The Effects of Gas Injection on Coalbed Methane Production. A Simulation Study

by

Nor Muhammad Kamar Ghaz bin Ab Ghani

supervised by

Mr. Saleem Qadir Tunio

Dissertation submitted in partial fulfillment of the requirements for the Bachelor of Petroleum Engineering (Hons.)

MAY 2013

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CERTIFICATION OF APPROVAL

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Approved by,

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(MR. SALEEM QADIR TUNIO)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

MAY 2013

CERTIFICATION OF ORIGINALITY

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

Certified by,

____

(NOR MUHAMMAD KAMAR GHAZ B. AB GHANI)

ABSTRACT

In optimizing the production of coalbed methane, several methods could be taken to increase the recovery process. One of the methods is by injecting gas with competitive adsorption capability compared to methane. Injection of gases such as carbon dioxide and nitrogen is currently a common practice in unconventional oil and gas industry. Apparently, research on the coalbed methane is numerous and actively done in countries with potential coalbed prospect. Historic wells data such as in American basin are very useful as they provide reliable information and variables for further research. Moreover, by conducting investigation on such wells, the understanding of how the gas injection affects the recovery process could be attained. In this research, the focus will be pointed on the usage of nitrogen and carbon dioxide as the injecting gases in San Juan basin production units through computerized simulation. This paper will also outlines comparative evaluation between nitrogen and carbon dioxide injection in coalbed reservoir in order to assess different outcomes from each type of gas injections respectively. In laboratory, experiments have managed to practically prove the different effects posed by both gas injections on coal matrix in terms such as the gas breakthrough time, the partial permeability trend, the displacement effectiveness and gas flooding polarity. However, it is fair to state that simulation is useful tool to estimate and predict the production trend using the real data obtained from laboratory experiments. Hence, it is expected that more information could be interpreted from this research simulation study thus bring out valuable findings to help in forming more solid inferences to what might have not been understood yet in coalbed study.

Key words – coalbed methane, enhanced coalbed methane recovery, gas injections, San Juan Basin.

ACKNOWLEDGEMENT

Alhamdulillah, I have finally made it to the end of this project work. Along with the completion of this Final Year Project (FYP), I would like to express my deepest gratitude to all parties and individuals that had given me the supports and motivations to ensure that this project is successfully done. Throughout the semesters of working on the project and report, I have managed to learn a lot of new things and gained so much experience which I will value and treasure personally.

First and foremost, I would like to thank UTP's Petroleum Engineering Department for providing students with instructions and guidance to complete the project as well as for arranging the project activities for us. With their support and advice, we as students were able to plan and conduct our project very well.

Next, a very special gratitude I bit to my Final Year Project supervisor, Mr. Saleem Qadir Tunio who had become the most important person in giving me the idea on my project. His willingness to teach and guide has greatly driven me to complete this work.

Besides that, I would like to thank the lab assistants and technicians who helped me to complete the simulation which is the critical part in this study. I truly appreciate their contributions and shared information throughout the process and execution of the simulation study.

Finally, my appreciation also goes to my family and friends in UTP for their continuous support and encouragement which keep pushing me to deliver my best for this course. It is the biggest hope of mine that the final work of this project would bring useful sharing and understanding on the related field of study.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 INTRODUCTION

1.1 Background Study

Based on the paper written by Puri and Yee (1990), America's coalbed methane gas-in-place is estimated to be 400 TCF. Around 90 TCF or 22.5 % is considered to be economically recoverable with current technology. Coalbed methane (CBM) well production began in 1971 and was originally intended as a safety measure in underground coal mines to reduce the explosion hazard. It was then became commercially produced starting from 1984. For the record, other countries besides America which are very familiar to CBM production include China, Australia, Russia, Canada and India (Stevens & Denis, 1998). In Malaysia however, research and exploration for CBM are still being run throughout the nation especially in Sarawak deltaic region.

CBM production is considered as unconventional as its extraction process is different from the usual conventional natural gas production. This is due to the fact that the methane gas is an adsorbed fluid inside the coal matrix. Moreover, the properties of coal matrix also distinct CBM reservoir from conventional gas reservoir where the fluid transmit capability and secondary porosity are greatly depends on special fracture system or known as coal matrix cleats. Primarily, the practice of producing coalbed methane is by using pressure depletion technique. Through this technique, hydraulic fracturing is applied on the coal formation which causes the cleats to enlarge. The underground water is then pumped out from the coal reservoir leading to reduction of the reservoir pressure. Due to the pressure reduction, the pure methane trapped inside the coal matrix diffuses through the micro porous blocks and free to escape into the cleats thus flowing into the wellbore to be produced. Although this technique is simple and cost effective, it is not efficient. This is because the reduction in reservoir pressure will eventually shrink the energy to flow the fluid into the wellbore. Furthermore, there is a practical and economic limit on the extent to which reservoir pressure can be reduced. According to Puri and Yee (1990), it is estimated that reservoir pressure depletion technique of coalbed methane production will permit the recovery of 50% or less of the gas-in-place. For this reason, enhanced recovery method needs to be introduced in order to fully optimize the coalbed methane production.

Enhanced coalbed methane recovery (ECBM) is the process of injecting gas into a coal reservoir to improve desorption and production of in-situ coalbed methane. Depending on the gas properties of certain gas injected, the process is mainly dominated either by displacing or stripping the methane from the coal matrix. This research will cover the study of carbon dioxide (CO_2) and nitrogen (N_2) injections into coalbed methane reservoir. Generally, carbon dioxide will help the recovery process by displacing the methane gas in the coal matrix while nitrogen contributes by stripping out the methane. Gas injection serves as a good recovery technique because it provides a mean of liberating the methane while maintaining the CBM reservoir pressure as well as it progressively increases the gas production total (Tang, Jessen, Kovscek & Standford, 2005). As both CO_2 and N_2 injections pose different effects on the coal matrix, comparative study on these two methods are the main the subject of this research.

1.2 Problem Statement

There are significant differences between N_2 and CO_2 injections. Basically, N_2 is a natural choice for ECBM due to its availability and the fact that it tends to yield incremental recovery response rapidly. Nitrogen also has almost all the properties of inert gas thus allowing it to penetrate through the coal matrix without significantly adsorbed. This in turn gives nitrogen gas the capability to strip away the methane by reducing the partial pressure of methane effectively. Whereas, CO_2 tends to adsorb to coal surfaces stronger than either nitrogen or methane. The strong adsorption characteristics of CO_2 are likely to inhibit premature breakthrough of injectant thus result in complete displacement of methane (Tang, Jessen, Kovscek & Standford, 2005). The use of CO_2 also could provide mutual benefits to both production optimization and environment. This is because; injection of CO_2 could also facilitate the removing process of greenhouse gas through underground sequestration.

The comparative study in this research will help to deliver a greater understanding on the effects of using both injection techniques. It will cover up several key points such as:

1) How does gas injection (ECBM) helps in optimizing the production of methane compared to common pressure depletion technique?

2) What are the substantial differences of both recovery techniques on the coalbed methane production?
3) What are the major advantages of each gas injections dependent on the type of coal rank and reservoir conditions?
4) What are the issues of using nitrogen and carbon dioxide as injectants in ECBM?

1.3 Objectives

The simulation of nitrogen and carbon dioxide injections are to be carried out in this study as to achieve following purposes:

1) To view the effects on reservoir pressure in each injection techniques.
2) To understand the effect of gas injection in coalbed methane production.
3) To evaluate the performance of each injection methods.
4) To compare the outcomes of both gas injection techniques in term of ECBM recovery.
5) To address the problems or drawbacks of each techniques from the simulation results.

1.4 Scope of Study

This research will cover a general analysis of gas injection specifically using CO_2 and N_2 as extended recovery methods on CBM production. The analysis will be based on the simulation results which were run according to the information obtained from the historic coal basin data published by several SPE papers as well as topical reports of field operations. Basic knowledge on unconventional production of CBM is required to complete the discussions part as well as to provide critical reasoning on the results obtained.

The fundamental of this study is based on the theory of Langmuir Sorption Isotherm and Extended Langmuir Sorption Isotherm. The theories are used to explain the effects of pressure on gas volume adsorbed in formation such as coal. The simulation results of this project are provided by ECLIPSE 300 simulator which applies the correlations and formulas suggested by the theories stated earlier.

1.5 The Relevancy of the Project

This project is relevant to the author as a Bachelor of Engineering student who had already completed most of the Petroleum Engineering courses during his last two semesters. However, it is to be acknowledged that the study of coalbed methane is considered newly advanced in Malaysia and differs from the conventional oil and gas production study. Hence, by carrying out this project, the author will gain exposure on unconventional production which perhaps, will be very beneficial in the future. Moreover, this project requires proficiency in using simulator which is not commonly emphasized in Petroleum Engineering courses. It is hope that, through this project the software skills related to petroleum analysis could be well developed in author's self. Also, the works in this project requires the author to come with critical thinking and analytical skill which are very useful as they help to improve the author's personal ability to deliver significant reasoning and deductions from reliable information. All of the skills and experiences acquired throughout this project will contribute to the development of engineering sense and the growth of knowledge for the author.

2.0 LITERATURE REVIEW

2.1 Coalbed Methane Production

Coal is defined as a rock that contains at least 50 percent organic matter by weight. This rock is formed through lithification of precursor deposition known as peat. Coal has a low primary porosity and permeability but due to its special fracture system (matrix cleats), coal is granted with good secondary porosity and secondary permeability (EPA report, 2004).

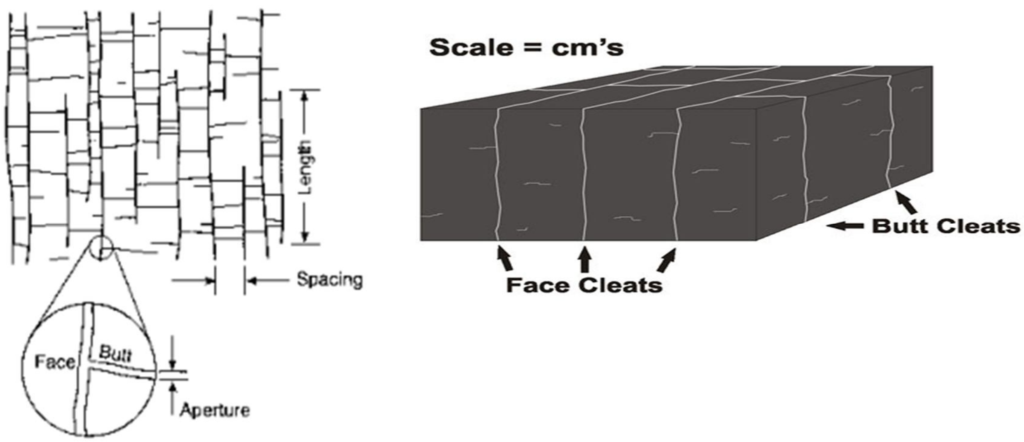

Figure 1: Schematic and oblique illustrations of coal rock fracture system (matrix cleats)

Source: Laubach S.E, Marrett R.A., OlsonJ.E and Scott A.R., 1996, "Characteristics and Origin of Coal Cleats – A Review", International Journal of Coal Geology.

Despite of not containing precious hydrocarbon liquid, coal is valuable as it holds pure methane gas inside it. Coalbed methane (CBM) is a gas formed as part of the geological process of coal generation, and is contained in varying quantities within all coal. CBM is exceptionally pure compared to conventional natural gas, containing only very small proportions of wet compounds and other gases. CBM is over 90 percent methane and is suitable for introduction into a commercial pipeline with little or no treatment needed (EPA report, 2004). In a typical gas reservoir, gas is compressed by the pressure in the formation. Expansion of the gas provides the means for the gas to be reservoir. In contrast, methane gas in coal reservoir is stored within the matrix by absorption process where the gas molecules adhere to the surface of the rock. Due to this, the production of CBM is very much different from the typical conventional production of methane gas. The production of CBM is done by serving a way to flow the methane gas trapped inside the matrix into the matrix cleats. Since the adsorption of the methane is reversible due to weak attraction force, production is not much of complexity. In normal practice, CBM production involves pressure depletion strategy. That is, the reservoir pressure is hydraulically fractured before removing water to reduce the reservoir pressure which causes methane to be desorbed from coal (Puri & Yee, 1990).

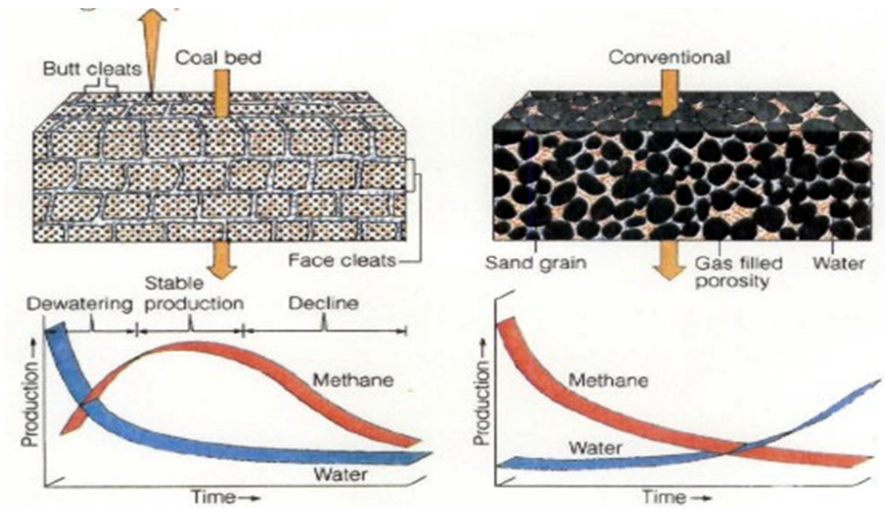

Figure 2: Coalbed methane production vs conventional methane production

Source: Crain E.R., 2011, "Coalbed Methane Basics", Crain's Petrophysical Handbook. Retrieved from http://www.spec2000.net/17-speccbm.htm.

