an University of Science and Technology

College of Petroleum Engineering and

ogy

Petroleum Engineering Department

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 OfB.tech in Petroleum Engineering

Prepared By:

Mahir Abdallah Elmajoup

Musaab Ibrahim Elhassan

Ahmed Fayad Ahmed

Mulham Abdalla Mohammed

Supervisor:

Sami Mohamed Elamin

Contents

Page

Figure	Page

Tables

بسم الله الرحمن الرحيم

قال تعالى (اقرأ باسم ربك الذي خلق(1)

خلق الإنسان من علق(2) اقرا وربك الاكرم(3)

الذي علم بالقلم(4) علم الإنسان ما لم يعلم(5)

كلا إن الإنسان ليطغى(6)).

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 resumeproduction&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 , تماقتراح معالجة قوة الدفع للمكمن باستخدام الغمر المائي للطبقة (Aradeiba-D) لاستعادة الانتاج وزيادة معدل الاستخلاص

تم استخدام (MBAL) لحساب تاثير الغمر المائي لرفع مستوى ضغط المكمن من (2500-1400 psi) ومعرفة الزمن اللازم للوصول للضغط المحدد والتنبؤ 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 from1400 psia to targeted reservoir pressure of 2500psia.
- **iii.** To restore the oil production and increase the reserve and recovery factor.

1.3.Theobjective of theirsearchby 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 towater 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 resultsandlastlywe put our future Recommendation.

Chapter Two

Literature Review &TheoreticalBackground

Chapter 2

Literature Review&Theoretical Background

2.1. Literature Review

The recovery of oil by any of the natural drive mechanisms is calledprimary recovery. The term refers to the production of hydrocarbonsfrom 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 theenergy, (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 use 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 1

"Updated EOR criteria – oil properties and reservoir characteristics" (Tabulation adopted from Ref. (Mortis, 2004) and Data from adopted from References (Cadelle et al., 1981; Taber et al., 1996; Anonymous, 1998; Demin et al., 1999; Anonymous, 2000; Demin et al., 2001; Anonymous, 2002; Hongfu et al., 2003; Mortis, 2004; Anonymous, 2006; Awan et al., 2006; Koottungal, 2008; Koottungal, 2010)).

Oil properties					Reservoir characteristics						
SN	EOR method	# Projects	Gravity (API)	Viscosity (cp)	Porosity (%)	Oil saturation (% PV)	Formation type	Permeability (md)	Net thickness	Depth (ft)	Temperature (F)
Miscible gas injection											
1	CO2	153	[22]–45 Avg. 37	35–0[a] Avg. 2.08	3–37 Avg. 15.15	15–89 Avg. 46	Sandstone or Carbonate	1.5–4500 Avg. 209.73	[Wide Range]	1500[b]–13365 Avg. 6230.17	82–257 Avg. 138.10
2	Hydrocarbon	67	[23] –57 Avg. 38.3	18000–0.04 Avg. 286.1	4.25–45 Avg. 14.5	[30] –98 Avg. 71	Sandstone or Carbonate	0.1–5000 Avg. 726.2	[Thin unless dipping]	4040[4000] –15900 Avg. 8343.6	85–329 Avg. 202.2
3	WAG	3	33–39 Avg. 35.6	0.3–0.9 Avg. 0.6	11 –24 Avg. 18.3		Sandstone	130–1000 Avg. 1043.3	NC	7545–8887 Avg. 8216.8	194–253 Avg. 229.4
4	Nitrogen	3	38[35] –54 Avg. 47.6	0.2–0[c] Avg. 0.07	7.5–14 Avg. 11.2	0.76[0.4] –0.8 Avg. 0.78	Sandstone or Carbonate	0.2–35 Avg. 15.0	[Thin unless dipping]	10000[6000] –18500 Avg. 14633.3	190–325 Avg. 266.6
Immiscible gas injection											
5	Nitrogen	8	16–54 Avg. 34.6	18000–0[d] Avg. 2256.8	11–28 Avg. 19.46	47–98.5 Avg. 71	Sandstone	3–2800 Avg. 1041.7		1700–18500 Avg. 7914.2	82–325 Avg. 173.1
6	CO2	16	11–35 Avg. 22.6	592–0.6 Avg. 65.5	17–32 Avg. 26.3	42–78 Avg. 56	Sandstone or Carbonate	30–1000 Avg. 217		1150–8500 Avg. 3385	82–198 Avg. 124
7	Hydrocarbon	2	22–48 Avg. 35	4–0.25 Avg. 2.1	5–22 Avg. 13.5	75–83 Avg. 79	Sandstone	40–1000 Avg. 520		6000–7000 Avg. 6500	170–180 Avg. 175
8	Hydrocarbon + WAG	14	9.3–41 Avg. 31	16000 –0.17 Avg. 3948.2	18–31.9 Avg. 25.09	Avg. 88	Sandstone or Carbonate	100–6600 Avg. 2392		2650 –9199 Avg. 7218.71	131–267 Avg. 198.7
Chemical methods											
9	Polymer	53	13–42.5 Avg. 26.5	4000[e]–0.4[f] Avg. 123.2	10.4–33 Avg. 22.5	34–82 Avg. 64	Sandstone	1.8[e]–5500 Avg. 834.1	[NC]	9460–700 Avg. 4221.9	237.2–74 Avg. 167
10	Alkaline surfactant polymer (ASP)	13	23[20] – 34[35] Avg. 32.6	6500[g]–11 Avg. 875.8	26–32 Avg. 26.6	68[35] –74.8 Avg. 73.7	Sandstone	596[10] –1520	[NC]	3900[9000] –2723 Avg. 2984.5	158[200] –118 [80] Avg. 121.6
11	Surfactant + P/A	4	22–39 Avg. 31.75	15.6–2.63 Avg. 7.08	14–16.8 Avg. 15.6	43.5–53 Avg. 49	Sandstone	50–60 Avg. 56.67	[NC]	5300–625 Avg. 3406.25	155–122 Avg. 126.33
Thermal/mechanical methods											
12	Combustion	27	[10] –38 Avg. 23.6	[5000]2770–1.44 Avg. 504.8	14–35 Avg. 23.3	[50] –94 Avg. 67	Sandstone or Carbonate [Preferably Carbonate]	10 –15000 Avg. 1981.5	[>10]	400–11300[11500] Avg. 5569.6	64.4–230 Avg. 175.5
13	Steam	274	[8] –33 Avg. 14.61	5E6–3[h] Avg. 32594.96	12–65 Avg. 32.2	35–90 Avg. 66	Sandstone	1[i]–15001 Avg. 2669.70	[>20]	200–9000 Avg. 1647.42	10–350 Avg. 105.91
14	Hot water	10	12 –25 Avg. 18.6	8000–170 Avg. 2002	25–37 Avg. 31.2	15–85 Avg. 58.5	Sandstone	900–6000 Avg. 3346	-	500–2950 Avg. 1942	75–135 Avg. 98.5
15	[Surface mining]	-	[7] - [11]	[Zero cold flow]	[NC]	[>8 wt% Sand]	[Mineable tar sand]	[NC]	[>10]	[> 3:1 overburden to sand ratio]	[NC]
Microbial											
16	Microbial	4	12–33 Avg. 26.6	8900–1.7 Avg. 2977.5	12–26 Avg. 19	55–65 Avg. 60	Sandstone	180–200 Avg. 190	-	1572–3464 Avg. 2445.3	86–90 Avg. 88

A. Al Adasani, B. Bai / Journal of Petroleum Science and Engineering 79 (2011) 10–24

Table2.1Selection 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 RecoveryThe 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 chemicalanalysis...etc.)
ii. Establish good record of reservoir pressure history &productionbehavior
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

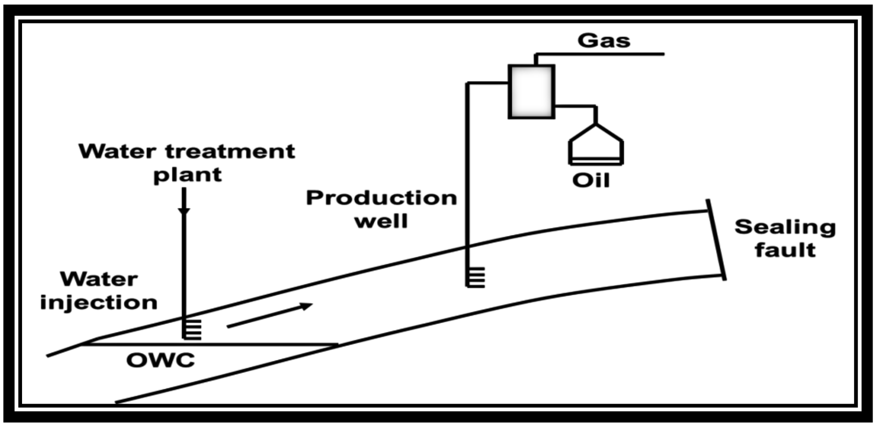


Figure 2.2 Wate flooding Displacement(Tarek, T.A,Book)

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

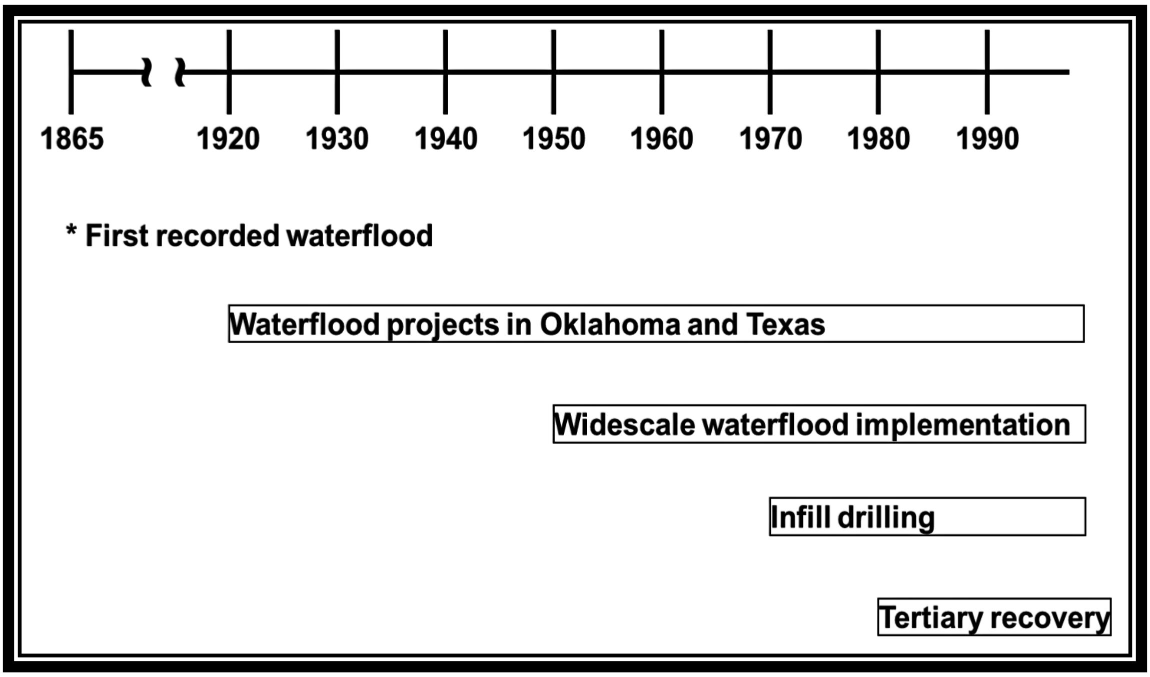
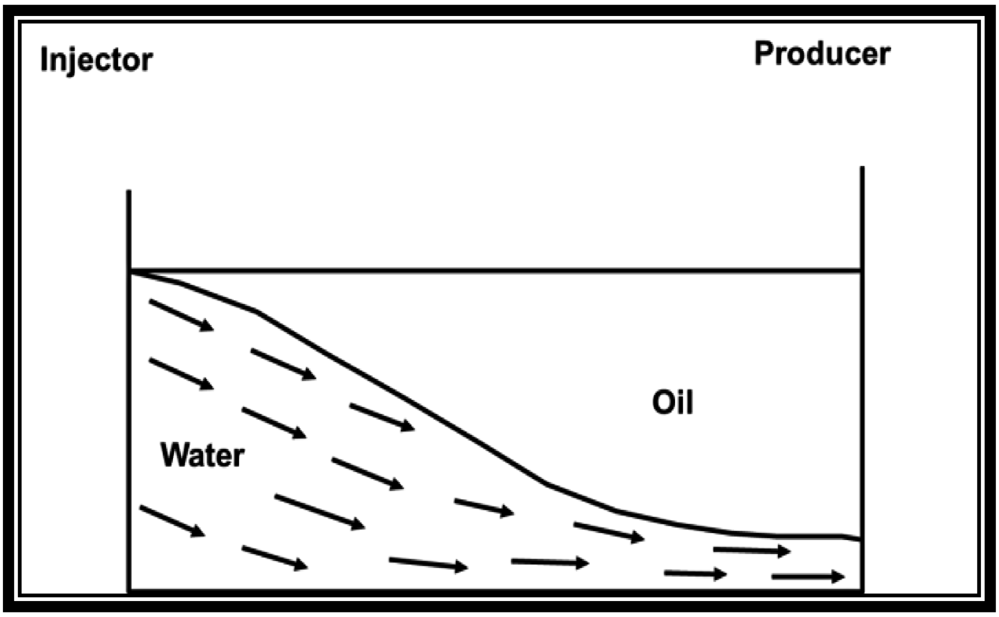


