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Secondary coal seam as a barrier to CO₂ leakage

Zainab Sahib Jawad

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SECONDARY COAL SEAM AS A BARRIER TO CO₂ LEAKAGE

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Thesis submitted to the

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College of Engineering and Mineral Resources

at West Virginia University

in partial fulfillment of the requirements for the degree of

Master of Science in

Civil & Environmental Engineering

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2013

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Coalbed methane, Horizontal and vertical wells, CO₂ injection, Permeable fractured zone

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ABSTRACT

Secondary Coal Seam as a Barrier to CO₂ Leakage

Zainab Sahib Jawad

Geologic formations, such as unmineable or depleted coal seams, are considered to be potential reservoirs for CO₂ storage. Coal seams are naturally fractured reservoirs which consist of primary and secondary cleat networks. During production, coalbed methane (CBM) is desorbed from the coal surface and flows through the cleat network. When carbon dioxide (CO₂) is injected into a coal seam, large amount of the injected CO₂ is sorbed on the coal surface due to the greater affinity of CO₂ towards coal than methane. This provides two advantages: potential CO₂ storage and enhanced coalbed methane recovery. Several pilot studies have been performed to evaluate enhanced coalbed methane production and assess the performance of coal reservoirs during CO₂ injection. Limited studies have been conducted to investigate CO₂ leakage in the overburden geologic layers. In certain cases, there is likely to be a secondary coal seam above the primary coal layer targeted for CO₂ injection. If CO₂ breaks through the seal layer into the overburden formations, the secondary (upper) coal seam could possibly act as a CO₂ barrier due to the high affinity of CO₂ to the coal matrix.

The main objective of the current research work is to investigate whether a coal layer present above the target coal reservoir could act as a CO₂ barrier. The study also investigates coalbed methane recovery from the upper coal seam, when some of the injected CO₂ in the lower coal seam leaks through a pre-existing permeable caprock zone. Coupled multiphase flow and deformation analyses were used to investigate the CO₂ transport behavior and ground response during CO₂ injection. Different injection scenarios were considered based on two different well configurations. Results of the current study are presented in this report. Modeling results obtained from this study show that secondary (upper) coal seam can act as a CO₂ barrier in the presence of a CO₂ leakage. However, the leaked CO₂ may not enhance the coalbed methane recovery from the upper coal seam.

This work is dedicated to my family, especially to my mother Zhoor Jafar, my late father Sahib Jawad, and to my husband Haidar Aldaach. They patiently gave me all their support in every step of my journey towards my degree.

To My Family

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NOMENCLATURE

A	=	Cross-sectional area
B_g	=	Gas formation volume fact
b, c_0	=	Langmuir parameter to volumetric shrinkage
c_f	=	Fracture pore volume compressibility
c_m	=	Compressibility of coal matrix
D	=	Diffusion coefficient
E	=	Young's modulus
$\exp$	=	Exponential function with base ($e \approx 2.71828$)
f_i	=	Stress induced by the body forces per unit volume
f	=	A fraction, usually between 0 to 1
G_c	=	Gas content of the coal basin
$\bar{G}_c$	=	Average adsorbed gas content
G_s	=	free gas content
G	=	Shear modulus
h	=	Thickness of the coal
$IGIP$	=	Initial gas in place
K	=	Bulk modulus of coal
k	=	Fracture permeability
L	=	Length
l	=	Fracture spacing
M	=	Constrained axial modulus
n	=	Adsorption components number
p	=	Pore pressure (Reservoir pressure)
P_o	=	Initial reservoir pressure
p_m, p_f	=	Total pressure in the matrix and fracture respectively
P_L	=	Langmuir pressure
P_{Lj}, P_{LK}	=	Langmuir pressure, component j/ component k
q_{gm}	=	Gas production (diffusion) rate
S_w	=	Water saturation

S_E	=	CO ₂ storage efficiency factor (assumed to be 2)
V_{adsorbed}	=	Volume of adsorbed gas in the coalbed reservoir
V_c	=	Matrix volume
V_{coalbed}	=	Total volume of gas in the coalbed reservoir
V_{free}	=	Volume of free gas in the coalbed reservoir
V_L	=	Langmuir volume
$y_{\text{ref},j}$	=	Composition at reference conditions, component j
$y_{\text{ref},k}$	=	Composition at reference conditions, component k
$y_j y_k$	=	Gas mixture composition, component j/ component k
$\varepsilon_{Li}, \varepsilon_{LK}$	=	Strain at infinite pressure, component j/ component k
ϕ_{ref}	=	Initial porosity
ϕ	=	Porosity
ν	=	Poisson's ratio
ρ	=	Coal density
ρ_c	=	Matrix density
ε	=	Matrix shrinkage and swelling strain
ε_{∞}	=	Strain at infinite pressure
σ'	=	Effective stress
σ	=	Total stress
μ	=	Viscosity of gas
α	=	Positive constant (usually =1)
δ_{ij}	=	The Kronecker delta function
ε_{ij}	=	Total strain
u_i	=	The displacement of element
β	=	Boit's coefficients
ε_s	=	The sorption-induced volumetric strain

Chapter 1 : INTRODUCTION

1.1 – Background

A significant rise in the levels of greenhouse gases (GHGs), such as carbon dioxide (CO_2), is considered the primary source for global warming and climate change worldwide (U.S. D.O.E., 2010; U.S. D.O.E., 2012; Gu, 2009). Greenhouse gas emissions are mainly due to the combustion of fossil fuels and human activities, such as transportation and residential heating. In addition to CO_2 , anthropogenic greenhouse gases include methane (CH_4), nitrous oxide (N_2O), chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs) (Tang, 2006). CO_2 is considered the primary contributor to the greenhouse gas effect accounting for about 70% of the total greenhouse gas emissions worldwide (Huy et al, 2010). Relative contributions of the other gases to the greenhouse gas effect are about 19.2% from (CH_4), about 5.7% from Nitrous oxide (N_2O), and about 11.5% from other sources (Mavor et al, 2002).

In the United States of America, CO_2 is considered the most prevalent greenhouse gas, contributing to around 80% of the total GHG emissions (Huy et al, 2010; U.S. D.O.E. 2007). Since fossil fuels are the key to energy supply for at least a few more decades, it is believed that CO_2 emissions from human activities are not going to decline drastically in the near future (Gu, 2009; Huy et al, 2010). It has been reported that the concentration of CO_2 in the atmosphere has increased to 393.31 parts per million (ppm), and the average annual increase for the past decade is 2.1 ppm per year (www.CO2NOW.org). Figure 1.1 shows the recent CO_2 atmospheric concentrations (from 2006 to 2012) in ppm. Reduction of CO_2 emissions to the earth's atmosphere could help to control the greenhouse gas effect and stabilize the ecosystem (Gu, 2009; Huy et al, 2010).

Several studies have been reported in published literature on how to mitigate greenhouse gas emissions, with a primary focus on CO_2 (U.S. D.O.E., 2010; U.S. D.O.E., 2012; Huy et al, 2010; Pan et al, 2010; Gu, 2009; Ripepi, 2009; White et al, 2005; Bachu, 2002; Hardisty, 2008; Lucier et al, 2006; Celia et al, 2005; Lucier and Zoback, 2008; and Michael et al, 2009; Siriwardane and Gondle, 2011; Brochard et al, 2012; He et al, 2013). CO_2 levels can be reduced by (U.S. D.O.E., 2010; He et al, 2013):

1. Switching to fuels which contain less carbon, such as natural gas instead of coal or oil.
2. Using renewable energy sources, such as solar and wind for power generation.
3. Changing the human daily lifestyle.
4. Using different geologic formations, such as coal seams, as long term storage for captured atmospheric carbon dioxide.

Details of different geologic formations suitable for carbon dioxide storage are discussed in the forthcoming sections. The current focus of this research work is the storage of carbon dioxide into unmineable coal seams.

Data Source: ([www.CO₂NOW.org](http://www.CO2NOW.org))

Figure 1.1: Atmospheric CO₂ concentrations from 2006 to 2012

1.2 – Carbon sequestration in different geologic formations

Several demonstration and commercial-scale projects were performed by various research teams to evaluate carbon dioxide storage in different geologic formations (Bachu, 1999; White et al, 2005). Different geologic formations suitable for CO₂ sequestration are shown in Figure 1.2 and a brief description of each formation is given below. Coal seams are considered to be an option for CO₂ storage due to their excellent, long-term storage potential and enhanced coalbed methane production (Ripepi, 2009; White et al, 2005; Bachu, 1999; Bachu et al, 2002; Bachu et al, 2007; and Pan et al, 2010).

Figure 1.2: Different geologic formations for CO₂ sequestration

(a) Unmineable or depleted coal seams

Carbon dioxide has a greater affinity for coal than methane (He et al, 2013). In fact, it is reported that carbon dioxide's affinity to coal is about twice of methane (Sams et al, 2002; LeNeveu et al, 2006; Wang et al, 2007; He et al, 2013). While CO₂ can be stored in an adsorbed state for significant time periods, injection of CO₂ into coal seams can also enhance the production of coalbed methane. Several pilot studies have been conducted to demonstrate the potential of CO₂ sequestration in unmineable or depleted coal seams (Cairns 2003; Mazzotti et al, 2009; Ripepi, 2009; White et al, 2005; He et al, 2013; Sams et al, 2002; Odusote et al, 2004; Siriwardane et al 2012). Different aspects related to the sequestration of CO₂ into coal seams have been discussed in published literature (White et al, 2005; Siriwardane et al, 2012; Bajura et

al, 2011; Odusote et al, 2004; Oudinot et al, 2005). Some of these aspects which are critical to the research work presented in this report are discussed in subsequent chapters.

(b) Deep saline aquifers

Saline aquifers are believed to have a very high storage capacity (Pan and Connell, 2010). Several studies have been conducted to evaluate CO₂ sequestration in saline aquifers (Michael et al, 2009; Bruant et al, 2002; Simon et al, 2008; Birkholzer et al, 2009; Pan and Connell, 2010; Pruess and Spycher, 2007; Rohmer and Olivier 2010). Saline aquifers have a caprock layer that can trap CO₂ for long geological periods due to changes in hydrogeological and geochemical behavior. Recently, several issues related to caprock failure, caprock integrity, and CO₂ leakage due to long-term CO₂ injection have been discussed in the literature (Rutqvist et al, 2007; Rohmer and Olivier, 2010).

(c) Depleted Oil and Gas Reservoirs

CO₂ sequestration in depleted reservoirs is considered the simplest and cheapest choice compared to the other formations (Bachu, 1999). Depleted oil and gas reservoirs are promising for several reasons. Some of these reasons include (Bachu, 1999; Pawar et al, 2004):

- The availability of data, such as reservoir properties and geological data.
- The ability of the reservoir to trap CO₂ is known and proven, because they had held gas or oil for significant periods of time.
- Available infrastructure and resources, such as pipelines and drilled wells, which were previously used to extract oil or natural gas.

(d) Oceans

Oceans are considered to be the largest natural sinks to store carbon dioxide (Bachu, 1999). It is possible to sequester CO₂ in the bottom of deep oceans because of its density, which is greater than seawater, which allows CO₂ to remain isolated from the seawater by forming plums or hydrates at the bottom of the ocean (Bachu, 1999). CO₂ sequestration in deep oceans has been investigated and can be found elsewhere (Bachu, 2002).

(e) Basalt

Basalt is a dark-colored rock rich in silica. It contains different cations (minerals) such as magnesium, calcium, and iron. When CO₂ is injected into basalt, it can combine with the basalt's cations forming carbonate minerals over a period of time. As a result, basalt formations can also act as a host reservoir for CO₂ sequestration (U.S. D.O.E., 2010).

1.3 – Problem statement/research objectives

For any large-scale carbon dioxide (CO₂) sequestration project to be successful, it is important to understand the flow behavior of the injected carbon dioxide and any geomechanical response, such as ground deformation behavior. When CO₂ is injected into a coal seam, large amounts of CO₂ are sorbed on the coal surface due to the greater affinity of CO₂ towards coal than methane. This provides two advantages: potential CO₂ storage and enhanced coalbed methane recovery. Several pilot studies have been performed to evaluate enhanced coalbed methane production and to assess the performance of the coal reservoir during CO₂ injection (Cairns 2003; Mazzotti et al, 2009; He et al, 2013). Limited studies have been conducted to investigate CO₂ leakage in the overburden geologic layers.

In certain cases, there is likely to be a secondary coal seam above the primary coal layer targeted for CO₂ injection. If CO₂ breaks through the seal layer into the overburden formations, the secondary coal seam could possibly act as a barrier to CO₂ leakage to the other overburden layers.

In the current study, reservoir and geomechanical modeling were performed, and coupled multiphase flow and deformation analyses were used to investigate the CO₂ transport behavior and ground response during CO₂ injection. The models were run with and without the presence of a hypothetical permeable pathway (i.e. a fracture) within the sandwich layer between two coal seams (upper and lower). Figure 1.3 shows a schematic diagram of a multi-layered geologic profile with a pre-existing permeable path (fracture). Different injection scenarios were considered based on well configurations proposed in pilot studies and demonstrated sequestration projects reported in published literature. In brief, the objectives of the current work can be listed as follows:

- Study CO₂ and geomechanical behavior for different well configurations.
- Investigate the response of the pressure and fluid flow due to the injection of CO₂ in the lower coal seam.
- Investigate coalbed methane recovery from the lower and the upper coal seams due to CO₂ injection in the lower coal seam.
- Investigate CO₂ leakage in the presence of a hypothetical permeable zone (i.e. a fracture) in the sandwich layer.
- Investigate different carbon dioxide (CO₂) leakage scenarios and compute the amount of leakage when different well configurations are selected.
- Investigate coalbed methane recovery from the lower and the upper coal seams due to CO₂ injection in the lower coal seam in the presence of a hypothetical permeable zone in the sandwich layer.
- Perform geomechanical modeling of ground response and fluid flow during CO₂ injection.
- Investigate whether a coal layer present above the target coal reservoir could act as a carbon dioxide (CO₂) barrier, if CO₂ leaks through a permeable zone present in the sandwich layer.

Figure 1.3: Schematic diagram shows a permeable fractured zone between two coal seams

Subsequent chapters present the research work performed to achieve the above mentioned objectives. Chapter 2 provides review of some previous literature and technical background of CBM recovery and potential of geologic storage of CO₂. Chapter 3 presents some mathematical details of CBM reservoir storage capacity and permeability changes due to fluids production and injection. CBM production and CO₂ injection were carried out by using different well configurations, and the results are presented with details of the reservoir modeling in chapter 4. Coupled flow and deformation analyses were performed, and ground displacements caused by coalbed methane production and CO₂ injection were computed. Chapter 5 provides all the computed ground surface displacements. Chapter 6 presents the influence of a permeable fractured zone, which is present in the overlying caprock layer, on CO₂ transport behavior. Reservoir modeling results for different CO₂ leakage scenarios with different well configurations are also provided in chapter 6. A brief summary, conclusions and future recommendations are presented in Chapter 7.

Chapter 2 : OVERVIEW OF COALBED METHANE RESERVOIRS

2.1 – Introduction

During this research work, a literature review was conducted to get a thorough understanding of the current issues related to coalbed methane (CBM) extraction and carbon dioxide (CO₂) injection into coal seams. Several topics related to CBM recovery and CO₂ sequestration are briefly discussed in the following sections based on published literature. Some of these topics include coal characteristics and properties, storage and transport mechanisms, coal shrinkage and swelling, and permeability evolution.

