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-THÈME-

SIMULATION AND OPTIMIZATION OF ENHANCED GAS RECOVERY UTILIZING CO2

Soutenue le : 07/06/2022 devant la commission d'examen

Jury :

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SIMULATION AND OPTIMIZATION OF ENHANCED GAS RECOVERY UTILIZING CO_2

Presented on: 07/06/2022 in front of the jury:

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Dedicated to the memory of my mother

BOUSSOUAR Hadjira

To the soul of An amazing father SEID AbdelKader, to my mentor and my big brother SEID Sohaib, The rest of my supportive Family: Hiba, Rihem, Chahd and Almi Samah

Thank you

SEID Mohamed Haitham

Dedication

I dedicate this achievement to my father Hocine and my mother Fatiha, who with love and effort have accompanied me in this process, without hesitating at any moment of seeing my dreams come true, which are also their dreams.

To my maternal grandmother may Allah heal her.

To my Brothers Mouad, Mohamed, Amer, to my sister Marwa, to my brother's wife Ilhem, who have always supported me unconditionally and whose good examples have taught me to work hard for the things that I aspire to achieve. To my nephew Sam, to my cousins, to my uncles and aunts, my friends Haithem, Abdelhak, Wafaa, Ahlem, Ilyes, Batoul, wahid, Rania, Nader and to all those who made this achievement possible: love and Unlimited gratitude.

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Abstract:

Today, with increasing energy demand and declining gas fields productivity it has become mandatory to focus on improving gas recovery from mature hydrocarbon fields. This thesis aims to study enhanced gas recovery with CO2 injection for depleted gas reservoir. In order to study EGR- CO2, a simulation was done by CMG software. we built a 2d model on which we studied the effect of various parameters such as reservoir heterogeneity, permeability distribution … on two factors: the recovery rate and the hydrocarbon pore volume of CO2 injected. we did also simulate a method for enhanced gas recovery with the injection of a water slug, it showed a promising result on both recovery factor, HCPV CO2 injected by delaying the CO2 breakthrough.

ملخص :

اليوم , مع زيادة الطلب على الطاقة و انخفاض إنتاجية حقول الغاز , أصبح من الضروري التركيز على تعزيز استخراج الغاز من حقول الهيدروكربون ضعيفة الإنتاج . تهدف هذه الأطروحة الى دراسة تعزيز استخراج الغاز عن طريق حقن ثاني أكسيد الكربون لخزانات الغاز المستنفذة . من اجل دراسة حقن ثاني أكسيد الكربون تم إجراء محاكاة بواسطة برنامج CMG , قمنا ببناء نموذج ثنائي الأبعاد , على أساسه تمت دراسة تأثير مختلف الخصائص مثل عدم تجانس الخزان و توزيع النفاذية .... على عاملين : معدل الاسترداد و حجم المسام الهيدروكربونية لثاني أكسيد الكربون المحقون .
قمنا أيضا بمحاكاة طريقة لتعزيز استعادة الغاز عن طريق حقن جحم من الماء ممزوج بالكربون , و أظهرت نتائج جيدة على كل من عامل الاسترداد و حجم مسام الخزان المحقونة بثاني اكسيد الكربون و التي ساهمت في تأخير إنتاج ثاني أكسيد الكربون المحقون .

Résumé :

Aujourd'hui, avec l'augmentation de la demande d'énergie et la baisse de la productivité des champs de gaz, il est devenu obligatoire de se concentrer sur l'amélioration de la récupération du gaz des champs d'hydrocarbures matures. Cette thèse vise à étudier la récupération améliorée du gaz par injection de CO_2 pour le réservoir de gaz épuisé. Afin d'étudier EGR-CO_2, à l'aide de logiciel CMG. Nous avons construit un modèle 2d sur lequel nous avons étudié l'effet de divers paramètres tels que l'hétérogénéité du réservoir, la distribution de perméabilité… sur deux facteurs : le taux de récupération et le volume de pores d'hydrocarbures de CO_2 injecté. Nous avons également simulé une méthode de récupération améliorée du gaz avec l'injection d'une water slug, elle a montré des résultats prometteurs sur les deux facteurs de récupération, HCPV CO_2 injecté en retardant la percée de CO_2.

Keywords: Enhanced gas recovery, CO_2 injection, Gas reservoir, simulation.

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Abbreviations:

EGR	Enhanced Gas Recovery
EOR	Enhanced Oi Recovery
R/P	Reserves-to-Production
CCS	Carbon dioxide (CO_2) capture and storage
CO2-VAPEX	CO2-Vapour Extraction Process
SCO_2	Supercritical carbon dioxide
DPC	Dykstra–Parson’s coefficient
BHP	Bottom Hole pressure
DWGC	Dip of Water-Gas contact, ft
S_g	gas saturation, %
S_w	Water saturation, %
K	reservoir permeability, mD
K_v	Vertical Permeability, mD
K_h	Horizontal Permeability, mD
HCPV	Hydrocarbons pore volume
ρ	density lb/ft^3
G	gravitational acceleration, 9.81 m/sec^2
H	reservoir thickness, ft
L	reservoir length in the flow direction, m
SCF	standard cubic feet
CMG	Computer Modeling Group simulator software

General Introduction

The demand for cleaner and affordable energy has been on the rise over the past few decades, and is currently one of the major global challenges [1]. A continuously growing population and rapidly expanding industries in many parts of the world are putting a strain on energy supply. Despite significant advances in renewable energies, fossil fuels will remain a primary source of energy for years to come [2-4]. Natural gas, an important energy source for power generation and other important processes such as water desalination. The consumption of natural gas has increased by 78 billion m^3 in 2019, representing a 2% rise from the previous year's consumption. On the other hand, the global reserves-to-production (R/P) ratio of natural gas has been steadily declining over the last 20 years [5]. With less new discoveries of conventional gas resources, it is crucial to improve the recovery factor from mature gas reservoirs. This can be achieved through enhanced gas recovery (EGR) processes. Injecting CO2 into gas reservoirs can provide a dual benefit of enhanced gas recovery (EGR) and partial capture of CO2 in the subsurface reservoir.

The role of CCS as an effective climate mitigation technology depends on our ability to securely store large volumes of carbon dioxide (CO2) in geological formations for thousands of years. We know that oil and gas have been contained in underground reservoirs for much longer periods of time. Some of the Current experiences from large-scale injection cases, and the CO2- EGR projects, has confirmed that CO2 can also be stored securely. Various trapping mechanisms work together in the subsurface to keep it from escaping back into the atmosphere. However, injected CO2 may leak through natural or man-made pathways, causing effects on drinking water and marine ecosystems. Adequate geological, geophysical and geomechanical assessment of a potential CO2 injection site is thus the key to safe operations. [6]

Most of the aspects of CO2 injection into the reservoirs for the purpose of Enhanced Oil Recovery (EOR) and Enhanced Gas Recovery (EGR) have been known for decades [7,8]. A large scale and practical CO2-EOR/EGR projects around the world have already been initiated and have shown the feasibility of these kinds of projects. Since 2004, CO2 has been separated from extracted natural gas at Krechba gas field at In Salah in the Algerian Sahara Desert and re-injected into the water leg of gas producing reservoir for the purpose of both sequestration and gas production enhancement [9]. Most CO2-EOR projects in the world are currently running in the United-State for recovering heavy oil, they used CO2-Vapour Extraction Process (CO2-VAPEX) and other method for producing more oil [10].

Many different mechanisms are involved during CO2 injection projects. A.R.Kovscek [11] thinks that there are three important mechanisms that governs CO2 injection into oil/water reservoir. The first is physical containment or so-called hydrodynamic trapping of CO2 as a gas or supercritical fluid beneath low permeable cap rock because of the capillary forces. The crucial concern for hydrodynamic trapping is the possible leakage of CO2 through the cap rock. Next, CO2 can react either directly or indirectly with minerals in the rock, with other solutes in the formation fluids, or the formation fluids themselves. It sometimes forms stable minerals called carbonates in a process called mineralization. Lastly the most important mechanism in CO2-EOR project is that carbon dioxide can dissolve directly in the water and oil phases by molecular diffusion. As a result, the density of the fluids present in the formation increases and eventually the CO2-fluid interface become unstable, for favourable conditions, density driven natural downward convection occurs and CO2-saturated fluid moves downward and it is replaced by underlying unaffected fluid, which enhances the mass transfer rates of CO2 into fluid formation followed by important enhancement in the amount of produced oil/gas and CO2 capacity storage.

Available literature didn't describe what types of gas reservoirs were suitable for CO2-EGR, and what geological conditions and working systems were suitable and reasonable. After that, studies by Amin and al. (2010) and Sidiq and Amin (2010) an immiscible interface between supercritical CO_2 and methane is documented. the Experimental results from this study focuses on the CO_2-methane relative permeability, water saturation and dip angle from displacement tests that were conducted under various conditions, pressures from 10.34 - 40.68 MPa, composition from 0.1 - 0.75 mole percent of CO_2 in the in-situ gas, and injection rates (velocities) from 1-10 cm/h (0.0166 - 0.166 cm/min). Different test conditions (pressure and temperature) and injection rates, (a various conditions of each factor) were implemented to evaluate the impact of the intrinsic behaviour of CO_2 at super critical conditions. They concluded that the supercritical CO2 injection have better EGR effect in case of lower permeability, higher water saturation and greater dip angle **[**12**]**

There are some other recent studies of other properties that affects the recovery of natural gas using CO2 such as rock properties, gas properties and operating conditions

Recently a number of studies have been carried out on the use of CO_2 for EGR to improve natural gas recovery and CO_2 storage [13,14,15-18]. While CO_2-gas mixing and early CO_2 breakthrough have been identified as a primary obstacle in CO_2-EGR, there has been little research done to identify potential strategies to overcome this issue and optimize the CO_2-EGR process with the simultaneous goal of CO_2 storage.

We propose to co-inject carbonated water and supercritical CO2. The first stage involves the injection of a slug of carbonated water. This serves two main purposes. First, the injection of carbonated water helps to build up the pressure before beginning supercritical CO2 injection. Second, CO2 is disposed of in the aqueous phase, in which it is stable and exhibits increasing solubility as the pressure builds up. Furthermore, the presence of carbonated water, which is dense and flows down-dip to the bottom of the reservoir, inhibits the mobility of free CO2. After a determined pore-volume of carbonated water is injected, the second stage begins. In this stage, pure CO2 is injected in its supercritical state. At the relatively higher reservoir pressure, CO2 has a better sweep and displacement efficiency, and its mobility is inhibited due to the presence of carbonated water, therefore delaying breakthrough and reducing recycling.

What are the ideal properties to stimulate gas production by injecting CO2 is the problem that this study focuses on. We used a numerical simulator as a tool to study some key parameters that control subsurface flow. Our simulation work is done on a theoretical base case with the aim of studying the general relationship between carbon dioxide storage and natural gas recovery with different reservoir conditions.

Chapter I :

Introduction to CCS/ CO2 –EGR Process

I-1 Carbon capture and storage

Carbon dioxide (CO_2) capture and storage (CCS) is a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. [19]

Injection into oil, gas, and water-bearing geological formations are widely regarded as the front running option for CO_2 storage and is the only option that has so far been applied on a commercial scale. The readiness of this option for commercial deployment is due to the use of site characterization, injection, and monitoring technologies. [20]

I-1-1 CCS contribution to fight against greenhouse gases and uses for EGR purposes

Other mitigation options include energy efficiency improvements, the switch to less carbon-intensive fuels, nuclear power, renewable energy sources, enhancement of biological sinks, and reduction of non-CO_2 greenhouse gas emissions. CCS has the potential to reduce overall mitigation costs and increase flexibility in achieving greenhouse gas emission reductions. The widespread application of CCS would depend on technical maturity, costs, overall potential, diffusion and transfer of the technology to developing countries and their capacity to apply the technology, regulatory aspects, environmental issues and public perception. Available technology captures about 85–95% of the CO_2 processed in a capture plant. A power plant equipped with a CCS system (with access to geological or ocean storage) would need roughly 10–40% more energy than a plant of equivalent output without CCS, of which most is for capture and compression. For secure storage, the net result is that a power plant with CCS could reduce CO_2 emissions to the atmosphere by approximately 80–90% compared to a plant without CCS (see figureI-1) [19] [21]

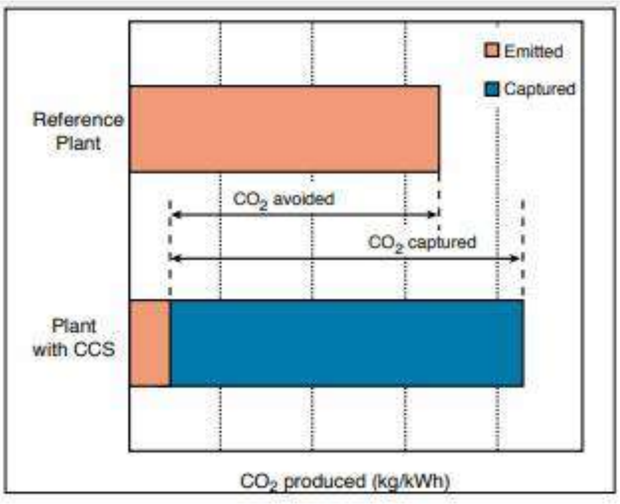

Figure I.1: CO_2 capture and storage from power plants.

I-1-3 Current status of CO_2 capture and storage technologies

I-3-1CO_2 capture technologies

There are different types of CO_2 capture systems: post combustion, pre-combustion and oxyfuel combustion. The concentration of CO_2 in the gas stream, the pressure of the gas stream and the fuel type (solid or gas) are important factors in selecting the capture system.

Post-combustion capture of CO_2 in power plants is economically feasible under specific conditions. It is used to capture CO_2 from part of the flue gases from a number of existing power plants. Separation of CO_2 in the natural gas processing industry.

The technology required for pre-combustion capture is widely applied in fertilizer manufacturing and in hydrogen production. Although the initial fuel conversion steps of precombustion are more elaborate and costly, the higher concentrations of CO_2 in the gas stream and the higher pressure make the separation easier.

Oxyfuel combustion is in the demonstration phase and uses high purity oxygen. This results in high CO_2 concentrations in the gas stream and, hence, in easier separation of CO_2 and in increased energy requirements in the separation of oxygen from air.

