

**TECHNO-ECONOMIC FEASIBILITY OF ETHANE BASED ENHANCED OIL
RECOVERY IN NIGERIA (CASE STUDY: NIGER DELTA)**

A thesis submitted to the faculty at African University of Science and Technology
in partial fulfilment of the requirements for the degree of Master of Science
in the Department of Petroleum Engineering

By

SANUSI Oluwabunmi Morenikeji

Supervised by
Professor David Ogbe



African University of Science and Technology
www.aust.edu.ng
P.M.B 681, Garki, Abuja F.C.T, Nigeria

Abuja, Nigeria

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CERTIFICATION

This is to certify that the thesis titled “TECHNO-ECONOMIC FEASIBILITY OF ETHANE BASED ENHANCED OIL RECOVERY IN NIGERIA (CASE STUDY: NIGER DELTA)” submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by SANUSI OLUWABUNMI MORENIKEJI in the Department of Petroleum Engineering.

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NIGERIA (CASE STUDY: NIGER DELTA)

By

Sanusi Oluwabunmi Morenikeji

A THESIS APPROVED BY THE PETROLEUM ENGINEERING DEPARTMENT

RECOMMENDED:

.....

Supervisor, Prof. David Ogbe

.....

Co-Supervisor: Dr. Akeem Arinkoola

.....

Head, Department of Petroleum Engineering

APPROVED:

.....

Chief Academic Officer

.....

Date

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ABSTRACT

SANUSI Oluwabunmi Morenikeji: Techno-economic feasibility of ethane based enhanced oil recovery in Nigeria (Case study: Niger Delta)
Under the direction of David Ogbe

Increasing oil recovery has been one of the issues enlisted for attention in oil producing countries around the world for past decades. So many forms of oil recovery techniques have been considered; infill drilling of new wells, production and injection control, pressure control, water flooding and other methods of Enhanced Oil Recovery (EOR), most of which have been implemented in other parts of the world. Nigeria as an oil producing country has not taken interest in EOR techniques solely because of the abundant occurrence of its conventional oil. Even though infill drilling and water flooding have been implemented to increase the productivity on some producing fields, a more viable and profitable method of EOR that can curb waste and reduce pollution should be applied in the field.

This study therefore aims at examining the technical and economic feasibility of Ethane-based EOR in Nigeria. This is a hydrocarbon gas injection process where ethane is injected into the reservoir to improve the oil recovery.

A Niger Delta field was characterized and the model is used to simulate ethane gas injection. Of all the different injection cases simulated ranging from water injection, ethane gas injection and ethane water-alternating gas (WAG) injection, the ethane WAG injection simulation shows more incremental recovery as the injected water sweeps out the oil bypassed by the gas.

Since ethane can be extracted from the natural gas routinely flared in Nigeria, economics of the study shows that having a natural gas processing plant for the extraction of ethane gas to be injected is more economically attractive than procuring the gas from external sources. This study shows that operation of ethane WAG for 25 years yields 14 years of payback of capital investment with substantial revenue generated in subsequent years from oil production.

Keywords: Enhanced Oil recovery, ethane gas injection, water-alternating gas, gas flaring, water flooding, condensing and vaporizing gas drive mechanisms.

I dedicate this thesis to God almighty, my beginning, my present and my future, to my late father and first love, my mother and my entire family.

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CHAPTER ONE

1.0 INTRODUCTION

Global proved oil reserves of crude oil in 2016 rose by 15 billion barrels (0.9%) to 1707 billion barrels, which would be sufficient to meet 50.6 years of global production at 2016 level (BP Global, 2017). These reserves include conventional and unconventional which are currently or will be produced by improved recovery techniques as primary or secondary recovery techniques will not be sufficient. OPEC countries currently hold 71.5% of this global proved reserves (BP Global, 2017) out of which Nigeria's current production stands at an average of 2.5 million barrels per day with proven reserves of 36 billion barrels expected to last about forty six years (Diezani, 2013).

Nigeria has however set for itself ambitious targets of producing 4 million barrels per day and reserves of 40 billion barrels of crude oil by the year 2020 (Diezani, 2013). Increasing the country's reserves can be done in four categories; discovering new fields, discovering new reservoirs, extending reservoirs in known fields and redefining reserves because of changes in extraction technology (Enhanced oil recovery) (Lake, 1989). All the four categories mentioned are capital intensive, the first three categories are more demanding as they involve drilling of new wells; the last category of adding reserves can utilize already drilled wells thereby reducing overall cost of the projects. Achieving the production rate of 4 million per day is quite fanciful owing to the fact that our current oil production has dropped by 280,000 barrels per day from 2013 to 2016 (BP Global, 2017) leaving our daily production at about 1.75 million barrels per day (Trading Economics, 2017) which is far below our proposed target of 4 million barrels per day. To attain this proposed production rate of 4 million barrels per day, then we must increase the recovery factor of producing fields, a reason for Nigeria to employ and practice enhanced oil recovery techniques.

The recovery factor of our fields as they mature daily approaches 20-35% obtainable by conventional methods (Zekri, Jerbi, El-honi, & Co, 2000); this reduces reserves forcing some field owners, e.g. multinationals to shut down production as it becomes economically unattractive (Kanshio, 2016).

Enhanced oil recovery (EOR) process involves the injection of fluid(s) into the reservoir as a way of mobilizing the immobile, stranded or remaining original oil in place for efficient production (D. Green & Willhite, 1988). EOR is classified into three major methods, namely: thermal, miscible and immiscible methods. This study concentrates on the miscible EOR methods of gas injection. Gas injection EOR methods involve the injection of gas into the reservoir to supplement its natural energy and displace oil into producing wells. This is achieved following the interaction of the injected fluid(s) with the reservoir fluid to lighten the crude oil and provide additional energy required for its production.

Of the different types of gases used for miscible EOR processes, CO₂ gas has been the most successfully applied injectant due to its economic availability and operational simplicity over the years. Other gases like nitrogen and hydrocarbon gases (methane and ethane) which can equally be used for miscible EOR processes have been neglected because of their perceived economic unavailability. This is not the case for Nigeria where flaring of hydrocarbon gas (ethane) is pronounced. About 1.85 billion standard cubic feet of natural gas is being flared annually as at 2016 (Ndu Ughamadu, 2017); this therefore indicates that ethane, a constituent of natural gas is a low-cost economically available injectant in this region.

1.1 PROBLEM STATEMENT

At present, the world-wide oil production statistics indicate that the ultimate recovery from light and medium gravity oils by conventional (primary /secondary) methods is around 25-35% of the original oil in place (OOIP), while from heavy oil deposits on the average, only 10% OOIP is recoverable. Hence, leaving substantial percentage of oil in place non-recoverable by the conventional methods and these remaining reserves are the target of EOR to increase the recovery percentage (Zekri et al., 2000).

Nigeria produces light and medium gravity crude oil strictly by conventional means at a recovery level that leaves about 60 – 70% of OOIP unrecovered. There is therefore need to improve its recovery factor and accelerate associated production which is the main driver behind the many EOR schemes practiced around the world.

Successful EOR projects are always based on the economic availability of the appropriate injectants (McGuire, Okuno, Gould, & Lake, 2016). It is for this reason that CO₂ unlike some other gases have been successfully used for EOR projects but with some limitations like its corrosive nature, high solubility and high minimum miscibility pressure. The huge amount of gas flared in Nigeria suggests the economic availability of natural gas (parent gas for ethane) which can be used for miscible gas injection EOR process. Considering the recent increase in gas flaring penalty currently put at \$3.5 per 1000 Standard cubic feet (scf), the environmental degradation and green house emission caused by gas flaring (Anyadiiegwu, 2016), there is a need to clearly understand the technical and economic feasibility of practising ethane-based EOR in Nigeria (Niger Delta) in order to achieve: an increase in recovery factor and associated production, reduce flaring of natural gas, promote a cleaner environment and surmount the limitations of the commonly used CO₂ for miscible gas injection. Application of ethane-based EOR in the Niger Delta is the thrust of this research.

1.2 JUSTIFICATION FOR ETHANE - BASED EOR

Although CO₂ injection EOR projects have been successful over the decades, the following are some significant drawbacks associated with them.

1.2.1 Availability

Successful EOR project is a lucrative project dependent on the economic availability of the injectant. The current global supply of low-cost CO₂ is diminishing especially in the US where most of its major sources of CO₂ has been developed, limiting the supply of low-cost CO₂ which makes CO₂ injection EOR projects less profitable (McGuire et al., 2016). Presently in Nigeria, as opposed to the norm, ethane is the cheapest, operationally simple readily available gas unlike CO₂. Ethane can be extracted from the substantial amount of natural gas being flared and reinjected into the reservoir to increase crude oil production. This gas unlike CO₂ can be produced simultaneously with the crude for other purposes.

1.2.2 Corrosion

CO₂ is a known corrosive gas; for this reason most of the CO₂ injection EOR projects require corrosion mitigation of pipelines, injection wells, production wells and surface facilities by use of plastic-coated or carbon-steel coated piping and valves as suggested by Meyer (McGuire et al., 2016). Ethane is non-corrosive and by dilution should act to reduce partial pressure and corrosivity of any acid-gas component present in the water flood produced fluids (McGuire et al., 2016). Since it does not pose any corrosion problem, it therefore does not require special piping or any form of mitigations to production or injection wells except for the tubular collar leaks which are prosaic to all forms of gas-injection projects.

1.2.3 Solubility

Ethane is less soluble in water than CO₂ and therefore reduces parasitic losses of ethane into large volume of water contacted in matured waterflood field; thus preventing the need of extra volume of ethane during Water Alternating Gas, WAG flood unlike CO₂(McGuire et al., 2016).

1.2.4 Minimum Miscibility Pressure, MMP

Ethane has a lower minimum miscibility pressure (MMP) compared to CO₂ which makes liquid ethane more effective EOR injectant than liquid CO₂(McGuire et al., 2016).

1.3 AIMS OF THE STUDY

Ethane-based injection has been a promising EOR project verified and practised outside Nigeria with good results. This study aims at showcasing the opportunity for ethane-based enhanced oil recovery application in Nigerian fields by running detailed reservoir simulations to demonstrate ethane as a good and economically viable option for EOR injectant.

1.4 OBJECTIVES OF STUDY

The objectives of this study include:

- Characterization of the reservoir fluid and the determination of minimum miscibility pressure (MMP) of ethane gas.
- Simulation of ethane flood design using an inverted five spot model built with sensor6K simulator.

- Selection of optimum operating parameters by performing parameter screening using experimental design methodology for selecting heavy hitters impacting cumulative oil, water and gas production.
- Evaluation of impacts of uncertain variables on cumulative oil, water and gas production.

The uncertain variables studied in this work include bottom hole injection pressure, WAG cycle, injection and production group rates, gas-oil ratio, vertical permeability anisotropy (kv/kh), porosity, permeability and dynamic parameters (i.e., relative permeability and capillary pressure curves).
- Optimization through surrogate modelling and uncertainty quantification of oil recovery for ethane gas injection-EOR
- Development of a Microsoft excel economic model to evaluate and validate the economics of oil production using ethane-based EOR in the Niger Delta.

CHAPTER TWO

2.0 LITERATURE REVIEW

OVERVIEW

Crude oil production from a reservoir to the surface is basically by pressure differential; most reservoirs produce through natural drive mechanisms which include solution gas, natural water drive, fluid and rock expansion, gravity drainage, water influx and gas cap drive. These natural drives are known as primary recovery mechanisms. Primary recovery mechanism utilizes the reservoir natural energy without external support or injection into the reservoir (D. Green & Willhite, 1988).

Most reservoirs are known for low-efficiency (25-35% recovery factor, RF) recovery by natural mechanism (Zekri et al., 2000), thereby retaining enormous amount of hydrocarbons after the natural energy has been depleted. The reservoir pressure depletes from its initial state till it can no longer produce naturally on its own; at this point there is need for additional recovery methods which could be either to maintain the reservoir pressure or provide external displacement energy.

To augment the natural energy of the reservoir, gas or water injection techniques known as secondary recovery are initiated. Gas injection technique for secondary recovery is usually an immiscible process where gas is injected into the gas cap for pressure maintenance (D. Green & Willhite, 1988). This immiscible gas injection process is not as efficient as water flooding which is synonymously referred to as the secondary recovery technique (D. Green & Willhite, 1988). After secondary recovery, approximately 30-35% of the oil originally in place can be produced by displacement methods of Enhanced Oil Recovery, EOR. Figure 2.1 shows the oil recovery mechanisms applied to produce hydrocarbons.

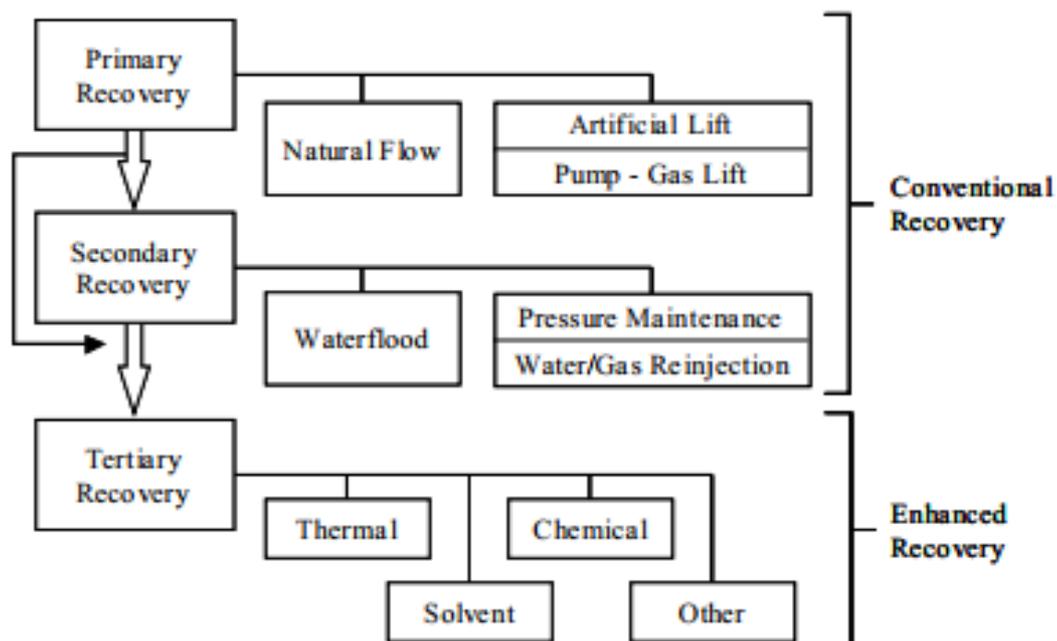


Figure 2.1 - Schematic representation of oil recovery mechanism (Lake, 1989)

2.1 ENHANCED OIL RECOVERY

In recent times, numerous techniques other than the above-mentioned techniques have been developed to produce the unrecovered crude oil remaining in the reservoir. These techniques are grouped into Enhanced Oil Recovery (EOR) process. EOR process used after primary and secondary recovery mechanisms have been exhausted and there is still significant amount of residual oil in place. Usually, conventional methods which include both primary and secondary recovery techniques can only recover about 30-35% of the original oil in place (Lake, 1989), leaving a huge quantity of about 65-70% of the original oil in place to be recovered by other possible means known as tertiary recovery or enhanced oil recovery process.

EOR processes are sometimes implemented at the initial or primary stage of oil production, this is usually possible in cases of reservoirs with viscous oil that would not be produced in economic quantities by primary mechanisms or waterflooding.

Enhanced oil recovery is a process in which oil recovery is attainable by injection of materials not normally present in the reservoir (Lake, 1989). These materials or fluid injected called injectant, supplement the reservoir natural energy by interacting with the reservoir rock or fluid system to create favourable conditions for oil recovery like reducing viscosity of the reservoir oil, lowering/eliminating the interfacial tension, swelling of the reservoir oil, modifying the wettability conditions or favourable phase behaviour (D. Green & Willhite, 1988)

Conventional oil recovery worldwide has continued to fall which makes the task of choosing a best recovery method very imperative for petroleum engineers. Most EOR processes especially the miscible processes require injecting more than one fluid; a relatively small volume of an expensive chemical or gas known as primary slug is injected to mobilize the reservoir oil while a larger volume of an inexpensive chemical, secondary slug, is used to displace the primary slug efficiently with as little deterioration of the primary slug as possible. In some cases, additional fluids of lower unit cost are injected to displace the secondary slug

to reduce the expenses (D. Green & Willhite, 1988). All the injected fluids used in a multiple fluid injection are considered part of EOR process even though the final slug injected solely to displace volumetrically the earlier injected fluids might be chemical, water or gas. In designing an EOR process for a specific reservoir, diverse conditions like reservoir oil type, reservoir rock, formation type, saturation, oil distributions and its physical state must be considered. Enhanced oil recovery methods can be classified into three major processes: chemical process, thermal process and miscible process.

