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OPTIMIZATION OF GAS INJECTION BY SMART WELL (SIMULATION ON BARONIA FIELD)

By

ANIE JELIE

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Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan.

CERTIFICATION OF APPROVAL

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Anie anak Jelie

A project dissertation submitted to the
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Approved by,

(Elias b. Abblah)
UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
May 2011

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

ANIE ANAK JELIE
Petroleum Engineering Department,
Universiti Teknologi PETRONAS

ABSTRACT

This project is to propose a new exploitation technique of smart well in gas injection to mitigate production depletion. It is known a field in Baram Delta, Baronia Field is approaching mature depletion, so a mitigation plan has to be investigated. Based on real data from Baronia field, the author will simulate gas injection as secondary recovery and miscible injection by rich gas execution in hypothetical smart well based on Baronia-7 well design.

Typically, smart completions will cost more per completion but manipulation of the technology and exploit reservoir will make it worthwhile. So, the reservoir management is essential to control operations to obtain the maximum possible economic recovery from a reservoir. Hence, some key factors that impact performance of gas injection projects have to be effectively understood such as reservoir pressure, fluid composition, reservoir characteristics and relative permeability. Apart from that, reservoir profile will define the optimization scheme for intelligence device of smart well as well as its control techniques. Completion of study is by showing optimization of smart well function in gas injection to improve deliverability reservoir performance.

Briefly, scope of study for this project will cover both reservoir engineering and production and well completion aspect as the author will have to enhance knowledge in smart well system and application then simulating the injections and perform analysis.

To achieve the expected outcome the author will conduct a research methodology as doing the literature research and case study review, then simulation which will be using sector modeling and Eclipse and Petrel RE software. A discussion will be done on the simulation result and correlate it with the knowledge from research to develop recommendation in the case study.

Hence, expectation on this project is to create another new finding in oil and gas research world involving smart well application. The author want to prove that smart well will improve reservoir performance by optimization of smart completion as well as to show that this new technology is more efficient in cost and time consumption.

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I would like to express special gratitude and thank to my sincere supervisor, Mr. Elias Abblah for his full support, advice, constant supervision, strength, courage and valuable guidance throughout this project, again, I would like to thank him for providing the necessary information and opportunities through arranging visits to the cement manufacture.

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CHAPTER 1

INTRODUCTION

1.1 Project Background:

Baronia field is located in Sarawak water on Baram Delta Province which is a Tertiary basin, located in the northern part of Sarawak and extends northeastward through Brunei into the southern part of Sabah. Basically, hydrocarbon-bearing zones comprise more than 25 separate zones deposited in a coastal to inner shelf environment, but our zone of interest is RRRS and RW. This field that located around 40km form Miri, Sarawak is operated by Petronas Carigali Sdn. Bhd. (PCSB).

Deep understanding of reservoir behavior is essential but it needs detailed reservoir characterization as soon it play an important role in selection of efficient exploitation techniques as well as realistic budget of ultimate reserves. In favorable condition such as; rock and fluid properties, application of gas injection processes can enhance the recovery efficiency. Gas injection that we will focus on is pressure maintenance gas injection and rich gas injection as enhance oil recovery method.

According to PCSB definition, smart well (SW) or intelligent well is "a systematic integration of emerging downhole measurement, communication, control and processing technologies in well and asset design" or "a system that combines monitoring of one or more downhole parameters with a capability to act remotely -without intervention - to make a change to the system configuration in order to improve production or injection characteristics." Understanding of this technology is important for optimization of utilization in enhancing production as well as to comply with cost-benefit view.

Currently, Baronia 7 is the only smart well operated by PCSB, and functions as a gas injection well by in-loop gas injection (ILGI) or controlled cross flow mechanism from RW into RRRS reservoir. Since implementation of smart well in PCSB is still new, this well is still under observation, study and development.

1.2 Problem Statement:

Since the first oil in January 1972 until today, Baronia field still producing but approaching mature depletion stage. Base on 2003 study, the reservoir having VRR (Voidage Replacement Ratio) target of 0.4, but it has not met the target as current observed pressure has been below the prediction. If this production mode continues without gas injection, the production life of RR/RS reservoirs will be shortened and deteriorate the EUR (Estimated Ultimate Recovery) of 100.7 MMstb. Currently with assist of gas injection for pressure maintenance, production still decline and estimated recovery efficiency still very low, hence the company is seeking another alternative to maximize the recovery or in other word to study further on enhanced oil recovery (EOR) method. On the other hand, implementation of SW is known to be expensive but it is more multifunction compare to conventional well. By investigating our reservoir potential and applying SW technology with EOR method, can we enhance the recovery?

1.3 Objective and Scope of study:

Objective

- To introduce new idea of smart well exploitation technique to enhance production applied in in-loop gas injection based on research and case study on the technology development
- Review of gas injection both involve in secondary and tertiary (EOR) recovery to mitigate production depletion as well as to increase recovery efficiency.
- To investigate effect of different cases gas injection into Baronia field that executed by smart well in simulation.

Scope of study

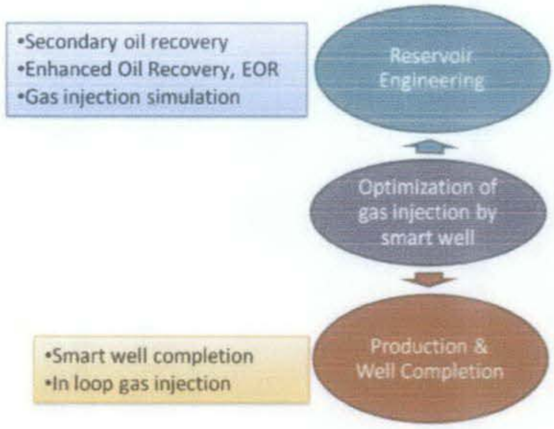


Figure 1.1: Scope of study

Secondary recovery is by gas injection into gas cap for pressure maintenance while EOR technique that the author chose is miscibility flooding by rich gas which the source is hydrocarbon gas itself from underneath reservoir. This will be simulated using Eclipse software.

While, smart well system mainly consist of monitoring devices which permanent downhole gauge (PDG) and inflow control valve (ICV) will be explained more in the report. Well completion design will be applied in the simulation together with the development strategy cases. In short, in loop gas injection workflow that author emphasized here is to develop full pressure maintenance for rich gas injection by smart well application.

1.4. Relevancy of Study:

Todays oil and gas market is increasing in price and cost of course. As demand increase, it'll give more courage to add more barrels in production. Having major reservoir such RRRS in Baronia with high potential but low performance is a challenge thus to seek for alternative in enhancing reservoir recovery efficiency. The operator still hunting for enhanced recovery method that suites the field. Perhaps, this project outcome will gives idea to PCSB solution in mitigating this issue.

Smart well is a recent and new technology been in implemented in Malaysia especially for PETRONAS. To have a fully understanding on the technology is essential as the operating company. Ideas of improvement will increase the market of this technology as well as to optimize the production. Furthermore, this BN-7 is the first level 2 smart well with integrated loop gas injection (ILGI) that operated by PCSB in Sarawak water.

Besides that, this 2-in-1 gas injection by internal in-loop gas injection via smart well never been done before and it will bring new findings to the oil and gas research world. Simulation by well known software will help the student to enhance knowledge in software application too.

2.5. Feasibility of Study

The study is expected to be feasible after much deliberation based on the below:

- Simulation software (Petrel RE and Eclipse) is readily installed in the university laboratory. Else, attachment to the PCSB is negotiable as well.
- Eclipse software was introduced to the student previously.
- An invitation for service provider of the software (Schlumberger) to deliver training on the software.
- Reservoir, fluids and rock details and well test production data for the field will be provided by advisor from operating company PCSB.

CHAPTER 2

LITERATURE REVIEW

2.1. Overview of study field

Location	:	40 km offshore Miri, in Baram Delta Province, Block SK15 at water depth of 76m.
Discovery	:	July 1967 (BN-1)
First oil	:	1972
Secondary recovery	:	2 gas injector + 4 water injector wells
Hydrocarbon bearing zone	:	3100 -10350 ft TVDSS (primary oil producing zones at 5,400 to 8,000 ft TVDSS)
Reservoir encountered	:	MAIN RESERVOIRS : Lower Cycle VI, Upper Mio-Lower Pliocene RR/RS, RV and RM/RN - carbonate MINOR RESERVOIRS : RG, RI, RJ, RL, RP, RT, RU, RW, RX, RZ
Area	:	Approximately 9km x 4km

For having more than hydrocarbon-bearing zones, oil bearing reservoirs (RM –RU) are sandwiched between the shallow gas-bearing reservoirs RG-RL and the deeper gas/condensate-bearing RW-RZ reservoirs.

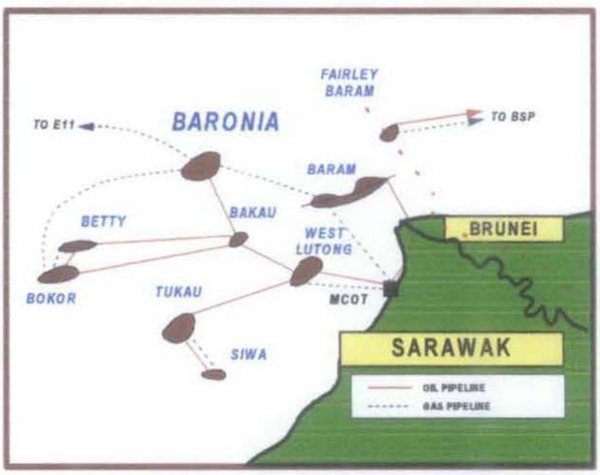


Figure 2.1: Baronia Field overview

2.1.1 RRRS Reservoir

Currently there are 20 producing wells in Baronia RR and RS reservoir. This RRRS is the largest contributor (39%) to total field oil production and started the production in October 1974 for RS and February 1976 for RR. Production is **3530 stb/d** with GOR of **25 Mscf/stb** and WCT of **51%** in Nov 2009. Average reservoir pressure is around 2140 psia. GOR increased start from injection in 1994 by gas recycling. Energy driven by gas cap expansion with a little or none support from aquifer. Current FDP study proposes STOIIP to be 349 MMstb and GIIP to be 1377 Bscf. Other reservoir data is as followed:

Porosity (%)	: 16 - 25
k(mD)	: 25 - 640
Soi (%)	: 34 - 79
Pi (psig)	: 3170
Pb (psig)	: 3164
Rsi (scf/stb)	: 1100
Boi (rb/stb)	: 1.550
Gascap Size(M)	: 2.0
Total drainage pts.	: 38

2.1.2 RW Reservoir

RW is Non-associated gas reservoir with reservoir pressure of 3500psi that is near to it's original pressure as this zone has never been produce before. Hence, the closest producing reservoir, RV will be reference for production history. It is found that no sand production history, hence we will not install any sand control equipment. And latest findings found that the gas from RW contained condensate; around 50 bbl/MMscf.