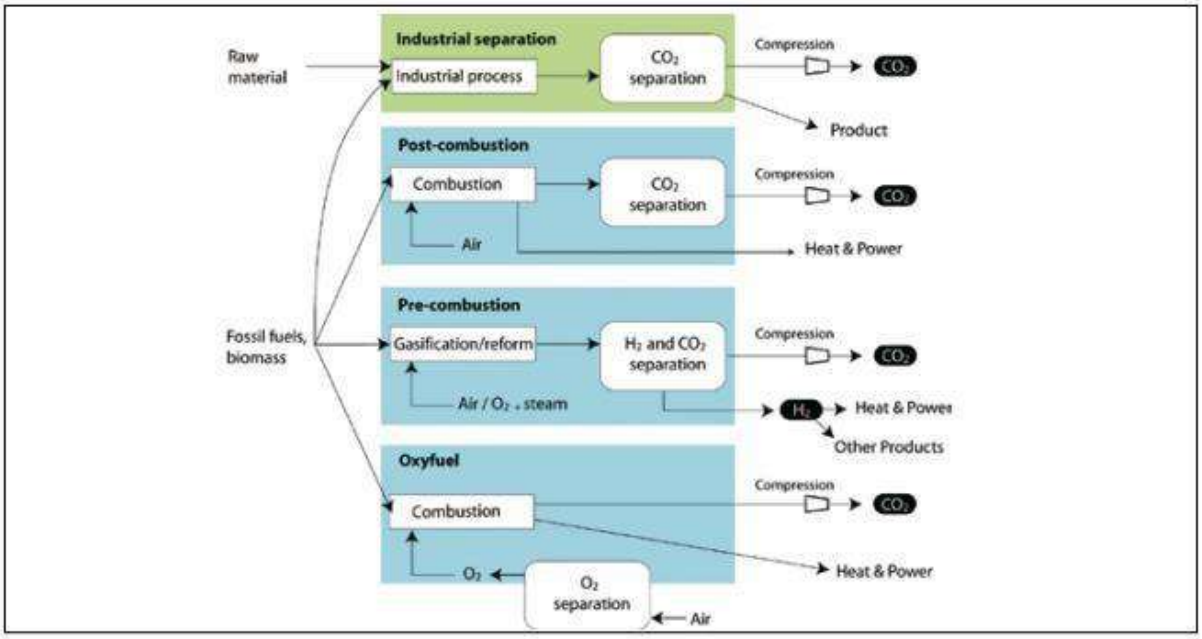

Figure I.2: Schematic representation of carbon capture systems.

I-3-2 CO_2 Storage options

Storage of CO_2 in deep, onshore or offshore geological formations, uses many of the same technologies that have been developed by the oil and gas industry and has been proven to be economically feasible under specific conditions for oil and gas fields and saline formations, but not yet for storage in unmineable coal beds.

Besides the underground geological storage (our targeted study), there are other options for CO_2 storage such as ocean storage, either by dissolving it in water or injecting it in the sea floor using an offshore platform, the second option is reactions of carbon dioxide, The technology is currently in the research stage. [19]

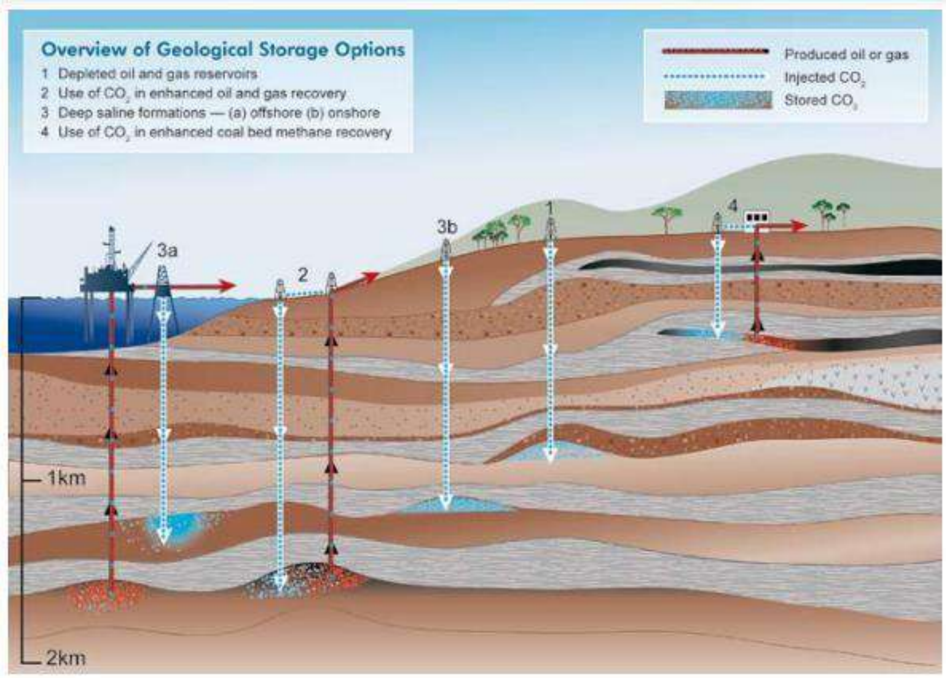

Figure I.3: Overview of geological storage options.

I-4 Existing and planned CO_2 storage projects

The Global CCS Institute, a think tank, announced that ten large-scale carbon capture and storage (CCS) facilities were verified and added to its database. "There are now 51 CCS facilities globally 19 in operation, four under construction, and 28 in various stages of development with an estimated combined capture capacity of 96 million tonnes of CO_2 per annum.

A number of pilot and commercial CO_2 storage projects are under way or proposed to date, some of actual or planned commercial projects are associated with major gas production facilities that have gas streams containing CO_2 in the range of 10–15% by volume, such as Sleipner in the North Sea, Snohvit in the Barents Sea, In Salah in Algeria and Gorgon in Australia, as well as the acid gas injection projects in Canada and the United States. At the Sleipner Project, operated by Statoil, more than 7 $MtCO_2$ has been injected into a deep subsea saline formation since 1996.

At the In Salah Gas Field in Algeria, Sonatrach, BP and Statoil inject CO_2 stripped from natural gas into the gas reservoir outside the boundaries of the gas field. Statoil is planning another project in the Barents Sea (concept phase), where CO_2 from the Snohvit field will be stripped from the gas and injected into a geological formation below the gas field. Chevron is producing gas from the Gorgon field off Western Australia, containing approximately 14% CO_2. The CO_2 is injected into the Dupuy Formation at Barrow Island. In the Netherlands, CO_2 is being injected at pilot scale into the almost depleted K12-B offshore gas field. Forty-four CO_2 -rich acid gas injection projects are currently operating in Western Canada, ongoing since the early 1990s. Although they are mostly small scale, they provide important examples of effectively managing injection of CO_2 and hazardous gases such as H_2S. Eight of these new major CCS projects are located in United States and two respectively in the United Kingdom and the United Arab Emirates.[19] [2]

I-5 Application of CO_2 storage in Algeria

The In Salah Gas Project, a joint venture among Sonatrach, BP and Statoil located in the central Saharan region of Algeria, is the world's first large-scale CO_2 storage project in a gas reservoir The Krechba Field at In Salah produces natural gas containing up to 10% CO_2 from several geological reservoirs and delivers it to markets in Europe, after processing and stripping the CO_2 to meet commercial specifications. The project involves re-injecting the CO_2 into a sandstone reservoir at a depth of 1800 m and storing up to 1.2 $MtCO_2$ per year. Carbon dioxide injection started in April 2004 and, over the life of the project, it is estimated that 17 $MtCO_2$ will be geologically stored. The project consists of four production and three injection wells (Figure I.4). Long-reach (up to 1.5 km) horizontal wells are used to inject CO_2 into the 5-mD permeability reservoir. [22]

The Krechba Field is a relatively simple anticline. Carbon dioxide injection takes place down-dip from the gas/water contact in the gas-bearing reservoir. The injected CO_2 is expected to eventually migrate into the area of the current gas field after depletion of the gas zone. The field has been mapped with three-dimensional seismic and well data from the field. Deep faults have been mapped, but at shallower levels, the structure is unfaulted. The storage target in the reservoir interval therefore carries minimal structural uncertainty or risk. The top seal is a thick succession of mudstones up to 950 m. A preliminary risk assessment of CO_2 storage integrity has been carried out and baseline data acquired. Processes that could result in CO_2 migration from the injection interval have been quantified and a monitoring program is planned involving a range of technologies, including noble gas tracers, pressure surveys, tomography, gravity baseline studies, microbiological studies, four-dimensional seismic and geomechanical monitoring.

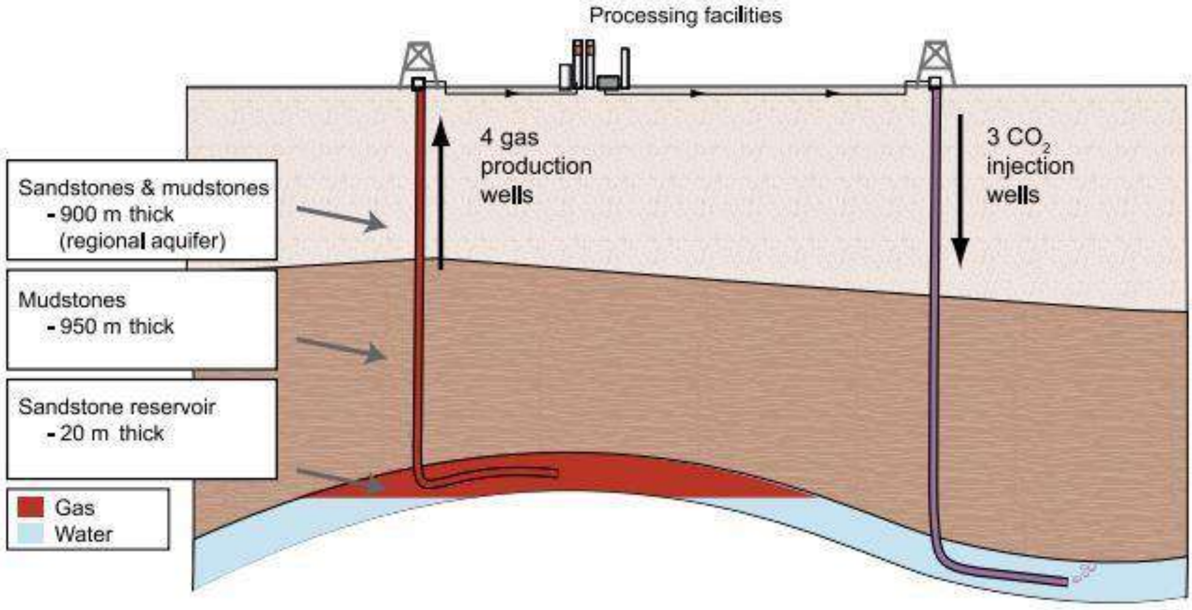

Figure I.4: Schematic of the In Salah Gas Project, Algeria.

I-6 Gas recovery by CO2 injection

I-6-1 CO2-EGR: definition and advantages

CO_2-EOR (enhancing oil recovery by injecting CO_2) has been a mature technology, but CO_2-EGR (enhancing gas recovery by injecting CO_2) is in a proactive study. Enhanced gas recovery by injecting CO_2, is to displace natural gas by injecting CO_2 in the supercritical phase. It can both enhance the recovery of gas reservoirs and realize CO_2 storage. Currently, this technique is still at its exploring stage. The effect of CO_2-EGR is not clarified, the geologic conditions for CO2-EGR are not definite, and the rational working system for CO_2-EGR is not available.

Globally, only three small-scale pilot projects have been carried out, namely the CSEGR pilot projects in the North Sea K12-B in the Netherlands, Budafa in Hungary and Algeria. The offshore gas reservoir, K12-B, in the North Sea, the Netherlands, is the world's first gas reservoir recovered by injecting CO_2 (13%) produced in the gas field [19]. In the 3800 m deep reservoir, CO_2 was injected at 20000 t/a in the pilot experimental stage, and at 310000e475000 t/a in the field implementation stage. In Budafa Szinfelleti, Hungary [16], CO_2 produced from a nearby CO_2 reservoir (80% CO_2 and 20% methane) was injected to enhance gas recovery. When the gas recovery reached 67%, CO_2-EGR was carried out. After 1.5 year of injection, CO_2 breakthrough occurred. At present, the enhanced gas recovery is

11.6% by injecting CO_2. In the Krechba gas field in deep Sahara Desert in Algeria, the CO_2-EGR project is the world's first gas reservoir to store CO_2 during production. CO_2 content in the gas reservoir is 5%e10%. After separation, CO_2 was injected into a 20 m thick reservoir with moderate permeability from three horizontal wells, while natural gas was produced from four wells. The average daily CO_2 injection is 1000 t and the total planned storage is 8 millions t. These pilot experiments have simply proved that gas recovery can be enhanced by injecting supercritical CO_2 during underground CO_2 storage.

The primary purpose of the pilot experiments of CO_2 injection into gas reservoirs is to store CO_2, and the gas reservoirs into which CO_2 is injected are medium and high permeability reservoirs. Available literature didn't describe what types of gas reservoirs were suitable for CO_2-EGR, and what geological conditions and working systems were suitable and reasonable. In this regard, the authors first built a heterogeneous model for well cluster based on mathematical modelling, and then analysed the influences of geological conditions on gas recovery by supercritical CO_2 and proposed reasonable CO_2 injection models. Finally, with the Daniudi gas field in the Ordos Basin taken as an example, the target area was selected and the CO_2-EGR performance was evaluated. This provides a basic reference for developing the tight and low-permeability sandstone reservoirs with low recovery in China. [23]

I-7 Physical properties of CO2 and supercritical CO2

I-7-1 properties Of Carbon Dioxide (CO2)

Carbon dioxide is formed from the combination of two elements: carbon and oxygen. It is produced from the combustion of coal or hydrocarbons. CO_2 is a colorless, odorless and non-toxic stable compound found in a gaseous state at standard conditions. In petroleum engineering application it can be in gas or liquid state depending on the PVT conditions. Table 1 gives the main properties of Carbon Dioxide. [24]

Table I.1 Carbon dioxide properties [21]

Property	Value
Molecular weight	44 g/mol
Critical temperature	31 °C
Critical pressure	73.77 bar
Critical density	467.6 kg/m^3
Triple point temperature	-56.5 °C
Triple point pressure	5.18 bar

Boiling (sublimation) point (1.013 bar)	-78.5 °C
Critical Z factor	0.274
Solid Phase	
Density of carbon dioxide snow at freezing point	1562 kg/m^3
Latent heat of vaporization (1.013 bar at sublimation point)	571.1 kJ/kg^1
Liquid Phase	
Vapor pressure (at 20 °C)	58.5 bar
Liquid density (at -20 °C and 19.7 bar)	1032 kg/m^3
Viscosity (at STP)	99 µPa.s
Gas Phase	
Gas density (1.013 bar at boiling point)	2.814 kg/m^3
Gas density (at STP)	1.976 kg/m^3
Specific volume (at STP)	0.506 m^3/kg
C_p (at STP)	0.0364 kJ/ (mol.K)
C_v (at STP)	0.0278 kJ / (mol.K)
C_p/C_v	1.308
Viscosity (at STP)	13.72 µPa.s
Thermal conductivity (at STP)	14.65 mW / (m K)
Enthalpy (at STP)	21.34 kJ/mol
Entropy (at STP)	117.2 J.mol/K

STP: Standard Temperature and Pressure, which are 0°C and 1.013 bar.

