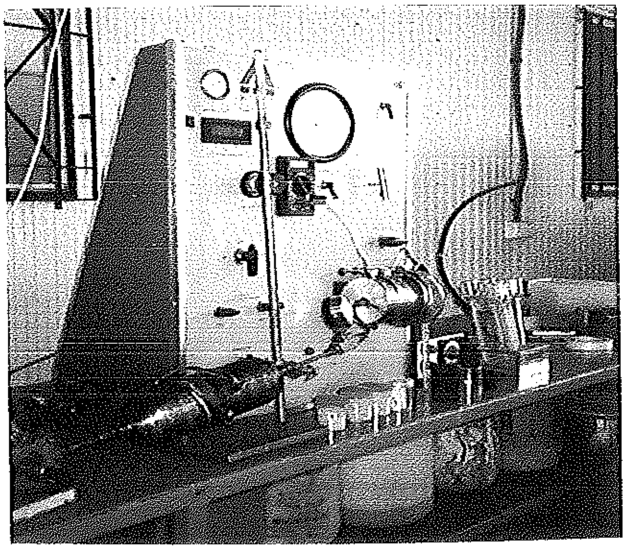

Figure M-1 Overburden Triaxial Pressure Cell

Procedure

The test sample is fully brine saturated. Firstly remove the sample from the storage container, remove any excess saturant from the surface of the sample using a non-absorbent cloth and record the weight of the sample. Load the core plug into the core holder of the pressure cell.

Measure the oil permeability where total down stream dead volume must be recorded. Prepare a selection of calibrated glassware for the collection of produced oil and water. Prepare for the hot-water flood by flushing brine at low pressure across the inlet platen entry and pressure ports and collect and record the volume removed.

Set the brine pressure and flow rate to be used against the closed inlet valve. Simultaneously open the inlet taps and start measuring flow time using stop watches. Thereafter record the brine and oil produced at intervals such that the individual increments of oil are collected each time. Record fluid temperature and flooding pressure.

Calculations

The relevant equations presented by JBN are as follows:
(Johnson E.F.,Bossler D.F., and Naumann V.O., 1958)

$$\frac{\dfrac{(1)}{d\,(WiIr)}}{\dfrac{(1)}{d\,Wi}} = \frac{fo}{Kro} \qquad \text{JBN Equation}$$

$$fo = \frac{Oi}{Oi + Wi}$$

$$Krw = \frac{(1-fo)\mu w}{fo\mu o} Kro$$

$$S_2 = Sar - Wi\,(fo)_2$$

$$S = S_2 + Swi$$

Where:

A	=	Cross sectional area of the core plug (cm^2)
Fw, Fo	=	Fractional flow of water, oil etc.
Fo	=	Fractional flow of oil = (1.0-Fw)
Ir	=	Relative injectivity
Kw, Ko	=	Absolute permeability to water, oil etc. (mD)
Keo	=	Effective permeability to oil (mD)
Krw, Kro	=	Relative permeability to water, oil etc. (mD)
L	=	Length of core plug (cm)
Oi	=	Instantaneous oil flow rate
Q	=	Flow rate
S_2	=	Saturation in outlet volume
Sw	=	Water saturation
Swir	=	Irreducible water saturation
Wi	=	Instantaneous water flow
μB	=	Brine viscosity, (cP Centipoise)
μo	=	Oil viscosity, (cP Centipoise)
μw	=	Water viscosity, (cP Centipoise)
Δp	=	Flooding pressure (psi)
ΔP Ko	=	Δp required for base Ko measurement
Q Ko	=	Resulting flow rate for above ΔP

Sample no. 1 Calculation Data

To calculate saturation (end face) at each point and relative permeabilities by the JBN (Johnson, E., Bossler, D., & Nauman, V. (1959), method.

Calculation on each point display in Figure 3.1

Sample Details

Length	=	4.82	(cm)
Area	=	11.10	(cm^2)
Pore Volume	=	9.68	(cm^3)
Swi	=	7.09	(%)
Ko	=	155.3	(mD)
Qo at 20.0 psi	=	0.075	(cm^3/sec)

Test Details

Flooding Pressure	=	20.0	(psi)
Brine Viscosity	=	1	(cP)
Oil Viscosity	=	6.477	(cP)

Time (sec)		Cumulative Oil (cm^3)		Cumulative Brine (cm^3)	
3600		0.50		0.80	
7200	3600	2.20	1.70	4.30	3.50
10800	3600	3.70	1.50	9.80	5.50
14400	3600	4.00	0.30	21.00	11.20
18000	3600	4.25	0.25	27.25	6.25
21600	3600	4.25	0.00	36.75	9.50

1. To calculate Kro

$$\text{From JBN} = \frac{\dfrac{(1)}{d\,(Wi Ir)}}{\dfrac{(1)}{d\,Wi}} = \frac{fo}{Kro} \quad \text{(equ. JBN)}$$

$$Kro = fo\ Ir$$

Relative Permeability to Oil = $fo\ Ir$

For 1st and 2nd data point

$$fo = \frac{Oi}{Oi + Wi} = \frac{1.70}{1.70 + 3.50} = 0.3269$$

$$Ir = \frac{5.5/3600}{0.075} = 0.0204$$

(Kro) Relative Permeability to oil = 0.0067

2. <u>To calculate Krw</u>

$$Krw = \frac{(1-fo)\mu w}{fo\mu o} Kro = \frac{(1-0.3269)1.00}{0.3269 x 6.477} 0.0067 \qquad \text{(equ. 9JBN)}$$

(Krw) Relative Permeability to water = 0.00213

3. <u>To calculate Saturation</u>

$$S_2 = Sar - Wi\,(fo)_2 \qquad \text{(equ. 4a JBN)}$$

$$Sar = Cumulative \;\; oil \;\; x \;\; \frac{100}{Pore \;\; volume}$$

$$Wi\,(fo)_2 = Cumulative \;\; Oil \;\&\; Brine \;\; x \;\; \frac{100}{Pore \;\; Volume} \;\; x \;\; fo$$

$$S_2 = 2.20 x \frac{100}{9.68} - 6.5 x \frac{100}{9.68}(0.3269)$$

$$= 0.7760$$

$$S = 0.7760 + Swi = 7.863\ \%$$

Sample Saturations at the first point = 7.863 %

See Figure 3.1 Percent Water Saturation

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	2			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Depth		Ko @ Swi (mD)	149.3	*m =*	
				Swi (%)	9.486	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	180			Oil Viscosity @ 76C	9.644
Date	5 Apr 98	Porosity (%)	17.1	Length (cm)	4.8		
		Pore Volume (cm^3)	9.8	Diameter (cm)	3.8		
		Residual Oil saturation (cc)	6.90	X-Sectional Area (cm^2)	11.341	Q @ Swir (cm^3/s)	0.050

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil *Recovery Percent*	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.50	0.80	90	1.00	9.64	0.30	0.30	3.13	0.50	0.80
7200.00	20.00	2.10	3.10	90	1.00	9.64	1.00	0.70	10.42	1.60	2.30
10800.00	20.00	6.90	8.60	90	1.00	9.64	1.70	0.70	17.71	4.80	5.50
14400.00	20.00	12.30	14.50	90	1.00	9.64	2.20	0.50	22.92	5.40	5.90
18000.00	20.00	18.60	21.20	90	1.00	9.64	2.60	0.40	27.08	6.30	6.70
21600.00	20.00	24.60	27.30	90	1.00	9.64	2.70	0.10	28.13	6.00	6.10

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2 (percent)*	Water Saturation *Sw (percent)*	Water Saturation	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.375	0.000	0.004	0.0	9.486	0.095	1.000	0.000	1.000	0.000	0.08	0.0
0.304	0.696	0.013	0.6	10.063	0.101	0.004	0.001	0.005	0.237	0.32	2.3
0.127	0.873	0.031	6.2	15.664	0.157	0.004	0.003	0.007	0.711	0.88	6.9
0.085	0.915	0.033	9.9	19.396	0.194	0.003	0.003	0.006	1.120	1.48	10.8
0.060	0.940	0.037	13.6	23.102	0.231	0.002	0.004	0.006	1.633	2.16	15.8
0.016	0.984	0.034	23.0	32.470	0.325	0.001	0.003	0.004	6.221	2.79	60.0

Table M-2 Relative Permeability Data Calculation, Plug Sample No.2

WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**2**
Porosity	**17.1 percent**
Initial Water Saturation	**9.5 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability

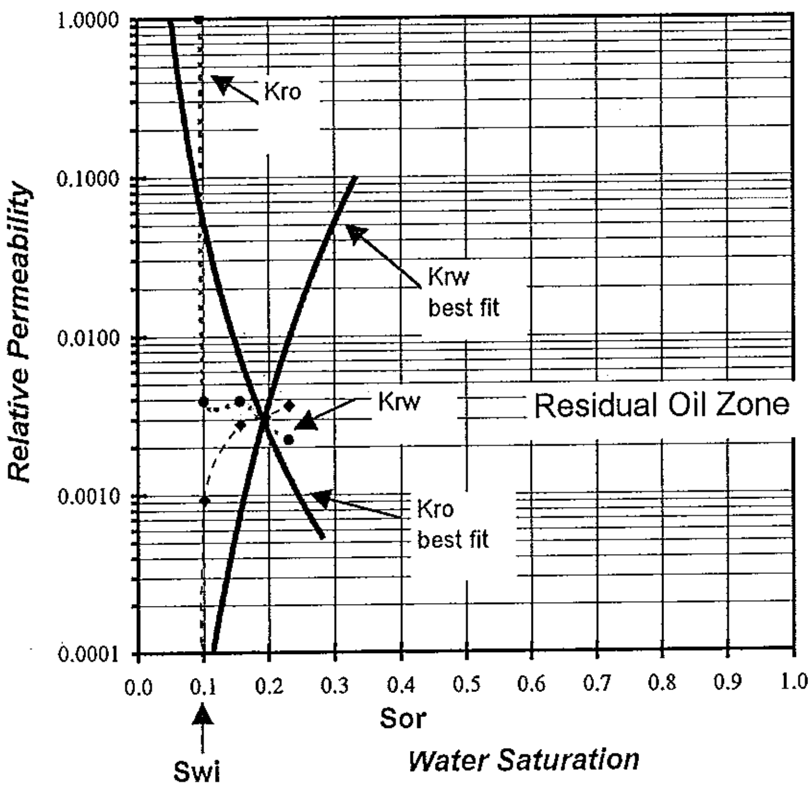

Figure M-2 Effect of Permeable Layer on Oil and Brine Permeability
Core plug sample no.2 : Effect of core plug water saturation on the oil and water relative permeabilities

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**2**
Porosity	**17.1 percent**
Initial Water Saturation	**9.5 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

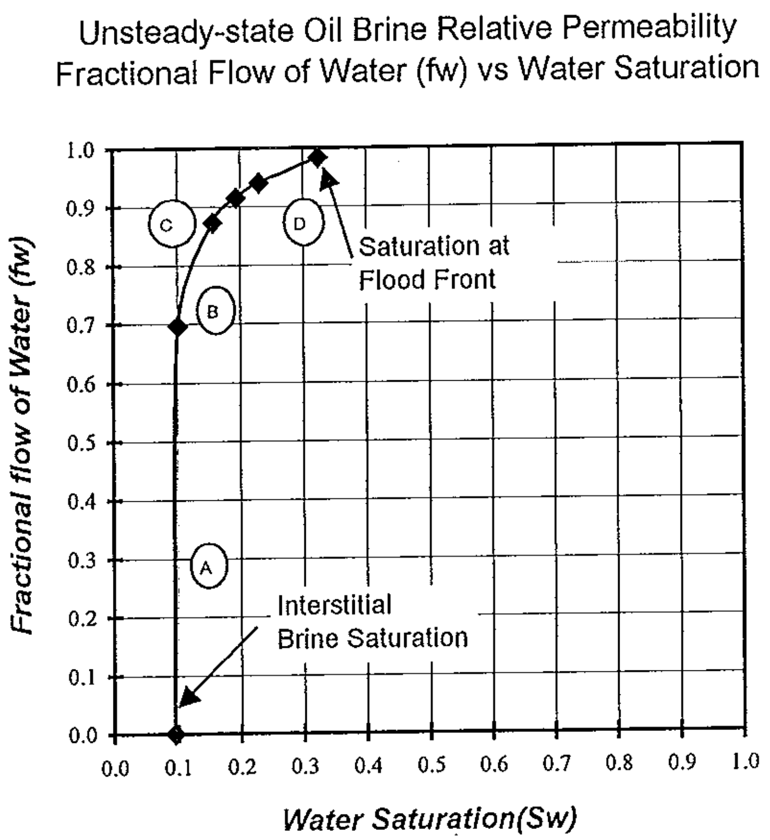

Figure M-3 Effect of water saturation of core plug 2 on the Fractional flow of water (fw) at reservoir temperature

WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**2**
Porosity	**17.1 percent**
Initial Water Saturation	**9.5 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

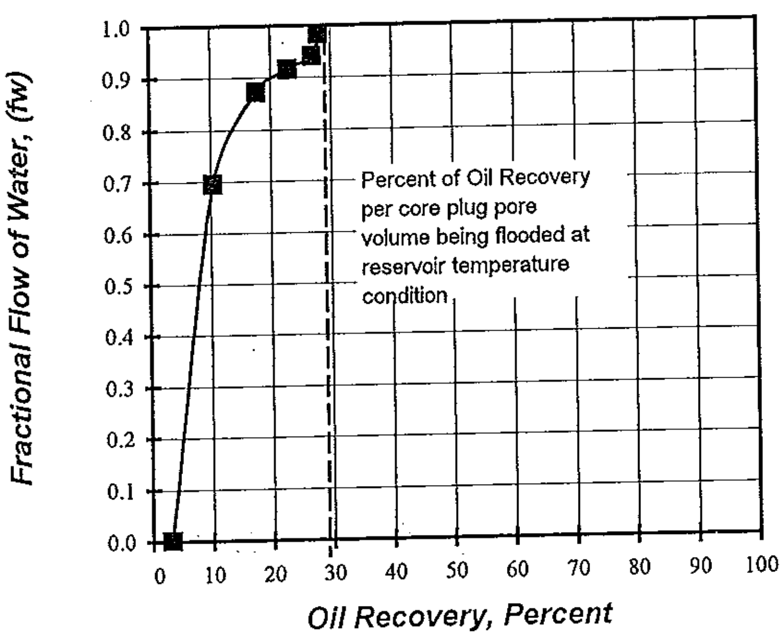

Figure M-4 Core plug sample no.2 : Percent of oil recovery against injected water under reservoir condition.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**2**
Porosity	**17.1 percent**
Initial Water Saturation	**9.5 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

Hot-water Flooding Performance
Oil Recovery vs Injected Hot Brine

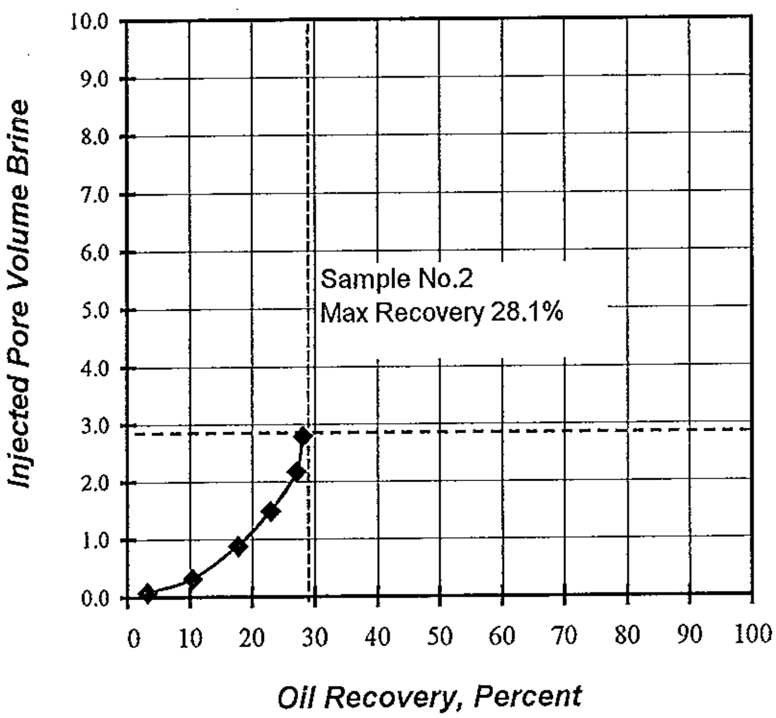

Figure M-5 Core plug sample no.2 : Oil recovery and Injected Water Relationship

Percent of crude oil recovery corresponeds to injected pore volume of water

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	3			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Depth		Ko @ Swi (mD)	150.1	*m =*	
				Swi (%)	8.73	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	181			Oil Viscosity @ 76C	9.644
Date	5 Apr 98	Porosity (%)	21.1	Length (cm)	4.8		
		Pore Volume (cc)	12.33	Diameter (cm)	3.8		
		Residual Oil Saturation (cc)	7.80	X-Sectional Area (cm^2)	11.341	Q @ Swir (cm^3/s)	0.050

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil *Recovery Percent*	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.50	0.90	90	1.00	9.64	0.40	0.40	3.70	0.50	0.90
7200.00	20.00	2.20	3.20	90	1.00	9.64	1.00	0.60	9.26	1.70	2.30
10800.00	20.00	6.90	8.70	90	1.00	9.64	1.80	0.80	16.67	4.70	5.50
14400.00	20.00	12.40	14.80	90	1.00	9.64	2.40	0.60	22.22	5.50	6.10
18000.00	20.00	19.20	22.00	90	1.00	9.64	2.80	0.40	25.93	6.80	7.20
21600.00	20.00	25.00	28.00	90	1.00	9.64	3.00	0.20	27.78	5.80	6.00

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.444	0.000	0.005	0.0	8.730	0.087	1.000	0.000	1.000	0.000	0.07	0.0
0.261	0.739	0.013	1.3	10.070	0.101	0.003	0.001	0.004	0.294	0.26	2.8
0.145	0.855	0.031	4.3	13.065	0.131	0.004	0.003	0.007	0.609	0.71	5.9
0.098	0.902	0.034	7.7	16.388	0.164	0.003	0.003	0.006	0.951	1.20	9.2
0.056	0.944	0.040	12.8	21.526	0.215	0.002	0.004	0.006	1.763	1.78	17.0
0.033	0.967	0.033	16.8	25.491	0.255	0.001	0.003	0.004	3.007	2.27	29.0

Table M-2 Relative Permeability Data Calculation, Plug Sample No.3

WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**3**
Porosity	**21.1 percent**
Initial Water Saturation	**8.7 percent**
Permeability to Air	**181 milliDarcy's**
Effective Oil Permeability	**150.1 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability

