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**Ethane Miscibility Correlations and Their Applications to Oil Shale
Reservoirs**

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Reservoirs**

by

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Dedication

To my mother, my late father, and my family

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Abstract

Ethane Miscibility Correlations and Their Applications to Oil Shale Reservoirs

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Compositional simulation studies were performed to evaluate the practicality and efficiency of using ethane as an enriching solvent in miscible displacements. More than 1,300 compositional simulation runs were used to build ethane minimum miscibility correlations. The miscibility conditions of four different reservoir fluids by mixtures of methane and ethane were determined for a range of pressures and temperatures. Correlations were built for pressures from 1,500 to 4,000 psi and temperatures from 100 to 260 °F. The correlations were modeled after Benham's et al. (1959) findings and they were obtained using reservoir pressure, temperature and the C₅+ molecular weight of the displaced fluid. The correlations were checked using data from the literature and with results obtained using other methods. The correlations are in good agreement with other data and showed a deviation of 5 to 10 mole % in the predicted ethane minimum miscibility enrichment.

As a second part of this study, additional compositional reservoir simulation models were used to assess the feasibility of using ethane as a solvent in shale reservoirs.

The obtained correlations in the first part of this study were used to predict the minimum miscibility condition in shale reservoirs. Based on cumulative oil recovered and sweep efficiency at simulation termination, results suggest that miscible ethane injection performs better than water injection, water alternating gas, and immiscible gas injection.

Sensitivity analysis was performed on shale reservoirs models with permeabilities of 0.1 md and 0.001 md. Parameters such as injector-producer spacing, fracture spacing, and injector placement were evaluated.

In the 0.1 md formations, simulation results suggest that cumulative production depends strongly on spacing. Assuming a one well pair in the 6000 ft × 6000 ft area, wider injector-producer spacing and fracture spacing produces more oil compared to close spacing because of the larger swept volume. Likewise, placing injectors on top of the producer showed some improvement in the oil recovery compared to placing producer and injector next to each other.

On the other hand, results show that it is very difficult to inject any fluid in formations with permeabilities in the range of 0.001 md. Close injector-producer spacing does not show any increase in recovery because the injected fluid does not reach the producer. The simulation results show that even an injector-producer spacing of more than 120 ft does not exhibit any difference in the recovery. Fracture spacing, on the other hand, shows some increase in the oil recovery because of the increase in the stimulated volume around the injector. In contrast to the 0.1 md reservoirs, results suggest that cumulative oil production is less dependent on the type of injected fluid. Water, miscible and immiscible injection show similar results. Saturation maps and injected pore volume calculations show that there is little matrix contribution and almost all production is dominated by fractures. Therefore, any sort of injection might not be considered a practical option.

Table of Contents

List of Tables	x
List of Figures	xi
Chapter 1: Introduction	1
1.1 Motivation.....	2
1.2 Review of Chapters.....	4
Chapter 2: Background	6
2.1 Solvent Flooding.....	6
2.2 Miscibility Mechanism	7
2.3 Minimum Miscibility Pressure and Minimum Miscibility Enrichment Definitions.....	8
2.4 Minimum Miscibility Condition Estimation.....	9
2.4.1 Minimum Miscibility Experiments.....	9
Rising Bubble Experiment.....	9
Slimtube Experiment	10
2.4.2 Minimum Miscibility Conditions from Calculations and Computational Methods.....	11
Minimum Miscibility Using Calculations Methods	11
Minimum Miscibility from Mixing Cell Method	12
Minimum Miscibility from Compositional Simulation	13
2.5 Minimum Miscibility Correlations	14
2.5.1 Minimum Miscibility Pressure Correlations.....	14
2.5.2 Minimum Miscibility Enrichment Correlations.....	15
Chapter 3: Simulation Model.....	17
3.1 Introduction.....	17
3.2 Grid Size Selection	17
3.3 Initial Conditions	19
3.4 PVT Properties.....	21
3.5 Porosity and Permeability	24

3.6	Relative Permeability.....	25
3.7	Wells and Constraints	27
Chapter 4:	Method of Investigation	28
Chapter 5:	Correlations and Correlation Accuracy.....	32
5.1	Correlations.....	32
5.2	Correlations Accuracy	36
5.3	Sensitivities.....	38
Chapter 6:	Applications of Miscible Ethane Injection to Oil Shale Reservoirs	40
6.1	Introduction.....	40
6.2	Simulation Model.....	41
6.3	Flooding Scenarios.....	43
6.3.1	Immiscible Gas Flooding	43
6.3.2	Miscible Gas Flooding.....	45
6.3.3	Water Flooding	47
6.3.4	Water Alternating Gas	49
6.3.5	Miscible Gas after Water Injection (Tertiary Recovery)	50
6.4	Sensitivity Analysis (0.1 Millidarcy Permeability)	53
6.4.1	Injector-Producer Spacing	53
6.4.2	Fracture Spacing	55
6.4.3	Injector Placement	56
6.5	Sensitivity Analysis (0.001 Millidarcy Permeability)	58
Chapter 7:	Summary and Conclusion	60
7.1	Correlations.....	60
7.2	Miscible Injection in Shale Formations	61
7.3	Limitations and Recommendations.....	61
References	63

List of Tables

Table 1:	Fluid Composition of Fluids A, B, C, and D (Benham et al, 1959).	20
Table 2:	Fluid Composition of Fluid E (Charles & Curtis, 1995).	20
Table 3:	Critical Properties of Fluids A to D.	21
Table 4:	Binary Interaction Coefficients of Fluids A, B, C, and D Based on a Binary Interaction Coefficient Parameter of 1.2	22
Table 5:	Critical Properties of Fluid E (Charles & Curtis, 1995).	23
Table 6:	Binary Interaction Coefficients of Fluids E (Charles & Curtis, 1995).	24
Table 7:	Fluid Composition of a Shale Reservoir Being Used in the Simulation Study.	42
Table 8:	Summary of Reservoir Parameters for the Base Case.	42

List of Figures

Figure 1:	Ethane Monthly Production in Thousand Barrels per Day (U.S Energy Information Administration).....	4
Figure 2:	Simulation Model Configuration.	19
Figure 3:	The Impact of Changing Relative Permeability Curves on Near Miscible Displacement.....	26
Figure 4:	The Effect of Changing Relative Permeability Curves on First Contact Miscible Displacement.....	26
Figure 5:	Recovery Percentage at 1.2 PV Injected Is Plotted For Each Ethane Mole Percentage.....	29
Figure 6:	Fluid (A) Recovery Percentage at 1.2 PV Injected for a Pressure Range from 1,500 to 4,000 psi at 100 °F.	30
Figure 7:	Fluid (A) Recovery Percentage at 1.2 PV Injected for a Pressure Range from 1,500 to 4,000 psi at 100 °F.	31
Figure 8:	Minimum Enrichment Correlations at 100°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.	33
Figure 9:	Minimum Enrichment Correlations at 140°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.	34
Figure 10:	Minimum Enrichment Correlations at 180°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.	34
Figure 11:	Minimum Enrichment Correlations at 220°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.	35
Figure 12:	Minimum Enrichment Correlations at 260°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.	35

Figure 13:	Minimum Enrichment Correlations Comparison at 1,500 psi.	37
Figure 14:	Impact of Changing Interaction Coefficients on Recovery.	39
Figure 15:	Zoomed in Map View of Producer and Injector Configuration.	41
Figure 16:	Immiscible Gas Injection Performance Compared to Primary Recovery.	44
Figure 17:	Gas Saturation Map Showing Early Gas Breakthrough.	44
Figure 18:	Miscible Gas Injection Performance Compared to Immiscible Flooding.	46
Figure 19:	Oil Saturation Map Showing the Sweep Efficiency of Miscible injection at the End of the 30 years Injection Period (2 PV Injected).	46
Figure 20:	Water Flooding Performance Compared to Miscible Gas Injection at Different Pore Volumes Injected.	47
Figure 21:	Water Saturation Map Showing Movement of Water through Fractures to the Producer.	48
Figure 22:	Water Cut Percentage in the Producer Well.	48
Figure 23:	Water Alternating Gas Performance Compared to Water Flooding, Immiscible, and Miscible Injection.	50
Figure 24:	Tertiary Recovery Using Miscible Injection.	51
Figure 25:	Gas Oil Ratio of the Miscible Injection Case Compared to Tertiary Miscible Injection Case.	52
Figure 26:	Oil-Gas Relative Permeability Curve.	52
Figure 27:	Injector-Producer Spacing Scenarios (Map View).	54
Figure 28:	Impact of Injector-Producer Spacing on Oil Recovery in a Miscible Gas Injection.	54
Figure 29:	Fracture Spacing of 120, 360, and 600 ft.	55

Figure 30:	The Effect of Fracture Spacing on Oil Recovery in a Miscible Gas Injection.	56
Figure 31:	Injector Placement Relative to the Producer.....	57
Figure 32:	Recovery Difference between Adjacent and Top Injector.....	57
Figure 33:	Injector-Producer Spacing Impact on Oil Recovery in a 0.001 Millidarcy Formation.....	59
Figure 34:	Fracture Spacing Impact on Oil Recovery in a 0.001 Millidarcy Formation.....	59

Chapter 1: Introduction

In recent years gas injection has become one of the most favored enhanced oil recovery methods. This popularity is based on the current low gas prices and environmental benefits by injected harmful gases, like CO₂, into reservoirs; plus gas injection has the further advantages of reducing oil viscosity, swelling the oil, and most importantly achieving miscibility by exchanging components with the reservoir oil.

The use of hydrocarbon gases for miscible displacements is becoming more and more attractive for ease of handling, availability, and economic value. Methane is the most commonly used gas in displacements. Nevertheless, miscibility conditions for methane are difficult to meet in most reservoirs. Therefore, there is a need to add intermediate components to achieve miscibility at reservoir conditions at a practical injection pressure.

Currently in the United States, excess quantities of ethane, even more than pipeline limits, are being produced from shale formations. Excess ethane can be mixed with natural gas to miscibly displace more oil from the formation. The required ethane mole percentage is called the minimum miscibility enrichment (MME). This minimum miscibility enrichment and the minimum miscibility pressure (MMP) are among the most critical parameters in any miscible displacement project.

Several experimental and computational methods have been proposed to determine the minimum miscibility conditions. Some of these methods have been used by several authors to build minimum miscibility pressure correlations or minimum miscibility enrichment correlations that work as a quick mean for determining the miscibility condition.

This thesis builds ethane minimum miscibility enrichment correlations based on compositional simulation results. The correlations provide a fast way to determine the estimated conditions for miscible displacement. Moreover, the thesis presents some applications for using the developed correlations in shale reservoirs. A shale reservoir undergoes miscible displacement using a mixture of methane and ethane. The cost of the displacement is reduced by using the minimum ethane mole percentage that can yield a miscible displacement based on the correlations.

1.1 MOTIVATION

With shale production booming in the United States, it is crucial to remember that not only methane and heavier NGLs, such as propane and butane, come out of the ground. A significant amount of ethane, too, is being produced from those fractured wells.

According to US Energy Information Administration (EIA), Figure 1, ethane production jumped from around 750 Mbbbl/d to more than 1100 Mbbbl/d in the past 3 years. The common practice is that ethane is separated from the methane and used for petrochemicals or converted into ethylene and polyethylene (e.g. household plastics).

Yet the abundance of ethane has reached a point at which the gas is now more profitable left in the natural gas stream than recovered for use as a petrochemical. The practice of leaving ethane in the gas stream is what is known today as ethane rejection. Ethane rejection stems from several factors. First is ethane's current low profit. Ethane spot prices have prompted gas processors to leave ethane within the natural gas stream in large volumes instead of processing it. Additionally, most of ethane processing plants are located in the US Gulf Coast region, far from major ethane producers like Marcellus,

which implies significant transport cost. Another factor is the market oversupply and limited demand by natural gas processors in recent years. Nevertheless, with ethane rejection being a temporary economic solution to the excess ethane production, the heat content of the gas in pipelines should not exceed the regulated limits. There is a maximum allowable value for ethane in the pipelines. For example, Texas Eastern Transmission BTU content was running as high as 1,070 versus 1,100 limit in 2013 (Bridges, 2013).

Both the ethane rejection and pipeline limits raise the question of what we can do to find a solution to this excess ethane. There are several possible economical solutions for the increasing ethane production. Apparently there will be many opportunities in the future to take advantage of excess ethane production, especially for petrochemicals companies, once the appropriate infrastructure for it has been built. In the meantime, ethane can be used as an EOR solvent to displace oil from reservoirs. Thus this study will investigate the possibility of using ethane as an enriching gas in miscible gas injection projects in unconventional reservoirs. To determine the feasibility of this use, we will first build minimum enrichment correlations using compositional simulation for a range of pressures and temperatures. Then we will use ethane with methane in a typical shale reservoir to assess the value of using it as an enriching solvent to produce more oil.

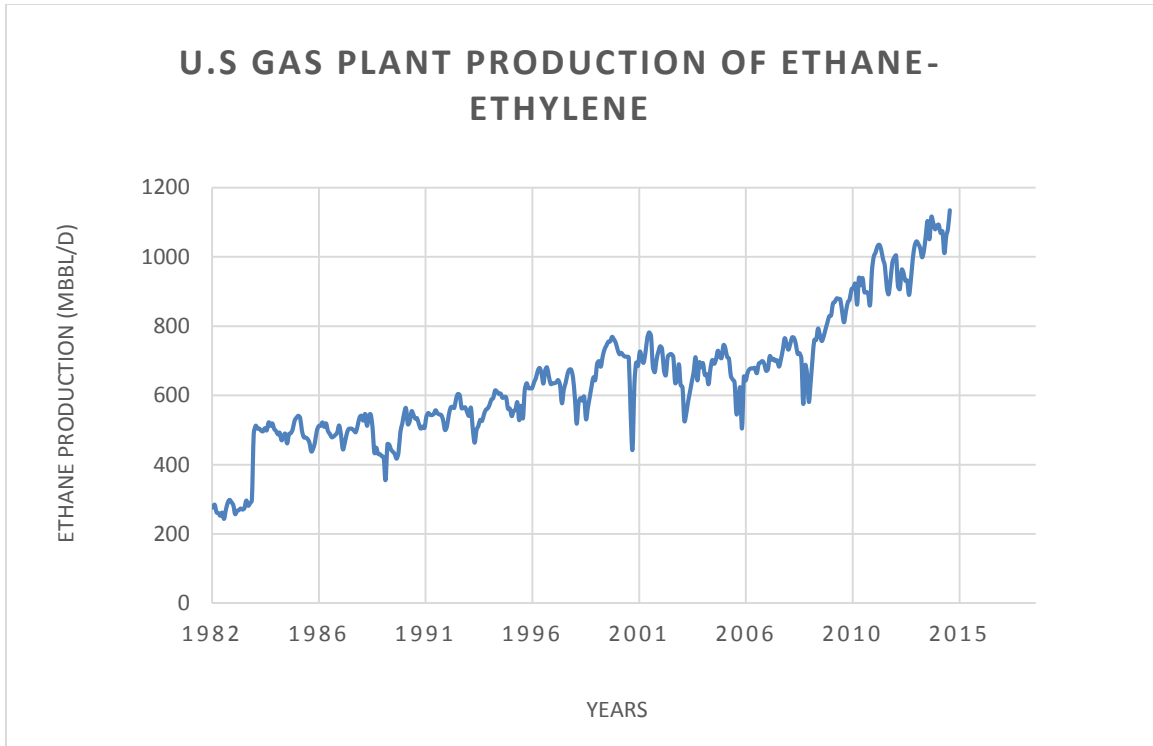


Figure 1: Ethane Monthly Production in Thousand Barrels per Day (U.S Energy Information Administration)

1.2 REVIEW OF CHAPTERS

This thesis is divided into 7 small chapters. Chapter 2 includes extensive background information about solvent flooding, miscibility conditions, minimum miscibility enrichment, and minimum miscibility pressure correlations. Chapter 3 presents information about the building blocks of the simulation model that is being used to study the minimum miscibility conditions and to construct the minimum miscibility enrichment correlations. Chapter 4 explains the method for estimating the miscibility conditions and making correlations.

Chapter 5 contains the minimum miscibility enrichment correlations obtained at different pressures and temperatures for mixtures of ethane and pure methane. It also presents a validation of the resulting correlations with existing data. Chapter 6 shows how the correlations can be used in predicting the miscibility conditions in shale reservoirs and the effectiveness of using a mixture of methane and ethane as an EOR solvent. Chapter 7 summarizes the research findings and presents conclusions and recommendations.

Chapter 2: Background

2.1 SOLVENT FLOODING

Using solvent to recover additional oil from oil reservoirs is one of the earliest and widely used methods of enhanced oil recovery. In the early days, solvent was injected in small slugs only and later became less attractive because of increase in solvent prices. Later in the 1970s, interest in using solvents resurged because of the rise in oil prices (Lake, 1989). More recently, the availability of CO₂ and the need to mitigate CO₂ emissions have further sparked interest in gas flooding research, miscible gas injection in particular.

Several potential gases such as natural gases, alcohols, LPG, LNG, carbon dioxide, air, nitrogen and many others can be used in the recovery process. (Lake, 1989) Most of the miscible displacement projects, however, use readily available and inexpensive gases such as CO₂ and CH₄.

