ABSTRACT

Water injection (waterflooding) is the commonly used method in most fields in the world to increase the hydrocarbons recovery. It is basically the pumping of water through an injection well into the reservoir. The Rosebank field used as a case study, is located in deepwater-offshore of the West of Shetland Islands, UK with a depth of 1,100 m (3,700 ft); right from the onset of the field, water injection has been implemented. Hence, secondary recovery mechanism is applied to optimize the oil production through waterflooding/water injection. The water injected into the reservoir assists to sweep the oil towards the production wells. The project aims to recover the oil-in-place optimally from the reservoir with respect to the operational constraints encountered and ensures realistic reservoir management.

This dissertation shows how reservoir simulation (RS) software (eclipse) was used to optimize water injection (waterflooding) under various operational constraints to forecast the Rosebank field performance for 20 years prediction. In order to achieve maximum oil production, different Cases were considered under each operational constraint with respect to the Base Case (initial production) of the Rosebank field in real life challenges. The economic impact was also analysed to evaluate the influence of the redrill case injection well and drill case for producing well.

After successful simulation of the field production for 20 years as predicted, 46.53 % of the oil-in-place was recovered in the Base Case – injection well C3I2, C3I3, C3I4 and C3I5 injects 10,000 STB/DAY each with respective pressure of 5,000 psia. Real life situation of the reservoir operational constraints was handled to ensure continuous production. For Constraint 1- injection well C3I5 was shut-in after year 3, Case 4 - the injection rate of injector C3I2, C3I3 and C3I4 increased to 15,000 STB/DAY and their respective pressure to 5,500 psia; it was recommended due to its high cumulative oil production close to the Base Case when compared to other 3 Cases used. During Constraint 2 – work over of injector well C3I5 or redrill of new injection well C3I6 in a new location to bring it back after year 4; the valve manufacturer advised that based on the operational limit of the surface chokes and valves which were recently lowered from a 20,000 STB/DAY to a 13,500 STB/DAY, the recommended Case 4 above cannot be implemented. Consequently, Case 3 (injection rate of C3I2, C3I3 and C3I4 increased to 13,340 STB/DAY and respective pressure increased to 5,500 psia) in constraint 1 became the best option, this Case was used to ascertain the economic impact of work-

over injection well C3I5 or redrill a new injection well C3I6 in a new location to sweep more oil to the producing wells considering their cost. Work-over injection well C3I5 was recommended due to its economic impact with respect to the cumulative oil production in both options. Finally, Constraint 3 was to drill a new producing well at the start of year 7. Two locations (133i, 62j and 106i, 63j) in the reservoir were considered in order to discover the best placement based on reservoir properties such as porosity, permeability, reservoir depth, oil saturation, pressure and cost of drilling using Constraint 1_Case 3 as the base case. Location 2 (106i, 63j) was recommended because it gives higher percentage of oil recovered (50.38%) compared to the initial Base Case recovery.

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LIST OF SYMBOLS AND ABBREVIATION

φ = Porosity

φ_c = Absolute porosity

Q = Flow rate (bbl/day)

K = Absolute permeability (mD)

P_1 and P_2 = Pressure (psia)

μ = Viscosity (cP)

L = Length (ft)

A = Cross-sectional area (ft^2)

S_o = Oil saturation

S_g = Gas saturation

S_w = Water saturation

C3I2, C3I3, C3I4 and C3I5 = Initial injection Wells

C3I6 = New drilled injection Well

C3P2, C3P3, C3P4 and C3P8 = Initial production Wells

C3PD= New drilled production Well

MNPV = Minimum pore volume

FIPNUM = Fluid-in-place region numbers

EQLNUM = Equilibration region numbers

PVTNUM = Pressure volume temperature region numbers

SCAL = Scaling

COMPDAT = Well completion specification data

WCONPROD = Control data for production wells

WCONINJE = Control data for injection wells

WELSPECS = Introduces a new Wells

FWPT = Field water production total

Wrt = With respect to

C1N = Colsay 1 North

C1S = Colsay 1 South

CHAPTER 1: INTRODUCTION

About 60% of the worldwide current primary energy supply is obtained from oil and natural gas [1]. Today the demand is very high and in the next decades, it is expected to increase. It is important for the operations of a field to be effective; the development of new fields is very expensive and technically challenging. However, due to the high expense of discovering and developing a new field, it gives economic motivation to maximize production from the new or existing fields. These factors led to the development and application of good methodologies for the optimization of oilfield operations to maximize oil production and develop an optimal water injection strategy that deals with the various operational constraints using Rosebank field data as a case study.