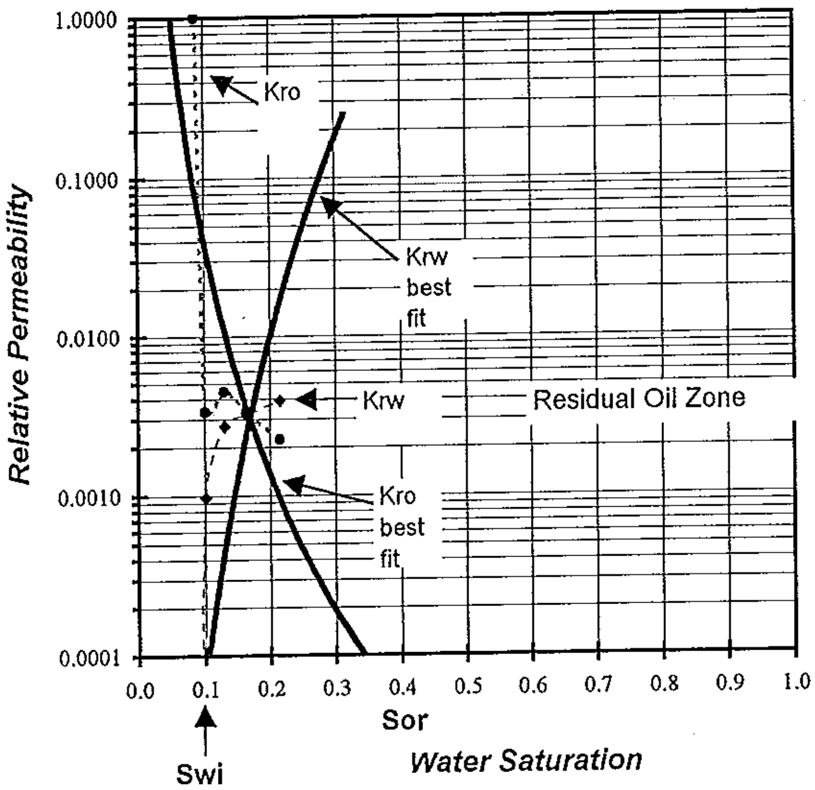

Figure M-6 Effect of Permeable Layer on Oil and Brine Permeability
Core plug sample no.3 : Effect of core plug water saturation on the oil and water relative permeabilities

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**3**
Porosity	**21.1 percent**
Initial Water Saturation	**8.7 percent**
Permeability to Air	**181 milliDarcy's**
Effective Oil Permeability	**150.1 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

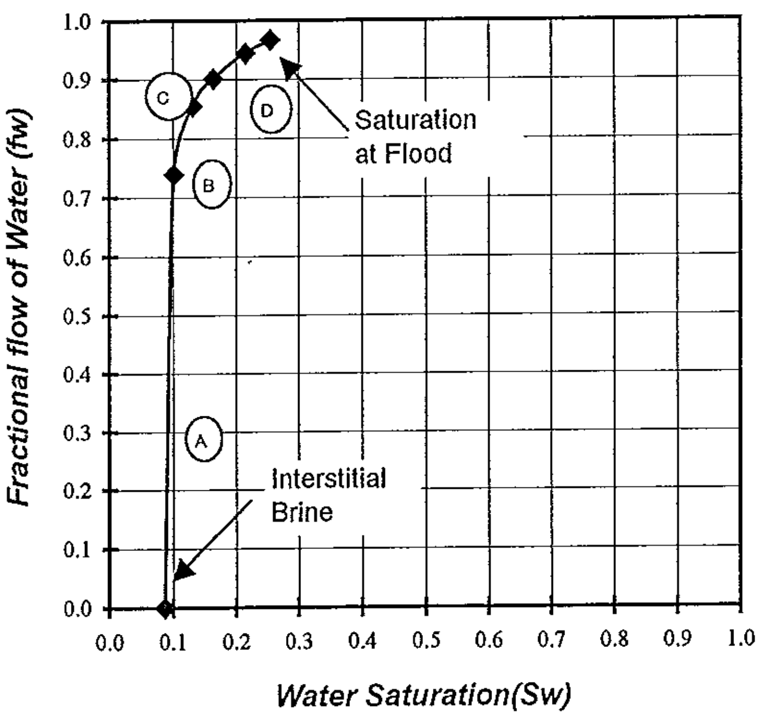

Figure M-7 Effect of water saturation of core plug 3 on the Fractional flow of water (fw) at reservoir temperature

WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**3**
Porosity	**21.1 percent**
Initial Water Saturation	**8.7 percent**
Permeability to Air	**181 milliDarcy's**
Effective Oil Permeability	**150.1 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

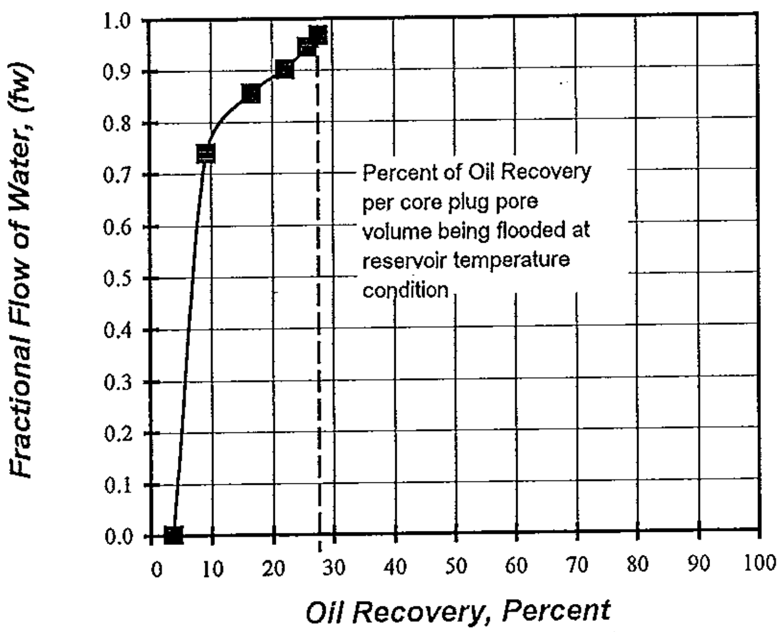

Figure M-8 Core plug sample no.3 : Percent of oil recovery against injected water under reservoir condition.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**3**
Porosity	**21.1 percent**
Initial Water Saturation	**8.7 percent**
Permeability to Air	**181 milliDarcy's**
Effective Oil Permeability	**150.1 milliDarcy's**

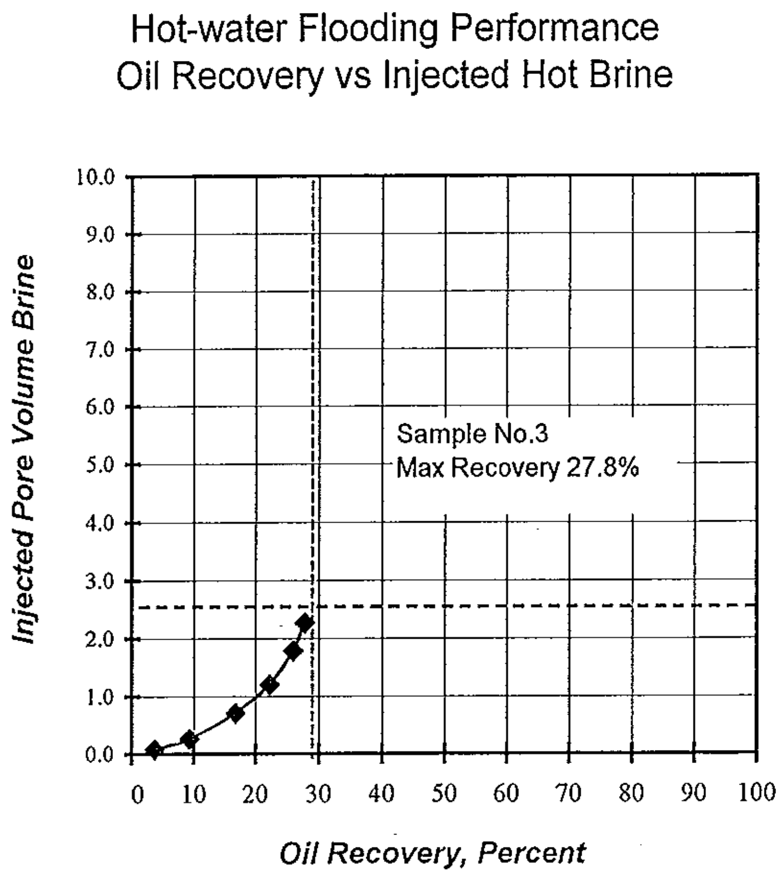

Figure M-9 Core plug sample no.3 : Oil Recovery and Injected Water Relationship

Percent of crude oil recovery corresponeds to injected pore volume of water

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information

Thesis Study	Hot-water Flooding Analysis
	Suphan Buri Oil Field
Analyst	Sombat Chunlasen
Date	5 Apr 98

Sample Information

Sample No	5	Ko @ Swi (mD)	151.0
Depth		Swi (%)	7.51
Air Permeability (mD)	182		
Porosity (%)	16.6	Length (cm)	4.91
Pore Volume (cc)	10.08	Diameter (cm)	3.74
Residual Oil Saturation (cc)	5.00	X-Sectional Area (cm^2)	10.986

Other Information

Oil Viscosity Equation	(y=mx+c)
m =	
c =	
Oil Viscosity @ 90C	6.477
Q @ Swir (cm^3/s)	0.071

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil *Recovery Percent*	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.40	1.20	90	1.00	6.48	0.80	0.80	8.00	0.40	1.20
7200.00	20.00	4.50	6.70	90	1.00	6.48	2.20	1.40	22.00	4.10	5.50
10800.00	20.00	10.00	13.50	90	1.00	6.48	3.50	1.30	35.00	5.50	6.80
14400.00	20.00	16.40	21.00	90	1.00	6.48	4.60	1.10	46.00	6.40	7.50
18000.00	20.00	23.20	28.10	90	1.00	6.48	4.90	0.30	49.00	6.80	7.10
21600.00	20.00	30.20	35.20	90	1.00	6.48	5.00	0.10	50.00	7.00	7.10

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.667	0.000	0.005	0.0	7.510	0.075	1.000	0.000	1.000	0.000	0.12	0.00
0.255	0.745	0.022	4.9	12.416	0.124	0.005	0.002	0.008	0.452	0.66	2.93
0.191	0.809	0.027	9.1	16.628	0.166	0.005	0.003	0.008	0.653	1.34	4.23
0.147	0.853	0.029	15.1	22.589	0.226	0.004	0.004	0.008	0.898	2.08	5.82
0.042	0.958	0.028	36.8	44.342	0.443	0.001	0.004	0.005	3.500	2.79	22.67
0.014	0.986	0.028	44.7	52.195	0.522	0.000	0.004		10.807	3.49	70.00

Table M-3 Relative Permeability Data Calculation, Plug Sample No.5

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**5**
Porosity	**16.6 percent**
Initial Water Saturation	**7.5 percent**
Permeability to Air	**182 milliDarcy's**
Effective Oil Permeability	**151.0 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Effect of Permeable Layer on Oil and Brine Permeability

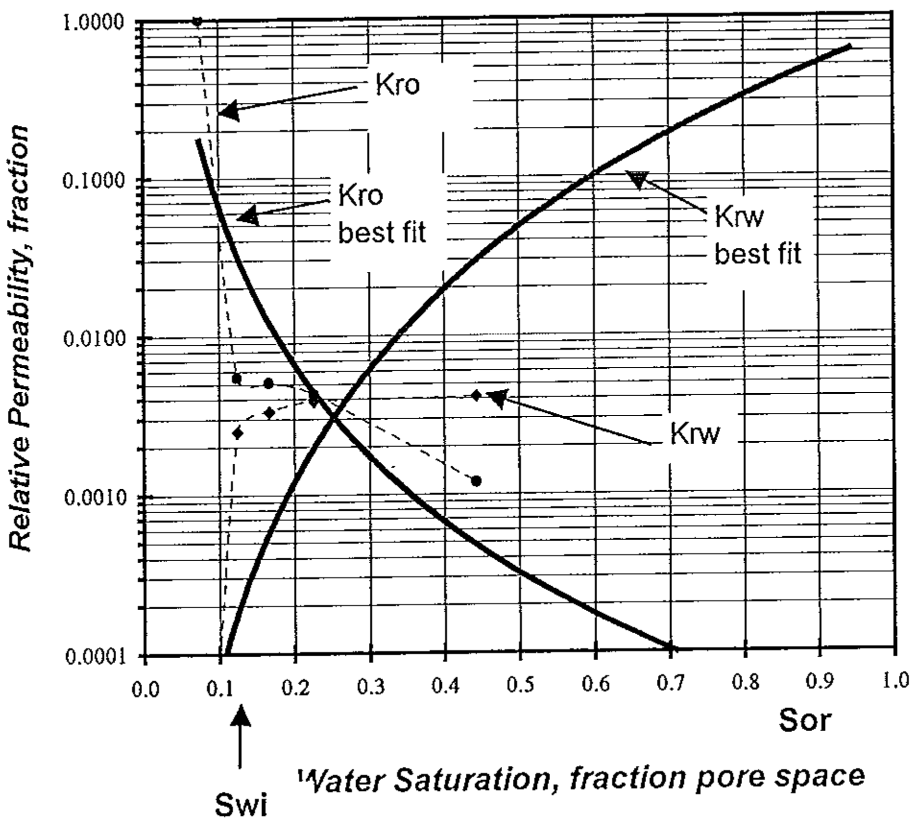

Figure M-10 Core plug sample no.5 : Relative Permeability and Water Saturation Relationship

The core plug condition started of having initial or connate water saturation of about 10 %. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, consequently reduces the relative permeability to oil. This results in decreasing oil production and on the other hand increasing water production. When the water saturation reaches 44%, relative permeability to oil reduced to 0.001 fraction of relative permeability and hardly any further oil flow. From this point onwards, the Kro best fit carries on to 70% water saturation, it represents Sor, residual oil saturation as the relative permeability is too low for oil to be injected out.

Kro is Relative Permeability to Oil and Krw is Relative Permeability to Water

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**5**
Porosity	**16.6 percent**
Initial Water Saturation	**7.5 percent**
Permeability to Air	**182 milliDarcy's**
Effective Oil Permeability	**151.0 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

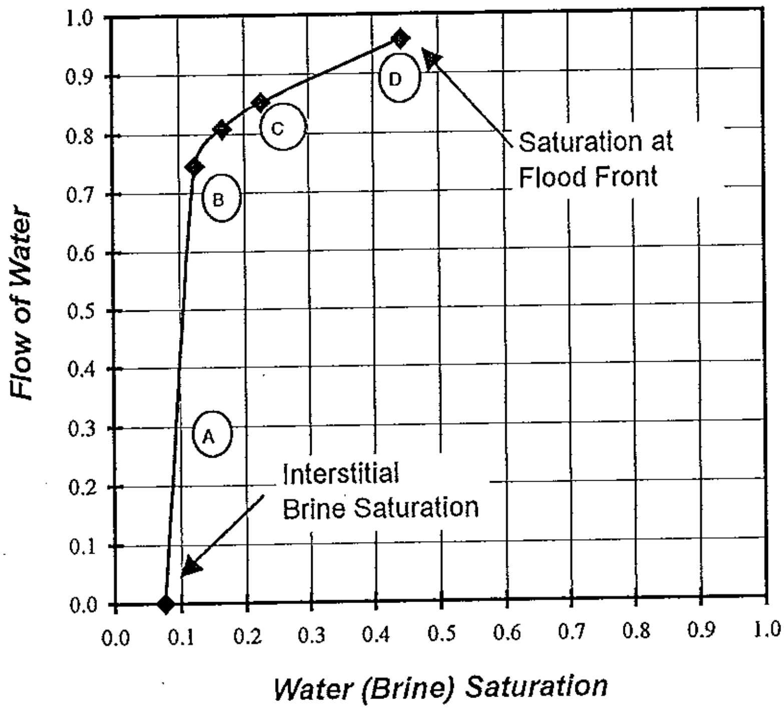

Figure M-11 Core plug sample no.5: Flow of Water and Water Saturation Relationship

The interstitial brine saturation, 0.08, the reservoir values or saturation conditions where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation till water breakthrough at B, 0.75 fraction

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**5**
Porosity	**16.6 percent**
Initial Water Saturation	**7.5 percent**
Permeability to Air	**182 milliDarcy's**
Effective Oil Permeability	**151.0 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

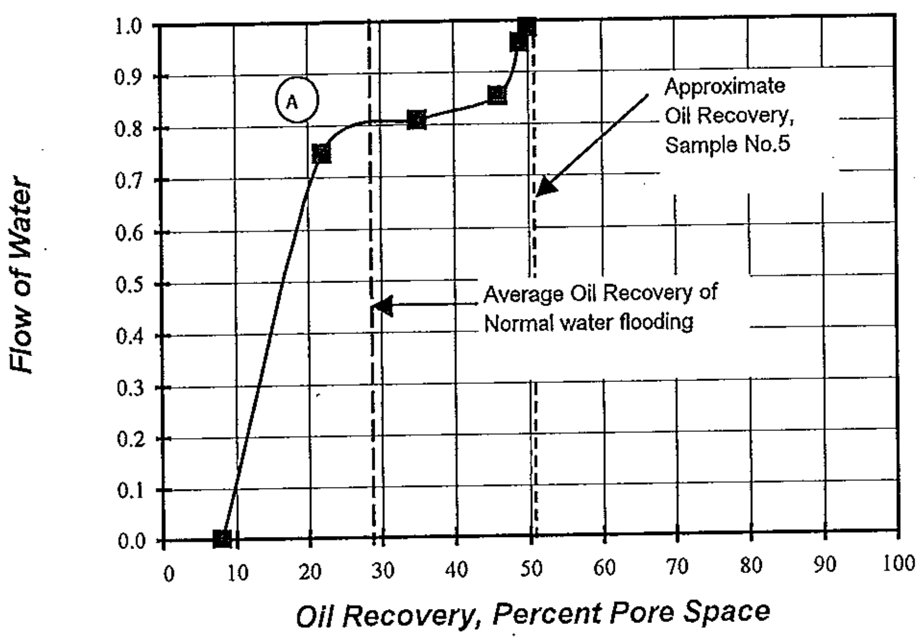

Figure M-12 Core plug sample no.5 : Crude Oil Recovery and Flow of Water Relationship

