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ROLE OF CO_2 INJECTION ON ENHANCE METHANE ECOVERY - A CASE STUDY FROM TURKISH COAL SEAM, AMASRA COAL FIELD TURKEY

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ABSTRACT

The study of Enhanced Coalbed Methane Recovery (ECBM) has become the interest of many researchers in many tertiary research institutes. Various recovery techniques have been identified and implemented to increase the production of methane gas from coal bed reservoirs. One of the method is CO_2 injection into coal seams where it helps to maximize the displacement of the adsorbed methane from the surface of coal matrix and enhance the methane recovery. A numerical model from Turkish Coal Seam Bed from Amasra Coal Field, Turkey was developed using CMG-GEM software by Computer Modelling Group to simulate the primary methane production and enhance recovery using CO_2 injection. The key petrophysical reservoir parameters to drive the CO_2 injection in coal bed methane reservoir are cleat permeability, cleat porosity, methane adsorption time, methane Langmuir isotherm and CO_2 Langmuir isotherm. Palmer and Mansoori parameters (porosity, compressibility and coal seam pressure) were also applied to model the compaction and dilation process as well. Three (3) cases were constructed to evaluate the impact of CO_2 injection on methane recovery. Case 1 acts as the base case where there is no CO_2 injection and is used in the first model while Case 2 includes the CO_2 injection in the coal beds. On the other hand, Case 3 was constructed to analyse the impact of different injection timing to investigate the final methane recovery. Other than that, the effect of varying parameters such as cleat porosity, cleat permeability and coal density were also assessed. The results show that the amount of methane recovered in the primary production is 28.2 Bscf while 45.4 Bscf of methane gas was recovered by CO_2 injection in Case 2. Therefore, it is found that the total recovery of methane from coal seams during enhanced production is more than that of primary recovery during the preliminary simulation model.

Keywords: coal bed methane, carbon dioxide, CO_2 injection, CMG, sorption.

INTRODUCTION

Turkey is known to be possessing the largest coal resources in the world other than India and China. The growing population and economy in the country put a high demand on production of coal and natural gas methane $_{CH4}$ in order to meet the energy needs. Zonguldak Hard Coal Basin which is located between Eregli and Amasra states. The location of Zonguldak Hard Coal Basin and Amasra Field is shown in Figure-1 below:

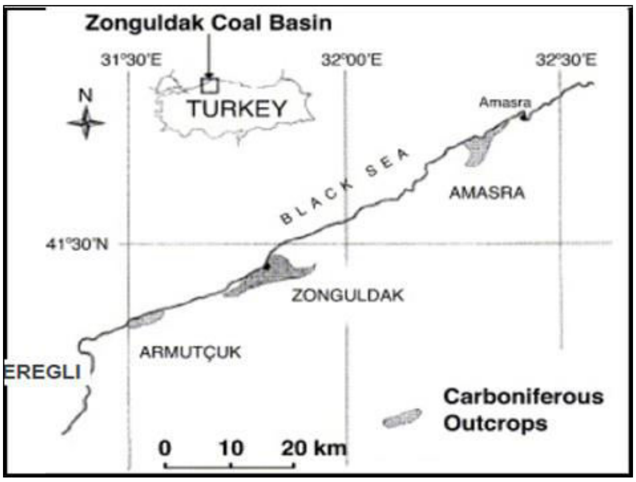

Figure-1. Map showing the location of Zonguldak Hard Coal Basin and Amasra Field (Baris *et al*., 2013).

The Amasra coal field is chosen to be the case study for CO2 injection in coal seams since it is one of the three main districts in the Zonguldak coalfields. Three wells were drilled in Amasra field which are CBM-1, CBM-2 and CBM-3. However, all three wells do not operate due to technical and marketing problems. Among all the three wells, only CBM-2 shows potential of methane production but it did not continue to produce methane gas due to limited market demand around that area. Therefore, this paper focuses on CBM-2 since it is the only well that has a potential to produce methane gas in commercial quantities.

Each year, the amount of greenhouse gases (GHG) including carbon dioxide (CO_2), methane (CH_4) and nitrous oxide release keeps on increasing. According to several studies, CO_2 is found to be the main contributor to the greenhouse effect and also major environmental issues. This would lead to global warming if it is unabated and some mitigation steps are not taken. As a result, many techniques and technologies globally have been developed to reduce the effect of global warming due to CO_2 emission. CO_2 injection and sequestration in coal seams has been acknowledged worldwide as one of the method to store CO_2 and prevent the direct emission and release of CO_2 into atmosphere. This technique has gained much interest among researchers in unconventional petroleum sector. CO_2 injection in coal seams allow production of methane and enhance the production of coal bed methane (CBM). CO_2 sequestration in deep coal seams helps to

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reduce the global warming effect and provide a significant CO_2 mitigation option. Coal bed methane is natural gas which is product of process called coalification, the degradation of organic matter due high temperature and pressure in limited oxygen content.

Like shale gas, gas hydrates Coal bed methane (CBM) is also an unconventional gas resource and has been recognized as a significant natural gas resource. CBM reservoir has dual porosity system that contains majority of the gas within the micro porous matrix of the coal seam. However, there are some gas exist in the natural fracture system or also known as cleats. Primary recovery of CBM is associated with desorption process which is done by reducing and lower down the overall pressure of the reservoir/coal seam or by lowering the methane partial pressure in the free gas by injecting a second gas (e.g.; CO_2) for enhanced recovery.