- ❖ The project background is to evaluate the Rosebank field which is being developed for a waterflooding with crestal producers and peripheral injectors; this field lies in deep water in the West of Shetlands region.
- ❖ The project objective is to simulate (using Eclipse) the real life challenges that the Rosebank asset will throw up over the course of its field life. Secondly to develop an optimal water injection strategy that deals with various operational constraints and other decisions that will be taken to optimize oil production including realistic reservoir management and the economic impact analysis.

1.1 History of Rosebank field, its location and properties

The Rosebank field was discovered December 2004 with a water depth of 1,100m (3,700ft) in deepwater-offshore of the West of Shetland Islands, UK lies in block 213/26 and 213/27 (see Fig 1 and 2) operated by Chevron(40%) partner with Statoil (30%), OMV (20%) and Dong E &P (10%) [2]. It was the 1st Northwest European field to find oil between volcanic rocks

The geology of the oil discovery is that the field reservoir is an intra and sub basalt four way inversion structure that is made up of siliciclastic fluvial and shallow marine sandstones which is estimated [2] to hold about 240million barrels of oil equivalent. The field development imposed various challenges due to harsh environmental conditions and undeveloped with the absence of infrastructure.

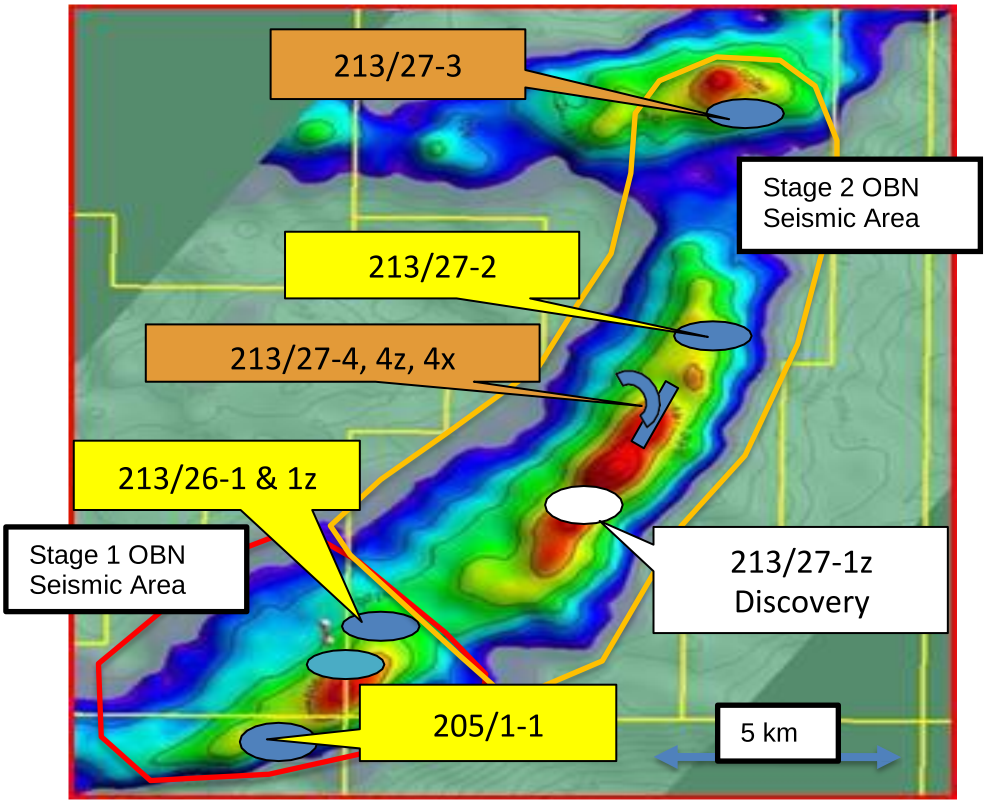

Fig 1.1: Rosebank map & appraisal activity [2]

