EG4013 – MEng Engineering Report (Winter Progress Report) **January, 2015**

Review of the *Winter Report* 'Study of Multiscale Waterflooding Mechanisms in Heterogeneous Reservoir Simulations' by Giulia Marzetti

The manuscript reports initial investigation of viscous fluid instabilities in waterflooding processes for oil and gas exploration. A brief overview of the main topics on reservoir engineering and simulation relevant to EOR was undertaken by Ms Marzetti including, (a) main terminology, (b) EOR techniques and reservoir morphological properties, (c) heterogeneity and (d) fundamental equation for reservoir simulation.

The report is relatively well-written with a number of typos and unrevised sentences. Several sentences are confusing and disconnected with no clear objectives and inter-connectivities. Most of all, the paper is well-structured with clear division and linkages between sections, leading to a relatively easy and smooth reading. However the numbering of a few sections are mixed up. A few general comments,

1. Dissertations and thesis are divided into chapters, reports however are always divided into sections.

2. The main aim of *Abstracts* is to briefly describe the work undertaken by the author. In general *Abstracts* are divided in 4 parts: (i) motivation, (ii) main objectives, (iii) summary of the main procedures / techniques / technologies (optional) and (iv) main findings. The current *Abstract* encompass only (i). In fact, the whole *Abstract* was written a short summary of the report.

3. The main *Introduction* section usually has the same (but more in-depth and descriptive) four parts of the *Abstract* and a brief summary of the remaining of the work. In addition, it is <u>always</u> expected a few clear statements -re main background (thus recent innovations related to the main topic), initial literature review and, most of all, technological / scientific gaps in the current understanding. Also, it is expected a summary of the remaining sections at the end of the *Introduction*. Current *Introduction* covered (i-ii), (iv) above but lacked explain/sumarise the main state-of-the-art aspects of the subject area.

4. The *References* have a fewh missing fields and no clear distinction between articles, conference proceedings, reports (internal or external), book chapters, books, communications (internal or external) etc. A few *references* used in the manuscript are incomplete and/or wrong. Regardless of the chosen citation style (e.g., ACS, AIP, AMS, IEEE, AIAA, etc) any reference **must** contain the following fields:

    (a) For journal papers: Authors, Paper Tittle, Journal Name, Volume, Pages, Year of publication;

    (b) For books: Authors, Book Tittle, Publisher, Year or Edition;

    (c) For book chapters: Authors, Chapter Tittle, Book Tittle, Editors, Publisher, Year or Edition;

    (d) For conference papers: Authors, Paper Tittle, Conference Tittle, Place (Country and/or City) where the conference was held, Year of the conference;

(e) For reports, private communications and Lecture Notes: Authors, Tittle, Place issued (Country and/or City and Institution where the document was originated), Year;

(f) For PhD Thesis and MSc Dissertations: Author, Tittle, Institution (University and Department/School), Year.

Thus, for example:

[1] P.L. Houtekamer and L. Mitchell, 'Data Assimilation Using an Ensemble Kalman Filter Technique', *Monthly Weather Review*, 126:796-811, 1998.

[2] K. Pruess, 'Numerical Modelling of Gas Migration at a Proposed Repository for Low and Intermediate Level Nuclear Wastes', Technical Report LBL-25413, Lawrence Berkeley Laboratory, Berkeley (USA), 1990.

[3] K. Aziz, A. Settari, *Fundamentals of Reservoir Simulation*, Elsevier Applied Science Publishers, New York (USA), 1986.

[4] R.B. Lowrie, 'Compact higher-Order Numerical Methods for Hyperbolic Conservation Laws', PhD Thesis, Department of Aerospace Engineering and Scientific Computing, University of Michigan (USA), 1996.

5. A few terms were used before being defined/explained, e.g., *sweep efficiency* was firstly used in page 10 whereas the definition was found in page 15.

6. Equations <u>must</u> be placed in a separated line (centered aligned with uniform font) followed by its number (rhs aligned). All terms used must be defined afterwards as part of the main text.

The paper is a good review of the fundamentals of reservoir engineering and simulation, but does not cover the literature review of the main subject area, fluid instabilities that leads to the fingering phenomena. In addition, as a winter report it was expected a work plan for the activities that will be undertaken during the spring (e.g., Gantt chart, list of activities with appropriate time frame work).

In the attached scanned document:

- **PE:** Poor English;

- **SC:** Sentence(s) is/are very confusing and do(es) not make much/any sense.

Study of Multiscale Waterflooding Mechanisms in Heterogenous Reservoir Simulations

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This Report has been submitted as a part of requirement for the MEng. Degree in Engineering.

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Abstract

motivation!

Waterflooding is still the most used secondary oil recovery method due to its inexpensive economic prospects. During waterflooding, water is injected in an injection well to displace oil in the production well.

PE

Since water and oil are immiscibile fluids, viscosity differences and interfacial tensions contributes to viscous fingering growth, a mechanical instability which causes a fingers-like pattern to develop resulting in a non-uniform displacement front.

Understanding the impact of viscous fingering growth in heterogeneous reservoir is of highly importance in enhancing waterflooding performance and therefore oil recovery.

Waterflooding performances are driven by the Mobility Ratio (MR), which is defined as the relative permeability of water over the relative permeability of the displaced fluid, oil.

Factors which determine waterflooding performance have been found to be the microscopic displacement, the vertical sweep efficiency and the areal sweep efficiency.