In primary recovery methods, large volumes of formation water are pumped out of the reservoir's cleats and subsequently, reservoir pressure is decreased. This process causes methane to be desorbed/detached from the coal and moving towards the production well. Meanwhile, in ECBM process CO_2 is injected in the coal formation and gets adsorbed onto the coal formation and causes the coal matrix to swell. The higher affinity of CO_2 to coal matrix than methane enables the coal seam to store twice as much CO_2 than the desorbed methane. The swelling of the coal seams will reduce the cleat permeability and porosity. The simulation of the methane production from coal seam beds are very complicated because of the unique feature of the coal. This project is aimed to investigate the impact of CO_2 injection on the cumulative amount of methane produced and also to compare between the amount of methane produce in primary production and enhanced production due to CO_2 injection. Other than that, sensitivity analysis will also be assessed on permeability, porosity and coal density.

BACKGROUND

Unconventional resources have become a more significant source of energy supply in the world. Coal bed methane (CBM) reservoir has been recognized as one of the important sources to produce natural gas specifically methane (Wei, Wang, & Massarotto, 2005). However, coalbed methane reservoir cannot be produced in the conventional way due to its unique petrophysical properties that are different from the conventional reservoirs. The most obvious difference between CBM and conventional gas reservoir is that in CBM, the coal seams act as both the source rock and also the reservoir rock for the gas (Sinayuc, 2007).

Coal is formed through deposition of organic materials that originates from plants. Over time, as more and more organic material deposits on top of each layer, the overburden increases pressure and temperature coalification-the formation of coal and production of coal seam gas. It is a process where peat is converted into coal seams. Coal seams reservoirs are naturally fractured reservoirs. Coal is characterized as a dual porosity medium or with dual storage mechanism consisting of the micro pores and macro pores (Sinayuc, 2007). The micro pores in the coal seams are known as the matrix system pores in which it contains majority of the gas in the reservoir.

On the other hand, the macro pores in the coal seams is the fracture system or also known as the cleat system. There are two types of different cleats in the formation which is the primary (face cleat) and secondary (butt cleat). It is common to find these two different types of fracture system in coal bed methane reservoir. Face cleat can be distinguished from the butt cleat by its long and continuous properties. Meanwhile, the butt cleat can be found intersected between the face cleat which makes it shorter and discontinuous.

Due to its continuous properties of the face cleat, it has a larger contact area with the matrix compared to the butt cleat as shown in Figure-2 below (Zulkarnain, 2005).

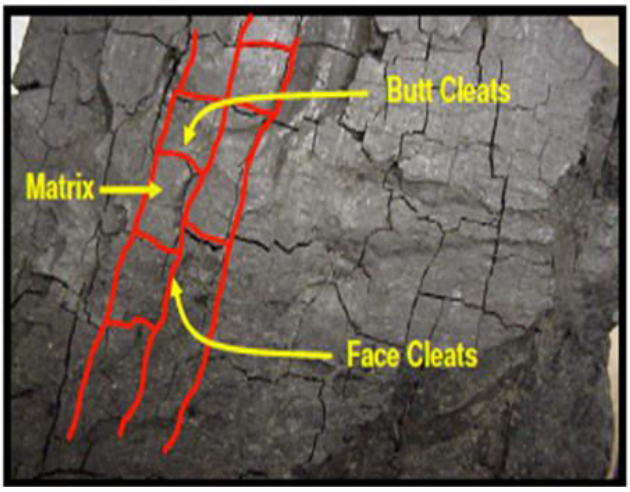

Figure-2. Schematic of coal seam cleat system (Zulkarnain, 2005).

The larger contact means that it is capable of draining a larger area of coal seams. The face cleats act as the major contributor to provide the path for gas to flow into the production wellbore (Sinayuc, 2007). The red lines in Figure-2 show the butt cleat and the face cleat in coal. The butt cleats are shorter that the face cleat and intersected by the face cleat.

At original condition, most of the gas is stored in the matrix of the coal. Adsorption process causes the gas to be stored on the surface of the coal where weak electrical forces bounded the individual gas molecules to the solid organic molecule that makes up coal. On the other hand, few gas is stored in the cleats as free gas (He, Mohaghegh, & Gholami, 2012). The ability of the CBM reservoir to store methane depends on reservoir pressure, composition and rank of the coal, micro pores structure and its surface properties, the molecular properties of the adsorbed gas constituents, and reservoir temperature (Puri & Yee, 1990). Fractures system is initially filled with water with a little amount of gas is stored in the fracture system. Table-1 below shows the characteristics of coal bed methane reservoir.

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Table-1. Summary of the characteristics of coal bed methane reservoir (Sinayuc, 2007).

Characteristic	Coal Bed Methane Reservoir
Gas Generation	Gas generated in coal seam and trapped within the coal seam. The coal seam is both the source rock and reservoir rock.
Natural Gas Methane Storage Mechanism	Adsorbed on Matrix Surface, Compressed Gas, and Dissolved in Brine in Cleats which are uniformly spaced
Transport Mechanism	Fick's Law – By diffusion Concentration Gradient Darcy's Law - Pressure Gradient
Production Performance	Initial Production by Dewatering, followed by Methane

Flow properties such as permeability and diffusivity play a major role to determine the ability of a CBM reservoir to transport fluid in the reservoir (Zulkarnain, 2005). The gas produced from coal bed is mostly composed of methane with traces of other gases such as carbon dioxide, nitrogen, hydrogen and carbon monoxide (Bahrami, Byfield, Hossain, Chitgar, & Wong, 2015). There are three major processes in the gas flow mechanism which are adsorption or desorption, diffusion and Darcy's flow (He, Mohaghegh, & Gholami, 2012). Initially, the primary production of coalbed methane happens by dewatering the naturally fractured system. This process will decrease the pressure in the fracture system. When the pressure is reduced, the gas from the surface of the coal matrix will be desorbed and released to the fractures. Gas diffuses from the surface of coal matrix towards the fracture system (Zulkarnain, 2005). Once the gas is in the natural fracture systems, the gas will flow throughout the fractures into the wellbore. The cleats act as a sink to the micro pore system and as a conduit to the wells (Sinayuc, 2007). The process in which gas is desorbed from the coalbed methane is consist of three processes as shown in Figure-3 below.

