Optimal conditions for CO2 permanent storage in a producing gas reservoir

Kružić, Valentina

UNIVERSITY OF ZAGREB

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OPTIMAL CONDITIONS FOR CO_2 PERMANENT STORAGE IN A PRODUCING GAS RESERVOIR

Master's Thesis

Valentina Kružić

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Valentina Kružić

Thesis completed at: University of Zagreb
Faculty of Mining, Geology and Petroleum Engineering
Department of Petroleum and Gas Engineering and Energy
Pierottijeva 6, 10 000 Zagreb

Abstract

Carbon capture and storage (CCS) is considered the best option for the removal of large amounts of CO_2. The CO_2 permanent storage could be achieved by injection of CO_2 into depleted and producing hydrocarbon reservoirs. This thesis examines both options using a typical model of a gas-condensate reservoir from Northern Croatia (Drava Basin) with a high CO_2 content. In total, 27 cases of CO_2 injection are simulated to optimize the position of the injection well and the start time of injection for the purpose of its permanent storage. Based on real field data, the reservoir was modelled using Schlumberger's Petrel software (Reservoir Engineering module, RE) with the help of compositional simulator E300. Retention, storability, reservoir pressure, and cumulative production of 'pure' natural gas and CO_2 were compared in all cases. Results have proved that CO_2 permanent storage is possible in producing gas-condensate reservoirs with a high CO_2 content.

Keywords: CCS, gas-condensate reservoir, simulation, injection, retention, storability
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Tech. assistance: Senior Assistant Lucija Jukić, PhD
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OPTIMALNI UVJETI ZA TRAJNO SKLADIŠTENJE CO_2 U PROIZVODNOM PLINSKOM LEŽIŠTU

Valentina Kružić

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Zavod za naftno-plinsko inženjerstvo i energetiku
Pierottijeva 6, 10 000 Zagreb

Sažetak

Geološko skladištenje ugljikovog dioksida (engl. *Carbon Capture and Storage*, CCS) smatra se najboljom opcijom za uklanjanje velikih količina CO_2. Trajno skladištenje moguće je ostvariti utiskivanjem CO_2 u iscrpljena ležišta ugljikovodika te u ležišta koja i dalje proizvode. U ovom radu ispitane su obje opcije na primjeru modela tipičnog plinsko-kondenzatnog ležišta iz Sjeverne Hrvatske (Dravska depresija) s visokim udjelom CO_2. Ukupno je simulirano 27 slučajeva utiskivanja CO_2 kako bi se optimizirali položaj utisne bušotine i vrijeme početka utiskivanja za njegovo trajno skladištenje. Na temelju podataka stvarnog ležišta, izrađen je ležišni model u softveru Petrel (modul Reservoir Engineering, RE) kompanije Schlumberger, korištenjem komponentnog simulatora E300. Retencija, uskladištivost, ležišni tlak i kumulativna proizvodnja 'čistog' prirodnog plina i CO_2 uspoređeni su za sve slučajeve. Rezultati su dokazali da je trajno skladištenje CO_2 moguće u proizvodnim plinsko-kondenzatnim ležištima s visokim udjelom CO_2.

Ključne riječi: CCS, plinsko-kondenzatno ležište, simulacija, utiskivanje, retencija, uskladištivost
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Mentor: Dr. sc. Domagoj Vulin, redoviti profesor RGNF-a
Komentor: Dr. sc. Lucija Jukić, viša asistentica RGNF-a
Ocjenjivači: Dr. sc. Domagoj Vulin, redoviti profesor RGNF-a
Dr. sc. Daria Karasalihović Sedlar, redovita profesorica RGNF-a
Dr. sc. Sonja Koščak Kolin, docentica RGNF-a

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LIST OF USED SYMBOLS AND UNITS