Figure 2.3 Water flooding history

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

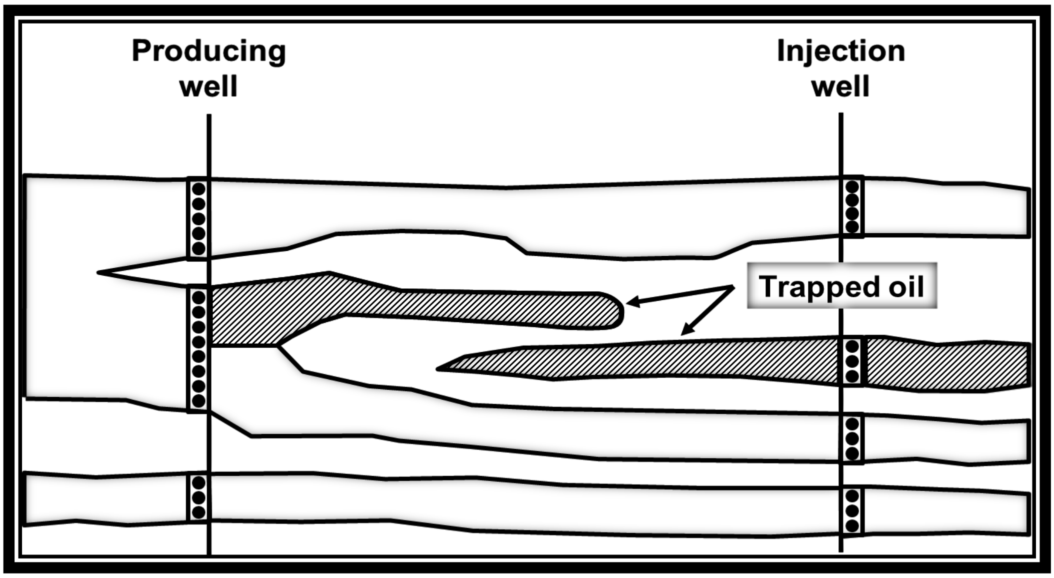


Figure 2.5Lateral pay discontinuities

iv. Completion interval inconsistencies

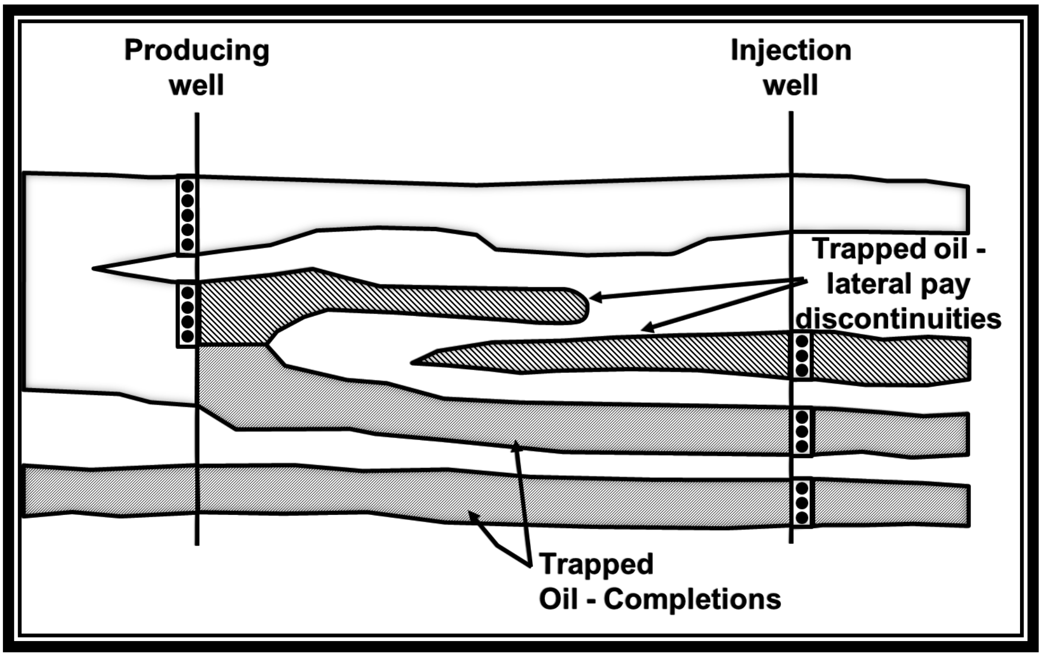


Figure 2.6 Completion interval inconsistencies

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

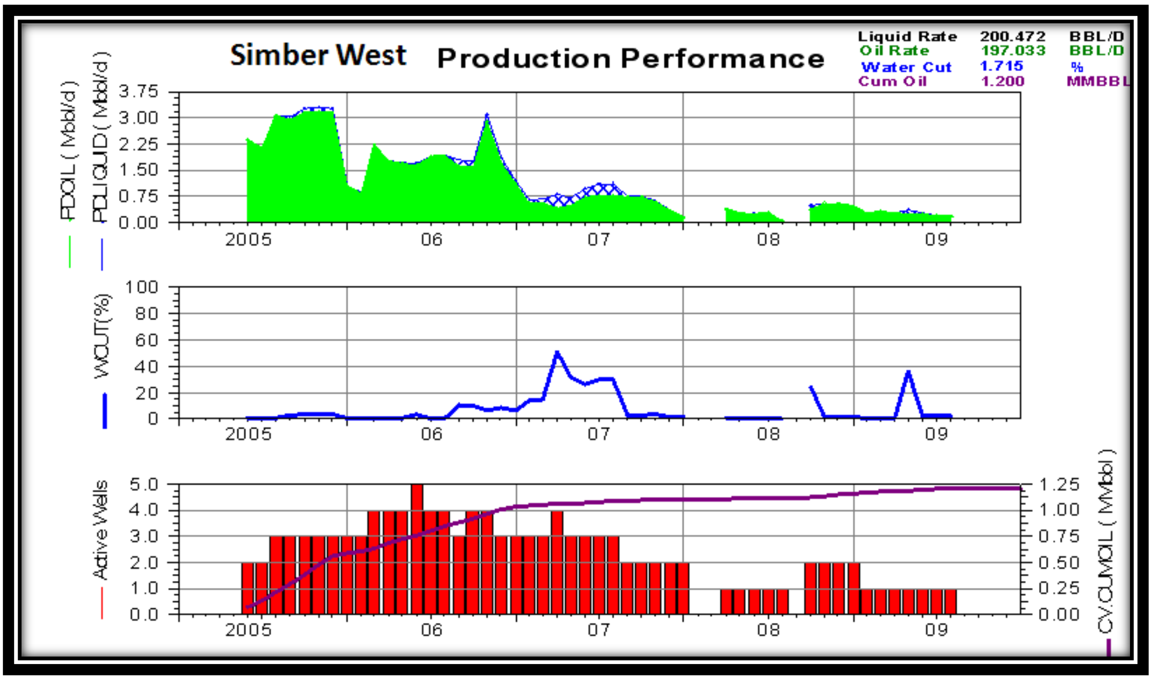


Figure 2.7field production performances.

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.

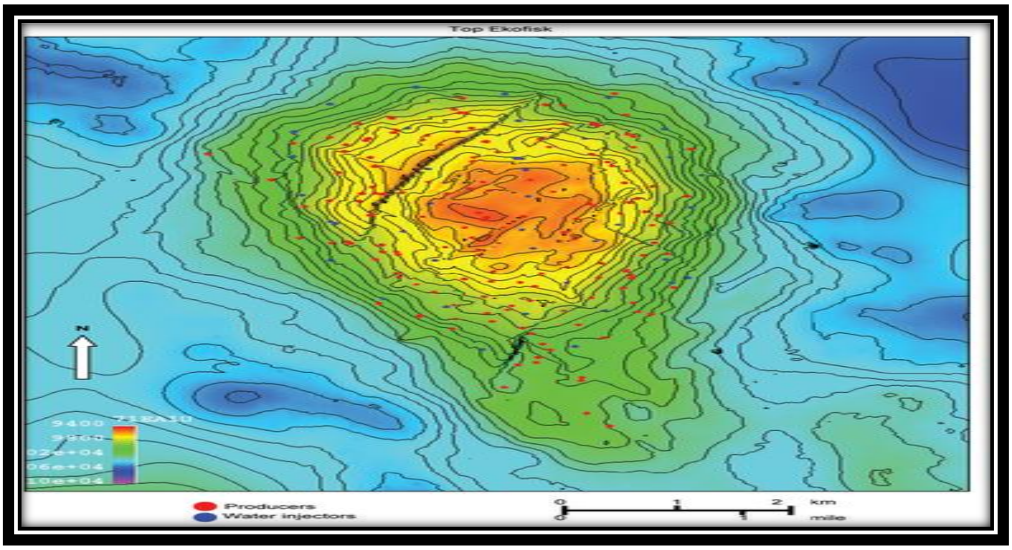


Figure 2.8 [(6.4 billion bbl stock tank original oil in place (STOOIP)]

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.

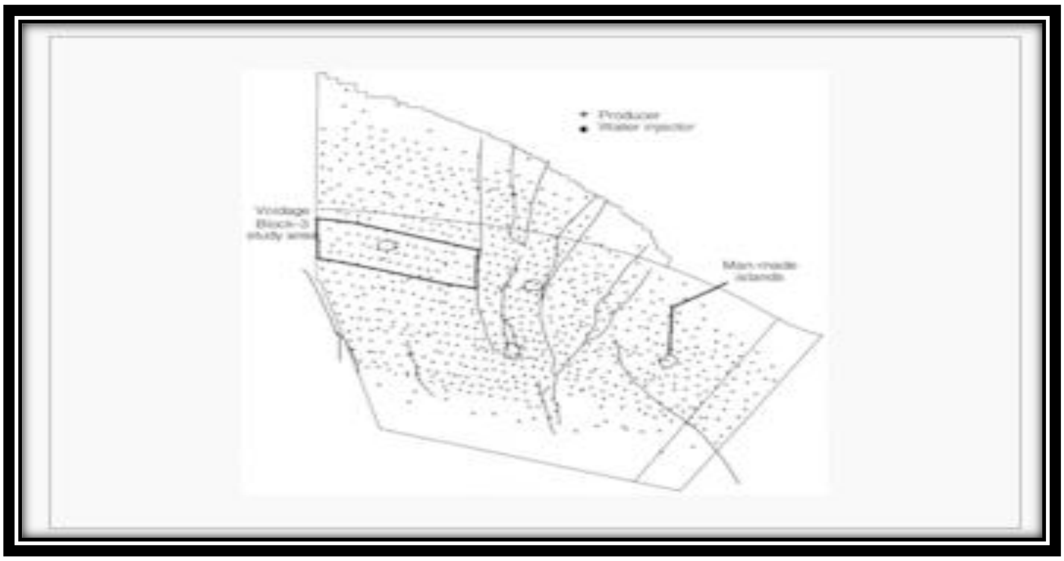


Figure 2.9 Areal maps of injection & production well in the Ranger –zone

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.

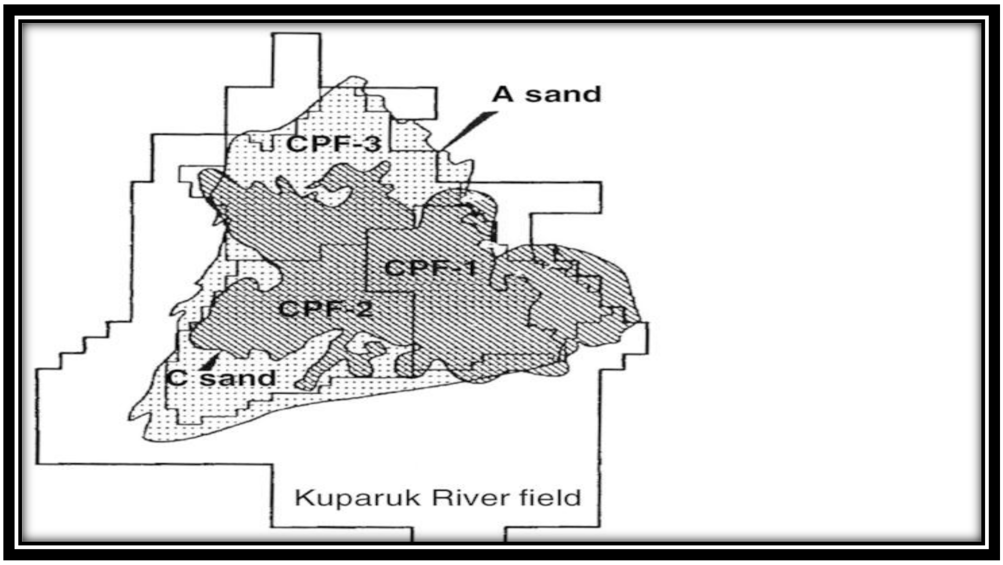


Figure 2.10 [A (62% of STOOIP) and C (38%of STOOIP)]

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.

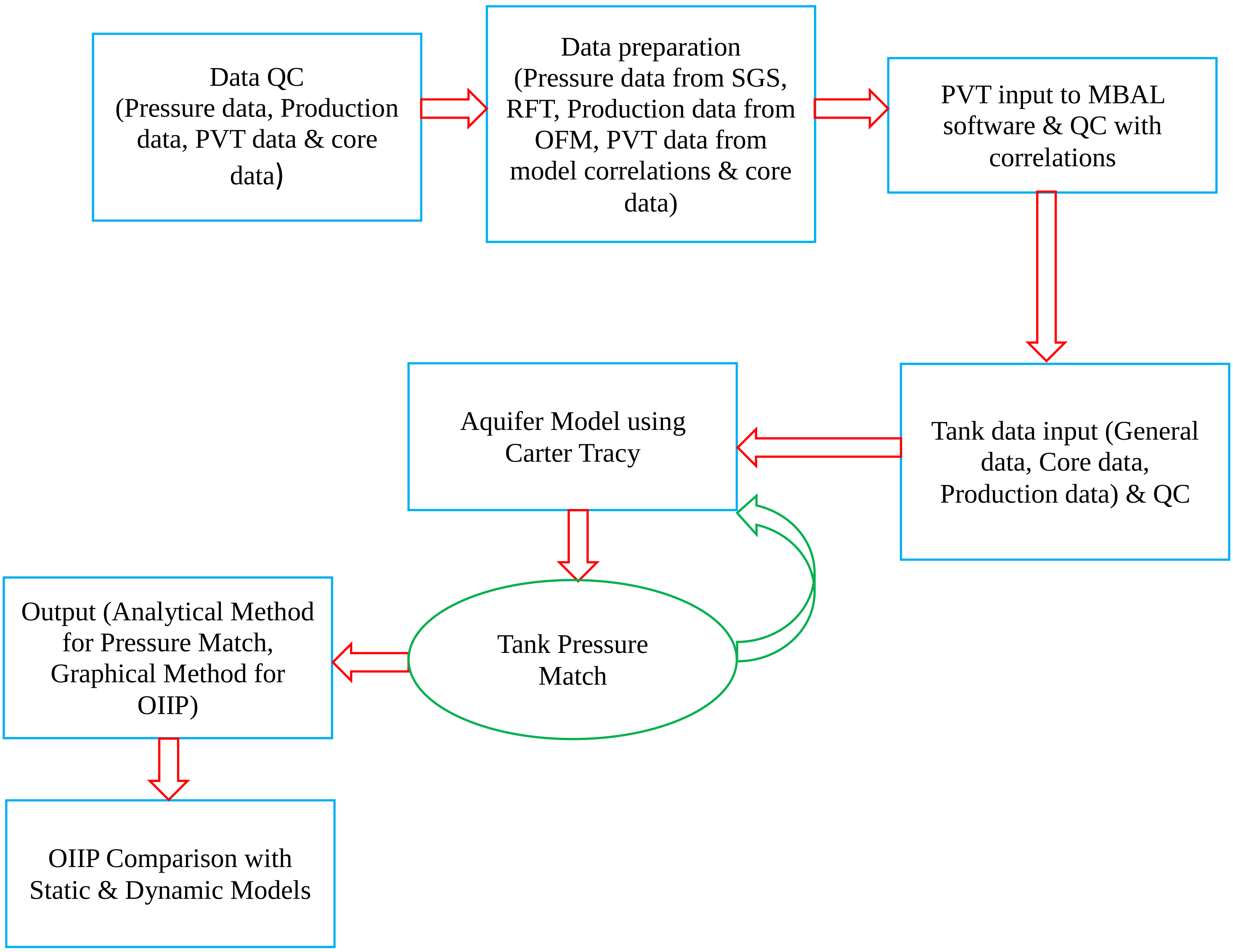
4-To improve the Recovery factor

Chapter Three

Methodology

Chapter 3

Methodology



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_E 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:

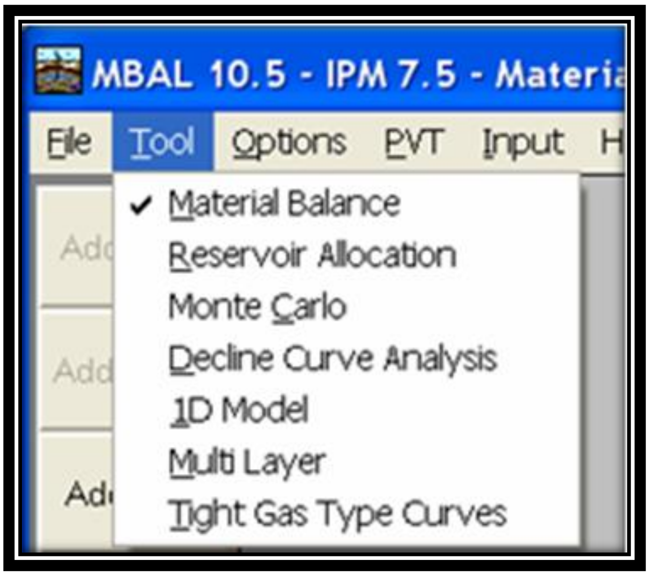
- Quantify different parameters of a reservoir such as hydrocarbon in place, gas cap size, etc.
- Determine the presence, the type and size of an aquifer, encroachment angle, etc.
- Estimate the depth of the Gas/Oil, Water/Oil, Gas/Water contacts.
- Predict the reservoir pressure for a given production 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 Over view

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



.

Figure3.1.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

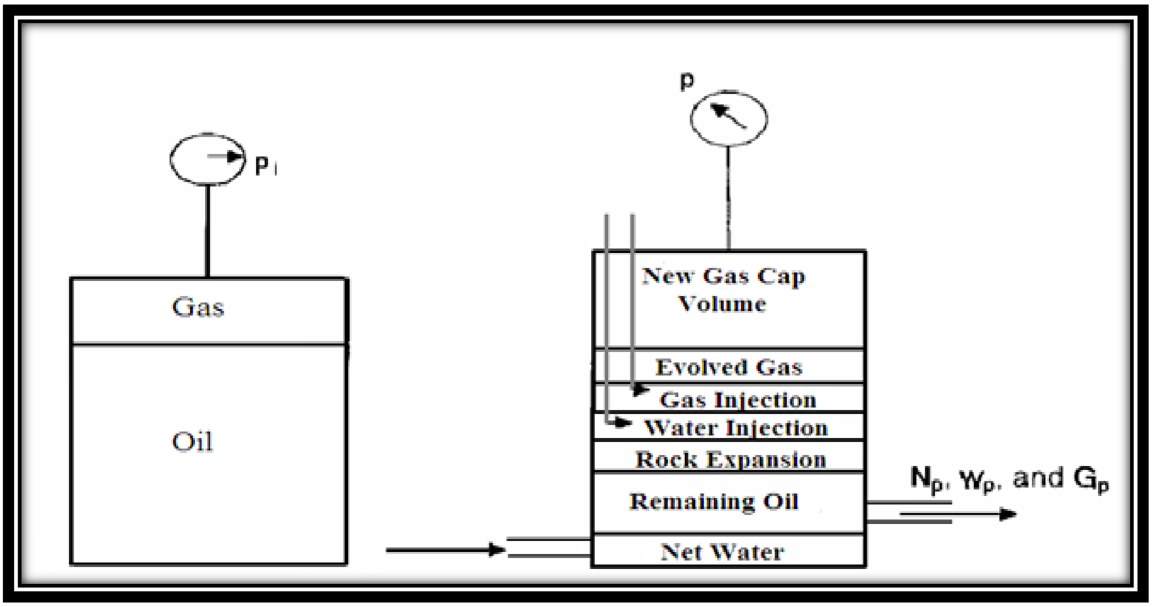


Figure 3.2 Tank balance

3.2.1.MBAL Software- Input Data

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

MBAL Software- Input Data Table 3.1

3.2.2.Setting up the Basic Model

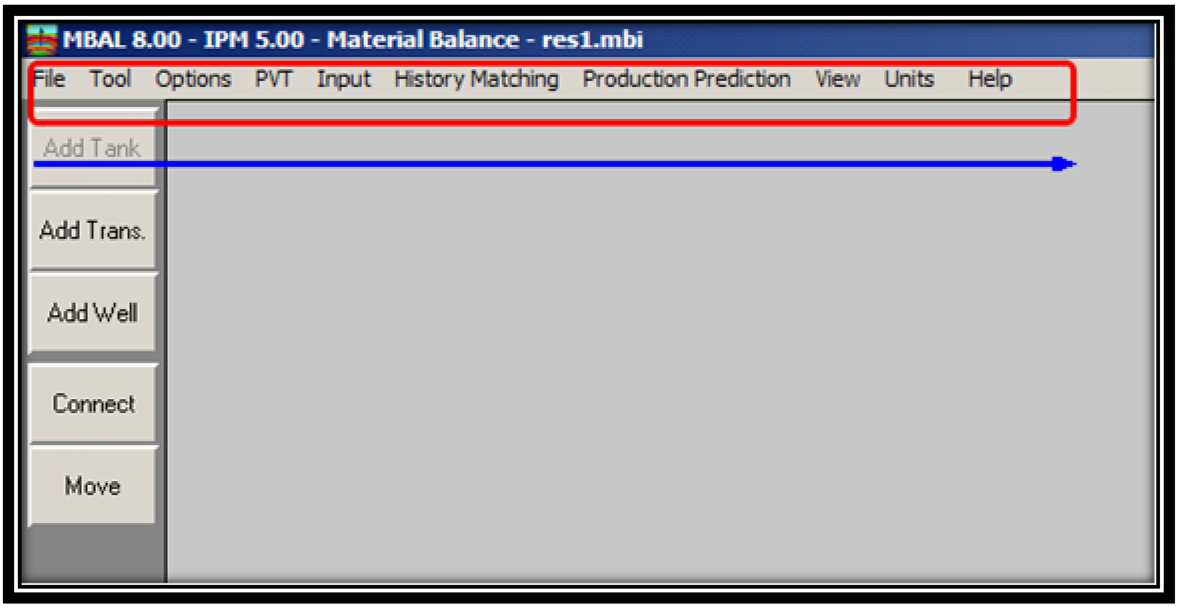


Figure 3.3In this screen, the fluid has been defined as oil.