The release of methane gas in coal seam is commonly described by a relationship called the Langmuir. The theory of Langmuir was developed to associate the reservoir pressure rate with gas sorption capacity. Generally, the Langmuir formula could be denoted as follow:

$$V = V_{max}\frac{bP}{1+bP} \qquad (2.1)$$

where;

V = gas volume adsorbed per unit weight of solid at pressure, P

V_{max} = maximum monolayer volumetric capacity per unit solid weight

b = the Langmuir constant

P = reservoir pressure

This general Langmuir is applicable with major assumptions which are:

- One gas molecule is adsorbed at a single adsorption site.
- An adsorbed molecule does not affect the molecule on the neighboring site.
- Sites are indistinguishable by the gas molecule.
- Adsorption is on an open surface, and there is no resistance to gas access to adsorption site.

In the formula, the Langmuir constant, b is defined as a reciprocal of the Langmuir Pressure, P_L which is the pressure that gives gas content equal to one-half of the monolayer capacity. The Langmuir constant is a function of rate of adsorption and desorption from complete monolayer coverage at constant temperature, r and adsorption equilibrium constant, k.

$$b = \frac{1}{PL} = \frac{k}{r} \qquad (2.2)$$

Theoretically, at low pressure, $(1+bP) \approx 1$ and equation 2.1 reduces to linear formula where the straight line passing through the origin on graph of absorbed volume vs pressure. Since the process is reversible, the linear formula or known as Henry's constant, infers that the gas desorption increases rapidly as pressures are lowered on the coal seam. For a given pressure drop, much more gas is evolved at these low pressures than at the high pressures where CBM production usually starts. The Henry's law could be denoted as follow:

$$V = V_{max}\, bP \text{ or} \qquad (2.3)$$

$$V = C_H P \qquad (2.4)$$

where; $C_H = Vmax\, b$

Equation 2.1 are used to construct the of methane sorption (both adsorption and desorption) on coal as pressure varied at constant temperature, a path similar to CBM production. In constructing sorption of methane, constants b and V_{max} need to be determined. This is done by rearranging equation 2.1 to:

$$\frac{P}{V} = \frac{1}{b\, Vmax} + \frac{P}{Vmax} \qquad (2.5)$$

Thus, a plot of *P/V* vs. *P* gives a straight line with an intercept of $1/V_{max}$ and slope of $1/V_{max}$. Data from laboratory work on pressurized and depressurized coal samples would give enough information to obtain the constants. As taken from the published paper, the samples of Cameo coal seam in Piceance basin Colorado were used to evaluate the absorptive characteristics (Rakop & Bell, 1986). The results as follows:

Table 1: Pressurizing (methane adsorption) of Cameo Coals

Pressure (psia)	Gas Content (scf/ton)
100	66
413	207
1016	306
1917	378

Table 2: Depressurizing (methane desorption) of Cameo Coals

Pressure (psia)	Gas Content (scf/ton)
1513	364
1014	328
767	287
417	215
211	143
163	118
113	88
63	53
12	0

Source of table 1&2: Rakop K.C. and Bell G.J, 1986, "Methane Adsorption/Desorption s for the Cameo Coal seam Deep Seam Well, Piceance Basin, Colorado", final report, Terra Tek, Inc.

Then, the tabulated data were plotted to form the linear relationship as shown in figure 3 which indicates Langmuir characteristics of the adsorption and desorption of methane on the Cameo coal. This is the normal practice in acquiring the Langmuir constants which later will be used in calculation to construct Langmuir model. The Langmuir model is the foundation of constructing analysis of any typical CBM production well in order to evaluate the well pressure integrity and methane sorption behavior.

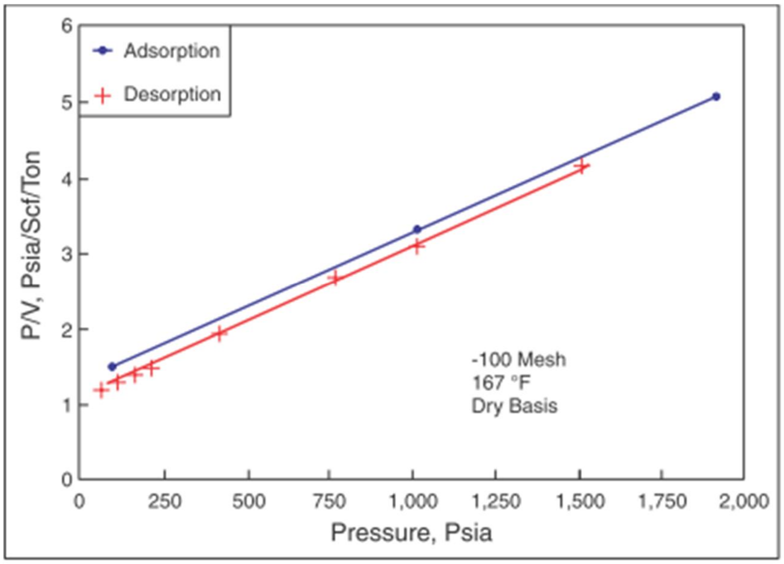

Figure 3: Langmuir coefficients of Cameo coal, Piceance basin

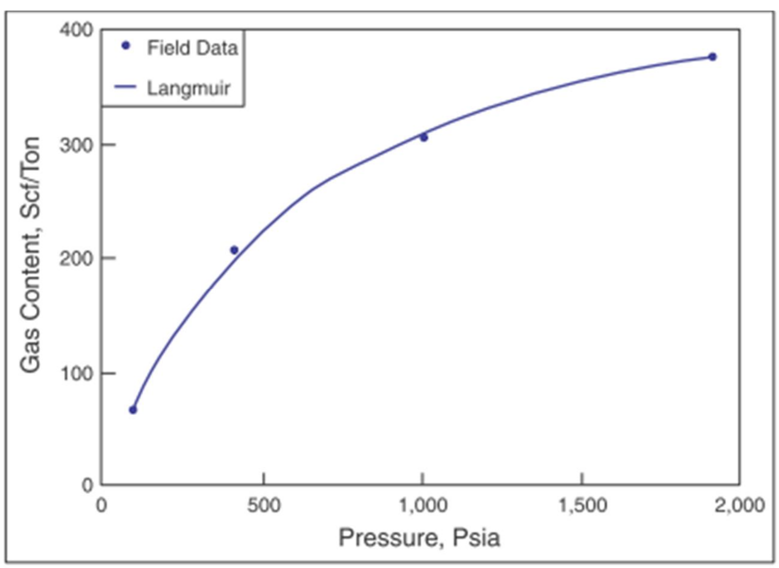

Figure 4: Cameo coal sorption analysis based on gas content at various pressure rates

Source of figure 3&4: Rakop K.C. and Bell G.J, 1986, "Methane Adsorption/Desorption s for the Cameo Coal seam Deep Seam Well, Piceance Basin, Colorado", final report, Terra Tek, Inc.

General Langmuir model is adequate to be used in describing CBM work on a single gas component in coal. However, in practice, coal seam contains multicomponent gas absorbed on the rock instead of just only methane. Commonly, gases which existed along with methane in the coal seam are ethane, carbon dioxide and nitrogen. Due to the presence of these gases, both heating value of the produced coalbed gas and the ultimate recovery of methane are lowered to certain points. Also, adsorbed heavier hydrocarbon such as ethane, will affect the accuracy of methane reserve calculation. Thus, the general Langmuir is insufficient to evaluate the coal seam in the production zone. In order to account for sorption of multiple gas components in the gas mixture, the general Langmuir model has been extended.

The extended Langmuir isotherm could be presented as follow:

$$V_i = \frac{(V_{max,i}) b_i P_i}{1 + \sum_{j=1}^{n} b_j P_j} \qquad (2.6)$$

where;

V_i = gas volume of component i absorbed per unit weight of solid at partial pressure, P_i

$V_{max,\,i}$ = monolayer volumetric capacity of component i per unit weight of solid, scf/ton

n = total number of j gas components in mixture

b_j = Langmuir constant of j component

The extended Langmuir isotherm model is satisfactorily accurate to fulfill the requirement in analyzing multicomponent gas in coal seam. In addition, as what stated in the published paper by Deo and coworkers (Deo & et cl, 1993), the extended Langmuir isotherm also resolves complex laboratory procedural problem for establishing the isotherm of a gas mixture.

2.2 Enhanced Coalbed Methane Recovery

Although pressure depletion technique provides simplicity and economic operation for CBM production, but the technique is unable to produce more than half of maximum recovery (Puri & Yee, 1990). Thus, enhanced recovery technique is required to optimize the CBM production. Enhanced Coalbed Methane (ECBM) recovery is the process of injecting a gas into a coal reservoir to enhance desorption and recovery of in-situ CBM (Oudinot, Schepers & Reeves 2007). Gas injection is very efficient in forcing out the methane inside the matrix as the adsorption of methane is controlled by the partial pressure rather than the total pressure. In other words, the amount of methane sorbed on coal matrix is not only dependent of the total pressure system, but also on the concentration of methane in the gas phase (Puri & Yee, 1990). Therefore, by controlling the saturation of gas inside the coal, it would create a drive to produce methane. Depending upon whether the injected gas exhibits a greater or lesser sorption capacity on coal than methane, the process is either dominated by displacing the CBM from matrix blocks into the cleats system or stripping methane out of matrix by reducing the partial pressure of it. Two of the most used gas for injections in ECBM recoveries are Carbon Dioxide (CO_2) and Nitrogen (N_2) gases. CO_2 is chosen because it has sorption capacity greater than methane where this causes preferential adsorption of CO_2 onto the coal matrix thus displacing methane and pushes it into the cleat system (Koperna & et al, 2009). This phenomenon is known as “displacement mechanism”. CO_2 is also used in ECBM recovery as to sequestrate the greenhouse gas into underground formation for environment preserving purpose. Whereas, N_2 is used in ECBM recovery due to its inert gas properties with low sorption ability compared to methane. Due to this, N_2 could invade the coal matrix pores and reduce the partial pressure of methane gas which allows the methane to desorb from the rock matrix. Likewise, N_2 is also found abundant and cheap while effectively stripping out CBM. Besides, ECBM recovery is performed in CBM production to maximize the CBM production while at the same time, maintain the reservoir pressure. Figure 5 shows the sorption characteristics of methane, CO_2 and N_2.

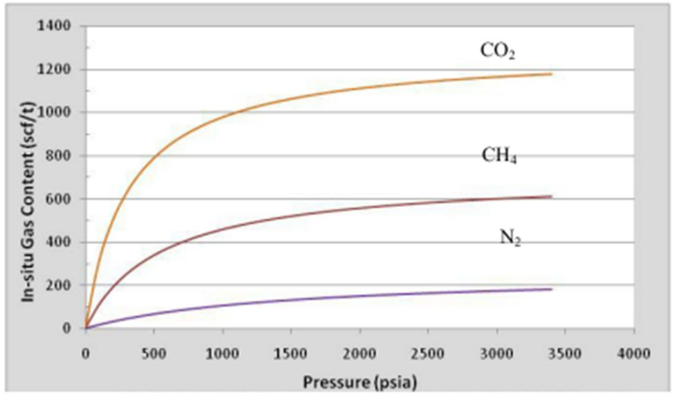

Figure 5: Gas contents in San Juan Basin at various pressures. Showing the degree of storage

Source: Koperna J.G. and etc.l, 2009:"CO_2-ECBM/Storage Activities at the San Juan Basin's Pump Canyon Test Site", Society of Petroleum Engineers (SPE), paper no: SPE 124002.

2.3 San Juan Basin

San Juan basin is located in Florida river plant, America. For simulation purpose, the data used are taken from historic field data of production units of San Juan basin as included in the published topical reports. These production units are taken to be the sample in the simulation models because each of them has had gas injection during the late years of their production. Thus, the samples would provide very compatible data for the study. The first unit in this basin is named Allison which located at southern Colorado. Allison unit provided the industry with first significant opportunity to examine carbon dioxide injection process. The primary production of this unit began in 1989 and after 6 years, the enhanced coalbed methane recovery (ECBM) was carried out from 1995 till 2001. Allison unit was run by Burlington Resource (now Conoco Phillips) with the ECBM operation held under continuous injection. The depth of the reservoir was measured at 3100 feet under while; the thickness of the coal pay zone is 43 feet. Allison unit contains medium volatile sub-bituminous with permeability of up to 100 milidarcy (mD). For the record, there were 4 injector wells with 16 producer wells for Allison ECBM-pilot. The wells were put in five-spot arrangement which enough to cover the field area of 320 acres. Figure 6 shows the wells location and the area of study. With six and half years of injection process, it is estimated that 6.4 billion cubic feet (bcf) of CO_2 has been injected into the reservoir.

Another production unit located in the same basin is known as Tiffany unit which located at northern New Mexico. Tiffany production unit started its first production in 1993 and ECBM operation was introduced in 1998 using N_2 as the injection gas. The ECBM operation was run for about 4 years until the producer wells stopped to produce in 2002. The pay zone was remarked to be at the depth of 300 feet under with 47 feet of thickness. The coal rank in this production unit is also from medium volatile sub-bituminous type with extremely low permeability of 1 mD. The operation was run by Amoco (now BP), where the ECBM was held up to 4 years of intermittent injection. The estimated volume of injected gas was estimated to be at almost 15.0 bcf of N_2. In contrast with Allison, Tiffany unit required 12 injector wells and 34 producer wells to operate efficiently. Figure 7 shows the study area of Tiffany unit as published by Reeves et al (2004) which covers the area of 320 acres.