Symbol	Unit	Description
$\mathbf{G_i}$	sm^3	initial gas in place at standard conditions
$\mathbf{G_p}$	sm^3	produced gas volume
$\mathbf{V_{CO2\,(s.c.)}}$	sm^3	CO_2 storage capacity
$\mathbf{B_{gi}}$	$\frac{rm^3}{sm^3}$	initial gas formation volume factor
$\mathbf{V_{g(r.c.)}}$	rm^3	gas volume at reservoir conditions
$\mathbf{V_{g(s.c.)}}$	sm^3	gas volume at standard conditions
$\mathbf{B_{g_{CO2+gas}}}$	$\frac{rm^3}{sm^3}$	formation volume factor of CO_2 and natural gas in a reservoir at the final injection conditions
PVT		pressure, volume, and temperature

LIST OF ABBREVIATIONS

BAU	business as usual
CCS	carbon capture and storage
CCS1	injection scenarios where B-9 is injection well
CCS2	injection scenarios where B-8 is injection well
CCS3	injection scenarios where B-6 is injection well
CCUS	carbon capture, utilization and storage
COP	Conferences of the Parties
DOGR	depleted oil and gas reservoirs
EGR	enhanced gas recovery
EOR	enhanced oil recovery
EU-ETS	European Union Emissions Trading System
GHG	greenhouse gas
HM_1	history matching for case where injection well is B-9
HM_2	history matching for case where injection well is B-8
HM_3	history matching for case where injection well is B-6
HM_BAU_STORE_1	scenario with injection after production end where B-9 is injection well
HM_BAU_STORE_2	scenario with injection after production end where B-8 is injection well
HM_BAU_STORE_3	scenario with injection after production end where B-6 is injection well
MSR	Market Stability Reserve

1. INTRODUCTION

In order to tackle the objectives set within the Conferences of the Parties (COP) – with the Kyoto Protocol, the Paris Agreement, and COP27 as the most notable – around 200 countries set themselves on track to reduce the impacts of global warming. For the temperature increase, greenhouse gas (GHG) emissions are considered one of the most significant factors, creating the greenhouse effect. Their anthropogenic sources have therefore been targeted across different industries. The petroleum industry has been recognized as one of the most significant sources with direct and indirect emissions of 8 and 33% of global emissions, respectively, summing up to over 42% total (Savenkova and Remme, 2020). However, there may be innovative approaches and solutions with which the petroleum industry can mitigate its environmental impact.

Carbon capture and storage (CCS) is a technology which aims to capture, transport, and permanently store CO_2 in appropriate geological formations. Compared to other climate change mitigation and adaptation measures, CCS is considered the best option for CO_2 removal in the short to medium term (Liu et al., 2023). The largest number of CCS studies are related to depleted hydrocarbon reservoirs and deep saline aquifers (Klusman, 2003; Michael et al., 2010; Wang et al., 2022). Depleted hydrocarbon reservoirs are considered to be the best option for storage due to their good sealing properties and many data collected during petroleum production. Additionally, parts of the existing infrastructure can be utilized or repurposed (e.g., wells and pipelines).

The main reason why CCS cannot compete with its low-carbon counterparts is its costs. However, the high price of CO_2 since the Green Deal, means it is possible to expect positive changes in the coming period (Rickels et al., 2021). The initial two phases of EU ETS (European Emission Trading Scheme) were marked by a significant number of free allocations and occasional imbalances between supply and demand, primarily caused by the global financial crisis that began in 2008. However, the two more recent phases have seen a rise in the proportion of allowances that are auctioned rather than allocated, the establishment of consistent rules, a decrease in the annual limit for emissions, and market reforms to address oversupply. These reforms include delaying the auctioning of excess allowances without reducing the overall number of allowances to be auctioned, and incorporating allowances into a Market Stability Reserve (MSR). The amended EU ETS Directive, issued in 2018, resulted in a significant decrease in the surplus of emissions allowances and a decrease of CO_2 price volatility.

