NUMERICAL INVESTIGATION OF ECBM RECOVERY AND CO_2 SEQUESTRATION

A THESIS SUBMITTED TO THE GRADUATE SCHOOL OF APPLIED SCIENCES OF NEAR EAST UNIVERSITY

By
SAMUEL ADAMU ABUBAKAR

In Partial Fulfilment of the Requirements for the Degree of Master of Science in Petroleum and Natural Gas Engineering

NICOSIA, 2021

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Approval of Director of Institute of Graduate Studies

Prof. Dr. K. Hüsnü Can BAŞER

We certify that this thesis is satisfactory for the award of the degree of Masters of Science in Petroleum and Natural Gas Engineering

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I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

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To my Family…

ABSTRACT

The need for unconventional hydrocarbon resources such as Coal Bed Methane (CBM), shale gas/oil, tight sand gas and gas hydrates in recent times cannot be overemphasized. Depleting amounts of conventional resources with simultaneous increasing energy demand necessitates a thorough look into these unconventional resources in an effort to produce them economically and in considerable amounts. In an attempt at finding ways to deploy properly unconventional resources, this thesis will be focused on the development of CBM.

This thesis aims to discuss the mechanisms involved in CBM and CO_2-ECBM (enhanced coal bed methane) production and by performing simulations using CMG GEM, compare the results from both of these to find the best method of producing from CBM as well as finding out the best well orientation/configuration. The characteristics of the Onyeama coalbed field in Enugu, Nigeria was used to create ten scenarios to make these comparisons. These scenarios each had different arrangements and numbers for the producer and injector wells and therefore had different results.

It was seen from the simulation that it is possible to produce a lot of methane while sequestering large volumes of carbon dioxide. Analysing the amount of methane that could be produced and the amount of carbon that could be sequestered showed that the tenth scenario performed the best in terms of both. However, the economical analysis showed that the third scenario was the most profitable. The effect of pressure on the performance of CBM/ECBM processes was also investigated.

Keywords: CBM; ECBM; carbondioxide sequestration; CMG GEM; coal; economical analysis

ÖZET

Son zamanlarda Kömür Yatağı Metanı (KYM), kaya gazı / petrol, sıkı kum gazı ve gaz hidratları gibi geleneksel olmayan hidrokarbon kaynaklarına duyulan ihtiyaç fazlasıyla artmıştır. Aynı anda artan enerji talebiyle geleneksel kaynakların miktarlarının tükenmesi, ekonomik ve önemli miktarlarda üretme çabası içinde bu konvansiyonel olmayan kaynakların kapsamlı bir şekilde incelenmesini gerektirir. Geleneksel (konvansiyonel) olmayan kaynakları uygun şekilde bularak üretim yollarını araştıran bu tezde KYM'nın geliştirilmesine odaklanılacaktır.

Bu tez, KYM ve CO_2-GKYM (geliştirilmiş kömür yatağı metanı) üretiminde yer alan mekanizmaları tartışmayı ve CMG GEM programı kullanarak oluşturulan saha modeli kesitiyle simülasyonlar gerçekleştirerek, KYM'dan en iyi üretim yöntemini ve aynı zamanda en iyi kuyu yönlendirmesini / konfigürasyonunu bularak, bunların sonuçlarını karşılaştırmayı amaçlamaktadır. Nijerya Enugu'da bulunan Onyeama kömür yatağının özellikleri, bu karşılaştırmaları yapmak için on değişik senaryo için kullanıldı. Bu senaryoların her biri, üretim ve enjeksiyon kuyuları için farklı düzenlemelere ve sayılara sahip olduğundan farklı sonuçlara ulaşıldı.

Simülasyonlarda, bu farklı senaryolarda büyük miktarlarda karbondioksit tutulurken çok fazla metan üretmenin de mümkün olduğu görüldü. Üretilebilecek metan ve depolanacak karbondioksit miktarının analizi, onuncu senaryoda en iyi performansın elde edildiğini gösterdi. Fakat, ekonomik analizden sonra, üçüncü senaryonun aslında en karlı olduğu ortaya çıktı. KYM / GKYM süreçlerinin performansı üzerindeki basınç etkisi de araştırıldı.

Anahtar Kelimeler: KYM; GKYM; karbondioksit depolaması; CMG GEM; kömür; ekonomik analiz

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CAPEX:	Capital Expenditures
CBM:	Coal Bed Methane
CSS:	Carbon Sequestration and Storage
ECBM:	Enhanced Coal Bed Methane
EGR	Enhanced Gas Recovery
EOR:	Enhanced Oil Recovery
GHG:	Green House Gases
IRR:	Initial Rate of Return
NPV:	Net Prevent Value
OPEX:	Operating Expenses
ROI:	Rate of Investment

CHAPTER 1
INTRODUCTION

To be an engineer means to be a problem solver, which means engineers are constantly seeking new approaches to solving problems. Petroleum engineers are no different. With the constant depletion of hydrocarbon resources, one major problem petroleum engineers are faced with is how to produce more hydrocarbons safely and economically. Attempts to solve this problem include the application of secondary recovery methods, Enhanced Oil Recovery (EOR) methods and development of unconventional hydrocarbon resources. This introductory chapter will give the background information for this thesis and as such, make the reader have a better understanding of the thesis subject matter.

1.1. Background

There was a time when the existence of hydrocarbon was seen through the presence of oil seepages at the surface, after some time, wells had to be drilled into conventional reservoirs for hydrocarbon extraction, then secondary recovery and EOR was developed and at some point, even that was not enough so the option of unconventional resources had to be explored. At this point, the distinction between conventional and unconventional hydrocarbon resources needs to be made.

The main difference between conventional and unconventional resources is the ease of extraction. Because the ease of extraction is greatly linked to the permeability/porosity of the reservoir, that is also a big difference between them. Conventional reservoirs are easier to develop and have higher permeabilities while unconventional reservoirs are more difficult to develop and have lower permeabilities. It is important to note that the hydrocarbon resources that are described by the term “unconventional” is subject to change as technology advances and more complex hydrocarbon plays are developed.

These unconventional hydrocarbon resources include tight sand gas, coal bed methane (CBM), shale gas and gas hydrates. For perspective, the permeabilities of these unconventional resources range from less than 0.1md to up to values of 1nd and porosities of less than 10% (Law & Curtis, 2002; Smith et al., 2009) whereas, the permeabilities of conventional reservoirs range from 0.1md to over 10D (Gluyas & Swarbrick, 2013).

As seen mentioned previously, the continous depletion of conventional hydrocarbon reservoirs necessitates finding new sources of hydrocarbon. This is why even though unconventional resources are harder to develop than the conventional rescourses, constant attempts are being made to develop them.

Of the four unconventional hydrocarbon resources mentioned above, the focus of this thesis will be Coal Bed Methane (CBM). Since these CBM plays have such low permeability values, the obvious issue that arises is how to recover commercial amounts of natural gas from such tight formations. Usually, the permeability is increased by fracturing the formation which also reduces the pressure, consequently allowing desorption of gases from the coal. This method is the conventional coal bed methane production method. There is another method for CBM production called Enhanced Coal Bed Methane (ECBM) where carbondioxide (CO_2 or N_2) is injected into the coal seams to take advantage of the preferential adsorption of CO_2 or N_2 to coal. During this process, CO_2 is injected into the coal seams and methane (CH_4) is released in exchange. These mechanisms will be detailed in Chapter 2.

1.2. Thesis Problem

Due to the declining conventional reserves, the need to develop unconventional hydrocarbon resources cannot be over emphasized. The problem this thesis aims to solve is presenting the best method of production of CBM plays in terms of gas recovery and economic feasibility. It is therefore important to analyse the two methods of CBM production which are outlined above – conventional CBM and ECBM – to see which one is more suitable and under what conditions for producing the Onyeama Coalbed Field in Nigeria.

1.3. Aim and Importance of the Study

As mentioned in the preceding sections, pressure depletion (CBM) and preferential adsorption (ECBM) are the two main options for the extraction of methane from coal. Obviously, the method chosen for application will be the one that is able to produce as much methane as possible in an economic and safe manner.

This thesis will be a comparative study on conventional and unconventional CBM production under high pressures to see which is better in terms of amount of methane produced. This will be done using CMG GEM - compositional and unconventional simulator - to provide a better understanding and decision making of which is better.

Some of the questions which this research aims to answer includes:

- Is ECBM actually better than CBM in terms of gas production/ reduction of gas in place? If so, which form of ECBM gives the best results
- What is the best well configuration/orientation for producing this CBM/ECBM?
- How viable is ECBM production as a method of carbon sequestration?
- To what degree does pressure affect the outcome of the CBM/ECBM performance?

1.4. Hypothesis

Because of the preferential adsorption mechanism associated with ECBM production, the reservoir pressure is preserved and as such used to drive out more methane from the reservoir than if conventional pressure decline CBM production was employed.

But are there underlying factors that could reduce production, such as permeability reduction of coal seams due to the presence of CO_2 associated with ECBM?

1.5. Structure of the Thesis

The thesis topic is introduced in the first chapter: background information of CBM and the research on CBM to be done is given. The second chapter contains literature review of past research on CBM and ECBM, the third chapter contains the detailed methodology of the reservoir simulation used to achieve the aim of the thesis and the fourth chapter contains in-depth analysis of the results of the reservoir simulation. The fifth chapter describes the economic analysis done to check the economic feasibility of all the scenarios used to develop the field and finally the sixth chapter gives conclusions of the research and possible recommendations.

1.6. Limitations of the Research

One limitation to this study is that data collection was done from review of previous literature because it was not possible to get reservoir field data from a company. Considering that not all the required data for the research will be available, realistic range of the values for some of the unavailable data will be taken.

Another limitation is that only a numerical simulator will be used (without being accompanied by a laboratory study). Since reservoir simulation models have some limitations to how accurately they capture the interaction of CO_2 injection with coal, there will be a limit to the accuracy of the results gotten from this simulation.

CHAPTER 2
LITERATURE REVIEW

This chapter contains a review of past published literature on coal – an introduction to coal, its formation process, types, its energy potential, recovery methods CBM and ECBM, as well as lessons learnt from the previous pilot and full-scale applications, laboratory experiments and simulations of CBM and ECBM processes and the presentation of a case study to be used in this thesis.

2.1. Coal as an Energy Source

Because of the non-renewable nature of hydrocarbon resources as well as the rapidly increasing energy demand, the gradual but certain decline of hydrocarbon resources as time progresses comes as no surprise. Therefore, it is extremely important to keep looking out for new and viable sources of energy to make up for this decline. This is why unconventional resources and Enhanced Oil Recovery (EOR) methods have become more and more popular in recent times. These unconventional resources include Coal Bed Methane (CBM), shale gas and oil, tight sand gas, and gas hydrates. Figure 2.1 shows the conventional and unconventional resources in increasing order of available volumes and difficulty in extraction from top to bottom. Of these unconventional resources, the focus in this thesis is CBM.

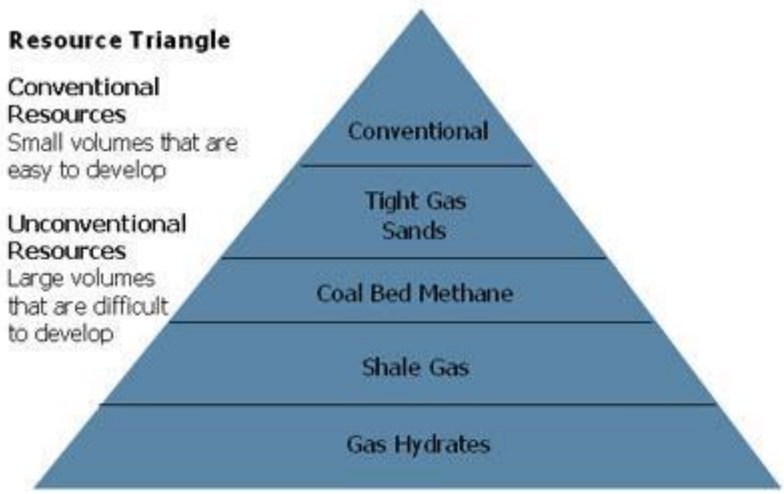

Figure 2.1: Conventional and unconventional hydrocarbon resources (Penner, 2013)

Coal is a combustible, black, organic, sedimentary rock with high amounts of carbon. Dead plants and animals subjected to high temperatures and pressure over time - millions of years, are converted to peat and then into coal in a process known as coalification (Steyn, 2019). Schopf (1956) defined coal as a readily combustible rock with over 50% by weight and over 70% by volume of carbonaceous material formed from compaction and induration of variously altered plant remains similar to those in peaty deposits. As such, coal is composed of mostly carbon as well as hydrogen, sulphur, oxygen and nitrogen. From the composition of coal, it is obvious that when burnt directly, it releases large amounts of greenhouse gases such as carbon dioxide (CO_2) and Sulphur dioxide (SO_2) which harmfully affects the environment (Steyn, 2019).

Depending on the conditions to which this coal is subjected to - temperature, pressure and formation time - different ranks of coal could be produced (World Coal Institute, 2009; Olumide et al., 2003). This relationship is illustrated in Figure 2.2 below. Lower rank coals are generally softer, have higher moisture content and lower carbon content and as such have lower burning energy. As the coal is subjected to more pressure and temperature and the coal increase rank, a decrease in the moisture content of the coal is seen, as well as a resultant decrease in the coal volume and an increase in the coal's burning energy (World Coal Institute, 2009; Olumide et al., 2003). Table 2.1 shows this relationship. The rank of coal also affects its physical properties such as permeability, porosity and adsorption characteristics. Generally, the higher the coal rank, the more favourable its physical properties (Perera & Ranjith, 2015).

Since both temperature and pressure increase with increasing depth, coal properties such as absolute permeability and gas content are affected by depth: the former decreases with depth while the later increases with depth. This is tricky because while the coal's burning energy is increasing, the permeability is decreasing. For this reason, commercial production of CBM is limited to depths less than 4000ft (Dani et al., 2013).

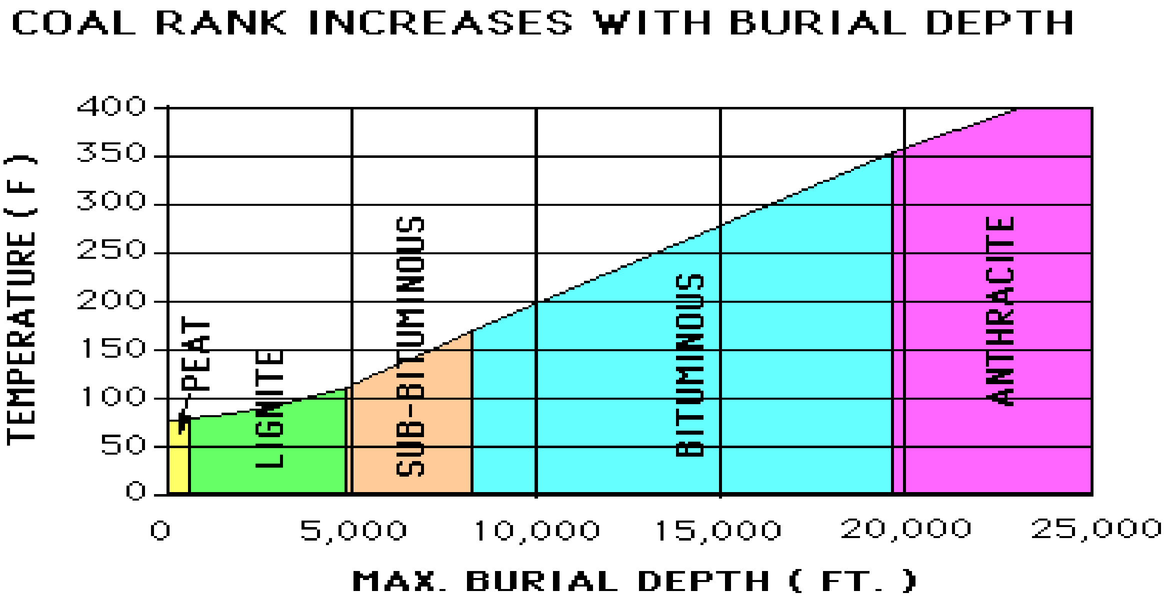

Figure 2.2: Relationship between coalition conditions and rank of coal formed (Plant Fossils of West Virginia, 2011)

Table 2.1: Carbon content for different coal rank (Plant Fossils of West Virginia, 2011)

Coal Rank	Carbon Content
Peat	10-20%
Lignite	20-35%
Sub-bituminous	35-45%
Bituminous	45-80%
Anthracite	80-96%

Coal has dual porosity: the macropores and micropores. The macropores involve the cleats and the fractures in the coal while the micropores involve the coal's molecular sized capillaries and cavities. According to Young et al. (1991), the horizontal permeability is about 42 times the vertical permeability. A study by McKee et al. (1988), showed that most United States coal seams have fracture permeabilities in the order of 0.1–50 milliDarcys. These macropores contain mostly water and a bit of methane gas while the micropores contain most of the methane gas which adheres to them by adsorption (Falode & Alawode, 2014).

The primary gas storage mechanisms in CBM reservoirs are by adsorption to the coal surface, storage in the coal's natural fractures, storage in the coal's micropores and solution of the gas in bitumen and formation water but really, adsorption is the method by which almost all of this methane is stored (Dani et al., 2013). Adsorption is different from absorption in that in the adsorption process, the methane gas adheres to the surface of the coal unlike absorption where the methane would be trapped in the coal. An interesting thing to note about the adsorption porosity type of methane is that although the coal porosity might appear to be low, they have the ability to store up to six times more gas than an equal sandstone volume at the same pressure (Steyn, 2019).

Coal could be produced directly by mining. Mining is the extraction of ore or minerals from the earth. Mining coal means extracting coal directly as coal and can be done on the surface or underground and by various methods, depending on the geological and environmental conditions. Mining is generally a dangerous operation to both the environment and the miners. In addition to the risks associated with mining coal, the processing, storage and impacts of direct coal utilization or coal processing is another issue. Burning coal directly for fuel releases nitrogen oxide and sulfur dioxide that cause acid rain, smog and respiratory illnesses. (Falode & Alawode, 2014).

To mitigate this issue, the produced coal could be processed to ensure that the coal is in accordance with the commercial market standard. Different ranks of coal require different processing processes. But generally, the coal is first crushed and then it is separated based on density. This separation stage can be done either wet or dry but for more effective results, the wet method is recommended. The higher density material is the less useful rock and the lower density material is the more useful organic material. After treatment, the various size fractions are screened and dewatered or dried and, then, recombined before going through final sampling and quality control procedures (ITP Mining, 2013; The National Academies Press, 2007).

However, some coal is unmineable, which puts a large limitation on the application of mining as a method of coal extraction (Falode & Alawode, 2014).

According to Falode & Alawode (2014), it is important to note that coal is the most abundant fossil fuel in the world. So, finding cleaner and more effective methods of harnessing the energy from these coal seams have been proposed, the most popular of which includes CBM and ECBM. These concepts are introduced in sections 2.2 and 2.3 respectively.

2.2. Coal Bed Methane (CBM)

Due to the aforementioned problems with conventional coal mining, a cleaner, safer and more efficient method of energy extraction from coal is more commonly used. This method is known as CBM production. An interesting thing to note is that burning the methane extracted from coal is a much cleaner energy source than oil or coal (Abu et al., 2016) and methane gas from CBM is much purer than the methane from any other energy source (Levine, 1993).

CBM production has seen a rise in recent years due to a growing interest in unconventional energy sources. In places like Queensland, for example, the use of methane from CBM for liquified natural gas export has increased the interest in CBM (Mazumder et al., 2013). Prospects have also been seen for the application of CBM in several coalfields and many researches/investigations have been done to see the viability of CBM application in several known coalbeds. Rahman (2009) examined the Jamalganj Coalfield for CBM applications. From this analysis, it was seen that with the characteristics of this field, CBM application was expected to yield promising results. MacLeod et al. (2000) investigated the CBM resource potential in Alberta, Canada. The major prospective coal horizons of the area and the technical and fiscal constraints to development were considered in this study and it was found that assuming a constant gas price of $2.50/Mcf, approximately 10 Tcf of CBM gas reserve potential could be economically developed.

CBM production involves producing the water that is in the coal’s cleats and fractures to reduce the coal’s pressure up to the methane desorption pressure. This allows for desorption of the methane gas from the coal micropores and cleat surfaces, so that the methane can be produced. For the coal to be produced, the reservoir pressure must be reduced to less than the coal's desorption pressure. Considering that a pressure decline gradient exists throughout the coal as shown in Figure 2.3, desorption occurs fastest near the well and slowest at distances further from the well. But concentration gradient and Fick's equation also have a part to play in the methane desorption process. By Fick's law, because of the concentration gradient of methane in the coal, more methane diffuses in the coal matrix. These properties, all influence the methane desorption time (Ayoub et al., 1991). Hence, first the water is produced, next gas desorption slowly occurs and when its concentration is high enough, the gas is produced as well.

Therefore, the production profile for CBM wells can be divided into the inclining trend and the declining trend which respectively are: the initial stage where mostly water is produced while the gas desorbs from the coal and then the latter stage where the gas rate peaks and starts to decline (Okuszko et al., 2008; Okuszko et al., 2007). This declining rate can be caused by the obvious decline of reservoir pressure as the well life increases, reduction in permeability as a result of compaction, liquid loading and migration of fines which could cause a choke skin close to the wellbore. The latter two can be mitigated by hydraulic fracturing as will be seen subsequently (Morad & Tavallali, 2011).

Another property that affects the adsorption and subsequent desorption of methane to the surface of coal is the Langmuir isotherm. Langmuir isotherm assumes that the gas attaches to the surface of the coal and covers the surface as a single layer of gas (a monolayer). Nearly all of the gas stored by adsorption coal exists in a condensed state, near liquid. At low pressures, this dense state allows greater volumes to be stored by sorption than is possible by compression (Memon et al., 2012).

Equation 2.1 below shows the Langmuir isotherm equation. Note that the Langmuir volume is the maximum amount of gas that can be adsorbed on a piece of coal at infinite pressure and is asymptotically approached by the isotherm as the pressure increases (Memon et al., 2012) while the Langmuir pressure is the pressure at which half of the Langmuir volume can be absorbed (Mazumder et al., 2013).

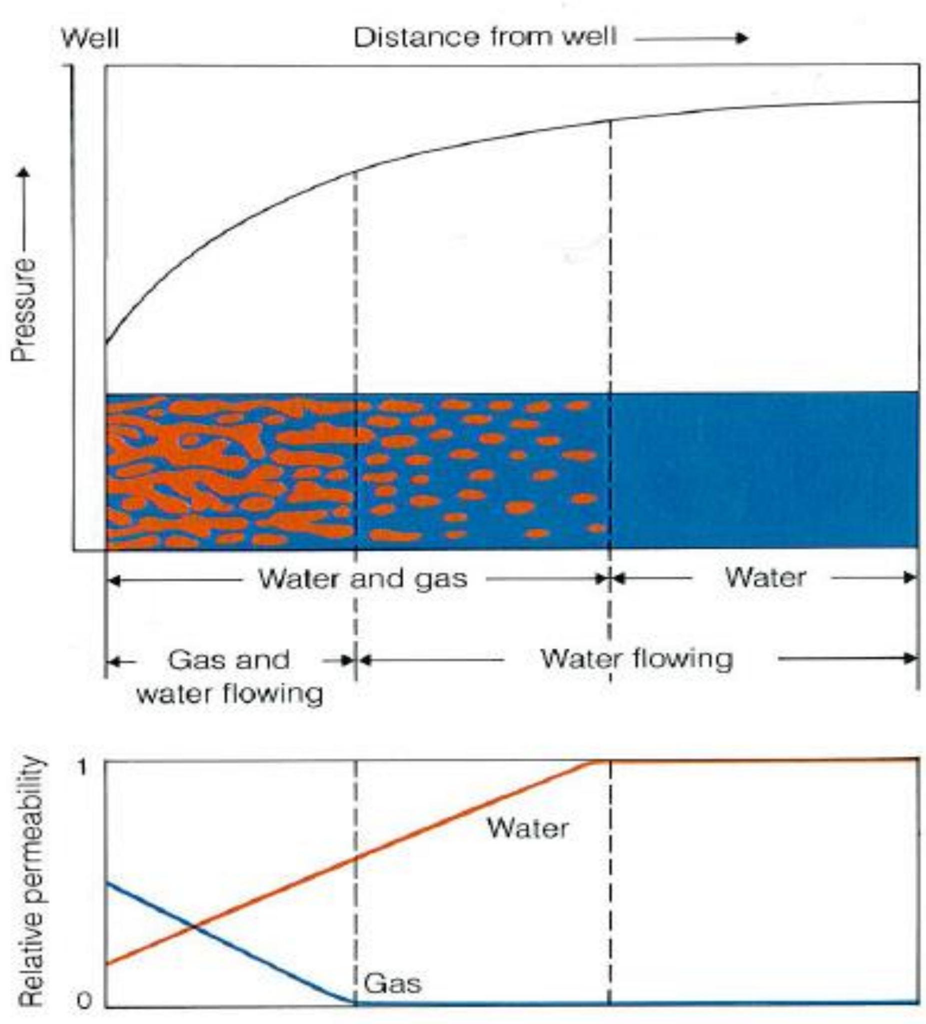

Figure 2.3: Pressure gradient and its influence on water and gas production (Ayoub et al., 1991)

$$V(p) = \frac{V_L P}{P_L} + P \tag{2.1}$$

Where $V(p)$ = amount of gas at a pressure, P (scf/ton)

P = pressure (psi)

V_L = Langmuir volume parameter (scf/ton)

P_L = Langmuir pressure parameter (psi)

The premise of dewatering CBM wells seems simple when it is thought of as just the conventional pumping of water from a well. However, for CBM wells (whether vertical or horizontal), it is a very different case. Neglecting to take basic precautions could lead to complications. First, it is important to know the nature of the coal in question. Different coal types mean different types of solid control methods needed and different wellbore stabilization technology that could prevent severity levels of potential sloughing. The idea of drilling a CBM well is not just for gas production but also for opening the surface area of coal which leads to better gas production and for housing the artificial lift system. When designing the wellbore, it is important to not only consider the production techniques and equipment needed immediately, but also the equipment and/or processes that could take place throughout the life of the well. Things such as sands reducing the hole diameter as time goes on, the need for better artificial lift systems as the well life progresses, future stimulation should be considered as opposed to just thinking of the immediate needs. Although this might mean larger initial costs, the flexibility provided by taking these into consideration more than makes up for the cost. In a scenario where the engineers decide to develop the well thinking of just the present conditions, what then happens when the well reaches its economic limit and the well is not designed to fit the new system needed? (Bassett, 2006).