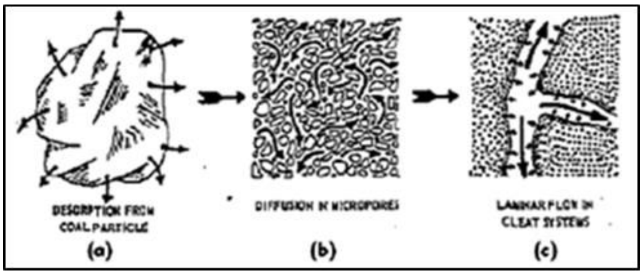

Figure-3. Schematic diagram shows gas flow in coal seam. (Sung, Ertekin, King, & Remner, 1986).

Three methods of methane gas release are as follows:

a) Diffusion: The released gas flows throughout the coal matrix into the fracture systems –cleat system

b) Desorption: Gas released from internal surface of micro pores of the matrix

c) Gas flows throughout the cleats into the wellbore

Gas is released from the tiny internal micro pores surface and known as desorption. The released gas is transported very gradually through the matrix into the cleat through diffusion process in which the driving force of this movement is the concentration gradient. On the other hand, when the gas is released from the coal matrix and flow through the fractures system into the wellbore, the driving force of this movement is pressure gradient.

The production profile of a coal well varies significantly from the typical decline of a conventional gas well. Production profile in coalbed formations shows three different production stages. The three phases of methane production are dewatering stage, stable production stage and declining stage. Primary recovery methods for CBM operations requires process that can help to lower the reservoir pressure. It is generally done by pumping off sizeable volume of formation water. This process will cause the methane to be desorbed from the coal matrix, moving in coal bed seam cleats. At the premature life of a coalbed methane well, gas rate increasing trend can be observed due to the movement of initially water in the fracture system of the reservoir which controls stream to the well. Dewatering process happen in order to remove the water from the fracture system before gas can be effectively flown to the well. A declining flowing bottom hole pressure and high water production rate can be observed in Phase I (Sinayuc, 2007). Furthermore, the gas rate may also increase during this stage as per shown in Figure-4.

For phase II, an increase trend in the gas production can be observed as well as a significant drop in the water production rate. Phase III will begin when the well has reached its maximum gas rate. At this phase, the gas production is observed to have a more decline trend. Water and gas saturation change very little and water production is low. At the beginning of Phase III, the well is considered to be dewatered. At this point, pseudo-steady state flow exists for the remainder of Phase III and also, the water has reached a very low level of production as shown in Figure-4 below.

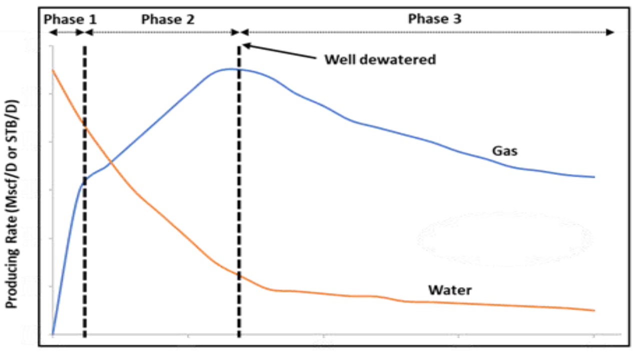

Figure-4. Gas and Water Rates for a typical Coalbed Methane Production Profile (Zuber, 1996).

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Governing Equations

Production of gas from coal requires dewatering process. Once water or free gas is produced from the fracture systems in the coal seam, pressure will start to drop. The adsorbed gas, which is methane will be desorbed and released from the matrix surface. The gas adsorption or desorption process can be explained by the Langmuir isotherm formula;

$$V(P) = \frac{V_L P}{P_L + P} \tag{1}$$

One of the Langmuir adsorption isotherm assumption is that gas is attached onto the coal surface where it covers the surface as a monolayer of gas. Langmuir volume (VL) shows the maximum amount of gas that can be adsorbed on a piece of coal at infinite pressure while Langmuir pressure (PL) is the pressure at which half of the Langmuir volume can be adsorbed. The higher the PL, the smaller amount of pressure drop is needed to recover a significant amount of gas adsorbed. The adsorbed gas content can be calculated at any pressure whenever the Langmuir volume and Langmuir pressure are known. The adsorption capacity will mostly depend upon Langmuir isotherm factors as shown in Figure-5 below (Jasinge & Ranjith, 2011).

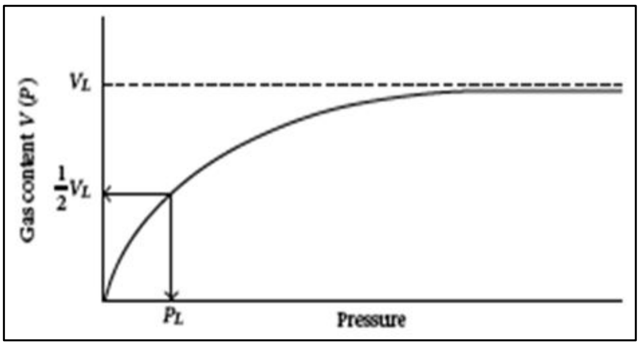


Figure-5. Langmuir Isotherm Function (Zulkarnain, 2005).