2.2 – Overview of coal and coalbed methane

Coal is a naturally fractured dark-colored rock which consists of carbonaceous materials and natural gas (Cervik, 1969; Rogers, 1994). Underground coal reservoirs are usually bounded by a caprock and floor strata which are known for their impermeable characteristics (Ekrem, 2009). Coal was formed long ago during the alteration of plant substances and peat by a process known as coalification (Cervik, 1969). Figure 2.1 shows a schematic diagram of the coalification process. The coal formation process begins when the earth's crust movements push plants and other organic materials to great depths. Over time, plant materials develop into organic materials and peat swamps, and then into coal and natural gas. The high overburden pressure and temperature play the most important role in providing a very mature coal (Rogers, 1994). Thus, the depth of the coal is a measure of its maturity (Ross, 2007). Different coal ranks in an ascending order are: lignite, subbituminous, high volatile bituminous, medium volatile bituminous, low volatile bituminous, semi-anthracite and anthracite (Ross, 2007).

In nature, coal consists of bulk geologic media known as "coal matrix", and fractured media known as "cleats" (Rogers, 1994). Natural gases, such as methane, are stored in the internal surface of the coal matrix, and flow takes place through the cleat network. In general, these natural fractures (cleats) have high permeability ranging from 1 to 30 millidarcy (mD) (Bromhal et al, 2005), which is much higher than the permeability of the coal matrix. For that reason, flow of any gas or fluid usually takes place within the cleats network. Face cleats

(primary cleats) and butt cleats (secondary cleats) form the majority of the cleat network (Rogers, 1994). Normally, butt cleats are formed perpendicular to face cleats. Figure 2.2 shows the cleat network with face cleats and butt cleats. Coal seams are usually saturated with water, thus the adsorbed methane in coal matrix is considered immobile (Sams et al, 2002).

Figure 2.1: Coalification process

Figure 2.2: Schematic diagram representing the coal structure

Coal constitutes one of the major energy resources and supplies in the world. It is considered a major source for electricity generation and heat (Cervik, 1969; Rogers, 1994). In the United States, coal is located in 14 basins (Rogers, 1994), and the extent of the coal basins can be seen in Figure 2.3. In 2011, coal was mined in 25 states and about 1,094.3 million short tons were produced. Thus, the U.S. is considered one of the biggest estimated reserves of coal in the world (Cervik, 1969). It is believed that for the next two decades, coal will continue to dominate the power generation in the U.S. (U.S. D.O.E., 2012).

Figure 2.3: Major CBM fields and coal basins in the U.S. (www.eia.gov/coal)

In certain cases, multiple coal seams are very likely to be found in sedimentary rock formations. Deeper coal seams are usually attractive for coalbed methane (CBM) production and carbon dioxide (CO₂) sequestration, because they are usually a higher rank and have higher gas storage capacity than shallower coals. In addition deeper coal seams have a very well developed fracture network (Cui and Bustin, 2005).

Coalbed methane (CBM) is a natural gas that exists in coal seams and is considered a serious risk for underground mining operations. In order to reduce methane's risk in underground coal mining, a large amount of air is forced through the mine workings. As a result, a significant amount of methane is emitted directly into the atmosphere, which makes it the second largest greenhouse gas after carbon dioxide and is more harmful (Chhajed, 2011). On the other hand, CBM is considered an excellent natural gas resource that can be produced and used in power generation (Rogers, 1994). Higher rank coal usually have higher amount of CH_4 (Cui and Bustin, 2005).

Injection of carbon dioxide (CO_2) into coal seams can enhance coalbed methane recovery (Cairns 2003; Mazzotti et al, 2009; Ripepi, 2009; Koperna et al, 2009). Figure 2.4 shows a schematic diagram of CO_2 injection forcing the coalbed methane to flow towards the production wells. The injected carbon dioxide could increase CBM production due to the fact that carbon dioxide molecules have more affinity to the coal surface compared to methane molecules (Chhajed, 2011; Bachu, 1999; He et al, 2013).

Figure 2.4: A schematic diagram for CO_2 sequestration in coal seams

2.3 – Coal characteristics

- **Coal porosity systems**

Coal is a dual-porosity geologic formation with micropores (bulk matrix) and macropores (cleat network) (Tang, 2006; Rogers, 1994). A dual porosity system means that any flow can take place in both coal matrix and cleats. Flow through the coal matrix is a diffusional process (Rogers, 1994; He et al, 2013). In general, coal bulk matrix usually has low to mid porosity and a large surface area which contains a very high percentage of adsorbed methane. For that reason, the porosity of a coal matrix is known as the primary porosity system (Sams et al, 2002). In addition, the porosity of coal fractures is known as the secondary porosity system (Rogers, 1994). Figure 2.5 illustrates the concept of the dual porosity system.

Figure 2.5: Dual porosity system

- **Coal permeability**

Coalbeds usually have low permeability and depends on cleats (natural fractures) to act as fluids conductors (Rogers, 1994). Face cleats have wider openings than butt cleats and are continuous. As a result, fluids and gases flow faster through face cleats. Therefore, coal is one type of rock which has a characteristic of anisotropic permeability (Tang, 2006; Rogers, 1994; He et al, 2013). Compared to conventional reservoirs rocks, coal is considered relatively

compressible which makes the permeability of coal reservoirs stress-dependent. Coalbed methane recovery can be influenced by the magnitude of that stress. Cleat permeability plays a very effective role during the sequestration process. The injected CO₂ causes the coal to swell, and as a result the permeability of the coal fractures will decrease (Siriwardane et al, 2009; Harpalani and Chen, 1997; Ross, 2007; Bromhal et al, 2005; Shi and Durucan, 2005).

2.4 – Storage and transport in coal seams

Coalbed methane (CBM) is stored in coal seams as a free gas within the cleat network and as an adsorbed gas within the internal surfaces of coal matrix. Maximum CBM is present in an adsorbed state on the internal surface of the coal matrix (Sams et al, 2002; He et al, 2013; Tang, 2006). Equations (2.1) to (2.3) provide the relationships that can be used to calculate total gas-in-place (White et al, 2005; He et al, 2013).

$$\textit{Total gas-in-place} = \textit{free gas} + \textit{adsorbed gas}$$

$$V_{\textit{coalbed}} = V_{\textit{adsorbed gas}} + V_{\textit{free gas}} \quad \text{..... Equation (2.1)}$$

Where:

$V_{\textit{coalbed}}$ = Total volume of gas in the coalbed reservoir

$V_{\textit{adsorbed}}$ = Volume of adsorbed gas in the coalbed reservoir

$V_{\textit{free}}$ = Volume of free gas in the coalbed reservoir

$$V_{\textit{adsorbedgas}} = \frac{V_L P}{P_L + P} (Ah\rho) \quad \text{..... Equation (2.2)}$$

$$V_{\text{free gas}} = \frac{Ah\phi(1 - S_w)}{B_g} \quad \dots\dots\dots \text{Equation (2.3)}$$

Where:

A = area of coalbed reservoir

h = thickness of the coalbed

P = pressure

V_L = Langmuir volume

P_L = Langmuir pressure

ρ = density of coal

Ø = coal porosity

S_w = water saturation

B_g = gas formation volume factor

In saturated coal reservoirs, coal cleats are usually filled with water, which makes CBM immobile (Sams et al, 2002). In order to produce CBM, water in the cleat network should be pumped out first. Removal of water induces the pressure to drop in the cleat network enhancing gas desorption from the adsorbed surfaces. Later, the released gas begins to diffuse into the fracture network once the dewatering completes. The flow occurs via random molecular motion from high concentration areas to lower concentration areas, and it is governed by Fick's Law (Cervik, 1969; Smith et al, 1984). Fick's Law is expressed in Equation (2.4) (Mora, 2007; Aminian, 2003). Gas diffusion from the coal matrix is typically very slow (Rogers, 1994). After the diffusion process, gas begins to flow through the cleat network towards the wellbore. Transport in the cleat network is governed by Darcy's Law, and the direction of the flow is determined by the pressure difference between the reservoir and the wellbore (Cervik, 1969; Rogers, 1994; Ross, 2007). Darcy's Law is expressed in Equation (2.7). The typical production profile for a CBM well is shown in Figure 2.6. Figure 2.7 shows a schematic diagram of the gas transport in coal seams.

$$q_{gm} = 2.697 \sigma D \rho_c V_c (\bar{G}_c - G_s) \quad \text{..... Equation (2.4)}$$

Where:

q_{gm} = Gas production (diffusion) rate

σ = Matrix shape factor

D = diffusivity coefficient

V_c = Matrix volume

ρ_c = Matrix density

$\bar{G}_c$ = Average adsorbed gas content

G_s = free gas content

Diffusivity and shape factor are usually combined into one parameter known as desorption time (τ), which can be expressed using equation (2.5) as shown below:

$$\tau = \frac{1}{\sigma D} \quad \text{..... Equation (2.5)}$$

Desorption time formulation was presented by Zuber et al, in 1987 by equation (2.6):

$$\tau = \frac{l^2}{8 \cdot \pi \cdot D} \quad \text{..... Equation (2.6)}$$

Where:

l = Fracture spacing

Darcy's law can be expressed using equation (2.7) (Cervik, 1969).

$$Q = \frac{-kA}{\mu} \frac{dP}{L} \quad \text{..... Equation (2.7)}$$

Where:

Q = Gas flow rate

k = Fracture permeability

A = Cross-sectional area

μ = Viscosity of gas

P = Pressure drop

L = the length over which the pressure drop is taking place

Figure 2.6: Gas and water production curve of a CBM reservoir (Huy et al, 2010)

Figure 2.7: Gas transport steps in coal seams

2.5 – Carbon sequestration in coal seams and enhanced coalbed methane recovery

Carbon sequestration is the process of storing compressed carbon dioxide (CO_2) in underground formations, such as oceans, deep saline aquifers, and unmineable or depleted coal seams. Geologic sequestration in unmineable or depleted coal seams is considered a promising option for long time periods of CO_2 storage, resulting in less greenhouse gas emissions (Brochard et al, 2012; He et al, 2013). These coal seams are considered unmineable for reasons such as poor quality, extreme depths, and unhelpful geology (e.g., steeply dipping) thus, mining is considered economically unfeasible in such cases (Bromhal et al, 2005; Winschel and Scandrol, 2007).

Generally, conventional CBM production technology recovers around 50% of CBM and leaves the remainder behind (Sams et al, 2002; John and Paul, 2009; Stevens et al, 1998; Odusote et al, 2004). CO_2 injection into coal seams provides a dual-benefit of not only CO_2 storage, but also enhanced gas production. CO_2 provides a great affinity towards coal, which is about twice that of methane (Chhajed, 2011; He et al, 2013). For that reason, when carbon dioxide is injected into a coal reservoir, the micropores of the coal desorb the existing methane and adsorb the injected carbon dioxide. This process is known as enhanced coalbed methane recovery (ECBM)

(White et al, 2005; Siriwardane et al, 2012; Harpalani and Chen, 1997; He et al, 2013). Figure 2.8 illustrates the enhanced gas recovery process. The injected CO_2 may cause the coal to swell, and as a result the coal fracture permeability may decrease, influencing CO_2 injectivity (Siriwardane et al, 2009; Harpalani and Chen, 1997; Ross, 2007; Bromhal et al, 2005 Shi and Durucan, 2005).

Figure 2.8: Carbon sequestration in coal/ Enhanced coalbed methane recovery

Some previous published literature (White et al, 2005; Siriwardane et al, 2012; Bajura et al, 2011; He et al, 2013; Bromhal et al., 2003; Mavor et al., 2002; Shi and Durucan, 2005; Ozdemir, 2009; Wang et al, 2007; Gu, 2009; Bachu, 1999) have addressed some other aspects related to CBM production and CO_2 sequestration in coal seams.

2.6 – Langmuir isotherm

Coals are known for their significant capacity to adsorb gases (Bachu et al, 2007). The molecules of the gas become attached to the internal surface of the coal by adsorption, which makes it different from absorption where a substance becomes trapped inside another (Mazzotti

et al, 2009; Ripepi, 2009). The Langmuir adsorption isotherm assumes that the gas is adhered to the coal and covers the internal surface as a single layer (Mazzotti et al, 2009; Ripepi, 2009; He et al, 2013). It also assumes that the gas stored in coal by adsorption could be present in a condensed, near liquid state. That allows a greater volume of gas to be stored by adsorption than by compression at low pressure (Mazzotti et al, 2009; Ripepi, 2009; He et al, 2013).

The Langmuir isotherm was developed by Irving Langmuir in 1916 to represent the relationship between pressure and gas storage capacity. It illustrates how the volume of a gas changes with the pressure in the formation (Langmuir, 1918). Figure 2.9 shows a typical Langmuir isotherm curve. The figure also shows the maximum amount of gas which exists in coal at stability conditions, Langmuir volume (VL), and Langmuir pressure (PL). VL is known as the maximum gas volume that can be adsorbed on a section of coal at infinite pressure. Langmuir pressure (PL) can be defined as the pressure at which half of the Langmuir volume (VL) is adsorbed. Equation (2.8) shows the typical formulation of Langmuir isotherm. It illustrates the relationship between gas content, pressure, Langmuir volume and Langmuir pressure (Mazzotti et al, 2009; Ripepi, 2009; Rogers, 1994; Langmuir, 1918; Aminian, 2003; He et al, 2013).

$$G_C = \frac{V_L P}{P_L + P} \quad \text{..... Equation (2.8)}$$

Where:

G_C = Gas amount (gas content) at P

V_L = Langmuir volume

P_L = Langmuir pressure

P = Reservoir pressure

Figure 2.9: A typical Langmuir isotherm curve for a coalbed reservoir

2.7 – Shrinkage and swelling of coal

Coal seams have exceptional abilities to sorb large amounts of carbon dioxide and desorb methane. Adsorption of injected CO_2 into the coal bulk matrix is known to induce a differential swelling of coal. On the other hand, when a gas, such as methane, is released from the coal matrix, coal tends to shrink (Siriwardane et al, 2009; Harpalani and Chen, 1997; Ross, 2007; Bromhal et al, 2005; Shi and Durucan, 2005). It has been reported in several published papers that shrinkage and swelling of coal has a significant impact on the permeability of the coal cleats, which makes this issue critical to CO_2 sequestration in coal seams (Brochard et al, 2012; Siriwardane et al, 2006; Siriwardane et al, 2009; Harpalani and Chen, 1997; Ross, 2007; Bromhal et al, 2005; Shi and Durucan, 2005). The performance of coal reservoirs is influenced by the change of coal cleats permeability (Siriwardane et al, 2009; Bromhal et al, 2005; Shi and Durucan, 2005).