Fig 1.2: Full-field cross section [2]

According to my technical instructor, during field appraisal programme, lots of data were collected as shown on Table 1 from drilling. Colsay 1 and 3 are the key reservoirs mapped out (see Fig 2), C1N contains gas at the same depth as oil found in C1S and the reservoir normally pressured close to bubble point.

Colsay 3 (C3) has highly permeable fluvial sands with marine sands, for the purpose of this dissertation; Colsay 3 is the only reservoir to be considered.

Table 1.1: Typical Rosebank reservoir properties [2]

Formation / Geologic Age	Paleocene Rosebank (Colsay sands) and Jurassic Lochnagar (Rona sands)		
Lithology / Depositional Type	Rosebank – Siliciclastic sandstone deposited in a fluvial to shallow marine environment Lochnagar - Siliciclastic sandstone deposited in a shallow marine environment		
Depletion Mechanism	Water Injection with possible aquifer support.		
Average Depth (ft)	9100' (Colsay)	**Average Net pay (ft)**	125' (Colsay)
Average NTG	Colsay 1 = 0.3, Colsay 3 = 0.7	**Productive Area (acres)**	Colsay 1 = 12,000 acres, Colsay 3 = 6,500 acres
Average Porosity	0.21-0.23 (Colsay)	**Average Permeability (mD)**	100 - 1500 - 4500
Initial Water Saturation	0.3 (Colsay)	**Reservoir Temperature (F)**	175
Oil API / % Sulphur	37 ° / ??	**Gas SG (Air =1)**	
Oil Viscosity	0.68 - 1.08 cP (Colsay)	**Water viscosity**	0.36 cP
Boi rb/stb	1.31 (Colsay)	**Initial GOR**	650 - 750 scf/stb (Colsay)
Initial Pressure	4066 psi (Colsay)	**Bubble Point pressure**	3820 - 3920 psi (Colsay)
Oil-Water-Contact ft	9305 & 9377 (Colsay1 & 3)	**Gas Oil Contact ft**	9089 - 9134 (Colsay1N & 2)
Dip Angle - degrees	0 – 4 deg	**HCIIP (P10-P50-P90)**	432 – 584 – 838 mmbbls

Before discussing the methodology and results of optimization of water injection under operational constraints, an understanding of fundamental concepts on reservoir will help to ease the approach.

1.2 Concept of Waterflooding

According to L. P. Dake [3], “waterflooding is defined as adopting a policy of water or gas injection, with the aim of complete or partial pressure maintenance and accelerated development through the positive displacement of oil towards the producing wells”. Waterflooding is a type of secondary recovery by which water is injected through the injection well(s) into the reservoir formation (fluid). This act physically sweeps the displaced oil to the adjacent producing wells, this show the breakthrough point of the injection system. High watercut (% of water produced as against the liquid produced) will occur from the producer well until it becomes uneconomical to run the field after the breakthrough point (water injected to maintain the reservoir pressure via injection wells breaks through to one or more of the producing wells). At this point, other tertiary recovery methods (steam or chemical injection) or enhanced oil recovery can be used [4].

Water injection is currently the injection method used round the world and today is without question responsible for the current high level of production rate and reserves [5]. The world consumption is increasing gradually and the total amount of new discoveries are decreasing rapidly, the best method to bring the gap close is to produce existing field more efficiently to meet the future demand and consumptions. The challenge with waterflooding techniques is inefficient recovery due to variable permeability or similar conditions affecting fluid transport within the reservoir and early water breakthrough that may cause production and surface processing problems.