Different approaches to determine reservoir heterogeneity have been investigated.

The Dysktra and Parson coefficient for heterogeneity has been found to be one of the most common methods to represent heterogeneity in a static scheme reservoir, where the main assumption is that the stratified layers of a reservoir are non communicative.

The latter assumption is relaxed in the dynamic scheme, where fluid properties and flow rates are taken into account to determine heterogeneity characterized by the Koval's heterogeneity factor.

Viscous fingering has been found to occur at unfavorable mobility ratio (Mobility Ratio greater than one).

Polymer flooding has been then found to be one of the most common methods to mitigate viscous fingering phenomena and to improve the interfacial tension between water and oil during waterflooding.

Motivation: ✓

Objective(s): X

Methods, procedure etc: X

Main findings: X

Nomenclature

Symbol	Description
$\mathbb{E}$	l displacement efficiency factor
E_A	Areal sweep efficiency
E_D	Fractional Macroscopic Efficiency factor
Ev	Vertical Sweep Efficiency
H_k	Koval's heterogeneity factor
k_e	Effective permeability
k_{rw}	relative permeability of water
k_{rO}	relative permeability of oil
$(k_{rw})_{Sor}$	relative permeability of water at residual oil saturation
n	Corey's exponent
S	Saturation
S_{iw}	Irreducibile water saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{wf}	Water saturation behind floor front
P	pressure
Pc	Capillarity pressure
q	Source or sink term
V_{dp}	Permeability of Dysktra Parsons
t	time
$t_{Dbreaktrough}$	Dimensionless time through breakthrough
u	Darcy's velocity
z	Potential depth
θ	Contact angle
λ	Mobility ratio
μ	Fluid viscosity
ρ	Fluid Density
$\emptyset$	Porosity
∇	Gradient Operator

Subscript	Description
α	Fluid phase
o	oil
w	Water

Abbreviation	Description
ANN	Artificial Neural Network
ASP	Alkaline/Surfactant/Polymer
BGS	Band of Generic Similarity
BPNN	BackPropagation Neural Network
CSP	Concentrating Solar Power
EOR	Enhanced Oil Recovery
FCM	First Contact Miscible process
IFT	Interfacial Tension
IMPES	Implicit Pressure Explicit Saturation
MCM	Multiple Contact Miscible Process
MEOR	Microbial enhanced oil recovery
MR	Mobility Ratio
PDEs	Partial Differential Equations
WAG	Water Alternate Gas

Table of Contents

NOT BOLD

NOT BOLD

1 Introduction

1.1 Motivation

Gen. Introd.

In order to recover part of the remaining oil after the initial production stage (primary recovery), water is injected into injections wells to displace the oil produced through production wells. PE This stage of oil recovery is called waterflooding and it is one of the most used secondary oil recovery method. [1] Alternative methods such as chemical injection, gas flooding and thermal recovery process have been established for secondary and tertiary oil recovery but they have higher investment costs and many operational drawbacks when compared to waterflooding. Water is almost inexpensive and ready available in proximity of oil production sites since approximately three barrel of water are produced together with each barrel of oil.

Motivation

Consequently the study of waterflooding and how to improve its performance is considered of high interest in petroleum industry.

When water is injected in the well during the waterflooding recovery stage a phenomenon ALWAYS? called viscous fingering occurs. Viscous fingering in a porous medium is a mechanical instability that occurs when a less viscous fluid such as water is injected through a porous medium saturated with a more viscous fluid (oil and hydrocarbons). Under this ? unfavorable viscosity distribution, the interface between the two fluids is unstable and "finger-like" patterns grow in the course of time. [2]

As a consequence, waterflooding performance and total oil recovery is decreased.

Waterflooding performances are driven by the Mobility Ratio (MR), which is defined as the relative permeability of the displacing fluid (water in this case) over the relative permeability of the displaced fluid (oil in the case of this investigation).

The relative permeability is a crucial property in governing multiphase flow in porous media. It is a parameter which defines the ratio of effective permeability of a fluid at a particular saturation to the absolute permeability of that fluid at a total saturation. Hence, relative permeability is a measure of how fluids flow in presence of other fluids.

One of the most complex concepts in reservoir engineering is heterogeneity due to difficulty in collecting properties from all reservoir fields. A reservoir is highly heterogeneous since its properties vary according to location.

Heterogeneity is characterized by different parameters on megascopic, macroscopic and microscopic scale. For the purpose of this investigation only the macroscopic scale is going to be investigated since its parameters highly influence fluid flow in injecting processes such as waterflooding.

One of the most common models used for heterogeneous reservoir is a multiple layer reservoir with different permeability layers. [3]

OBS

The focus of this dissertation is to investigate the combination of the effect of viscous fingering and heterogeneity on waterflooding performance.

1.2 Objectives

The aim of this project is to investigate how the parameters chosen to describe heterogeneity in a reservoir affect viscous fingering phenomena and waterflooding performance.

The objectives were state as follows:

- Conduct a literature review on technologies for Enhanced Oil Recovery (EOR) and multiscale viscous fingering.
- Investigate technologies to identify heterogenous media in reservoir and its effect on oil recovery and viscous fingering.
- Perform computational simulation in Fluidity while focusing on one aspect of the viscous instability (in particular how the viscosity ratio influences waterflooding performances).
- Critical evaluation of numerical and computational simulation.