Gas production from coal seams causes the reservoir pressure to decline, and increases the effective rock stresses. Thus, the reservoir permeability will decrease as a result of high rock compressibility. At the same time, the extracted coalbed methane causes the coal matrix to shrink and the cleats to open-up, increasing the permeability (Ross, 2007; Siriwardane et al, 2009; Shi and Durucan, 2005; Harpalani and Chen, 1997; He et al, 2013). That means as gas production from a coal seam begins, compressibility affects permeability in early time, and shrinkage causes the coal permeability to increase in later time. These two actions will induce the permeability change in opposite ways (He et al, 2013). On the other hand, reservoir permeability tends to decline when a gas, such as CO₂, is injected into the coal reservoir. This is due to the swelling of the coal bulk matrix, which usually narrows the coal fractures (Ross, 2007; Brochard et al, 2012; Siriwardane et al, 2009; Chikatamarla et al, 2004; Ripepi, 2009). Figure 2.10 illustrates how the coal shrinkage/ swelling effects on the fracture network. In previous literature, there are simulation studies (Balan and Gumrah, 2008; Siriwardane et al, 2009; Shi and Durucan, 2005; Harpalani, 2005; Harpalani and Chen, 1997; Siriwardane et al, 2006; Siriwardane et al, 2009; Harpalani and Schraufnagel, 1990; Pekot and Reeves, 2003) investigating the effects of swelling and shrinkage of coalbed reservoirs on the permeability and hence on the performance of these reservoirs.

Figure 2.10: Swelling and shrinkage of coal formation

2.8 – Previous studies

Several previous modeling studies have been performed successfully to model coalbed methane production and carbon dioxide injection, and to assess the performance of coal reservoirs during CO₂ injection (Sams et al, 2002; Siriwardane et al, 2012; Bajura et al, 2011, He et al, 2013; Bromhal et al, 2003; Mavor et al, 2002; Shi and Durucan, 2005; White et al, 2005; Ozdemir, 2009; Wang et al, 2007; Bachu, 1999). Different numerical simulators were used at different pilot studies. Some of these studies are discussed briefly in this section.

Sams et al. (2002) used PSU-COALCOMP (Manik et al, 2002), which is a compositional coalbed methane reservoir simulator, to perform a hypothetical pilot-scale project. Some important design parameters, such as well pressures and well lengths were considered to investigate the effects of these parameters on the reservoir performance. The model consists of four horizontal production wells that form a square pattern, and four horizontal injection wells at the center at the square pattern. Similar well configurations were used in the lower coal seam of our study presented in this paper. It was observed that the reservoir pressure dropped significantly during coalbed methane production. The injection of CO₂ was initiated when the reservoir was depleted and the reservoir pressure was significantly low. Results from this study show that length of injection wells have a significant impact on the injection volumes, and high injection pressures could result in early breakthrough of CO₂.

A similar project was conducted by Odusote et al. (2004) by using the same coalbed methane reservoir simulator, PSU-COALCOMP (Manik et al, 2002), to perform an enhanced CBM recovery study. The project was also performed to study the sequestration of carbon dioxide (CO₂) in unmineable coal seams and investigate the effects of some coal reservoir properties and design parameters on the performance of the reservoir. Moreover, the modeling study also shows a comparison between diagonally placed horizontal injection wells and plus-shaped horizontal injection wells to evaluate the effect of the injection wells configuration on CBM recovery and the amount of the sequestered CO₂. Similar injection well configuration

(plus-shaped) was assumed in the lower coal seam of our study. All the properties that have been used in the study can be found elsewhere (Odusote et al, 2004). The results of the study drew the following conclusions:

- When carbon dioxide (CO₂) is injected into a coal reservoir, the coal matrix can desorb the existing CBM within the swept area, and adsorb the injected CO₂.
- An increase in the porosity of the reservoir would increase the amount of free gas in place.
- An increase in the reservoir permeability would increase the CBM recovery, but with shorter breakthrough time.
- Smaller cleat spacing results in an increase in the production rate.
- A high initial reservoir pressure results in higher methane recovery. That is because of the increase in the gas content associated with the high reservoir pressure.
- The amount of the sequestered CO₂ increases as the length of the injectors increase.
- A better sweep of the reservoir and more enhancement of CBM can be provided by using diagonally placed horizontal injectors.

A mathematical model was developed by Ozdemir (2009) in order to predict the amount of CO₂ that can be injected into a candidate coal reservoir, the period of time that the injection process would consume, coal swelling/shrinkage effects, and the CO₂ injection rate. For modeling purposes, the reservoir thickness was assumed to be constant. All the properties that have used in this study can be found elsewhere (Ozdemir, 2009). Coal swelling and shrinkage effects on the performance of the reservoir were considered in our current study, and the thickness of the reservoir was assumed to be constant also. The most important conclusions of this study were:

- The primary CBM production would leave most of the in-situ water and CBM behind.
- The injected CO₂ has the ability of pushing the water of the cleat network and replacing the adsorbed methane.
- CO₂ adsorption results in coal matrix swelling.

- When CO₂ is injected into the coalbed methane reservoir, an alteration in the injection rate was observed, which could be related to coal matrix swelling and shrinkage.

In order to simulate the primary and enhanced (using carbon dioxide injection) coalbed methane production, a real sequestration project was conducted in the Marshall County, West Virginia by He et al (2013). The model was developed by using the Computer Modeling Group's GEM (Generalized Equation-of-State Model) simulator (CMG, 2012). The numerical model of our current study was constructed by using the same numerical simulator GEM (CMG, 2012). The study also provided a numerical modeling and a sensitivity analysis to predict the influence of some important reservoir parameters (such as cleat permeability, cleat porosity, CO₂ adsorption time, and the Palmer and Mansoori parameters) on the performance of the reservoir (Palmer and Mansoori 1996). In order to simulate the changes in the reservoir permeability, the Palmer and Mansoori model was used. In our current reservoir model, coal swelling/shrinkage and permeability changes during methane production were also modeled by using the Palmer and Mansoori model (Palmer and Mansoori, 1996; CMG, 2012). All the data that have been used in this study can be found elsewhere (He et al, 2013). In addition, history matching was conducted to show the initial and current condition of the reservoir. The results of the study can be listed as follows:

- The sensitivity analysis showed that coal sorption time, cleat permeability, and Langmuir parameters are the most effective properties during CBM production and CO₂ injection.
- The total reservoir sequestration capacity was estimated to be about 22,817 tons excluding the free gas part.
- During the first three years of the CO₂ injection period, the total CO₂ injected was about 2,600 tons.
- CBM production and CO₂ injection results in matrix shrinkage and swelling, respectively.

In order to simulate a pilot sequestration site located in the San Juan coal basin of northern New Mexico, a three dimensional dual porosity model was developed using the coalbed methane simulator PSU-COALCOMP (Manik et al, 2002). In addition, a tracer modeling study was developed to investigate the potential leakage of CO₂. The model was developed using some estimated properties. The site contained 63 wells and the production was considered for 30 years. An injection well was developed later at the center of the site, and around 18,000 tons of CO₂ were injected into the coal seam which was located at a depth of 3000 feet. The results of the study showed a successful potential option for long term geologic storage of CO₂ into the Pump Canyon reservoir. Moreover, results showed that tracer modeling is a very useful tool to study and investigate the movements of the injected CO₂ into the coal seam. More details about the study can be found elsewhere (Siriwardane et al, 2012).

Chapter 3 : NUMERICAL METHODOLOGY

3.1 – Mathematical details of permeability changes

Fluid flow in coal seams takes place through the cleat fracture network according to Darcy's law. The cleat permeability is not a constant but changes with net overburden pressure (Palmer and Manosoori 1996; Brochard et al, 2012). Coal swelling and shrinkage also influence the permeability changes during production and injection operations (Palmer and Manosoori, 1996; CMG, 2012; Brochard et al, 2012; Harpalani et al, 2006). Gas production from coal reservoirs causes the reservoir pressure to drop and increase the effective rock stresses. Thus, the reservoir permeability will decrease as a result of high rock compressibility. At the same time, the produced coalbed methane (CBM) causes the coal matrix to shrink and the cleats to open-up increasing the reservoir permeability (Palmer and Manosoori, 1996; Siriwardane et al, 2009; Shi and Durucan, 2005; Harpalani and Chen, 1997; He et al, 2013). Palmer and Mansoori (1996) have developed a theoretical model for stress-dependent permeability. The Palmer and Mansoori model also considers the coal matrix swelling and shrinkage effects on permeability (Palmer and Manosoori, 1996; Balan and Gumrah, 2008; CMG, 2012). The theoretical model calculates the changes in porosity and permeability as a function of changes in cleats pressure and matrix swelling and shrinkage strain. Equation (3.1) shows the calculation for the swelling and shrinkage strain of coal matrix. Equation (3.2) shows the original Palmer and Mansoori relationship, which was used in their theoretical model. Equation (3.3) shows the extended Palmer and Mansoori relationship, which can be used when a reservoir contains a mixture of fluids (Palmer and Mansoori, 1996; Mavor and Vaughn, 1998). In the current research work, the permeability changes due to swelling and shrinkage are accounted using the extended Palmer and Mansoori model as shown in Equation (3.3) (Palmer and Manosoori, 1996; Mavor and Vaughn, 1998).

$$\varepsilon = \frac{\varepsilon_{\infty} P}{P_{\circ} + P_{\varepsilon}} \quad \text{..... Equation (3.1)}$$

Where:

ε = Matrix shrinkage and swelling strain

ε_{∞} = Strain at infinite pressure

P_{ε} = Pressure at strain of 0.5 ε_{∞}

P = Current reservoir pressure

$P_{\circ}$ = Initial reservoir pressure

$$\frac{\phi}{\phi_{\circ}} = 1 + \frac{c_m}{\phi_{\circ}} (P - P_i) + \frac{c_{\circ}}{\phi_{\circ}} \left[\frac{k}{M} - 1 \right] \left[\frac{bP}{1 + bP} - \frac{bP_i}{1 + bP_i} \right]$$

..... Equation (3.2)

Where:

$\phi_{\circ}$ = Initial porosity

ϕ = Final porosity

c_m = Compressibility of coal matrix

P_i = Original reservoir pressure

P = Reservoir pressure

b, c_0 = Langmuir parameter to volumetric shrinkage

k = Bulk modulus of coal

M = Constrained axial modulus

$$\frac{\phi}{\phi_{ref}} = \exp \left[c_f (p - p_i) \right] + \frac{1}{\phi_{ref}} \left(1 - \frac{K}{M} \right) \times \left[\sum_{j=1}^n \frac{\varepsilon_{Lj} y_{ref,j} p_{ref} / p_{Lj}}{1 + p_{ref} \sum_{k=1}^n y_{ref,k} / p_{Lk}} - \sum_{j=1}^n \frac{\varepsilon_{Lj} y_j p / p_{Lj}}{1 + p \sum_{k=1}^n y_k / p_{Lk}} \right]$$

..... Equation (3.3)

Where:

ϕ_{ref} , ϕ_i = Initial porosity

ϕ = Final porosity

c_f = Fracture pore volume compressibility (Equation (3.5))

c_m = Compressibility or compliance of coal matrix (Equation (3.7))

P_{ref} = Reference state reservoir pressure; P = Reservoir pressure

ε_{Lj} , ε_{LK} = Strain at infinite pressure, component j/ component k

K = Bulk modulus of coal

M = Constrained axial modulus (Equation (3.6))

P_{Lj} , P_{LK} = Langmuir pressure, component j/ component k

n = Adsorption components number

$y_{ref,j}$, $y_{ref,k}$ = Composition at reference conditions, component j/ component k

y_j , y_k = Gas mixture composition, component j/ component k

$\exp$ = Exponential function with base ($e \approx 2.71828$)

The ratio of bulk to axial modulus can be calculated using Equation (3.4) (Palmer and Manosoori, 1996).

$$\frac{K}{M} = \frac{1}{3} \left(\frac{1 + \nu}{1 - \nu} \right) \quad \text{..... Equation (3.4)}$$

and

$$c_f = \frac{1}{\phi_i M} \quad \text{..... Equation (3.5)}$$

$$M = E \frac{(1 - \nu)}{(1 + \nu)(1 - 2\nu)} \quad \text{..... Equation (3.6)}$$

$$c_m = \frac{1}{M} - \left(\frac{K}{M} + f - 1 \right) \quad \text{..... Equation (3.7)}$$

Where:

ν = Poisson's ratio

E = Young's modulus

f = A fraction, usually between 0 to 1

Equation (3.8) shows the relationship between cleat porosity and the reservoir permeability according to the Palmer and Mansoori theory (Palmer and Mansoori, 1998).

$$k = k_i \left(\frac{\phi}{\phi_i} \right)^3 \quad \text{..... Equation (3.8)}$$

Where:

k_i = Initial reference permeability

k = Final permeability

ϕ_i = Initial reference porosity

ϕ = Final porosity

3.2 – Mathematical details of storage capacity of coal seams

Coal is known for its significant potential to adsorb CO₂ and store them on its surface or within its porous structure (White et al, 2005). Estimates of coal seam capacity are considered important and necessary to characterize and evaluate CO₂ sequestration potential (Bachu et al, 2007). Shown below are Equations (3.9) and (3.10), which provide the relationships, used to calculate the reservoir storage capacity. More details on storage capacity calculations can be found elsewhere (He et al, 2013; Gondle, 2010).

$$IGIP = \frac{V_L P}{P_L + P} [Ah\rho] \quad \text{..... Equation (3.9)}$$

$$\text{Gas storage capacity} = IGIP \times S_E \quad \text{..... Equation (3.10)}$$

Where:

IGIP = Initial gas in place

A = Area of the coal

h = Effective thickness of the coal

P = Pressure

V_L = Langmuir volume

P_L = Langmuir pressure

ρ = Density of coal

S_E = CO₂ storage efficiency factor

3.3 – Mathematical details of geomechanical modeling

In term of effective stress, according to Yang et al (2011) and Wu et al (2011), the stress equilibrium equation can be written as:

$$\sigma + f = 0 \quad \text{..... Equation (3.12)}$$

Where:

σ = Total stress

f = Stress induced by the body forces per unit volume

The total stress can be related to the effective stress as shown by Equation (3.13) on the basis of Terzagi's effective stress principle (Yang et al, 2011).

$$\sigma = \sigma' + \alpha \times p \times \delta \quad \text{..... Equation (3.13)}$$

Where:

σ = Total stress

σ' = The solid phase effective stress

α = Positive constant

p = Pressure

δ = The Kronecker delta function

The substitution of Equations (3.13) into Equation (3.12) results in Equation (3.14) as shown below

$$\sigma' + f + (\alpha \times p \times \delta) = 0 \quad \text{..... Equation (3.14)}$$

The constitutive relation for the deformable dual porosity coal seam which accounts for the influences of pore pressure and strain induced by sorption is expressed by Equations (3.15) and (3.16) (Liu et al 2011; Yang et al, 2011; Wu et al, 2011; Cui and Bustin, 2005; Connell, 2009).

$$\epsilon_{ij} = \frac{1}{2G} \sigma_{ij} - \left(\frac{1}{6G} + \frac{1}{9K} \right) \sigma_{kk} \delta_{ij} + \left(\frac{\alpha}{3K} \right) p_m \delta_{ij} + \left(\frac{\beta}{3a.Kn} \right) p_f \delta_{ij} + \left(\frac{\epsilon_s}{3} \right) \delta_{ij}$$

..... Equation (3.15)

Where:

σ_{ij} = Stress tensor

ϵ_{ij} = Strain tensor

E = Young's modulus of coal

ν = Poisson's ratio of coal

δ_{ij} = The Kronecker delta function with 1 for $i=j$ and 0 for $i \neq j$

p_m, p_f = Total pressure in the matrix and fracture respectively

K= Bulk modulus of coal (can be calculated using equation (3. 17))

G = Shear modulus (can be calculated using equation (3. 18))

α, β = Boit's coefficients (can be calculated using equation (3. 19) and (3. 20), respectively)

ϵ_s = The sorption-induced volumetric strain

Kn = Stiffness of coal fracture

$$\sigma_{ij} = \frac{E}{1+\nu} \left(\epsilon_{ij} + \frac{\nu}{1-2\nu} \epsilon_b \delta_{ij} \right) + \beta p \delta_{ij} + K \epsilon_v \delta_{ij} \quad \text{..... Equation (3.16)}$$

Where:

σ_{ij} = Stress tensor

ϵ_{ij} = Strain tensor

E= Young's modulus

ν = Poisson's ratio

ϵ_v =Volumetric strain induced by sorption

ϵ_b = Bulk volumetric strain

β =Boit's coefficient

K= Bulk modulus

$$K = \frac{E}{3(1-2\nu)} \quad \text{..... Equation (3.17)}$$

$$G = \frac{E}{2(1+\nu)} \quad \text{..... Equation (3.18)}$$

$$\alpha = 1 - \frac{K}{K_S} \quad \text{..... Equation (3.19)}$$

$$\beta = 1 - \frac{K}{K_n \cdot a} \quad \text{..... Equation (3.20)}$$

Where:

K_S = Bulk modulus of coal grains

K_n = Stiffness of coal fracture

3.4 – Numerical modeling objectives

In the current research work, coupled multiphase fluid flow and deformation analyses were performed to investigate CO₂ transport behavior and ground response during CO₂ injection. Different injection scenarios were considered based on well configurations proposed in pilot studies and demonstrated sequestration projects reported in published literature (Sams et al, 2002; Wilson et al, 2009; Bromhal et al, 2005; Winschel et al, 2011; Odusote et al, 2004; Huy et al, 2010). A hypothetical permeable pathway connecting two coal seams was assumed to evaluate CO₂ flow behavior, when such a fracture exists. In brief, the research objectives of the current modeling work can be seen below:

- Investigate CO₂ migration in the reservoir due to different well configurations.
- Investigate geomechanical responses, such as ground displacements, due to different well configurations.
- Investigate the migration of CO₂ in the reservoir and overburden layers in the presence of a hypothetical permeable fractured zone in the overburden caprock layer.
- Investigate different carbon dioxide (CO₂) leakage scenarios and compute the amount of leakage when different well configurations were selected.