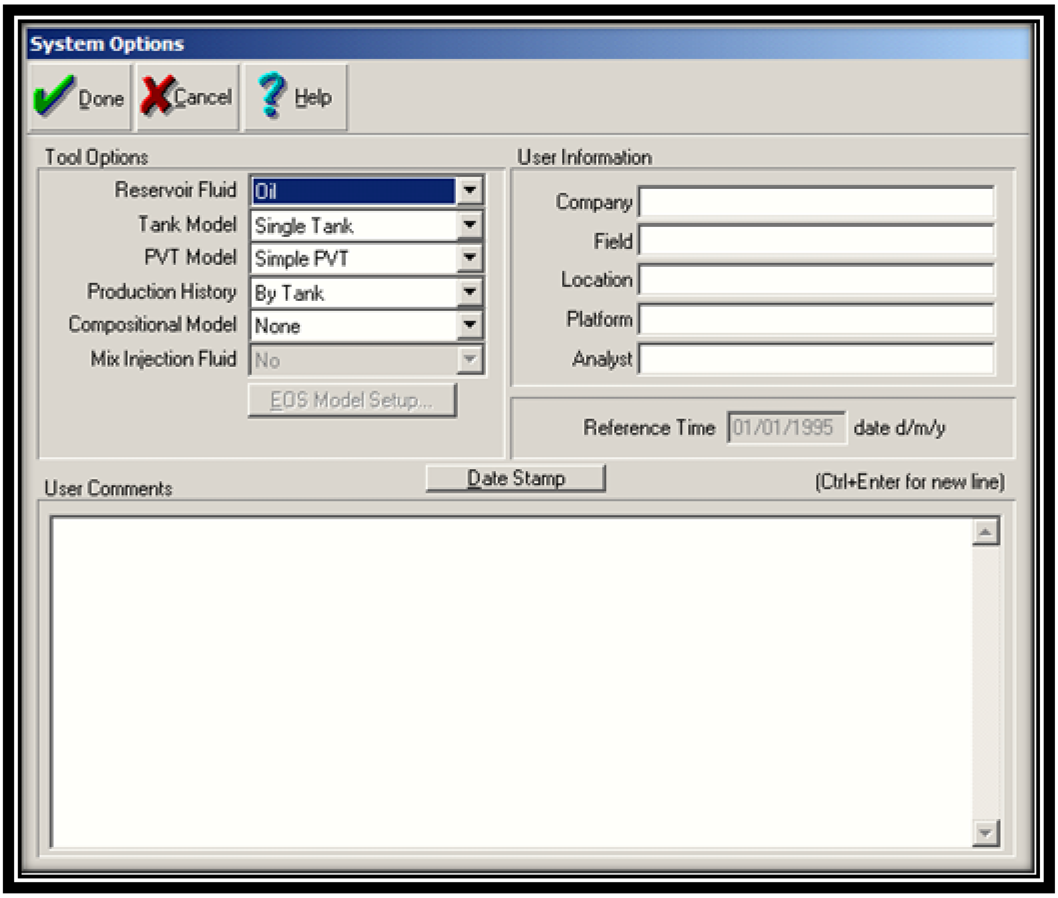


Figure3.4. Selection Model

3.2.3. Plotting

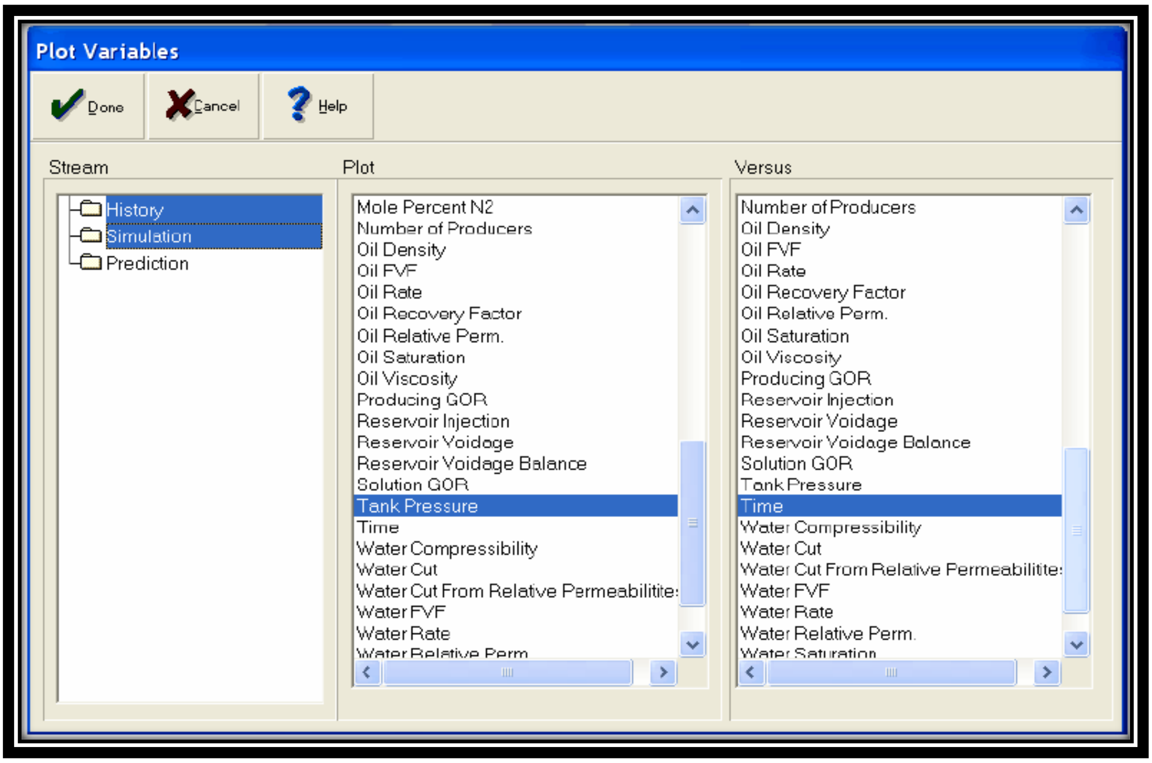


Figure 3.5order plot variable

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

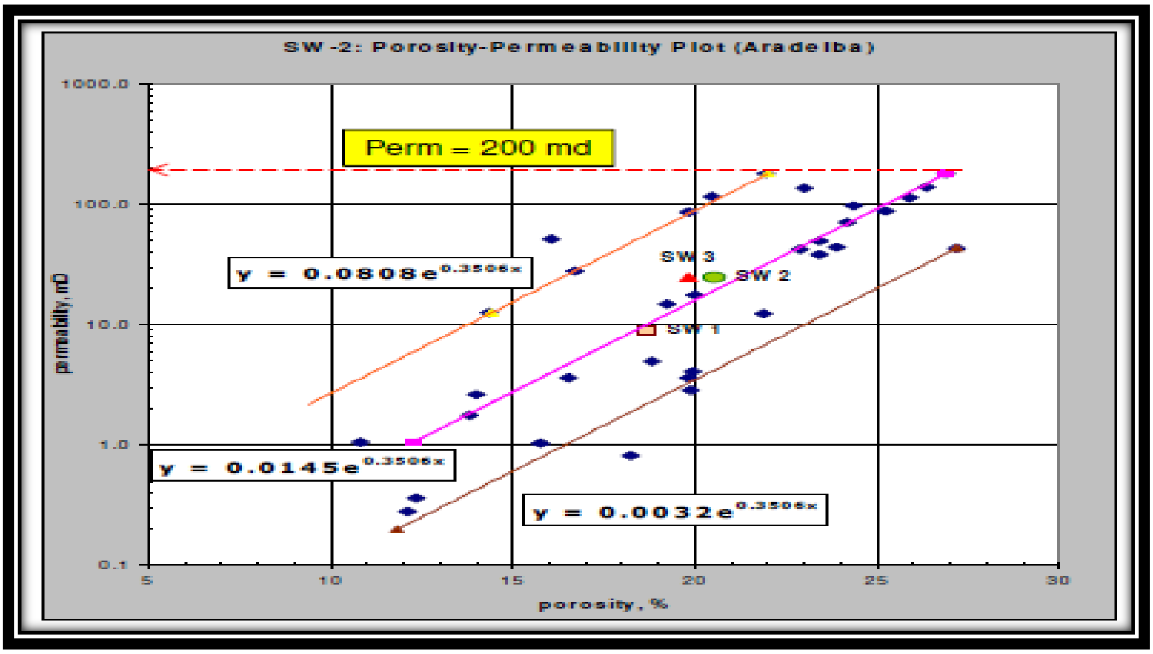


Figure 3.6.Porosity -Permeability Information

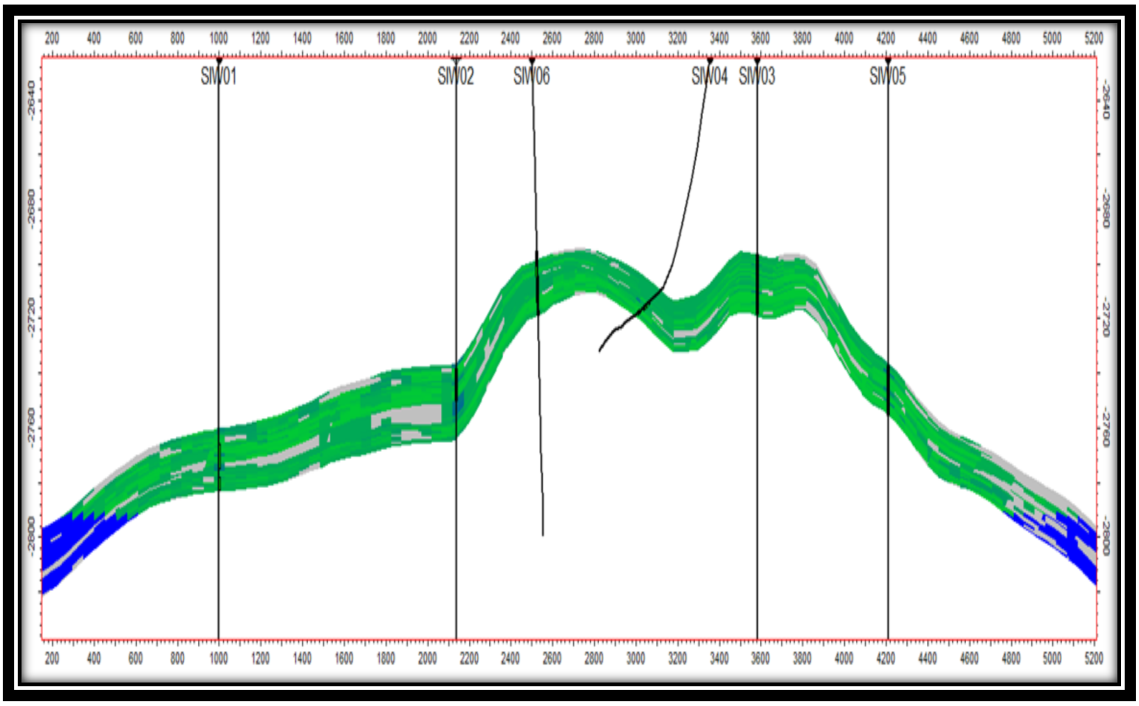


Figure3.7.Simber west wells depth distribution

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 stored 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 his 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)

