Project Title

Water Flooding Analysis

(Simber West Field Case Study)

تحليل عملية الغمر المائي

(دراسة الحالة في حقل Simber West)

Submitted in partial Fulfillment of the Requirements
Of the Degree Of B.tech in Petroleum Engineering

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صدق الله العظيم
(سورة العلق)
Abstract

Simber west field was shut in due to low reservoir pressure in Q3 2009 represented rapid decline reservoir pressure and low water cut so suggested that minimum aquifer support to Ard-D reservoir To restore the oil production and increase the reserve and recovery factor water injection has been perform for Aradeiba-D reservoirs.

MBAL had been used to estimate the effectiveness of water injection in increasing current reservoir pressure from 1400psia to targeted reservoir pressure of 2500psia

Also to determine the optimum production rate when reservoir starts resume production & to determine the timeline for reservoir pressure to achieve 2500 psi with the current water injection operating conditions.
تجريد

توقف الانتاج في حقل (Simber west) وذلك للانخفاض السريع في ضغط الممكن في الربع الثالث من سنة 2009. تم اقتراح معالجة قوة الدفع للممكن باستخدام الغمر المائي للطبقة (Aradeiba-D) لاستعادة الانتاج وزيادة معدل الاستخلاص.

تم استخدام (MBAL) لحساب تأثير الغمر المائي لرفع مستوى ضغط الممكن من (1400-2500 psi) ومعرفة الزمن اللازم للوصول للضغط المحدد والنتبوي بالانتاج الامثل.
Chapter One
Introduction
Chapter 1

Introduction

1.1. Background of problem:
Initially field start to produce since 2005 with four producers (SIW01, SIW02, SIW03, SIW04) which were produced about 1000 bp/d each but experienced severe decline and HGOR due to sharp pressure depletion.
The two subsequent infill wells (SIW05, SIW06) were unable to produce due to HGOR, the field was shut in since 2010 due to low reservoir pressure.
The rapid decline reservoir pressure and low water cut suggested that provide minimum aquifer support to Ard-D reservoir.

1.2. Objective of Simber Water Injection
The main objective of operating an individual injection well is to inject the maximum amount of water without having it go out of the intended pay zone.
The goal is to maximize injection into, and only into, the oil productive zones by
   i. To perform water injection for Aradeiba-D reservoirs.
   ii. To estimate the effectiveness of water injection in increasing current reservoir pressure from 1400 psia to targeted reservoir pressure of 2500 psi.
   iii. To restore the oil production and increase the reserve and recovery factor.

1.3. The objective of their search by using Material Balance
   i. To validate the tank in place volume
   ii. To determine the timeline for reservoir pressure to achieve 2500 psi with the current water injection operating conditions
   iii. To determine the optimum production rate when reservoir start resume production
1.4. Objective of project:

The scope of our project is use tank model to validate the water injection project and back the wells to production by maintain pressure by using,

i. Material balance model.

ii. OFM software (production data).

1.5. Project Layout:

This project report has been divided into five chapters:-Chapter one represents a brief introduction related to our project. Chapter two explains the literature review & Theoretical Backgrounds related to water injection project. Chapter three customized represent Basic reservoir data Field Performance before implement water injection & introduction to software use in research (MBAL and OFM overview). In Chapter four we enter all require data to software and analyze the output data calculations of. Also we make software by visual Basic language to predict liquid loading. In chapter five we show our results and lastly we put our future Recommendation.
Chapter Two
Literature Review & Theoretical Background
Chapter 2

Literature Review & Theoretical Background

2.1. Literature Review

The recovery of oil by any of the natural drive mechanisms is called primary recovery. The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir.

Performance of oil reservoirs is largely determined by the nature of the energy (driving mechanism, available for moving the oil to the wellbore).

2.1.1. Primary recovery

There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

i. Rock and liquid expansion drive
ii. Depletion drive
iii. Gas cap drive
iv. Water drive
v. Gravity drainage drive
vi. Combination drive

2.1.2. Secondary recovery:

Its process of produce oil out from reservoir by using outside energy

i. Water flooding
ii. Gas injection

2.1.3. Territory recovery:

Its boost energy in reservoir to increase oil production and reduce residual oil

i. Thermal
ii. Chemical
iii. Miscible
iv. Microbial
2.1.4. Selection criteria:

Table 2.1 Selection criteria
2.2. Theoretical Background

2.2.1. Water flooding

Why is water flood the most popular Enhance Oil Recovery Scheme?