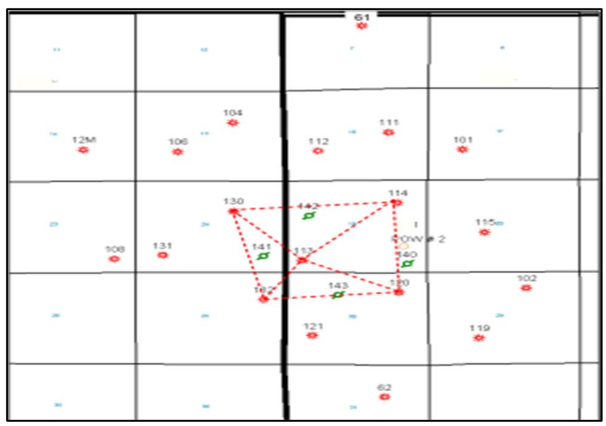

Figure 6: Allison five-spot pattern of study area

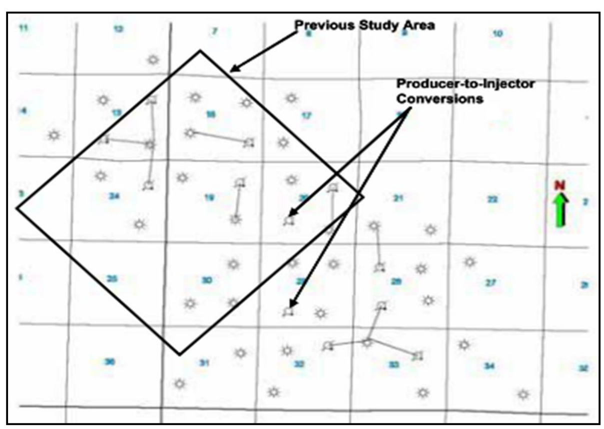

Figure 7: Tiffany bundle pattern of study area

Source of figure 6: Reeves S., Taillefert A., Pekot L., 2003, "The Allison Unit CO_2-ECBM Pilot: A Reservoir Modeling Study", U.S. Department of Energy Topical Report prepared by Advanced Resources International.

Source of figure 7: Reeves S., Oudinot A., 2004, "The Tiffany Unit N_2-ECBM Pilot: A Reservoir Modeling Study", U.S. Department of Energy Topical Report prepared by Advanced Resources International.

2.4 ECLIPSE Simulator

As stated in the previous section, the simulation of this research will be conducted using the CBM option in Schlumberger ECLIPSE software. Generally, in ECLIPSE, CBM dual porosity model is run by the application of modified Warren and Root model. The modified Warren and Root model could be presented as follow:

$$\Phi_f c_f \frac{\partial P_f(x_f,t)}{\partial_t} = \frac{k_f}{\mu} \nabla^2 P_f\left(x_f,t\right) + Q\left(x_f,t\right) \quad (2.7)$$

where;

Φ_f = total fracture porosity

c_f = total compressibility of the fractures

P_f = fluid pressure in the fracture

x_f = position vector of a point in the fracture continuum

t = time

k_f = absolute permeability of the fracture continuum

Q = net addition of fluid to the fracture system from matrix blocks, per unit of total volume

In this dual porosity, the total porosity is a sum of both primary and secondary porosity of formation. Warren and Root model describes the single-phase, slightly compressible fluid flow through macroscopically-homogeneous fractured medium (coal).Thus, from the components of equation, the required parameters for simulation could be acknowledged. Apart from the dual porosity model, ECLIPSE also applied the Extended Langmuir Isotherm model as the basic equation for adsorption model in its CBM application.

As for the reservoir equation of state, through ECLIPSE 300, the Peng-Robinson equation is used to evaluate the fluid behavior relationship based on certain conditions of reservoir. The Peng-Robinson equation of state could be presented as follow:

$$P = \frac{RT}{V_m - b} - \frac{a\alpha}{{V_m}^2 - 2bV_m - b^2} \qquad (2.8)$$

where;

$a \quad = \frac{0.45724R^2{T_c}^2}{P_c}$

$b \quad = \frac{0.07780RT_c}{P_c}$

$\alpha \quad = (1 + (0.37464 + 1.5422\omega - 0.2699\omega^2)(1 - {T_r}^{0.5}))^2$

$T_r \quad = \frac{T}{T_c}$

$P_c \quad =$ critical pressure

$T_c \quad =$ critical temperature

$\omega \quad =$ acentric factor for involved species

This correlation is used to calculate the volume of 100% methane gas as a function of pressure and temperature. This equation expresses fluid properties in terms of the critical properties and acentric factor for each species involved. Thus, it is suitable to be applied in the simulation since coalbed matrix commonly is filled with pure methane instead of other type of gas.

In addition, it is a concern that ECLIPSE software came up with many versions with different extended applications. In ECLIPSE 100, CBM applications are to the degree of simulating CBM production with single porosity system. However, ECLIPSE 100 also could introduce a second gas known as solvent for ECBM project. Since CBM is made up of dual porosity system, ECLIPSE 100 seems to be unfit for this simulation study. Meanwhile, ECLIPSE 300 provides full compositional treatment for advanced ECBM work and generates dual porosity system simulation. Thus, ECLIPSE 300 is selected.

3.0 METHODOLOGY

3.1 Data Acquisition

In preparation of this report, the writer has to go through various resources as well as obtaining justification from related person. This is to ensure the integrity of the analysis and to provide reliable information. Basically, the process of data acquisition is as follow:

i) Meeting with entitled supervisor to have consultation and advice on the topic. Through brainstorming, the topic could be well defined and clarified. Then, completion of proposal follows after that in order to draft the structure of the research.

ii) Finding the required information from sources such as journal, technical papers and books. Papers such as those published by SPE and other Oil and Gas Research parties help to provide valuable data. It is important to find historic wells published data to be used in the reservoir modeling during simulation session.

iii) Attending simulation lab under the supervision of lecturer. This helps to understand how the simulation system works and what to be obtained from the output of the program.

3.2 Key Milestone

This report is also going to be completed in following stages:

i) <u>Overview of title</u>

Clarify the requirements, objectives and expected results from the study.

ii) <u>Finding and gathering data</u>

Collect available information related to the topic. Gather supportive materials for reference purpose.

iii) <u>Examination of data</u>

Identify problem statement. Interpret valuable information to be used in the analysis.

iv) <u>Simulation</u>

Work on the simulation of historic wells data. Attain the required results.

v) Technical Description

Work on precise and reliable explanation of data attained. Provide result and discussion.

vi) Output justification.

Proving the inference by calculation or/and discussion.

vii) Documentation

Compile all the paper work and references to form a complete report.

viii) Presentation

Supervisor's evaluation. Recommend improvement.

ix) Modification

Advance project work. Imply certain change and enhancement.

3.3 Flow Chart #1: Project Work Flow

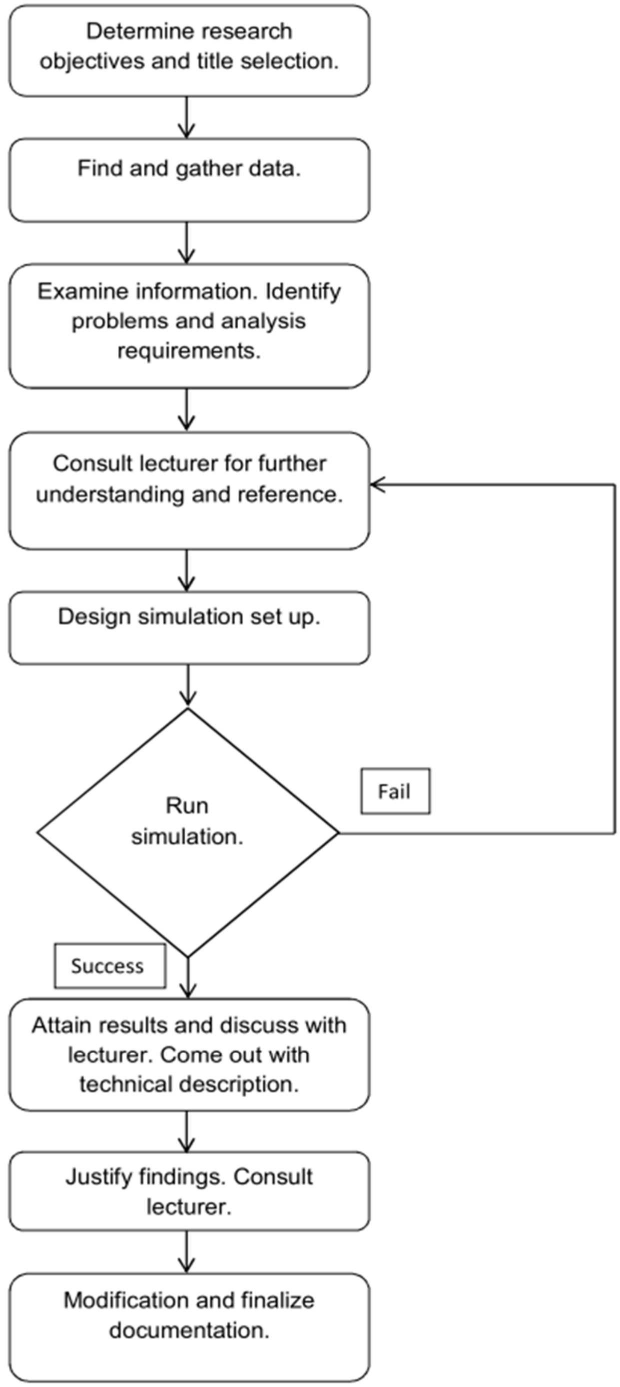

Figure 8: Project work flow

3.4 Data Preparation

Firstly, to run the simulation, preparation of data is required. The data that are involved in this research are reservoir data, gas properties and injection operation data. The required data and information were collected from the SPE paper published by Oudinot et al (2007). In summary, the data and information collected are as follows:

3.4.1 Reservoir Data

Table 3: Allison and Tiffany reservoir characteristics

Basin Name	**San Juan Basin**	
Production Unit	**Allison**	**Tiffany**
Depth of Top Coal	3100 ft	3000 ft
Thickness	43 ft	47 ft
Permeability	100 mD	1 mD
Average Matrix Porosity	20 %	20 %
Coal Rank	Med vol sub-bituminous (1.33%)	Med vol sub-bituminous (1.33%)
Initial Reservoir Pressure	1650 psi	1600 psi
Reservoir Temperature	120°F	120°F
Initial Fluid Saturation	Water: 0.95 Gas: 0.05	Water: 0.95 Gas: 0.05

Sources (1): Reeves S., 2003, "Enhanced Coalbed Methane Recovery", Advanced Resources International, Houston, TX, presented during SPE Distinguished Lecture Series of 2002/2003 season.

(2): Reeves S., Tailefert A., Pekot L., 2003, "The Allison Unit CO_2-ECBM Pilot: A Reservoir Modeling Study", U.S. Department of Energy Topical Report prepared by Advanced Resources International.

Table 4: Relative permeability relationship of Allison production unit

Water Saturation S_w	Rel. Perm. to Water K_{rw}	Rel. Perm. to Gas K_{rg}	Water Saturation S_w	Rel. Perm. to Water K_{rw}	Rel. Perm. to Gas K_{rg}
0.00	0.000	1.00	0.55	0.100	0.015
0.05	0.030	0.260	0.60	0.110	0.010
0.10	0.040	0.130	0.65	0.115	0.000
0.15	0.050	0.090	0.70	0.120	0.000
0.20	0.060	0.060	0.75	0.120	0.000
0.25	0.065	0.050	0.80	0.125	0.000
0.30	0.070	0.040	0.85	0.125	0.000
0.35	0.075	0.030	0.90	0.130	0.000
0.40	0.080	0.025	0.95	0.130	0.000
0.45	0.083	0.025	0.975	0.475	0.000
0.50	0.095	0.020	1.00	1.000	0.000

Table 5: Relative permeability relationship of Tiffany production unit

Water Saturation S_w	Rel. Perm. to Water K_{rw}	Rel. Perm. to Gas K_{rg}	Water Saturation S_w	Rel. Perm. to Water K_{rw}	Rel. Perm. to Gas K_{rg}
0.00	0.000	1.000	0.55	0.190	0.060
0.05	0.010	0.640	0.60	0.220	0.050
0.10	0.020	0.300	0.65	0.250	0.045
0.15	0.035	0.220	0.70	0.280	0.038
0.20	0.040	0.130	0.75	0.330	0.035
0.25	0.060	0.110	0.80	0.380	0.030
0.30	0.080	0.090	0.85	0.490	0.020
0.35	0.100	0.080	0.90	0.600	0.015
0.40	0.120	0.075	0.95	0.800	0.010
0.45	0.140	0.070	0.975	0.880	0.005
0.50	0.160	0.060	1.00	1.000	0.000

Sources (1): Reeves S., 2003, "Enhanced Coalbed Methane Recovery", Advanced Resources International, Houston, TX, presented during SPE Distinguished Lecture Series of 2002/2003 season.

(2): Reeves S., Tailefert A., Pekot L., 2003, "The Allison Unit CO_2-ECBM Pilot: A Reservoir Modeling Study", U.S. Department of Energy Topical Report prepared by Advanced Resources International.

3.4.2 Reservoir Data

Table 6: Basic descriptions of San Juan basin ECBM operations

Basin Name	San Juan Basin	
Production Unit	Allison	Tiffany
Total Production Duration	1989-2001 (12 years)	1993-2002 (9 years)
ECBM Duration	6 years continuous injection	4 years intermittent injection
Injection Rate	660 Mcuft / day of CO_2 per well	3.3MMcuft / day of N_2 per well

Sources (1): Reeves S., 2003, "Enhanced Coalbed Methane Recovery", Advanced Resources International, Houston, TX, presented during SPE Distinguished Lecture Series of 2002/2003 season.

(2): Reeves S., Tailefert A., Pekot L., 2003, "The Allison Unit CO_2-ECBM Pilot: A Reservoir Modeling Study", U.S. Department of Energy Topical Report prepared by Advanced Resources International.