Component	Wt.%	Mol.%
Nitrogen	0.67	0.57
Hydrogen Sulphide	0.00	0.00
Carbon Dioxide	1.49	0.80
Methane	55.14	81.75
Ethane	7.04	5.56
Propane	8.44	4.55
Isobutane	2.15	0.88
N-Butane	3.15	1.29
Isopentane	1.48	0.49
N-Pentane	1.13	0.37
Hexanes	1.91	0.53
Heptanes	3.26	0.77
Octanes	4.76	0.99
Nonanes	2.72	0.50
Decanes	1.95	0.32
Undecanes	1.40	0.21
Dodecanes	0.95	0.13
Tridecanes	0.98	0.13
Tetradecanes +(C14+)	1.38	0.16
Total	100.00	100.00

Table 2.1: Recombined fluids composition

Currently, they are injecting gas from RW to the RRRS gas cap reservoirs by cross-flow that connected by Baronia-7 smart well. This project will investigate if there was potential for miscibility displacement by injecting RW gas into RRRS oil layer or at least simulate the effect of injecting into oil layer instead of gas cap.

2.2 What is smart well?

2.2.1 Definitions

- WellDynamics' Definition[1]

A well that combines a series of components that collect, transmit and analyze completion, production and reservoir data, and enable selective zonal control to optimize the production process without intervention as shown below.

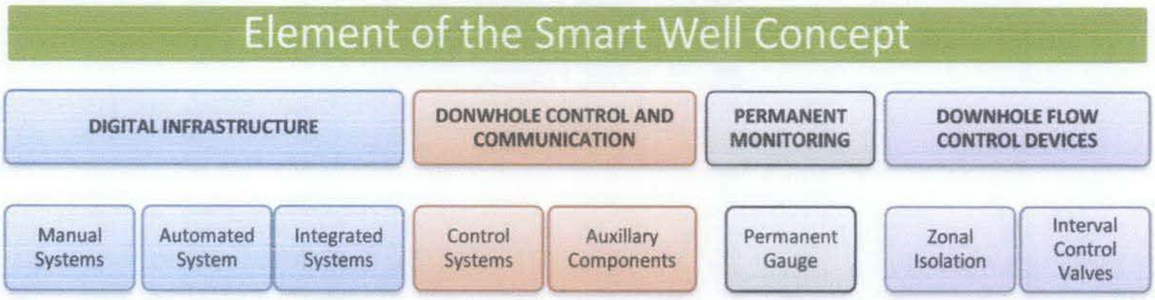


Figure 2.2: Element of the Smart Well Concept by WellDynamic

- Schlumberger's Definition[2]:

A well equipped with monitoring equipment and completion components that can be adjusted to optimize production, either automatically or with some operator intervention.

- Intelligent Well Reliability Group (IWRG) Definition[3]:

A well equipped with means to monitor specified parameters (e.g. fluid flow, temperature, pressure) and controls enabling flow from each of the zones to be independently modulated from a remote location.

- Petronas' Definition[4]

According to Petronas Carigali Sdn. Bhd (PCSB) definition, smart well or intelligent well is "a systematic integration of emerging downhole measurement, communication, control and processing technologies in well and asset design" or "a system that combines monitoring of one or more downhole parameters with a capability to act remotely -

without intervention - to make a change to the system configuration in order to improve production or injection characteristics."

Hence, we can say that smart well is the design of completions with downhole equipment for flow control and sensors that measure pressure, temperature, and flow. Data from the sensors are transmitted to surface facilities, providing useful information for monitoring the reservoir and optimizing production. Then the smart well allow us to go from passive/reactive production scenarios to active/proactive production control.

2.2.2. Intelligent devices

Monitoring/measurement[9]

- Single point measurement of pressure and temperature : permanent down hole gauges (PDG)
    - Sensors using resonating quartz crystals: the resonance frequency of the electrically excited crystals is a function of pressure and temperature
    - Recent development:
        - Electric resonating diaphragms which have the advantage of having no electronics down hole
        - Fibre brag grating technology
        - Which does away with electronics altogether and uses fibre optics for measurement and data transmission to surface.
- Distributed measurement of pressure and temperature : distributed temperature sensing (DTS)/ distributed pressure sensing (DPS)
    - Employs a thin glass fibre optical cable running along the entire length of the well
    - Possible to obtain a very accurate (0.1 degree) temperature profile
    - Installation of DTS is through pumping it down through a U-tubed ¼ inch control line that was run with the completion
    - DPS is still under development
- Flow rate and composition meters
    - To obtain accurate three-phase measurement
    - Flow metering concepts under development : fibre brag grating technology

- Compositional meters under development: gamma ray absorption, capacitance or conductance measurements and electromagnetic helical resonators.
- Combination of down hole and surface measurement with inflow control device downhole will determine flow rate of zonal isolation which is so called well testing with exception.

Control [10, 11]

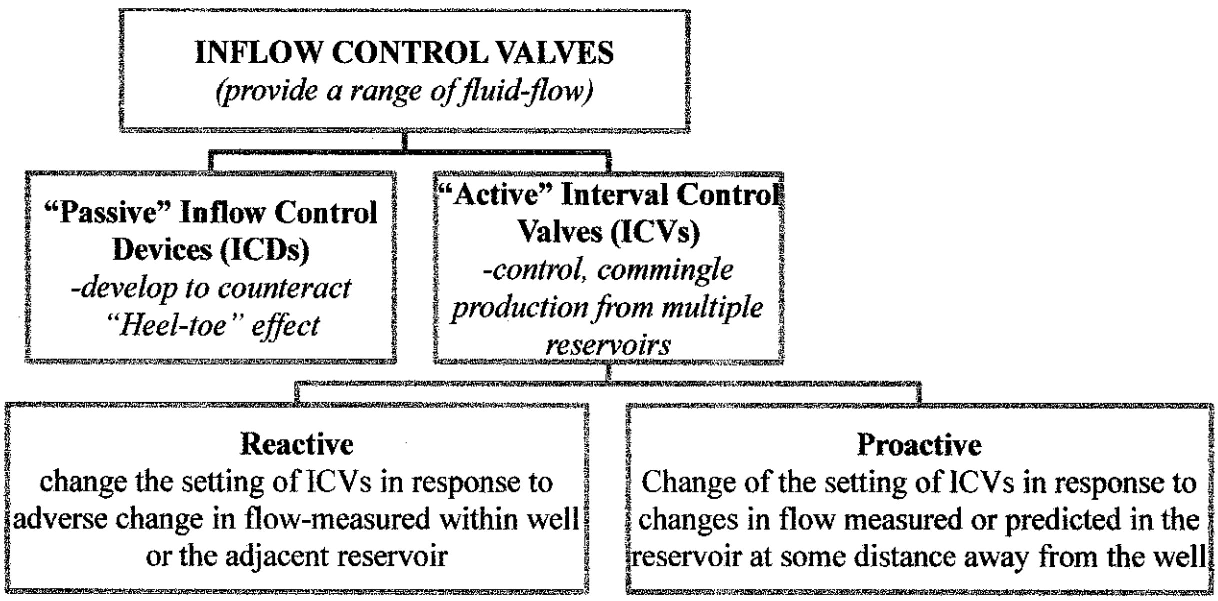


Figure 2.3: Inflow control valves

2.2.3 Baronia-7 (BN-7) Smart Well

BN-7 relatively the best location with thickest sand in the RW gas reservoir and RR/RS reservoir with anticipated AOF more than 100MMscf/c. This well is located in platform Baronia A in Northern Cluster which operated by Petronas Sarawak Operation (SKO).

- **Workover/ Installation** : September 2009
- **Total depth**: 8456 ft MDTHF
- **Reservoir**: communicated with 10 reservoir layers (both oil and gas)
- **Completion** : single string (**ICV & PDG** installed), no gravel pack for sand control

We will use BN-7 profile to create a hypothetical well because the simulation will be conducted using sector modeling of RRRS which do not take BN-7 area.

2.3 Introduction to In Loop Gas Injection (ILGI)

Gas injection is a technique of injecting gas into a reservoir. It may be done for pressure maintenance, oil viscosity reduction, light end stripping or storage[5]. In favorable condition such as; rock and fluid properties, application of gas injection processes can enhance the recovery efficiency and value of a field development. The key factors that influence outcome of the gas injection are such as; reservoir pressure, fluid composition, reservoir characteristics and relative permeability[6].

Hence, ILGI is when a smart well is used to connect an oil reservoir with depletion in production (either due to the mechanism drive or microscopic factor) to an underlying gas reservoir with higher pressure. In my project, we will go investigate on both secondary and tertiary recovery method by ILGI.

2.4 ILGI for Secondary Recovery

The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells[2].

Inflow performance relationship (IPR)

The IPR for a well is a the relationship between flow rate into the wellbore and wellbore flowing pressure P_{wf}.

$$q_o = J(\bar{p} - p_{wf}),$$

where J is the productivity index, P_{wf} is the well-flowing pressure in front of the perforated zone, $\bar{P}$ is the static pressure, and q_o is the oil-mass flow-rate from the well.

For saturated reservoirs, Vogel's formula (Vogel, 1968)[7] gives:

$$q_o = q_{max}\left[1 - 0.2\frac{p_{wf}}{\bar{p}} - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2\right]$$

where q_{max} is the maximum oil flow-rate (for P_{wf}=0).

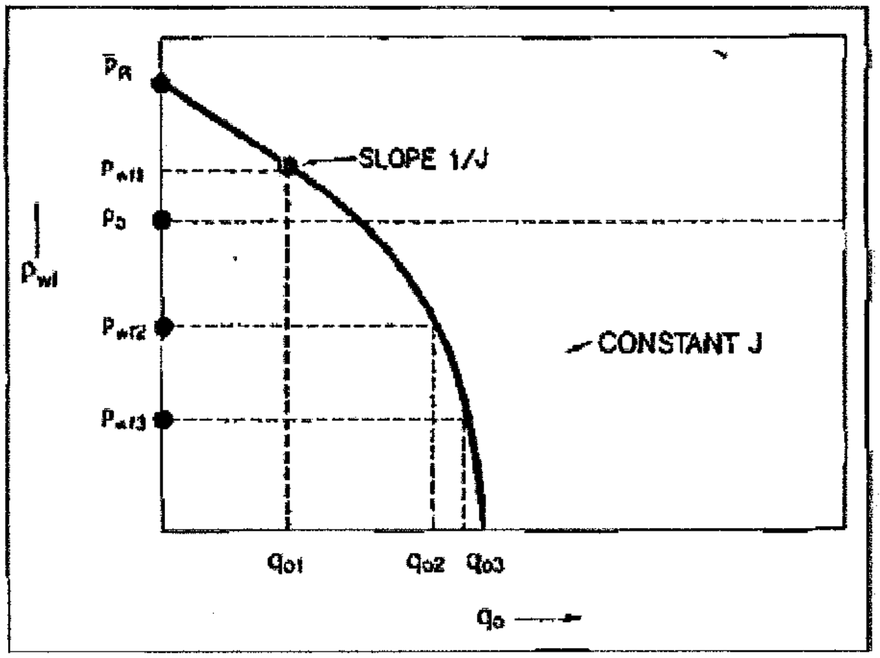


Figure 2.4: Typical Inflow Performance Relationship

Other IPR models are found in (Fetkovich, 1973), (Richardson and Shaw, 1982), (Raghavan, 1993), (Wiggins et al., 1996), and (Maravi, 2003).