To achieve the best results, the well design should take into consideration the need for gas separation from the water before the water enters the pump since pumps are not designed for two phase flow. Various pumps can be used: progress cavity pump, rod pump, jet pump or CBM electric submersible pump. It is also possible to use a gas lift method to try to reduce the fluid gradient. It is important for the engineer to consider the CBM field being developed and choose the best one for that field keeping in mind the limitations of these pumps in relation to CBM wells as opposed to their limitations in either oil field production or purely water wells (Bassett, 2006).

CBM production potential is determined by a number of factors that vary from basin to basin, and include fracture permeability, development history, gas migration, coal maturation, coal distribution, geologic structure, well completion options, hydrostatic pressure, and produced water management. In most areas, naturally developed fracture networks are the most sought-after areas for CBM development. Areas where geologic structures and localized faulting have occurred tend to induce natural fracturing, which increases the production pathways within the coal seam.

According to the Sydney Catchment Authority (2012), a coal seam suitable for CBM development should contain high gas content, preferably between 15 and 30 m3/ton of methane (Scott, 2002), have good permeability usually greater than 1 mD (Brown et al., 1996), have sufficient thickness usually greater than 30m (Sharma, 1996) and lateral continuity for easy movement of gas into wells, and be located between 250 and 1000 m below the surface.

Although this method is a considerably preferable alternative to mining, producing coal in this way presents its own challenges. First, even though CBM produces more from coal that conventional mining, there is still considerable amount of methane left behind after production done by the CBM method. Due to large amounts of pressure depletion (usually about 70-80%), only less than 50% of the gas in place can be recovered using CBM, which means that even after the economic lifetime is reached, there is still considerable amount of methane left in these coal seams (Yan, 2015). Again, taking into consideration the large volumes of produced water associated with conventional CBM and the number of impurities such as sodium, potassium, magnesium, calcium, carbonate, bicarbonate, chlorine and sulphate ions, the problem of safely disposing the produced water arises disposal of CBM water with groundwater without treatment causes contamination of this ground water which makes it unsafe for the residents of that area. Proper treatment and disposal of this produced water is also a huge environmental concern in CBM. For context, on average, CBM wells in the USA produce about 1.74cm^3 of water per m^3 of gas (Memon et al., 2012).

Additionally, an immense source of environmental concern is that due to the micro porosities of coal, hydraulic fracturing is usually done in CBM to increase permeability. Because of the micro-porosity of coal, hydraulic fracturing is usually done in CBM cases. Hydraulic fracturing is a method by which water sand and other chemicals are injected into the reservoir through a well at a pressure above the formation fracture pressure. The artificially created fractures could expand and affect fresh water aquifers (Steyn, 2019).

Previous studies have shown that hydraulic fracturing produces more hydrocarbon and are especially effective in unconventional reservoirs where permeabilities are in the range of nano Darcy.

A look at some of the previously published literature on stimulating CBM wells shows without a doubt just how effective this process is in increasing the gas recovery. Hydraulic fracturing not only improves the permeability of coal by improving the coal fracture network, it also helps to clean up the wellbore and the neighboring zones. Morad & Tavallali (2011) carried out a study by conducting a series of simulations on the CMG GEM simulator to see the effects of fracturing vertical and horizontal wells after loss of productivity begins to take place. This study showed that refracturing a well after a decline in production starts shows considerable increase in well gas productivity and practically reverses the permeability loss. Considering the difference between conventional and unconventional reservoirs, hydraulic fracturing mechanisms are obviously different which means that care must be taken when performing simulations to ensure that the fracturing mechanisms of CBM reservoirs are adequately captured. Han et al. (2020) investigated the use of hydraulic fracturing in a CBM reservoir in Ordos Basin, China. These reservoirs typically have unfavourable properties: low permeability, small pore size and low reservoir pressure. It was seen from this study that the cleats present in coal formations causes premature leak-off and consequently the premature screeen-out during hydraulic fracturing processes which limits fracture growth and propagation. To try to mitigate this problem, Han et al. (2020) proposed that the design objective should be longer fracture length and high net pressure so that even with this limitation, the fracture will still be within reasonable limits.

Additionally, the effects of multi-stage hydraulic fracturing at the Dawson Valley CBM project in the Bowen Basin in Queensland, Australia was studied in a research. It was seen from this research that hydraulic fracturing improved the productivity of the CBM wells and it was also interestingly noticed that water volume and not sand volume influences the effectiveness of the fracture stimulation (McMillan & Palanyk, 2007). In a study of advanced multi-lateral horizontal well in CBM reservoir using a simulation model, it was observed that while the rate of gas production increases with an increase in the number of branches that the wellbore has, a threshold exists. It was also observed in this study that threshold pressure gradient and gas slippage effect not being considered could lead to huge errors during simulations (Zheng & Xue, 2012).

Pulse fracturing has also been looked into as a technology for CBM. Pulse fracturing involves raising the pressure up to several thousands of psi in microseconds to create multiple fractures. Although a relatively new technology, it has been seen in many studies to be more effective than conventional hydraulic fracturing and has even been represented with a numerical model successfully (Tariq et al., 2019; Li et al., 2020; Sheng et al., 2019; Li et al., 2014). This study however, will not implement this technology as the commercial simulator used was not equipped with this feature.

As with any other investment, before the CBM is implemented, some prediction must be done to determine how profitable an investment in this will be. It is important to know with reasonable certainty, how much of this CBM can be produced and the best method(s) of production. This prediction acts as a determinant for whether or not this CBM will be implemented in a coalfield. Obviously, the CBM volumes need to be estimated but an economic analysis must also be done in order to decide whether the process of producing this methane will be too expensive to warrant undergoing this process or if it will be beneficial to go through with it. This estimation requires certain data such as geological parameters, CBM specific parameters and production history (Dani et al., 2013). The conventional analysis tools developed for conventional reservoirs have to be modified for use in CBM reservoirs as key reservoir characteristics such as relative permeability, absolute permeability, the stress-permeability and desorption-permeability relationship during depletion and the anisotropy of permeability vary widely in coalbeds which could lead to grossly inaccurate prediction (Haskett & Brown, 2005; Clarkson & McGovern, 2005). This is one of the reasons why pilots are essential in CBM exploration: they help to reduce uncertainties of the key reservoir parameters mentioned above as well as test for the most cost-effective completion and drilling method (Dani et al., 2013).

Four methods are generally implemented in assessing CBM reserves: volumetric method, material balance method, production data analysis (PDA), reservoir simulation, depending on the stage of CBM reservoir development. The volumetric and reservoir simulation could be applied at all stages of development but as production progresses and more data becomes available. The other two methods listed can be implemented only after certain data is available (such as production data, flowing and shut-in pressure) in considerable amounts (Dani et al., 2013).

Conventional material balance and PDA methods of reservoir evaluation have been modified for CBM reservoirs. These advancements allows the determination of reservoir properties such as permeability, drainage radius and original gas in place (OGIP) (Clarkson et al., 2007; Clarkson et al., 2008). Mazumder et al. (2013) did a PDA of existing CBM wells in the Surat Basin in Queensland whose gas is composed of about 97% of methane and about 3% of impurities. The PDA methods utilized in this analysis involved the flow regime identification, Fetkovich Type-curves, analytical history matching and material balance. To be sure that these PDA gave good reservoir characterization, it was compared to other methods of determining the derived properties. These include comparison of type-curves method and well deliverability history match for permeability with the drill stem test (DST) permeability results, comparison of OGIP from flowing material balance method with the well deliverability history matched forecast method. These results showed that PDA methods could be used reliably for CBM reservoir evaluation.

Clarkson et al. (2008) also investigated the use of PDA techniques in characterizing the reservoirs. They pointed out that during the application of these techniques, the coal storgae and transportation properties must be taken into consideration. This was shown for a two phase CBM well in Eastern Wyoming with encouraging results. Even in the less common single phase (gas) CBM reservoirs, it is possible to use PDA techniques for reservoir characteristics determination as was seen in the Horseshoe Canyon coals of Western Canada (Clarkson et al., 2007). Another study was done on PDA of Horizontal CBM wells in the Arkoma Basin of Southeastern Oklahoma which showed that PDA techniques can be applied on horizontal CBM wells with reasonable results (Mutalik & Magness, 2006). Therefore, PDA techniques can be modified to fit different scenarios of complex CBM reservoir with a limitation being the assumption of a single-layer reservoir behavoir unlike the actual multi-layer behaviour usually encountered (Clarkson et al., 2008).

Analysis of the production decline of CBM has been used as an evaluation method of CBM reserves. But a longstanding issue with this is the whether the production profile is exponential or hyperbolic. It was seen in a research by Okuszko et al. (2008) that despite the more complex production mechanisms of CBM reservoirs, the decline behaviour is similar to that of conventional gas. As with conventional gas production, CBM production decline usually matches a hyperbolic decline exponent (0-0.5) during the decline trend of the production profile but during the inclining trend, it may appear to be exponential. It was also noted that while the Langmuir volume does not affect the b value, an inverse relationship exists between the b value and the Langmuir pressure. In addition to this, like the layered conventional gas reservoirs, layered CBM reservoirs exhibit b values greater than 0.5 when the layers have a high degree of heterogeniety. Generally, lower drawdown in the reservor causes a more exponential behaviour while increased drawdown casuses a more hyperbolic behavior (b approximately 0.5) (Okuszko et al., 2008; Okuszko et al., 2007).

Since proper decription of a reservoir rock is necessary for any successful hydrocarbon recovery project, it is important to ensure that the model to be used, matches the reservoir that is being modelled. This becomes tricky as unconventional reservoirs have more complex features and more complex production mechanisms compared to conventional reservoirs and therefore care must be taken to model them accordingly. Warren & Root (1963) in an attempt to model dual pososity reservoirs developed a mathematical model which has a shape factor to control the drainage rate from the reservoir matrix to it's fractures and they also gave formulas to be used in calculating shape factors. Many other formulas have been given for calculating the shape factor which resulted in an obvious confusion about which one is accurate. Mora & Wattenbarger (2006) conducted an investigation to find out which of these formulas was most correct. It was seen that diferent boundary conditions gave different values for the shape factor: for a constant pressure boundary condition, the formulas from the studies by Zimmerman et al. (1993) and Lim & Aziz (1995) gave similar results, while for a constant rate boundary condition, Coats (1989) gave similar results (Mora & Wattenbarger, 2009; Mora & Wattenbarger, 2006).

An additional attempt to get an accurate description of the CBM reservoir was the creation of empirical or theoritical models which accounted for changes in relative permeability as a result of the matrix shrinkage/swelling that could occur during CBM/ECBM processes. Clarkson et al. (2010) created a model to predict permeability growth as a result of depletion in CBM and the additional gas rates resulting from this. This model was incorporated into an analytical simulator and was used to predict and match the permeability changes in a CBM well in the Fruitland Coal fairway of the San Juan Basin in the USA. This of course shows that this model is promising.

Roy & Parulkar (2012) did a simulation of a coalfield in the Bokaro Basin in India using the CMG's option for CBM for GEM. From this study and others done, one notable challenge observed with simulation of CBM in many cases, is the absence of production history which limits history matching to the initial production testing profile. Even with this limitation, the simulation produced reasonably accurate results because the most important data for history matching is water production rate with time.

Although CBM is considerably better than mining for energy production from coal, due to the problems associated with CBM production, ECBM is a considerably better alternative to both.

2.3. Enhanced Coal Bed Methane (ECBM)

The unconventional CBM production method, which also serves as a method of carbon sequestration, involves the injection of liquefied CO_2/N_2 into the coal which is preferentially adsorbed by the coal. Because of this preferential adsorption, rather than depressurizing the reservoir to allow for methane desorption, the methane gas is released as CO_2/N_2 is injected as a kind of exchange (Godee et al., 2014). This unconventional method of CBM is called Enhanced Coal Bed Methane (ECBM) production.

Interestingly, the ratio of replacement of CO_2 molecule to methane molecule is 2:1 and 5:1 at depths of about 700m and 1500m respectively but beyond 2000m depth, increasing temperature and pressure places a limit on the coal methane content and reduces the coal seam permeability respectively (Bergen et al., 2000). It was seen in a study on the CO_2 flooding in the Allison Unit of the San Juan Basin that the ratio of injected CO_2 to produced methane was about 3.1:1.0 (Journal of Petroleum Technology, 2005). These ratios are just average values as the maturity of the coal plays a great part in adsorption/desorption process.

Primary recovery of CBM typically recovery up to 20-60 percent of the OGIP and in the San Juan basin in the U.S.A., primary recovery methods will leave up to 10Tcf of natural gas behind. It is important to note that the problem of water disposal is greatly reduced by ECBM as compared to conventional CBM production. Another noteworthy fact is that many previous studies done on these suggests that ECBM is a kind of EGR (Enhanced Gas Recovery) process in which the CO_2/N_2 can produce the methane from unmineable coal seams as well as coal that has undergone CBM processes. To put this in perspective, conventional CBM typically produces less than 50% of the gas in place and ECBM records up to 90% recovery of the gas place (Falode & Alawode, 2014; Godee et al., 2014; Reeves, 2003) and over 94% of the OGIP in some cases (Kovscek et al., 2005).

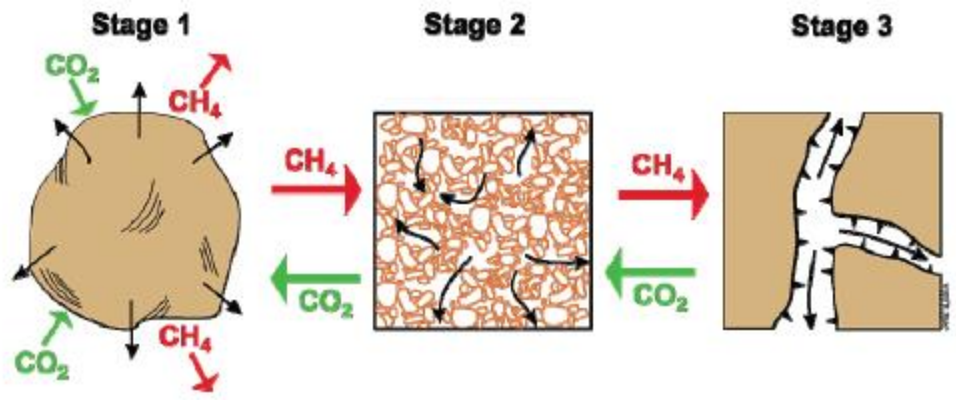

Figure 2.4: Flow process of CO_2 and CH_4 in coal seams (Godee et al., 2014)

2.3.1. Carbon dioxide enhanced coal bed methane (CO_2-ECBM)

CO_2-ECBM recovery is one of the few CO_2 sequestration techniques that is beneficial because by using this method, a harmful greenhouse gas is being gotten rid of while simultaneously enhancing the production of methane (Stevens et al., 1998).

It is important for a prospective reservoir to which CO_2-ECBM is being applied to have certain criteria to ensure the success of the project. These criteria include: homogeneity of the reservoir to ensure efficient sweep of the CO_2, a simple enough reservoir structure to prevent the CO_2 from being diverted from the reservoir and although CBM reservoirs have typically low permeabilities, it is also important to have about 5mD at least to allow for passage of the CO_2 into the reservoir (Stevens et al., 1998).

As with any other hydrocarbon production process, being able to properly capture the various processes going on in the reservoir while making a model is important for the success of that project. This is to say, understanding the mechanisms of ECBM processes are key in successful modelling and application of this process. One of such attempts was an observation by Clarkson et al. (2008) that the Palmer-Mansoori equation which is commonly used in CBM reservoir modelling works best if the stress-dependent permeability term is ignored and if the coal porosity is below 0.1% which begs the question: if this equation has problem with CBM, how effective will it's applicability to CO_2 sequestration be? It is important for observations like this to be considered if the model created is expected to be successful. Because of this, several attempts have been made to understand these mechanisms (Ozdemir, 2009).

In a study undertaken to investigate the variation in the structure and density of coal during CBM/ECBM processes with X-ray experiments, it was noticed that net stress, gas adsorption capacity and production history all cause change in coal density and density distributions (Guo & Kantzas, 2008).

In some studies, CO_2 injection led to reduction in permeability of the coal which placed a restriction on the production of methane (Godee et.al., 2014). It has also been seen that significant permeability changes occur during the adsorption-desorption process that accompanies ECBM processes (Journal of Petroleum Technology, 2005). Coal swelling during CO_2 injection is also an important phenomenon to consider as this swelling leads to reduction in coal permeability. CO_2 could cause the coal to swell up to three times the swelling caused by methane and in the Allison CO_2-CBM pilot, CO_2 injection was seen to cause a 99% permeability decrease (Mitra & Harpalani, 2007). Modelling this swelling is obviously important if the simulations are expected to give reliable results. Mitra & Harpalani (2007) showed that although the extended Langmuir theory gave some errors in modelling coal swelling as a result of CO_2 injection, it still gave reliable enough results that it can be used until a better way of representing this sorption-strain relationship is found.

A question that could arise in the mind of the reader at this point, is where the CO_2 for the ECBM process comes from. One important source is from flue gases. In some countries, like Nigeria, most of the recovered gas is flared as opposed to being processed. This burnt gas contains CO_2 which is extremely harmful to the environment but very useful in secondary recovery, EOR processes, as well as in EGR processes. These flue gases can be from power plants, industrial cogeneration plants (like gas and steam turbines), waste incineration plants and chemical industry (Lako, 2002). A very optimistic picture that could be drawn in the mind of the reader is a methane power plant where the CO_2 emissions from the power plants can be injected into the coal seam where the methane was gotten from. Another source of CO_2 could be from naturally occurring high pressure CO_2 from underground reservoirs. This is the most cost-effective way if the CO_2 reservoir is close enough to the CBM site to avoid additional transportation costs (Stevens et al., 1998).

CO_2-ECBM injection has been applied in many places: The United States' San Juan Basin and Uinta and Raton Basins, the Bowen and Sydney basins in Australia, the Ordos Basin in China, Mannville coal in Western Canada and so on. The results from these have shown the effectiveness of ECBM recovery and increased interests in researching and pursuing this area (Stevens et al., 1998).

Taking the permeability reduction issue previously mentioned into consideration, it makes one wonder if this process is actually effective especially in highly ranked coals. A review of past literature clears this doubt. For example, the highly volatile B bitumen rank of the Mannville coal of the Western Canada sedimentary basin and the anthracite rank coal of the No. 3 coal of the Qinshui basin in China had micropilot programs that showed that the sequestration potential exists even in highly ranked coals (Journal of Petroleum Technology, 2005). An attempt at mitigating this permeability reduction problem will be seen in section 2.3.3. A study by Godee et al. (2014) on the coal seams of the Allison unit of the San Juan basin showed that CO_2 injection can improve methane recovery from 77% using conventional CBM method to about 95% using ECBM method. This study also showed that CO_2 injection could lead to permeability reduction which in turn could lead to loss of injectivity of the coal seams but there a recovery was seen in the injectivity of the coal as methane production progressed.

2.3.2. Nitrogen enhanced coal bed methane (N_2-ECBM)

Although, CO_2 is typically used in these ECBM recovery processes, nitrogen (N_2) can also be injected into CBM for EGR processes. The main sources of N_2 are atmospheric precipitation, geological sources, agricultural land, livestock and poultry operations and urban waste (Ghaly & Ramakrishnan, 2015). One challenge associated with the use of N2 is that it is less available and more costly than CO_2. Settari et al. (2010) analyzed the use of nitrogen stimulation in the Horseshoe Canon coal seams in Alberta. From this research, it was seen that the controlling mechanisms of this process are permeability-stress relationship of the coal as well as the permeability anisotropy as shown from the use of a geomechnical model. Although this process of nitrogen injection has shown success, it was observed that for proper modelling, sufficient data is required to calibrate geomechanical models for reliable prediction of results (Settari et al., 2010). Godee et al. (2014) also did a study on the injection of N_2 into coal seams in the Tiffany unit in the San Juan basin . This study showed that N_2 injection leads to a rapid increase in methane production – even more than the CO_2-ECBM - with an accompanying rapid increase in permeability and consequently rapid breakthrough of N_2.

2.3.3. Carbon dioxide-nitrogen hybrid enhanced coal bed methane (CO_2-N_2-ECBM)

Considering the issue of permeability reduction associated with CO_2 injection (Godee et al., 2014) and the contrasting increase in permeability and early breakthrough associated with N_2 injection (Godee et al., 2014; Zhou et al., 2013), researchers have implemented the hybrid CO_2-N_2-CBM method. Production rate of both CO_2 and N_2 ECBM depends on the injection pressure, efficiency of movement of the CBM from the adsorbed state in the coal matrix into the cleat or the fracture system of the coal, the permeability of the cleats and the pathway to the borehole.

Various studies have been done to investigate this hybrid method. Kovscek et al. (2005) performed some experiments and simulations to understand the adsorption/desorption mechanism of methane/CO_2/N_2 in coals. From this research, it was seen that due to the piston-like movement of CO_2 in CBM reservoirs, breakthrough happens slowly unlike with N_2 which displays a more dispersed front and has quicker breakthrough and that CO_2

adsorption to coal could be up to 3 times more than for methane and 7 times more than for N_2 for the coal from the Wyoming Powder River Basin. Laboratory experiments conducted by Sim et al. (2009) on gas-gas displacement also showed similar results with Kovscek et al. (2005) in terms of nitrogen and carbondioxide breakthrough time. It also showed that gas-gas displacement in an attempt to increase gas recovery and extend reservoir life could give very positive results even under low pressure and low flow velocity. Another research of interest in the ECBM mechanism is one done by Mavor et al. (2004) on two wells in the Manville coal in Canada. Cyclic CO_2 and N_2 injection performed on these wells showed that the injectivity of CO_2 is greater tham that of N_2 and that even with a permeability as low as 1md, the injection increased the absolute and effective permeability to gas to where easy injection could be done. These proved that although coal seams with very low permeabilities could not be produced using conventional CBM method, ECBM could allow for commercial production of methane from these coals (Mavor et al. 2004).

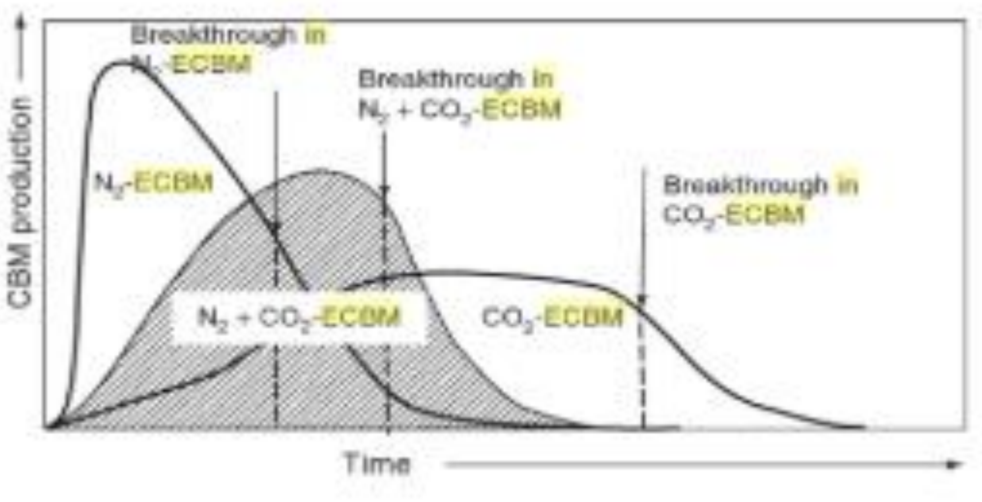

Figure 2.5: Optimization of ECBM recovery through combination of CO_2-ECBM and N_2-ECBM (Yan, 2015)

From the results of these studies, it was deduced that a combination of CO_2 and N_2 for ECBM processes could yield better results than just the use of either as shown in Figure 2.5 above. Memon et al. (2012) also showed that different percentages of N_2 and CO_2 combinations produce different amounts of methane as shown in Figure 2.6. The study also showed that higher ratios of N_2 to CO_2 yielded better results.

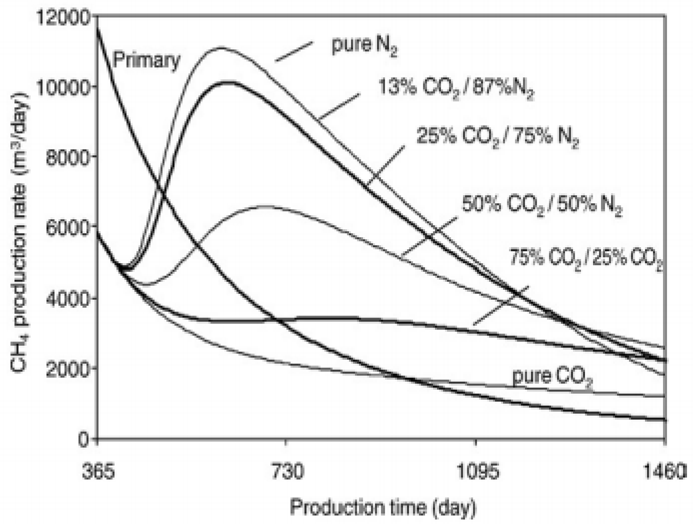

Figure 2.6: Comparison of methane production rates with different CO_2-N_2-ECBM combinations (Memon et al. 2012)

2.4. Case Study of the Onyeama Coalbed Field

The Onyeama coalbed field is located in within the Nigerian Anambra basin. The Onyeama coalbed field is situated on the western edge of the Cross river plain and is dominated by the Enugu escarpment just west of the town. For the first 122 – 152m, the escarpment is steep, but it then rises more gently to about 427m above sea level and about 183m above Enugu. Further west, several large but low hills attain an elevation of nearly 518m. The field is located within the coordinates long 70 27'' E, Lat 60 29'' N; Long 70 25''E, Lat 60 25''N; Long 70 29''E, Lat 60 25''N; Long 70 29''E, Lat 60 22''N covering area of about 4013.853 Hectares (Behre, 2004). Figure 2.7 and 2.8 show the map of the Onyeama coalbed field.