3.4.3 Gas Properties

Table 7: Gas properties of Methane, CO_2 and N_2

Type of Gas	Methane, CH_4	Carbon Dioxide, CO_2	Nitrogen, N_2
Langmuir Pressure	509 psi	245.3 psi	1429 psi
Langmuir Volume	0.01192374 m^3/kg	0.0173860 m^3/kg	0.00802199 m^3/kg
Molecular Weight	44.01	16.043	28.013
Critical Temperature	190.45 K	304.15 K	126.1 K
Critical Pressure	1070.7 psi	666.6 psi	492.23 psi
Critical Z-factor	0.274	0.285	0.292
Critical Volume	0.098 m^3/kg-mol	0.094 m^3/kg-mol	0.090 m^3/kg-mol
Acentric Factor	0.013	0.228	0.040

Sources (1): Reeves S., 2003, "Enhanced Coalbed Methane Recovery", Advanced Resources International, Houston, TX, presented during SPE Distinguished Lecture Series of 2002/2003 season.

(2): Reeves S., Tailefert A., Pekot L., 2003, "The Allison Unit CO_2-ECBM Pilot: A Reservoir Modeling Study", U.S. Department of Energy Topical Report prepared by Advanced Resources International.

3.4.4 Size of Grid

The actual study areas of Allison and Tiffany production units are around 320 acres or 13, 939, 200 ft^2. This however is too big for ECLIPSE simulator to run. For simplicity, the size of the grid is made smaller than actual field size. The size of the grid is 11x11x2 with 20 m per unit side as shown in figure 9. Thus, the total grid area is 48400 m^3 or 11.96 acres which 28 times reduction in size compared to actual study area. In addition, the numbers of injector and producer wells are set as 1 instead of using the actual numbers. The injection rate however, is fixed to actual injection per well.

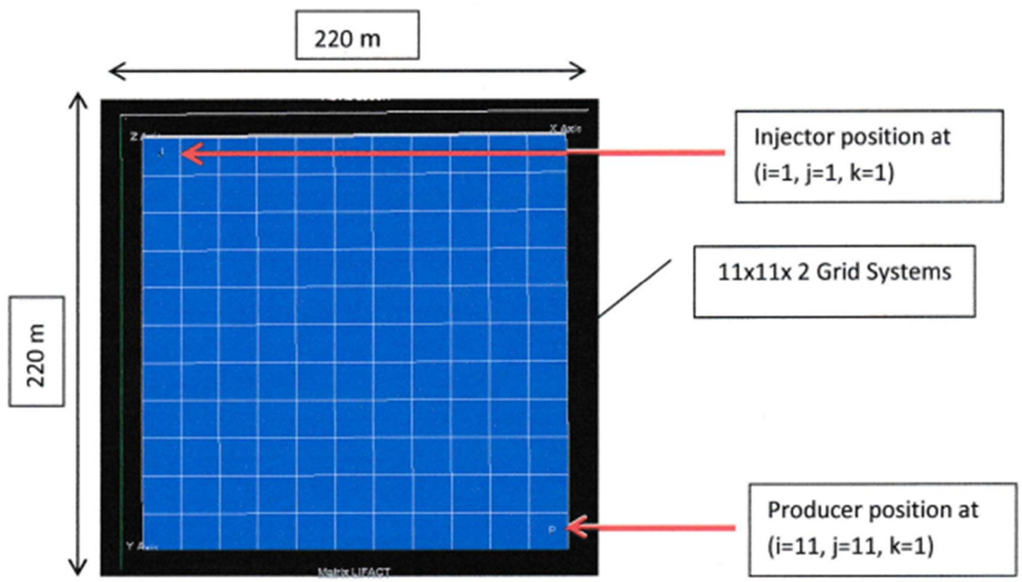

Figure 9: Schematic diagram of rectangular grid system used in simulation

3.4.5 Production/Injection Timing and ECBM Interchange

It is interesting to see the corresponding production due to different time of ECBM operation. For example, between injection of gas after two years of production and injection of gas after 3 years of production, which one leads to greater total production? Thus, by choosing different timing of injection prior to production period, the optimum time for ECBM could be noticed. In addition, since both production units are from the same basin and the reservoir properties are almost the same, the ECBM process could be interchanged in every separate simulation run. This means that Allison unit which was injected using CO_2 could be simulated to run the production along with injection of using N_2. The same also goes to Tiffany unit where previous N_2 injection could be changed to CO_2 injection in simulation. This will provide useful data that could be implemented in comparative study later on. The simulation of both Allison and Tiffany units are going to be run as shown in the figure below.

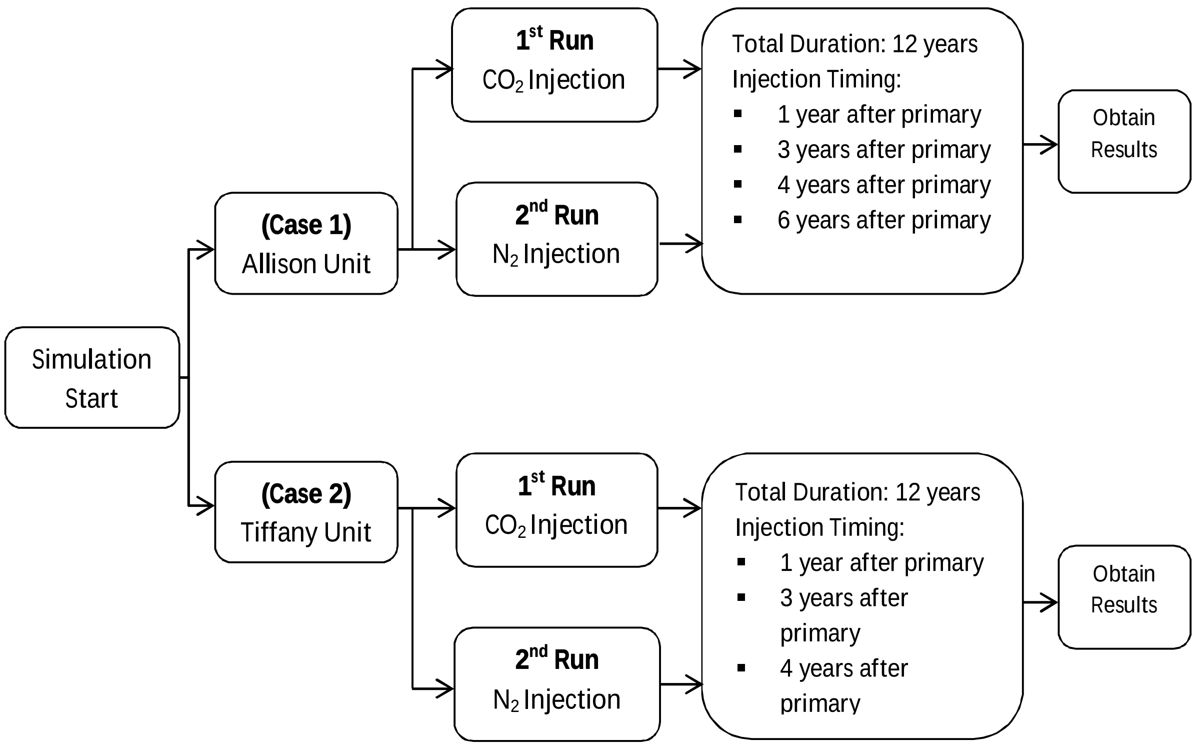

Figure 10: Simulation work flow

3.4.6 Langmuir Constants Assumptions

One of the key elements required to complete the coding for the simulation model is the availability of Langmuir constants for each gas that already or will presence in the coal formation. In this simulation study, the Langmuir constants for methane, CO_2 and N_2 must be derived based on the reservoir conditions. These constants could be generated through the works of laboratory with using coal samples. In the case of Allison production unit, the Injectant used is CO_2, thus there is no available data on N_2 Langmuir constants and goes to Tiffany unit where CO_2

Langmuir constants are unidentified. Thus, there would be a complexity to do ECBM interchange. However, since both production units are from the same basin, and the fact that the reservoir conditions of both units are almost the same, the Langmuir constants could be assumed the same in any location throughout the basin. With this assumption, the ECBM interchange study is possible.

3.5 Gantt Chart

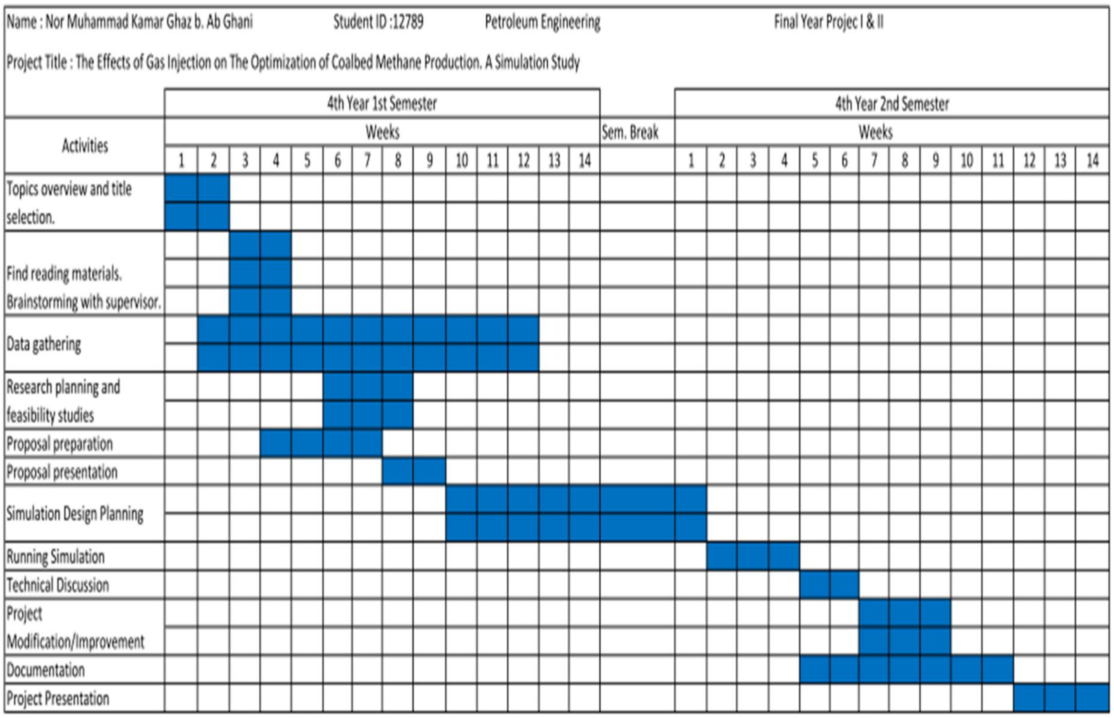

Figure 11: Project Gantt Chart

4.0 RESULTS AND DISCUSSIONS

4.1 Case 1, 1st Run: Allison Production Unit with CO_2 Injection

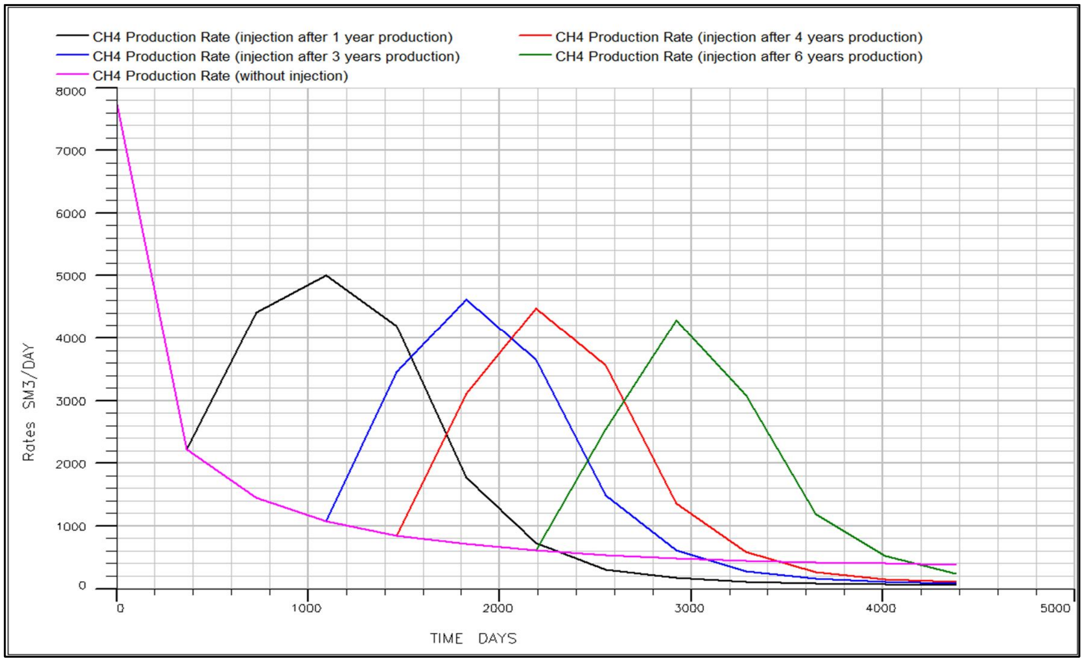

Figure 12: Production rates of CH_4 due to CO_2 injection for Allison production unit