2.1.1 CHEMICAL PROCESS

The chemical EOR process involves the injection of a particular/combination of chemicals ranging from alkaline, surfactants agent and polymers into the reservoir to displace the reservoir oil by increasing the displacement efficiency through the combination of favourable phase behaviour and interfacial tension reduction. The specific liquid chemicals injected effectively displace the reservoir oil because of their phase-behaviour properties which result in decreasing the interfacial tension between the displacing liquid and reservoir oil. This chemical (surfactant/polymer) process described have the most potential in terms of ultimate oil recovery among the EOR methods. Injection fluid used for chemical process are susceptible to loss through rock–fluid interactions, therefore maintaining adequate injectivity is a tenacious issue with this process (D. Green & Willhite, 1988). Figure 2.2 shows the screening criteria for application of chemical EOR processes.

Polymer flooding, one of the chemical processes where polymer is used, consists of adding polymer to the water in a waterflooding process to decrease its mobility. The resulting increase in viscosity of the water, as well as a decrease in aqueous phase permeability that occurs with some polymers, causes a lower mobility ratio. This mobility ratio lowering increases the efficiency of the waterflood through greater volumetric sweep efficiency and a lower swept zone oil saturation (Lake, 1989). Polymer flooding displacement technique is immiscible, that is, complete solubility does not occur between the injected chemicals and the reservoir oil. Generally, a polymer flood will be economic only when the waterflood mobility ratio is high, the reservoir heterogeneity is high, or a combination of these two

occurs, therefore greater recovery efficiency constitutes the economic incentive for polymer flooding when applicable.

First micellar solution formulations, were developed in 1973 at the Research Institute of Campina and the first field test was planned for the Sarmatian VIII Ticleni field. Since the method is expensive and process control is difficult, studies are carried out to determine the required quantity of chemicals for micellar solutions. Recently, better and cheaper micellar solutions have been developed with emphasis being placed on the use of petroleum sulphonate (Carcoana, 1982).

Chemical process is complex technologically and can be justified only when oil prices are relatively high and when residual oil after waterflooding is substantial. The chemical solutions which contain surfactant, cosurfactant and sometimes oil is expensive. Chemical losses resulting from adsorption, phase partitioning and trapping, bypassing owing to fingering if mobility control is not maintained can be severe. These losses can be compensated for by increasing the volume of the chemical solutions injected. The stability of surfactant systems in general is known to be sensitive to high temperatures and salinity, systems that can withstand these conditions must be developed if the process must have wide applicability (D. W. Green & Willhite, 1998).

Chemical Flooding Process	Fluid Properties			Reservoir Properties				
	Gravity (° API)	Viscosity (cp)	Temp. (°F)	Porosity (%)	Perm. (md)	Oil Sat. at start (% PV)	Lithology	Depth (ft)
Polymer/surfactant Flooding	14–34	5–80	80–160	20–30	170–900	60–75	Sandstone	1300–4600
Alkali/Surfactant/Polymer (ASP) Flooding	14–34	5–80	80–160	20–30	170–900	60–75	Sandstone	1300–4600
Polymer Flooding	14–34	5–80	80–160	20–30	170–900	60–75	Sandstone	1300–4600
Microbial (MEOR)*	—	5–50	< 176	≥20	>50	—	Sandstone or Carbonate	<7700

* Includes water salinity <150,000 ppm.

Figure 2.2 - Screening criteria for chemical EOR process (Taber, Martin, & Seright, 1997)

2.1.2 THERMAL PROCESS

This is the use of thermal energy (hot water, steam injection or in-situ combustion in the reservoir rock resulting from air or oxygen injection) to improve oil recovery by alteration of oil viscosity (lightening of reservoir oil), favourable phase behaviour and some other possible physical process (Naqvi, 2012). The application of thermal energy to increase heavy oil recovery has become more popular as conventional reserves decline. Steam injection accounts for the majority of the thermal recovery projects currently in operation.

Thermal processes are commonly performed in highly viscous reservoirs (heavy oil), to reduce the viscosity by means of heat and to provide the force to increase the flow rates of the oil to the production well. This is why thermal processes are also classified as thermal drives. Figure 2.3 shows the screening criteria for application of thermal EOR processes. Generally, there are two thermal methods of recovering heavy oil; process of injecting heat into the reservoir and the process of generating heat within the reservoir itself, in-situ combustion (Naqvi, 2012).

Hot fluid injection method is an example of injecting heat into the reservoir, the preheated fluids are injected into the relatively cold reservoir as shown in figure 2.4. Injected fluids are usually heated at the surface; although these days well bore heaters which are also known as the down-hole heaters are seeing a wider use. The fluids range from water (both liquid and vapor) and air to others, such as natural gas, carbon dioxide, exhaust gases, and even solvents (Naqvi, 2012).

Thermal Process	Fluid Properties			Reservoir Properties				
	Gravity (°API)	Viscosity (cp)	Temp. (°F)	Porosity (%)	Perm. (md)	Oil Sat. at start (% PV)	Lithology	Depth (ft)
ISC or HPAI	19–33	2–660	110–230	17–32	10–1265	50–94	Sandstone or Carbonate	400–8300
Steam	8–30	50–500,000	45–290	15–65	100–10000	44–90	Sandstone* or Tripolite	200–3600

* Includes unconsolidated sandstone.

Figure 2.3 - Screening criteria for Thermal EOR process (Taber et al., 1997)

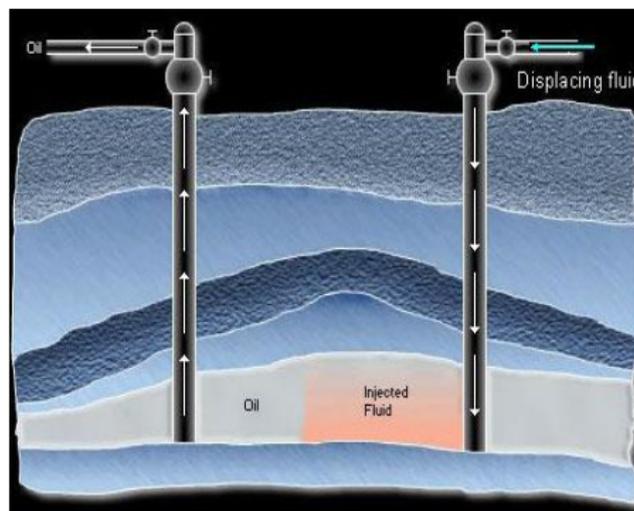


Figure 2.4 - Hot fluid injection (Naqvi, 2012)

In - situ combustion, process of generating heat within the reservoir, applies to the reservoirs that contain low gravity oil, which is heated with the help of air injection and the burning part of the crude oil. The oil is then driven out of the reservoir with the help of steam, hot water or gas drive, as it becomes less viscous. Either dry or moist air can be injected. The fire propagates from the air injection well to the producing well, moving oil and the combustion gases to the front. The coke left behind the displaced oil works as a fuel. The temperature reaches hundreds of degrees which is enough to crack heavy oil into low boiling products. The displacement of oil is the result of the combination of hot water, steam and gas drive, vaporization, and light hydrocarbons (Naqvi, 2012). In-situ combustion offers many

theoretical advantages if the operational characteristics of the process are incorporated in the design and operation of the field project. The in-situ combustion process has the potential of partial upgrading of the oil in the reservoir, which restrains the undesirable constituents of oil from moving along with the oil. Also, there is no need to generate energy on the surface. There are several variants of the in-situ combustion process, which are:

1. Forward Dry in-situ combustion
2. Wet and partially quenched combustion, also known by the acronym COFCAW (combination of forward combustion and water flooding) (Naqvi, 2012).

Thermal stimulation techniques require heating only the reservoir near the production well, it can also be combined with thermal drives, and in this case the driving forces are both natural and imposed. The fluid is injected continuously through injection wells to displace oil and obtain production from other wells. The same pressure which maintains the injection of the fluid in the well also increases the driving forces in the reservoir, which increases the flow of crude oil to the producing well(s). Driving forces present in the reservoir, such as gravity, solution gas, and natural water drive, affect the improved recovery rates once the flow resistance is reduced and overcome by the driving force. Thermal processes use heat in well-bores to increase the production rates for heavy crude oils. The drive process can also be applied to recover the residual oil in energy depleted reservoirs that hold conventional oil.

2.1.3 MISCIBLE PROCESS

Miscible process aims at displacing the reservoir oil with miscible fluids, i.e., fluids that form a single phase when mixed in all proportions with the reservoir oil at the conditions existing at the interface between the injected fluid and the reservoir oil bank being displaced (D. Green & Willhite, 1988). This process involves injecting into the reservoir a fluid directly miscible with the reservoir oil or those that generate miscibility in the reservoir by composition variation. The injection fluid type considered in this case study is gas, examples of which include hydrocarbon gas, carbon dioxide, CO₂, nitrogen or flue gas and other

combination of gases that can alter the phase behaviour of the reservoir oil for additional oil recovery. In miscible gas injection process, the gas injected mixes with the reservoir oil in all proportions to form single phase with the reservoir oil. Gas with its low viscosity provides considerable higher injectivity than water which makes it viable for use in cases of extremely tight reservoir where water flooding is impractical due to its low injectivity. Carbon dioxide is used as re-pressurization gas; inert gases, and natural gas can also be used to pressurize the well, but air is not suitable for that because it causes deterioration of the oil (Naqvi, 2012).

Gas injection, a widely used enhanced oil recovery method, will probably play a more important role in the future due to several reasons:

- Gas injection is effective to recover residual oils and its application is likely to be promoted by higher oil prices
- For deeper reservoirs and particularly offshore deeper reservoirs, gas injection, a means to achieve a higher oil recovery can be crucial to viability of a project
- When combined with CO₂ capture, gas injection can be used to mitigate CO₂ emission. During gas injection, the injected gas will swell the oil, reduce oil viscosity, and most importantly, achieve miscibility by exchanging components with the oil (Yan, Michlesen, & Stenby, 2012).

In a typical gas flooding project, one of the most important design parameters is the Minimum Miscibility Pressure, MMP (Li & Luo, 2017). The extent of miscibility increases with pressure, and the threshold pressure above which the injected gas becomes completely miscible with the oil is known as the minimum miscibility pressure, MMP. Above the MMP, 100% displacement efficiency can be expected on the microscopic scale (Yan et al., 2012). Hawthorne et al., 2017 stated that hydrocarbon in the very fine pores can be mobilized by CO₂ if miscibility was reached. A dramatic mass transfer between oil and CO₂ in a high-pressure view cell was observed when pressure was near or above MMP (Li & Luo, 2017).

Of all the enhanced oil recovery methods, miscible gas injection has been effective primarily because of the miscibility attained between the injecting gas and the reservoir oil. When two fluids become completely miscible, they form a single phase; one fluid can completely displace the other fluid, leaving no residual saturation. A minimum pressure is required for two fluids to attain miscibility (Wijaya, 2006). This is so as the injected gas molecules dissolved in the oil reduce its viscosity and make it mobile which increases the well output. After the crude oil is pumped out, the natural gas is once again recovered (Naqvi, 2012). There are two major variations in the miscible gas injection process;

- First - Contact Miscibility, FCM and
- Multiple - Contact Miscibility, MCM.

First – Contact Miscibility, FCM means that the injected fluid can immediately at first – contact mix with the reservoir oil in all proportions and produce a single-phase fluid. The process involves the injection of relatively small slug of hydrocarbon fluid such as liquefied petroleum gas, LPG to displace the reservoir oil, the LPG slug is in turn displaced by a larger volume of inexpensive gas that is high in methane concentration. In some cases, water can be used as the secondary displacing fluid. Primary slugs/oil interfaces are eliminated, oil drops are mobilized and moved ahead of the primary slug. Miscibility between primary slug and secondary displacing fluid is also desirable, otherwise the primary slug would be trapped as residual phase as the process progresses (D. Green & Willhite, 1988). Butane and crude oil also are first contact miscible and butane might make an ideal solvent for oil (Wijaya, 2006).

A ternary composition diagram can be used to determine whether two mixtures are first-contact miscible or if they can develop miscibility after several contacts. Two fluids are first-contact miscible if the line connecting the compositions of these two fluids is not crossing the region within phase envelope on the ternary composition diagram. Typical ternary composition diagram of system at 280°F and 2000 psia shown in Figure 2.5 is an example where G1 and G2, O1 and O2, G2 and O2 are first-contact miscible fluids (Shpak, 2013).

In the other miscible process of Multiple-Contact miscibility, MCM the injected fluid is not miscible with the reservoir oil at first contact. The process rather depends on modification of composition of the injected fluid phase, or oil phase through multiple contact between the phases in the reservoir and mass transfer of components between them. Under proper conditions of pressure, temperature, and composition this composition modification will generate miscibility between the displacing and displaced phases in-situ (D. Green & Willhite, 1988).

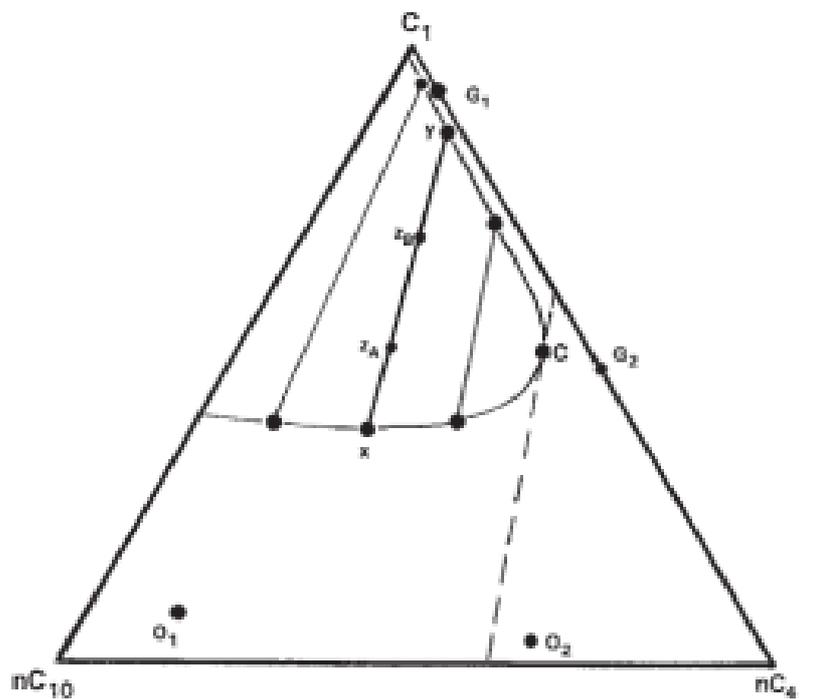


Figure 2.5 - Ternary composition diagram (Shpak, 2013)

The critical tie-line on the ternary composition diagram determines whether two fluids can develop miscibility by multiple-contact process. Two fluids can develop multiple-contact miscibility if their compositions lie on the different sides of the critical tie-line. As shown in Figure 2.6, G_1/O_2 and O_1/G_2 can develop miscibility (Shpak, 2013).

MCM could either be by vaporizing gas drive, condensing gas drive or both condensing and vaporizing gas drive depending on the mechanism with which the injected gas develops miscibility with the reservoir oil.

The ternary diagram in Figure 2.6 shows that C1 and O2 fluids can develop miscibility through vaporizing-gas drive mechanism. Intermediate and heavy components from the oil O2 vaporize into the gas phase, making the original lean gas C1 richer, which later contact oil again and becomes even richer until it gets to the critical composition C, which is miscible with oil O2. The gas and oil are mixed in the proportions that the overall composition of the mixture falls into the two-phase region. The equilibrium gas G2 is now enriched with intermediate and heavy components, and then again is mixed with the original oil O2 at proportions to form two phase conditions. The more enriched gas G3 is obtained. The process goes on until critical composition C is reached, when miscibility is developed (Shpak, 2013).