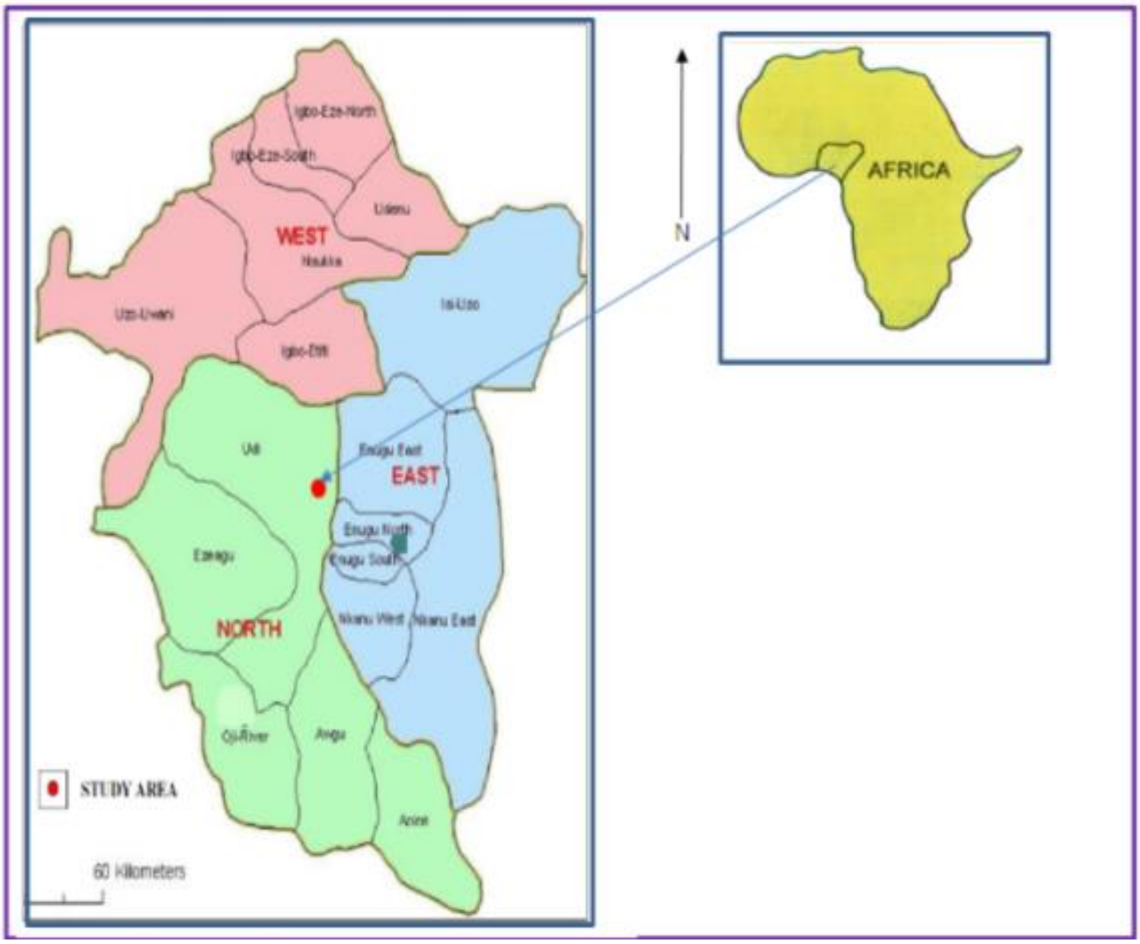

Figure 2.7: Map showing the location of Onyeama coalbed field (Salufu & Salufu, 2014)

The area of coal deposit is 9,404,948.72m^2 with thickness of 5.77ft located at a depth of 100.2m. This field contains sub bituminous coal with specific gravity of 1.33 (density of 1.4g/m^3) with a porosity of 1.9% and a permeability of 45mD. There are an estimated 150 million tonnes of coal reserves of which 40 million tonnes are proven. The Onyeama coalbed field has a maximum temperature of 428^{o}C. The moisture content from Onyeama samples range from 1.98 to 4.15% with mean value of 3.40% (Abu et al., 2016).

The Onyeama coalbed field will be used as the case study for the comparison of CBM and ECBM in this thesis.

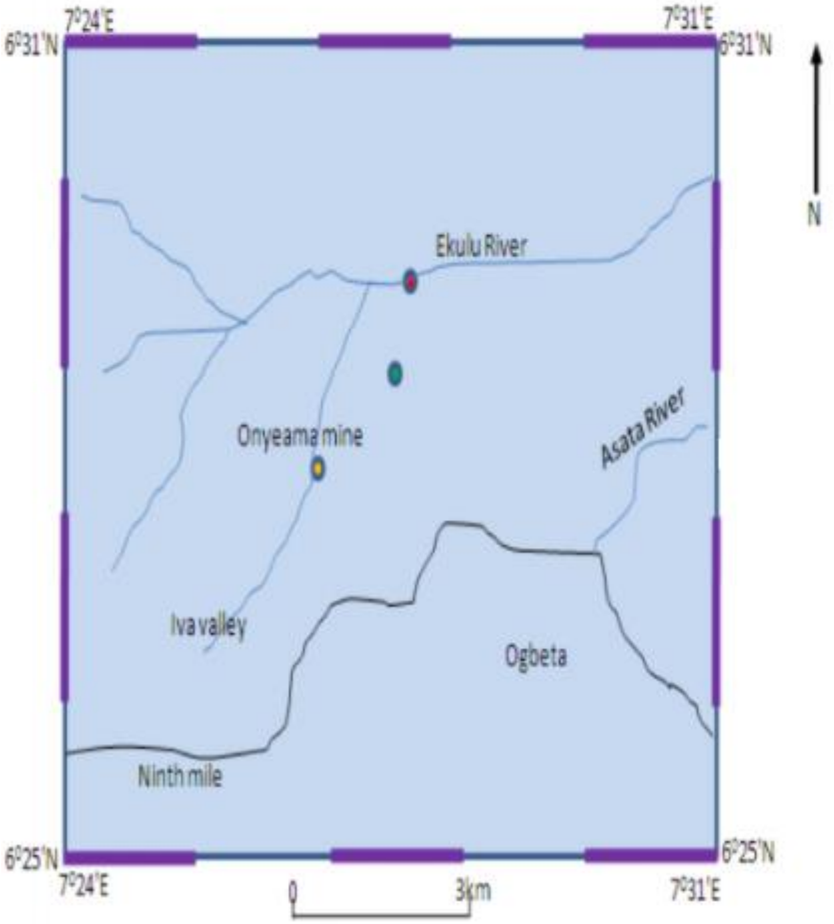

Figure 2.8: Detailed map of the Onyeama coalbed field location (Salufu & Salufu, 2014)

CHAPTER 3
METHODOLOGY

This chapter details the procedures followed to solve the previously outlined thesis problem. Parameter selection, the simulation model, the simulation constraints, the simulation software and how these are used in the comparison of CBM/ECBM efficiency are discussed in detail in this chapter.

The Onyeama coalbed field in Enugu, Nigeria is an unmineable coal in which CBM and ECBM can be successfully applied – this chapter will focus on this application. The characteristics of this field were mentioned in Section 2.4 above. As stated in Section 2.4, the model created was based on reservoir data gotten from literature review on the Onyeama coalbed field in Nigeria and as expected, not all the data needed to construct a model to accurately capture the reservoir properties were available. Still, the model created was good enough to achieve the aim of this thesis.

In this chapter, the use of both horizontal and vertical wells for CBM and CO_2-ECBM will be investigated using the CMG GEM 2010 reservoir simulator. Ten scenarios will be presented to compare how much production of methane and injection of carbon dioxide is possible using different well orientations. The result of these models is explained in chapter 4.

A two-dimensional cartesian model with uniform grid size, single permeability, single porosity and single water saturation was created. The dimension of the model was 16 by 16 by 1 (as can be seen in Figure 3.1) with each grid block having a width of 670.75ft in both the x and y directions and a thickness of 5.77ft. The model was simulated to originally contain a single hydrocarbon phase (methane) and water. The original gas in place (OGIP) of the model was $9.118 * 10^9$ scf.

Table 3.1 summarizes the properties of the constructed model and Figures 3.1, 3.2, 3.3, 3.4, 3.5, 3.6 and 3.7 show the 3D view, matrix and fracture porosity, matrix and fracture permeability and matrix and fracture saturation of the model respectively.

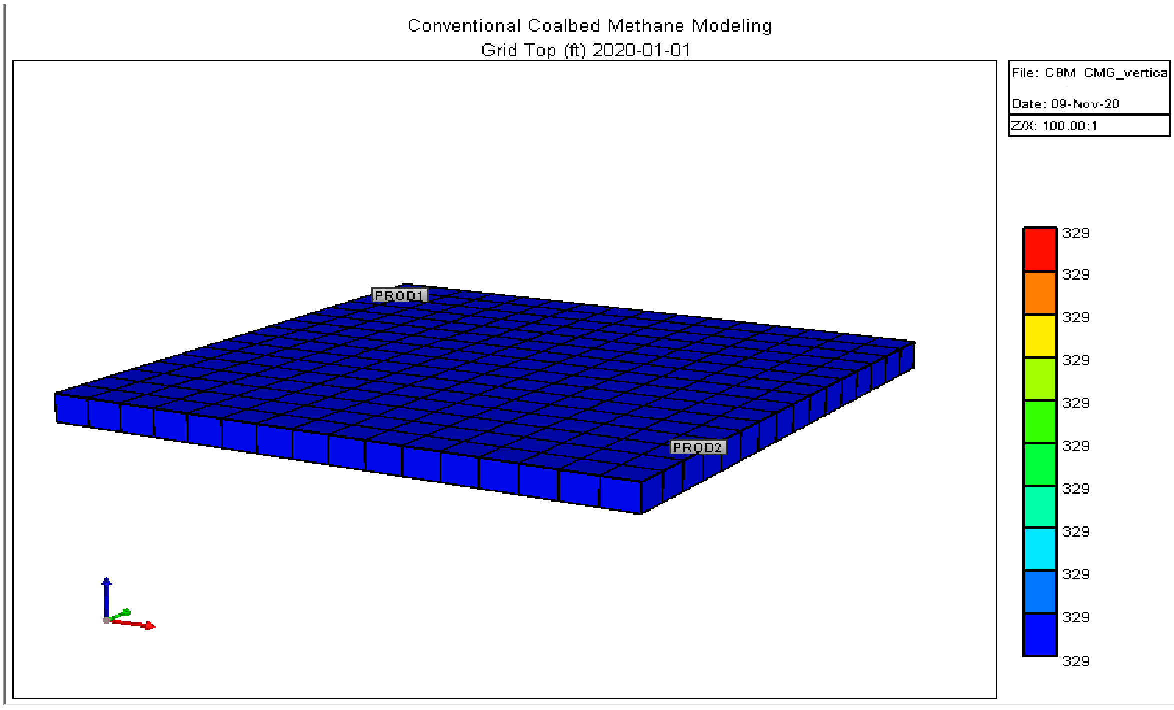

Figure 3.1: 3D view of the reservoir model (generated from CMG builder)

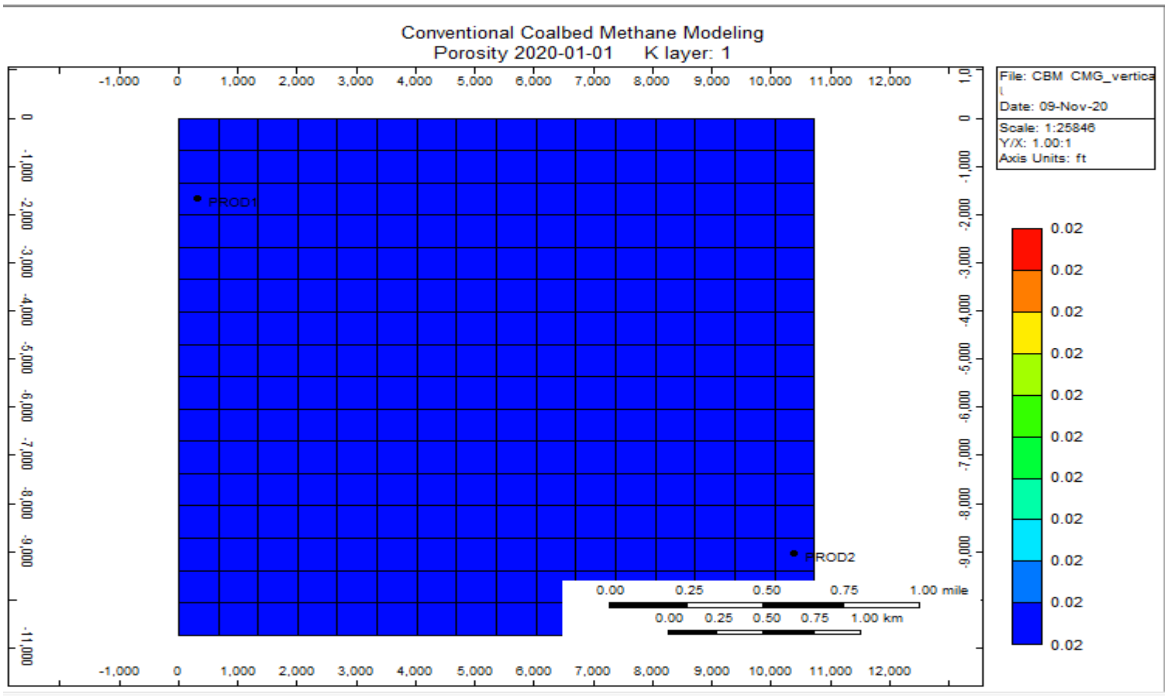

Figure 3.2: Matrix porosity of the reservoir model (generated from CMG builder)

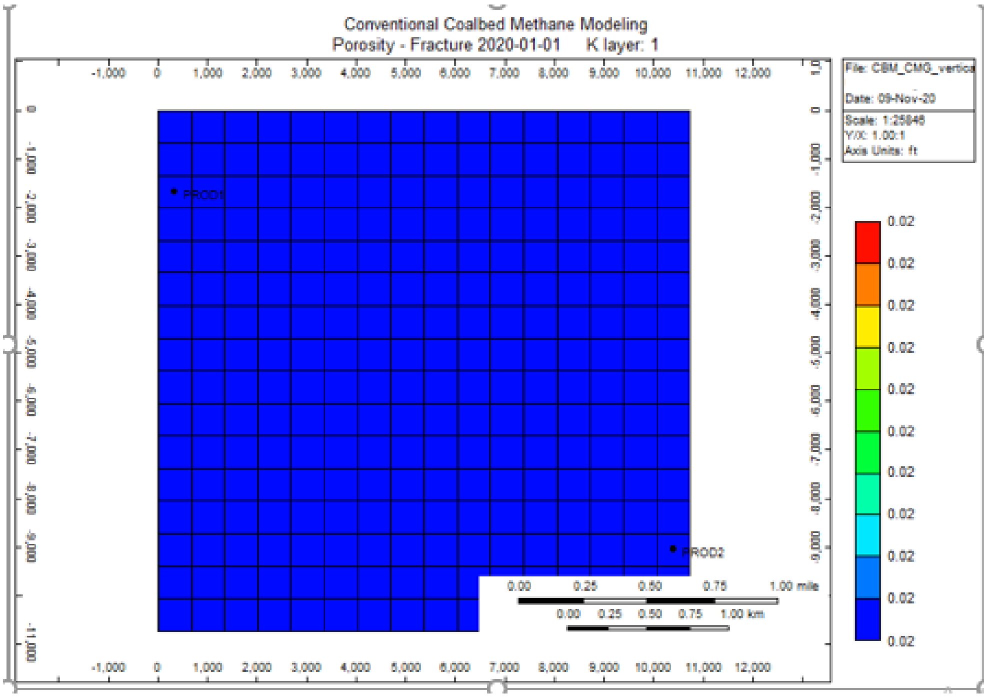

Figure 3.3: Fracture porosity of the reservoir model (generated from CMG builder)

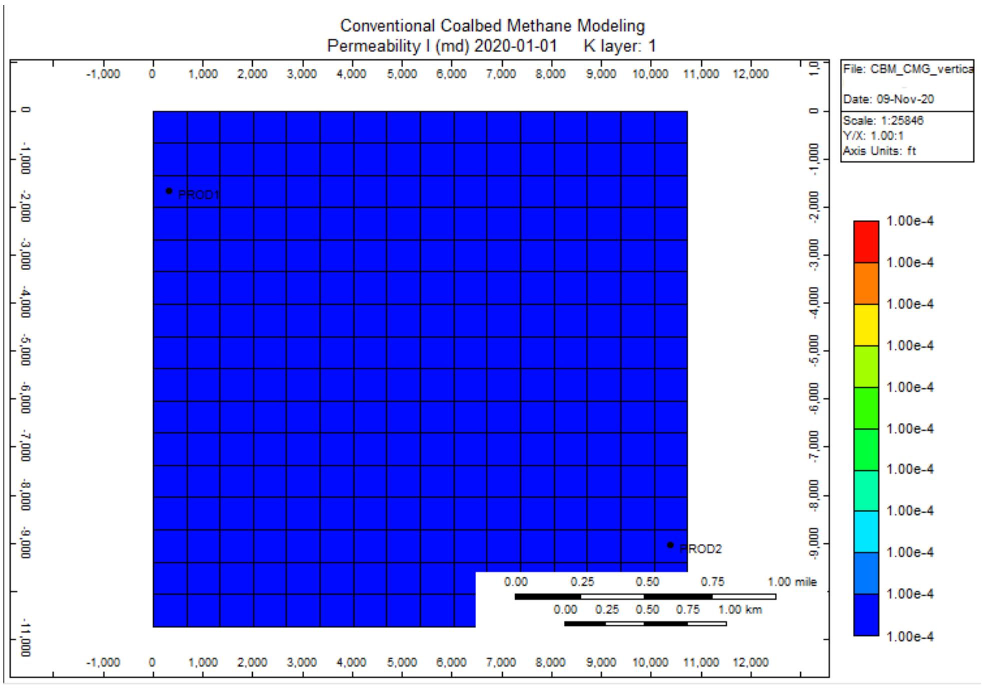

Figure 3.4: Matrix permeability of the reservoir model (generated from CMG builder)

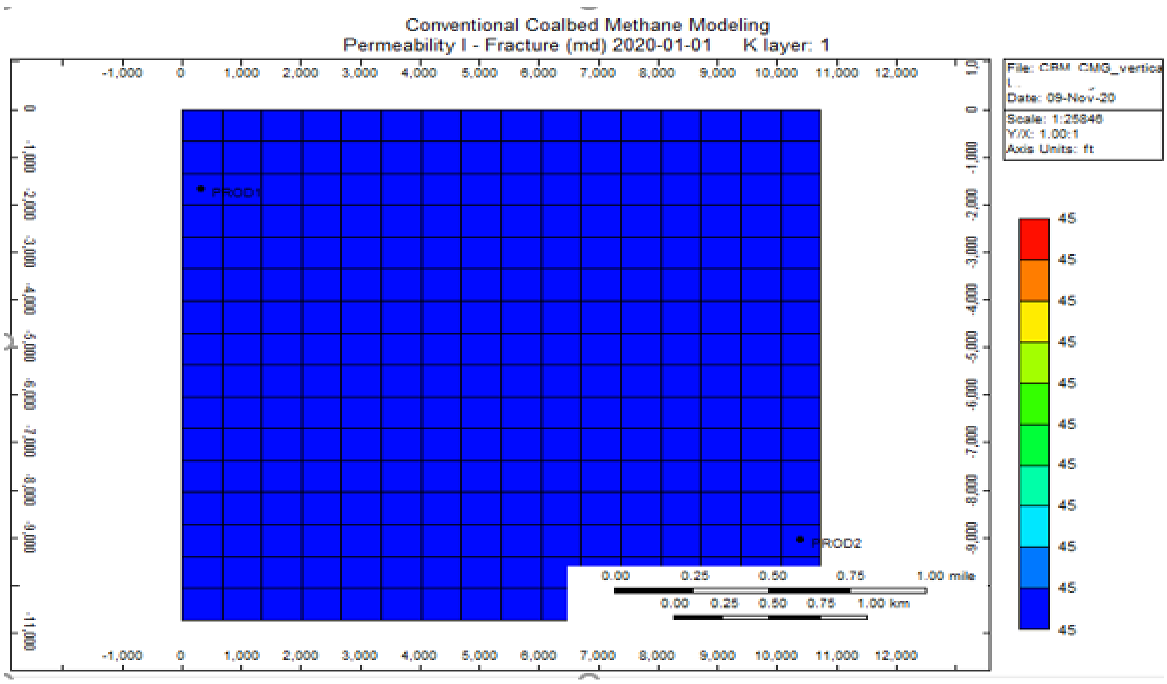

Figure 3.5: Horizontal Fracture permeability of the reservoir model (generated from CMG builder)

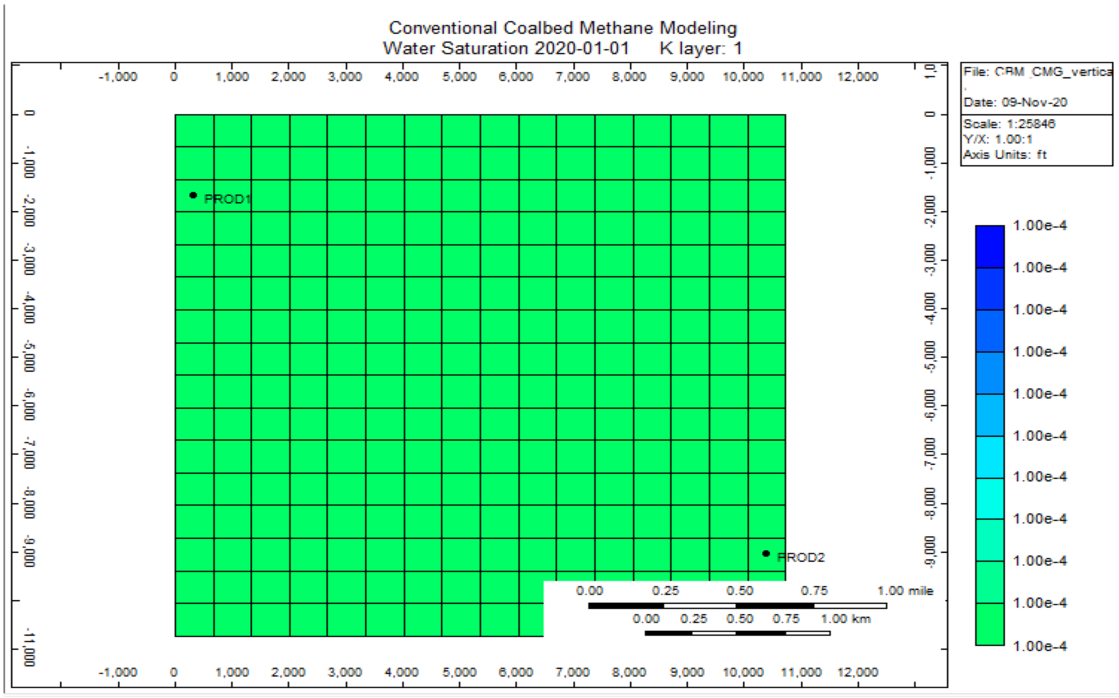

Figure 3.6: Matrix water saturation of the reservoir model (generated from CMG builder)

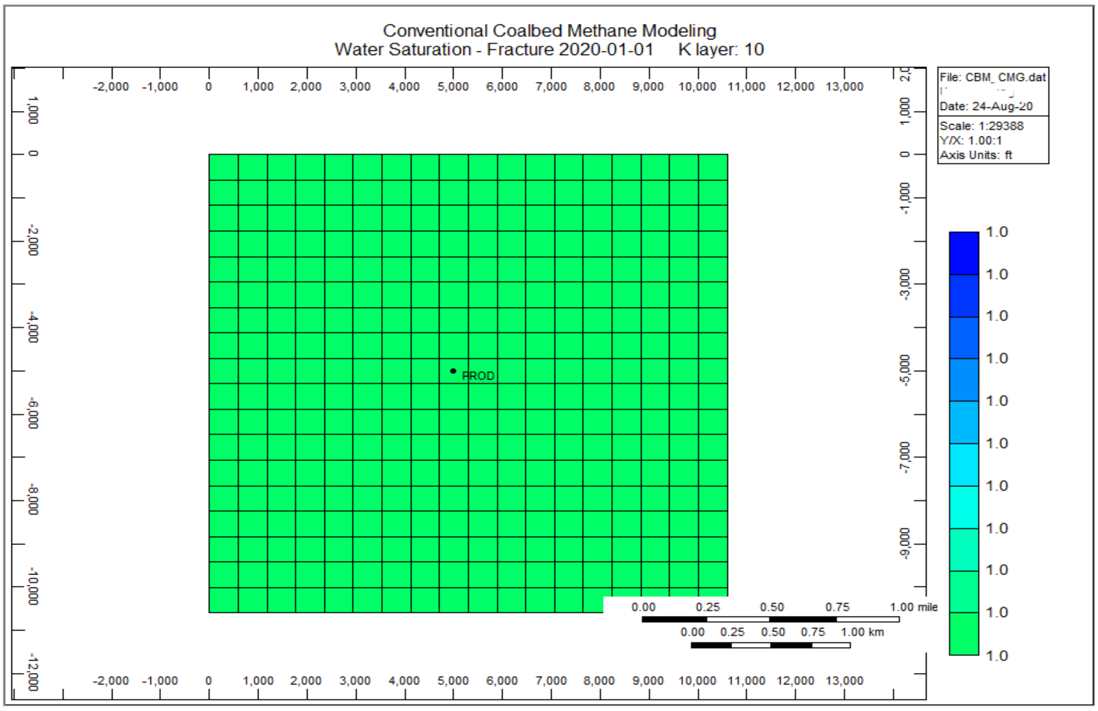

Figure 3.7: Fracture water saturation of the reservoir model (generated from CMG builder)

As can be seen from Table 3.1, the model was made to have some fractures, with the horizontal permeability of these fractures set to be 45md and the vertical permeabilities set to be 1.1md (which is 42 times less than the horizontal permeability). The reservoir temperature was set to be 95^{o}F. It is important to note that the fracture is initially filled with water (Sw = 0.99999). With these properties, the model was made to mimic the actual CBM production as accurately and reliably as possible.