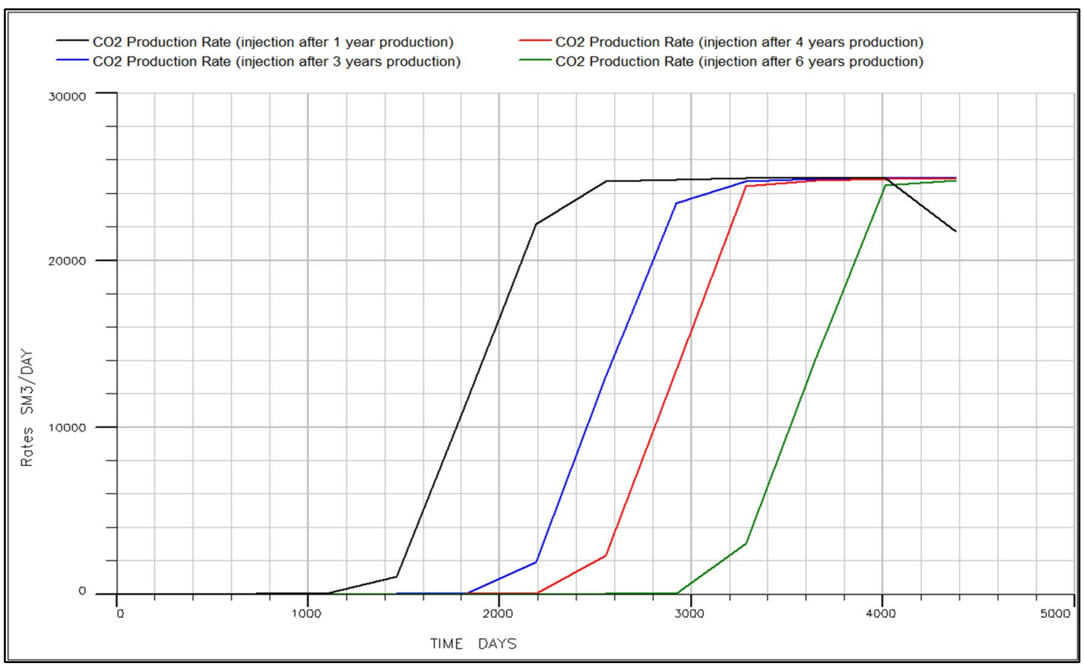

Figure 13: CO_2 production rate for Allison unit

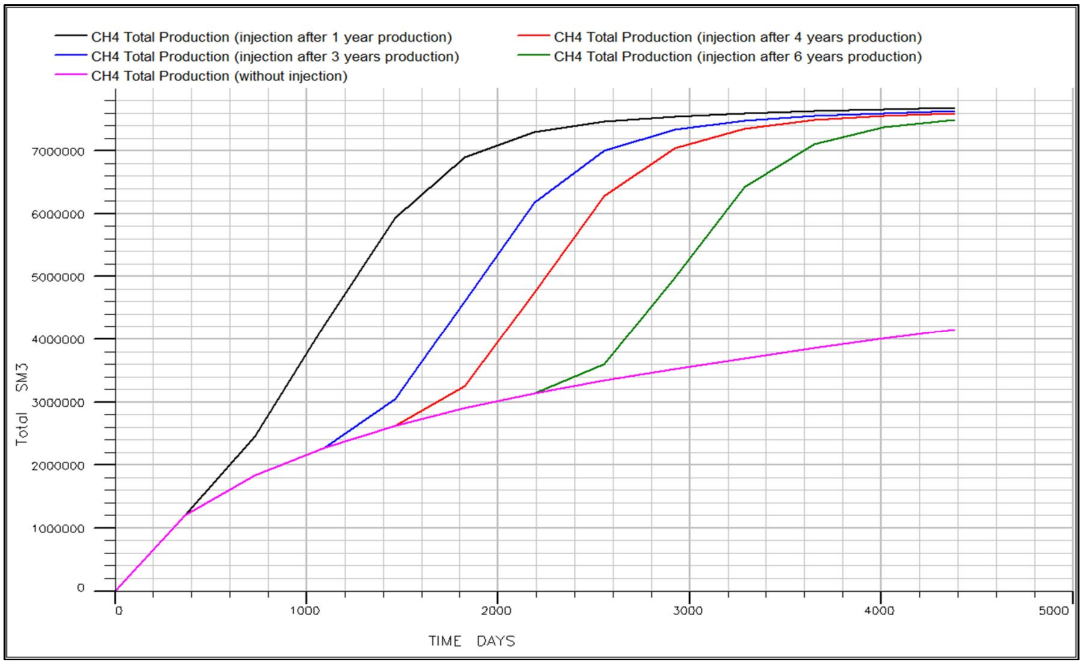

Figure 14: Total production of CH_4 due to CO_2 injection for Allison production unit

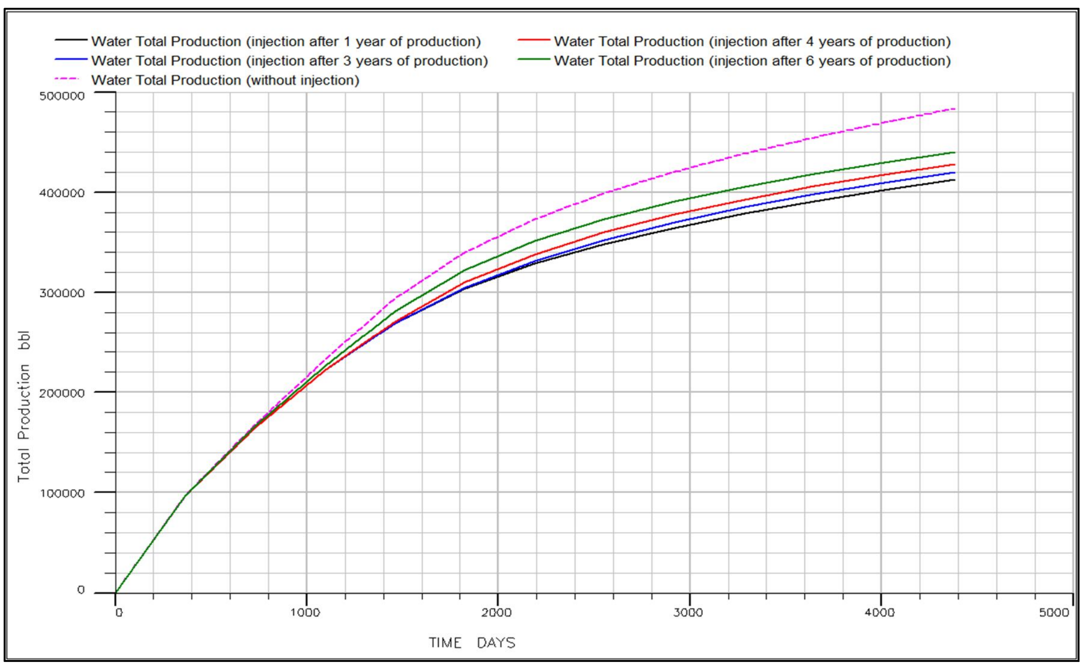

Figure 15: Total water production due to CO_2 injection for Allison production unit

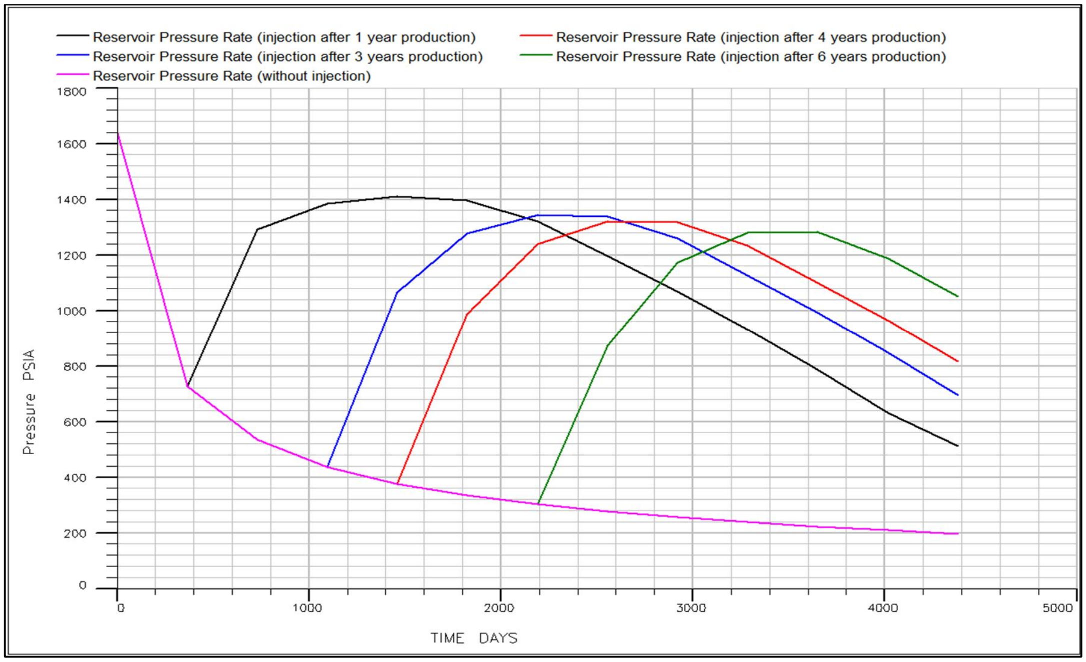

Figure 16: Reservoir pressure rate due to CO_2 injection for Allison production unit

Table 8: Output data obtained for Allison (Case 1, 1st run - CO_2 ECBM)

Gas Injection Timing	Total CH_4 Production	Total Water Production	Maximum Pressure Build-up
No injection	147 MMcuft	484 Mbbl	-
1 year after primary	271 MMcuft	412 Mbbl	1410.8 psia
3 years after primary	269 MMcuft	420 Mbbl	1343.9 psia
4 years after primary	268 MMcuft	429 Mbbl	1325.7 psia
6 years after primary	265 MMcuft	441 Mbbl	1289.2 psia

From the first run of case 1; Allison production unit with CO_2 injection, it can be seen that the total production of methane is the highest when the gas injection is made at 1 year after primary production (see figure 14). The CO_2 injection just after a year of production able to boost the production with maximum incremental of 3.53 $MMsm^3$ or 124 MMcuft compared to production without ECBM. Approximately, the total productions of all ECBMs at different injection timing are not gap with too much of end values. Consistently, from the graph of figure 13, the production of injection gas which is CO_2 take place roughly after 2 years of injection in each ECBM and as the injection of gas take place earlier, the total injected gas production will be higher. In addition, the total productions of water also show declination due to injection in each ECBM (see figure 15). Maximum pressure build-up as shown in figure 16 occurred when CO_2 is injected after 1 year of primary production. However, the maximum pressure build-up of 1410.8 psia is still below the reservoir initial pressure which is 1650 psia. Table 8 is the summarization of the output data from the simulation run.

4.2 Case 1, 2nd Run: Allison Production Unit with N_2 Injection

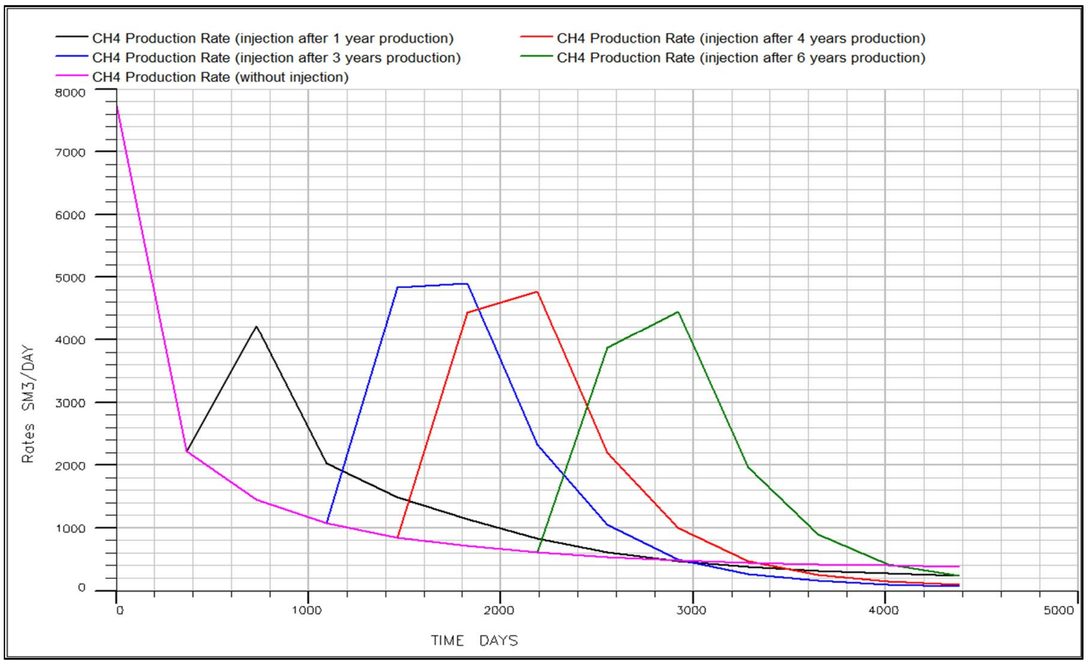

Figure 17: Production rates of CH_4 due to N_2 injection for Allison production unit