1.3 Methods and Procedures

For the purpose of this investigation, hydrodynamics of the fluid flow in porous media is described by Darcy's law. Computational Fluid Dynamics will be the method used to carry out the investigation. Fluidodynamics simulations on Fluidity will be carried out during the spring term to better understand how viscosity ratio and viscous fingering phenomena influence waterflooding performance.

1.4 Summary of the work and Chapter Structures

Literature review and background reading on Enhanced Oil Recovery techniques and reservoir engineering concepts relevant for this investigation have been carried out during the winter term. A summary of the preliminary founding regarding heterogeneity and viscous fingering is present in Chapter 4 and Chapter 5.

An overview on reservoir simulation is going to be presented in chapter 7.

Reports are divided in sections whereas thesis & dissertations are divided into chapters → sections → subsections...

Motivation:

Objectives:

Methods, procedures:

Findings & Conclusions (preliminary):

Brief description of the work:

2. Enhanced Oil Recovery Techniques (EOR) Review

2.1 Enhanced oil Recovery overview

Enhancing the recovery of an oil reservoir is one of the major objectives of any oil company. This is achieved by development of the oilfields by employing different techniques such as infill drilling, water injection, gas injection, water alternate gas (WAG) injection and even thermal methods.[4] PE/SC

FORCES ?

FROM

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. [1]The initial production stage is defined as Primary oil recovery, resulted form the displacement of oil due to natural energy sources such as gravity drainage, gas-cap drive, fluid and rock expansion, and natural pressure difference. SC
Secondary recovery occurs when primary production declines. Together with waterflooding, the most common oil recoveries processes are pressure maintenance and gas injection. However waterflooding is the most common secondary recovery technique.
Tertiary oil recovery or Enhanced Oil Recovery (EOR) takes place when secondary oil recovery is no longer economically feasible and includes gas flooding, chemical flooding polymer flooding, CO_2 flooding and thermal recovery.

YOU HAVEN'T DEFINED VSE YET!!!

2.2 Chemical Processes

Chemical injections decrease the interfacial tension between the displacing fluid and the oil. Usually the displacing fluid is a micellar solution which contains surfactants.
Micellar and polymeric solution are designed to decrease the IFT between the displacing fluid and the oil therefore increasing the volumetric sweep efficiency and the microscopic displacement efficiency. These solutions are costly because have been developed accordingly to the crude oil characteristic in he reservoir and they often have been designed to tolerate brine and salinity in the reservoir. Therefore micellar solution must be displaced by a relative inexpensive fluid which will maintain a favorable mobility ratio. Usually a mobility buffer slug containing a solution of polymers and water is used for this purpose since water manifests an unfavorable mobility ratio when mixed with micellar. Salinity of a reservoir plays an important part when choosing the right

?

surfactant for chemical flooding. However this issue will not be treated in details in this investigation.

pH

Another chemical process is alkaline flooding. Alkaline (high-PH) solution is injected in the well to react with the crude therefore forming surfactants in-situ.
Sodium hydroxide, sodium orthosilicate, sodium carbonate and ammonium carbonate are some of the alkaline agents used in the process.
Oil recovery due to alkaline flooding occurs through emulsification and entrainment, wettability reversal (oil-wet to water-wet and water-wet to oil-wet) and emulsification and entrapment mechanism.
The first stage, emulsification and entrainment, occurs when the IFT is reduced and as a consequence an emulsion which entrains the oil is created. The alkaline injection then reverses the wettability from either oil-wet to water-wet or vice versa causing a readjustment of the fluid in the pores of the reservoir and positively effecting the relative permeability.
Alkaline/Surfactant/Polymer (ASP) is an EOR technique which combines the effect of three different types of chemicals to decrease IFT, increase capillarity number and improve macroscopic sweep efficiency, displacing efficiency and mobility ratio.

2.3 Miscible processes

In miscible EOR processes, the displacing fluid and the displaced fluid form a single phase solution when mixed together.
There are two types of miscible processes: first-contact-miscible processes and multiple-contact-miscible processes.
In the First Contact Miscible process (FCM) the displacing fluid and the oil are miscible instantaneously as soon as they come in contact in the reservoir.
In the Multiple Contact Miscible Process (MCM) the displacing fluid is not immediately soluble in the displaced fluid. Solubility of the two fluids is later achieved by modification of the existing conditions of pressure, composition and temperature in the reservoir.

An example of MCM is the injection of CO_2 in the reservoir, an increasingly common practice in EOR techniques. CO_2 is used to displace residual hydrocarbons in the reservoir. Density of the CO_2 is lower than the density of oil and therefore oil and water are displaced under unfavorable mobility ratio. To overcome this, water-alternate-gas (WAG) is used as an alternative EOR method. Alternate water injections reduce the relative permeability of CO_2 therefore decreasing its mobility.

Carbon dioxide flooding is particularly effective in deep reservoir where CO_2 will be in supercritical state. CO_2 is limited to reservoir with sufficient depth to miscibility pressure. When CO_2 is injected into the reservoir, it dissolves in oil decreasing its density therefore increasing its areal sweep efficiency.

2.4 Thermal processes

Thermal EOR process consist of hot-water floods, stem processes and in-situ combustion. The thermal energy released by these processes increase the reservoir temperature consequently reducing the oil viscosity and facilitating the displace of oil to the production well. The main factors influencing thermal oil recovery processes are reservoir pressure, reservoir permeability and depth.