Hot-water flooding technique shows 50% crude oil recovery at 3.49 injected pore volume, compare to average 28% recovery when normal flooded at reservoir temperature. At 0.8 fractional flow of water, indicates the fine materials loosen off and causes abrupt flushing along the flow path. When crude oil recovery is getting close to 47-48%, the recovery decreases dued to flow path or pore throats are being blocked off by the suspended loosen materials. Along this stage, small amount of crude oil received and the injected brine keeps carrying on flowing.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**5**
Porosity	**16.6 percent**
Initial Water Saturation	**7.5 percent**
Permeability to Air	**182 milliDarcy's**
Effective Oil Permeability	**151.0 milliDarcy's**

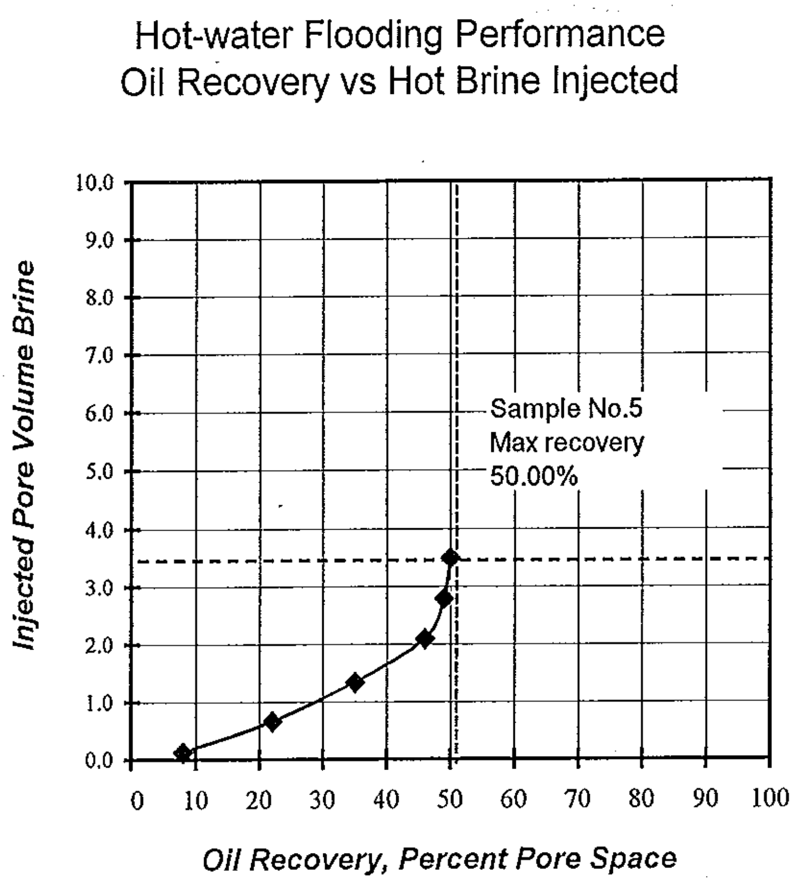

Figure M-13 Core plug sample no.5 : Effect of Crude Oil Recovery and Injected Hot-water

Crude oil recovery corresponding to injected brine has maximum recovery of 50.0% pore space.

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	6			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Depth		Ko @ Swi (mD)	145.0	*m* =	
				Swi (%)	7.302	*c* =	
Analyst	Sombat Chunlasen	Air Permeability (mD)	175			Oil Viscosity @ 90C	6.477
Date	5 Apr 98	Porosity (%)	16.3	Length (cm)	4.8		
		Pore Volume (cc)	9.92	Diameter (cm)	3.75		
		Residual Oil saturation (cc)	5.00	X-Sectional Area (cm^2)	11.045	Q @ Swir (cm^3/s)	0.070

Data Entry and Calculation

Cumulative Time (s)	ΔP (psi)	Cumu. Brine (cm^3)	Cumulative Oil & Brine (cm^3)	Temp (C)	Water Viscosity (cp)	Oil Viscosity (cp)	Cumu. Oil (cm^3)	Increm. Oil (cm^3)	Cumu. Oil Recovery Percent	Increm. Water (cm^3)	Increm. Oil & Water (cm^3)
3600.00	20.00	0.50	1.20	90	1.00	6.48	0.70	0.70	7.37	0.50	1.20
7200.00	20.00	4.60	6.80	90	1.00	6.48	2.20	1.50	23.16	4.10	5.60
10800.00	20.00	10.40	13.60	90	1.00	6.48	3.20	1.00	33.68	5.80	6.80
14400.00	20.00	18.80	23.10	90	1.00	6.48	4.30	1.10	45.26	8.40	9.50
18000.00	20.00	26.00	30.40	90	1.00	6.48	4.40	0.10	46.32	7.20	7.30
21600.00	20.00	34.50	39.00	90	1.00	6.48	4.50	0.10	47.37	8.50	8.60

Flowing Oil Fraction *fo*	Flowing Water Fraction *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.583	0.000	0.005	0.0	7.302	0.073	1.000	0.000	1.000	0.000	0.12	0.00
0.268	0.732	0.022	3.8	11.118	0.111	0.006	0.003	0.008	0.422	0.69	2.73
0.147	0.853	0.027	12.1	19.399	0.194	0.004	0.004	0.008	0.895	1.37	5.80
0.116	0.884	0.038	16.4	23.686	0.237	0.004	0.005	0.009	1.179	2.33	7.64
0.014	0.986	0.029	40.2	47.459	0.475	0.000	0.004	0.005	11.116	3.06	72.00
0.012	0.988	0.034	40.8	48.093	0.481	0.000	0.005		13.123	3.93	85.00

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis Suphan Buri Oil Field**
Sample Number	**6**
Porosity	**16.3 percent**
Initial Water Saturation	**7.3 percent**
Permeability to Air	**175 milliDarcy's**
Effective Oil Permeability	**145.0 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Effect of Permeable Layer on Oil and Brine
Permeability

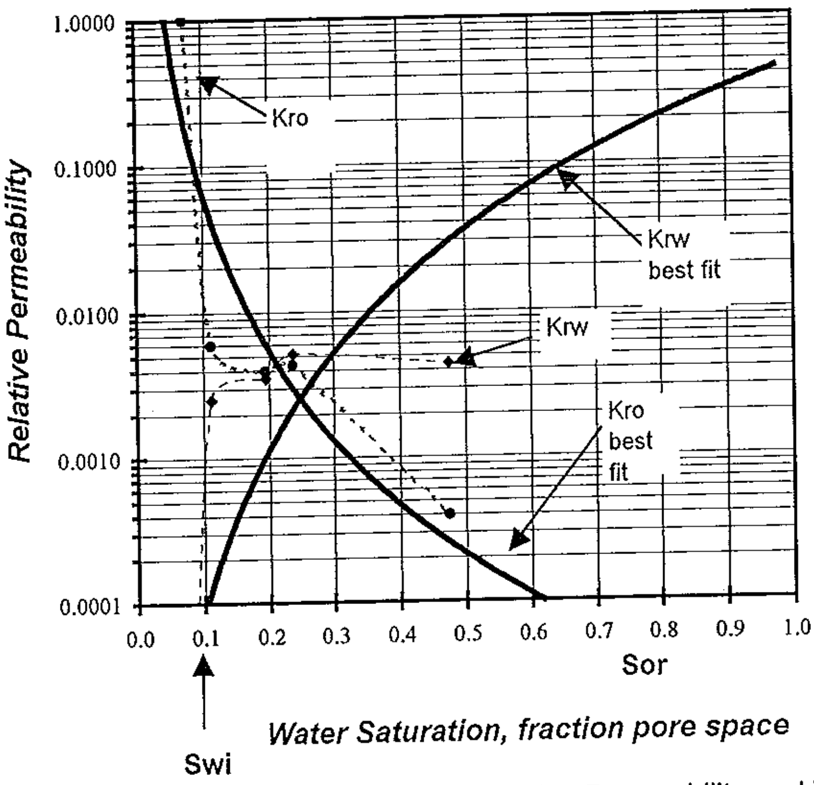

Figure M-14 Core plug sample no.6 : Relative Permeability and Water Saturation Relationship

Oil and water relative permeabilities plotted as functions of water saturation. The core plug condition started of having initial or connate water saturation of about 10 %. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, reduce the relative permeability to oil. This results in decreasing oil production and on the other hand, increasing water production. When the water saturation reaches 47%, relative permeability to oil reduced to 0.0004 fraction of relative permeability and hardly no further oil flow. From this point of Kro best fit to 60% water saturation, it represents, Sor, residual oil saturation as the relative permeability at 0.0001 to 0.001 will be too low for oil to flow.

Kro is Relative Permeability to Oil
Krw is Relative Permeability to Water
Sor is Residual Oil Saturation

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**6**
Porosity	**16.3 percent**
Initial Water Saturation	**7.3 percent**
Permeability to Air	**175 milliDarcy's**
Effective Oil Permeability	**145.0 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

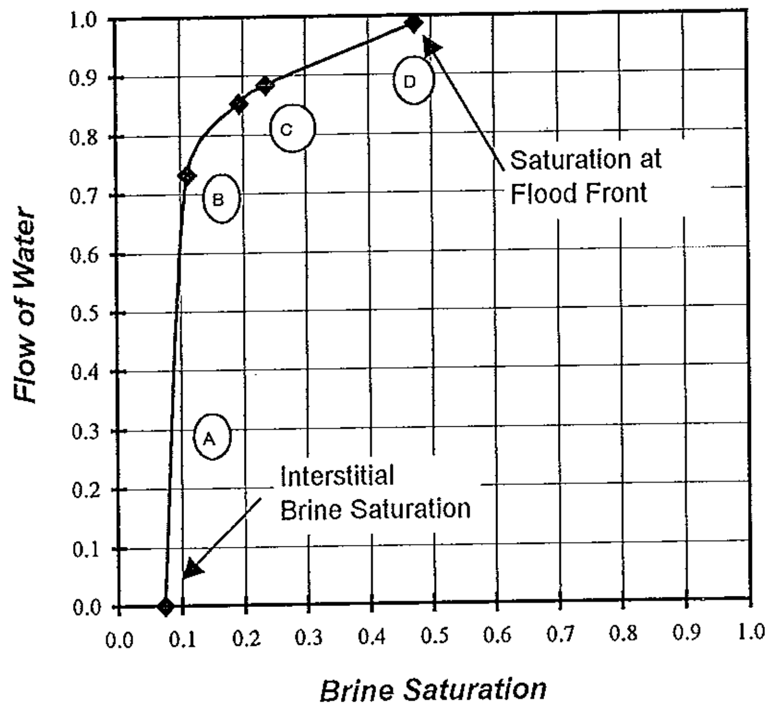

Figure M-15 Core plug sample no.6: Flow of Water and Water Saturation Relationship

At the interstitial brine saturation, 0.08, the reservoir values or saturation conditons where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation until water breakthrough at B, 0.75 fraction flow of water, which corresponds the water breakthrough on table at 0.69-1.37 injected pore volume. Water and crude are flushed out along C, and stopped at D.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**6**
Porosity	**16.3 percent**
Initial Water Saturation	**7.3 percent**
Permeability to Air	**175 milliDarcy's**
Effective Oil Permeability	**145.0 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

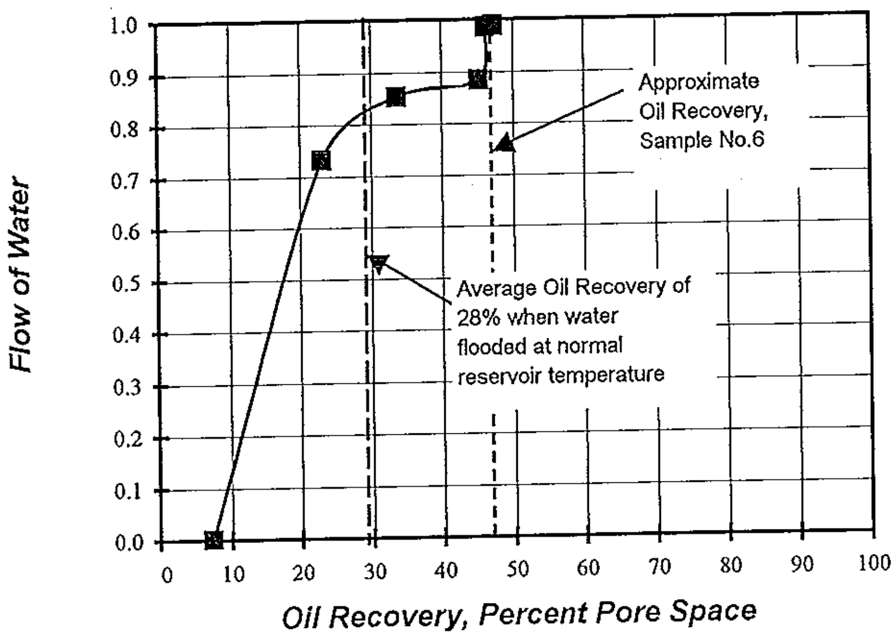

Figure M-16 Core plug sample no.6 : Crude Oil Recovery and Flow of Water Relationship

47.37% crude oil recovery compare to 28% recovery when normal water flooded at reservoir temperature. At 0.69 fractional flow of water, indicates the fine materials loosen off and caused abrupt flushing along the flow path. When crude oil recovery is getting close to 44%, the recovery decreased due to flow path or pore throats are being blocked off by suspended loosen materials. Along this point, only small amount of crude oil received and eventually hardly flow at 45 percent pore space.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**6**
Porosity	**16.3 percent**
Initial Water Saturation	**7.3 percent**
Permeability to Air	**175 milliDarcy's**
Effective Oil Permeability	**145.0 milliDarcy's**

Hot-water Flooding Performance
Oil Recovery vs Injected Hot Brine

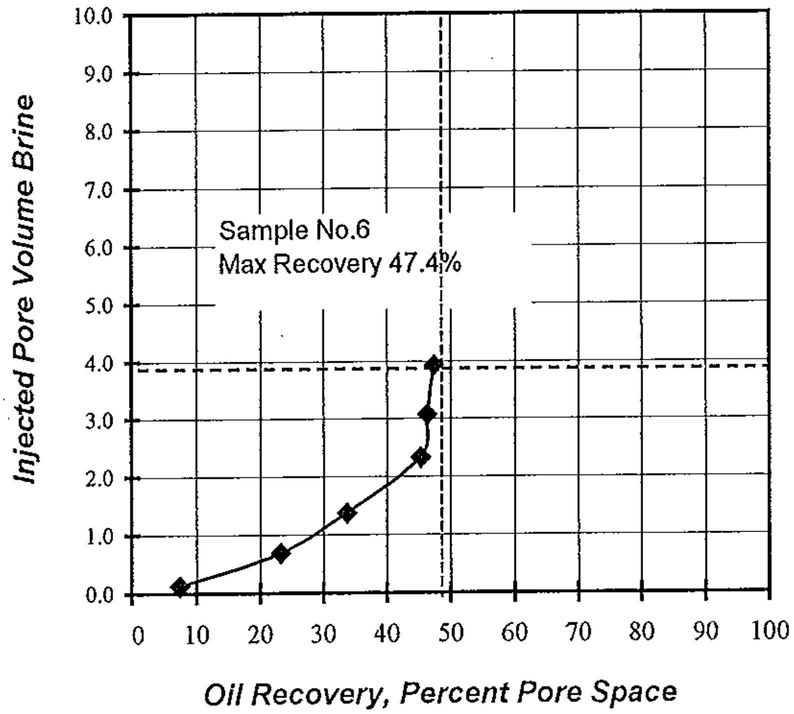

Figure M-17 Core plug sample no.6 : Oil Recovery and Injected Hot-water Relationship

Crude oil recovery corresponeds to injected brine and stops at around 47.4 % pore space. Injected hot-water exceeds 3.8 pore volume of the core plug will not produce any further crude recovery.

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information	
Thesis Study	Hot-water Flooding Analysis
	Suphan Buri Oil Field
Analyst	Sombat Chunlasen
Date	5 Apr 98

Sample Information			
Sample No	7		
Depth		Ko @ Swi (mD)	157.0
		Swi (%)	7.808
Air Permeability (mD)	189		
Porosity (%)	17.5	Length (cm)	4.81
Pore Volume (cc)	10.77	Diameter (cm)	3.76
Residual Oil Saturation (cc)	4.60	X-Sectional Area (cm^2)	11.104

Other Information	
Oil Viscosity Equation	(y=mx+c)
m =	
c =	
Oil Viscosity @ 90C	6.477
Q @ Swir (cm^3/s)	0.076

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil *Recovery Percent*	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.80	1.40	90	1.00	6.48	0.60	0.60	5.77	0.80	1.40
7200.00	20.00	4.40	7.00	90	1.00	6.48	2.60	2.00	25.00	3.60	5.60
10800.00	20.00	10.60	15.00	90	1.00	6.48	4.40	1.80	42.31	6.20	8.00
14400.00	20.00	21.00	26.50	90	1.00	6.48	5.50	1.10	52.88	10.40	11.50
18000.00	20.00	26.30	32.00	90	1.00	6.48	5.70	0.20	54.81	5.30	5.50
21600.00	20.00	39.60	45.40	90	1.00	6.48	5.80	0.10	55.77	13.30	13.40

Flowing Oil Fraction *fo*	Flowing Water Fraction *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.429	0.000	0.005	0.0	7.808	0.078	1.000	0.000	1.000	0.000	0.13	0.00
0.357	0.643	0.020	0.9	8.737	0.087	0.007	0.002	0.009	0.278	0.65	1.80
0.225	0.775	0.029	9.5	17.325	0.173	0.007	0.003	0.010	0.532	1.39	3.44
0.096	0.904	0.042	27.5	35.340	0.353	0.004	0.006	0.010	1.460	2.46	9.45
0.036	0.964	0.020	42.1	49.928	0.499	0.001	0.003	0.004	4.091	2.97	26.50
0.007	0.993	0.049	50.7	58.515	0.585	0.000	0.007		20.534	4.22	133.00

Table M-5 Relative Permeability Data Calculation, Plug Sample No.7

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**7**
Porosity	**17.5 percent**
Initial Water Saturation	**7.8 percent**
Permeability to Air	**189 milliDarcy's**
Effective Oil Permeability	**157.0 milliDarcy's**

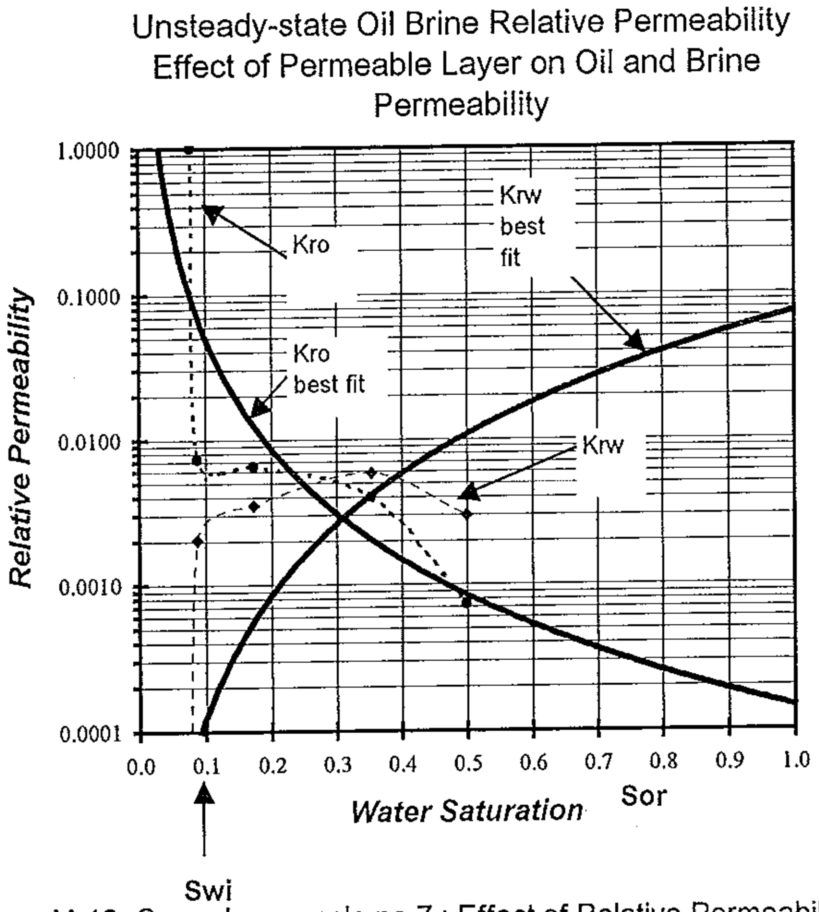

Figure M-18 Core plug sample no.7 : Effect of Relative Permeability and Water Saturation

The core plug condition started of having initial or connate water saturation of about 9%. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, would reduce the relative permeability to oil. This would results in decreasing oil production and on the other hand increasing water production. When the water saturation reaches 50%, relative permeability to oil reduced to 0.0008 fraction of relative permeability and hardly any further oil flow. From this point of Kro best fit to 100% water saturation, it represents Sor, residual oil saturation as the relative permeability at 0.0001 to 0.001 will be too low for oil to flow.