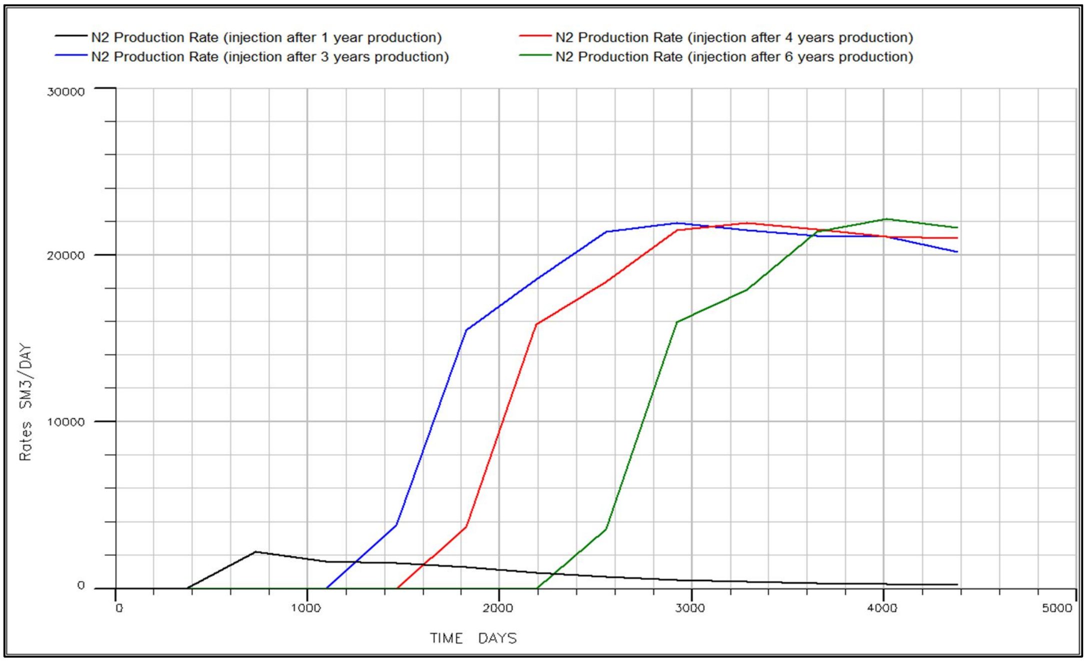

Figure 18: Production rates of N_2 for Allison production unit

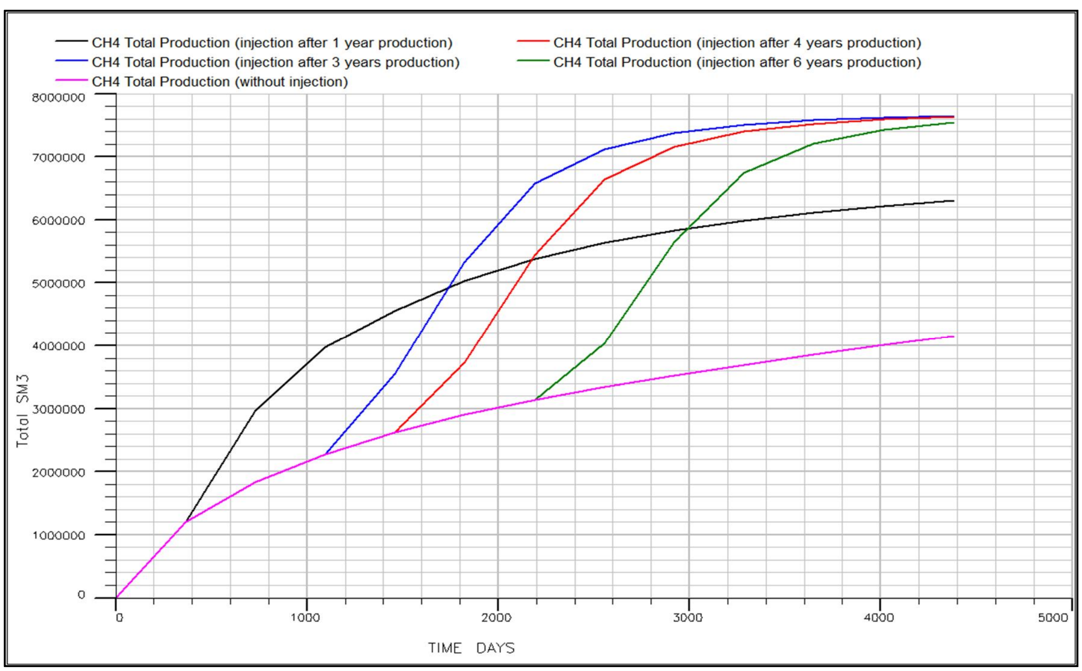

Figure 19: Total production of CH_4 due to N_2 injection for Allison production unit

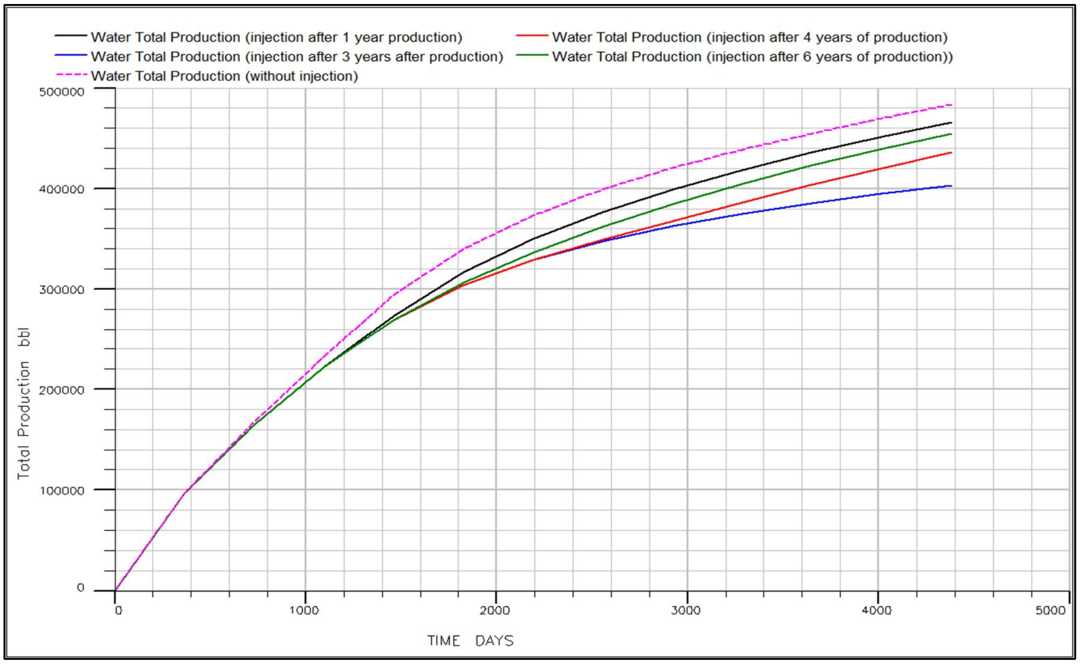

Figure 20: Total water production due to N_2 injection for Allison production unit

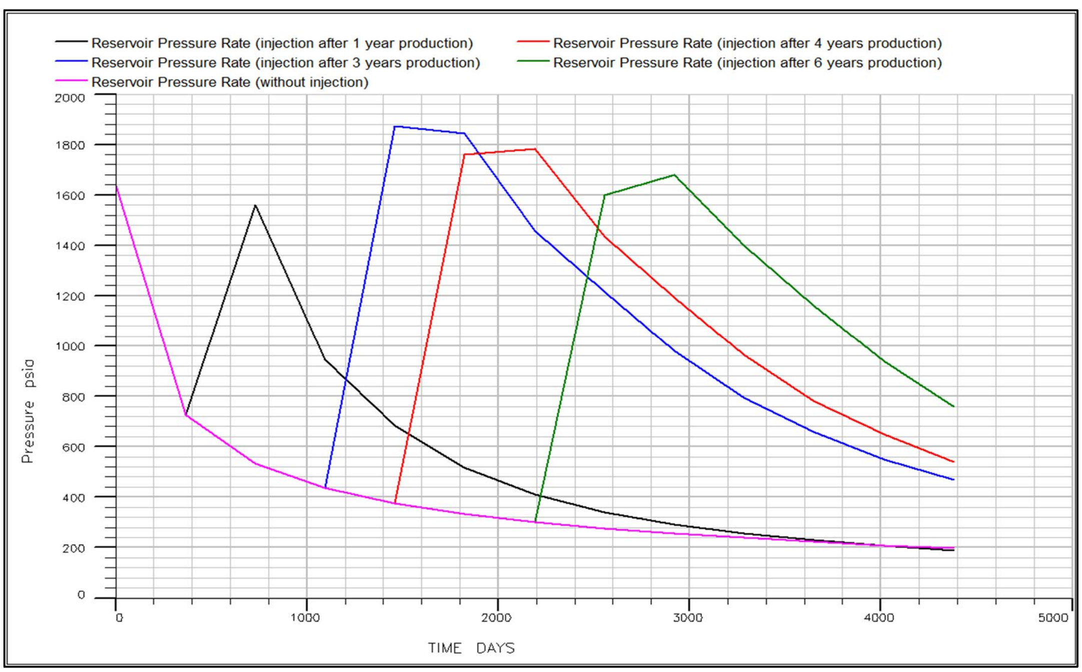

Figure 21: Reservoir pressure rates due to N_2 injection

Table 9: Output data obtained for Allison (Case 1, 2nd run - N_2 ECBM)

Gas Injection Timing	Total CH_4 Production	Total Water Production	Maximum Pressure Build-up
No injection	147 MMcuft	484 Mbbl	-
1 year after primary	223 MMcuft	403 Mbbl	1560.8 psia
3 years after primary	270 MMcuft	436 Mbbl	1871.6 psia
4 years after primary	269 MMcuft	456 Mbbl	1790.5 psia
6 years after primary	266 MMcuft	484 Mbbl	1684.2 psia

From the second run of case 1; Allison production unit with N_2 injection, it is observed that the total production of methane is the highest when the gas injection is made at 3 years after primary production (see figure 19). The N_2 injection at after 3 years of production driven up the production to maximum incremental of 3.50 $MMsm^3$ or 123 MMcuft compared to production without ECBM. Total production of ECBM with injection timing of 1 year after primary production is the lowest compared to other ECBMs but still at higher accumulative value than primary production alone. From the graph of figure 18, the production of injection gas which is N_2 takes place immediately after its introduction to the reservoir. As expected, the total productions of water also show declination due to injection in each ECBM as shown in figure 20. In term of pressure build-up, based on figure 21, maximum reading is noted when N_2 is injected after 3 years of primary production. In this simulation, the maximum pressure build-up of 1871.6 psia is above the reservoir initial pressure which is 1650 psia. Table 9 summarized the output data of the simulation run.

4.3 Case 2, 1st Run: Tiffany Production Unit with CO_2 Injection

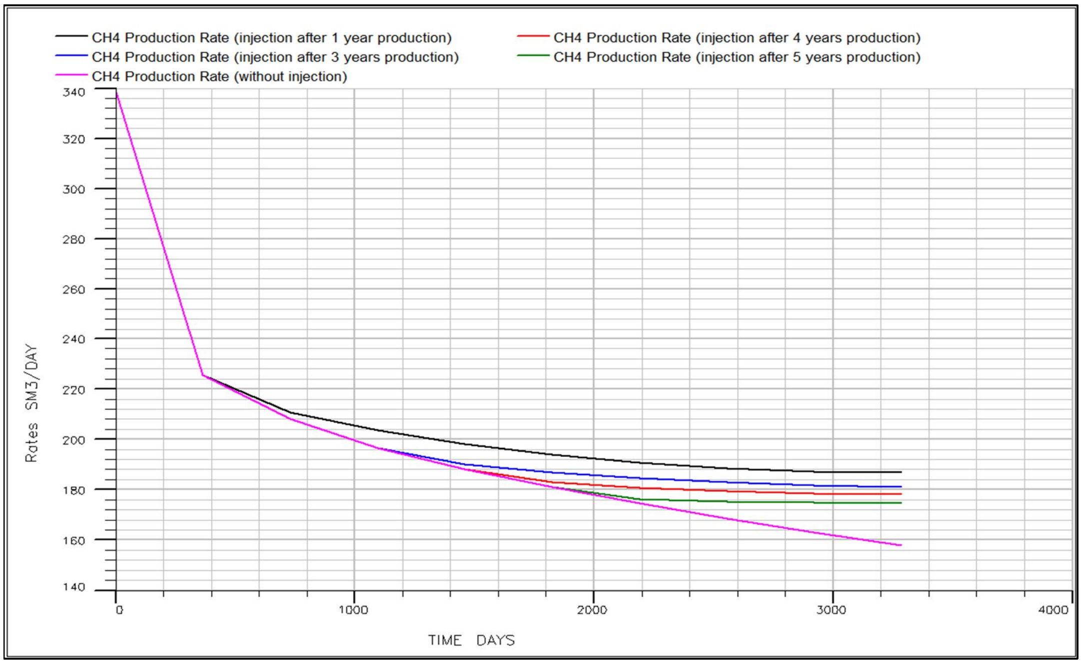

Figure 22: Production rates of CH_4 due to CO_2 injection for Tiffany production unit

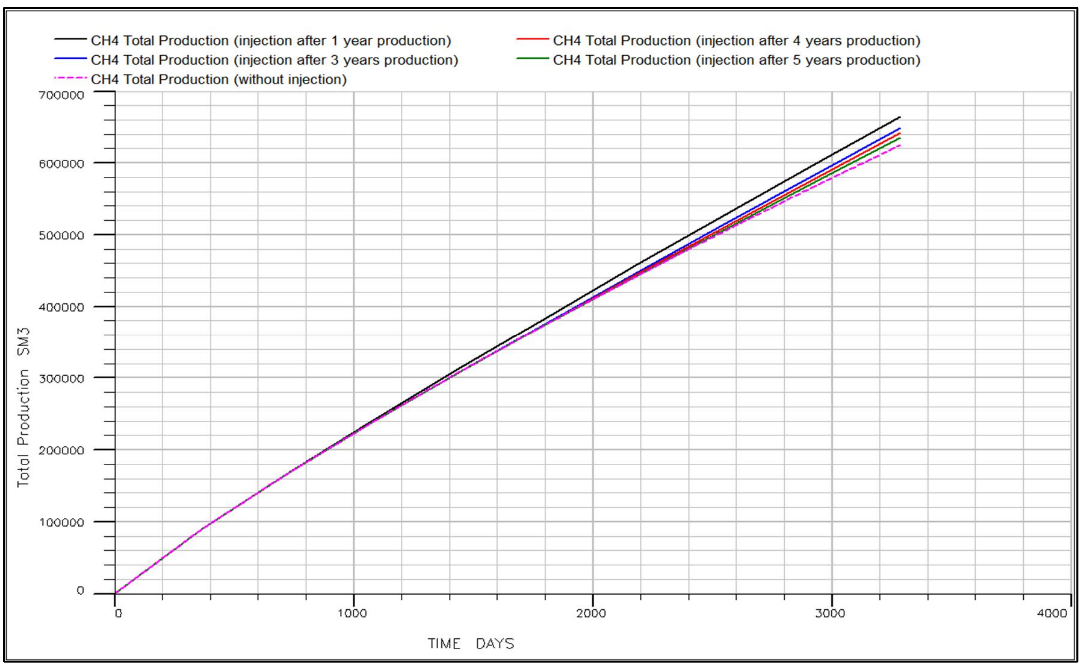

Figure 23: Total production of CH_4 due to CO_2 injection for Tiffany production unit