From screening criteria found that

i. Water is the cheapest flooding agent for Enhance Oil Recovery
   The need to dispose of produced water
ii. Easy and safe to inject
iii. Proven technology

Planning a water flood scheme:

i. Ensure good understanding of fluid properties (PVT, water chemical analysis...etc.)
ii. Establish good record of reservoir pressure history & production behavior
iii. Establish rock and mineral properties (relative perm., clay contents, Compressibility...etc.)
iv. Establish geological maps (structure, net pay, cross-section)

Plan well spacing and pattern

i. Lease geometry & ownership
ii. Formation continuity
iii. Fracture system or permeability orientation

Stages of water flooding,

i. Interference Stage
ii. Fill-up
iii. Break-through
iv. Flood-out (after break-through)
2.2.2. Goal of Water flooding

   i. Maintain Reservoir Pressure – (Pressure Maintenance)
   ii. Support Emergency service.
   iii. Supplement Natural Water Influx

But:-

   i, ii&iii are Displacement Processes and the Goal is to Displace Oil to a Production well

![Image of Water flooding Displacement](image)

Figure 2.2 Wate flooding Displacement(Tarek, T.A, Book)

2.2.3. Conventional Improved Recovery (IR)

   Injection of immiscible fluid

   i. Water injection
   ii. Nitrogen injection
   iii. Casing head gas reinjection

Often used in ‘secondary recovery ‘WaterfloodingInjection of water into a reservoir to

   i. Increases reservoir energy
   ii. Sweeps oil towards producing wells

Most widely applied secondary recovery method, Accounts for about 50% of U.S. oil production
2.2.4. Factors Affecting Water flooding

i. Gravity

ii. Figure 2.4 Barriers to vertical flow (Tarek, T.A, Book)
iii. Lateral pay discontinuities

![Diagram of Lateral pay discontinuities]

Figure 2.5 Lateral pay discontinuities

iv. Completion interval inconsistencies

![Diagram of Completion interval inconsistencies]

Figure 2.6 Completion interval inconsistencies
2.2.5. Field Performance before implement water injection:

First oil was achieved on June 2005
Peak production achieved on Nov 2005 with about 3200 bp/d
The reservoir become idle since Aug 2009 due to low productivity
Water cut is low, in the range of 0~40%
Current reservoir pressure has been declined to 1600 psi.
The rapid decline of reservoir pressure and low water cut suggested minimum aquifer support to Aradeiba-D
Potentially also sand continuity and quality are poor, resulted all wells in Simbir West experiencing low inflow

Figure 2.7 field production performances.
2.2.6. Previous Study:

2.2.6.1. Ekofisk (North Sea)

The Ekofisk oil field is in the North Sea, south of Norway. It is a large, carbonate reservoir that has two zones.

Figure 2.8 [(6.4 billion bbl stock tank original oil in place (STOOIP))]

2.2.6.2. Wilmington Oil Field (California)

The LBU area of the Wilmington oil field (southern California, U.S.A.) is mainly under the Long Beach harbor and contains more than 3 billion bbl of OOIP.

Figure 2.9 Areal maps of injection & production well in the Ranger –zone

2.2.6.3. Kuparuk River (Alaska North Slope)

The Kuparuk River oil field is west of the supergiant Prudhoe Bay oil field on Alaska’s North Slope.

The sandstone reservoir consists of two zones that are separated by impermeable shale and siltstones.

Figure 2.10 [A (62% of STOOIP) and C (38% of STOOIP)]
2.2.6.4. Started in Unity at November 2001, with WSW03 & 04

1- To Provide artificial aquifer support to Ghazal, Zarga and Aradeiba Reservoirs.
2- To improve the areal and vertical sweep efficiency moving the oil to the producers.
3- To raise the depleted reservoir pressure at the desired reservoirs pressure and sustain void age replacement ratio.
4- To improve the Recovery factor
Chapter Three
Methodology
Chapter 3
Methodology

Data QC
(Pressure data, Production data, PVT data & core data)

Data preparation
(Pressure data from SGS, RFT, Production data from OFM, PVT data from model correlations & core data)

PVT input to MBAL software & QC with correlations

Aquifer Model using Carter Tracy

Tank data input (General data, Core data, Production data) & QC

Tank Pressure Match

Output (Analytical Method for Pressure Match, Graphical Method for OIIP)

OIIP Comparison with Static & Dynamic Models
3.1. Material Balance:
The material balance concept is based on the principle of conservation of mass:
Mass of fluids originally in place = fluids produced + Remaining fluids in place.
This can be synthesized in the fundamental equation:

\[ F = N.E_t + W_e \]

Where:
\( F \) is the production
\( E_t \) is this expansion term, depending on PVT and reservoir parameters
\( W_e \) is the water influx term

The material balance program uses a conceptual model of the reservoir to predict the reservoir behavior based on the effects of reservoir fluids production and gas to water injection.