- Evaluate enhanced coalbed methane recovery (ECBM) from the lower and the upper coal seams due to CO₂ injection into the lower coal seam, with and without the presence of a fractured zone in the sandwich layer.
- Investigate whether a coal layer above the target coal reservoir could act as a carbon dioxide (CO₂) barrier, if CO₂ leaks through a permeable fracture in the impervious seal layer.

In order to achieve our objectives of this study, a hypothetical, three-dimensional, two-phase (gas–water) model was used. The numerical model was constructed by using Computer Modeling Group's GEM (Generalized Equation-of-State Model) simulator, which is commercially available software (CMG, 2012). GEM is capable of simulating dual porosity, multiphase flow, diffusion and adsorption of mixed gas, stress-dependent permeability, and coal shrinkage and swelling (David et al, 2002). The model is capable of handling any changes in the reservoir pressure or permeability during fluids production and injection. The simulator is also capable of modeling reservoir performances under primary and/or enhanced recovery. Figure 3.1 shows the flow chart of different well configurations and different modeling schemes considered in this study. More details about each modeling step are presented in the subsequent chapters.

Figure 3.1: Case studies

Chapter 4 : RESERVOIR MODELING

4.1 – Reservoir geometry and properties

Figure 4.1 shows a schematic diagram of the different layers considered in the modeling study. The model consists of five layers: overburden, upper coal seam, sandwich layer, lower coal seam, and underburden. The assumed thickness of each layer is shown in the figure. Each coal seam was assumed to be 6 feet thick, and they are separated by 600 feet, which represents the sandwich layer. It was assumed that both coal seams are overlain by an impermeable overburden layer. The upper coal seam is located at a depth of 850 feet, and the lower coal seam is located at a depth of approximately 1,456 feet from the ground surface. The underburden rock was assumed to be 3,000 feet thick. Figure 4.2 shows the geometry of the model used in the current study. This model covers an area of $10,560 \times 10,560$ square feet (2 Miles $\times$ 2 Miles). The overburden, sandwich layer, and underburden layers were subdivided into different layers, as shown in Figure 4.2. Grid block configuration of $60 \times 60 \times 12$ was used in the X, Y, and Z directions, respectively. A grid block dimension of 176 feet was used in the X and Y directions. The grid block dimensions in the Z direction were variable based on the thicknesses of each layer. Table 4.1 shows the reservoir properties used in the study. Table 4.2 shows ranges of some properties that have been reported in the literature. Table 4.3 shows some properties of the five layers of the model.

The initial pressures of the upper and lower coal seams were calculated to be 372.9 psi and 627.45 psi, respectively, by assuming a pressure gradient of 0.42 psi/foot. Reservoir properties were assumed based on the literature. Some previous studies (Bajura et al., 2011; Gu, 2009; Bromhal et al., 2005; Bromhal et al., 2003; Rushing et al., 2008; Karacan and Goodman, 2008; Ross, 2007) have shown that cleat spacing ranges between 0.02 feet and 0.3 feet. Based on this range, the cleat spacing of the two coal seams in the current study was assumed to be 0.3 feet in the I, J, and K directions. The permeability of the upper and the lower coal seams were assumed to be 25 mD and 1 mD, respectively. It is believed that deep coal seams have low cleat permeability compared to shallow coal seams; this is because of the increase in effective stress

with depth (Cui and Bustin, 2005). Therefore, the permeability of the upper coal seam was assumed to be 25 times higher than the permeability value of the lower coal seam. Generally, coalbed methane, which can be found in the coal matrix, is considered immobile because the coal seam cleat networks are often saturated with water (Sams et al., 2002). For that reason, the initial water saturation of 90% was assumed in the current research work. Swelling and shrinkage of coal was modeled using the extended Palmer and Mansoori equation, as shown in Equation (3.3). Some important assumptions made in the current research work are summarized below. Similar assumptions were reported in the literature (Balan and Gumrah, 2008).

- All the layers of the model were assumed to be fully saturated with water except coal layers. The initial water saturation of each coal layer was assumed to be 90%.
- Negligible free gas-in-place.
- There is no water in the coal matrix; water is present in the cleat network of the two coal layers.
- Isotropic cleat permeability.
- Swelling and shrinkage constants were assumed to be the same.
- Diffusion controls CBM transportation from the coal matrix to the cleats.
- Cleats spacing are uniformly distributed throughout the reservoir.

Figure 4.1: A schematic diagram shows the thickness of the model layers

Figure 4.2: Model geometry

Table 4.1: Reservoir properties

Input Data	Upper Coal Seam	Lower Coal Seam
Reservoir area (feet* feet)	10,560* 10,560	10,560* 10,560
Grid (I, J)	60, 60	60, 60
Individual Grid Block Size (feet)	176	176
Thickness (feet)	6	6
Depth (feet)	850	1,456
Cleat Spacing (feet)	0.3	0.3
Matrix porosity	0.01	0.01
Cleat Porosity	0.01	0.01
Matrix permeability (mD)	0.1	0.1
Cleat permeability (mD)	25	1
Coal Density (pcf)	89	89
Coal Compressibility (1/psi)	1.00E-06	1.00E-06
Temperature (F)	80	80
Reservoir Pressure (psi)	372.9	627.4
Water Saturation	0.9	0.9
Water Viscosity (cp)	0.7	0.7
Water Density (pcf)	62.47	62.47
Gas Composition, % (CH₄, CO₂)	(100, 0)	(100, 0)
Coal desorption time (day)	1	1

Table 4.1: Reservoir properties (Continued)

Input Data	Upper Coal Seam	Lower Coal Seam
Initial gas content (SCF/ton)	226	290.6
Implicit flag	3	3
Langmuir Parameters for CH₄ (V_L, P_L)	(500 SCF/ton, 452 psi)	(500 SCF/ton, 452 psi)
Langmuir Parameters for CO₂ (V_L, P_L)	(1000 SCF/ton, 239.9 psi)	(1000 SCF /ton, 239.9 psi)
Strain at infinite pressure for CO₂	0.01266	0.01266
Strain at infinite pressure for CH₄	0.01266	0.01266

Table 4.2: Reservoir properties from literature

Input Data	Range	References
Reservoir area (feet* feet)	(360*360) – (15000*15000)	42, 11, 13, 83, 84, 94,111
Grid (I, J)	(7*7) – (100*100)	42, 59, 84, 92, 94
Individual Grid Block Size (feet)	365 -765	92
Thickness (feet)	2 - 60	11, 13, 35, 42, 47, 81, 83, 84, 86
Depth (feet)	669 - 3280	12, 35, 42, 81, 83, 94
Cleat Spacing (feet)	0.02 – 0.3	11, 13, 35, 46, 80, 9
Matrix porosity	0.001 – 0.25	22, 31, 35, 46, 69, 74, 81
Cleat Porosity	0.001 - 0.1	12, 13, 31, 35, 81, 84, 94
Matrix permeability	0.01- 0.1	23, 35, 47, 83, 94, 111
Cleat permeability	1 - 50	11, 12, 13, 22, 31, 81, 84, 86
Coal Density (pcf)	81.2 -111	46, 58, 72, 81, 92
Coal Compressibility (1/psi)	1.00E-05	81
Poisson's Ratio	0.1 -0.35	31, 46, 59, 81, 86
Elastic Modulus (psi)	125000 – 600,000	31, 46, 59, 81, 86
Temperature (F)	61.52 - 126	11, 13, 31, 35, 48, 81, 83, 84, 86, 94
Reservoir Pressure (psi)	221.6 -7500	11, 12, 13, 22, 23, 31, 35, 46, 47, 81, 83, 86, 92
Water Saturation (%)	0.65 - 1	22, 35, 81
Water Viscosity (cp)	0.7	92
Water Density (pcf)	62.4	68, 72, 92
Number of coal seams	1 - 2	12, 15, 31, 84

Table 4.2: Reservoir properties from literature (Continued)

Gas Composition, % (CH₄, CO₂)	(90,10) – (100,0)	31, 83, 92
Coal desorption time (day)	1 - 13	84, 92
Langmuir Parameters for CH₄ (V_L, P_L)	(259.5, 350.8) – (652, 110.2)	42, 46, 68, 81, 86, 111
Langmuir Parameters for CO₂ (V_L, P_L)	(550.1, 179.8) – (1499.1, 412)	42, 46, 69, 81, 86, 111
Strain at infinite pressure for CO₂ (SCF/ton)	0.003 to 0.01	24, 39, 51, 62, 77
Strain at infinite pressure for CH₄ (SCF/ton)	0.003 to 0.034	24, 39, 51, 62, 77

Table 4.3: Assumed properties of five layers

Layer	Thickness (feet)	Cleat Spacing (feet)	Matrix perm. (mD)	Cleat perm. (mD)	Matrix pro.	Cleat pro.
Overburden	850	0.01	0.0001	0.0001	0.1	0.1
Upper Coal Seam	6	0.3	0.1	25	0.01	0.01
Sandwich layer	600	0.01	0.0001	0.0001	0.1	0.1
Lower Coal Seam	6	0.3	0.1	1	0.01	0.01
Underburden	3000	0.01	0.0001	0.0001	0.1	0.1

4.2 – Production and injection operations

In the current study, coalbed methane was produced from both coal seams (upper and lower) for 21 years. Different well configurations were selected with the use of vertical or horizontal wells. The injection was carried out only in the lower coal seam when it was depleted. The injection of CO₂ was carried out with an injection pressure of 1,000 psi for 10 years in all the case studies described in this report. More details about production and injection operations are presented in the following sections.

4.3 – Well configuration

Different well configurations, (horizontal or vertical) which have been used in previous pilot studies and demonstration projects, can be found described in detail in the literature (Sams et al, 2002; Wilson et al, 2009; Bromhal et al, 2005; Winschel et al, 2011; Odusote et al, 2004; Huy et al, 2010). Details of the well configurations used in the current study are given below:

4.3.1 – Horizontal well configuration

Several demonstration and commercial-scale projects were performed by various research teams to evaluate carbon dioxide storage using horizontal wells (Sams et al, 2002; Wilson et al, 2009; Bromhal et al, 2005). Horizontal drilling has been known since 1927, but it did not become a common practice in the oil and gas industry until 1980 (Joshi, 2003). The increase in productivity is considered the main objective of using horizontal wells (Sams et al, 2002). Some of the benefits of using horizontal wells over vertical wells are listed below (Al Haddad and Crafton, 1991; Joshi, 2003; Joshi, 1994):

- **Thin reservoir layers** - A horizontal well is usually able to cover a much wider contact area of a thin reservoir layer, because it drills through the length of the reservoir, while drilling a vertical well in the same reservoir will result in a very small contact surface.
- **Productivity** - Horizontal wells have greater productivity than vertical wells, because they are capable of accessing the natural gas or oil surrounding the entire section of the

horizontal path, while vertical wells are able to access hydrocarbons that surround the vertical portion of the well only.

- **Low permeability reservoirs** - Horizontal wells can enhance the drainage area in low permeability reservoirs because they can cover wider contact area compared to vertical wells.
- **High permeability reservoirs** - During production from high permeability reservoirs, some turbulence could occur near the wellbore. Using horizontal wells in such reservoirs can reduce these turbulences.
- **Heterogeneous reservoirs** - Horizontally drilled wells can access the isolated oil and gas accumulations in heterogeneous reservoirs, while vertically drilled wells have the ability of accessing hydrocarbon accumulations which lie below the tip of the well only.

In the current study, simulation of coalbed methane production was carried out in both coal seams (upper and lower), and CO₂ injection was carried out only in the lower coal seam. The well configuration assumed in both coal seams is different, and Figure 4.3 shows the well configuration used for each coal layer. Four horizontal production wells (UCPW-1, UCPW-2, UCPW-3, and UCPW-4) were completed in the upper coal seam, forming a square pattern. Each of these horizontal production wells is about 3,500 feet long, as shown in Figure 4.3. Four horizontal production wells (LCPW-1, LCPW-2, LCPW-3, and LCPW-4) forming a square pattern on the periphery, and the legs of two central productions wells (LCPW-5 and LCPW-6) forming a 'plus-shaped' well pattern at the center of the modeling area, were completed in the lower coal seam. The wells in the outer periphery are 3,500 feet long, and the central wells are 880 feet long. After five years of primary production of coalbed methane from all the wells, the central production wells (LCPW-5 and LCPW-6) were ceased for one year and then converted to injection wells (LCIW-1 and LCIW-2). A similar 'plus-shaped' well configuration was used for CO₂ injection in different studies reported in the literature (Sams et al, 2002; Wilson et al, 2009; Bromhal et al, 2005; Winschel et al, 2011; Odusote et al, 2004). While the CBM production was continued from all the wells in both coal layers, CO₂ injection was carried out for 10 years by assuming an injection pressure of 1,000 psi. Figure 4.4 shows a schematic diagram of production and injection operations in both coal seams (upper and lower). Figure 4.5 shows the well

configuration in the model geometry. Figure 4.6 shows a plan view of the well configurations assumed in the upper and the lower coal layers.