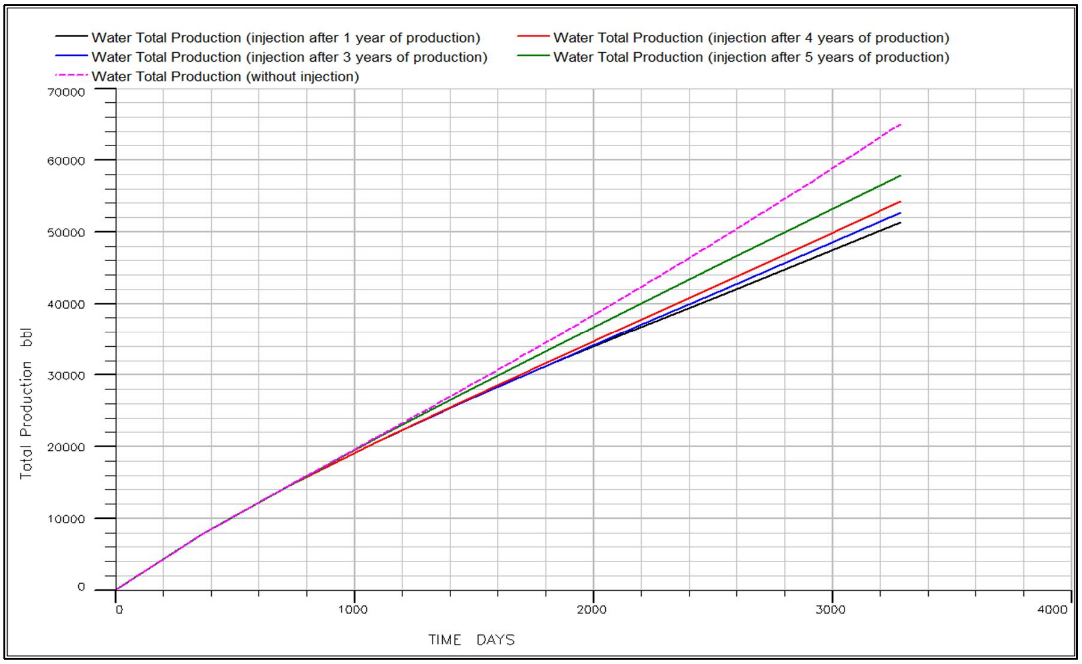

Figure 24: Total water production due to CO_2 injection for Tiffany production unit

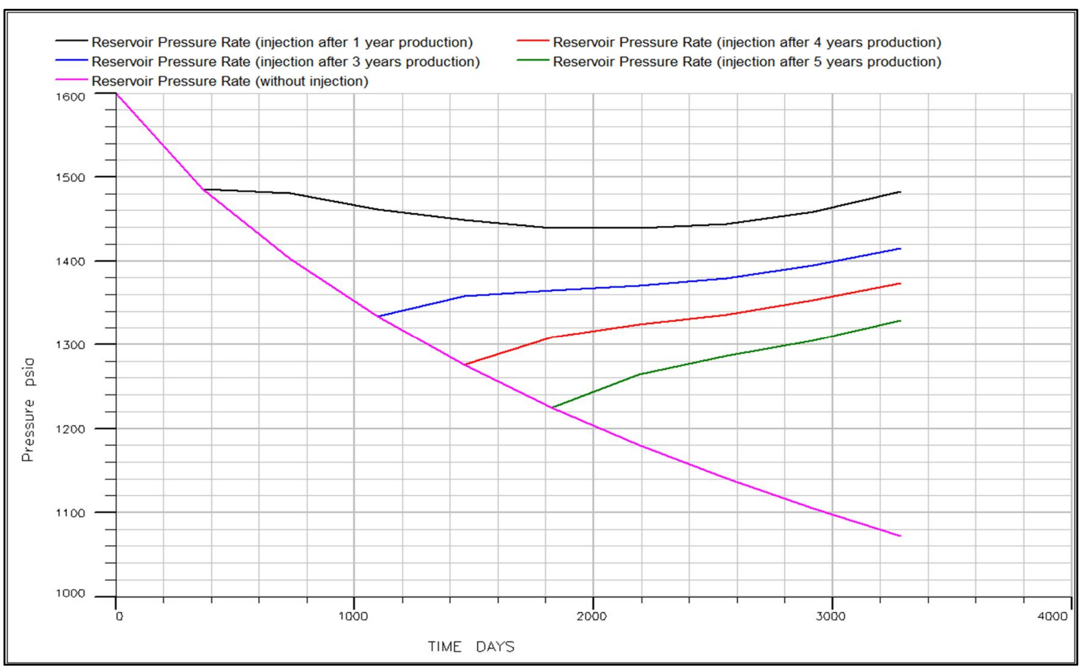

Figure 25: Reservoir pressure rates due to CO_2 injection for Tiffany production units

Table 10: Output data obtained for Tiffany (Case 2, 1st run - CO_2 ECBM)

Gas Injection Timing	Total CH_4 Production	Total Water Production	Maximum Pressure Build-up
No injection	22.1 MMcuft	65.0 Mbbl	-
1 year after primary	23.4 MMcuft	51.5 Mbbl	1483.0 psia
3 years after primary	22.9 MMcuft	52.7 Mbbl	1414.7 psia
4 years after primary	22.7 MMcuft	54.2 Mbbl	1373.5 psia
5 years after primary	22.5 MMcuft	58.0 Mbbl	1328.7 psia

Based on the first run of case 2; Tiffany production unit with CO_2 injection, it is observed that the total production of methane is the highest when the gas injection is made at 1 year after primary production (see figure 23). The CO_2 injection at after 1 year of production driven up the total production to maximum incremental of 41 Msm^3 or 1.45 MMcuft compared to total production without gas injection. Generally, the total productions of all ECBMs of different injection timing are not far departed from primary production with no injection. For some reasons, the injected gas in this simulation which is CO_2, is not been produced within the operation time. Likewise, the total productions of water also show declination due to injection in each ECBM as shown in figure 24. In term of pressure build-up, maximum reading is taken from ECBM with injection timing of 1 year after primary production. The maximum pressure build-up based on figure 25 is 1483.0 psia. This maximum pressure build-up is low compared to reservoir initial pressure which is 1650 psia. Table 10 summarized the output data of this simulation.

4.4 Case 2, 2nd Run: Tiffany Production Unit with N_2 Injection

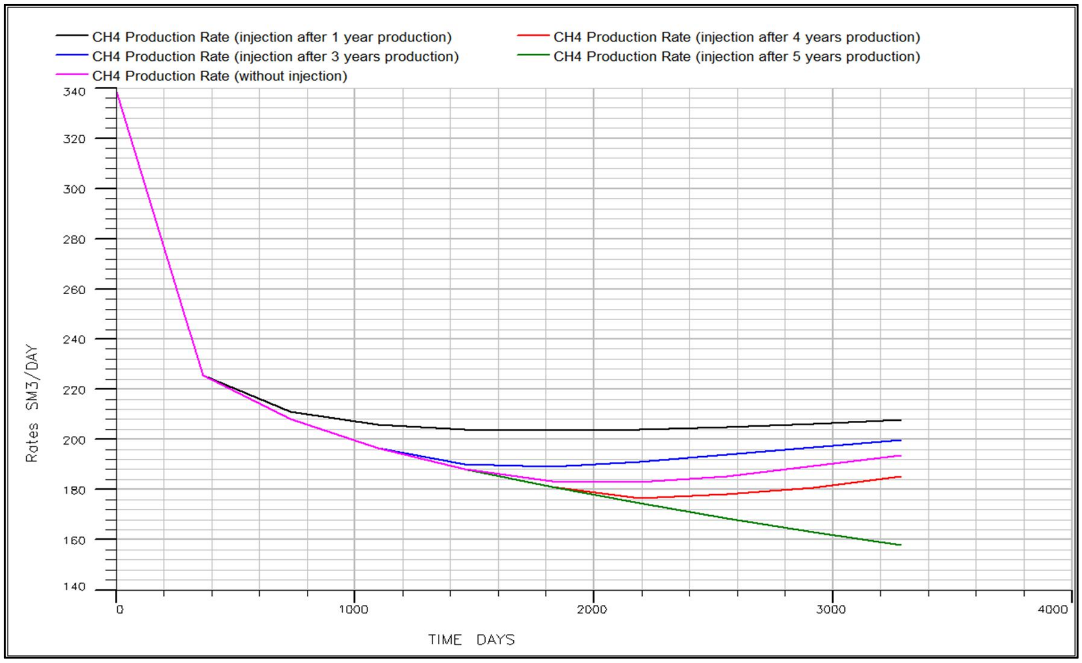

Figure 26: Production rates of CH_4 due to N_2 injection for Tiffany production unit

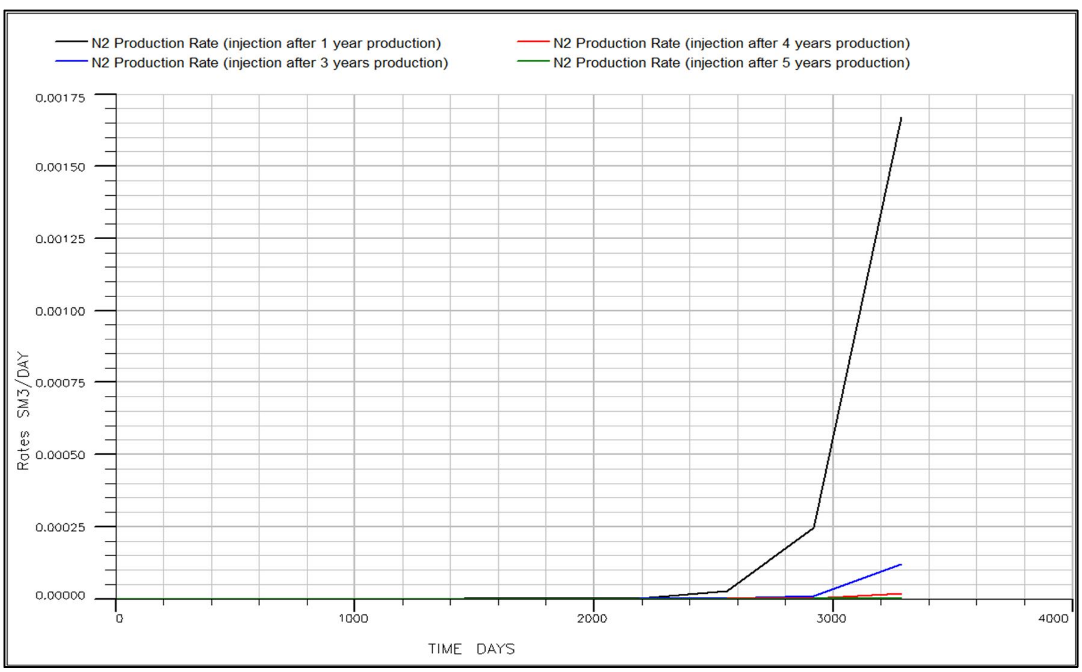

Figure 27: Production rates of N_2 for Tiffany production unit

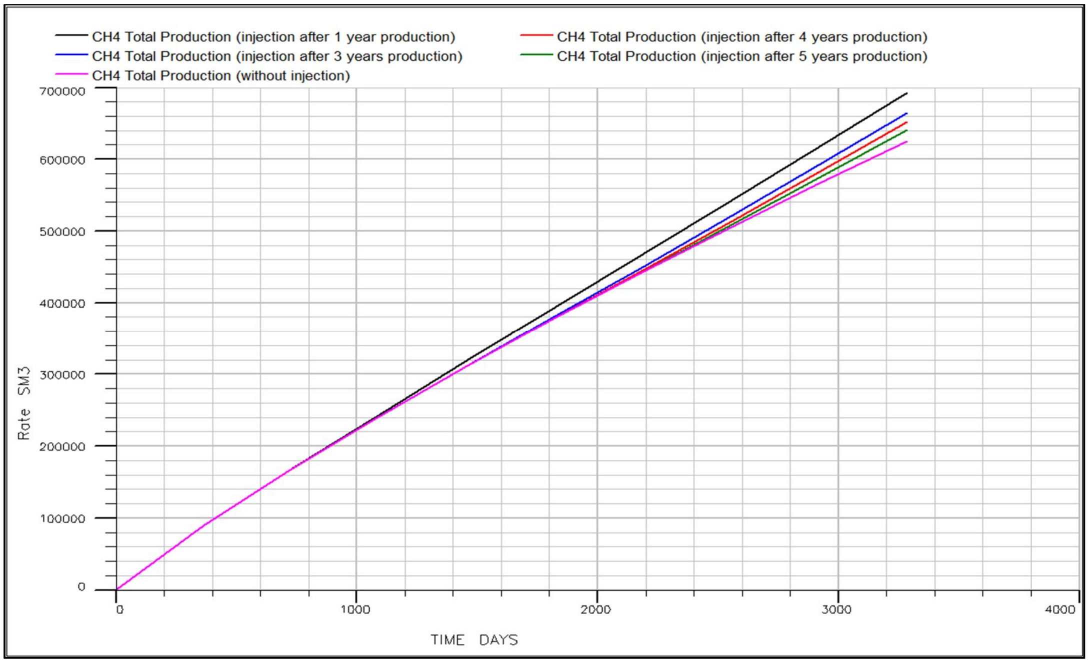

Figure 29: Total production of CH_4 due to N_2 injection for Tiffany production unit