1.3 Fundamental theories of waterflooding factors

Some factors need to be considered for waterflooding and these factors are:

- **Reservoir geometry:** Natural features like aquifers (the body of rock whose fluid saturation, porosity and permeability permit production of groundwater) and petroleum reservoirs have boundaries. The reservoir structure map (contours of the subsea depth) is projected onto the top surface of the reservoir. The grid extending through the thickness of the reservoir is projected vertically downward. It is clear that this grid is not orthogonal and cross derivatives will be required to properly describe the flux. Usually, these cross derivatives are neglected. Areal geometry influences well & facilities locations, and If offshore, number and location of platform(s) may provide insights on aquifer location & strength.

- **Lithology:** The lithology describes the physical characteristics of rock types, clay type and content, mobile clays and swelling clays (e. g. Montmorillonite--is a very soft phyllosilicate group of minerals that typically form in microscopic crystals, forming a clay) of the reservoir.
- **Porosity:** This is a physical characteristic in the rock that contains spaces which stored fluid and later allow the fluid to flow. If the rock has openings, voids and spaces in which liquid and gas may be stored, it is said to be porous. Porosity is the ratio of the pore volume to the total volume (bulk volume) [6]. It can be expressed mathematically as:

$$\varphi = \frac{Pore\,Volume}{Bulk\,Volume} \text{ (Where } \varphi = \text{porosity)} \tag{1.1}$$

The two types of porosity are Absolute and Effective porosity due to the deposition formation of the rocks creating any void spaces which isolated from the other void spaces by excessive cementation, most of the void spaces are interconnected while some of the pore spaces are completely isolated [7].

Absolute porosity: The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume.

$$\varphi_a = \frac{Total\ Pore\ Volume}{Bulk\ Volume} = \frac{Bulk\ Volume - Grain Volume}{Bulk\ Volume} \tag{1.2}$$

(Where φ_a = absolute porosity)

Note: A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection.

Effective porosity: The effective porosity is the percentage of interconnected pore space with respect to the bulk volume.

$$\varphi = \frac{Interconnected\ Pore\ Volume}{Bulk\ Volume} \tag{1.3}$$

(Where φ = effective porosity)

The effective porosity is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids [6]

- **Permeability:** Fluid movement in porous media is governed by three forces: viscous, capillary and gravitational. These forces depend on the properties of the porous media and fluids. This is also known as absolute permeability - ability of the porous media to transmit fluids.

  Fluids pass through irregular expanding and confining pathways at a microscopic level [8]. It would be a daunting task to calculate the frictional losses and compressional effects through the media at this level. Fortunately, on a lab scale to the field scale, Darcy's empirical equation holds and greatly simplifies the analysis. The single phase Darcy equation for steady state conditions is [8]:

$$Q = \frac{0.001127kA(P_1 - P_2)}{\mu L} \tag{1.4}$$

Where; Q = flow rate (bbl/day), k = absolute permeability (mD), P = pressure (psia), μ = viscosity (cP), L = distance (ft), A = cross-sectional area (ft^2)

Darcy's equation is a part of many of the flow analysis done by petroleum engineers.

- **Fluid saturations and distributions:** Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water) [6]. This property is expressed mathematically by the following relationship [6]:

$$Fluid\ Saturation = \frac{Total\ Volume\ of\ fluid}{Pore\ Volume} \tag{1.5}$$

In terms of the concept of saturation to each reservoir fluid;

$$Oil\ Saturation,\ S_o = \frac{Volume\ of\ oil}{Pore\ Volume} \tag{1.6}$$

$$Gas\ Saturation,\ S_g = \frac{Volume\ of\ gas}{Pore\ Volume} \tag{1.7}$$

$$Water\ Saturation, S_w = \frac{Volume\ of\ water}{Pore\ Volume} \tag{1.8}$$

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zeros to 100%. By definition, the sum of the saturations is 100% [6].

$$S_g + S_o + S_w = 1 \tag{1.9}$$

The fluids in most reservoirs are believed to have reached a state of equilibrium as it becomes separated according to their density, i.e., oil between gas and water. In addition to the bottom (or edge) water, there will be connate water (water existing in the reservoir at recovery) distributed throughout the oil and gas zones. The water in these zones will have been reduced to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as capillary forces because they are important only in pore spaces of capillary size.