Carbon capture, utilization and storage (CCUS) technology is considered an extension of CCS - the captured CO_2 may be utilized before storage via conversion into another chemical compound, or simultaneously utilized and stored without changing its chemical structure (physical utilization). Utilization makes projects more financially attractive by allowing the expenses of CO_2 capture and storage to be balanced out by the revenues generated by its utilization (Bajpai et al., 2022). In the petroleum industry, CCUS has been used for years by means of enhanced oil recovery (EOR). CO_2 interacts with residual oil decreasing oil's density and viscosity, increasing relative permeability and oil mobility in general, which facilitates higher recovery. Furthermore, there is a benefit of trapping a large amount of CO_2 into a reservoir (Stosur, 2003). CO_2-EOR technologies have been widespread in the USA for years, and since the last decade, EOR has been implemented in reservoir management of Žutica and Ivanić oil fields in the Republic of Croatia (Novosel et al., 2020).

Enhanced gas recovery (EGR) is a concept similar to CO_2-EOR, and is considered to increase the recovery in gas reservoirs. Compared to EOR, EGR seems far less efficient and cost-effective, primarily due to CO_2 and methane mixing (Hamza et al., 2021). Still, many recent studies examined the various aspects of that technology due to its attractiveness. Firstly, it is possible to store more CO_2 in gas reservoirs than in oil reservoirs with the same original hydrocarbon in place. Ultimate gas recovery is about 65% of initial gas in place, almost double that of oil (35%). The second advantage is the compressibility of CO_2 – it is some 30 times more compressible than oil at 138 bar (Mamora and Seo, 2002; Khan et al., 2013). The mixing of CO_2 and methane could be overcome with production control because the physical properties of CO_2 change with increasing pressure. A proper estimate of the CO_2 injection start is possible by using software and reservoir modeling, when there is a significant amount of known data available.

The challenge of injecting CO_2 into gas reservoirs still leaves room for improvement, especially considering producing reservoirs. The primary objective of this study was to evaluate a gas-condensate reservoir characterized by a significant initial concentration of carbon dioxide.

The primary emphasis lies on the storage of CO_2 rather than the production of gas. Nevertheless, the fundamental assumption is that commencing CO_2 injection during gas production would result in enhanced cost efficiency. This is attributed to the early development and building of CO_2 injection facilities, data acquisition, and a relatively earlier depletion of natural gas, which would consequently create additional capacity for CO_2 storage.

The hypothesis of this study is that it is possible to improve the reservoir potential for CO_2 storage by choosing the optimal starting time for injection, i.e., conditions at producing gas reservoir. Reservoir potential is determined by two parameters - retention and storability, while optimal conditions are defined by the positioning of the injection well and start time of the injection.

2. LITERATURE REVIEW

A review of existing literature was needed prior to numerical simulations in this thesis to provide theoretical understanding for interpreting the results. Many scholars highlight the difference between storage in depleted reservoirs vs. storage in producing reservoirs, which is here explained. An overview of important properties and mechanisms is also given in this section.

2.1. CO_2 geological storage in depleted gas reservoirs

The history of CO_2 storage began in the early 1970s (Global CCS Institute, 2016). Since then, it is notable that most development projects have never started operating. Recent studies show a positive trend for CCS, especially in Europe and North America, where more than 80% of all projects are planned (Askarova et al., 2023).

There are three main options for CO_2 geological storage: depleted oil and gas reservoirs (DOGR), deep saline aquifers, and coal bed methane reservoirs. DOGRs are considered the best option due to the following reasons: (i) existing infrastructure can be used or repurposed (pipelines and wells), (ii) hydrocarbon reservoirs have proven sealing properties and can retain CO_2 for a long time, (iii) CO_2 can be used in EOR or EGR, thus making a project more profitable. On the other side, deep saline aquifers also have respective benefits – larger CO_2 quantities could be stored there, and aquifers have wider distribution (Liu et al., 2023). Coal bed methane reservoirs remain the option for future development. Currently, they are not of great interest due to their low storage capacity, risk of induced seismicity, competing economic interests with methane extraction, and technical challenges related to CO_2 absorption via the coal matrix, which can reduce mobility.