Note:

- Production wells of the upper coal seam – UCPW-1, UCPW-2, UCPW-3, and UCPW-4.
- Production wells of the lower coal seam – LCPW-1, LCPW-2, LCPW-3, and LCPW-4, LCPW-5, and LCPW-6
- Injection wells of the lower coal seam - LCIW-1 and LCIW-2

Figure 4.3: Well configurations assumed in the upper (a) and the lower (b) coal seams

Figure 4.4: A Schematic diagram of production and injection operations in both coal layers (upper and lower)

Note:

- Production wells of the upper coal seam – UCPW-1, UCPW-2, UCPW-3, and UCPW-4.
- Production wells of the lower coal seam – LCPW-1, LCPW-2, LCPW-3, and LCPW-4, LCPW-5, and LCPW-6
- Injection wells of the lower coal seam - LCIW-1 and LCIW-2

Figure 4.5: Well configurations used in the model

Figure 4.6: Plan view of well configurations assumed in the upper (a) and the lower (b) coal layers

4.3.2 – Vertical well configurations

Coalbed methane production was carried out in both coal seams (upper and lower), and CO₂ injection was carried out only in the lower coal seam. The well configuration assumed in both coal seams is different, and Figure 4.7 shows the well configuration used in each coal layer. Four vertical production wells (UCPW-1, UCPW-2, UCPW-3, and UCPW-4) were completed in the upper coal seam. The well spacing was assumed to be 3,500 feet, as shown in Figure 4.7. Five vertical production wells (LCPW-1, LCPW-2, LCPW-3, LCPW-4, and LCPW-5) forming a five-spot pattern were completed in the lower coal seam. The well spacing was assumed to be 3,500 feet for outer wells, and 1,584 feet between the outer wells and the central well. After 5 years of primary production of coalbed methane from all the wells, the central production well (LCPW-5) was ceased for one year and then converted to an injection well (LCIW). A similar five-spot pattern was used for CO₂ injection in studies reported in the literature (Huy et al, 2010). While CBM production was continued from all the wells in both coal layers, CO₂ injection was carried out for 10 years by assuming an injection pressure of 1,000 psi. Figure 4.8 shows a schematic diagram of production and injection operations in both coal layers (upper and lower).

Figure 4.9 shows the well configuration in the model geometry. Figure 4.10 shows a plan view of the well configurations assumed in the upper and the lower coal layers.

Note:

- Production Wells of the upper coal seam – UCPW-1, UCPW-2, UCPW-3, and UCPW-4.
- Production Wells of the lower coal seam – LCPW-1, LCPW-2, LCPW-3, and LCPW-4, and LCPW-5
- Injection wells of the lower coal seam - LCIW

Figure 4.7: Well configurations assumed in the upper (a) and the lower (b) coal seams

Figure 4.8: Schematic diagram of production and injection operations in both coal layers (upper and lower)

Note:

- Production Wells of the upper coal seam – UCPW-1, UCPW-2, UCPW-3, and UCPW-4.
- Production Wells of the lower coal seam – LCPW-1, LCPW-2, LCPW-3, and LCPW-4, LCPW-5, and LCPW-6
- Injection wells of the lower coal seam - LCIW-1 and LCIW-2

Figure 4.9: Well configurations used in the model

Figure 4.10: Plan view of the upper coal seam well configuration (a) and the lower coal seam well configuration (b)

4.4 – Case studies for reservoir modeling

Two different case studies were considered with two different well configurations (horizontal and vertical) to evaluate the differences in primary and enhanced coalbed methane production. Figure 4.11 shows the flow chart of these cases. The first case study is intended to simulate coalbed methane production in a conventional way, and to evaluate the differences in reservoir performance when different well configurations (horizontal and vertical) are used. The second case is intended to evaluate the enhanced coalbed methane production during CO₂ injection when different well configurations (horizontal and vertical) are used. More details of each case study are presented in the subsequent sections of this report.

Figure 4.11: Reservoir modeling case studies

4.4.1 – Conventional CBM production by using horizontal wells

For the purpose of this case study, coalbed methane was produced for 21 years from both coal layers (upper and lower). The central wells (LCPW-1, LCPW-2) located in the lower coal seam were shut-in after 5 years of gas production. The time-line of the production period is shown in Figure 4.12. A horizontal well configuration as shown in Figure 4.3 was used to evaluate the reservoir performance during the primary production of coalbed methane. In this reservoir model, coal shrinkage and permeability changes during methane production were performed by using the extended Palmer and Mansoori model (Palmer and Mansoori, 1996; Mavor and Vaughn, 1998).

Figure 4.12: Assumed time-line for conventional CBM production by using horizontal wells

Figure 4.13 shows the pressure distribution in both coal seams (upper and lower) at different times during CBM production. Results from the Figure show a reduction in the reservoir pressure during gas production. In the upper coal seam, the initial reservoir pressure was reduced from 372.9 psi to 80 psi after 5 years of CBM production. The reservoir pressure was reduced from 627.5 psi to 130 psi in the lower coal seam after 5 years of CBM production at the center of the modeling area. After 21 years of CBM production, the reservoir pressure in the upper coal seam was further reduced to 45 psi, and was built up to 215 psi in the central area of the lower coal seam. This increase in the pressure of the reservoir central area in the lower coal seam was caused by the shut-in of the central production wells. Figure 4.14 shows the cumulative gas produced from each well in both coal seams (upper and lower). Figure 4.15 shows the cumulative gas produced from both coal seams (upper and lower). After 21 years of gas production, the amount of CBM produced from the upper and the lower seams were about

3.67×10^9 SCF and 1.26×10^9 SCF, respectively. The amount of coalbed methane produced from the upper coal seam is more than the lower coal seam due to the assumed higher cleat permeability of the upper coal seam (see Table 4.1 for more details).

Figure 4.13: Pressure distribution in upper (a) and the lower (b) coal seams at different times during CBM production

(a) Cumulative gas produced from all the wells in the upper coal

(b) Cumulative gas produced from all the wells in the lower coal seam

Figure 4.14: Cumulative gas produced from all the wells in the upper (a) and the lower (b) coal seams

(a) Cumulative gas produced from the upper coal seam

(b) Cumulative gas produced from the lower coal seam

Figure 4.15: Cumulative gas produced from the upper (a) and the lower (b) coal seams

Results show an increase in cleat permeability of both coal seams due to coal shrinkage during gas depletion. The permeability changes associated with coal shrinkage were computed, and variations of permeability changes with time in different blocks in the lower coal seam are shown in Figures 4.16 to 4.18. Permeability appears to increase by around 35% of the initial permeability value near the center, while it appears to increase by around 20% near the outer wells.

Figure 4.16: Permeability changes associated with coal shrinkage in block # 26, 26 in the lower coal seam

Figure 4.17: Permeability changes associated with coal shrinkage in block # 19, 19 in the lower coal seam

Figure 4.18: Permeability changes associated with coal shrinkage in block # 35, 27 in the lower coal seam

4.4.2 – Enhanced CBM production by using horizontal wells

CBM production was carried out in both the lower and upper coal seams, and CO₂ injection was carried out only in the lower coal seam to evaluate the reservoir performance during CO₂ injection and enhanced CBM production. As discussed in previous sections, the well configurations assumed in both coal seams are different, and Figure 4.3 shows the well configuration used for each coal layer. More details of the well configurations are presented in previous sections. After five years of primary production of CBM from all the wells, the central production wells (LCPW-5 and LCPW-6) were ceased for one year and then converted to two injection wells (LCIW-1 and LCIW-2). While the CBM production was continued from all wells in both coal layers, CO₂ injection was carried out in the lower coal seam for 10 years by assuming an injection pressure of 1,000 psi. The time-line of the production and injection period is shown in Figure 4.19. The changes in cleat permeability associated with coal swelling and shrinkage were also computed.

Figure 4.19: Time-line of the enhanced CBM production case

Figure 4.20 shows the reservoir pressure distribution due to CBM production and CO₂ injection at different times during the project life. During the first five years of gas depletion, a decrease in the reservoir pressure was noticed. In the upper coal seam, the initial reservoir pressure was reduced from 372.9 psi to 80 psi after 5 years of CBM production. The reservoir pressure was reduced from 627.5 psi to 130 psi in the lower coal seam after 5 years of CBM production at the center of the modeling area. The central production wells (LCPW-5 and LCPW-6) were closed for one year and then converted to two injection wells (LCIW-1 and LCIW-2). After 10 years of injection, about 62,800 short tons of CO₂ were injected at an injection pressure of 1,000 psi. During CO₂ injection, an increase in the reservoir pressure was

noticed along and around the legs of the two injection wells (LCIW-1 and LCIW-2), located at the center of the modeling area. The reservoir pressure increased from 130 psi to 962 psi around the central injection wells due to CO₂ injection. Figure 4.21 shows the cumulative gas produced from both coal seams (upper and lower). After 21 years of CBM production and 10 years of CO₂ injection, the amount of CBM produced from the upper and the lower coal seams were about 3.67×10^9 SCF and 1.4×10^9 SCF, respectively. The amount of coalbed methane produced from the upper coal seam is more than the lower coal seam due to the assumed higher cleat permeability of the upper coal seam (see Table 4.1 for more details).

The permeability changes caused by coal swelling and shrinkage were computed, and the permeability change with time in different blocks in the lower coal seam is shown in Figures 4.22 to 4.24. Results show an increase in cleat permeability of both coal seams due to coal shrinkage during gas depletion. While an increase in cleat permeability was observed during CBM production, a significant reduction in cleat permeability was observed during CO₂ injection. Coal matrix swelling is considered the main reason for the permeability reduction.

(a) Upper coal seam

(b) Lower coal seam

Figure 4.20: Pressure distribution in the upper (a) and the lower (b) coal seams

(a) Cumulative gas produced from the upper coal seam

(b) Cumulative gas produced from the lower coal seam

Figure 4.21: Cumulative gas produced from the upper (a) and the lower (b) coal seams

Figure 4.22: Permeability changes associated with coal swelling and shrinkage in block # 26, 26 in the lower coal seam

Figure 4.23: Permeability changes associated with coal swelling and shrinkage in block # 35, 27 in the lower coal seam

Figure 4.24: Permeability changes associated with coal swelling and shrinkage in block # 18, 22 in the lower coal seam

Figure 4.25 shows the water saturation of the upper and the lower coal seams. The results showed that the water saturation starts dropping during the depressurizing process. The remaining water in the cleat network of the lower coal seam can be pushed toward the production wells by flooding the coal with CO₂, which is clear in Figure 4.25 (e). It is also clear from the figures that most of the water produced over the 21 year time period had come from the central part of the coal seam where the wells were constructed.

Figure 4.26 shows the CO₂ saturation in the lower coal seam. The results show that the CO₂ is migrating laterally through the cleat network, sweeping the water within the cleats ahead of CBM so that more water and gas is produced during the enhanced coalbed methane recovery than during primary production. Figure 4.27 shows the CH₄ saturation within the lower coal seam before and after 10 years of CO₂ injection. It is also clear from the results that after 10 years of CO₂ injection, the CH₄ in place has desorbed where CO₂ has been adsorbed, which is expected with enhanced coalbed methane recovery. In addition, results show that the injected CO₂ is reaching the producers very fast, because the tips of each injector are just 880 feet away from each producer. For that reason, production should be stopped 5 years after the CO₂ injection stops. Otherwise, a very large amount of CO₂ will be produced.

Figure 4.28 shows the total amount (62,800 short tons) of CO₂ that has been injected into the lower coal seam. From the total amount injected, only 1,116 short tons of CO₂ were produced (see Figures 4.28 and 4.29), which is only a 1.8% loss.

Figure 4.25: Water saturation in the upper (a) and the lower (b) coal seams

Figure 4.26: CO₂ saturation in the lower coal seam before (a) and after (b) 10 years of CO₂ injection

Figure 4.27: CH₄ saturation in the lower coal seam before (a) and after (b) 10 years of CO₂ injection

Figure 4.28: Cumulative carbon dioxide injected into and produced from the lower coal seam

Figure 4.29: Cumulative carbon dioxide produced from the lower coal seam

4.4.3 – Comparison of conventional and enhanced CBM production by using horizontal wells

After 21 years of coalbed methane production from the upper coal seam about 3.67×10^9 SCF of CH_4 was produced from the upper coal seam in both cases (with and without CO_2 injection into the lower coal seam). Figure 4.30 shows the cumulative CBM production in both cases. It can be observed from the figure that the amount of the produced CBM is equivalent in both cases. That is because the injection of CO_2 into the lower coal seam did not affect the CBM production from the upper coal seam, since there is no communication between the two layers.

Figure 4.30: Cumulative CBM production from the upper coal seam with and without CO_2 injection into the lower coals seam

After 21 years of coalbed methane production from the lower coal seam, about 1.26×10^9 SCF of CH_4 was produced from the lower coal seam using conventional CBM production. However, about 1.4×10^9 SCF of CH_4 was produced when CO_2 was being injected into the lower coal seam, which makes a percentage gain of 10.4% in comparison to the conventional CBM production case. Figure 4.31 shows the cumulative CBM production in both cases (conventional and enhanced CBM production).

Figure 4.31: Cumulative CBM production with and without CO_2 injection

4.4.4 – Conventional CBM production by using vertical wells

Vertically drilled wells are not very effective when they used in reservoirs that have very low permeability (e.g. 1 mD in this case). Figure 4.32 shows CO₂ saturation in the lower coal seam when a vertical well was used. It is clear from the results that CO₂ injection is very confined to the injection region which will not be enough to enhance CH₄ production.

Figure 4.32: Cumulative CBM production with and without CO₂ injection

On the other hand, vertically drilled wells are considered very effective with relatively high permeability reservoirs (Al Haddad and Crafton, 1991; Joshi, 2003). For that reason, the permeability of the lower coal seam was assumed to be 15 mD in the modeling of this case.

In this case study, coalbed methane was produced from both coal seams (upper and lower) for 21 years using a vertical well configuration, as shown in Figure 4.7. The central well (LCPW-5) located in the lower coal seam was shut-in after 5 years of CBM production. The time-line of the production period is shown in Figure 4.33. The extended Palmer and Mansoori model was used to perform coal matrix shrinkage and permeability alteration associated with the coal shrinkage (Palmer and Mansoori, 1996; Mavor and Vaughn, 1998).

Figure 4.33: Assumed time-line for conventional CBM production case by using vertical wells

Figure 4.34 shows the pressure distribution in both coal seams (upper and lower) before and after CBM production. Results from the figure show a reduction in the reservoir pressure during gas production. After 21 years of CBM production, the initial reservoir pressure was reduced from 372.9 psi to 175 psi in the upper coal seam. The reservoir pressure was reduced from 627.5 psi to 260 psi in the lower coal seam after 21 years of CBM production in center of the modeling area. Figure 4.35 shows the cumulative gas produced from both coal seams (upper and lower). After 21 years of gas production, the amount of CBM produced from the upper and the lower coal seams were about 9.62×10^8 SCF and 1.6×10^9 SCF, respectively. In this case, the cumulative gas produced from the lower coal seam is more than the upper coal seam due to many reasons such as assumed high cleat permeability of the lower coal seam, number of production wells in the lower coal seam, and high initial reservoir pressure. The cleat permeability of the lower coal seam in this case was assumed to be 15 mD, which is still high but less than the assumed cleat permeability of the upper coal seam (25 mD). During the 21 years of gas production, a five-spot well pattern was used for production wells as shown in Figure (4.10). The initial reservoir pressure was assumed to be 627.5 psi.