Steam processes including steamdrive processes are not effective in reservoir deeper than 3,000 ft due to excessive heat losses occurring in the well. Insulated injection tubing is often used to reduce heat losses while increasing the depth. Pressure is also a limiting factor for steam processes since steam temperature increases with pressure while heat is lost to the surroundings.

UNITS (SI)

In-situ combustion can be used in reservoir with a lower permeability than the one needed for steam processes and pressure is not a limiting factor for this type of processes as long as the air-injection rate can sustain the source of combustion.

SC

One of the newest thermal oil recovery techniques is Solar thermal enhanced oil recovery. In 2011 two thermal oil recovery sites were developed in California and in Oman. Concentrating Solar Power (CSP) is used instead of natural gas to produce steam. A central power tower concentrate sunlight to heat water and activates turbines which produce steam then injected into the wells to mobilize crude. [5]

is this plus of thermal processes?

In recent years Microbial enhanced oil recovery (MEOR) has been also used.[6] Microorganism and their metabolic byproducts are used to mobilize crude oil.
MEOR mechanics alter the oil/water/rock interfacial properties and modify the fluid behavior due to bioclogging. [7]

2.5 Waterflooding

Even if the interest in alternative recovery methods is increasing, waterflooding is still the most secondary oil recovery method used due to economical and practical reasons.
To recover part of the remaining oil after the primary recovery, water is injected into injections wells while oil is produced through production wells. This process serves to maintain high reservoir pressure and flow rates. This stage of oil recovery is called waterflooding and it is one of the most used secondary oil recovery method. [8]
In this recovery stage, if the reservoir pressure is above the bubble point pressure of the oil phase, then there ~~us~~ is two-phase immiscible flow, one phase being water and the other being oil, without mass transfer between the phases.[8]Non-immiscible assumption is important when modeling mathematically waterflooding performance.

According to Rahman (1991) the effectiveness of waterflooding in a reservoir depends on three factors: macroscopic displacement and the areal and vertical sweep efficiency which are going to be treated in details in later chapters. SECTIONS
The key factor in waterflooding is the amount of oil displaced by the displacing fluid.
? To measure it, an overall displacement efficiency factor has been defined as the product of the microscopic and macroscopic displacement efficiencies.
As in the equation $E = E_D E_V$ (1) EQNS IN A SINGLE LINE!
E is the overall displacement efficiency which is a measure of the oil recovered from the process. E_D is the fractional microscopic displacement efficiency measuring how effectively the displacing fluid moves the oil from the pores in the rock. E_V measures the effectiveness of the displacing fluid in sweeping vertically and areally the volume of a reservoir therefore moving the oil towards production wells and it is expressed as a fraction. Efficiency factors are functions of the initial oil saturation S_{oi} and the residual oil saturation S_{or}.

?

An important factor for good macroscopic efficiency is the density difference between the displacing and the displace fluid, which will be further investigated during the fluid-dynamic simulation.

2 Fluid and rock properties and background theory

3.1 Interfacial Tension (IFT)

Def ???

As already mentioned in the EOR state of art review, interfacial tension (IFT) is an important property to be considered in waterflooding performance.

IFT is a thermodynamic property of the interface which origins when two phases with limited solubility come in contact. It is a measure of miscibility; the lower the IFT, the most likely the two phases are going to mix.

3.2 Porosity

Porosity of a rock measures the storage capacity (pore volume) which is capable of holding fluids. [9]

Due to cementation in past geological areas, some of the void spaces formed in reservoir became isolate from other void spaces whereas other remained interconnected to each other. Reservoir engineering literature distinguish between absolute and effective porosity.

The absolute porosity is the ratio between the total rock pores space to the bulk volume.

The effective porosity is defined as the ratio of the interconnected pore space to the bulk volume as in equation 2:

$$\phi = \frac{interconneted\ pore\ volume}{total\ volume} \qquad (2)$$

Since the effective porosity represents the interconnected pore space that contains the hydrocarbon to recover, it is the parameter used for all reservoir engineering calculations.

3.2 Saturation

Saturation of a fluid is the ratio of the pore volume occupied by α to the total void space or pore volume. Mathematically it is expressed by:

$$S_{\alpha} = \frac{total\ volume\ of\ \alpha}{pore\ volume} \quad (3)$$

In reservoir fluids, α is either oil, water or gas and saturation of each phase is therefore indicated as $S_o = oil\ saturation$ and $S_w = water\ saturation.$

Since saturation is a ratio or percentage: $\sum S_{\alpha} = 1$, where S_{α} is the saturation of a specific phase or fluid α. FRACTION

In waterflooding performance two terms of saturations are important: irreducible water saturation S_{iw} and residual oil saturation S_{or}.

Irreducible water saturation S_{iw} is the initial amount of water in the reservoir before starting the waterflooding process, when the hydrocarbon content is maximum.

Residual oil saturation S_{or} is the amount of oil which cannot be recovered.