When solvent is mixed with oil in any proportions within the single fluid phase, the two fluids are miscible (Lake, 1989). But most solvents are only partially miscible with crude oil. Many researchers since the early 1960s have been studying the miscibility conditions for several common gases. Throughout the years several approaches including experimental methods, analytical models, and correlations have been proposed to determine the minimum miscibility pressure or minimum miscibility enrichment for gas injection. This chapter focuses on comparing the different approaches and identifying the strengths and weaknesses of the existing methods to propose a new, easy, and more accurate methane minimum miscibility enrichment correlation that can be used to screen potential solvent flooding projects and approximate the miscibility conditions.

2.2 MISCIBILITY MECHANISM

Miscibility at reservoir pressure and temperature is usually achieved by two mechanisms. The first mechanism is First Contact Miscibility. This mechanism is achieved when the injected solvent is completely miscible with the oil. In this case, the injected fluid will fully displace the reservoir fluid. A good example of a First Contact Miscible condition is propane or butane miscibility at reservoir conditions. The second mechanism is Multiple Contact Miscibility. It involves several mixing and displacing stages between the displacing fluid and the oil. CO₂ and ethane usually make multiple contacts at reservoir conditions. During the mass transfer between the injected fluid and the crude oil, miscibility can develop through a vaporizing process or a condensing process. Later, several authors such as Zick (1986) and Stalkup (1987) found that multiple contact miscibility can even include a combination of both processes. Zick explained that as the light intermediates, ethane to butane, condense from the injected solvent, the middle intermediates (butane to heptane) evaporate to the solvent. Johns et al. (1993) demonstrated this combined condensing vaporizing drive mathematically.

In the vaporizing process, intermediate components from the crude oil vaporize into the gas allowing it to become miscible with the displaced fluid. In the condensing process, the injected gas is enriched with intermediate molecular weight hydrocarbons. This enrichment continues until there is no interfacial tension between the phases and a single hydrocarbon phase is produced (injected fluid and reservoir oil becomes miscible). As mentioned earlier, miscibility can also develop through a combination of the vaporizing and condensing processes. Miscibility depends on the pressure, temperature, solvent purity, and molecular weight of the heavy fraction of the reservoir fluid (Lake, 1989). The pressure at which the injected solvent and the crude oil are miscible with each other is called the minimum miscibility pressure, and the intermediates mole percentage that must be added to the dry gas to develop miscibility is called the minimum miscibility enrichment (Lake, 1989).

2.3 MINIMUM MISCIBILITY PRESSURE AND MINIMUM MISCIBILITY ENRICHMENT DEFINITIONS

Minimum miscibility pressure can be defined generally as the pressure above which a further pressure increase causes only a minimal increase in the oil recovery. Several authors have defined minimum miscibility pressure more specifically in various ways. Most of the widely used definitions set the recovery level at a given amount of gas injection. For example, a commonly used standard injection pore volume is 1.2. Some authors use ultimate recovery or breakthrough to define minimum miscibility. Still others defined the minimum miscibility pressure as the pressure above which oil recovery did not increase more than 1% per 100 psi pressure increase (Elsharkawy et al., 1992). Fixed recovery levels that range from 90 to 94 or 95 have been also used to define minimum miscibility (Emanuel et al, 1986). Other authors define minimum miscibility pressure at the bend in the recovery curve (Emanuel et al. 1986). Yellig and Metcalfe (1980) employed a definition based on maximum or near maximum recovery at 1.2 pore volume injected (PV). Holm and Josendal (1974) used a definition based on 94% recovery at gas breakthrough and at a gas oil ratio of 40,000 SCF/stb.

There is still no industry standard for defining the minimum miscibility pressure or minimum miscibility enrichment condition. Although the use of simulation can allow for any of the mentioned definition for minimum miscibility pressure/enrichment, for the purpose of this study minimum miscibility enrichment will be defined as the minimum intermediate concentration above which there is no major increase in oil recovery at 1.2 PV injected.

2.4 MINIMUM MISCIBILITY CONDITION ESTIMATION

2.4.1 Minimum Miscibility Experiments

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 (20 cm) 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 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 experiments are repeated over a range of pressures at a constant temperature to measure the minimum miscibility pressure. This experiment can be also used to determine the minimum miscibility enrichment by repeating the experiment for different injected gases at a constant pressure and temperature. Below the minimum miscibility condition, the gas bubble transfers to the oil phase, and will maintain its near spherical shape as it rises. But 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. This behavior suggests multiple contact miscibility. In the First

Contact Miscibility, the bubble disperses immediately upon contact with oil. This experiment allows the visual observation of miscibility and requires less than two hours to determine minimum miscibility condition. The experiment also requires minimum fluids to determine the minimum miscibility pressure or minimum miscibility enrichment.

Slimtube Experiment

The most common standard experimental technique for determining minimum miscibility conditions experimentally is using the slimtube experiment. A typical slimtube apparatus consists of a 6.3 mm OD stainless steel tube 40ft long and packed with 160-200 mesh sand (Yellig & Metcalfe, 1980). One end of the slimtube 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 slimtube 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 slimtube. 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). For minimum miscibility enrichment, the experiment is repeated for several enrichment levels at a constant pressure and temperature. 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 enrichment is the enrichment level or pressure in the case of MMP at which

the oil recovery is 90% or more or the pressure/concentration above which no significant recovery is achieved. The slimtube method is a valuable technique for determining minimum miscibility condition and offers the advantage of using real reservoir fluid. But 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.

2.4.2 Minimum Miscibility Conditions from Calculations and Computational Methods

Because of the disadvantages of experimental methods, many computational methods for estimating minimum miscibility condition from cubic equation of state have been developed over the years (Ahmadi and Johns, 2008). There are several methods for estimating minimum miscibility conditions computationally, some of these methods are: analytical calculations based on Method of Characteristics (MOC), the multicontact mixing cell method, and slimtube compositional simulations.

Minimum Miscibility Using Calculations Methods

Over the years, many researchers developed methods to estimate minimum miscibility condition using analytical models and calculations. Most of the early work is based on systems with three components. The minimum miscibility pressure is determined by finding the pressure at which the oil composition or the injected gas composition is located on the extension of a critical tie line (Wang & Orr, 1998). Benham et al. (1959), for example, used the critical tie line theory in a ternary diagram to estimate the minimum enrichment for a condensing gas drive. Later Kuo (1985) developed a

single mixing cell method based on the Peng-Robinson equation of state to determine minimum miscibility pressure in an enriched gas drive process as well. Nouar and Flock (1986) came up with a new approach to predict minimum miscibility pressure for a vaporizing gas drive based on the critical compositions and tie line slopes. They also proposed a way to handle a system with multiple components if the reservoir temperature and the oil compositions are known. Subsequent authors (Orr & Silva, 1987; Jensen & Michelsen, 1990; and Monroe et al. 1990), though, showed that using ternary diagrams and single cell methods could not predict an accurate minimum miscibility condition value for a multicomponent system. Wang and Orr (1998) proposed a new analytical approach to estimate minimum miscibility condition in a multicomponent system based on the theory of one-dimensional dispersion free flow. Although this method can be more accurate than the previous ones, it is also heavily dependent on accurate fluid characterization.

Minimum Miscibility from Mixing Cell Method

The basic concept in the mixing cell method is to mix oil and gas analytically to get a new equilibrium composition (Ahmadi & Johns, 2008). The method can predict the changes in composition in the transition zone between the injected gas and reservoir oil. In the vaporizing process or lean gas injection, the equilibrium gas is repeatedly mixed with the fresh oil, causing the equilibrium gas to move to the oil tie line that controls the miscibility. In the condensing gas drive, the gas tie line controls miscibility. Some authors over the years have developed several mixing cell methods to estimate minimum miscibility pressure.

Metcalf et al. (1973) developed a mixing cell computer program based on the Cook et al. gas cycling program. The model enables transferring excess oil and gas from cell to cell in a series of constant temperature constant pressure cells. The transferred gas to oil ratio is controlled by the mobility ratio. This mobility controlled calculation accounts for the reservoir processes more realistically. Metcalfe, though, stated that the model is limited to enriched gas drive and has not been tested for vaporizing gas drive operations. Jaubert et al. (1998) developed a similar model to Metcalfe's that can determine miscibility conditions for condensing, vaporizing, and the combined condensing vaporizing process. To address the dispersion issue in such methods, Jaubert et al. (1998) estimated the recovery factor at zero dispersion from a plot of recovery factor versus $1/\sqrt{N}$, where N is the number of cells. Minimum miscibility condition is then determined from a plot of the zero dispersion recovery at different pressures or enrichments. Later Ahmadi and Johns (2008) proposed a new continuing cell-to-cell contact method that can automatically solve the dispersion issue without the need for extrapolating the recovery at zero dispersion. Using such mixing cell methods can provide an accurate and quick estimate of MMP/MME, but the method relies significantly on accurate fluid characterization by an equation of state (EOS).

Minimum Miscibility from Compositional Simulation

Another approach to determine minimum miscibility condition is using one-dimensional compositional simulation. In contrast to the mixing cell model, the simulation approach can better mimic fluid flow in porous media. In the simulation process, oil is displaced by gas at different pressures. A plot of the recovery factor at different pressures is then used to determine minimum miscibility pressure. To determine

minimum miscibility enrichment, the model can be used to displace oil by different gases at a constant pressure and temperature. Zick (1986) showed that determining minimum miscibility condition from slimtube simulations requires more work to reduce the numerical dispersion effect and it can be time-consuming. However, Stalkup (1987) demonstrated that the simulation has to be performed at fine grid size to reduce the truncation error caused by the numerical dispersion. Our work is primarily based on the compositional simulation approach. In this approach, one-dimensional reservoir simulations are used to determine the minimum miscibility enrichment for oil displacement by a methane-rich gas.

2.5 MINIMUM MISCIBILITY CORRELATIONS

2.5.1 Minimum Miscibility Pressure Correlations

Minimum miscibility pressure correlations are inexpensive, easy-to-use tools that can provide a quick estimate of the miscibility conditions. With minimum parameters, they can be used for screening potential gas injection reservoirs. Although there is a significant interest in miscible displacement of oil by light hydrocarbons, the literature contains limited minimum miscibility pressure correlations that can be used for hydrocarbon gas injection. Rutherford (1962) used a high-pressure sand pack experiment to develop a correlation for miscibility in the displacement of oil by light hydrocarbons. West Texas oils were displaced by a dry gas and ethane and by a dry gas and propane. The results showed that miscibility is a function of the pseudocritical temperature of the injected gas. However, his work is based on one temperature and one pressure and was done on West Texas oil. Thus his correlation has limited applications. Firoozabadi and Aziz (1986) developed a general correlation for approximating minimum miscibility

pressure in lean gas and N₂ injection based on experimental data and simulation runs. The correlation suggests that minimum miscibility pressure in such projects depends on the amount of intermediates and the volatility of the reservoir fluid and to a lesser extent on the temperature. Their correlation is also based on limited data and it only applies to lean gas injection (e.g., methane) or N₂. Thus such studies and several others are less accurate than the rest of the minimum miscibility pressure estimation methods and can only be used within a certain range of pressure and temperature or for a certain type of fluid.

2.5.2 Minimum Miscibility Enrichment Correlations

The literature reveals some enrichment correlations for both pure hydrocarbon gas injection and hydrocarbon gas with some impurities. Benham et al. (1959) developed one of the first correlations for predicting the conditions for a miscible displacement of reservoir fluid by a rich light hydrocarbon. The correlation is based upon the reservoir temperature and pressure, C₅+ molecular weight of the reservoir fluid, C₂+ molecular weight of the displacing fluid, and the mole percent methane in the displacing fluid. The minimum allowable methane in the displacing fluid is less for fluids with lower C₅+ molecular weight, temperature, and pressure. His method of miscibility estimation is based on the limiting tie line technique, and the correlation represents a first approximation of the limiting conditions for miscibility. According to Benham et al. (1959), the method should be used with caution, especially when injecting fluids that contain high ethane mole percentage.

One purpose of this research is to develop a minimum enrichment correlation similar to that presented by Benham et al. (1959). The new correlation, however, is based on a one-dimensional compositional simulation approach to determine minimum miscibility pressure. With advances in the computational power, the simulation block size is reduced to 0.05 ft. to minimize truncation error or numerical dispersion. The simulation approach accurately mimics the physical processes that happen in the reservoir or in slimtube experiments, and consequently produces more robust minimum enrichment correlations.

Chapter 3: Simulation Model

3.1 INTRODUCTION

To build robust miscibility enrichment correlations, one-dimensional simulation models were built using CMG GEM, a compositional simulator developed by the Computational Modeling Group. All models in this study were built with the same number of cells, initial conditions, PVT properties, and flow properties. However, well bottomhole pressure and injected fluid composition were varied to approximate the minimum miscibility enrichment at each injection pressure value. This chapter presents details of the building blocks of the one-dimensional compositional simulation model used in this study.

3.2 GRID SIZE SELECTION

Grid size selection is a significant parameter in miscible gas injection simulations since a large grid size can lead to a substantial error in the calculated recovery. Most of the reservoir simulators evaluate convective coefficients at the upstream gridblock (Stalkup, 1995). These coefficients are subject to large truncation errors called numerical dispersions. Numerical dispersion can lead to a considerable error in the estimated minimum miscibility pressure and misinterpretation of the physics of the displacement process. Stalkup (1987), for example, found that numerical dispersion is sensitive to gridblock size and decreases the recovery factor in slimtube enriched gas drive simulations. This numerical dispersion can be approximated by $\Delta x/2$, where Δx is the gridblock size (Lantz, 1971). In many simulators, unless a small gridblock size is used, the numerical dispersion is normally larger than the actual physical dispersion (Min et al., 1997).

In this study, the estimated minimum miscibility pressure from compositional simulations at different gridblock sizes was compared with the published minimum miscibility pressure from slimtube experiments described by Charles and Curtis (1995). Minimum miscibility pressure was used because of the limited availability of minimum miscibility enrichment experiments in the literature. Fluid E in Table 2 was used with different gridblock sizes. Since the same fluid was used in slimtube experiments, the size of the gridblock was optimized based on the agreement between the minimum miscibility pressure from published slimtube experimental data and the simulation minimum miscibility pressure value. The results showed that minimum miscibility pressure continued to change regardless of how small the gridblock size was. This result agrees with the findings by Stalkup (1990) that reducing the gridblock size does not make the oil recovery constant at a certain small gridblock. In our study, the numerical dispersion effect was reduced by using a very small gridblock size, $\Delta x=0.05$ ft. The 50 ft distance between the injector and producer was modeled with 1,000 cells (Figure 2). Using Lantz's (1971) one-dimensional quantitative expression for dispersion, this gridblock size allows the same degree of mixing as a physical dispersivity of 0.025 ft.

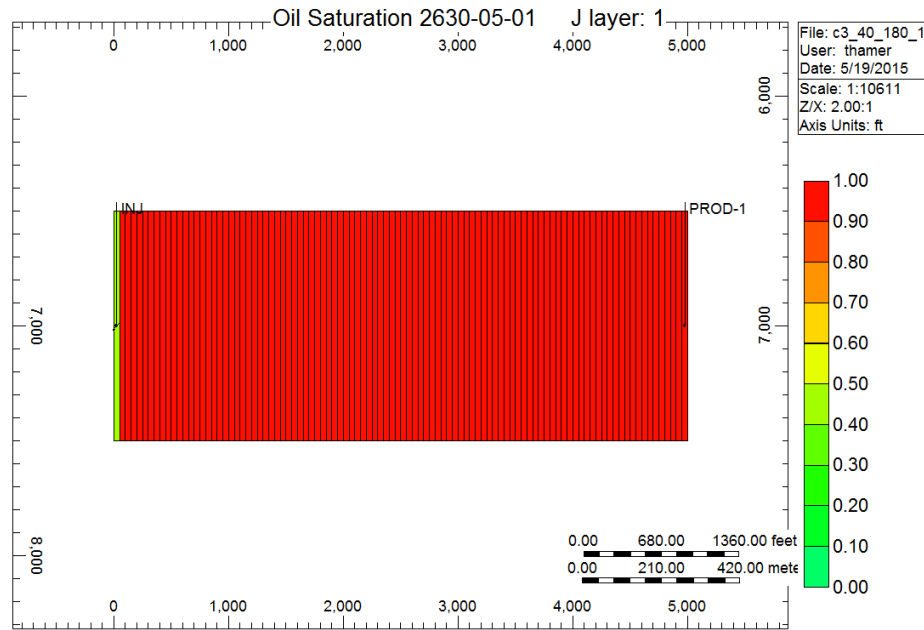


Figure 2: Simulation Model Configuration.

3.3 INITIAL CONDITIONS

The compositional simulation model was initialized with zero water saturation, to closely mimic the slimtube experiments, and with a constant pressure. The initial pressure was kept constant at a datum depth of 6505 ft in each run, but varied from 1,500 psi to 4,000 psi depending on the case being simulated. The oil in the reservoir is undersaturated with a bubble point pressure of 1,000 psi. Since we are simulating a one-dimensional slimtube, no aquifer was attached to the reservoir.

Five reservoir fluids were selected for a study of miscible displacement of reservoir fluid by a mixture of ethane and methane. Table 1 contains detailed composition of fluids A, B, C, and D used in the study to build the correlations. Properties of Fluids A, B, C, and D are taken from Benham et al., (1959). Properties of Fluid E in Table 2 come from Charles and Curtis (1995) in which some slimtube experiments data are available.

