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INTRODUCTION

Before considering the ecological impact of the Carbon Capture and Storage CCS it is necessary to understand what CCS is and where does this carbon come from. We are living in a rapidly developing world with its daily growing needs. Everything surrounding us from the clothes we wear to the technology we use directly or indirectly connected with the industrial processes. These are the processes that cause emissions (including CO_2). So, Carbon Capture and Storage is a separation of carbon dioxide from the emissions of industrial processes and its storage deep underground in general in depleted oil and gas reservoirs, saline formations, and basalt formations (onshore or offshore) prior release emissions into the atmosphere.

It has been proved that CCS is one of the most effective tools in decarbonization of the atmosphere. According to the International Energy Agency (IEA), CCS could contribute up to 13% to the required emissions reductions by 2060. But at the same tie it is very important to understand each level of CCS, all benefits, and risks and how it is impacting the environment. This paper aimed to assess mentioned above risks and goals of the Carbone Capture and Storage process.

Nowadays climate change and global warming turned out into a common problem that all countries involved all their efforts to find the solution. CCS is a working tool to reduce the greenhouse gas emissions (including CO_2) in the atmosphere. However, in order to provide its environmental sustainability, it is vital to estimate CCS ecological impact.

Purpose of the research:

The paper evaluates the cost-effectiveness of CO_2 storage in aquifers compared to other storage options. Such factors as a long-term monitoring of the storage facilities and liability have been taken into consideration to evaluate the total viability of CCS projects in aquifers.

Objective of the research:

Overall, this paper contributes to the growing body of knowledge on CCS in aquifers, highlighting its potential as a sustainable solution for reducing carbon emissions and addressing climate change challenges.

CHAPTER I. LITERATURE REVIEW

The problem of air pollution is one of the most pressing and serious problems of the modern world. One of the main sources of air pollution is carbon dioxide emissions, which are the main contributor to the greenhouse effect and climate change.

Carbon capture and storage (CCS) facilities are increasingly being used to combat this problem. This technology allows carbon dioxide to be captured from various industrial and energy sources, transported to special storage areas and stored in underground formations.

Recently, many studies have been conducted on the application of CCS plants in air pollution control. One of the main areas of research is to assess the effectiveness and economic feasibility of using CCS technology. The author of the paper referred to the various international sources: books, articles as well as international organizations and universities' reports.

In their 2014 paper titled "An overview of the current status of carbon capture and storage technologies," Leung, Caramanna, and Maroto-Valer provide a comprehensive review of the advancements and challenges in the field of carbon capture and storage (CCS). The authors cover various aspects of CCS technologies, including post-combustion capture, pre-combustion capture, and oxy-fuel combustion, as well as the storage of captured carbon dioxide.

Detailed analysis of the current state of CCS technologies, their potential to reduce greenhouse gas emissions and mitigate climate change is highlighting by Leung, D. Y. C., Caramanna, G., et. all in the paper "An overview of the current status of carbon capture and storage technologies" 2014. The authors discuss the economic and regulatory challenges facing the widespread implementation of CCS, providing valuable insights for policymakers and stakeholders in the energy sector.

Overall, this paper serves as a valuable resource for researchers, policymakers, and industry professionals interested in the development and deployment of CCS technologies. The authors present a balanced view of the opportunities and obstacles in the field, making it a comprehensive and informative review of the status of carbon capture and storage technologies.

Mathias, Gluyas, Gonzalez Martinez de Miguel, and Hosseini (2011) investigated the role of partial miscibility on pressure buildup due to constant rate injection of CO_2 into closed and open brine aquifers. Their study, published in Water Resources Research, provides valuable insights into the behavior of CO2 injection in different types of aquifers. Their findings suggest that partial miscibility plays a significant role in determining the pressure buildup during CO_2 injection, with different implications for closed and open aquifers. The study is well-structured and clearly presented, with detailed explanations of the methodology and results. The authors provide a thorough discussion of the implications of their findings for CO2 injection projects, highlighting the importance of considering partial miscibility in modeling pressure buildup.

Shi, Xue, and Durucan's study “Seismic monitoring and modeling of supercritical CO_2 injection into a water-saturated sandstone: Interpretation of P-wave velocity data.” examine the behavior of CO_2 in geological formations. The interpretation of P-wave velocity data offers a detailed understanding of the changes that occur during the injection process. Besides. authors demonstrate an approach to analyze the seismic data, prove the importance of monitoring and modeling techniques in studying CCS. The authors state that focusing on the P-wave velocity data, it is possible to track the movement and behavior of CO2.

The article "The innovation dilemma of carbon capture and storage (CCS)" by Wicki, S., & Bürki, T. (2018) published in Technological Forecasting and Social Change provide valuable information on the challenges and opportunities of CCS technologies. This source is relevant on long-term oil production forecasting, as it discusses the innovation aspects of CCS, which potentially intersect with the use of reservoir simulation models and machine learning approaches in the energy industry. Analyzing this article allow to gather additional perspectives on the topic and potentially incorporate relevant findings.

Thus, a review of the literature on this topic provides understanding of the current state of research on the application of CCS plants in air pollution control and identify key areas for further research.

CHAPTER II. CARBON DIOXIDE CAPTURE AND STORAGE

There are three steps in CCS process: a plant capturing carbon dioxide, transportation, and storage. This paper aims to consider each stage in detail for better understanding.

Capture. The main part of the capture plant is usually a separator. It catches emission gases, separate carbon dioxide by using solvents. Then the captured CO_2 is chilled up to the liquid state and ready to be transported. Sometimes amount of captured carbon dioxide can reach up to 2 m. t. per annum. In this case appropriate transportation way is pipeline rather than by ship. Since pipelines operate on high pressure depending on physical properties of carbon dioxide while ship transport requires moderated fridge to maintain the appropriate temperature level. The total amount of captured CO_2 varies between 3.5% and 14% depend on the source. It requires a huge amount of energy that quite costly. Thus, sometimes implementation of CCS plant on sites with the small portion of CO_2 emissions become inefficient.

There are different options available for carbon dioxide storage. But the most appropriate option is geological formations. Each step of the CCS plant installation process requires significant investments. Typical plant with the average power (approx. 500 MW) is capable to capture up to 2 million t/year while pipelines capability to transport liquid CO_2 is up to 20 million t/year. Thus, it makes sense to connect several plants to one pipeline for the cost saving.

Based on different studies and research (IPCC (2005) and standard engineering procedures it is possible to calculate the average cost of CCS process. It is possible to refer to the balance of costs based on a recent study of European costs (ZEP (2011). Based on the table below, additional 10% of related with storage

Table 2.1 Additional costs of CCS with the capacity 20 mil.t. per year

	Component	Cost (approx.)	Contribution to electricity cost
Power generation (base)	Pulverized fuel power stations	5.5 B€	
Power generation (capture)	Pulverized fuel or IGCC power/st	8.5-10 B€	
Capture and compression	Post or pre combustion capture	Additional 3-4.5 B€	22-27 €/MWh

Transport	500 km offshore pipe system	Additional 1.2 B€	5 €/MWh
Storage	depleted oil/ gas fields deep saline aquifers	0.5 B€ 1.0 B€	2.5-5 €/MWh

The range of options for storing captured CO_2. Once it is to reach significant reduction of emissions on the global level, the CCS plants will be capable to capture and store thousands of millions tones worldwide. There are many facilities for CO_2 storage, but not all of them can be useful since injected CO_2 to be monitored and to be close to the infrastructure. Depleted oil/gas reservoirs are the best option to store captured carbon dioxide, due to availability of all detailed information about the well. Besides, saline aquifers can also be a good option once all calculations completed accurately.

Some institutions consider deep ocean as a possible CO_2 storage facility (Kaya, Freund, 1998). They suppose that if captured carbon dioxide will be injected to the appropriate depth, its density will be greater than surrounding water, and this will keep it in the seabed. Injected CO_2 will react with seawater and form hydrates. However, number of international agreements prohibit release of carbon dioxide into ocean waters (Hendriks, Mace, and Coenraads, (2005).

Another way – to use captured CO_2 in production different solid material or chemicals. In addition of reducing carbon dioxide, it can be profitable. But all demands on these products to be researched in advance. Nevertheless, this method cannot be main one, since it is not capable to use all the huge amount of CO_2 (Freund, et al. (2005).

EOR – enhancing oil recovery is also considering as a method of carbon dioxide reducing. It can be profitable since it increases the oil ang gas recovery, and partially can cover storage costs. But from the other side increased recovery will case increase of pollution. Thus, effectiveness of this method is questionable.

One of the possible ways to utilize CO_2 is to produce solid material like serpentinite or olivine that based on carbon dioxide (Fagerlund, et al. (2012). Then its utilization will be easier. But the challenge is to produce the solids as the volume as CO_2 is produced daily, will require a chemical engineering process. And in turn this will require significant amount of electricity that produce air polluting emissions. As an option renewable energy can be used but again the cost makes the efficiency questionable. For these reasons, carbon dioxide transformation into solids is unlikely to be solution of the problem.

Trends in CO, capture and storage (CCS). Since carbon dioxide was successfully stored underground for the first time back in 1996, several trends in CO_2 storage technology emerged (Woodhead Publishing Limited, 2013).

Later, in 1972 in USA the first commercial injection process was realized but it was done in order to EOR (Han, McPherson, (2007). The first international shipping of carbon dioxide was in 2000. Captured CO_2 in USA was sent to Canada for injection.

The first CO_2 injection to reduce the greenhouse effect was carried out in 1996 in Norway. Norwegian company Statoil along with its partners injected captured carbon dioxide into saline aquifers at more than 800 m depth. This followed by the BP project in Algeria in 2004, and a smaller offshore project of CO_2 injection in Netherlands (K12-B gas field). This practice made it possible long-term monitoring of carbon dioxide behavior after injection.

Along with commercial projects, some research injections of carbon dioxide were carried out in a such projects like Nagaoka (Japan), Ketzin (Germany) and in USA. The amount of injected CO_2 was small since it was quite expensive to buy carbon dioxide only for injection. All mentioned above demonstrate the trend towards increasing CCS technologies implementation whether for EOR or for emission reduce. And more likely depleted oil or gas fields are more interesting for carbon dioxide storage instead of saline aquafers, do to available data and infrastructure. Besides getting approval to store captured CO_2 in saline aquafers takes a long time and requires more investments.

Store location. Locations of carbon dioxide storage may vary from offshore to onshore locations depend on the region. In northern European countries due to governmental ban and public opinion the best location for storage is under the sea, while onshore locations are preferable in the US or in China. This also related with economic factor, since significant capital is required to transport captured carbon dioxide offshore.

Wells. One of the post important issue related with injection is leakage. In short or long term, it should be monitored. There is a high risk of CO_2 release into atmosphere especially while injection. After the process is completed, the reservoir pressure is decline due to carbon dioxide dissolution. The same is applicable to the monitoring or passing through wells.

In the most cases monitoring carried out based on oil and gas practice. But recent interest and increase of CCS technologies cause number of research and different monitoring equipment designed especially for injection wells. Different ways to monitor the well are implementing remote monitoring techniques (micro seismicity, satellite observation etc.), invasive techniques (measurements directly from the wells) or indirect techniques in injection process. One more way to monitor leakage is direct carbon dioxide measuring in waters close to the storage or in the air located near onshore CO_2 storage. However, it is quite difficult to determine which method is more efficient until there is enough experience in this relatively new industry.

Regulation of the CO_2 storages to be worked out. A big progress has been achieved in Europe. European countries implement the regulations in bill and clarify it to attract more investors in CCS projects. The same trend is observed in the USA.

There is also one more issue that is a matter of debates. It is expected that once injection process is completed it should be handed over to the government at the legal level. However, it is difficult to guarantee that the storage is safe and there is no leakage risk due to lack of experience in this industry.

Now it is not clear who will own and operate storage. More likely oil and gas experience will be implemented to the CCS process but as for the regulations companies ae to provide capital for further monitoring and operation. In this case small companies will not be able to enter the market and be a part of it.

CCS projects are big and require appropriate investments. It is expected that in the long-term CCS technologies will be able to cover own expenses due to high price on carbon dioxide. Until that time to increase CCS technologies implementation governmental financial support is required (like in EU or in the USA).

Significant role in CCS project history played a Durban Conference of the United Nations in 2011, then CCS has been approved as a major method to reduce greenhouse emissions. It has been stated in the UN Framework Convention on Climate Change. Unfortunately, up to date due to some reasons most of the CCS projects have not been realized.

Public opinion is very important factor and may influence on government decision in implementation of CCS projects. The more information spread about the global climate change and a role of CCS in reducing emissions, the more people are interested in implementation of Carbon Capture technologies like it happened in UK (Shackley, McLachlan, (2004) and in China (Liang, Reiner, (2011). There is one more prove that public opinion is very important. For example, when research injection was proposed in Ketzin (Germany) local people opinion was favorable. While in Netherlands local people rejected proposal of carbon dioxide injection in depleted gas field since it was close to their habitat. It is clear that large number of campaign to be held to inform people about importance of CCS projects.

2.1 Carbon Capture Methods and its Ecological Impacts

Here are some general ways of CCS: post-combustion, pre-combustion, oxy-fuel combustion, and direct air capture.

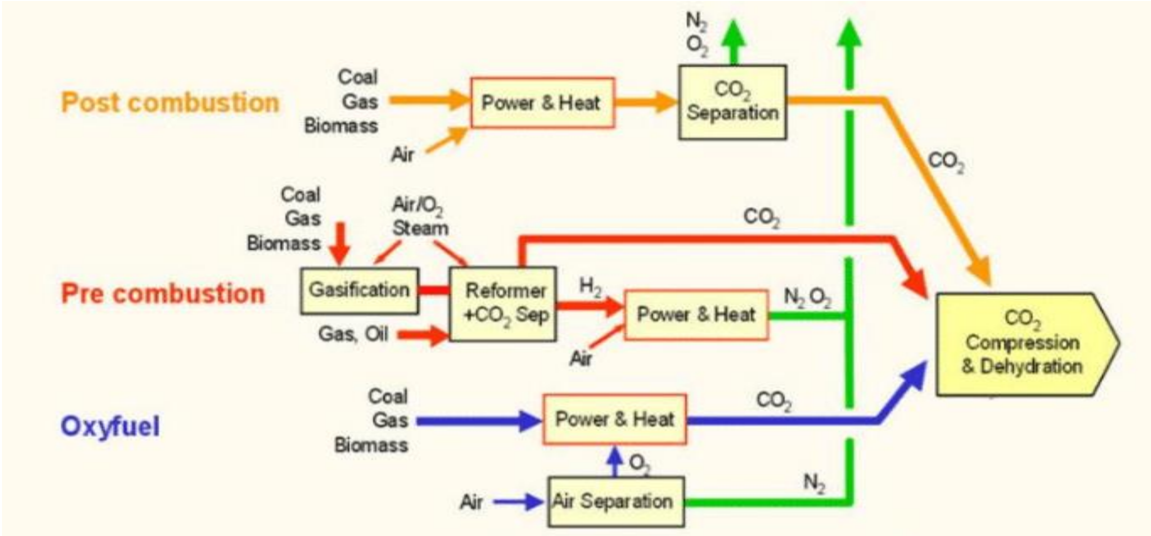

Fig. 2.1 Combustion types.

Post-combustion method includes carbon capture by usage of a large number of amine-based solvents. While the process pollution control system captures separately carbon dioxide (i.e., getting in contact with solvents, CO_2 molecules are attracted by them). Then the gas is heated in a special column in order to separate CO_2 from the solvents. The separated carbon then compressed to the liquid state that make it easier to transport to the storage reservoirs. The advantage of this method is that separated and captured CO_2 can be easily transported by adding a pipe to the already existing system. But on the other hand, the percentage of the captured carbon is significantly low (4-15 %) despite the pricey equipment and solvents. Another disadvantage is the solvent leakage may be harmful for the environment (Rochelle, 2009).

Pre-combustion method means to separate carbon dioxide prior the combustion. There are 3 stages of pre-combustion:

1. hydrocarbon fuel is converted into hydrogen and carbon monoxide to form a synthesis gas;
2. CO is converted into CO_2 by water gas shift reaction;
3. Carbon dioxide is extracted from hydrogen. Then it can be combusted completely. The captured CO_2 will be compressed into liquid and transported to a storage site (Basile, Morrone, 2011).

The benefits of this method are high percentage of the captured emissions (90-95%), can be applied to the gas and coal IGCC, less risk, possibility of producing H_2. The disadvantages are the cost of this process.

Oxy-fuel combustion this is the process of fuel combustion, which results in the release of almost pure Carbon Dioxide. The one of the important benefits of this carbon capture method is that during a process the mixture undergoes dehydration and there is no need in solvents or other chemicals. It is also important that oxy-fuel combustion method can be implemented in the already existing facilities. Disadvantages of this type of carbon capture is the price of the special equipment and materials, and high energy requirements in order to separate oxygen from the other gases in the air, and high combustion temperatures (1,650 to 2,480 °C) (Baugh, 2024). Besides, it requires modifications to existing facilities and generates additional air pollutants while oxygen production (International Energy Agency 2011).

Direct air capture (DAC) technologies separate carbon dioxide right from the atmosphere. It can be settled at any location. But the problem is in the atmosphere CO_2 is less concentrated than in plants emissions. Thus, comparing the amount of captured CO_2 and the price of the DAC technologies this method become very unprofitable and costly (Budinis, 2022).

Membrane separation is an innovation for post-combustion carbon dioxide capture. It can reduce energy, chemical and solvent consumption. Nevertheless, this technology has not been widely implemented due to the lack of improvements (Hou, et al. 2022). It is still under development and may not be suitable for all emission sources (D'Alessandro, Smit, & Weckler 2010).

2.2 Transport of Captured CO_2 and Ecological Considerations

In the most cases when capture plant is not straight above the carbon storage area it is necessary to transport the captured CO_2. The main transportation way is the pipeline, although shipment of CO_2 is also appropriate in some situations. Pipeline transport require carbon dioxide to be in a liquid or supercritical phase in order to provide its flow (Scoping the environmental impacts of Carbon Capture, Transport and Storage, 2022)

Carbon dioxide transporting comes with certain ecological risks:

- Pipeline leaks may cause vital effect on a surrounding environment including plants and animal life. Additional gas components of CO_2 may release (National Academies of Sciences, Engineering, and Medicine. 2019).

• Piping CO_2 requires huge energy consumption, thus efficiency of CCP become questionable unless renewable energy resources are used (Leung, Caramanna, & Maroto-Valer, 2014).

Geological Storage and Potential Environmental Impacts: In attempt to prevent greenhouse effect minimize harmful emissions captured carbon dioxide is stored deep underground in geological formations, in depleted oil and gas reservoirs. But there are some risks for environment.

• Leakage. In this case environment and ecosystem faces with the harmful damage. CO_2 can acidify groundwater, rendering it unsuitable for drinking or irrigation, and potentially harm wildlife (Benson, et al. (2018).

• Seismic activity: seismicity induced by CO_2 injection can be a serious hazard that also becomes an obstacle to the development of CO_2 geological storage (Cheng. Y., et al. 2023).

Conclusion. Global CCS Institute's 2022 report state that, there are 194 large-scale CCS plants all around the world, in 2019 there were only 51. 30 of these projects are in operation, 11 under construction and the remainder in various stages of development. 94 in USA, 73 in Europe, 21 in Asia-Pacific and 6 in the Middle East. All these plants together able to capture 244 million tons of CO_2 per year. This is 44% increase over the year (Daniels, 2022)

Despite above mentioned achievements carefully consideration of ecological impact is vital in order to reduce harmful effect of CO_2 on our environment and ecosystem.

2.3 Geological Storage of Captured Carbon Dioxide: Types, Locations, and Operations

The average temperature on Earth rose by 0.99 °C (1.78 °F) in 2016 according to a combined report from the National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA). It has been proven that carbon dioxide is one of the main greenhouse gases that leads to global warming. This is the reason for many researches about implementing carbon capture and storage technology and worldwide attempts to increase the number of installed CCS plants.

After capturing carbon dioxide, it is compressed into a liquid phase and transported to storage locations. It can be injected into porous rock formations deep underground. There are three main types of geological storage for CO_2: oil and gas reservoirs, deep saline formations, and un-minable coal beds.

CO_2 can be trapped under a sealed rock layer or in the rock pores. Besides it can be chemically trapped by dissolving in water and reacting with the surrounding rocks. In this case leak risk is is significantly small. CO_2 storage in geological formations is cheap and the most ecologically friendly. This paper aims to highlight the different types of geological storage, their locations, and the operational processes involved.

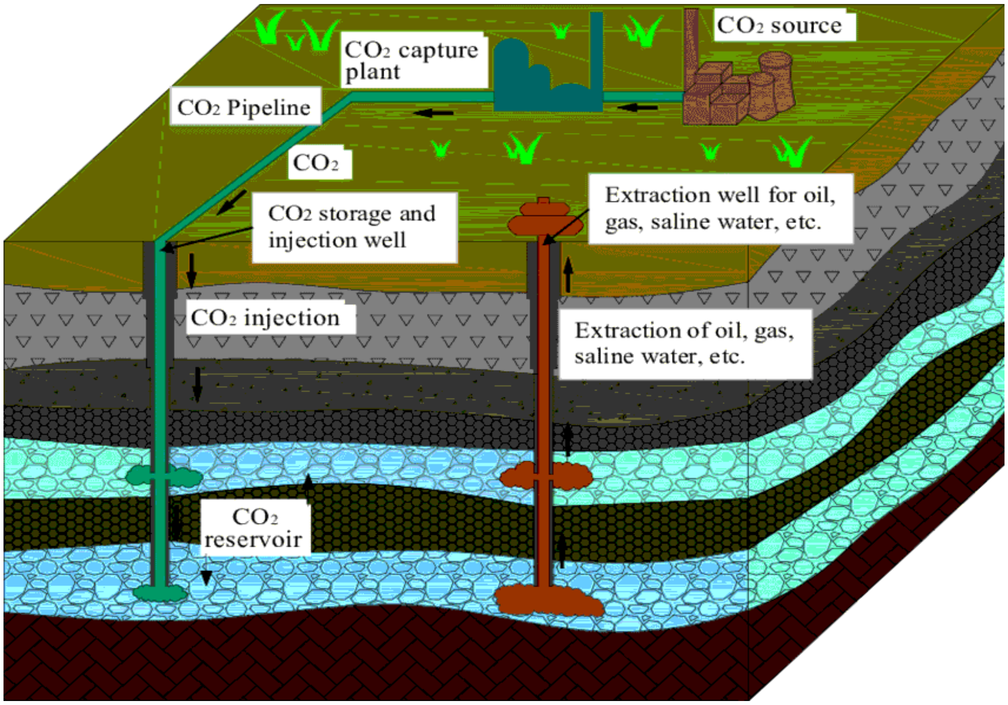

Fig.2.2 Overall schematic of carbon capture and storage concept.

1. Types of Geological Storage:

• **Depleted Oil and Gas Reservoirs:** This is the most reliable option for carbon dioxide storage. Since while oil and gas production all formations data have been collected. Besides formations have previously held hydrocarbons and possess suitable characteristics for carbon dioxide storage, including a rock layer above that prevents CO_2 upwards migrating and escaping into the atmosphere (Benson, & Cole, (2000). Pore presence also makes these reservoirs favorable for CO_2 storage (Yu, & He, (2017). In addition, there is exact information about the reservoir capacity. thus, sufficient CO_2 volume may be injected and accommodate within the reservoir (Bachu, (2015).

It also should be noted that depleted reservoirs have the infrastructure i.e., injection wells, surface facilities that significantly reduce storage costs.

• **Saline Aquifers:** deep underground formations also considered as a storage for CO_2. There are several and main factors for this. First, in comparison with the other geological formations saline aquifers has the larger storage capacity (Bachu, (2015). From the other side brine and CO_2

do not readily mix, that minimizing the risk of CO_2 dissolving and contaminating the brine (Metz, et (2005). Wide geographical distribution is increasing the accessibility of the CO_2 storage on saline aquifers (International Energy Agency (2023). But the biggest disadvantage of using saline aquifers is the infrastructure absence (i.e., Injection wells and pipelines). This leads to large investments requirement.

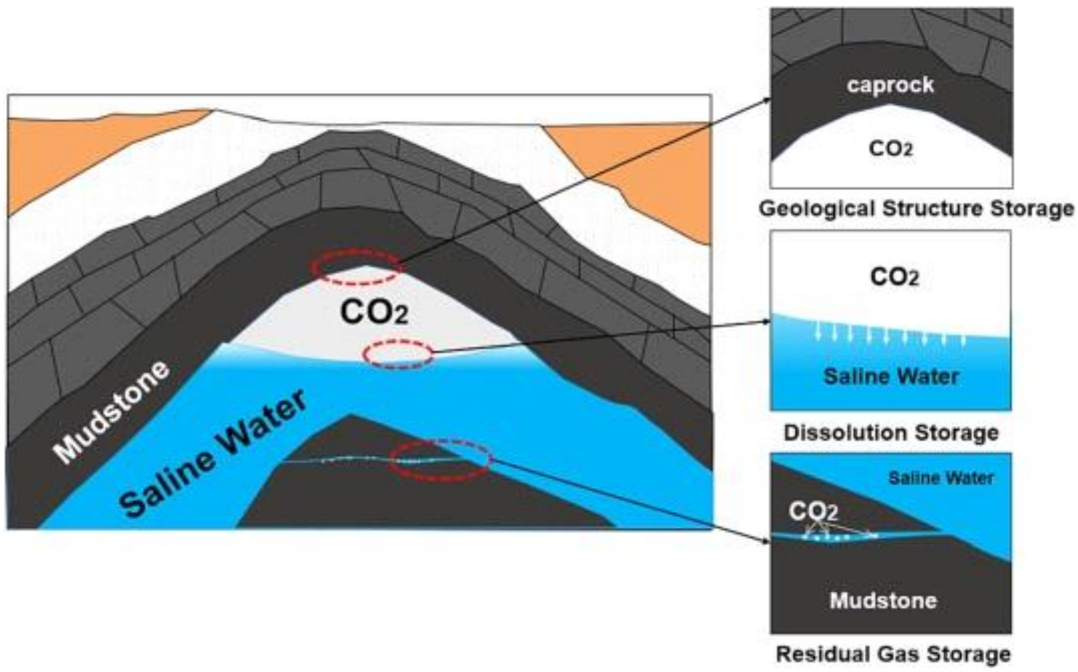

Fig.2.3 Captured Carbon Dioxide storage in saline aquifers.

- **Unmined coal seam.** In addition to the mentioned above methods there is a possibility of carbon dioxide storage in unmined coal seam. Sometimes coal seam locates very deep or quite thin that makes its production economically unprofitable. In this case it may be used as a CO_2 storage. Due to its adsorption features CO_2 sticks to the coal surface.

- **Basalt Formations.** CO_2 injected into basalt fractions reacts with magnesium and calcium. As a result of this reaction, stable mineral forms of calcite and dolomite appear. This transformation of gas into solid minerals guarantees its long-term trapping deep underground.

2. Locations of Geological Storage:

There are different factors that make a geological formation suitable for captured carbon dioxide. Even though potential carbon storage sites are located all over the world, there are some countries and regions demonstrate greater activity and potential of CCS technologies. This is related with the high level of economic development, great attention to the environment and a large amount of oil and gas production.

• **USA and Canada:** actively exploring CCS. example Petra Nova project in Texas (Petra Nova: World's First Large-Scale CO_2 Capture, Utilization, and Storage Project. (2024).

• **Europe:** Some European countries, (Norway, the Netherlands, and the United Kingdom and others) are engaged in CCS initiatives. The Sleipner Project in Norway injects CO_2 captured from a natural gas processing facility into a saline aquifer (Sleipner CO_2 Storage Project. (2024).

• **Australia:** Australia possesses significant potential for CO_2 storage in saline aquifers, with ongoing research and demonstration projects underway (Carbon Capture and Storage (CCS) Association. 2024).

3. Operations of Geological Storage: Carbon dioxide injection into a geological formation contains from the steps mentioned below:

• **Site characterization:** geological and geophysical investigations are conducted (i.e. evaluating the caprock integrity, reservoir properties, and associated potential risks) in order to assess the suitability of the formation for safe and secure CO_2 storage (U.S. Department of Energy. (2023).

• **Well construction:** specialized wells are drilled to promote a safe access to the formation, ensuring it meets environmental requirements (American Petroleum Institute (2005). These wells should be designed to withstand the pressure of injected CO_2 and prevent leakage.

• **CO_2 injection:** The injection process is carefully monitored and controlled to ensure safe and efficient CO_2 storage (Global CCS Institute (2018).

• **Monitoring and verification:** Long-term monitoring of the storage site is very important to ensure the continued safe and secure storage of CO_2. This involves monitoring pressure, temperature, and CO_2 plume movement within the formation (Benson, Oldenburg, (2014).

Conclusion. Geological carbon storage provides solution to climate change by permanently trapping CO_2 emissions underground. Understanding the different types of storage formations, potential locations, and operational processes involved is viral for the responsible and effective implementation of CCS technology. Ongoing research and development efforts important to optimize storage technologies, enhance operational efficiency, and ensure the long-term safety and environmental sustainability of geological CO_2 storage.

2.4 Economic Factors Influencing the Application of Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) remains to be one of the most important tool against air pollution. The constantly high cost of the technology can be explained by its design complexity and the continuous maintenance. It is quite difficult to calculate exact price of CCS technology since it depends on various factors. This paper aims to highlight these factors, exploring both advantages and disadvantages of CCS technology implementation.

Concentration of the captured carbon dioxide also determines the cost of CCS technology. The lower concentration of carbon dioxide in emissions, the higher the energy demand for tis separation. Concentration of CO_2 ammonia production is higher than in steel or cement production. Therefore, cost of CCS technology implementation in ammonia production going to be cheaper than in cement or steel one.

On the other side efficiency of CCS technology is calculated based on the type of the energy source used while its exploitation. For example, it is known that CCU operation requires significant energy consumption and additional CO_2 emissions appear unless renewable energy used.

Cost of CCS Technology: Initial investments: Setting up CCS system requires sizable investments, frightening potential adopters, especially in developing economies (International Energy Agency. (2015).

- **Ongoing costs:** CCU operation requires significant energy consumption and leads to additional expenses (Leung, Caramanna, & Maroto-Valer, (2014).
- **Carbon Pricing Mechanisms:**
- **Taxes:** Implementation of emission taxes or emission trading mechanisms may stimulate CCS application and they strive to reduce the emissions (Hepburn, et al. (2006).
- **Lack exact pricing methods:** The absence of established cost calculating mechanisms prevents CCS adoption and widespread use (Meckling, Stephan, (2017).
- **Government Support and Subsidies:**
- **Direct subsidies:** CCS technology application may be stimulated by direct government subsides, which make their installation more attractive to investors (Feron, Jessen, & Riemer, (2011).