3.3 Wettability

Wettability is defined as the tendency of one fluid to spread on and adhere to a solid surface in the presence of other immiscibile fluids. [9]

If a rock is water-wet, the water will tend to occupy small pores and be in contact with most of the rock surface which is the ideal situation for anyone wishing to extract oil from a reservoir. In an oil-wet system, the rock retains the oil in its small pore spaces, making production more difficult. [10]The spreading tendency of the liquid to adhere to a solid phase is usually expressed measuring the contact angle θ between the liquid and solid phase. If $\theta$is greater than 90°, the system is oil-wet therefore the pores in the rock retain oil increasing difficulty in recovery. If θ is smaller than 90°, the system is water-wet, water will occupy small pores in the rock increasing the surface contact therefore facilitating oil recovery. Wettability is the most important factor influencing relative permeability curves. [11]

3.4 Areal sweep efficiency and vertical sweep efficiency

FLOODING

As anticipated in the introduction, microscopic displacement and areal and vertical sweep efficiency are important parameters to determine waterflodding performance. The overall waterflooding performance is obtained by multiplying these three factors.

Microscopic displacement efficiency is a measure of how easily the oil can be removed from the rock pores. [10]

Vertical sweep efficiency (E_v) measures the uniformity of water invasion in a vertical cross section. Vertical sweep efficiency is less than one in heterogeneous media meaning that waterflooding performance is decreased.

Areal sweep efficiency E_A is a measure of how much of the reservoir has been in contact with the flood water in an areal plane. [10]

If water displaced oil with a uniform front, E_A would be one at breakthrough, when the well starts producing some of the water injected.

Unfortunately, the difference in densities between water and oil and the presence of heterogeneities in the reservoir cause water to penetrate or finger with a non-uniform front through oil zone. This phenomenon is called Viscous Fingering.

Both the areal and vertical sweep are dependent on ~~a~~ several factors including permeability, wettability, reservoir thickness, fluid characteristics and injection rate.

3.5 Capillarity pressure

Combined effects of rock and fluids interfacial tensions, pore size and geometry and the wetting characteristics of the system result in capillarity forces.

When two immiscibile fluids are in contact, a discontinuity in pressure exists between the two fluids, which depends upon the curvature of the interface separating the fluids.[9] The capillarity pressure (p_c) is defined as following:

$$p_c = P_o - P_w \quad (4)$$

Capillarity is influenced by the saturation direction change phenomena like drainage and imbibition. Drainage occurs when a wetting phase (water in waterflooding case) is displaced by a non-wetting phase (oil). On the other hand, imbibition occurs when a non-wetting phase is displaced by a wetting phase.

3.6 Permeability and relative permeability

Permeability is a property which measure the ability of the porous media to transmit fluids. ?

In multiphase flow, relative permeability (k) describes how the presence of one phase changes the ability to flow of the other phases in the same porous media.[11] As capillarity, relative permeability is a function of saturation change (drainage and imbibition). Relative permeability is also influenced by wettability, pore geometry and surface tension. Correlation of relative permeability helps predicting the fluid flow in porous media.

Corey's correlation is one of the most accepted equations for the correlation of water-oil relative permeability. However this parameter is suitable only for well-sorted homogeneous rock.

$$k_{rw} = (k_{rw})_{S_{or}} \left[\frac{S_w - S_{iw}}{1 - S_{iw} - S_{or}}\right]^{n_w} \quad (5)^{[9]}$$

$$k_{ro} = (k_{ro})_{S_{iw}} \left[\frac{1 - S_w - S_{or}}{1 - S_{iw} - S_{or}}\right]^{n_o} \quad (6)$$

where k_{rw} relative permeability of water

k_{ro} relative permeability of oil

$(k_{rw})_{S_{or}}$ relative permeability of water at residual oil saturation

$(k_{ro})_{S_{iw}}$ relative permeability of oil at irreducibile water saturation

S_w water saturation

S_{iw} irreducibile water saturation

S_{or} residual oil saturation

n_w Corey's water exponent

n_o Corey's oil exponent

Corey's exponents vary depending on wettability.

This needs to be part of the text!!

*1

3.7 Mobility ratio

The fluid mobility (λ) is defined as the ratio between the effective permeability k_e and the viscosity of the fluid μ.

$$\lambda = \frac{k_e}{\mu} \quad (7)$$

where λ is the fluid mobility (darcy/dp)

k_e $effective\ permeabilty$

*1

Waterflooding is driven by the mobility ratio MR which is defined as the ratio between the mobility of the displacing fluid (water in this case) and the mobility of the displaced fluid (oil in this case).

$$MR = \frac{\lambda_w}{\lambda_o} \qquad (8)$$

where λ_w mobility of displacing fluid (water) and λ_o mobility of diplaced fluid (oil).

Waterflooding process takes into account immiscible flow. The mobility of the water is evaluated at the average saturation behind floor front ($\bar{S}_{wf}$) whereas the mobility of the oil is evaluated at the irreducible water saturation ($\bar{S}_{iw}$).

The mobility of waterflooding process based on average saturation in flooded area is defined by Eq. 9

$$MR = \frac{\lambda_w}{\lambda_o} = \frac{(\frac{K_{rw}}{\mu_w})\,\bar{S}_{wf}}{(\frac{K_{ro}}{\mu_o})\,\bar{S}_{if}} \qquad (9)$$

The physical meaning of MR is the ability of water to flow to respect to oil. [11]

If the mobility ratio MR is greater than one, water flows faster than oil and penetrates through oil saturated areas, resulting in low sweep efficiency.

When MR is equal or less than one, water moves slower than oil with uniform front, resulting in high areal sweep efficiency.

4. Heterogeneity

An important concept to characterize a reservoir is heterogeneity.