Fluid E is used in the grid size selection process in which the minimum miscibility pressure value from the simulation model is compared to slimtube data as mentioned in the grid size selection section.

Mole %	A	B	C	D
CH ₄	12.93	48.96	46.59	15.77
C ₂ H ₆	3.74	4.18	9.72	1.54
C ₃ H ₈	7.04	1.98	6.46	2.20
C ₄ H ₁₀	8.68	1.36	3.92	4.79
C ₅ H ₁₂	7.01	1.40	2.21	4.36
C ₆ H ₁₄	6.72	1.36	4.77	4.73
C ₇ +	53.88	40.76	26.33	66.61
MWC ₅ + (g/mol)	182.6	202.6	221.6	241

Table 1: Fluid Composition of Fluids A, B, C, and D (Benham et al, 1959).

Fluid E					
Component	Mole%	Component	Mole %	Component	Mole %
N ₂	0.7	IC ₄	2.1	C7+ (1)	9.6
CO ₂	0.60	C ₄	3.9	C7+ (2)	9.9
C ₁	33.4	IC ₅	2.0	C7+ (3)	8.7
C ₂	5.0	C ₅	2.8	C7+ (4)	6.8
C ₃	5.5	C ₆	4.4	C7+ (5)	4.6
MWC ₅ + = 189 g/mol					

Table 2: Fluid Composition of Fluid E (Charles & Curtis, 1995).

3.4 PVT PROPERTIES

The phase behavior of the reservoir oil under different conditions was simulated using the Peng-Robinson equation of state. Despite the fact that the minimum miscibility pressure or minimum miscibility enrichment estimation is sensitive to critical properties, the original paper by Benham et al. (1959) does not contain detailed critical properties of the fluids. Therefore, the critical properties in Table 3 are based on the CMG simulator. However, the critical properties of the C₇₊ were adjusted slightly for each fluid to match the value of the minimum miscibility enrichments published in Benham et al. (1959) for fluids A to D. The final components' properties and EOS parameters are shown in Table 3.

	Mol. Weight	Critical	Critical	Acentric	Critical Z-	Specific	Vol.Trans.	Omega	Omega
	g/mol	Temp K	Pressure psi	Factor	Factor	Gravity	Shift	A	B
C ₁	16.04	190.56	45.44	0.0080	0.3039	0.3300	-0.0833	1.0	1.0
C ₂	30.07	305.44	48.163	0.0908	0.2898	0.4500	-0.0927	1.0	1.0
C ₃	44.10	369.83	41.937	0.1520	0.2824	0.5077	-0.1	1.0	1.0
C ₄	58.12	425.17	37.47	0.1928	0.2738	0.5844	-0.12	1.0	1.0
C ₅	72.15	469.67	33.25	0.2510	0.2659	0.6310	-0.0933	1.0	1.0
C ₆	86.18	507.44	29.73	0.2957	0.2708	0.6640	0.0223	1.0	1.0
*C ₇₊		594.91	24.07	0.5764	0.2697	0.7385	0.0940	1.0	1.0
* C ₇₊ Molecular Weight for fluids A, B, C and D are: 209, 211, 258.7 and 263 respectively.									

Table 3: Critical Properties of Fluids A to D.

The hydrocarbon-hydrocarbon interaction coefficients for fluids A-E were calculated using the built in equation in the CMG simulator:

$$BIN_{ij} = 1 - \left| \frac{2 * \sqrt{VC3_i \times VC3_j}}{VC3_{il} + VC3_j} \right|^{PVC3}$$

Where;

BIN_{ij} = The Binary interaction coefficient between component i and j.

$$VC3_i = \text{Critical Volume of Component } i \times \frac{1}{3}$$

$$VC3_j = \text{Critical Volume of Component } j \times \frac{1}{3}$$

The binary interaction coefficients based on a PVC3 value of 1.2 are shown in Table 4. The interaction coefficient between C_1 and C_{7+} was modified slightly to match the minimum miscibility enrichment data published in the original paper by Benham et al. (1959) before the attempt to use the fluids in building the correlations.

	C_1	C_2	C_3	C_4	C_5	C_6
C_2	0.0026890					
C_3	0.0085370	0.00166249				
C_4	0.01474853	0.00491433	0.00086625			
C_5	0.02064084	0.00857793	0.00271213	0.00051467		
C_6	0.02832972	0.01384239	0.00597800	0.00230522	0.0006430	
C_{7+}	0.04949049	0.02990602	0.01775777	0.01087902	0.00669807	0.00320585

Table 4: Binary Interaction Coefficients of Fluids A, B, C, and D Based on a Binary Interaction Coefficient Parameter of 1.2

Moreover, the critical properties and binary interaction coefficients of fluid E are presented in Tables 5 and 6, respectively.

Component	Mol Weight	Critical Temp K	Critical Pressure psi	Acentric Factor	Critical Z-Factor	Specific Gravity	Vol.Trans. Shift	Omega A	Omega B
N ₂	28.01	126.28	33.546	0.0450	0.2916	0.4700	-0.19300	1.0	1.0
CO ₂	44.01	304.22	72.850	0.2310	0.2742	0.5072	-0.08200	1.0	1.0
C ₁	16.04	190.56	45.440	0.0115	0.3039	0.3300	-0.16220	0.9927	1.0104
C ₂	30.07	305.44	48.163	0.0908	0.2898	0.4500	-0.11373	1.0	1.0
C ₃	44.10	369.83	41.937	0.1454	0.2824	0.5077	-0.09094	1.0	1.0
IC ₄	58.12	408.17	36.00	0.1756	0.2826	0.5631	-0.08898	1.0	1.0
C ₄	58.12	425.17	37.47	0.1928	0.2738	0.5844	-0.07186	1.0	1.0
IC ₅	72.15	460.44	33.37	0.2273	0.2701	0.6247	-0.06583	1.0	1.0
C ₅	72.15	469.67	33.25	0.2510	0.2659	0.6310	-0.04373	1.0	1.0
C ₆	86.18	507.44	29.73	0.2957	0.2708	0.6640	-0.01259	1.0	1.0
C7+ (1)	106.04	570.06	27.83	0.3201	0.2697	0.7385	0.04289	0.99992	1.00350
C7+ (2)	138.92	633.94	24.01	0.4007	0.2624	0.7860	0.05721	0.99984	1.00464
C7+ (3)	201.35	722.56	18.67	0.5600	0.2801	0.8354	0.09615	0.99984	1.00574
C7+ (4)	301.14	817.28	14.05	0.7825	0.2655	0.8814	0.12086	0.99975	1.01306
C7+ (5)	460.00	914.28	10.76	1.0468	0.2440	0.9268	0.10953	0.99975	1.01306

Table 5: Critical Properties of Fluid E (Charles & Curtis, 1995).

Binary Interaction Coefficients									
Component Name	N ₂	CO ₂	C ₁	C ₂	C ₃	IC ₄	C ₄	IC ₅	C6-C7+ (4)
CO ₂	0								
C ₁	0.0250	0.1050							
C ₂	0.0100	0.1300	0.0						
C ₃	0.0900	0.1250	0.0	0.0					
IC ₄	0.0950	0.1200	0.0	0.0	0.0				
C ₄	0.0950	0.1150	0.0	0.0	0.0	0.0			
IC ₅	0.1000	0.1150	0.0	0.0	0.0	0.0	0.0		
C ₅	0.1100	0.1150	0.0	0.0	0.0	0.0	0.0	0.0	
C ₆	0.1100	0.1150	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C7+ (1)	0.1100	0.1150	0.02016	0.0	0.0	0.0	0.0	0.0	0.0
C7+ (2)	0.1100	0.1150	0.02626	0.0	0.0	0.0	0.0	0.0	0.0
C7+ (3)	0.1100	0.1150	0.03536	0.0	0.0	0.0	0.0	0.0	0.0
C7+ (4)	0.1100	0.1150	0.04566	0.0	0.0	0.0	0.0	0.0	0.0
C7+ (5)	0.1100	0.1150	0.05638	0.0	0.0	0.0	0.0	0.0	0.0

Table 6: Binary Interaction Coefficients of Fluids E (Charles & Curtis, 1995).

3.5 POROSITY AND PERMEABILITY

For the purpose of simulating slimtube experiments, the porosity and permeability of the simulation model were homogenous and isotropic. The porosity value is set to 25%. To minimize the differential pressure between the producer and injector, the

simulation model is assigned a permeability value of 3 Darcy. This value allows the pressure in the simulation model to be the same everywhere in the model. There is a difference of approximately 10-20 psi between the pressure at the injector and the pressure at the producer, but the overall pressure is maintained constant throughout the simulation duration.

3.6 RELATIVE PERMEABILITY

Relative permeability curves are one of the most important parameters for a reservoir simulator in predicting reservoir performance throughout the life of a reservoir. A study by Li et al. (2014) showed that relative permeability data obtained from conventional experiments may lead to inaccurate predictions of miscibility conditions. The study demonstrated that conventional relative permeability experiments typically use short cores, which can hardly display miscible flooding features because of early gas breakthrough and the insufficient contact time.

In our study, however, we are using relative permeability data from a conventional relative permeability experiment. Some sensitivities studies have been conducted though to confirm the effect of relative permeability curves on the predicted miscibility conditions. Two different relative permeability curves were used to simulate the miscible displacement process. The results in Figure 3 demonstrated that the relative permeability curves may have some impact on the recovery factor during an immiscible displacement. Nevertheless, using different relative permeability curves in the first contact miscible displacement, which is what we study here, shows no difference in the overall recovery factor as shown in Figure 4.

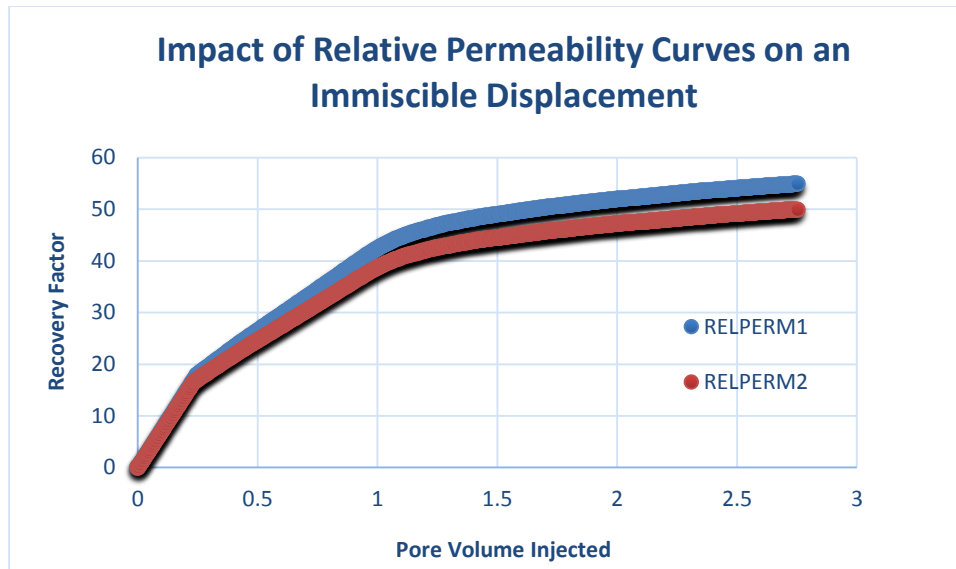


Figure 3: The Impact of Changing Relative Permeability Curves on Near Miscible Displacement.

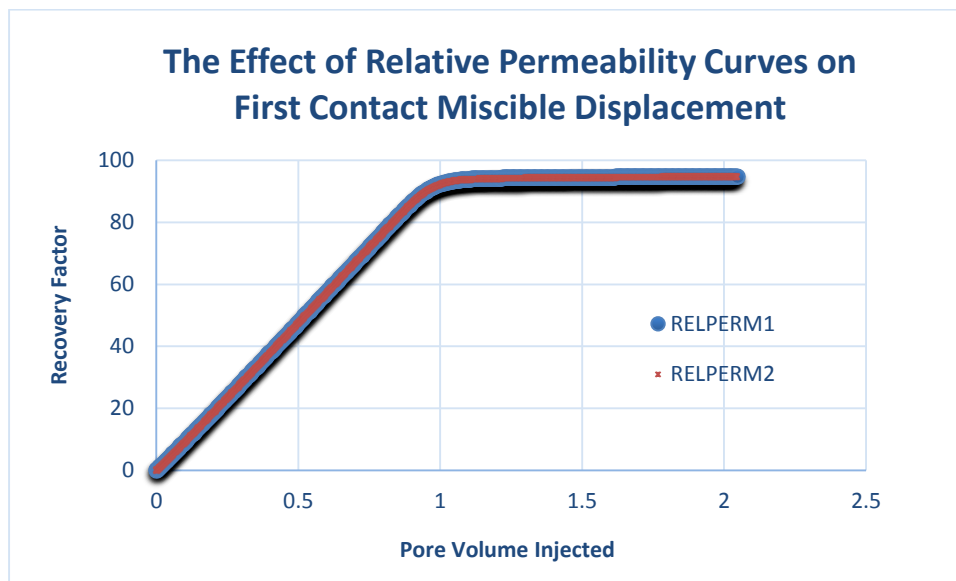


Figure 4: The Effect of Changing Relative Permeability Curves on First Contact Miscible Displacement.

3.7 WELLS AND CONSTRAINTS

To accurately simulate the slimtube miscible gas injection process, two vertical wells are placed at each end of the one-dimensional compositional simulation model. The bottomhole pressure of the producer and the injection were set to be equal in every case. With the high permeability value, this is necessary to accurately determine the minimum miscibility conditions. The wells were perforated across the whole layer in the z direction. Both the producer and the injector were placed on stream from the simulation start time.

The injector has no rate constraints as long as the pressure is equal to or slightly above the pressure at the producer. Similarly, the producer has no rate control assigned and it is controlled by the bottomhole pressure. The well will only stop if the oil rate drops to zero bbl/day.

Chapter 4: Method of Investigation

Reservoir simulation is considered one of the most accurate non-experimental methods in estimating minimum miscibility conditions for two fluids. Such simulation has the advantage over many other methods of incorporating reservoir properties as well as fluid properties in all calculations. To build miscibility correlations, a total of more than 1300 simulation models were performed using a CMG compositional reservoir simulator (GEM). Simulation models were made for each fluid covering a range of temperatures and injection pressures. The selection of pressure and temperature range depends purely on the common values encountered in most of the fields. This section presents a step-by-step explanation of the approach used to create minimum enrichment correlations using compositional reservoir simulation.

To determine the minimum ethane required to achieve miscibility for each fluid at a certain injection pressure and reservoir temperature, simulations were conducted using the same grid block size and same reservoir properties for a range of injection gas enrichments. For a single temperature value, the pressure was varied from 1,500 to 4,000 psi at an increment of 500 psi. Both the value of the reservoir pressure and the injection pressure were changed at the same time and assigned the same value. Pressure was always kept above the bubble point pressure. Under each pressure value the ethane mole percentage in the injection gas stream was increased at 10% increments from 0% (pure methane) to 100% (pure ethane). The incremental value was set to be smaller than 10% in many cases whenever there was not enough resolution to discern the minimum miscibility enrichment. The main objective here is to limit the volume of enriching gas while maintaining miscibility. As mentioned earlier, the minimum miscibility enrichment was defined as the maximum recovery at 1.2 PV injected. The PV value is calculated by

dividing the injected gas volume, at reservoir conditions, by the total PV of the reservoir (not the hydrocarbon PV). The oil recovery percentage at 1.2 PV injected is plotted for each ethane concentration value for one temperature value and one pressure value as can be seen in Figure 5.

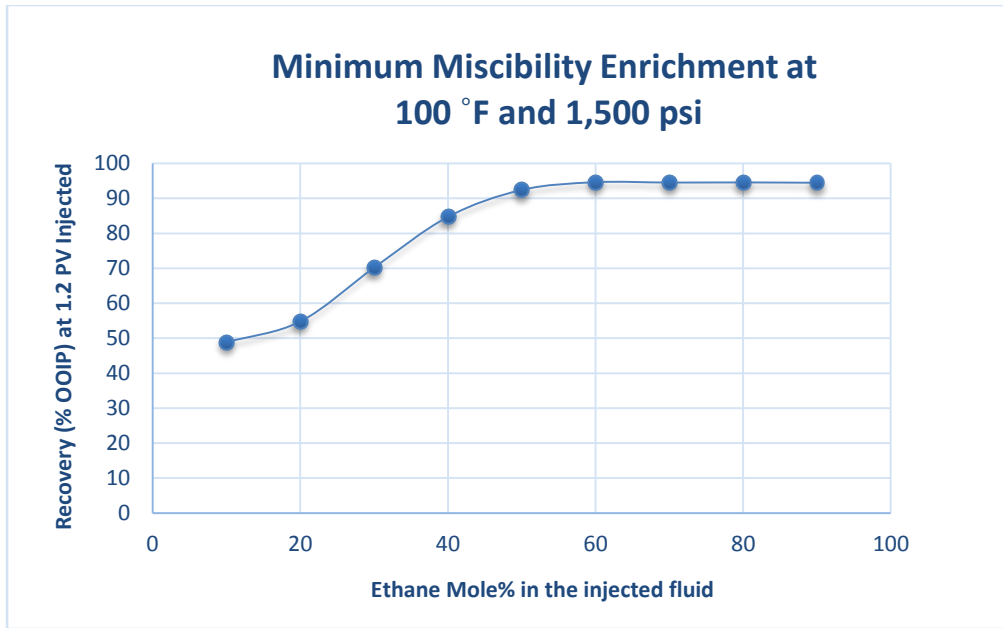


Figure 5: Recovery Percentage at 1.2 PV Injected Is Plotted For Each Ethane Mole Percentage.