The saturation and distribution has high S_w (risky), lower moveable oil target, free gas saturation, higher free gas saturation, longer waits for flood response, uneven fluid distributions, depleted reservoir often have gas at the top, primary or secondary gas caps complicate waterflood and bottom water drive may cause problems. The fluid saturation can be in the below state of saturation:

1. **Critical oil saturation** (S_{oc}) **:** For the oil phase to flow, the saturation of the oil must exceed a certain value which is called critical oil saturation. At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow.
2. **Residual oil saturation** (S_{or}) : During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment) there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the residual oil saturation (S_{or})
3. **Movable oil saturation** (S_{om}) **:** Movable oil saturation is another saturation of interest and is defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

$$S_{om} = 1 + S_{wc} + S_{oc} \tag{1.10}$$

Where; (S_{wc} = connate water saturation and S_{oc} = critical oil saturation)

- **Reservoir depth:** When considering water injection, the drilling costs as a function of depth of the reservoir, dual porosity systems, temperature gradient, and oil viscosity vs. temperature must be considered. If primary operations were extensive, fracturing (maximum Injection pressure vs. depth) and fracture type (vertical vs. horizontal) are all important factors of waterflooding.
- **Continuity of rock properties:** Hydraulic connectivity is critical, variance in permeability, spatial location of the different permeable layers, faults & fractures, location, orientation, length, conductivity, effective permeability on an inter-well basis and cross-bedding. However, temperature, pressure and composition of the fluids in place are factors.
- **Pressure, temperature, FIP:** This keeps average reservoir pressure high, improved well hydraulics equipment costs are higher for increasing pressures; waterflood should always be evaluated while considering the project life-cycle with other enhanced oil recovery methods in mind. Temperature and composition of fluids in place (FIP) are factors to be considered.

1.4 Relationship between porosity-permeability-saturation

Timur [9] put forward the following expression for estimating the permeability (K) from connate water saturation (S_{wc}) and porosity (φ) through experiment:

$$K = 8.58102 \frac{\varphi^{4.4}}{S_{wc}^{\ 2}} \tag{1.11}$$

Morris et al [7] also put forward the following two expressions for estimating the permeability if oil and gas reservoirs:

For oil reservoir:

$$K = 62.5 \left(\frac{\varphi^{4.4}}{S_{wc}^{\ 2}} \right)^2 \tag{1.12}$$

For gas reservoir:

$$K = 2.5 \left(\frac{\varphi^{3}}{S_{wc}} \right)^2 \tag{1.13}$$

1.5 Need for waterflooding

Waterflooding performs two basic functions, using Rose bank field;

- To maintain the reservoir pressure
- To drive the oil towards the producing wells.

The governing efficiency (main factors) of the waterflooding at the scale of the field is:

1. Mobility Ratio
2. Gravity
3. Reservoir heterogeneity and sweep efficiency

Mobility ratio: Accordingly to Craig [9], mobility of a fluid is the effective permeability of the rock to that of fluid divided by the fluid viscosity.

Mobility ratio is defined as the ratio of the water mobility to the oil mobility.

Mathematically expressed as:

$$M = \frac{K_{rw}}{\mu_w} \frac{\mu_o}{K_{ro}} \tag{1.14}$$

(Where $\frac{K_{rw}}{\mu_w}$ is water mobility and $\frac{K_{ro}}{\mu_o}$ is oil mobility)

If M < 1, the waterflooding is efficient at the reservoir conditions since the water pushes out an equivalent volume of oil. The velocity of the water cannot be more than the velocity of oil, i.e. the displacement of oil by water is stable. There is a shock-front saturation profile, high water saturations trailing high oil saturation.

If M > 1, the waterflooding is inefficient, and it will take more time for the pore volume of water to circulate in order to extract an equivalent unit of pore volume of oil. The velocity of water exceeds the velocity of oil, i.e. the displacement of oil by water is unstable and there is high tendency to fingering and differentiating breakthrough.