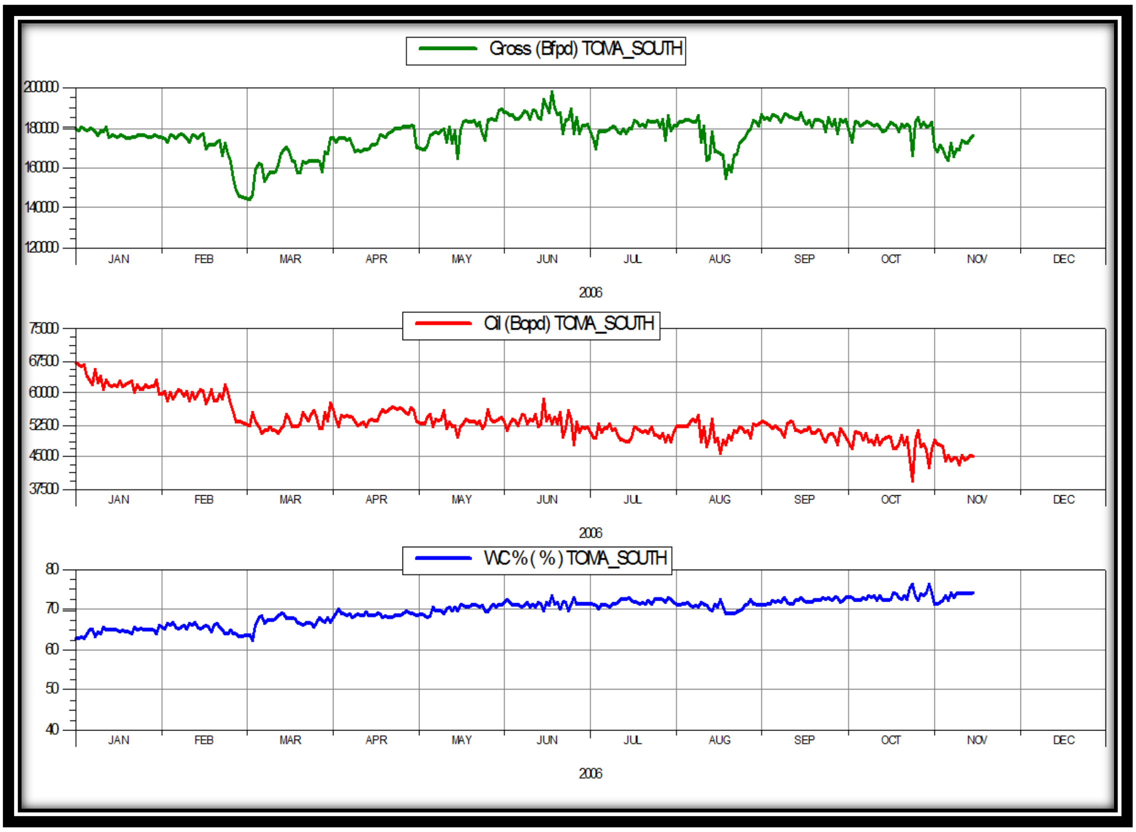


Figure 3.8Production performance plot using OFM

3.5.2. Analysis plot

To analysis the water production behavior

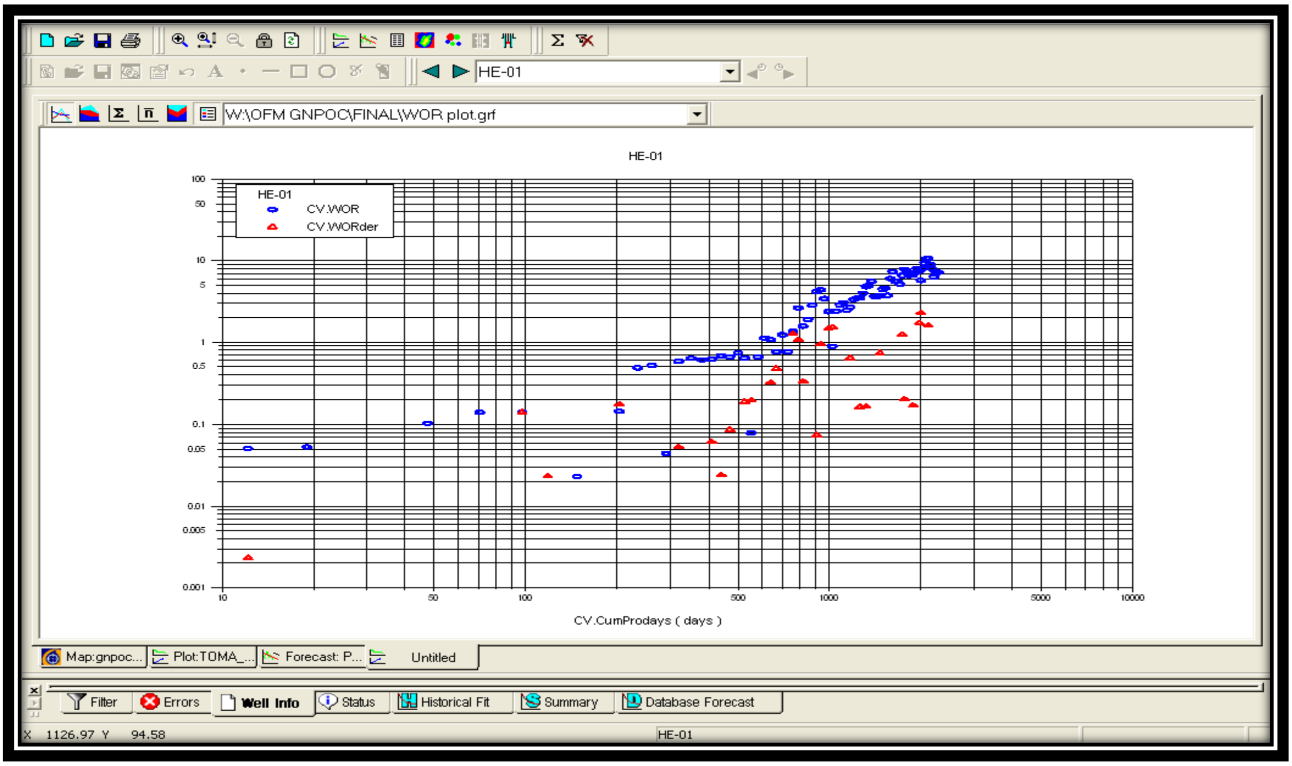


Figure 3.9water production behavior using OFM

3.5.3. Production Forecasting

To study the depletion rates and mitigation plan

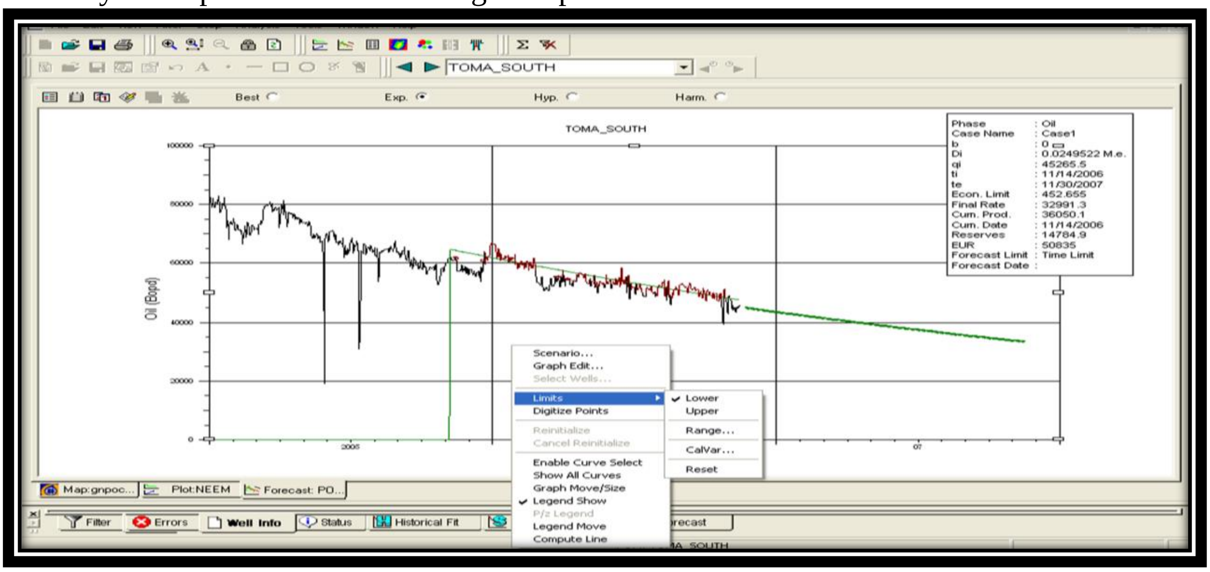


Figure 3.10Production Forecasting chart by OFM

3.5.4.Bubble map

To study the spacing and production coverage

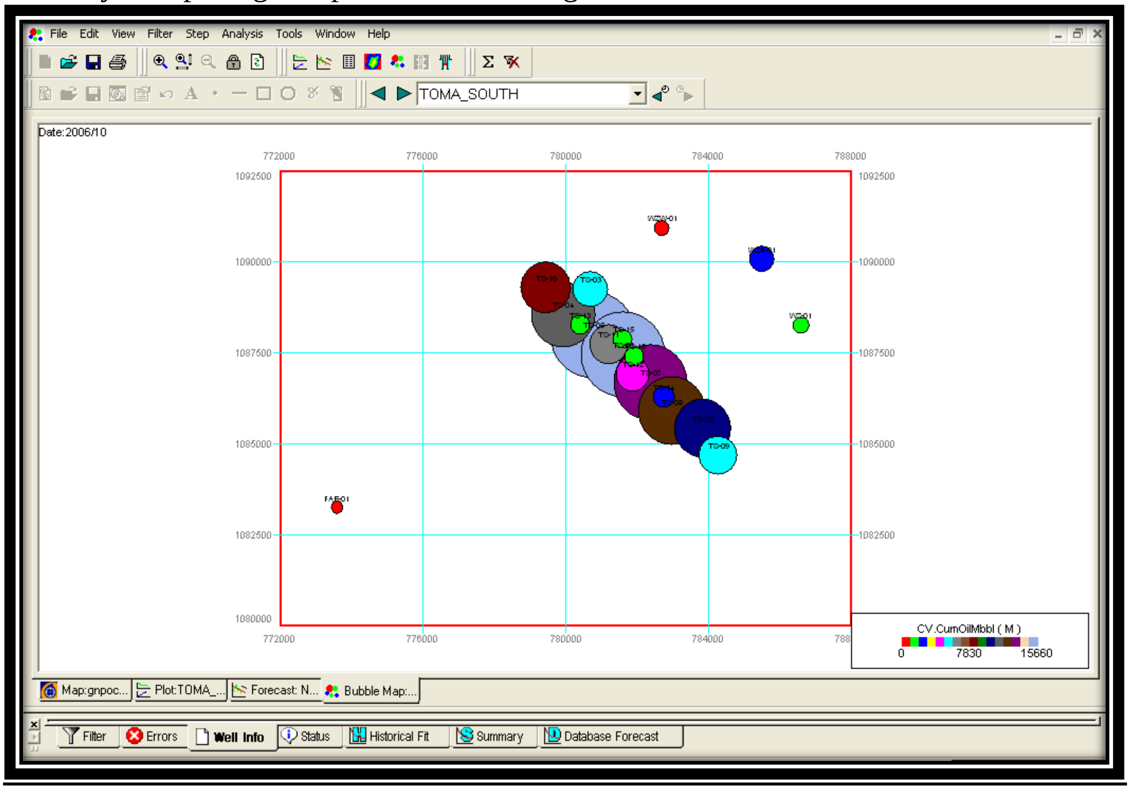


Figure 3.11 Bubble map by OFM

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).

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

Table 4.1.Basic Data

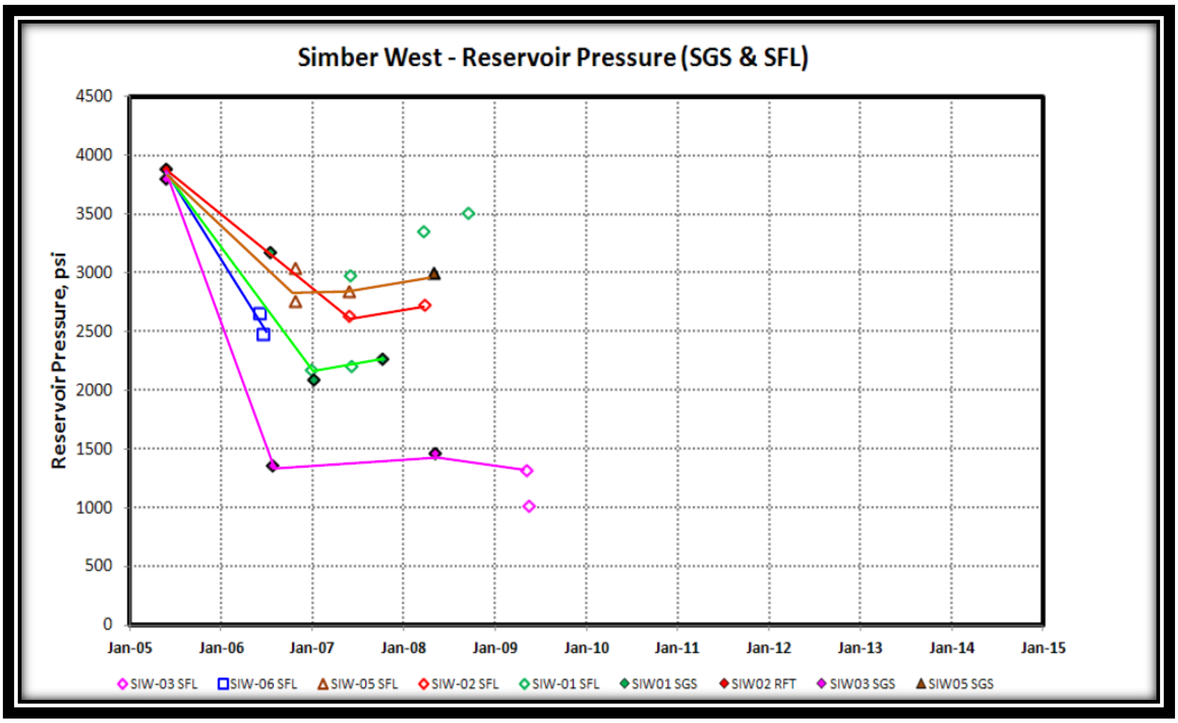


Figure 4.1 SGS & SFL vs Time

Pressure Analysis

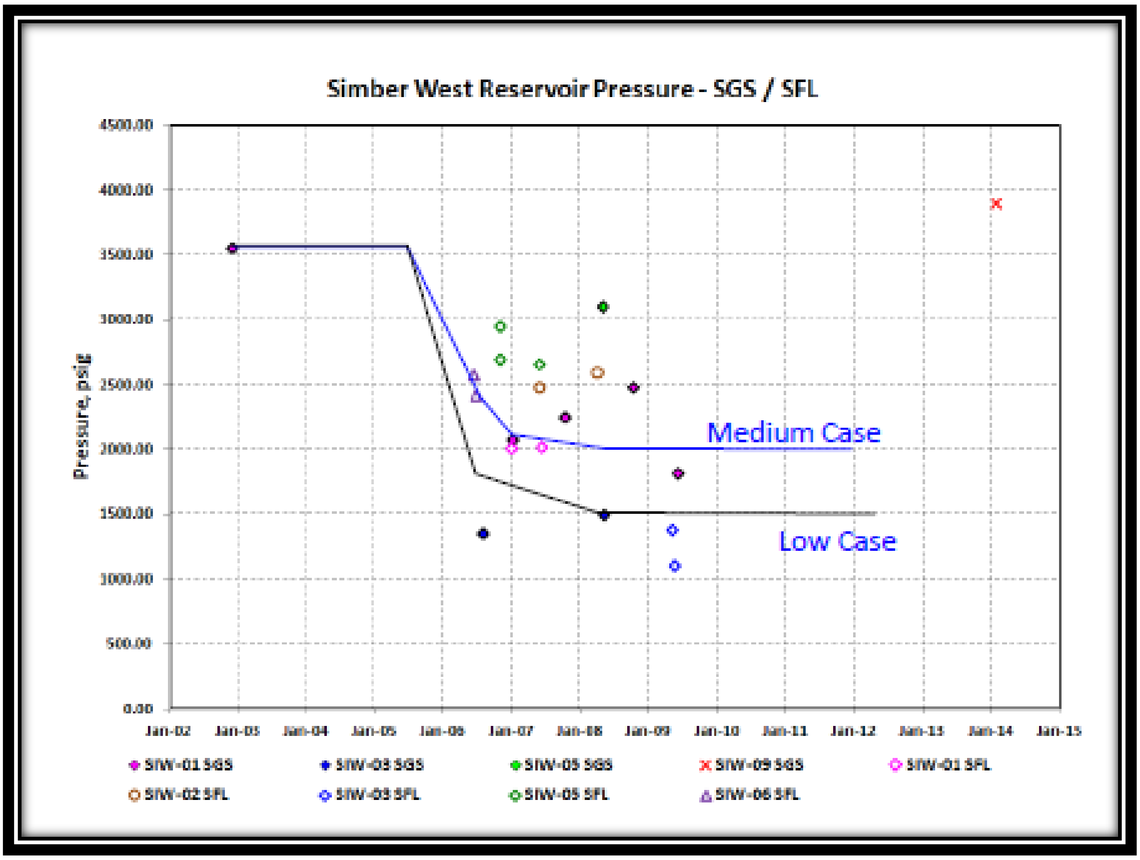


Figure 4.2 the reservoir pressure difference established for MBAL analysis

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

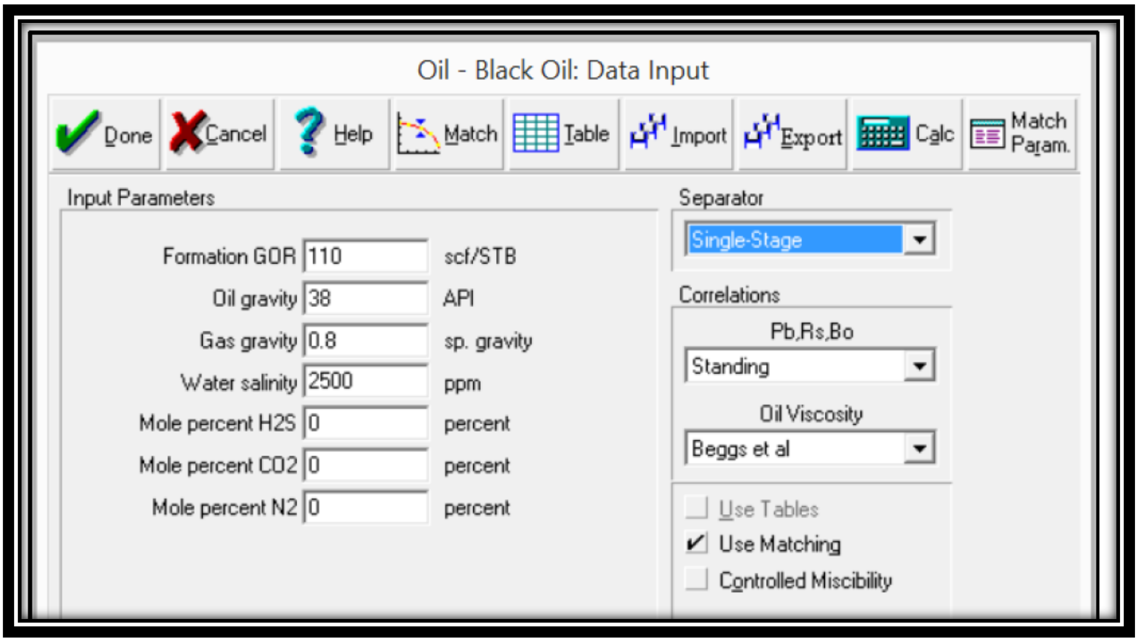


Figure 4.3Due to Limit fluid data available, correlation was used to generate the PVT data