To determine the minimum miscibility enrichment value for this temperature and pressure, for instance, we identified the concentration above which there is no significant increase in the oil recovery at 1.2 PV injected. In the example in Figure 5, the minimum enrichment value was taken to be 55 mole % of ethane in the injected fluid. At this point, the value for minimum miscibility enrichment is defined for a single temperature and injection pressure value. To build a correlation at a certain temperature, the values of the minimum miscibility enrichment at each pressure value are plotted as in Figure 6. Similar

to the previous case, the minimum ethane value that corresponds to the maximum recovery percentage is taken.

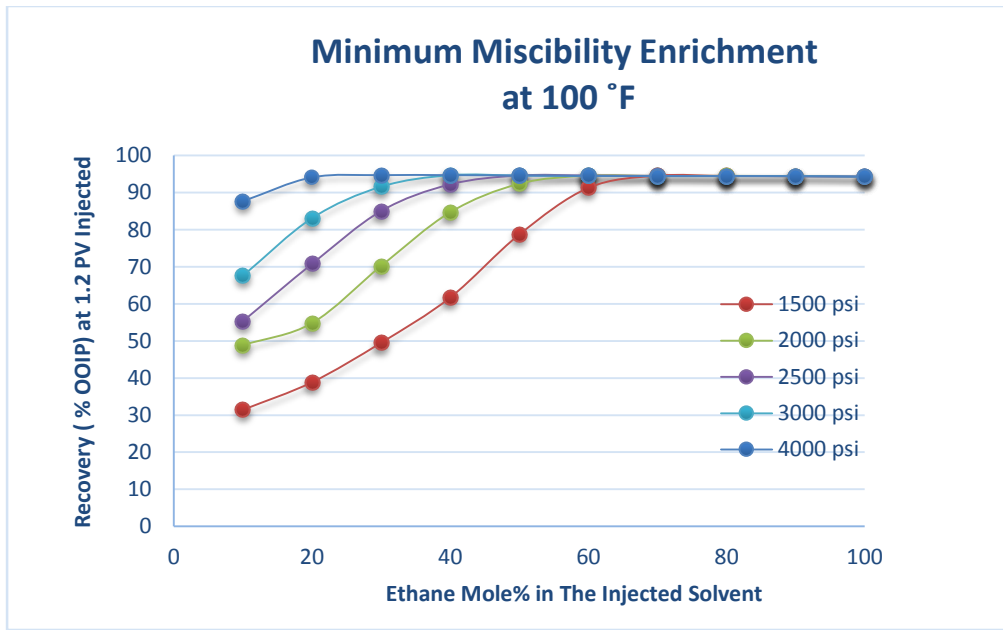


Figure 6: Fluid (A) Recovery Percentage at 1.2 PV Injected for a Pressure Range from 1,500 to 4,000 psi at 100 °F.

After approximating the minimum enrichment value at each pressure point, a correlation curve is plotted for the injection pressure with the minimum ethane required (Figure 7).

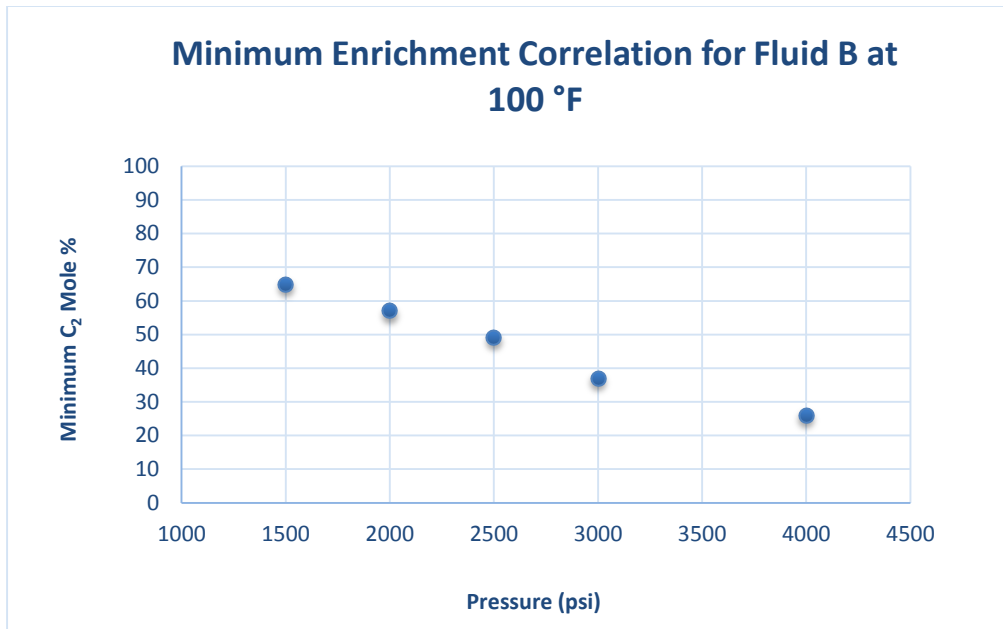


Figure 7: Fluid (A) Recovery Percentage at 1.2 PV Injected for a Pressure Range from 1,500 to 4,000 psi at 100 °F.

The main disadvantage of this method is the number of required computations. Specifically, each reservoir fluid requires more than 250 simulation runs to complete the correlations for five temperature values. Figure 7, for instance, required more than 50 simulation runs to get five points. More than 1300 simulation runs were used to build the correlations in this thesis. Each run takes about 30 minutes to complete.

Chapter 5: Correlations and Correlation Accuracy

5.1 CORRELATIONS

Based on more than 1300 simulation runs using a compositional simulator, correlations of the minimum miscibility enrichment are developed. The correlations in Figures 8-12 are expressed in field units covering a range of pressures from 1,500 to 4,000 psi and temperatures from 100 to 260 °F. Four fluids with C_5+ molecular weights of 182, 202, 221, and 241 g/mol are plotted together. The molecular weights of the C_5+ fraction of reservoir fluids were obtained by calculating a new mole fraction for each C_5+ component based on the total mole fraction of the C_5+ in the fluid. This new mole fraction of the individual components is then multiplied by its molecular weight. The reported molecular weight of the C_5+ is the sum of the individual molecular weight fractions. From the final correlations one observes that the minimum ethane enrichment required to achieve miscibility is a function of temperature, pressure, and the C_5+ molecular weight of the reservoir fluid.

Thus, according to the correlation, the minimum ethane percentage needed to mix with methane to achieve miscible displacement strongly depends on the injection pressure. A lower reservoir pressure requires more ethane to achieve miscibility at the same temperature. However, this minimum miscibility enrichment is not the same for all fluids. As seen in the correlations, fluids with higher C_5+ molecular weight require slightly more ethane than those with lower molecular weight. Notably, this difference in the minimum ethane required is less than 5 mole% between two fluids with a C_5+ molecular weight difference of 20. In addition, the difference is very small at higher pressures. Based on Figures 8-12, one sees that the miscibility curves are steeper for

higher temperatures. High temperature reservoirs require more ethane in the injected fluid to achieve miscibility. A fluid at 260 °F requires around 30% more ethane than a fluid at 100 °F. This difference is very likely because the two-phase envelope in a ternary diagram of a fluid increases at higher temperatures and lower pressures; consequently, more intermediates are required in the injected fluid to achieve miscibility.

To use these correlations for miscible conditions, the C_5+ molecular weight of the reservoir fluid has to be calculated as explained earlier. Using the reservoir temperature and injection pressure, the minimum ethane required can be determined from the correlation charts. For example, a reservoir fluid that is characterized by C_5+ molecular weight of 182, reservoir pressure of 2500 psi, and at 100 °F requires a minimum of 45 mole % ethane in the injected fluid to achieve miscibility.

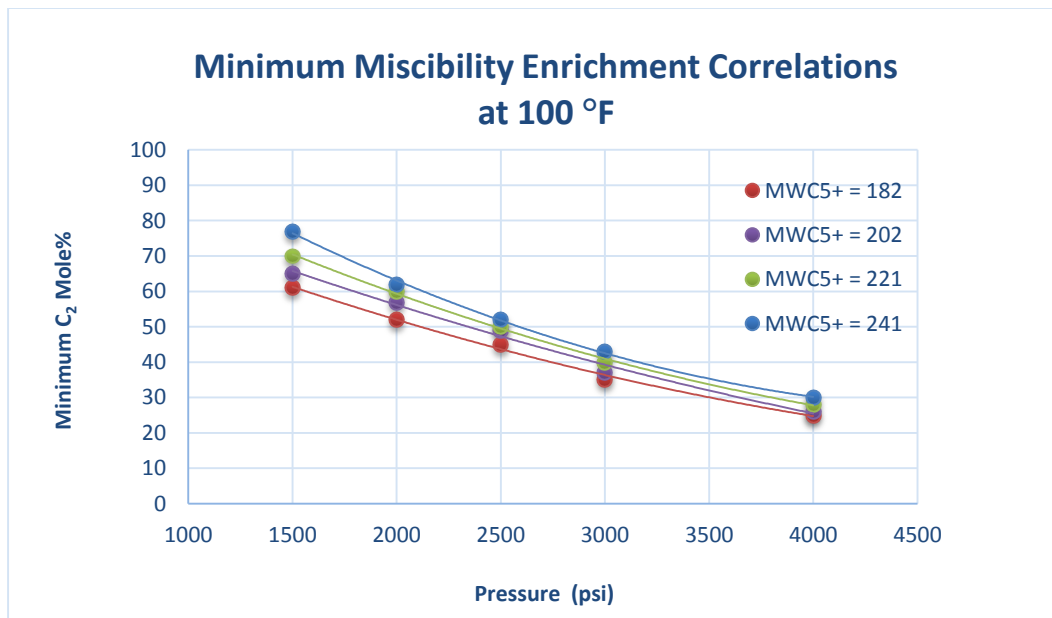


Figure 8: Minimum Enrichment Correlations at 100°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.

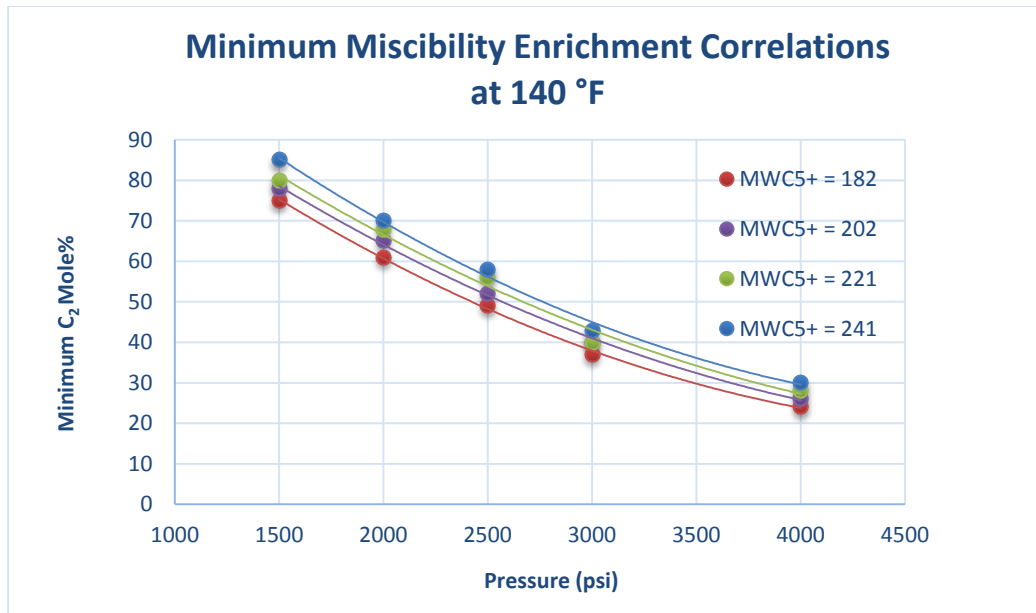


Figure 9: Minimum Enrichment Correlations at 140°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.

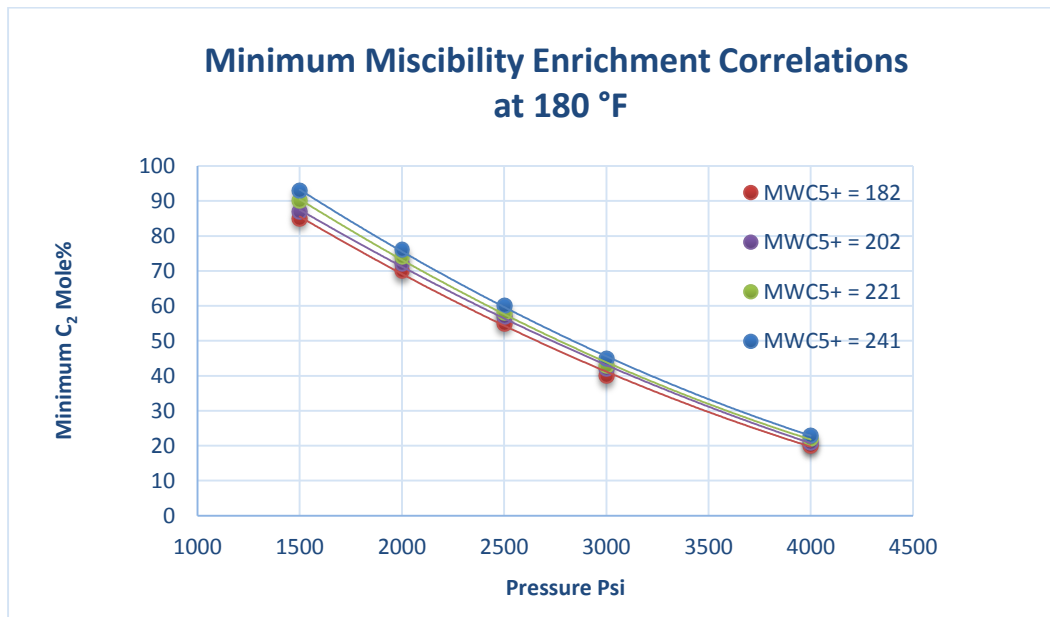


Figure 10: Minimum Enrichment Correlations at 180°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.

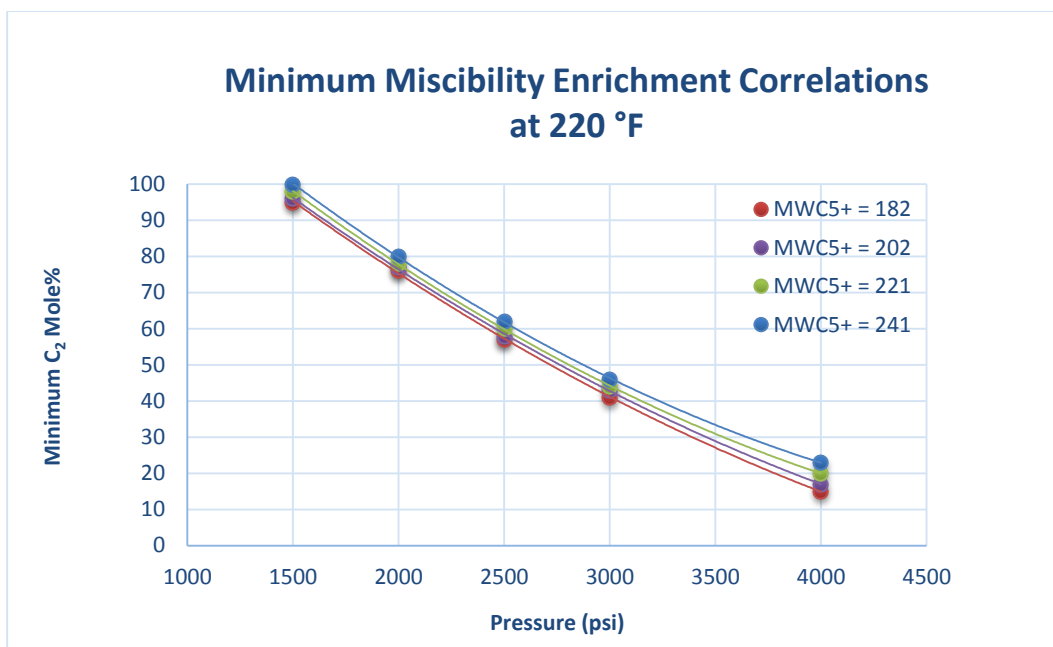


Figure 11: Minimum Enrichment Correlations at 220°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.