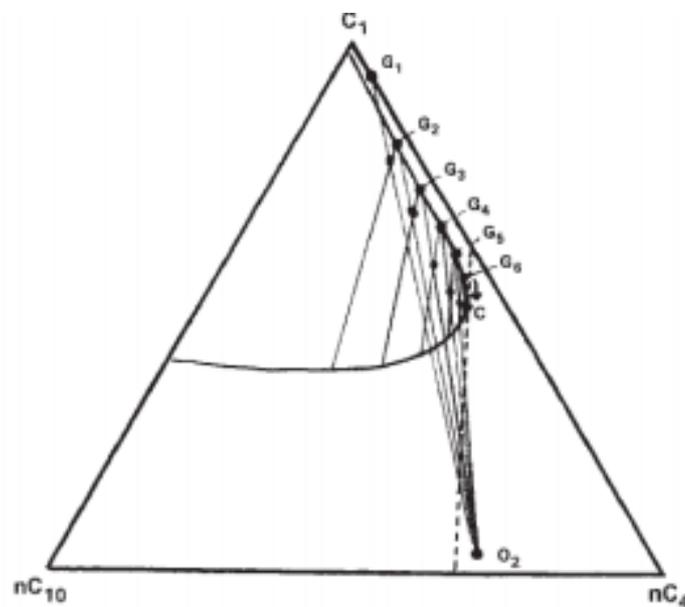


Figure 2.6 - Path of developed miscibility by vaporizing-gas miscible drive process for C1/n-C4/nC10 system (Shpak, 2013)

For a three-component hydrocarbon system, like in a ternary diagram, when a rich injection gas displaces oil that is relatively lean in the intermediate component, it is by a mechanism that is called a condensing-gas drive. In this process, the oil near the injection point is enriched by repeated contacts with the injection gas. The intermediate component in the gas condenses into the oil, moving its composition toward the critical point on the phase envelope. Eventually, if the gas is rich enough, i.e. if its composition lies on the single-phase side of the extended critical tie line, the oil becomes so enriched with the intermediate

component that it becomes miscible with the gas. Since the miscible zone moves with the velocity of the injection gas, the oil is completely displaced. This process can be easily visualized with the aid of a ternary diagram in Figure 2.7 which was generated by simulating a methane – butane – decane multi-contact process at minimum miscibility conditions with the Peng-Robinson EOS (Zick & Co, 1986). The condensing gas drive is applicable in hydrocarbon injection which makes it suitable for use in this study.

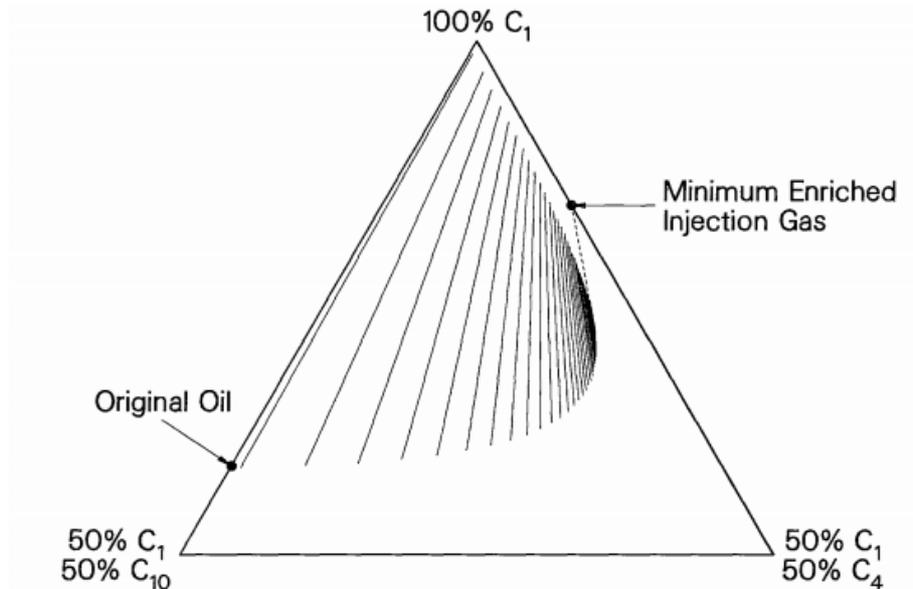


Figure 2.7 - Ternary diagram for a condensing-gas drive mechanism (Zick & Co, 1986)

Experimental evidence shows that displacements of a real, multicomponent, reservoir fluid by enriched gases, which were 98% efficient and by all indications appeared to have developed miscibility, could not have involved either the condensing-gas drive mechanism or the vaporizing-gas drive mechanism alone, instead, a combined condensing/vaporizing mechanism explains the efficient displacements. With this mechanism, a region of near miscibility is developed and propagated, but it is possible that a point of true miscibility is never actually developed. It was further argued that the true condensing-gas drive mechanism may rarely, if ever, occur in displacements of real reservoir fluids by enriched gases (Zick & Co, 1986).

The condensing/vaporizing mechanism is most applicable to this study and the easiest way to understand the condensing/vaporizing mechanism is to consider an oil/gas system

composed of essentially four groups of components. The first group consists of the lean components, such as methane, nitrogen, and carbon dioxide, which usually have equilibrium K-values greater than one. The second group consists of the light intermediate components, such as ethane, propane, and butane, which are the enriching components present in the injection gas. The third group contains the middle intermediates which are present in the oil but not significantly present in the injection gas, these are components that can be vaporized from the oil. The lightest component in this group typically ranges from butane to decane, depending on the injection gas composition. The heaviest component in this group cannot be defined precisely, but might be around C_{30} . The fourth group consists of everything else, i.e., those heavy components in the oil which are very difficult to vaporize (Zick & Co, 1986).

When the enriched gas comes into contact with the oil, the light intermediates condense from the gas into the oil, making the oil lighter. The equilibrium gas is more mobile than the oil, so it moves on ahead and is replaced by fresh injection gas, from which more light intermediates condense, making the oil even lighter. If this kept occurring until the oil was light enough to be miscible with the injection gas, it would constitute the condensing-gas drive mechanism (Zick & Co, 1986).

However, this is unlikely to occur with a real reservoir oil. As the light intermediates are condensing from the injection gas into the oil, the middle intermediates are being stripped from the oil into the gas. Since the injection gas contains none of these middle intermediates, they cannot be replenished in the oil. After a few contacts between the oil and the injection gas, the oil becomes essentially saturated in the light intermediates, but it continues to lose the middle intermediates which are stripped out and carried on ahead by the mobile gas phase. The light intermediates of the injection gas cannot substitute for the middle intermediates the oil is losing. So after the first few contacts make the oil lighter, by net condensation of intermediates, subsequent contacts make the oil heavier, by net vaporization of intermediates. Once this begins to occur, the oil no longer has a chance of becoming miscible with the gas. Ultimately, all of the middle intermediates are removed and the residual oil will be very heavy, containing only the heaviest, nonvolatile fraction and the

components present in the injection gas. If the mechanism stopped there, a considerable amount of oil would remain unrecovered (Zick & Co, 1986).

However, there are further steps to the mechanism. Consider the oil in place slightly downstream from the injection point. The first gas it will see will not be the injection gas, but equilibrium gas. This relatively lean gas will be essentially injection gas that has lost most of its light intermediates and picked up a very small amount of middle intermediates. There will be very little mass transfer between this gas and the fresh oil. The gas that follows, however, will be richer. Eventually, the gas that comes through will be gas that has passed over oil that was saturated in the light intermediates. Therefore, this gas will have about the same amount of light intermediates as the injection gas. But it will also contain a small amount of middle intermediates that it stripped from the oil over which it passed. Thus, it will actually be a little richer than the original injection gas. The oil that sees this gas will receive slightly more condensable intermediates than did the oil just upstream. Before the vaporization process takes over and again makes it heavier, this oil will become slightly lighter than the upstream oil had become. The above process continues farther downstream. The farther downstream, the richer the gas that eventually comes through, because it will have passed over an increasing amount of residual oil, allowing it to pick up increasing amounts of middle intermediates. This is beginning to sound like the vaporizing-gas drive mechanism, in which a lean injection gas passes over an oil rich in intermediates, vaporizing the intermediates, becoming richer and richer, until it becomes rich enough to be miscible with the original oil (Zick & Co, 1986).

However, the gas in the condensing/- vaporizing mechanism does not become rich enough to be miscible with the original oil. The original oil does not have to be rich in intermediates, nor does it even have to be undersaturated, both of which are necessary conditions for developing a vaporizing-gas drive mechanism. Instead, the gas develops only enough richness by the vaporization part of the mechanism so that it nearly generates a condensing-gas drive mechanism with the original oil. The intermediates that were originally present in the gas, plus those that were stripped from the oil, condense when the gas encounters fresh

oil downstream. This condensation proceeds in a manner very much like the condensing-gas drive mechanism. A sharp transition zone develops and propagates, and multi-contact miscibility is almost achieved before the condensation process reverts to the vaporization process. The vaporization results in a trail of residual oil being left behind the moving transition zone, although the saturation level of the residual can be very small. The residual oil supplies subsequent gas with the middle intermediates necessary to continue the propagation of the transition zone. The intermediates are vaporized from the residual oil, carried upstream into and beyond the transition zone, condensed there, and again become part of the residual oil after the transition zone has passed (Zick & Co, 1986).

The condensing region is at the leading edge of the enriched-gas displacement while the vaporizing region, with a small saturation of residual oil, is at the trailing end. In between is the sharp, two-phase transition zone, the two phases of which are almost, but not quite, miscible. The propagation of the sharp transition zone results in a very efficient, "apparently miscible" displacement, even though miscibility is not actually developed. The sharpness of the transition zone deteriorates rapidly as either the pressure or the enrichment of the injection gas falls below some critical value, resulting in the reduced displacement efficiencies typical of immiscible displacements (Zick & Co, 1986).

Above an apparent minimum miscibility pressure, the condensing/vaporizing mechanism can generate displacements that are effectively miscible, although true miscibility may not actually be developed (Zick & Co, 1986) also pointed out that for a multicomponent reservoir fluid systems, it is impractical to achieve a condensing gas drive miscibility. These displacements are characterized by the development and propagation of a nearly miscible (but two phase) transition zone which is preceded by a zone of original oil in equilibrium with gas that has lost its condensable intermediates, and which leaves behind it a heavy, residual oil that has lost its vaporizable intermediates. Pseudo ternary diagrams cannot be used to explain or predict effectively miscible displacements of oil by enriched gases when the mechanism is the condensing/vaporizing-gas drive (Zick & Co, 1986).

2.1.3.1 NITROGEN GAS INJECTION

Nitrogen is available in unlimited quantities from the air and can be produced in an Air Separation Unit (ASU) , by cryogenic distillation of air, to a purity of 99.995 Mol %.

Nitrogen/Flue-gas is sometimes selected as the injection gas for miscible flooding because it is relatively cheap and abundantly available in comparison to other potential injection gases such as hydrocarbon (HC) gas or carbon dioxide. Nitrogen/Flue-gas can achieve miscibility at higher MMP than either HC gas or CO₂ at the same reservoir conditions. This condition limits the application of nitrogen/flue gas to reservoirs with relatively high pressures. The mechanism by which nitrogen/flue-gas achieves miscibility with oil is through vaporization of the light intermediate components present in the oil. This is essentially the mechanism of vaporizing gas drive. For this reason, nitrogen/flue-gas is suitable for light oil reservoirs as candidates for miscible flooding (Class & Objectives, 2013).

Evaluation of nitrogen for use as an injection gas should include the cost of removing nitrogen from the produced gas before it can be sold. Note that flue gas is corrosive and may not be suitable for application in many reservoirs without preventative procedures implemented to combat corrosion in processing equipment (Class & Objectives, 2013).

2.1.3.2 CARBONDIOXIDE GAS INJECTION

CO₂ is a unique fluid that can be used as an efficient oil recovery agent for miscible process, though it is gaseous in nature, it is still regarded as a dense gas with liquid properties at reservoir condition since most reservoir temperature lies above the critical values of 88°F (Biu Victor, 2011). Carbon dioxide, CO₂ could displace oil by either miscible or immiscible displacement. Miscible displacement by CO₂ is more preferred to immiscible displacement. While the miscible process, is best applicable to light and medium gravity crude oils, the immiscible process, may apply to heavy oils (Hashemi Fath & Pouranfard, 2014). CO₂ EOR recovers additional oil by injecting slugs of CO₂ at pressure above the MMP into the reservoir, usually alternated with slugs of water. The injected CO₂ mixes with the reservoir oil, thereby reducing capillary forces that trap the oil in pores of the rock and allowing oil that would otherwise remain stranded to flow towards production wells (Phillips & Veld, 2005).

There mainly two methods of carbon dioxide injection; continuous injection of CO₂ during flood and intermittent injection of CO₂ followed by water alternating gas, WAG (Picha, 2007). Of these method, the injection of a CO₂ slug in the oil reservoir alternated with water injection to achieve miscibility, is the most effective process for increasing oil recovery (Carcoana, 1982). The major recovery mechanisms of CO₂ flooding are believed to be oil viscosity reduction, wettability alternation, interfacial tension (IFT) reduction, and swelling of reservoir oil and solution gas drive (Li & Luo, 2017). The combination of these mechanisms enables most of the reservoir's remaining oil to be mobilized and produced.

CO₂ EOR is a long-proven technology for improving production from mature oil fields. In recent years, there has been an increasing global demand for the mitigation of atmospheric greenhouse gases such as CO₂. CO₂ EOR process has the potential of both improving oil recovery and sequestering large volumes of injected CO₂ thereby reducing greenhouse gas emissions (Ampomah et al., 2017). Most of the CO₂ emitted is traced to industrial setup such as thermal power plant, manufacturing industries, refineries which consume huge amount of energy, thus there is need to capture CO₂ and re-inject it into underground formation or alternatively use it to enhance oil recovery from mature and depleted oil and gas field (Biu Victor, 2011).

The use of CO₂ for EOR is considered one of the most promising methods for commercial application (Hashemi Fath & Pournafard, 2014). It is common for an EOR project to take 20 years or longer, to maintain a given CO₂ injection rate, thus EOR creates a derived demand for relatively pure CO₂ gas, operators of CO₂ EOR projects therefore need reliable sources of CO₂ over extended periods of time (Phillips & Veld, 2005). The easy industrial sources of CO₂ have almost all been developed, if natural sources of CO₂ and easy industrial sources will be inefficient where will the CO₂ to satisfy the remaining CO₂ demand come from. Most economic sources of CO₂ are already on the line and developing substantial volumes of additional CO₂ supply will be difficult (McGuire et al., 2016). These questions leave the reservoir engineers out sourcing for alternative low-cost gas for EOR.

There are other numerous challenges in the widespread implementation of CO₂ flooding. The most significant issue has been that of corrosion. This has been the problem in surface facilities, pipeline, injection wells and production wells. This problem is well understood and successful mitigation strategies have been developed, e.g., American Petroleum Institute, API recommendations for CO₂ injection wells (McGuire et al., 2016).

CO₂ injection technique is typically only implemented in regions where CO₂ is available in large quantities and at very low cost compare to hydrocarbon gases. The main barriers in application of this EOR technique is the economics of CO₂ supply, availability of low CO₂ at the injection site and the corrosive nature of the CO₂ gas requiring special materials which further increases the cost and return on investment (Dekker et al., 2012).

2.1.3.3 HYDROCARBON GAS INJECTION

Different types of gas have been used for EOR process, hydrocarbon gas has a higher potential for residual oil recovery by miscible mechanism of vaporizing and condensing gas drive. Hydrocarbon gas ranges from methane, ethane, propane, to butane, all of which can be used for EOR process. Methane, the largest component of natural gas, has been examined for use in EOR process but its high MMP value limits its use and further research into its feasibility. Ethane is therefore considered for further study in examining its technical and economic feasibility for use in EOR process.

The key source of ethane is natural gas deposits which comprise mixtures of hydrocarbons from methane upwards and other components such as nitrogen, carbon dioxide, and sulphur compounds. The quantity of ethane-and-heavier natural gas liquids contained in natural gas stream depends on the type of reservoir from which the natural gas originates. The highest concentration of ethane of 10% or more is usually found in associated-gas-streams, some non-associated gases can have ethane concentrations of 1% or lower (Farry, 1998).

Experimental results on heavy oil-solvent process for bitumen-ethane and bitumen-methane indicates that ethane has a higher viscosity reduction than methane at all conditions while their solubility increases with pressure at different temperatures (Kariznovi, Nourozieh, &

Abedi, 2012). Methane enriched with ethane, propane, and butane has been injected for EOR in north slope (McGuire et al., 2016). MMP increases as the hydrocarbon chain increases therefore methane has a higher MMP than ethane, ethane than propane and the trend goes on. In recovery of crude oil hydrocarbon from middle Bakken and lower Bakken shale, MMP for methane was twice that of ethane and since recovery efficiency is indirectly related to MMP, ethane gas yielded faster and more efficient than methane in crude oil recovery. Not much of the hydrocarbon gases have been used for injection for EOR (Hawthorne et al., 2017).