When the reservoir pressure declines as the result of dewatering, gas is desorbed from the coal seams, it will diffuse in the coal matrix, moving from high concentration to a low concentration region. At this stage, diffusion happen due to the tiny structure of the micro pores in the coal matrix. The small sized of micro pores eventually imposes a very high drag flow in the pathway compared to path in the macro pores which prevents the gas to flow obeying Darcy's Law. This diffusion process is described using the Fick's Law below.

$$Q = -DA\frac{dC}{dL} \tag{2}$$

Then, gas will flow through the fracture systems into the wellbore by Darcy's Law. Darcy's law shows that pressure gradient plays an important role as the driving force for the gas flow in the fracture system. The Darcy's Law can be described using the equation below.

$$q = -\frac{kA}{\mu}\frac{dp}{dL} \tag{3}$$

Palmer & Mansoori (1998) model is used to represent the changes in permeability during production and injection phase and it is crucial to include this model in simulation of coalbed methane performance.

$$\frac{\emptyset}{\emptyset_o} = 1 + C_f\left(\frac{P-P_o}{\emptyset_o}\right) + \frac{\varepsilon_\alpha}{\emptyset_o}\left(\frac{K}{M}-1\right)\left(\frac{P}{P+P_L}-\frac{P_o}{P_o+P_L}\right) \tag{4}$$

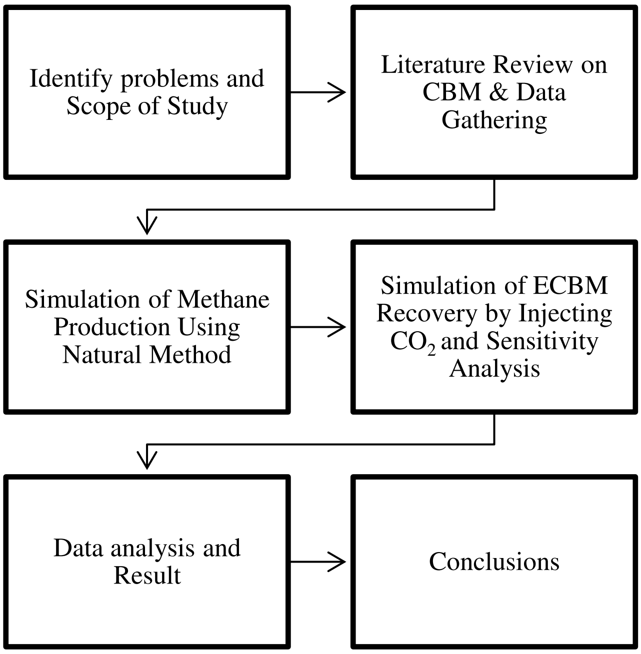
METHODOLOGY

The first step before initializing the project is to conduct data gathering process. In initial phase of research an intensive literature review was done. The sources that have been referred to are listed in the reference section of the report.

Table-2. Case study for simulation.

	Type of Well	Start of Injection
Case 1	Producer only	-
Case 2	Producer and Injector	Year 1
Case 3	Producer and Injector	Year 5

Project Workflow



CMG-GEM Simulation software has been used in order to illustrate the production of methane from coal seam by natural production and also enhanced coal bed methane recovery by CO_2 injection.

The objective of the study is to investigate the natural production of methane CH_4 and impact of CO_2 injection on the cumulative methane production which

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requires a base case to meet the objective of this project. This case is used to compare primary and natural production with enhanced coal bed methane process and it is represented by case 1. Another objective of this project is to investigate the impact of CO_2 injection timing on the final recovery of methane from coal. Three (3) different cases are built to analyse the scenarios. Each of this case will have different time for start of injection and also different duration of injection. The rest of the parameters involved for injection will be controlled scenario.

Base case model

The base case for the simulation is taken from CMG GEM case data entitled ECBM problem. The reservoir is represented by grid block with dimensions of 10 x 10 and placed with 2 wells for injection and production. The reservoir contains two (2) phase flow of fluid methane gas initially in place and aquifer. Figure-6 below illustrates 3D projection view of the reservoir grid blocks and optimal well positioning.

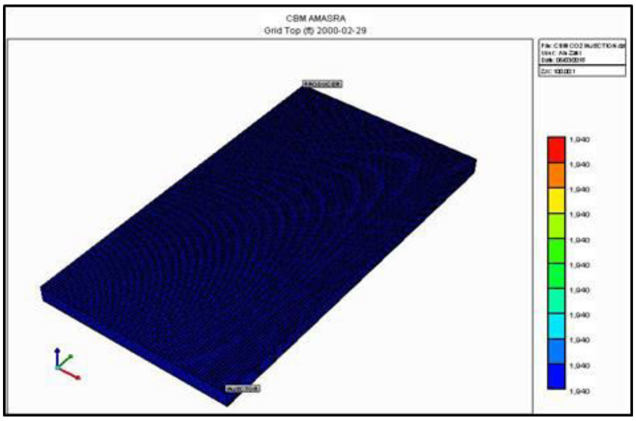

Figure-6. Base Case Model.

Before initiating the simulation study, the case model is redesigned to suit the project objectives and to ease the evaluation of data. Detailed information on the size of grid block and reservoir parameters are shown in the Table-3.

Table-3. Parameters used for the model.

Grid	68 x 127 x 1
Grid block length, ft.	160
Fracture porosity	0.02
Matrix porosity	0.04
Perm I fracture, md	8.0
Perm I matrix, md	0.01
Perm J fracture, md	8.0
Perm J matrix, md	0.01
Perm K fracture, md	1.0
Perm K matrix, md	0.001
Fracture spacing I J K, ft.	6
Reference pressure for rock compressibility –Fracture, psi	237
Reference pressure for rock compressibility - Matrix, psi	237
Rock compressibility - Fracture and matrix, 1/psi	0.0002
Poisson ratio	0.2
Young's modulus, psi	521000
Strain at infinite pressure	0.0101
Langmuir pressure CH_4, psi	1436.5
Langmuir pressure CO_2, psi	718.2
Langmuir volume CH_4, scf/ton	496.52
Langmuir volume CO_2, scf/ton	993.05
Palmer and Mansoori exponent	3.0
Model	Peng-Robinson EOS

Table-3. Parameters used for the model, (Continued)