Kro is Relative Permeability to Oil
Krw Relative Permeability to Water
Swi is Initial Water Saturation
Sor is Residual Oil Saturation

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**7**
Porosity	**17.5 percent**
Initial Wäter Saturation	**7.8 percent**
Permeability to Air	**189 milliDarcy's**
Effective Oil Permeability	**157.0 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

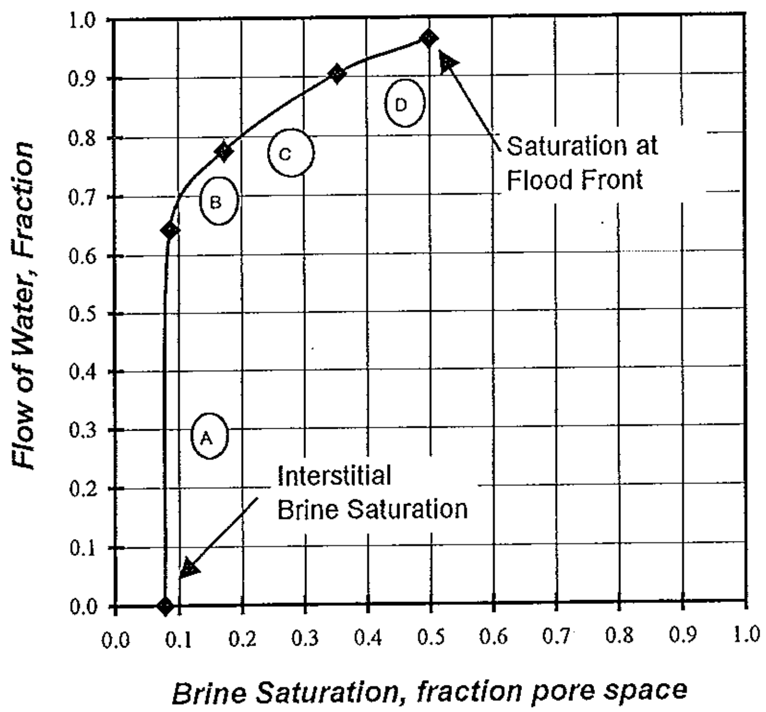

Figure M-19 Core plug sample no.7: Effective of Flow of Water and Water Saturation

At the interstitial brine saturation, 0.08, the reservoir values or saturation conditons where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation till water breakthrough at B, 0.75 fraction flow of water, which corresponds the water breakthrough on table at 0.65-1.39 injected pore volume. Water and crude are flushed out along C, and stopped at D.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**7**
Porosity	**17.5 percent**
Initial Water Saturation	**7.8 percent**
Permeability to Air	**189 milliDarcy's**
Effective Oil Permeability	**157.0 milliDarcy's**

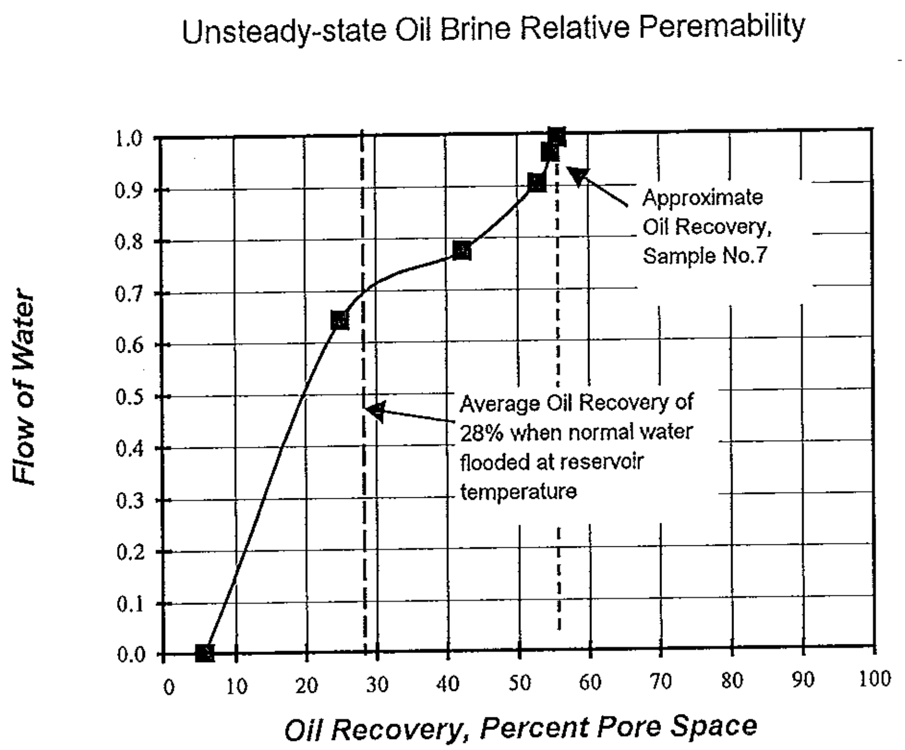

Figure M-20 Core plug sample no.7 : Crude Oil Recovery and Flow of Water Relationship

55.77% crude oil recovery compare to 28% recovery when the sample was normal water flooded at resevoir temperature. At 0.75 fractional flow of water, indicates the fine materials loosen off and caused abrupt flushing along the flow path. When crude oil recovery is getting close to 54%, the recovery gradually decreased due to flow path or pore throats are being blocked off by suspended loosen materials.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**7**
Porosity	**17.5 percent**
Initial Water Saturation	**7.8 percent**
Permeability to Air	**189 milliDarcy's**
Effective Oil Permeability	**157.0 milliDarcy's**

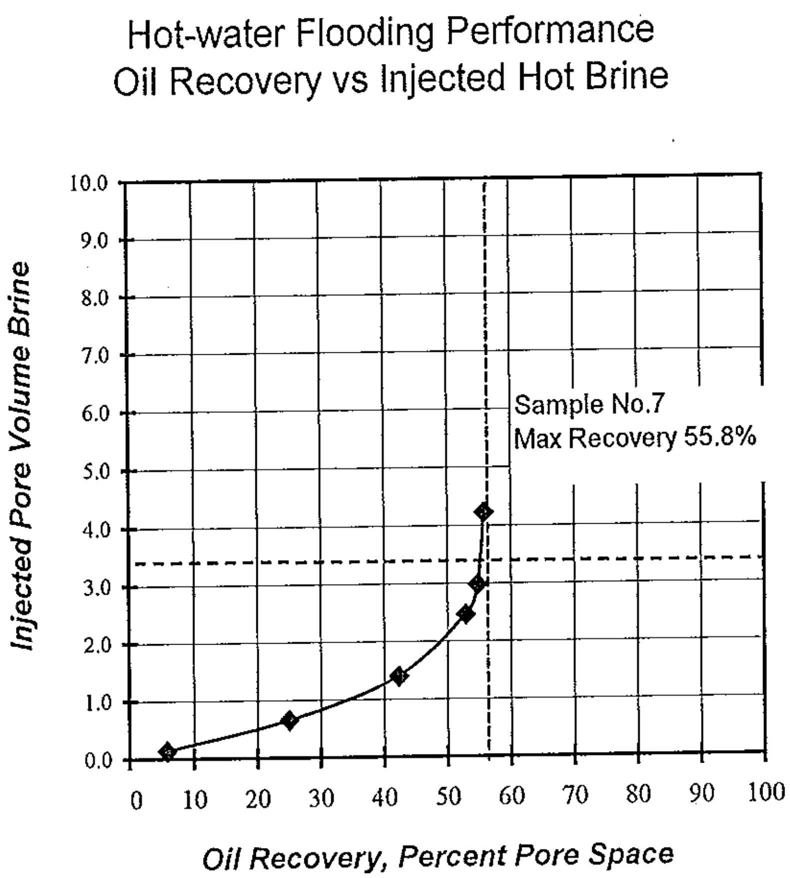

Figure M-21 Core plug sample no.7 : Crude Oil Recovery and Injected Hot-water Relationship

Crude oil recovery corresponeds to injected brine and stops at around 55.8 % pore space. No further recovery for hot-water flooding exceed over 3.2 pore volume.

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information

Thesis Study	Hot-water Flooding Analysis
	Suphan Buri Oil Field
Analyst	Sombat Chunlasen
Date	5 Apr 98

Sample Information

Sample No	8		
Depth		Ko @ Swi (mD)	149.3
		Swi (%)	6.745
Air Permeability (mD)	180		
Porosity (%)	15.4	Length (cm)	4.83
Pore Volume (cc)	10.63	Diameter (cm)	3.75
Residual Oil Saturation (cc)	3.70	X-Sectional Area (cm^2)	11.045

Other Information

Oil Viscosity Equation	(y=mx+c)
m =	
c =	
Oil Viscosity @ 90C	6.477
Q @ Swir (cm^3/s)	0.072

Data Entry and Calculation

Cumulative Time (s)	ΔP (psi)	Cumu. Brine (cm^3)	Cumulative Oil & Brine (cm^3)	Temp (C)	Water Viscosity (cp)	Oil Viscosity (cp)	Cumu. Oil (cm^3)	Increm. Oil (cm^3)	Cumu. Oil *Recovery Percent*	Increm. Water (cm^3)	Increm. Oil & Water (cm^3)
3600.00	20.00	0.90	1.40	90	1.00	6.48	0.50	0.50	5.68	0.90	1.40
7200.00	20.00	4.70	6.50	90	1.00	6.48	1.80	1.30	20.45	3.80	5.10
10800.00	20.00	11.00	14.50	90	1.00	6.48	3.50	1.70	39.77	6.30	8.00
14400.00	20.00	17.20	22.00	90	1.00	6.48	4.80	1.30	54.55	6.20	7.50
18000.00	20.00	23.00	28.00	90	1.00	6.48	5.00	0.20	56.82	5.80	6.00
21600.00	20.00	33.00	38.10	90	1.00	6.48	5.10	0.10	57.95	10.00	10.10

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.357	0.000	0.005	0.0	6.745	0.067	1.000	0.000	1.000	0.000	0.13	0.00
0.255	0.745	0.020	1.3	8.092	0.081	0.005	0.002	0.007	0.451	0.61	2.92
0.213	0.788	0.031	3.9	10.684	0.107	0.007	0.004	0.010	0.572	1.36	3.71
0.173	0.827	0.029	9.3	16.027	0.160	0.005	0.004	0.009	0.736	2.07	4.77
0.033	0.967	0.023	38.3	45.002	0.450	0.001	0.003	0.004	4.477	2.63	29.00
0.010	0.990	0.039	44.4	51.174	0.512	0.000	0.006		15.439	3.58	100.00

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis Suphan Buri Oil Field**
Sample Number	**8**
Porosity	**15.4 percent**
Initial Water Saturation	**6.7 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

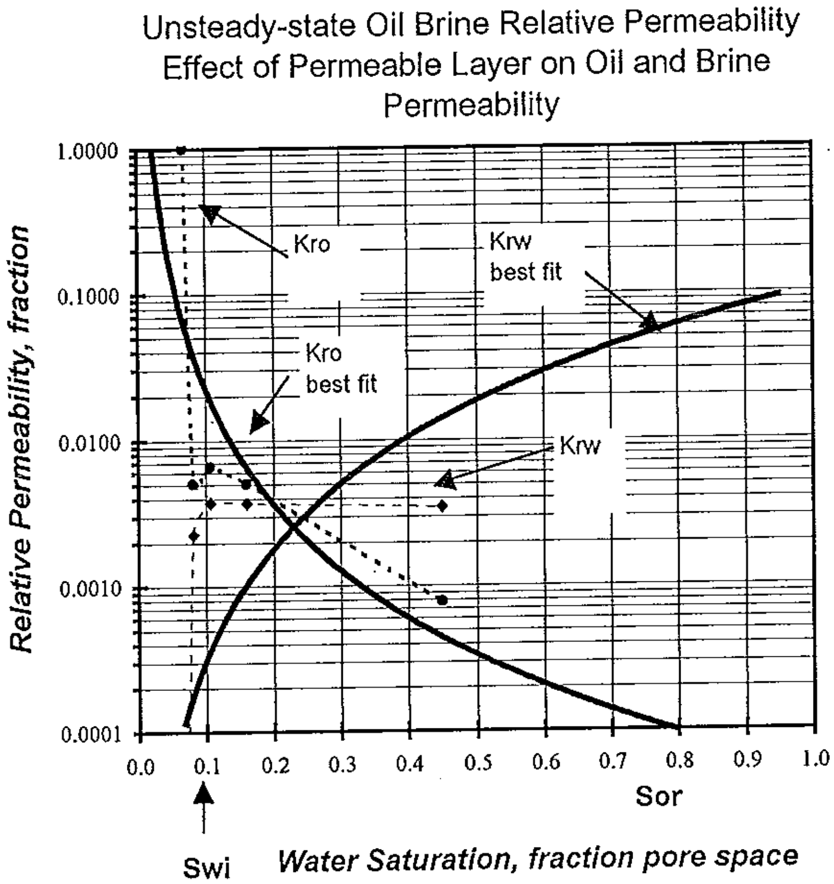

Figure M-22 Core plug sample no.8 : Effect of Relative Permeability and Water Saturation

The core plug condition started of having initial or connate water saturation of about 7 %. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, reduces the relative permeability to oil. This results in decreasing oil production and on the other hand increasing water production. When the water saturation reaches 47%, relative permeability to oil reduced to 0.0008 fraction of relative permeability and hardly any further oil flow. From this point of Kro best fit to 79% water saturation, it represents Sor, residual oil saturation and the relative permeability at 0.0001 to 0.001 will be too low for oil to flow.

Kro is Relative Permeability to Oil
Krw Relative Permeability to Water
Swi is Initial Water Saturation
Sor is Residual Oil Saturation

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**8**
Porosity	**15.4 percent**
Initial Water Saturation	**6.7 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

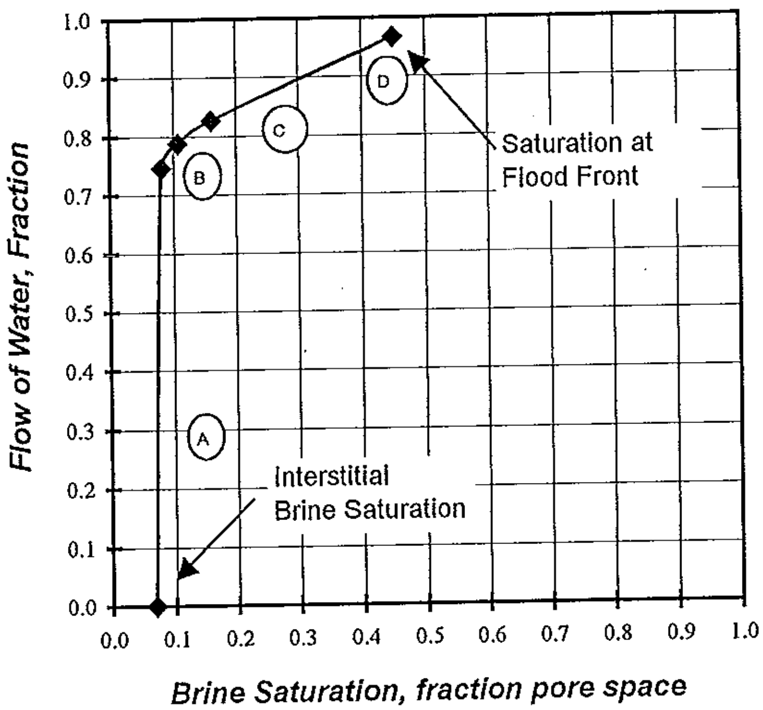

Figure M-23 Core plug sample no.8: Flow of Water and Water Saturation Relationship

At the interstitial brine saturation, 0.08, the reservoir values or saturation conditons where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation till water breakthrough at B, 0.77 fraction flow of water, which corresponds the water breakthrough on table at 0.61-1.36 injected pore volume. Water and crude are flushed out along C, and stopped at D.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**8**
Porosity	**15.4 percent**
Initial Water Saturation	**6.7 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