The production wells were constrained to a maximum surface water rate of 31448.55 stb/day with a minimum bottomhole pressure of 36.26 psi while the injection wells were constrained to a maximum bottomhole pressure of 2175.56 psi during the production/sequestration period. When sequestration alone was being done, the injection well pressure constraint was increased to 4000 psi to allow injection of the carbon dioxide but prevent accidental fracturing of the coal.

The created model was then made to run on CMG GEM for 10/15 years starting from the 1st of January, 2020 for the production/injection until it reached its economic limit. After the economic limit was reached, the injection was continued for the ECBM cases for 10 more years. Other than the first scenario which was run for 15 years, all the other CBM scenarios were run for 10 years before they reached economic limit and production was stopped. For the ECBM scenarios, they were run for 15 years each with injection of CO_2 and production of methane before they reached their economic limit and production was stopped. After this economic limit was reached, carbon dioxide was sequestered for the next 10 years in the reservoir. The 10 years were chosen for sequestration because this was the time that was roughly taken for the reservoir pressure to reach the formation fracture pressure.

Table 3.1: Reservoir model parameters (Abu et al., 2016)

	Parameter (Unit)	**Value**
1	Area of the reservoir (acres)	2664
2	Depth to the top of the reservoir (ft)	328.74
3	Thickness (ft)	5.77
4	Porosity (fraction)	0.019
5	Matrix Permeability (md)	0.0001
6	Horizontal Fracture Permeability (md)	45
7	Vertical Fracture Permeability (md)	1.1
8	Reservoir Temperature (^oF)	95
9	Initial matrix water saturation (fraction)	0.0001
10	Initial fracture water saturation (fraction)	0.999995
11	Langmuir Adsorption Constant for CH_4 (1/psi)	0.00199
12	Langmuir Adsorption Constant for CO_2 (1/psi)	0.00345
13	Bulk density (lb/ft3)	90
14	Initial Reservoir Pressure (psi)	3600
15	CH_4-Coal Desorption time (day)	30

The method of injection/production followed by stopping production and injecting alone was chosen because while injection/production occurs, some of the carbon dioxide being injected was produced together with the methane. This defeated the purpose of injecting gas for sequestration. When sequestration was done without production, the carbon stayed in the reservoir.

The reservoir properties were kept constant for the ten scenarios while the well configuration was changed for each scenario to compare their results and thereby find the most ideal configuration.

3.1. Scenario 1

For the first scenario, the well configuration was two vertical producers at the corners of the model. As mentioned previously, this model had the properties listed in Table 3.1 above.

Figure 3.8 below shows the top view of the created model and wellbore configuration for scenario 1.

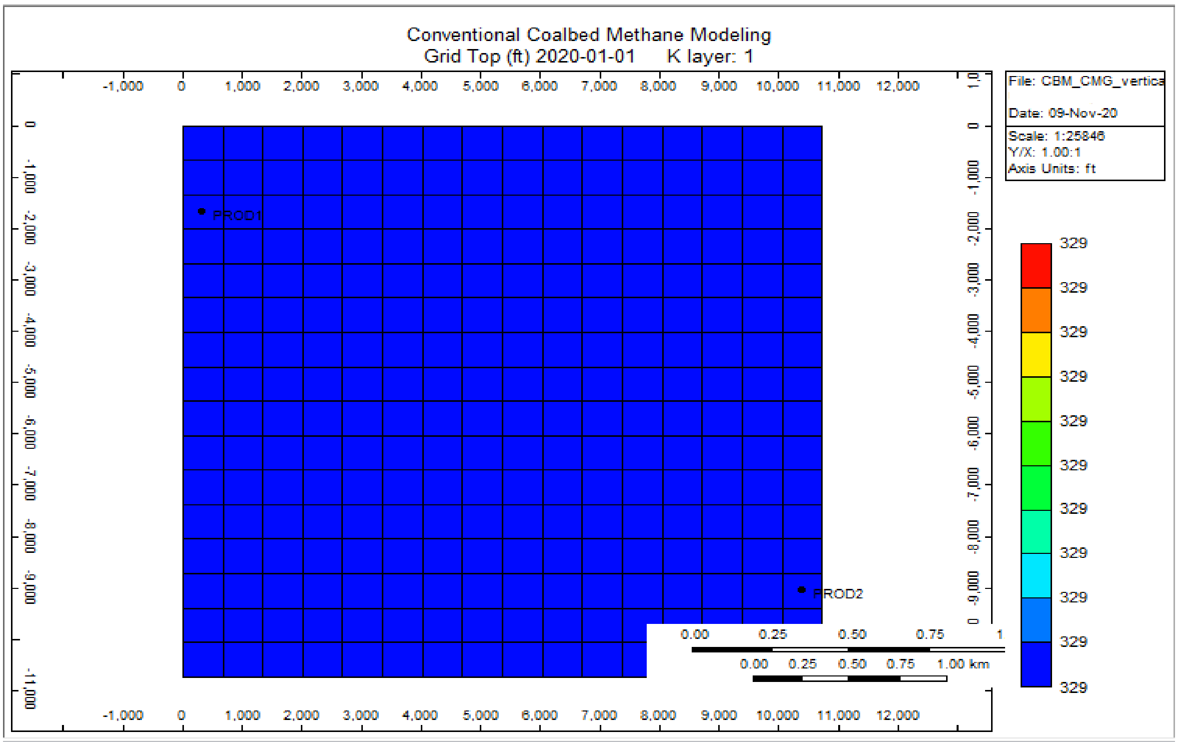

Figure 3.8: Top view of reservoir model for scenario1 (generated from CMG Builder)

3.2. Scenario 2

For this model, the well configuration was two horizontal producers at the corners of the model. Just like the model in scenario 1, this model had the properties listed in Table 3.1 above. Creating a model with only horizontal wells help to directly compare the results of vertical production wells with horizontal production wells in a CBM production process as well as compare the results with results from vertical/horizontal CO_2-ECBM production.

Figure 3.9 below shows the top view of the created model and wellbore configuration for scenario 2.

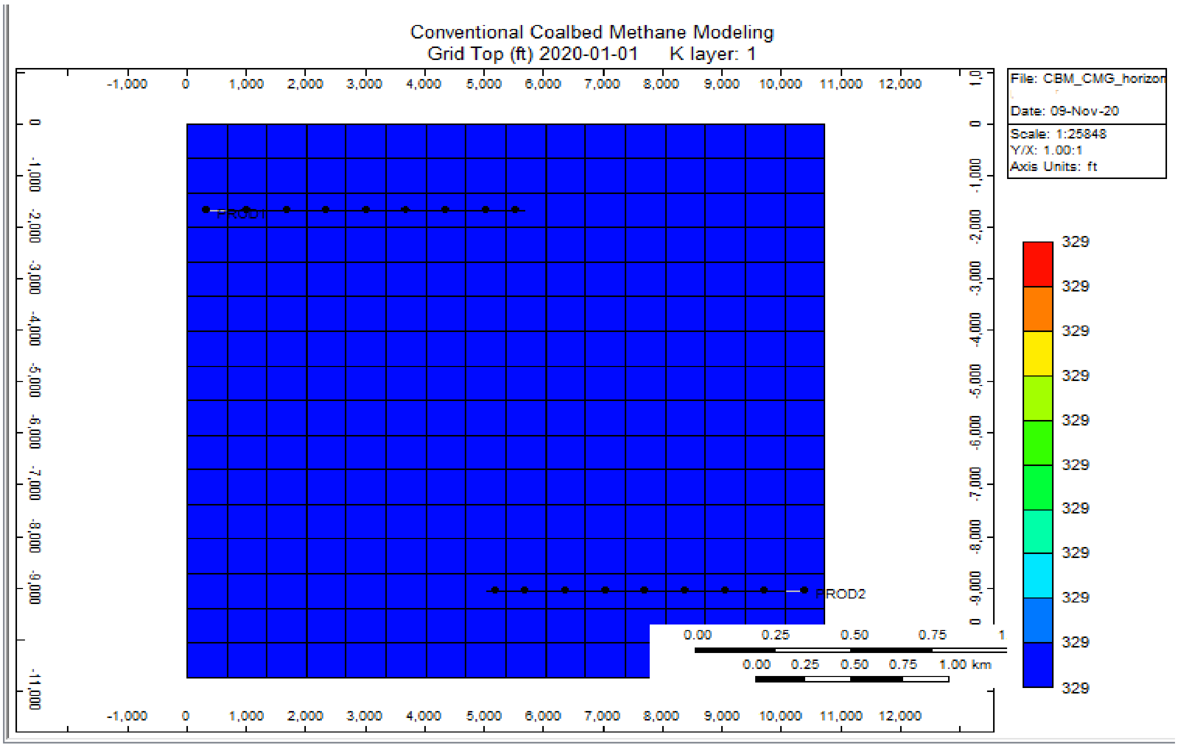

Figure 3.9: Top view of reservoir model for scenario 2 (generated from CMG Builder)

3.3. Scenario 3

For the third scenario, the well configuration was two horizontal producers at the corners of the model (like in the second scenario) with an additional two vertical CO_2 injectors. Just like the model in scenarios 1 and 2 above, this model had the properties listed in Table 3.1 above.

This model was created to compare the use of vertical injection wells with using horizontal injection wells in a CO_2-ECBM process as well as comparing the results of choosing to produce the reservoir using conventional CBM or CO_2-ECBM method.

Figure 3.10 below shows the top view of the created model and wellbore configuration for scenario 3.

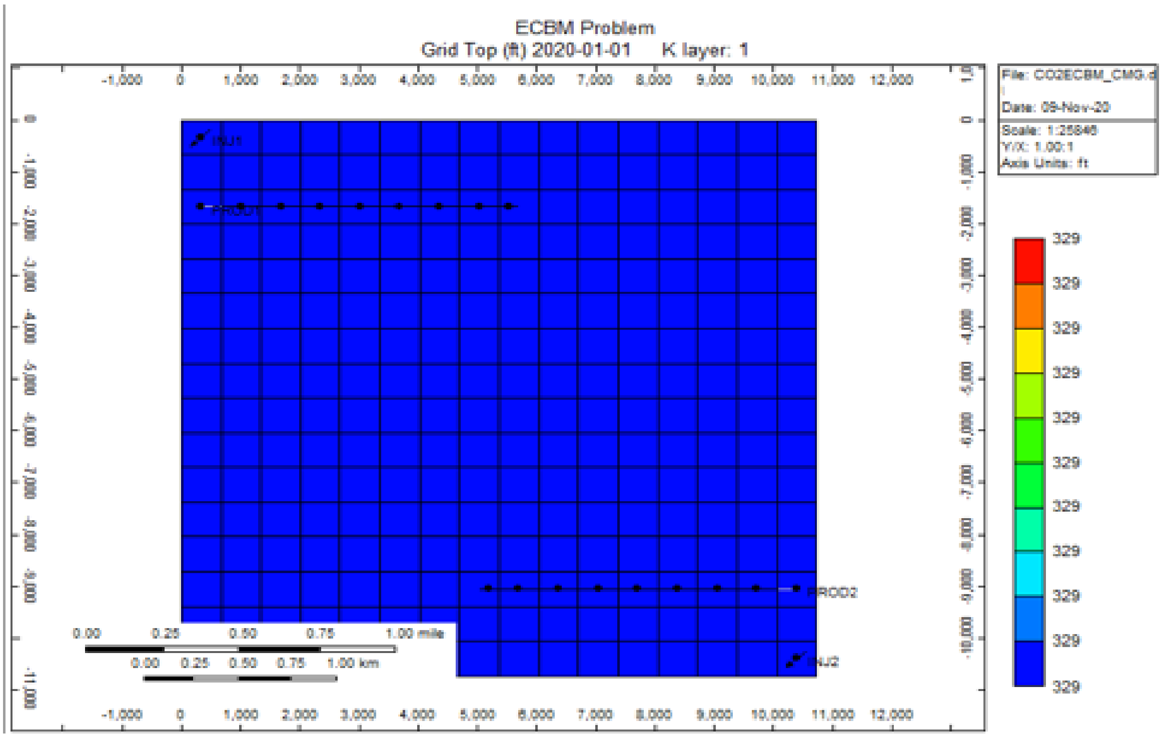

Figure 3.10: Top view of reservoir model for scenario 3 (generated from CMG Builder)

3.4. Scenario 4

The well configuration is the same as for scenario 3 but in this scenario, the injection wells were also horizontal, making all four wells – two injectors and two producers - horizontal. Just like the model in scenarios 1, 2 and 3 above, this model had the properties listed in Table 3.1 above.

Creating this model helps to understand if the best way of producing a coal mine using the CO_2-ECBM method is through the use of a horizontal injection well (as opposed to using a vertical injection well in scenario 3) and if CO_2-ECBM is indeed a better way to produce methane from coal than the conventional CBM.

Figure 3.11 below shows the top view of the created model and wellbore configuration for scenario 4.

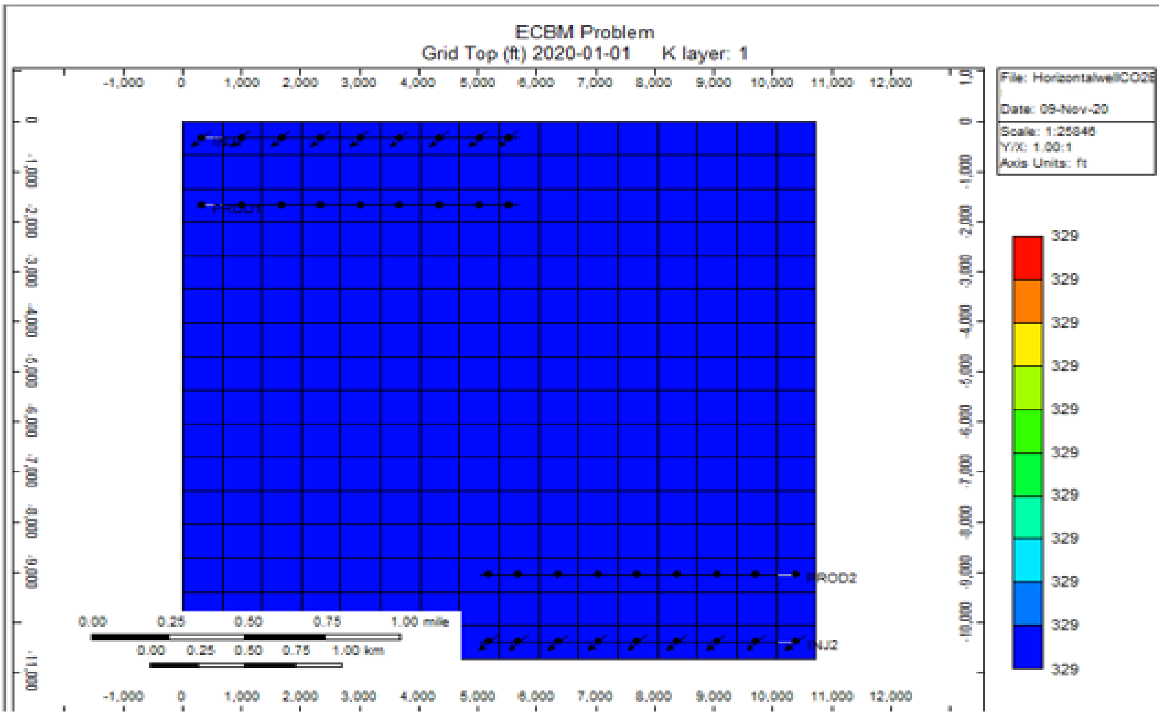

Figure 3.11: Top view of reservoir model for scenario 4 (generated from CMG Builder)

3.5. Scenario 5

The well configuration of the fifth scenario incudes 5 vertical producers with the properties listed in Table 3.1 above. Seeing the results from the first scenario, it was decided to add more vertical wells to the model to see how much this would impact production.

Figure 3.12 below shows the top view of the created model and wellbore configuration for scenario 5.

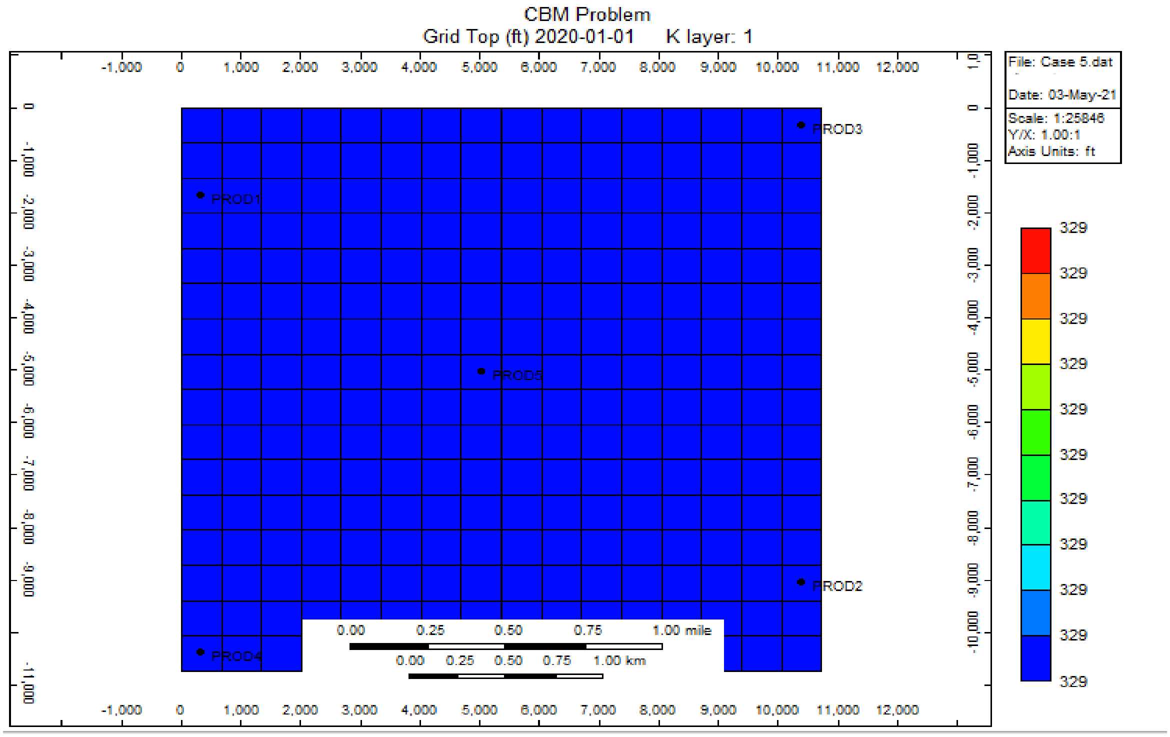

Figure 3.12: Top view of reservoir model for scenario 5 (generated from CMG Builder)

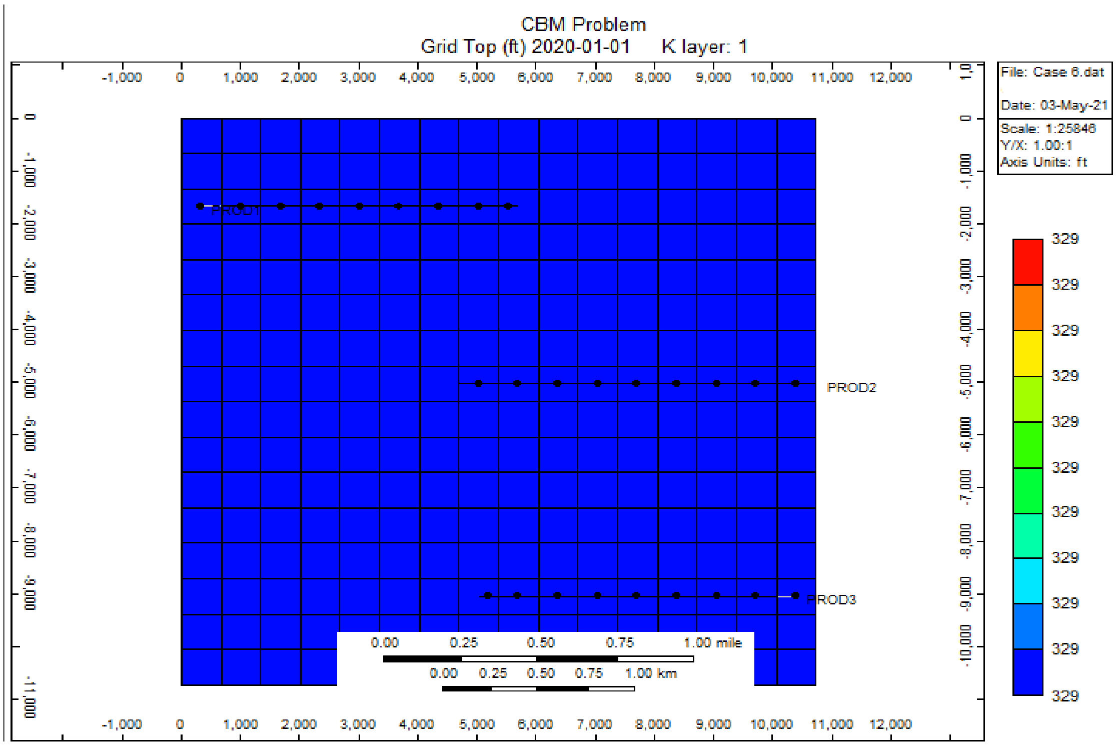

Figure 3.13: Top view of reservoir model for scenario 6 (generated from CMG Builder)

3.6. Scenario 6

The well configuration of the sixth scenario incudes 3 horizontal producers with the properties listed in Table 3.1 above. This model is a variation of the model of the second scenario in order to see how much additional production could be realised with the addition of a horizontal well.

Figure 3.13 shows the top view of the created model and wellbore configuration for scenario 6.

3.7. Scenario 7

The well configuration of the seventh scenario incudes 6 wells in total – three vertical injectors and three horizontal producers.

Figure 3.14 below shows the top view of the created model and wellbore configuration for scenario 7.

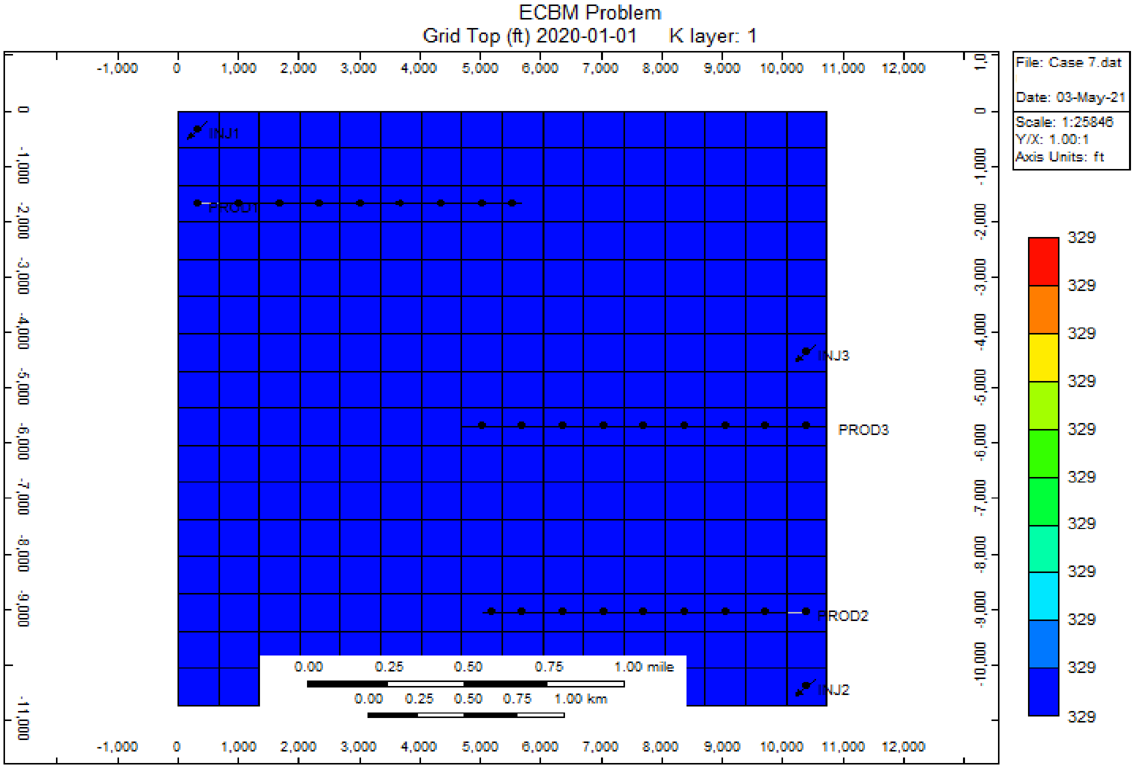

Figure 3.14: Top view of reservoir model for scenario 7 (generated from CMG Builder)

3.8. Scenario 8

The well configuration of the eighth scenario incudes 6 wells in total – three horizontal injectors and three horizontal producers. Figure 3.15 below shows the top view of the created model and wellbore configuration for scenario 8.