The phase diagram (Figure I.5) of CO_2 is also a key data since we can inject it under different temperature and pressure conditions. The three phases are shown in this diagram, with the triple and critical point. Above the critical point the CO_2 is considered as a supercritical fluid.

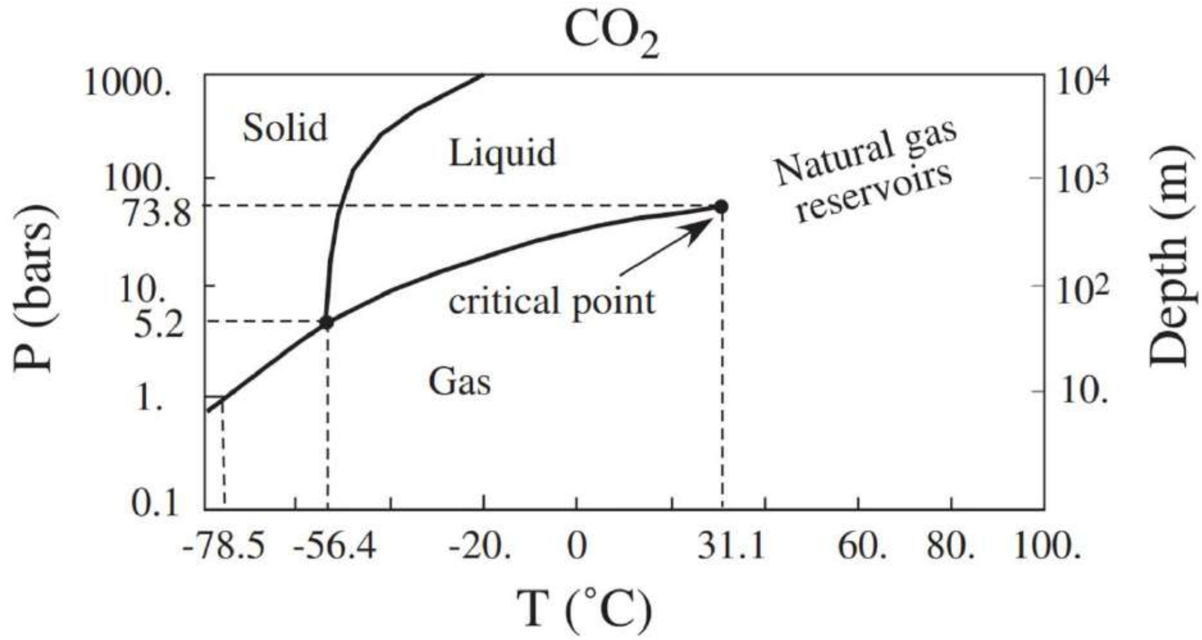

Figure I.5: Phase diagram showing CO2 will normally be supercritical in natural gas reservoir

I-7-2 Behavior of SCO_2-natural gas

I-7-2-1 Density comparison of CO_2 and CH_4

The thermodynamic properties Of Carbon Dioxide (CO_2) and Methane (CH_4) are important, because they are responsible to optimize compression, monitor transportation and model mobility of gas in the reservoir conditions.

Likely, CO_2 at deep reservoir conditions behave as a super critical fluid which has viscosity of a gas and density of a liquid. The higher density of CO_2 means that it will migrate downward in the reservoir as relative to CH_4. Figure I.6 describe the density comparison Of CH_4 and CO_2 changes with depth.

- Methane density is calculated using Jacobsen and Stewart equation
- CO_2 density is estimated by an equation developed by Chapela and Rowlinson

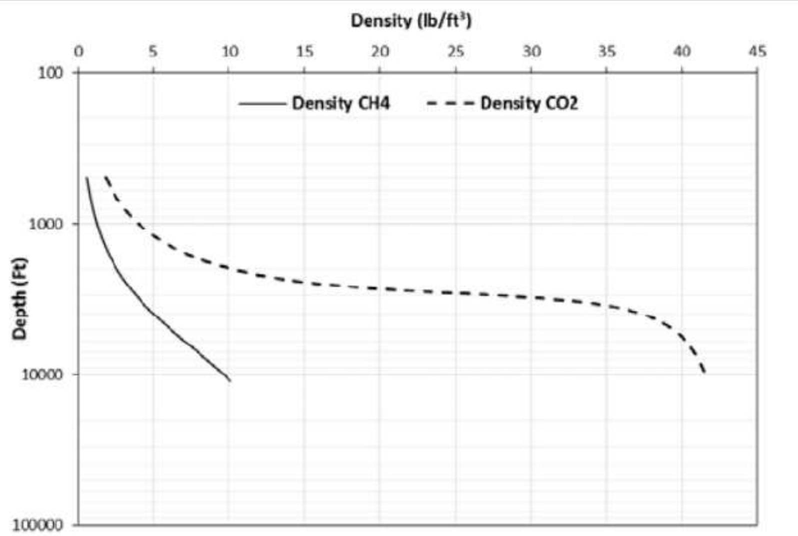

Figure I.6: density comparison of CO_2 and CH_4 with formation depth

The figure clearly signifies that CO_2 is highly denser than CH_4 throughout the reservoir pressure range. CO_2 will tend to migrate in the downward direction relative to CH_4.

I-7-2-2 Viscosity and solubility comparison of CO_2 and CH_4

Figure I.7 shows the viscosity comparison of CO_2 and CH_4 with respect to formation depth. The mobility ratio of CH_4 displacement by CO_2 will be very favorable rendered by the highly viscous property of CO_2. Figure 3 shows the comparison of solubilities of CH_4 and CO_2

- Solubility of CO_2 is modeled using correlations developed by Chang, Coats and Nolen
- CH_4 solubility in aqueous phase is modeled using correlation developed by Duan and Mao.

The solubility curve shows that CH_4 solubility in brine water is negligible as compared with the solubility of CO_2. In these correlations, the solubilities of CO_2 and CH_4 are a function of temperature, pressure and salinity.

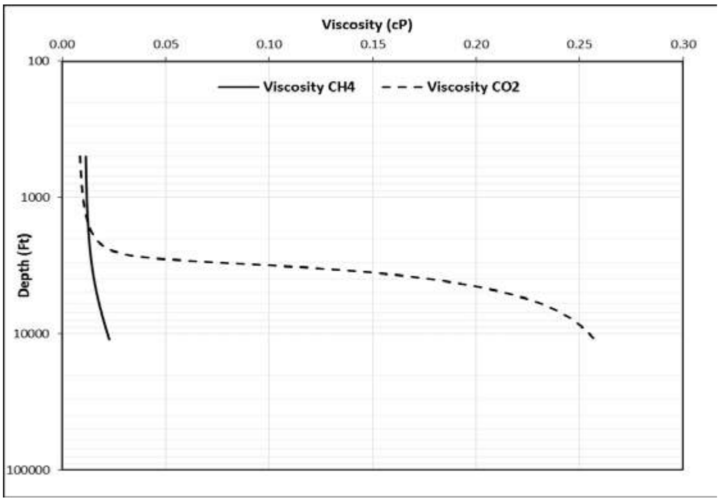

Figure I.7: Viscosity comparison of CO_2 and CH_4 with formation depth

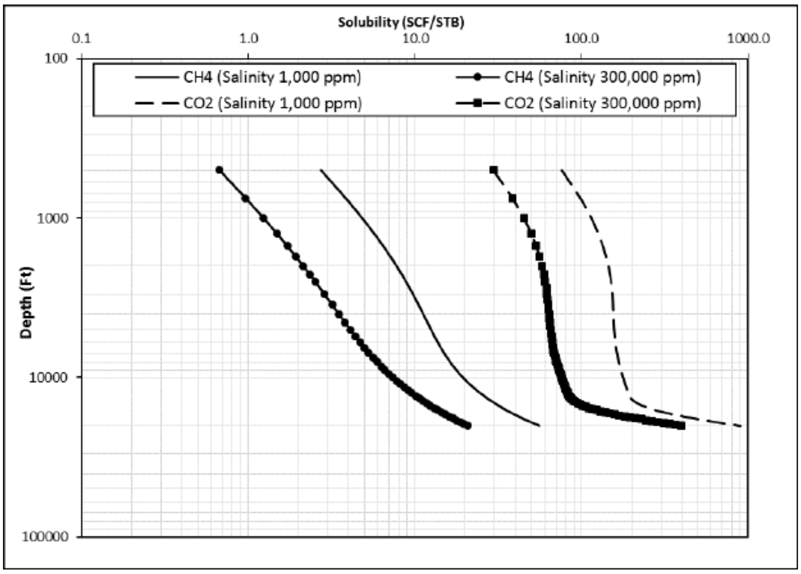

Figure I.8: **Solubility of CO_2 and CH_4 with varying formation depth and salinity**

The comparison of solubility at salinity ranges from 1,000 ppm to 300,000 ppm in Figure I.8 indicates that the solubility decreases with an increase in salinity because of the presence of dissolved solids in the formation water, also termed as a salting out effect. [25]

I-7-2-3 adsorption capacity

A study on gas field, a tight-sandstone gas reservoir in western China, was used in the experiments. The permeability was $0.11{\times}10^{-3}\mu m^2$ and the porosity was 6.98%. to study the Adsorption capacity of supercritical CO_2 and CH_4 (natural gas) in tight core ($0.11{\times}10^{3}\mu m^2$), the results are shown in Figure I.9

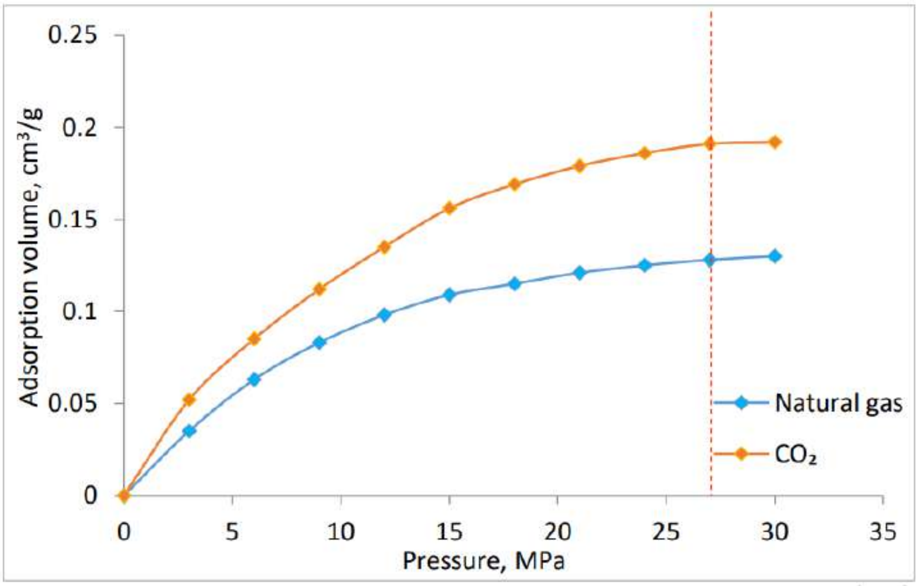

Figure I.9: Adsorption volume of natural gas and CO2 in tight core of $0.11{\times}10^{-3}\mu m^2$

From Figure I.9 It can be seen that the adsorption volume of both CH_4 and supercritical CO_2 in tight core increase with the increase of the pressure. Moreover, the adsorption volume sCO_2 in tight core is significantly higher than that of natural gas. Adsorption volume supercritical CO_2 is 0.191cm3 /g under reservoir condition, nearly 50% higher than that of natural gas (0.128cm3 /g). This result indicates that in case of sCO_2 injection in tight gas reservoirs, natural gas can be easily replaced from the reservoir by sCO_2 through competitive adsorption, since sCO_2 has stronger adsorption capacity in tight cores than natural gas. [26]

I-7-2-4 Diffusion capacity

In the same studies in gas reservoir in western China. Gas injection EGR effect appeared to be strongly affected by the diffusion between natural gas and injected gas. The diffusion test of CO_2 in natural gas (temperature: 82°C) were performed and the results are shown in Figure I.10.