The essential criteria for a prospective reservoir include the reservoir's temperature and pressure conditions, as these factors directly impact the effectiveness of the CO_2 injection. Before permanent storage, CO_2 is captured, dehydrated and compressed. It is common to inject CO_2 in supercritical phase owing to its higher density and favorable viscosity (Askarova et al., 2023). Hence, the temperature must exceed 31.1 °C, and the pressure should be above 7.4 MPa (Figure 2-1). While CO_2 injection is possible in both liquid and gaseous states, the supercritical state is favored – it has higher bulk compressibility compared to water, resembling a gas and facilitating CO_2 flow into smaller pores. Additionally, as pressure increases at greater depths, the density of CO_2 rises, leading to a liquid-like behavior that enhances storage capacity. Consequently, reservoirs exceeding a depth of 800 meters are expected to have pressures and temperatures that do not pose a challenge to the phase stability of supercritical CO_2.

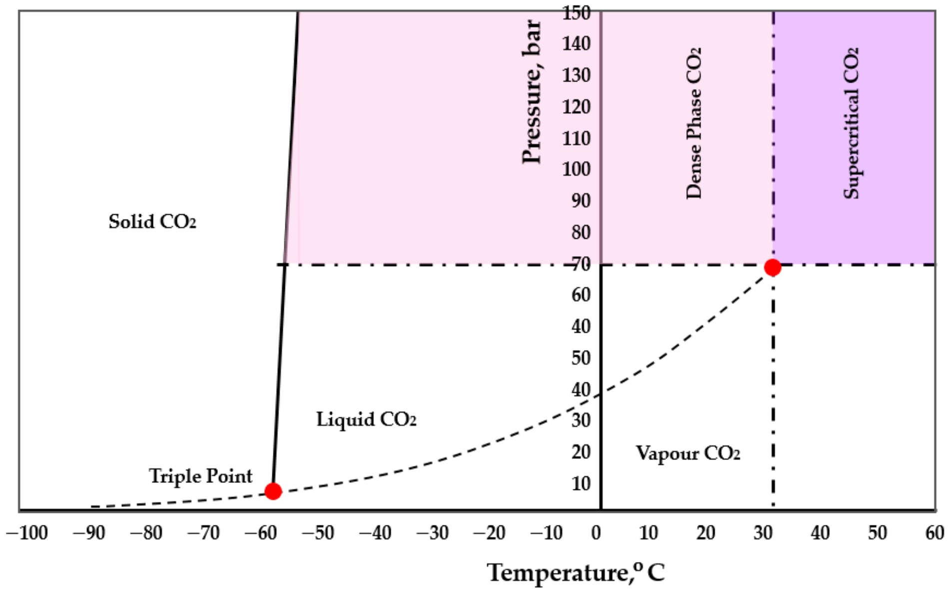

Figure 2-1 Phase diagram of pure CO_2 (Askarova et al., 2023).

Important parameters considered in potential storage quality estimation are porosity and thickness, cap rock integrity, well injectivity, and stable geological environment (Liu et al., 2023).

The assessment of CO_2 storage capacities can be sufficiently accurately determined using a volumetric material balance formula (Lai et al., 2015):

$$V_{CO_2 \, (s.c.)} = \frac{G_i \cdot B_{gi} - (G_i + G_p) \cdot B_{g_{CO_2+gas}}}{B_{g_{CO_2+gas}}} \tag{2-1}$$

where G_i is the initial gas in place at standard conditions (m^3, s.c. or sm^3), G_p is the produced gas volume (sm^3), $V_{CO2(s.c.)}$ is the CO_2 storage capacity (sm^3), and B_{gi} is the initial gas formation volume factor:

$$B_{gi} = \frac{V_{g(r.c.)}}{V_{g(s.c.)}} \left[\frac{rm^3}{sm^3}\right] \tag{2-2}$$

where $V_{g(r.c.)}$ is the gas volume in reservoir conditions, while $V_{g(s.c.)}$ is the volume of the same gas quantity at standard conditions. $B_{g_{CO_2+\text{gas}}}$ is a formation volume factor of CO_2 and natural gas in a reservoir in the final injection conditions. The overall molar composition of the system, which involves a mixture of the original gas composition in the reservoir and CO_2, can be calculated using widely used cubic equations of state such as Peng-Robinson (Peng and Robinson, 1976), Redlich-Kwong (Soave, 1972) or Stryjek-Vera (Stryjek and Vera, 1986).