The material balance equation is zero-dimensional, meaning that is based on a tank model and does not take into account the geometry of the reservoir, the drainage areas, the position and orientation of the wells, etc.

However, the material balance approach can be a very useful tool in performing many tasks, some of which are highlighted below:

- Quantify different parameters of a reservoir such as hydrocarbon in place, gas cap size, etc.
- Determine the presence, the type and size of an aquifer, encroachment angle, etc.
- Estimate the depth of the Gas/Oil, Water/Oil, Gas/Water contacts.
- Predict the reservoir pressure for a given production and/or injection schedule,
- Predict the reservoir performance and manifold back pressures for a given production schedule.
- Predict the reservoir performance and well production for a give manifold pressure schedule.
3.2. MBAL Software Overview

MBAL is a reservoir modeling tool, this tool was designed to allow for greater understanding of the current reservoir behavior and perform predictions while determining its depletion.

Reservoir modeling can be carried out within MBAL with the use of several different tools to focus on different aspects:

i. Material Balance,
ii. Reservoir Allocation
iii. Monte Carlo volumetric,
iv. Decline Curve Analysis,
v. 1-D Model (Buckley-Leverett)
vi. Multi-Layer (relative permeability averaging)
vii. Tight Gas Type Curve tool

Figure 3.1. Selection Material Balance.
The material balance approach can be a very useful tool in performing many tasks:

i. Quantify different parameters of a reservoir such as hydrocarbon in place, gas cap size,

ii. Determine the presence, the type and size of an aquifer, encroachment angle, etc.

iii. Predict the reservoir pressure for a given production and/or injection schedule

iv. Predict the reservoir performance and well production for a given manifold pressure

When a volume of oil is produced from a reservoir, the space once occupied by this volume must be filled by something else

Figure 3.2 Tank balance
### 3.2.1. MBAL Software- Input Data

<table>
<thead>
<tr>
<th>Item</th>
<th>Unit</th>
<th>Formation A</th>
</tr>
</thead>
<tbody>
<tr>
<td>GOR</td>
<td>Scf/STB</td>
<td>5</td>
</tr>
<tr>
<td>API</td>
<td>Degrees</td>
<td>20</td>
</tr>
<tr>
<td>Gas Gravity</td>
<td>Sp.gr</td>
<td>0.74</td>
</tr>
<tr>
<td>Water Salinity</td>
<td>ppm</td>
<td>3000</td>
</tr>
<tr>
<td>H2S</td>
<td>f</td>
<td>0</td>
</tr>
<tr>
<td>Co2</td>
<td>f</td>
<td>0</td>
</tr>
<tr>
<td>N2</td>
<td>f</td>
<td>0</td>
</tr>
<tr>
<td>Pi</td>
<td>psia</td>
<td>1866</td>
</tr>
<tr>
<td>Avg Thickness</td>
<td>m</td>
<td>16.18</td>
</tr>
<tr>
<td>Porosity</td>
<td>f</td>
<td>0.19</td>
</tr>
<tr>
<td>Connate Water Saturation</td>
<td>f</td>
<td>0.2</td>
</tr>
<tr>
<td>Water Compressibility</td>
<td>psi-1</td>
<td>2.99E-06</td>
</tr>
<tr>
<td>Initial Gas cap</td>
<td>Scf</td>
<td>0</td>
</tr>
<tr>
<td>Oil in Place</td>
<td>MMSTB</td>
<td>100.77</td>
</tr>
<tr>
<td>Start Oil Production</td>
<td>Date</td>
<td>Mar-2002</td>
</tr>
<tr>
<td>Rock Compressibility</td>
<td>psi-1</td>
<td>3.50E-06</td>
</tr>
</tbody>
</table>

MBAL Software- Input Data Table 3.1
3.2.2. Setting up the Basic Model

Figure 3.3 In this screen, the fluid has been defined as oil.

Figure 3.4. Selection Model
3.2.3. Plotting

Figure 3.5 order plot variable

3.3. Basic Reservoir Data

Porosity - Permeability Information

i. Based on Routine Core Analysis of SIW-2 (Air perm).

ii. Calibrated with permeability result from DST at SIW-1, SIW-2 & SIW-3

Figure 3.6. Porosity - Permeability Information
Figure 3.7. Simber west wells depth distribution
3.4. OFM overview

OFM (Oil Field Manager) is application software with an array of tools to manage oil and gas data. It has many useful functions from simple plots to decline curve analysis. OFM stores the data in a separate database and this database can be shared and used by several parties.