Component	CO_2, CH_4
Reservoir temperature, ^oF	95
Coal mass density matrix and fracture, lb/ft^3	96.13807
Gas phase diffusion values CO_2 matrix, cm^2/sec	0.003855
Gas phase diffusion values CH_4 matrix, cm^2/sec	0.001928
Water saturation matrix	0
Water saturation fracture	0.01
ZGLOBALC CO^2 matrix and fracture	0
ZGLOBALC CH_4 matrix and fracture	1.0
Producer - Operate min BHP, psi	50
Injector -Operate max STG, scf/day -Operate max BHP, psia	30000 1161.1
Injection fluid	100% CO_2

RESULTS AND DISCUSSIONS

Primary production of Coal Bed Methane - Case 1

The base case was modeled using CMG and run in GEM, using the data from Table-3. For the base case, only primary production of methane gas was recorded without considering CO_2 injection into the coal bed. The Palmer and Mansoori model was used to assess the effect of shrinkage and swelling of the coal to the porosity and permeability. Based on Figure-7, during the primary production the pressure of the coal bed was monitored decreasing gradually from 5000 psi to 1381 psi from Year 2000 to Year 2010. On the other hand, it can be seen that the cumulative gas produced is up to 28.2 Bscf throughout time.

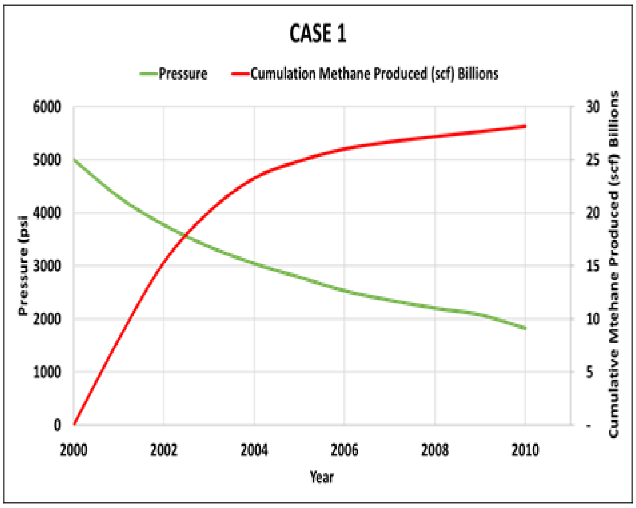

Figure-7. Graph of Pressure and Cumulative Methane Produced against Years (time) for Case-1.

The amount of methane production increases when the reservoir pressure decreases throughout the time as illustrated in Figure-7. This is because as the reservoir pressure decreases, the adsorbed methane on the surface of the coal matrix will be desorbed and diffuse from higher concentration to lower concentration into the fractures – face and butt cleats. The methane then will flow towards the wellbore and finally produced to the surface.

Figure-8 shows a rapid decrease in water rate at the early stage of production (Year 2000 to Year 2002).

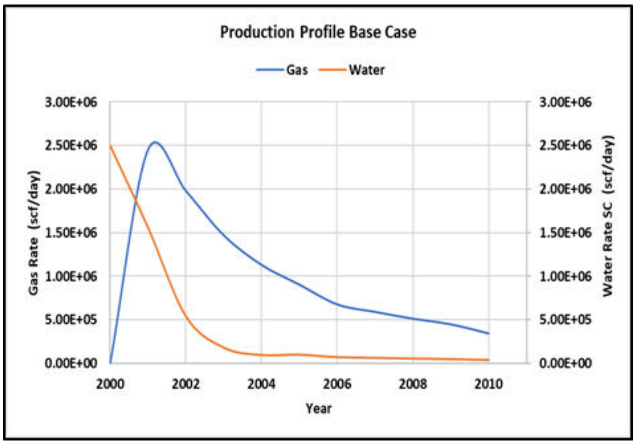

Figure-8. Graph of Gas Rate and Water Rate against Years (time) for Case-1.

However, after Year 2002 it is observed that the rate of water produced decreases very slowly as compared to the first 2 years of production. Meanwhile, gas rate increases rapidly from Year 2000 to Year 2002 and started to decrease when the rate of water produced decreases very slowly. This is because the first 2 years of production is known as the dewatering stage. The dewatering stage happens when a large amount of water is being pumped off from the coal bed methane. This will cause the reservoir pressure to decrease which then leads to desorption/bleeding of methane and moving towards to production well.

CO2 injection in CBM as enhanced recovery - Case 2

Usually, CO_2 is injected in the coal bed in order to continue producing methane when the methane production become plateau after a while due to pressure reduction in the reservoir. For this case, CO_2 gas is injected on the first day of the production in order to simplify the simulation process.

Figure-9 shows that the reservoir pressure decreases while the cumulative methane produced increases through time from Year 2001 to Year 2010.

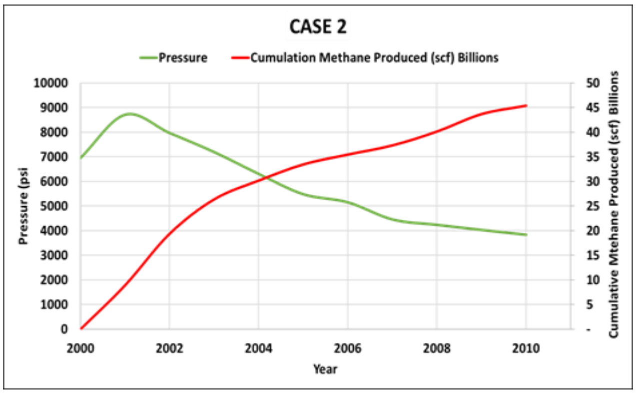

Figure-9. Graph of Pressure and Cumulative Methane Produced against Years (time) for Case-2.