If the data regarding the produced gas is reliable, the previously mentioned equations prove valuable for static assessments of CO_2 storage capacity as an initial screening parameter (Jukić et al., 2021). Still, for estimating the dynamic changes in injectivity, additional details concerning the CO_2 injection strategy and reservoir properties become necessary (Vulin et al., 2018). The injectivity is primarily influenced by reservoir permeability, heterogeneity, and both reservoir and injection pressure. In regions where CO_2 saturation rises, there is a corresponding increase in relative permeability (Al-Abri et al., 2009; Hamza et al., 2021), leading to an enhanced injectivity. Low injectivity results in increased pressure, requiring more energy for CO_2 compression and leading to higher injection costs (Zhang et al., 2010). The immiscible process can take place when supercritical CO_2 displaces natural gas, a phenomenon described through the impact of relative permeability (Al-Abri et al., 2009). As described in Honari et al. (2016) and Kashefi et al. (2016), incorporating detailed microscopic aspects such as miscibility, wettability, and changes in interfacial tension within the rock-CO_2-natural gas-brine system into reservoir-scale simulation models is more challenging.

The risk of leakage is still the biggest challenge, but it could be managed through monitoring techniques such as saturation change from 4D seismic data and observations at monitoring wells. Proper well positioning and injection time using numerical modeling are also necessary for the prediction of leakage scenarios. The source of CO_2 near the storage field almost always ensures economic profit (van der Meer, 2005), which favors the development of the field investigated in this thesis.

2.2. Enhanced gas recovery

Unlike 'pure' geological storage in depleted gas reservoirs, enhanced gas recovery (EGR) is a technology that enables the start of the storage process even earlier during the production phase in the reservoir. Although its counterpart CO_2-EOR technology has been applied for more than 40 years, CO_2-EGR has been significantly developing only in the past 10 years. The reasons for the lack of research are cost constraints and complex reservoir mechanisms.

Apart from injecting CO_2 into oil reservoirs, it is more challenging to increase recovery in gas reservoirs due to the mixing of CO_2 with methane, i.e., the rapid breakthrough of CO_2 at production wells, which can significantly decelerate natural gas production (Hamza et al., 2021). The mentioned problems can be overcome by optimal positioning of the wells - injection wells should be placed in the lower layers of the reservoir, and production wells in the upper ones to enable gravity segregation. This logic in well placement is driven by CO_2 PVT behavior. CO_2 has two to six times higher density compared to natural gas in reservoir conditions, which dictates lower mobility than that of natural gas (methane) – this property should enable the migration of CO_2 towards the lower part of the reservoir and a slower exchange of CO_2 and methane from the reservoir. The CO_2 solubility factor in brine is higher than the solubility factor of methane in reservoir conditions, which also delays the CO_2-breakthrough (Khan et al., 2013).

The physical properties (e.g., density and viscosity) of CO_2 and natural gas differ significantly under typical reservoir conditions, which reduces their ability to mix, and thus the likelihood that natural gas from the reservoir is contaminated with injected CO_2. The difference in density between CO_2 and natural gas causes gravitational segregation, whereby the CO_2 (denser gas) sinks towards the bottom of the reservoir, creating a ‘gas cushion’ that favors the production of natural gas by pushing it (so-called piston-like displacement) towards production wells (Oldenburg et al., 2001). Figure 2-2 shows the described displacement mechanism. Moreover, the viscosity of CO_2 is higher than the viscosity of natural gas in reservoir conditions, which has a positive effect on displacement characteristics due to the favorable mobility ratio between CO_2 and natural gas (Oldenburg and Benson, 2002).