Templates can be generated where users can customize it based on their requirement that will speed up his analysis well or field wise.

In field we have 2 licenses shared among users

3.5. Fundamental relationship

Software – OFM – what it can offer??

3.5.1. Production Plot

(To study well performance over time)

Figure 3.8 Production performance plot using OFM
3.5.2. Analysis plot

To analysis the water production behavior

![Figure 3.9 Water production behavior using OFM](image)

3.5.3. Production Forecasting

To study the depletion rates and mitigation plan

![Figure 3.10 Production Forecasting chart by OFM](image)
3.5.4. Bubble map

To study the spacing and production coverage

Figure 3.11 Bubble map by OFM

3.6. Data to be entered

Basic data

i. Coordinate well (X,Y)

ii. Country/Block/Field/Well name

iii. Production Data

iv. PVT data

v. Allocated Monthly Production Data by Well

vi. Well test

vii. DFL/ SFL

viii. Downtime

ix. Lab test
Chapter Four
Results & Discussion
Chapter 4
Results & Discussion

4.1. Evaluation of Material Balance

1. To validate the tank in place volume
2. To determine the timeline for reservoir pressure to achieve 2500 psi with the current water injection operating conditions
3. To determine the optimum production rate when reservoir start resume production

4.2. Assumptions:
- Single Tank mode, single PVT mode, single stage separator
- 2 case studies established due to pressure regime different (Medium & Low Case).

<table>
<thead>
<tr>
<th>Basic Reservoir Data</th>
<th>Rock Properties</th>
<th>Fluid Properties</th>
<th>Resource &amp; Reserve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location: Block 2A</td>
<td>Net Sand: 10~15 m</td>
<td>API: 38</td>
<td>In Place: 80.75 MMstb</td>
</tr>
<tr>
<td>Discovery: November 2002</td>
<td>Porosity: 17 ~ 21%</td>
<td>i. Viscosity: 2.4 cp @ 80C</td>
<td>EUR: 21.80 MMstb (27% RF)</td>
</tr>
<tr>
<td>MajorSand: Aradeiba-D</td>
<td>Permeability: 10 ~ 100 mD</td>
<td>Average Swi: 0.31</td>
<td>Np: 1.20 MMstb (1.5% recovery)</td>
</tr>
<tr>
<td>Depth: 2740 – 3100 mkb</td>
<td>Initial Pressure: 3800 psi</td>
<td>Rsi: 110 scf/stb</td>
<td>Producers: 7 Ops (SIW-04 converted to WI)</td>
</tr>
</tbody>
</table>

Table 4.1 Basic Data
Figure 4.1 SGS & SFL vs Time

Pressure Analysis

Figure 4.2 the reservoir pressure difference established for MBAL analysis
The reservoir pressure range is quite significant difference, 2 cases (medium & low) established for MBAL analysis.

4.3. Material Balance Case Study

4.3.1. Medium Case

First enter fluid properties

Figure 4.3 Due to Limit fluid data available, correlation was used to generate the PVT data

Figure 4.4 Black Oil Input Data
PVT – Correlations generated PVT data

Figure 4.5 Pressure vs Oil viscosity

Figure 4.6 Pressure vs oil FVF
Figure 4.7 pressure vs Gas viscosity

Figure 4.8 pressure vs GOR
Figure 4.9 Pressure vs Gas FVF
The in place value estimated from static model was honored in the MBAL study.

Figure 4.10. No aquifer attach as understood from reservoir pressure and water cut behavior

Figure 4.11. Tank Input Data – Water Influx
Typical Kr was used

Figure 4.12 Tank Input Data – Rermeabilities.
4.4. Production Data

Oil & Water production from OFM database

4.4.1. Cumulative water production

Figure 4.13 Pressure & Cumulative water production

4.4.2. Cumulative oil production

Figure 4.14 Pressure & Cumulative oil production
4.4.3 Cumulative GOR

Figure 4.15 Pressure & cumulative GOR production

Gas production was estimated base on Rsi of 110 Scf/stb due to no gas measurement available
4.7. MBAL – History Match (Analytical Method)

4.7.1. Matching on Energy Balance

• By using the original estimated in place (80.75 MMstb), the theoretical reservoir pressure should be high, but in reality, the reservoir pressure is lower than that.