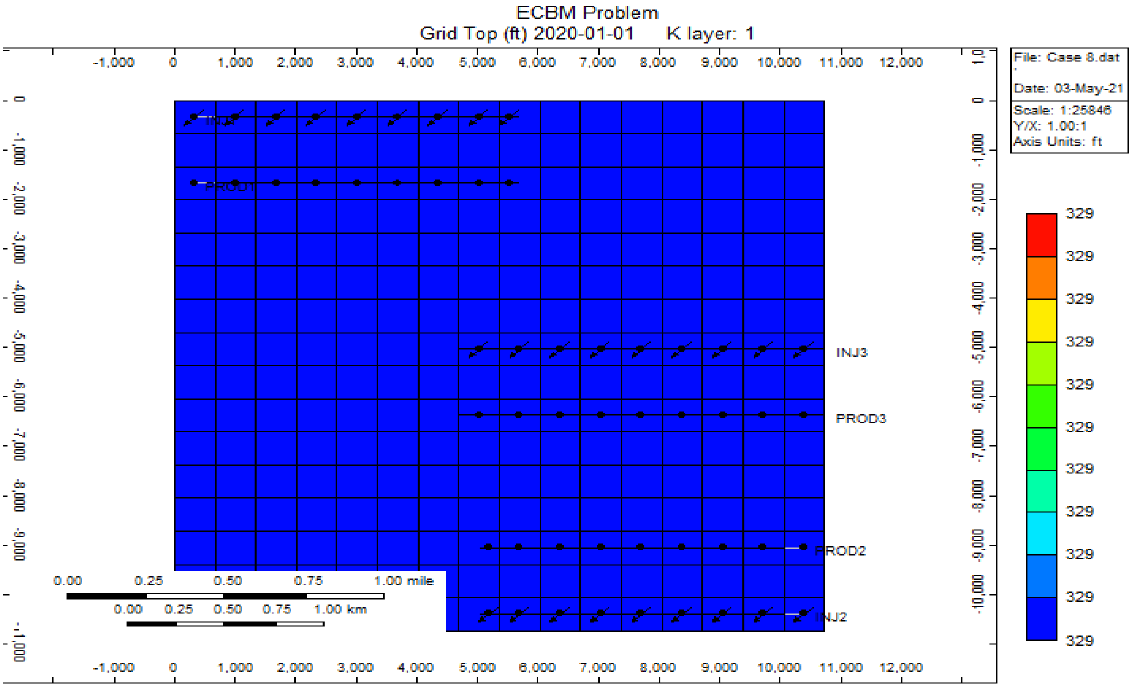

Figure 3.15: Top view of reservoir model for scenario 8 (generated from CMG Builder)

3.9. Scenario 9

The well configuration of the ninth scenario incudes 4 horizontal producers with the properties listed in Table 3.1 above. Figure 3.16 below shows the top view of the created model and wellbore configuration for scenario 9.

3.10. Scenario 10

The well configuration of the tenth scenario incudes eight wells in total – two vertical injectors, two horizontal injectors and four horizontal producers.

Figure 3.17 below shows the top view of the created model and wellbore configuration for scenario 10.

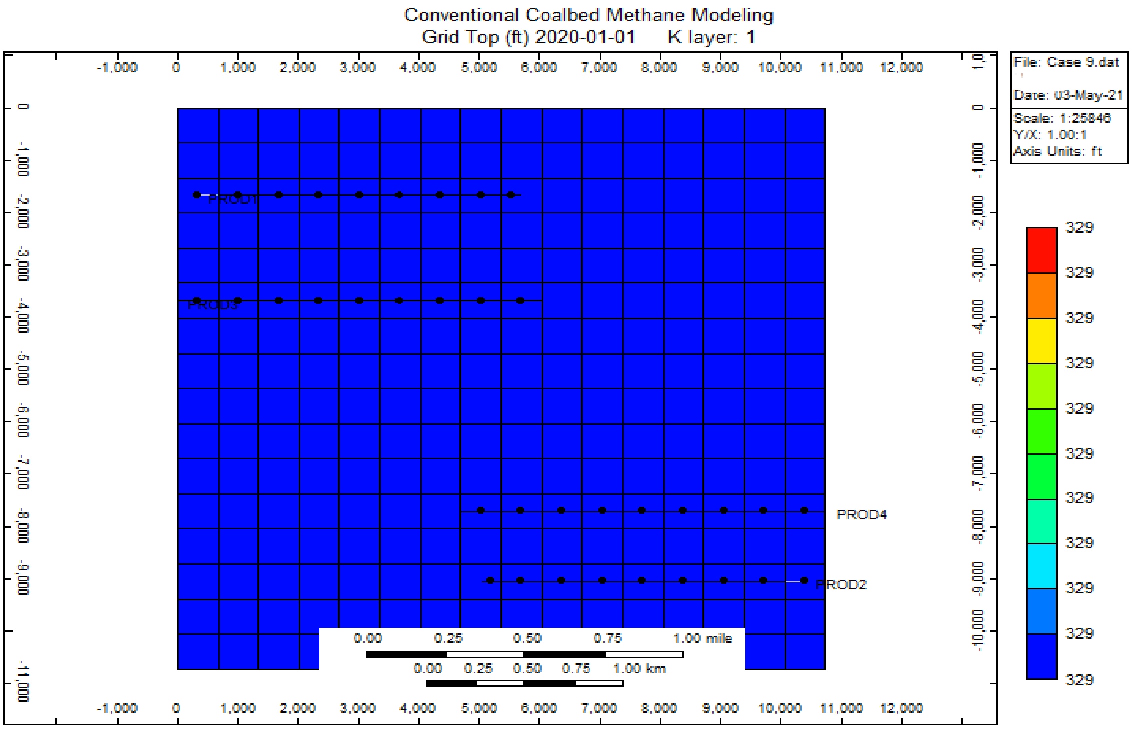

Figure 3.16: Top view of reservoir model for scenario 9 (generated from CMG Builder)

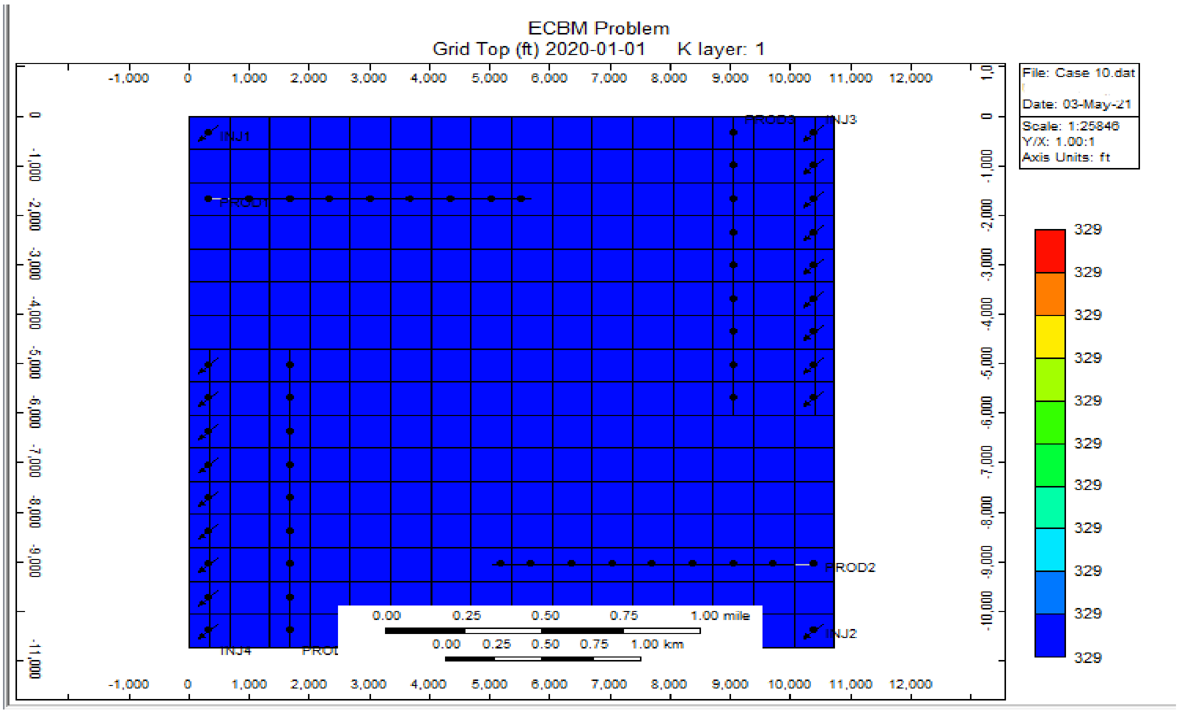

Figure 3.17: Top view of reservoir model for scenario 10 (generated from CMG Builder)

CHAPTER 4
RESULTS AND DISCUSSIONS

In this chapter, the extracted results from each of the scenarios outlined in chapter 3 are shown and analysed in details. The effect of the well orientation as well as the chosen method of production from the unmineable coal is analysed and compared to decide the best one.

As explained in chapter three, a model was created and the ten scenarios were run using the CMG GEM simulator. After this, the simulation results graphs were gotten by running each of the .irf files on the Results Graph on CMG. These results are discussed in this section. The sequestration potential of the CO_2-ECBM is also measured.

The properties that are extracted from the .irf file are the cumulative gas production, cumulative carbon dioxide injected, adsorption of methane at the end of the simulation and adsorption of carbon dioxide at the end of the simulation.

4.1. Effect of Pressure on CBM

From the Langmuir Isotherm equation given in Equation 2.1, it is obvious that the pressure conditions to which a CBM is subjected largely affects the volume of gas adsorbed to the coal, which largely affects the performance of the CBM.

To investigate this, scenario three was subjected to three different pressure conditions: high pressure at 2000 psi, medium pressure at 800 psi and low pressure at 36.26 psi. It is important to note that scenario 3 was originally investigated at low pressure (36.26 psi). These pressure conditions were set in the reservoir by setting the constraints of the producers to have a minimum pressure equal to the desired pressure conditions.

Running these simulations revealed that the relationship between pressure and volume of adsorbed gas is directly proportional, that is, at lower pressures, there is lower amount of gas adsorbed to the coal and vice versa (in agreement with the Langmuir isotherm equation).

This means that the lower the pressure in the CBM reservoir, the more methane can desorb from the coal and be produced. At higher pressures however, there is a high limitation on the amount of methane that can be desorbed from the coal.

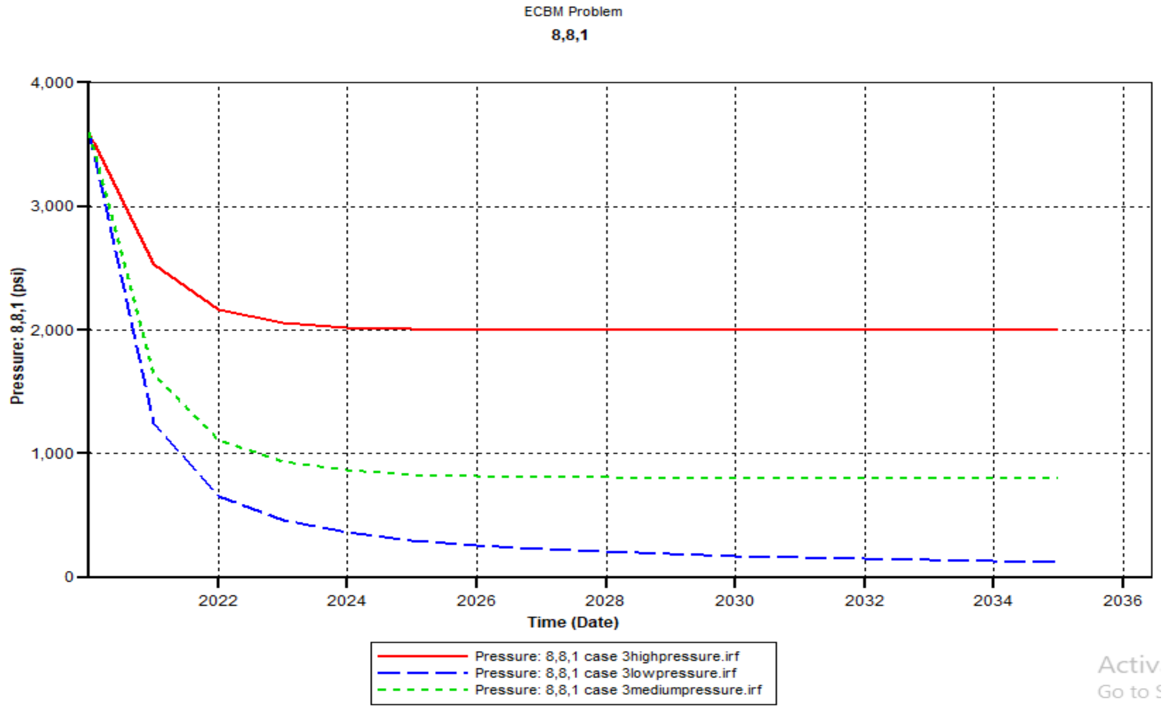

Figure 4.1: Pressure at the middle of the reservoir for high, low and medium pressure conditions (generated from CMG Results Graph)

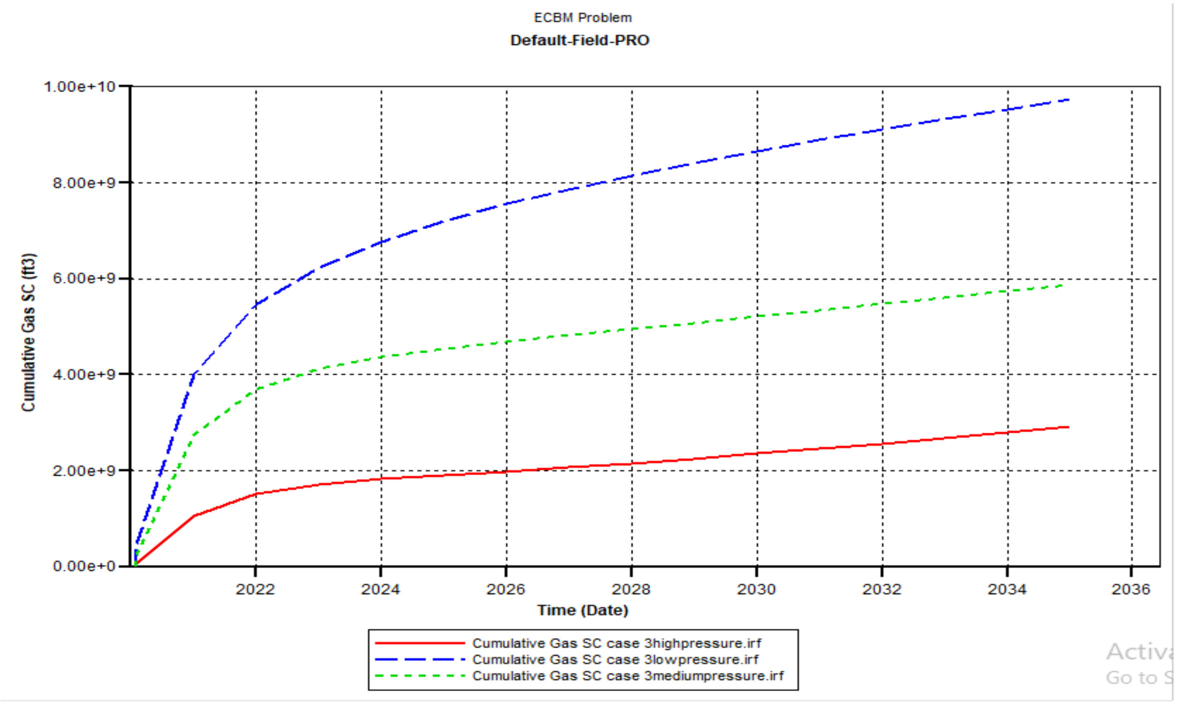

Figure 4.2: Cumulative gas produced for high, low and medium pressure conditions (generated from CMG Results Graph)

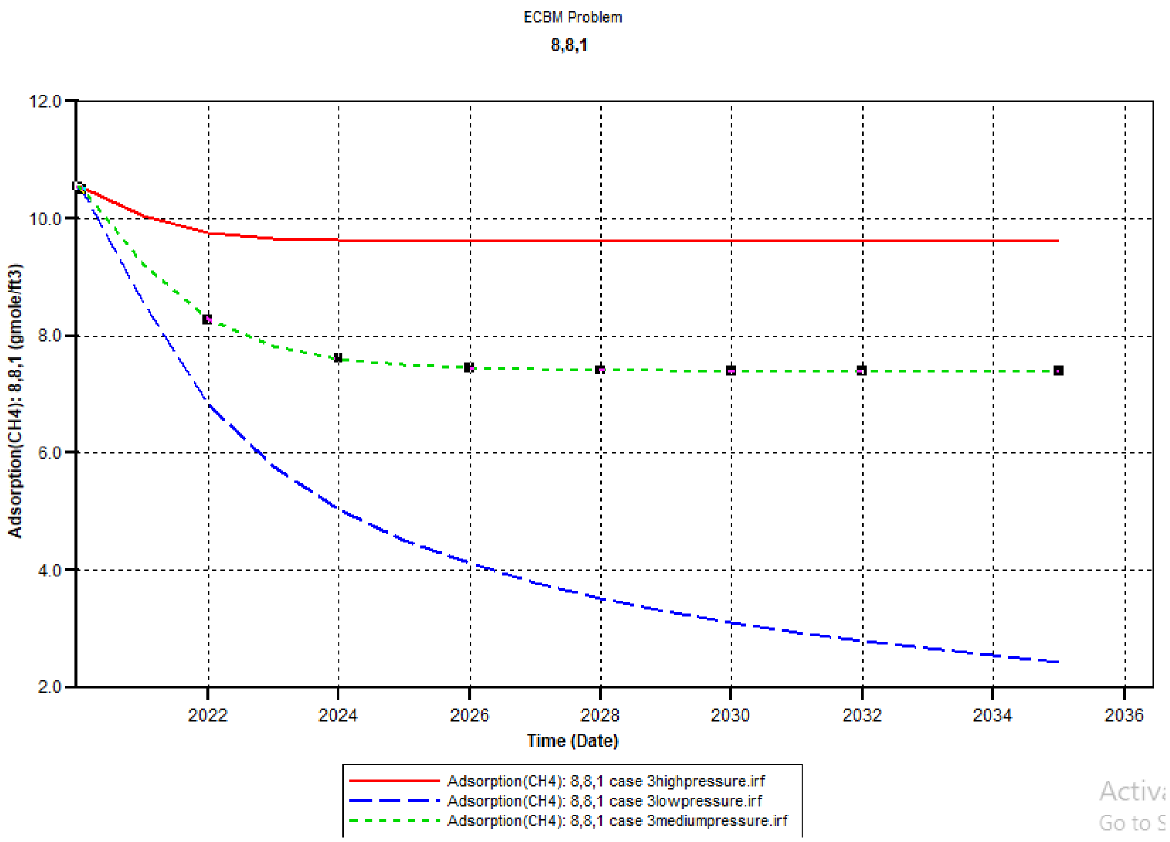

Figure 4.3: Amount of methane adsorbed to coal for high, low and medium pressure conditions (generated from CMG Results Graph)

Which means that most of the methane remains adsorbed to the coal and is not produced. From this, it follows that the performance of the ECBM/CBM depends largely on lowering the pressure of the reservoir.

Figure 4.1 shows the pressure conditions for each of the three scenarios at the middle of the reservoir and Figure 4.2 shows the cumulative gas produced for each of the three scenarios. Figure 4.3 shows the amount of methane adsorbed to the coal for each of the three scenarios at the middle of the reservoir.

4.2. Best Scenario for Gas Production and Carbon Sequestration

The obvious way to measure the success of each of the scenarios is by checking the amount of gas produced by each scenario. From Figure 4.4 and Table 4.1, it shows that the tenth

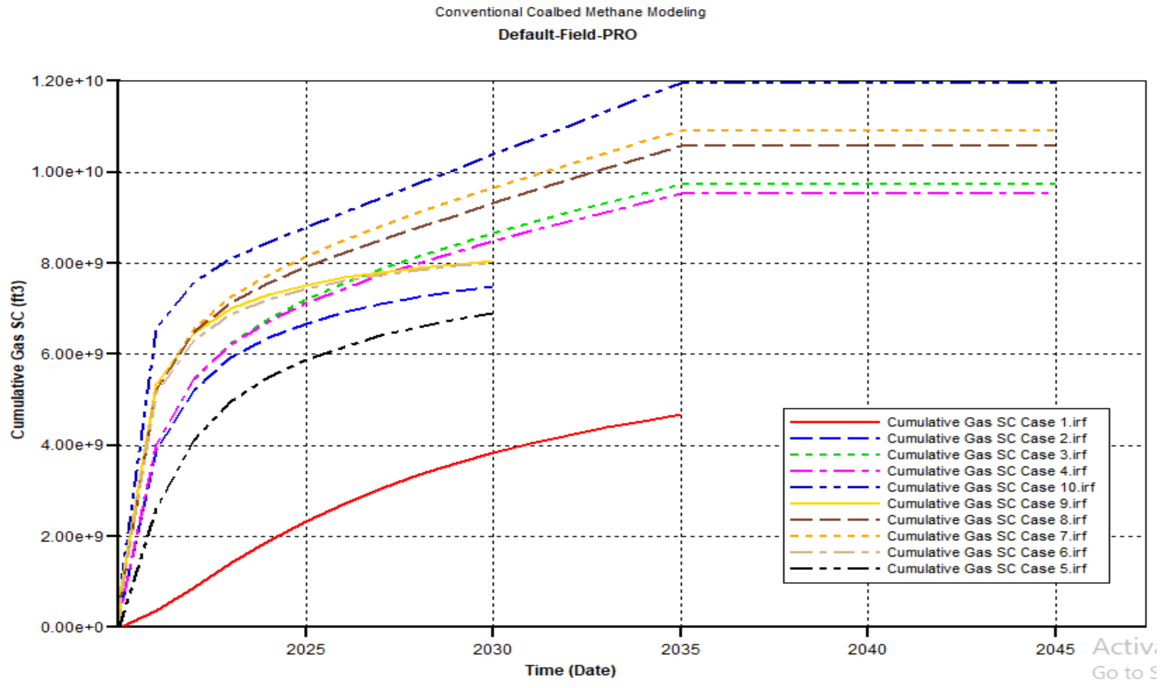

Figure 4.4: Cumulative gas production with time (generated from CMG Results Graph)

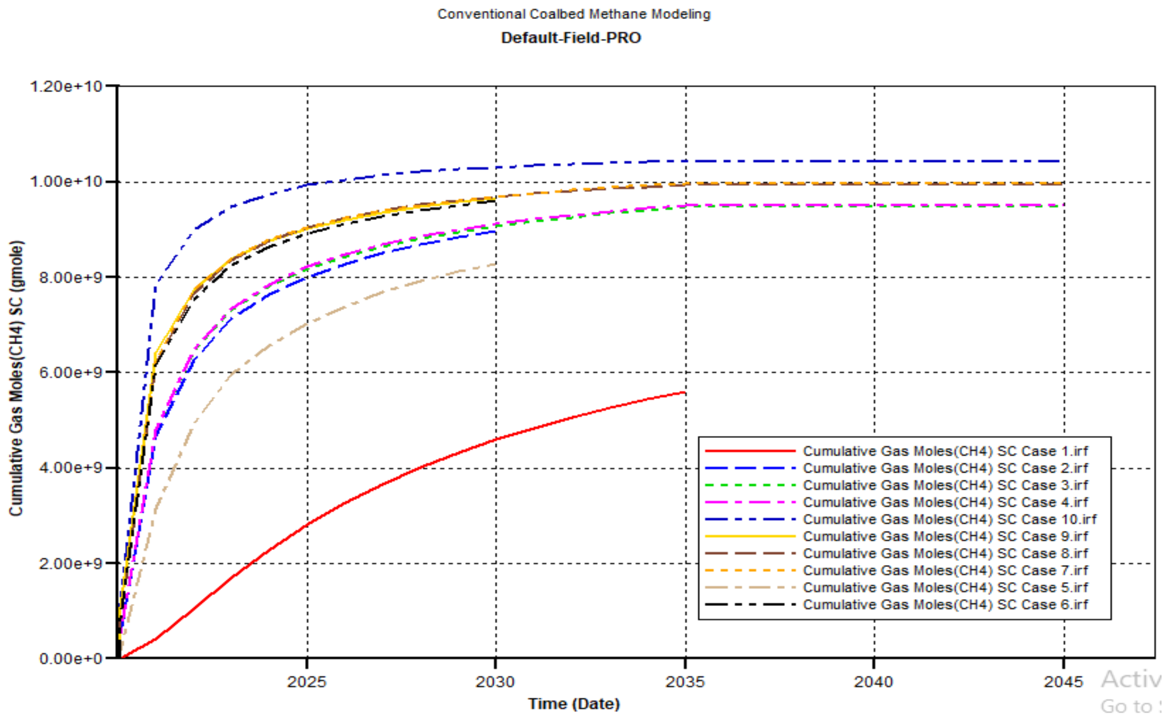

Figure 4.5: Cumulative amount of methane produced (generated from CMG Results Graph)

scenario produces the maximum amount of gas. This result was expected because this scenario had the most amount of production and injection wells of any of the scenarios. It is of course possible, that one scenario has a higher amount of cumulative gas production and less methane produced compared to another scenario with lower cumulative gas production and higher methane produced. This could happen as a result of high amounts of CO_2 being produced. To ensure that scenario 10 actually has the highest cumulative production of all ten, it is important to check the amount of methane actually produced in all ten scenarios (Figure 4.5). This was also the scenario that performed the best for carbon sequestration, as can be seen in Figure 4.6.

These results show that as seen from previously published literature, increasing the number of wells lead to an increase in gas production and sequestration. Awaad et al. (2020) saw this increase in production due to addition of more wells in their scenario study of several fields in Egypt. The idea is that by drilling these additional wells, there is an increased communication between the wells and hydrocarbons from unswept areas can be recovered as well.