- **Tax breaks and other incentives:** The CCS technology implementation process can also be stimulated by different tax breaks, loans, or other governmental concessions (IEA Greenhouse Gas R&D Programme (2011).

Market Demand for Captured CO_2:

CO_2 utilization: Utilizing captured carbon dioxide in various areas of production (i.e. enhanced oil recovery, production of synthetic fuels or chemicals). This can generate an income that may be invested in carbon capture and storage technology (International Energy Agency (2023).

Expansion market for captured CO_2: Existing market for captured carbon dioxide remains limited. Its expansion can increase the viability of CCS projects (Finkenrath, Lux, & Möller, (2017).

Technological Achievements:

- **Cost reduction by innovation:** Continued research by different international institutions and agencies may lead to technological improvements and thereby make CCS more effective and competitive (IEA Greenhouse Gas R&D Programme (2013).

- **Undefined achievements:** From another side uncertain advances may create an "innovation dilemma" and companies might delay investment in currently available CCS technologies (Wicki, Bürki, (2018).

- **Public Perception and Social Acceptance:**

- **Public concerns about safety and environmental risks:** Public disinformation and wrong perception related with CCS implementation may also obstruct projects approval and investment (Whitmarsh, & Lorenzoni, I. (2005).

- **Effective communication and public engagement:** CCS deployment may be simplified by transparent communication with publicity and engaging communities in decision-making processes (Brynolfsson, & Painter, (2016).

- **Conclusion:** As a conclusion of the material above the following challenges in CCS implementation can be highlighted: cost, technical difficulties, safety, storage capacity, and regulatory requirements. Besides public perception may also criticize the carbon capture and storage technology. In addition, sometimes there is an opinion that the CCS technology deployment may hinder the further implementation and use of renewable energy sources. Despite all the challenges CCS is a working technology towards reducing Greenhouse gas emissions. Likely further researches will increase the CCS technology efficiency and allow this technology implemented on a wider scale.

2.5 Analytical calculation for storage capacity evaluation

Relevant institutions of each country are making efforts to identify and assess estimated capacity of carbon dioxide storage that they have. The reason for this is the daily increasing necessity in CCS technology implementation. This paragraph aims to identify methods of storage capacity calculation. As it mentioned in previous paragraphs of this paper there are different types of CO_2 storages, however the most capacious are saline formations. That is what main attention was paid to defining the capacity of these formations, nevertheless other types have also been considered.

Even though resent years many methodologies have been offered, all of them are based on the same physical principals and to make the calculation methods more clear and simple standardization efforts have been made. As a result of this we have two basic methods of CO_2 calculation: **static and dynamic**. Static methods are based on pressure build-up. And doesn't depend on time while dynamic methods based on analytical approach, change with time. In all cases after carbon dioxide volume is estimated. it is possible to calculate mass capacity knowing the density of CO_2. Capacity is indicated in mega or giga tones (Mt or Gt).

Summary of standardization is all methods are divided into two groups: **static and dynamic** methods of storage capacity evaluation. In turn, static methods can be volumetric and pressure buildup.

<u>Volumetric methods:</u>

- Calculate pore volume in the formation
- Estimate efficiency of the storage
- Simple implementation

<u>Pressure build-up</u>

- Evaluate closed system
- Evaluate the maximum pressure build-up
- Estimate carbon dioxide volume while compressibility and increase of the pressure

Types of dynamic methods are:

<u>Semi-closed</u>

- This is almost the same with the pressure build-up method. The only difference of this method is it allows brine leak.

Pressure build-up at wells

- Implement analytical formula to calculate pressure of injection
- Suppose pressure in the injection well – the limiting factor

Material balance

- This is almost the same with the pressure build-up method. The difference is it update calculations

Decline curve analysis

- Monitor carbon dioxide pressure increase
- Opposite of decline curve analysis in hydrocarbon reservoir

Reservoir simulation

- Based on detailed geological model of reservoir
- Simulate water or brine leakage
- Based on more detailed information

Static methods. The main idea of volumetric approach is quite simple. To estimate the capacity of CO_2, mass that can be injected in the saline aquifer there are three aspects to be considered: total volume of pores in the reservoir, the volume proportion that carbon dioxide will occupy and the density of CO_2. Once there are no exact data average numbers can be used. In general, to calculate the volume the following formula is used:

$$V_p = A \text{ x } H \text{ x } \Phi \tag{2.1}$$

V_P – pore volume, A – area, H – thickness, Φ is porosity.

There is one more formula designed for volume calculation in case more detailed information is available.

$$V_P = \text{Iff } \Phi dxdydz \tag{2.2}$$

It is known that density of carbon dioxide depends on pressure and temperature, so it can be easily calculated based on state equation. As for the volume proportion which may be occupied by CO_2, the following formula can be referred to.

$$E= \frac{Vco2}{Vp} \tag{3.3}$$

Based on the formula above:

$$V_{co2} = V_p \text{ x } E \tag{2.4}$$

Considering the physical and chemical properties of carbon dioxide, Department of Energy of US (DOE US) propose to consider some factors in calculation of proportion of volume that CO_2 may occupy. As per DOE carbon dioxide is not able to fill in all pore space. So, the factors are horizontal and vertical net to - gross, connected porosity to total porosity ratio.

The other factors to be considered are pore space proportion contacted with carbon dioxide; horizontal and vertical sweep; a gravity factor since CO_2 is rise to the top of reservoir; the microscopic sweep efficiency. Besides, storage capacity and efficiency factors to be estimated in volumetric method.

It has been proven this method is very useful in preliminary estimation of carbon dioxide storage capacity in large regions.

Compressibility method. Sometimes the aquifer is limited in space, so while carbon dioxide injection there is a possibility of caprock fracture. In this case the amount of injected CO_2 depends on pores compressibility and the maximum average pressure range.

$$C = \frac{1}{V} + \frac{\partial \mathrm{V}}{\partial \mathrm{P}} \approx \frac{1}{V} \frac{\Delta \mathrm{V}}{\Delta \mathrm{P}} \tag{2.5}$$

Following the formula, the volume should be calculated as stated below:

$$V_{CO2} = (c_r + c_w) \text{ x } V_p \text{ x } \Delta P = c_t \text{ x } V_p \text{ x } \Delta P \tag{2.6}$$

V - volume, P - pressure. subscripts r -rock (pore space), w - water (brine) t - total.

To avoid the fracture in any case maximum pressure of the injection to be less than fracture closure presser is. This is applicable for each formation.

Traditional engineering approaches. In the process of carbon dioxide pumping into a reservoir with constant pressure, the rate of injection will decrease due to the formation pressure build up. Scott M. Frailey - scientist and engineer of the University of Illinois suggests that decline curve analysis can be used to determine capacity of injected CO_2.

$$q_{C02,}{}^{t} = q_{C02,}{}^{i} \exp(-Dt) \tag{2.7}$$

CO_2 - injection rate, t - time, i - initial time, D - decline coefficient.

This way can be implemented only after exact amount of carbon dioxide has already been injected. In this case log to time plot going to be approximately a straight line, and its slope will indicate decline coefficient. This formula can be used for calculation of carbon dioxide amount that can be injected.

$$V_{CO_2} = \frac{q_{CO2,i} - q_{CO2,A}}{D} \tag{2.8}$$

Although this method is very different than other ones, this is a simple way for estimating the total amount of CO_2 that can be stored.

The scientist also proposes to use the material balance equation for the storage capacity estimation. He believes that this method can be applied to a storage that already contain stored CO_2, and there are some pressure data is available. Based on results it is possible to assume brine amount leaking from the reservoir, and then implement for estimating CO_2 capacity and maximum pressure limit.

Numerical reservoir simulation. The most methods to analyses and estimate the capacity of storage are based on homogeneity of saline aquifers, but in general they are more difficult shapes and different layers which differ in their composition, density, and permeability.

Accordingly, all these factors will influence the behavior of carbon dioxide and its moving after injection. Besides, the aquifer structure affects the pressure in reservoir. While injection chemical and physical properties of carbon dioxide also to be considered to not underestimate the capacity of the storage. Processes like dissolution, evaporation, and others. Since all of them affect the capacity of aquifer.

Special designed software with reservoir simulation can be used to estimate the aquifer capacity. Building a reservoir simulation models can be explained by several reasons. First, basic reservoir structures may be assessed to estimate the efficiency of storage using a volumetric method. The most important this modeling doesn't require detailed information about the aquifers. From the other side the reservoir imitation is important to estimate the capacity in exact reservoir. But in this case geological model to be built, based on more information. Thus, it becomes possible to simulate injection according to different scenarios, controlling pressure build-ups, to find out the most efficient way of the highest capacity of CO_2 injected. Storage efficiency calculation can refer to the following formula:

$$E = \frac{Minj}{pVp} \tag{2.9}$$

p = CO_2 density in the reservoir.

2.6 PVT behavior of Carbon dioxide

It is known that Carbon dioxide has three states that may change under certain conditions of pressure and temperature. The understanding of each phase behavior of carbon dioxide is crucial during CCS especially in transport and injection. While CO_2 pipeline transport two processes play an important role here: the cooling of the CO_2 in the pipeline and the well pressure between the well head and the storage reservoir. These processes have a significant impact on the CO_2 phase behavior. They require a thorough understanding and precautionary measures to ensure that the CO_2 enters the reservoir at the right pressure and temperature. Otherwise, density changes can have a major impact on the ability to inject CO_2 into the reservoir (Firoozabadi, (1999.) Hence this paper aims to find out PVT behavior of carbon dioxide and phase diagram of CO_2.

PVT Behavior of CO_2: Carbon dioxide is a compound that demonstrates different phase behavior in different pressure and temperature conditions. For example, CO_2 is a gas at low pressures and temperatures, while at high pressures and temperatures it transforms into a liquid or a supercritical fluid.

Phase Diagram of CO_2:

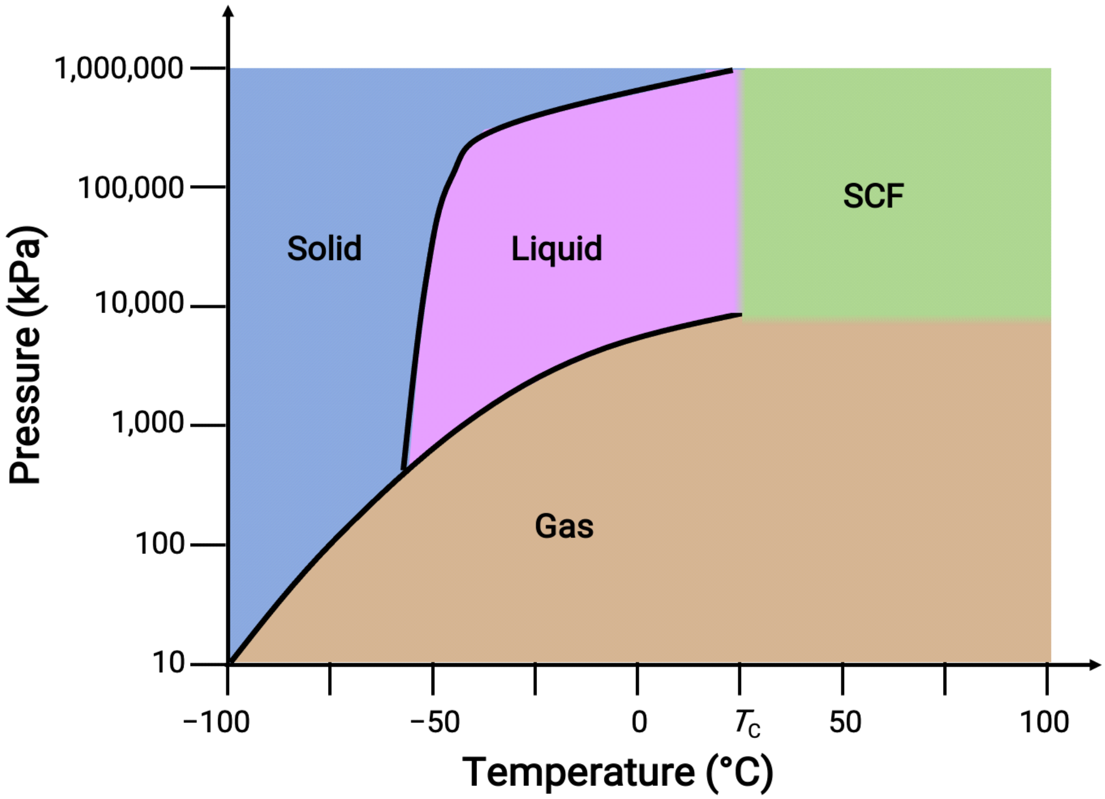

Fig.2.4 Phase diagram of carbon dioxide.

The diagram above shows how CO_2 behaves in different pressure and temperature conditions. It consists of parts representing gas, liquid, and supercritical phase of CO_2. The phase boundaries, known as the vapor pressure curve and the critical point, separate these regions (Span, (1992).

The diagram above demonstrates that there is a positive slope of the curve separating liquid and solid parts, it means that the CO_2 melting point increases along with pressure. This diagram also demonstrates that carbon dioxide cannot exist as a liquid in conditions under ambient pressure. CO_2 cooling at 1 atm, results in its transformation into solid. But solid carbon dioxide does not melt at 1 atm, instead it transforms into yield gaseous CO_2. And last, carbon dioxide's critical point is observed at much more modest temperature and pressure indicators (Uddin, Mioara, (2016).

Conclusion. Understanding how CO_2 behaves under different pressure and temperature conditions is essential for optimizing CCS processes.

CHAPTER III. MODELING OF CARBON DIOXIDE CAPTURE AND STORAGE

3.1 Modeling the injectivity, migration, and trapping of CO_2 in CCS

Carbon dioxide injection causes significant pressure and saturation changes in formations and affects the system. To predict, monitor, and control all these changes modeling the injectivity, migration, and trapping of carbon dioxide is very important. Though infectivity can be predicted by analytical models, CO_2 migration and trapping can be analyzed by special numerical codes. On the other hand, storage capacity can be increased by modeling the process.

As was mentioned in the previous paragraphs of this paper different facilities can be used as a storage for captured carbon dioxide, including saline aquifers, unamenable coal fields, depleted oil/gas reservoirs, producing reservoirs, etc.

CO_2 injection may serve various purposes (as EOR) but in each case, it should be done safely and prevent the leakage risk. Injection is accompanied by significant pore pressure increase, especially near the surrounding areas, but depending on porous medium connectivity it can affect the areas in kilometers or sometimes tens of kilometers away. In general, the pressure surge accrues instantly and then stabilizes, but sometimes depending on the porous medium it can take more time. The equation below reflects the pressure wave speed;

$$\frac{\partial P}{\partial t} = \left(\frac{k}{\mu \Phi\ C_f}\right)\left(\frac{\partial^2 P}{\partial x^2}\right) \tag{3.1}$$

P - pressure, t – time, x - distance, k - absolute permeability, μ - fluid viscosity, Φ - porosity Cf - fluid compressibility. The larger the hydraulic diffusivity constant, the faster the pressure wave will spread out the porous medium. The structure of the porous medium is also very important since pressure wave speed changes if the medium consists of different phases, and the compressibility of carbon dioxide indicators changes accordingly. In addition, carbon dioxide dissolution affects the surrounding liquid compressibility.

During the CO_2 injection underground fluid saturation will change, even after injection is completed, carbon dioxide migration doesn’t stop due to the buoyancy property of the gas. This can continue for a long period, sometimes up to years. Carbon dioxide is capable of displacing formation fluids, and vice versa fluids can replace CO_2, in case it moves up. Darcy's law determines the speed of fluid movements through the porous medium.

$$u_i = \left(\frac{k*k_{ri}}{\mu_{\ i}}\right)\left(\frac{\partial P_i}{\partial x} - g p_i\ \frac{\partial z}{\partial x}\right) \tag{3.2}$$

U – phase velocity, i, k - absolute permeability, k_{ri} - phase relative permeability, μi phase viscosity, g – gravity acceleration, x – horizontal, z – vertical directions.

Carbon dioxide migration speed will increase with higher indications of rock permeability, fluid mobility, gradient of imposed pressure, and a large phase density difference.

Following the equations above there are a lot of factors affecting carbon dioxide migration. However, the common factor for both equations is permeability. High permeability promotes dissipation and reduces pressure build-ups while injection. But at the same time, permeability contributes to the migration of CO_2, and sometimes it can migrate out of the storage.

As for the saline aquifers, the capacity of the storage is calculated based on the amount of carbon dioxide to be safely injected. Saturation and pressure changes that arise during the injection are the only parameters considered during injection into saline aquifers, and these factors should not cause CO_2 migration.

In any case, there is always a risk of leakage during injection. It may be caused by human activity. It can be prevented by continuous pressure monitoring. Besides, a leakage pathway may already exist in the system. To recognize and prevent leakage in this case saturation monitoring is to be arranged. However, both cases require sufficient knowledge of geology, and how injected carbon dioxide may react with rock or pore fluids. Based on the above, the most important is pressure monitoring during injection, while saturation control is required if Carbon dioxide migrates (it can take quite a long time, up to years).

Pressure and migration response may be predicted by engineering calculations, that are used in the oil industry. Possible pressure changes and migration pathways are analyzed and calculated solely by numerical codes and modeling since minor changes in permeability may strongly affect migration.

Grid resolution influences the simulation of carbon dioxide migration and its dissolution simulation. The vertical grid resolution right under the cap rock influences the migration lateral extent calculation. Besides, the displaced amount of carbon dioxide during the exact period during simulation may contact and dissolve into the brine. Thus, models with approximate data are likely to significantly overpredict the amount of dissolved CO_2.

Modeling of reservoir processes. As soon as carbon dioxide is injected, the underground system is changing. There are two major parameters to this change evaluation. These are pressure and saturation and are calculated in each grid cell at each time step in every simulation model of finite difference and are of primary interest. However, in addition to this, simulation considers various processes that happen in the reservoir and affect pressure and saturation, such as fluid phase behavior, and interactions between fluid-fluid and fluid-rock. In addition, geochemical, geomechanically effects and dissolution.

Impact of reservoir processes on injection pressure. Some circumstances (i.e., poor rock conductivity, low mobility of fluid, or precipitation of solids) may cause more pressure in the well during injection. Low rock conductivity leads to more tortuous paths and more dead-end space. A homogeneous permeability doesn't depend on scale, unlike relative permeability. It can be explained by relative permeability dependence on fluid saturation, and saturation, in turn, depends on the scale. Besides, the overall pressure response of the system is of importance. If CO_2 injection occurs in a reservoir with closed boundary conditions, the internal pressure of the system will increase very rapidly compared to injection into a sealed reservoir with open boundary conditions. It happened while injection in Norway when the operation had to be stopped due to internal pressure build-up in the reservoir. The reason was the smaller capacity of the aquifers than was assumed, due to closed boundary conditions.

Hence, injection pressure calculations include factors of both the wellbore and reservoir. The internal diameter of the wellbore and its internal surface affect the frictional pressure drop in the well. That is why friction pressure drop is calculated in direct proportion to friction factor length and density and to the flow rate square and inversely proportional to the diameter to the fifth power. Following above stated the inner diameter of the wellbore significantly affects injection pressure. But the larger the inner diameter, the pricier the wellbore is. Horizontal or deviated wells increase wellbore and formation contact, therefore improving injectivity. But from the other side, considering the friction pressure drop is proportional to the length of the bore, therefore there is no additional benefit accordingly.

Density, viscosity, and carbon dioxide compressibility are the determining factors of injection pressure and vary with well pressure and temperature. That is why the Equation of State (EOS) is to be implemented in calculations (Galic, et al. 2009).

To finalize, bottom hole pressure depends on several factors (wellbore parameters, wellbore and reservoir fluid properties, fluid–rock interactions, and structure of the reservoir. It has been determined that relative permeability affects injection in reservoirs with open boundary conditions while formation compressibility affects material balance in closed boundary conditions (Mathias, et al. 2013).

Impact of the reservoir processes on the carbon dioxide migration. Injected carbon dioxide migrates due to different gravitational processes which accrue due to density differences. As an example, rise to the cap rock of CO_2 since its density is lower than the surrounding brine. Capillarity traps carbon dioxide may reduce migration. CO_2 is considered trapped when it cannot migrate to the possible leakage area in both the free phase and as a component of the existing phase. There are different trapping mechanisms depending on the storage location, injection start, and completion time.

Structural trapping is one of the possible ways to trap carbon dioxide. Due to its properties, CO_2 migrates upwards and there should be a barrier to prevent further rise. Anticline, a fault-juxtaposed seal as well as shale gouge may fulfill this role.

Stratigraphic trapping. Pinchout inconsistency may act as a carbon dioxide trap. Usually, the lateral extent of the permeable layer ends with the impermeable rock that prevents carbon dioxide vertical migration. Sometimes structural and stratigraphic traps may occur at the same reservoir. Both mentioned above methods are studied very well since they are widely used in the oil and gas industry. Based on oil and gas storage examples, it has been proven that these methods are reliable, and a store of captured carbon dioxide in depleted oil and gas reservoirs guarantees minimum leakage risk. Storing CO_2 in depleted oil and gas reservoirs should also be kept under control due to the availability of significant data on the reservoir. While injection into the unknown aquifers may be accompanied by unpredictable problems due to lack of sufficient data (Smith, et al. (2012).

Structural and stratigraphic traps are perfect seals, due to their closed boundary condition, while aquifer calculation is to consider the permeability of the overlying strata, and the absence of the hydrocarbons beneath increases the likelihood of its permeability (Jin, et al. 2012).

Capillary or residual trapping. Each storage formation has its own specific factors that affect the percentage of injected carbon dioxide that will be trapped. This may be lower than 5% or sometimes more than 50%. These factors are the wettability of the rock, fluid-fluid interfacial tension, pore structure, and inter-connectedness. In addition, unsaturated rock also slows down CO_2 migration.

Dissolution trapping. Carbon dioxide dissolves very well in brine which also contributes to its trapping (Duan, Sun, (2003), (Spycher, et al. (2003). Saturated brine is denser and keeps dissolved CO_2 downwards (Ghanbari, et al. (2006). Therefore solubility and capillary trapping mechanisms are the most effective. Even though carbon dioxide is kept trapped in the first two cases, it will start migrating at any suitable convenience. However, in dissolution or capillary trapping cases, the possibility of dissolved carbon dioxide mobility is reduced to zero.

Mineralization trapping is the safest way to store carbon dioxide. Mineralization means that CO_2 becomes a part of a mineral compound as the result of its dissolution in the brine (for example Ca CO_2) (Xu, Apps, (2005).

3.2 Reservoir Processes Modelling

In the previous paragraphs of this paper, it was stated that there are two ways of modeling: analytical and numerical (Mathias, et al. (2013). But in most cases to monitor saturation, migration, and trapping numerical modeling is used. Numerical models are usually either finite difference or streamline models (Jin, et al. (2012). These models simulate time and space and calculate saturation and pressure for each element of the grid.

Numerical errors. But even in numerical methods of modeling errors may arise. It can happen during discretization since it is possible to use only a single value in model initialization for a given property. On the other side, such important parameters deep in the storage like porosity, permeability, initial saturation, etc. may be uncertain.

Furthermore, the grid cell resolution of the modeling is also one of the significant aspects affecting the final information. Once the size of a set grid cell is smaller the saturation under the same parameters will be greater than in case a larger grid cell resolution has been set. It means that injection modeling under the same conditions (time, permeability, saturation, etc.) will give two different results only because of the grid cell size.

More accurate results can be reached by the fine grid resolution modeling, which requires more cells, but in general computing power limits the resolution. Some errors may be fixed by scaling techniques.

There are some reasons cause numerical errors:

(a) Due to density difference injected carbon dioxide rises to the top and spreads out under the cap rock. And to resolve CO_2 buoyancy, vertical resolution models are required.

(b) To avoid pressure build-ups injections to the large aquifers is more favorable. But the larger is reservoir, the larger grid cell resolution is required.

Since CO_2 injection will often be limited by the pressure response of the system, it will be

(c) One more important factor is scaling restrictions. Some parameters such as relative permeability can be scaled while injection modeling to provide more accurate results. However, some parameters are difficult to scale up. Let us say to evaluate trapping mechanisms it is important to have accurate CO_2 dissolution data, and this in turn depends on the size of the grid. In modeling once carbon dioxide enters the grid it is supposed to come into contact with brine in a whole grid and dissolve in it. And if the grid cell is 100 meters long, CO_2 is supposed to dissolve in brine 100 meters away. But real numbers can be different.

Therefore, grid resolution is very important to reach accurate data. In comparison with numerical models, analytic models may be more accurate and flexible in adjusting data where it is required. Thus, more efforts to be made to improve analytic models. Dynamic griding techniques to be also improved (Computer Modeling Group (2012).

Geochemistry processes are very important in the CO_2 storage process since while injection carbon dioxide dissolves in phase brine and reduces its pH and in turn, this leads to different geochemical effects particularly mineralization that require years to reach equilibrium (Gundogan, et al. (2011).

Geochemical effects are crucial for the following reasons:

1. Brine acidification causes dissolution in the formations that may have positive as well as negative outcomes. Based on oil and gas industry practice carbon dioxide injection acid treatment is used to increase injectivity. The fines that are released block pores or cause subsidence in carbonate reservoirs.

2. During injection, a large amount of carbon dioxide is pumped into a wellbore zone and displaces mobile brine. The left brine evaporates into the flowing CO_2, and as a chemical reaction appears salt – NaCl. This reaction increases pore space since halite occupies less space than brine. But if sediment is mobile, especially at different pressure levels, it may block pore throats and as a result reduce permeability.

3. Once CO_2 or carbon dioxide-saturated brine reacts with wells there is a risk of leakage pathways may be created. Thus, all materials that will be used to be selected carefully. Therefore, it is crucial to minimize the risk of brine contact with the well bores.

Even though several research have been done on geochemical modeling of phase water systems, thermodynamic and kinetic data of behavior in higher temperature and pressure conditions remains unexplored.

Geomechanics. In most cases, geochemical processes are not considered. The reason is the lack of data, and it is quite difficult to input data in the modeling. Unlike the oil and gas industry where voidage replacement takes place and there is no significant pressure change, in carbon dioxide injection more likely that phase pressure will rise. Thus, the amount of injected CO_2 to be carefully adjusted to avoid cap rock failure. Hence geomechanical modeling is essential to ensure safe CO_2 injection and storage (Olden, et al (2012). Besides, geomechanical processes in underburden and overburden layers are to be considered.

Temperature. The density and viscosity of carbon dioxide depend on temperature changes. Small errors in temperature data during high-pressure injection are not significant. But, in the systems close to the critical point, or with Joule-Thomson effects temperature date to be accurate (Mathias, et al. (2010).

Impurities. Usually, modeling is based on pure carbon dioxide. However, depending on the source, CO_2 may contain different impurities (e.g., NOx, 02, H2, CO, Hg, As, Se, etc.) that can affect the critical point (Chapoy, 2011). Further development of adaptation of the models that consider the influence of impurities is important. It is especially necessary to study the impurities' effect on injectivity properties.

Engineering options to manage CO_2 storage. Carbon dioxide capture and storage is a relatively new industry and requires a lot of improvements. However, oil and gas and other mature industries' practices can be implemented to reach safety and efficiency in storage as well as CCS economics.

Injectivity. One of the major challenges during CO_2 injection is pressure build-ups, that may cause cap rock failure. The main method to reduce the wellbore pressure is to extend the pumping length. It can be reached by additional wells drilling or using deviated or horizontal wells. But this method has a disadvantage as well. Drilling additional wells or extending well length will lead to additional expenses. Besides, injectivity is reduced by the wellbore friction from the heel to the toe.

Greater depth injection requires higher injection pressure. Therefore, due to higher pressure higher injection rate is maintained before the risk of fracture occurs. This method requires fewer wells used instead of injection into shallower depths. The greater the depth is, the more layers are available to capture injected carbon dioxide and the greater is long-term security.

Another way of pressure management is to extract the brine from the storage. This requires EV (enhanced voidage) wells to be drilled at the same formation but away from the location where CO_2 is supposed to be stored or may migrate. The EV well is to be in pressure communication with the injected well. Brine extraction is capable of increasing storage capacity up to four times, which consequently contributes to savings (Jin, Mackay, (2009).

It should also be noted that according to data from the UK Department of Energy and Climate Change (DECC), from the start of oil production in the Nort Sea (in the Argyll Field in June 1975) through to October 2011, some 5.6 x 109m3 (35 billion barrels) of water have been produced, 5.1 × 109m3 (32 billion barrels) of which have been treated and disposed of in the sea. (This compares with a total of 4.5 × 109m3 (28 billion barrels) of oil that have been produced and exported during that period.) Thus, water extraction and disposal is a well-established procedure, and strict quality controls are already in place (e.g. limit of 30 ppm oil in water content, regulations on chemical content determined by the OSPAR convention, etc.)

Migration pathways. The most possible leakage way is the well. To prevent carbon dioxide leakage well is flush with the brine once the CO_2 injection is completed (Qi, LaForce, (2010).

To prevent the free phase of carbon dioxide leakage it can be dissolved in the brine. CO_2 - dissolved brine is denser and sinks downwards, keeping carbon dioxide away from possible pathways. Therefore, ensuring significant cost savings in monitoring and leak verification (Burton, Bryant, (2009).

The disadvantage of this method is requiring of significant amount of energy (to dissolve 1 kg of CO_2 30 kg of brine is required), on another site it will lead to the pressure increase in the formation due to a greater volume of injected brine. To manage pressure build-up, brine of the same formation can be used. Implementation of the multilateral system may reduce energy requirements. Since one lateral produces brine, brine and carbon dioxide are mixed in the next lateral and injected into the storage through another lateral (Shariatipour, et al. 2012).

Challenges and future trends. Despite the number of direct parallels between the CCS and the oil and gas industry, there are some completely different issues. Due to data gaps, they are to be developed. CO_2 *injection in aquifers*. In general, the aquifer’s size is much larger than the hydrocarbon reservoirs. The reservoir description is less clear due to the lack of appraisal wells. Due to its large size, the saline aquifer may host several CO_2 storages projects or one or more oil and gas fields. Since in the oil and gas industry pressure buildups are fixed by water injection, there will not be a big pressure difference in the aquifer, and interference of the oil fields sharing the same aquifers is not significant.

However, because of a large amount of carbon dioxide injection, pressure in the saline aquifer is rising and affecting the oil and gas field located in the same aquifer. Increased pressure after CO_2 injection affected oil fields in the Central North Sea (Heward, (2003).