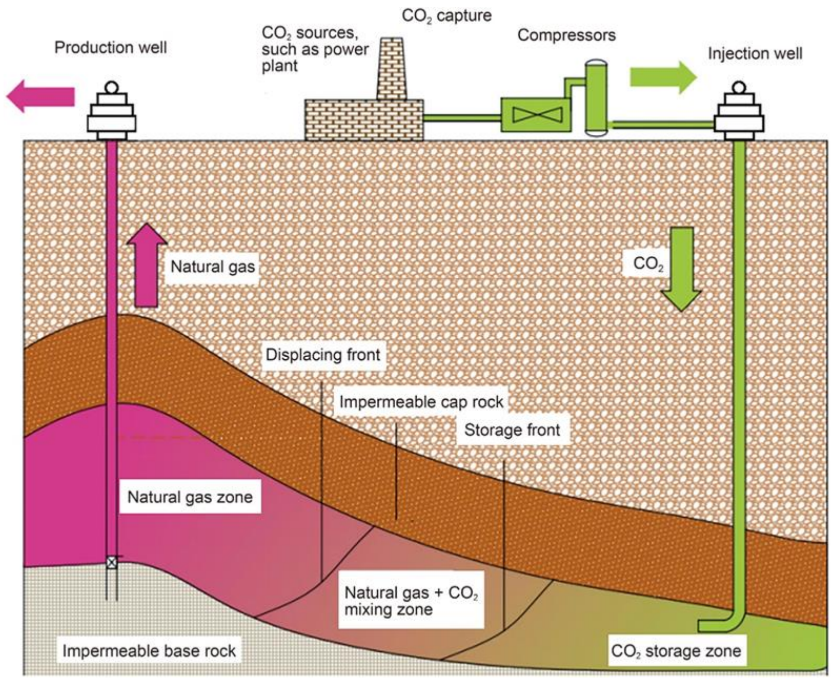

Figure 2-2 Schematic representation of the displacement mechanism of natural gas by CO_2 (Liu et al., 2022)

The differences in PVT properties between CO_2 and natural gas suggest that CO_2 has the potential to serve dual purposes in reservoir operations. Specifically, it can facilitate reservoir repressurization, which involves restoring the original pressure levels within the reservoir, while simultaneously displacing natural gas. This displacement process entails 'pushing' the natural gas to be recovered from the reservoir. Previous simulation studies (Jikich et al., 2003; Al-Hashami et al., 2005) have shown that natural gas production can be increased by 5 to 15% using CO_2-enhanced gas recovery (EGR). However, it was proven by the K12-B pilot project that 0.03 to 0.05 tons of natural gas can be obtained per ton of injected compressed CO_2 (van der Meer et al., 2006), which indicates the potential for CO_2 storage during gas production. These findings support the fact that depleted gas reservoirs have a greater capacity for permanent CO_2 storage compared to oil reservoirs. The ultimate recovery (which is proportional to the CO_2 storage capacity) from gas reservoirs is about 60% of the initial geological reserves, which is almost twice as much as the ultimate oil recovery.

The mixing of CO_2 and CH_4 can be managed and monitored by production control due to changes in CO_2 physical properties with pressure increase. A precise injection start estimation together with well positioning is essential to increase the permanent CO_2 storage through CO_2-

EGR. Using software and reservoir modeling with a significant amount of known data, this thesis will contribute to further investigation of that topic.

2.3. Potential of gas-condensate reservoirs

A characteristic gas-condensate reservoir from Northern Croatia (Drava Basin) was used to test whether it is possible to find optimal conditions for CO_2 permanent storage. Since there are more similar reservoirs in the same geographic area where the point source of CO_2 is already available (Molve Natural Gas Processing Plant), it was useful to investigate the potential of CO_2 storage in gas-condensate reservoirs.