Ethane is a colourless and odourless gas at standard pressure and temperature and like many other hydrocarbons, ethane is isolated on an industrial scale from natural gas and as a by-product of petroleum refining. Ethane is most efficiently separated from natural gas (methane) by liquefying it at cryogenic temperatures. The most economical process presently in wide use employs a turboexpander and can recover 90% of the ethane in natural gas. In this process, chilled gas is expanded through a turbine reducing the temperature to about 148°F. At this low temperature, gaseous methane can be separated from liquefied ethane and heavier hydrocarbons by distillation. Further distillation then separates ethane from the propane and heavier hydrocarbon (Wikipedia). The absorption of NGL components in oil is an older method of ethane extraction still used in some cases. The oil used in the gas-oil distillation range is usually refrigerated (Farry, 1998).

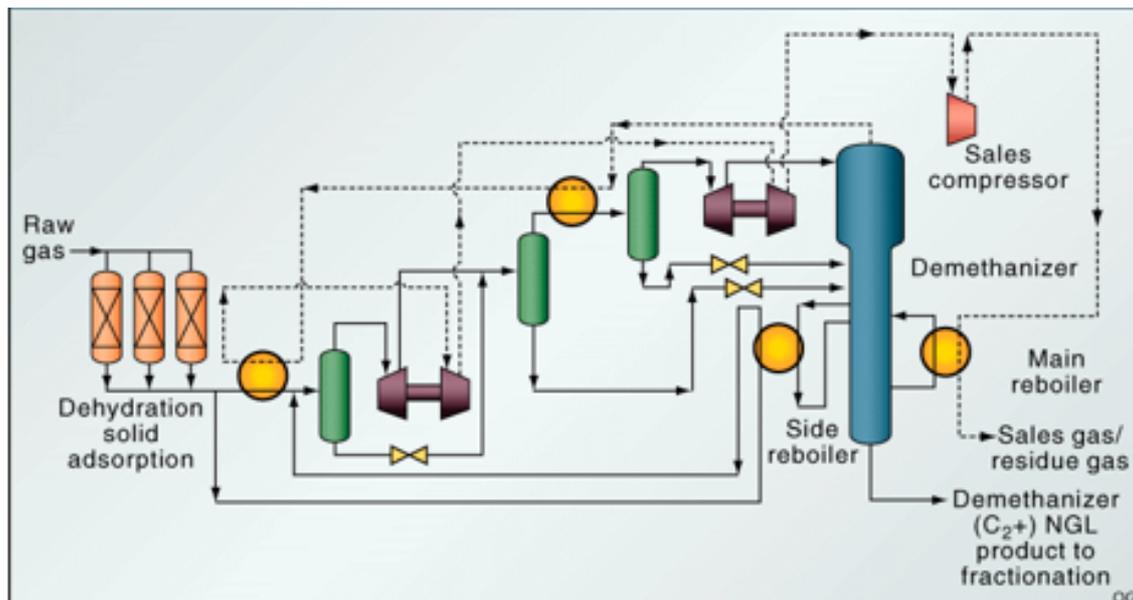


Figure 2.8 - Schematic of a typical two-stage turbo-expander (Farry, 1998)

2.2 FLUID CHARACTERIZATION

Fluid characterization is an essential tool that forms the basis of any reservoir simulations, recovery estimates, well completion and facility design decisions, pipeline flow assurance choices and production optimization strategies. It aims at reducing the number of pseudo-components of the fluid to a practical minimum and also matches fluid properties in simulated flashes with the properties of the real flashed fluids in PVT reports (Farry, 1998).

Pressure-Volume Temperature (PVT) analysis is the study of the changes in volume of a fluid(s) as function of pressure and temperature. The essence of PVT analysis is to simulate what takes place in the reservoir and at the surface during production and injection and to provide vital information about physical and thermodynamic behaviour of the reservoir fluids. Laboratory measurements of PVT properties are the primary source of PVT data determined from laboratory studies on samples collected from the bottom of the wellbore or from the surface. Such experimental data are however not always available because of one or more of such reasons:

- Samples collected are not reliable
- Samples have not been taken because of cost saving

- PVT analyses are not available when data are needed, this situation often occurs in production-test interpretation in exploration wells.

However, in the absence of such tests the use of correlations provides the only viable option for the prediction of PVT properties. Correlations are useful as a check against laboratory results, when these results are not available or reliable, the PVT software in the simulator is used to characterize the fluid (Adeeyo & Marhoun, 2013).

PVT software for characterization of the reservoir oil sample is used in this study to characterize the fluid samples. Insufficient description of heavier hydrocarbons can reduce the accuracy of PVT predictions. PVT matching generally starts with splitting the plus components into two or three pseudo components, specifically when there are many of them compared with the other components. The heavy C_{6+} component can be split into two pseudo-components; the critical properties correlation and acentric properties correlation can also be selected to describe the newly defined components. This is followed by grouping of components; components with similar molecular weight must be put in the one group. The main reason for grouping components is to speed-up the compositional simulation. In a compositional simulation, the number of grouped components depends on the process that is modelled. For miscibility, more than 10 components may sometimes be needed. In general, 4 – 10 components should be enough to describe the phase behaviour. In the PVT software, the main criterion for a successful grouping is whether the new grouped components can predict observed experimental results at least as well as the original ungrouped components, therefore care is to be taken when grouping the components. Shapes of phase diagrams for grouped and ungrouped components can be compared, if close shapes are obtained then good grouping is achieved (Hashemi Fath & Pouranfard, 2014).

Lastly, an Equation of State, EOS, is to be fitted into the PVT data have an agreement between the observed data and the results calculated with the EOS. The 3-parameter, Peng–Robinson or Soave Kwong-Redlich EOS can be used. Peng–Robinson EOS, a cubic

EOS that was developed by Peng and Robinson in 1976, has been shown to accurately model hydrocarbons and is the most widely used EOS in compositional reservoir simulators (Hashemi Fath & Pouranfard, 2014).

2.3 MINIMUM MISCIBILITY PRESSURE

Minimum miscibility pressure, MMP can be defined as the optimum pressure for oil recovery above which there is no significant increase in oil recovery. There have been so many definitions for MMP by different authors some of which are mentioned below;

MMP is the minimum pressure for a specific temperature at which miscibility can occur independent of overall composition. The MMP is reported to be a function of temperature and composition (Shpak, 2013).

Minimum miscibility pressure is the lowest pressure where practically all oil can be recovered after injection of just above a hydrocarbon pore volume of gas from a core with negligible dispersion (Wijaya, 2006).

MMP is a critical and most important parameter in the design and operation of a miscible gas injection process for oil reservoirs (Li & Luo, 2017). Displacement efficiency depends on minimum miscibility pressure and a dependable estimation of minimum miscibility pressure can help the operator to design the injection conditions and surface facilities (Hashemi Fath & Pouranfard, 2014).

Minimum Miscibility Pressure, MMP is the lowest pressure at which multi-contact miscibility can be achieved. In petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface (Hashemi Fath & Pouranfard, 2014). N.B: -The reservoir or formation to which the gas is applied must be operated at or above the MMP. Factors affecting miscibility in petroleum reservoirs are; the reservoir fluid composition, injection gas composition, reservoir temperature and pressure.

There are many methods for calculating the MMP, some of which include;

Method 1: The rising bubble apparatus experiments

Method 2: Slim-tube experiment

Method 3: Simulating slim tube experiment

Method 4: Use of define empirical correlation

2.3.1 RISING BUBBLE EXPERIMENT

The rising bubble apparatus was developed in the late 1980s to determine the minimum miscibility pressure for oil with pure gases and a blend of gases (Christiansen and Heimi, 1987). The apparatus consists of a flat glass tube, approximately 8 inches (20cm) long, mounted vertically in a high-pressure sight gauge in a temperature-controlled bath. The sight gauge is backlighted for visual observation and photography of the bubbles rising in the oil. A hollow needle is connected to the glass tube at the bottom of the sight gauge for injecting gas bubbles.

For minimum miscibility pressure measurement, the sight gauge and glass tube are filled with distilled water. Oil sample is then injected into the glass tube to displace all but a short volume of water in the tube's lower end. Then a small bubble of any gas is injected into the water. The bubble will eventually rise through the column of water, through the oil/water interface, and through the oil itself because of the buoyancy forces. The shape and motion of the bubble are observed and photographed as it rises through the oil column.

The rising bubble experiment is repeated over a range of pressures at a constant temperature to measure the minimum miscibility pressure, this behaviour suggests multiple contact miscibility. Below the minimum miscibility condition, the gas bubble transfers to the oil phase, and will maintain its near spherical shape as it rises. At or above minimum miscibility condition, the gas bubble will develop a tail at the bottom. As it moves up the oil column, the bottom of the bubble will degrade and quickly disperse into the oil. The experiment also requires minimum fluids to determine the minimum miscibility pressure or minimum miscibility enrichment (Alsulaimani & Lake, 2015). RBA is quicker than slim-tube

experiment as it uses approximately one-tenth of the time required for a slim-tube experiment (Class & Objectives, 2013).

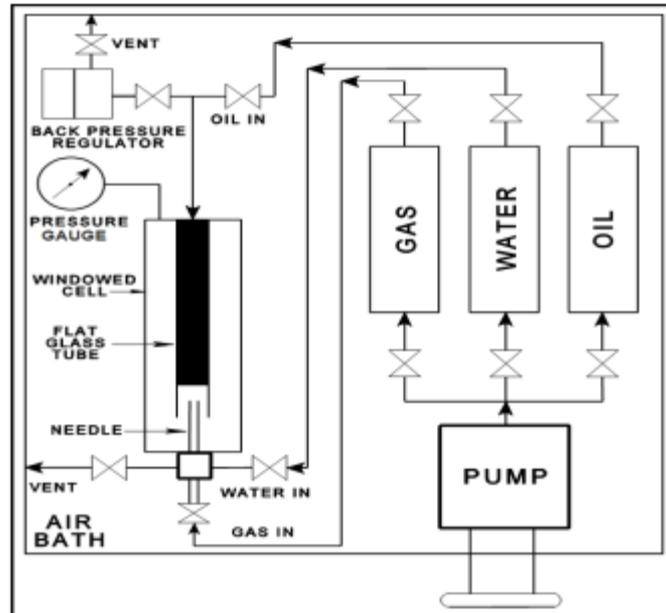


Figure 2.9 - Schematic of Rising bubble apparatus notes

2.3.2 SLIM-TUBE EXPERIMENT

The most common standard experimental technique for determining minimum miscibility conditions is the slim-tube. A typical slim-tube apparatus consists of a 6.3 mm outer diameter, OD stainless steel tube of 40ft long and packed with 160-200 mesh sand (Yellig & Metcalfe, 1980). One end of the slim-tube is connected to a fluid transfer cylinder and the other end is connected to a visual cell and a back-pressure regulator. At each displacement test, the slim-tube is saturated with reservoir oil at reservoir temperature. Then gas is injected at a constant rate using a positive displacement pump to displace the oil. The back-pressure regulator maintains a fixed pressure at the outlet of the slim-tube. In some experiments, gas is injected at a low rate to establish a mixing zone, and then the rate is increased to complete the experiment in a shorter time (Elsharkawy et al., 1992).

To determine the minimum miscibility pressure for a given oil composition at a fixed temperature, the displacement is conducted at various (typically five) pressures (Yellig &

Metcalfe, 1980). The percent recoveries at 1.2 PVs of injected gas are then plotted as a function of the operating pressure or enrichment level. The minimum miscibility pressure is the pressure at which the oil recovery is 90% or above which no significant recovery is achieved. The slim-tube method is a valuable technique for determining minimum miscibility condition and offers the advantage of using real reservoir fluid. The method can be expensive and time-consuming, thus many researchers over the years have developed other non-experimental methods that can be used to approximate the miscibility conditions (Alsulaimani & Lake, 2015).

Slim-tube data are also used in tuning an Equation of State (EOS) model to better predict both the development and loss of miscibility (Wijaya, 2006).

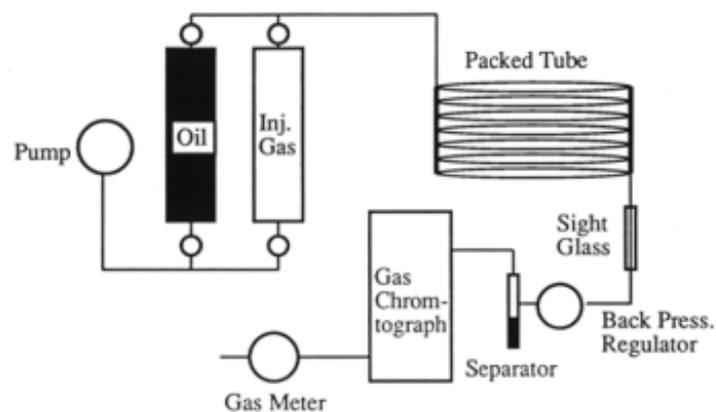


Figure 2.10 - Schematic of slim tube apparatus (Kossack, 2013).

2.3.3 SIMULATION OF SLIM-TUBE EXPERIMENT

The alternative method to the slim-tube experiment in determining minimum miscibility condition is the use of one-dimensional compositional simulation of a slim-tube model. In this simulation process, oil is displaced by injected gas at different pressures (Alsulaimani & Lake, 2015). Slim-tube results are interpreted by plotting oil recovery vs. pressure for 1.2 pore volume injected.

To estimate the minimum miscibility pressure, a one-dimensional compositional slim-tube model is simulated by increasing the injection pressure which increases the recovery factor

until the recovery factor vs. pressure curve flattens, showing miscible displacement performance (Alsulaimani & Lake, 2015). The displacement experiment is run at different pressures and often terminated after injecting 1.2 pore volumes (PV) of the injected gas. Miscible displacement basically results in very high recoveries hitting 100%, as there is one phase and zero capillary pressure (Shpak, 2013). Zick (1986) showed that determining minimum miscibility condition from slim-tube simulations requires more work to reduce the numerical dispersion effect and it can be time-consuming. However, Stalkup (1987) demonstrated that the simulation should be performed at fine grid size to reduce the truncation error caused by the numerical dispersion.

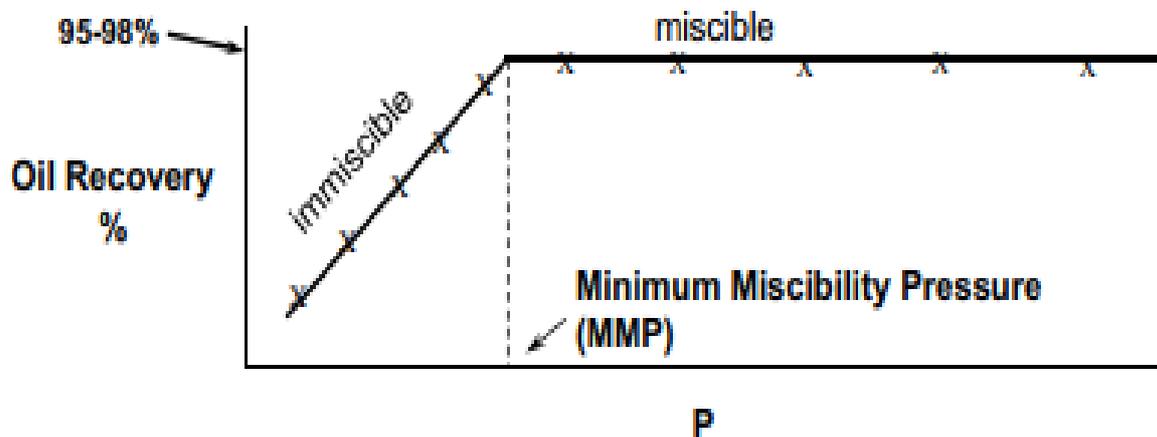


Figure 2.11 - Results of slim-tube displacement @1.2HPV at various pressure (Kossack, 2013).

2.3.4 EMPIRICAL CORRELATIONS FOR MMP

Different well-established empirical correlations have been in use for decades, they have shown a substantial degree of accuracy as most of them were derived from experimental data. Empirical correlations are sets of equations generated from MMP data measured by experimental methods and/or MMP data calculated from compositional simulations. Empirical correlations are used to predict the MMPs for reservoir oils with various types of injected gas. These correlations provide quick estimates of MMPs which can be useful during screening of various gas injection processes for the reservoir. The MMPs calculated from empirical correlations can have large errors and should not replace MMPs obtained

from experimental or compositional simulation methods. Empirical correlations should be used to predict MMP value during the early stages of screening the reservoir for various types of miscible gas injection processes. Empirical correlations for prediction of MMPs have been developed based on type and composition of the injection gas (Class & Objectives, 2013).