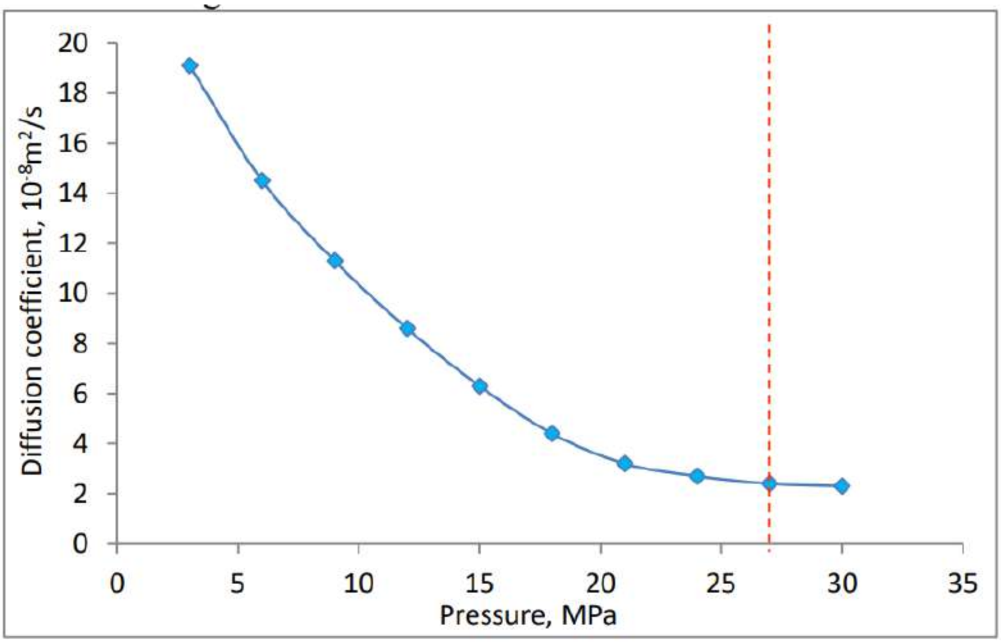

Figure I.10: Diffusion coefficient of CO2 in natural gas

It is clear from Fig. 4 that diffusion coefficient of CO_2 in natural gas show quick decrease with the increasing pressure, and the decreasing rate become lower when the pressure is greater than 20MPa. The diffusion coefficient is 2.4×10-8m^2 /s under reservoir pressure, which indicates that the CO_2 and natural gas will not substantially mix in that case. Therefore, the near-piston displacement can be achieved in the case of CO_2 injection, which will lead to a better EGR effect. [26]

Chapter II:

Enhanced gas recovery with CO2 injection simulation

II-1 Similar previous simulations

A lot of studies were performed to test non-hydrocarbons CO_2 & N_2 Gases for enhancing gas recovery.

Guo Ping studied the various EGR method for various reservoir conditions like for low-permeability gas reservoirs, condensate gas reservoirs and edge/bottom water gas reservoirs. They found that EOR technologies cannot be directly applied to EGR due to the difference between them in definition and residual oil/gas description methods and EGR technologies for low-permeability gas reservoirs focus on reducing abandonment pressure and increasing sweep volume. Guo Ping presented screening criteria for EGR methods depending on reservoir flow dynamics and geo-parameters. [23]

Hossein Zangeneh, Saeid Jamshidi and Mohammad Soltanieh performed simulation studies to study enhanced gas recovery and carbon dioxide sequestration in natural gas reservoirs. They found that Injecting carbon dioxide in natural gas reservoirs for enhanced gas recovery and carbon dioxide sequestration is an effective process and can avoid emission of significant amount of CO_2intothe atmosphere. Therefore, as the gas reservoir recovery and revenues of Clean Development Mechanism (CDM) increases, the process of enhanced gas recovery/carbon capture and storage (EGR/CCS) becomes economically and environmentally profitable. The importance of optimization in this process should be considered, because if this process is conducted in non-optimized condition, it may result in negative NPV due to extra mixing of the gases in the reservoir and early breakthrough of injection gas in the production well and causing extreme separation costs. Injecting pure CO_2using five spots well setting (central injection well) causes the optimum results for the process. In this condition the injection rate should be lower than production rates in order to prevent extra mixing of the base gas and CO_2andearly breakthrough of the injecting gas in production well and imposing separation costs on the surface. Early CO_2 injection from the beginning of the production (Case1) in this study can decrease the net present value (NPV) due to significant mixing of injecting and base gases, but CO_2injectionafter reservoir depletion (Case 2) has the potential of increasing NPV [24]

Ding chen took an experimental approach to study the Supercritical CO_2 ($SCCO_2$) injection for EGR in tight gas reservoirs. Phase behavior investigation was performed to indicate the property difference between $SCCO_2$ and natural gas under reservoir condition. Results show that $SCCO_2$ has significantly higher density and viscosity than natural gas under reservoir condition. Gravity differentiation and near-piston displacement can be achieved in case of SCCO2 injection and thus the displacement efficiency can be improved. [25]

Muhammad Attique Amer highlighted a newly proven gas reservoir from the western Poland classically investigated for EGR and CO2 sequestration, based on the results of diverse prediction scenarios. Simulation results reveal that 90% primary recovery can be taken from the reservoir up to 25 years of production, however, the gas rate of production will be very low after 2034. This recovery will not be economical for production and distribution point of view after this year. By injecting the CO2 from 2032, sweep efficiency can be increased and repressurized the reservoir again to get the more production at economical level. Results illustrate that almost 14% additional gas can be obtained by using this sequestration process. Breakthrough of CO2 for EGR is allowed maximum 7% in the production wells. Additional recovery can be increased if we allowed breakthrough up to 15-20%. But this scenario assumes the need to separate installation for the refining purpose of this CO2 which can increase the operational and investment cost of this project. One million ton of CO2 per year can be injected from the one well and using two injection wells, total 60-million-ton CO2 can be injected into the reservoir up to 30 years. Saturation of CO2 stream with the passage of time may also look after by the help of this modeling and simulation. This can be helpful for the proper monitoring of CO2 leakage aspects in the reservoir. [26].

II-2 Simulator software

In this study, we use CMG GEM v2019.1, a commercial simulator from Computer Modeling Group (CMG). GEM is a fully-coupled compositional Equation of State (EOS) simulator capable of modeling subsurface flow problems, including CO2 storage in oil and gas reservoirs

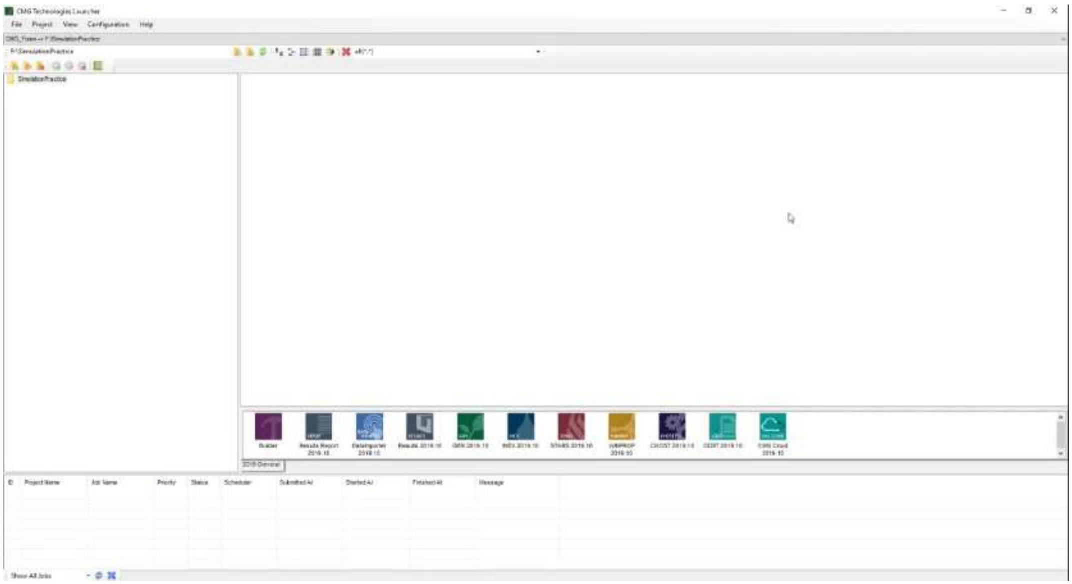

Figure II.1 : CMG software interface and tools

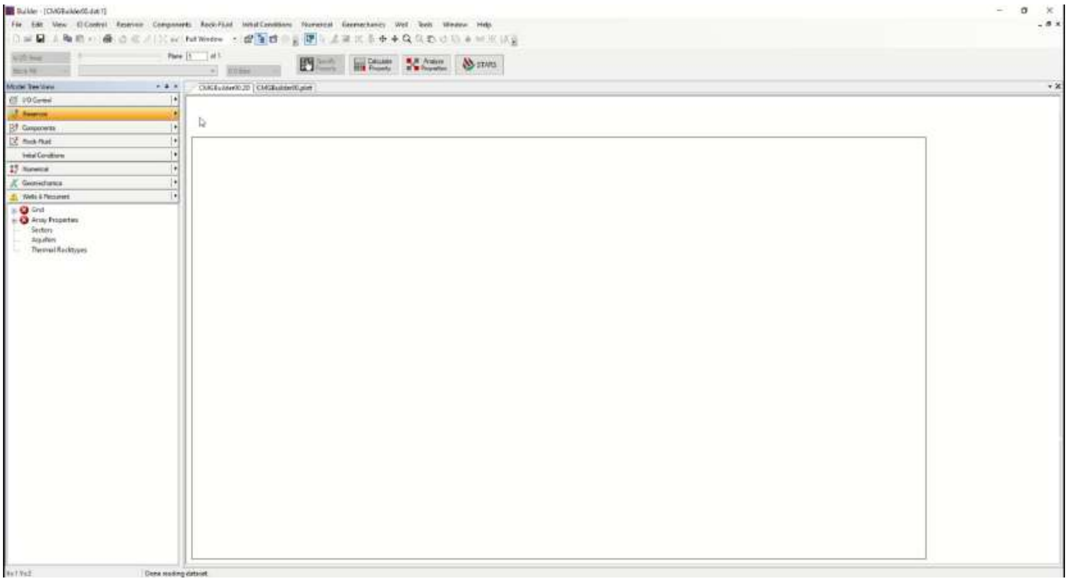

Figure II.2 : CMG model builder interface

II-3 Mechanistic Simulations: Synthetic Reservoir 2D Cross-Section

We first consider a 2D gas reservoir model of physical dimensions 500 × 10 × 100 m representing a vertical (I-K) cross-section. The cross-section is discretized into a 50 × 1 × 20 regular Cartesian grid, as shown in Figure 3. There are 10 geological layers with varying permeability. Each layer is assumed to be homogenous, and the physical properties are uniform. The heterogeneity of the reservoir model is quantified by the Dykstra–Parson's coefficient [27], which is 0.5 for the case shown. There are two vertical wells (an injector and producer) completed across the entire thickness of the reservoir. Other physical, initialization, and sensitivity parameters for the simulation model are summarized in Table 1. The simulations of CO2-EGR and storage for the synthetic reservoir cross-section are controlled by the constraints summarized in Table 2

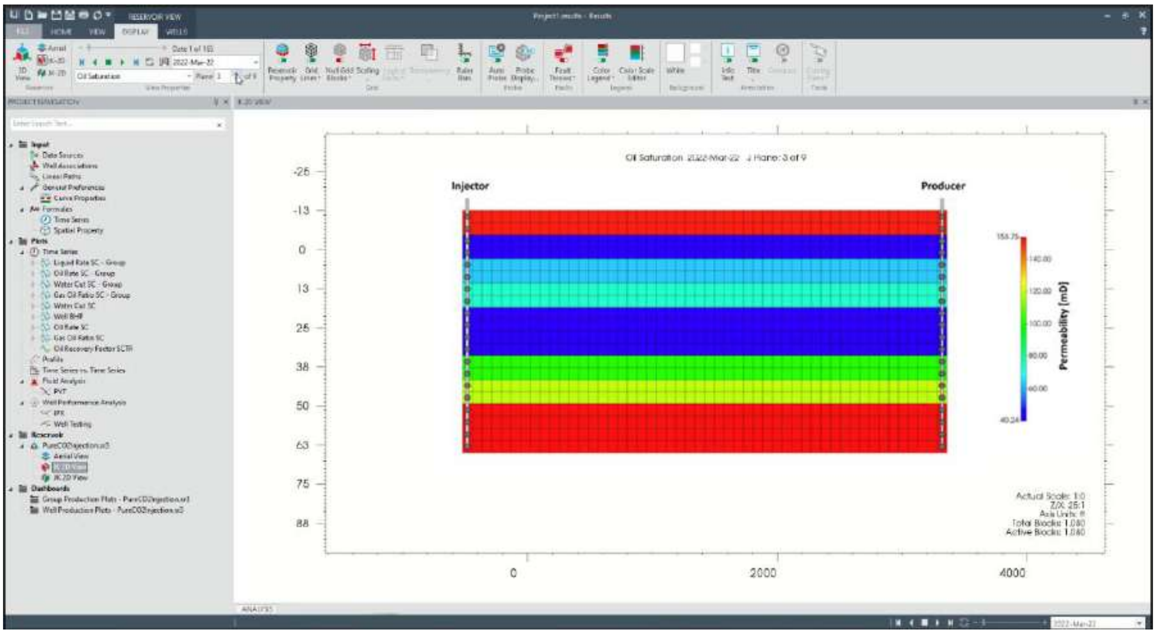

Figure II.3: 2D synthetic reservoir cross-section showing the geologic layers, grid discretization,

Table II.1 :Reservoir and operation parameters in the synthetic simulation model (values defined as ranges are parameters in the sensitivity analysis and uncertainty assessment).

Parameter	Value/Range	Unit
Original reservoir pressure	20,000	kPa
Reservoir temperature	75	◦C
Porosity	0.3	-
Average permeability	50–500	mD
Dykstra-Parson's coefficient	0.5–0.9	-
kv/kh	0.1–0.5	-
Initial methane saturation	0.8	-
Irreducible water saturation	0.2	-
Salinity	0–3	molal
Molecular diffusion coefficient (aq)	0–1 × 10−5	cm2/s

CO2 injection rate	10	% PV/year
Carbonated water slug volume	0–20	% PV
Productivity ratio	0.5–1.5	-
Depletion pressure ratio	0.1–0.25	-

Table II.2: Simulation constraints for the synthetic reservoir model

Constraint	Value	Unit
Simulated time	100	years
Minimum allowed producer bottom Hole pressure (BHP)	2000	KPa
Maximum allowed injector BHP	20 000	Kpa
Maximum allowed CO2 cut in production stream	50	%

II-4 Simulator Validation

Prior to conducting multi-dimensional simulations, we performed controlled calibration and verification of the simulator used to identify and assess the key governing mechanism related to CO2-EGR and storage. These mechanisms were studied to ensure the accuracy and representativeness of our simulation models. The investigated mechanisms include:

- CO2 solubility in water as a function of pressure, temperature, and salinity.
- CO2 density (molar volume) as a function of pressure and temperature.
- CO2-saturated water density as a function of pressure and temperature.
- Water vaporization as a function of pressure and temperature.