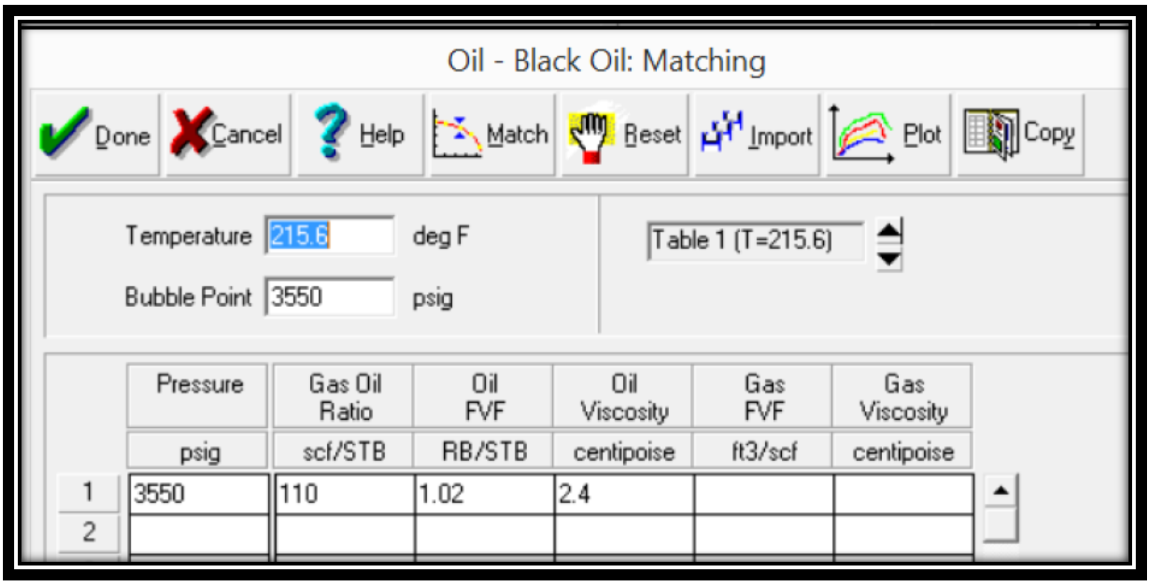


Figure 4.4 Black Oil Input Data

PVT – Correlations generated PVT data

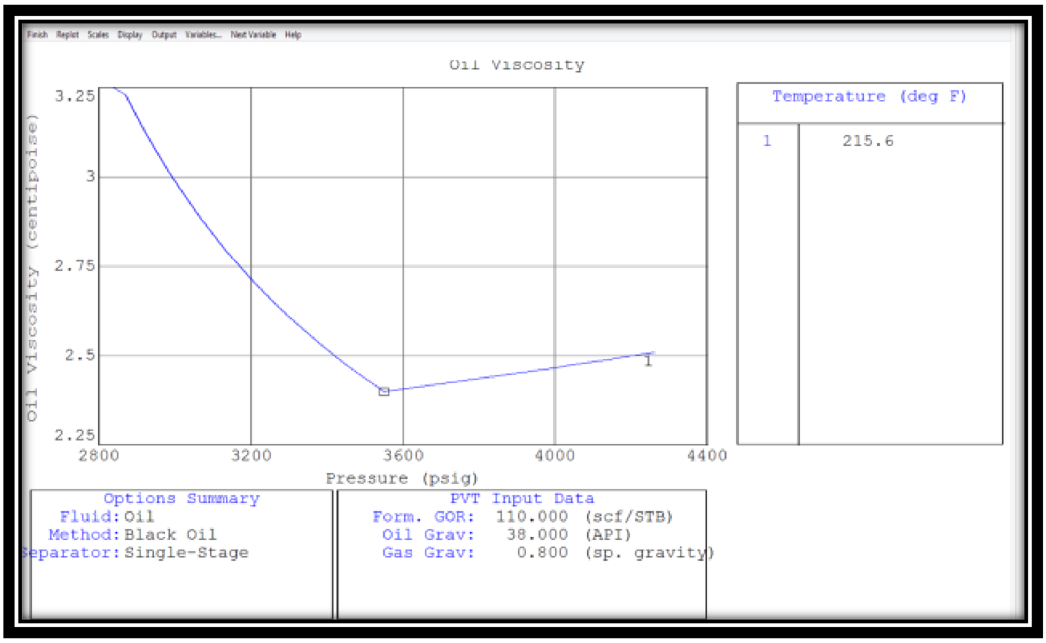


Figure 4.5Pressure vs Oil viscosity

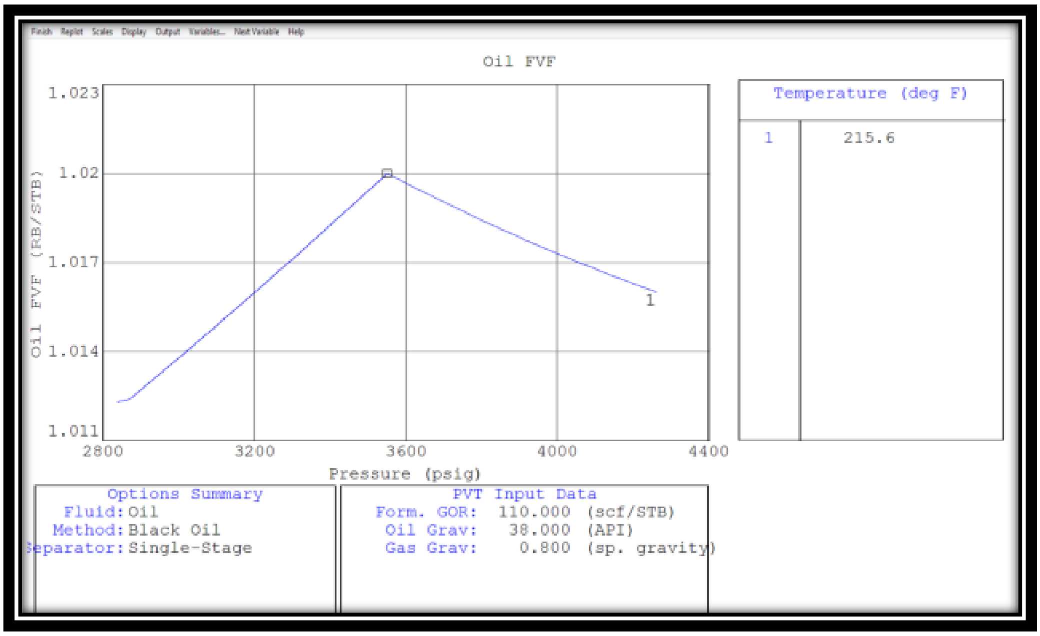


Figure 4.6Pressure vs oil FVF

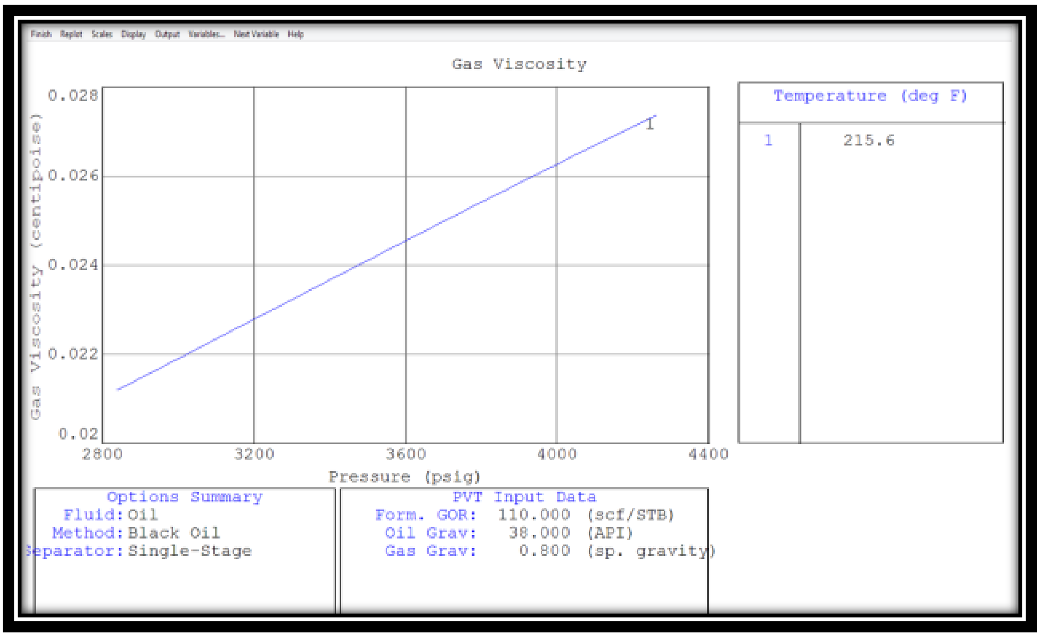


Figure 4.7pressure vs Gas viscosity

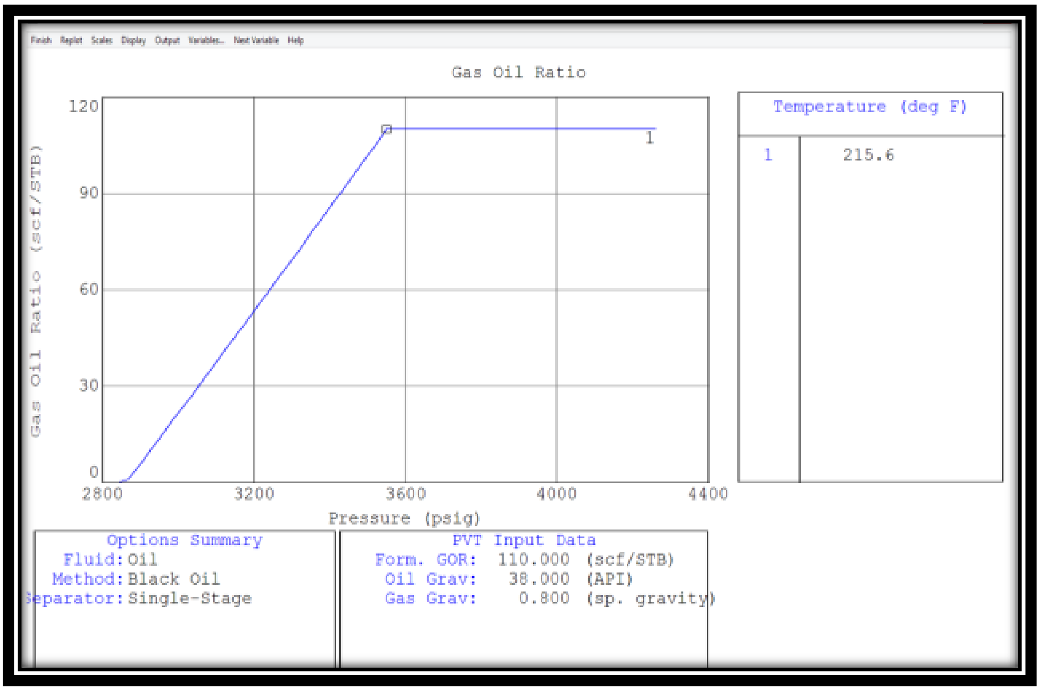


Figure 4.8pressure vs GOR

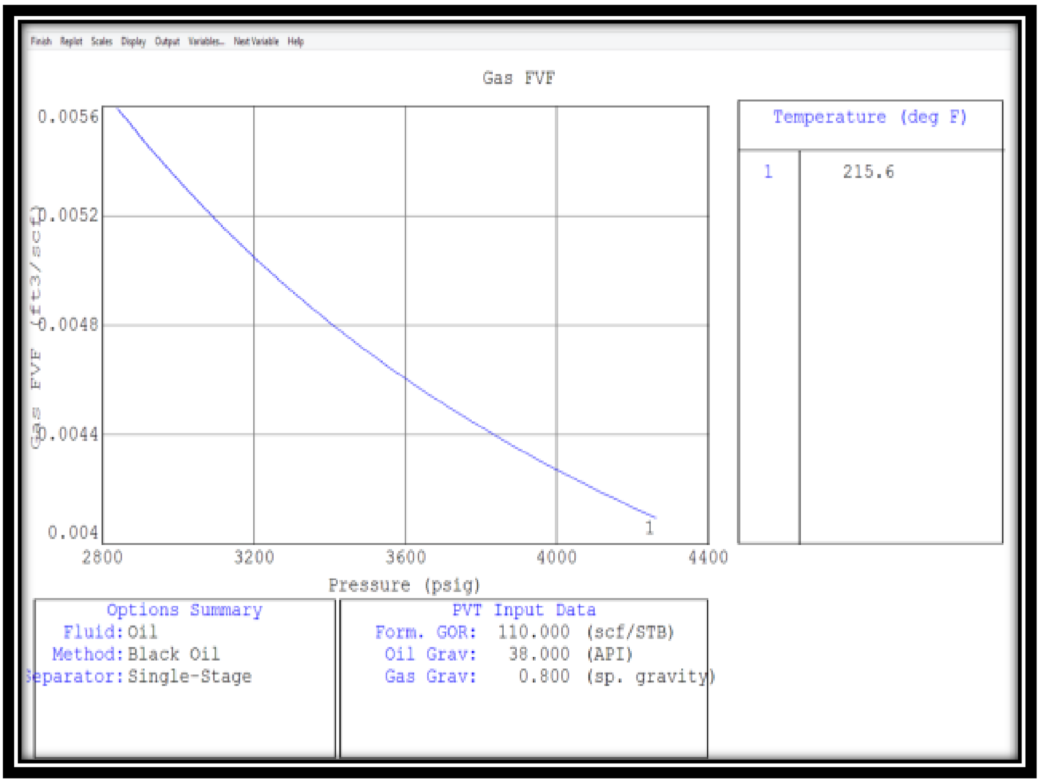


Figure 4.9pressure vs Gas FVF

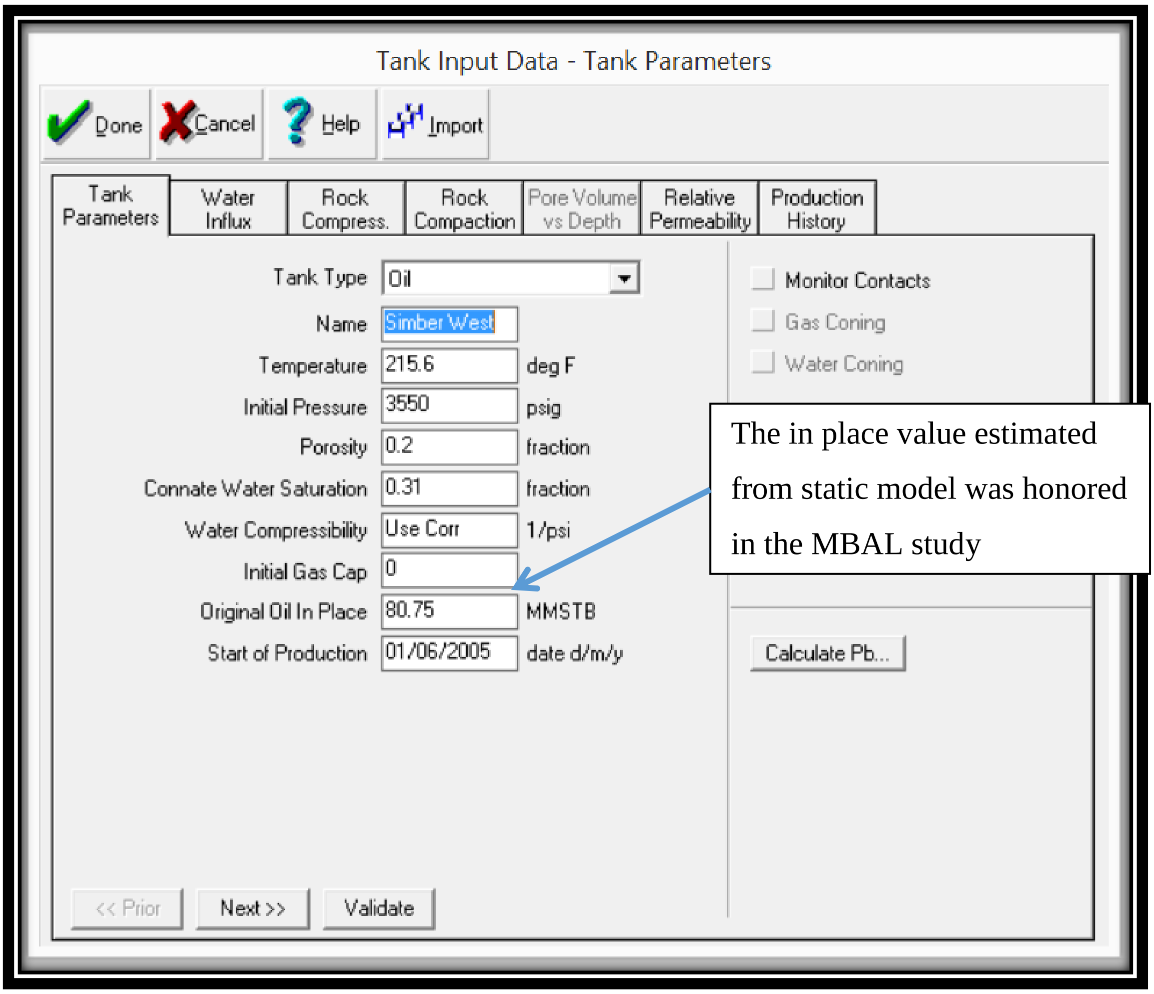


Figure 4.10.No aquifer attach as understood from reservoir pressure and water cut behavior