The porous media is considered as homogeneous with regard to a specific property if that particular parameter is constant all over the interested domain otherwise is called heterogeneous. [12]

Since heterogeneity includes many different aspects including macroscopic, microscopic and megascopic heterogeneities for the purpose of this investigation only porosity and permeability are going to be investigated in depth. The reservoir heterogeneity is then defined as a variation in reservoir properties as a function of space.[9]

Example of reservoir heterogeneity are differences in permeability, fractures, flow barriers, heterogeneous (uneven) permeability and porosity distribution.

In most cases, reservoir heterogeneity will result in early breakthrough and poor areal sweep, resulting in large pockets of bypassed oil.[13]

An approach to define heterogeneity is the layer-cake permeability.

In the layer-cake or stratified configuration, each layer is unique with respect to its range and continuity of permeability; hence, each layer posses an over-all permeability average and areal extent different from that of its neighbor. [3]

However the model described in the layer-cake scheme is unlikely to be true.

Alpay (1972) then introduces the concept of Band of Generic Similarity (BGS) according to which tiny layers with permeability ~~in~~ OF the same range are included into a stratified band.

Historically reservoir heterogeneities have been studied through core sample, x-ray and well log data.

More recent approaches to characterize heterogeneities in reservoir include Artificial Neural Network (ANN) and Backpropagation Neural Network (BPNN). HOW? WHY?

Reservoir heterogeneity can be mathematically modeled by static and dynamic schemes. [13]The static model defines levels of heterogeneity based on statistical data of permeability and porosity. The main assumption is that stratified layers are non communicative stratified layers in the reservoir.

On the other hand, the dynamic scheme takes into account flow rates, well patterns and fluid properties together with the statistical data of the rock.

MODELED OR REPRESENTED?

4.1 Static scheme

TH TO

The most common used parameter for describing reservoir heterogeneity is permeability of Dysktra and Parsons (V_{dp}).[13] Dykstra and Parsons introduced in 1950 the concept of the permeability variation coefficient V_{dp}, which is a statistical measure of non-uniformity of a set of data. This model assumes that the permeability data are log-normally distributed. [9]

In the model, the probability at percentile 50 is the median probability (k_{50}) and the probability at one standard deviation from the latter is the permeability at percentile 84.1 ($k_{84.1}$)

$$V_{dp} = \frac{\textit{standard deviation}\ (\log(k))}{\textit{average}\ (\log(k))} = \frac{k_{50} - k_{84.1}}{k_{50}} \quad (10)$$

(*1)

where V_{dp} permeability of Dysktra and Parsons

k_{50} permeability at percentile 50 of the log distributed data

$k_{84.1}$permeability at percentile 84.1 of the log distributed data

Jensen and Currie proposed and improved Dysktra and Parsons coefficient which defines reservoir heterogeneities through a non logarithmic distribution. [14]

However, Dysktra and Parsons coefficient does not take into account the connectivity of permeability heterogeneity which is one of the main characteristic of a heterogeneous reservoir.

4.2 Dynamic scheme

As previously outlined, dynamic schemes consider the interaction between the flow and heterogeneity. Koval's heterogeneity factor (H_k) is the most used parameter in dynamic models. Koval's factor was originally developed to include the effect of heterogeneities in the study of viscous fingering in a porous media.[13]

It is defined as:

$$H_k = \frac{1}{t_{Dbreaktrough}}$$

(number?)

where H_k Koval's heterogeneities factor

$t_{Dbreaktrough}$ dimensionless time to breakthrough defined as the ratio between the total volume of water injected to the pore volume.

Koval's parameter is equal to one for homogeneous reservoir and increases with heterogeneity.

5. Viscous fingering

During waterflooding water is injected in the well to displace oil. The displacing fluid is less viscous than the displaced fluid and under this unfavorable viscosity distribution, the interface between the two fluids is unstable and ''finger-like'' patterns grow in the course of time.[2]

The mechanism of viscous fingering growth in a homogenous porous media can be explained by three main patterns which are tip splitting, shielding and spreading.[15]

In waterflooding, the viscosity difference between water and oil causes the surface tension to decrease resulting in poor areal sweep efficiency, tips splitting and non-uniform front. Viscous fingering phenomena therefore decrease waterflooding performance and oil recovery.

Viscous fingering usually occurs at unfavorable mobility ratio (MR greater than one).

In EOR the most used solution for unfavorable mobility ratio is to apply polymer flooding process. The viscosity of the polymer is much higher than the viscosity of water and therefore the MR is reduced. [1]The polymer has a big molecular structure which can be trapped in the porous media therefore reducing the effective permeability of water without changing the properties of the oil. As a result, Mobility ratio MR decreases.

The presence of heterogeneities and how difference in porosity and permeability affect viscous fingering in a reservoir is going to be investigated in the computational fluid dynamic simulation of this project.

IMPES IS ONE OF THE METHODS USED IN RESERVOIR SIMULATION!!

6. Set of Methods and Mathematical Models

SECTION

In this chapter an overview of reservoir simulation and of the IMPES method, the most used method to solve waterflooding problems is going to be given. ?

6.1Governing equations of waterflooding

The mathematical model of waterflooding is based on the assumption of two-phase immiscible flows. Since the two phases (water and oil) are not miscible, the mass is conserved. Other assumption are that the fluids are Newtonian, the, porous media are not deformable and the flow in the porous media fracture is negligible.

The conservation of momentum equation is given by Darcy's law.

The model is then coupled with the saturation equation and the capillarity equation.

In a two phase non-miscible model as considered in this investigation water is the wetting phase and oil is the non-wetting phase.