II-4-1 CO2 solubility in water

The solubility of CO2 in pure water versus pressure and temperature is shown in Figure 4. CO2 solubility increases with increasing pressure and decreases with increasing temperature.

The simulator calculates the fugacity of gas components soluble in the aqueous phase using Henry's law [28], as previously discussed. There is a good match between the experimental data and the calculations for the range of data presented.

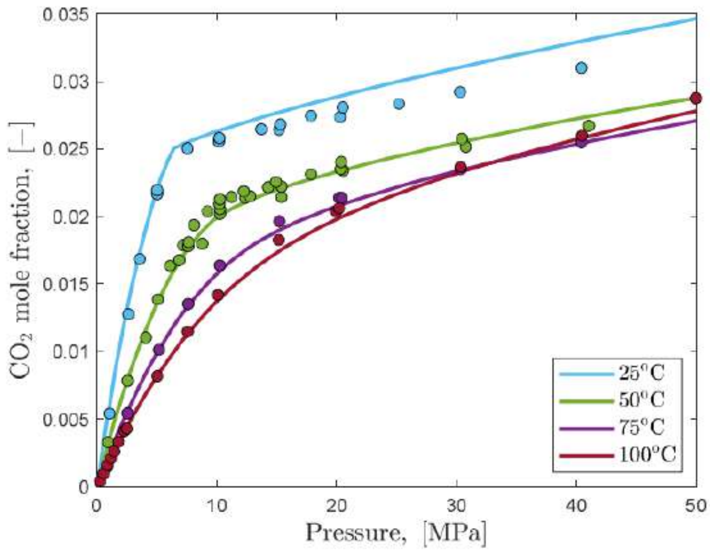

Figure II.4: Solubility of CO2 in pure water as a function of pressure and temperature. The discrete points represent experimental data from [29], and the continuous lines are calculated by the simulator.

II-4-2 CO_2 and CO2-saturated water density

The of the gaseous phase is calculated using the Peng-Robinson correlation [30]. Figure 5 shows excellent agreement between the calculated density of CO2, related to the molar volume by molar mass, and the experimental data for a range of pressures and temperatures. The density of the aqueous phase considering dissolved components is calculated using the Rowe-Chou correlation [31]. Figure 6 shows the density of the CO2-saturated aqueous phase as a function of temperature and pressure. The aqueous density increases with increasing pressure and decreases with increasing temperature. Water vaporization enables the mobilization of previously immobile water at low saturations, which could lead to salt precipitation [32,33]. The water content in the CO2-rich gas phase as a function of temperature and pressure is shown in Figure 7, with a good match between the calculations and the experimental data

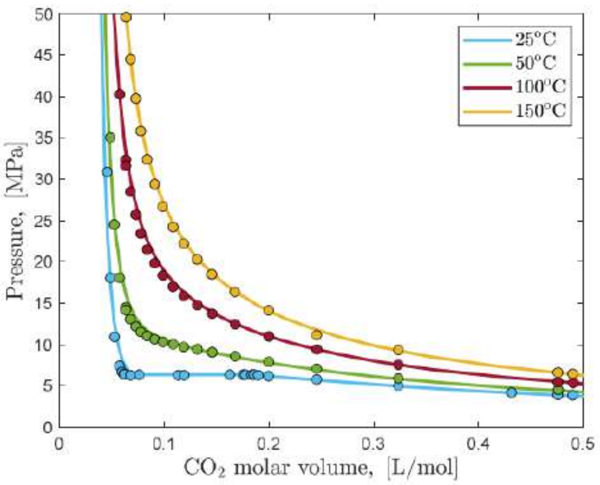

Figure II.5: Molar volume of CO2 as a function of temperature and pressure. The discrete points are experimental data presented in [29], and the continuous lines are calculated by the simulator

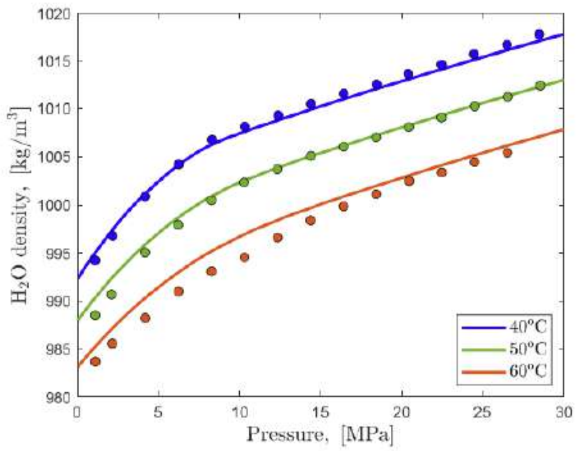

Figure *II.*6 : Density of CO2 -saturated water as a function of temperature and pressure. The discrete points are experimental data presented in [34], and the continuous lines are calculated by the simulator

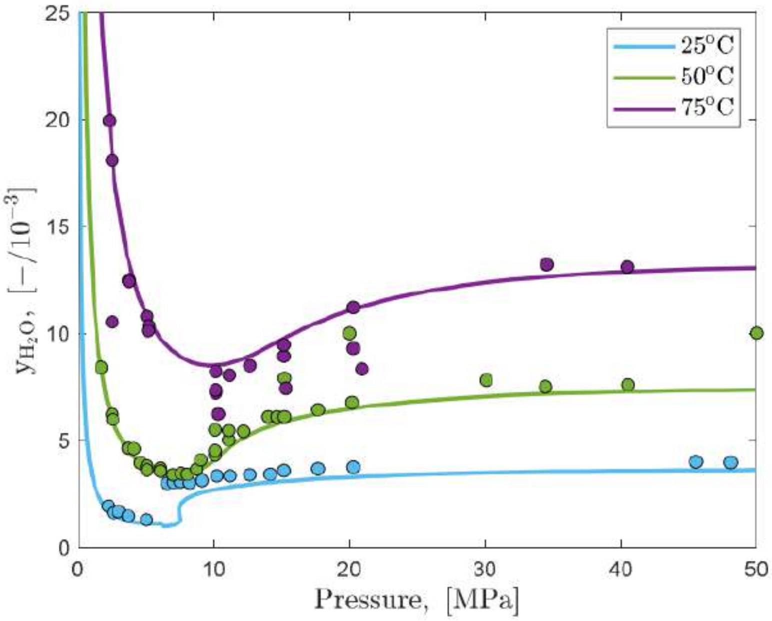

Figure II.7: Mole fraction of water in the CO2 -rich gas phase in a water-CO2 mixture as a function of temperature and pressure. The discrete points are experimental data from [29], and the continuous lines are calculated by the simulator.

In all the simulations below, we want to study the effect of various parameters on 2 essential factors to maximize both:

$$\text{recovery factor} = \frac{\text{CH4 mass produced}}{\text{ch4 mass originally in place}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

$$\%\text{HCPV CO2 injected} = \frac{\text{cumulated CO2 injected volume at depleted reservoir conditions}}{\text{hydrocarbons pore volume of the reservoir}} \ldots\ldots\ldots (2)$$

II-5 EGR method with carbonated water slug

II-5-1 Carbonated Water Injection

We performed mechanistic simulations to assess the feasibility of a proposed EGR method, the simulation covers four main periods. First, natural depletion followed by carbonated water injection when the reservoir pressure drops to a certain depletion pressure limit. After a defined volume of carbonated water is injected, pure CO_2 injection follows. Once the reservoir pressure reaches the original reservoir pressure, injection is stopped., we compared two baseline cases to observe the difference between EGR that starts with pure CO2 injection and the other that starts with carbonated water slug first followed by CO2 injection. Results shown in figure 8.

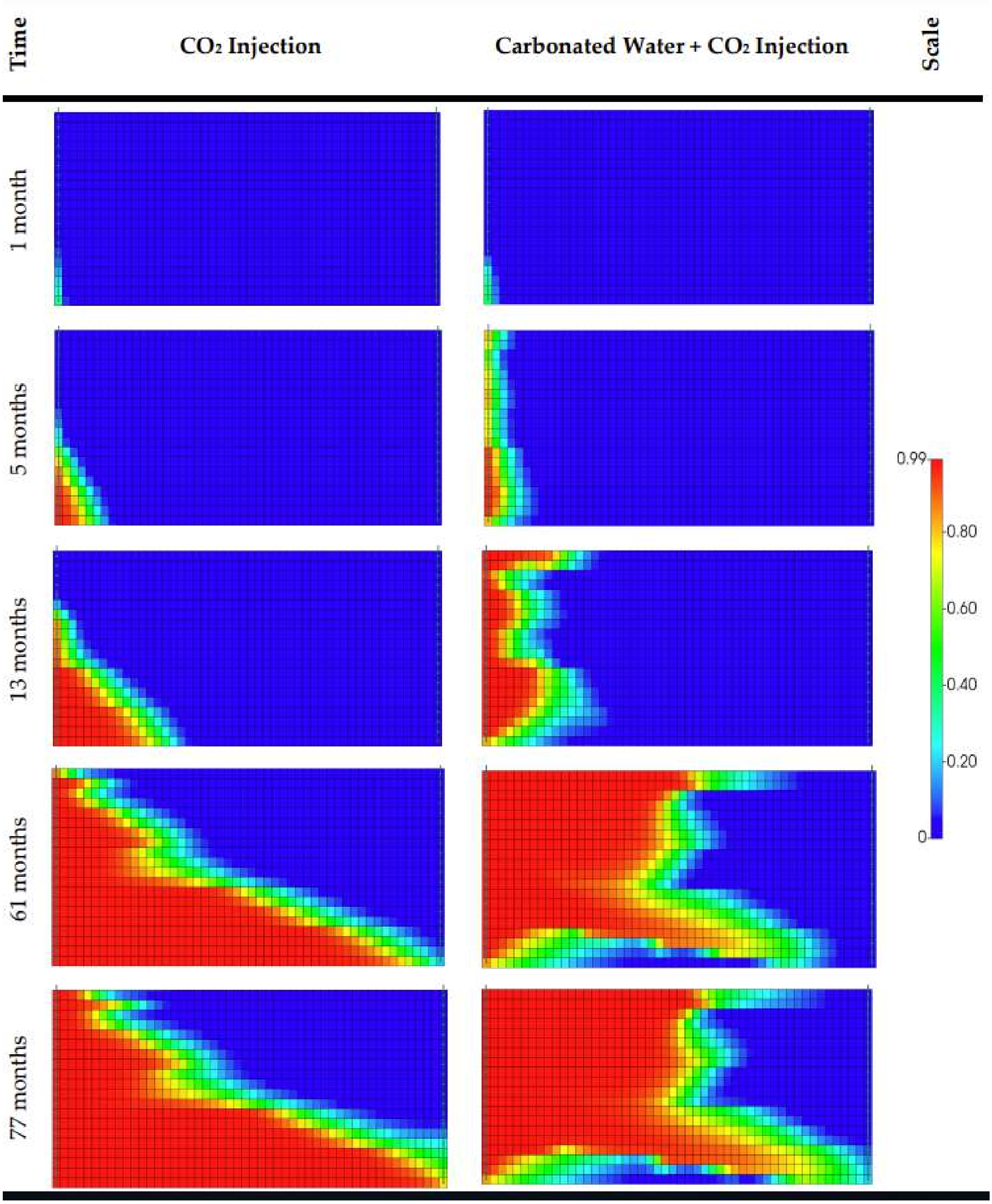

Figure II.8: Overall CO_2 mole fraction at different times for CO_2 injection only (left) and carbonatedwater combined with CO_2 injection (right). The time is given in months since injection began.

II-5-2 Results Discussion of carbonated water EGR simulation

Figure 8 shows a series of concentration maps comparing the flow and sweep patterns of the case of CO_2 injection only and the hybrid case of carbonated water combined with CO_2 injection. CO_2 injection and carbonated water injection begin in their respective cases. After 5 months, better sweep and displacement efficiency can be seen in the hybrid case. In the hybrid case, the high permeability channels contain water which inhibits the mobility of CO_2 through these channels, unlike in the absence of carbonated water injection. After 13 months, the injection of the pre-determined carbonated water slug is completed, and the hybrid case switches to pure CO_2 injection. At 61 months, CO_2 breaks through at the production well in the case with no carbonated water slug injected. Comparatively, CO_2 breaks through after 77 months in the hybrid case.

II-6 Base case

A gas reservoir with an original pressure of 7000 psia. After primary recovery the reservoir pressure dropped to 4350 psia which is the initial reservoir pressure for our study, The reservoir temperature is a constant 200 °F during injection and production. We use 99.9% CH_4 and a trace of CO_2 to represent the original gas composition in the reservoir. When we analyze the results, CH_4 recovery will be used to represent the natural gas recovery.

Key parameters in the model of reservoir and well properties for the base case are outlined in Table 3

Figure 9 illustrate the relative permeability curve used in the simulation study and Figure 10 depicts the simulation model for the base case with an injector and a producer well

The reservoir top layer is at a depth of 9,700 ft with 300 ft payzone thickness and a positive dip of 15°. Water-Gas contact (DWGC) is defined at 9,700 ft signifying the presence of aquifer zone (S_w=1.0).

Initially, the reservoir is saturated with natural gas and 10% residual water saturation. Injector well has perforations at the lower most grid block and producer well perforations are in the top layer because of the density contrast to delay CO_2 breakthrough during natural gas production. For all simulation modeling, natural gas production is stopped at a time when mole fraction of CO_2 in the producing stream reaches a set value of 50%. For the injector, the injection will stop when injection bottomhole pressure reaches the original reservoir pressure. For the base case, the reservoir has a uniform permeability of 100 mD.