The results from the simulation also showed that having horizontal wells contributes more to production than the number of wells. For example, comparing scenario 5 (with 5 vertical wells) to scenario 6 (with 3 horizontal wells) shows this. The aim of horizontal wells is to expose larger surface areas of the reservoir to production than would be done by using vertical wells. These larger surface areas are meant to cause an increase in water production which would reduce the reservoir pressure, thereby allowing the gas to desorb. Abu et al. (2016) also showed similar results when using horizontal wells to develop CBM reservoirs.

Comparing the results of scenario 7 to scenario 8, using vertical injectors gave better results than using horizontal injectors. A careful look into the pressures surrounding the wells in scenario 7 and scenario 8 gives an explanation for this. It was observed that using six horizontal wells causes more pressure decrease - especially around the wells – than using three horizontal and three vertical wells. Since the bottomhole pressure of all the wells are the same, this means that the third scenario has higher drawdown which pushes the gas faster into the wellbore. This slight reduction in methane recovery when using horizontal injectors as wells as horizontal producers was reported by Jikich et al. (2003) for CO_2 sequestration in a shaly sandstone as well as by Fatemi et al. (2009) for toe-to-heel air injection study.

Additionally, the comparison of CBM to CO_2-ECBM as methods of production CBM reservoirs, showed that CO_2-ECBM generally gave better results. Wahid et al. (2018) also got similar results on the simulation studies of using CBM to improve the recovery from a CBM field in Indonesia.

Figure 4.7 to Figure 4.22 shows the amount of adsorbed methane and carbon dioxide at the end of the simulation for each scenario. These figures show that drilling more wells lead to increased methane production leading to the low amount of adsorbed methane seen in the figures at the end of the production and a similar increase in carbon dioxide sequestration leading to higher amounts of adsorbed carbon dioxide at the end of the injection also seen in the figures. The figures also support the theory that drilling directional wells leads to better performance – both in terms of methane production and carbon sequestration.

Table 4.2 scales the created model to the Onyeama field.

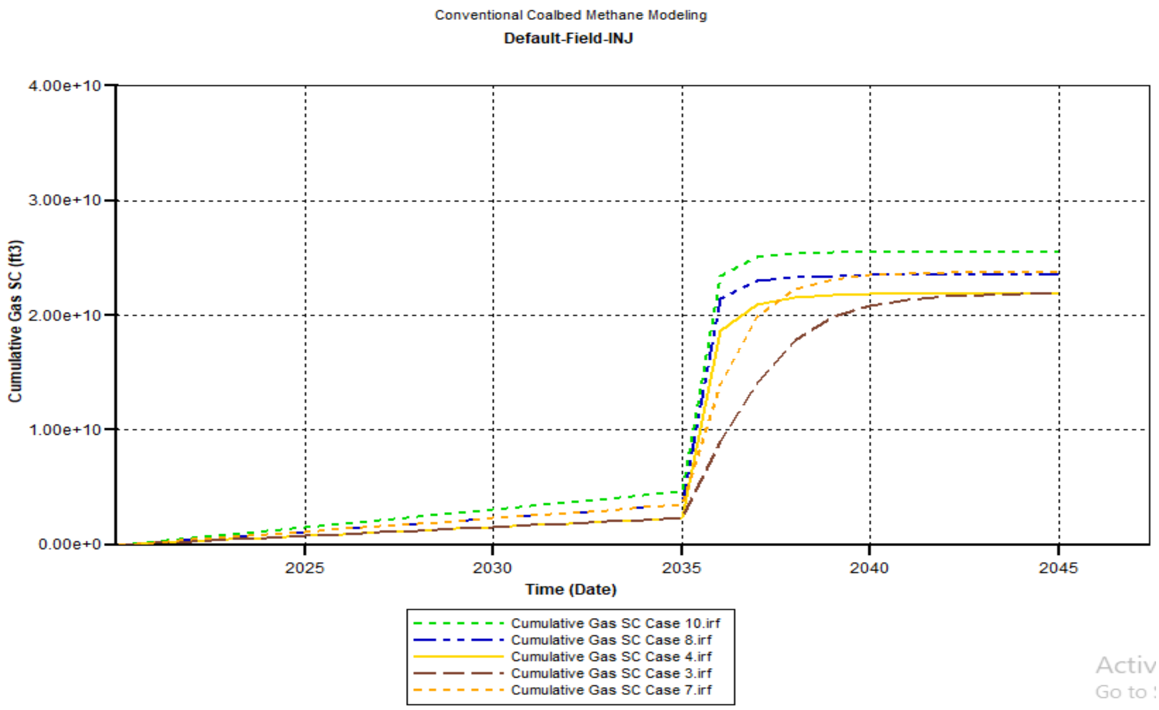

Figure 4.6: Cumulative carbon dioxide injected with time (generated from CMG Results Graph)

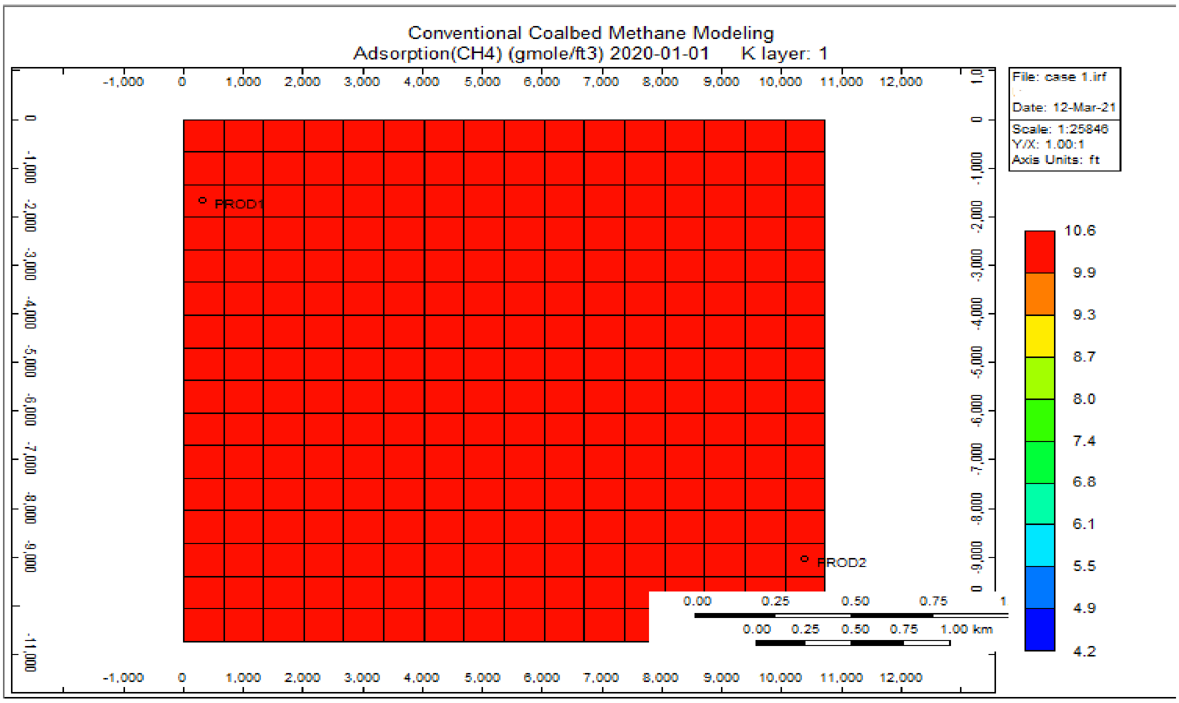

Figure 4.7: Amount of adsorbed methane at the beginning of the simulation life (generated from CMG Results 3D)

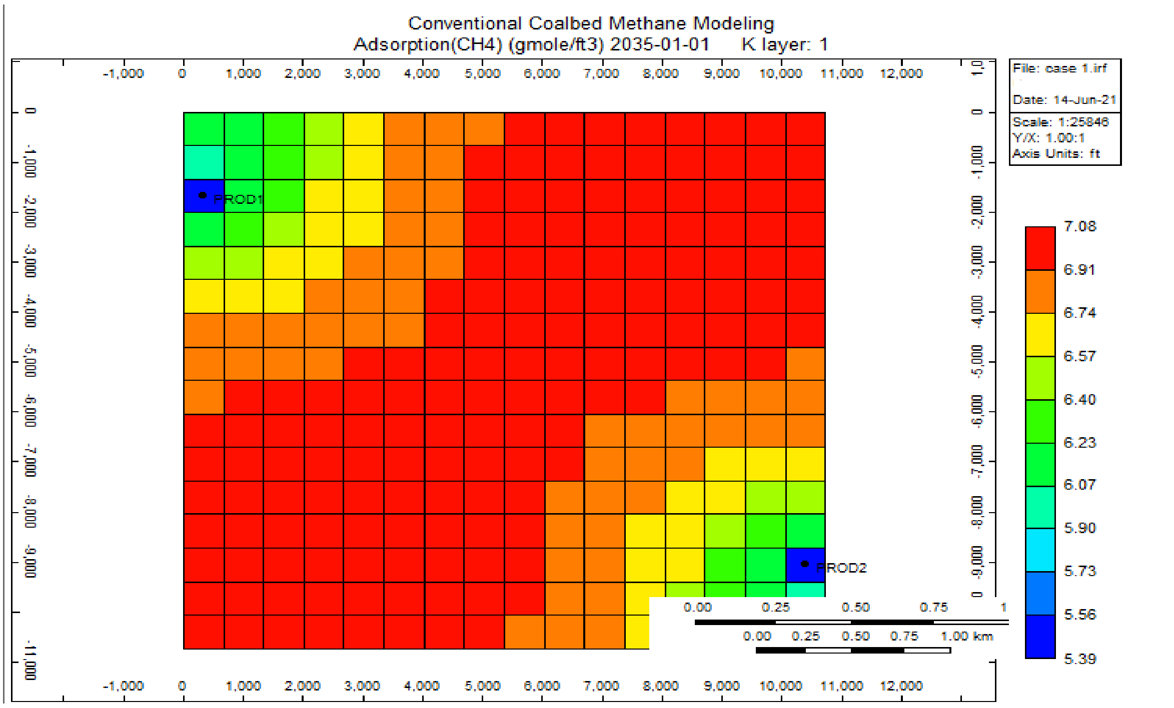

Figure 4.8: Amount of adsorbed methane at the end of the simulation life for scenario 1 (generated from CMG Results 3D)

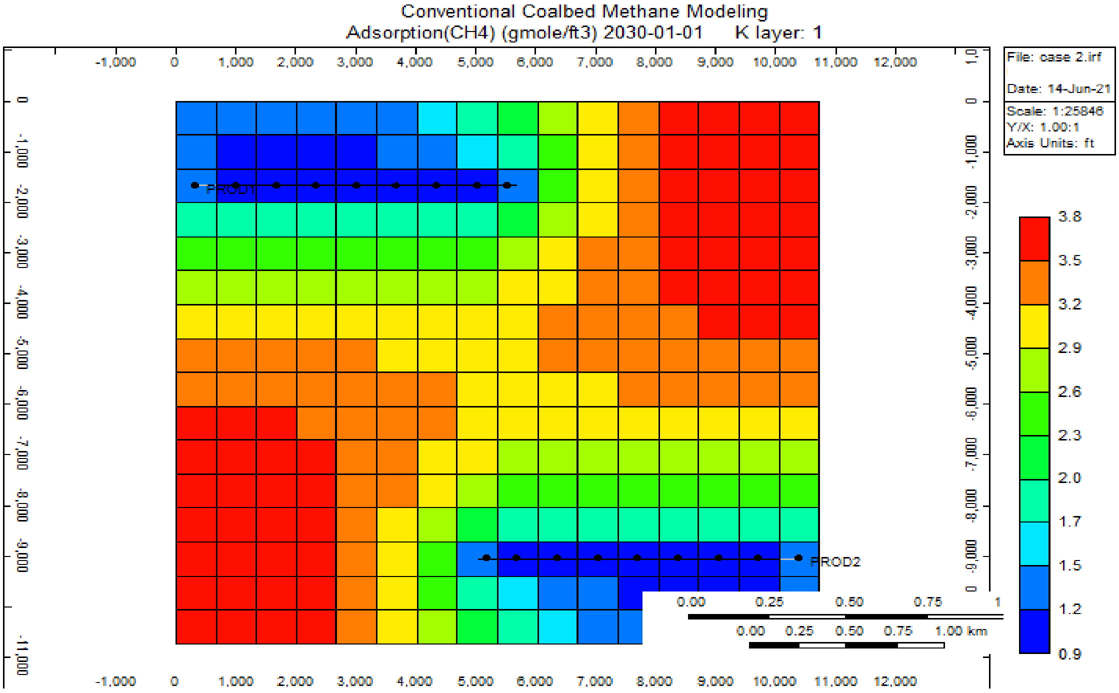

Figure 4.9: Amount of adsorbed methane at the end of the simulation life for scenario 2 (generated from CMG Results 3D)

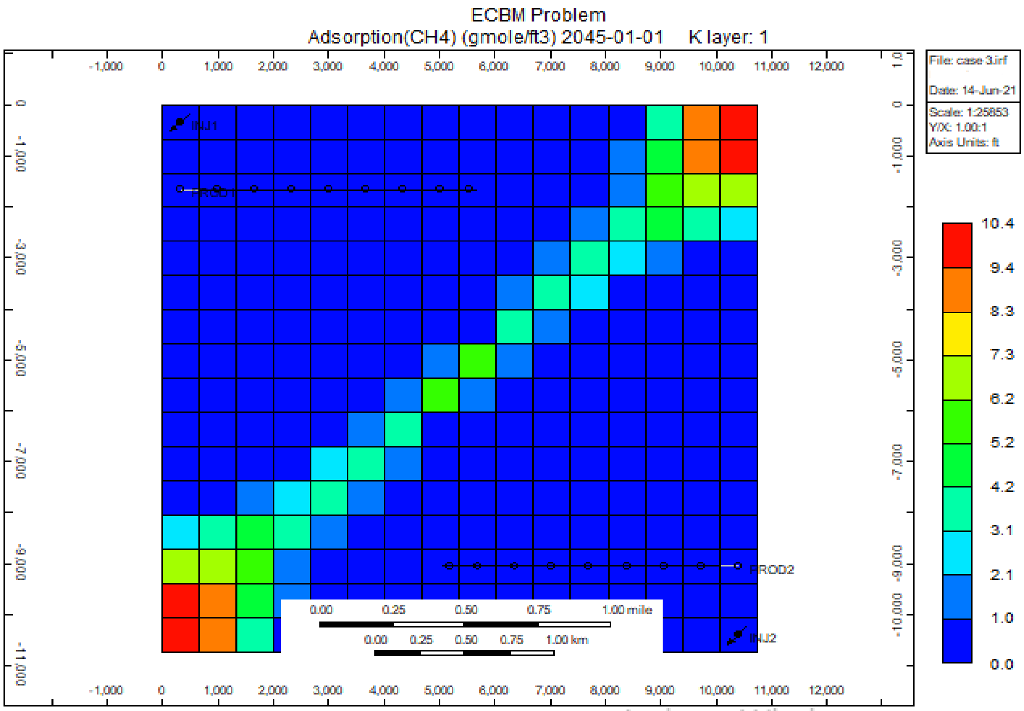

Figure 4.10: Amount of adsorbed methane at the end of the simulation life for scenario 3 (generated from CMG Results 3D)

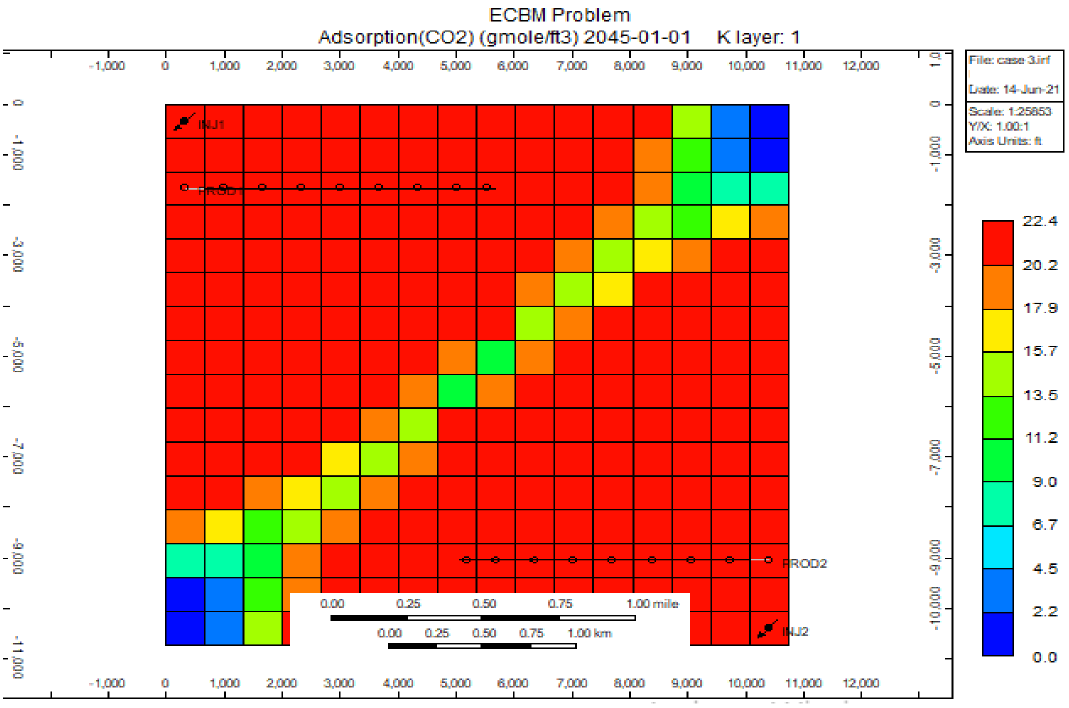

Figure 4.11: Amount of adsorbed carbon dioxide at the end of the simulation life for scenario 3 (generated from CMG Results 3D)

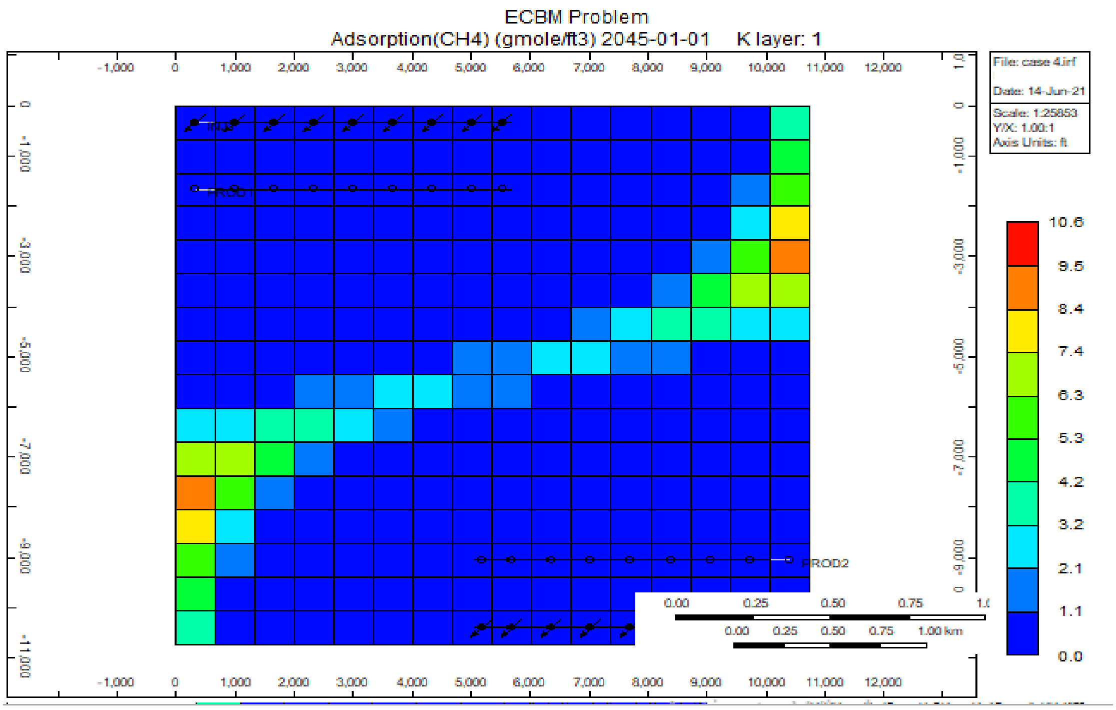

Figure 4.12: Amount of adsorbed methane at the end of the simulation life for scenario 4 (generated from CMG Results 3D)

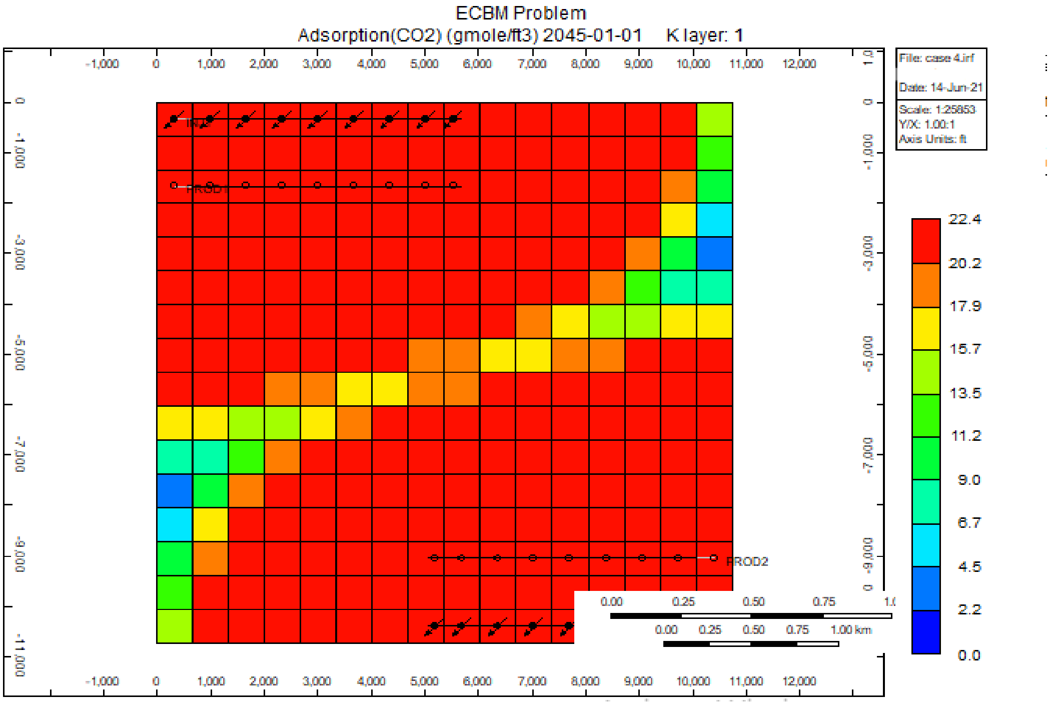

Figure 4.13: Amount of adsorbed carbon dioxide at the end of the simulation life for scenario 4 (generated from CMG Results 3D)

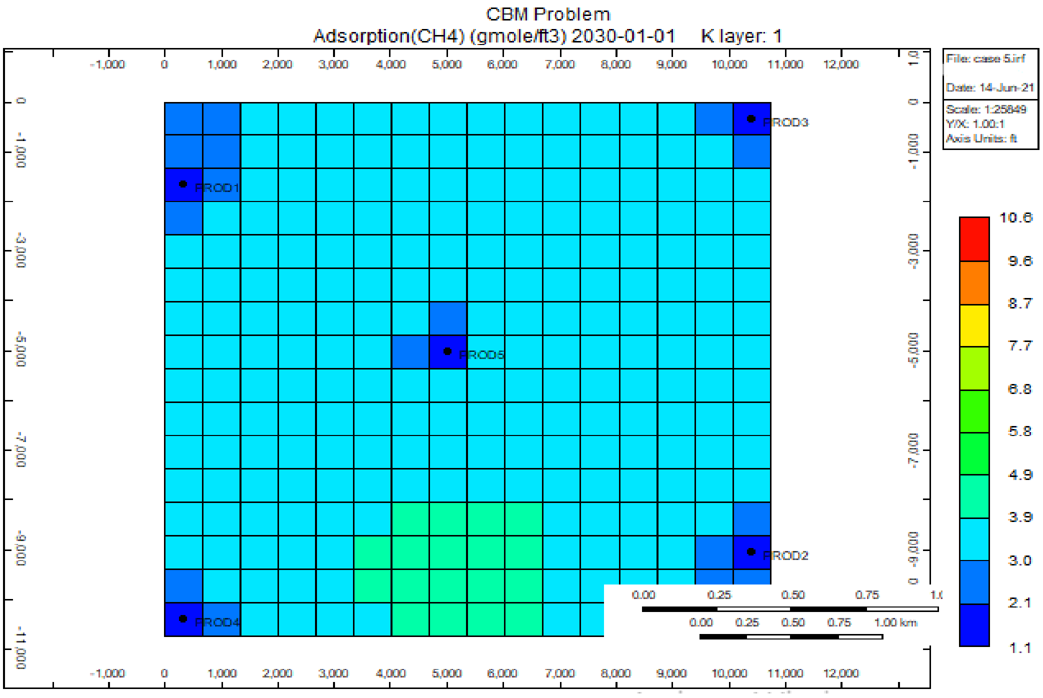

Figure 4.14: Amount of adsorbed methane at the end of the simulation life for scenario 5 (generated from CMG Results 3D)