Carbon dioxide migration may continue for centuries. Thus, monitoring of injected CO_2 flow for a long period and a quite long distance away from the injection point causes significant financial challenges.

Usually, there is not sufficient information about relevant permeability in the reservoir which is crucial in the prediction of the injected carbon dioxide migration. Generally, this date is based on the experiments on core samples of the formation. It should be taken into consideration that this is dynamic behavior, and formation data does not apply to one another.

Geochemical processes play an important role in determining the risk of halite precipitation, dissolution, fines migration, etc.

Unlike the oil and gas industry, in carbon dioxide injection accurate characterization of the cap rock is vital since it may seep through the overburden.

CO_2 injection for Enhanced Oil Recovery (EOR). Despite CO_2 capture and storage requiring huge capital amounts, more attention is paid to CO_2injection to enhance oil recovery. This partially may cover expenses. In most cases, CO_2 is used as a sweep fluid. Under the high-pressure carbon dioxide dissolves into the oil phase and expands it. Once CO_2 comes into contact with residual oil, it gets saturated and becomes mobile. Besides, oil may evaporate into the flowing CO_2 steam, which also mobilizes it. It has been proven that tertiary recovery using CO_2 may increase recovery up to 5-10%. Over a hundred EOR projects have been realized in the USA and contain 6% of US oil production and 95% of natural CO_2. Due to the cost of carbon dioxide transporting these projects are not designed to maximize CO_2 storage. However, if the target is CO_2 storage, then injection of CO_2, into the underlying aquifer may be considered. Then injected carbon dioxide will provide pressure support. Also, CO_2 injection may be implemented instead of water injection in regions with poor water provision. Reach natural resources of carbon dioxide explain the onshore location of CO_2 EOR projects in the US. Using these resources is cheaper than capturing them from the plants or importing them.

In general, in this project wells are located close to each other, and this leads to the following consequences:

1. Modeling studies can be carried out in small areas.
2. Production of injected CO_2 reduces the amount of carbon dioxide, to be transported to the field for injection.

Unlike the US, in Europe, most of these projects are located offshore and use anthropogenic carbon dioxide. Due to wide territorial capabilities project sizes tend to be larger. However, it has its disadvantages since modeling of the larger offshore EOR projects will require significant large grid resolution. In addition, offshore layers oftentimes are thicker and therefore Dietz tongue may occur and a fine grid resolution in the vertical direction to be implemented. Optimizing of the CCS projects should be done based on the following criteria: maximizing and accelerating oil recovery and ensuring that injected CO_2 as long as possible stays in the storage complex.

There are different reasons why CO_2 is not widely implemented in offshore EOR projects:

1. Large costs. Ensure that the well is CO_2 compliant, sourcing and transporting of carbon dioxide.
2. Lack of a constant supply of carbon dioxide in sufficient quantities.
3. The fact that using seawater is much more secure in comparison with the CO_2.
4. Lack of data and research in the CCS industry.
5. Obligation to monitor the field even after the completion of the project.

3.3 Carbon dioxide leakage from storage facilities

Carbon dioxide capture and storage significantly reduce greenhouse gas emissions into the atmosphere. However, the CCS process requires constant monitoring to prevent leakage. This paper aims to highlight the ways of leakage monitoring and preventive measures.

Even though CO_2capture and storage mitigate the environmental effect of harmful gas pollution, carbon dioxide leakage or migration may cause serious problems. One of the main reasons preventing the widespread use of CCS technologies along with significant financial costs is the leak risks. As an example, the ban on the CCS installation in the Netherlands can be mentioned, when local people due to the risk of CO_2 leakage and its potential impact on the environment did not approve the project. Thus, long-term geological storage risks and their potential influence on the environment, health, and economy should be understood and considered. There should be reliable methods and strategies for leakage prevention for the successful deployment of CCS.

Monitoring and risk prevention is quite a complex task and includes many geological, geochemical, and geophysical aspects. Besides, it should consider transport integrity and accident possibilities. Some projects conduct research and consider all the above-mentioned aspects, but they lack direct observations due to the relatively newness of this industry.

Risks and impacts: General approach. Risk consideration and possible impact should be based on FEP – features (physical component, e.g., fracture of a cap rock), events (something that affects the process, e.g., earthquake), and process (evaporation, dissolution, etc.). Only in this case can modeling be complete and cover all necessary aspects. FEP database (Maul, et al. 2005) can be reached online at the International Energy Agency webpage. This database contains all necessary aspects that are important for long-term safety and storage system performance once carbon dioxide injection is completed. The database is generic and can be applied to any project.

CO_2 release into marine system and consequences. Large amount of carbon dioxide in the seawater enhances the photosynthesis process therefore causing eutrophication. On another hand, CO_2 has detrimental effects on carbonate-based structures like seashells or corals and many pH-sensitive physiological processes.

Carbon dioxide plumes disperse in seawater is a complex process. As soon as CO_2 is released into the water it rapidly dissolves. Water saturated with carbon dioxide is denser and tends to sink. CO_2 plume dispersion is sensitive to the ebbs and flows particularly in such regions like the North Sea. It has been observed that carbon dioxide dispersion is a relatively quick process, thus only in the leakage point strong impact of CO_2 is observed (Blackford, (2008).

Usually, localized leaks tend to affect the exact environment, and more likely will affect habitat and organisms limited in horizontal mobility. Thus, mobile pelagic organisms are unlikely to be affected by carbon dioxide leakage. It should be noted that a slow flow of carbon dioxide moving along the seabed will cause acidification of sediment-water and in turn affect sediment organisms.

Carbon dioxide is commonly found naturally in water and the habitats of many organisms, unlike other pollutants. Thus, many organisms can adapt and cope with minor changes in the seawater carbonate chemistry. However, larger changes caused by the carbon dioxide leakage in the water lead to negative effects on basic ecological processes as well as loss of organisms' adaptability to these changes (Blackford, et al. 2010).

Different organisms have different effects on changes in the chemical composition of water. Each species has a different level of adaptation and behavior (Wicks, and Roberts, (2012). For example, calcified structures-dependent organisms will suffer in the high pH or CO_2 level environment rather than non-dependent. Therefore, a decrease in species and functional diversity may happen. This community response has been demonstrated during mesocosm experiments as well as in studies around natural carbon dioxide seeps (Widdicombe, et al. 2009).

Assessment of the impact of aquatic pollution should also consider the ability of organisms to adapt to other harmful substances. Since migrating carbon dioxide passing through sediments can release or carry heavy metals, methane, and hydrogen sulfide if CO_2 storage is located inside or close to the oil and gas reservoirs it can carry hydrocarbons or other pollutants related to drilling.

Based on research carried out up to date, it has been proven that organisms are more sensitive to CO_2 if mixed with other environmental stressors (Pörtner, (2008). Besides large amounts of carbon dioxide may cause an impact upon the key biogeochemical processes, since sediment bacteria and archaea that responsible for elemental cycling, primary production, and waste degradation are also affected (Tait, et al. (2013).

However, CO_2 leakage does not negatively impact all microbes. Some microorganisms consume carbon dioxide or other substances that have been released (e.g., methane) because of leakage.

Carbon dioxide transport. Near-surface environment. As soon as carbon dioxide rises to the water top it remains floating in the near-surface environment due to its higher density than air. Only close to the springs or rivers area, or high CO_2 flux area carbon dioxide may break through at the water surface (Lu, et al. 2010).

Potential environmental impacts.Despite several studies on physiology, the effect of carbon dioxide on organisms and ecosystems is still poorly understood (West, et al. (2005). Respiratory system and pH control are the main mechanisms that control the organism's response to increased exposure to CO_2. The study of the influence of carbon dioxide based on physiology and botany. The goals of current research are to develop the knowledge base important to assess the CO_2 leakage impact on near-surface ecosystems. A study carried out in Italy regarding the CO_2 impact on human life proved that the risk of mortality is quite low even at the largest release (Roberts, et al. 2011).

Description of the economic impact of ecosystem services. The likelihood of a CCS technology's widespread implementation and installation will likely depend on the economic consequences of leaks and their impact on society (Van der Zwaan, and Gerlagh, (2009). To understand and assess the consequences of carbon dioxide leakage, it is necessary to evaluate ecosystem services. These are aspects of the ecosystem that humans use for their well-being (Fisher, et al. 2009). There are four basic groups of ecosystem services:

- provisioning (food, fuel, natural resources)
- regulating (air, water, climate)
- cultural (knowledge, recreation)
- supporting (nutrient cycling, primary productivity)

Provisioning services. It was found that the area of impact of a carbon dioxide leak into the marine environment is negligible. Since important commercial fish species may avoid leakage areas, on another hand leakage may affect trees that impact photosynthesis and some plants important for food provision. However as in the case with marine leakage influence will be miserable as well. Besides CCS may have implementation on drinking water provision. Though CO_2 contained in the water itself may not be harmful, it can react with the minerals in the water or the storage thereby contributing to the release of harmful substances (Pires, et al (2011). Carbon dioxide may acidify groundwater, negatively affecting the quality of obtained from it drinking water accordingly (Van der Zwaan, and Smekens, (2009).

Regulating services. Carbon dioxide leakage from the underground storage facilities potentially threatens the work of several regulatory services. As mentioned in previous paragraphs of the paper, CO_2 causes acidification of sweater and seabed sediments which in turn affects marine organisms responsible for bioturbation. Disruption of the bioturbation system leads to failures of the waste, including organic matter disposal system in marine sediments (Solan, et al. (2004). On-land leakage may cause changes in hydrology in the seep area. A decrease in the vegetation area is known to increase runoff and contribute to erosion in turn (Bosch, and Hewlett, (1982). However carbon dioxide leakage both onshore and offshore is likely to affect a relatively small area, thus its effect on the listed above process is likely to be miserable.

Cultural services. Since cultural services are not material it is quite difficult to determine CO_2 leakage impact on it. The level of impact will depend on public perception. Studies show that the public is little informed about CCS (Huijts, et al. (2007).

One of the cultural services is an environment for leisure and recreation in particular the marine environment. Carbone dioxide leakage is unlikely may impact the environment due to its depth and distance of CO_2 storage. There were indicated cases when carbon dioxide leakage led to asphyxia symptoms (Farrar, et al. 1995) or human and animal mortality. However, this was caused by other stages of the CCS process or car accidents (Roberts, et al. (2011).

Based on the above, it can be concluded that it is essential to carefully choose a storage location. It should be easily reached in case of leakage and should be far from human habitat.

Monitoring and mitigation of storage sites

MMV (monitoring, measurement, and verification) strategy is based on the following:

- Nature and capacity of storage
- The status of monitoring (survey, containment verification, leakage quantification)

Usually, this is applicable for both, onshore and offshore reservoirs. Typically, the extent of the carbon dioxide storage in depleted oil reservoirs is approximately 250-400 km3 and overlain with an ocean volume of approx. 25-40 km3. Conventional storage capacity is approximately >28 Gt. As for the saline aquifers storage rates are significantly higher. Storage capacity is more than 50 Gt (Senior, (2010).

This size and volume storage are naturally prone to leak. It may be a point source leakage with high discharge (more than 200 t./day) or a dispersed source with low discharge (less than 20 t/day).

Depending on the leak scenario, extensive operational and stage-by-stage monitoring is required. More common carbon dioxide storage and leakage monitoring practices (EU Carbon Capture Storage Directive (2009). make extensive use of deep geophysical monitoring of the reservoir containment and integrity of the cap rock. Besides, particular attention is paid to monitoring the migration of carbon dioxide in the reservoir.

Based on the example of Sleipner carbon dioxide storage (Norway, Statoil project), it was proven that 4D seismic exploration i.e., surveys of the repeating seismic reflection is an effective way to visualize CO_2 migration within a reservoir (Chadwick, et al. 2009). Here amplitude and velocity differences are considered as CO_2 fluid (Shi, et al. 2007).

There are other geological methods of CO_2 storage monitoring have been proposed. These are passive micro-seismicity recording, seafloor gravimetry, control electromagnetics source, tomography of borehole electrical resistivity, electromagnetic monitoring, etc. All listed above methods are based on geophysical changes caused by supercritical CO_2 saturation. Electrical resistivity and rock density are used to qualitatively image carbon dioxide migration or to quantitatively predict CO_2 volumes.

Seafloor monitoring can detect carbon dioxide leakage once the leakage source is containment formation, leakage fluids (containing formation brines and reduced pore fluids) are more likely to be released first due to the buoyant properties of CO_2. In this case, seeped brine has elevated temperature and salinity, while pore fluid reaches Mn, ferrous Fe, acidity, H2S, and lower dissolved oxygen.

Physical and chemical monitoring is also able to identify and prevent carbon dioxide leakage. Seafloor, and overlying ocean, provide an opportunity to conduct direct and quantitative measurement of carbon dioxide flux. Physical techniques include acoustic bubble detection (both;

passive and active). The passive method implies acoustic bubble detection by hydrophones while in passive method records the backscatter response of ascending gas bubbles.

Chemical methods indicate seawater carbonate chemistry change. Carbon dioxide leakage signatures are high levels of CO_2, low pH levels, and reduced pore-fluid signatures. Newly developed solid-state optical transistor techniques (Garcia, and Masson, (2004) as well as microfluidic reagent reaction sensors allow the observation of many chemical properties (Floquet, et al. 2011). This improves detection limits, pressure, and temperature changes indicators of monitoring. Besides, developed submarine platforms (seafloor observatories (Bagley, et al. 2007) as well as mobile autonomous underwater vehicles (AUV) (McPhail, (2009) allow to set sensors for long-term deployment.

Autonomous underwater vehicles are capable of being underwater and operating non-stop for up to six months and are allowed to explore large seabed areas and large ocean volumes in the restricted ship support areas (Caramanna, et al. 2011).

Spatial and temporal scale understanding determine the efficiency of chemical monitoring. Being more effective, multidimensional monitoring more accurately identifies violations than highly accurate one-dimensional methods.

Horizontal extension of carbon dioxide storage requires a much larger CCS monitoring area compared to, for example, oil and gas production. Cameras mounted to AUV can cope with this task perfectly.

Challenges and future trends. The operator should continuously monitor the storage complex and all aspects of CO_2 flow, and take according measures in case of any change. Besides, the operator should identify all vulnerable domains surrounding the storage complex and acquire and review all required environmental data crucial for screening (EU Carbon Capture Storage Directive (2009).

There are some objectives of the research listed below:

- Effective and productive monitoring methods to be improved.
- Accurately identify the definition “irregularities”. Natural systems are dynamic. That is why it is vital to understand each process and interpret it accurately.
- To assess possible sensitive areas and realize the economic value of the environment.

CHAPTER IV. CALCULATIONS

4.1 Dynamic Model Description

3D compositional isothermal Eclipse 300 numerical reservoir model was built for the purpose of modeling CO_2 injection into aquifer. Simple synthetic static model with uniform property distribution was generated using the Petrel Software. Table 4.1 illustrates the properties of base case model.

Table 4.1 The properties of base case model.

Parameter	Value	Unit
Permeability	100	md
Porosity	0.2	
Pressure	200	Bar
Temperature	60	degC
Swi	1	
Depth	2000	m
Relative Permeability		
ng	2	
nw	2	
Krg	1	
Krw	1	
Swcr	0.2	
Sgcr	0.2	

Grid resolution and the model extent were both carefully selected to optimize the memory requirements and simulation run times. The grid cell size of 250m*250m with 5m vertical resolution was used for discretization of the static model. Total number of cells was equal to 535,780. The model dimensions were 33km in North-South and 15km in West-East direction with uniform formation thickness of 215m. The model was built with up-dip inclination of around 5 degrees from East to West direction.

To replicate the aquifer, the static model was initialized with one phase - water. Water salinity and impurities in the CO_2 injection were ignored in this study. Given the initial reservoir conditions (table 4.1) the CO_2 injection was taking place in a supercritical state. Relative permeability curves for water and CO_2 were generated using generic Corey exponents and end points.

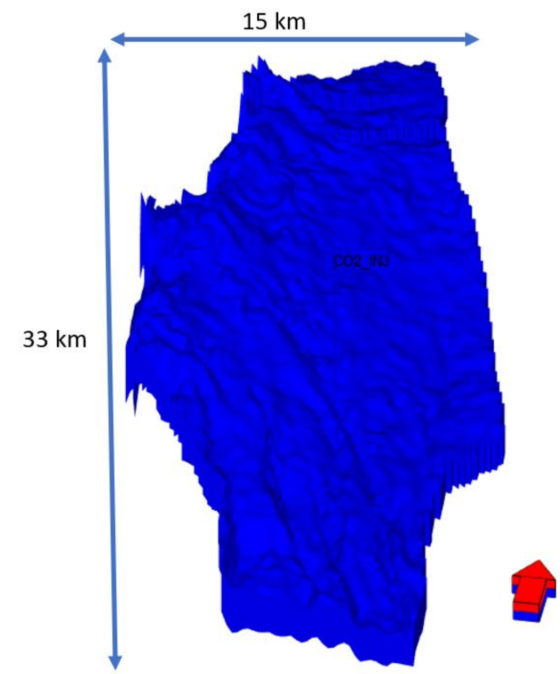

Fig. 4.1. Water salinity and impurities in the CO_2

Injection of CO_2 into the formation was modeled via simple vertical well, open for flow across the entire reservoir thickness. Injection was controlled via bottom hole pressure limit and no other constraints were introduced (pressure losses within tubing, caprock and formation rock geomechanical litmits and other practical aspects were not considered). Therefore, the resulting injection rates and other well specific parameters have to be considered as purely theoretical. The CO_2 injection strategy is illustrated in the table 4.2.

Table 4.2 The CO_2 injection strategy

Parameter	Value	Unit
Start of inejction	2030	year
End of injection	2040	year
Shut-in till	3000	year
BHP	450	Bar
Number of wells	1	

4.2 Sensitivity and Uncertainty Analysis

To understand the influence of various parameters on CO_2 injection and plume migration, sensitivity analysis was performed with the variables illustrated in Table 4.3.

Table 4.3 Sensitivity analysis was performed with the variables

Parameter	Values
Horizontal Permeability (Kxy)	10, 500, 1000, 5000
Vertical to Horizontal Perm. Ratio (Kv/Kh)	0.01, 0.05, 0.25, 0.5
Porosity	0.1, 0.15, 0.2, 0.25
Pore Volume Mutliplier - PVM	1, 10, 1000, 10000
Gas Corey exp. - ng	1.5, 3.0
Water Corey exp. - nw	1.5, 3.0
Critical Water Saturation - Swcr	0, 0.5
Critical Gas Saturation - Sgcr	0, 0.5

The sensitivity cases were based on the input data from Table 4.3 and using the parameters from Table 3. Each sensitivity parameter from Table 3 was varied in isolation and for simplicity reason the combination and interdependence of parameters was ignored. For example, it is well known that porosity and permeability are correlated, but within the framework of this study changing the porosity did not result in any change of permeability.

In addition to the variables listed above a well placement sensitivity scenario was also studied within the framework of this study. In total the results of 40 simulation runs were analyzed and reported in this paper. Influence of each parameter was analyzed with respect to the volume of CO_2 injection, injection pressure, plume migration and entrapment mechanisms.

Permeability. The permeability distribution in the model was uniform without horizontal or vertical heterogeneity. In total 4 cases with the permeabilities listed below were generated:

- Case 1 – Kxy=10md
- Case 2 - Kxy=500 md
- Case 3 – Kxy=1000 md
- Case 4 – Kxy=5000 md

In addition to the scenarios shown above, analysis of the sensitivity scenarios included also the base case model with permeability = 200 md.

Permeability of the formation had a critical influence on well injectivity, cumulative injection and plume migration. As expected, increasing the permeability of the formation resulted in increase of well injectivity and cumulative injection. Increase of permeability from 10md up to 5,000md (500 fold increase in permeability) caused almost 100 fold increase in cumulative injection from 28Mt up to 2,800 Mt (Figure 4.3). However, further increase in permeability did not add much as cumulative injection tends to plateau for the case of 10,000 md.

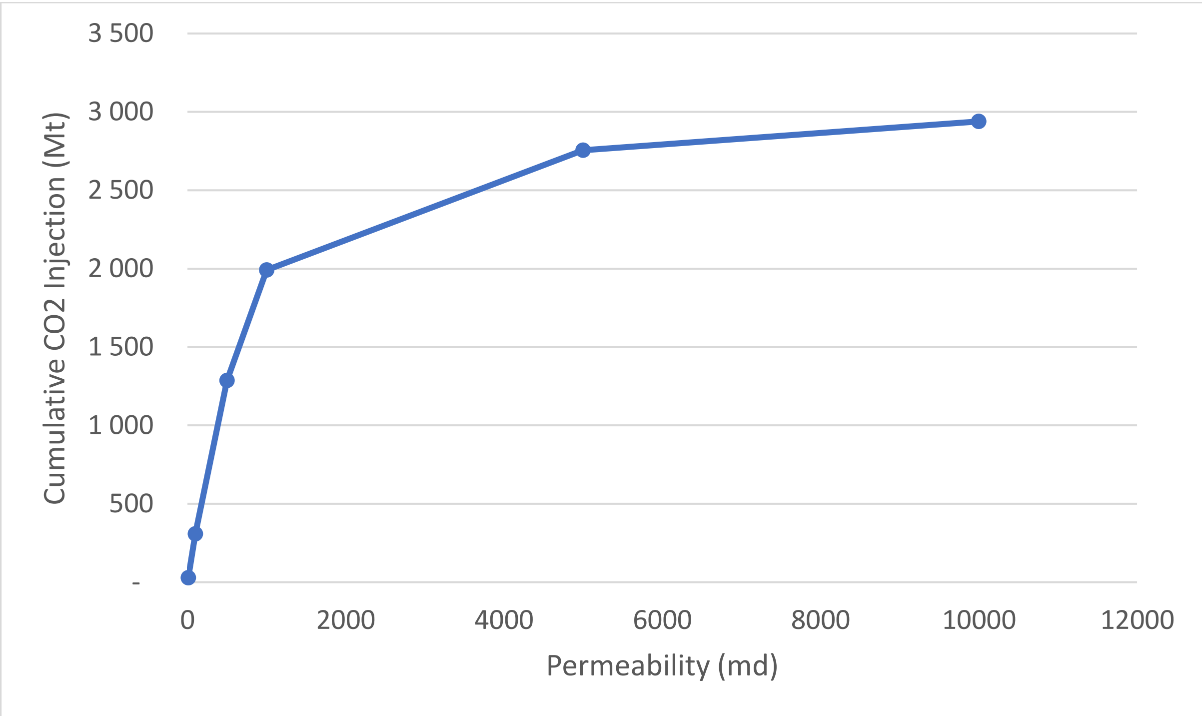

Figure 4.3. Observation of injection rates

Observation of injection rates suggest that for the case with Kxy=5,000 md the decline in injection rate was sharpest (Figure 4.3). Change of injection rate in comparison to initial rate is also illustrated in Figure 4.4. As can be seen from this graph the injection rate builds up with time for scenario with lowest permeability Kxy=10 md and shows gradual decline for the scenarios with higher permeability.

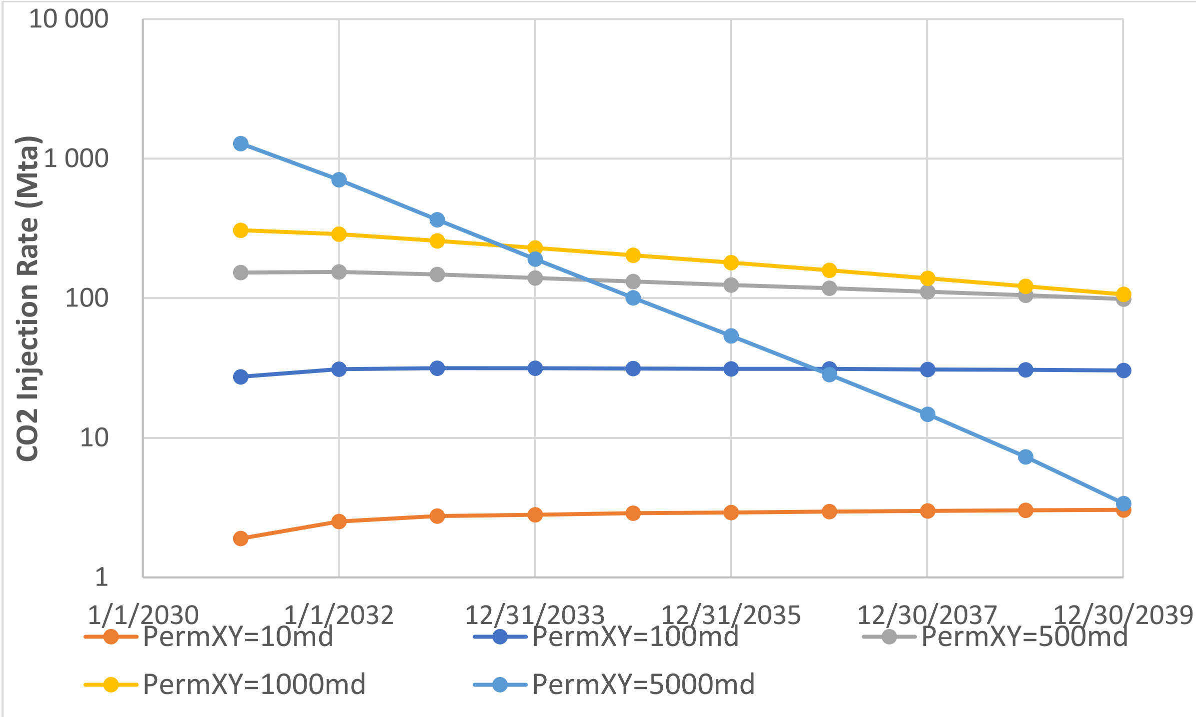

Fig. 4.4. Change of injection rate in comparison to initial rate

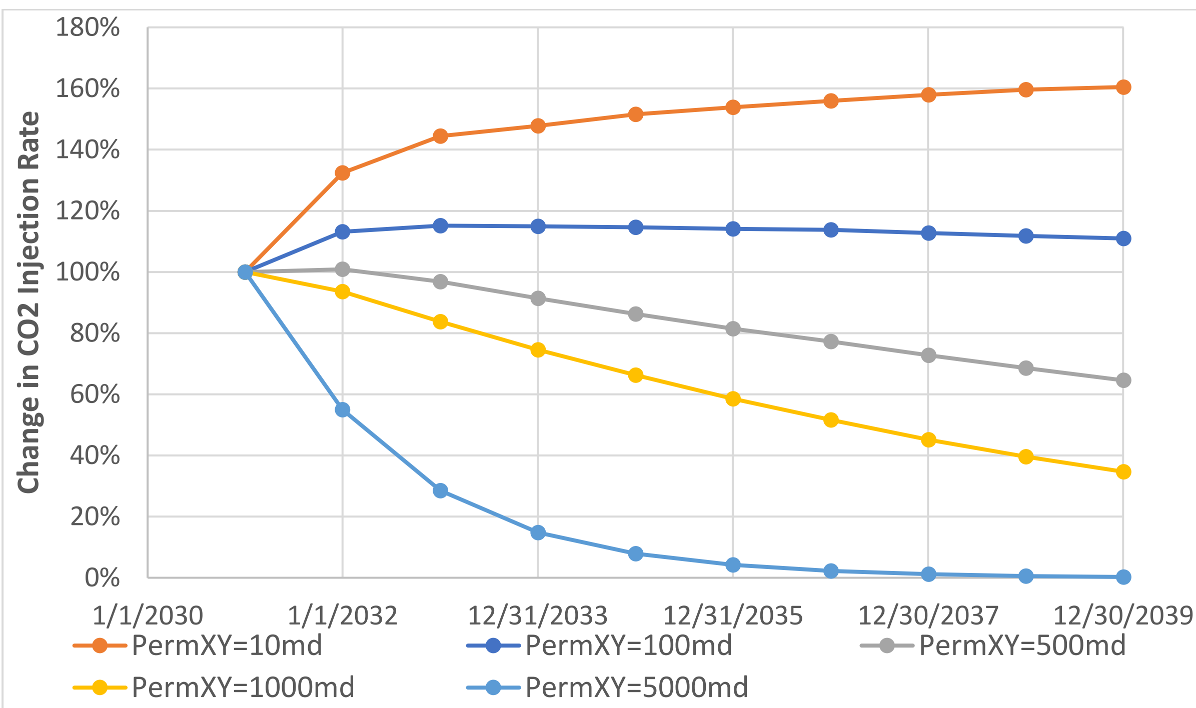

Figure 4.5. Change in CO_2 Injection Rate

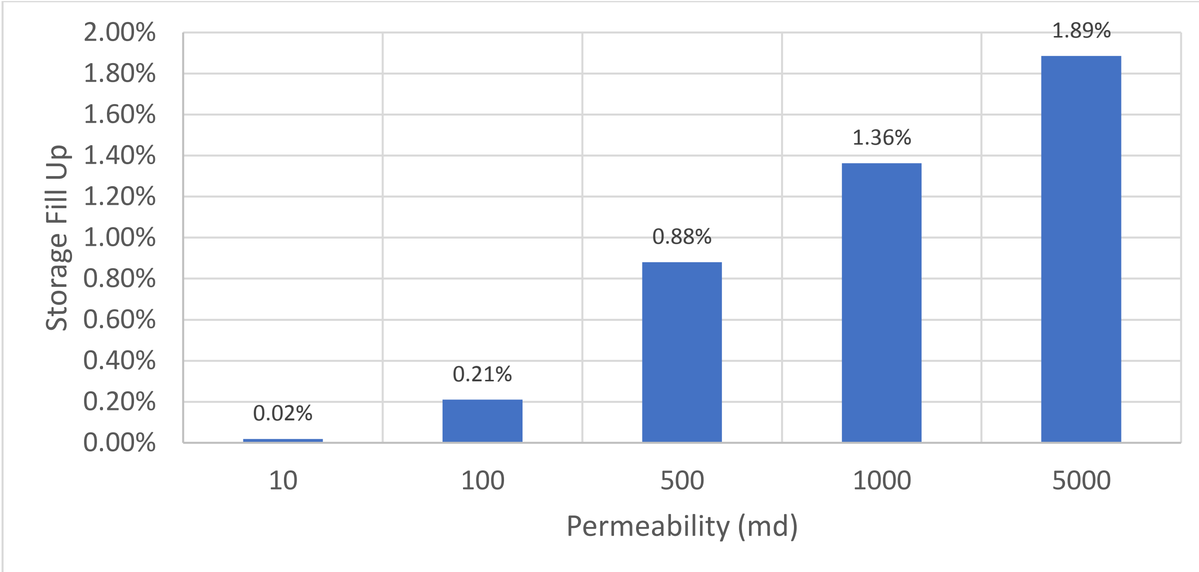

Figure 4.6. The fraction of aquifer pore volume filled up with CO_2

Figure 4.6 illustrates the fraction of aquifer pore volume filled up with CO_2 at the end of injection period for various permeability sensitivity cases. Less than 0.1% of pore space is filled up with CO_2 for the case Kxy=10md, while for the case Kxy=5,000md cumulative CO_2 injection is orders of magnitude higher accounting to 2% of formation pore volume. Figure 6 and Figure 7 show that the highest increase of average pressure corresponds to the case Kxy=5,000md, while reducing the permeability results in much slower pressure build up in the formation. A correlation between the injected volume and pressure dissipation can be also seen from the Figure 8. It can be seen that for the case with highest injection volume the formation pressure is not dissipating even after the closure of the injection well. At the same time, there is more pressure relief for the cases with decreasing volume of CO_2 injection.