For oil reservoir the principal factors affecting the IPR are:

1. A decrease in k_{ro} as gas saturation increases
2. An increase in oil viscosity as pressure decreases and gas is evolved.
3. Shrinkage of the oil as gas is evolved when pressure on the oil decreases.
4. Formation damage or stimulation around the wellbore ($S \neq 0$) as reflected in the term $S' = S - Dq_o$
5. An increase in in the turbulence term Dq_o as q_o increases.

These factors can change either as a result of drawdown change at a constant value of $\bar{P}$ or as $\bar{P}$ declines because of depletion. In Beggs' Nodal analysis[8], 3 factors that effecting IPR such as drive mechanism, drawdown and depletion are discussed in detail;

- **Drive mechanism** – the source of energy to cause the oil and gas to flow into the wellbore has a substantial effect on both the performance of the reservoir and the total production system. There are 4 drive mechanism been discussed in the analysis; dissolved gas drive. gas cap drive, water drive and combination drive

- **Drawdown or producing rate** - The principal a change in the productivity index was the change in the pressure function, $f(p) = k_{ro}/\mu_o B_o$. If the pressure anywhere in the reservoir drops below bubble point pressure, gas will evolve and the permeability to oil will decrease, causing a decrease in J.
- **Effect of depletion** - In any reservoir in which the average reservoir pressure is not maintained above the bubble point pressure gas saturation will increase in the entire drainage volume of the wells. This will cause a decrease in the pressure function in .the form of decreased k_{ro} which will cause an increase in the slope of the pressure profile and the IPR.

Therefore to maintain a constant inflow rate into the well or to increase the production it is necessary to increase the drawdown. As the drawdown is function of bottom hole flowing pressure, P_{wf} and reservoir pressure, $\bar{P}$. **Thus, gas injection is a process of pressure maintenance by manipulating the$\bar{P}$.**

Pressure maintenance by smart well (ILGI)

Pressure sensor and a continuously variable ICV at the injection interval allow control of the "gas dump flood". In figure 6, the oil could be produced through the same well as used for the internal gas injection (or crossflow).

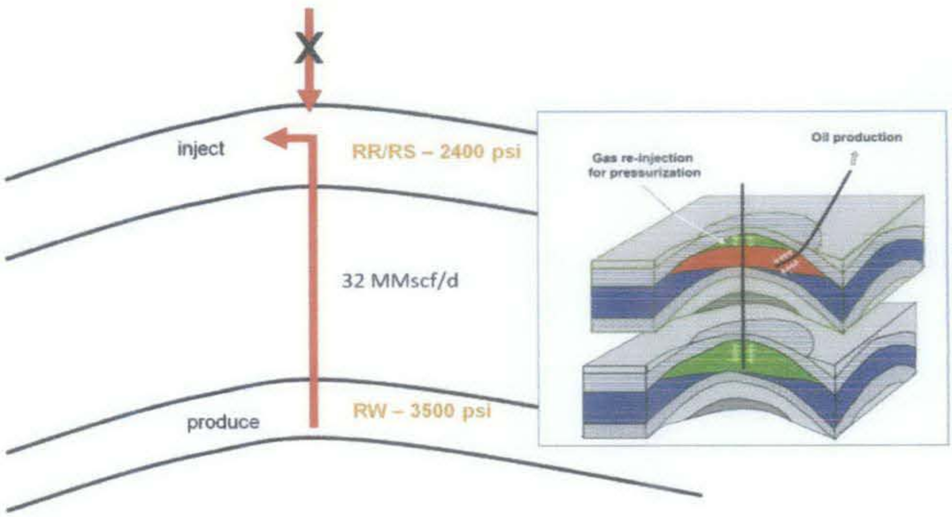


Figure 2.5: Pressure reservoir maintenance in an oil reservoir through controlled in loop (cross flow) gas injection in Baronia Field.

So the design criteria for smart well (BN-7) that went through these reservoirs is to:

- Enable "in-loop" gas injection from RW to RR/RS
- Enable selective production of the RW to surface
- Enable selective production/injection for the RR/RS reservoir
- Enable commingled production of RW and RR/RS to surface

Risk assessment in Ampa Field, Brunei[12] which is **related to Baram delta geologically** during early phase of their ILGI project found 5 potential risks such as:

1. Injection fracture – to overcome this the injection pressure must be lower that correlated fracture initiation pressure.
2. Fault breakdown – high pressure drop across fault could lead to fault breakdown which then causing the leakage of injected gas and subsequent loss of recovery.
3. Gas breakthrough - Stratified nature of the reservoirs may result in different from velocities for different reservoir sands hence it will cause gas out earlier than others so called breakthrough. Thus to optimize the area sweep efficiency, the reservoir energy should be really distributed. So we should manipulate two aspect to achieve this, first is by position of injection well in the reservoir which it targeted in the middle of the secondary gas caps and the oil production targets are close to the water oil contact. Next is manipulation of the completion to allow gassed out intervals to be preferentially closed in.
4. Sub-optimal infectivity/productivity – in this case, the concerns are on the plugging by fine sands from the gas reservoir at the injection zone, fortunately based on closest reservoir, there are no sand production history. As the performance monitored by PDG then once it shows the symptom of the scenario then temporary flow back or production or acid stimulation for the cleaning can be executed. For worst case, an additional new injection well could be considered too.
5. Failure of intelligent completion- In case of failure either PDG or ICV or both the completion design contains back-up system that is by conventional wireline intervention. SPM can be utilized as socket t install memory gauges and SSD can

be opened or close by normal wireline operation in case the failure of hydraulic system. But if worse came to worst then a workver will be considered.

Intelligent Completion Design

1. Sand control such as gravel pack or screening wire.
2. Surface controlled, mini-hydraulic lubricator valve (LV) and interval control valve (ICV) for on/off control of the internal gas injection, back production and acidization of the injected reservoir (RR/RS) without wireline intervention,
3. Two permanent downhole annular pressure and temperature gauges (PDG) used to monitor the pressure drop in the tubing for gas injection rate calculations and to monitor the reservoir pressures if the zones are shut in,
4. Mechanical redundancy, installing conventional well completion such as SSD and side pocket mandrel (SPM) to ensure continued operability of the well even if all "smart" components fail.

2.5 ILGI for tertiary recovery (EOR)

2.5.1. Enhanced oil recovery (EOR)

Enhanced oil recovery is also known as improved oil recovery or tertiary recovery and it is abbreviated as EOR. Generally, EOR method using sophisticated techniques that alter the original properties of oil. Once ranked as a third stage of oil recovery that was carried out after secondary recovery, the techniques employed during enhanced oil recovery can actually be initiated at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir[2].

The intent of EOR is to[14]:

- Improve sweep efficiency by reducing the mobility ratio between injected and in-place fluids
- Eliminate or reduce the capillary and interfacial forces and thus improve displacement efficiency
- Act on both phenomena simultaneously

Miscible methods have their greatest potential for enhanced oil recovery by basic principle improving in displacement efficiency. Among the methods are by CO_2, nitrogen, alcohol, LPG or rich gas, and dry gas.

2.5.2. Miscible injection

Miscible injection can be defined as a displacement of oil by fluids with which it mixes inn all proportions without the presence of an interface, all mixtures remaining single phase. As miscible injection works by reducing the residual oil saturation to the lowest possible values, and this parameter is depends on the capillary number N_c,

$$N_C = \frac{u\mu}{\sigma}$$

Where;

μ =superficial of actual velocity, ft/day, since only pores and not the full area conduct fluid, ($u=v/\phi$)

u = oil viscosity, cp

σ= interfacial tension, dynes/cm

Residual oil saturation decreases when capillary number increases[12] , this is shown in Stalkup findings in Figure 7. Hence, interfacial tension should be reduced until miscibility achieved where no IFT between the fluids. This miscibility injection can be done in either first-contact miscible or multiple-contact miscible fluids[12].

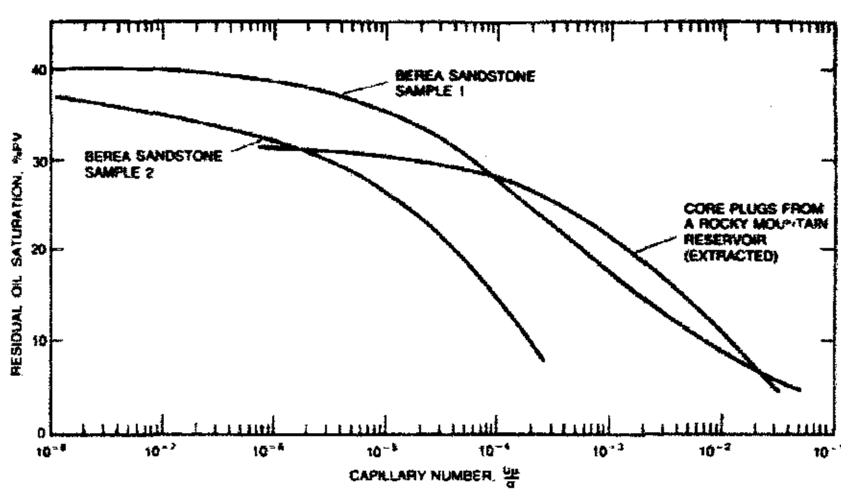


Figure 2.6: Dependence of residual oil saturation on capillary number (Stalkup, 1984)

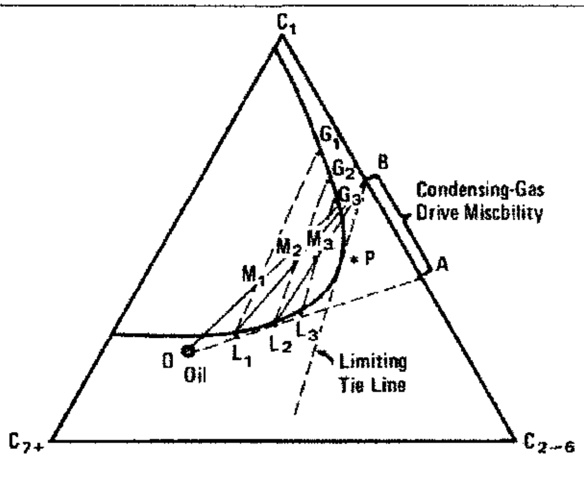
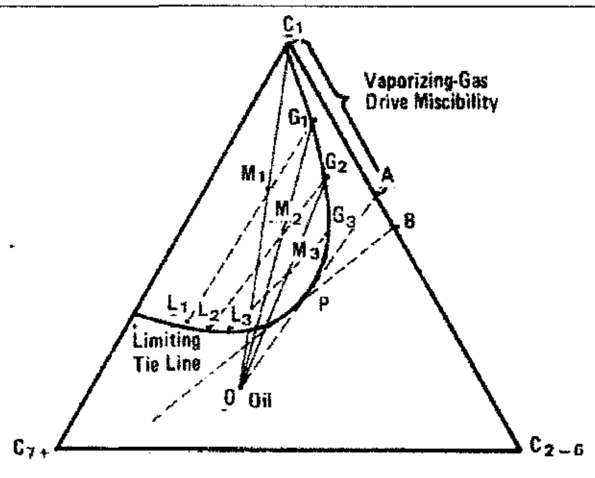
First contact or direct miscibility

Regularly, injection fluids used are liquid petroleum gas mixtures. The solvent mix directly with reservoir oils in all proportions and the mixture remains single phase.