Table II.3 : Reservoir Properties

Length	**7,500**	**ft**
Width	75	ft
Thickness	300	ft
Reservoir Grid	(NX, NY, NZ)	(100, 1, 10)
Dip	15°	degree
Initial Pressure	4,350	psia
Reference depth	10,000	Ft.
Initial Temperature	200	°F
kv/kh	1	/
Reservoir Permeability	100	mD
Reservoir Porosity	20	%
Initial Water Saturation	0.1	
Well Properties		
Injection Rate	4.5	MMSCF/Day
Maximum Injection Bottomhole Pressure Limitation	7,000	psia
Production Rate	3	MMSCF/Day
Minimum Production Bottomhole Pressure Limitation	1,000	psia
Simulated Time	10	years

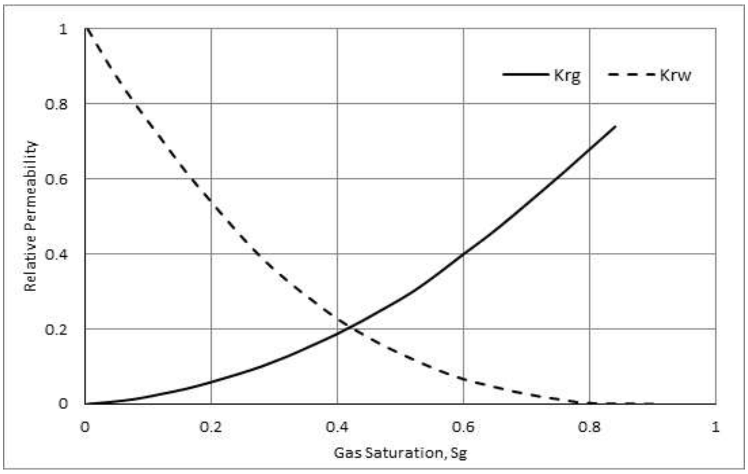

Figure II.9 Relative permeability curves used in the base case simulation.

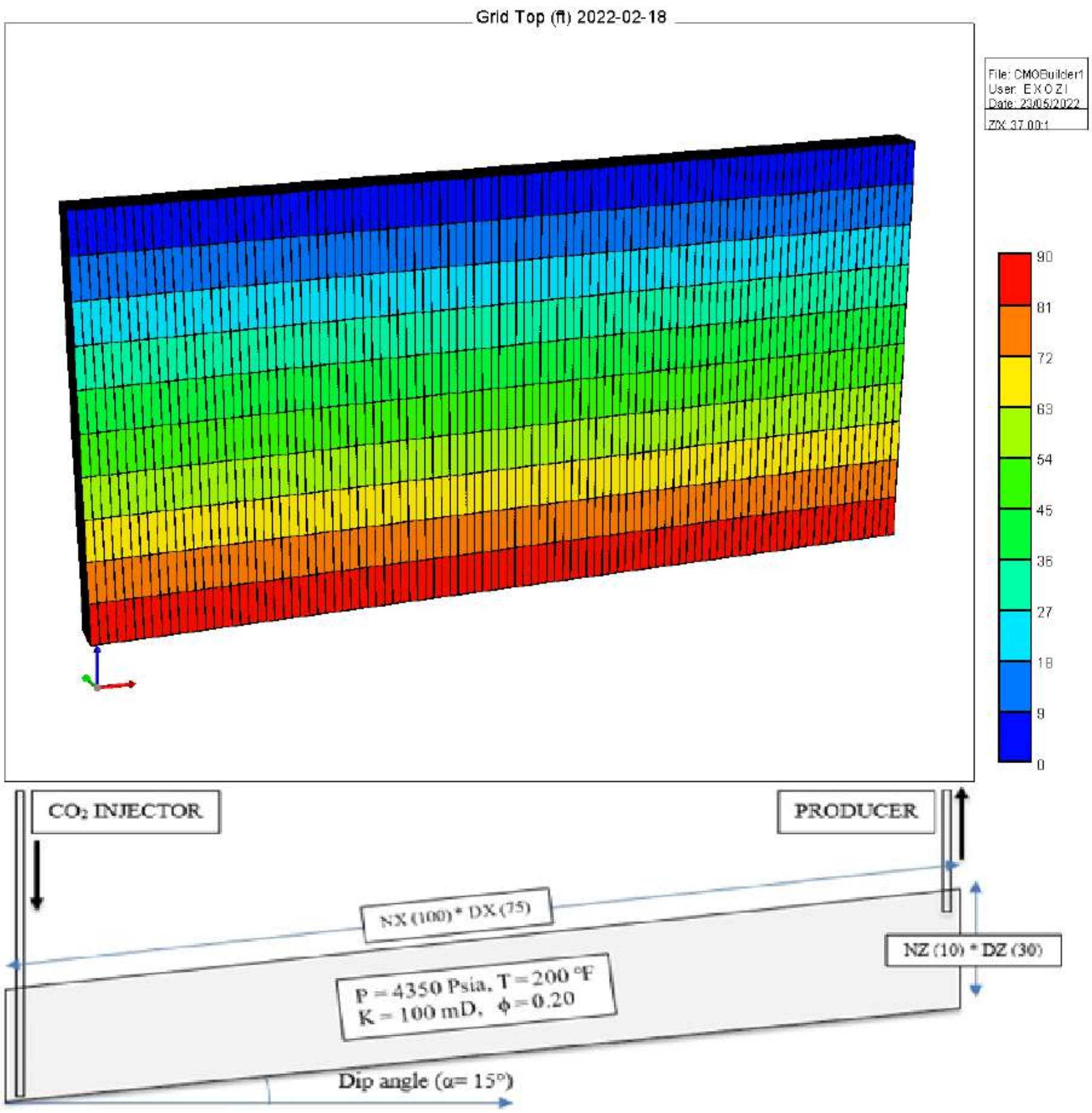

Figure II.10: 2D gridblocks model for the base case

Figure 11 demonstrates the importance of CO_2 injection. Three scenarios were simulated: No injection (reservoir blowdown till the reservoir pressure reaches 2000 psia); No Production case, and using CO_2 injection simultaneously with natural gas production. It shows that the natural gas recovery factor increases from 46.3% to 94.8 % and also the percent hydrocarbon pore volume (%HCPV) of CO_2 injected is increased from 95.8% to 166.6%. The simulated results clearly justify the importance of CO_2 injection to potentially revive the gas production and also allow higher quantity of CO_2 storage into the subsurface formation.

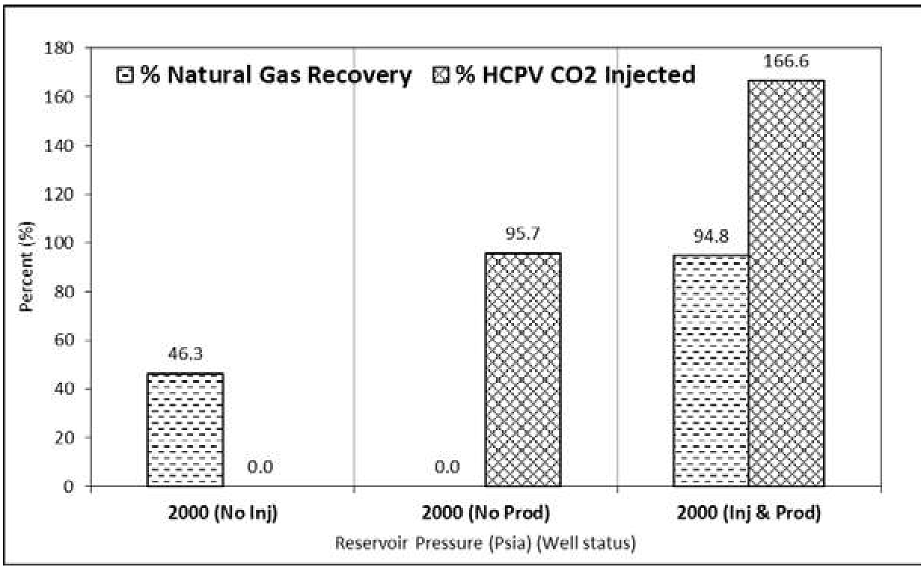

Figure II.11: Importance of CO2 injection in enhancing natural gas recovery before limits for production and injection reaches

II-7 Sensitivity Analysis on the Base Model

II-7-1 Reservoir Heterogeneity

Reservoir heterogeneity is probably the most important parameter to be considered for numerical simulation studies because reservoir permeability defines the path for the fluid to flow. For the base case, we considered ideal situation with uniform permeability of 100 mD. The study evaluated the effects of reservoir heterogeneity in the displacement process. The method used to quantify reservoir heterogeneity is the Dykstra-Parsons Coefficient (DPC). The Dykstra-Parsons Coefficient relates standard deviation of permeability profile to the median permeability. CO_2 mixing with the in-situ gas in the reservoir can potentially degrade the gas price. Therefore, it is important to capture the mixing physics using the numerical simulation. Recovery efficiency depends on how much CO_2 "mixes" with the in-situ gas in the reservoir. In reservoir simulation, physical dispersion is commonly approached by numerical dispersion.

As considering reservoir heterogeneity, the permeability variation within the reservoir applying the Dykstra-Parsons Coefficient of 0.5 can be observed in Figure 12. The effect of dispersion can be observed in Figure 13 where the profile of mole fraction of CO_2 mixing in the reservoir is described with varying Dykstra-Parson Coefficient. The CO_2 mole fraction profile is observed when 46% HCPV of CO_2 is injected into the reservoir. It shows that with zero DPC, no mixing takes place and CO_2 profile is very smooth. With increasing diffusivity, bigger mixing zones are observed and CO_2 is displaced all over the reservoir. Bigger mixing zones leads to early CO_2 breakthrough in the producer and results in lower natural gas recovery as observed in Figure 14. Given that the uniform permeability for analysis also provides best case scenario of the reservoir which is usually not observed during operations, it is very important to take into account the effect of reservoir heterogeneity in defining the operational parameters for CO_2 sequestration and enhanced gas recovery.

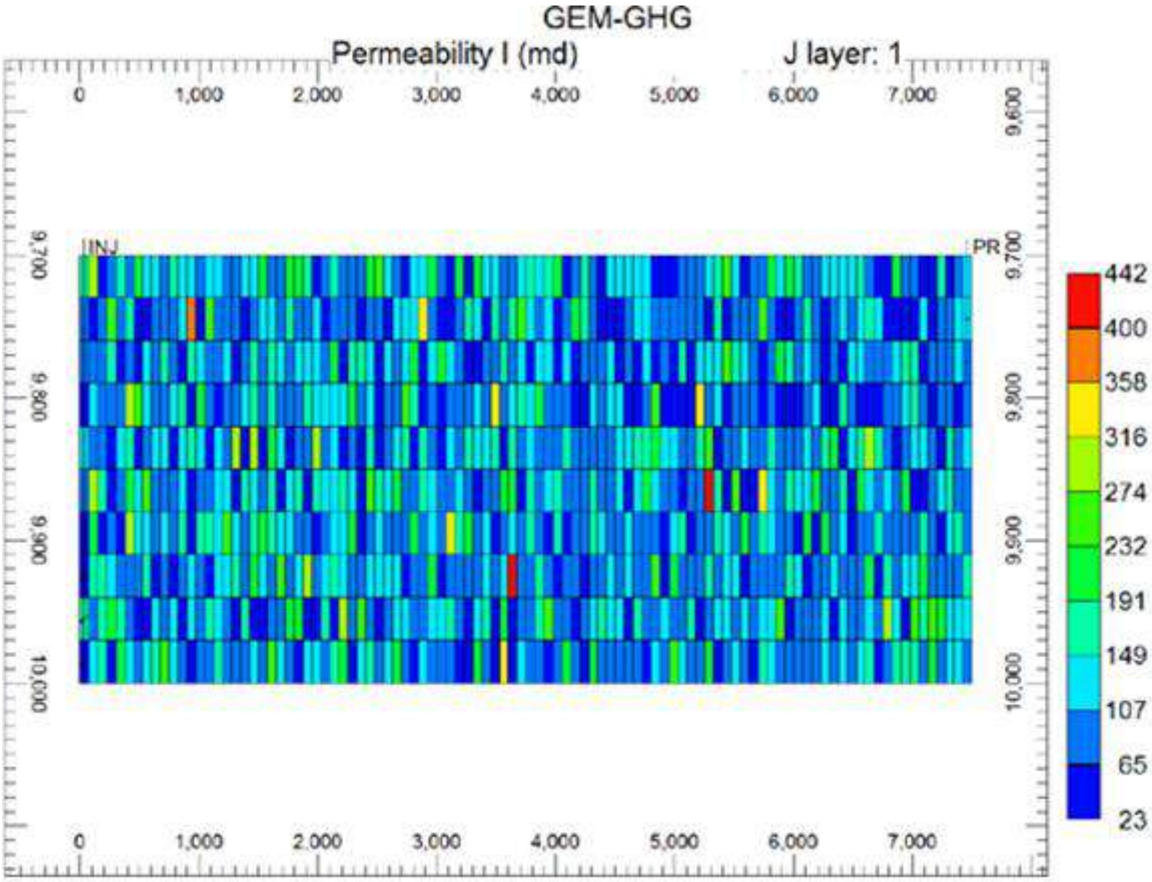

Figure II.12: Permeability distribution along x-axis with mean permeability of 100 mD

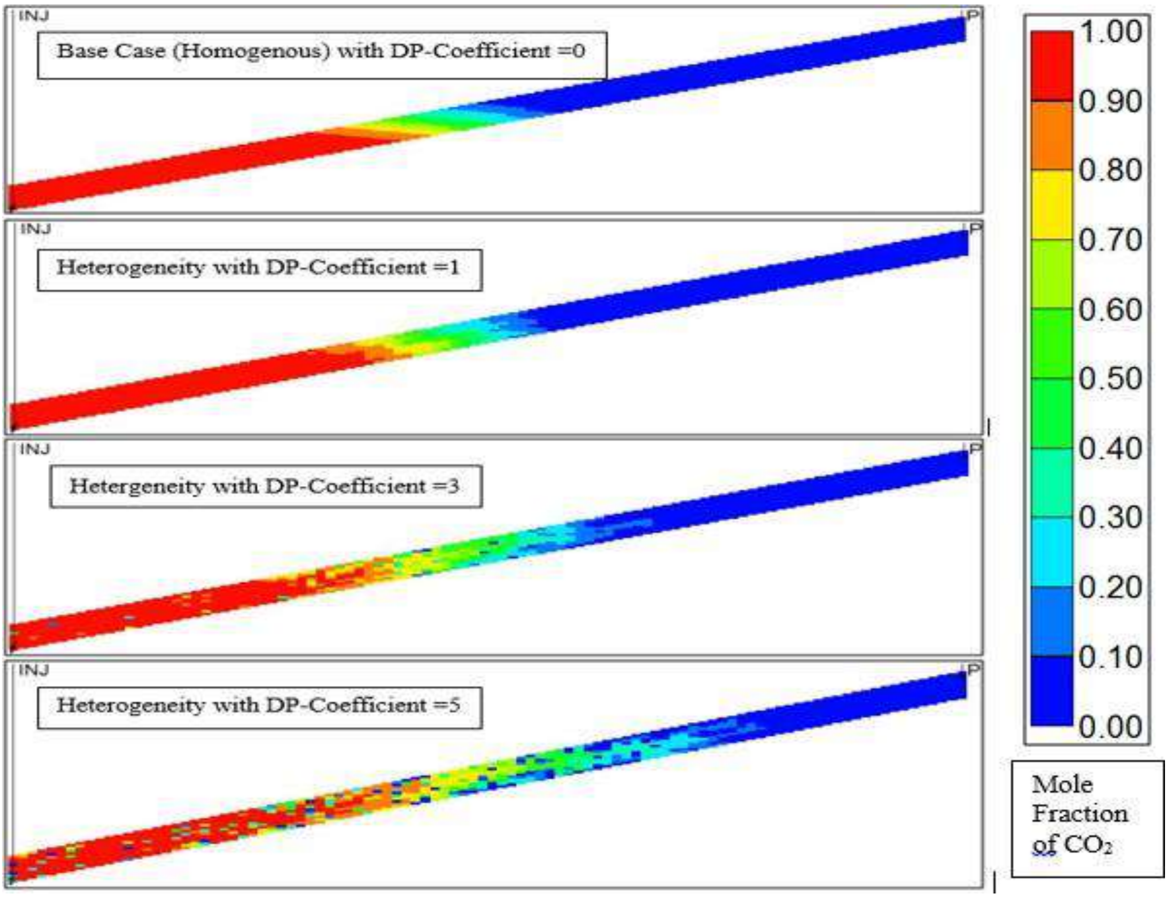

Figure II.13: CO2 concentration in reservoir injected with varying reservoir heterogeneity at 46 %HCPV CO2