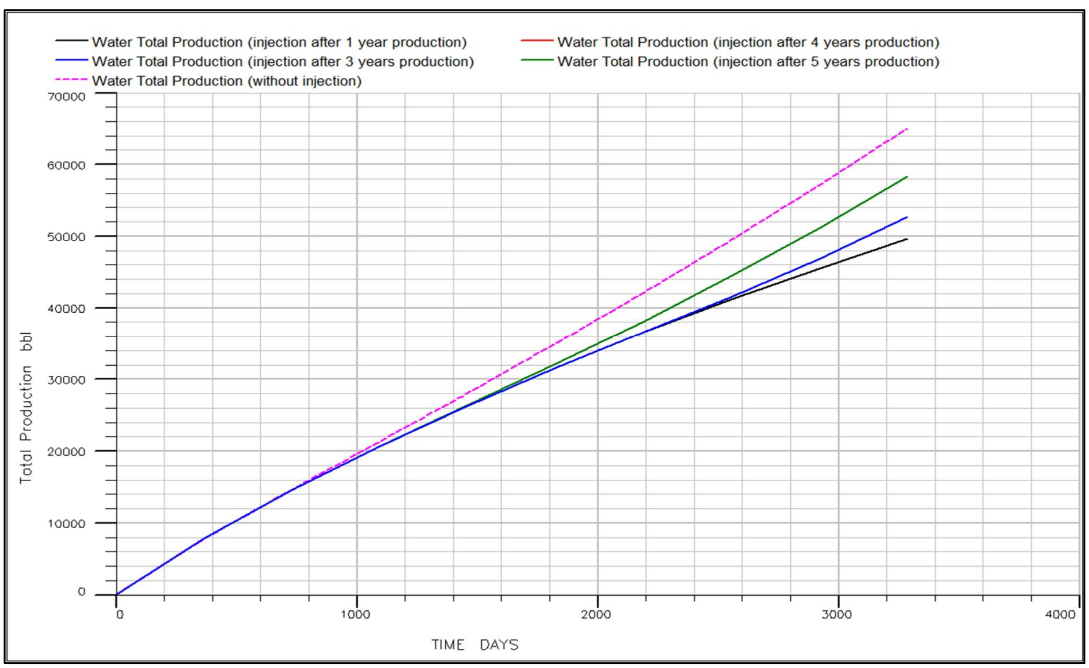

Figure 28: Total production of water due to N2 injection for Tiffany production unit

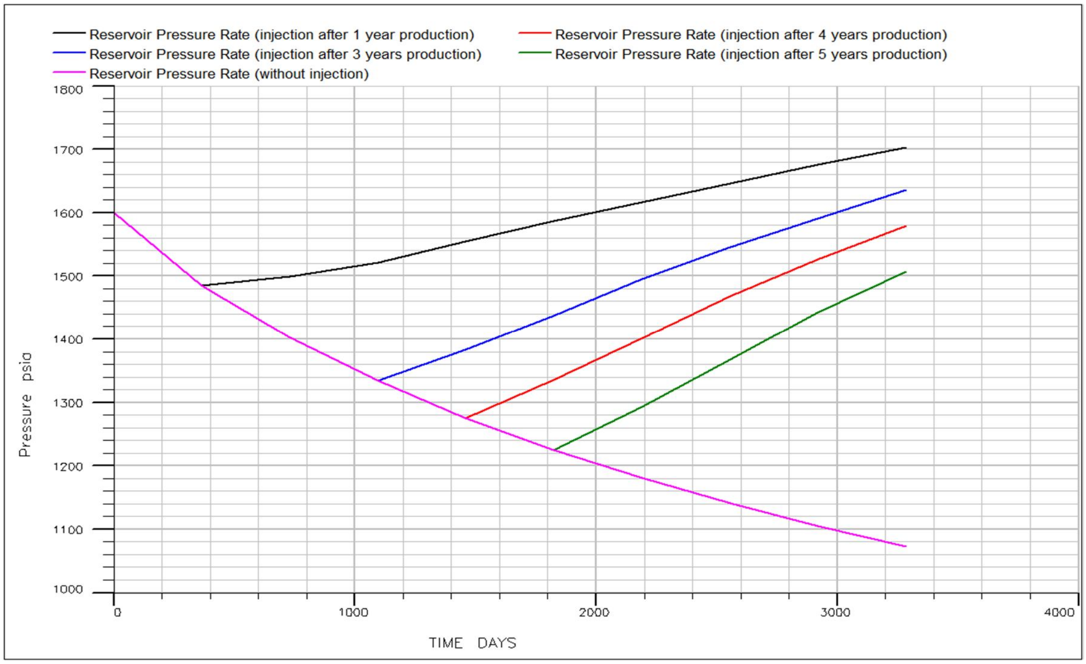

Figure 30: Reservoir pressure rates due to N_2 injection for Tiffany production unit

Table 11: Output data obtained for Tiffany (Case 2, 2^{nd} run – N_2 ECBM)

Gas Injection Timing	Total CH_4 Production	Total Water Production	Maximum Pressure Build-up
No injection	22.1 MMcuft	65.0 Mbbl	-
1 year after primary	24.5 MMcuft	45.3 Mbbl	1702.7 psia
3 years after primary	23.5 MMcuft	52.7 Mbbl	1635.3 psia
4 years after primary	23.0 MMcuft	49.7 Mbbl	1579.4 psia
5 years after primary	22.6 MMcuft	58.3 Mbbl	1506.8 psia

Based on the second run of case 2; Tiffany production unit with N_2 injection, it can be inferred that the total production of methane is the highest when the gas injection is made at 1 year after primary production (see figure 28). The N_2 injection at after 1 year of production boost-up the total production to maximum incremental of 68 Msm^3 or 2.4 MMcuft compared to total production without gas injection. Generally, the total productions of all ECBMs of different injection timing are not far departed from primary production with no injection. In contrast with the first run where there is no injected CO_2 production, the production of N_2 in this second run happened 1 year after injection (see figure 27). As shown is figure 16, the total productions of water also show declination due to injection in each ECBM. In term of pressure build-up, figure 30 shows that maximum reading is taken from ECBM with injection timing of 1 year after primary production. The maximum pressure build-up of 1702.7 psia is far greater than the reservoir initial pressure which is 1650 psia. Table 11 summarized the output data for this simulation run.

4.5 Comparative Study of ECBM CO2 and N2 Injection

From the graphs generated in case 1 for Allison unit, N_2 injection provides superior production total than CO_2 at all injection timings except for the injection at 1 year after primary production. At timing of 1 year after production, it can be said that the CO_2 injection has effectively displaced methane and boost the total production to highest point compared to N_2 injection. This could be explained by knowing the reservoir condition at the time frame. As stated in the EPA report (68-W-00-094), though that N_2 injection reduced methane partial pressure in the coal seam, sometime the total pressure is still constant due to the availability of mass volume of water inside the formation. In this case, the production of methane could not be fully optimized since the deliberation of methane by partial pressure reduction technique is demoted by the presence of high volume of water which maintains the reservoir total pressure. Thus, it explained the low total production curve for N_2 injection at timing of 1 year after production where in this time frame, the production of water is still low and the reservoir pressure is still significantly high. In contrast, CO_2 which displaces the methane would have no problem to push out the adsorbed methane from the formation even if the dewatering rate is low. In overall, the N_2 injection however, gives faster methane recovery than CO_2 injection. The advantage of N_2 over CO_2 is its nature of adsorption. Methane adsorbs more strongly to coalbed surface than does nitrogen and this helps with reduction of the partial pressure of methane in the free gas within pores. This also results in a faster response time for N_2 injection relative to CO_2 injection because a smaller volume of the injectant is lost due to adsorption to coal surface. Thus, N_2 injection has shorter time of breakthrough compared to CO_2 injection. This is why N_2 injection results in faster methane recovery. In term of injectant production, CO_2 is less produced since it absorbed strongly in coalbed formation. Graph of figure 13 indicates that CO_2 took about two years to be produced after injection while N_2 production rate is immediately taking place after injection (see figure 18). At the end, N_2 is been produced far greater in amount than CO_2. Ultimately, if there is ever a selection to be made between these two kinds of injection for Allison unit based on the simulations, it would be CO_2 injection as it provides higher recovery at early timing of injection. CO_2 also resulted in lesser injectant and water production which contributes to economic and environmental sides of the CBM operation.

Next, from the results obtained for case 2 which is Tiffany unit, it is clear that N_2 injection helps to increase the total production of methane better than CO_2 injection. Even at timing of 1 year after production, it can be deducted that N_2 injection has boosted the total production to highest point compared to CO_2 injection. This is very in contrast with the production trend which resulted from Allison simulation run. To explain the domination of N_2 in this simulation it is important to take a look at Tiffany reservoir permeability as provided in table 3. Tiffany coal formation is known to have extremely low permeability with value of 1mD. Due to this, gas transmissibility in the reservoir is very low. As explained by Peihong and Haixia (2008), coal permeability has great influence on gas volume drainage flow rate. As the permeability is low, the pressure drop is little thus resulting in poor transmission of fluid along the matrix. Since this is the biggest problem, drainage rate could be increased by growing up the pressure of the reservoir to an extent where the pressure drop is bigger thus improving gas delivering. To understand this better, following graph is generated from simulation of gas production rate with different permeability.

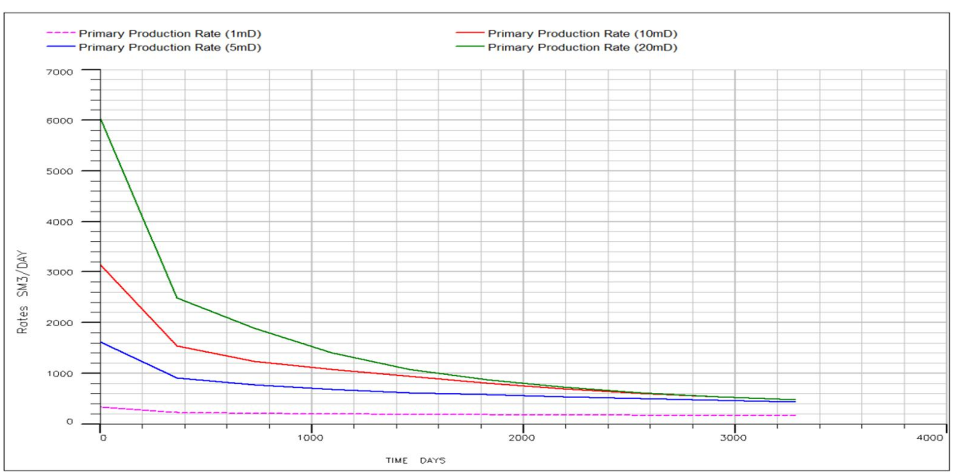

Figure 31: Production rate at different permeability

Above graph shows that, as the permeability is greater, the production rate is higher. Therefore, permeability brings a vital effect on gas delivering. It is a common understand that N_2 does not adsorb very well in coal seam as it has lower sorption capability than methane. This in turn, causes N_2 injection to build up higher pressure compared to CO_2 injection. For this reason, N_2 injection provides superior incremental of total production than CO_2 injection. Since the simulation in this study is set to be one producer and one injector, the incremental of total production depends greatly on duration injection timing in which the longer the injection timing, the higher the pressure build up. Figure 30 shows the pressure development due to N_2 injection at various injection timing. Thus, for Tiffany unit with very low permeability, injection of N_2 at 1 year after primary production delivers highest incremental of methane total production. Generally, it is observed that the total production of primary method is not at too much of a gap from ECBM total production. This is so because the number of injector is only one and thus, the injection of N_2 is quiet low to enhance the production of methane from Tiffany low permeability formation. In the previous real production scenario, Tiffany used up to 12 injector and 15 producing wells. Hence, in order to obtain higher production, the numbers of injector and producer wells have to be adjusted compliance with the reservoir sensitivity. In the end, for Tiffany production unit with very low permeability, N_2 injection is the best selection instead of CO_2 in term of production performance.

5.0 CONCLUSIONS

In the previous sections, we have investigated the performances of CO_2 and N_2 injections towards coalbed methane production of Allison and Tiffany units. An interesting observation is that each injection has advantage over another depending on the reservoir conditions. For Allison unit which made up of very high permeability range to 100mD, CO_2 is favorable as it provides high recovery in each injection timing, lower production of water and late production of injected gas compared to N_2 injection. Whereas, in simulation of Tiffany unit, due to very poor permeability of the coal formation, N_2 delivers significantly higher production incremental compared to CO_2 due to optimum partial pressure build-up. On the economical side, CO_2 is an effective enhanced recovery method due to the fact that it lowers the production of water and injected gas. This is because; the cost of separating the CO_2 and water from the stream of methane would definitely be reduced since the amounts of the mixture components are lower. However, it should not be deny that N_2 provides a good alternative in enhanced coalbed methane production. Due to this, the approach of introducing the mixture of both N_2 and CO_2 is brought forward. Numerous studies are now being conducted to delineate optimal gas mixture that will optimize methane production and CO_2 storage while minimizing the associated water production.

In conclusion, based on the results of this simulation study, it is deducted that:

1. Methane recovery from primary production is very low with a relatively large water production.
2. Injecting CO_2 increases methane recovery and decreases water production compared to injecting $N_{2.}$
3. Injecting N_2 at early timing will not results in optimized methane recovery as the partial pressure of N_2 is smaller compared to total pressure due to abundance presence of water.
4. CO_2 injection provides lower performance than N_2 injection in very low permeable coal formation.
5. Production of injected CO_2 would take longer period than injected N_2. This is due sorption characteristics of both gases. CO_2 has high sorption capability than methane, does it tend to retains in the formation. While N_2 with low sorption capability would transmits along with methane into the production borehole.
6. N_2 injection provides faster recovery than CO_2 as N_2 has faster breakthrough time.

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