As CO_2 gas is injected in the coal bed, the reservoir pressure increases from year 2000 to 2001. Meanwhile, the reservoir pressure decreases as more methane is being produced from year 2002 to 2010 with reservoir pressure of 3836 psi after 10 years. A similar trend can be seen on the reservoir pressure and cumulative methane produced when CO_2 is injected in the reservoir as the base case. The amount of cumulative methane produced after 10 years is 45.4 Bscf. The amount methane produced shows an increment of 17.203 Bscf as compared to Case 1. When CO_2 is injected into the coal bed methane reservoir, the CO2 molecules will be adsorbed on the matrix surface and methane is replaced by CO_2 from the matrix surface. As more CO_2 is introduced in the reservoir, more methane can be desorbed and produced in the wellbore. This happens due to the higher affinity of CO_2 to the matrix of the coal as compared to methane. The methane then will move to the fractures and the difference in pressure (pressure gradient) will drive the methane to be produced to the surface through the well.

CO2 injection in CBM as enhanced recovery - Case 3

Based on Figure-10, it can be observed that when CO_2 is injected in the coal seam at year 2005 the pressure of coal seams increases.

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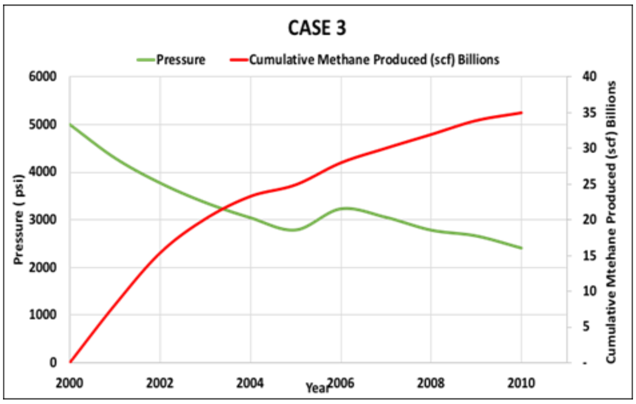

Figure-10. Graph of Pressure and Cumulative Methane Produced against Years (time) for Case-3.

CO_2 injection increases the partial pressure of the coal seam and causes a reduction in methane partial pressure. This will cause the methane to be desorb from the coal matrix surface and create a difference in concentration in the coal seams. The methane will then move from the matrix to the fracture system by diffusion until it reaches wellbore. Furthermore, when CO_2 is injected at Year 2005, it can be observed that the gradient in the cumulative methane produced increases. This shows that CO_2 injection in coal seams help to increase methane production even at later stage of production life. In Case 3, the amount of cumulative methane produced is 34.962 Bscf. An increment of 10.4 Bscf methane is observed as compared to the Case 1 where no CO_2 injection is applied. The findings further confirm that CO_2 injection help to increase the methane production as well as maximizing the methane recovery.

Timing of CO_2 injection

To assess the effect of CO_2 injection timing to cumulative methane recovery, all the 3 cases were analysed. Case 1 which is the case without CO_2 injection is used as the base case. The rate of injection for Case 2 and Case 3 remain constant. Based on the results, Case 2 has the highest cumulative amount of CO_2 injection followed by Case 3 and lastly Case 1? Figure-11 below shows the cumulative amount of methane produced in all 3 cases.

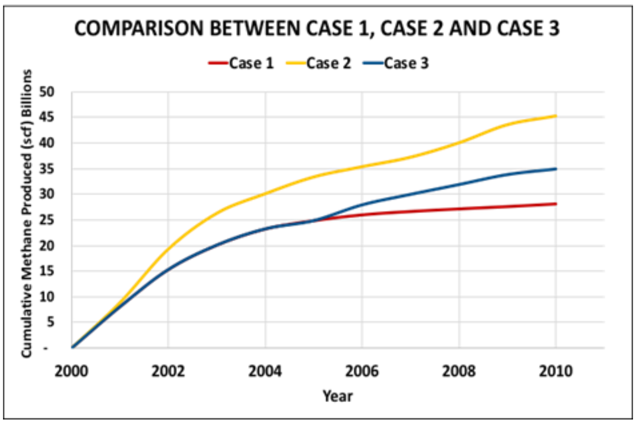

Figure-11. Comparison of Methane Produced by Case 1, Case 2 and Case 3.

The highest cumulative methane production is observed for Case 2 (CO_2 injected at day 1) followed by Case 3 (CO_2 injected after 5 years) and lastly, Case 1 with no injection as shown in Table-4 below.

Table-4. Summary of methane production for Case 1, Case 2 and Case 3.

Case	Cumulative Methane Produced (Scf) Billions	Increment from Case 1 (Scf) Billions
Case 1	28.159	-
Case 2	45.362	17.203
Case 3	34.962	10.4

This observations and results further confirm that CO_2 injection in coal seams helps to enhance methane production. Besides, more methane is being produce when injection occurs at the early life of production compared to inject at year 5. This is because the injection helps to increase the partial pressure of the coal seams. When CO_2 injection operation is performed at the early life of production, a higher reservoir pressure can be maintained as compared to injection at later stage of production. Thus, more methane is desorbed when the injection starts in the early life of the production compared to the later stage of production. Figure-12 through Figure-14 show the total moles of CH_4 remaining in targeted coal seam after 10 tears of production for all 3 cases.

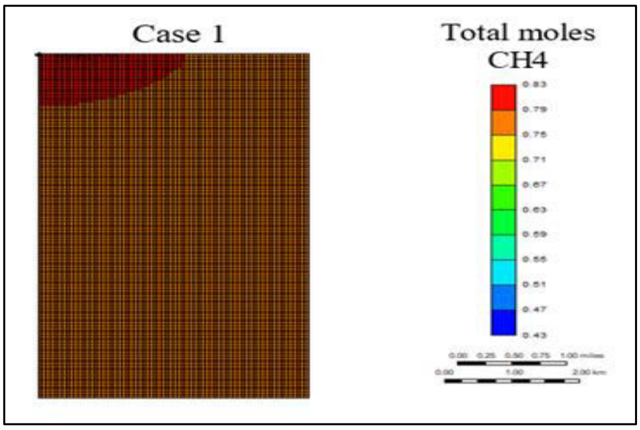

Figure-12. Moles of CH4 remaining after 10 years of production - Case 1.