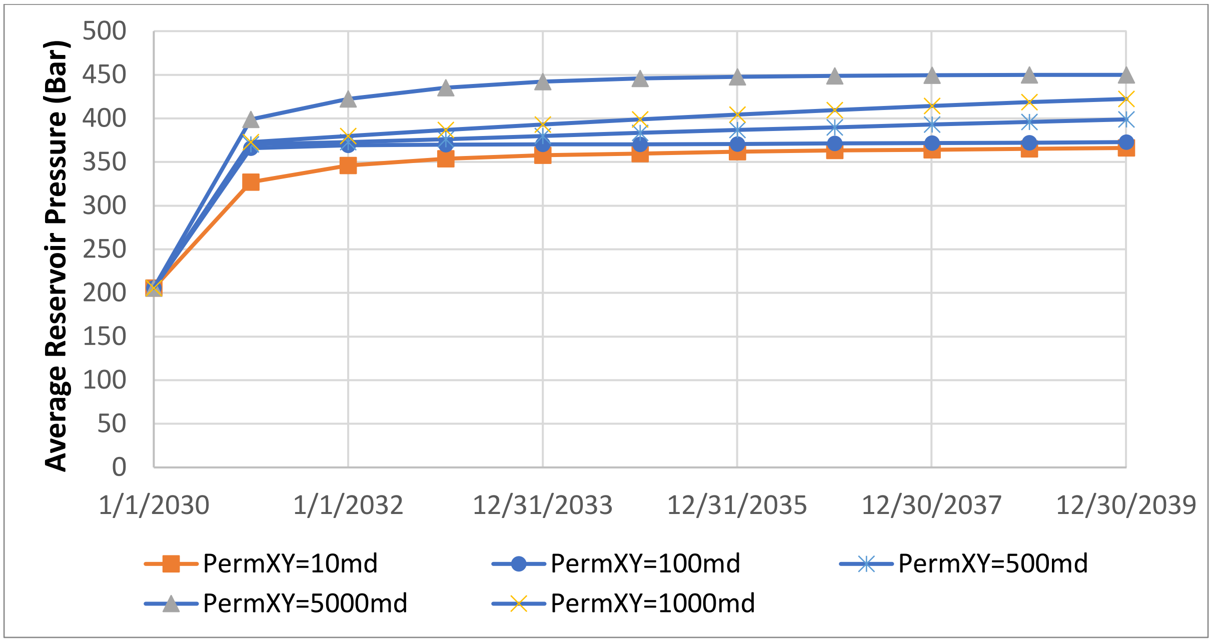

Figure 4.7. Average Reservoir Pressure (Bar)

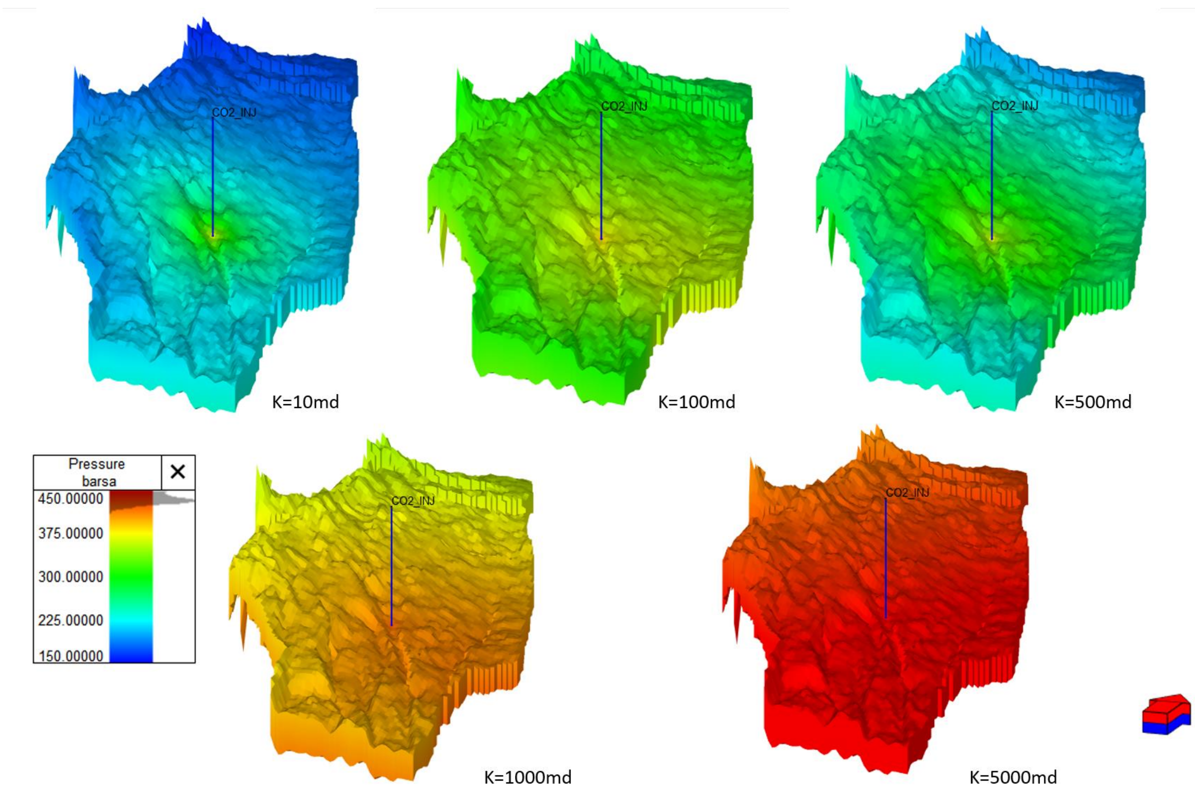

Figure 4.8. Pressure distribution

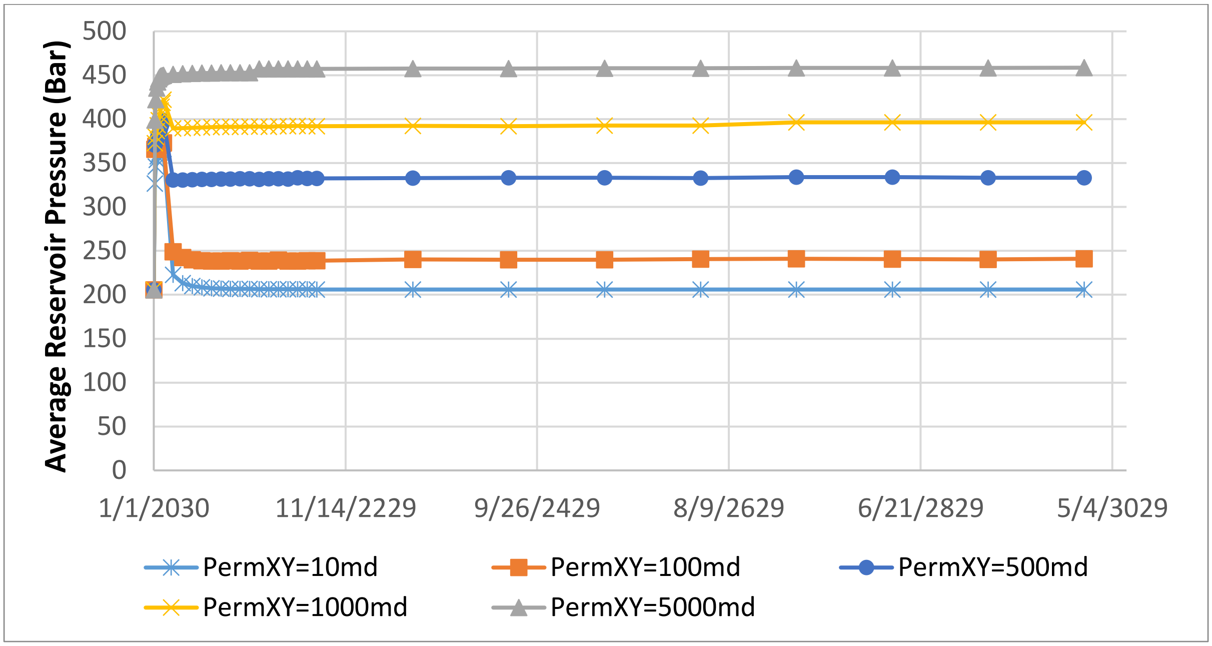

Figure 4.9. Average Reservoir Pressure (Bar)

The observed pressure behavior indicates that for the higher permeability cases with highest injection volume the aquifer is filled up to a maximum capacity at a much faster rate. This can also be seen from the pressure development for the case Kxy=5,000md, when the reservoir pressure reaches the injection well BHP=450 Bar limit in less than 5-6 years (Figure 8). The corresponding case with highest permeability and injection volume therefore defines the maximum storage capacity of the reservoir. In other words, at the given boundary conditions and Kxy=5000 md the reservoir is filled up to a full capacity and no further injection is possible.

For the case of lowest permeability Kxy=10md a small CO_2 saturation is formed around the injection well. The lateral extent of CO_2 distribution is expanding with increase of injection volume. Following the shut-in of the injection well the gravity driven CO_2 plume starts to migrate up-dip in East-West direction and accumulates under Western boundary of reservoir model.

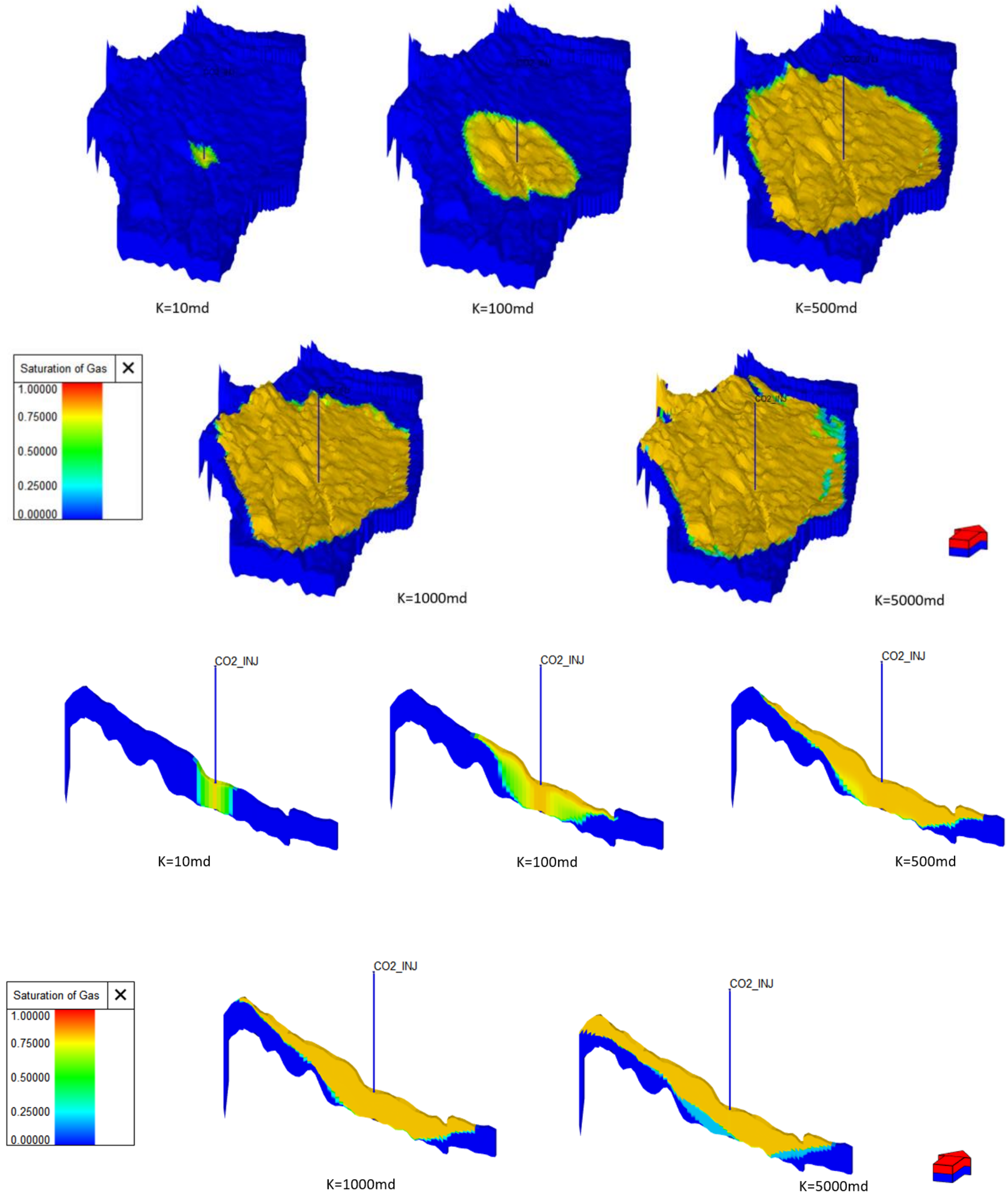

Figure 4.10. CO_2 saturation at the end of injection period

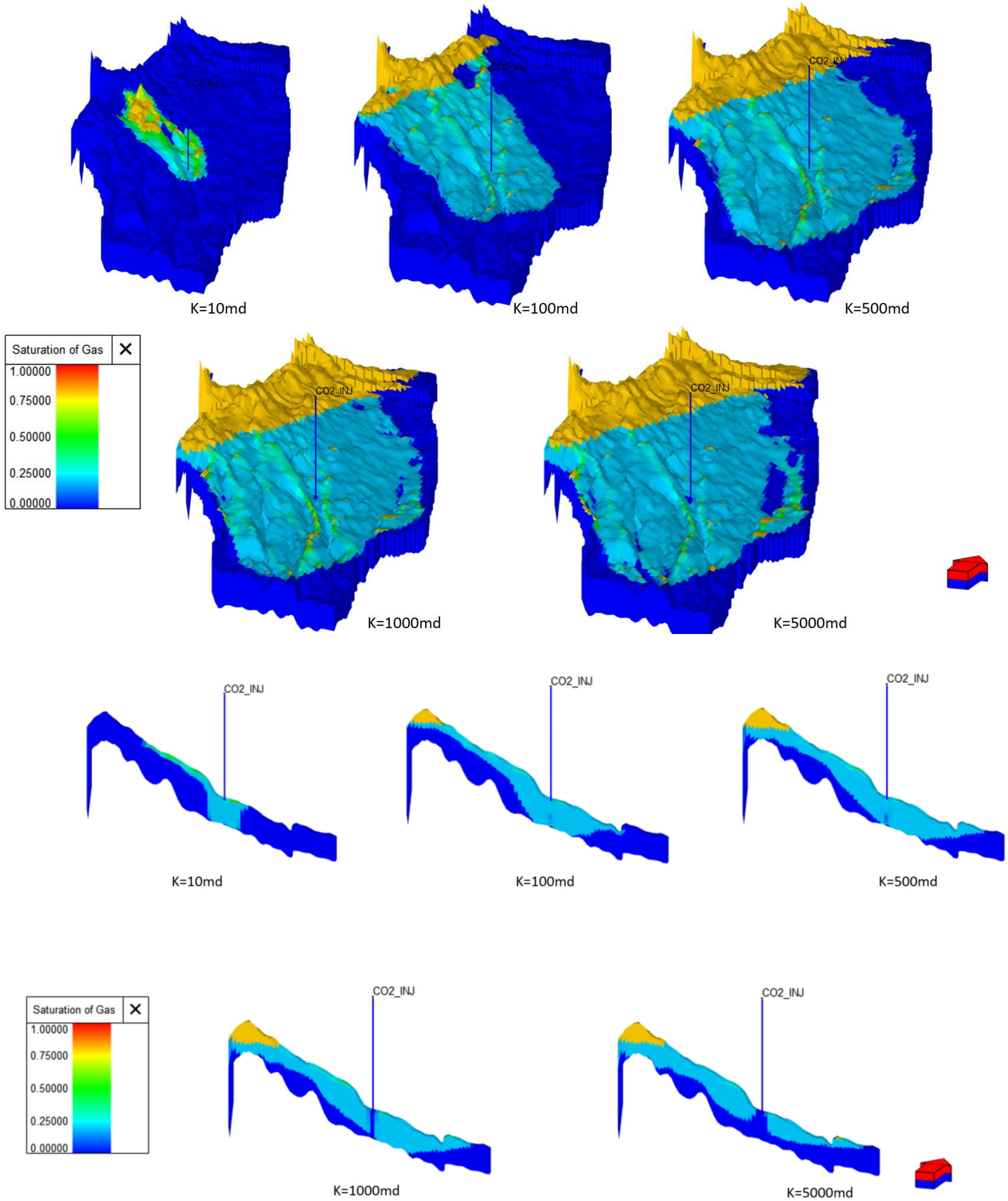

Figure 4.11. CO_2 saturation 2,000 years after injection well shut-in

To isolate the effect of injection volume to plume migration extra simulations runs were introduced. The control parameter was switched from BHP to injection rate of 1Mta while keeping the other parameters of the development strategy unchanged.

The speed of plume migration showed a clear correlation with permeability of the formation. The higher was the permeability of formation the further away from injection well in up-dip Western direction migrated the CO_2 plume (Figure 4.11). For the case with lowest permeability the plume did not reach the Western boundary of the model, even after 2,000 years following the shut-in of the injection well.

Cross sectional view of plume migration revealed that the vertical gravity override was more prominent for the cases with higher permeability. This can be explained due to lower vertical permeability which was set as a function of horizontal permeability (Kv/Kh=0.1). Therefore, it is not surprising that for the cases with both higher horizontal and vertical permeability the plume gravity segregation with water was more obvious.

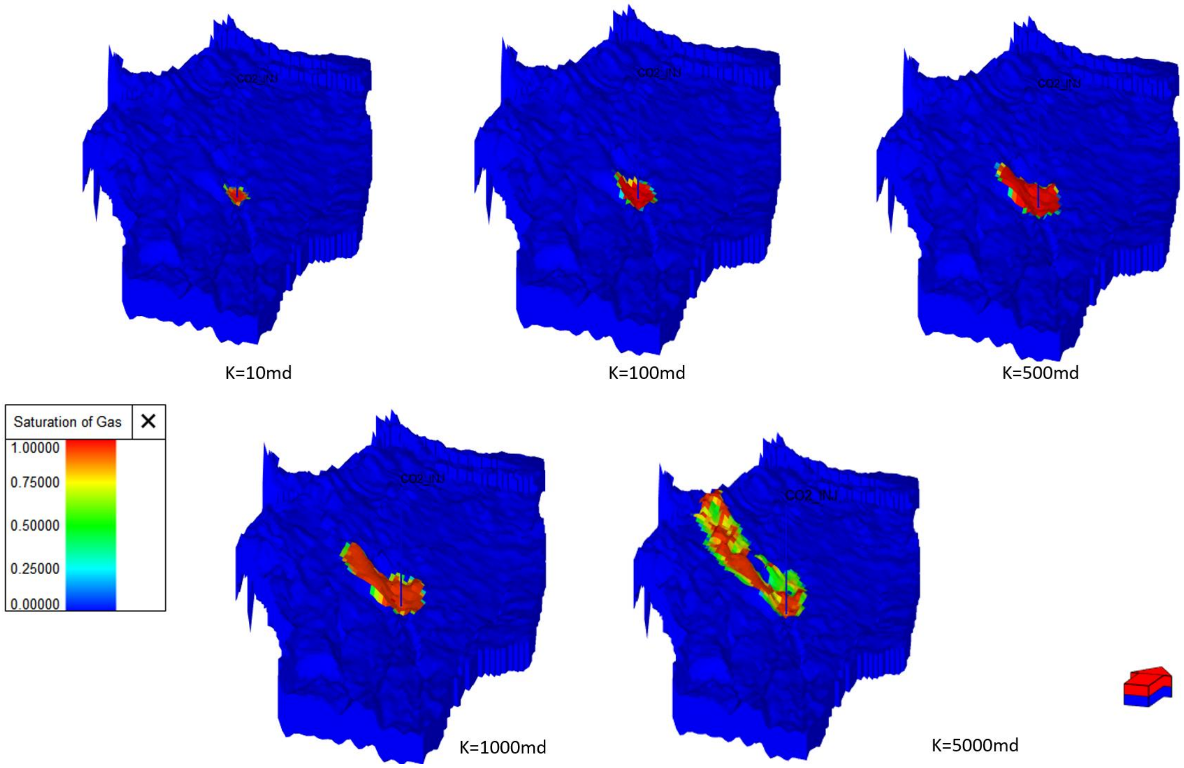

Figure 4.12. CO_2 Migration

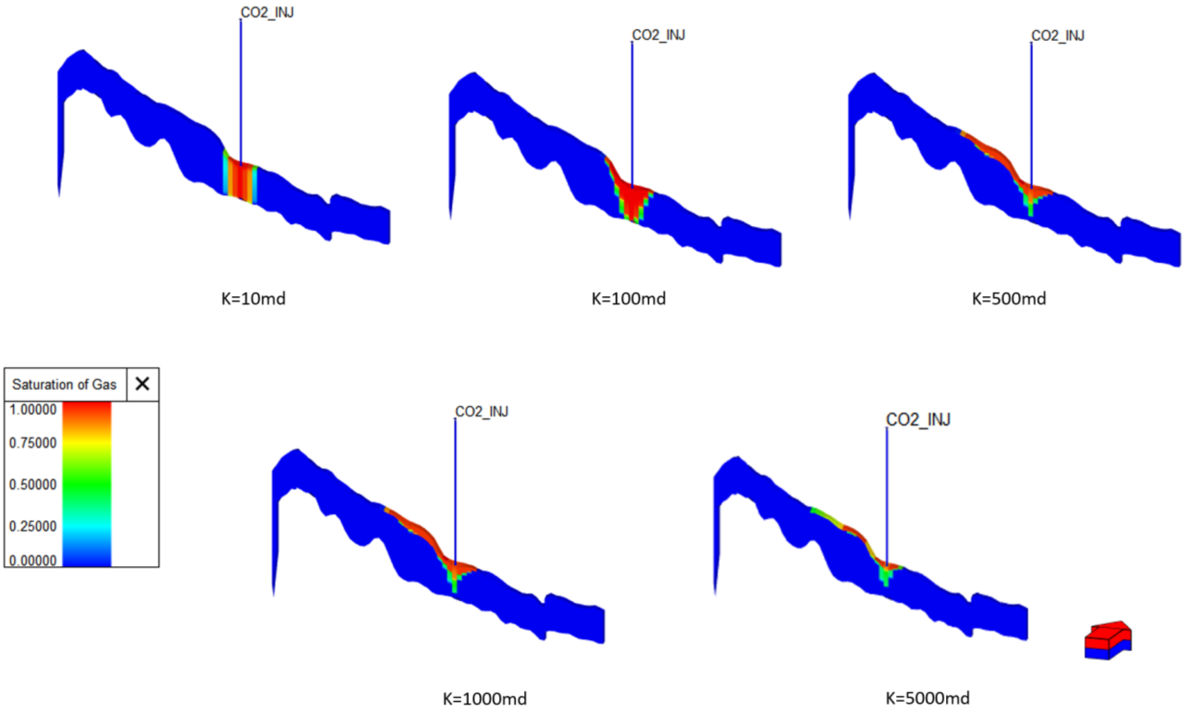

Fig. 4.13. CO_2 saturation at the end of injection period

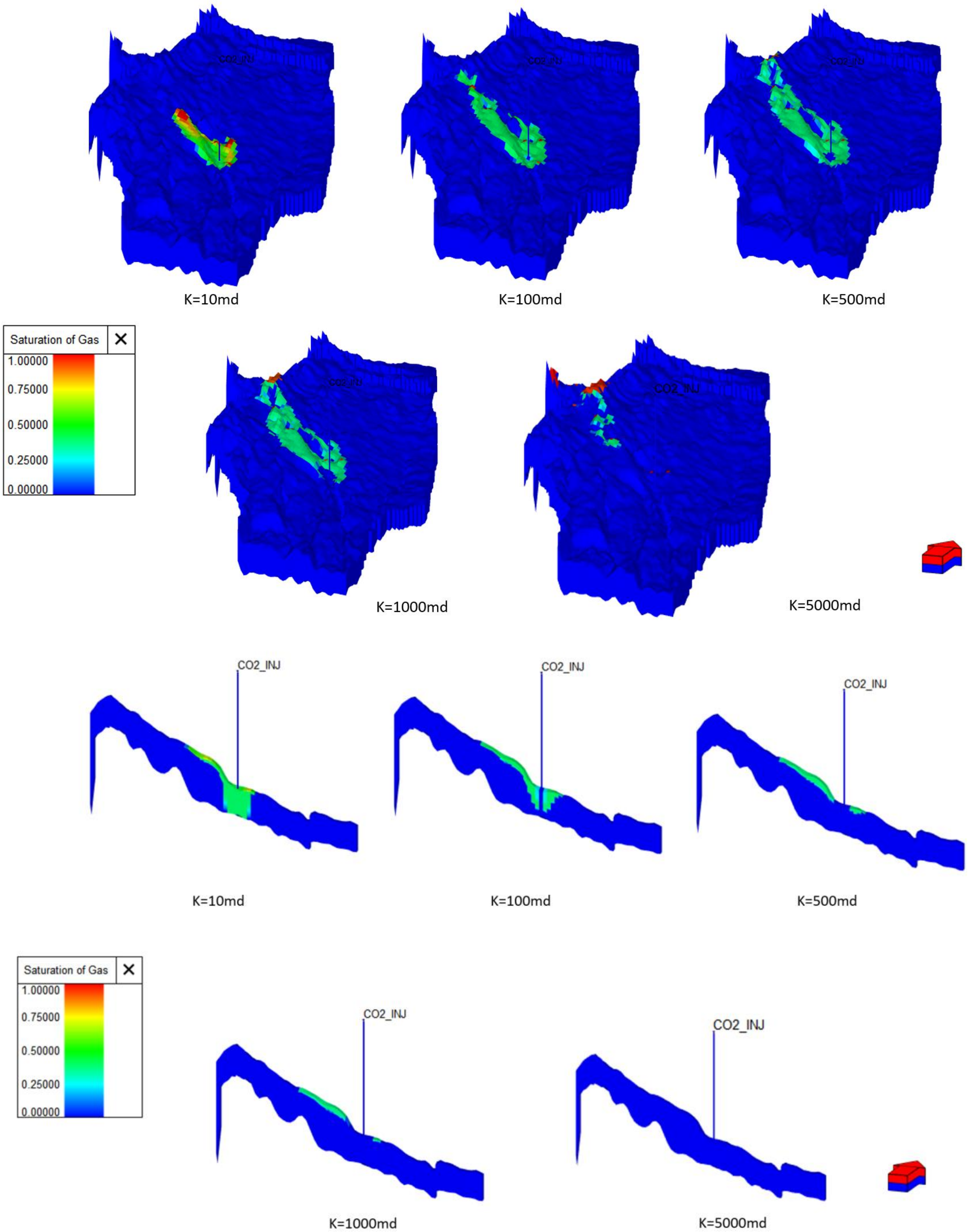

Fig. 4.14. CO_2 saturation 2,000 years after injection well shut-in

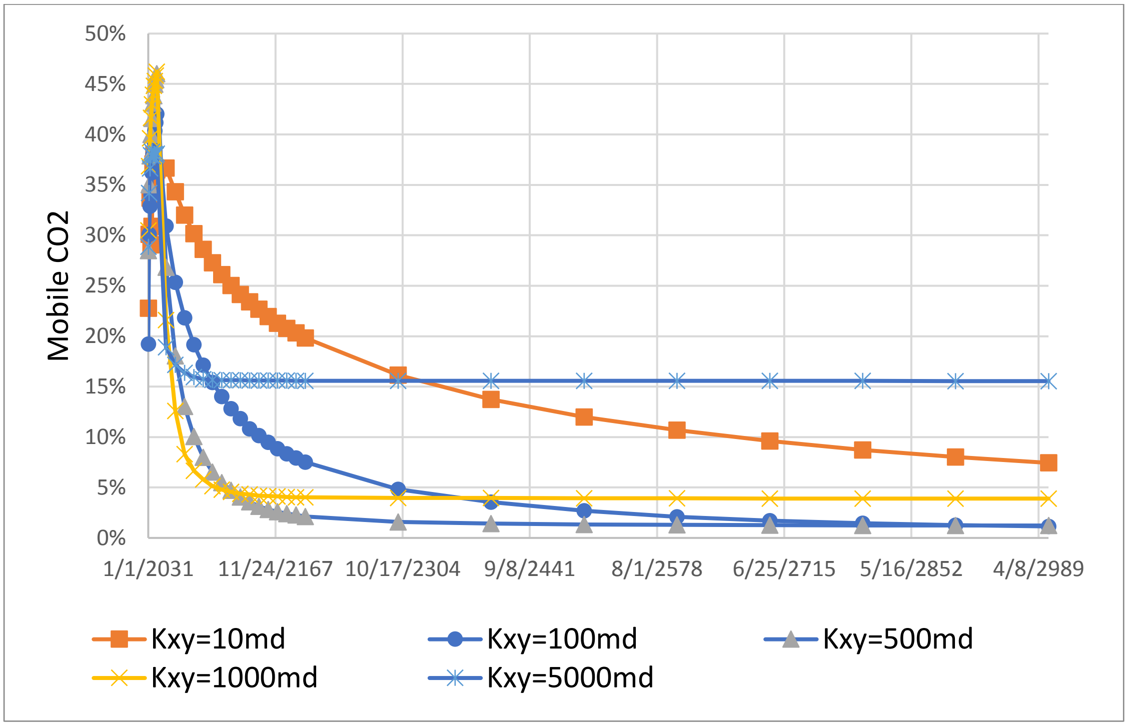

Fig. 4.15 Mobile CO_2

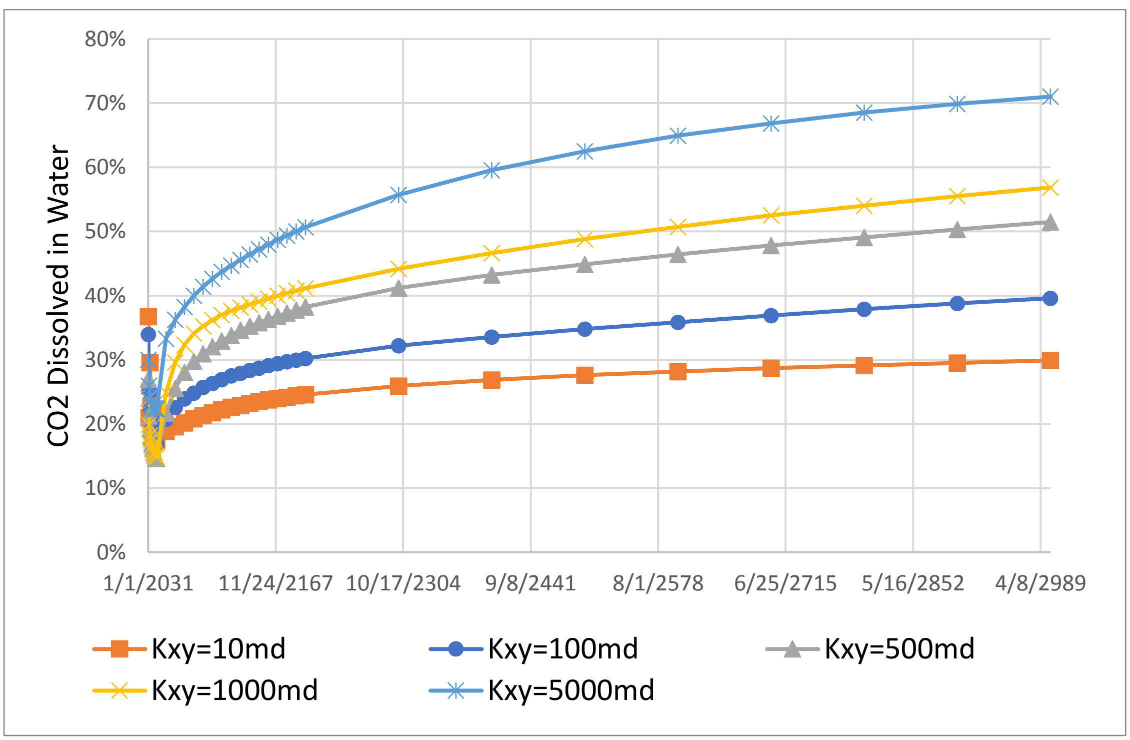

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Fig. 4.16. CO_2 Dissolved in Water