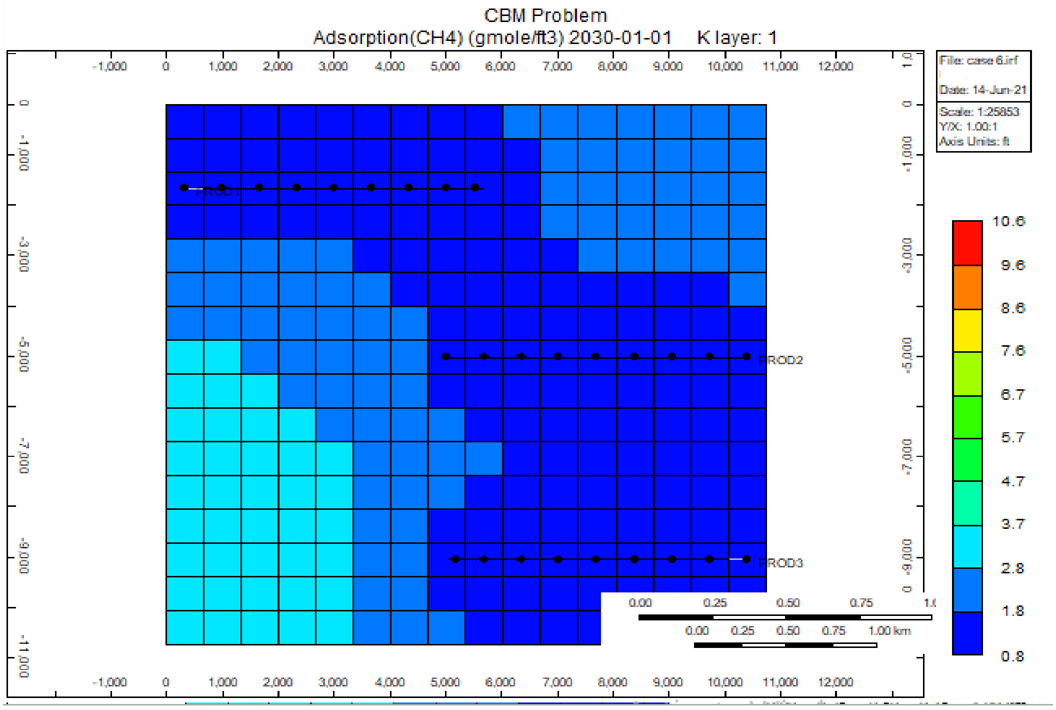

Figure 4.15: Amount of adsorbed methane at the end of the simulation life for scenario 6 (generated from CMG Results 3D)

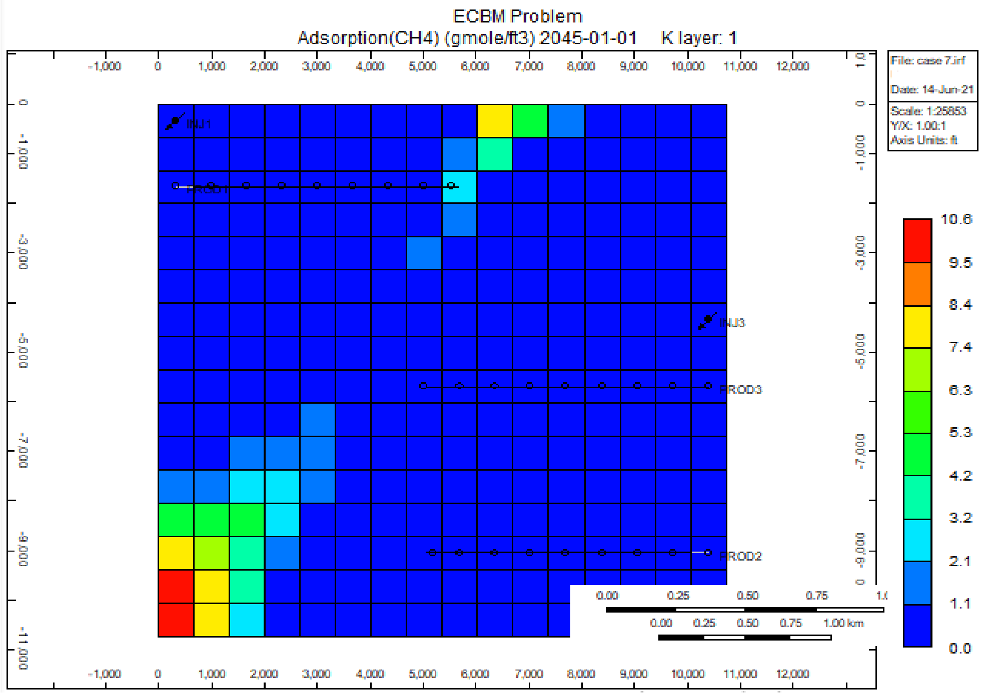

Figure 4.16: Amount of adsorbed methane at the end of the simulation life for scenario 7 (generated from CMG Results 3D)

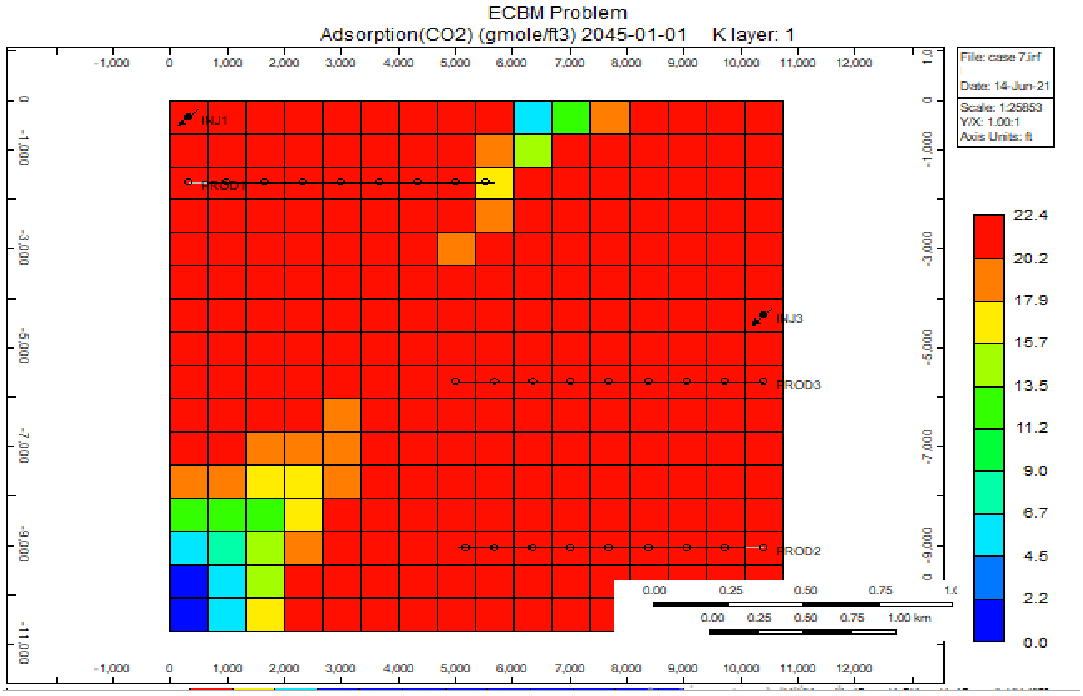

Figure 4.17: Amount of adsorbed carbon dioxide at the end of the simulation life for scenario 7 (generated from CMG Results 3D)

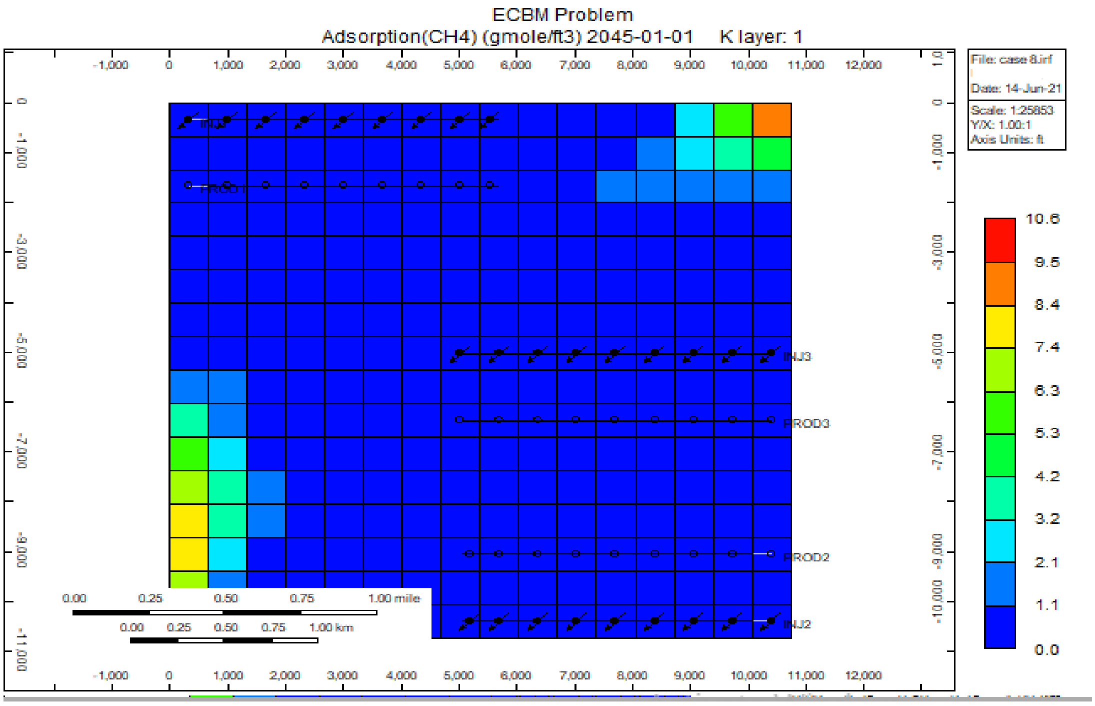

Figure 4.18: Amount of adsorbed methane at the end of the simulation life for scenario 8 (generated from CMG Results 3D)

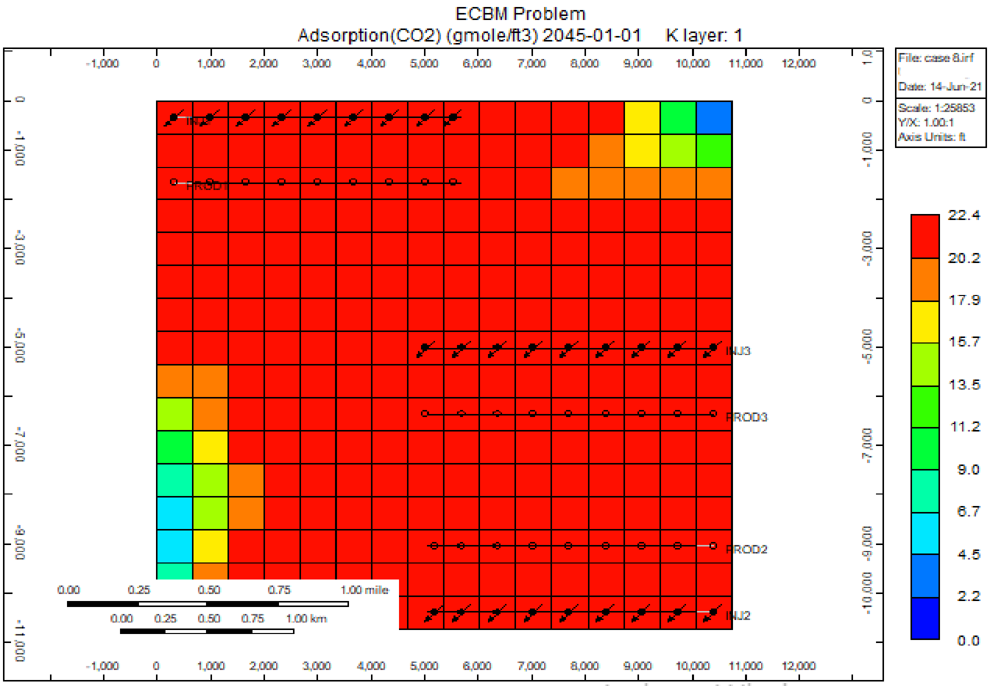

Figure 4.19: Amount of adsorbed carbon dioxide at the end of the simulation life for scenario 8 (generated from CMG Results 3D)

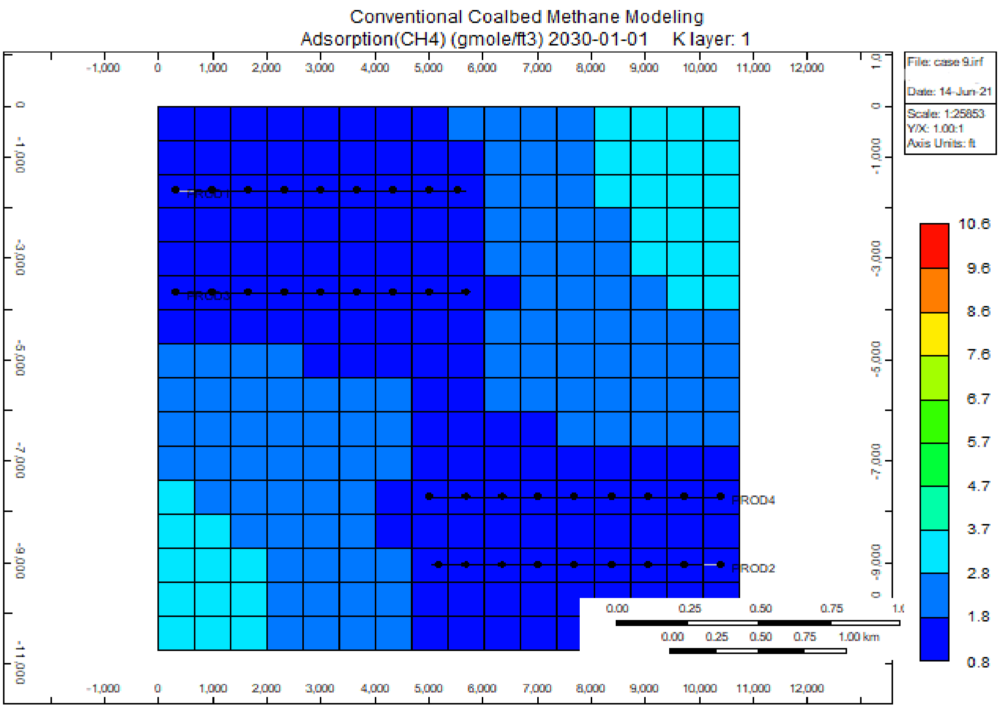

Figure 4.20: Amount of adsorbed methane at the end of the simulation life for scenario 9 (generated from CMG Results 3D)

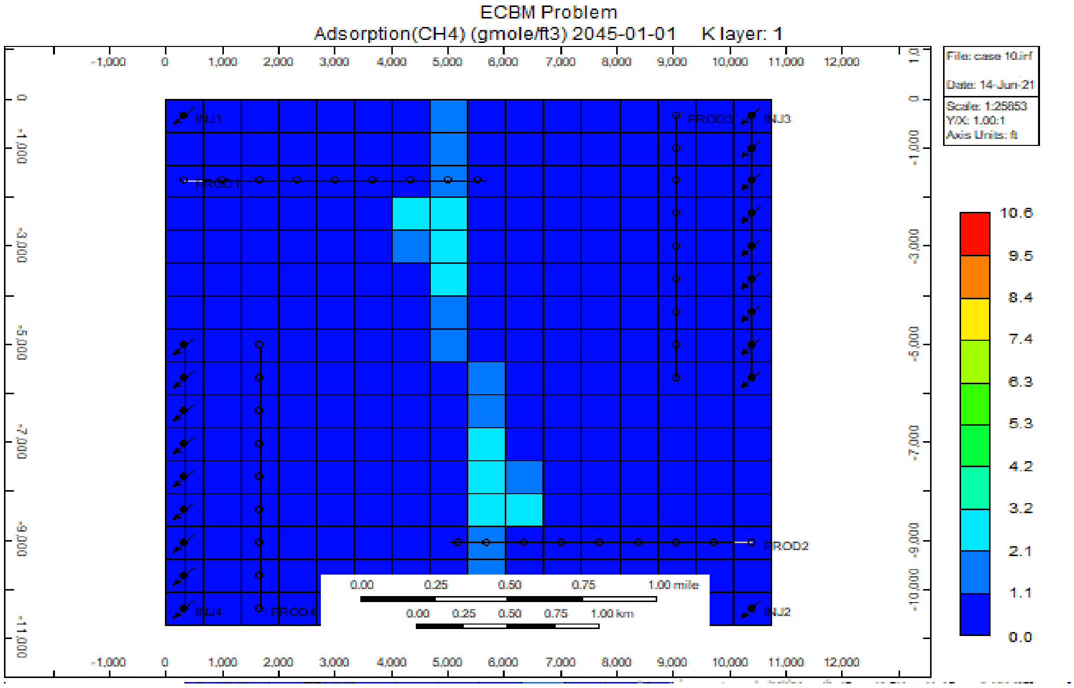

Figure 4.21: Amount of adsorbed methane at the end of the simulation life for scenario 10 (generated from CMG Results 3D)

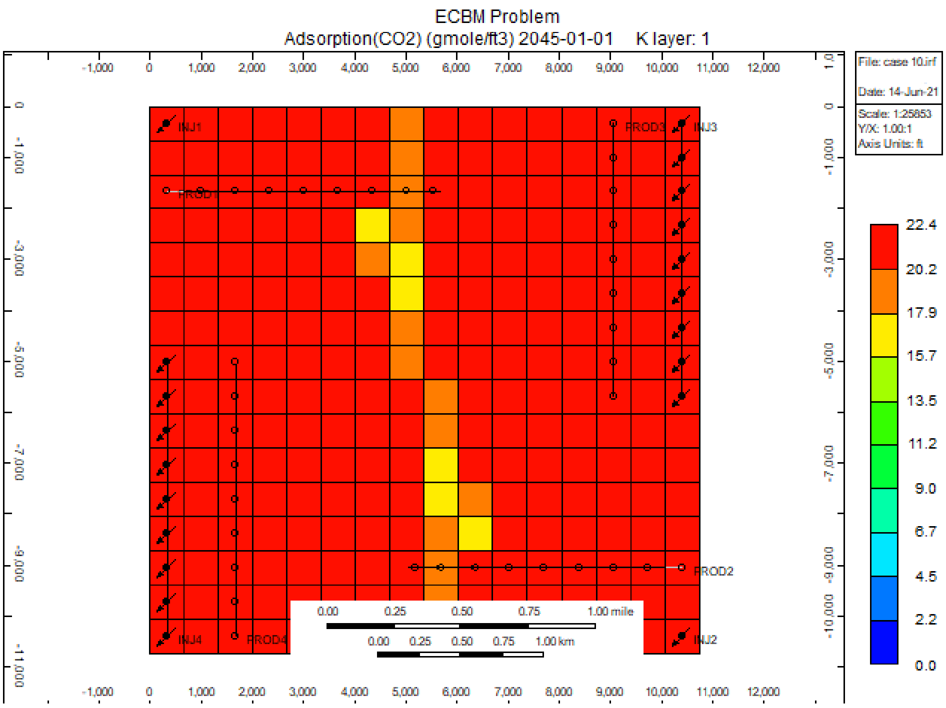

Figure 4.22: Amount of adsorbed carbon dioxide at the end of the simulation life for scenario 10 (generated from CMG Results 3D)

Table 4.1: Result summary of best scenario for Onyeama CBM development

Scenario Number	**Description**	**Cumulative Methane Recovery (MMMSCF)**	**Recovery Factor (%)**	**Rank**
Scenario 1	CBM with two vertical wells	4.68	51.3	10^{th}
Scenario 2	CBM with two horizontal wells	7.49	82.2	8^{th}
Scenario 3	CO_2-ECBM with two horizontal producers and two vertical injectors	7.91	86.8	7th
Scenario 4	CO_2-ECBM with two horizontal producers and two horizontal injectors	7.94	87.0	6th
Scenario 5	CBM with five vertical producers	6.92	75.9	9^{th}
Scenario 6	CBM with three horizontal producers	8.02	88	5^{th}
Scenario 7	CO_2-ECBM with three horizontal producers and three vertical injectors	8.32	91.2	2^{nd}
Scenario 8	CO_2-ECBM with three horizontal producers and three horizontal injectors	8.29	90.9	3^{rd}
Scenario 9	CBM with four horizontal producers	8.05	88.3	4^{th}
Scenario 10	CO_2-ECBM with two vertical injectors, two horizontal injectors and four horizontal producers	8.68	95.2	1^{st}

Table 4.2: Scaling the model to field

		Original Gas in Place (MMMSCF)	Methane Produced (MMMSCF)	Carbon Dioxide Sequestrated (MMMSCF)
Scenario 1	Actual Field	0.856	0.439	-
	Created Model	9.1187	4.68	-
Scenario 2	Actual Field	0.856	0.703	-
	Created Model	9.1187	7.49	-
Scenario 3	Actual Field	0.856	0.743	2.06
	Created Model	9.1187	7.91	21.9
Scenario 4	Actual Field	0.856	0.745	2.06
	Created Model	9.1187	7.94	21.9
Scenario 5	Actual Field	0.856	0.649	-
	Created Model	9.1187	6.92	-
Scenario 6	Actual Field	0.856	0.753	-
	Created Model	9.1187	8.02	-
Scenario 7	Actual Field	0.856	0.781	2.24

	Created Model	9.1187	8.32	23.8
Scenario 8	Actual Field	0.856	0.778	2.21
	Created Model	9.1187	8.29	23.5
Scenario 9	Actual Field	0.856	0.756	-
	Created Model	9.1187	8.05	-
Scenario 10	Actual Field	0.856	0.815	2.4
	Created Model	9.1187	8.68	25.6

CHAPTER 5
ECONOMICAL ANALYSIS

An economical analysis is important to determine which of the ten alternatives mentioned in Chapter 3 and 4 is the most economically advantageous for producing the Onyeama coalbed field. In this section, the costs and benefits for each alternative will be checked and analysed to make the best selection.

CAPEX is the money spent by a business to acquire assets that could be beneficial for a long period of time. Examples of CAPEX include money spent buying a building or buying equipment needed for the business. For instance, in the petroleum industry, CAPEX includes the cost of drilling and completing a well. It is important to note that these capital expenditures do not include periodic payments (Collaborative Minds Blog, 2020). The drilling costs comprises about 30-40% of the total well costs, completion costs include about 55-70% of the total well costs and other facility costs such as artificial lift systems, separators, dehydrators, etc. comprise about 7-8% of the total well cost (U.S. Energy Information Administration, 2016).

OPEX is the money spent periodically to ensure the smooth running of the day-to-day business. Examples of OPEX includes maintenance/repair of the equipment needed for the business and in the petroleum industry could include fees for oil and water hauling and facility electricity (Collaborative Minds Blog, 2020). OPEX can be divided into fixed OPEX and variable OPEX. Operating costs vary depending on location, well size, well productivity and other factors. These OPEX can be fixed (such as artificial lift, well maintenance and workover activities) or variable (such as gas gathering, process, transport and compression) (U.S. Energy Information Administration, 2016).

The most recent and accurate data that could be found for the economical analysis of the ten gas production scenarios (as shown in Table 5.1) and calculations were done for each scenario depending on the conditions of production (amount of gas injected, well oritntation and length of wellbore) as shown in Table 5.2. Three variables commonly considered in economical analysis are the net prevent value (NPV), initial rate of return (IRR) and rate of investment (ROI). The NPV reperesnts the difference in cash inflows and outflows over a period of time. Equation 5.1 shows the NPV equation. The IRR is used to estimate how profitable an investment could be by calculating the annual rate of growth that the investment is required to generate. It has the same concept as NPV except that it sets the NPV to zero. Finally, the ROI is the ratio between net income and net investments which is useful in direct measurements of the amount of return on a particular investment, relative to the cost of the investment.

$$NPV = \sum_{t=1}^{n} \frac{R_t}{(1+i)^t} \tag{5.1}$$

Where NPV = Net Present Value (USD)

R_t = Net cash inflows and outflows during a single period, t (USD)

i = Discount rate or return that could be earned in alternative investments (percentage)

t = Number of periods (years)

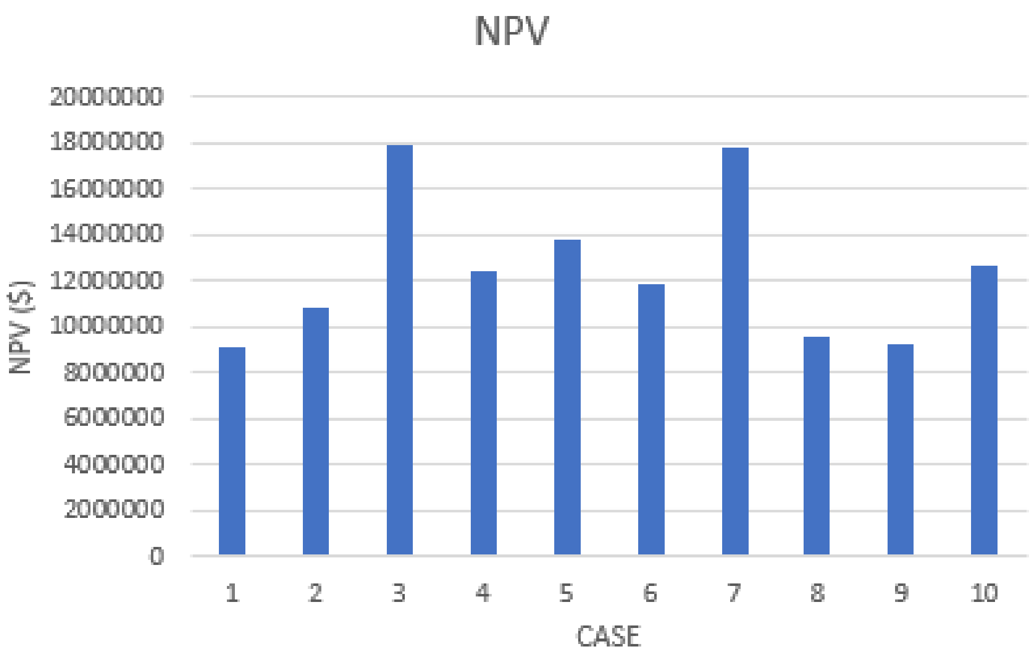

Figure 5.1: Graph of NPV calculations (generated from Excel)

Table 5.1: Variables used in economic analysis

Parameter	Value	Reference
Gas price (USD/MSCF)	4.07	(U.S. Energy Information Administration, 2021)
Interest rate	10%	
Yearly operating cost per well (USD/Well.Yr)	11,986	(Ibim et al., 2019)
Drilling cost per foot ($/ft)	125	(U.S. Energy Information Administration, 2016)
Completion cost per foot ($/ft)	400	(U.S. Energy Information Administration, 2016)
CO_2 sequestration cost ($/tonne)	8	(Vidas et al., 2012)
Production period (years)	10/15	
Sequestration period (years)	45	
TVD (ft)	330.15	
MD (ft)	5056	

Table 5.2: Result of economic analysis

Scenario For CBM Development	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10
Drilling expense ($)	82537.5	1264000	1346537	2528000	206343	1896000	2019806	3792000	2528000	3874537
Completion expense ($)	264120	4044800	4308920	8089600	660300	6067200	6463380	12134400	8089600	12398520
Gas volume sequestered (tonne)	0	0	1161594	1160363	0	0	1260332	1246365	0	1352509
Sequestration cost (1000$)	0	0	9292	9282	0	0	10082	9970	0	10820
yearly sequestration cost ($/yr)	0	0	206506	206287	0	0	224059	221576	0	240446
Yearly cost/OPEX (USD)	23972	23972	113471	113480	59930	35958	170194	170214	47944	226950

Projected gas production (MSCF)/yr	312000	749000	648667	636000	601810	801000	726666	706666	805000	800000
Yearly revenue (USD)	1269840	3048430	2640073	2588520	2449366	3260070	2957533	2876133	3276350	3256000
NPV (1000$)	9129	10893	17927	12459	13815	11847	17848	9626	9219	12661
IRR	318%	31%	29%	11%	242%	26%	19%	6%	16%	7%
ROI	23.63	1.04	2.03	0.15	13.91	0.48	1.03	-0.41	-0.14	-0.24

CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

6.1. Conclusions

This study compared the efficiency of using CBM and CO_2-ECBM recovery with both horizontal and vertical injectors as a method of producing more methane from the Onyeama coalbed field in Enugu, Nigeria while simultaneously sequestering carbon in this field. This is a particularly beneficial study in Nigeria because of the large amounts of unmineable coal as well as the large amounts of GHG emission due to gas flaring.