(a) Glasø Correlations

A set of equations for prediction of MMPs for hydrocarbon injection gases was presented by Glasø. These equations were derived from the graphical correlations developed by Benham et al.

The Glasø correlations of predicting MMP for hydrocarbon oil/gas systems are

$$MMP_{x=34} = 6329.0 - 25.410 y - z(46.745 - 0.185 y) + T \left(1.127 \times 10^{-12} y^{5.258} e^{319.8 xy^{-1.703}} \right)$$

..... equation 2.1

$$MMP_{x=44} = 5503.0 - 19.238 y - z(80.913 - 0.273 y) + T \left(1.70 \times 10^{-9} y^{3.730} e^{13.567 xy^{-1.058}} \right)$$

..... equation 2.2

$$MMP_{x=54} = 7437.0 - 25.703 y - z(73.515 - 0.214 y) + T \left(4.920 \times 10^{-14} y^{5.520} e^{21.706 xy^{-1.109}} \right)$$

..... equation 2.3

where y = Corrected C7+ molecular weight, x = Molecular weight of injection gas, z = Mole fraction of methane in injection gas.

Where molecular weight of injection gas (x) is not exactly the value given in the equations, the MMP of such gas is either interpolated or extrapolated.

Glasø correlations of predicting MMP for nitrogen gas injection is listed below.

For molecular weight of C7+ greater than 160 and mole percent of intermediates greater than 28%, the correlation is

$$\begin{aligned}
 & 23,025 M_{C_{7+i}}^{-1.703} - 20.80 \\
 & M_{C_{7+i}}^{5.258} e^{\frac{i}{T}} \\
 & 1.127 \times 10^{-12} i \\
 & C_{7+i} + T i \\
 MMP = & 6364 - 12.090 M_i
 \end{aligned}$$

..... equation 2.4

For molecular weight of C7+ less than 160 and mole percent of intermediates greater than 28%, the correlation is

$$\begin{aligned}
 & 23,025 M_{C_{7+i}}^{-1.703} - 39.77 \\
 & M_{C_{7+i}}^{5.258} e^{\frac{i}{T}} \\
 & 1.127 \times 10^{-12} i \\
 & C_{7+i} + T i \\
 MMP = & 7695 - 12.090 M_i
 \end{aligned}$$

..... equation 2.5

If the mole percent of intermediates is less than 28%, the correlation is

$$\begin{aligned}
 & 23,025 M_{C_{7+i}}^{-1.703} - 20.80 \\
 & M_{C_{7+i}}^{5.258} e^{\frac{i}{T}} \\
 & 1.127 \times 10^{-12} i - 99.3 C_{2-6} \\
 & C_{7+i} + T i \\
 MMP = & 9634 - 12.090 M_i
 \end{aligned}$$

..... equation 2.6

Note in Equations 2.4 through 2.6, $M_{C_{7+i}}$ = molecular weight of the C₇₊ in the stock tank oil, lbm/lbmol, T = reservoir temperature, °F; and C_{2-6} = mole percent of the intermediates (C₂ through C₆) in the reservoir oil.

(b) Firoozabadi and Aziz MMP correlation for nitrogen/oil systems

The Firoozabadi and Aziz correlation for prediction of MMP for nitrogen/oil systems can also be used for lean gas. This correlation is

$$MMP = 9433 - 188 \times 10^3 \frac{M_{C_{7+i}} T^{0.25}}{C_{2-5}} \dots \dots \text{equation 2.7}$$

where $\frac{M_{C_{7+i}}}{M_i}$ = molecular weight of C₇₊ lbm/lbmole; C₂₋₅ = mole percent of C₂ through C₅ including CO₂ and H₂S in the reservoir fluid; and T = reservoir temperature, °F.

(c) Emera MMP correlation for pure CO₂ injection

The Emera MMP correlation for pure CO₂ injection is given by

$$MMP_{Pure} = 5.0093 \times 10^{-5} \times \left(\frac{M_{C_{5+i}}^{1.2785} C_{C_{1+N_2}}}{C_{C_{2+N_2}} H_2S + CO_2} \right) (188 T + 32)^{1.164} \times i \dots \dots \text{equation 2.8}$$

If the bubble point pressure, Pb of the oil is less than 50 psi, equation 2.8 becomes:

$$MMP_{Pure} = 5.0093 \times 10^{-5} \times M_{C_{5+i}}^{1.2785} (188 T + 32)^{1.164} \times i \dots \dots \text{equation 2.9}$$

Note that for Emera correlation, if MMP is less than Pb, then $MMP_{Pure} = Pb$. The terms used in Equation 2.8 and 2.9 are defined as follows.

MMP_{Pure} = minimum miscibility pressure for pure CO₂, MPa, T = reservoir temperature,

°C, $\frac{C_{5+i}}{M_i} = i$ molecular weight of the C₅₊ in the stock-tank oil, lbm/lbmole, $C_{C_{1+N_2}} = i$ mole

fraction of the volatiles (C_1 and N_2) in the reservoir oil, and $C_{C_2+N_2} H_2S+CO_2 = i$ mole fraction of the intermediates (C_2 , C_3 , C_4 , H_2S and CO_2) in the reservoir oil.

(d) Orr and Metcalfe MMP correlation for pure CO_2 injection

The Orr and Metcalfe MMP correlation for pure CO_2 injection is

$$MMP_{Pure} = 1833.717 + 2.2518055 T + 0.01800674 \times T^2 - \frac{10349.93}{T} \quad \dots \text{equation 2.10}$$

where the reservoir temperature, T in $^{\circ}F$, is the only known variable (Alsulaimani & Lake, 2015)

2.4 OVERVIEW OF ETHANE-BASED ENHANCED OIL RECOVERY

The opportunities, engineering and economic issues of hydrocarbon gas EOR are well understood and have been proved by decades of research and field experience. The conventional wisdom has been that hydrocarbon gas is too expensive as natural gas prices are too high (McGuire et al., 2016). This is no longer the case in Nigeria where about 1.85 billion standard cubic feet of natural gas is being flared as at 2016 (Ndu Ughamadu, 2017). Ethane, being the second-largest component of natural gas after methane is in abundance and therefore represent the low-cost available gas of EOR in Nigeria. Some work and experiments have been done on the current state and opportunity of ethane for EOR processes.

McGuire et al., 2016 summarizes the current state of Ethane industry in U.S and explores the opportunity for using ethane for EOR process. Simulated data and field examples were used to demonstrate ethane as an excellent EOR injectant considering its availability. The limited supply of low-cost CO_2 , its significant drawbacks in terms of corrosion, solubility and high MMP value deters its use in shallow and low-pressure reservoirs. Ethane has maintained superiority over CO_2 as EOR injectant in terms of solubility, swelling, viscosity reduction and in developing multi-contact miscibility owing to its low MMP values. Ethane-based EOR can supplement the very successful CO_2 based EOR industry in the U.S. The

current abundance of low-cost ethane presents a significant opportunity to add new gas EOR projects. Ethane is operationally simpler than CO₂ for EOR, its now inexpensive and will likely stay inexpensive. Ethane-based EOR has become a viable option as large volumes of low-cost ethane are available (McGuire et al., 2016).

The perception of hydrocarbon gas being expensive for decades is no longer true as shale revolution in the U.S has created major EOR opportunity for low-cost ethane used for miscible/immiscible WAG projects. McGuire et al., 2016 concluded that shale production in the US has brought about an enormous increase in ethane production and ethane prices have dropped steeply. Ethane prices have dropped substantially as it is no longer priced as petrochemical feedstock but as fuel with substantial quantities currently being flared.

CHAPTER THREE

3.0 METHODOLOGY

Compositional simulator is the major tool used in this study starting from PVT software tool used for the reservoir characterization down to simulation of ethane injection process. Thereafter, an economic model was built based on the deterministic value of the cumulative oil production obtained after the ethane water alternating gas (ethane WAG) process was simulated.

3.1 RESERVOIR AND FLUID PROPERTIES

The case study was carried out using a pilot area of the ABD field in the Niger Delta. The structure of ABD field is a roll-over anticline controlled by a large south to southwest dipping growth fault that forms the northern boundary of the field. The structure is fault-bounded towards the north and dip-closed towards the east, south and west. Secondary normal fault occurs south of the down-dip. A structural saddle to the east of the field controls the spill of hydrocarbon towards the east. The field consists of several reservoirs of the Agbada formation, a succession of the alternating deltaic or near-shore sands and marine shale of Oligocene and Pliocene age.

The reservoir depth ranges from 6600ftss – 7300ftss with the reservoir of interest having top of sand depth at 7126ft, oil-water contact (OWC) of 7184ft, and depth of perforation between 7145ft and 7155ft. Table 3.1 shows the detailed fluid and reservoir properties of the candidate ABD reservoir.

Table 3.1 - ABD reservoir and fluid properties

Field property	Unit	Value	Field property	Unit	Value
----------------	------	-------	----------------	------	-------

Depth	Ft	6600 - 7300	Porosity	%	30
Gravity	°API	17	Permeability	mD	1600
Reservoir Pressure	Psia	3200	Oil Viscosity	Cp	61
Area	Acres	6	Temperature	°F	200
Net pay	Ft	58	GOR	68Mscf/stb	7:1

3.2 CHARACTERIZATION OF RESERVOIR FLUID

The reservoir fluid components ranging from nitrogen to heavy hydrocarbon chain was given as shown in Table 3.2. The components were reduced to 8 major components with absence of CO₂ and other components from C8 - C20+ lumped into C7+. The PVT parameters which included reservoir fluid components, weight fractions, mole weight of the C7+ component its specific gravity were specified as input while the composition (Z_i) was generated by the PVT software tool. The reservoir temperature and pressure were provided in the PVT software tool to simulate constant composition expansion experiment with different equations-of-state (EOS) to calculate the reservoir fluid properties.

The Peng-Robinson (PR) and Soave-Redlich-Kwong (SRK) three-parameter EOS and Lohrenz-Bray-Clark viscosity correlation were used in this study to model the reservoir fluid. The omega values, critical value of temperature and pressure, acentric factor, binary interaction coefficient, BIC, overall composition and other characteristic properties of the fluid were estimated. The saturation pressure of the fluid was estimated at 1035psia from PR EOS and 940psia from the SRK EOS.

Table 3.2 - ABD fluid components

No.	Component	Reservoir Fluid (mol %)	No.	Component	Reservoir Fluid (mol %)
1	N2	0.11	16	C12	2.7
2	CO ₂	0	17	C13	8.1
3	C1	1.85	18	C14	13.2
4	C2	0.45	19	C15	12.47
5	C3	0	20	C16	7.66
6	i-C4	0	21	C17	2.41
7	n-C4	0.09	22	C18	1.61
8	i-C5	0.4	23	C19	1.25
9	n-C5	0.26	24	C20+	33.72
10	C6	2.54		MW	357.13

12	C8	0.01		C₇₊	94.3
13	C9	0.01		C₇₊ MW	375.41
14	C10	3.69		Flash GOR	7.1
15	C11	2.95		Gravity	0.596

3.3 DETERMINATION OF MINIMUM MISCIBILITY PRESSURE

Three different methods were used to determine the minimum miscibility pressure for ethane in this study. They included use of correlations, simulation of slim-tube experiments and equations of state.

3.3.1 Correlations

The Glasø correlation and Orr & Metcalfe correlations were used to estimate the Minimum Miscibility Pressure, MMP.

3.3.1.1 Glasø MMP correlations

The Glasø correlations shown in equation 2.1, 2.2 and 2.3 were used to predict the MMP for hydrocarbon oil/gas systems studied in this work.

3.3.1.2 Orr and Metcalfe MMP correlation

A second correlation used to estimate MMP was the Orr and Metcalfe MMP correlation presented earlier as Equation 2.10. Note for this correlation the reservoir temperature (T) is the only variable needed to use it.

The results obtained from these correlations are not unique to the reservoir fluid as some of the parameters included in the equations were not required for pure ethane gas injection.

The Orr and Metcalfe correlation on the other hand was specifically designed for Carbon dioxide, CO₂, gas injection and so it does not accurately predict the MMP for pure ethane gas injection.

3.3.2 Equation of state

Equation of state (using the PVT software tool) was used to simulate a multiple-contact process of lightening up the reservoir fluid using 100 percent or pure ethane gas based on multi-cell condensing gas miscible drive. The Peng-Robinson (PR) and Soave-Redlich-

Kwong (SRK) three-parameter EOS and Lohrenz-Bray-Clark viscosity correlation were used to estimate the multiple contact minimum pressure values. The minimum miscibility pressure calculated from the PR EOS was used in the ethane-based EOR process simulation.

3.3.3 Simulation of Slim-tube Experiment.

Slim-tube experiment is the most accurate method for determining minimum miscibility pressure, MMP. In the absence of real samples to work with, this experiment can be simulated using a compositional simulator. The PVT data generated with PR and SRK 3-parameter equation of state was exported into the slim-tube model for estimating the MMP.

3.3.3.1 The Slim-tube model

One-dimensional slim-tube model is gridded to contain 1000 grid blocks with 0.05-ft grid block size in the x-direction. The length of the slim tube used for this simulation is 50ft with an average permeability of 1600mD, oil gravity of 17°API and a constant reservoir temperature of 200F. The injection into the slim-tube was controlled by reservoir pore volumes injected, while the reservoir pressure was varied from 500psia to 3000psia. A total of 1.2 pore volumes were injected in 12hours by injecting 0.1PV per hour, which is equivalent to reservoir pore volume of 0.2671bbl per hour. The initial reservoir pressure was changed for each run. The volume injected can be calculated using the following:

$$\text{Volume of slimtube simulated} = L \times B \times H \quad \text{equation 3.1}$$

$$\text{Volume of slimtube simulated} = 50 \text{ ft} \times 1 \text{ ft} \times 1 \text{ ft} = 50 \text{ ft}^3$$

$$\text{Total pore volume of slimtube simulated} = \text{Volume} \times \text{Porosity} \quad \text{equation 3.2}$$

$$50 \text{ ft}^3 \times 0.3 = 15 \text{ ft}^3$$

$$\text{Total pore volume of slimtube simulated (barrels)} = \frac{15 \text{ ft}^3}{5.615 \frac{\text{ft}^3}{\text{bbl}}} = 2.67 \text{ bbl}$$

Recall that 1.2PV is to be injected in 12 hours. So, the reservoir barrel equivalent to 0.1PV to be injected per hour is

Reservoir volume of slimtube injected per hour = 2.67 bbl × 0.1 = 0.267 bbl

The resulting percentage recovery at 1.2PV injection was plotted as a function of the operating pressure (Figure 3.1). It was observed that the recovery efficiency increases with pressure until a point of deflection is reached after which an increase in pressure gives no additional recovery. The pressure value at this point of deflection is called the minimum miscibility pressure for the ethane miscible gas flooding; and it is about 1900 psi as shown in Figure 3.1.

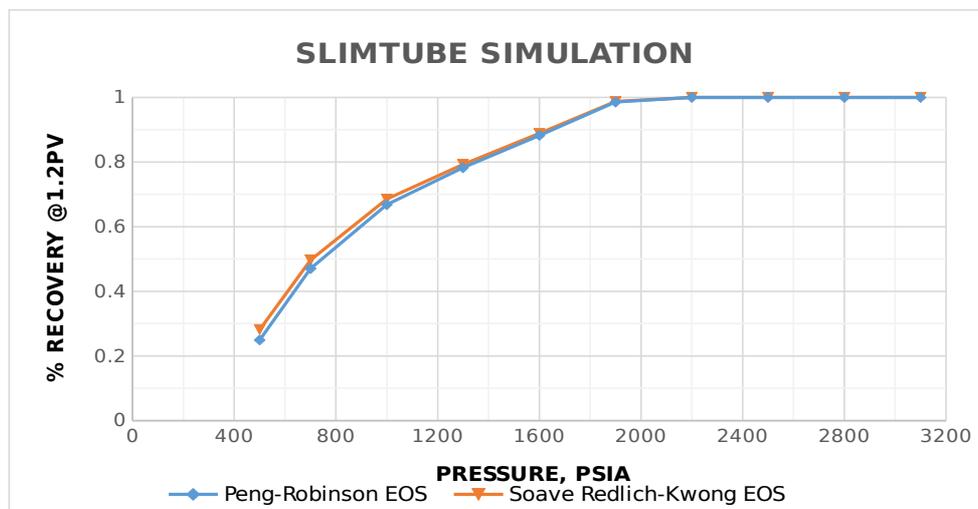


Figure 3.12 - Oil recovery vs. pressure plot of slim-tube simulation showing MMP

3.4 RESERVOIR MODEL DESCRIPTION

The reservoir model used for the study was an inverted five-spot consisting of one “injector” at the centre and four “producers” at the corners of the reservoir. An eight-component Peng-Robinson EOS model of the reservoir fluid was used for this study. The number of grid blocks in the model was $9 \times 9 \times 4$ ($N_x \times N_y \times N_z$), a total of 324 cells. The grid size is the same in the x- and y-directions, i.e., $\Delta x = \Delta y = 293.3\text{ft}$. Each of the reservoir layers is homogeneous and of constant porosity but varying permeability and thickness. The reservoir top of sand was kept at 7150ft with an initial pressure of 3200psia, oil density of 59.51 lb/ft^3 , the datum depth was set to oil-water contact, OWC of 7190ft. The reservoir model properties are summarized in Table 3.1. As shown in figure 3.2, the oil saturation decreases downward with the first layer containing more oil than other layers.