Multiple contact or dynamic miscibility

The injection fluids been used are natural gas, flue gas, nitrogen and carbon dioxide. These fluids are not first contact miscible and form two phase regions when mixed directly with reservoir fluids. The miscibility achieved by the mass transfer of components which result from multiple and repeated contact between the oil and injected fluid during the flow through the reservoir.

There are two processes through which dynamic miscible displacement can be achieved in the reservoir, namely condensing gas drive and vaporizing gas drive.

Condensing gas drive	**Vaporizing gas drive**
Take place when the reservoir oil composition "O" lies to the left of the limiting tie-line PB (intermediate-lean crude oil) on pseduoternary diagram and when the injected solvent, which is a mixture of natural gas (C1) and intermediate (C2-6), has a composition underlying A-B.	Occurs when the reservoir oil composition "O" lies on or to the right of the limiting tie-line PB (crude oil reach in intermediates), and when the injected solvent has a composition lying to the left of the limiting tie line and also to the left of the tangent line OA.
 Condensing gas driving miscibility scheme	 Vaporizing gas driving miscibility scheme

The miscibility results from the in-situ transfer by condensation of intermediate HC ethane through butane from the solvent injected into the reservoir oil.	The mechanism results from the in situ mass transfer through vaporization of intermediate HC components from the reservoir oil into the injected gas.

Table 2.2: Condensing and Vaporising gas drive mechanism

The miscibility is attained above the minimum miscible conditions called minimum miscibility pressure (MMP) or minimum miscibility enrichment (MME).

2.5.3. Minimum miscibility conditions[13]

The minimum conditions at which the resulting mixture of two fluids mixed together at any proportion is homogeneous in compositions and identical in intensive properties (e.g. density and viscosity).

For reservoir engineering, as the reservoir temperature usually is assumed to be constant, the minimum miscibility conditions refer to either the minimum miscibility pressure (MMP) when compositions of the two fluids are fixed, or the minimum miscibility enrichment (MME) when the oil composition and the reservoir pressure are specified.
A number of parameters affect the minimum miscibility conditions: including depth, chemical compositions of the oil and the injection gas, and the reservoir temperature as well as physical dispersion can locally have some impact on the minimum miscibility conditions.

The oil viscosity	• For horizontal flood: 1cp or less • Upper viscosity limit :3-5cp (depends on reservoir's vertical permeability
Gravity	• First contact miscibility to condensing gas drive: > 30° API • Vaporizing gas drive: > 40° API with rich in intermediate molecular weight HC components
Reservoir pressure & depth	• Injection pressure should maintain the minimum miscibility pressure and below formation parting pressure in reservoir

	• First contact miscibility : 900-1300 psia with depth 1500 – 2500 ft • Condensing gas drive : 1500-3000 psia with depth 2000-3000 ft • Vaporizing gas drive : 3500-6000 psia and restricted to **deep** reservoirs
Reservoir geometry	• High and uniform permeability • For horizontal reservoirs, vertical permeability has to be restricted to avid or reduce gravitational segregation
Oil saturation at early project	• 25% PV residual oil saturation is desirable. • Higher percentage of oil in place at early start is beneficial. • Vaporizing gas drive perform better (up to date) in large and nonwaterflooded reservoirs as secondary EOR
High risk factors	• Extensive fracturing • Gas cap • Strong water drive • High permeability contrast

Table 2.3: Screening criteria for injected reservoir[15]

3.5.4. Full pressure maintenance miscible gas injection

Once miscibility achieved, most of gas injected in the course of recovery by miscible displacement is only needed to push forward the miscible front and fill up the porous medium. It is thus to ensure good pressure and injection rate management.

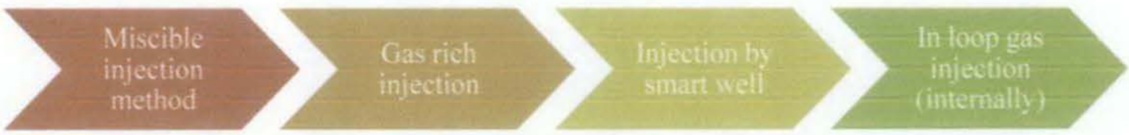
Full pressure maintenance represents one of the injection strategies for miscible gas flooding of this type of reservoir. The advantage of full pressure maintenance is that the reservoir fluids will not be altered in composition when dispersion effect is negligible. Consequently, the first-contact miscible nature of the fluids will be preserved and this will lead to miscible (near-100%) recovery efficiency for a 1D the displacement. MMP of the reservoir fluid changes only with depth, independent of reservoir pressure[13].

Know that the miscibility bank is extremely stable. If a miscibility rupture occurs due to e.g. heterogeneities or channeling, the miscibility bank reforms. Somehow, this process required high pressure reservoir pressure (deep formations). The minimum pressure required is around 3000-4500 psi. Another demand is the oil must rich in intermediates (C2-C6) with gravity higher or at least equal to 35° API[14].

3.5.4. Rich gas injection (miscible flooding) by in loop gas injection (SW)

According to my research, this project, rich gas injection by in loop (internal) gas injection is never been done before and no paper on this idea yet. Somehow, miscible injection by smart well using CO2 gas did implemented in SACROC field. The source of injection is from surface and not internally as my idea. In this SACROC CO2 injection, they consider both injection and production by smart well while my project only looking on the injection part.

For a clearer view I would like to emphasize on characteristic of this idea of injection as follows;



It is said that most significant challenge for miscible EOR injection is profile control[17].

- Highly heterogeneous – non-uniform gas injection front displacement.
- Injected gas sweeps high-permeability zones - early injected gas breakthrough
- Hence, unnecessary cycling impact the oil produced.

Based on SACROC CO2 injection by smart well case study[16], it is found that smart well application in miscible injection is beneficial in various aspects. Thus some modification and add on to the case study to suite it to this internal rich gas injection.

**production is from injecting zone (source of gas, donor) and injection is into injected zone (receiver)*

Intelligent Completion	Industrial tools (*by WellDynamic*[1])	Application/ Benefit
Flow-Control Devices	*Accu-PulseTM* • Hydraulic, incremental control system • Can be configured to either close or open an ICV from any position, in one pressure cycle • Provision of up to 11 discrete positions with appropriate ICV	• Most current downhole flow-control devices use sliding-sleeve or ball-valve technologies. Flow control may be binary (on/off), discrete positioning (several preset fixed positions), or infinitely variable. The motive force for these systems may be hydraulic or electrical systems. • Allows controlling the drawdown and fluid injection/production form individual zone. Zones can be choked back or shut in when excessive gas injection into injected zone to control the sweeping area as well distribution of injectant between zones. Hence, it will reduce the risk of breakthrough, thief and swept zones. This device also can control consumption of gas from the gas source reservoir.
Feedthrough Isolation Packers.	*HF-1 Packer* Retrievable, cased-hole packer with a facility for bypass of multiple electrical and/or hydraulic control lines.	• Zone control requires that each zone be isolated with packers incorporating feedthrough systems for control, communication, and power cables. • Isolation of zone can give chance for individual zone to be stimulated and cleaned up such as bullheading the acid whenever the zone having sand problem or high skin.
Control, Communication, and Power Cables	*1.FMJ Connector* *2.Flatpack* *3.Direct Hydraulics* • Provides all-hydraulic control • Operates as a closed-loop system	• Current intelligent-well technology requires one or more conduits to transmit power to and data to/from downhole monitoring and control devices. These may be hydraulic control lines, electrical power and data conductors, or fiber-optic lines. • Avoidance of conventional intervention either by

	• No setting depth limitations	e-line or CTU for any downhole operation such as zone change or zone shut off.
Downhole Sensors.	*ROC™ Permanent Downhole Gauges* • Providing reliable, real-time permanent data about downhole conditions • Accurate quartz pressure/temperature sensor • Flow measurements for specific applications	• A variety of downhole sensors is used to monitor flow-performance parameters from each zone of interest. Several single-point electronic quartz-crystal pressure and temperature sensors may be multiplexed on a single electrical conductor, thus allowing very accurate measurements at several zones. Optical fibres are used for distributed-temperature surveys throughout the length of a wellbore and provide temperature measurements for each meter of the well depth. • This downhole monitoring devices permit the well testing (production, composition, flow rate, pressure gradient, PLT etc) of individual reservoir layers and zones. This is essential for in loop rich gas injection as sensors need to determine properties of donor zone either it's meet current needed for receiver zone and vice versa. Besides that, it is important to understand the performance of each zone.
Surface Data Acquisition and Control.	*XPIO 2000® data acquisition and control system* Allows operators to monitor and control downhole gauges and topside instrumentation.	• Systems are required to acquire, validate, filter, and store the large volume of data. Processing tools are required to examine and analyze the data to gain insight into the performance of the well and the reservoir. In combination with the knowledge gained from the analysis, predictive models can assist in the generation of process-control decisions to optimize production from a well and asset

Table 2.4: SW devices with function to fit in in-loop rich gas injection

Rich gas injection in this project contact is assumed to be the hydrocarbon gas which sourced from underneath reservoir, RW that injected into RRRS. Somehow, if the miscibility displacement found to be a failure, hence a new hypothetical reservoir condition will be created based on RW characteristic just modification on composition. This is to determine miscibility operating conditions for RRRS. All in all, the injection simulation will be executed using smart well design as application of smart well in this in-loop-rich gas injection having advantages in cost, time, equipment, man-power effectively as well as reducing the surface system to supply injection.