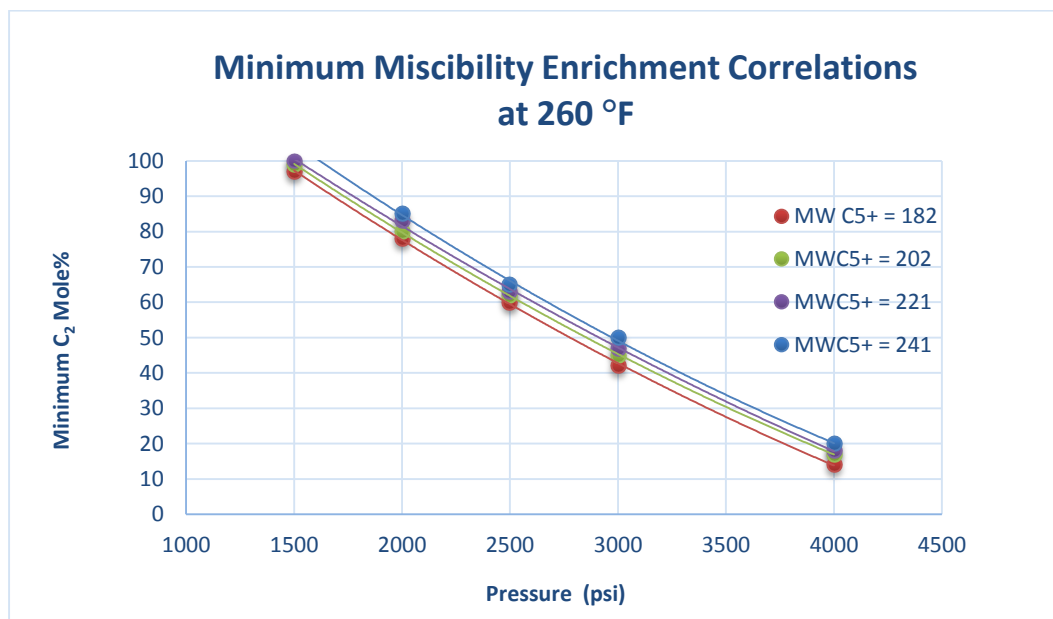


Figure 12: Minimum Enrichment Correlations at 260°F for a Reservoir Fluid Characterized by Molecular Weights of 182, 202, 221, and 241.

5.2 CORRELATIONS ACCURACY

Several experimental and analytical methods as well as published correlations can be used to estimate the miscibility conditions for a certain reservoir fluid that is being displaced by a solvent. A method by Ahmadi and Johns (2008) uses the mixing cell method to analytically find the minimum miscibility pressure. A PVT software was provided by Dr. Russell T. Johns that calculates the minimum miscibility pressure for a fluid and a solvent using composition of the fluids and critical properties. The software does not directly determine the minimum miscibility enrichment, but was used to match the minimum miscibility pressure and hence compare the solvent compositions. Additionally, Benham et al. (1959) contains minimum enrichment correlations (based on the ternary diagrams method) for the same displaced fluids used in this thesis. Despite the small difference in the C_2+ molecular weight, the injected fluid in Benham et al. (1959) is not pure ethane as is the case in our correlations.

The 25 numerically determined miscibility correlations of the four different fluids are compared with values predicted using the mixing cell method and Benham et al. (1959) correlations. The comparison shows the same trend with an algebraic difference of 5-10% in the predicted minimum enrichment value. This small deviation is likely because of the difference in the accuracy of the calculation methods. Figure 13 is a comparison chart showing the minimum miscibility enrichment predictions using the correlations, mixing cell method, and Benham's et al. (1959) correlation.

One of the most accurate and widely used methods in the industry to predict miscibility is the slimtube method. Published slimtube experimental data exists; however, it was difficult to compare the correlations to any of them because none of them have pure ethane injected or a solvent with C_2+ molecular weight close to 30. A slimtube experiment was done on a reservoir fluid in Safah Field (Charles & Curtis, 1995) with

C₅+ molecular weight of 189, temperature of 212 °F, and a solvent that contains 14 mole% intermediates (MW C₂+ is 36). The experimental results show that achieving miscibility at such conditions requires a pressure of around 5000 psi. Using the developed correlations at 220 °F and for a fluid that is characterized by C₅+ molecular weight of 182, the extrapolated predicted minimum miscibility is around 7-10 mole % ethane. Our prediction lies within a 10% difference from the Charles and Curtis (1995) experimental data. The comparison illustrates the reasonable accuracy of the prediction correlation compared to both analytical and experimental data.

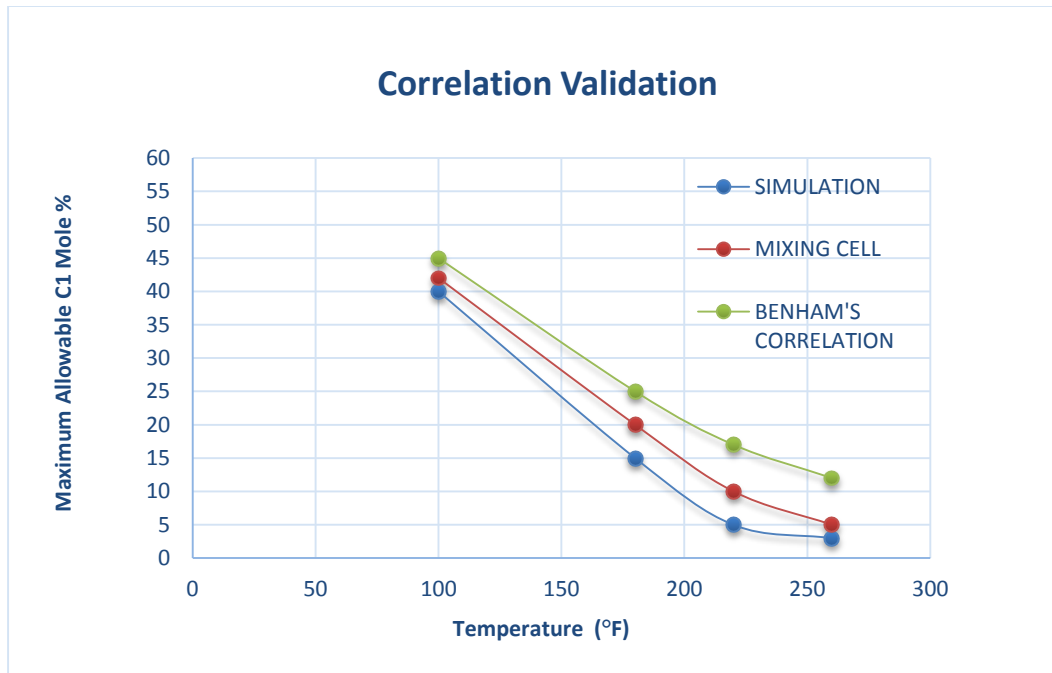


Figure 13: Minimum Enrichment Correlations Comparison at 1,500 psi.

5.3 SENSITIVITIES

Minimum miscibility predications using simulation show some sensitivity to changing the interaction coefficients. As mentioned in section 3.4, the interaction coefficients are calculated using the equation

$$BIN_{ij} = 1 - \left| \frac{2 \times \sqrt{VC3_i \times VC3_j}}{VC3_{il} + VC3_j} \right|^{PVC3}$$

The recovery factor at 1.2 PV injected varies with changing the exponent (PVC3) in the equation above. A value of zero for the exponent means no interaction between the different components. The higher the exponent value, the higher the value of the interaction coefficient--especially between the heavy and light components such as C_1 and C_{7+} . A typical value for the exponent is 1.2. Changing the exponent from 0 to 1 reduces the recovery factor by more than 5% as can be seen in Figure 14.

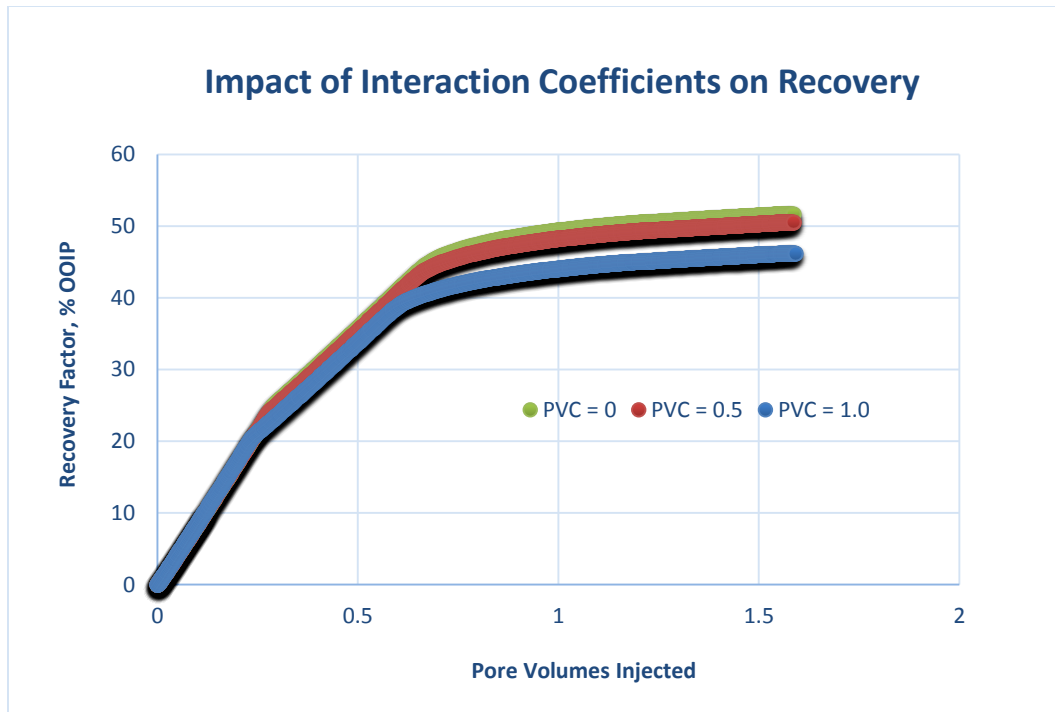


Figure 14: Impact of Changing Interaction Coefficients on Recovery.

Chapter 6: Applications of Miscible Ethane Injection to Oil Shale Reservoirs

6.1 INTRODUCTION

Improving the recovery of oil from unconventional reservoirs has gained great attention in recent years. Currently, the most widely used economical technique to produce unconventional reservoir oil is through primary recovery using a combination of horizontal drilling technology and hydraulic fracturing. Productivity in such reservoirs depends significantly on the size and the number of the fractures and the stimulated volume. However, the ultimate recovery factor from primary production is only a few percent. Numerous studies such as Taw et al. (2013), Cuiyu and Hoffman (2013), Gamadi et al. (2013), and Hoteit and Firoozabadi (2009) have been conducted to evaluate gas injection or cyclic gas injection as a potential EOR method. Results showed that implementing cyclic gas injection can increase the oil recovery by more than 15% (Tao et al., 2015). In this chapter, we will evaluate the impact of using miscible gas injection to recover additional oil from shale reservoirs.

Ethane will be the primary enriching gas in this study. Ethane minimum enrichment correlations will be used to determine the minimum required mole% of ethane to efficiently produce more oil. The recovery factor will be compared to water alternating gas, immiscible gas injection, and water injection performances. In addition, studies will be done to optimize several parameters such as the spacing between the producer and injector, the fracture spacing, fracture conductivity, and injector location that may have significant impact on recovery. The concept of stimulated reservoir volume (SRV) is not being used in the analysis of different parameters performances.

6.2 SIMULATION MODEL

To study the impact of miscible gas injection on oil recovery from a shale reservoir, a compositional simulation study was completed using a CMG GEM compositional simulator. A shale reservoir with 826 acres was simulated using a simple three-dimensional model. The model dimensions are 6000 ft long, 6000 ft wide and 200 ft thick with a total of 12500 cells. Two adjacent horizontal wells, forming a producer and injector, are simulated. The distances between the wells are 120, 240, 360, and 600 ft depending on the run. Each well has multiple, evenly spaced hydraulic fractures with 120, 360, and 500 ft spacing. The fractures' half-length was set at 180 ft. A zoomed in map view of the well configuration is in Figure 15. The cell size is 120 ft in the x and y directions with local grid refinement between the wells (shaded area). This single porosity, single permeability reservoir model is assumed to be homogenous and isotropic with a porosity of 7% and a permeability of 0.1 millidarcy (md). In another case, the reservoir permeability is set to 0.001 millidarcy. The fracture permeability is 100 md. A detailed reservoir fluid composition is listed in Table 7.

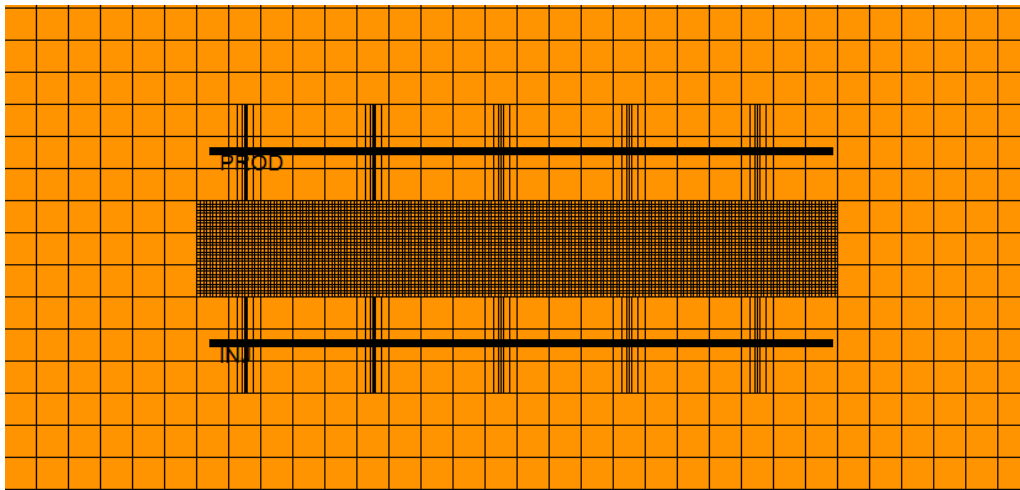


Figure 15: Zoomed in Map View of Producer and Injector Configuration.

Component	Mole %	Component	Mole %
N ₂	0.04	C ₃ -NC ₄	16
CO ₂	0.02	IC ₅ -C ₇	20
CH ₄	25	C ₈ -C ₉	13
C ₂	6	C ₁₀ +	19.94

Table 7: Fluid Composition of a Shale Reservoir Being Used in the Simulation Study.

The producer is subjected to a minimum bottomhole pressure constraint of 500 psi, slightly above the bubble point pressure. The injection pressure is kept at 1,000 psi above the initial reservoir pressure. In the case of miscible displacement, the injection pressure is maintained above the minimum miscibility pressure required to achieve developed miscibility between the injected solvent and the reservoir fluid. The injector is simulated with a maximum bottomhole pressure of 9000 psi. Table 8 summarizes the reservoir parameters for the base case.

Reservoir Length, ft	6000	Lateral Length, ft	2000
Reservoir Width, ft	6000	Fracture Half-Length, ft	180
Reservoir Thickness, ft	200	Injector-Producer Spacing, ft	360
Porosity, %	7	Reservoir Pressure, psi	8000
Matrix Permeability, md	0.1	Injection Pressure, psi	9000
Fracture Permeability, md	100	Bottomhole Pressure, psi	500
Initial Oil and Water Saturations, %	75% and 25%	$K_{rw} @ S_{or}$ $K_{ro} @ S_{wi}$	0.66 1

Table 8: Summary of Reservoir Parameters for the Base Case.

In this simulation model, local grid refinement (LGR) with equal spacing is used to accurately model the injected fluid flow from the tight matrix to fractures because of the high permeability contrast between fracture and matrix. LGR is also important for accurately capturing the changes of pressure and saturation between the producer and injector. It is considered that gas flows to the wellbore with non-Darcy effect. However, the non-Darcy effect is only applied to cells with 100% gas saturation.

6.3 FLOODING SCENARIOS

6.3.1 Immiscible Gas Flooding

In most oil reservoirs, a considerable amount of methane is produced. Most of this gas is flared or burned as a fuel. It is possible to use methane as an EOR solvent. But pure methane is a poor option, especially in a hydraulically fractured reservoir where gas breakthrough is strongly possible. Therefore, it is necessary to mix it with some intermediate components to achieve a miscible or near miscible condition.

Using a GEM compositional simulator, methane is injected into the reservoir at a near miscible condition to evaluate the chance of using it to improve oil recovery from a shale reservoir with 0.1 md permeability. Although methane injection provided substantial pressure support and extra recovery (especially in the early stages between 0 to 10 years of injection), results in Figure 16 demonstrate that immiscible gas injection leads to less oil recovery over 30 years when compared to the primary recovery case. This is likely because of early gas breakthrough in the producer well (Figure 17). Furthermore, the increase in gas saturation in the area causes the relative permeability to oil to be close to zero. This small relative permeability to oil can explain the plateau of production after approximately 10 years of immiscible gas injection. Despite the lack of

pressure support, the primary recovery case in Figure 16 still shows better recovery efficiency than the immiscible injection case at the end of 30 years of production.