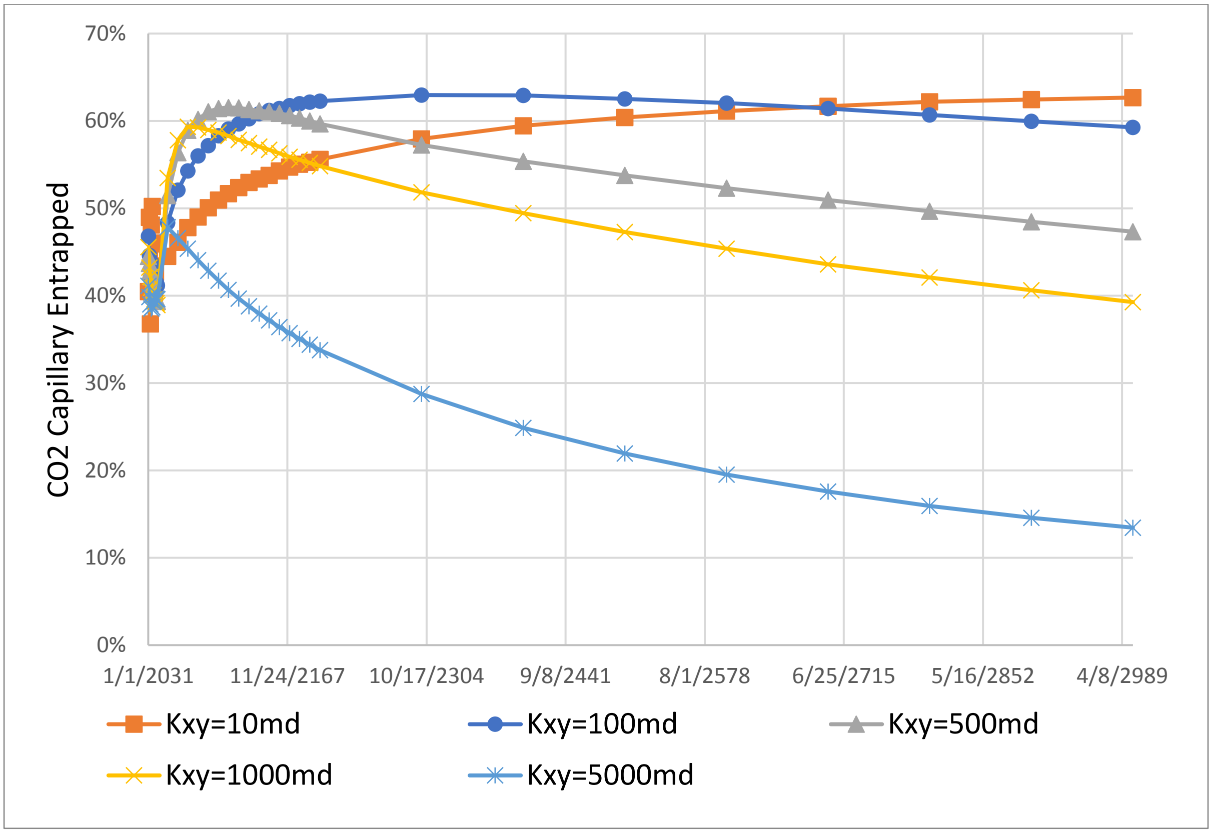


Fig. 4.17. **CO_2 Capillary Entrapped**

4.3 Vertical Permeability and Porosity

The previously discussed scenarios concerned the variation of horizontal permeability, while keeping the ratio of vertical to horizontal permeability the same. Base case model with 4 different Kv/Kh scenarios was modeled and evaluated to understand the impact on CO_2 injection and storage capacity:

- Case 6 - Kv/Kh=0.01
- Case 7 - Kv/Kh=0.05
- Case 8 - Kv/Kh=0.25
- Case 9 - Kv/Kh=0.5

The simulated sensitivity scenarios were all compared against each other including also the base case model with Kv/Kh=0.1. A slight increase in total CO_2 injection was observed with increase of vertical permeability (Figure 4.18). Given the order of magnitude change of vertical permeability and less than 10% difference in injection volume, it can be concluded that vertical permeability had limited impact on storage CO_2 capacity.

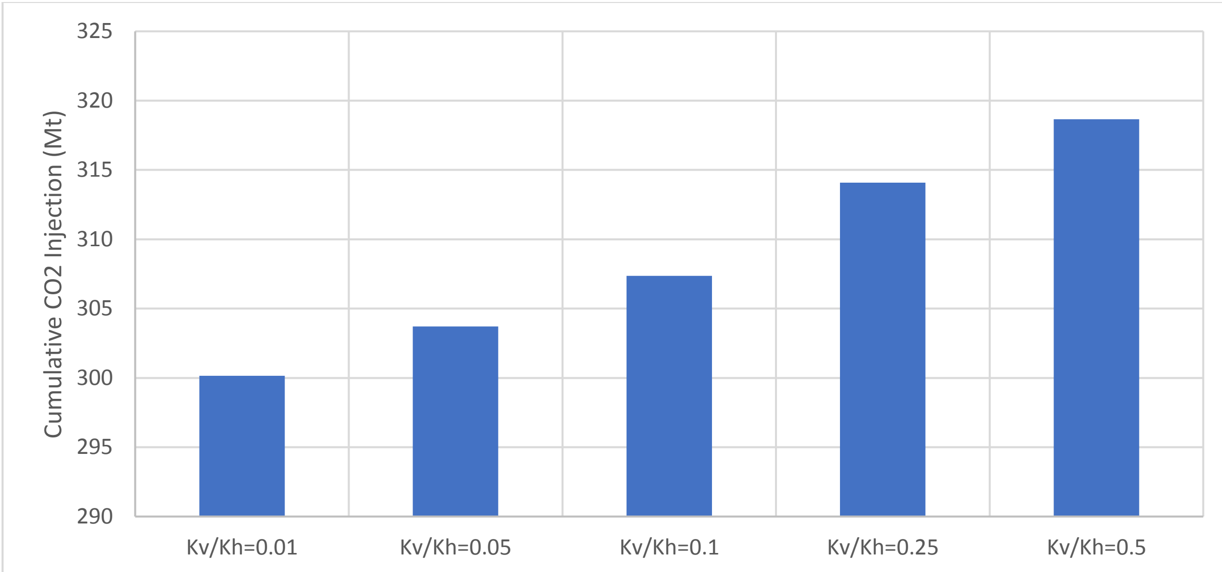


Fig. 4.18. Cumulative CO_2 Injection (Mt)

This observation is explained due to relatively limited influence of vertical permeability on injectivity of vertical wells. Influence of vertical permeability on the average pressure build up in the formation was less than 5 bar and that confirms again relatively negligible influence of this parameter on cumulative injection (Figure 4.19).

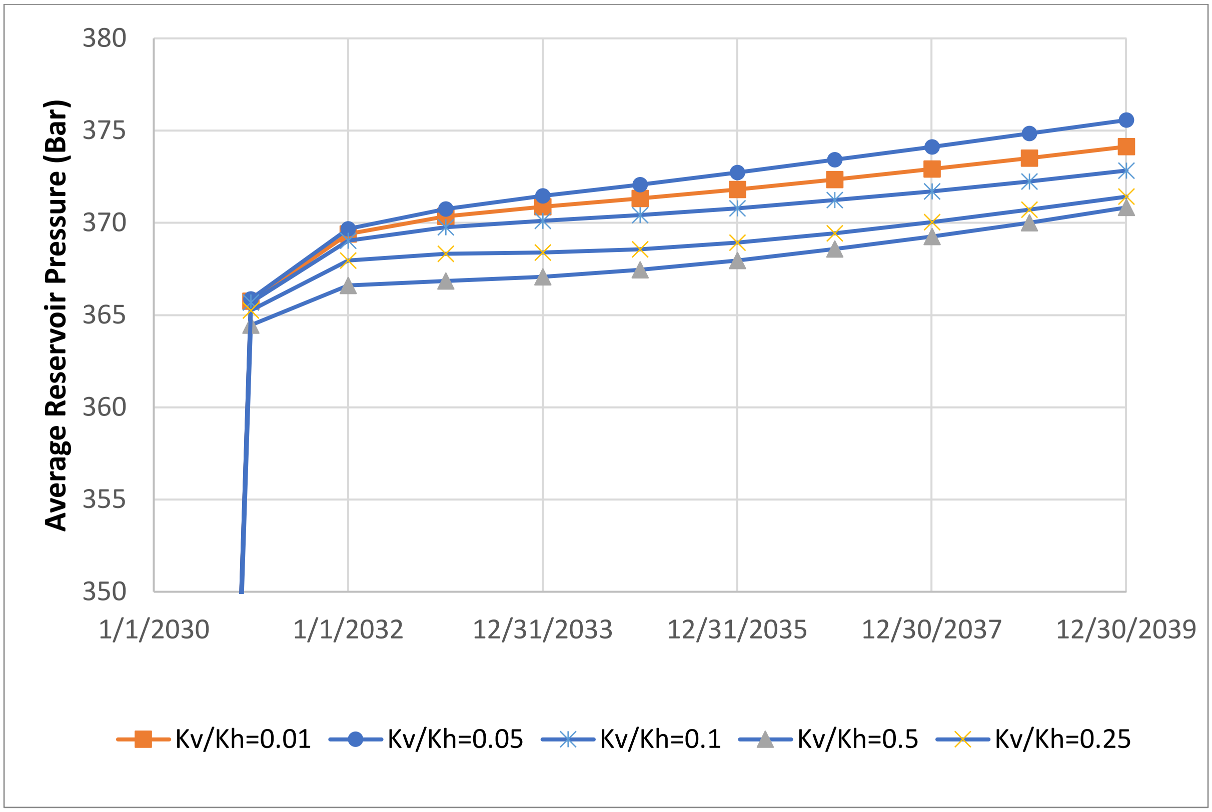


Fig. 4.20. Average Reservoir Pressure (Bar)

Similar observations were also made on influence of vertical permeability on plume containment. The reduction of vertical permeability worked against the vertical segregation of CO_2 and caused relatively more uniform vertical distribution of CO_2. Under these circumstances the contact area of the CO_2 plume is increased, and it caused more entrapment of the injected CO_2. However, this effect was rather limited to initial time period, while on the long-term perspective not much of a difference on plume distribution was observed between different scenarios. Notwithstanding an order of magnitude difference in vertical permeability the difference in the share of CO_2 entrapped and mobile between Kv/Kv=0.01 and Kv/Kh=0.5 was less than 10%.

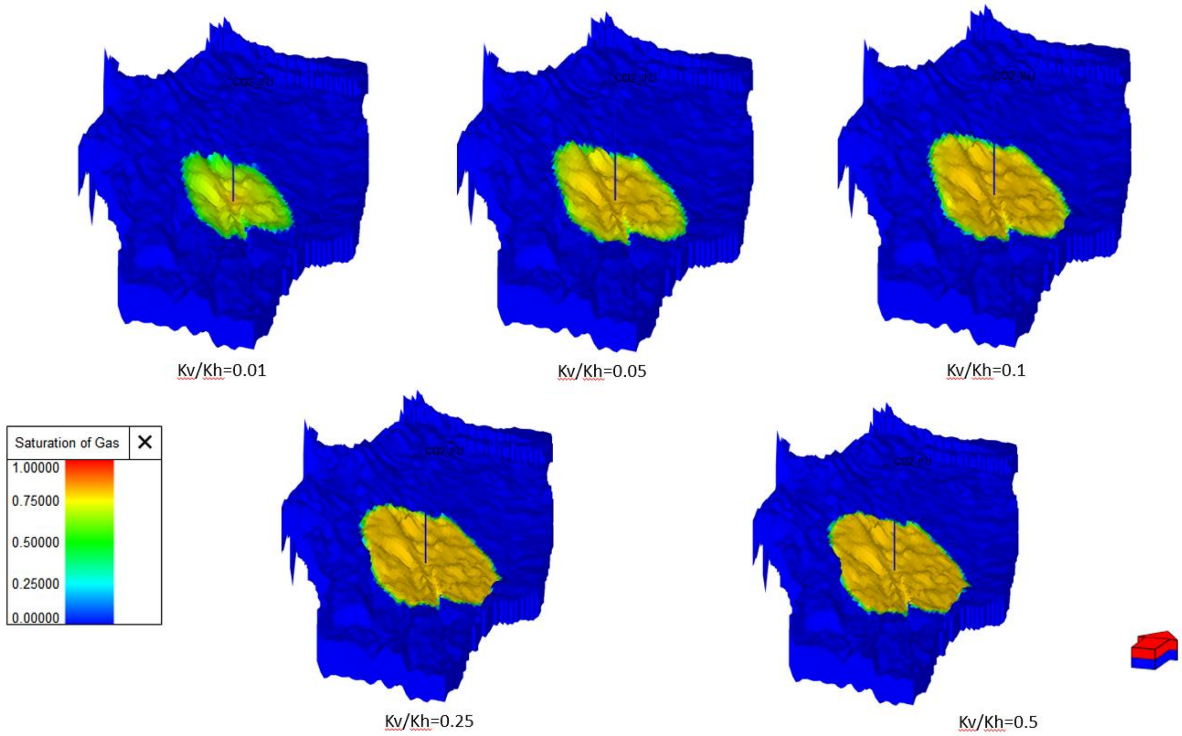


Fig. 4.21. CO_2 saturation 2,000 years after injection well shut-in

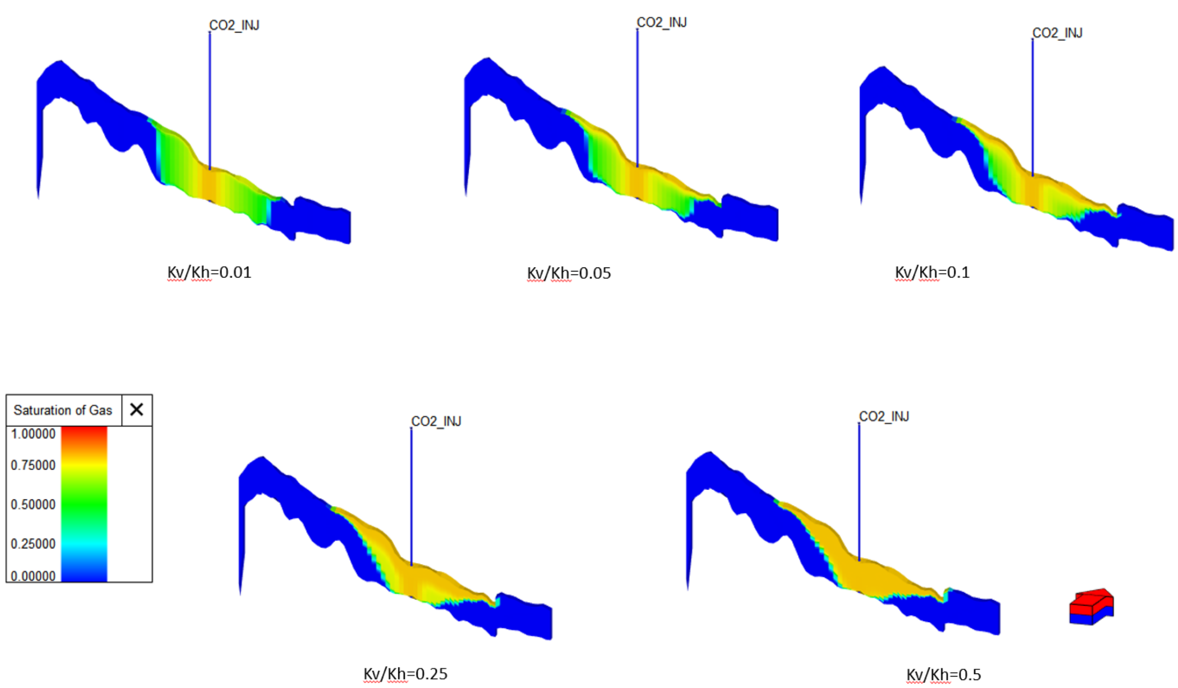


Figure 4.22. CO_2 saturation at the end of injection period

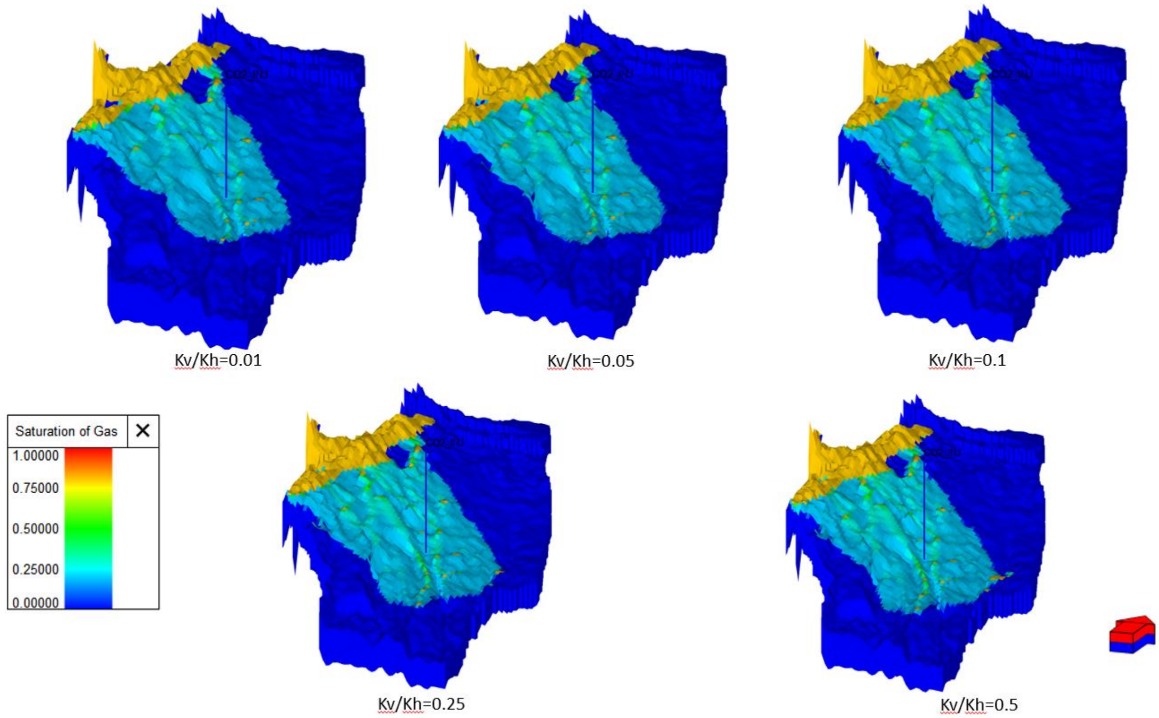


Fig. 4.23. CO_2 saturation 2,000 years after injection well shut-in

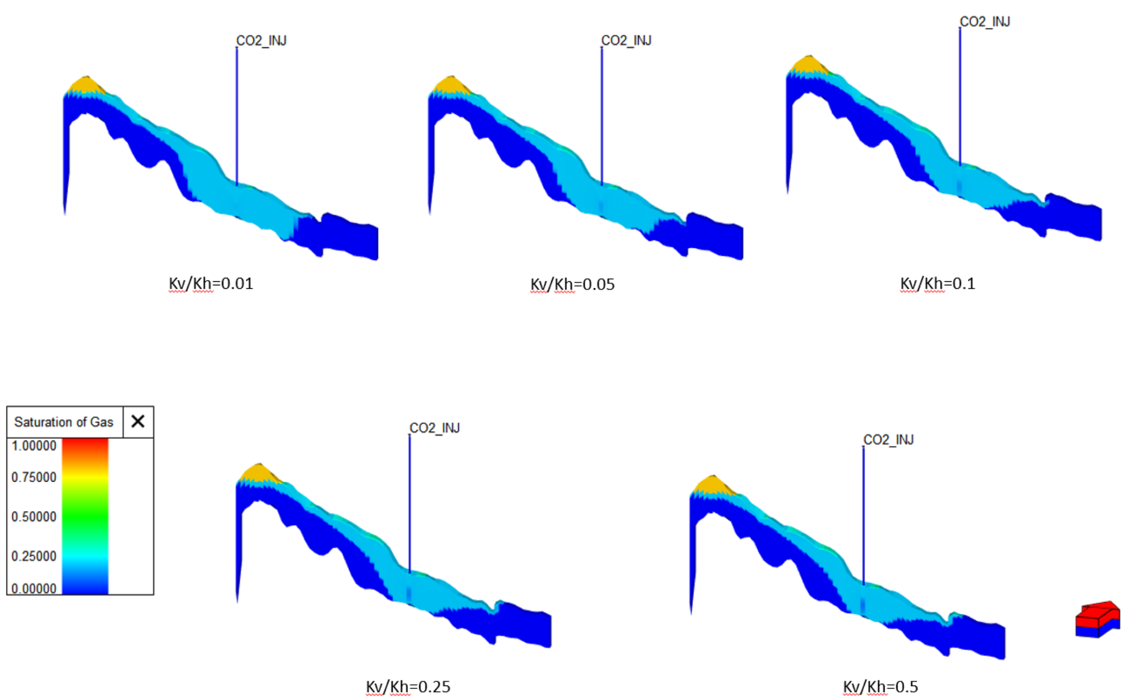


Figure 4.24. CO_2 saturation 2,000 years after injection well shut-in

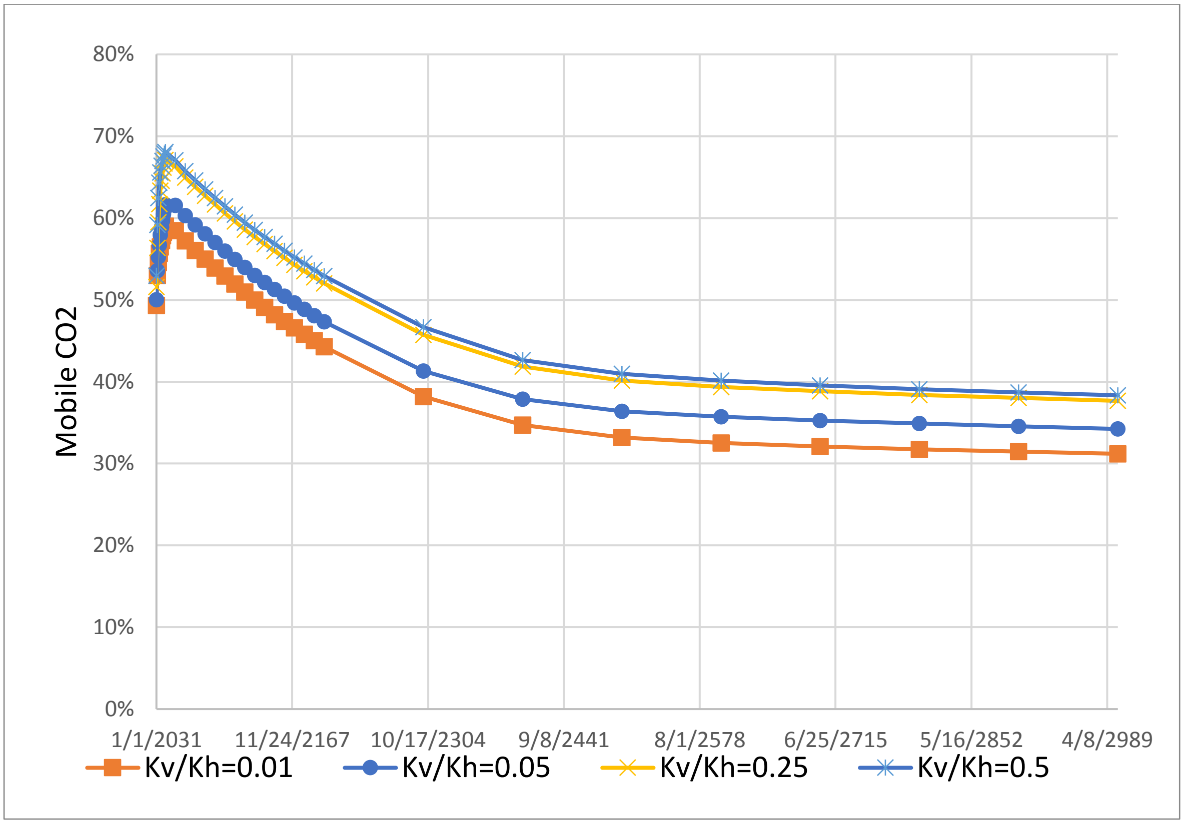


Fig. 4.25. Mobile CO_2

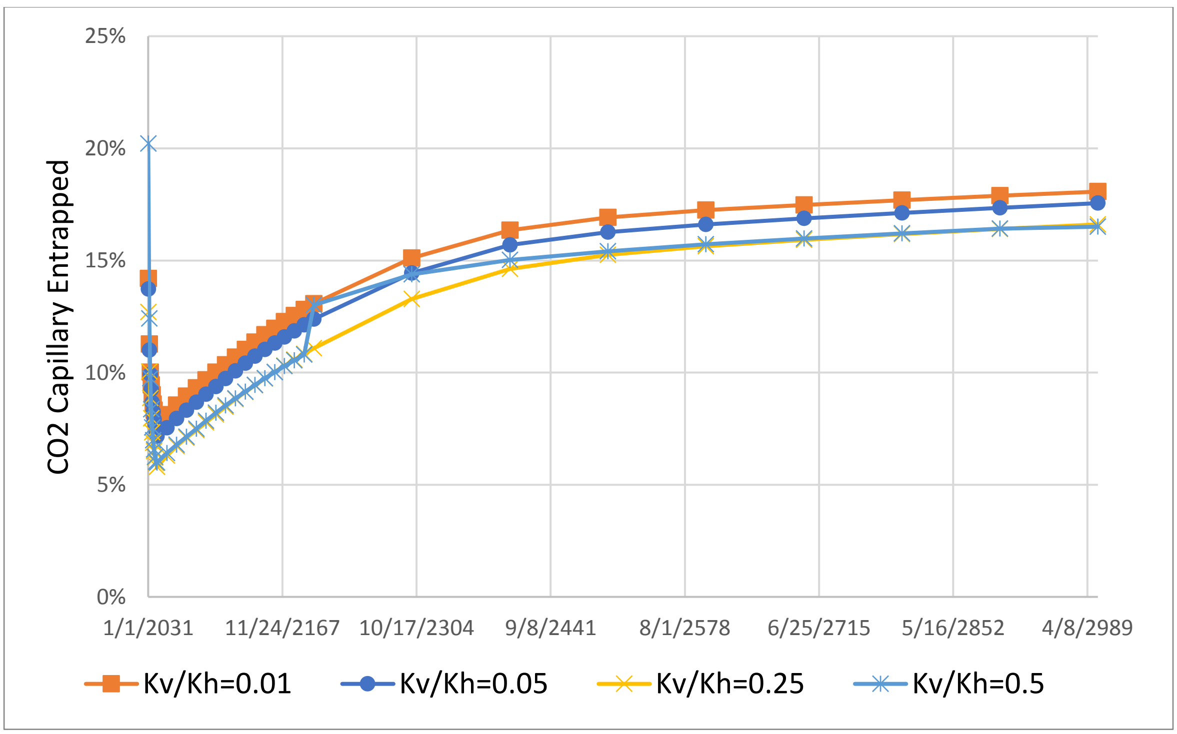


Fig. 4.26. CO_2 Capillary Entrapped

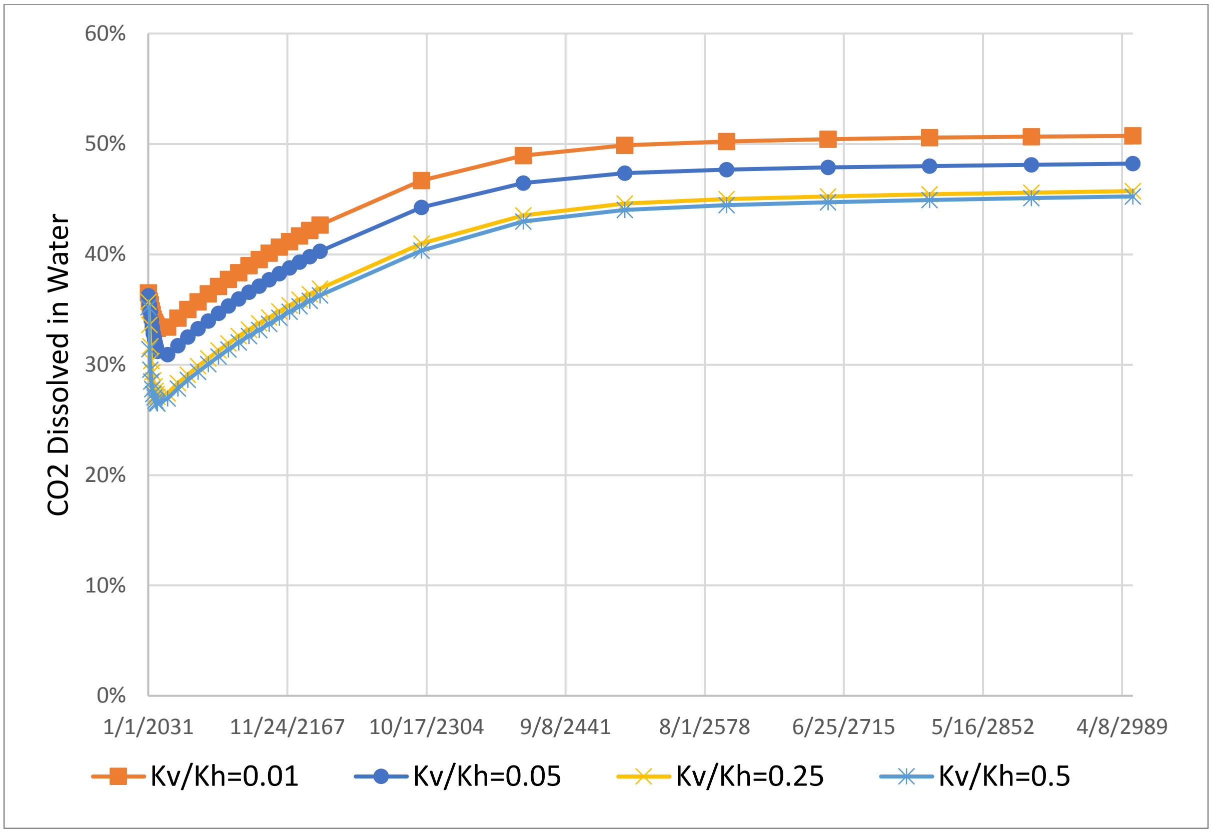


Fig. 4.27 CO_2 Dissolved in Water

Overall, analyzing the influence of vertical permeability on CO_2 injection and plume migration it is can be concluded that this parameter has relatively negligible influence on storage efficiency and plume containment of the aquifer.