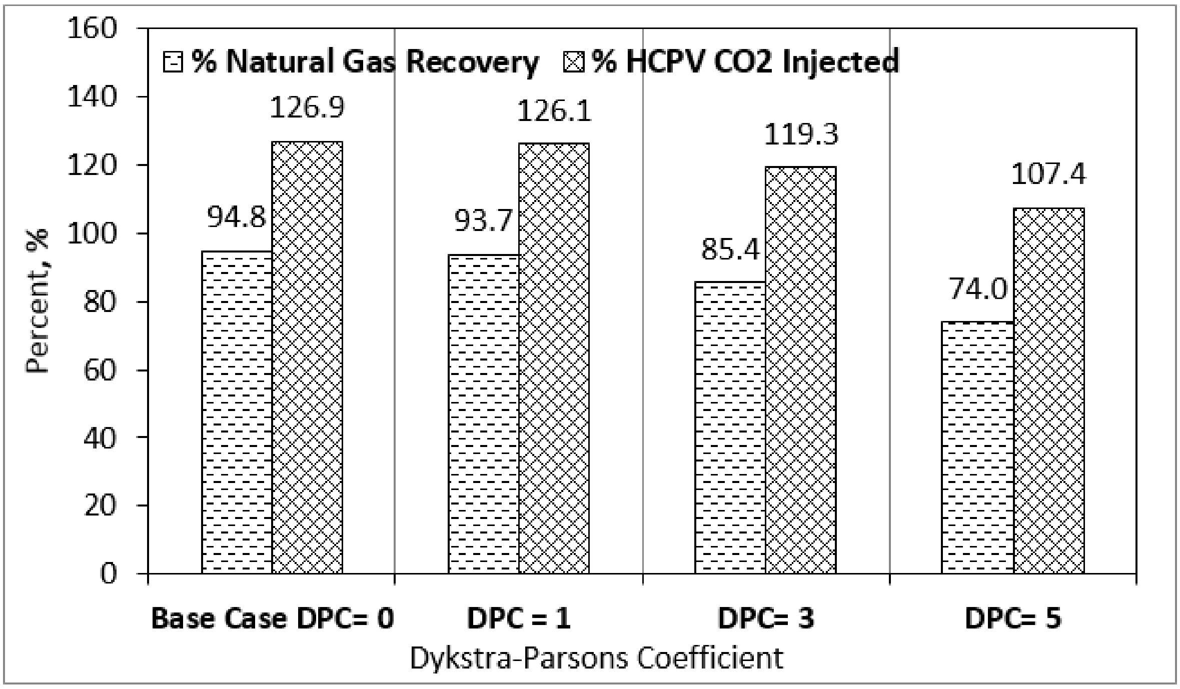

Figure II.14: Effect of reservoir heterogeneity0 with varying Dykstra-Parsons Coefficient (DPC)

For all the following simulation analysis, we assumed reservoir heterogeneity with Dykstra-Parsons Coefficient of 0.5. Also, the maximum injection bottomhole pressure is kept constant at 7,000 Psia and minimum production bottomhole pressure is constant at 1,000 Psia.

II-7-2 Depletion Pressure Ratio

Depletion pressure ratio is defined as the ratio of initial reservoir pressure when EGR starts to the original reservoir pressure. Depletion pressure provides broader understanding of the present reservoir conditions instead of analyzing results considering only current reservoir pressure. It will help in the decision making for the time frame in a reservoir development to be considered for CO_2 injection and allow the production from the reservoir through secondary recovery. Three cases with initial reservoir pressures of 4,500, 3,000 and 2,000 Psia are considered for the study leading to depletion pressure ratios of 0.65, 0.43 and 0.30. The results shown in Figure 15 indicates that CO_2 injection should be started as late as possible if no other detrimental factors are involved. For example, in the case of active or strong aquifer, starting the CO_2 injection late may indicate that a large quantity of natural gas will be trapped by the water invasion.

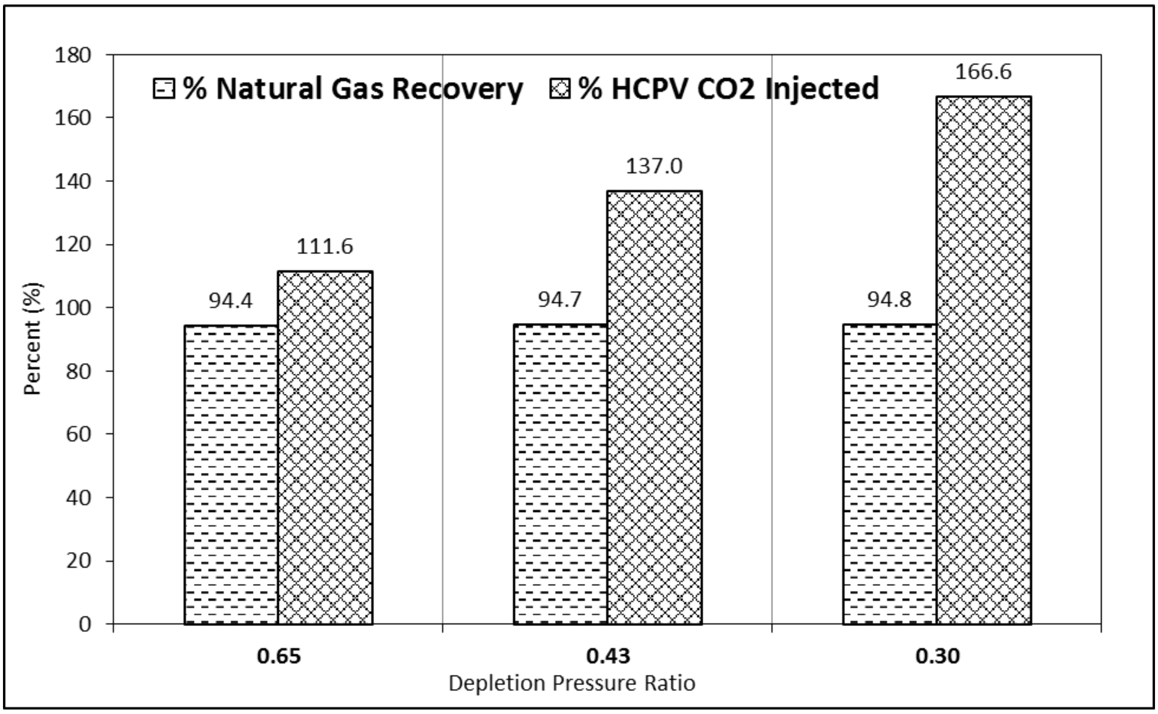

Figure II.15: Depletion pressure impact on the natural gas recovery and CO2 storage.

II-7-3 Location of Injection Well:

Existing wells (previous producer or injector) are usually considered for CO_2 injection rather than drilling new wells. Therefore, the location of injection well is an important parameter in planning for CO_2 injection in a field. A case study was run by changing the location of injection well and moving it towards the producer well in the reservoir. Three injections well locations were simulated in the cells 1, 20, and 40 in the X-direction. Figure 16 shows the recovery factor of natural gas and %HCPV of CO_2 injected in all the three cases. The result shows that perforating an injection well closer to the producer will lead to a significantly less natural gas recovery and CO_2 storage. With early production well shut-in, the reservoir pressure will build up at a higher rate as compared to an injector well at a farther location and less amount of CO_2 will be sequestered in the reservoir. So, considering all candidate injection wells in a reservoir, decision can be made to select the well which is very far from the current producer well.

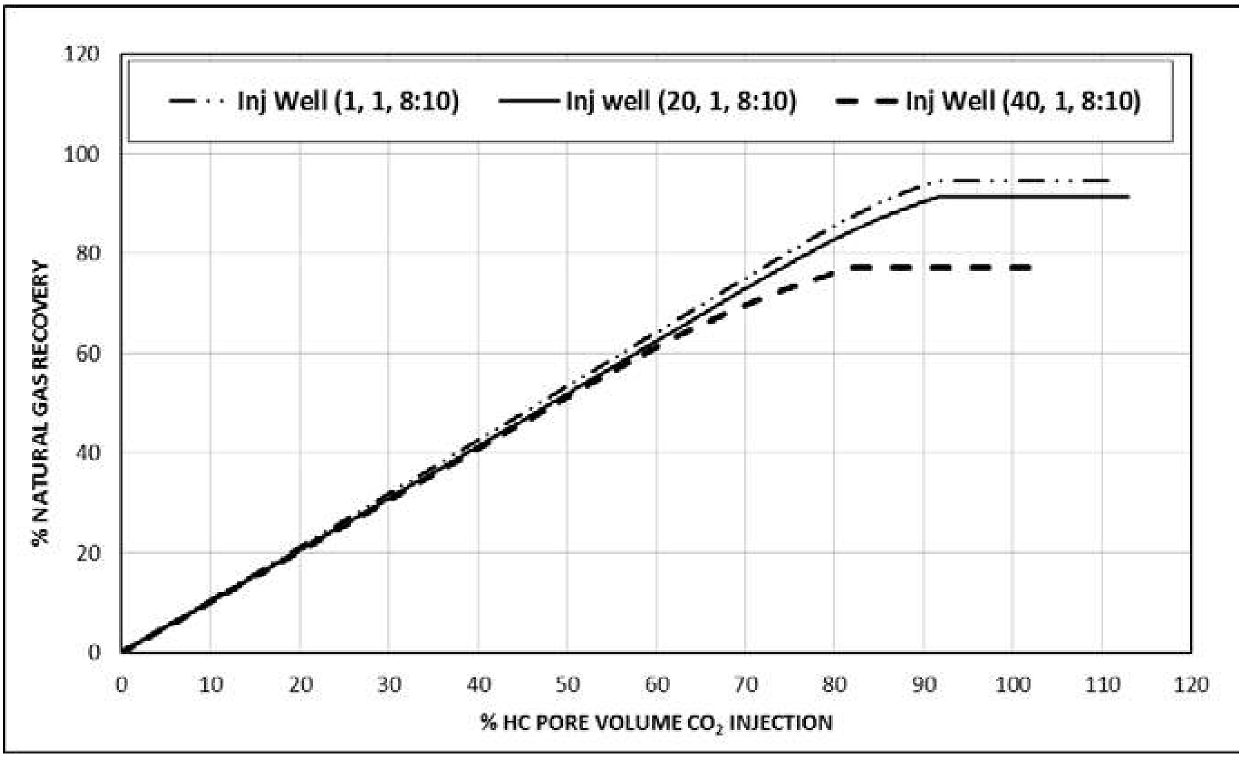

Figure II.16: Injection well location effect on the natural gas recovery

II-7-4 Arrangement of Permeability Layers and Anisotropy

In order to model a very heterogeneous reservoir, we considered 5 layers of permeability throughout the payzone thickness of 300 ft. The reservoir grid block is modified to (100, 1, 5) (NX, NY, NZ) with each layer in the vertical direction has a different mean permeability and permeability of each grid block in that layer is calculated using 0.5 Dykstra-Parsons Coefficient. The schematic of different permeability arrangements used for the simulation study are drawn in Figure 17. Figure 18 shows the natural gas recovery and CO_2 storage for different permeability arrangements when the operational limits are reached. From the simulated results, it can be inferred that the injection and production well should be perforated in relatively lower mean permeability zones. In case of permeability arrangement (K3-K5-K1-K2-K4), natural gas recovery is the highest and also more CO_2 stored. In this case, the injection well is perforated in a mean permeability of 5 mD and production well in mean permeability of 1 mD. Perforating the producer well in a lower permeability zone will delay CO_2 breakthrough into the producer well to reach 50% and will allow more time for the reservoir pressure to reach the injection well pressure and thus higher CO_2 can be injected into the subsurface formation.

In the above study, the permeability is assumed to be isotropic. We also performed sensitivity study on reservoir permeability contrast between the vertical permeability and the horizontal permeability. Simulation results show that as long as the vertical equilibrium is satisfied, the natural gas recovery and CO_2 storage would be about the same for different permeability anisotropic contrasts. This is because vertical equilibrium is achieved very quickly and will not affect the production or injection profile.