Mass for each phase is conserved according to eq. 11:

$$\frac{\partial(\emptyset \rho_\alpha s_\alpha)}{\partial t} = \nabla \cdot (u_\alpha \rho_\alpha) + q_\alpha \qquad (11)$$

where α is the subscript indicates the phase of the fluid (w for water and o for oil)

(*1)

s_α is the saturation of phase α

u_α is the velocity of each phase

ρ_α is the density of each phase

q_α is the source of sink term of each phase

$\emptyset$ is the porosity

The conservation of momentum equation according to Darcy's law is expressed in eq. (12)

$$u_\alpha = -\frac{k_{r\alpha}}{\mu_\alpha} K(\nabla P_\alpha - \rho_\alpha g \nabla z) \qquad (12)$$

where u_α is the Darcy's velocity of each phase

$k_{r\alpha}$ is the relative permeability of phase α

μ_α is the dynamic viscosity of phase α

K is the absolute permeability tensor

∇ is the gradient operator

P_α is the pressure of phase α

ρ_α is the density of phase α

z is the potential depth

g is the gravitational acceleration

FONTS

Substituting Eq. 12 into Eq.11, the governing equations for the water and oil phase are obtained as shown in Eq.13 and Eq.14 respectively.

Water; $$\frac{\partial(\phi s_w)}{\partial t} = \frac{k_{rw}}{\mu_w} K\nabla \cdot (\nabla P_w - \rho_w g \nabla z) + q_w \quad (13)$$

Oil; $$\frac{\partial(\phi s_o)}{\partial t} = \frac{k_{ro}}{\mu_o} K\nabla \cdot (\nabla P_o - \rho_o g \nabla z) + q_o \quad (14)$$

Equations 13 and 14 are then coupled with the saturation equation (Eq. 15) and the capillarity equation (Eq.16), which are peculiar quantities of multiphase flow.

natural saturation constraint

Total saturation equation; $$S_w + S_o = 1 \quad (15)$$

Where S_w is the water saturation

S_o is the oil saturation

Capillarity pressure equation; $$P_c = P_o - P_w \quad (16)$$

Where P_c is the capillarity pressure which is the pressure difference between the two phase

P_o is the oil phase pressure

P_w is the water phase pressure

The total velocity is then defined in Eq. 17 as:

$$u = u_o + u_w \qquad (17)$$

The capillarity pressure equation (Eq. 16) and Darcy's law (Eq.12) are then substituted into Eq. 17 to yield the total velocity expressed in Eq. 18

$$u = -K[\lambda(S)\nabla p - \lambda_w(S)\nabla P_c - (\lambda_w \rho_w + \lambda_o \rho_o)(g \nabla z)] \qquad (18)$$

where $\lambda = \lambda_w + \lambda_o$ total mobility of fluid

$\lambda_w = \frac{k_{rw}K}{\mu_w}$ mobility of water

$\lambda_o = \frac{k_{ro}K}{\mu_o}$ mobility of oil

K is the absolute permeability tensor

∇ is the gradient operator

P_c is the capillarity pressure

P_o is the oil pressure

ρ_w is the density of water

ρ_o is the density of oil

z is the potential depth

g is the gravitational acceleration

6.2 IMPES method

Waterflooding governing equations can be solved by several numerical methods.

IMPES (Implicit Pressure Explicit Saturation) method consists in solving the pressure and saturation equation separately. It was developed by Sheldon et al. (1959) and Stone and Garder (1961).[8] The pressure equation is solved implicitly with respect to time and the saturation equation is solved explicitly with respect to time. It has been assumed that the flow is incompressible and that the oil pressure P_o and the water saturation S_w are the primary variable.

By taking the derivative with respect to time of Eq. 15, the total saturation term is zero $\left(\frac{\partial(S_o+S_w)}{\partial t}\right) = 0.$

Adding Eq. 13 to Eq.14 the saturation term is eliminated, yielding the **pressure equation** as shown in Eq. 19.

Pressure equation:

$$-\nabla \cdot (\lambda K \nabla P_o) = (q_w + q_o) - \nabla \cdot [\lambda_w K \nabla P_c + (\lambda_w \rho_w + \lambda_o \rho_o) g \nabla z] \qquad (19)$$

where $\lambda = \lambda_w + \lambda_o$ total mobility of fluid

$\lambda_w = \frac{k_{rw}K}{\mu_w}$ mobility of water

$\lambda_o = \frac{k_{ro}K}{\mu_o}$ mobility of oil

K is the absolute permeability tensor

∇ is the gradient operator

P_c is the capillarity pressure

P_o is the oil pressure

q_w is the water phase source term

q_o is the oil phase source term

ρ_w is the density of water

ρ_o is the density of oil

z is the potential depth

g is the gravitational acceleration

You have already defined these terms in Eqns 11, 12 & 18.

(-X)

The pressure equation is solved implicitly, it is therefore evaluated the capillarity pressure and mobility, which are function of saturation, at the present time t^n to compute the value of pressure at a future time t^{n+1}.

3C PE

The **saturation equation** (Eq.20) is obtained by applying the mass conservation equation (Eq. 11) and Darcy's law (Eq.12) to Eq. 19

$$\phi \frac{\partial s_w}{\partial t} = q_w - \left[\boldsymbol{K} f_w(S) \lambda_o(S) \left(\frac{dP_c}{dS} \nabla S + (\rho_o - \rho_w) g \nabla z \right) + f_w(S) \boldsymbol{u} \right] \quad (20)$$

where $f_w(S) = \frac{\lambda_w(S_w)}{\lambda(S_w)}$ fractional flow function

SATURATION (?)