Porosity

The influence of porosity on CO_2 injection behavior was analyzed via building a dynamic model with the following cases:

- Case 10 - Por=0.1
- Case 11 - Por=0.15
- Case 12 - Por=0.2
- Case 13 - Por=0.25

The cumulative CO_2 injection showed consistent increase with porosity increase. However, as can be seen from the Figure 20 the overall increase of cumulative injection was rather limited and tend to plateau towards the maximum porosity value.

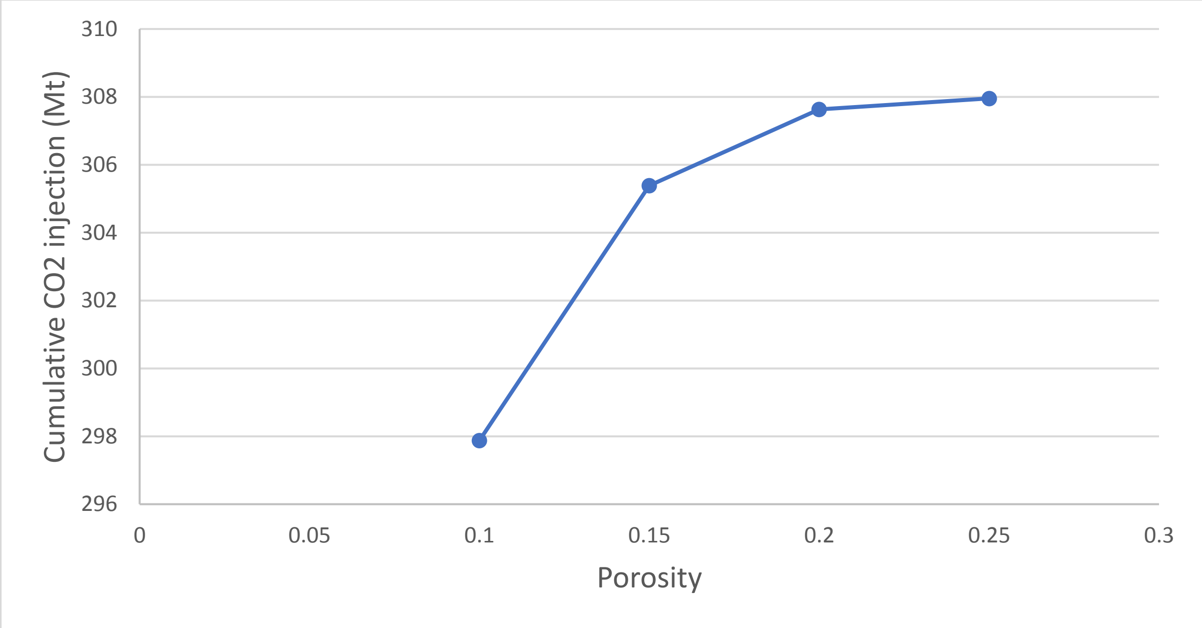
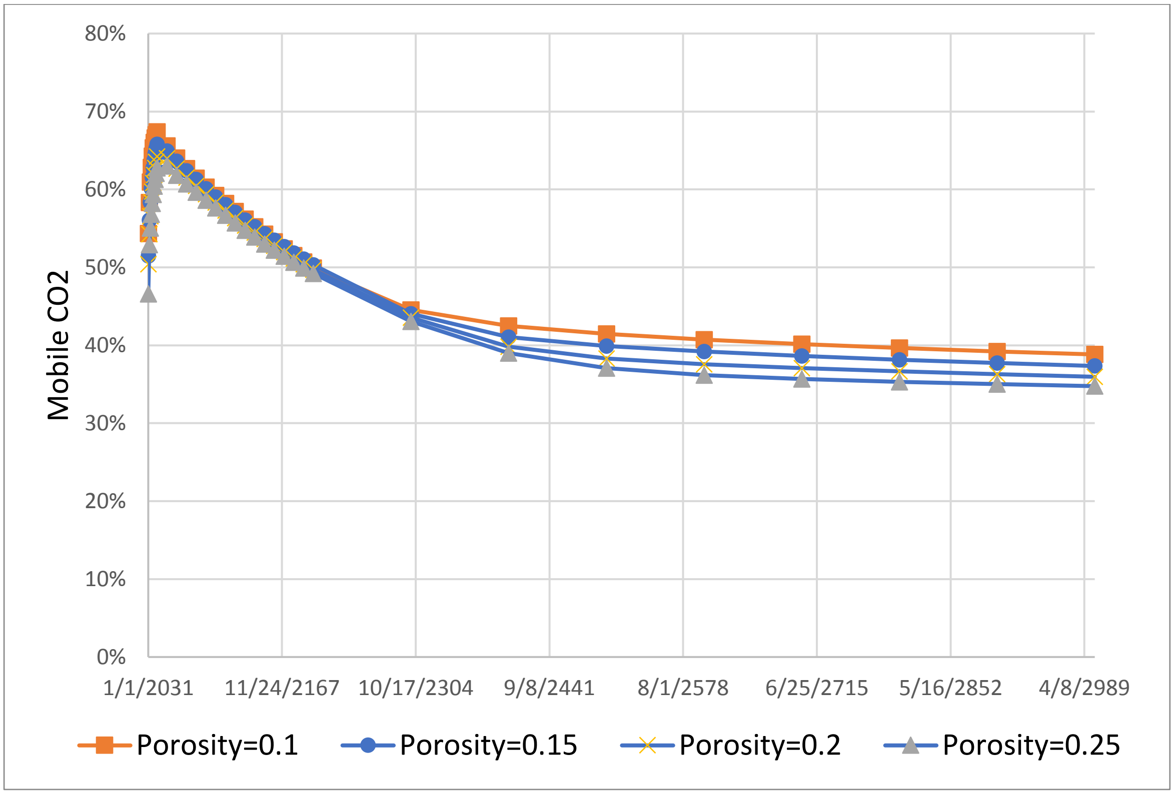


Figure 4.28 Cumulative CO_2 injection (Mt)

The amount of free/mobile CO_2 showed inverse relationship with porosity. The higher the porosity, the lower was the amount of CO_2 remaining free in the formation. In contrary, the amount of CO_2 dissolved in water and capillary entrapped showed an increase with higher porosity. This effect can be explained due to

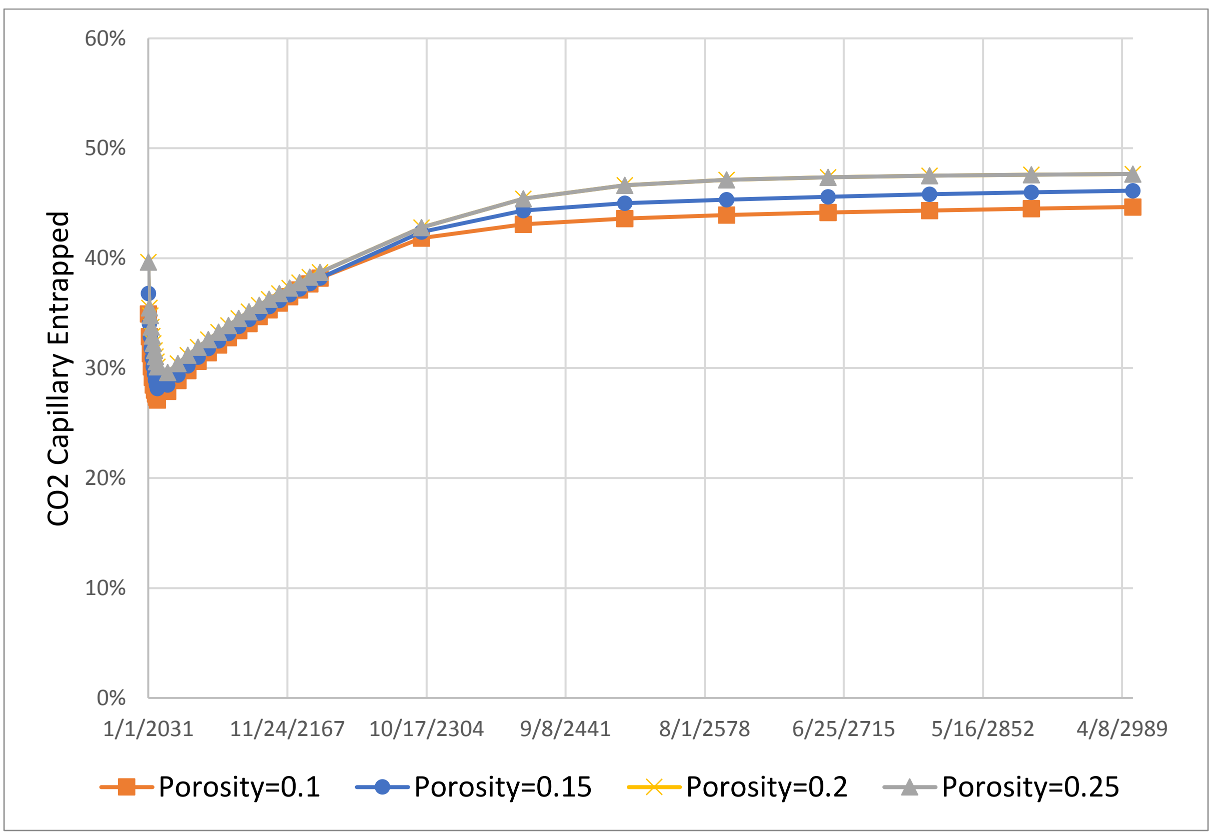
- The amount of water in place increased with higher porosity causing the enhanced effect of dissolution per unit of injected CO_2.
- Although, the residual saturation of CO_2 was constant, due to increase in porosity the absolute volume of entrapment was more with higher porosity.

These effects illustrate the overall positive influence of porosity increase on injection volume and particularly on plume containment.



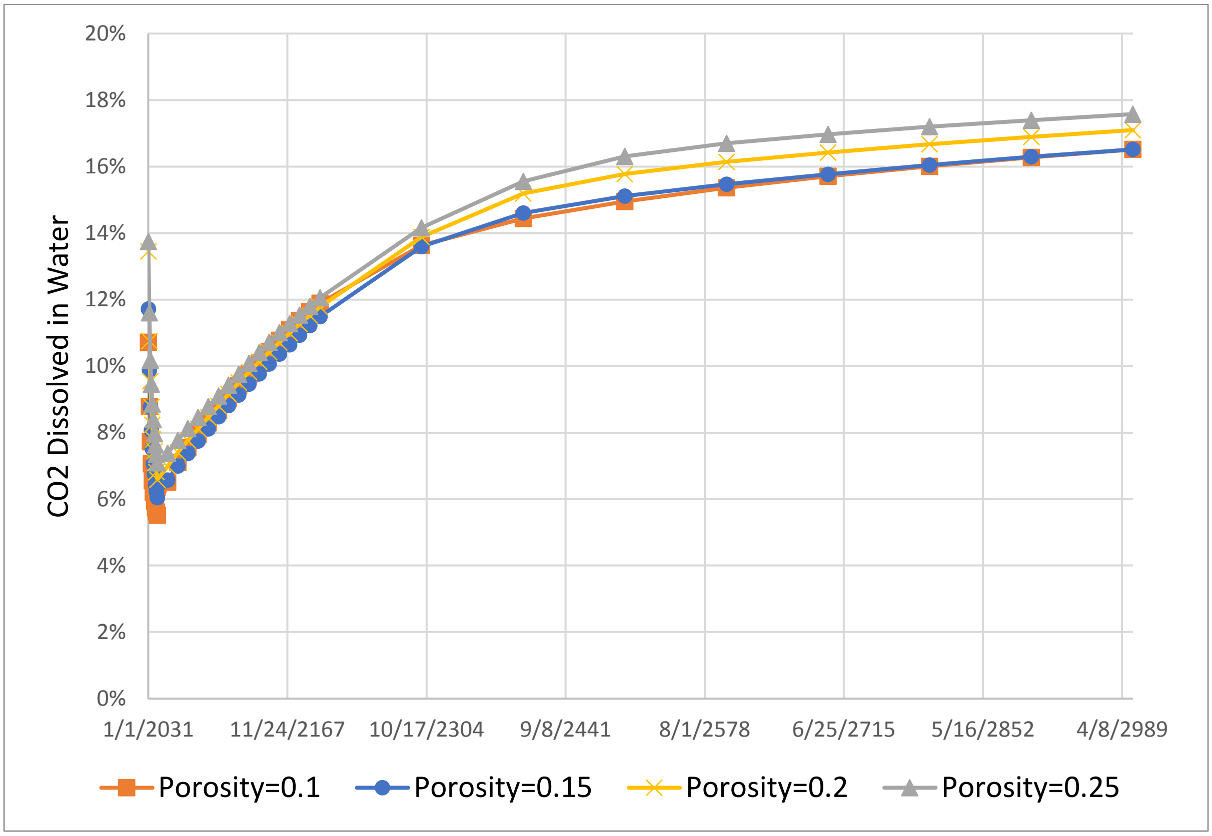
Mobile CO2
80%
70%
60%
50%
40%
30%
20%
10%
0%
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
Porosity=0.1
Porosity=0.15
Porosity=0.2
Porosity=0.25

(A)



CO2 Capillary Entrapped
60%
50%
40%
30%
20%
10%
0%
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
Porosity=0.1
Porosity=0.15
Porosity=0.2
Porosity=0.25

(B)



(C)

Figure 4.29. CO_2 Dissolved in Water

Although increase in porosity caused relatively higher injection volumes, but the overall increase was less than 10%, while increase in porosity from 0.1 to 0.25 comprised increase of 250%. Similar observations from plume migration leads to the conclusion that porosity of the aquifer has limited impact on storage efficiency and plume containment.

4.4 Connected Pore Volume

As it is well known the subsurface aquifers can have a geographical stretch which can extend to several dozens and even hundreds of kilometers. Needless to say, that building static models with such extent can cause memory and performance problems during reservoir simulations. To capture the effect of aquifer extension pore volume multipliers were added into the boundary grids of the numerical model. Several scenarios with following pore volume multipliers were introduced to evaluate the effect of connected pore volume on CO_2 injection:

- Case 14 – PVM=1

- Case 15 – PVM=10
- Case 16 – PVM=1000
- Case 17 – PVM-=10000

The higher was the connected pore volume the more pronounced was the effect of pressure dissipation. For example, for the scenario with no pore volume multiplier PVM=1 there was no pressure dissipation as the aquifer remained completely pressurized even after the shut-in. In contrast, when pore volume was increased the pressure dropped almost to initial pressure following the shut-in of the injection well (Figure 4.30).

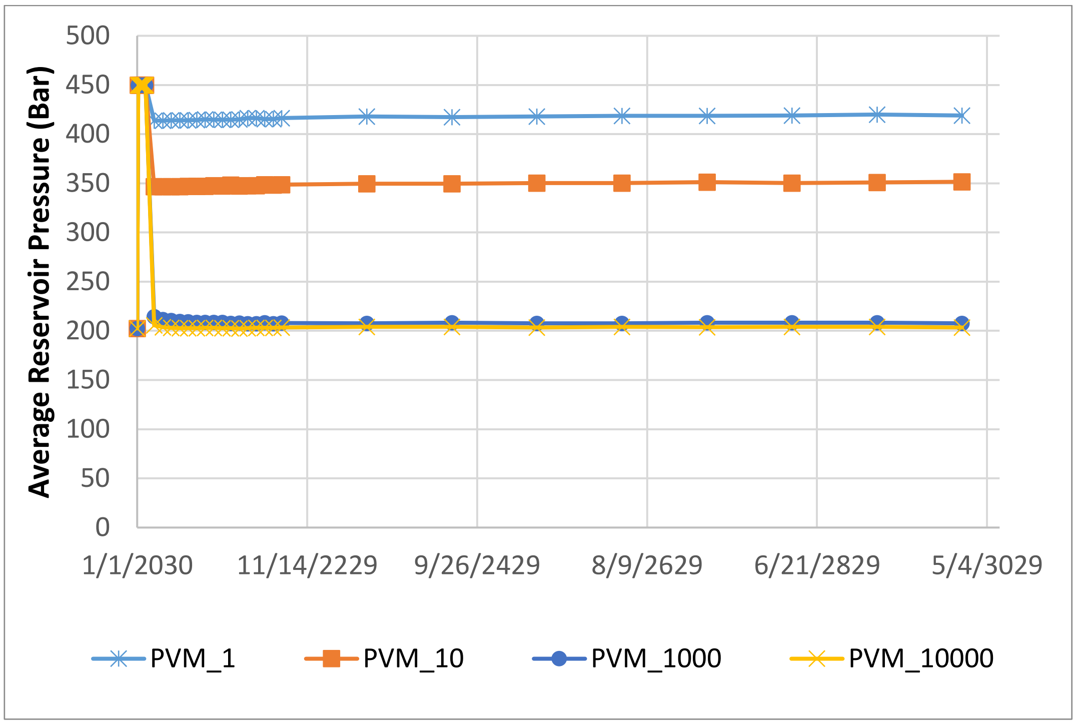


Figure 4.30. Average Reservoir Pressure (Bar)

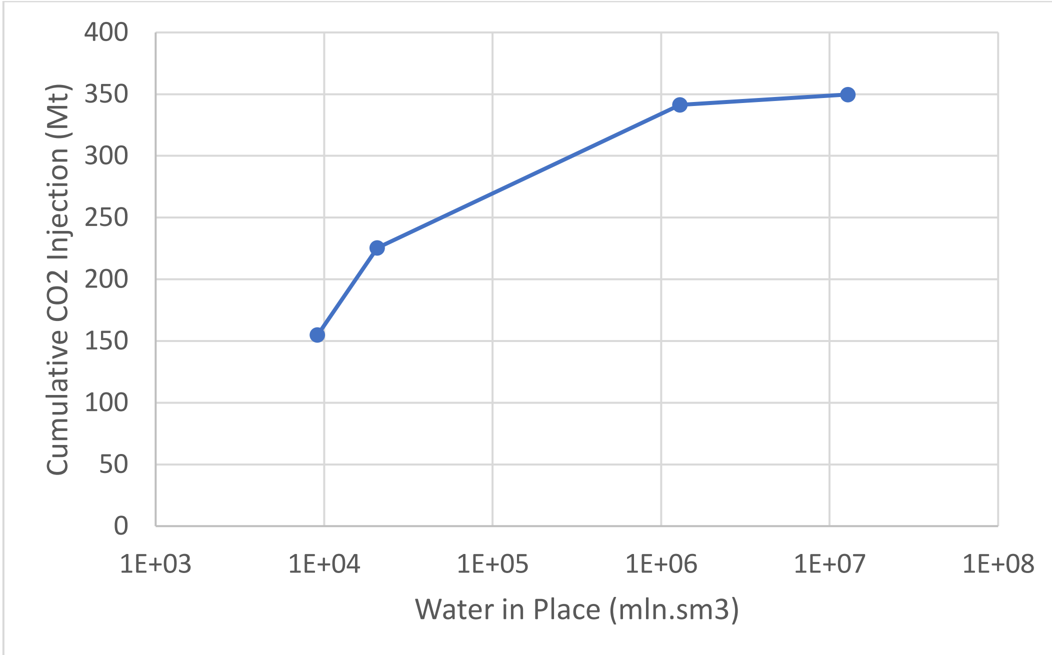


Figure 4.31. Cumulative CO_2 Injection (Mt)

As a result of this behavior the amount of CO_2 injection showed a direct correlation with the amount of connected pore volume (Figure 4.31) Since PVM is applied into boundary grids of the models not affected by CO_2 plume migration, the discussion on PVM influence on CO_2 plume migration and containment becomes irrelevant.

Although definition of the actual aquifer can have practical complications the dynamic simulations results show the utmost importance of this parameter on storage efficiency.

4.5 Relative Permeability

Relative permeability is essential for evaluation of multiphase flow in the porous medium. For injection of CO_2 into aquifers the fluid dynamics is different to that of the conventional oil and gas water flooding. First the aquifers are porous medium saturated with single phase – water and there is no second phase initially residing in the formation.

During the CO_2 storage process the non-wetting fluid CO_2 starts to displace the wetting phase water. So, the saturation of water, particularly around the wellbore is decreasing as more CO_2 is injected into the formation. As this effect continues to evolve the relative permeability to CO_2 starts to increase, thus causing improvement in CO_2 injectivity. End points, for example, the critical water saturation plays a crucial role in storage capacity of the aquifers. Critical water saturation determines the share of porous volume that can be displaced and saturated with CO_2, hence defining the CO_2 storage capacity.

The mechanisms mentioned before, and other effects of relative permeability are studied in detail within the framework of this paper. Generic relative permeability curves with Corey approximation were used as an input into the dynamic reservoir simulation model. The following sections analyze in detail the influence of each relative permeability parameter on CO_2 injection, storage capacity and plume migration. The effect of relative permeability parameters on CO_2 cumulative injection is summarized in Figure 4.32.

4.6 Corey exponent of Gas

Two cases with ng=1.5 and ng=3.0 were run to for evaluation of influence of gas Corey exponents (ng) on dynamic behavior of the CO_2 injection. The resulting relative permeability curves are illustrated in the Figure 4.32.

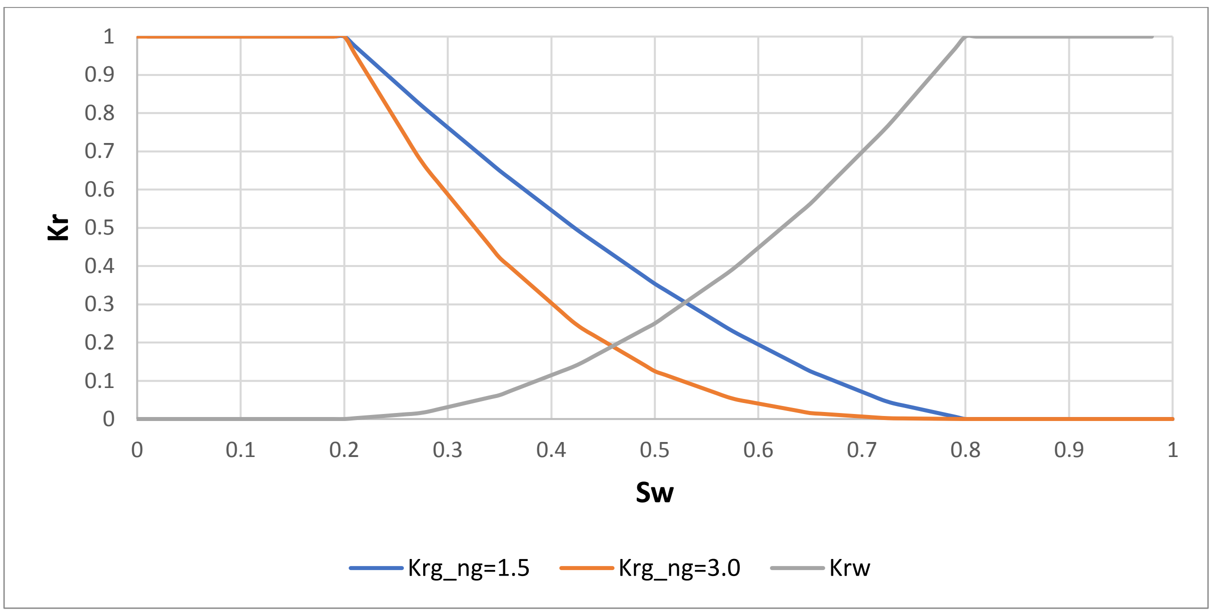
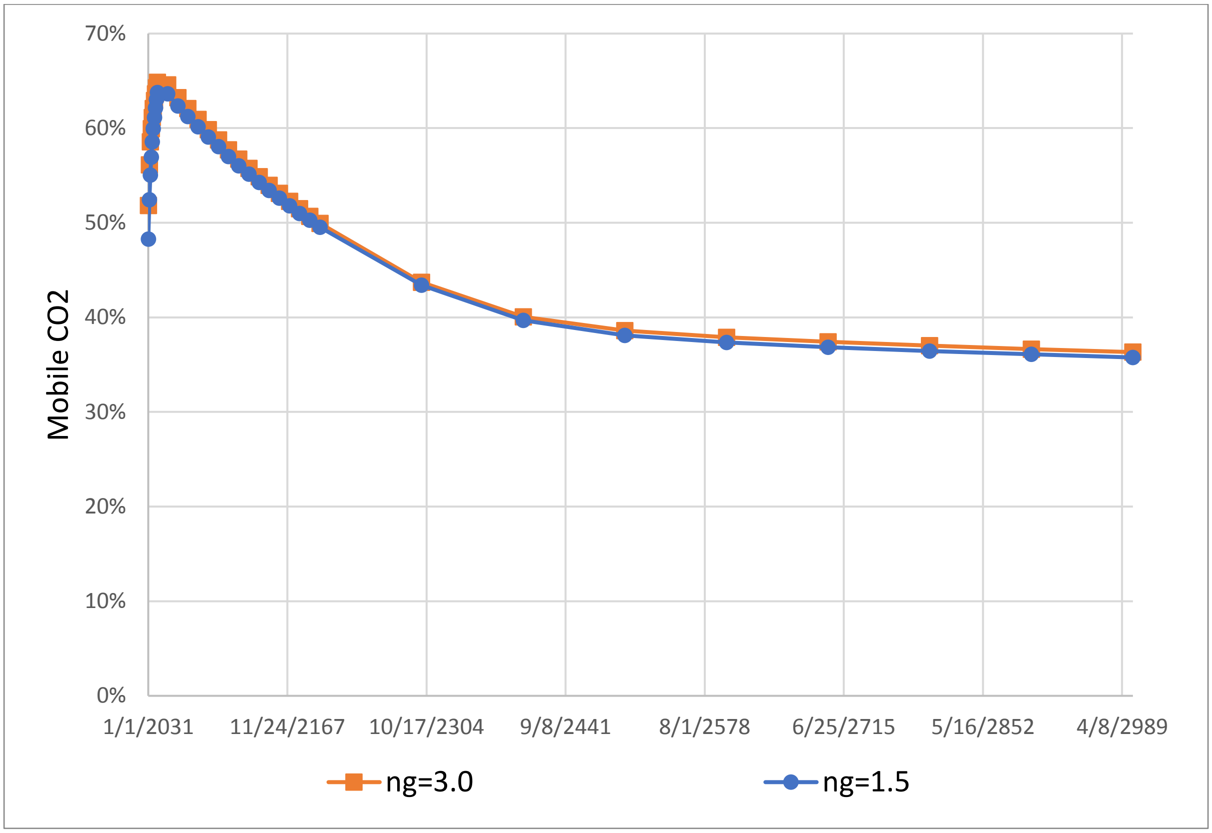
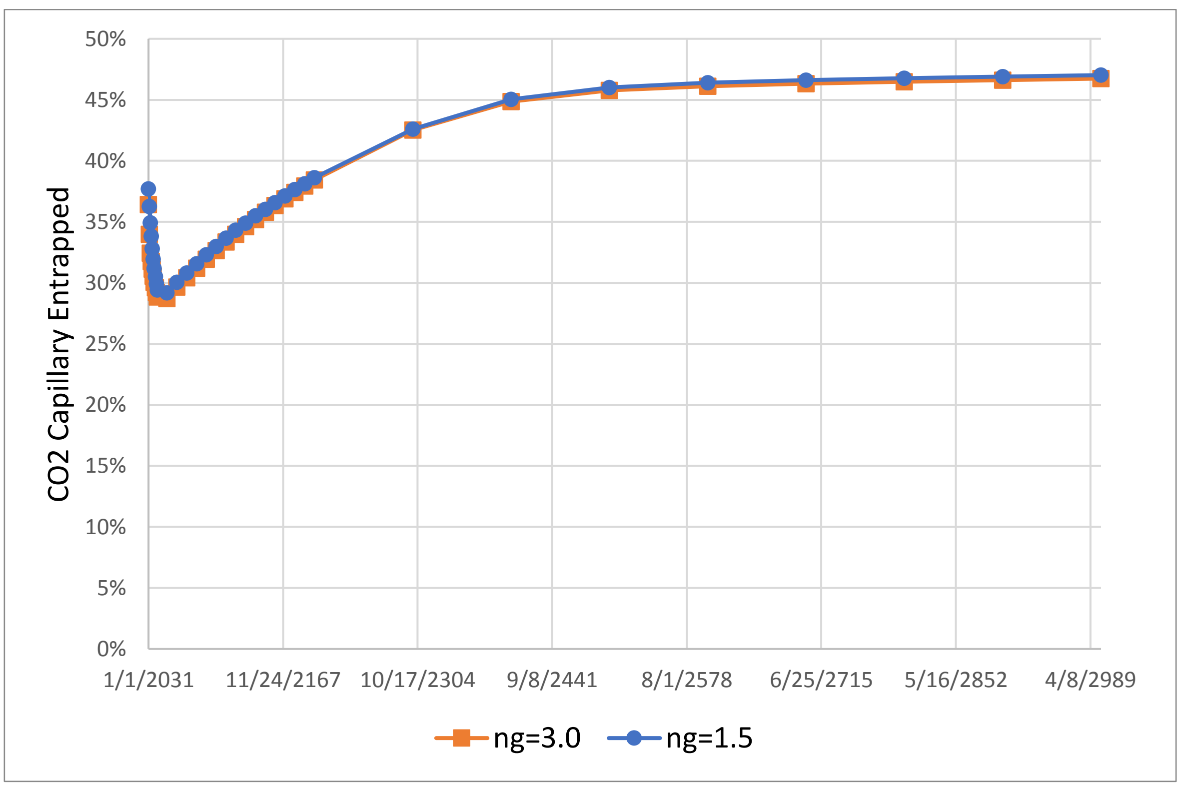