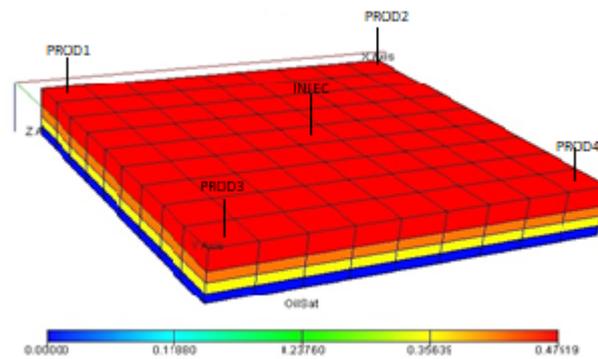


Figure 3.0.13 - Reservoir model oil saturation before simulation

The injection well located at the centre of the reservoir was completed in layer 3. For the production wells, PROD1 and PROD2 were completed in layer 1; PROD3 was completed in layer 2 and PROD4 was completed in layer 3, just above the oil water contact. All the production wells are attached to a field separator at atmospheric condition.

3.5 RESERVOIR SIMULATION

The reservoir model was used to carry out four (4) cases of simulations.

Case 1: the base case involves running the model under primary depletion; that is, model is run without any injection for 25 years with each producer BHP set at 500psia.

Case 2: Waterflooding – water was injected into the centre injector and oil was produced from the four corners wells. This case was simulated for 25 years.

Case 3: Ethane gas injection – pure ethane gas was injected for 25 years and oil was produced from the four corner wells.

Case 4: Ethane WAG – water alternation gas injection, water was injected for 2 years to establish the reservoir injectivity. A slug of ethane gas was injected for 2 years and then followed by water injection for the next 2 years. This cycle of water alternating ethane gas injection (ethane WAG) was repeated for 12.5 number of times to simulate the 25 years of WAG production.

The different cases of simulations were performed by varying some key operating conditions like BHP at the producers and injector, well injection and production rates to determine the most favourable flood operating conditions with reasonable increase in the cumulative oil production.

3.6 SENSITIVITY ANALYSIS

To optimize the ethane EOR process, there is need to understand the model input parameters and operating variables and their impacts on the oil recovery performance of the model. Sensitivity analysis is used to better understand the effect of each parameter on the objective function (cumulative recovery) and reduce the number of control variables in the ethane EOR optimization. There are many input parameters used in building the reservoir model but the main uncertain parameters considered for sensitivity analysis in this study range from the length of the WAG cycle to the well production and injection rates, BHP at the four corner producers and centre injector, initial water saturation, net-to-gross thickness, and permeability in x- and z-directions K_v/K_h . With the use of experimental design, these parameters were varied in each of the 12 runs of the reservoir model simulations, while the cumulative production, water cut and oil production rates for each run was observed.

3.6 QUANTIFYING THE UNCERTAINTY IN ETHANE EOR CUMMULATIVE OIL RECOVERY

Having identified the heavy hitters amongst the specified model input parameters and operating variables from the sensitivity analysis, there is need to understand the relationship between these parameters and the cumulative oil production. An uncertainty analysis is carried out to quantify the range of the cumulative oil production from application of an ethane-based EOR process. About 45 runs were made with the surrogate WAG reservoir model which was used to generate data for an analysis of variance, ANOVA.

3.7 ECONOMIC ANALYSIS OF ETHANE EOR PROCESS

Having completed the technical feasibility aspect of the study, there is need to understand the economic feasibility of ethane EOR which controls the key decision of its application in the Niger Delta. Without proper understanding of the economics, no projects can be successfully executed considering the risks involved in the oil and gas industry.

A typical Nigerian natural gas contains a total inert ($\text{CO}_2 + \text{N}_2$) content of less than 4% by volume, which is the allowable and 0% sulphur compounds. Hence, the conditioning costs of nitrogen and Sulphur will not be included in the extraction of ethane from natural gas. This assumption has been corroborated by the findings of Enyi et al. (2005). They stated that the low inert gas and sulphur content of Nigerian natural gas makes projects requiring the conditioning process viable, economical and profitable (Enyi, Appah, & Engineering, 2005). This is an economic advantage for ethane extraction in Nigeria since conditioning process of natural gas is the major stage of ethane extraction after which it is subjected to low temperature to separate methane before applying fractional distillation to separate ethane from heavier hydrocarbon components. The overall costs of conditioning Nigeria's natural gas and extraction of ethane should be economical considering a simple or less complex on-site processing equipment with absence of cost of gas sweetening. In this study, we used the Enyi et al. (2005) estimate of 12.4 million dollars (USD) for the total capital investment cost of processing 10MMscf of Nigeria natural gas per day.

In absence of the exact capital cost/expenditure required to set up an ethane extraction plant or natural gas processing plant in Nigeria, the following assumptions were made for economic analysis of the ethane-based EOR project:

- Capital investment of 1.24 million USD is required for daily processing of 1MMscf of gas (Enyi et al., 2005).
- Operating cost for ethane injection and smooth running of the field per year is assumed to be 0.6 million USD, which includes the cost of water injected.
- The spot market price of ethane was set at 4.15 USD per Mscf as at January 1st, 2016. This was taken from McGuire et al. (2016).
- The base case oil price is 55 USD per barrel.

- The royalty of 20%, petroleum property tax (PPT) of 60%, income tax of 30% was used and tax credit of 20% was given to the investor.

The Economic analysis was done for two different categories;

1. Constructing a natural gas processing plant with an ethane extraction unit primarily to ensure uninterrupted supply of ethane gas for injection and production of other commercial gases that occur as end products. This involves estimating the capital investment cost required for daily processing of natural gas required to produce the quantity of ethane to be injected. Table 3.3 summarises the assumptions invoked in this case.

Table 3.3 - Basic assumptions for economics of constructing a gas processing plant

Item	Value
Year Begin	2017
STOIP (MM bbl)	5.9
Reservoir model	
Production life	25 years
OPEX, (million USD)	\$0.06
Depreciation (straight line depreciation)	5 years
MOD Oil price	\$55/bbl
Royalty rate (%)	12.5
CAPEX (million USD)	\$1.24/MMscf
Income tax rate (%)	30
Discount rate (%)	10

1. Buying quantity needed

the required of ethane gas for injection at

the spot market price. The spot market price was increased by 20-30% to accommodate for the possible increase in price from 2016. Table 3.4 shows the assumptions and parameters used in the economic analysis for this case.

Note: The spot price of \$4.50 per Mscf was used for this study compared to the \$4.15 per Mscf reported by McGuire et al., 2016, to accommodate for logistics and regional difference.

Table 3.4 - Basic assumptions for economics of procuring ethane gas

Item	Value
Year Begin	2017
STOIP (MMbbl)	5.9
Production life	25 years
OPEX, (million USD)	\$0.06
Depreciation (straight line depreciation)	5 years
MOD Oil price	\$55/bbl
Royalty rate (%)	12.50
CAPEX (Spot price)	\$4.5/MMscf
Income tax rate (%)	30
Discount rate (%)	10

CHAPTER FOUR

4.0 RESULTS AND DISCUSSION

The results obtained from this study are presented in this chapter. The results are discussed to improve our understand of the technical and economic feasibility of applying ethane based enhanced oil recovery process in Niger Delta.

4.1 RESULTS OF CALCULATION OF MINIMUM MISCIBILITY PRESSURE OF ETHANE

As discussed in chapter 3, the reservoir and fluid properties given in Table 3.1 and Table 3.2, were used to characterize the reservoir fluid properties. This PVT analysis produced a phase envelop replica of dead oil, which is an exact representation of the reservoir fluid under study.

The result of the PVT analysis of the characterized reservoir fluid was supplied as input data to the simulation model of the slim-tube experiment used to determine the minimum miscibility pressure (MMP) of ethane. Though other methods like correlations and mixing cell

methods were used for determination of MMP, the published literature has shown that slim-tube experiment is the most accurate MMP method. In absence of the slim-tube experiment, the simulation of slim-tube experiment is the most accurate method for determining MMP and must not be replaced with any alternative method. The MMP value obtained from the simulation of slim-tube experiment using two different EOS (3-parameter Peng-Robinson and Soave-Redlich-Kwong) is approximately 1900psia, which is lower than reservoir pressure. Table 4.1 lists the MMP values obtained from the various methods used in this study.

This MMP of about 1900psia indicates the possibility of injecting ethane-gas without fracturing the reservoir or exceeding the reservoir pressure. The estimated MMP is above bubble point pressure; therefore, it is high enough to maintain the reservoir energy for significant oil recovery.

Table 4.5-Results of MMP of ABD reservoir fluid

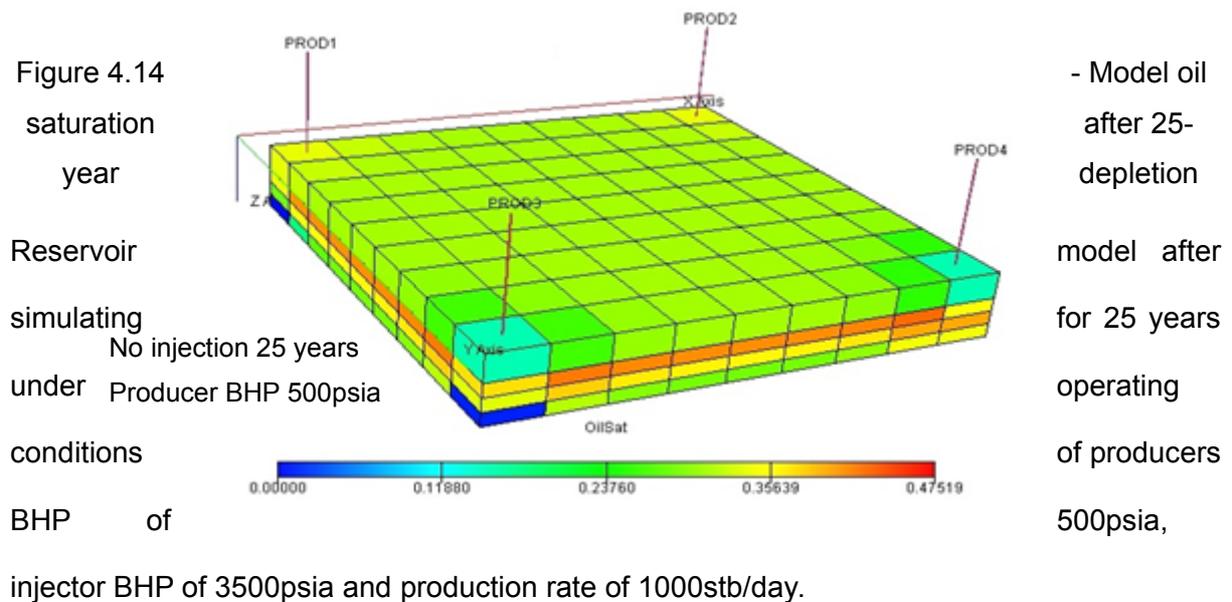
METHOD	MMP (PSIA)
GLASO CORRELATION	2438
ORR AND METCALFE	2953
PENG-ROBINSON EOS	1896
SOAVE REDLICH-KWONG EOS	1900
SLIMTUBE SIMULATION	1910

4.1 RESULTS OF SIMULATIONS OF ETHANE EOR PROCESS

To estimate the amount of oil recovered from an ethane based EOR process, a Niger Delta case study was developed. In this case study, an inverted five spot reservoir model was built with one injection well at the centre and four production wells at the corners. The reservoir model was used to determine the cumulative oil recovery considering four production cases. In case 1, the reservoir model was used to study primary depletion, i.e., producing the reservoir without injecting any fluids for 25 years. Case 2, involved using the reservoir model to simulate 25 years of waterflooding where water is injected from the centre well and oil

produced from the four corner production wells. In case 3, pure ethane was injected at the centre well to displace oil to the corner production wells for 25 years. For case 4, an ethane water alternating gas (WAG) process was simulated. Here the oil is produced by injecting a slug of ethane gas followed by a slug of water injection. The cycle of water injection followed by gas injection is repeated 12.5 number of times to account for the 25-year production. The pictorial representations and results of the simulated cases are shown in figures 4.1 through 4.9.

CASE 1: Primary Depletion with no fluid injection



CASE 2: Water flooding for 25 years

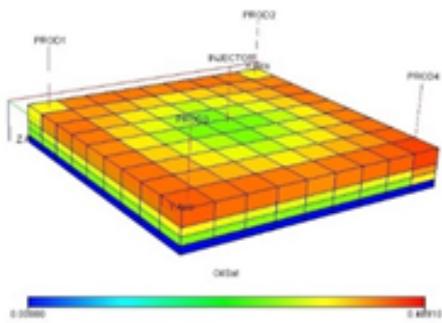


Figure 4.15 - Water injection

2000stb/day

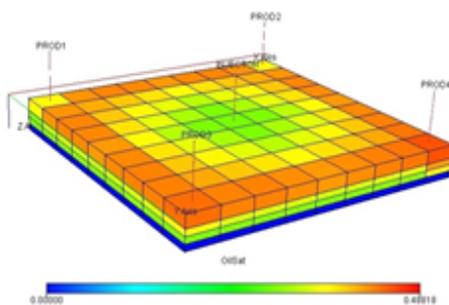


Figure 4.16 - Water injection

3000stb/day

CASE 3: Pure ethane gas injection for 25 years

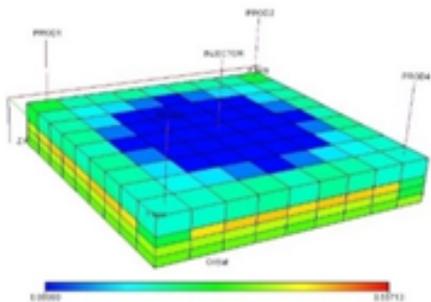


Figure 4.18 Pure Ethane injection

2Mscf/day

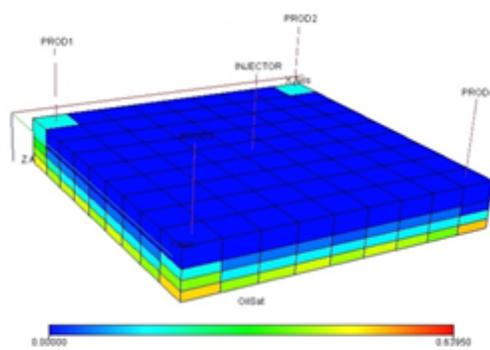


Figure 4.17 - Pure Ethane injection

3Mscf/day

CASE 4: Ethane water-alternating-gas with series of 2-year water injection followed by 2-year gas injection