At initial reservoir conditions, a gas condensate exists as a single-phase fluid (right of the critical point in Figure 2-3). Under specific conditions of temperature and pressure, the fluid undergoes separation into a gas phase and a liquid (retrograde) phase. During production, the most significant pressure declines typically take place near the production wells. When the pressure in a reservoir decreases to a threshold - saturation pressure or dew point, a liquid phase with heavier compounds separates from the solution. A continual reduction in pressure results in an expansion of the liquid phase until it reaches its maximum volume, after which the liquid volume begins to decrease (Fan et al., 2005).

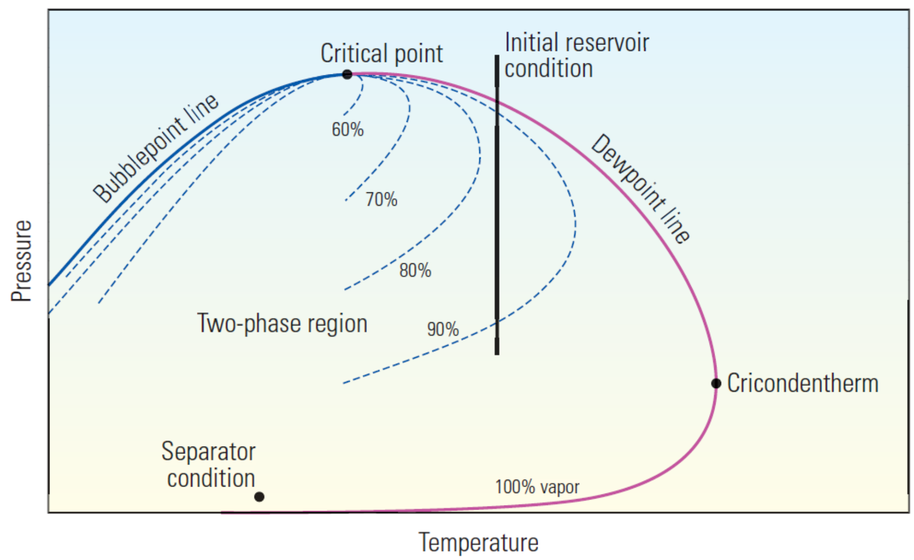

Figure 2-3 Phase diagram of gas-condensate system (Fan et al., 2005)

Hamza et al. (2021) investigated the economic attractiveness of EGR in such reservoirs. The implementation of CO_2 huff and puff techniques can enhance recovery factors, particularly when the condensate is close to the wellbore, but the optimization of the number of cycles is crucial for effectiveness. The injection rate could be regulated to produce condensate and methane. Furthermore, the low miscibility pressure between CO_2 and retrograde gas condensate offers the potential for CO_2 sequestration in these reservoirs.

Raza et al. (2018) came to similar results with the conclusion that gas-condensate formations have the best potential for long-term CO_2 immobilization, compared with dry and wet reservoirs. This can be ascribed to the small remaining gas volume, the phase behavior of the condensate gas-CO_2 mixture, favorable injectivity, and the lower concentration of methane mole fractions within the medium. It was found that the optimal choice of injection rate has the potential to maximize storage capacity in gas reservoirs, particularly in gas-condensate reservoirs.

3. METHODOLOGY

The hypothesis was tested using the available geological (static) model of an existing, producing gas-condensate reservoir. The model was created by using Schlumberger Petrel software package (2022). Different development strategies (dynamic models) were created in order to define optimal start time of injection and position of injection well. Following, the scenarios were compared to each other and to the base cases with focus on reservoir's potential for permanent CO_2 storage. The impact on gas production was also investigated. The main objectives of this research can be defined as follows:

- develop a consistent simulation model by achieving a sufficient historical match,
- define prediction strategies for base cases in which the current trend of production continues without CO_2 injection, and only after the end of production lifetime, the reservoir is converted into a CO_2 storage facility,
- define prediction strategies for CO_2 injection with simultaneous gas production,
- determine the influence of the injection well selection and the start time of CO_2 injection on the storage potential,
- evaluate the success of different CO_2 injection strategies with regard to the amount of permanently retained CO_2,
- compare different CO_2 injection strategies with baseline scenarios (without injection) regarding the produced gas,
- examine the influence of the injection well placement and the start time of CO_2 injection on the CO_2-breakthrough at the production wells, including the original reservoir fluid contamination,
- observe the effect of CO_2 storage after the production period on the reservoir pressure and storage potential regarding the different stages of reservoir depletion.