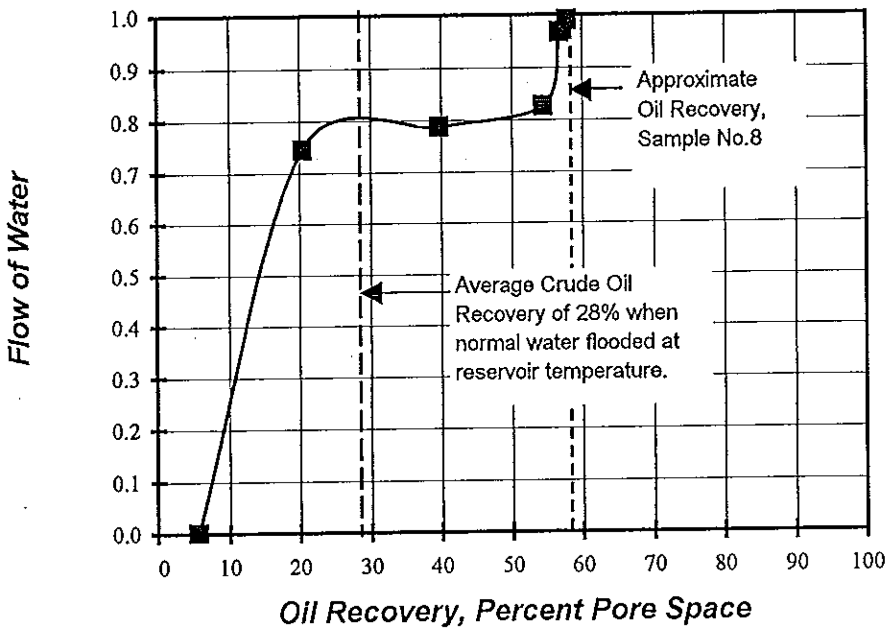

Figure M-24 Core plug sample no.8 : Crude Oil Recovery and Flow of Water Relationship

57.95% crude oil recovery compare to 28% recovery when normal water flooded at reservoir temperature. At 0.80 fractional flow of water, indicates the fine materials loosen off and caused abrupt flushing along the flow path. When crude oil recovery is getting close to 48%, the recovery decreased due to flow path or pore throats are being blocked off by suspended loosen materials. Along this point, only small amount of crude oil received and eventually hardly flow at 58 percent pore space.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**8**
Porosity	**15.4 percent**
Initial Water Saturation	**6.7 percent**
Permeability to Air	**180 milliDarcy's**
Effective Oil Permeability	**149.3 milliDarcy's**

Hot-water Flooding Performance
Oil Recovery vs Injected Hot Brine

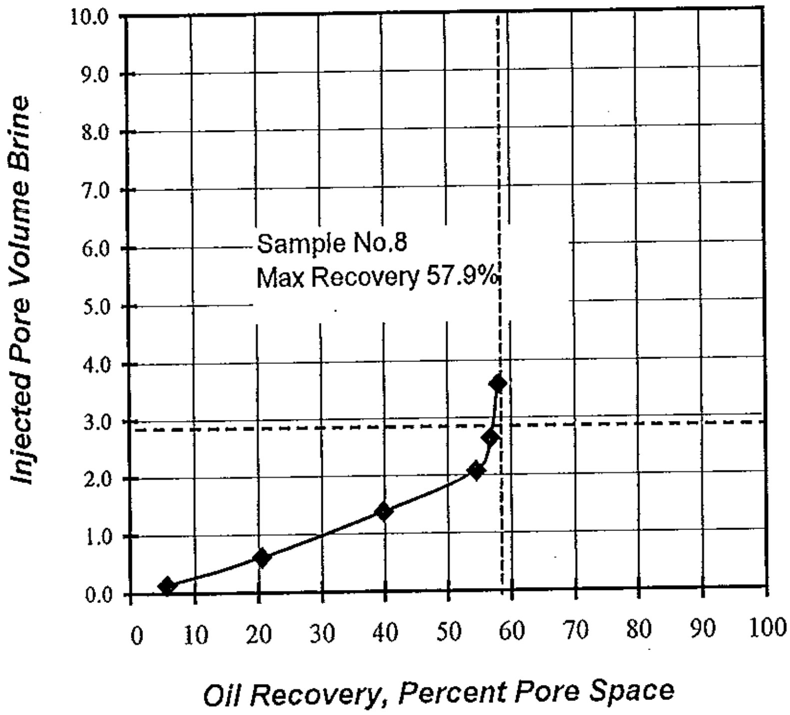

Figure M-25 Core plug sample no.8 : Oil Recovery and Injected Ho-water Relationship

Crude oil recovery corresponeds to injected brine and stops at around 57.9 % pore volume.

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	9			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Depth		Ko @ Swi (mD)	146.7	*m =*	
				Swi (%)	6.902	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	177			Oil Viscosity @ 90C	6.477
Date	5 Apr 98	Porosity (%)	15.5	Length (cm)	4.85		
		Pore Volume (cc)	8.7	Diameter (cm)	3.75		
		Residual Oil saturation (cc)	5.50	X-Sectional Area (cm^2)	11.045	Q @ Swir (cm^3/s)	0.070

Data Entry and Calculation

Cumulative Time (s)	ΔP (psi)	Cumu. Brine (cm^3)	Cumulative Oil & Brine (cm^3)	Temp (C)	Water Viscosity (cp)	Oil Viscosity (cp)	Cumu. Oil (cm^3)	Increm. Oil (cm^3)	Cumu. Oil *Recovery Percent*	Increm. Water (cm^3)	Increm. Oil & Water (cm^3)
3600.00	20.00	0.60	0.90	90	1.00	6.48	0.30	0.30	3.30	0.60	0.90
7200.00	20.00	3.20	4.30	90	1.00	6.48	1.10	0.80	12.09	2.60	3.40
10800.00	20.00	8.00	10.00	90	1.00	6.48	2.00	0.90	21.98	4.80	5.70
14400.00	20.00	15.50	18.50	90	1.00	6.48	3.00	1.00	32.97	7.50	8.50
18000.00	20.00	19.30	22.70	90	1.00	6.48	3.40	0.40	37.36	3.80	4.20
21600.00	20.00	25.40	29.00	90	1.00	6.48	3.60	0.20	39.56	6.10	6.30

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2* *(percent)*	Water Saturation *Sw* *(percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.333	0.000	0.004	0.0	6.902	0.069	1.000	0.000	1.000	0.000	0.10	0.00
0.235	0.765	0.013	1.0	7.916	0.079	0.003	0.002	0.005	0.502	0.49	3.25
0.158	0.842	0.023	4.8	11.742	0.117	0.004	0.003	0.006	0.823	1.15	5.33
0.118	0.882	0.034	9.5	16.368	0.164	0.004	0.005	0.009	1.158	2.13	7.50
0.095	0.905	0.017	14.2	21.133	0.211	0.002	0.002	0.004	1.467	2.61	9.50
0.032	0.968	0.025	30.8	37.699	0.377	0.001	0.004		4.709	3.33	30.50

Table M-7 Relative Permeability Data Calculation, Plug Sample no.9

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis Suphan Buri Oil Field**
Sample Number	**9**
Porosity	**15.5 percent**
Initial Water Saturation	**6.9 percent**
Permeability to Air	**177 milliDarcy's**
Effective Oil Permeability	**146.7 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Effect of Permeable Layer on Oil and Brine
Permeability

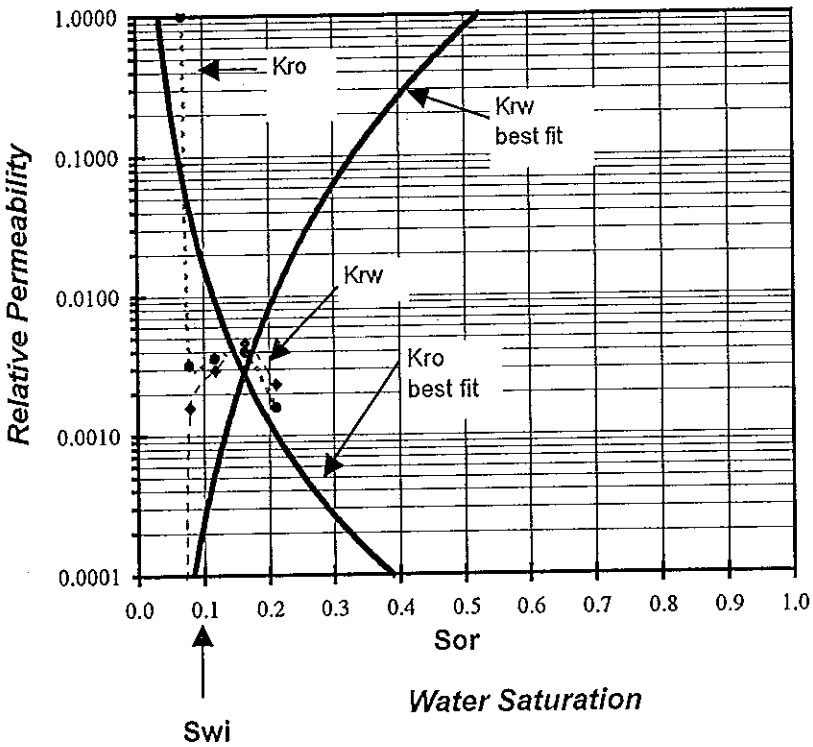

Figure M-26 Core plug sample no.9 : Effect of Relative Permeability and water Saturation

The core plug condition started of having initial or connate water saturation of about 8 %. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, consequently reduces the relative permeability to oil. This results in decreasing oil production and on the other hand increasing water production. When the water saturation reaches 23%, relative permeability to oil reduced to 0.0015 fraction of relative permeability and hardly no further oil flow. From this point of Kro best fit to 42% water saturation, it represents Sor, residual oil saturation as the relative permeability at 0.0001 to 0.001 will be too low for oil to flow.

Kro is Relative Permeability to Oil
Krw Relative Permeability to Water
Swi is Initial Water Saturation
Sor is Residual Oil Saturation

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**9**
Porosity	**15.5 percent**
Initial Water Saturation	**6.9 percent**
Permeability to Air	**177 milliDarcy's**
Effective Oil Permeability	**146.7 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

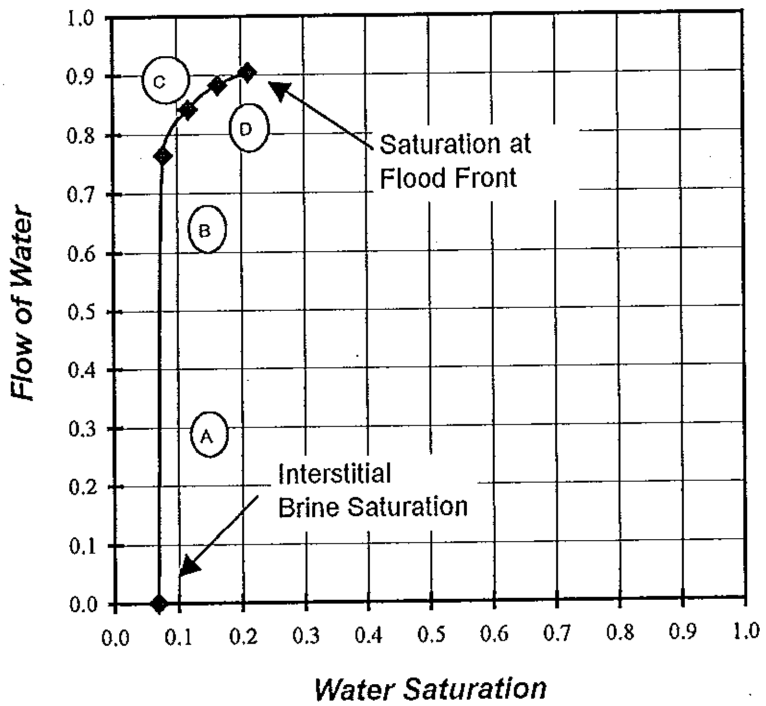

Figure M-27 Core plug sample no.9: Effective of Flow of Water and Water Saturation

At the interstitial brine saturation, 0.08, the reservoir values or saturation conditons where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation till water breakthrough at B, 0.75 fraction flow of water, which corresponds the water breakthrough on table at 0.49-1.15 injected pore volume. Water and crude are flushed out along C, and stopped at D.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**9**
Porosity	**15.5 percent**
Initial Water Saturation	**6.9 percent**
Permeability to Air	**177 milliDarcy's**
Effective Oil Permeability	**146.7 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

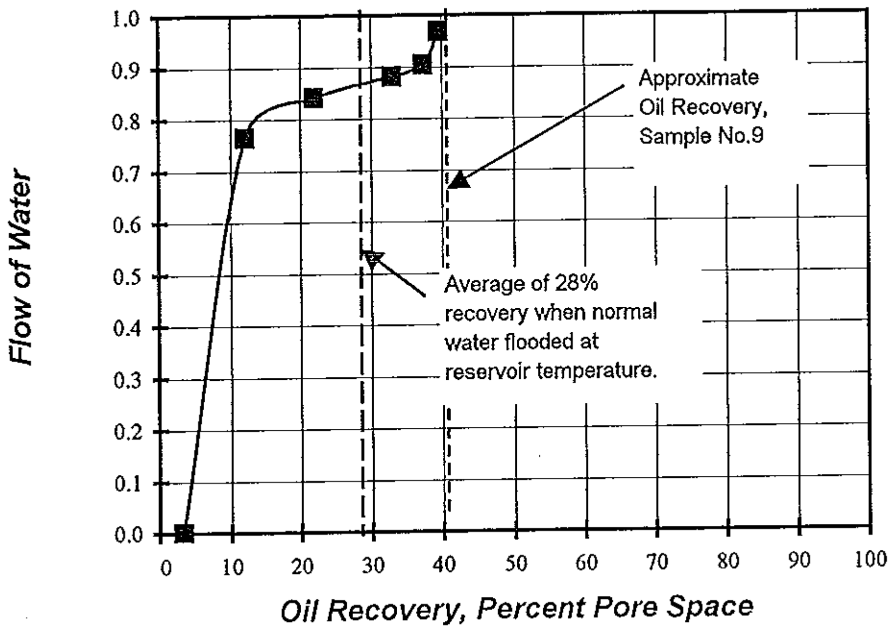

Figure M-28 Core plug sample no.9 : Crude Oil Recovery and Flow of Water Relationship

39.56% crude oil recovery compare to 28% recovery when water flooded at reservoir temperature. At 0.75 fractional flow of water, indicates the fine materials loosen off and caused abrupt flushing along the flow path. The flow stops at low flood front at close to 40% recovery. Only small amount of additional crude oil received beyond this point.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**9**
Porosity	**15.5 percent**
Initial Water Saturation	**6.9 percent**
Permeability to Air	**177 milliDarcy's**
Effective Oil Permeability	**146.7 milliDarcy's**

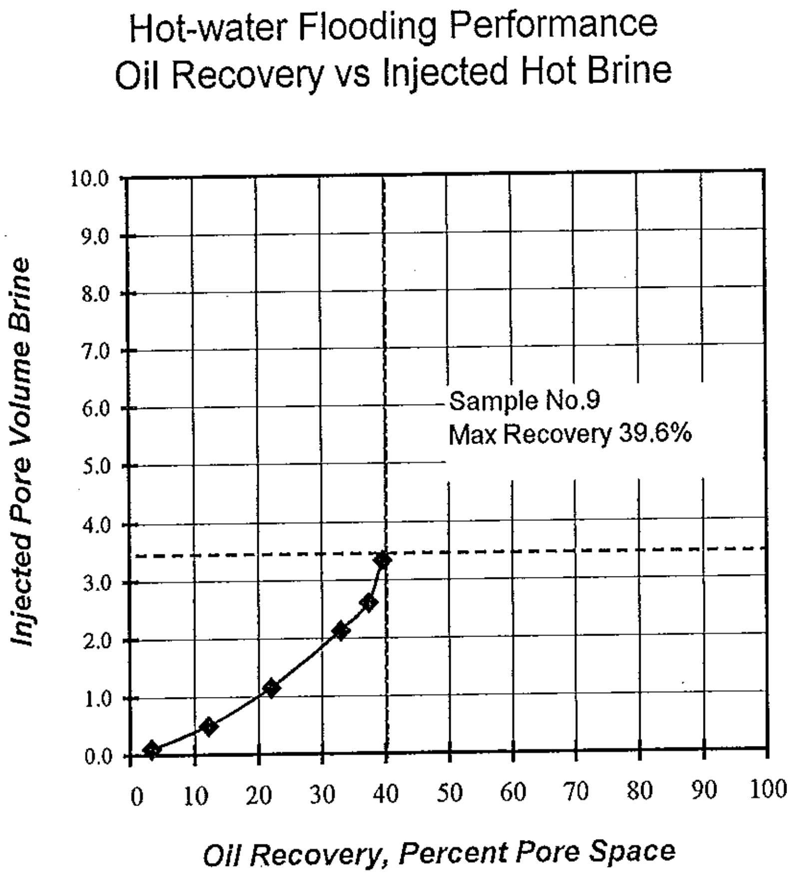

Figure M-29 Core plug sample no.9 : Oil Recovery and Injected Hot-water Relationship

Crude oil recovery corresponeds to injected brine and stops at around 39.56% pore space.