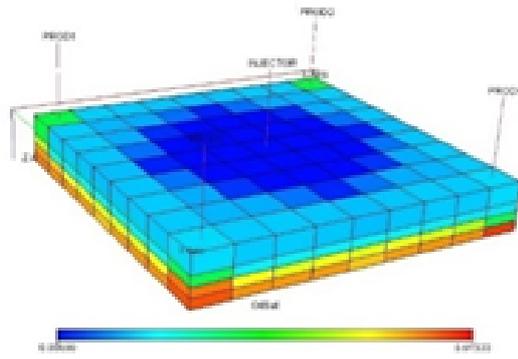


Figure 4.19 - WAG injection Water- 2000stb & Ethane gas- 2Mscf per day

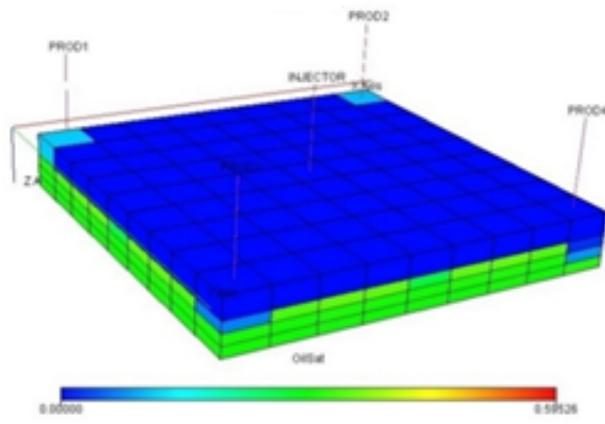


Figure 4.20 - WAG injection Water- 2000stb & Ethane gas- 2Mscf per day

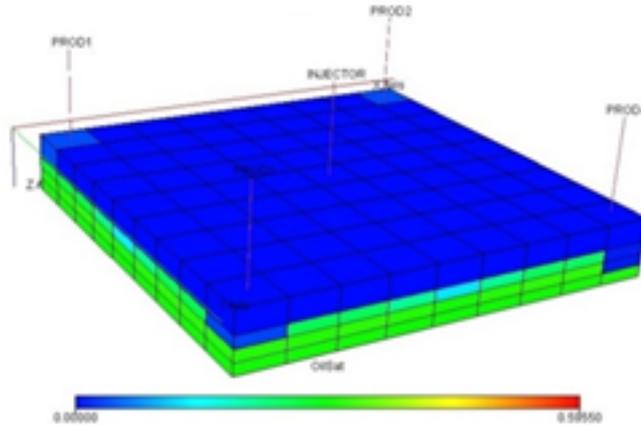


Figure 4.21 - WAG injection Water- 5000stb & Ethane gas- 10Mscf per day

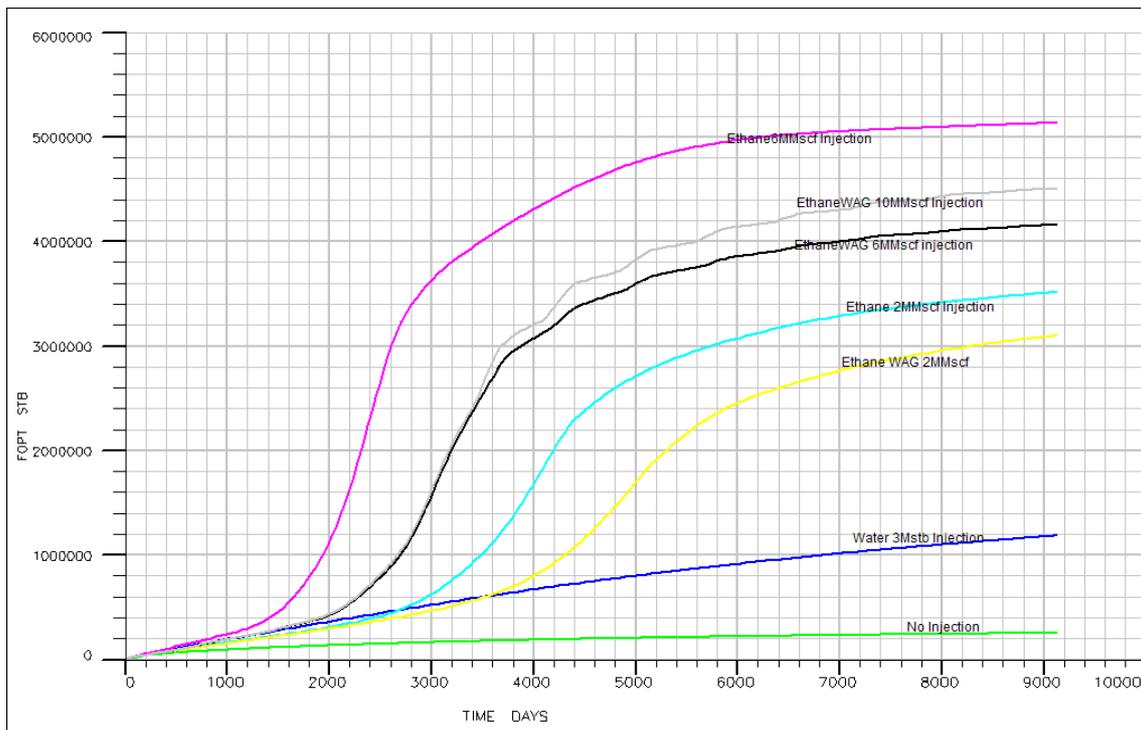


Figure 4.22 - Graph showing simulation results

4.3 RESULTS OF SENSITIVITY ANALYSIS

An inverted five spot reservoir model was built using the estimated MMP value and sensitivity analysis was conducted by varying the operating parameters used in the study to identify the heavy hitters. The heavy hitters are the operating parameters whose contributions have high impacts on the results of the model simulations, i.e., the cumulative oil production (FOPT) in this study.

The results of the 12-simulation run using the ABD reservoir model are shown in Table 4.2.

Table 4.6 - Results of runs of simulated reservoir WAG models

Run	Injector BHP	Injector Rate	Prod Rate	Prod BHP	Perm Z	Perm X	Kv/ Kh	Poro sity	Thick ness	WAG Cycle	Swi	FOPT (STB)	FWCT	FGPT (MSCF)
1	3700	5500	500	800	150	1800	0.15	0.2	150	14.5	0.15	8010609	0.756	15939774
2	3200	6500	1500	1200	50	1800	0.15	0.2	150	10	0.15	3260472	0.383	598590
3	3200	5500	1500	1200	150	1300	0.15	0.4	100	14.5	0.15	4692087	0.285	855272
4	3200	6500	500	800	50	1800	0.15	0.4	100	14.5	0.2	7832818	0.256	4110023
5	3200	5500	500	800	50	1300	0.05	0.2	100	10	0.15	6036443	0.411	6539697
6	3700	6500	500	1200	50	1300	0.05	0.4	150	14.5	0.15	5593824	0.531	854347
7	3700	6500	500	1200	150	1300	0.15	0.2	100	10	0.25	5823445	0.563	9280407
8	3700	6500	1500	800	150	1800	0.05	0.4	100	10	0.15	5245304	0.214	1072061
9	3200	5500	500	1200	150	1800	0.05	0.4	150	10	0.25	2681727	0.703	403138
10	3700	5500	1500	1200	50	1800	0.05	0.2	100	14.5	0.25	6650031	0.907	18141188
11	3200	6500	1500	800	150	1300	0.05	0.2	150	14.5	0.25	8207829	0.582	11526777

A response surface equation model based on the cumulative oil production (FOPT) was obtained using analysis of variance, ANOVA which is expressed thusly.

$$FOPT = 5.4097 \times 10^5 + 866.069 \times Injec\ BHP + 651.071 \times Injector\ Rate - 656.129 \times \prod Rate - 4424.0777 \times \prod$$

equation 4.0

The validity of the model given in equation 4.0 is evident by the degree of correlation of 0.9999 shown in the plot displayed as Figure 4.10. This high degree of correlation indicates that the equation is adequate for the analysis carried out in this study.

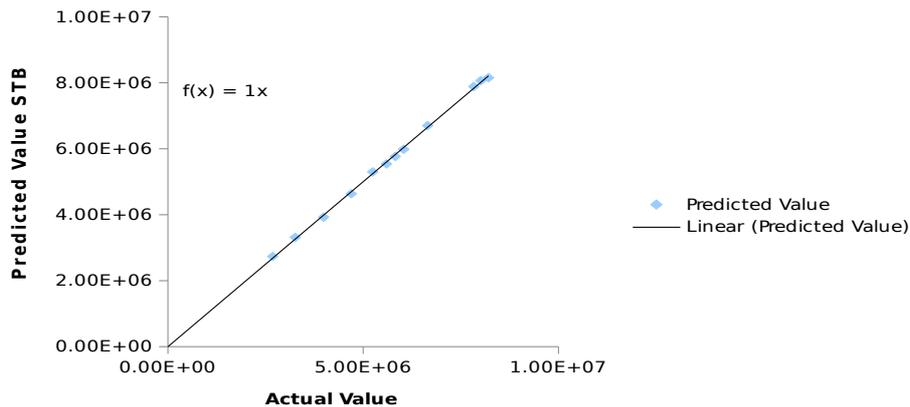


Figure 4.23 - Validity plot showing degree of correlation between predicted and actual cumulative recovery, FOPT

The sensitivity analysis was conducted with the validated equation of the proxy model to evaluate the impact of each parameter on the cumulative production, FOPT. The contribution of each of these parameters in percentage and their impacts on the FOPT is shown in the Pareto chart in Figure 4.11. The results show that six operation parameters; WAG cycle, Production BHP, model porosity, thickness, Production rate and Injection rate have the most impacts on the cumulative production and therefore must be properly adjusted or managed in order to attain optimum ethane EOR operating conditions.

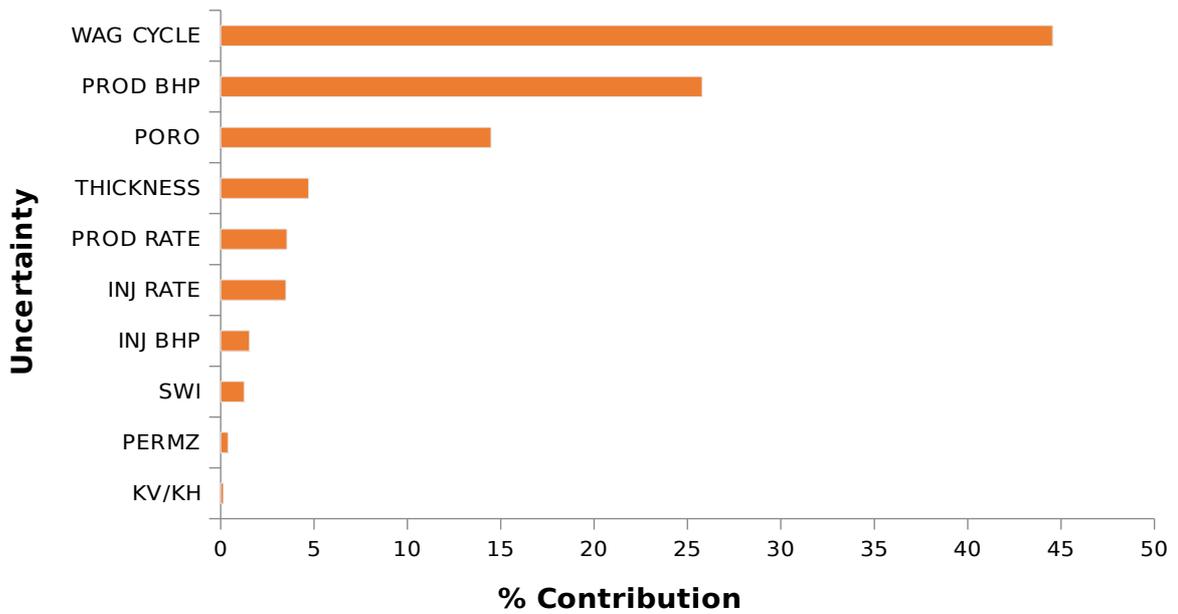


Figure 4.24 - Pareto chart between predicted and actual FOPT

4.4 RESULTS OF QUANTIFYING THE UNCERTAINTY IN CUMULATIVE OIL RECOVERY FROM ETHANE EOR PROCESS

Using result from the runs made with the surrogate WAG reservoir model to generate data for ANOVA, the equation of the response surface obtained is a reduced quadratic model; and it is valid for the estimation of FOPT. Figure 4.13 shows the response surface validation plot of Equation 4.1. The results show that Equation 4.1 can be used to quantify the uncertainty in the cumulative oil production derived from the ABD reservoir model.

$$FOPT = -4.41570 \times 10^7 + 99521.48 \times WAG\ cycle + 2044.5897 \times Injector\ Rate + 1745.074 \times \prod Rate - 450.60$$

..... equation 4.1

The heavy hitters were identified and their impacts on the cumulative production (FOPT) are indicated in results shown in figures 4.13 through 4.15. Table 4.3 also lists the percentage contributions of the heavy hitters on cumulative oil production, FOPT.

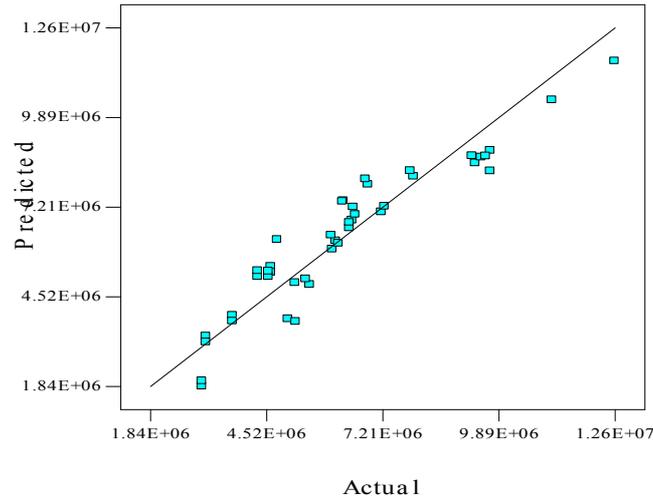


Figure 4.25 - Cross plot of simulated reservoir model and quadratic model

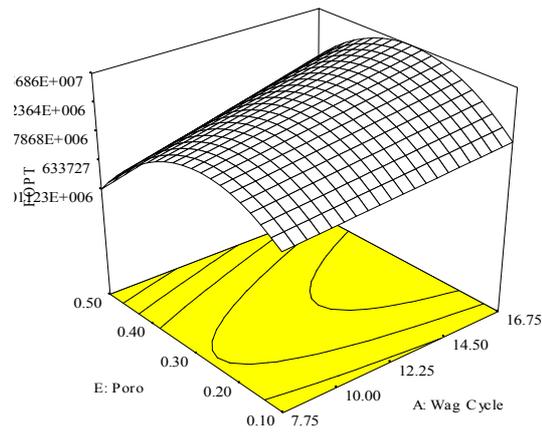


Figure 4.26 - Interaction between Porosity, WAG cycle and FOPT

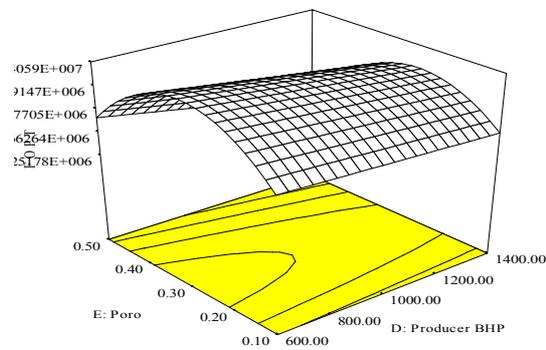


Figure 4.27 - Interaction between Porosity, Producer BHP and FOPT

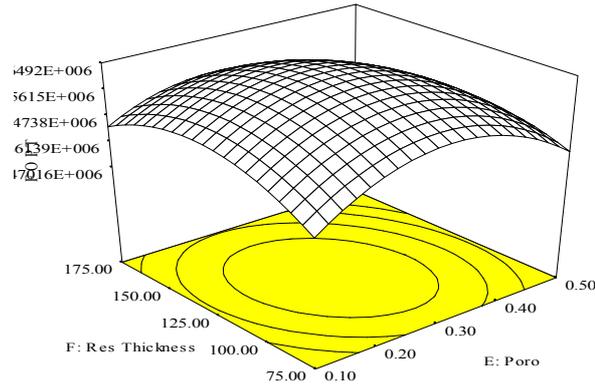


Figure 4.28 - Interaction between Porosity, Thickness and FOPT

Table 4.7 - Heavy hitter parameters and their degree of contribution to FOPT

Parameters	Degree of contribution to FOPT
WAG cycle	44.54%
Production BHP	25.8%
Reservoir porosity	14.50%
Reservoir thickness	4.71%
Production rate	3.55%
Injection rate	3.49%

From the analysis of the data in Table 4.3 it can be deduced that the WAG cycle which indicates the length of time for fluid injection of either water or gas (and the switch between gas and water injection), has the highest impact on the cumulative oil produced. This implies that after the ethane gas is injected and a miscible front (of reservoir oil and injected gas) is created, the water injected aids in displacing most of the reservoir oil in this model towards the producing wells. The injected water is also contributing as water flooding

mechanism, the more the number of WAG cycles, the more contacts the ethane gas makes with the reservoir oil; and the more oil the injected water displaces which results in higher sweep efficiency.