(a) Upper coal seam

(b) Lower coal seam

Figure 4.34: Pressure distribution in the upper (a) and the lower (b) coal seams before and after CBM production

(a) Cumulative gas produced from the upper coal seam

(b) Cumulative gas produced from the lower coal seam

Figure 4.35: Cumulative gas produced from the upper (a) and the lower (b) coal seams

An increase in cleat permeability was observed in both coal seams due to coal shrinkage during methane production. The computed permeability changes with time in different grid blocks in the lower coal seam are shown in Figures 4.36 to 4.38. The sudden change in cleat permeability in Figure 4.36 and 4.37 is due to the shut-in of the central production well and the high reservoir permeability.

Figure 4.36: Permeability changes associated with coal shrinkage in block # 28, 28 in the lower coal seam

Figure 4.37: Permeability changes associated with coal shrinkage in block # 31, 36 in the lower coal seam

Figure 4.38: Permeability changes associated with coal shrinkage in block # 19, 19 in the lower coal seam

4.4.5 – Enhanced CBM production by using vertical wells

CBM production was completed in both coal seams (upper and lower), and CO₂ was injected only in the lower coal seam by using vertical wells as shown in Figure 4.7. The purpose of modeling this case was to evaluate the reservoir performance during CO₂ injection and enhanced CBM production. After five years of primary CBM production from all the wells, the central production well (LCPW-5) was ceased for one year and then converted to an injection well (LCIW). While CBM production was continued from all wells in both coal layers, CO₂ injection was carried out in the lower coal seam for 10 years by assuming an injection pressure of 1,000 psi. The time-line of the production and injection period is shown in Figure 4.39.

Figure 4.39: Time line of the enhanced CBM production case

Figure 4.40 shows the reservoir pressure distribution at different times during CBM production and CO₂ injection. During the first five years of gas depletion, a decrease in the reservoir pressure was noticed. In the upper coal seam, the initial reservoir pressure was reduced from 372.9 psi to 175 psi after 21 years of CBM production. The reservoir pressure was reduced from 627.5 psi to 296 psi in the lower coal seam after 5 years of CBM production at the center of the modeling area. After 10 years of injection, about 110,350 short tons of CO₂ were injected into the lower coal seam at an injection pressure of 1,000 psi. The reservoir pressure increased from 296 psi to 790 psi near the central injection well (LCIW) due to CO₂ injection.

Figure 4.41 shows the cumulative gas produced from both coal seams (upper and lower). After 21 years of CBM production and 10 years of CO₂ injection, the amount of CBM produced from the upper and the lower coal seams were about 9.6×10^8 SCF and 1.94×10^9 SCF, respectively. In this case, the cumulative gas produced from the lower coal seam is more than the

upper coal seam due to many reasons such as assumed high cleat permeability of the lower coal seam, number of production/injection wells in the lower coal seam and high initial reservoir pressure. The cleat permeability of the lower coal seam in this case was assumed to be 15 mD, which is still high but less than the assumed cleat permeability of the upper coal seam (25 mD). A five-spot well pattern was used for this purpose. For the first five years of gas production, all the five wells were producing. Later, the center production well was shut-in for one year while the other wells continued to produce coalbed methane. The central production well was then converted to a CO₂ injection well and injection was carried out for 10 years while the other wells were producing. Also, the initial reservoir pressure was assumed to be 627.5 psi.

Figures 4.42 to 4.44 show the computed permeability changes caused by coal swelling and shrinkage in different blocks in the lower coal seam. Results show an increase in the cleat permeability of both coal seams due to coal shrinkage during gas depletion. While an increase in cleat permeability was observed during CBM production, a significant reduction in cleat permeability was observed during CO₂ injection. Coal matrix swelling is considered the main reason for the permeability reduction. In the blocks surrounding the injection well, the permeability is reduced to a specific point, and it becomes constant after that until the post injection period of 5 years, which tends to increase the permeability again.

Figure 4.40: Pressure distribution in the upper (a) and the lower (b) coal seams

(a) Cumulative gas produced from the upper coal seam

(b) Cumulative gas produced from the lower coal seam

Figure 4.41: Cumulative gas produced from the upper (a) and the lower (b) coal seams

Figure 4.42: Permeability changes associated with coal shrinkage in block # 28, 28 in the lower coal seam

Figure 4.43: Permeability changes associated with coal swelling and shrinkage in block number 31, 36 in the lower coal seam

Figure 4.44: Permeability changes associated with coal swelling and shrinkage in block number 8, 7 in the lower coal seam

The water saturation in the upper and the lower coal seams is shown in Figure 4.45. The results show that the water saturation starts dropping during the depressurizing process. The injected CO₂ can push the remaining water in the cleat network of the lower coal seam toward the production wells.

Figure 4.46 and Figure 4.47 show CO₂ and CH₄ concentrations in the lower coal seam, respectively. The results show the laterally migration of CO₂ through the cleat network. After 10 years of CO₂ injection, the CH₄ in place has desorbed where CO₂ has been adsorbed, which is expected with enhanced coalbed methane recovery. Due to the high permeability of the lower coal seam (15 mD), the injected CO₂ is reaching the producers very fast. For that reason, production should be stopped 5 years after the CO₂ injection stops.

Figure 4.48 shows the cumulative CO₂ injected into the lower coal seam (110,350 short tons). Due to the assumed high permeability of the lower coal seam (15 mD), it was possible to inject large amounts of CO₂ in this case when compared to CO₂ injection in low-permeability coal reservoir (e.g., coal seam with 1 mD permeability). About 398 short tons of CO₂ were produced from the production wells of the lower coal seam (see Figure 4.48 and 4.49), results in a loss of only 0.4%.

Figure 4.45: Water saturation in the upper (a) and lower (b) coal seams

Figure 4.46: CO₂ saturation in the lower coal seam before (a) and after (b) 10 years of CO₂ injection

Figure 4.47: CH₄ saturation in the lower coal seam before (a) and after (b) 10 years of CO₂ injection

Figure 4.49: Cumulative carbon dioxide injected into and produced from the lower coal seam

Figure 4.48: Cumulative carbon dioxide produced from the lower coal seam

❖ **Comparison of conventional and enhanced CBM production by using vertical wells**

About 9.62×10^8 SCF of CH_4 were produced from the upper coal seam in both cases (with and without CO_2 injection into the lower coal seam), after 21 years of production. Figure 4.50 shows the cumulative CBM production in both cases. Since there is no communication between the two layers, the same amount of CBM was produced in both cases (with and without CO_2 injection into the lower coal seams).

Figure 4.50: Cumulative CBM production from the upper coal seam with and without CO_2 injection into the lower coal seams

After 21 years of coalbed methane production, about 1.6×10^9 SCF of CH_4 was produced from the lower coal seam using conventional CBM production. However, about 1.94×10^9 SCF of CH_4 was produced when CO_2 was being injected into the lower coal seam, which is 17.8% gain in comparison to the conventional CBM production case. Figure 4.51 shows the cumulative CBM production in both cases (conventional and enhanced CBM production).

Figure 4.51: Cumulative CBM production with and without CO_2 injection

4.5 – Parametric studies

4.5.1 – Influence of anisotropic permeability

In order to investigate the influence of anisotropic permeability on CH₄ production and CO₂ transport behavior, an anisotropic ratio (A_R) (ratio of face cleat permeability to butt cleat permeability) of 3 was considered (Ross, 2007; Siriwardane and Gondle, 2011; White et al, 2005). Figure 4.52 (a) shows the water saturation in the upper coal seam after 21 years of production. Figure 4.52 (b) shows the water saturation in the lower coal seam after 21 years of production with 10 years of injection. Modeling results show that the reduction in water saturation in the face cleat direction is more when compared to the butt-cleat direction. Figure 4.53 shows CO₂ saturation in the lower coal seam. Figure 4.54 shows a comparison of the cumulative gas production at different anisotropy ratios ($A_R = 1$ and $A_R = 1/3$).

Figure 4.52: Water saturation in the upper (a) and lower (b) coal seams when the face cleats permeability is higher than the butt cleats permeability

Figure 4.53: CO₂ saturation in the lower coal seam before (a) and after (b) 10 years of CO₂ injection

Figure 4.54: Cumulative gas produced from the lower coal seam

4.5.2 – Influence of swelling and shrinkage constants on cleats permeability

Different values of swelling and shrinkage constants for CH_4 and CO_2 , respectively were used in order to investigate their influence on cleats permeability of coal during CH_4 production and CO_2 injection. Figure 4.55 shows the change in cleats permeability for different values for the shrinkage constant, while a constant value was assumed for the swelling constant. Modeling results show that the cleats permeability increases with an increase in shrinkage constant. Figure 4.56 shows the changes in cleats permeability with different values for the swelling constant while the shrinkage constant was assumed to have a constant value. Modeling results show that the cleats permeability decreases when higher values were assumed for the swelling constant.

Figure 4.55: Change in fracture permeability with different values for the shrinkage constant (block # 26, 26, 7)

Figure 4.56: Change in fracture permeability with different values for the swelling constant (block # 27, 27, 7)

Chapter 5 : GEOMECHANICAL MODELING

5.1– Introduction to geomechanics

The study of geomechanical aspects associated with fluid injection and production into and from underground formations is considered a primary interest for gas and oil companies (Capasso and Mantica, 2006; Chan, 2004). Hydrocarbon extraction from underground reservoirs can have a significant influence on reservoir properties, such as compressibility, porosity, and permeability, and may result in ground subsidence (Li and Li, 2010; Tran et al, 2008; Connell and Detourany, 2008; Capasso and Mantica, 2006). On the other hand, fluid injection into subsurface formations may result in ground uplift (Li and Li, 2010; Tran et al, 2008; Connell and Detourany, 2008; Capasso and Mantica, 2006; Chan, 2004; Siriwardane and Gondle, 2011). Figure 5.1 shows the schematic diagram of the ground subsidence during production and ground uplift during injection. Additionally, ground movements due to production and injection could result in well failures (e.g. well casing), and can sometimes trigger faults or activate dormant fractures (Abou-Sayed et al, 2004; Capasso and Mantica, 2006; Chan, 2004; Fredrich et al, 2000).

According to Terzaghi's principle of effective stress (Terzaghi, 1936); any mechanical behavior of a porous medium is governed by the effective stress. The weight of overburden layers is supported by the bulk matrix and fluids in pore spaces of subsurface geologic layers (Capasso and Mantica, 2006). During production, the fluid pressure in the formation is reduced, and, as a result, effective stresses increase and reservoir compaction takes place (Capasso and Mantica, 2006). Equation (5.1) shows the relationship between the effective stress and pore pressure (Capasso and Mantica, 2006; Yang et al, 2011).

$$\sigma' = \sigma - \alpha \times p \times \delta \quad \text{..... Equation (5.1)}$$

Where:

σ' = Effective stress

σ = Total stress

α = Positive constant

p = Pore pressure (reservoir pressure), δ = The Kronecker delta function

Ground surface BEFORE fluids production and injection

Ground surface AFTER fluids production and injection

Figure 5.1: Production and injection influence on the ground surface

5.2 – Monitoring technologies

In large scale CO₂ sequestration projects, monitoring technologies play a major role in investigating the site integrity and ground response (Davis et al, 2008). In addition, monitoring of surface deformation is considered an important tool for understanding fluid flow behavior in underground geologic formations, and evaluating reservoirs behavior under production and injection (Davis et al, 2008). The most commonly available tools for ground monitoring in oil and natural gas applications are tiltmeters and InSAR. Some of these techniques were used in previous projects, and are described in more detail in the literature (Siriwardane and Gondle, 2011; Chen and Lin 2012; Davis et al, 2008; Koperna et al, 2009; Ringrose et al, 2009; Gondle, 2010).

5.2.1 – Tiltmeters

Tiltmeters are high-precision instruments widely used in the oil and gas industry to measure changes in the ground surface (Siriwardane and Gondle, 2011). They are very sensitive to surface deformation caused by fluid injection and production into and from underground formations. Tiltmeters are used in different areas, such as volcano monitoring and hydraulic fracturing (Siriwardane and Gondle, 2011). Figure 5.2 shows a detailed view of a tiltmeter. It consists of a liquid filled glass tube and a gas bubble (Siriwardane and Gondle, 2011). When the gas bubble moves due to any motion or tilt from the horizontal level, the tiltmeter sensors begin to record resistivity changes between electrodes (Siriwardane and Gondle, 2011; Gondle, 2010). Tiltmeters are usually installed in shallow boreholes to isolate from any thermal effects or surface noise (Davis et al, 2008). More details about the use of tiltmeters can be found elsewhere (Davis et al, 2008; Ringrose et al, 2009; Li and Li, 2010; Du et al, 2008; Siriwardane and Gondle, 2011).

Figure 5.2: A Tiltmeter (Gondle, 2010)

In some recent studies (Siriwardane and Gondle, 2011; Li and Li, 2010), tiltmeters have been used in CO₂ sequestration projects to detect any ground deformation caused by the injected or produced of fluids. In brief, these two studies are discussed below.

A tiltmeter study was conducted by Siriwardane and Gondle (2011) to monitor ground deformations caused by CO₂ injection at a field site located in Appalachian coal, West Virginia, USA. Tilt data was collected on daily basis prior to and during CO₂ injection by using an array of 36 high-precision tiltmeters and two GPS receivers at the field site. The field site included two coal layers—the Upper Freeport coal (lower coal layer) and the Pittsburgh coal (Upper coal seam). The injection of CO₂ was carried out into the lower coal seam, and coalbed methane was simultaneously produced from both coal seams. The geometric details and material properties assumed in our current study are similar to this field site. At the field site, about 1,000 tons of CO₂ was injected and a maximum ground uplift of 0.13 inch (3.3 mm) was observed due to CO₂ injection. These ground displacements are insignificant as the injected volume is low. More details about the field site can be found elsewhere (Siriwardane and Gondle, 2011).

In addition to the field measurements, coupled fluid flow and deformation modeling was performed to compute the ground displacements during CO₂ injection, and to understand the behavior of injected CO₂. Reservoir properties were selected by history matching the actual CBM production and CO₂ injection. Coal swelling and shrinkage were incorporated by using the Palmer and Mansoori model. Modeling results were compared with field measurements, and a good correlation was observed.

In another tiltmeter study conducted by Li and Li (2010), ground displacements were measured and computed for a short term CO₂ injection into a shallow coal seam in Alberta, Canada. An array of tiltmeters was set up at the field site to cover the area surrounding the injection well. Numerical modeling was performed using a two-dimensional continuum code finite difference formulation FLAC (Fast Lagrangian Analysis of Continuum) and Computer Modeling Group's GEM simulator. The results of the study showed a maximum displacement (uplift) of 0.55 mm measured by the tiltmeters array, and the numerical modeling results correlated well with the field measurements.

5.2.2 – InSAR

InSAR (Interferometric Synthetic Aperture Radar) is another ground monitoring tool that can be used in measuring ground deformations (Ringrose et al, 2009). InSAR is suitable to use when long term monitoring plans are needed, where large areal extents need to be monitored, and where the use of ground instruments is extremely expensive. Measurements are recorded directly using satellites, thus there is no need of using surface equipment, which can be considered one of the most important advantages of using InSAR. Microwaves radiation is emitted through these satellites and their reflection is recorded. This technique detects the changes in the reflected energy between satellite passes. The phase of the reflection should always be the same, as long as the distance between the satellites and the detected object is the same. A change in the reflected phase happens either when the satellite moves, or when the surface deforms (Davis et al, 2008). More details about using InSAR in CO₂ sequestration projects can be found in the literature (Davis et al, 2008; Ringrose et al, 2009). Figure 5.3 shows the use of InSAR technique.