Fig. 4.32. Relative permeability curves



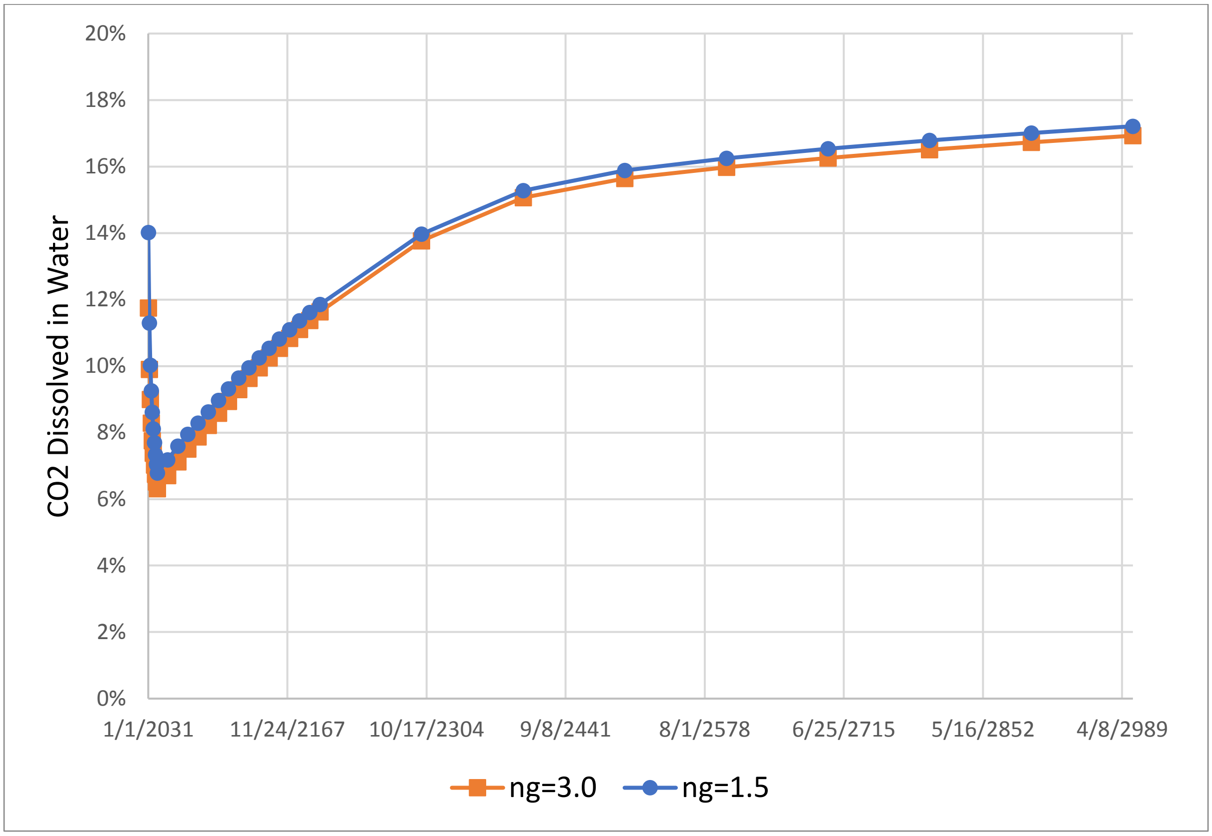
Mobile CO2
70%
60%
50%
40%
30%
20%
10%
0%
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
ng=3.0
ng=1.5

(A)



CO2 Capillary Entrapped
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
ng=3.0
ng=1.5

(B)



(C)

Fig. 4.33. CO_2 Dissolved in Water

As can be seen the figure 25 the variation of ng had little impact on CO_2 plume migration. Almost no difference in share of mobile and entrapped CO_2 was observed for the two cases. This effect is also confirmed from the visual comparison of the sensitivity cases. Extend of CO_2 and distance travelled away from the injection well showed almost identical results.

Similar results were also observed on impact of ng on cumulative CO_2 injection. The difference in total CO_2 injection between the two cases was less than 5% (Figure 4.33).

4.7 Corey exponent of Water

Two cases with nw=1.5 and nw=3.0 were run to for evaluation of influence of water Corey exponents (ng) on dynamic behavior of the CO_2 injection. The resulting relative permeability curves are illustrated in the Figure 4.34.

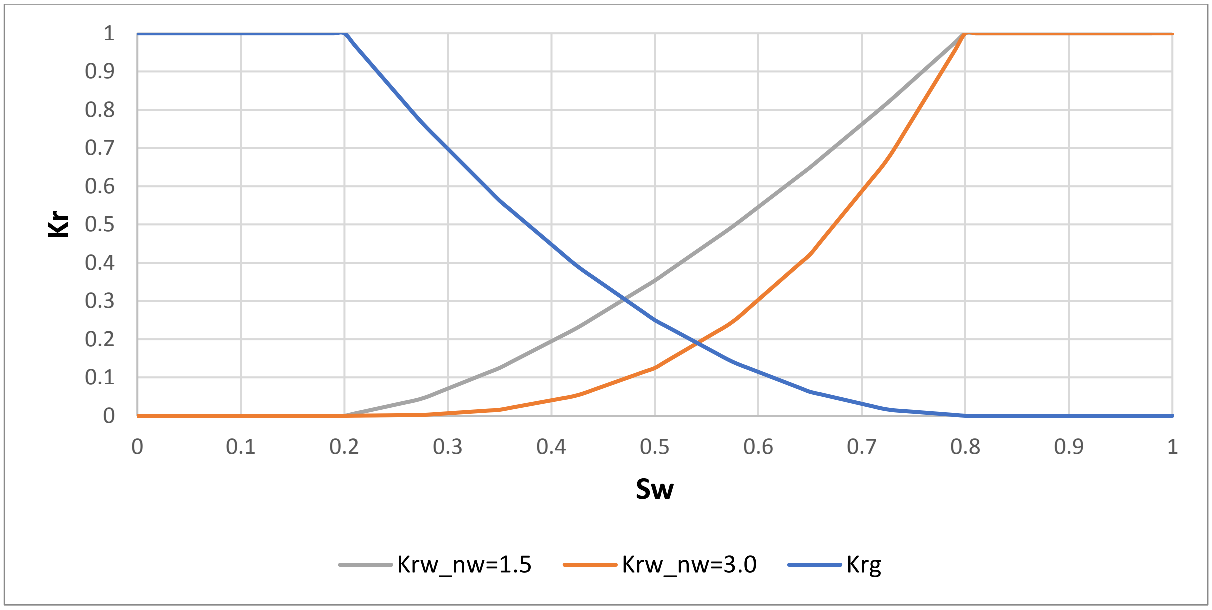
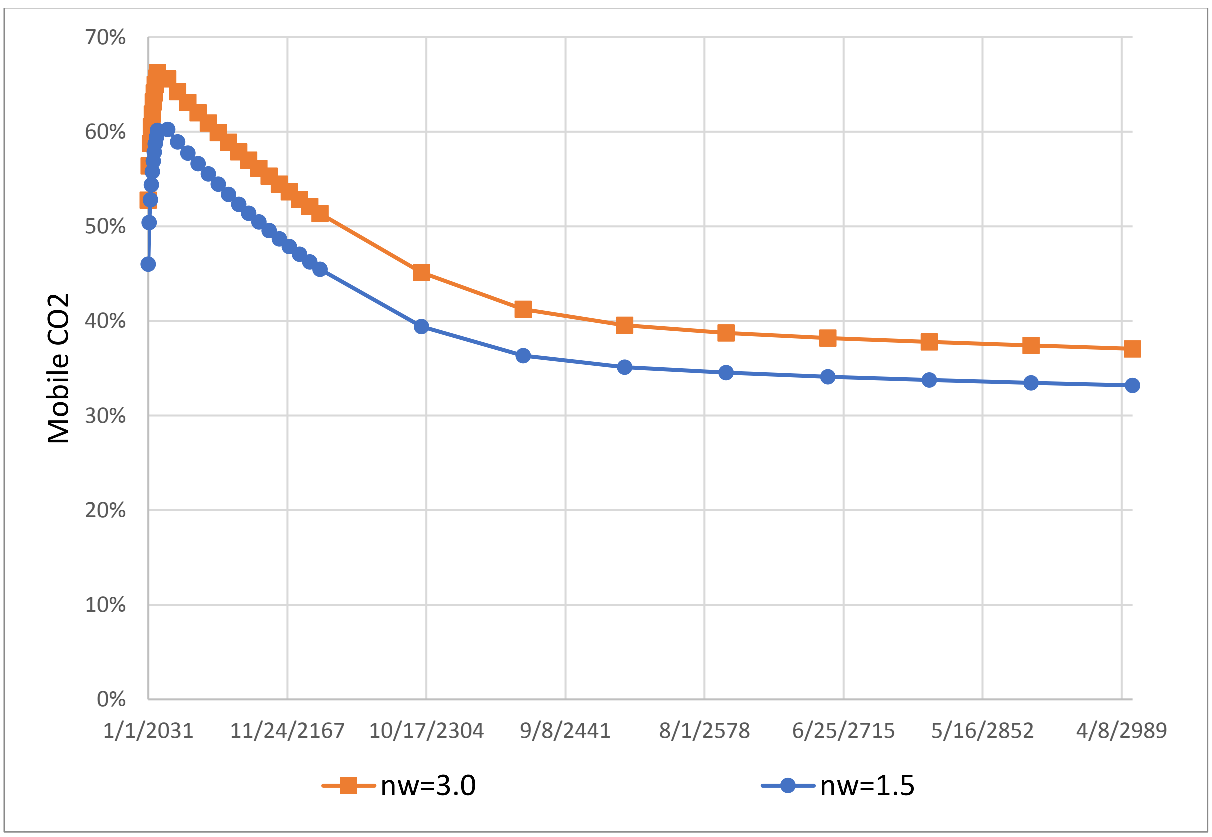
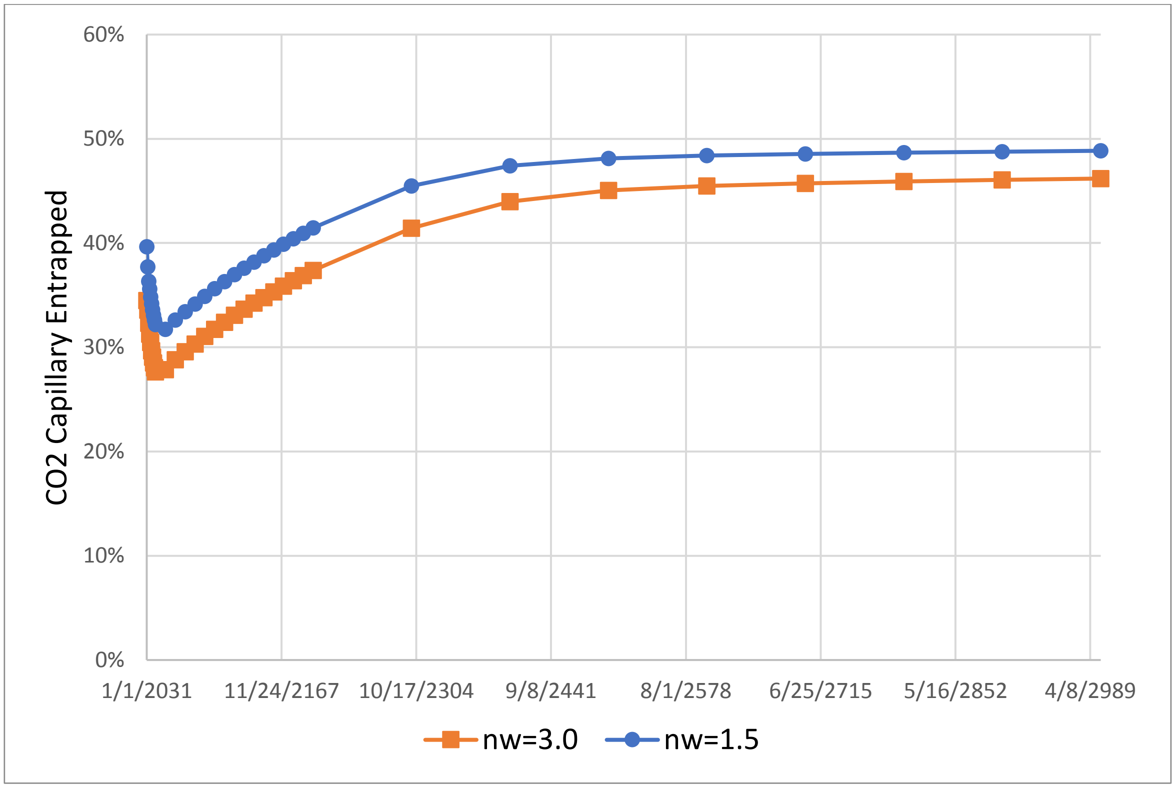


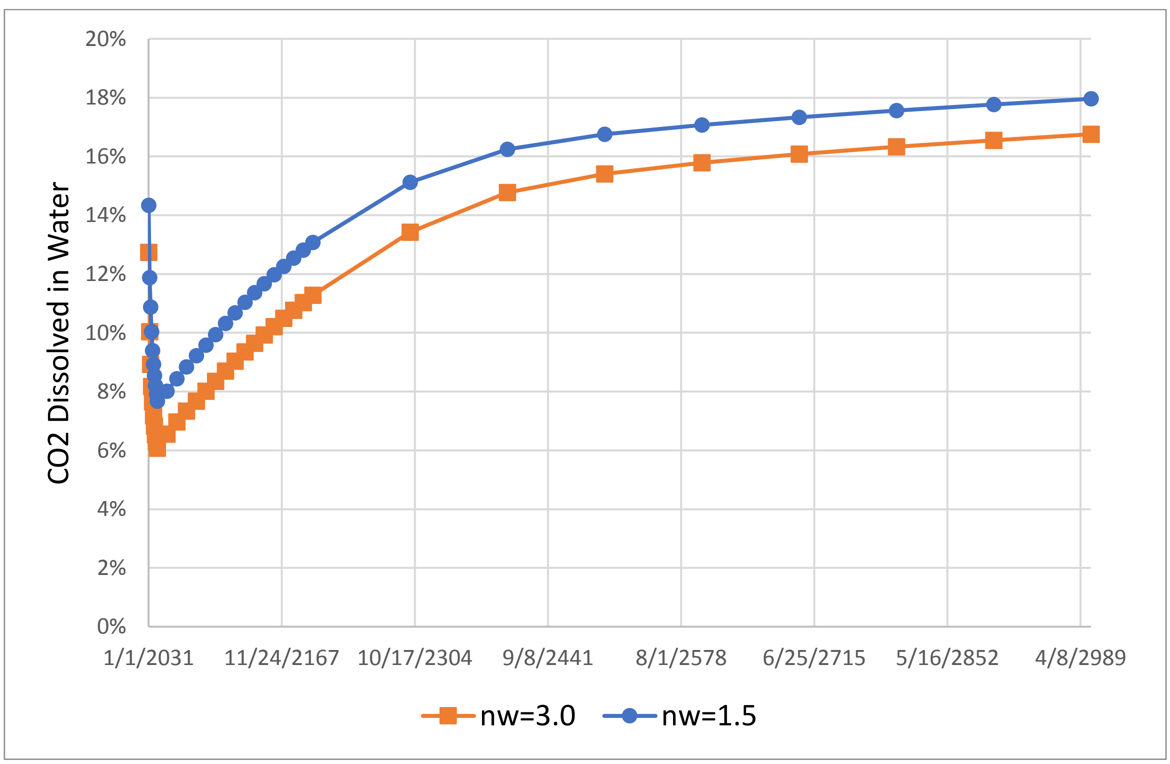
Fig. 4.35. Resulting relative permeability curves



(A)



(B)



(C)

Fig. 4.36. CO_2 Dissolved in Water

In comparison to ng, change in nw had relatively higher influence on CO_2 dynamic behavior in the reservoir. However, the overall effect on plume migration was rather limited, with difference in the share of free and entrapped CO_2 being just a few percents.

Meanwhile the change in mobility of water phase had more pronounced effect on cumulative injection of CO_2. In case of nw=1.5 the overall amount of CO_2 injected was around 15% higher than for nw=3.0. For nw=1.5 refering to higher mobility of water phase, CO_2 injection faced less resistance. In other words, the displacement of water phase was easier in comparison to when nw=3.0. Therefore, it can be concluded that the higher mobility of water phase can be beneficial for overall storage capacity of CO_2, while this parameter showed limited impact on plume containment.

4.8 Residual Gas Saturation

Two cases with Sgcr=1.5 and Sgcr=3.0 were run to for evaluation of influence of gas residual saturation (Sgcr) on dynamic behavior of the CO_2 injection. The resulting relative permeability curves are illustrated in the Figure 22.

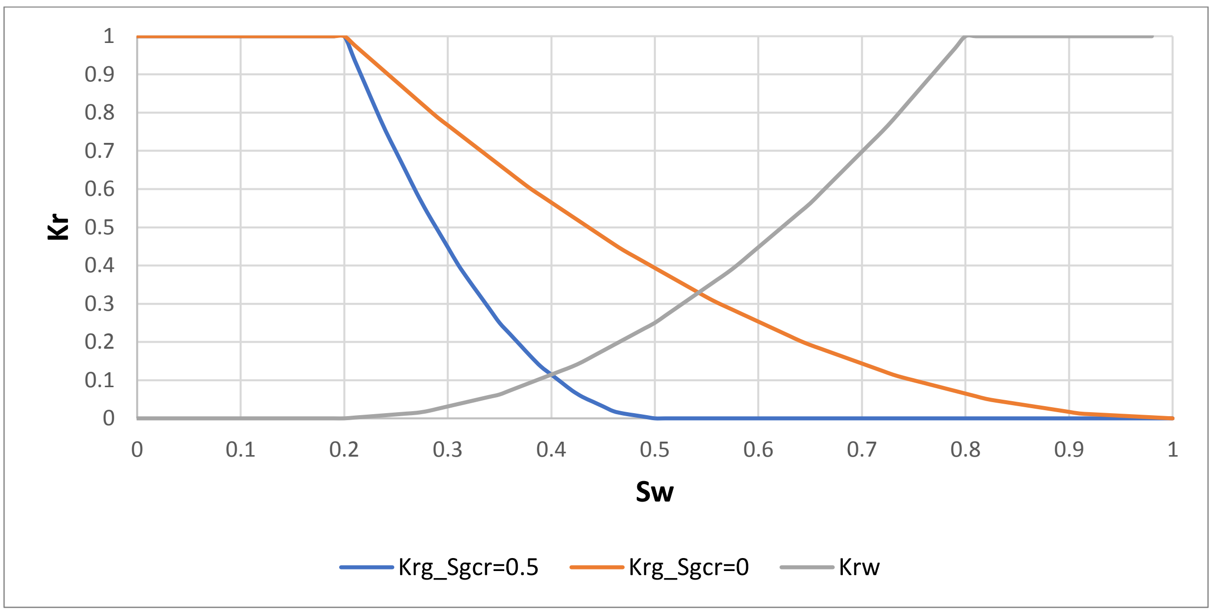
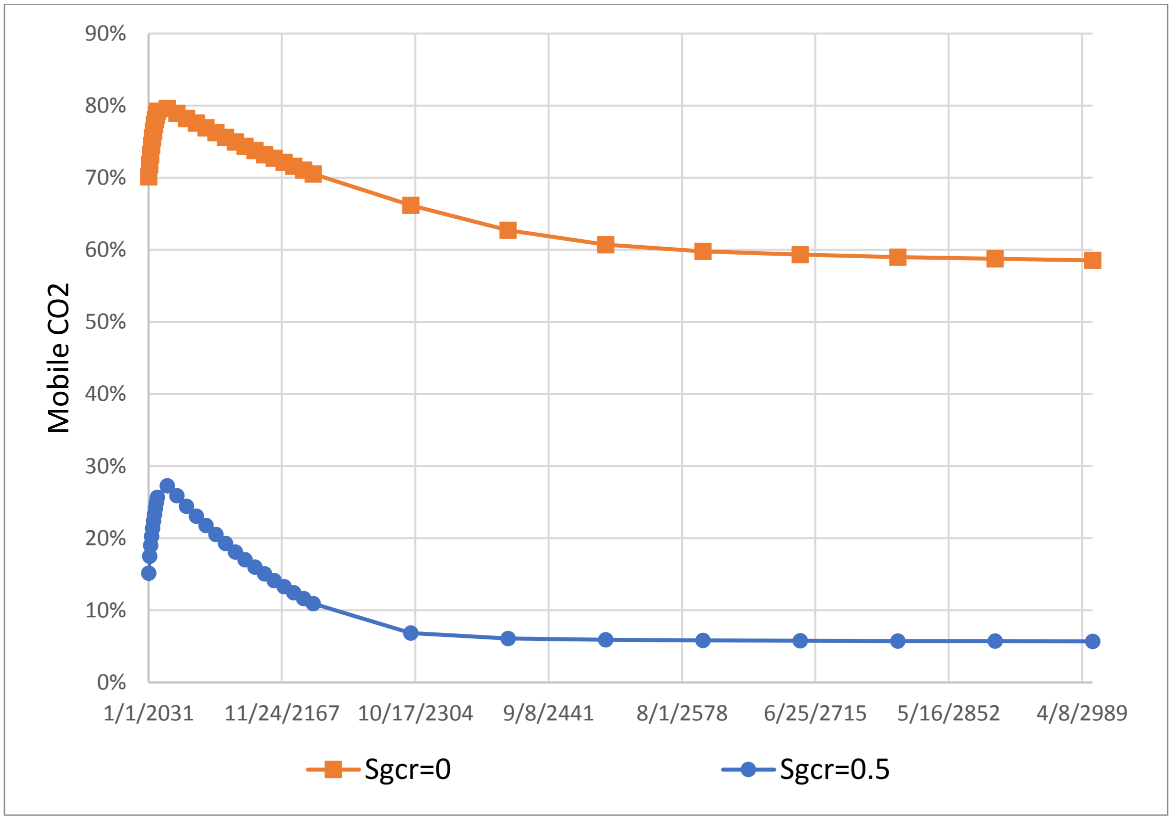
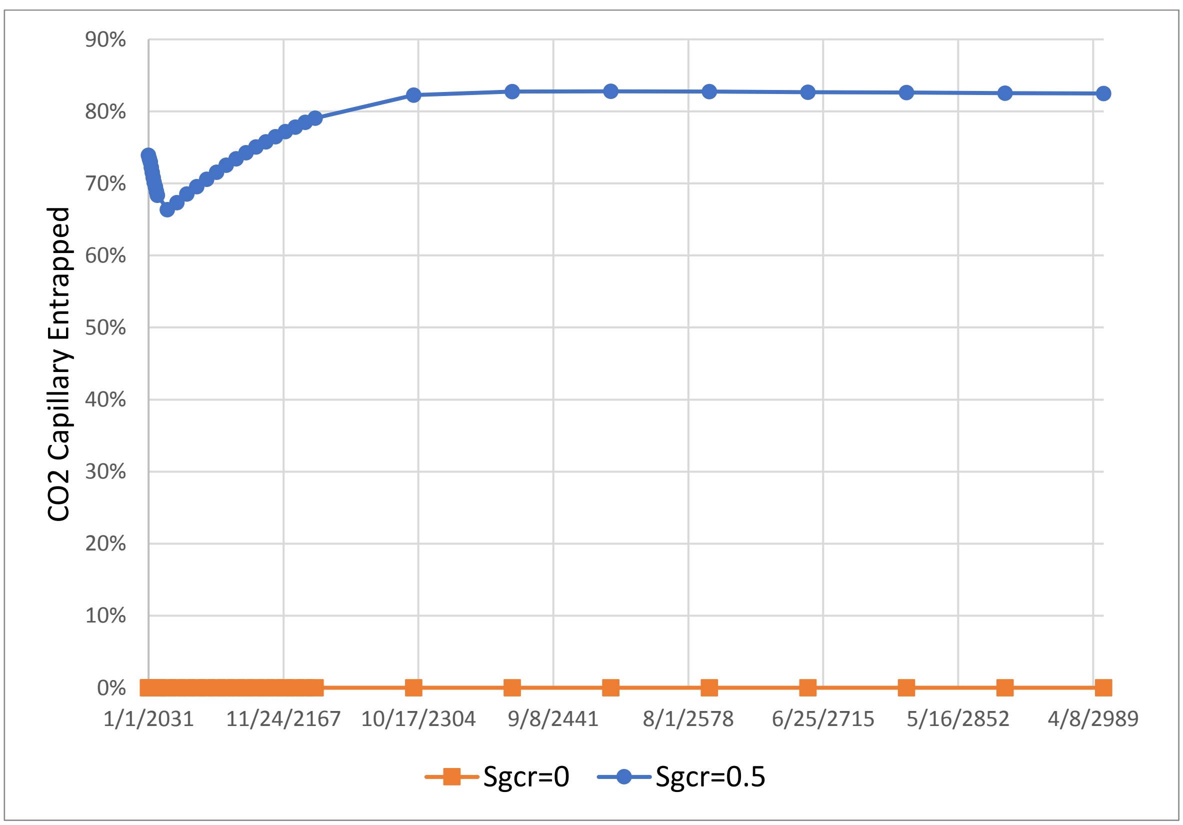


Fig. 4.37. Relative permeability curves



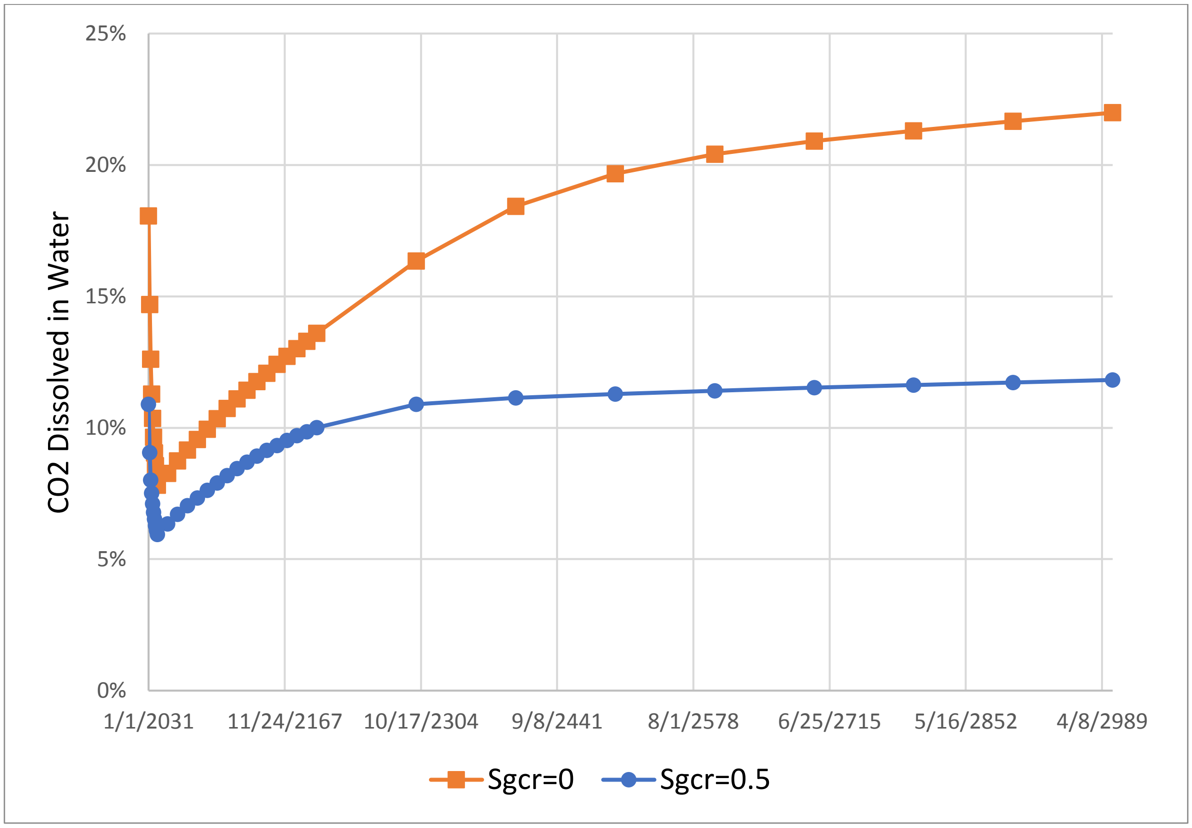
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Mobile CO2
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
Sgcr=0
Sgcr=0.5

(A)



90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
CO2 Capillary Entrapped
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
Sgcr=0
Sgcr=0.5

(B)



(C)

Fig. 4.38. CO_2 Dissolved in Water

As expected in case of Sgcr=0 there was no capillary entrapment of CO_2. Although the share of dissolved of water was higher for Sgcr=0, it did not compensate for absence of capillary entrapment and nearly 75% of CO_2 remained free. In comparison almost no CO_2 was left free when Sgcr=0.5, as the largest share of CO_2 was capillary entrapped.