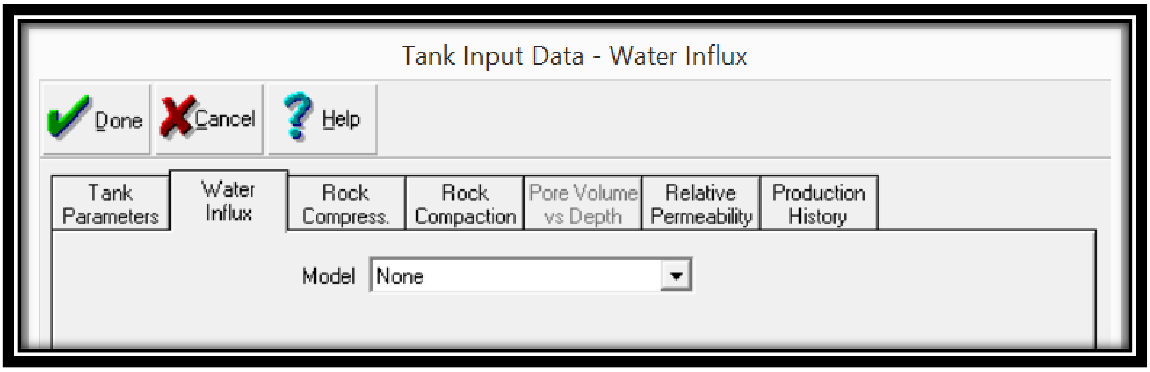


Figure 4.11.Tank Input Data – Water Influx

Typical Kr was used

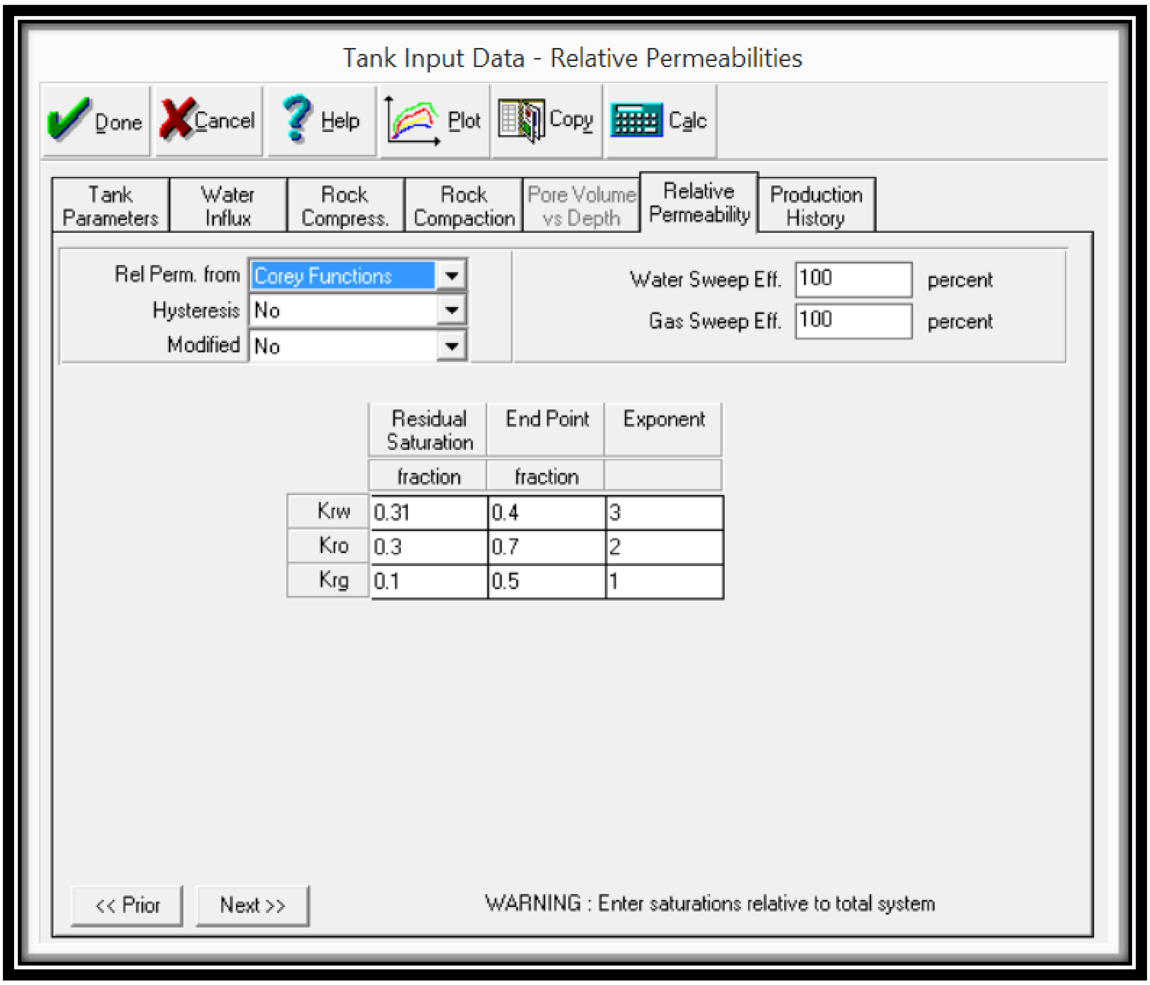


Figure 4.12 Tank Input Data –Rermeabilities.

4.4. Production Data

Oil & Water production from OFM database

4.4.1.Comulative water production

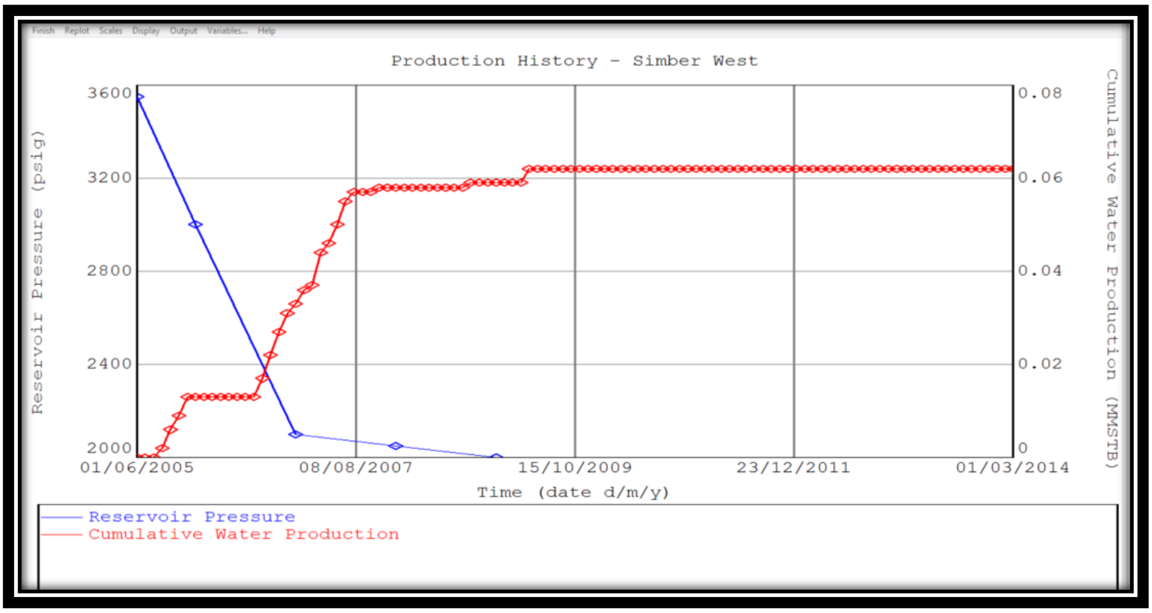


Figure 4.13Pressure&Cumulative water production

4.4.2Comulative oil production

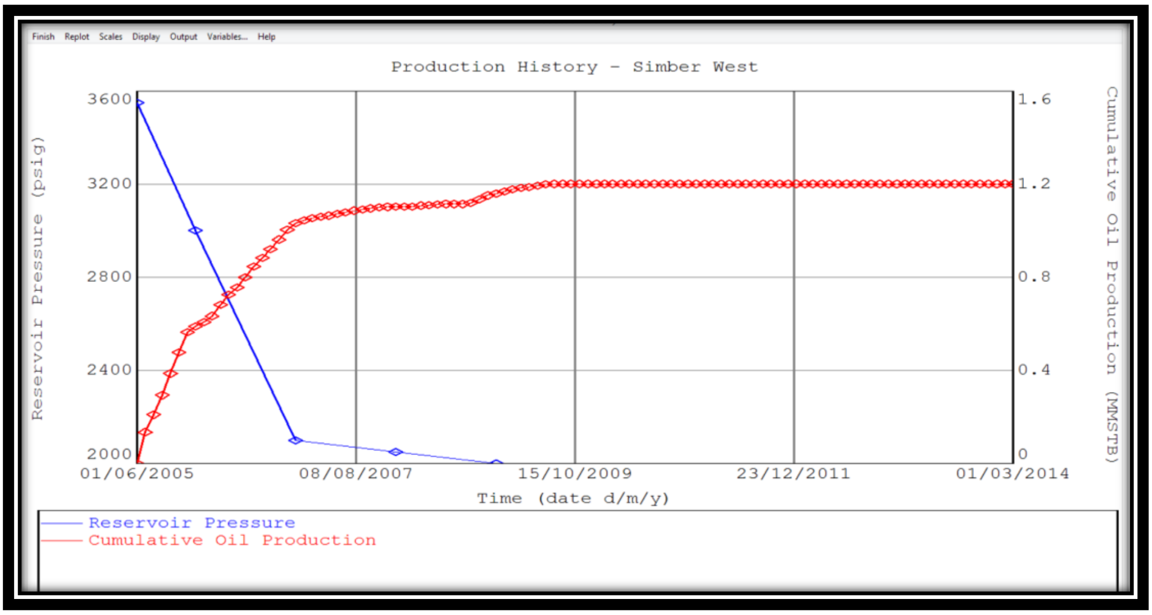


Figure 4.14Pressure & Cumulative oil production

4.4.3Comulative GOR

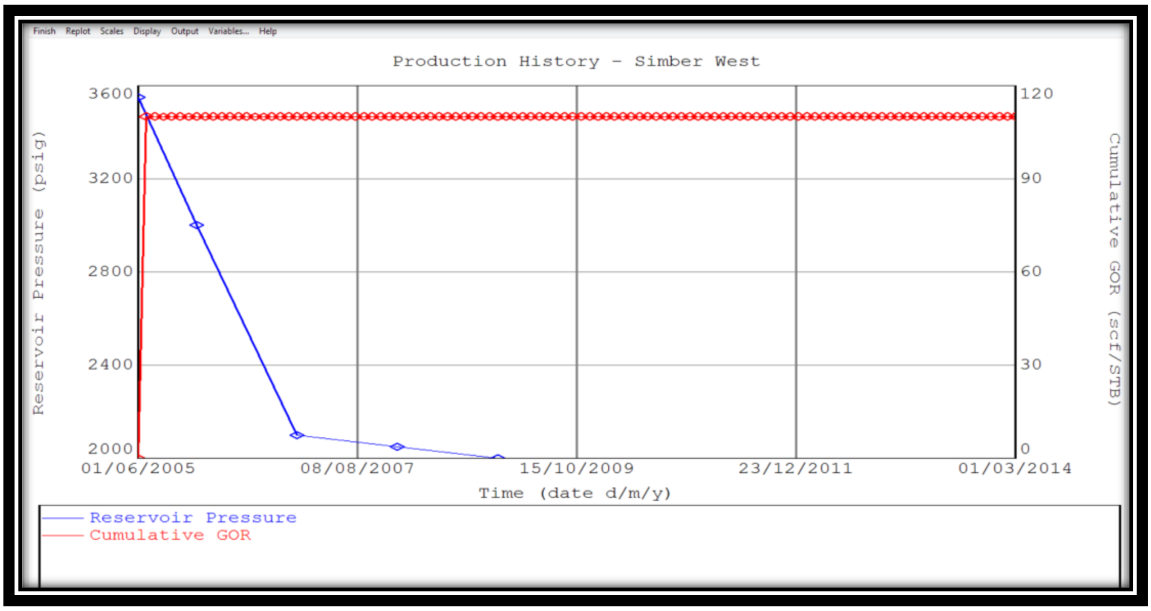


Figure 4.15Pressure & cumulative GOR production

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

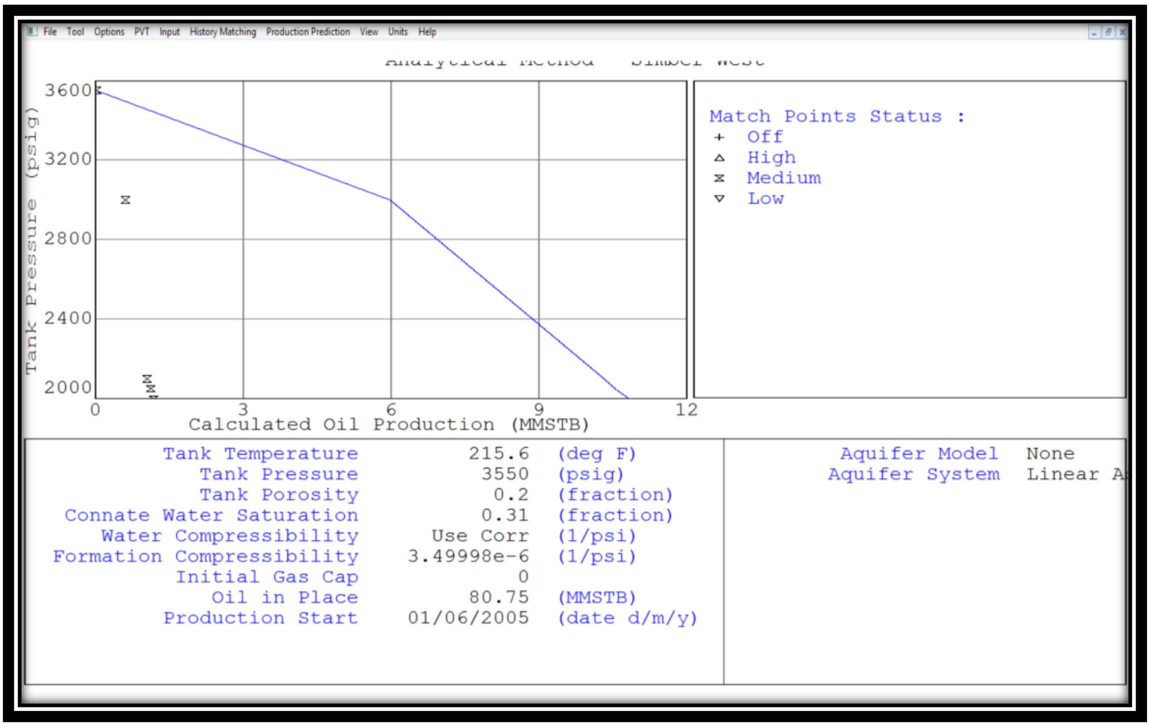


Figure 4.16calculated oil production by MBAL

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

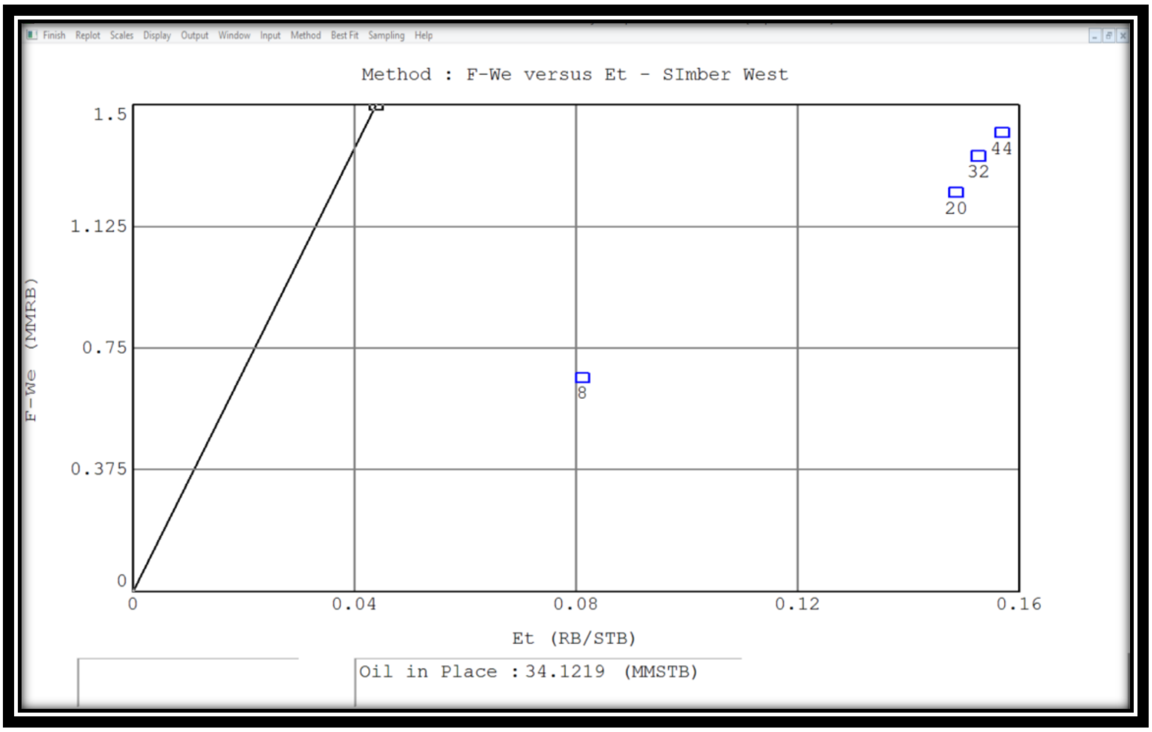


Figure 4.17Matching on Tank Volume (calculated oil in place by MBAL)