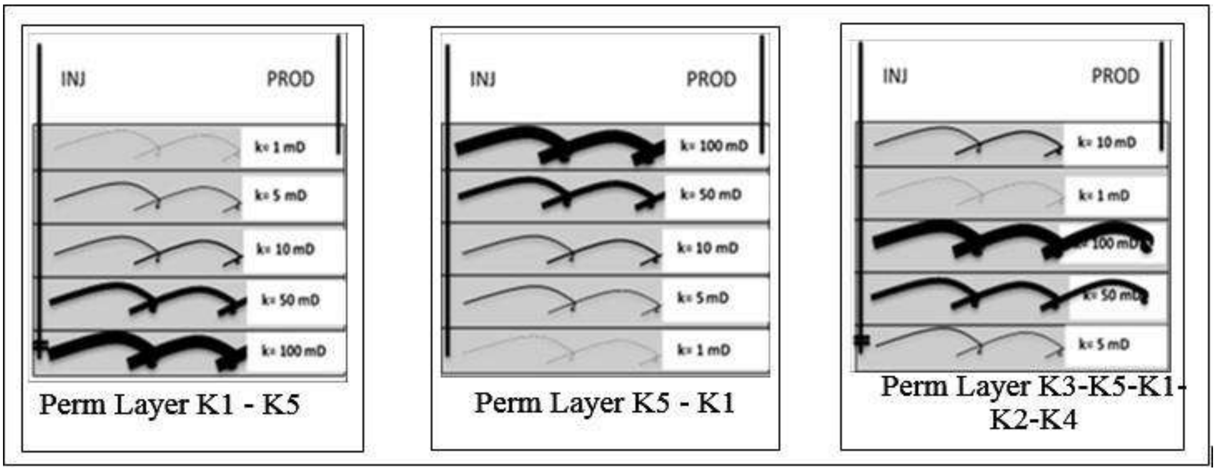

Figure II.17: Arrangement of permeability layers for simulation study

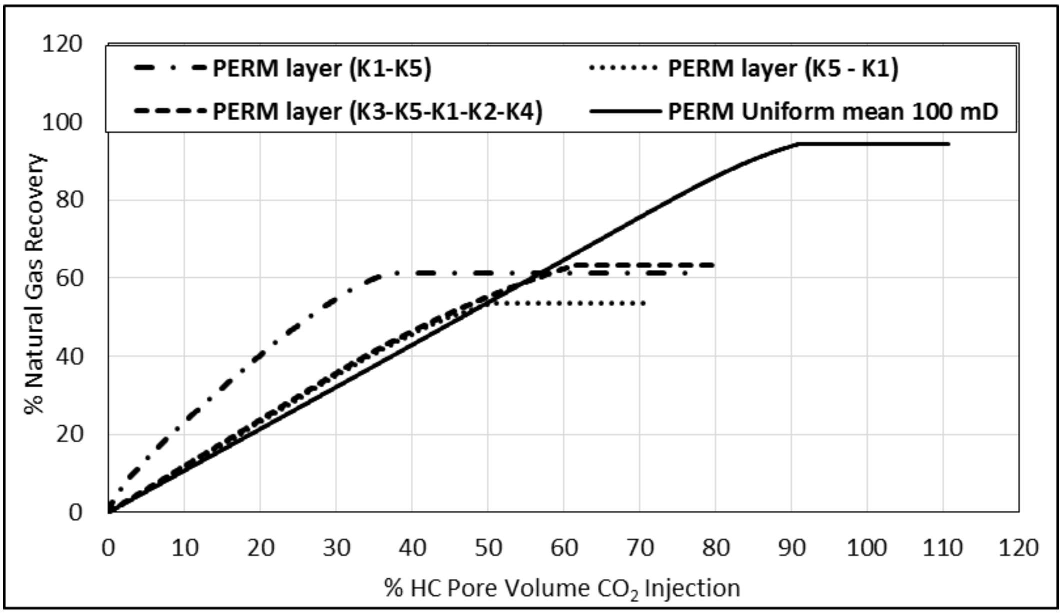

Figure II.18: Permeability arrangement impact on natural gas recovery

II-7-5 Injection Rate

Simulation study was carried out by varying injection rate and keeping other parameters constant. In this case, four rates of injection are simulated as shown in Figure 19. The figure shows that natural gas recovery does not vary much by changing the injection rate. But, with increasing the injection rate, the pore volume of CO_2 injected into the reservoir decreases. This happens because the maximum injection bottomhole pressure limitation is kept constant, and with very high injection rates, the reservoir pressure reaches quickly the maximum pressure i.e. the injection pressure and will allow less time for CO_2 injection.

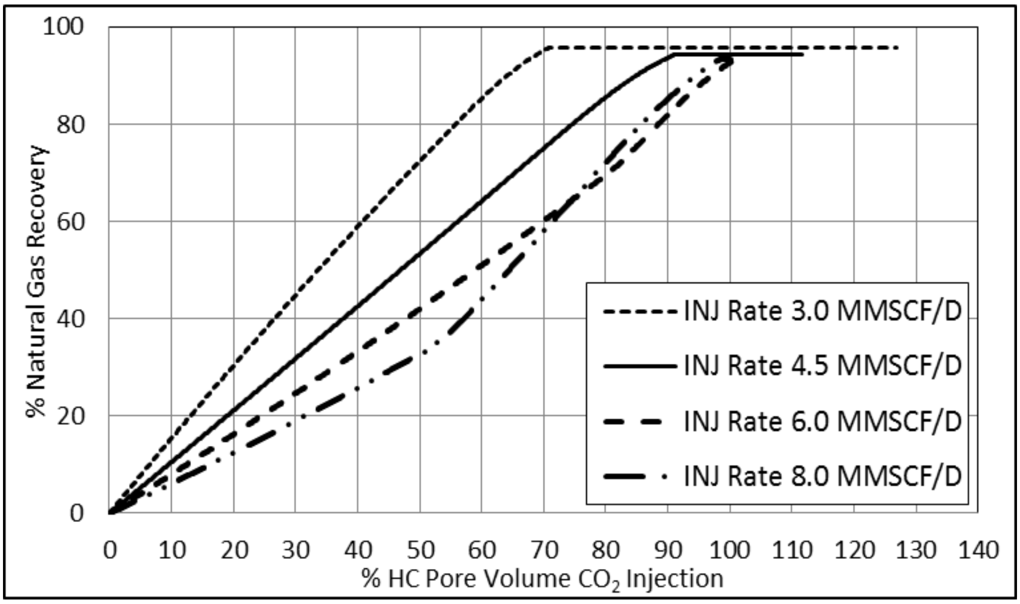

Figure II.3 Effect of injection rate on natural gas recovery and CO2 storage

II-7-6 Production Rate

For this case, simulation study was carried out by varying production rates as shown in Figure 20. The figure indicates that the recovery of natural gas is not sensitive to the production rate, and about 92% is achieved with all production rates but the time to achieve the same recovery significantly increases by reducing the production rate. Similarly, the amount of CO_2 storage remains relative constant.

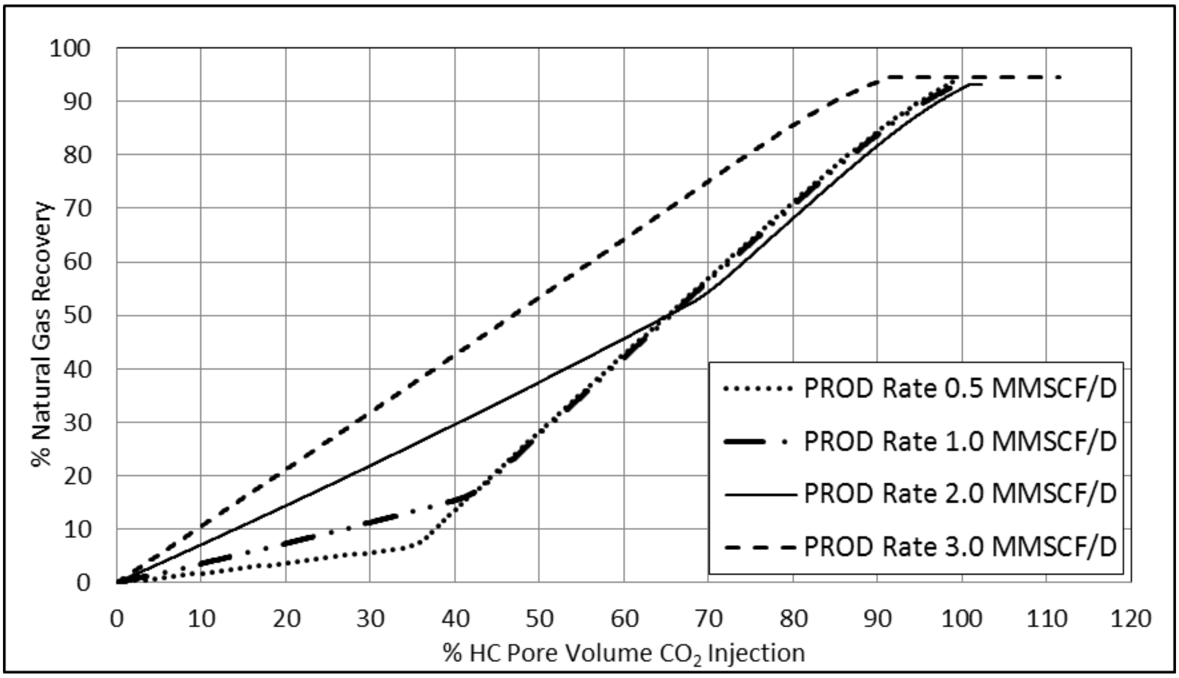

Figure II.20: Natural gas recovery with changing production rate

II-7-7 Activity of Aquifer

Energy from aquifer is very important in natural gas development. Strong aquifer can sustain high production rate; however, aquifer invasion also traps a large quantity of gas which cannot be produced, and some producers close to the aquifer might be watered out. For simulation study, three cases are modeled by varying the aquifer zone comparative to the reservoir drainage area. It can be observed in Figure 21 that by increasing the presence of aquifer in the reservoir from no aquifer zone to 30% reservoir being covered by aquifer, we achieve higher natural gas recovery and CO_2 sequestered. By moving the well away from aquifer, natural gas recovery is reduced. But this may also be an effect of the lesser distance between the injector and producer well.

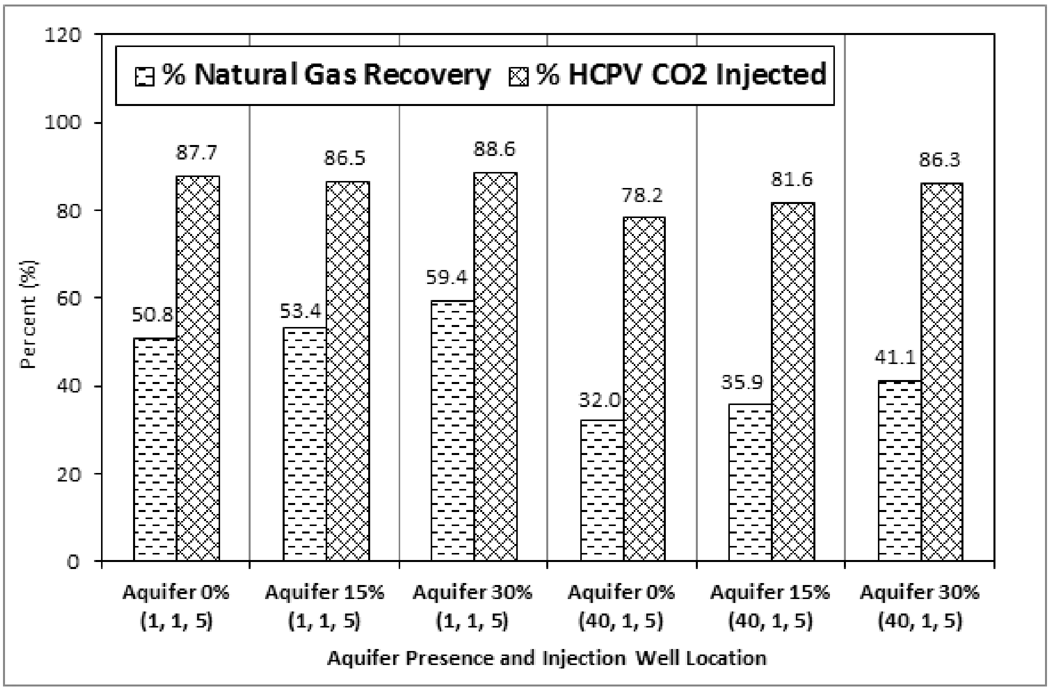

Figure II.21: Effect of aquifer on the recovery of natural gas and CO2 storage

General Conclusion

Based on above analysis, the following conclusions can be drawn:

a) Physical property study of CO_2 and CH_4 indicates that the minimum formation depth is of 4,000 ft for enhanced gas recovery and carbon storage.
b) Injection of a slug of carbonated water followed by CO_2 injection is beneficial to some extent considering three factors; recovery factor, CO_2 stored. By mitigating the issue of early CO_2 breakthrough and excessive recycling in CO_2.
c) The heterogeneity of the reservoir is one of the most important parameters that affect the recovery rate and the volume of CO_2 stored. The more homogenous the reservoir is. the better. highly heterogeneous reservoir will lead to lower natural gas recovery and will further reduce the percentage hydrocarbon pore volume of CO_2 being sequestered because of higher mixing zones in the formation.
d) Gas reservoirs must be depleted as much as possible before being considered for CO_2 injection as lower depletion pressure ratios provided higher natural gas recovery and also more carbon storage.
e) If the reservoir is relative homogeneous, the injector should be as far as possible away from the producer for high natural gas recovery and more storage of CO_2
f) Perforations of producer well should be in lower permeability zone as it will delay CO_2 breakthrough into the production well. and will allow more more time for the reservoir pressure to reach the injection well pressure and thus higher CO_2 can be injected into the subsurface formation.
g) Strong aquifer can sustain high production rate; however, aquifer invasion also traps a large quantity of gas which cannot be produced. So, aquifer connectivity with the reservoir should be carefully studied before considering CO_2 injection.

Recommendations

Based on the results of our study we recommend for the upcoming EGR projects and studies:

a) For choosing candidate reservoirs: to look for ones that are deeper than 4000ft with homogenous permeability.

b) For choosing the injection well location: it should be drilled as far away as possible from production wells and its perforations should be located as deep as possible to avoid mixing to gravity segregation.

c) For the production wells: in case of a heterogenous reservoir, perforations of producer well should be in lower permeability zone. To delay the CO_2 breakthrough

d) The gas reservoir should be depleted as much as possible and the CO_2 EGR should be delayed until the primary recovery is no longer economical.

e) Aquifer interactions are complicated and should be studied per case because Strong aquifer can sustain high production rate; however, aquifer invasion also traps a large quantity of gas which cannot be produced.

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