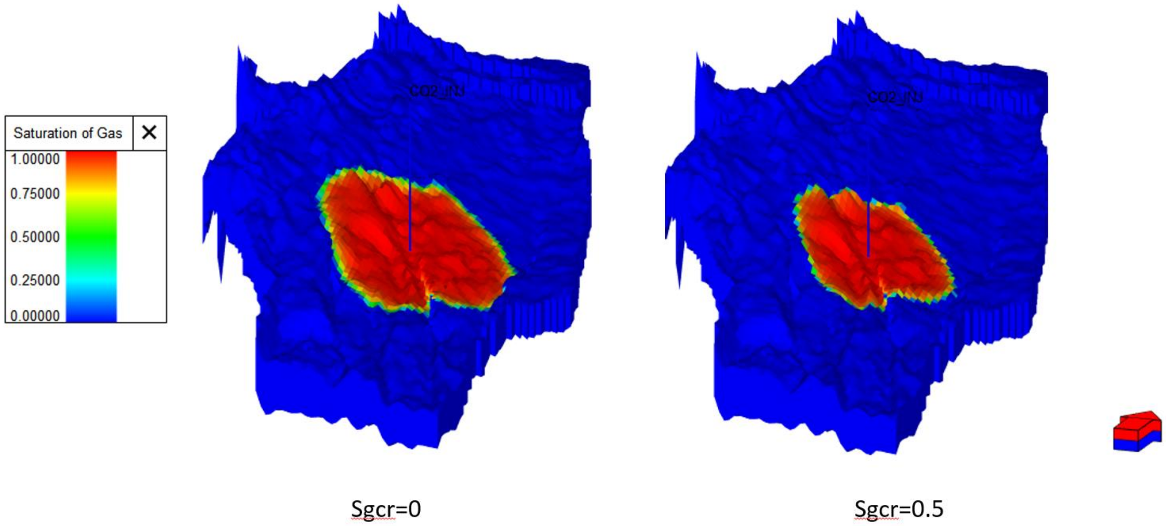


Fig. 4.39. CO_2 saturation at the end of injection period

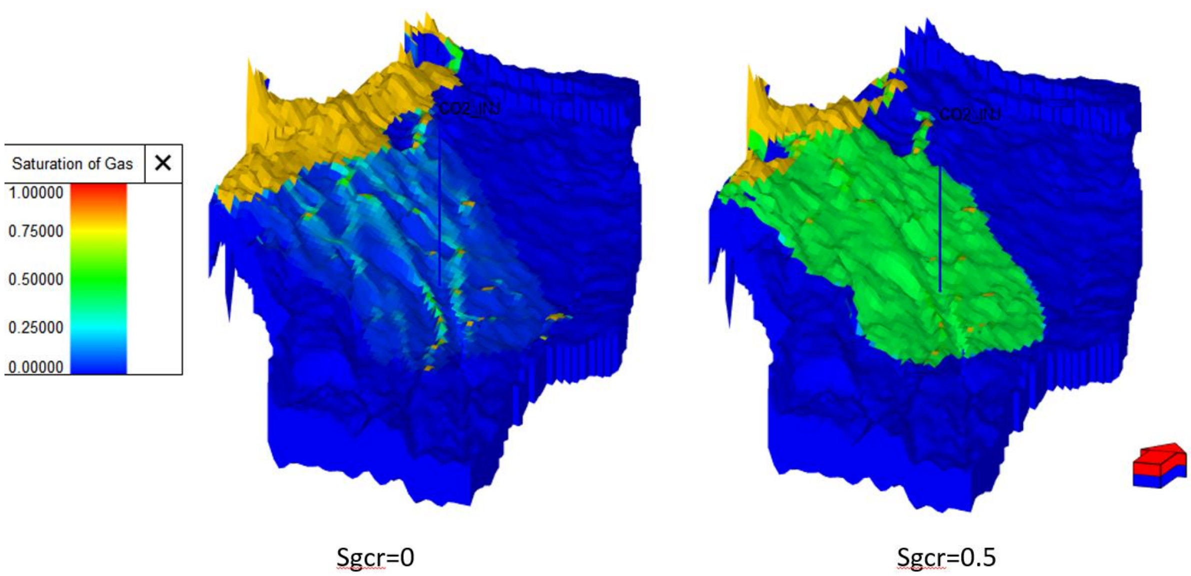


Fig.4.40 CO_2 saturation 2,000 years after injection well shut-in

This figure shows the plume migration for both cases discussed in this section. Without any capillary entrapment of CO_2 the plume migration is much faster, while increase in Sgcr causes more retardation of the CO_2 plume.

As already seen from the previous results the injectivity of CO_2 is more dictated by the mobility of water, by how easily the water can be displaced. In consistency with these observations less dramatic effects were observed on influence of residual gas saturation on cumulative CO_2 injection.

4.9 Residual Water Saturation

Two cases with Swcr=0 and Swcr=0.5 were run to for evaluation of influence of critical water saturation (Sgcr) on dynamic behavior of the CO_2 injection. The resulting relative permeability curves are illustrated in the Figure 4.41.

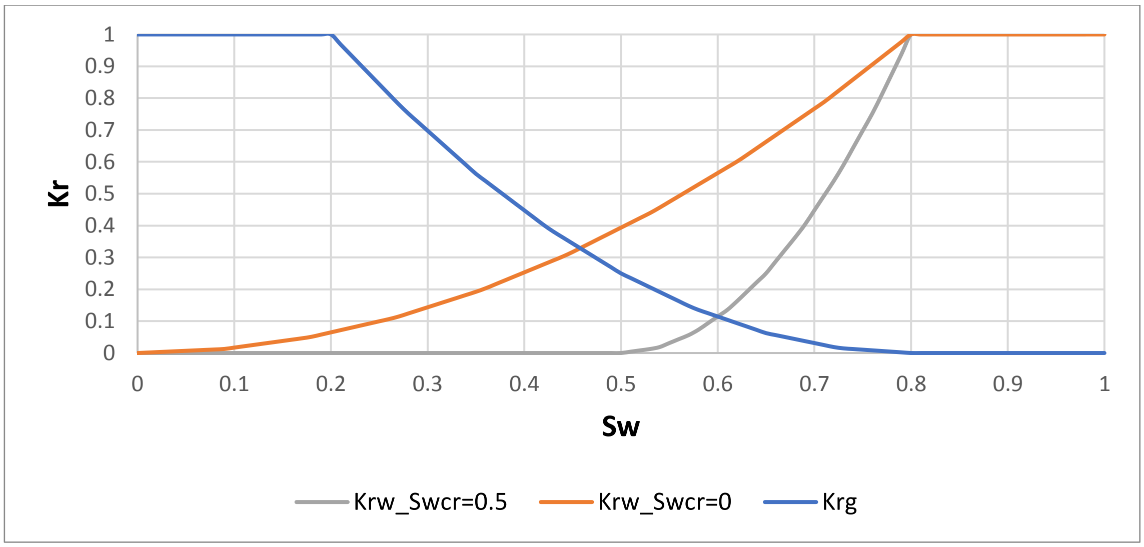
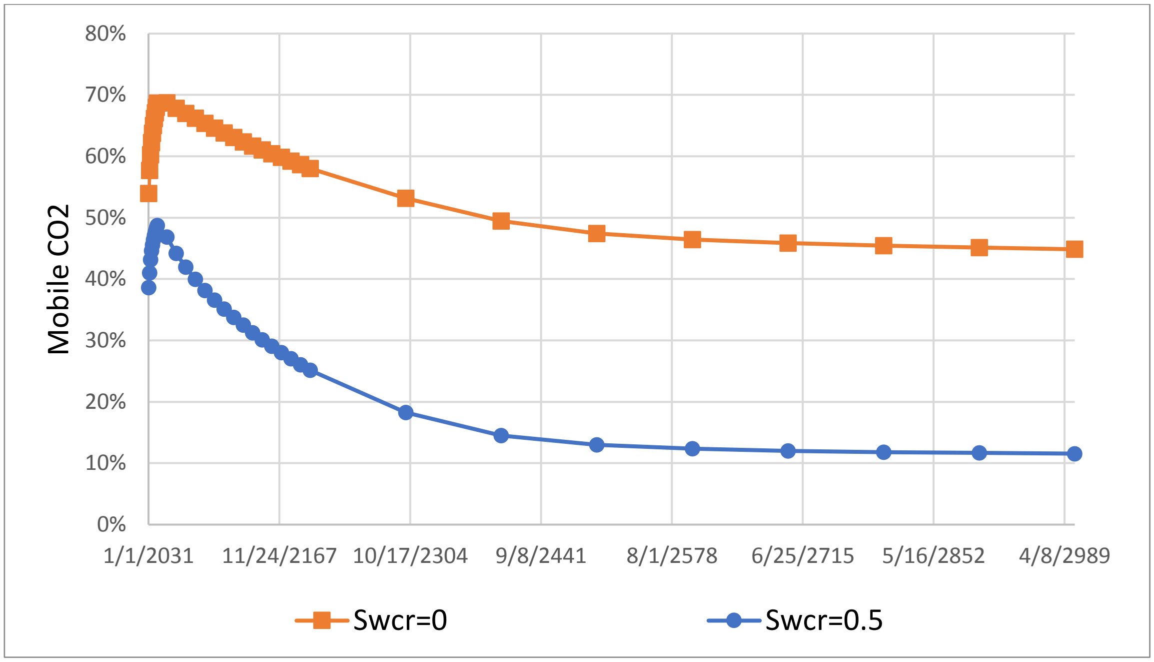
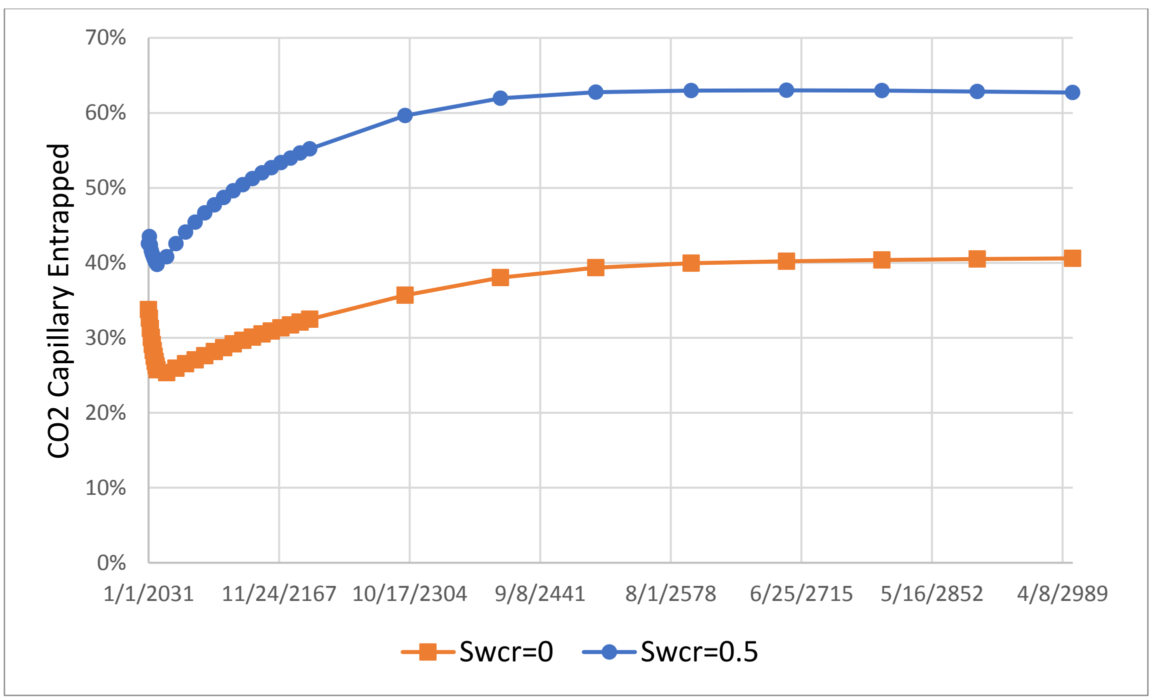


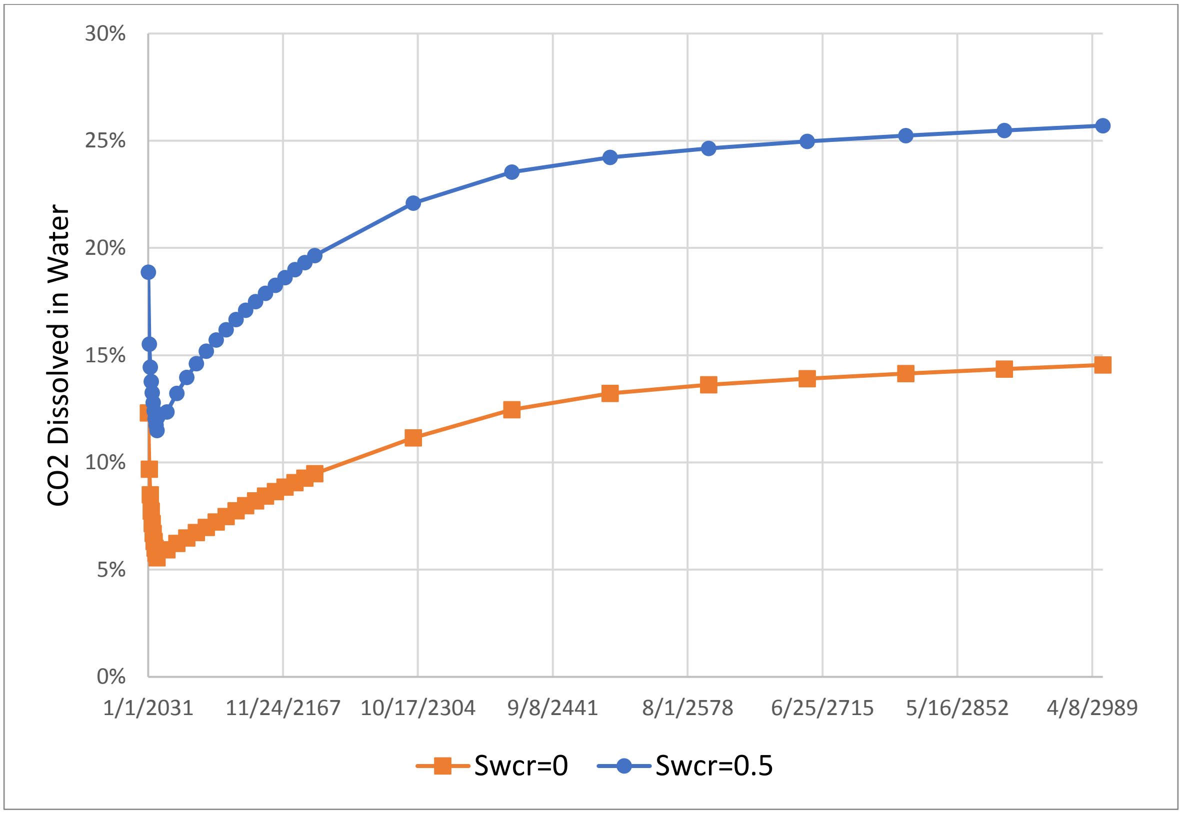
Fig. 4.41. Relative permeability curves


80%
70%
60%
50%
40%
30%
20%
10%
0%
Mobile CO2
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
Swcr=0
Swcr=0.5

(A)


70%
60%
50%
40%
30%
20%
10%
0%
CO2 Capillary Entrapped
1/1/2031
11/24/2167
10/17/2304
9/8/2441
8/1/2578
6/25/2715
5/16/2852
4/8/2989
Swcr=0
Swcr=0.5

(B)



(C)

Fig. 4.42. CO_2 Dissolved in Water

Variation of Swc had a very strong impact both on cumulative CO_2 injection and plume migration. Absence of critical water saturation Swc=0 had significantly weakened the entrapment of CO_2. As can be seen from Figure 25, nearly half of the injected remained free (unbounded) in case of Swc=0. With Swc=0 the extend of plume migration was rather limited in comparison to Swc=0.5. Increase in critical water saturation resulted in less volume available per unit of pore volume for CO_2, thus forcing CO_2 to migrate further. For CO_2 entrapment this means that there was an increase in water contact for the case of higher Swc. Not surprisingly in comparison to Swc=0, when Scw=0.5 nearly 90% of the injected CO_2 was entrapped within the porous volume and only 10% remained free.

A dramatic effect of Swc was also observed on the cumulative storage capacity of CO_2. There was nearly 3 times less CO_2 injected for the case when Swc=0.5. Of course, increase in critical water saturation reduces the overall pore volume available for storage capacity. An extra effect can be also explained by the change in gas relative permeability with increase in critical water saturation. Higher critical water saturation also reduced the mobility of displaced fluid water.

Thus, the combined effect of reduced pore volume and lower gas phase mobility causes a significant influence on storage capacity and injectivity of the aquifer.

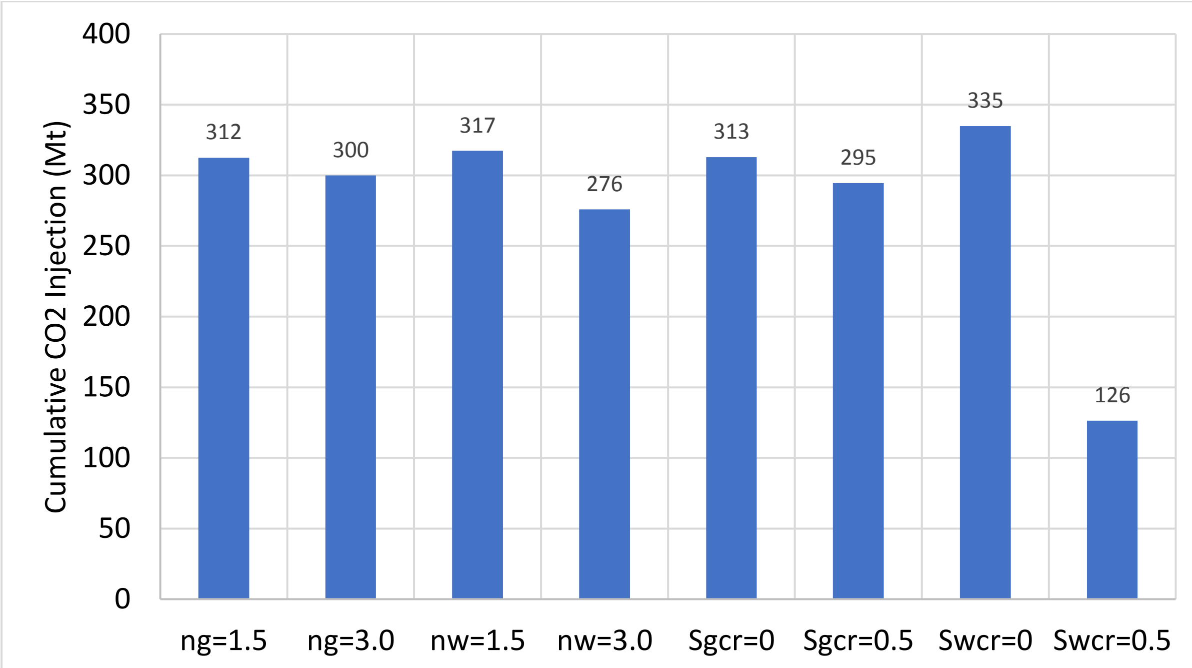


Fig. 4.43. Cumulative CO_2 injection

4.10 Well Location

To evaluate the effect of well placement on CO_2 injection and further plume migration in subsurface, two cases were run with the injection well location shown in Figure 4.43.

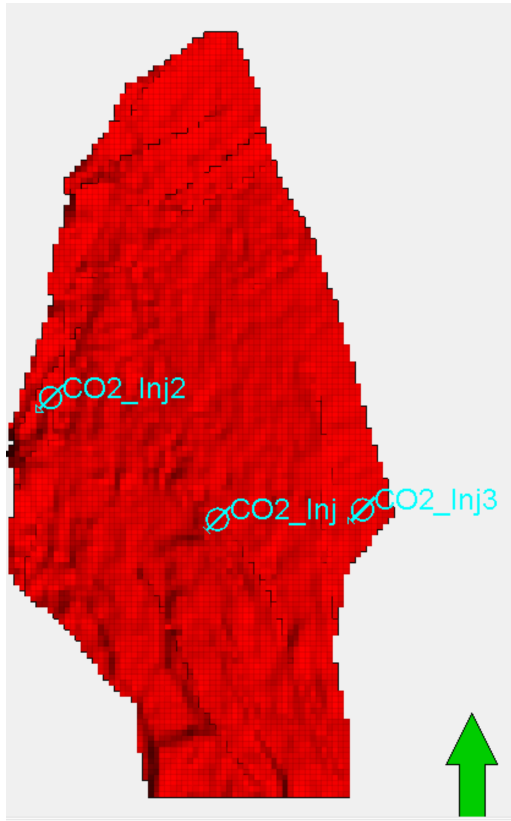
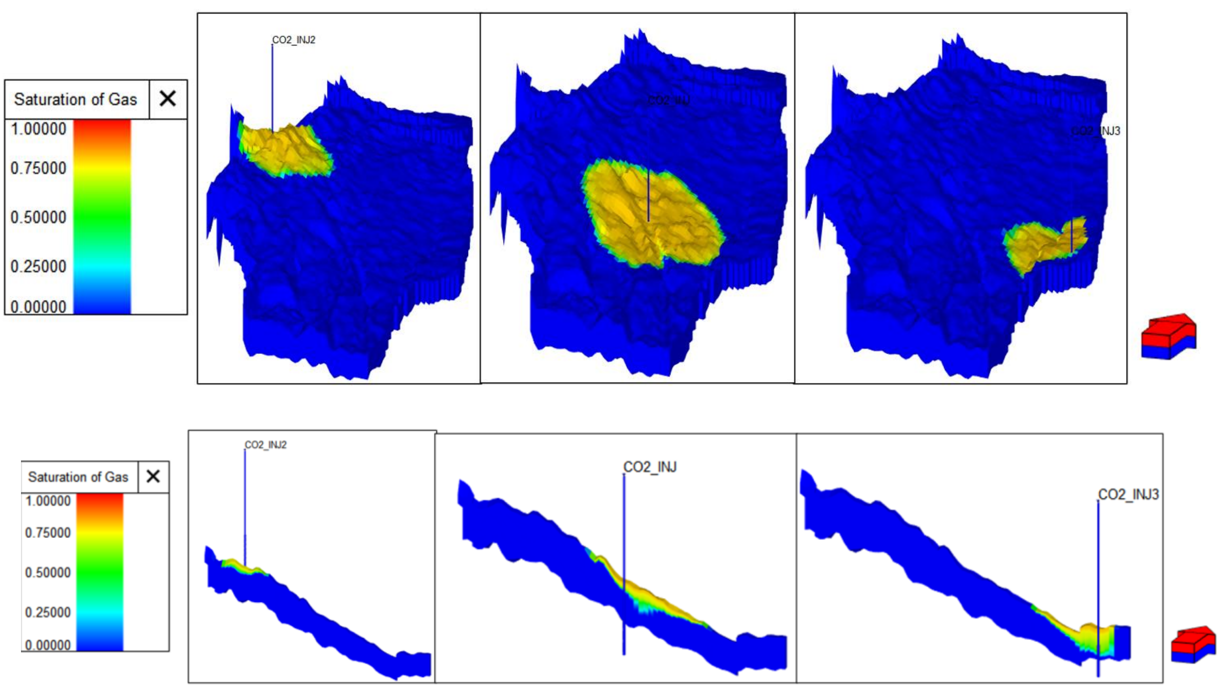
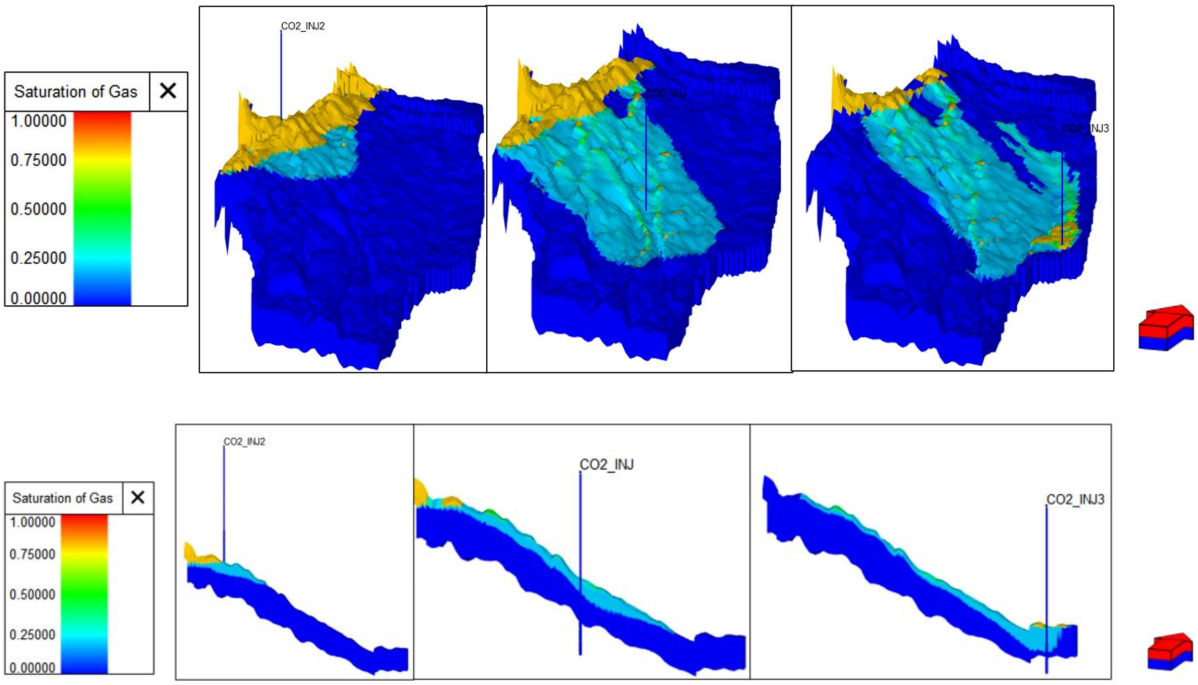


Fig. 4.44. Well location



(A)



(B)

Fig. 4.45. Migration of CO_2

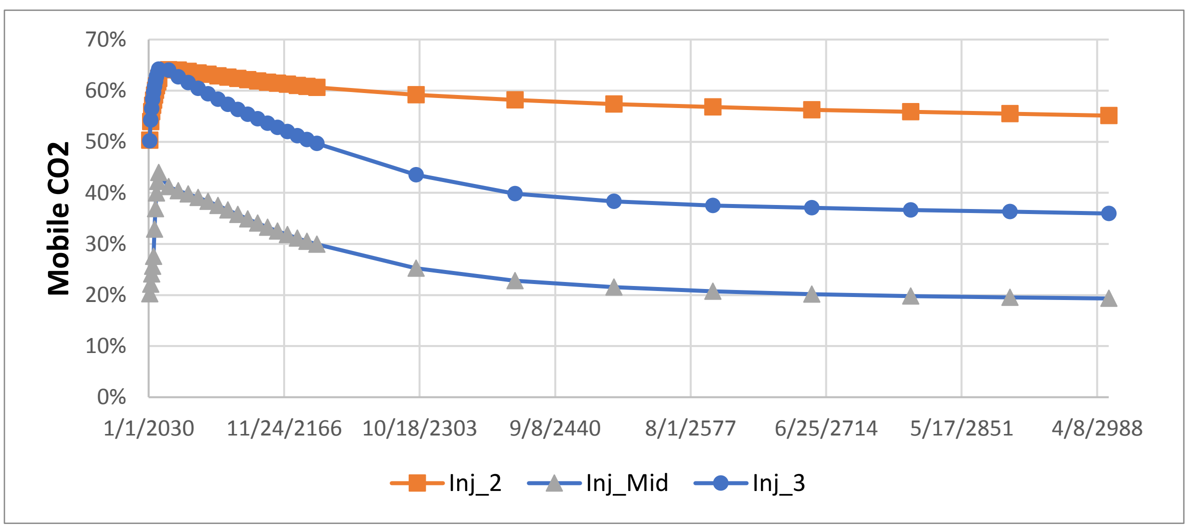


Fig. 4.46. Mobile CO_2 diagram

CONCLUSIONS

The dynamic simulation with given sensitivity studies provided a deep insight on the overall CO_2 storage efficiency of aquifers. From analyzing the influence of various parameters on CO_2 storage efficiency and plume containment the following conclusions can be made from this study:

- Permeability is one of the most important parameters influencing both the cumulative CO_2 injection and plume migration. The higher the permeability of the aquifer the higher should be the expected storage efficiency. At the same time, the effect of vertical permeability on CO_2 storage can be ignored, as no reasonable influence of this parameter was observed on cumulative injection and plume containment. A note must be made that different results can be obtained in case if the injection well is horizontal, when the vertical permeability also plays crucial role in the injectivity of the well. Further studies can be performed to analyze the impact of vertical permeability on injectivity of horizontal wells.
- While pore volume of the aquifer has direct impact on storage efficiency of the CO_2 a difference must be made between porosity and areal extension of the aquifer. From the results of simulations performed within this thesis porosity showed negligible effect on storage efficiency of CO_2. In contrast, the connected pore volume/areal extension of the aquifer plays a crucial role in storage efficiency of the aquifer. The higher the connected pore volume the higher is cumulative injection of CO_2.
- The relative permeability curves had also important effect on both CO_2 storage efficiency and plume migration. However, the significance of relative permeability curve parameters is limited only to critical gas saturation and critical water saturation. Critical gas saturation had a strong effect on plume migration and containment of CO_2 plume. The higher is Sgcr the higher was the containment of CO_2 plume. In comparison, Swcr showed more pronounced effect on cumulative injection of CO_2. As expected, increase in Swcr resulted in decrease of pore volume available for CO_2 storage and caused a dramatic drop in storage capacity.
- Another important parameter analyzed in this study was a distance of CO_2 injection well to the final trap. The higher was the distance more of the injected CO_2 was entrapped in the formation.

- To sum up, the observations made from this study confirmed low storage efficiency factor of aquifers. Due to low compressibility huge volumes of water in place are required to obtain reasonable storage capacities.

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