Figure 5.3: Schematic diagram of the Interferometric Synthetic Aperture Radar (InSAR)

5.3 – Geomechanical modeling

In the current research work, geomechanical modeling work was performed by using CMG-GEM's inbuilt geomechanical simulator. Coupled fluid flow and geomechanics models were constructed for the same cases that discussed in the previous chapter (section 4.4), and ground response during CBM production and CO₂ injection was investigated. For the purpose of geomechanical modeling, the modeling area was enlarged to capture any deformations away from the production or injection wells. Figure 5.4 shows the geometry of the geomechanical model. The model covers an area of 84,560 × 84,560 square feet (about 16 Miles × 16 Miles) as shown in Figure 5.4. Grid block of 140 × 140 × 12 was used in the X, Y, and Z directions, respectively. The grid block dimensions in the X, Y, and Z direction were variable. Table 4.1 shows the reservoir properties and Table 5.1 shows the geomechanical properties, such as elastic modulus and Poisson's ratio. These geomechanical properties have been identified from the literature (Gondle, 2010). Coal swelling/shrinkage was incorporated, and permeability changes during methane production and CO₂ injection were modeled by using the extended Palmer and Mansoori model (Palmer and Mansoori, 1996; CMG, 2012). Results are presented in the following sections of this chapter.

Figure 5.4: Geomechanical model geometry

Table 5.1: Reservoir geomechanical properties used in this study

Layer	Thickness (feet)	Poisson's Ratio	Elastic Modulus (psf)
Overburden	850	0.23	8.6E+008
Upper Coal Seam	6	0.28	7.4E+008
Sandwich	600	0.18	1.078E+009
Lower Coal Seam	6	0.28	7.4E+008
Underburden	3000	0.23	8.6E+008

5.3.1 – Geomechanical modeling results (horizontal well configuration)

❖ Conventional CBM production by using horizontal wells

CBM production was simulated in both coal seams (upper and lower) by using a horizontal well configuration to evaluate the ground response during primary CBM production. Figure 4.3 shows the well configuration used for each coal layer. More details of the well configurations of this case were presented in previous sections (section 4.3). Figure 5.5 shows the computed ground displacements (subsidence) due to CBM production. The maximum ground subsidence (subsidence was assumed to be positive deformations in the model) computed was 0.032 feet (0.38 inches). Figure 5.6 shows the computed vertical displacements along the central line of the modeling area at different times during the production period. Table 5.2 shows the computed ground surface displacements at different times during the production period.

(a) after 5 years of CBM production

(b) after 16 years of CBM production

(c) after 21 years of CBM production

Figure 5.5: Ground surface displacements along the Z-direction at different times during CBM production

Figure 5.6: Computed maximum ground surface displacements (subsidence) at different times during CBM

Table 5.2: Ground surface displacements (subsidence) at different times during CBM production

Time	Ground surface displacements -feet
5 years of production	0.024
16 years of production	0.030
21 years of production	0.032

❖ **Enhanced CBM production by using horizontal wells**

In order to evaluate the ground surface response during CO₂ injection and enhanced CBM production, CBM production from both coal seams (upper and lower) was simulated, and CO₂ injection was carried out only in the lower coal seam by using a horizontal well configuration. As discussed in previous sections (section 4.31), the well configurations assumed in both coal seams are different, and Figure 4.3 shows the well configuration used for each coal layer. More details of the well configurations can be found in previous sections (section 4.3.1). Figure 5.7 shows the ground displacements computed at different time periods during CBM production and CO₂ injection. Figure 5.8 shows the computed ground displacements caused by CBM production and CO₂ injection at different times along the central line of the modeling area. The maximum ground subsidence (assumed to be the positive deformations) computed was 0.0254 feet (0.30 inches). CBM production is considered the predominant reason for the ground subsidence. Figure 5.9 shows small magnitudes of ground uplift near the injection region (during CO₂ injection) when modeling results were carefully analyzed. Table 5.3 shows the computed ground surface displacements caused by CBM production and CO₂ injection at different times.

(a) after 5 years of CBM production

(b) after 16 years of CBM production with CO₂ injection

(c) after 21 years of CBM production

Figure 5.7: Ground surface displacements along the Z direction at different times during CBM production and CO₂ injection

Figure 5.8: Computed maximum ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Table 5.3: Ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Time	Ground surface displacements - feet
5 years of production	0.024
16 years of production with 10 years of CO ₂ injection	0.018
21 years of production with 10 years of CO ₂ injection	0.0254

5.3.2 – Geomechanical modeling results (vertical well configuration)

❖ **Conventional CBM production by using vertical wells**

In order to evaluate the ground surface response during primary CBM production, CBM production was carried out in both coal seams (upper and lower) by using a vertical well configuration. The well configuration used for each coal layer is shown in Figure 4.7. Figure 5.9 shows the computed ground surface displacements (subsidence) at different times at different times during the production period. The maximum surface subsidence (subsidence was assumed to be positive deformations in the model) computed was 0.0135 feet (0.162 inches). Figure 5.10 shows the computed vertical displacements along the central line of the modeling area at different times during the production period. Table 5.4 shows the computed ground surface displacements at different times during the production period.

(a) after 5 years of CBM production

(b) after 16 years of CBM production

(c) after 21 years of CBM production

Figure 5.9: Ground surface displacements along the Z direction at different times during CBM production

Figure 5.10: Computed maximum ground surface displacements (subsidence) at different times during CBM

Table 5.4: Ground surface displacements (subsidence) at different times during CBM production

Time	Ground surface displacements -feet	Ground surface displacements - inches
5 years of production	0.009	0.108
16 years of production	0.0124	0.14
21 years of production	0.0135	0.162

❖ **Enhanced CBM production by using vertical wells**

CBM was produced from both coal seams (upper and lower), and CO₂ injection was carried out only in the lower coal seam by using a vertical well configuration to evaluate the ground surface response during CO₂ injection and enhanced CBM production. As discussed in previous sections (section 4.3.2), the well configurations assumed in both coal seams are different and Figure 4.7 shows the well configuration used for each coal layer.

The maximum surface subsidence (assumed to be the positive deformations), which was computed when vertical production and injection wells were used, was 0.0118 feet (0.141 inches). Figure 5.11 shows the computed ground surface subsidence at different time periods during CBM production and CO₂ injection. CBM production is considered the main reason for the ground subsidence, and CO₂ injection into the lower coal seam caused no significant ground uplifts (assumed to be the negative deformations). Figure 5.12 shows the maximum ground displacement caused by CBM production and CO₂ injection at different times along the central line of the modeling area. Table 5.5 shows the computed ground surface displacements caused by CBM production and CO₂ injection at different times.

(a) after 5 years of CBM production

(b) after 16 years of CBM production with 10 years of CO₂ injection

(a) after 21 years of CBM production

Figure 5.11: Ground surface subsidence along the Z direction at different times during CBM production and CO₂ injection

Figure 5.12: Computed maximum ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Table 5.5: Ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Time	Ground surface displacements -feet	Ground surface displacements - inches
5 years of production	0.009	0.108
16 years of production with 10 years of CO ₂ injection	0.0065	0.078
21 years of production with 10 years of CO ₂ injection	0.0118	0.141

Chapter 6 : INFLUENCE OF A VERTICAL PERMEABLE ZONE ON FLUID FLOW BEHAVIOR AND GEOMECHANICAL RESPONSE

6.1 – Introduction to CO₂ leakage via vertical permeable pathways

The objective of storing CO₂ in a geological formation is to ensure that the injected CO₂ remains in the targeted formation for a long period of time. An immediately overlying tight caprock layer above the targeted reservoir traps the injected CO₂, reducing the risk of leakage. The caprock layers (e.g. shale) are believed to have very low permeability values, in the nanodarcy to microdarcy range (Liu et al, 2012; Rutqvist et al, 2007). However, it is important to investigate the caprock integrity and any possible leakage scenarios through the caprock layer during large-scale, long-term CO₂ injection operations. Sometimes, the caprock layer could have fractures or fault zones, in which case CO₂ could escape or migrate (Liu et al, 2012, Rutqvist et al, 2007).

In the current research work, a hypothetical vertical permeable zone was simulated directly above the lower coal seam, and the migration of CO₂ in the overburden layers was investigated. Also, the production of coalbed methane from the upper coal seam was evaluated in the presence of the hypothetical vertical permeable zone. The modeling objective in this case is to investigate whether a secondary coal seam (upper coal seam in this case) would be useful to capture the migrated CO₂ and if it could lead to increased coalbed methane production. Figure 6.1 shows a schematic diagram of a multi-layered geologic profile with a pre-existing permeable path (fracture), which interconnects the lower coal seam with the upper one. Figure 6.2 shows the location of the permeable grid block in the CMG model. The sandwich layer acts as a caprock layer in this modeling study. The size of the permeable grid block was assumed to be 176 feet in width and 600 feet in length, and the permeability of the permeable grid block was assumed to be 0.5 mD in the model. This correlates to a fracture width of 0.88 feet and a permeability of 100 mD.

Figure 6.1: Schematic diagram showing a permeable fractured zone within the sandwich layer

Figure 6.2: CMG model showing the permeable grid block

Some of the main objectives of the modeling work presented in this chapter are listed below:

- Investigate the migration of CO₂ in the presence of a hypothetical permeable pathway in the sandwich layer. Different well configurations were used.
- Investigate the influence of the location of a permeable zone on the migration of CO₂.
- Investigate the influence of the permeability of a fractured zone in the impervious caprock layer on the amount of CO₂ leakage.
- Evaluate the production of coalbed methane from the lower and the upper coal seams in the presence of a hypothetical permeable zone in the sandwich layer.
- Investigate whether the secondary (upper) coal layer could act as a CO₂ barrier, if CO₂ leaks through the permeable path in the sandwich layer.

6.2 – Modeling results for the horizontal well configuration

6.2.1 – Influence of a vertical permeable zone on the migration of CO₂

In order to investigate the influence of a vertical permeable zone on the flow behavior of CO₂, a permeable zone (grid block – 28, 28) in the sandwich layer (located at 350 feet diagonally away from the injection region) was added to the model. The permeability of the vertical permeable zone was assumed to be 0.5 mD in the model. This correlates to a fracture width of 0.88 feet and a permeability of 100 mD. Figure 6.3 shows the migration of CO₂ through the assumed permeable zone in the sandwich layer. Figure 6.4 shows the flow of CO₂ into the upper coal seam, when CO₂ leaks through the sandwich layer and reaches the upper coal seam. The coal cleats in each coal layer were assumed to 90% water-saturated. The fracture block (vertical permeable zone in the sandwich layer) was assumed to be fully saturated with water.

After 10 years of CO₂ injection, approximately 63,040 short tons of CO₂ were injected into the lower coal seam. Due to the presence of a hypothetical vertical permeable zone in the sandwich layer, about 1,030 short tons of CO₂ leaked into the upper coal seam, which makes a 1.6% loss of injected CO₂. Figure 6.5 shows the cumulative CO₂ injected into the lower coal seam and the cumulative CO₂ which leaked into the upper coal seam.

Figure 6.3: CO₂ saturation in the sandwich layer

Figure 6.4: CO₂ saturation in the upper coal seam

Figure 6.5: Cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam

6.2.2 – Evaluation of CBM production in the presence of a permeable zone in the caprock layer

In order to evaluate the CBM production in the presence of a permeable zone in the sandwich layer, a permeable zone was assumed to be located at 350 feet diagonally away from the injection region. The permeability of the zone was assumed to be 0.5 mD. This correlates to a fracture width of 0.88 feet and a permeability of 100 mD. Figure 6.6 shows the cumulative CBM production from the upper coal seam with and without the presence of a hypothetical permeable zone in the sandwich layer. Results from Figure 6.6 show a cumulative CBM production of 3.67×10^9 SCF when there was no communication between the two coal seams (upper and lower). However, about 3.65×10^9 SCF of CH₄ was produced when a hypothetical permeable fracture was interconnecting the upper coal seam with the lower one. The coalbed methane

production in the upper coal seam was not improved, because only a fraction of injected CO₂ reached the upper coal seam through the permeable fractured zone.

Figure 6.6: Cumulative CBM production from the upper coal seam with and without the presence of a permeable zone in the sandwich layer

Figure 6.7 shows the cumulative CBM production from the lower coal seam with and without the presence of a permeable zone in the sandwich layer. After 21 years of coalbed methane production from the lower coal seam, about 1.40×10^9 SCF of CH₄ was produced when there was no communication between the two coal seams (upper and lower) and CO₂ was been injected into the lower coal seam. However, about 1.39×10^9 SCF of CH₄ was produced when a hypothetical permeable fracture was interconnecting the upper coal seam with the lower one and CO₂ was been injected into the lower coal seam.

Figure 6.7: Cumulative CBM production from the lower coal seam with and without the presence of a permeable zone in the sandwich layer

6.2.3 – Geomechanical modeling with the presence of a permeable zone in the caprock layer

Geomechanical modeling was performed with the presence of a hypothetical permeable pathway in the sandwich layer to evaluate the ground surface respond when such a fracture exists. Figure 6.8 shows the computed ground surface subsidence at different time periods during CBM production and CO₂ injection. CBM production from the upper and the lower coal seams is the main reason for the ground surface subsidence shown in the figure. The maximum ground subsidence (assumed to be the positive deformations) computed was 0.0249 feet (0.29 inches). That means there was no significant difference between the case with no fracture in the sandwich layer and this case and that is due to the small amount of CO₂ which was leaked to the upper coal seam (1%). Table 6.1 shows the computed ground surface displacements caused by CBM production and CO₂ injection at different times.

Figure 6.8: Maximum ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Table 6.1: Ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Time	Ground surface displacements - feet
5 years of production	0.0242
16 years of production with 10 years of CO ₂ injection	0.017
21 years of production with 10 years of CO ₂ injection	0.0249

The influence of the permeability of the fractured zone in the sandwich layer on the amount of CO₂ leakage was investigated by assuming different permeability values for the permeable zone in the sandwich layer. Two different permeability values were selected: 0.5 mD and 30 mD. The permeability of 0.5 mD correlates to a fracture width of 0.88 feet and a permeability of 100 mD, while the permeability of 30 mD correlates to a fracture width of 0.88 feet and a permeability of 6000 mD (6 Darcy). Figure 6.9 shows the cumulative CO₂ injected into the lower coal seam and cumulative CO₂ leaked to the upper coal seam when the permeability of the fractured zone was assumed to be 0.5 mD. The results from Figure 6.9 show that approximately 1,030 short tons of CO₂ leaked into the upper coal seam, which makes a 1.6% loss of injected CO₂. However, about 8,200 short tons of CO₂ leaked into the upper coal seam, which makes a 12% loss of injected CO₂, when the permeability of the fractured zone was assumed to be 30 mD. Figure 6.10 shows the cumulative CO₂ injected into the lower coal seam and the cumulative CO₂ which leaked into the upper coal seam when the permeability of the fractured zone was assumed to be 30 mD.

Figure 6.9: Cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam

Figure 6.10: Cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam

Figure 6.11 shows the influence of the permeability of the fractured zone on the amount of CO₂ leakage. Results show an increase in the leakage with an increase in the permeability values of the fractured zone. The amount of leakage remains the same beyond a certain value of the permeability of the fractured zone, as can be seen.