Gravity: The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in the densities of the reservoir fluids. Gravity segregation of fluids is probably present to some degree in all petroleum reservoirs, but it may contribute substantially to oil production in some reservoirs.

Factors that affect the ultimate recovery from gravity-drainage reservoirs are:

- Permeability in the direction of dip.
- Dip of the reservoir
- Reservoir producing rates
- Oil viscosity
- Relative permeability characteristics

1.6 Reservoir heterogeneity and sweep efficiency

Accordingly to Tarek [6], “reservoir heterogeneity is defined as a variation in reservoir properties as a function of space”. It depends upon the depositional environments and successive appearances, even on the nature of particle of sediment, i.e. a reservoir field that is not thick, clean, sand section with strong water drives. It measures the reservoir property at any location which will describe fully the reservoir. The properties of heterogeneity reservoir vary as a function of a spatial location [10].

These properties may include permeability, porosity, thickness, saturation, faults and fractures, rock facies, and rock characteristics. There are two types of heterogeneity; vertical heterogeneity and areal heterogeneity

- **Vertical heterogeneity:** This is the most important parameter influencing the vertical sweep and its degree of variation in the vertical direction. A reservoir display different layers in the vertical section that have highly contrasting properties of high permeability and will move at a higher velocity. As the process progress, at the time of water breakthrough in higher-permeability zones, a significant fraction of the less-permeable zones will remain un-flooded [6].
- **Areal heterogeneity:** It's made up of areal variation in formation properties such as permeability, porosity, connate water saturation and geometrical factors such as the position, any sealing nature of faults, and boundary conditions due to the presence of an aquifer or gas cap. Areally, of course, matters are much more uncertain since methods of defining heterogeneity are indirect, such as attempting to locate faults from well testing analysis. Consequently, the areal sweep efficiency is to be regarded as the unknown in reservoir-development studies [6].
- **Vertical sweep efficiency:** Another name for vertical sweep efficiency is the vertical displacement efficiency in a displacement process. This is the ratio of the cumulative height of the vertical sections of the pay zone (oil zone) that are

on injection fluid to the total vertical pay zone height. It depends on parameters such as mobility ratio and total volume of fluid injected. The injected fluid flows faster in high permeability zones than in low permeability zones as a result of non-uniform fluid that may cause an irregular front which affects the displacement efficiency. In other word, vertical sweep efficiency (also known as invasion efficiency) is the measure of the uniformity of water invasion.

- **Areal sweep efficiency:** Water is injected into some wells and produced from other wells during waterflooding at the same point which cause pressure distributions and similar streamlines are formed between injection and production wells. The shortest streamline between the injection and producing wells is a straight line connecting them in a symmetrical well pattern. The section on the shortest streamline reaches the producing well before the water on any other streamline. During water breakthrough, only the area of the reservoir section between these injections and producing wells get hold of water [9].

1.7 Outline of Report

This project is presented in Five (6) chapters, outlined as follows:

- **Chapter One** is a basic introduction to water injection (waterflooding) and the objective of the project, Rosebank field properties, summarising the waterflooding and its fundamental theories and applicability.

- **Chapter Two** consists of an in-depth review into past literatures in the field of water injection under operational constraints including simulation techniques, and the various concept of oil recovery. Optimization of water injection and water production are also investigated from past works.

- **Chapter Three** gives a detailed methodology of the steps taken to achieve optimal production from the Rosebank field using the Eclipse simulation package. Detailed approach to handle the operational constraints during the production years of the field was also analysed to ensure continuous maximum oil production.

- **Chapter Four** presents results obtained from simulations, with detailed discussions and explanations. The cost for work-over injection well, redrill of new injection well and drill of new producing wells were investigated to check the economic impact to the revenue generated using the base case scenario as a target for improvement.

- **Chapter Five** presents the conclusions from this research, and makes recommendations in order to maintain oil production of the field for the predicted years of operation.