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	10			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Depth		Ko @ Swi (mD)	139.9	*m =*	
				Swi (%)	7.216	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	169			Oil Viscosity @ 90C	6.477
Date	5 Apr 98	Porosity (%)	15.5	Length (cm)	4.85		
		Pore Volume (cc)	9.19	Diameter (cm)	3.75		
		Residual Oil Saturation (cc)	4.50	X-Sectional Area (cm^2)	11.045	Q @ Swir (cm^3/s)	0.067

Data Entry and Calculation

Cumulative Time *(s)*	ΔP *(psi)*	Cumu. Brine *(cm^3)*	Cumulative Oil & Brine *(cm^3)*	Temp *(C)*	Water Viscosity *(cp)*	Oil Viscosity *(cp)*	Cumu. Oil *(cm^3)*	Increm. Oil *(cm^3)*	Cumu. Oil *Recovery Percent*	Increm. Water *(cm^3)*	Increm. Oil & Water *(cm^3)*
3600.00	20.00	0.65	1.30	90	1.00	6.48	0.65	0.65	6.70	0.65	1.30
7200.00	20.00	4.30	6.50	90	1.00	6.48	2.20	1.55	22.68	3.65	5.20
10800.00	20.00	9.50	13.30	90	1.00	6.48	3.80	1.60	39.18	5.20	6.80
14400.00	20.00	16.50	21.10	90	1.00	6.48	4.60	0.80	47.42	7.00	7.80
18000.00	20.00	23.40	28.10	90	1.00	6.48	4.70	0.10	48.45	6.90	7.00
21600.00	20.00	29.10	34.30	90	1.00	6.48	5.20	0.50	53.61	5.70	6.20

Flowing Oil Fraction *fo*	Flowing ater Fractio *fw*	Relative Injectivity *Ir*	Water Saturation *S2 (percent)*	Water Saturation *Sw (percent)*	Water Saturation *fraction*	Relative Perm to Oil *Kro*	Relative Perm to Water *Krw*	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.500	0.000	0.005	0.0	7.216	0.072	1.000	0.000	1.000	0.000	0.14	0.00
0.298	0.702	0.022	2.9	10.072	0.101	0.006	0.002	0.009	0.364	0.71	2.35
0.235	0.765	0.028	7.3	14.513	0.145	0.007	0.003	0.010	0.502	1.45	3.25
0.103	0.897	0.032	26.5	33.722	0.337	0.003	0.004	0.008	1.351	2.30	8.75
0.014	0.986	0.029	46.8	53.990	0.540	0.000	0.004	0.005	10.653	3.06	69.00
0.081	0.919	0.026	26.5	33.700	0.337	0.002	0.004	0.006	1.760	3.73	11.40

Table M-8 Relative Permeability Data Calculation, Plug Sample No.10

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**10**
Porosity	**15.5 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**169 milliDarcy's**
Effective Oil Permeability	**139.9 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Effect of Permeable Layer on Oil and Brine Permeability

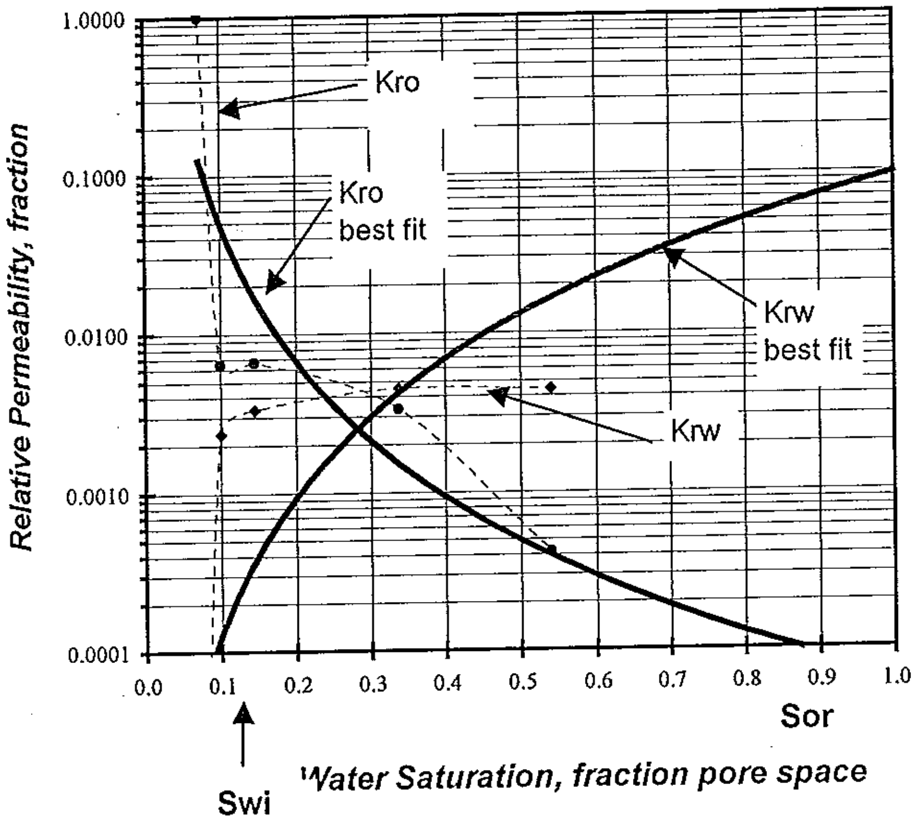

Figure M-30 Core plug sample no.10 : shows the oil and water relative permeabilities plotted as functions of water saturation. The relative permeability is a function of cumulative injection as other variables. The core plug condition started of having initial or connate water saturation of about 8 %. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, would reduce the relative permeability to oil. This would results in decreasing oil production and on the other hand increasing water production. When the water saturation reaches 53%, relative permeability to oil reduced to 0.0003 fraction of relative permeability and hardly any further oil flow. From this point onwards, the Kro best fit carries on to over 85% water saturation, it represents Sor, residual oil saturation as the relative permeability is too low for oil to be injected out.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**10**
Porosity	**15.5 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**169 milliDarcy's**
Effective Oil Permeability	**139.9 milliDarcy's**

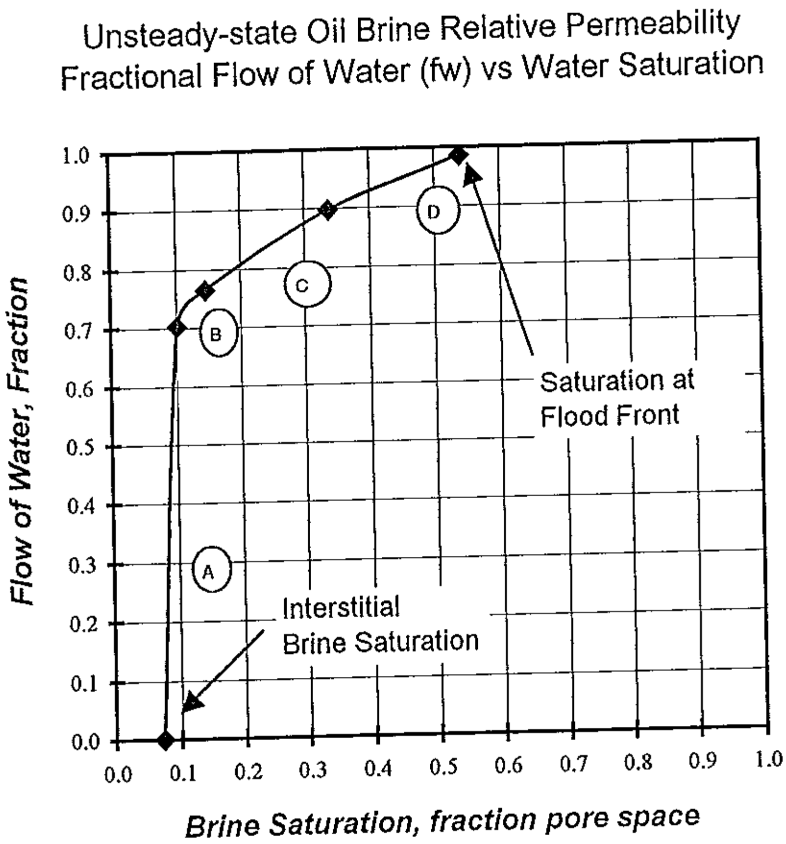

Figure M-31 Core plug sample no.10: at the interstitial brine saturation, 0.08, the reservoir values or saturation conditions where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation till water breakthrough at B, 0.75 fraction flow of water, which corresponds the water breakthrough on table at 0.71-1.45 injected pore volume. Water and crude are flushed out along C, and stopped at D.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**10**
Porosity	**15.5 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**169 milliDarcy's**
Effective Oil Permeability	**139.9 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

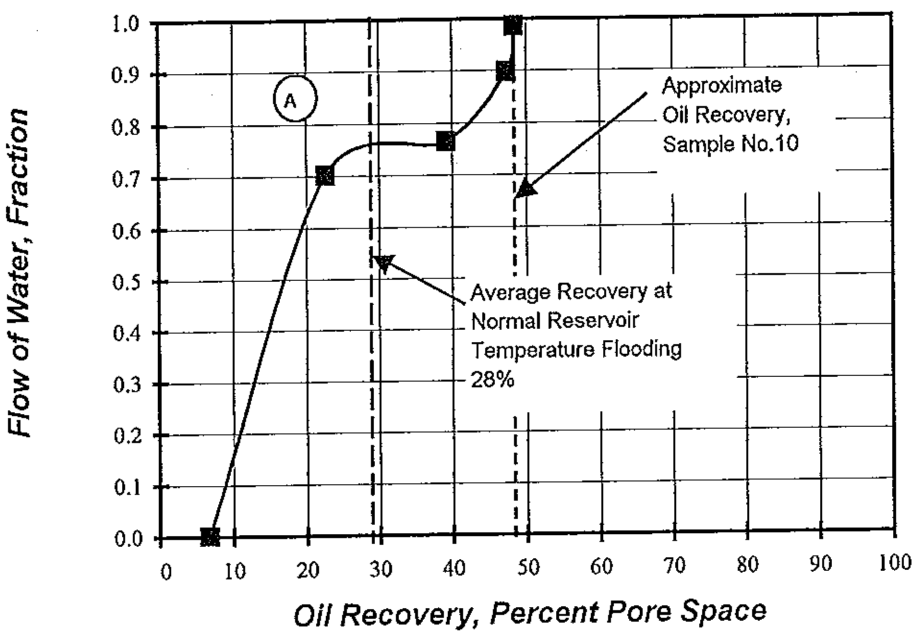

Figure M-32 Core plug sample no.10 : hot-water flooding technique shows 53.61% crude oil recovery compare to normal recovery 28%. At 0.8 fractional flow of water, indicates the fine materials loosen off and causes abrupt flushing along the flow path. When crude oil recovery is getting close to 52%, the recover decreases dued to flow path or pore throats are being blocked off by the suspended loosen materials. Along this stage, small amount of crude oil received and the injected brine keeps carrying on flowing.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**10**
Porosity	**15.5 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**169 milliDarcy's**
Effective Oil Permeability	**139.9 milliDarcy's**

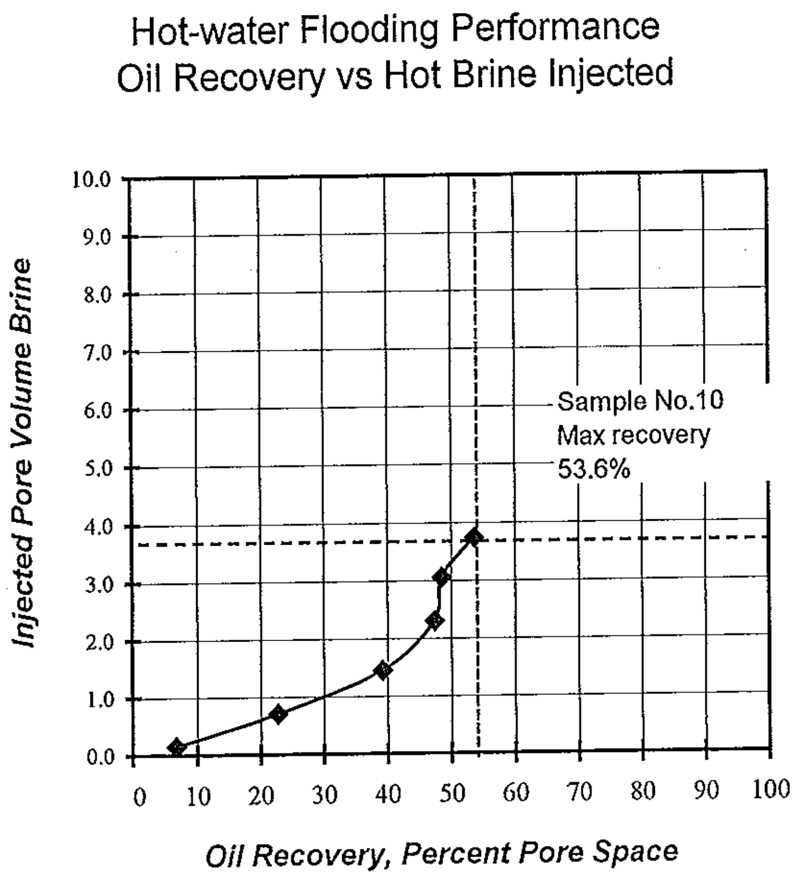

Figure M-33 Core plug sample no.10 : crude oil recovery corresponding to injected brine has maximum recovery of 53.6% pore space. Maximum injected hot-water should not exceed 3.7 pore volume of the core plug because any excess injected hot-water will not produce any higher crude recovery.

UNSTEADY STATE WATER OIL RELATIVE PERMEABILITY - DATA ENTRY AND CALCULATION

Job Information		Sample Information				Other Information	
Thesis Study	Hot-water Flooding Analysis	Sample No	11			*Oil Viscosity Equation*	(y=mx+c)
	Suphan Buri Oil Field	Depth		Ko @ Swi (mD)	148.4	*m =*	
				Swi (%)	7.165	*c =*	
Analyst	Sombat Chunlasen	Air Permeability (mD)	179			Oil Viscosity @ 90C	6.477
Date	5 Apr 98	Porosity (%)	15.6	Length (cm)	4.8		
		Pore Volume (cc)	9.05	Diameter (cm)	3.75		
		Residual Oil Saturation (cc)	7.00	X-Sectional Area (cm^2)	11.045	Q @ Swir (cm^3/s)	0.072

Data Entry and Calculation

Cumulative Time (s)	ΔP (psi)	Cumu. Brine (cm^3)	Cumulative Oil & Brine (cm^3)	Temp (C)	Water Viscosity (cp)	Oil Viscosity (cp)	Cumu. Oil (cm^3)	Increm. Oil (cm^3)	Cumu. Oil Recovery Percent	Increm. Water (cm^3)	Increm. Oil & Water (cm^3)
3600.00	20.00	1.00	2.20	90	1.00	6.48	1.20	1.20	12.37	1.00	2.20
7200.00	20.00	9.00	11.00	90	1.00	6.48	2.00	0.80	20.62	8.00	8.80
10800.00	20.00	23.60	26.00	90	1.00	6.48	2.40	0.40	24.74	14.60	15.00
14400.00	20.00	29.50	32.00	90	1.00	6.48	2.50	0.10	25.77	5.90	6.00
18000.00	20.00	47.90	50.50	90	1.00	6.48	2.60	0.10	26.80	18.40	18.50
21600.00	20.00	67.70	70.40	90	1.00	6.48	2.70	0.10	27.84	19.80	19.90

Flowing Oil Fraction fo	Flowing ater Fractio fw	Relative Injectivity Ir	Water Saturation S2 (percent)	Water Saturation Sw (percent)	Water Saturation fraction	Relative Perm to Oil Kro	Relative Perm to Water Krw	Kro + Krw	Water/Oil Relative Perm Ratio	Cumul. Injected Brine Pore Volume	Mobility Ratio
0.545	0.000	0.009	0.0	7.165	0.072	1.000	0.000	1.000	0.000	0.24	0.00
0.091	0.909	0.034	11.0	18.215	0.182	0.003	0.005	0.008	1.544	1.22	10.00
0.027	0.973	0.058	18.9	26.023	0.260	0.002	0.009	0.010	5.635	2.87	36.50
0.017	0.983	0.023	21.7	28.896	0.289	0.000	0.004	0.004	9.109	3.54	59.00
0.005	0.995	0.072	25.7	32.878	0.329	0.000	0.011	0.011	28.408	5.58	184.00
0.005	0.995	0.077	25.9	33.090	0.331	0.000	0.012		30.570	7.78	198.00

Table M-9 Relative Permeability Data Calculation, Plug Sample No.11

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**11**
Porosity	**15.6 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**179 milliDarcy's**
Effective Oil Permeability	**148.4 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Effect of Permeable Layer on Oil and Brine Permeability

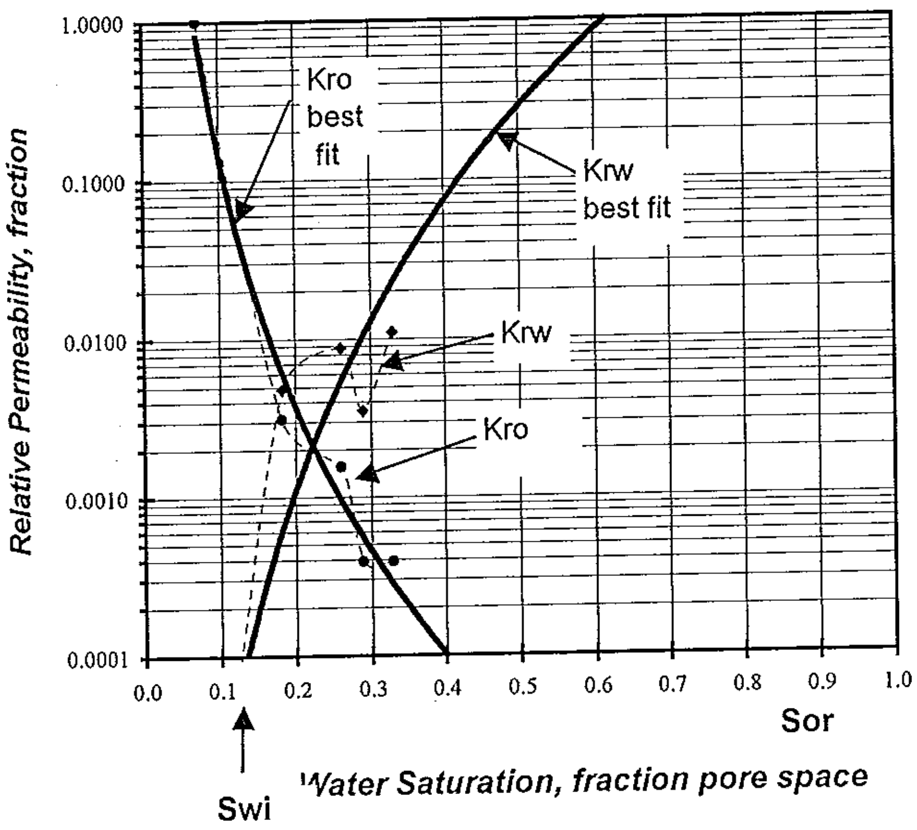

Figure M-34 Core plug sample no.11 : shows the oil and water relative permeabilities plotted as functions of water saturation. The relative permeability is a function of cumulative injection as other variables. The core plug condition started of having initial or connate water saturation of about 12 %. With an active hot-water flooding drive to maintain the pressure, it increases in water saturation as the hot-water flooded in to expel the crude oil, would reduce the relative permeability to oil. This would results in decreasing oil production and on the other hand increasing water production. When the water saturation reaches 32%, relative permeability to oil reduced to 0.0004 fraction of relative permeability and hardly any further oil flow. From this point onwards, the Kro best fit carries on to 40% water saturation, it represents Sor, residual oil saturation as the relative permeability is too low for oil to be injected out.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**11**
Porosity	**15.6 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**179 milliDarcy's**
Effective Oil Permeability	**148.4 milliDarcy's**

Unsteady-state Oil Brine Relative Permeability
Fractional Flow of Water (fw) vs Water Saturation