The pressure equation is then solved explicitly, with coefficients evaluated at a future time t^{n+1}.

IMPES method solves the waterflooding equations at the time t^n to evaluate oil pressure and water saturation at the next time step t^{n+1}.
Therefore the time step $\Delta t = t^{n+1} - t^n$ must be small for the IMPES method to be valid.
Since in fluid flow in porous media pressure changes less rapidly in time than saturation, classical IMPES spends most of the time computing implicit pressure calculation. An Improved IMPES method has been proposed by Chen et al. which is valid for solving two-phase flow coning problems. [8]

7. Reservoir Simulation

Nowadays reservoir simulation is the most powerful tool to solve all the aspect of reservoir engineering and to predict reservoir performance.

The first step in reservoir simulation is modeling its physical characteristics through mathematical equations. This step is defined as the *formulation* step. The mathematical equations are then applied to control volume in the reservoir. Newton's approximation is used to convert these control volume equations into a set of coupled, nonlinear partial differential equations (PDEs) that describe fluid flow through porous medium.[16] There are then three different types of PDE: Elliptic, Parabolic and Hyperbolic. The

(?)

e p h

discretization step transforms PDEs into non-linear algebraic equations by numerical methods such as finite difference method, which uses Taylor expansions to discretize PDEs. Fluid production and injection terms are included into the governing equation in the *well representation* step. The non-linear algebraic equations are then linearized in space and time. The *validation* step is the final decision-making process which checks that no errors have been made in the previous steps and that the simulator is ready to be used in practical reservoir application. Figure 1 shows the process of developing a reservoir simulation. [Adapted from [17]]

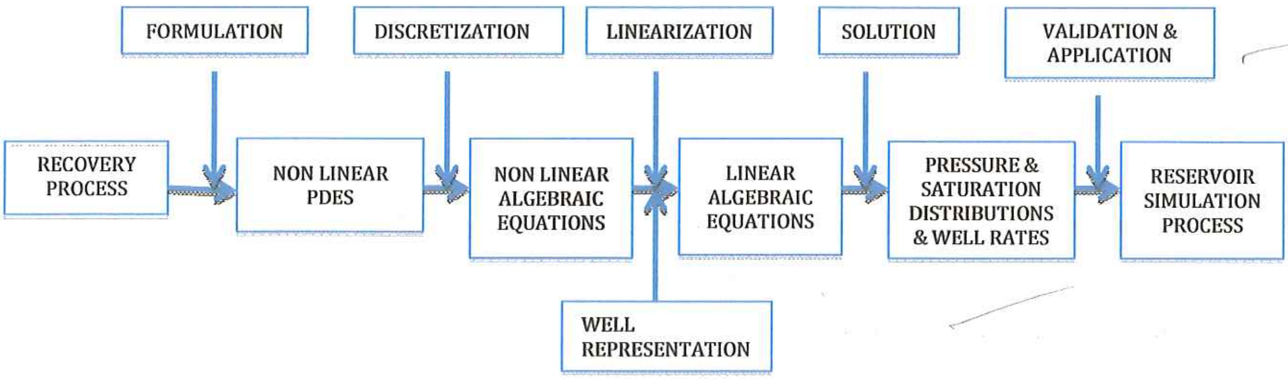

Figure 1: Steps to develop reservoir simulator. Adapted from [17] 6

8. Conclusions

From the literary review undertaken in the winter term, a good measure of heterogeneity had been found to be the Dysktra-Parson coefficient for a static model, where interaction between fluidand heterogeneity are not considered, and the Khoval coefficient for dynamic model, where interaction between fluid and reservoir heterogeneity are taken into account.

Waterflooding performance decreases with unfavorable mobility ratio (MR greater than one).

Polymer flooding has been found to be one of the most used methods to mitigate effects of unfavorable mobility ratio.

8.1 Further recommendation for Spring Term

Computational Fluid Dynamic simulations on Fluidity will be carried out during the spring term to better understand how heterogeneity and viscous fingering phenomena influence waterflooding performance.

Further literature review on other methods to identified and contrast viscous fingering growth other than polymer flooding will be investigated in the spring term.

Characterization of heterogeneity in the Fluidity simulation will be addressed further in this course.

The focus of Fluidity Simulations will be to investigate which parameters including viscosity and density instabilities influence viscous fingering and therefore waterflooding performance.

A critical analysis on the results obtained during the simulation will be carried out.

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(*) Book, PhD/MSc Thesis, Technical Report, ...?

Appendix A Risk Assessment

What are the hazards?	Who might be harmed and how?	What are you doing and what further action is necessary?
Visual fatigue	Since the project requires mainly computational work, visual fatigue might result while working for many hours in front of a screen.	Avoid sitting for long periods in front of a computer.
Electrical	Electrical shocks might occur while working with computers.	Check that electrical equipment used is not faulty.
Musculoskeletal disorders and injuries	Sitting in a wrong posture while working for long hours in front of a monitor will result in back and muscular problems.	Take breaks, sit in the right posture and use a suitable chair.
Lone Working	Sudden illness or accident could happen to staff and students when working alone and they might be unable to get help.	Another person should be present in the room or nearby.