4.8. After matching with the SGS pressure data:

4.8.1. Matching on Tank Volume

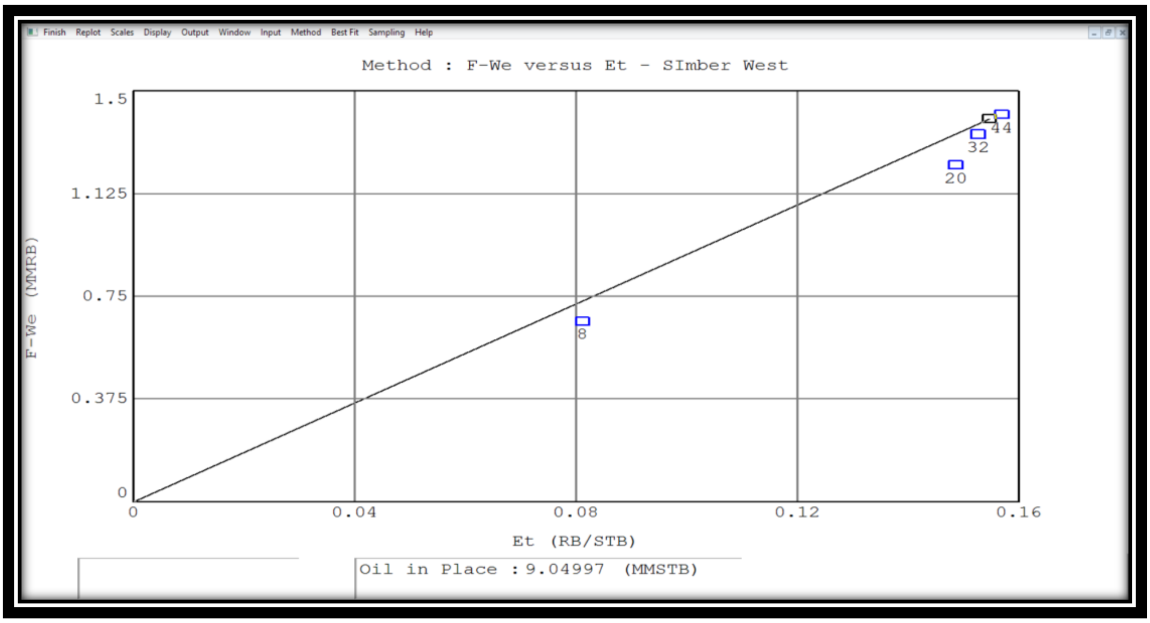


Figure 4.18Matching on Tank Volume (actual Oil in place by MBAL)

4.8.2. Matching on Energy Balance

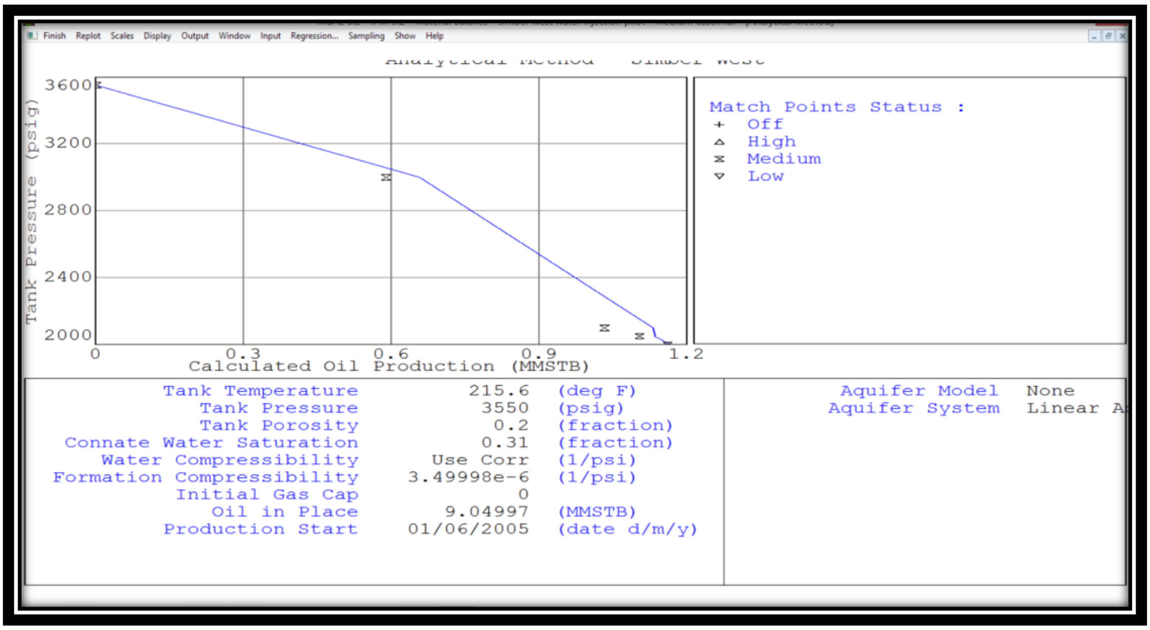


Figure 4.19Tank Pressure vs Calculated oil production

4.8.3. Drive Mechanism

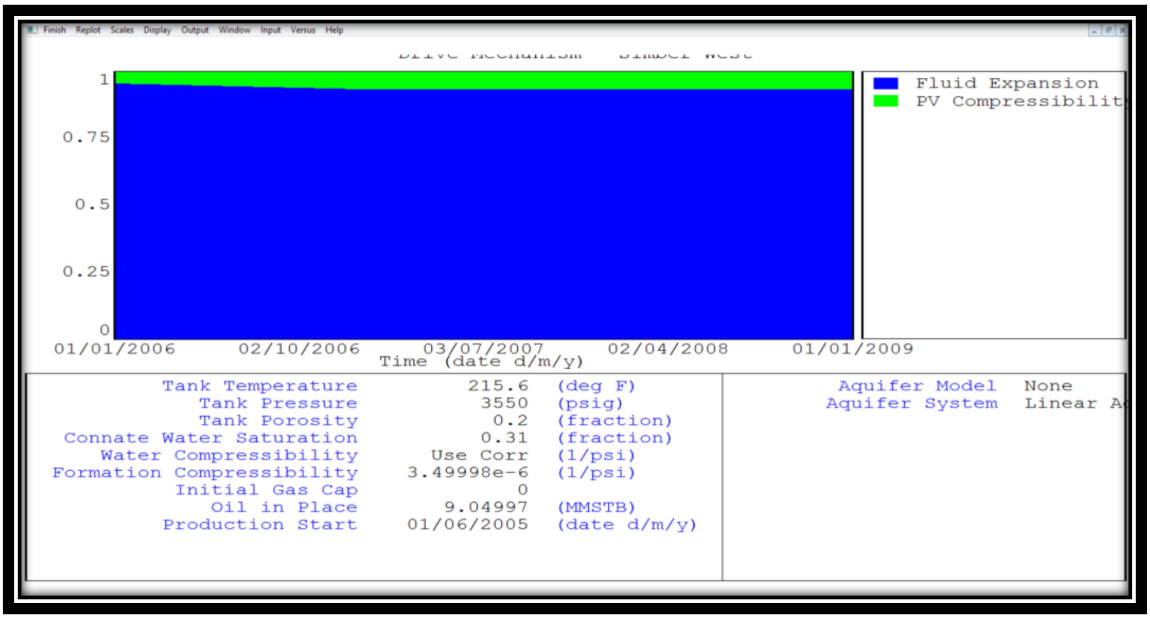


Figure 4.20Drive Mechanism identifying

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

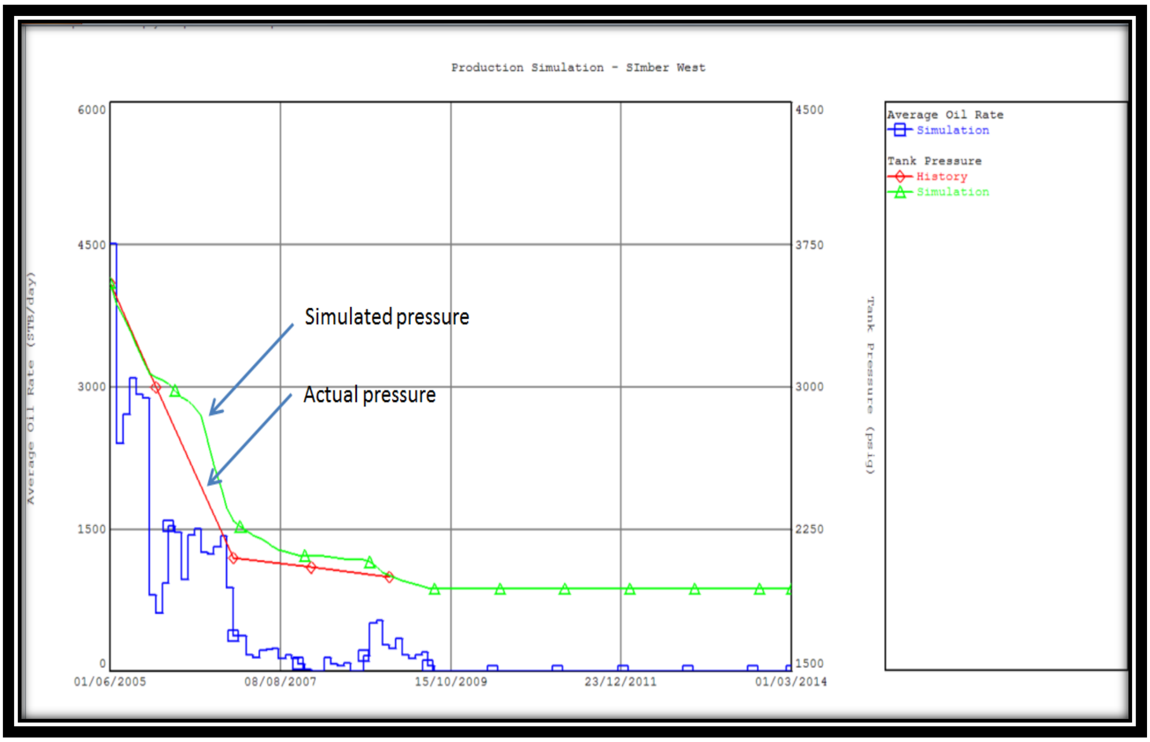


Figure 4.21Oil productions (Stimulated pressure vs actual pressure)

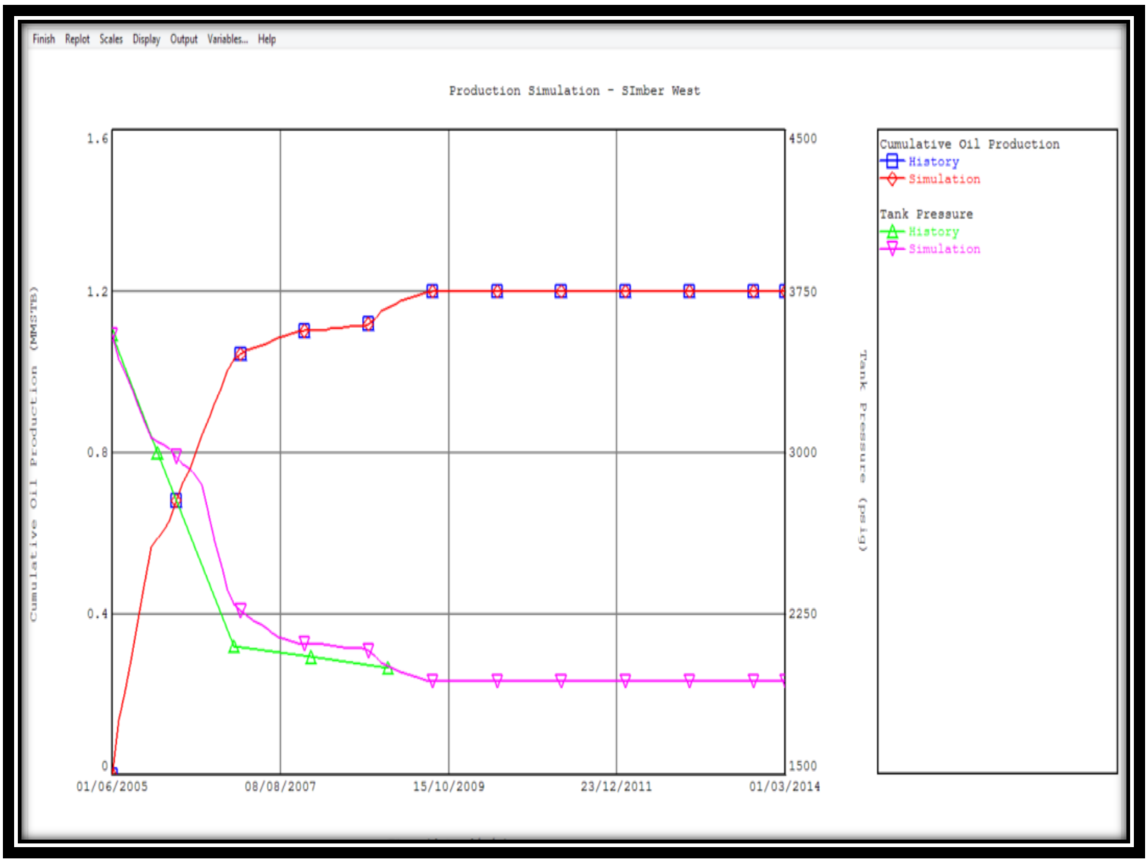


Figure 4.22 cumulative oil production vs time

•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

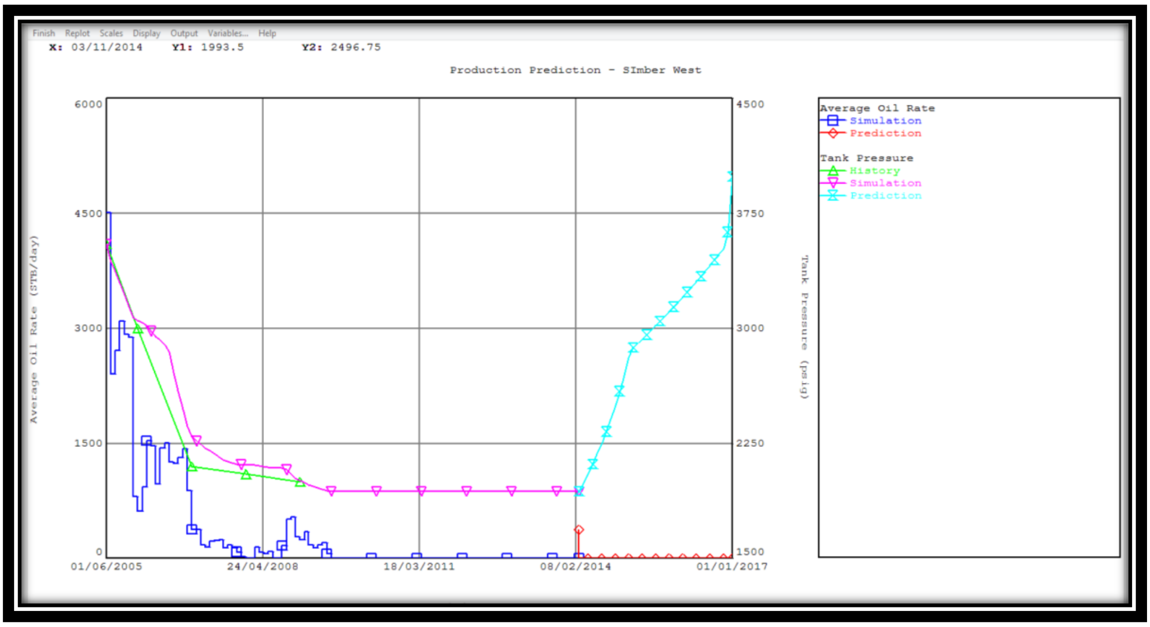


Figure 4.23cumulative oil prod vs time(avg oil & tank pressure)

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

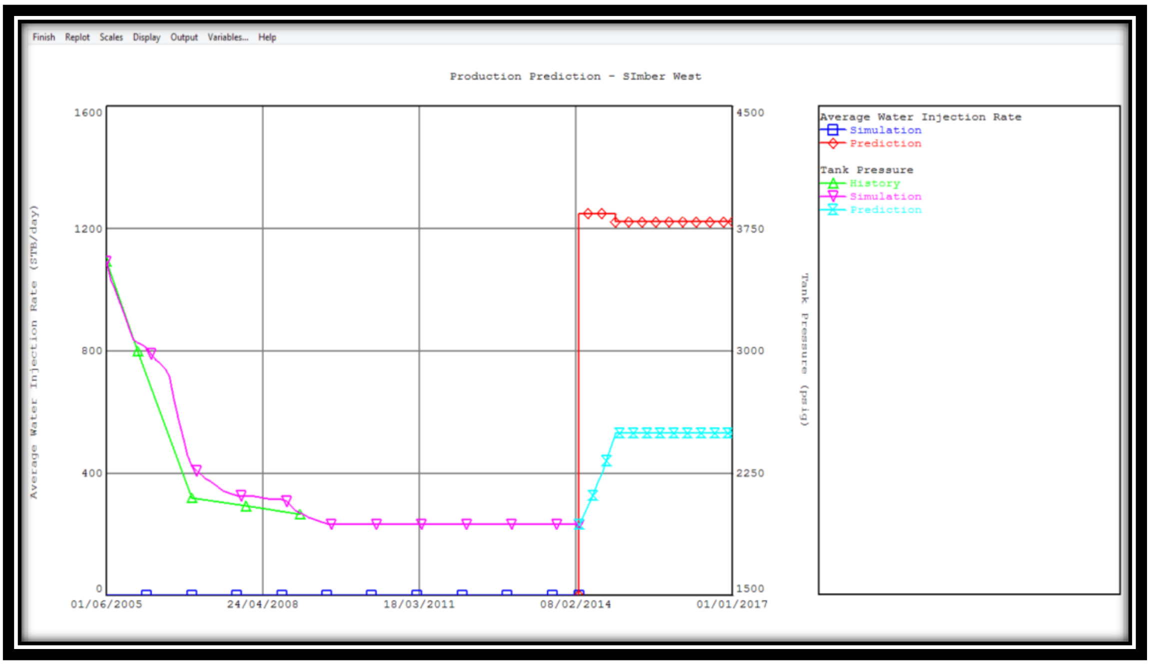


Figure 4.24.Average water Inj vs Time (tank pressure & Time)