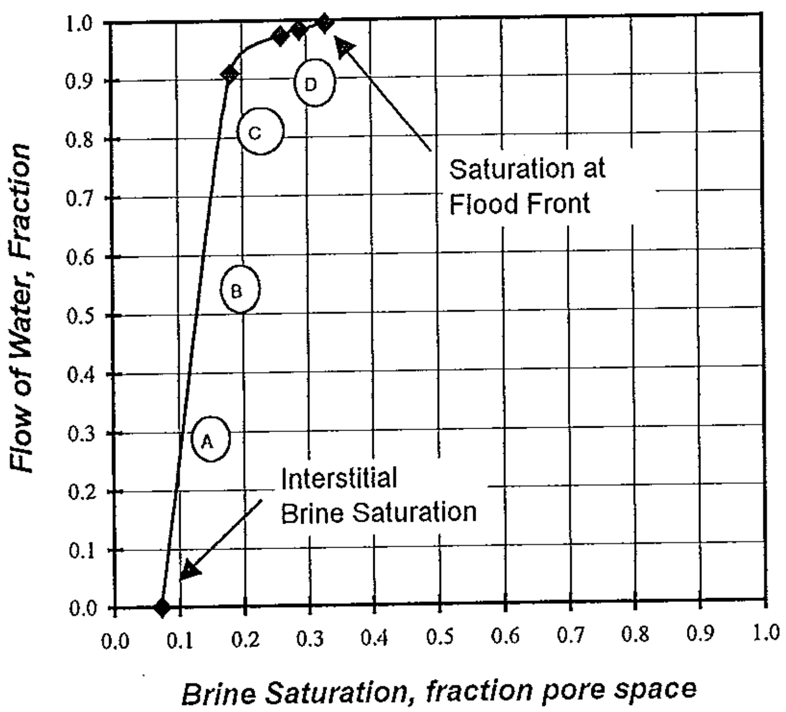

Figure M-35 Core plug sample no.11: at the interstitial brine saturation, 0.08, the reservoir values or saturation conditions where pore space contains water and crude oil are at rest. Saturations at flood front is at the condition where permeability to water is at residual oil saturation and irreducible water saturation. At A, a straight line indicates steady water saturation till water breakthrough at B, 0.9 fraction flow of water, which corresponds the water breakthrough on table at 1.22-2.87 injected pore volume. Water and crude are flushed out along C, and stopped at D.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**11**
Porosity	**15.6 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**179 milliDarcy's**
Effective Oil Permeability	**148.4 milliDarcy's**

Unsteady-state Oil Brine Relative Peremability

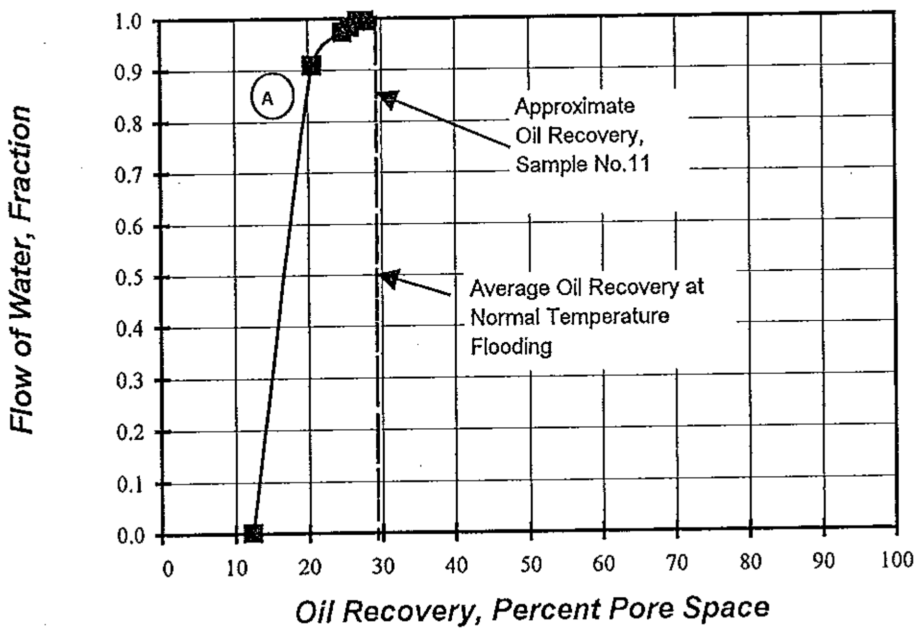

Figure M-36 Core plug sample no.11 : hot-water flooding technique shows 27.84% crude oil recovery compare to normal temperature flooding 28%. At 0.9 fractional flow of water, indicates the fine materials loosen off and causes abrupt flushing along the flow path. When crude oil recovery is getting close to 27%, the recover decreases dued to flow path or pore throats are being blocked off by the suspended loosen materials. Along this stage, small amount of crude oil received and the injected brine keeps carrying on flowing.

HOT-WATER FLOODING ANALYSIS

Thesis Study	**Hot-water Flooding Analysis**
	Suphan Buri Oil Field
Sample Number	**11**
Porosity	**15.6 percent**
Initial Water Saturation	**7.2 percent**
Permeability to Air	**179 milliDarcy's**
Effective Oil Permeability	**148.4 milliDarcy's**

Hot-water Flooding Performance
Oil Recovery vs Hot Brine Injected

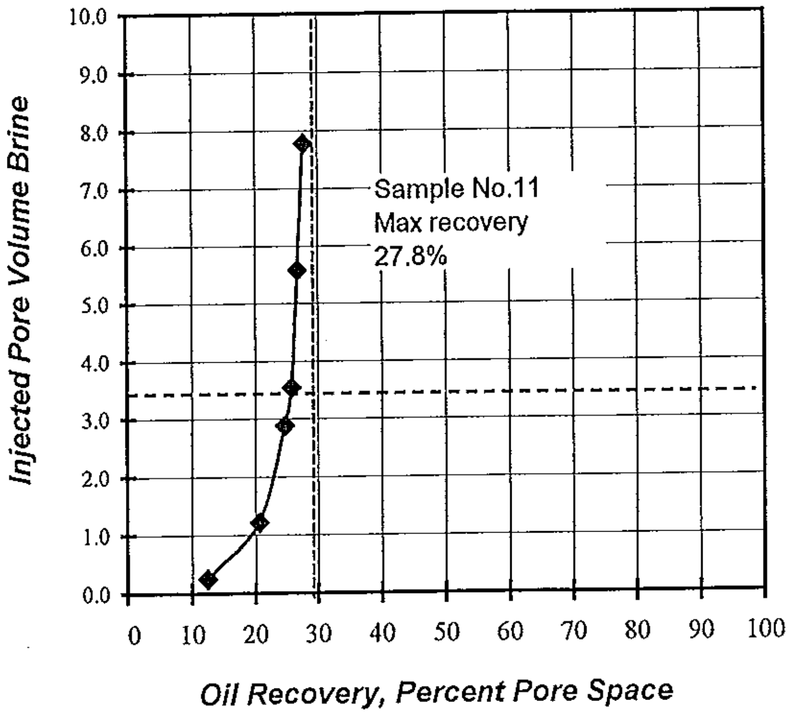

Figure M-37 Core plug sample no.11 : crude oil recovery corresponding to injected brine has maximum recovery of 27.8% pore space. Maximum injected hot-water should not exceed 3 pore volume of the core plug because any excess injected hot-water will not produce any higher crude recovery. This plug shows a very low recovery. It is probably due to formation fractures caused by high confining overburden pressure.

Appendix N

Suphan Buri Crude Oil Cloud-Point Determination

Introduction

The cloud point represents the temperature at which wax or paraffin begins to precipitate from a hydrocarbon solution. There are several methods for cloud point determination but some are not applicable to dark crude oils. The reliable method consists of determining the temperature at which wax deposits begin to form on a cooled surface exposed to warm and visa versa, flowing oil.

Cloud point is a significant parameter in evaluating crude oil and product handling. There has been trying to measure the Suphan Buri crude but was a questionable for the visual observations of cloudiness in the crude.

Material

Suphan Buri crude oil sample collected from well site.
Standard core plugs

Apparatus

- Triaxial Overburden Pressure Cell
- Receiving tubes with calibration
- Pressure measurement apparatus
- Stop watch
- Pressure Pump
- Pump for the application of overburden pressure
- Digital thermometer
- Heating system
- Laboratory data sheet

Procedure

The cloud point determination for this crude was taken in laboratory using self constructed temperature control triaxial overburden pressure cell. Two known standard core plugs were selected for cloud point determination. The plug was individually placed in a Hassler cell at an overburden reservoir pressure of 2000 psig. The Suphan Buri crude was heated to 90°C and then injected to the upstream face of the standard core plug, creating a flow through the core plug sample. During the flow, fixed amount of recovered crude and duration were recorded and the same time temperature decreased gradually. The system temperature was decreased continuously until there was no any further flowing of crude. Using the above method but the system was heated up and the flow rates were recorded.

The summary of the test results were plot out as in Figures N-1& N-2 , the cloud point of the Suphan Buri crude is determined at approximately 58°C.

Results

Sample 1		Sample 2	
Degree C Temp	Seconds Time	Degree C Temp	Seconds Time
90	60.47	73	165.97
83	74.46	71	183.91
74	79.69	67	187.39
63	103.52	64	201.86
60	107.95	62	202.07
56	141.12	59	238.52
52	204.25	57	292.19
50	271.18	55	298.18
42	336.15	52	435.52
		49	726.59

Table N-1 Two Standard Core Plug Samples performed for cloud point determination of Suphan Buri Oil Field

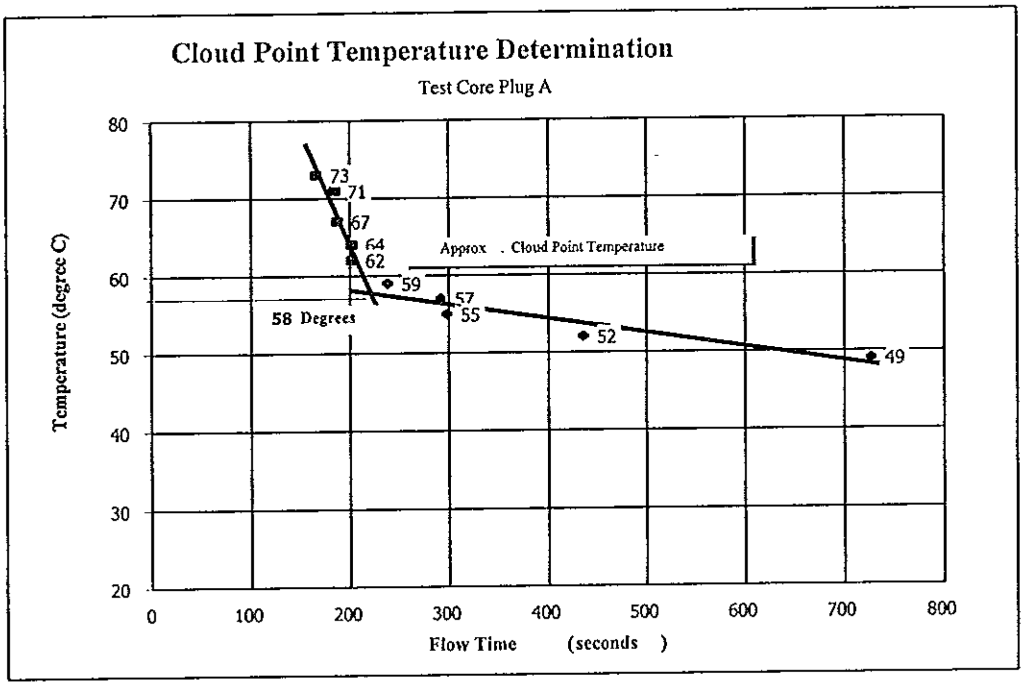

Figure N-1 Cloud Point Determination

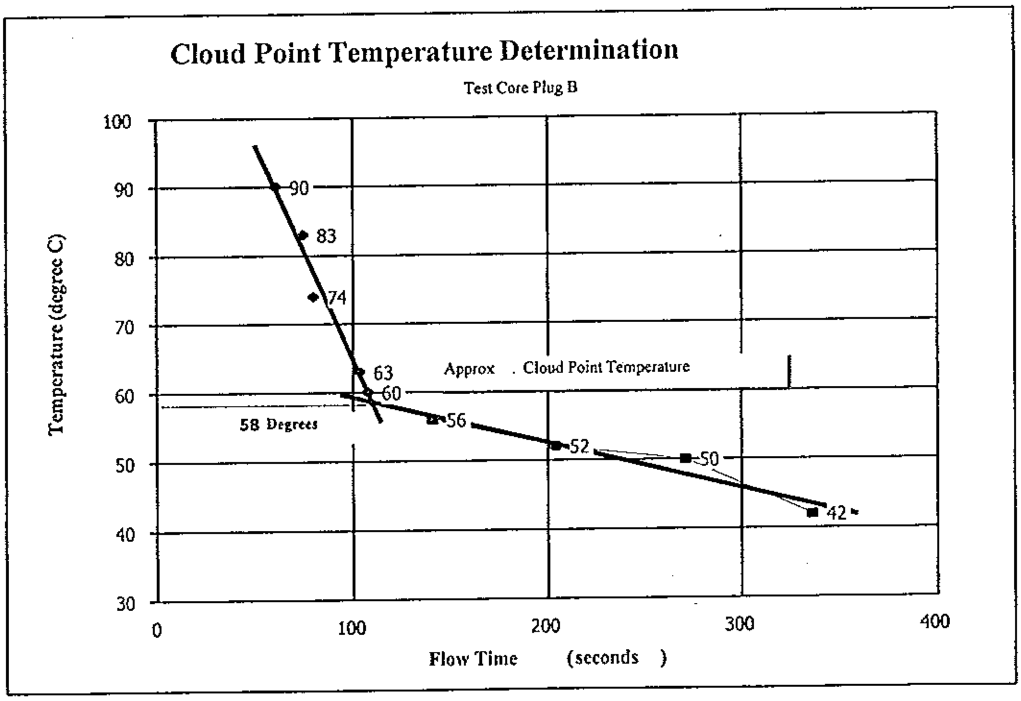

Figure N-2 Cloud Point Determination

Appendix O

Crude Viscosity Determination

Introduction

Crude oil viscosity is the property that controls its ability to flow under certain temperature conditions. Oil viscosity is customarily measured in units of the centipoise (cP) by the petroleum industry. The viscosity of oil in a hydrocarbon reservoir increases with the decreasing or increasing pressure, due to the release of solution gas at bubble point. The solution gas consists of small molecules, which tend to hold the longer chain liquid hydrocarbon molecules apart, as these molecules are released, the chains clump together and tend to interfere with each other, thus increasing the oil viscosity (Koederitz, Harvey, Honarpour 1989).

The previous Suphan Buri crude analysis does not give the wide range of the crude viscosity at different temperature. Viscosity in this experiment can be estimated from correlations or extrapolation on plot graph (Figure O-2). A popular correlation for dead oil viscosity is that of Chew and Connally (Koederitz L.F., Harvey A.H., Honarpour M., 1989). The available Suphan Buri oil viscosity for this experiment is considered a dead oil as it was collected at base pressure.

$$\mu_{do} = \{0.32 + [1.8 \times 10^7/(API)^{4.53}]\}[360/(T+200)]^D$$

where

D	=	$10^{[0.43 + (8.33/API)]}$
API	=	oil gravity @60°F
	=	23.5 °API (Crude oil analysis, Core Labs)
T	=	reservoir temperature, °F
μ_{do}	=	dead oil viscosity, cP

Crude oil density is its specific gravity or the ratio of its density to the density of water. $\text{Degree API} = \dfrac{141.50}{\textit{specific gravity} @ 60 \deg F} - 131.50$

LIQUID VISCOSITY					
Information			*Liquid Information*		
Hot-water Flooding	Analyst	Sombat	Liquid	Suphan Buri Crude
Suphan Buri	Job No		Oil Gravity @60F	23.5 API

$$\mu_{do} = \{0.32 + [1.8 \times 10^7/(API)^{4.53}]\}[360/(T+200)]^D$$

D	=	$10^{[0.43 + (8.33/API)]}$
API	=	oil gravity, °API
T	=	reservoir temperature, °F
μ_{do}	=	dead oil viscosity, cP

e.g. 1	API power (4.53)	1625314.52
2	0.32+(1.8*10000000/API power4.53)	11.39
3	0.43+(8.33/API)	0.78447
4	D=10power[0.43+(8.33/API)]	6.08791

Data Entry					
Temperature °F	Temperature °C	(360/T+200)	power D	Viscosity (cP)	
170	76.7	00.97	00.85	9.64	
175	79.4	00.96	00.78	8.89	
180	82.2	00.95	00.72	8.20	
185	85.0	00.94	00.66	7.57	
190	87.8	00.92	00.61	7.00	
195	90.6	00.91	00.57	6.48	
200	93.3	00.90	00.53	6.00	
205	96.1	00.89	00.49	5.56	
210	98.9	00.88	00.45	5.16	

Suphan Buri Crude	*Viscosity at reservoir temperature 90C*	=	*6.477 cP*

Table O-1 Curde Oil Viscosity Measurement

The relationship of crude oil viscosity data and temperature is graphically plot in Figure O-1.

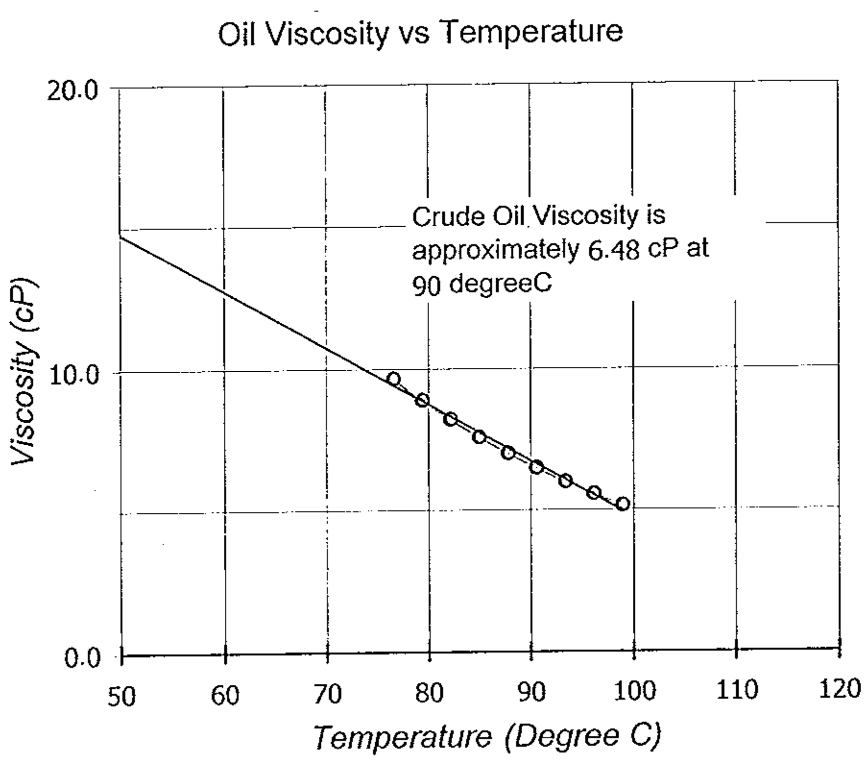

Figure O-1 Oil Viscosity and Temperature Correlations

Crude oil viscosity can as well be extrapolated using ASTM Viscosity Temperature Chart. Charts are available in several sizes and ranges of viscosity and temperature. Figure O-2 is of particular interest as it allows the estimation of crude viscosities at any temperature when only one set of viscosities-temperature data is known.