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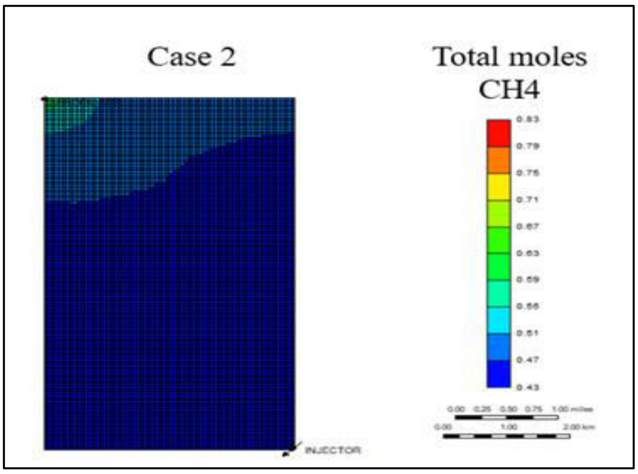

Figure-13. Moles of CH_4 remaining after 10 Years of Production - Case 2.

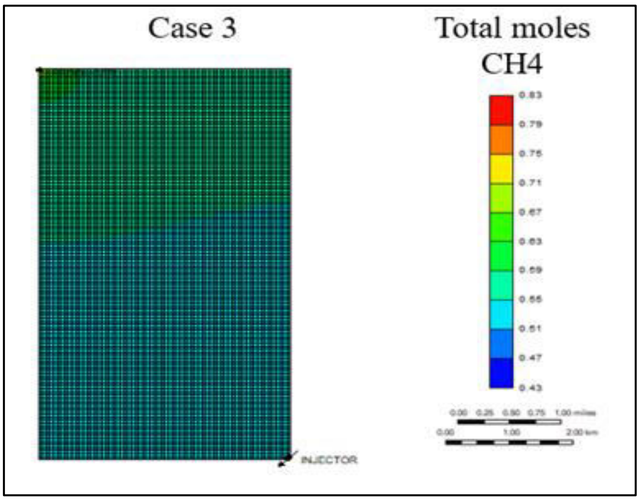

Figure-14. Moles of CH_4 remaining after 10 Years of Production - Case 3.

Case 1 has the highest total moles of methane left after 10 years of production followed by Case 3. Case 2 has the least methane left in the reservoir. It shows that CO_2 injection in coal bed methane improves the sweep efficiency of methane throughout the reservoir. This concludes that the timing of CO_2 injection also plays an important role in determining the final methane recovery in coal bed methane reservoir.

SENSITIVITY ANALYSIS

Cleat permeability

Cleat permeability is expected to have an impact on the production of methane. To assess the effect of cleat permeability, the value of parameters for methane production when the cleat permeability is reduced and increased are as below. All the other reservoir parameters remain same as the base case. However, the size of the reservoir is changed to smaller scale in order to simplify the simulation process. The values used to investigate the effect of cleat permeability is shown in Table-5.

Table-5. Sensitivity case for cleat permeability.

Properties	Condition	Permeability, mD
Cleat permeability I, J	Increase	12
	Base Case	8
	Decrease	4

Figure-15 shows that the amount of cumulative methane production after 10 years is 3.8 Bscf, 3.9 Bscf and 2.3 Bscf for base case, case with cleat permeability increase and case with cleat permeability decreases respectively.

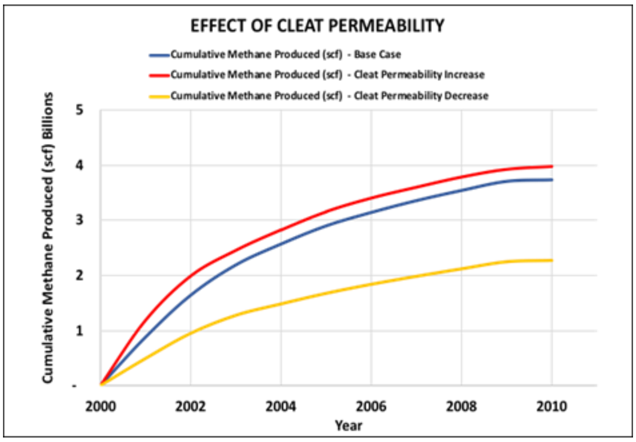

Figure-15. Effect of Changing Cleat Permeability to Cumulative Methane Produced.

Severe reduction in methane recovery was observed when the cleat permeability is reduced from 8 mD (base case) to 4 mD. On the other hand, when the cleat permeability is increased from 8 md (base case) to 12 md, the higher amount of cumulative methane production is observed. The increase in cleat permeability accelerates the methane production as well as increases the cumulative amount of methane production. This is because the cleat permeability or fracture permeability serve as the pathway for methane to flow from the matrix to the wellbore. Permeability can be defined as the ability of fluid to flow through rock formation. When permeability of cleat increases, the area of methane gas to flow also increases resulting in higher amount of methane production. This proves that permeability plays an important role in determining the amount of methane production in a coal bed methane reservoir.

Cleat porosity

In order to assess the effect of cleat porosity to the methane production, only the cleat porosity value is changed while the other parameters remain constant. The porosity values used for assessing the effect of cleat porosity to the cumulative of methane gas produced is shown in Table-6.

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Table-6. Sensitivity case for cleat porosity.

Properties	Condition	Porosity
Cleat porosity	Increase	0.2
	Base Case	0.02
	Decrease	0.01

Figure-16 shows the amount of cumulative methane produced when cleat porosity is varied.