4.7. Material Balance Case Study

4.7.1. Low Case

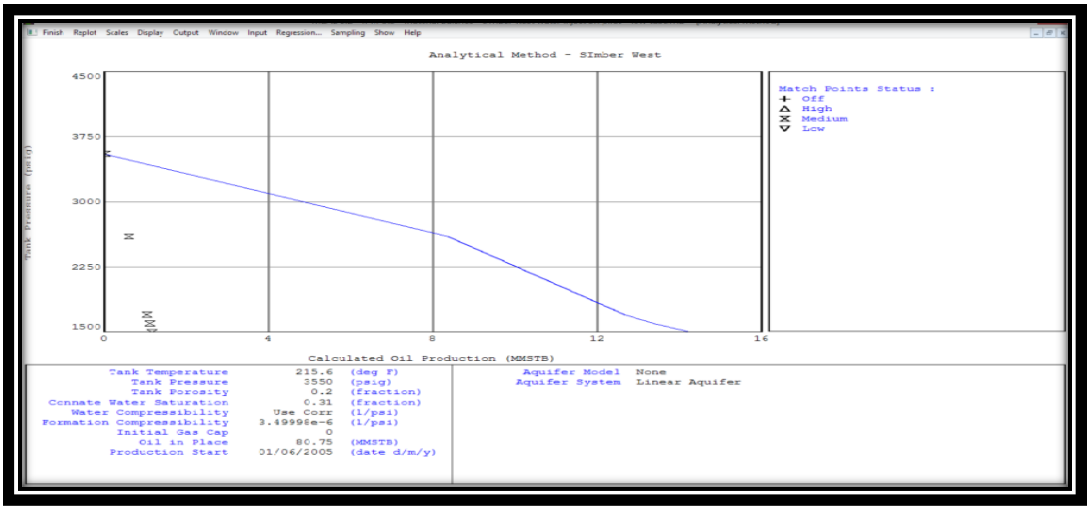


Figure 4.25.calculated oil production vs tan pressure

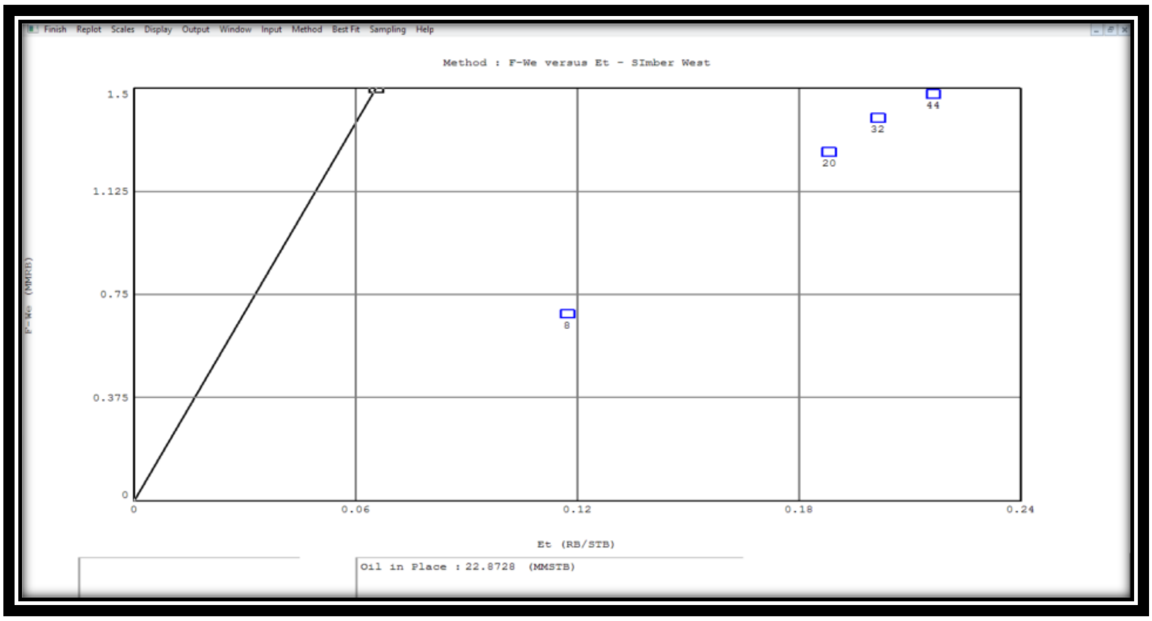


Figure 4.26.actual oil in place vs calculated from MBAL

Similar to Medium case, the in place of low case also require to be tuned.

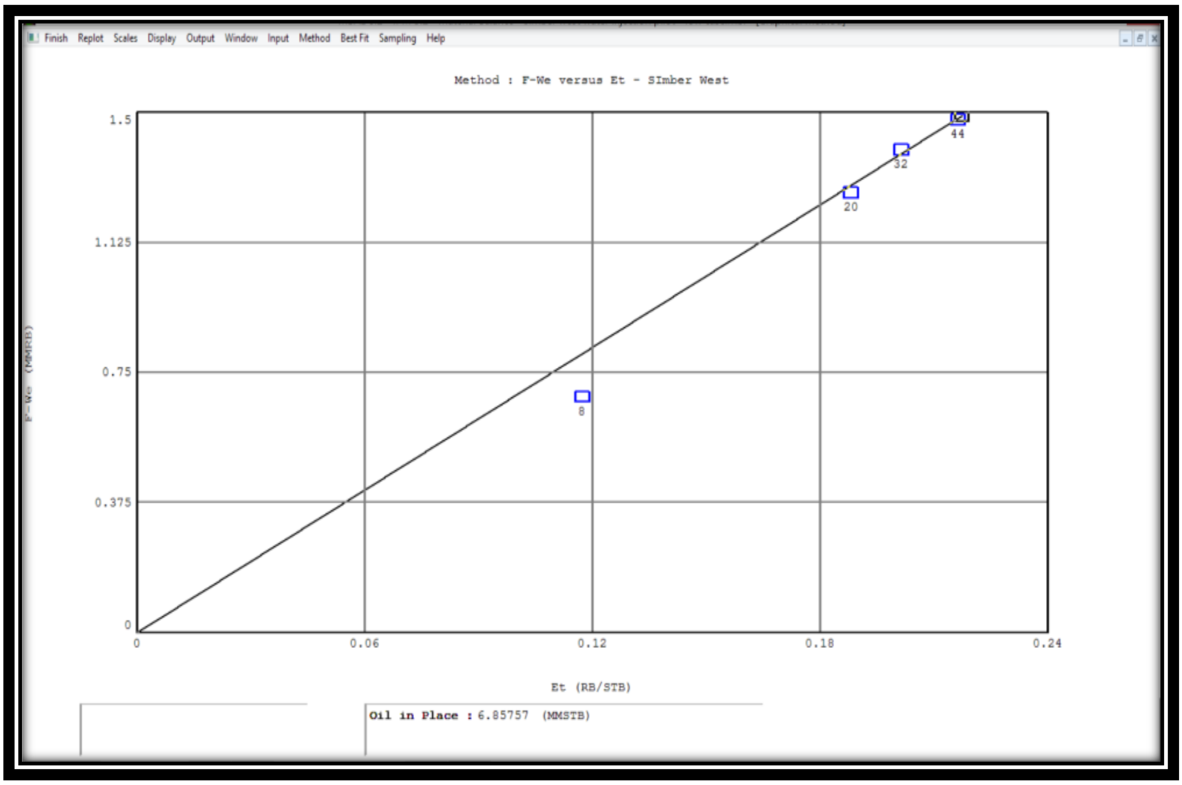


Figure 4.27data matching

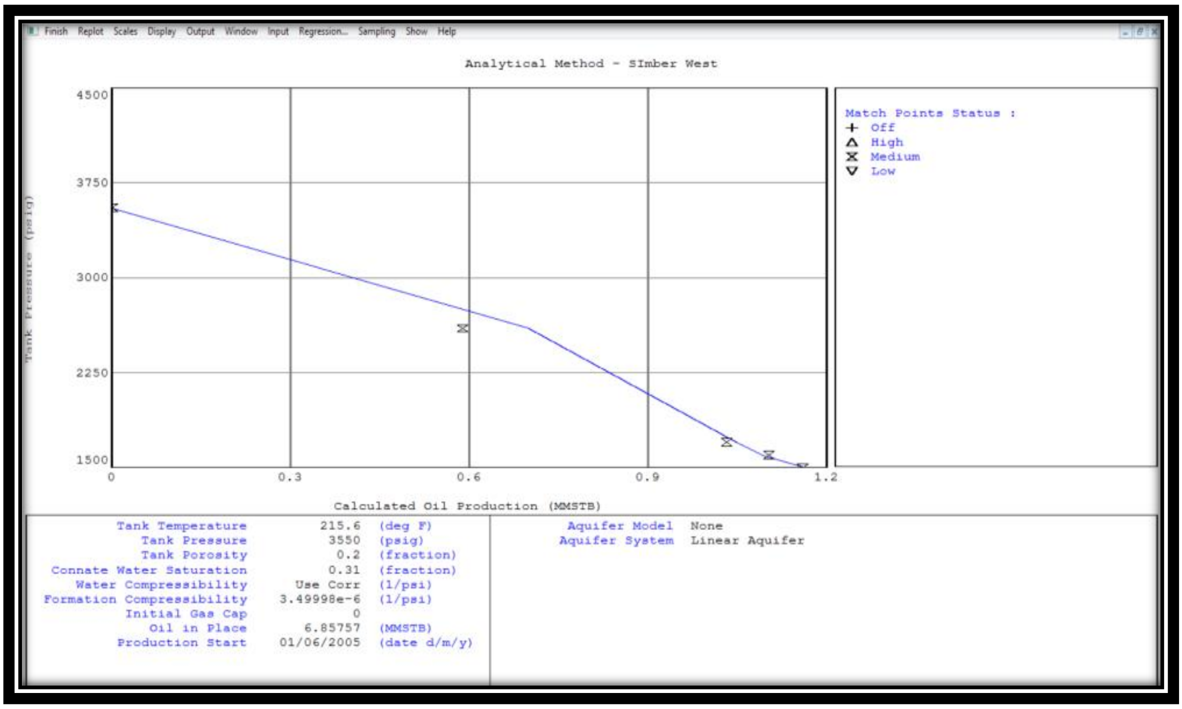


Figure 4.28pressure vs calculated oil

The suggested in place volume should be 6.86 MMstb (for Medium Case)

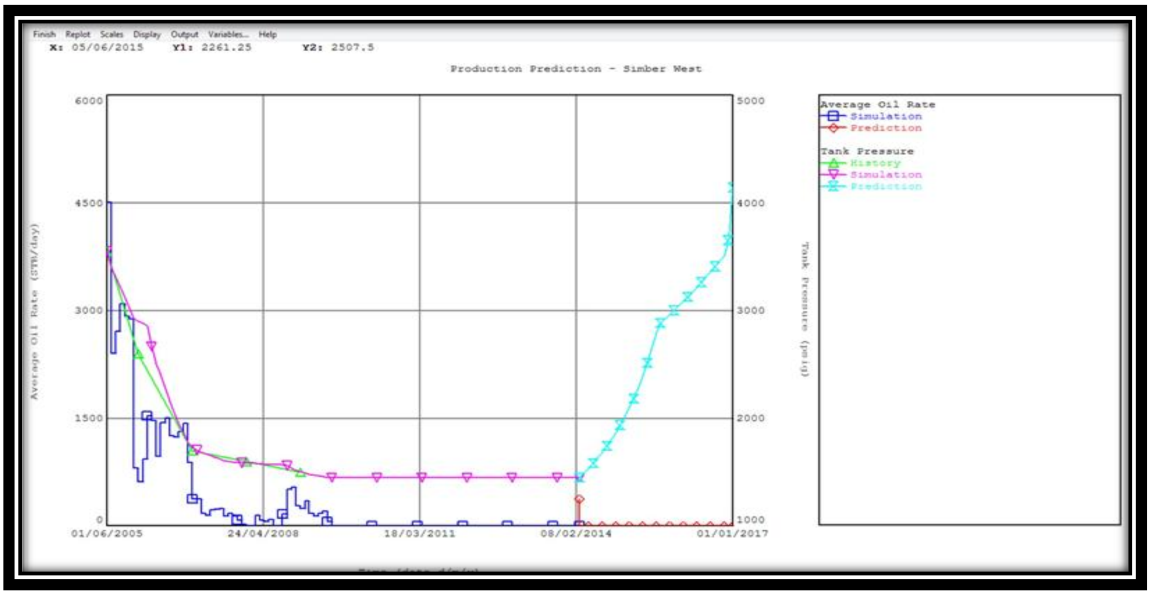


Figure 4.29Average oil actual pressure& estimated pressure

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

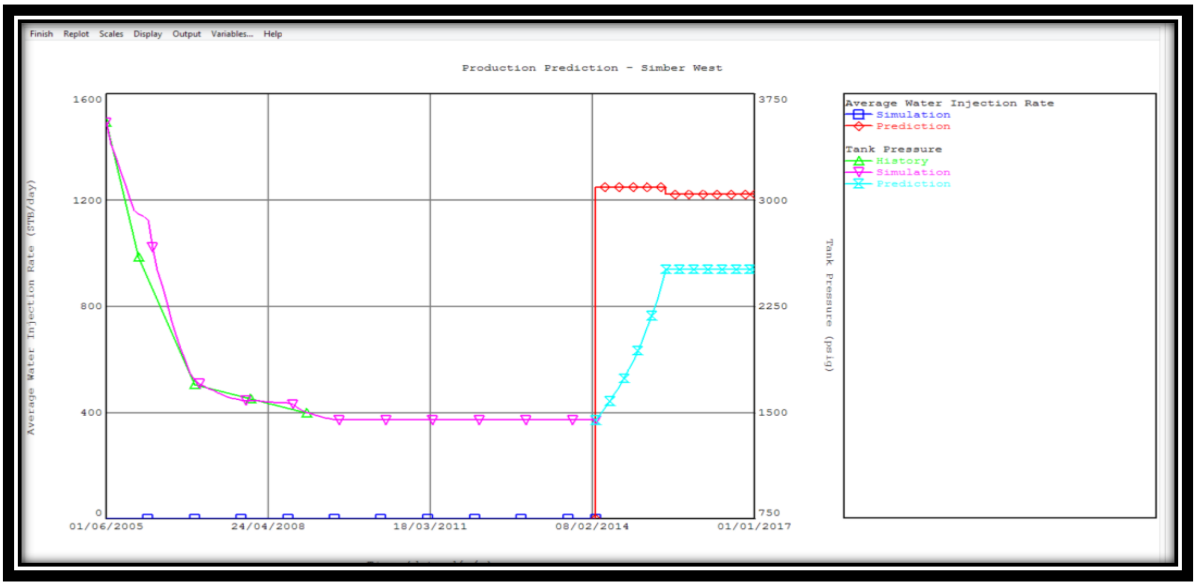


Figure 4.30Average Water Injection vs tank pressure

With the water injection rate of 1250 bp/d, and to maintain reservoir pressure at 2500 psi, suggested the production should be resumed at maximum 1200 bp/d

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:-

-Tarek, T.A,Paul,D. McKinney,(2005) *Advanced_Reservoir_Engineering,* Senior Staff Advisor, V.P. Reservoir Engineering, Anadarko Petroleum Corporation, Anadarko Canada Corporation.

-Bose,R.B. (2007) *Unloading Using Auger Tool and Foam and Experimental Identification of Liquid Loading of Low Rate Natural Gas Wells,* MSc Thesis, Texas A&M University.

-Binli,O. (2009) *Overview Of Solution To Prevent Liquid-Loading Problems In Gas Wells,* MSc Thesis, Middle East Technical University.

-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

-CARTER, R. and TRACY, G. (1960). *An improved method for calculations of water influx.Trans. AIME,* **152**

- CRAFT, B. and HAWKINS, M. (1959). *Applied Petroleum Reservoir Engineering* (Englewood Cliffs, NJ: Prentice Hall)

-HAWKINS, M. (1955). *Material Balances in Expansion TypeReservoirsAbove Bubble-Point*. SPE Transactions Reprint Series No. 3, pp. 36–40