The key lessons learnt from this study:

1. In the choice between conventional CBM and CO_2-ECBM for producing from unmineable coalbed reservoirs, it was seen that CO_2-ECBM generally performed better in terms of gas production with the best scenario for CBM giving 630 MMSCF less gas than the best scenario for CO_2-ECBM but CBM is a cheaper method since no injection wells have to be drilled.
2. Although the use of horizontal wells is generally believed to produce better results than vertical wells, certain factors could discredit this. This study showed that the seventh scenario performed better than the eighth scenario with a difference of 30MMSCF. This performance could be attributed to the small drawdown when four horizontal injectors are used, which leads to less gas flow into the producer.
3. It was seen that large amount of CO_2 (up to 2.4 MMMSCF) could be sequestered into the Onyeama CBM reservoir without reaching the reservoir fracture pressure. This showed potential for using CBM in Nigeria as a method of CSS to make up for the large volumes of flared gas.
4. Subjecting the reservoir to high pressure conditions leads to lower gas recovery because most of the gas stays adsorbed to the coal surface. On the other hand, subjecting the reservoir to low pressure conditions leads to higher gas recovery since more desorption can occur under this condition.
5. Although the tenth scenario performed best in terms of production and injection, the economic analysis showed that was not the most economically feasible. Generally, it can

be seen that CBM scenarios were more economically advantageous than the ECBM scenarios. This is because of the cost of drilling additional wells to serve as injection wells and the cost of injection operations. The NPV analysis showed that the most profitable of the ten scenarios is the third scenario.

6.2. Recommendations

More detailed reservoir data would help to make a more accurate description of the reservoir on the simulator which would lead to more exact results. An accompanying laboratory study will help to understand more about the effect of CO_2 on the coal structure for example the permeability increase.

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APPENDICES

APPENDIX 1

CMG DATA FILE FOR SCENARIO 10

```
** ---------------------------------------------------------------------**
** MODEL: CART 16x16x1 GRID              PRIMARY PRODUCTION           **
** 2 COMPONENTS                    PALMER AND MANSOORI           **
** ---------------------------------------------------------------------**
** ** CASE 10
** Coal Bed Methane problem.                                          **
** Palmer and Mansoori coal mechanics.                                **
** **
** Use of simplified relative permeability tables ( no oil re perm    **
** columns are required to be input with KRCBM keyword )              **
**                                                                    **
** ---------------------------------------------------------------------**
** CONTACT CMG at (403)531-1300 or support@cmgl.ca                    **
** ---------------------------------------------------------------------**
RESULTS SIMULATOR GEM 201510

*TITLE1 'ECBM Problem'
*TITLE2 'Use of *LANGMULT Keyword'

INUNIT FIELD
WSRF WELL TIME
WSRF GRID TIME
OUTSRF GRID SO SG SW PRES POROS PERM ADS 'CH4' ADS 'CO2' *ZALL *YALL
WPRN GRID 0
OUTPRN GRID NONE
OUTPRN RES ALL

**$  Distance units: ft
RESULTS XOFFSET           0.0000
RESULTS YOFFSET           0.0000
RESULTS ROTATION          0.0000  **$  (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0
**$
*************************************************************************
**
**$ Definition of fundamental cartesian grid
**$
*************************************************************************
**
GRID VARI 16 16 1
KDIR DOWN
DI IVAR
 16*670.75
DJ JVAR
 16*670.75
DK ALL
 256*5.77
DTOP
 256*328.74

*DUALPOR
*SHAPE *GK
```

```
NULL FRACTURE CON           1
NULL MATRIX CON             1

POR MATRIX CON       0.019
POR FRACTURE CON     0.019

PERMI MATRIX CON       0.0001
PERMI FRACTURE CON     45
PERMJ MATRIX EQUALSI

PERMJ FRACTURE CON     45
PERMK MATRIX EQUALSI

PERMK FRACTURE CON   1.1

DIFRAC CON    0.15
DJFRAC CON    0.15
DKFRAC CON    0.15

PINCHOUTARRAY CON  1

PRPOR FRACTURE 3067
PRPOR MATRIX 3067
CPOR FRACTURE 0.00003
CPOR MATRIX 0.00003
** ------------------  Fluid Model and number of components -------------
-----
** Model and number of components
** Model and number of components
MODEL PR
NC 2 2
COMPNAME 'CH4' 'CO2'
TRES 95
MW
16.043 44.01
AC
0.008 0.225
PCRIT
45.4 72.8
VCRIT
0.099 0.094
TCRIT
190.6 304.2
PCHOR
77 78
SG
0.3 0.818
TB
-258.61 -109.21
HCFLAG
1 0
HEATING_VALUES
844.29 0
BIN
0.103

DENW 62.48
```

```
REFPW 14.7

**-------------------------------------------------ROCK FLUID----------
*ROCKFLUID
*RPT 1
*SWT
**   Sw          Krw         Krow
   0.00000     0.0000     0.00001
   0.05000     0.0006     *int
   0.10000     0.0013     *int
   0.15000     0.0020     *int
   0.20000     0.0070     *int
   0.25000     0.0150     *int
   0.30000     0.0240     *int
   0.35000     0.0350     *int
   0.40000     0.0490     *int
   0.45000     0.0670     *int
   0.50000     0.0880     *int
   0.55000     0.1160     *int
   0.60000     0.1540     *int
   0.65000     0.2000     *int
   0.70000     0.2510     *int
   0.75000     0.3120     *int
   0.80000     0.3920     *int
   0.85000     0.4900     *int
   0.90000     0.6010     *int
   0.95000     0.7310     *int
   0.97500     0.8140     *int
   1.00000     1.0000     0.0000

*SLT
**   Sl          Krg         Krog
   0.00000     1.0000     0.0000
   0.05000     0.8350     *int
   0.10000     0.7200     *int
   0.15000     0.6270     *int
   0.20000     0.5370     *int
   0.25000     0.4660     *int
   0.30000     0.4010     *int
   0.35000     0.3420     *int
   0.40000     0.2950     *int
   0.45000     0.2530     *int
   0.50000     0.2160     *int
   0.55000     0.1800     *int
   0.60000     0.1470     *int
   0.65000     0.1180     *int
   0.70000     0.0900     *int
   0.75000     0.0700     *int
   0.80000     0.0510     *int
   0.85000     0.0330     *int
   0.90000     0.0180     *int
   0.95000     0.0070     *int
   0.97500     0.0035     *int
   1.00000     0.0000     0.00001
ADGMAXC 'CO2' *FRACTURE CON             0
ADGMAXC 'CO2' *MATRIX CON        0.274
ADGMAXC 'CH4' *FRACTURE CON             0
ADGMAXC 'CH4' *MATRIX CON        0.137
```

```
ADGCSTC 'CO2' *FRACTURE CON            0
ADGCSTC 'CO2' *MATRIX CON      0.00345
ADGCSTC 'CH4' *FRACTURE CON            0
ADGCSTC 'CH4' *MATRIX CON      0.00199

**RTYPE *MATRIX   *CON 1
**RTYPE *FRACTURE *CON 2

**$ Property: Rock Density (lb/ft3)
ROCKDEN MATRIX   CON      89.52
ROCKDEN FRACTURE CON      89.52
COAL-DIF-TIME 'CO2' CON           30
COAL-DIF-TIME 'CH4' CON           30

**LANGMULT *MATRIX  *IJK ** applies to all components
**  1:10  1:10  1:1 0.75  ** multiplier applied to final calc. adsorbed
amounts

**LANGMULT *FRACTURE  *IJK ** applies to all components
**  1:10  1:10  1:1 1.00  ** multiplier applied to final calc. adsorbed
amounts

**----------------------------------------------------INITIAL CONDITION---
INITIAL
USER_INPUT

SEPARATOR
**$  Stage Pres.  Stage Temp.
         14.7     60

SW MATRIX   CON     0.0001
SW FRACTURE CON     0.999995

PRES MATRIX CON       3600
PRES FRACTURE CON     3600
ZGLOBALC 'CO2' *FRACTURE CON            0
ZGLOBALC 'CO2' *MATRIX CON            0
ZGLOBALC 'CH4' *FRACTURE CON            0
ZGLOBALC 'CH4' *MATRIX CON            1

**----------------------------------------------------NUMERICAL-----------
NUMERICAL
NCHECK-CEQ 3

**----------------------------------------------------WELL DATA-----------
RUN
DATE 2020 1 1
WELL  'PROD1'
PRODUCER 'PROD1'
OPERATE  MAX  STW  31448.55  CONT REPEAT
OPERATE  MIN  BHP  36.26  CONT REPEAT
**          rad  geofac  wfrac  skin
GEOMETRY  I  0.354  0.37  1.0  1.0
      PERF       GEO  'PROD1'
** UBA            ff         Status  Connection
    1 3 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    2 3 1         1.0  OPEN    FLOW-TO  1
    3 3 1         1.0  OPEN    FLOW-TO  2
```

```
    4 3 1          1.0  OPEN    FLOW-TO  3
    5 3 1          1.0  OPEN    FLOW-TO  4
    6 3 1          1.0  OPEN    FLOW-TO  5
    7 3 1          1.0  OPEN    FLOW-TO  6
    8 3 1          1.0  OPEN    FLOW-TO  7
    9 3 1          1.0  OPEN    FLOW-TO  8
LAYERXYZ  'PROD1'
** perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length
    1 3 1  335.375000  1676.875000  328.740000  335.375000  1676.875000
334.510000  5.770000
    2 3 1  670.750000  1676.875000  331.625000  1341.500000  1676.875000
331.625000  670.750000
    3 3 1  1341.500000  1676.875000  331.625000  2012.250000  1676.875000
331.625000  670.750000
    4 3 1  2012.250000  1676.875000  331.625000  2683.000000  1676.875000
331.625000  670.750000
    5 3 1  2683.000000  1676.875000  331.625000  3353.750000  1676.875000
331.625000  670.750000
    6 3 1  3353.750000  1676.875000  331.625000  4024.500000  1676.875000
331.625000  670.750000
    7 3 1  4024.500000  1676.875000  331.625000  4695.250000  1676.875000
331.625000  670.750000
    8 3 1  4695.250000  1676.875000  331.625000  5366.000000  1676.875000
331.625000  670.750000
    9 3 1  5366.000000  1676.875000  331.625000  5701.375000  1676.875000
331.625000  335.375000


WELL  'PROD2'
PRODUCER 'PROD2'
OPERATE  MAX  STW  31448.55  CONT REPEAT
OPERATE  MIN  BHP  36.26  CONT REPEAT
**          rad  geofac  wfrac  skin
GEOMETRY  I  0.354  0.37  1.0  1.0
      PERF       GEO  'PROD2'
** UBA              ff          Status  Connection
    16 14 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    15 14 1         1.0  OPEN    FLOW-TO  1
    14 14 1         1.0  OPEN    FLOW-TO  2
    13 14 1         1.0  OPEN    FLOW-TO  3
    12 14 1         1.0  OPEN    FLOW-TO  4
    11 14 1         1.0  OPEN    FLOW-TO  5
    10 14 1         1.0  OPEN    FLOW-TO  6
    9 14 1          1.0  OPEN    FLOW-TO  7
    8 14 1          1.0  OPEN    FLOW-TO  8
LAYERXYZ  'PROD2'
** perf geometric data: UBA, block entry(x,y,z) block exit(x,y,z), length
    16 14 1  10396.625000  9055.125000  328.740000  10396.625000
9055.125000  334.510000  5.770000
    15 14 1  10061.250000  9055.125000  331.625000  9390.500000
9055.125000  331.625000  670.750000
    14 14 1  9390.500000  9055.125000  331.625000  8719.750000
9055.125000  331.625000  670.750000
    13 14 1  8719.750000  9055.125000  331.625000  8049.000000
9055.125000  331.625000  670.750000
    12 14 1  8049.000000  9055.125000  331.625000  7378.250000
9055.125000  331.625000  670.750000
```

```
    11 14 1  7378.250000  9055.125000  331.625000  6707.500000
9055.125000  331.625000  670.750000
    10 14 1  6707.500000  9055.125000  331.625000  6036.750000
9055.125000  331.625000  670.750000
    9 14 1   6036.750000  9055.125000  331.625000  5366.000000
9055.125000  331.625000  670.750000
    8 14 1   5366.000000  9055.125000  331.625000  5030.625000
9055.125000  331.625000  335.375000

WELL  'PROD3'
PRODUCER 'PROD3'
OPERATE  MAX  STW  31448.55  CONT REPEAT
OPERATE  MIN  BHP  36.26  CONT REPEAT
** UBA             ff          Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  J  0.354  0.37  1.0  1.0
      PERF       GEO  'PROD3'
** UBA              ff          Status  Connection
    14 1 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    14 2 1         1.0  OPEN    FLOW-TO  1
    14 3 1         1.0  OPEN    FLOW-TO  2
    14 4 1         1.0  OPEN    FLOW-TO  3
    14 5 1         1.0  OPEN    FLOW-TO  4
    14 6 1         1.0  OPEN    FLOW-TO  5
    14 7 1         1.0  OPEN    FLOW-TO  6
    14 8 1         1.0  OPEN    FLOW-TO  7
    14 9 1         1.0  OPEN    FLOW-TO  8

WELL  'PROD4'
PRODUCER 'PROD4'
OPERATE  MAX  STW  31448.55  CONT REPEAT
OPERATE  MIN  BHP  36.26  CONT REPEAT
** UBA             ff          Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  J  0.354  0.37  1.0  1.0
      PERF       GEO  'PROD4'
** UBA              ff          Status  Connection
    3 16 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    3 15 1         1.0  OPEN    FLOW-TO  1
    3 14 1         1.0  OPEN    FLOW-TO  2
    3 13 1         1.0  OPEN    FLOW-TO  3
    3 12 1         1.0  OPEN    FLOW-TO  4
    3 11 1         1.0  OPEN    FLOW-TO  5
    3 10 1         1.0  OPEN    FLOW-TO  6
    3 9 1          1.0  OPEN    FLOW-TO  7
    3 8 1          1.0  OPEN    FLOW-TO  8


WELL  'INJ1'
INJECTOR 'INJ1'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  STG  211888.0  CONT REPEAT
OPERATE  MAX  BHP  2175.56  CONT REPEAT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ1'
** UBA             ff          Status  Connection
    1 1 1         1.0  OPEN    FLOW-FROM  'SURFACE'
```

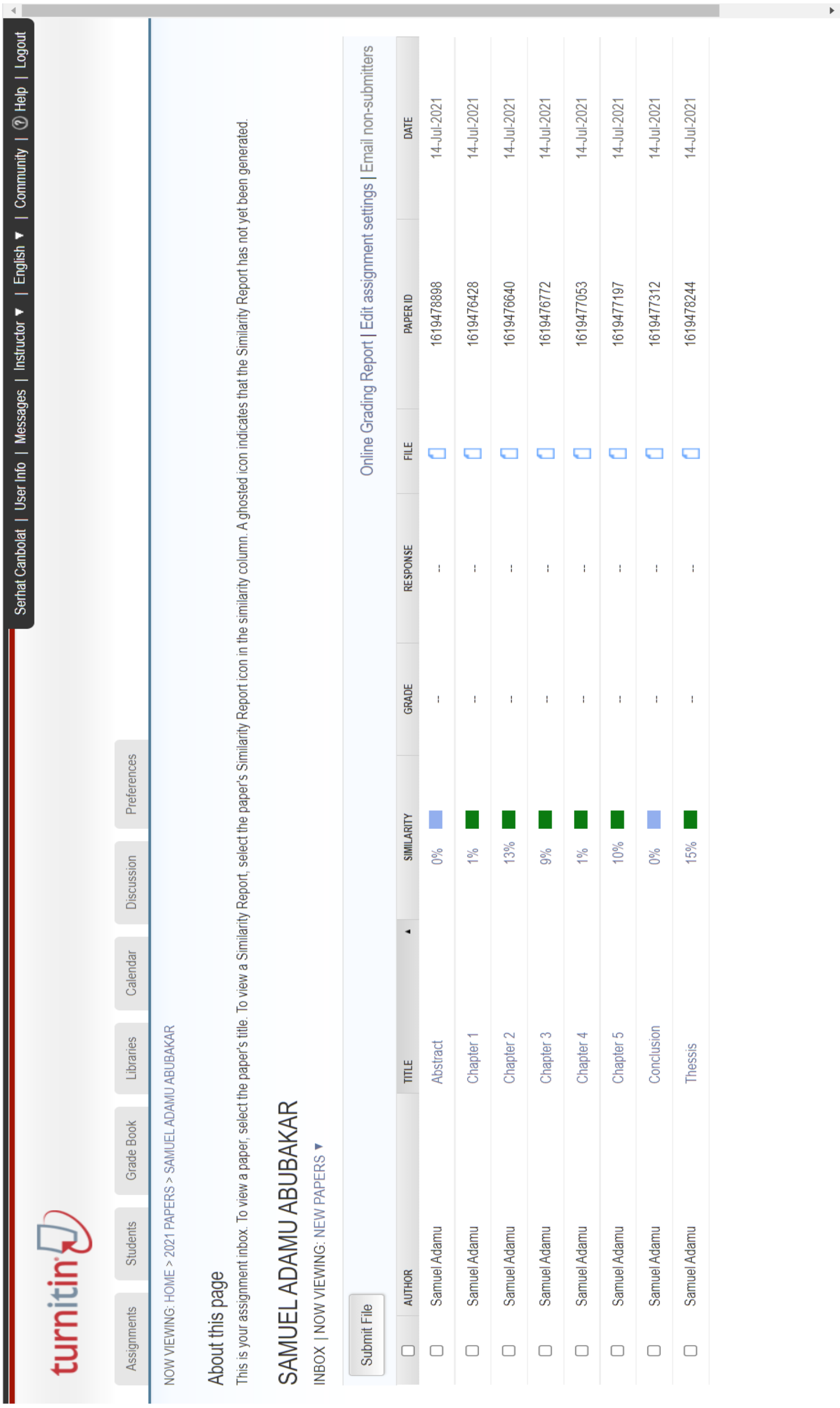
```
WELL  'INJ2'
INJECTOR 'INJ2'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  STG  211888.0  CONT REPEAT
OPERATE  MAX  BHP  2175.56  CONT REPEAT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ2'
** UBA              ff           Status  Connection
    16 16 1         1.0  OPEN    FLOW-FROM  'SURFACE'

WELL  'INJ3'
INJECTOR 'INJ3'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  STG  211888.0  CONT REPEAT
OPERATE  MAX  BHP  2175.56  CONT REPEAT
** UBA              ff          Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  J  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ3'
** UBA              ff           Status  Connection
    16 1 1         1.0  OPEN    FLOW-TO  'SURFACE'
    16 2 1         1.0  OPEN    FLOW-TO  1
    16 3 1         1.0  OPEN    FLOW-TO  2
    16 4 1         1.0  OPEN    FLOW-TO  3
    16 5 1         1.0  OPEN    FLOW-TO  4
    16 6 1         1.0  OPEN    FLOW-TO  5
    16 7 1         1.0  OPEN    FLOW-TO  6
    16 8 1         1.0  OPEN    FLOW-TO  7
    16 9 1         1.0  OPEN    FLOW-TO  8

WELL  'INJ4'
INJECTOR 'INJ4'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  STG  211888.0  CONT REPEAT
OPERATE  MAX  BHP  2175.56  CONT REPEAT
** UBA              ff          Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  J  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ4'
** UBA              ff           Status  Connection
    1 16 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    1 15 1         1.0  OPEN    FLOW-TO  1
    1 14 1         1.0  OPEN    FLOW-TO  2
    1 13 1         1.0  OPEN    FLOW-TO  3
    1 12 1         1.0  OPEN    FLOW-TO  4
    1 11 1         1.0  OPEN    FLOW-TO  5
    1 10 1         1.0  OPEN    FLOW-TO  6
    1 9 1          1.0  OPEN    FLOW-TO  7
    1 8 1          1.0  OPEN    FLOW-TO  8

*AIMSET *FRACTURE *CON 3
*AIMSET *MATRIX   *CON 3

DATE 2020 2 1
DATE 2021 1 1
DATE 2022 1 1
```

```
DATE 2023 1 1
DATE 2024 1 1
DATE 2025 1 1
DATE 2026 1 1
DATE 2027 1 1
DATE 2028 1 1
DATE 2029 1 1
DATE 2030 1 1
DATE 2031 1 1
DATE 2032 1 1
DATE 2033 1 1
DATE 2034 1 1
DATE 2035 1 1

**SHUTIN WELLS
SHUTIN 'PROD1'
SHUTIN 'PROD2'
SHUTIN 'PROD3'
SHUTIN 'PROD4'

WELL  'INJ1'
INJECTOR 'INJ1'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  BHP  4000  STOP
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ1'
** UBA            ff          Status  Connection
    1 1 1         1.0  OPEN    FLOW-FROM  'SURFACE'

WELL  'INJ2'
INJECTOR 'INJ2'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  BHP  4000  STOP
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ2'
** UBA              ff          Status  Connection
    16 16 1         1.0  OPEN    FLOW-FROM  'SURFACE'

WELL  'INJ3'
INJECTOR 'INJ3'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  BHP  4000  STOP
** UBA            ff          Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  J  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ3'
** UBA             ff          Status  Connection
    16 1 1         1.0  OPEN    FLOW-TO  'SURFACE'
    16 2 1         1.0  OPEN    FLOW-TO  1
    16 3 1         1.0  OPEN    FLOW-TO  2
    16 4 1         1.0  OPEN    FLOW-TO  3
    16 5 1         1.0  OPEN    FLOW-TO  4
    16 6 1         1.0  OPEN    FLOW-TO  5
    16 7 1         1.0  OPEN    FLOW-TO  6
    16 8 1         1.0  OPEN    FLOW-TO  7
    16 9 1         1.0  OPEN    FLOW-TO  8
```

```
WELL  'INJ4'
INJECTOR 'INJ4'
INCOMP  SOLVENT  0.0  1.0
OPERATE  MAX  BHP  4000  STOP
** UBA             ff         Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  J  0.354  0.37  1.0  1.0
      PERF       GEO  'INJ4'
** UBA              ff          Status  Connection
    1 16 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    1 15 1         1.0  OPEN    FLOW-TO  1
    1 14 1         1.0  OPEN    FLOW-TO  2
    1 13 1         1.0  OPEN    FLOW-TO  3
    1 12 1         1.0  OPEN    FLOW-TO  4
    1 11 1         1.0  OPEN    FLOW-TO  5
    1 10 1         1.0  OPEN    FLOW-TO  6
    1 9 1          1.0  OPEN    FLOW-TO  7
    1 8 1          1.0  OPEN    FLOW-TO  8
DATE 2036 1 1
DATE 2037 1 1
DATE 2038 1 1
DATE 2039 1 1
DATE 2040 1 1
DATE 2041 1 1
DATE 2042 1 1
DATE 2043 1 1
DATE 2044 1 1
DATE 2045 1 1

STOP

RESULTS SPEC 'Permeability K' MATRIX
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Permeability J' MATRIX
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP
```

APPENDIX 2

SIMILARITY REPORT



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APPENDIX 3

ETHICAL APPROVAL LETTER

YAKIN DOĞU ÜNiVERSiTESi ETHICAL APPROVAL DOCUMENT

Date 29/06/2021

To the Graduate School of Applied Sciences

The research project titled "**NUMERICAL INVESTIGATION OF ECBM RECOVERY AND CO2 SEQUESTRATION**" has been evaluated. Since the researchers will not collect any data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Assist. Prof. Dr.

Name Surname: Serhat CANBOLAT

Signature:

Role in the Research Project: Supervisor