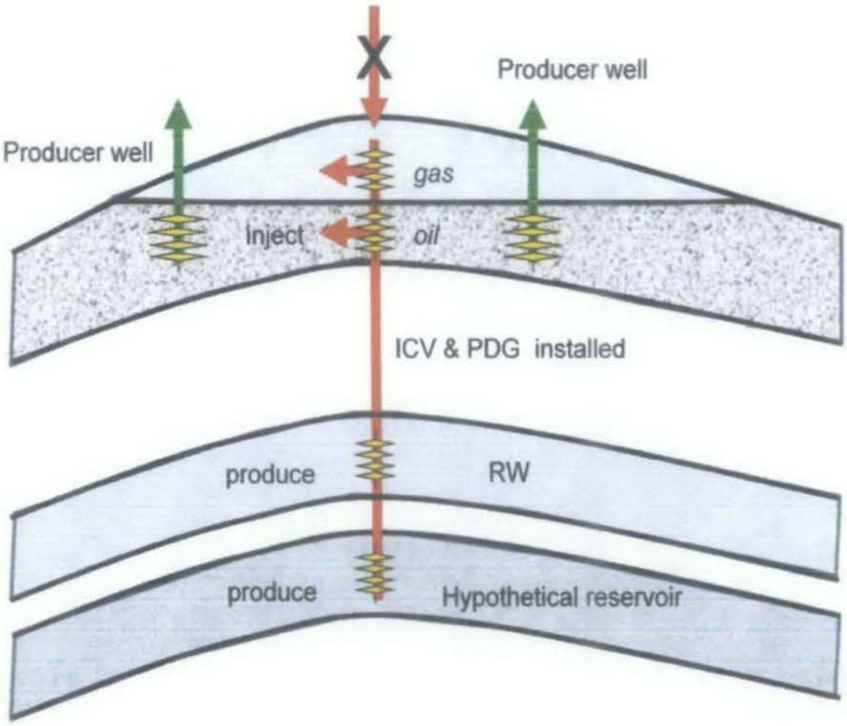


Figure 2.7: Illustration of full pressure maintenance miscibility gas injection

CHAPTER 3

METHODOLOGY

Overall this project is to investigate application of smart well in multi-purpose gas injection which will be done internally or so called in-loop-gas injection (ILGI). Multi-purpose representing the ability of smart well in executing secondary recovery method by gas injection for pressure maintenance and enhanced oil recovery by rich gas injection. Hence, the expected outcome is to show that this application will optimize the reservoir from view of recovery or production rate by simulation.

3. 1 Research Methodology and project activities outline

Figure 3.1: Project methodology

3.2 Literature Research & case study

1. Inflow control (ICV) function to cope with objective
2. Downhole sensors monitoring (PDG/DTS/DPS etc) ability or detecting composition
3. Injection gas for pressure maintenance
4. Rich gas injection (EOR) as miscible injection
5. Simulation of ILGI or gas injection and result analysis
6. Advantage of smart well injection compare to conventional method
    - HSE
    - Cost
    - Recovery or production parameters

3.3 Simulation preparation

3.3.1. RRRS details

1. PVT (Pressure-Volume-Temperature)

Components	Mole percent
Nitrogen	0.03
Carbon dioxide	0.24
Hydrogen sulphide	-
<u>Hydrocarbons</u>	
Methane	49.08
Ethane	4.87
Propane	5.24
I - Butane	1.34
N - Butane	2.22
I - Pentane	1.13
N - Pentane	1.13
Hexanes	2.38
Heptanes plus	32.34
Octanes	-
Nonanes	-
Decanes	-
Undecanes	-
Dodecanes	-
TOTAL	100.00

Molecular weight of Heptanes plus : 161
Molecular weight of reservoir fluid : 69.7
Gravity of Heptanes plus in STO : 0.815 (60/60°F)

Table 3.1: Molecular composition for RRRS

Static Pressure : $P_{initial}$ = 3170 psig

Bottomhole Temperature : 186°F

<u>Reported Reservoir Conditions</u>

Static Reservoir Pressure@7220 Ft SS : 3165 psig (RFT 1976)

Reservoir Temperature : 186 °F

<u>Initial Recombination</u>

P_b : 3445 psi @ 186°F

GOR : 1100 scf/bbl (RS2 BN-16L PVT on 1976)

Recombined GOR (PR, T not specify) : 937 scf/bbl

CCE: Bubble Point Pressure @ 186 °F : 3160 psig

Differential Vaporization Test @186°F

Oil Formation Volume Factor @ P_b : 1.860 bbl/stb

Solution Gas Oil Ratio @ P_b : 1448 scf/stb

Oil Density @ P_b : 0.589 g/cc

Oil Density @ 60/60°F : 0.811 g/cc

2. MMP/MME of RR/RS

   According to analysis done in year 1976 from well BN-16, the calculated MMP is **2093 psi = 2107.4 psia** with Alston et al (1985) correlation.

3. SCAL (Special Core Analysis)

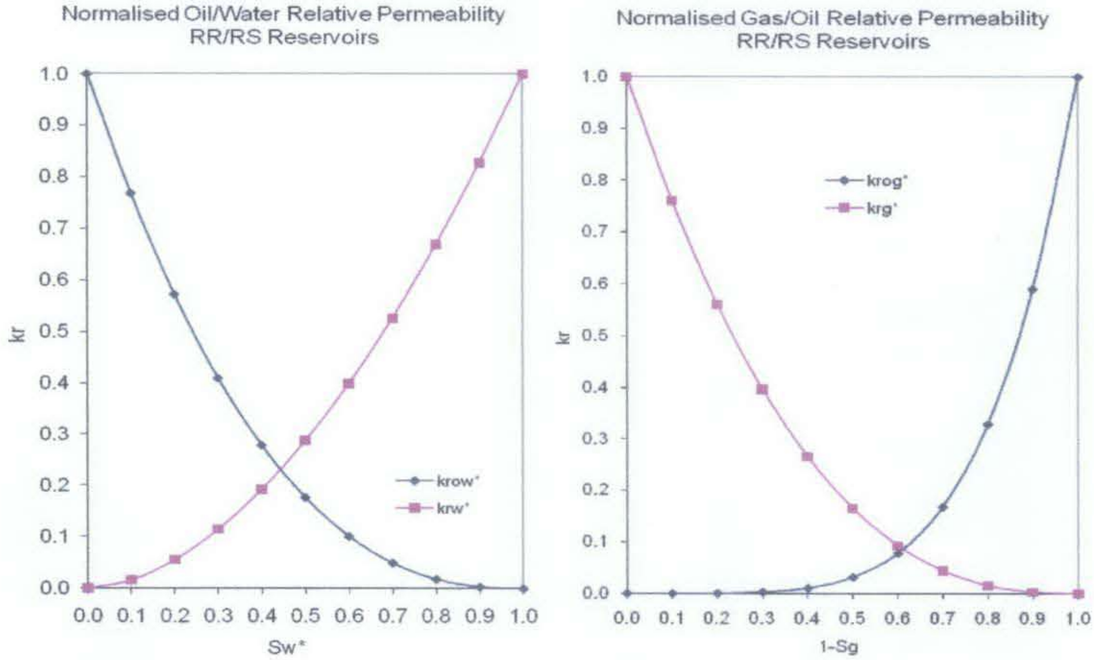


Figure 3.2: Normalized Relative Permeability RRRS Reservoirs

3.3.2 Injecting gas details

There are two source of gas to be injected into RRRS in the simulation. RW gas is according to the real data provided by PCSB, which this reservoir having pressure of 3515psi, temperature of 205°F and GIIP of 187 Bscf. While for hypothetical reservoir, the different is composition and is assumed to have infinite reservoir.

	Mole fraction %	
Component	RW	Hypothetical Reservoir
N2	0.0057	0.00225
CO2	0.008	0.002775
C1	0.817	0.63008
C2	0.0556	0.049725
C3	0.0455	0.11127
IC4	0.0088	0.094437
NC4	0.0129	0.096988
IC5	0.0049	0.00415
NC5	0.0037	0.003475
C6	0.0053	0.002375
C7+	0.0326	0.002475
C17+	0	0
C37+	0	0

Table 4.2: Composition mole fraction for injecting gas

Note that, finding composition fraction for hypothetical reservoir that meet miscibility of RRRS is beyond this project scope and composition above was given by operating company upon their own reason.

3.3.3. Tool: Compositional simulator

- Eclipse 300 by Schlumberger – will do PVTi modeling and compositional simulation
- Petrel RE by Schlumberger- as interface between user and simulator, it is friendlier user compare to conventional coding on compositional simulator itself. Easier to change the properties.

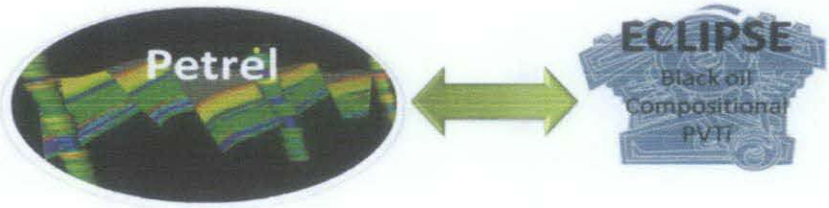


Figure 3.3: Petrel RE function

3.4. Simulation the ILGI workflow

3.4.1. Simulation models

This simulation will be run in compositional sector modeling for RRRS and the assumed underneath reservoir is not connected as illustrated in Figure 2.7 due to modeling ability restriction. In short, the modeling been used is history matching model up to year October 2010 but with no further action provided by PCSB. Predictions are run using upscaled grid from 201 x 35 x 70 (492,450 cells) to 48 x 11 x 70 (36, 390 cells) model that has been cut from original geological model at I 22 and I 222; J 35 and J 69. Below is saturation at year 2010.