Table 4.3 also shows that production well BHP is the next operating parameter with significant impact on the cumulative oil produced. The reservoir pressure keeps dropping during production, even though the fluid injection would tend to maintain the reservoir pressure, there will be a time during production and injection when the average reservoir pressure will drop remarkably; once it drops below the producer bottom hole pressure, the producing well will shut down which reduces cumulative production. Therefore, to keep all the wells open throughout production period, the well BHP should be set at pressure reasonably below the bubble point pressure or MMP; the lower the value of BHP, the better is the recovery. The optimum production BHP used in the simulations was 500psia.

The reservoir porosity has some impact on recovery; the more tightly packed a reservoir is (lower porosity), the lesser is the sweep efficiency and thus the cumulative oil produced.

Though reservoir thickness is also a determining factor/parameter which affects the cumulative production, it is not as significant as the previously mentioned parameters, However, reservoir thickness has more significant impact on cumulative production compared to production rate and injection rate.

The injection rate of the ethane gas is very important parameter to this study as it contributes to the cumulative oil produced. It is the major factor influencing the WAG cycle; if the injection rate, i.e., quantity of ethane injected is increased, the sweep efficiency increases as well as the oil recovery as shown in Figure 4.1 – 4.8. The sensitivity analysis in Table 4.4 shows that the operationally optimum injection rate is 6MMscf/day of ethane gas.

Table 4.8 - Operating conditions vs cumulative recovery

OPERATING CONDITIONS (Injector BHP of 3500psia and producer BHP of 500 psia)	TOTAL CUMMULATIVE OIL PRODUCED, MMstb
NO INJECTION	0.259
WATER INJECTION	1.14
ETHANE INJECTION 2MMSCF	3.45
ETHANE WAG INJECTION 2MMscf	3.14
ETHANE INJECTION 6MMscf	5.05
ETHANE WAG INJECTION 6MMscf	4.19
ETHANE WAG INJECTION 10MMscf	4.45

The cumulative oil produced when 2MMscf per day of pure ethane gas was injected was higher than that of 3Mstb of water per day. The injection rate for pure ethane was increased to 6MMscf per day for 25 years and a significant increase was noticed. Injection rate for ethane gas during the WAG process was increased from 2MMscf to 6MMscf, and a significant increase in the cumulative oil produced was noticed as compared to the pure ethane gas injection. But when the ethane gas injection rate for WAG was increased to 10MMscf/day, there was little or no change in the production rate. The slight increase in the cumulative oil produced in the case of 10MMscf/day WAG compared to the 6MMscf/day WAG is not significant to justify the injection of additional 4MMscf/day of ethane during the WAG. There is a need to consider the cost implication of the additional ethane gas injected in order to identify the operational and economically optimum injection rate.

4.5 RESULTS OF ECONOMIC ANALYSIS OF ETHANE EOR PROCESS

Annual production for 25 years was used for the economics analysis in this study. For no fluid injection case, the cumulative net cash flow shows that the field generated income for the first five (5) years, even though the income was very low and no income for the next two years. Annual production decreases gradually from the 8th year to the last year without sufficient revenue to sustain the field operations. It is therefore advisable to shut down the operation of oil production from this field after the 5th year.

When water is injected, the annual production increases slightly compared to that of the base case of no fluid injection. Water injection provides enough revenue to run the field for seven (7) years, after which the annual oil production declines and could no longer generate

enough revenue to sustain the field operation. The field oil production is shut down at the end of the seventh year.

Pure ethane gas injection and water-alternating-gas injection cases were also simulated for 25 years using the ABD reservoir model. In these cases, the quantity of ethane gas and water injected was varied. The resulting cumulative oil recovery is analysed to identify the most economically viable option.

The economics analysis was carried out using two options for sourcing the gas to be injected.

1. Construct a natural gas processing plant primarily for ethane extraction.

Figure 4.16 shows the results of net cash flow from the economic analysis for Option 1, i.e., onsite gas processing plant as a source of ethane injection gas. The results indicate that the net cash flow from the annual oil production for the case of pure ethane injection (2MMscf/day and 6MMscf/day) was more than that obtained from the base case (no fluid injection) and water injection case. While pure ethane injection could generate enough revenue needed to run the field operation, but the revenue generated is not enough to pay for the capital needed for constructing a gas processing plant of 2MMscf/day or 6MMscf/day capacity. The gas plants for 2MMscf/day and 6MMscf/day injection capacity cost \$2.48MM and \$7.44MM, respectively, during the project life of 25 years. Though pure ethane injection process is technically viable, it is not economically attractive because the capital invested in the construction of the processing plant required to generate the ethane gas through extraction cannot be recovered within the 25 years study period. This same inference applies to ethane WAG project with the injection of 2MMscf/day of ethane gas, as can be seen from the results shown in Figure 4.16.

Ethane WAG project with the injection of 6MMscf/day of ethane gas yields higher annual oil production than all the previous cases of injection considered in this study. Even with a capital investment of \$7.44MM and operating cost of \$60M, the annual oil production from the ethane-based WAG could still generate enough revenue to sustain the field operations

and completely pay off the capital cost of the 6MMscf capacity processing plant at the end of the 14th year. From the 15th year, all the revenue accumulating from the oil production is used for the smooth running of the field operation leaving a substantial amount of income for the company. The economics of this injection scheme is attractive, and it can be implemented technically.

The annual revenue generated from oil production using the Ethane WAG process with the injection of 10MMscf/day of ethane gas was enough to support the operational costs but not enough to pay for the capital cost of constructing a 10MMscf/day capacity processing plant for the period of 25 years considered in this study. This implies that constructing a gas processing plant for the extraction of 10MMscf/day of ethane gas for WAG injection is not economically viable.

2. Procure the required quantity of ethane gas at the spot market price.

The annual oil production from all forms of ethane and ethane WAG injection (regardless of the quantity of ethane injected, number of WAG cycles or production rate or BHP) could not generate revenue sufficient to purchase the quantity of ethane required to run the EOR process as shown in Figure 4.17. This option or category is totally uneconomic and is unworkable except there is substantial increase in the price of oil to justify the purchase of the ethane injection gas.

Sensitivity analysis carried out by varying the economic input parameters shows that the price of oil per barrel has significant impact on the net present value (NPV) and the internal rate of return (IRR) of the project. The results imply that this project could be more economically attractive, if the oil price per barrel increases. The higher the capital expenditure, CAPEX, the lesser is the NPV and the IRR. The CAPEX is dependent on the infrastructure or facilities required for the project. The discount rate also has slight impact on profitability of the project. The higher the discount rate, the lesser is the NPV and the IRR. Depending on the minimum IRR of interest, the company can decide to either reject or embark on the project.

Table 4.9 - Result of sensitivity analysis on economic parameter

VARIABLES	VALUE	NPV (Million USD)	IRR (%)	PVR (Ratio)
Oil price	44	8.1	18	1.1
	50	9.9	19.5	1
	55	11.7	20.7	1.6
	61	13.4	21.8	1.8
	66	15.2	22.7	2
CAPEX	6	13	21.5	1.8
	6.7	12.8	21.4	1.7
	7.4	11.7	20.7	1.6
	8	12	20.5	1.5
	8.9	12	19.6	1
DISCOUNT RATE	8	18	22	2
	9	15.4	21	2
	10	11.7	20.7	1.6
	11	11	19.2	1.5
	12	10	18	1

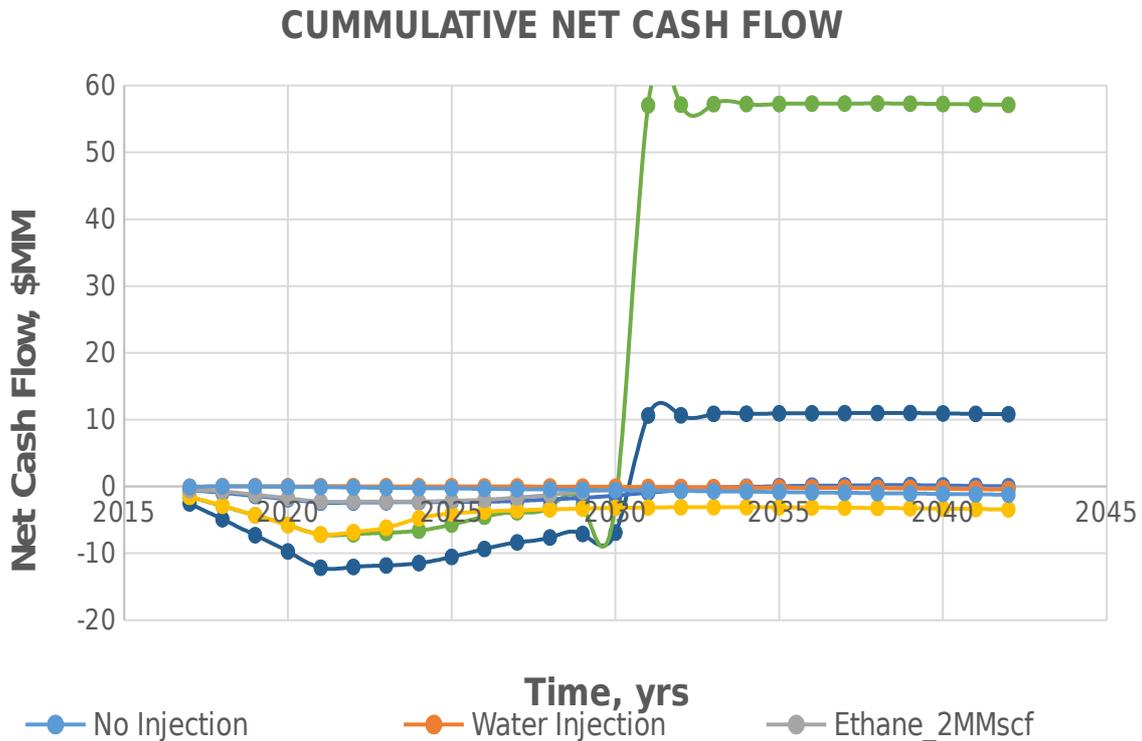


Figure 4.29 - Plot of cumulative net cash flow for all injection in category 1

CUMMULATIVE NET CASH FLOW

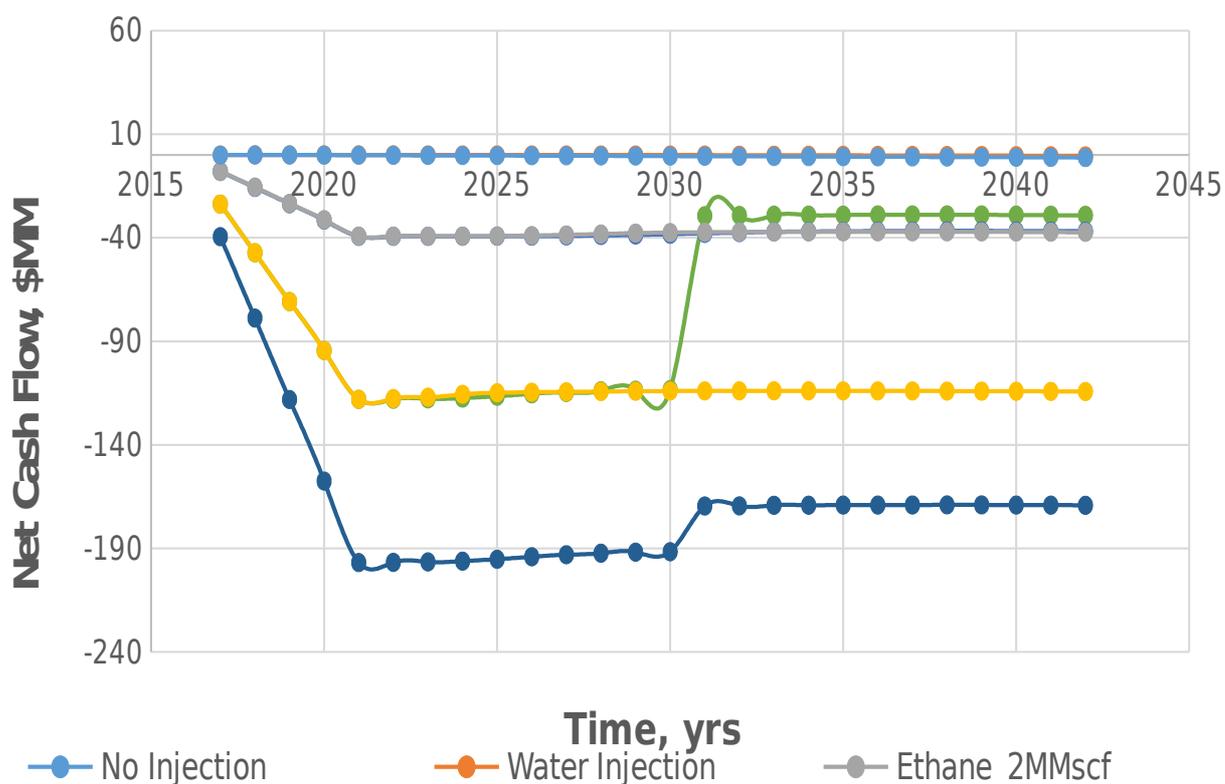


Figure 4.30 - Plot of cumulative net cash flow for all injection in category 2

CHAPTER FIVE

5.0 SUMMARY AND CONCLUSION

In this thesis, the technical and economic feasibility of ethane based EOR is studied using a case study to model a reservoir in the Niger Delta. The reservoir fluid was characterized using the PVT software after which the minimum miscibility pressure, MMP was obtained from the simulation of one-dimensional model of the slim-tube experiment. Four different cases of oil production were considered by varying the type, quantity and blend of the injected fluid at the MMP.

The following conclusions can be derived from the results of this study:

The cumulative oil production increases with increase in quantity of ethane injected within the 25 years study period. The highest oil recovery (86% of STOOIP) was obtained from the injection of 6MMscf/day of pure ethane gas compared to the application of WAG process with the injection rate of 6MMscf/day of ethane gas and 3000stb of water per day (71% of

STOOIP); waterflooding at 2000stb per day (19% of STOOIP) and natural depletion (4% of STOOIP) where no fluid was injected in the reservoir model used in the case study.

Sensitivity analysis indicated that the WAG cycle had the most impact on the cumulative oil recovered from EOR process followed by the injection rate of the ethane gas. The 12.5 WAG cycles operated during the 25 years of the study (i.e., 2 years of injecting 3000 stb/day of water alternating with 2 years of 6MMscf/day or 10MMscf/day of ethane gas injection) are the optimum technical operating conditions for the EOR process implemented in the ABD reservoir.

The economic analysis shows that the most viable project is to inject water at 3000 stb/day followed by injection of 6MMscf/day of ethane gas every two years in an ethane-based WAG EOR project for 25 years. This WAG project is economically attractive because it would generate enough revenues to pay for operating and maintenance cost, and the capital investment of constructing a 6MMscf/day capacity natural gas processing plant for ethane extraction with a payback period of 14 years. During ethane extraction from this processing plant other commercially viable secondary products can be harnessed, for example the extraction plant can produce methane gas (major component of natural gas) that could be used as cooking gas and other higher hydrocarbon gases such as propane and butane can be produced and sold as petrochemical feedstock. This study showed that ethane WAG EOR process is economically feasible considering the current oil price of \$50 per barrel and the economics will become more attractive with the increase in the oil price.

5.1 RECOMMENDATION

Ethane as a hydrocarbon gas is known to be an expensive and non-economical gas especially its unavailability as an EOR injectant in this part of the world (Nigeria), where there is no gas infrastructure in place for its refining and sales to the market. Flaring of natural gas in Nigeria creates an opportunity for extraction of significant quantity of ethane from processed natural gas to be used in EOR operations.

This study uses the spot price of ethane \$4.50 per Mscf as at 1st of January 2016 from McGuire et al. 2016 as basis for estimating the price of ethane. Future studies should consider escalating the ethane price to properly evaluate the economics of applying ethane WAG EOR. It is recommended that the option of building natural gas processing plants primarily for the extraction of ethane should be evaluated critically in field locations where there is interest in ethane-based EOR and there is high volume of gas flaring or no readily available market for monetising the natural gas.

More detailed economic analysis should be done in a future study using the true cost of ethane gas in this region (Nigeria) and considering the application of other investment ranking criteria (e.g., cost of acquiring capital to be invested) with the net present value (NPV) and the internal rate of return (IRR) proposed in this work.

This study uses an inverted five-spot pattern for the simulation of ethane gas injection EOR process. Other EOR patterns like regular five-spot, seven- and nine-spots and staggered-line drive should be considered in future research.

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