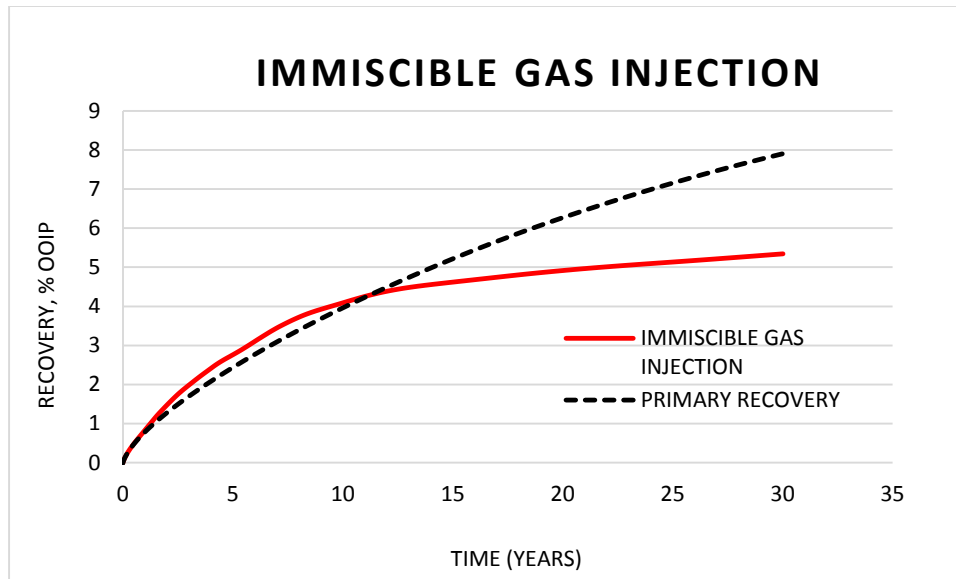


Figure 16: Immiscible Gas Injection Performance Compared to Primary Recovery.

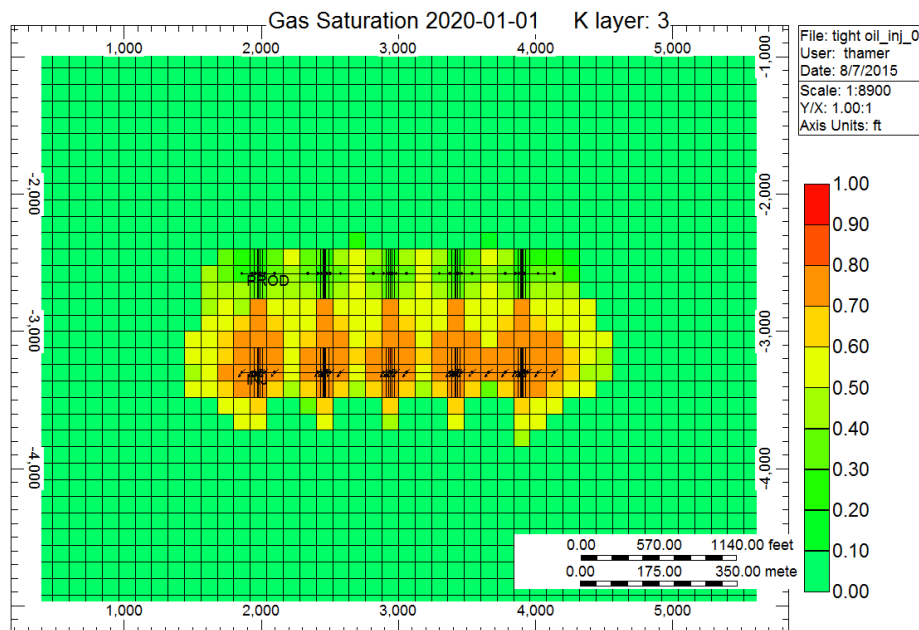


Figure 17: Gas Saturation Map Showing Early Gas Breakthrough.

6.3.2 Miscible Gas Flooding

Oil recovery does not solely depend on the pressure support. The magnitude of recovery depends on the type of fluid that provides support, which in turn affects the sweep efficiency. Immiscible gas injection failed to show incremental recovery over the life of the field and that is very likely because of the sweep efficiency and early breakthrough. Miscible displacement, on other hand, offers greater sweep efficiency. With miscibility, there are no capillary forces to cause oil to be trapped in rocks as residual oil saturation. Additionally, miscible mixing causes a reduction in the interfacial tension and oil viscosity of the displaced fluid. In an effort to simulate miscible gas flooding, the two horizontal wells were placed on stream starting from the first simulation time-step. The production period is set to be 30 years and the injector is kept open for the entire production period. By looking at the miscibility correlations in section 5.1, for a reservoir fluid with C_7+ molecular weight of 205 g/mol, at a temperature of 200 °F, and a pressure above 8000 psi, approximately 10 mole % ethane is required in the solvent stream to achieve miscibility.

Figure 18 compares the oil recovery for the immiscible scenario with miscible gas injection at different pore volumes injected. The figure shows higher recovery starting early in the field life. Moreover, miscible injection exhibits better sweep efficiency as shown in Figure 19. The area between the producer and injector in the miscible injection case is 100% swept as can be seen from the saturation map at the end of the 30 years of injection.

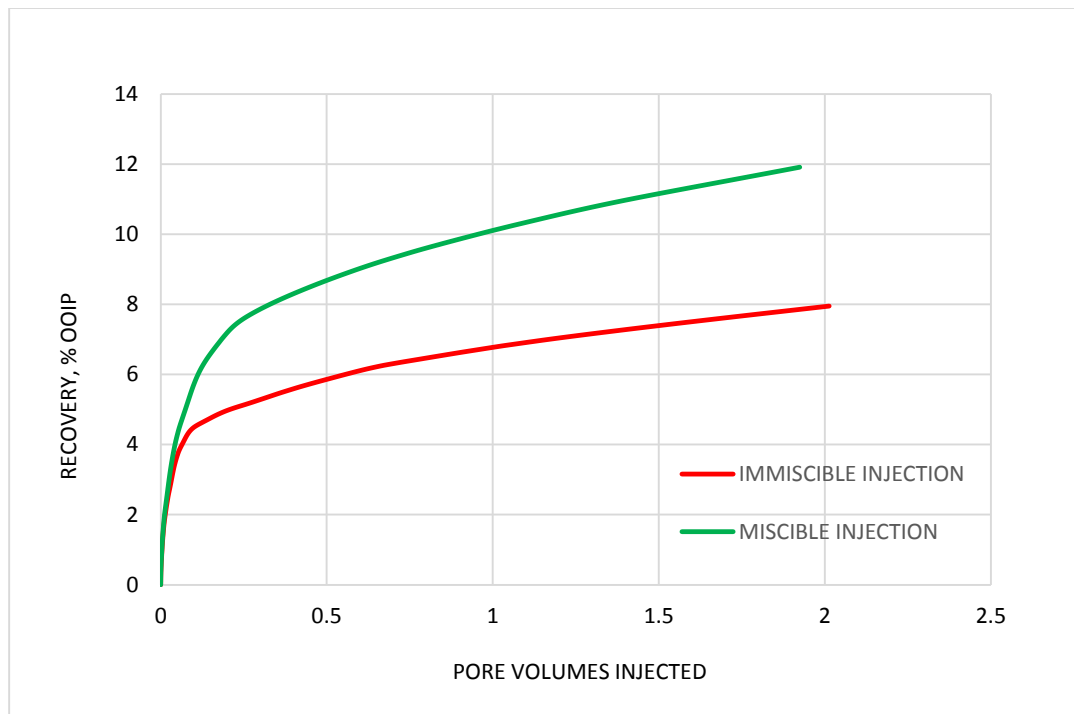


Figure 18: Miscible Gas Injection Performance Compared to Immiscible Flooding.

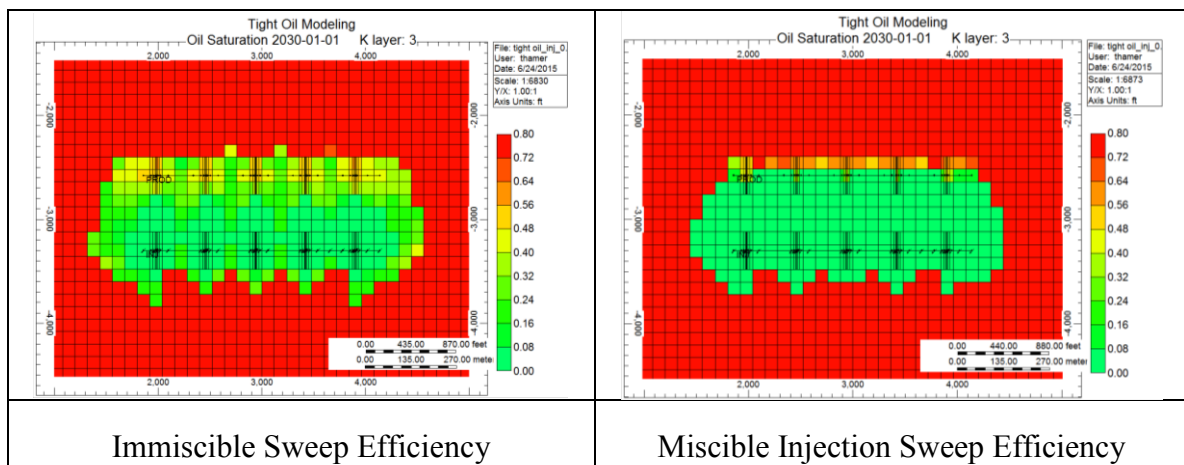


Figure 19: Oil Saturation Map Showing the Sweep Efficiency of Miscible injection at the End of the 30 years Injection Period (2 PV Injected).

6.3.3 Water Flooding

Water injection is the most widely used method to recover additional oil from conventional reservoirs because of its efficiency, cost, and availability. Nevertheless, in unconventional/shale reservoirs, where permeability is very small, the outcomes might turn out to be different.

Similar to previous scenarios, a horizontal well with multiple hydraulic fractures is used to evaluate the possibility of using a water injector to displace additional oil from the 0.1 md reservoir. The comparison in Figure 20 shows that the recovery at the end of the production period of the water flooding option is significantly less than the miscible gas flooding case. This reduced recovery is because of the early breakthrough of the water through fractures in addition to the increase in water saturation in the area between the producer and injector. Figure 21 shows water movement through the fractures to the producer. Water saturation reaches more than 75% in the area between the wells and consequently causes a drastic increase in the watercut in Figure 22.

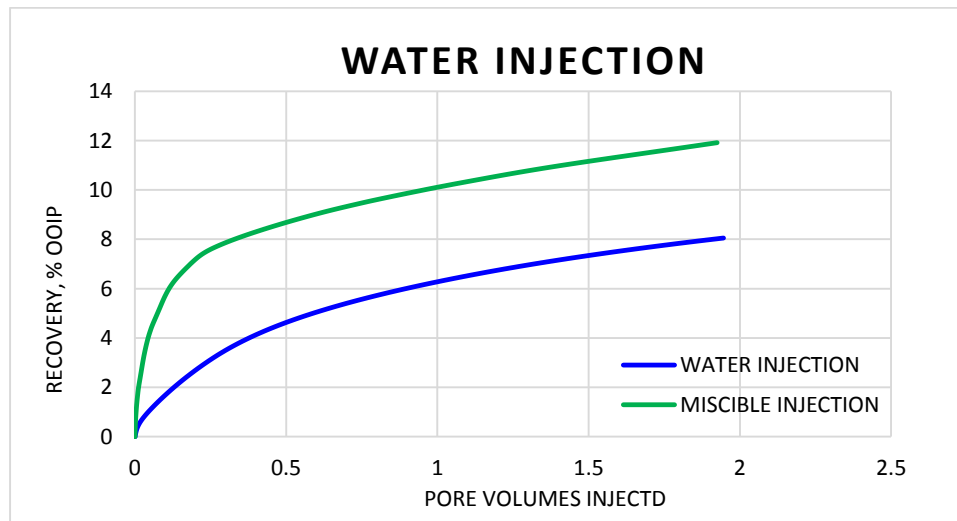


Figure 20: Water Flooding Performance Compared to Miscible Gas Injection at Different Pore Volumes Injected.

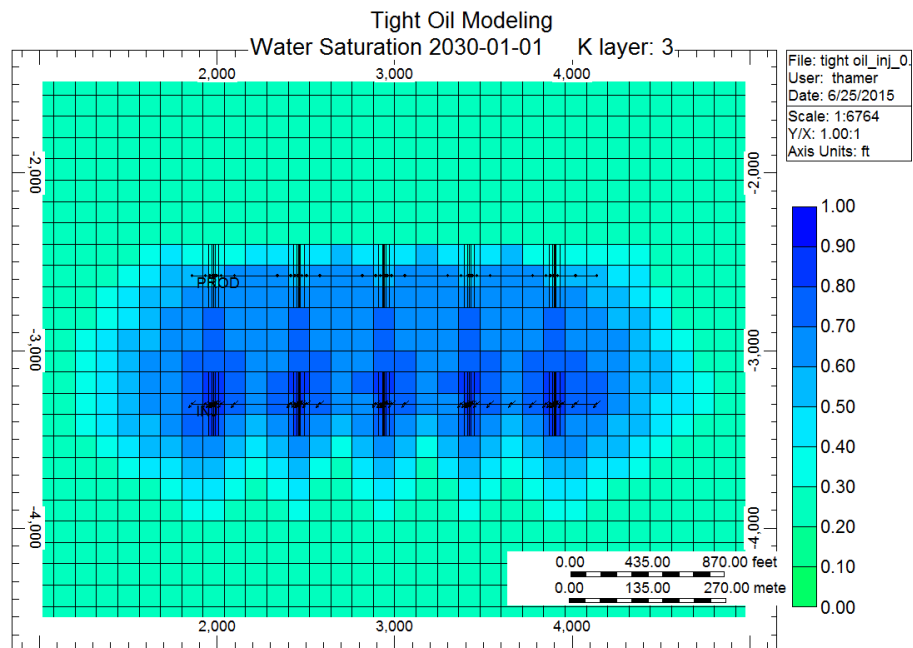


Figure 21: Water Saturation Map Showing Movement of Water through Fractures to the Producer.

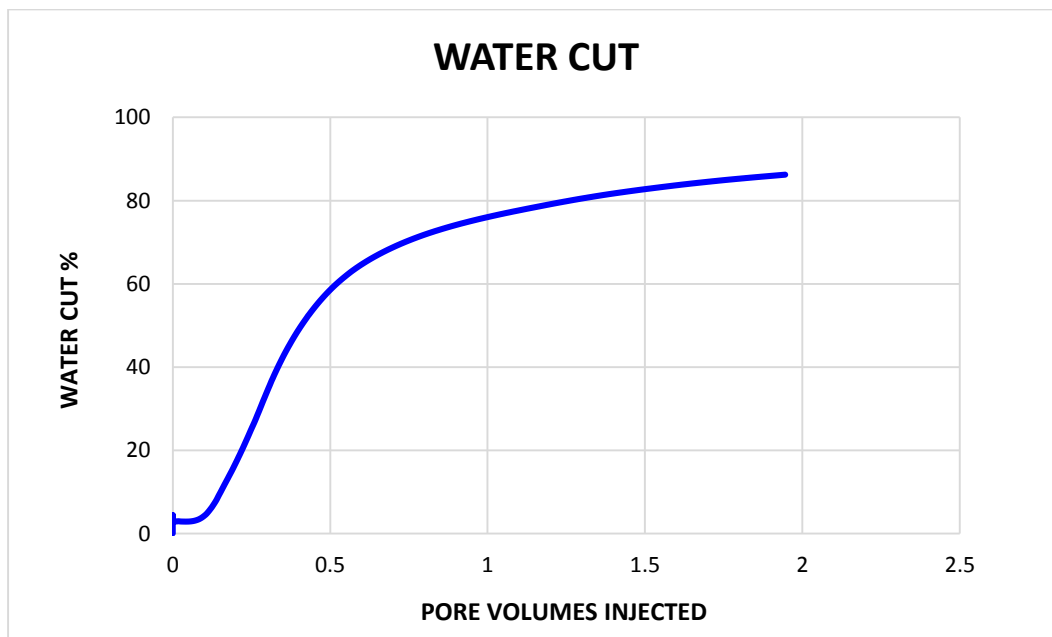


Figure 22: Water Cut Percentage in the Producer Well.

6.3.4 Water Alternating Gas

Injecting through a hydraulically fractured well provides an easy path for the injected fluid to breakthrough to a production well. This flooding process causes insufficient enhanced oil recovery because of the early breakthrough, like the water flooding case. One way to solve this issue is to do a water alternating gas case, by which water and miscible gas are injected alternatively at the same well. In this simulation case, water is injected to push some oil and increase the pressure above the miscibility pressure. Miscible gas is then injected to reduce oil viscosity, displace more oil, and allow the water to settle because of gravity segregation. The result presented in Figure 23 shows the performance of water alternating gas injection compared to other cases at different pore volumes injected. The figure shows that water alternating gas reduces the water channeling because of the time the water is allowed to settle. Water alternating gas still shows slightly less recovery than the miscible injection case. The presence of injected water in the area reduces the sweep efficiency compared to miscible injection.