The Suphan Buri viscosity at reservoir condition is at 9.64cP at 76°C. Locate the point representaing 9.64 cP on the viscosity scale, and proceed horizonatlly to the curve. Proceed vertically downward to the base line, and measure off a distance represenating the difference of 76°C and 90°C (14°C). Proceed verticall upward to the curve and read the corresponding viscosity to be 6.48cP. Thus the experimental value at 90°C is found to be 6.5 cP as similar in the above calculation.

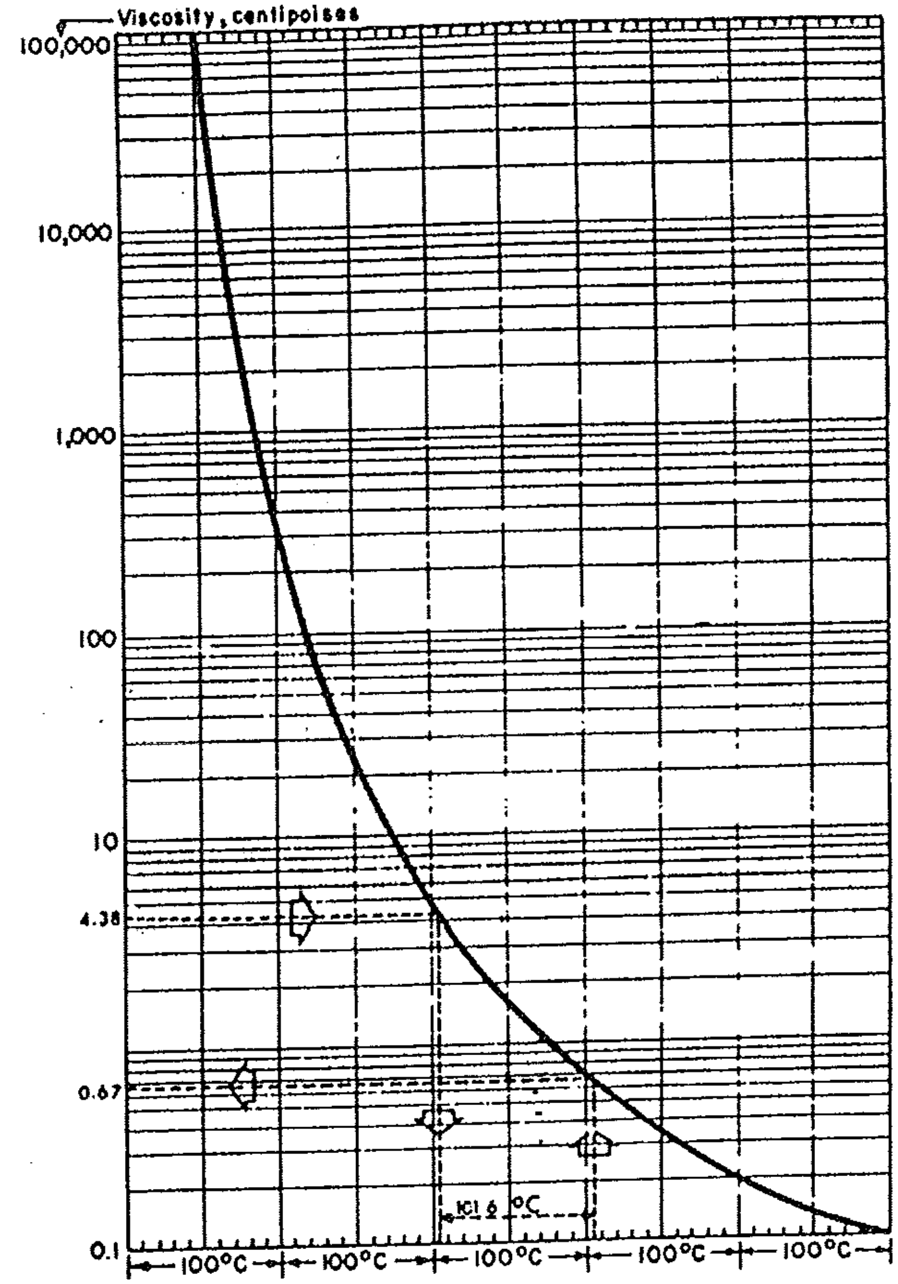

Figure O-2 Viscosity & Temperature Correlation Chart (Prat,1986)

Appendix Q

GLOSSARY

Absolute Permeability : The permeability of a porous medium which is 100% saturated with a particular fluid.

Ambient Conditions : Tests performed at ambient temperature and low sealing pressure.

Amott Wettability : A laboratory method to measure wettability that combines imbibition and forced displacement to obtain an average wettability of the core

API Gamma Ray Unit : An arbitrary unit defined as 1/200th the difference between the background and peak height of a gamma ray log run at the API test pit, located in Houston.

API Gravity : Can be measured in the laboratory on recovered oil or retorted oil. Retorted oil is likely to have lost light ends and been cracked during the retort process, hence the API value is likely to vary systematically from the true API.

Apparent Formation Factor : The formation factor when excess conductivity exists which results in the formation factor being a function of brine resistivity.

Archie Rock : A clean formation with intergranular porosity where the resistivity versus saturation response can be adequately described by Archie's Law.

Archie's Law : The fundamental (empirical) relationship which relates rock resistivity to saturation percent and porosity.

Average Permeability : The average permeability (horizontal or vertical) of a sample or sequence can be calculated using arithmetic, harmonic or geometric averaging techniques.

Basic Flood : A special core analysis test where a core plug saturated with gas or oil is flooded with water. The test provides end-point permeability and saturations.

Boyle's Law : States that at constant temperature $P_1V_1 = P_2V_2$ ie, the pressure times volume relationship is constant for a perfect gas.

Bulk Density : Somewhat ill defined, may be used as an equivalent term to natural density or to signify clean sample density ie, sample weight divided by clean sample bulk volume.

Bulk Modulus : The ratio of hydrostatic stress relative to volumetric strain. The inverse of bulk modulus is bulk compressibility. Obtained from acoustic velocity tests (dynamic) or stress/strain measurements (static).

Bulk Volume : The total volume of the sample. Measured by mercury immersion or caliper.

Bypassing : The passage of air between the rubber sleeve and the sample during a permeability experiment causing an erroneously high permeability value. Generally only a problem with tight samples.

Capillary Pressure : The property of the rock/fluid system which controls hydrocarbon saturation distribution in the reservoir prior to production. Capillary pressure is defined as hydrocarbon phase pressure minus water phase pressure. Commonly performed in the laboratory by saturating a plug in brine and subjecting the sample to increasing capillary pressure, causing brine to be replaced by the non-wetting phase. This allows a plot of water saturation versus capillary pressure to be determined which may then be used to determine water saturation as a function of height above free water level for the reservoir under investigation.

Capillary Water : Water held in place by capillary forces, consists of immobile water held in place at grain to grain contacts by the process of capillary condensation, and free water which becomes mobile if the pressure on the non-wetting phase (capillary pressure) is increased.

Conventional Core : A large diameter core (generally 4 inches to 5 1/4 inches in diameter) cut with a conventional core barrel. The conventional coring system consists of inner and outer steel barrels, a core catcher and a core bit. The outer barrel rotates and is attached to the drill bit. The inner barrel holds the core and is attached to the core catcher, which is designed to hold the core in place, and is activated when coring is complete.

Cool Solvent Extraction : If the sample contains clays with structural water it is advisable to extract samples with cool solvent to avoid clay dehydration. This can be achieved with a Soxhlet by adding an additional condenser or placing a cooling coil inside the extraction chamber.

Core Preservation : Procedures carried out to prevent physical and chemical changes to the core during movement from the field to the laboratory. Physical changes may be induced by rough handling or loss of pore fluids. Chemical changes are more subtle and difficult to control. Oxidation of pore fluids can alter wettability.

Darcy's law : The empirical equation for calculating flow in porous media. Assumptions are laminar flow, no gas slippage, 100% saturation of the pore space and no rock fluid reaction.

Effective permeability : The permeability of a porous medium to a fluid which partially saturates the porous medium.

Effective Porosity : A poorly defined term, may denote all connected porosity. In core analysis denotes a porosity after humidity drying ie, a porosity excluding the bound water volume.

Fluid Saturations : The percent or decimal fraction of each fluid contained in the pore space. Measured by Dean Stark, Retort or chromatography methods.

Gas Permeability : Provided by routine core analysis. Cue to gas slippage the permeability to gas varies according to the mean pressure, (within the porous medium) at which the measurement is performed. Occasionally nitrogen or other gases may be used to determine permeability.

Gas Slippage : During gas flow the gas exhibits a finite velocity at the pore wall, this phenomenon is called gas slippage and is a result of diffusion dominated by collisions between the gas molecules and the pore walls.

Grain Density : The average density of the core sample matrix.

Grain size Distribution : Calculated from sieve analysis, laser particle size analysis or point counting, this data is used for gravel pack, screen size design and in sedimentological studies.

Grain Volume : The volume of grains in the sample. Measured by helium injection.

Hassler Holder : A core holder used in routine core analysis to confine a core plug at low pressure during a permeability measurement. Consists of a metal sleeve with an internal rubber boot which seals around the sample.

Helium Injection porosity : A porosity obtained using a helium injecjtion porosimeter. This instrument functions according to Boyle's Law and consists of a reference chamber containing a known volume of helium at a known pressure and a core holder (matrix cup).
When the helium is introduced to the core holder the resultant pressure allows the unknown grain volume to be calculated. Bulk volume is measured by mercury immersion, (except for coarse grained or vuggy/fractured samples). If the porosimeter is used in conjunction with a cell containing a sealing rubber boot, pore volume can be determined, (though some pressure has to be applied to seal the boot, hence this is not a true ambient porosity measurement).

Horizontal Permeability : The standard measure in routine core analysis. Permeability will often differ in the horizontal plane because of sand body fabric orientation and differential stress. The degree of variation between maximum and minimum horizontal permeability is an important characteristic assessed by whole core analysis.

Humidity Dried Porosity : This porosity includes the porosity associated with pore fluids. It does not include the porosity associated with structural ie, mineral water, unconnected port space, and bound (adsorbed) water.

Humidity Drying : Applies to core drying at controlled humidity conditions commonly 60C and 40% to 55% relative humidity. This technique is designed to retain adsorbed water on the mineral surfaces.

Imbibition : Any process where the fluid that preferential wets the grain surfaces is increasing in saturation. Waterflooding a water wet reservoir is an imbibition process.

Initial Saturation : The saturation at the beginning of a particular test sequence, often the initial saturation is oil or gas at irreducible water saturation.

Irreducible Water, Immobile Water : The water saturation present in a sample above the transition zone or when subjected to a capillary pressure higher than that in the transition zone. The relative permeability to water is effectively zero when the water is at an irreducible saturation.

Klinkenberg Permeability : (Equivalent Liquid Permeability): A gas permeability corrected for the effects of gas slippage.
Laminar Flow : The flow regime applicable for use with Darcy's Law. If the flow rate is non-laminar then the pressure versus flow rate relationship deviates from that predicted by Darcy's Law. Non-laminar flow is also called non-Darcy flow.

Mercury Injection Capillary Pressure : A technique for determining the capillary pressure properties of a sample using mercury as the non-wetting phase. Volume mercury injected as a function of mercury pressure is measured. The technique is useful for measurements on tight clean formations requiring high pressures.

Microfractures : Stress relief can induce microfracturing in well cemented samples during core retrieval. These microfractures can radically affect measured permeability. Micorfractures tend to align perpendicular to the direction of maximum horizontal stress.

Miscible Solvent Extraction : A flow cleaning technique using a series of miscible solvents which is designed to clean samples without the formation of a liquid/gas interface. The force associated with liquid/gas interfaces has been seen to damage4 samples containing fragile clay morphologies, particularly filamentous illite.

Native-state : Denotes that the core has been taken with lease crude as the drilling fluid in order to maintain reservoir wettability. Very rarely performed because of safety aspects involved when drilling with crude.

Natural Density : The density of the core sample as received ie, including fluids and solids.

Oil-wet : The grain surfaces are contacted with oil. Water is located in the center of the pores.

Oven Dried Porosity : The porosity associated with pore fluids and bound (adsorbed) water. It does not include the porosity associated with structural ie, mineral water or unconnected pore space.

Oven Drying : Applies to core drying with a standard oven up to 105C

Overburden conditions : Denotes that simulated reservoir stress is applied during the test procedure. Unless the test is performed at reservoir pore pressure the overburden stress applied is effective rather than total.

Permeabiltiy : Measure of the capacity of a formation to flow. Standard unit is the Darcy, defined as the permeability of a medium allowing the passage of 1 cm^3/sec of fluid whose viscosity is 1 centipoise with a pressure gradient of 1 atm/cm^2 through a survace area of 1 cm^2.

Permeameter : Anintrument for measuring permeability.

Plug : A sub sample taken from the whole core at regular intervals and used for analysis. Standard size is 1 ½ inches diameter and 2 inches long. Plugs are drilled from the whole core using a drill press fitted with a diamond impregnated drill bit.

Pore volume : The volume of pores in the sample. Measured by helium injection in a cell, by saturation with a known density fluid or by measuring the volume of pore fluids.

Porosity : Defined as the ratio of pore volume to bulk volume of a porous medium. May be reported as a decimal fraction or a percentage. In order to determine porosity in the laboratory any two of the three associated volumes ie, bulk volume, port volume and grain volume needs to be measured.

Relative Permeability : The ratio of effective permeability to specific permeability.

Reservoir Conditions : Tests performed at reservoir temperature and pressure, sometimes abbreviated to res con. Full res con signifies recombined or bottom hole samples are used at reservoir port pressure rather than stock tank oil.

Residual Saturation : The saturation at the end of a particular test procedure. For example if an oil saturated core at irreducible water has been gas flooded, the core contains irreducible water, residual oil and gas. The residual hydrocarbon saturation depends on the process used to attain that saturation. For example residual oil saturation after waterflood may well be different to residual oil saturation after and imbibition capillary pressure experiment.

Retort : A high temperature oven containing a number of samples individually placed in steel holders. At 180C pore water, adsorbed water and some hydrocarbons are recovered, at 650C mineral and non-connected pore fluids along with the remainder of the oil are recovered. The technique is quick and provides both residual fluid saturations and summation of fluids porosity.

Routine Core Analysis : those analysis performed on the core as soon as it arrives in the laboratory. Routine analysis is often performed in laboratories close to the wellsite. Commonly requested analysis include core gamma, porosity, permeability, grain density and fluid saturations.

SCAL : Special core analysis, generally considered to be analyses such as electrical properties, capillary pressure relative permeabilities etc, performed on a subset of samples after routine core analysis.

Sealing Pressure, Confining pressure : The pressure applied to seal the rubber boot around the sample during an air permeability experiment, generally 250 to 400 psi for ambient condition analysis.

Sieve Analysis : A method for obtaining grain size distribution on friable samples using a nest of sieves of various aperture sizes.

Slabbing : The process of cutting the core longitudinally to expose the surface for description, sample selection and core photography.

Solvent Extraction : The process of extracting pore fluids from the core samples using a hydrocarbon solvent. Commonly used solvents include toluene, and chloroform methanol mixtures.

Soxhlet : The apparatus most commonly used for solvent extraction. The soxhlet consists of a heating mantle containing a round bottom flask holding the solvent, a chamber containing the core plugs and a condenser. When heat is applied the solvent evaporates and is condensed, causing it to fill the Soxhlet chamber and cover the core samples. The solvent leaches port fluids from the core samples. When the solvent fills the chamber a siphon arrangement empties the chamber and the cycle is repeated.
Summation Of Fluids Porosity : A porosity determined by measuring the volumes of gas, oil and water in the pore space. May be determined by the retort method or the Dean Stark method.

Surface Area : The grain surface are within the sample, expressed as area per unit sample weight, or area per unit sample volume. The volume is usually the pore volume but surface area may also be expressed per unit grain or bulk volume.

Total Porosity : In core analysis total porosity is measured after oven drying ie, pore fluid porosity plus adsorbed or bound water connected porosity.

Triaxial : A stress regime that applies equal pressure to the two principal horizontal axes, and a different stress to the vertical axis. Should be used only on vertically oriented plugs.

Uniaxial : Stress applied along one axis only. An unconfined sample may be used, for example to measure uniaxial compressive strength. The sample may also be confined in a rigid container such that stress is applied to the vertical axis only. Application of vertical stress in the confining cell creates the horizontal stresses. Application of this stress regime requires almost perfect cylindrical, vertically oriented core plugs and is rarely used as a result.

Unsteady-State : Not steady-state. When used in conjunction with relative permeability experiments signifies a test wher either flow or pressure and saturations are changing. When use in conjunction with a single phase permeability measurement it denotes that both pressure and flow rate are constantly changing, (or transient) during the course of the measurement.

Vertical permeability : Maybe considerably less than horizontal permeability, used to assess potential vertical flow barriers and determine Kv/Kh ratiosin reservoir sections.

Viscosity Ratio : The ratio of the viscosities of fluid pairs. This data is required for waterflood and water/oil relative permeability experiments. In these experiments it is important to duplicate the reservoir water/oil viscosity ratio, as this value influence produced data.

Waterflood : A test in which a core plug saturated with gas or oil is flooded with water. The test produces end-point permeability and recovery versus water volume throughput data.

Water-wet : The grain surface are wet by water and water occujpies the samllest pores, hydrocarbons are effectively isolated from grain surfaces and are located in the centre of the pores.

Wettability : Defined as "the tendency of one fluid to spread on or adhere to a solid surface in the presence of another immiscible fluid" . In an oil reservoir it is extremely important to know which fluid is wetting the grain surfaces since wettability is a major factor controlling the location, flow and distribution of fluids in the reservoir. It is vital to perform special core analysis test on samples that have the same wettability characteristics as they had in the reservoir.

Whole Core Analysis : A term to describe analysis of the whole core. Rarely performed except in heterogeneous limestones. It is far commoner to take full diameter sections at regular intervals, along with plugs.

Vitae

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Educational Attainment

Degree	Name of Institution	Year of Graduation
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