Figure 6.11: The influence of fractured zone permeability on the amount of CO₂ leakage

6.2.5 – Influence of the permeable zone location on the migration of CO₂

The influence of the permeable zone location on CO₂ migration was investigated by considering two different locations for the permeable zone in the sandwich layer: one close to the injection region (permeable zone- A - grid block 28, 28) and another farther from the injection region (permeable zone- B - grid block 26, 26). The permeable zone closer to the injection region is about 350 feet diagonally away from the center, and the permeable zone farther from the injection region is located about 700 feet diagonally away from the center as shown in Figure 6.12. The permeability values of the fractured zone were assumed to be the same.

(A) the permeable zone is 350 feet diagonally away from the center

(B) the permeable zone is 700 feet diagonally away from the center

Figure 6.12: A plan view of the lower coal seam shows the distance between the injection region and the permeable block of two different cases

Figure 6.13 shows the CO₂ saturation in the upper coal seam for different locations of the permeable zone. About 1,030 short tons of CO₂ leaked into the upper coal seam when the permeable zone was located at 350 feet diagonally away from the center of the modeling area, which results in a 1.6% total loss of CO₂. However, around 60 short tons of CO₂ leaked into the upper coal seam when the permeable zone was located farther from the injection region, which makes an insignificant total CO₂ loss of about 0.09%.

(a) the permeable zone is 350 feet diagonally away from the center

(b) the permeable zone is 700 feet diagonally away from the center

Figure 6.13: CO₂ saturation in the upper coal seam when a permeable path is present in the sandwich layer in different locations and CO₂ is being injected into the lower coal seam

6.2.6 – Can a secondary coal seam act as a CO₂ barrier?

One of the objectives of the current study is to investigate whether a second coal layer present above the target coal reservoir could act as a carbon dioxide (CO₂) barrier, if CO₂ leaks through a permeable fractured zone present in the sandwich layer. The previous sections demonstrated how the CO₂ may leak into the overburden layers via a permeable path present in the sandwich layer. In order to investigate whether the CO₂ which leaked into the upper coal seam could migrate beyond this layer; a permeable fractured zone was added to the overburden caprock layer of the upper coal seam. Results show that CO₂ was able to transport through the permeable pathway, but it couldn't migrate farther than that permeable zone even in the worst possible case scenario (when around 12% of injected CO₂ leaked into the upper coal seam) because of the assumed very low permeability of the overburden layers. It is clear from the results that the upper coal seam can act as barrier for CO₂ leakage since no CO₂ was able to leak to the overburden layer. Figure 6.14 shows the CO₂ saturation in the upper coal seam and the caprock layer of the upper coal seam. Figure 6.15 shows the CO₂ saturation in the overburden seal layer with and without the presence of a permeable zone in the caprock layer of the upper coal seam.

Figure 6.14: CO₂ saturation in the upper coal seam (a) and the overburden layer (b)

Figure 6.15: CO₂ saturation in the overburden layer without (a) and with (b) a vertical permeable path

6.3 – Modeling results for the vertical well configuration

6.3.1 – Influence of a vertical permeable zone on the migration of CO₂

A permeable zone (grid block – 28, 28) in the sandwich layer (located at 350 feet away from the injection point) was assumed in order to investigate the influence of a vertical permeable zone on the flow behavior of CO₂. The permeability of the vertical permeable zone was assumed to be 0.5 mD. This correlates to a fracture width of 0.88 feet and a permeability of 100 mD. Figure 6.16 shows the CO₂ saturation in the upper coal seam, when CO₂ leaks through the sandwich layer to the upper coal seam.

After 10 years of CO₂ injection, about 560 short tons of CO₂ leaked into the upper coal seam due to the presence of a vertical permeable path in the sandwich layer, which makes a 0.5% loss of CO₂ from the lower coal seam. Figure 6.17 shows the cumulative CO₂ injected into the lower coal seam and the cumulative CO₂ which leaked into the upper coal seam.

Figure 6.16: CO₂ saturation in the upper coal seam

Figure 6.17: Cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam

6.3.2 – Evaluation of CBM production in the presence of a vertical permeable path in the sandwich layer

A vertical permeable path was assumed to be located at 350 feet away from the injection point in order to evaluate CBM production from both coal seams (upper and lower). The permeability of the path was assumed to be 0.5 mD. The cumulative CBM production from the upper coal seam with and without the presence of a permeable path in the sandwich layer is shown in Figure 6.18. About 9.6×10^8 SCF of CBM was produced when there was no communication between the two coal seams (upper and lower). About 9.4×10^8 SCF of CBM was produced when a hypothetical permeable fracture zone was interconnecting the upper coal seam with the lower one. The reduction in CBM production is caused by the migration of water from the sandwich layer through the permeable zone, which filled the cleat network of the upper coal seam and inhibited the CBM production process. However, this behavior was not obvious in the case of horizontal well configuration because CO_2 was displacing the water present in the fracture block and the cleats of the upper coal seam. In addition, results from Figure 6.18 show no enhancement in CBM production due to CO_2 leakage. This is because the amount of the leakage was only a small fraction.

Figure 6.18: Cumulative CBM production from the upper coal seam with and without the presence of a permeable zone in the sandwich layer

Figure 6.19 shows the cumulative CBM production from the lower coal seam with and without the presence of a permeable path in the sandwich layer. After 21 years of coalbed methane production from the lower coal seam, about 1.94×10^9 SCF of CBM was produced when there was no communication between the two coal seams (upper and lower), and CO_2 was been injected into the lower coal seam. However, about 1.91×10^9 SCF of CBM was produced when a hypothetical permeable path was interconnecting the upper coal seam with the lower one and CO_2 was been injected into the lower coal seam.

Figure 6.19: Cumulative CBM production from the lower coal seam with and without the presence of a permeable zone in the sandwich layer

6.3.3 – Geomechanical modeling with the presence of a permeable zone in the caprock layer

In order to evaluate the ground surface respond when a permeable fractured zone is present in the sandwich layer, geomechanical modeling was performed with the presence of a hypothetical permeable pathway in the caprock of the lower coal seam. Figure 6.20 shows the computed ground surface subsidence at different time periods during CBM production and CO₂ injection. The maximum surface subsidence (assumed to be the positive deformations), which was computed when vertical production and injection wells were used, was 0.0111 feet (0.133 inches). Table 6.2 shows the computed ground surface displacements caused by CBM production and CO₂ injection at different times. Table 6.3 shows the CO₂ leakage amount and ground surface displacements for both cases (horizontal and vertical).

Figure 6.20: Computed maximum ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Table 6.2: Ground surface displacements (subsidence) at different times during CBM production and CO₂ injection

Time	Ground surface displacements -feet	Ground surface displacements - inches
5 years of production	0.0085	0.102
16 years of production with 10 years of CO₂ injection	0.006	0.072
21 years of production with 10 years of CO₂ injection	0.0111	0.133

Table 6.3: CO₂ leakage amount and ground surface displacements (subsidence)

Case	Leakage (%)	Ground surface displacements -feet
Horizontal Well Configuration	1.6	0.025
Vertical Well Configuration	0.5	0.0111

6.3.4 – Influence of the permeability of the fractured zone on the amount of CO₂ leakage

The influence of the permeability of the sandwich layer's fractured zone on the amount of CO₂ which was leaked was investigated by considering two different permeability values for the permeable zone. A permeability value of 0.5 mD was considered in the first case and a permeability value of 30 mD was considered in the second case. Figure 6.21 shows the cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam when the permeability of the fractured zone was 0.5 mD. The results show that about 560 short tons of CO₂ leaked into the upper coal seam due to the presence of a permeable path in the sandwich layer. This makes a 0.5% loss of the injected CO₂ to the upper coal seam.

Figure 6.21: Cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam

However, when the permeability of the fractured zone, was 30 mD, about 13,620 short tons of CO₂ leaked into the upper coal seam. Figure 6.22 shows the cumulative CO₂ injected into the lower coal seam and the cumulative CO₂ which leaked into the upper coal seam when the permeability of the fractured zone, was 30 mD. This makes a 12% loss (worst possible case scenario) of the injected CO₂ to the upper coal seam.

Figure 6.22: Cumulative CO₂ injected into the lower coal seam and cumulative CO₂ which leaked into the upper coal seam

6.3.5 – The influence of the permeable zone’s location on the migration of CO₂

By changing the location of the vertical permeable zone in the sandwich layer, the influence of the permeable zone’s location on the CO₂ migration was investigated. Two different locations for the permeable zone in the sandwich layer were considered: one close to the injection region (permeable zone- A - grid block 28, 28), and another farther from the injection region (permeable zone- B - grid block 26, 26). The permeable zone – A is assumed to be located at around 350 feet away from the injection point, while the permeable zone – B is located at about 700 feet away from the injection point, as shown in Figure 6.23. The permeability values of the fractured zone were assumed to be the same.

Figure 6.23: A plan view of the lower coal seam shows the distance between the injection point and the permeable block of two different cases

Figure 6.24 shows the CO₂ saturation in the upper coal seam when a permeable zone is considered in two different locations in the sandwich layer. About 560 short tons of CO₂ leaked to the upper coal seam when the permeable zone was located at 350 feet away from the injection point. However, around 134 short tons of CO₂ leaked into the upper coal seam when the permeable zone was located farther from the injection region.

(a) the permeable zone is 350 feet away from the injection point

(b) the permeable zone is 700 feet away from the injection point

Figure 6.24: CO₂ saturation in the upper coal seam when a permeable path is present in the sandwich layer in different locations, and CO₂ is being injected into the lower coal seam

6.3.6 – Can a secondary coal seam act as a CO₂ barrier?

The previous sections (6.3.5) showed how that CO₂ can leak into the upper coal seam through a permeable fractured zone present in the sandwich layer. In order to investigate whether the secondary (upper) coal seam located in the overburden layers can act as a barrier to CO₂ leakage, the overburden layers was evaluated for any evidence of CO₂ leakage. The modeling results showed no evidence of CO₂ in the overburden layer, even when around 12% (the worst possible case scenario) of the injected CO₂ leaked to the upper coal seam. This verifies that the secondary overburden coal layer can act as a CO₂ barrier if some of the injected CO₂ into the target coal reservoir leaks through a permeable path. Figure 6.25 shows the CO₂ saturation in the upper coal seam and the overburden layer when 12% of the injected CO₂ leaks into the upper coal seam. However, no leakage of CO₂ was seen in the immediate overburden layer as shown in Figure 6.25 (b).

Figure 6.25: CO₂ saturation in the upper coal seam (a) and the overburden layer (b)

Chapter 7 : SUMMARY AND CONCLUSIONS

7.1 – Summary

Unmineable or depleted coal seams are considered as an option for long-term carbon dioxide (CO₂) storage, due to the high affinity of CO₂ to the coal matrix. In the present study, two coal seams in the overburden were considered (Figure 4.1). When CO₂ is injected into a coal seam, a large amount of the injected gas is sorbed on the coal surface due to the greater affinity of CO₂ towards coal than methane. In the current research work, a hypothetical, three-dimensional, two- phase (gas–water), dual porosity model was constructed by using the Computer Modeling Group's GEM (Generalized Equation-of-State Model) simulator to achieve the following goals:

- Evaluate CBM recovery from both coal seams (upper and lower).
- Investigate CO₂ movement in the reservoir due to different well configurations.
- Investigate the swelling and shrinkage of coals.
- Investigate geomechanical responses, such as ground displacements, due to different well configurations.
- Investigate the migration of CO₂ in the reservoir and overburden layers in the presence of a hypothetical vertical permeable zone in the sandwich layer.
- Investigate different CO₂ leakage scenarios and compute the amount of leakage when different well configurations were selected.
- Investigate the influence of the permeability of the fractured zone in the sandwich layer on the amount of CO₂ leakage.
- Evaluate enhanced coalbed methane recovery (ECBM) from the lower and upper coal seams due to CO₂ injection into the lower coal seam, with the presence of a permeable fractured zone in the sandwich layer.
- Investigate whether a coal layer above the target coal reservoir could act as a CO₂ barrier, if CO₂ leaks through a permeable fractured zone in the impervious seal layer.

Two coal layers (Figure 4.1) at different depths were simulated with different well configurations. Reservoir properties were assumed based on the literature. The production of coalbed methane from both coal seams was evaluated by using horizontal and vertical well configurations in two different case studies. CO₂ injection was carried out into the lower coal seam by using a horizontal well configuration in one case study and by using a vertical well configuration in another case. The injection of CO₂ into a coal seam provides a dual-benefit of storing CO₂ in the formation as well as displacing methane to improve coalbed methane recovery. In low permeability coal reservoirs, horizontal wells can cover a large areal extent of the coal resulting in a large CBM recovery. Horizontal wells not only provide a large CBM potential but also provide enormous CO₂ storage potential. For the case with horizontal well configuration (coal reservoir permeability of 1 mD), about 10% gain of coalbed methane production was observed from the lower coal seam due to CO₂ injection. Vertical well configuration is usually preferred in reservoirs that have high permeability values. For the case with vertical well configuration (coal reservoir permeability of 15 mD), about 17.8% gain of coalbed methane production was observed from the lower coal seam due to injection of CO₂.

Coupled multiphase flow and deformation analyses were used to compute ground displacements caused due to coalbed methane production from both coal seams and CO₂ injection into the lower coal seam. Coalbed methane was produced from both coal seams for 21 years, and CO₂ injection was carried out into the lower coal seam for later 10 years. Details of the well configurations and time lines can be found in previous chapters of this report. Ground subsidence was observed due to coalbed methane production. During the injection of CO₂, very small magnitudes of ground uplift were observed near the injection zone. Even though some ground uplift was observed near the injection zone, ground subsidence was predominant.

In order to investigate CO₂ transport in the presence of a fractured zone in the caprock layer of the lower coal seam (sandwich layer), a hypothetical permeable fractured zone was simulated in the sandwich layer that communicates between the lower and the upper coal seams. Both, horizontal and vertical well configurations were used in different case studies. Also, two different locations of the permeable fractured zone were considered: close to the injection zone and far from the injection zone. Results showed that the presence of a permeable fractured zone in the overlying sandwich layer significantly influences the CO₂ transport behavior in the lower

and the upper coal seams. Results from the study also showed that the upper coal seam could act as a CO₂ barrier during a leakage scenario. However, the leaked CO₂ did not improve coalbed methane production from the upper coal seam even in the worst possible leakage scenarios.

7.2 – Conclusions

- The injection of CO₂ into a depleted coal seam provides dual benefit option of CO₂ storage and enhanced coalbed methane production.
- The permeability changes in the reservoir due to coalbed methane production and CO₂ injection are dependent on coal shrinkage and swelling.
- Production or injection horizontal wells cover a large areal extent of coal reservoirs, and provide enormous CBM potential and CO₂ storage capacity.
- In low permeability coal reservoir, horizontal wells are more effective compared to vertical wells.
- Coalbed methane production from a coal reservoir can cause ground subsidence, while CO₂ injection may cause ground uplift near the injection well(s).
- The presence of a permeable fractured zone in the caprock layer may have significantly different influence on CO₂ transport behavior.
- The amount of CO₂ leakage depends on the permeability of the fractured zone in the caprock layer.
- A secondary (upper) coal seam that can be found in the overburden layers above the targeted reservoir can possibly act as a CO₂ barrier, due to the high affinity of CO₂ to coal matrix. However, the leaked CO₂ may not enhance coalbed methane production from the upper coal seam.

7.3 – Recommendations

The following points are recommended for future research work:

- Use of different well configurations for the injection wells (e.g. an “X” configuration instead of a “+” configuration). Also, the use of different orientations for horizontal production wells is recommended.

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