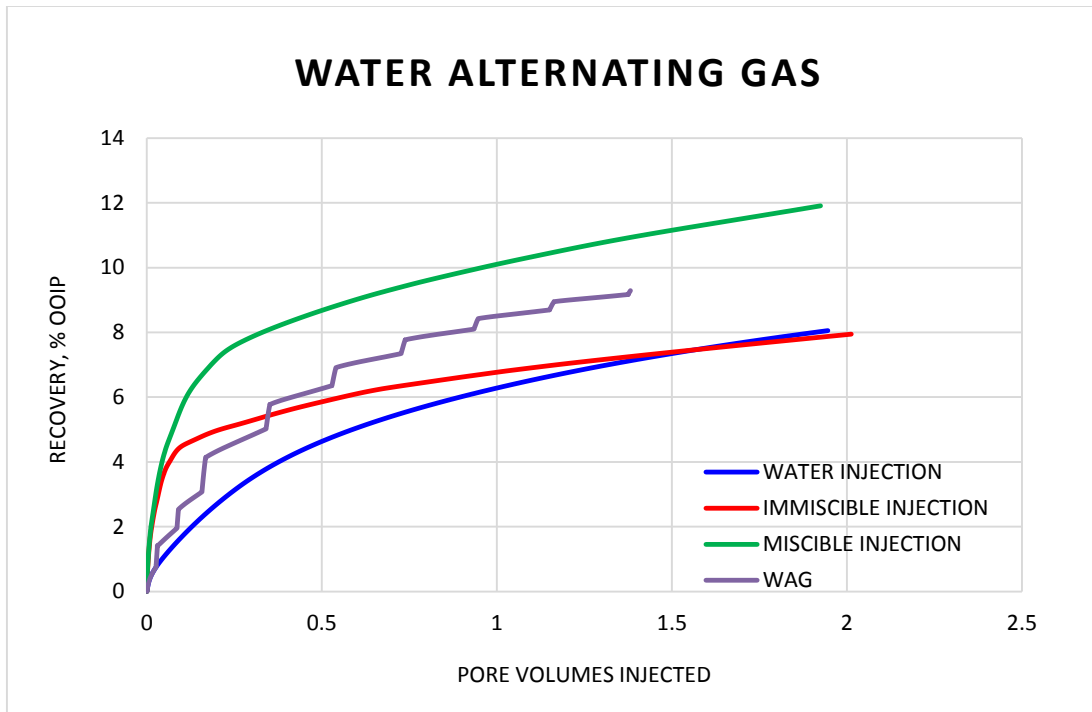


Figure 23: Water Alternating Gas Performance Compared to Water Flooding, Immiscible, and Miscible Injection.

6.3.5 Miscible Gas after Water Injection (Tertiary Recovery)

The interest in using miscible flooding as a mean of recovering tertiary oil after water flooding is increasing. While the water alternating solvent scenario showed good results, especially in terms of recovery, the presence of movable water in tertiary oil recovery can significantly reduce the miscible displacement efficiency. A significant amount of oil might be trapped by the water after water flooding; however, the trapped oil might not be completely isolated from the solvent.

Stalkup (1969) conducted experiments on the miscible displacement performance at the presence of high flowing water saturation in long, consolidated sandstone cores. He

concluded that much of the bypassed oil is not actually isolated from the solvent, but is possibly in communication with the solvent by diffusion.

In our scenario, water is used to displace oil until the watercut become large in the producer (around 95% watercut). The injector is then converted into a miscible gas injector with 10 mole % ethane and 90 mole % methane.

The results in Figure 24 show lower oil recovery at the beginning because water has no significant advantage in recovery as explained in section 6.3.3. Yet after starting miscible gas injection, the recovery increased instantly to give a slightly higher cumulative recovery over the 30 years production period than that of miscible injection. This result can be explained by the lower gas oil ratio (GOR) in the tertiary miscible injection case in 30 years and hence higher relative permeability to oil in the presence of low gas saturations as can be seen in Figures 25 and 26.

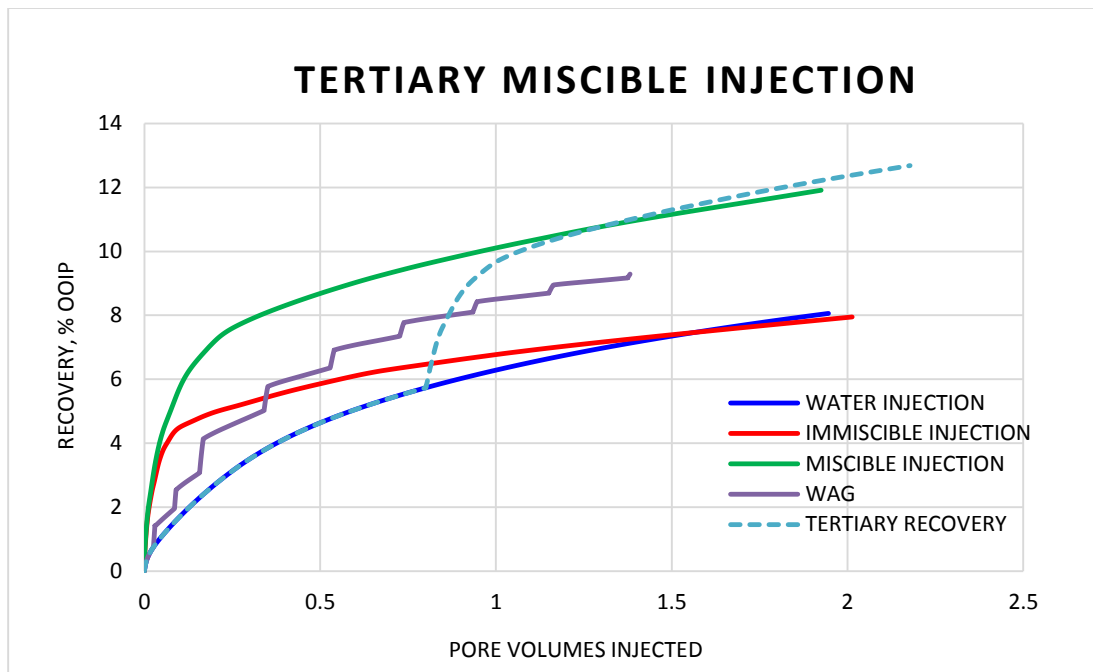


Figure 24: Tertiary Recovery Using Miscible Injection.

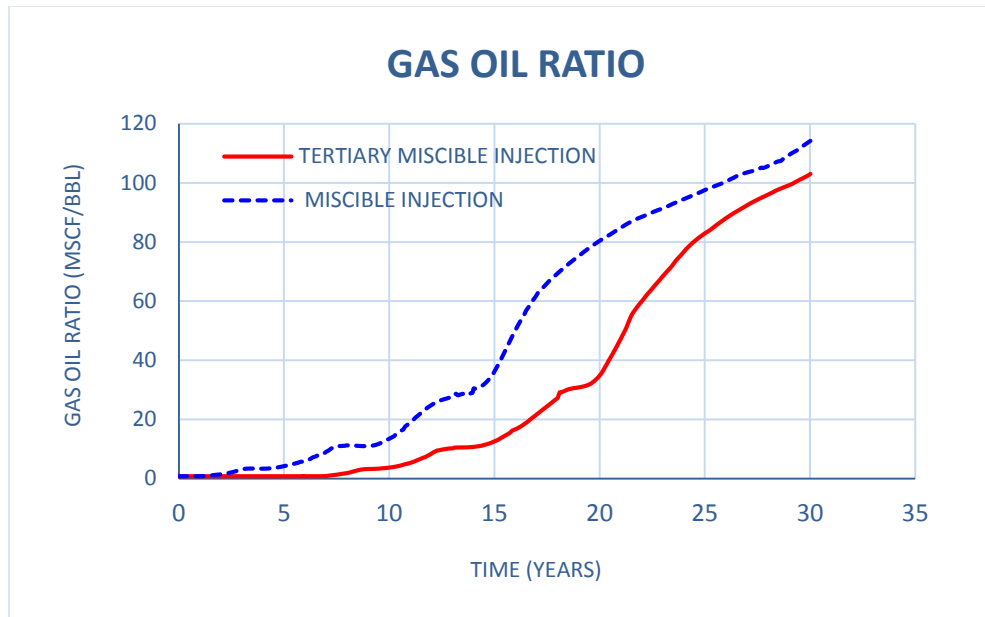


Figure 25: Gas Oil Ratio of the Miscible Injection Case Compared to Tertiary Miscible Injection Case.

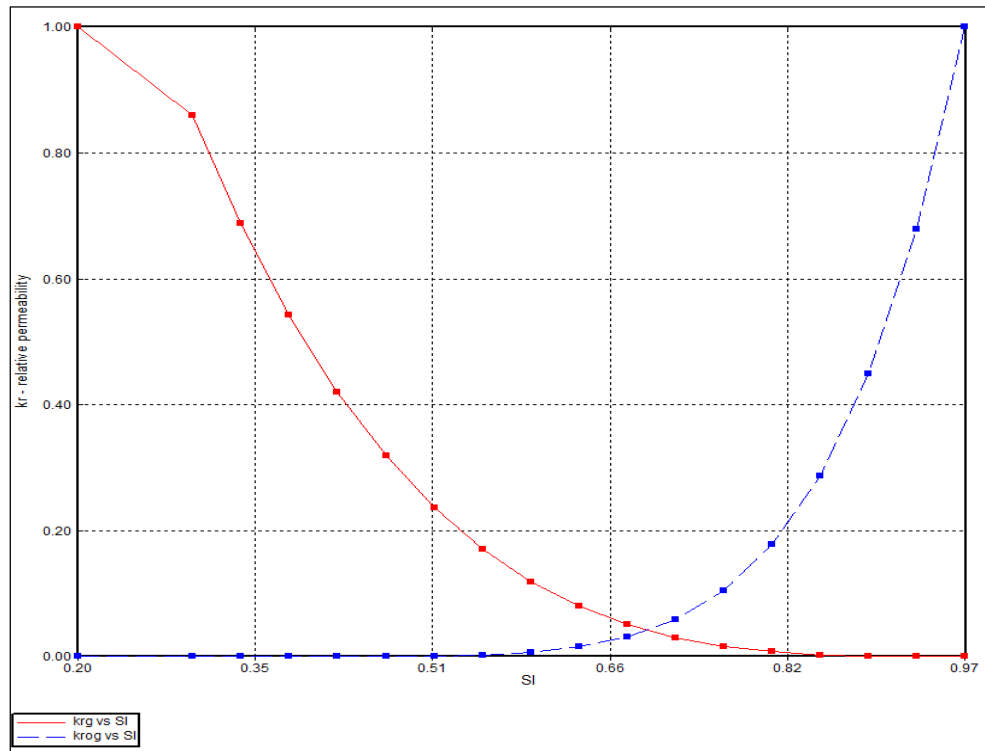


Figure 26: Oil-Gas Relative Permeability Curve.

6.4 SENSITIVITY ANALYSIS (0.1 MILLIDARCY PERMEABILITY)

6.4.1 Injector-Producer Spacing

Voluminous literature has been published about optimizing well spacing or injector-producer spacing (Driscoll, 1974, Kern, 1981, Leman et al., 1990, and Suttles & Kwan, 1993). Spacing is an essential factor in maximizing the net present value (NPV) of a shale reservoir's development mainly because of the eliminated cost of drilling unnecessary long laterals with multiple hydraulic fractures. The dilemma is that the wells should be close enough so that the producer can feel the pressure from the injector in a timely manner; on the other hand, they should be far enough from each other to allow the injected fluid to efficiently sweep the maximum possible area before breaking through. Therefore, the purpose of this section is to try to find a balance between the well spacing and ultimate recovery. To evaluate this, three well spacing scenarios are simulated (Figure 27). Well spacings of 120, 360, and 600 ft are compared. Only one well pair is drilled in the 6000 ft \times 6000 ft area. The wellbore's lateral length, number of fractures, and the half-length are kept constant. The oil recovery in terms of pore volumes injected for the three cases is in Figure 28.

Based on 30 years of production, it is clear that there is no gain from drilling the injector closer to the producer. In contrast to wider injector-producer spacing, production in close spacing cases is controlled by fractures. The fast breakthrough of the injected fluid does not allow enough time for matrix to fracture mass transfer to occur. Hence most of the injected fluid is produced through the fractures.

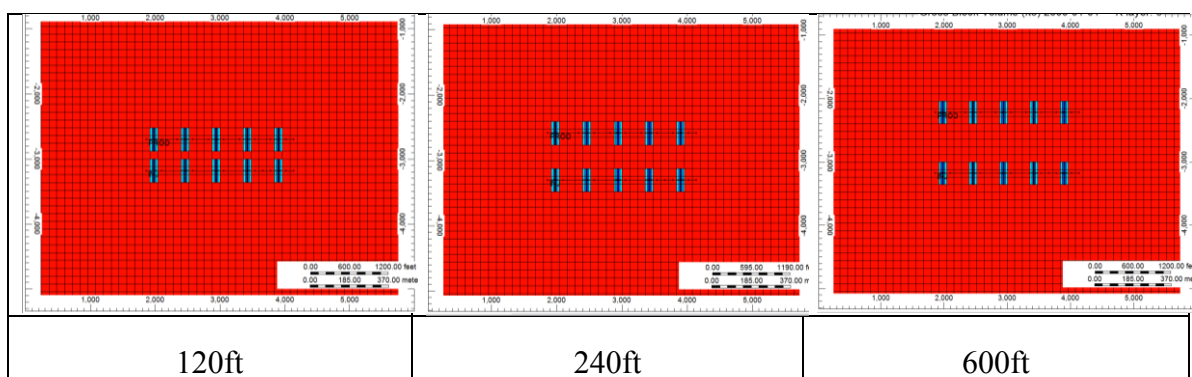


Figure 27: Injector-Producer Spacing Scenarios (Map View).

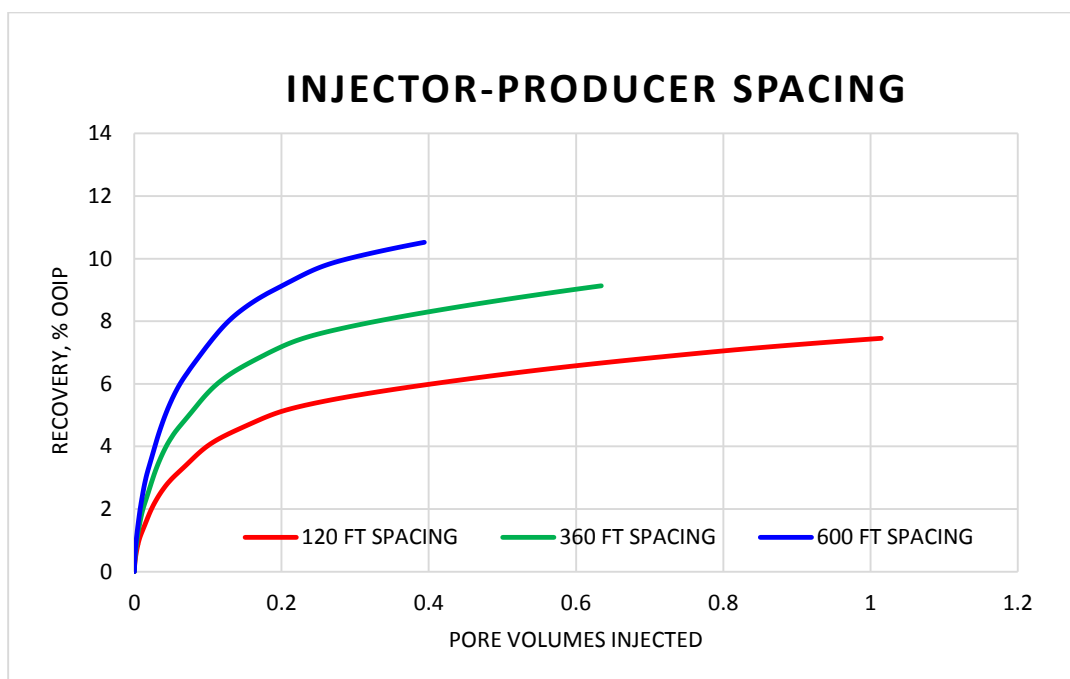


Figure 28: Impact of Injector-Producer Spacing on Oil Recovery in a Miscible Gas Injection.

6.4.2 Fracture Spacing

Similar to well spacing, fracture density is a key factor in economical production from shale formations. To assess the impact of fracture spacing in both the producer and injector, three different scenarios with the same drainage area are performed. Fracture spacings of 120, 240, and 600 ft are considered in this case as in Figure 29.

Results in Figure 30 demonstrate that oil recovery from shale formation is slightly larger early in the life of the field in the higher fracture density cases. More oil is being produced from the additional fractures and more solvent is injected to maintain pressure and displace oil. However, the ultimate recovery at the end of the 30 years production period is larger for the wider spacing. This consequence is possibly because of smaller pressure drop compared to the close fracture spacing. In addition, a higher matrix contribution is expected in the wider spacing case and hence a better sweep efficiency. By looking at Figure 30, oil recovery is highest for the 600 ft fracture spacing.