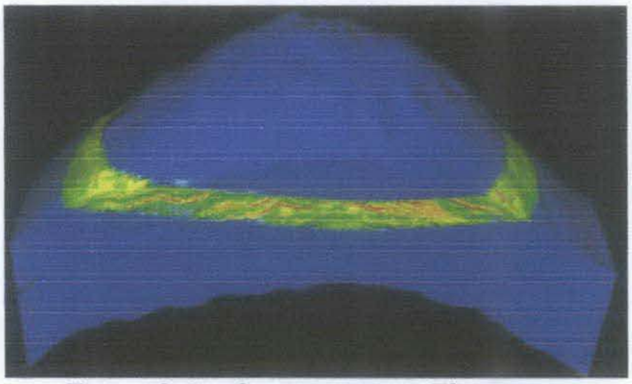


Figure 3.4: oil saturation on Floviz view

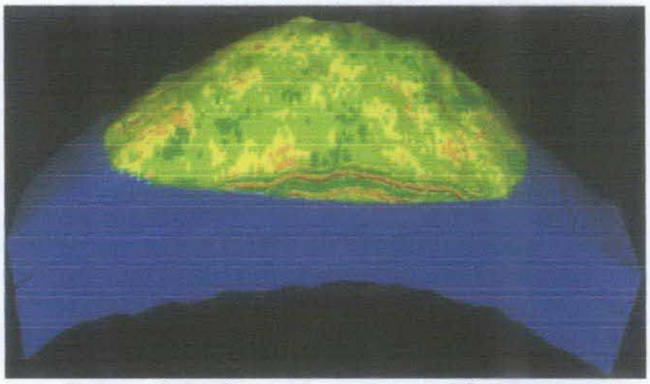


Figure 3.5: Gas saturation on Floviz view

Since the sector modeling did not cross BN-7, hence the existed well is modified into smart well and only 2 producers producing along simulation which started in June 2011.

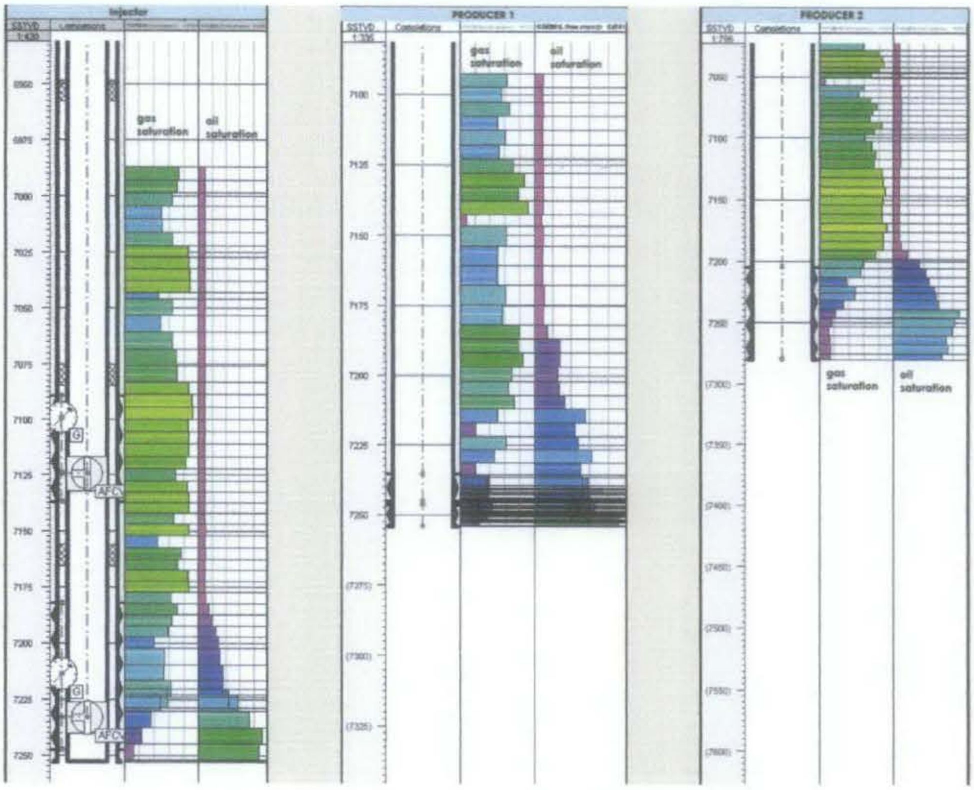


Figure 3.6: Well section for smart well (injector), and 2 producers in Petrel RE

3.4.2. Simulation cases

There will be 5 case study of simulation:

Case 1: Natural depletion

Case 2: Injection into gas cap

Injection into oil layer

Case 3: RW reservoir gas

Case 4: Hypothetical reservoir gas (rich gas)

Case 5: Alternate gas injection for full pressure maintenance rich gas injection by created rule/ workflow:

PDG monitoring	ICV action
Receiving reservoir pressure above minimum miscibility pressure (MMP)	Inject to oil zone for miscible injection (EOR) from donor reservoir that have rich gas
Receiving reservoir pressure below MMP	Inject to gas cap for pressure maintenance (secondary recovery) from donor reservoir that have less rich gas
None of donor reservoir having rich gas	Inject to gas cap for pressure maintenance (secondary recovery)
Any donor reservoir having very rich in heavy composition .	Produce

Table 4.3: Gas injection workflow

During the simulation, injection rate is set to be constant which is 5000Mscf/d which is according to current injection rate of BN-7. While, the producers maximum production rate is 900 stb/d. composition of injecting gas assumed to be constant

This simulation is a bit complicated hence we will create a few assumptions; that injecting reservoir is the producing reservoir and RRRS PVT model will manipulate type of injection (either pressure maintenance or EOR). Hence, the simulation workflow is as follows:

a. At first try with RW as injecting reservoir solely
b. Then RW together with hypothetical reservoir that will meet either EOR or pressure maintenance (depends on the need) as injecting reservoir

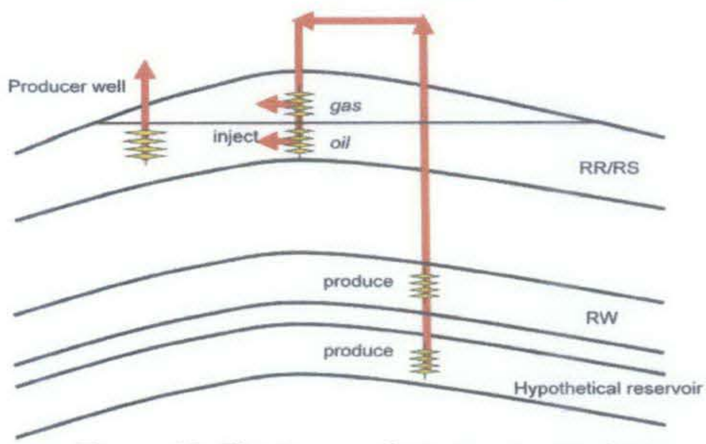


Figure 13: Illustration of injection in simulation

3.5 Key milestones

Date	Activity
13th June 2011	Briefing & updates on student progress
13th July 2011	Progress Report Submission
1st-5th August 2011	PRE-EDX
8th August 2011	EDX
August 2011 (week 14)	Final Oral Presentation
10-12th August 2011	Submission of Final Report to External Examiner
September 2011	Submission of Hardbound Copies

3.6 Key milestones and Gantt chart

No	Details	Week														
		1	2	3	4	5	6	7	MID SEMESTER BREAK	8	9	10	11	12	13	14
1	Data gathering	■	■	■	■	■	■	■		■	■					
2	Develop reservoir model (RRRS) both black oil/compositional		■	■	■	■	■	■		■	■					
3	Develop RW black oil model		■	■	■	■	■	■								
4	Create PVTi model for RRRS & RW					■	■	■		■	■					
5	Smart well design in Petrel							■		■	■					
6	Run the simulation															
	a) Base case – natural depletion						■	■		■						
	b) Gas injection for pressure maintenance						■	■		■						
	c) Rich gas injection									■	■					
	d) Alternate gas injection into gas cap & rich gas										■	■				
7	Result analysis						■	■		■	■	■	■			
8	Discussion and Project Alteration							■		■	■	■	■	■	■	
9	Construct a mechanism of gas injection by smart well							■		■	■	■	■	■	■	
10	Progress Report Submission									■						
11	Pre-EDX												■			
12	EDX													■		
13	Final Oral Presentation															■
14	Delivery of Final Report to External Examiners													■		
15	Submission of Hardbound Copies															■

● Suggestion milestone ■ Process

Gantt chart for second semester

CHAPTER 4

RESULTS & DISCUSSION

4.1. Results

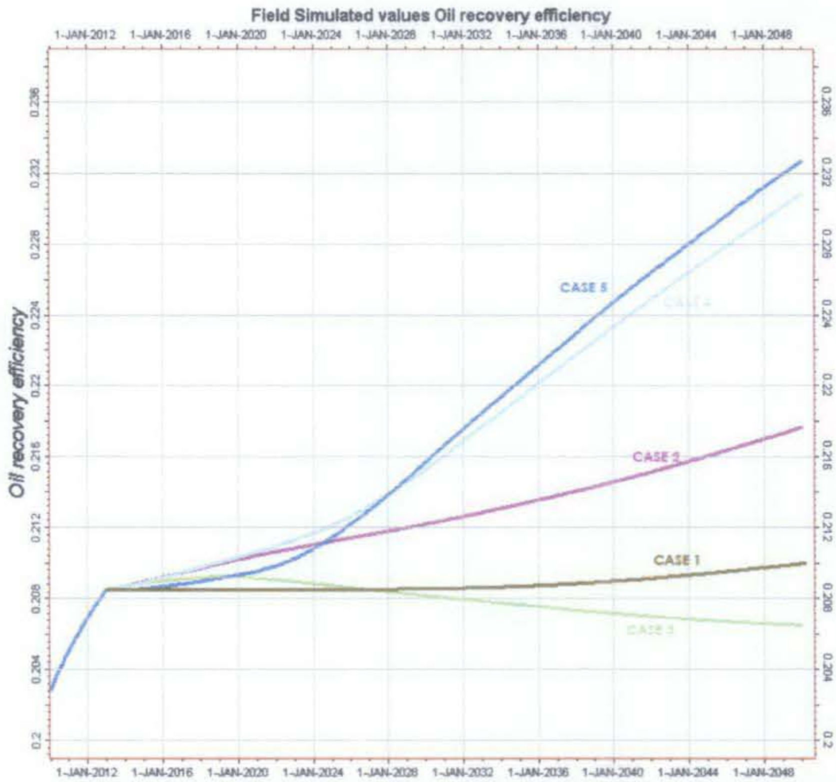


Figure 4.1: Oil recovery for all cases

Case	Recovery efficiency %
Case 1	21.00
Case 2	21.72
Case 3	20.68
Case 4	23.16
Case 5	23.28