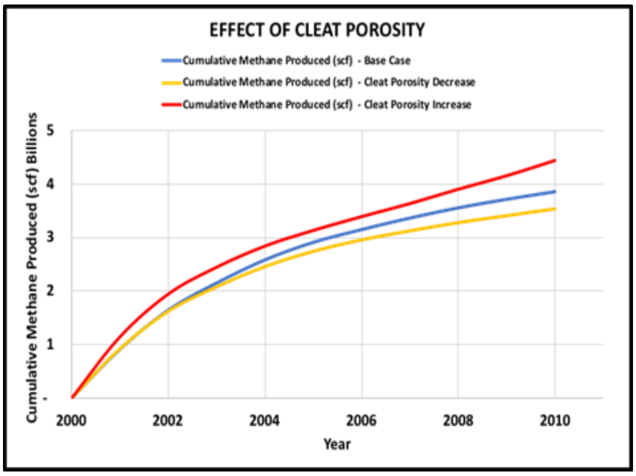

Figure-16. Effect of Cleat Porosity to Cumulative Methane Production.

The amount of cumulative methane production after 10 years is 3.8 Bscf, 3.5 Bscf and 4.4 Bscf for base case, case with cleat porosity decrease and case with cleat porosity increase respectively. When the cleat porosity reduced to 0.01 from the initial value of 0.02, the cumulative amount of methane production also decreases. On the other hand, when the cleat porosity increases from 0.02 to 0.2, it can be observed that the amount of cumulative methane produced is higher compared to the base case. High cleat porosity increases the amount of free gas in place in the fracture system while low cleat porosity causes a decrease in the amount of free gas in place found in the cleat system. It can be observed that the amount of cumulative methane produced increases when the value of cleat porosity increases. This is because, as the cleat porosity increase, the amount of free gas exist in the cleat will also increase. However, the gas in place in the matrix decreases since there is a reduction in the matrix volume when the cleat porosity is increased. Although the cumulative amount of methane produced decreases when the cleat porosity decreases and methane production increases when the cleat porosity increases, methane recovery were remained almost the same for both cases. Cleat porosity only affect the amount of total gas in place. Changes in cleat porosity value does not affect the production of the methane but it will change the storage capacity of methane in coal bed methane reservoir.

Coal density

The amount of gas in place in a coal bed dependent on the coal density as well as on the rank of the coal seam. Thus adsorption parameters are related with the mass of the coal per unit volume which is coal density. Sensitivity analysis on the coal density is important in order to determine the amount of gas that can be produced from a particular field. Table-7 shows the value used in sensitivity case for varying coal density, a coal seam.

Table-7. Sensitivity case for coal density.

Properties	Condition	Coal density, lb/ft^3
Coal density	Increase	114.242
	Base Case	96.13807
	Decrease	80.46882

Figure-17 shows the amount of cumulative methane produced when coal density is varied.

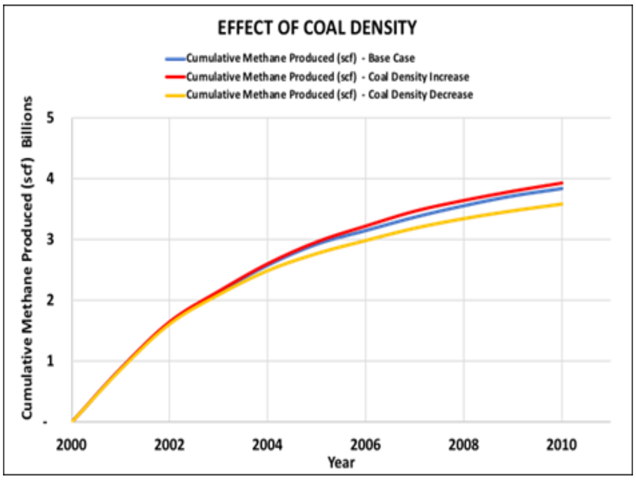

Figure-17. Effect of Coal Density to Cumulative Methane Production.

The amount of adsorbed gas in coal matrix is directly related to coal density and rank of that particular coal. We observed that with an increase in density, more natural gas is available to be produced, and similarly more carbon dioxide can be stored in a coal seam. We found, with a cumulative production in base case only 3.6 Bscf, when density increase can jump to 3.9 Bscf cumulative production. Based on Figure-17, the higher the coal density, the higher the cumulative methane production. This is because the higher density coal has higher capacity for adsorbing carbon dioxide, due to increase in surface area within coal seam. When more CO_2 is adsorbed on the coal, more methane is released and desorbed from the coal surface. These findings support that coal density plays a vital role in determining the amount of methane that can be recovered from coal bed methane reservoir.

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CONCLUSIONS

CO_2 injection into coal seams to displace the coalbed methane adsorbed on the surface of the matrix is interest of many researchers. The process not only enhances the methane production from coal seams but also serves as an alternative solution to reduce greenhouse effect through CO_2 sequestration in coal seams from where methane gas been produced.

The simulation of CO_2 injection and methane production is a complicated process due to the additional special features of swelling and shrinkage as well as gas retention in CBM reservoirs. The result of the simulation shows that injection of CO_2 gas enhances production of methane gas from coal seam in a significant way. Furthermore, it is proven that the enhanced coal bed methane recovery process results in a much higher recovery than just primary production. It is also found that the injection timing plays a big role in enhanced coal bed methane project. Injection during the early stage of production will recover higher amount of methane compared to injection at later stage of production. It is also concluded that the cleat permeability, cleat porosity and coal density are the crucial parameters in determining the final recovery on methane from CBM reservoir. Higher cleat permeability gives a higher methane production due to higher ability of methane to flow in the system. More free gas was found in higher porosity cleat systems resulting in higher recovery of methane. The cumulative methane production was higher when the coal was denser, since coal density was directly related to the adsorbed amount of gas in the matrices of coal reservoirs. Denser coal has higher capacity for adsorbing methane and capture more carbon dioxide in sequestration process.

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