• This indicate the volume estimation need to be adjusted

Figure 4.16 calculated oil production by MBAL
4.7.2. Matching on Tank Volume

• By using the original estimated in place (80.75 MMstb), the straight line method is not fulfill, which indicate the original estimated volume is bigger than what it should be
• This indicate the volume estimation need to be adjusted

Figure 4.17 Matching on Tank Volume (calculated oil in place by MBAL)
4.8. After matching with the SGS pressure data:

4.8.1. Matching on Tank Volume

![Figure 4.18Matching on Tank Volume (actual Oil in place by MBAL)](image)

4.8.2. Matching on Energy Balance

![Figure 4.19Tank Pressure vs Calculated oil production](image)
4.8.3. Drive Mechanism

Figure 4.20 Drive Mechanism identifying

Indicate that fluid expansion is the major energy in the reservoir

The simulated pressure match the Actual pressure data, the tank can use for prediction

Figure 4.21 Oil productions (Stimulated pressure vs actual pressure)
Figure 4.22 cumulative oil production vs time

- MBAL analysis suggested that by Nov 2014, Simber West reservoir pressure should be reached 2500 psi
- The production should be resumed after the reservoir pressure achieve target

Figure 4.23 cumulative oil prod vs time(avg oil & tank pressure)
With the water injection rate of 1250 bwpd, and to maintain reservoir pressure at 2500 psi, suggested the production should be resumed at maximum 1200 bopd

Figure 4.24. Average water Inj vs Time (tank pressure & Time)
4.7. Material Balance Case Study

4.7.1. Low Case

Figure 4.25. Calculated oil production vs tan pressure

Figure 4.26. Actual oil in place vs calculated from MBAL
Similar to Medium case, the in place of low case also require to be tuned.

Figure 4.27 data matching

Figure 4.28 pressure vs calculated oil
The suggested in place volume should be 6.86 MMstb (for Medium Case)

Figure 4.29 Average oil actual pressure & estimated pressure

i. MBAL analysis suggested that by June 2015, Simber West reservoir pressure should be reached 2500 psi

ii. The production should be resumed after the reservoir pressure achieve target

Figure 4.30 Average Water Injection vs tank pressure

With the water injection rate of 1250 bpd, and to maintain reservoir pressure at 2500 psi, suggested the production should be resumed at maximum 1200 bpd
4.8 Observation

i. MBAL analysis suggested that the reservoir should achieve pressure of 2500 psi by Nov 2014 (medium case) or June 2015 (low case) with production rate of about 1100 bopd. However, close monitoring require to enhance the understanding of subsurface to achieve optimize production.

ii. Fluid properties (PVT data) data quality may detriment the quality of the analysis because the main drive mechanism is fluid expansion

iii. The reservoir pressure range indicate that the sand continuity is uncertain, Geophysicist’s seismic input are essential to further understand the sand continuity

4.9. Discussion, Water Injection Operation & Implementation:

i. Water injection metering performance is dissatisfactory

ii. Untreated injection water probably caused the scale / skin formation

iii. Water injection parameters established through injectivity test

iv. SIW01, SIW03 not really supported by water injection

v. SIW05 supported by water injection, but experiencing +ve skin problems probably due to untreated injection water.
Chapter Five
Conclusions & Recommendations
Chapter 5
Conclusions & Recommendation

5.1. Conclusion
i. Simber West oil properties is suitable for water injection scheme
ii. Geological understanding is dissatisfactory (unknown sand continuity)
iii. STOIIP probably less than expectation (Based on MBAL analysis)
iv. Weak and moderate aquifer available, but due to geological structure, only support to SIW01 relatively
v. SIW01, SIW03, SIW05 are probably are located at different sand body (Based on reservoir pressure respond)
vi. SIW03 production is fluctuating probably due to small volume of connected sand body

5.2. Recommendation
i. The first part requires that water be injected at the highest pressure possible
ii. The second part limits the injection pressure to just below formation fracture pressure.
iii. In practice, operators commonly use a surface injection pressure of 50 psig below formation parting pressure minus the static pressure of a column of injection fluid.
iv. More SGS pressure to ensure the analysis are properly calibrated
v. Gas measurement are recommended to avoid lost count of energy
References:


-AGARWAL, R.G. (1980). A new method to account for producing time effects when drawdown type curves are used to analyze pressure buildup and other test data. SPE Paper 9289, Presented at SPE–AIME 55th Annual Technical Conference, Dallas, Texas, Sept. 21–24