Table 4.1: Tabulated recovery efficiency

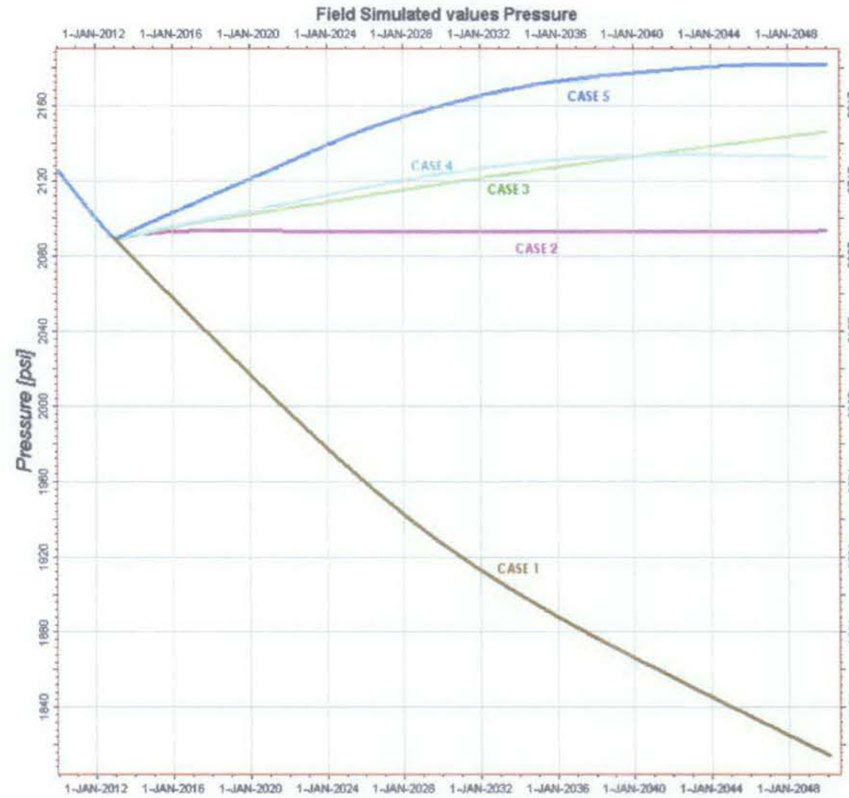


Figure 4.2: pressure profile for all cases

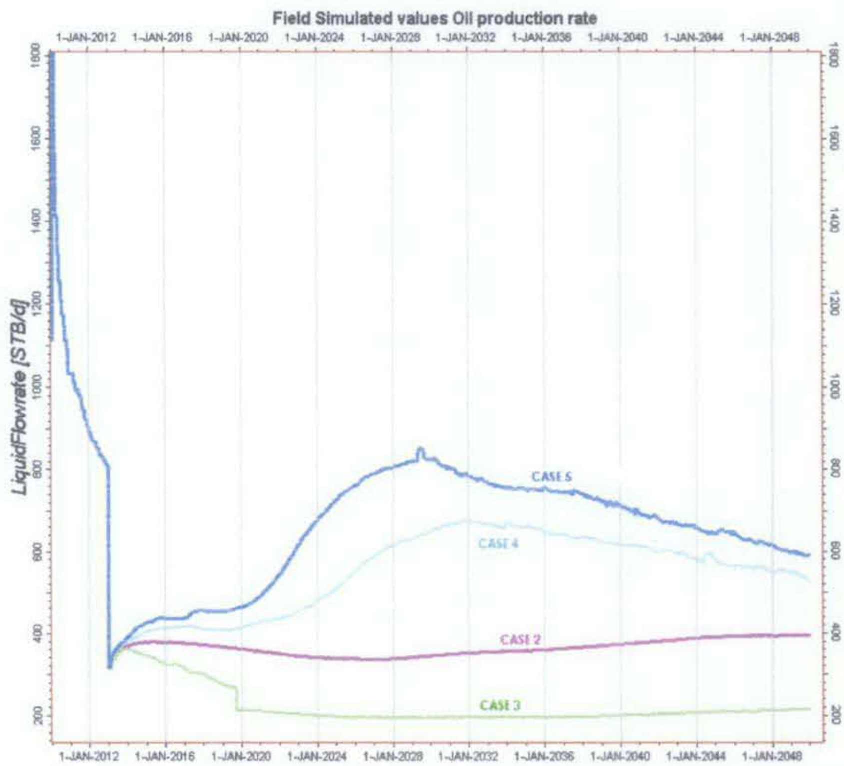


Figure 4.3: oil production rate comparison

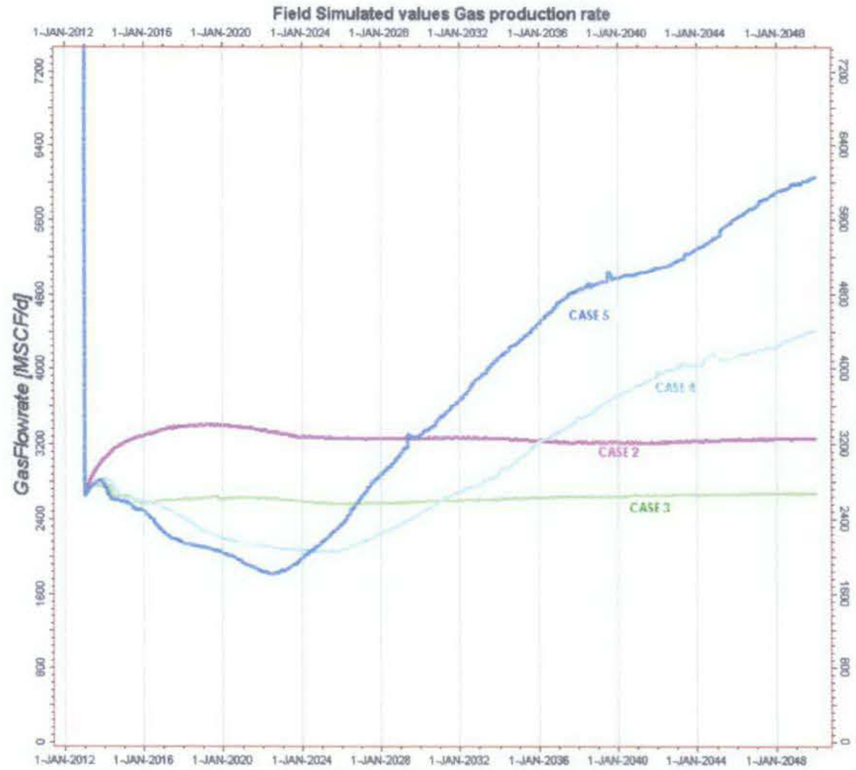


Figure 4.4: Gas production rate comparison

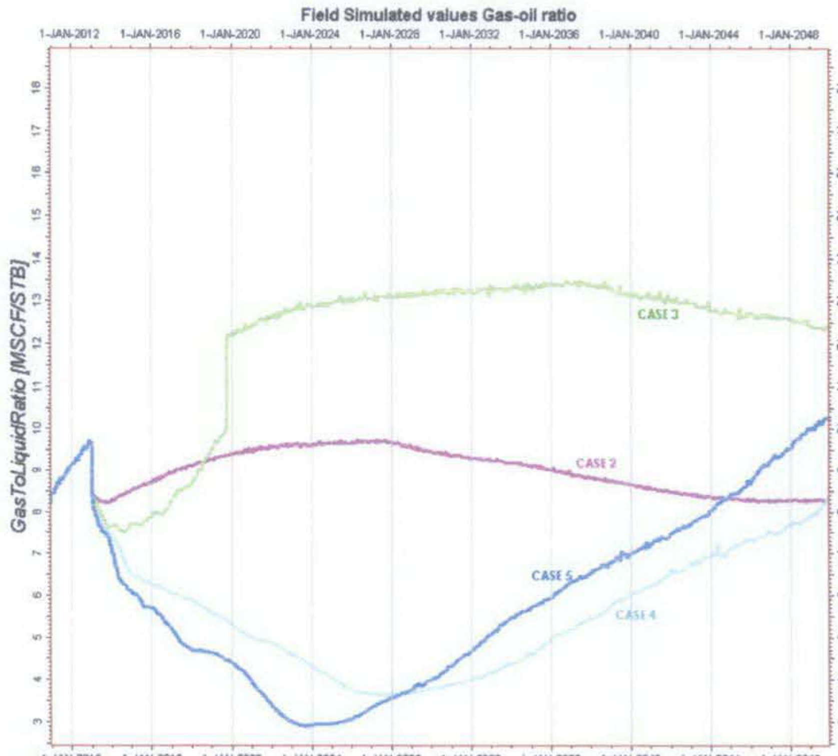


Figure 4.5: Gas oil ratio comparison

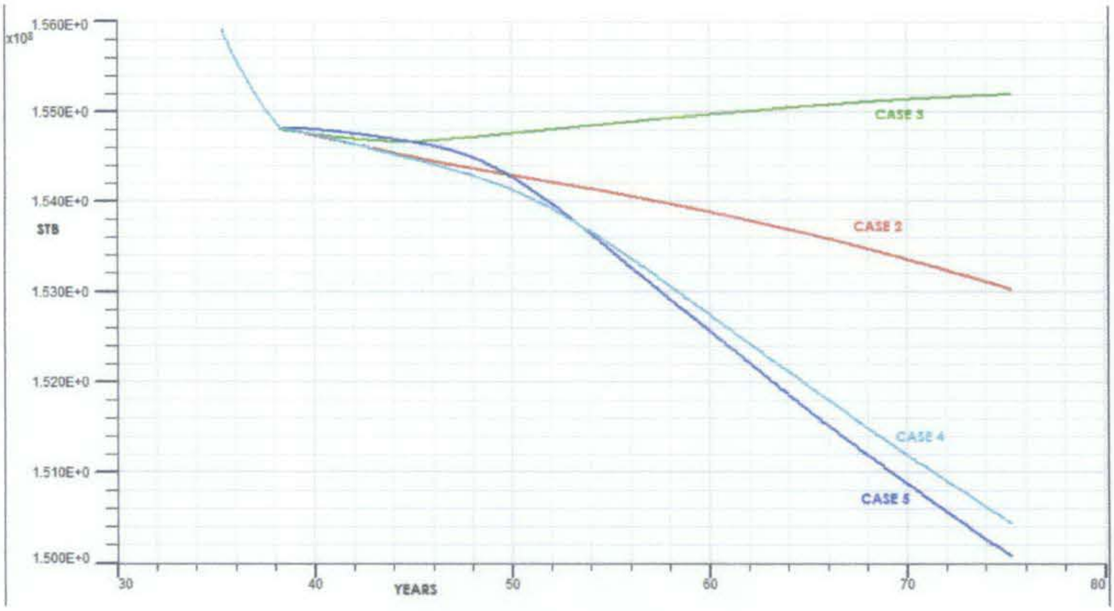


Figure 4.6: Oil in place (FOIP) comparison

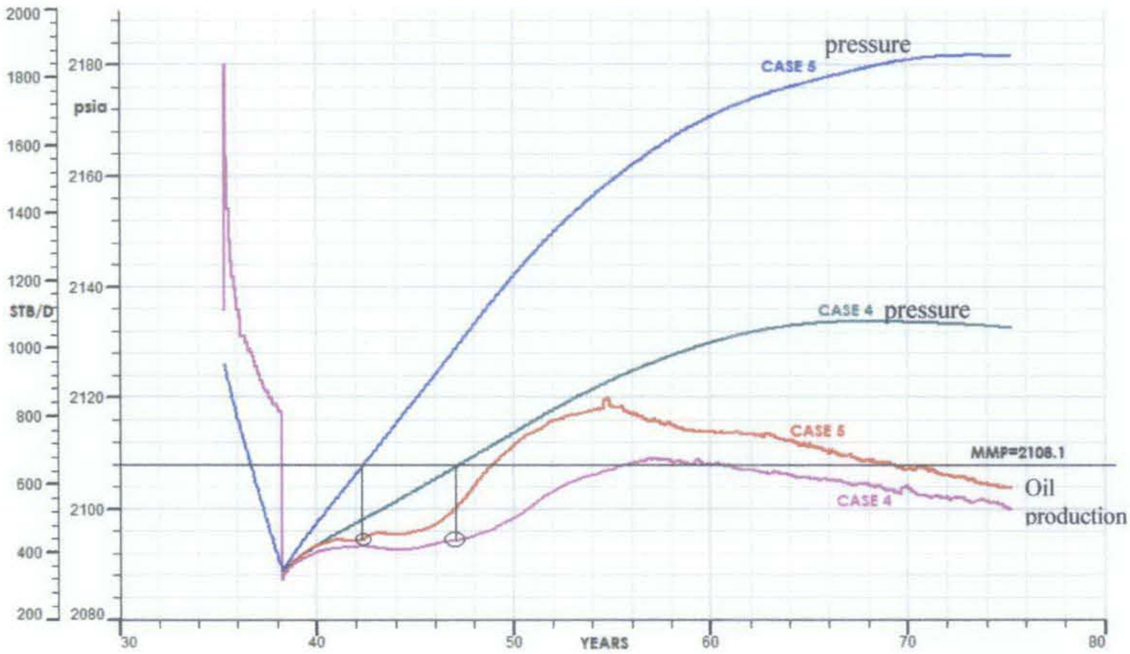


Figure 4.7: comparison for pressure and oil production of Case 4 and Case 5

4.2 Discussions

4.2.1 Recovery

Table 4.1 shows that insignificant differential value from base case. Insignificant recovery different might due to:

1. This is sector model that could be cut in high heterogeneity zone.
2. Simulation error or model error as this sector model still under development and this is the first compositional model created for RRRS.
3. Simulation by upscaled model from geological model.
4. Limitation of producers well. Maximum rate is 900bbl/d while injection rate 5000Mscf/d. Decision for well position and completion made solely on gas and oil saturation without considering reservoir rock and fluid properties.
5. Rich gas injection is not the really an efficient method to enhance recovery in RRRS reservoir.

Anyhow, recovery result show Case 5 gives the highest recovery followed by Case 4, case 2 and Case 1. While Case 3 which injecting RW gas is the least recovery and we can say it having negative recovery towards the end, and this will be explained later.

4.2.2 Pressure

Figure 4.2 shows Case 2 having approximately constant pressure along simulation, this is because gas injection into gas cap for pressure maintenance to enhance gas cap drive mechanism in secondary recovery method.

Particularly for this reservoir, according to the simulation gas injection into oil layer has greater effect on pressure than into gas cap. This is shown in case 3 where we inject RW gas into the oil zone, and due to fluids composition the miscibility failed, hence it is treated as secondary gas injection which to increase pressure and resulted in almost straight line pressure profile.

Case 4 also showing greater pressure increment at the same injection rate as it is injected into the oil zone compare to case 2 which injected into gas cap. As known, gas have higher compressibility factor compare to oil, hence this might be the cause of bigger pressure increment when oil zone injected with gas compare to gas cap zone which contained only gas. Pressure curve for Case 4 also showing pressure slow depletion since year 2044 because no pressure maintenance and the reservoir keep producing thus injection into reservoir not sufficient enough to replace produced reservoir fluids.

The pressure curve for Case 5 shows greater increment from beginning compare to other cases even it have same injection rate as other which is 5000MSCF/d. This is because position of injection that been decided by ICV which suspected to be near GOC zone while for case 2, it is in the middle of gas cap and Case 3 and 4 is somewhere in middle of oil layer. This will give greater effect on reservoir average pressure for this RRRS layer. Since ICV controlled the injection hence, type of injection either into gas cap or oil layer or both is undefined.

4.2.3 Gas breakthrough

There is no gas breakthrough shown in the simulation for any case. This is because implementation of ICV in the smart well. In simulation, well segmentation has to be set so that ICV functioning by segmentation calculation. Conventional well models treat the entire wellbore as a single entity, averaging all the fluid properties in the well bore. This means that, for example, if an upper zone is flowing gas and a lower zone is flowing water, the density assumed in calculating the pressure drop in the wellbore will be incorrect. The default segregated well model in ECLIPSE 100 and ECLIPSE 300 improves on this by treating the fluid from each flowing connection separately.

No gas breakthrough has been proved in gas production curve in Figure 4.4 and gas oil ratio (GOR) in Figure 4.5. Highest gas production is from case 5 because oil production decreases due to reduction in oil in place that shown in Figure 4.6. Suspected as well that the oil rim getting lowered and producers' connection is approaching GOC line as producers are set to be conventional well which no intelligent device installed to detect gas or water encroachment. Furthermore this reservoir is not supported by aquifer to push the oil rim upward. In addition to that, case 5 having 2 ways injection hence, GOR for this case will keep increasing.

4.2.4 Gas oil ratio (GOR)

The highest average gas oil ratio out of all cases is Case 3 but still under tolerate ratio that haven't reach gas breakthrough. Since miscibility failed, gas injection into oil layer can disperse the oil bank hence we will have lower production of oil but a slight fingering of gas in the oil zone and lead to early gas reaching producers.

Somehow, case 5 also having active increment of GOR towards the end of simulation. We can relate this scenario to the oil in place (FOIP) curve, Figure 4.6. Increase of gas production might due to FOIP that much less than initial with addition of oil sweeping efficiency factors.

4.2.5 Performance comparison

Based on recovery efficiency we can say that case 5 gives the best performance while case 3 is under performance and not recommended to be executed. Overall, compare to natural depletion, gas injection proved to enhance recovery and mitigation for RRRS reservoir depletion.