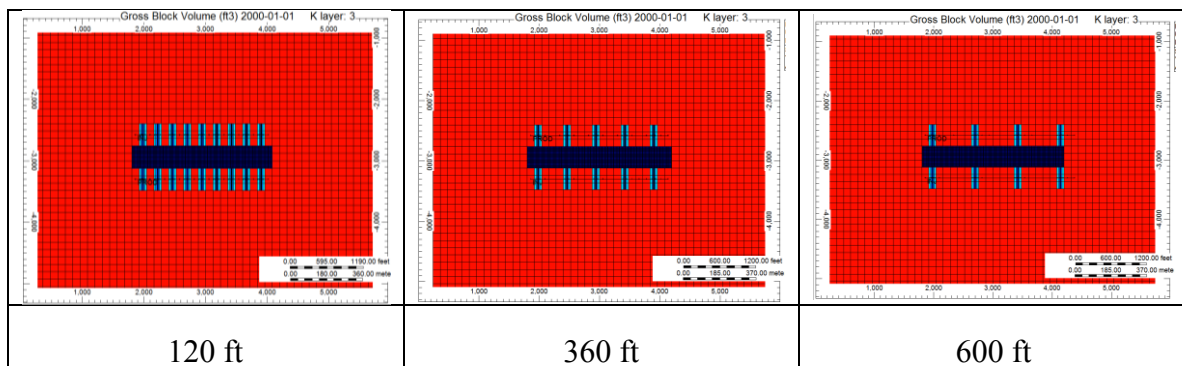


Figure 29: Fracture Spacing of 120, 360, and 600 ft.

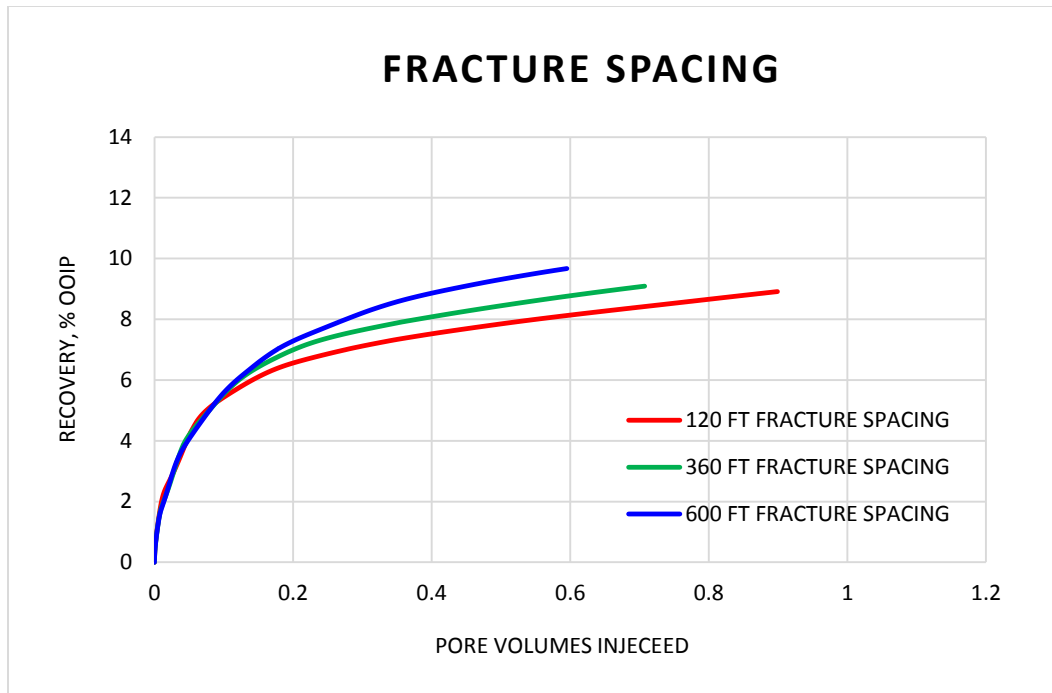


Figure 30: The Effect of Fracture Spacing on Oil Recovery in a Miscible Gas Injection.

6.4.3 Injector Placement

Horizontal wells are increasingly used in reservoirs for injection as they allow more contact with the reservoir and large rates of injection (Suri & Sharma, 2009). In shale reservoirs where permeabilities are in the range of a few millidarcies, fractured horizontal injectors could be the only economic option. Placement of the injector relative to the producer could possibly show some difference in the cumulative recovery. Particularly in the miscible gas injection case, gravity could add some incremental oil.

In the interest of evaluating the impact of the injector location, two cases are compared. In one of the cases, the injector is placed directly above the producer. While in the other case, the injector and the producer are placed next to each other (Figure 31). Oil recovery comparison shows that placing the injector on top of the producer yields

extra oil recovery from the reservoir. Figure 32 shows the oil recovery increase achieved by placing the injector directly above the producer.

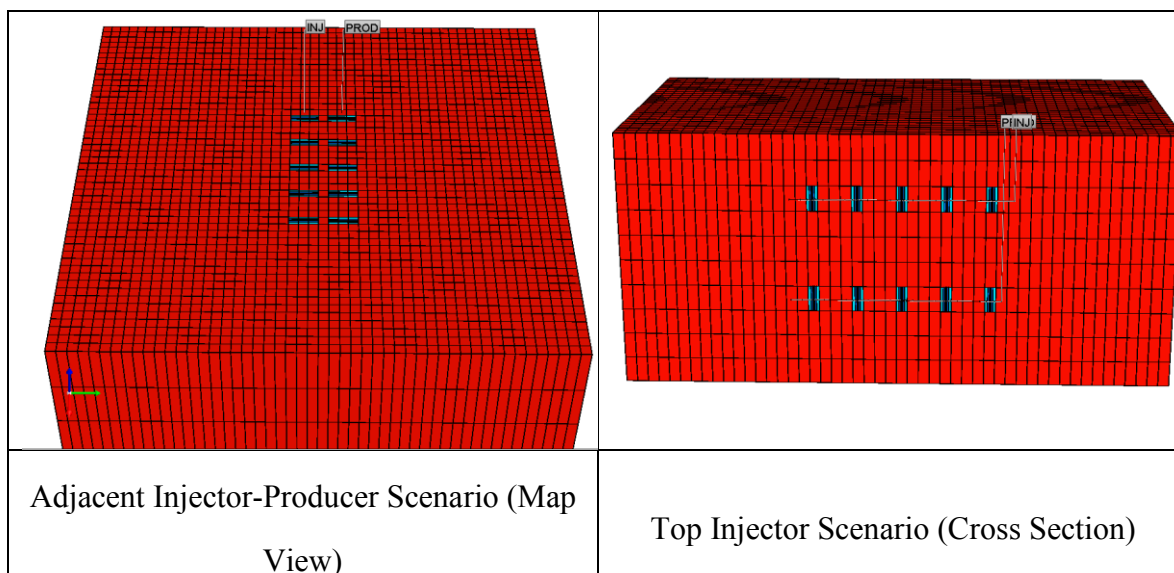


Figure 31: Injector Placement Relative to the Producer.

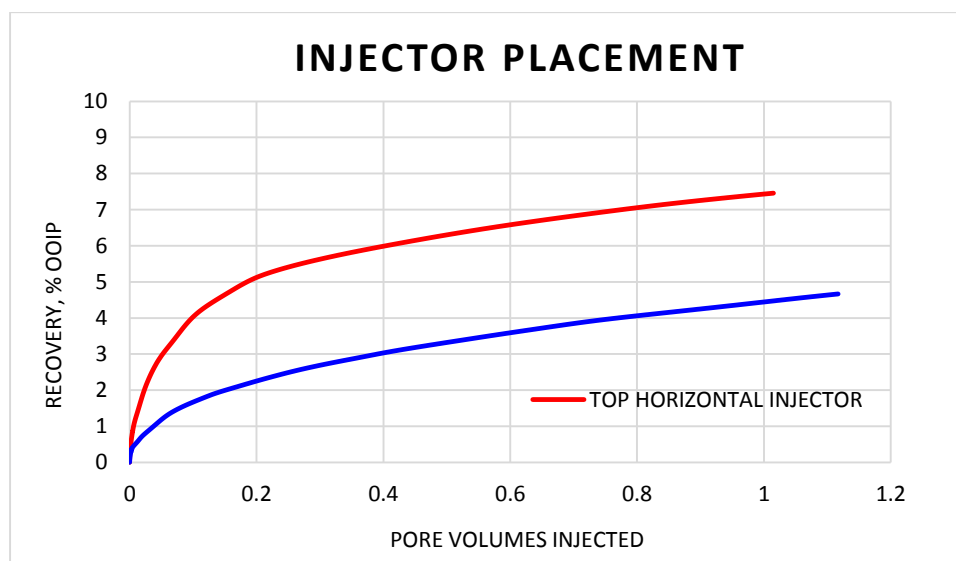


Figure 32: Recovery Difference between Adjacent and Top Injector.

6.5 SENSITIVITY ANALYSIS (0.001 MILLIDARCY PERMEABILITY)

Many shale reservoirs have permeabilities much less than 0.1 md. Hence it is inevitable in this study to evaluate the viability of using miscible injection in very tight formations with permeabilities in the range of 0.001 millidarcy. Similar to what has been done in section 6.4, a sensitivity analysis was performed on a tighter formation. The same simulation model was used with the exception of changing the reservoir permeability to 0.001 millidarcy. Miscible gas injection analysis shows that it is almost impossible to inject in such tight formations. Pore volume injected calculations show that a maximum of 0.001 PV is injected over 30 years and none of the injected fluid reached the producer.

Results in Figures 33 and 34 suggest that even with a close injector-producer spacing, a very small impact on recovery is observed. A 2000 ft-long borehole injector with multiple fractures shows no impact on oil recovery whenever the distance between producer and injector is more than 120 ft. Additionally, a fracture spacing of less than 120 ft is necessary in such a tight reservoir to see little impact on recovery. The incremental oil recovery at very close fracture spacing is resulted from the increase in the stimulated volume around the producer. At this point, it is not clear whether a field development with a well spacing and fracture spacing of less than 120 ft is reasonable, especially that the difference in recovery does not exceed 0.2 % OOIP. Detailed economical study is required in this case to evaluate the practicality of such development.

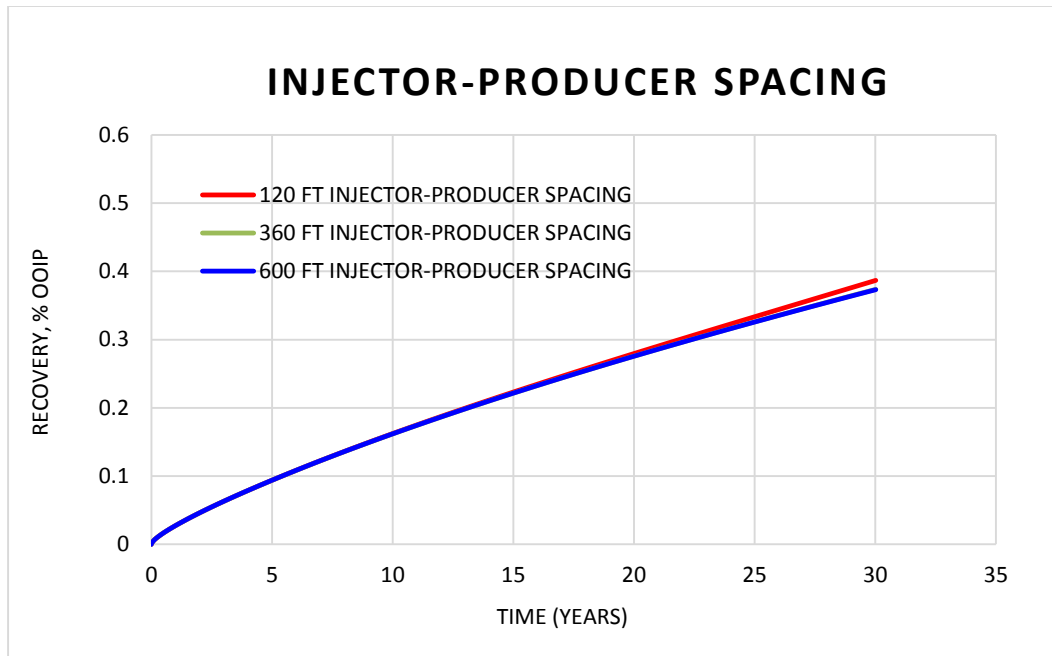


Figure 33: Injector-Producer Spacing Impact on Oil Recovery in a 0.001 Millidarcy Formation

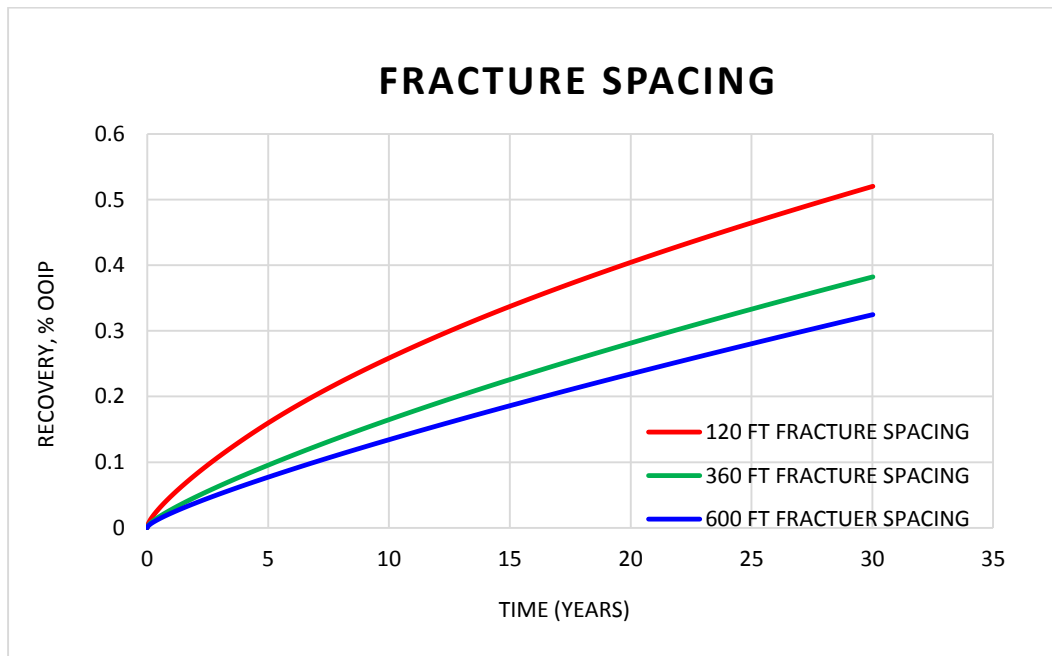


Figure 34: Fracture Spacing Impact on Oil Recovery in a 0.001 Millidarcy Formation.

Chapter 7: Summary and Conclusion

Minimum miscibility enrichment is among the most critical parameter in miscible displacement projects. Ethane was found to be an excellent intermediate option to mix with methane because of the former's low miscibility pressure, price, and availability. Ethane miscibility depends on the reservoir temperature, pressure, and the intermediate composition of the displaced fluid. The produced correlations using compositional simulation are generally applicable to a number of fields whenever ethane is accessible. These correlations provide a rapid method of estimating the minimum miscibility conditions with an excellent degree of accuracy. The correlations serve as a tool for predicting the miscibility for mixtures of methane and ethane.

7.1 Correlations

Several correlations were built using compositional reservoir simulation. The correlations showed that the miscibility conditions for a mixture of ethane and methane depend on reservoir temperature, pressure, and the C_5+ mole fraction in the displaced fluid. Correlations can be used to determine miscibility conditions for temperatures between 100 to 260 °F, pressures between 1,500 and 4,000 psi, and fluids with C_5+ molecular weight between 180 and 245 g/mol. The correlations were benchmarked against existing correlations, experimental methods, and other minimum miscibility pressure predicting methods (such as the mixing cell method). The correlations showed an excellent agreement with other methods with 5-10 % difference in the predicted ethane minimum miscibility enrichment.

7.2 Miscible Injection in Shale Formations

Miscible conditions for a shale reservoir were determined based on the developed correlations. A mixture of methane and ethane was used to displace oil in a shale formation. Displacement results were compared to water injection, immiscible injection, WAG, and miscible gas after water injection. Results showed that miscible injection has the best cumulative recovery in shale. Assuming a one injector and producer in the 6000 ft × 6000 ft area, sensitivity analysis indicated that the spacing between injector and producer and also optimizing the fracture spacing all depend on the tightness of the reservoir. Close spacing is not necessary in formations with permeability around 0.1 md. However, in very tight reservoirs, around 0.001 md, injection has no effect on recovery because of the tightness of the formation. Close injector-producer spacing showed no significant impact and recovery. Fracture spacing, on the other hand, showed little increase in oil recovery because of the increase in the stimulated volume. Placing the miscible gas injection above the producer has also shown some incremental recovery compared to drilling the injector next to the producer.

7.3 Limitations and Recommendations

The correlation serves as an excellent and accurate method to predict the minimum miscibility enrichment required. But it is difficult to account for all fluid and reservoir parameters or other variables that might significantly affect the results. The correlation should be limited to mixtures of ethane and methane and they best work at temperatures between 100 to 260 °F and pressures between 1,500 to 4,000 psi.

Since the correlations will be used to approximate the miscibility conditions in the field, it is imperative to account for the other impurities in the injected fluid. The correlations have not been tested in the presence of other impurities in the injected fluid

such as N_2 and CO_2 . So it might be necessary to test the effect of impurities on the miscibility enrichment. Moreover, the correlation showed some sensitivity to the critical properties of the displaced fluid; the impact has been shown earlier, but it is important to further investigate to what degree this impact can affect the minimum miscibility enrichment predictions. In addition, it was shown in some literature data, like Rutherford (1962), that miscibility correlation is dependent on other parameters such as pseudocritical properties. Therefore, it is recommended to do an in-depth simulation study to address the impact of all fluid parameters on minimum miscibility correlations.

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