In case 5, miscibility is achieved with full pressure maintenance it's fluid composition won't be altered and the first-contact miscible nature of the fluids will be preserved. Having high pressure injection to increase pressure can help in pushing forward the miscible front and fill up the porous medium thus oil production will increase rapidly. And by having the least oil in place after 36 years of injection, it show that full pressure maintenance in rich gas injection enhance the sweeping efficiency.

On the other hand, case 3 that give negative recovery mainly due to failure in miscibility increase the oil in place in the end of simulation. This is because injected hydrocarbon liquid absorbed and settled down in the oil layer. Miscibility study of RRRS is beyond this project thus I won't elaborate more. Simply, RW gas doesn't have enough percentage of intermediates carbon (C2-C6) which brings greater effect in description of phase behavior, which either rich or lean gas.

4.2.6 Full pressure maintenance vs. partial pressure maintenance

Different between case 4 and 5 is the existence of gas cap injection in case 5 to keep pressure high. Generally, this alternative gives effect into production pattern. Case 4 having delay in reaching miscibility for almost 4.5 years than case 5, hence we can say that injection below MMP is for pressure increment and only reaching miscibility after that since composition of injecting gas assumed to be constant.

As case 5 showed better performance, it has been explained in 4.2.4. Somehow, both cases having delays in rapid oil production incremental about 8 years might be cause of miscibility mechanism which suspected to be multiple contact miscibility with condensing and vaporizing mechanism. This result depends also on solubility rate of fluids and mass transfer within gas and oil in reservoir condition.

4.2.7 Smart well effect on reservoir performance and economic view

Due to time constraint, the author's didn't go further in simulating the flow pattern of gas injection within oil layer, else we can see thoroughly the effect of miscibility. Anyhow, smart well application in this study has proved to eliminate gas breakthrough uncertainties and perhaps helping in controlling the distribution of gas injected to overcome heterogeneity within reservoir as this is the main challenges been faced by EOR injection up to date.

To install monitoring devices, it will help in real time monitoring and instant action into decision according to the rule set. While in high tech sensor that able to sense properties of the fluid can eliminate logging intervention purpose and the result transmitted to surface without physical manpower. In well test such pressure build up survey or static bottom hole pressure survey, we don't have to shut the well and lose production opportunity and moreover, conventional shut in well test will increase probability of damage into reservoir. In industrial, it is difficult to gain back production performance of the well after shut in and well test.

Smart well is a well occupied with ability to monitor and acting on decision on it's own then it's application has eliminated man power for monitoring and intervention cost, save time in operation. The best part is it helps to diminish surface equipment in case of in loop gas injection as this project and to create full field life cycle besides avoiding surface facilities risks.

CHAPTER 5

CONCLUSION & RECOMMENDATION

5.1 Conclusion

- Full pressure maintenance for miscibility flooding could be achieved and sustained by in loop gas injection using smart well system.
- Full pressure maintenance miscible injection in RRRS gives the best performance among any other injection type. This method also gives greater recovery efficiency and production.
- Somehow, current gas source reservoir, RW, will not meet miscibility with RRRS. It is recommended to further study on other gas injection such as CO_2.
- Insignificant recovery increment might shows that all in all rich gas injection method is not efficient enough to apply as EOR in RRRS reservoir.
- Using SW inflow control, we could prevent fingering which lead to gas breakthrough.
- In general, optimization manipulation of smart well system in gas injection could be very beneficial to operator as it could prevent gas injection risks, elimination of surface facilities for in loop gas injection, less manpower as it is automatically control zonal isolation according to workflow or condition input and moreover, it will increase the recovery of the reservoir.

5.2 Recommendation

- For compositional and especially miscibility injection, it is advisable to conduct in finer grid simulation for more accurate result.
- It is recommended to further study on other gas injection such as CO_2 or solvent
- Since RW is not meeting miscibility condition, then it is better to keep injecting it as pressure maintenance. Somehow, there are more reservoirs layer underneath it such RW-RZ and RZ (8000-9000ft) zones than non associated gas reservoir and haven't been develop. RZ has not been cored yet so properties of it unknown.
- Since this project didn't observe the injection and fluid movement pattern after injection in the oil layer, it is beneficial to see the effect of ICV for future reference.
- This injection is after years of production and as known, saturation of oil decreased by production, it could be better recovery if the injection executed earlier while reservoir fluid more favorable to develop miscibility.

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