3.1. Study workflow

The simulation model was initialized based on the available geological model and reservoir and fluid data (properties), and by using correlations for insufficiently tested properties, such as rock compaction. Development strategies were created by setting different production conditions (constraints) in the wells (Figure 3-1). The results were analyzed to determine the influence of different production/injection wells placement and different CO_2 injection start time on the reservoir behavior. The observed parameters are: the amount of CO_2 injected and produced (stored CO_2), produced hydrocarbons, and the reservoir pressure.

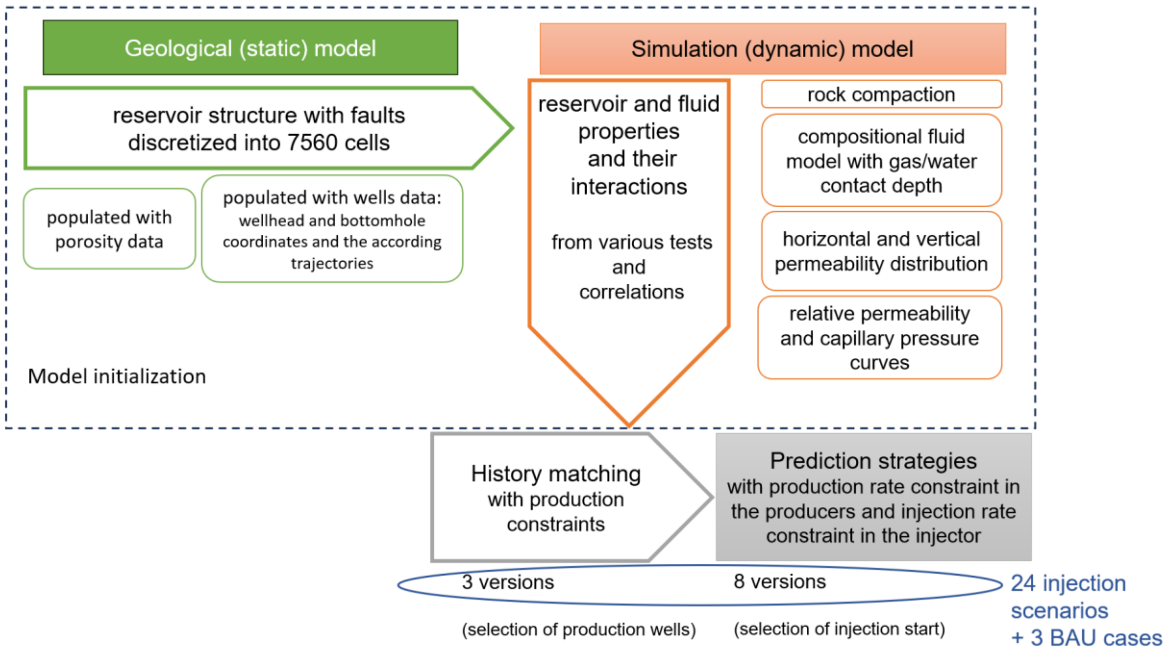

Figure 3-1**.** Conceptual workflow of simulation scenarios

3.2. Reservoir model

Reservoir modeling is a multidisciplinary process of creating a 3D representation of a reservoir. Based on well logging, laboratory measurements and seismic data, detailed model is created. Today, reservoir modeling is crucial in reservoir management and field development.

For the purpose of this study, 3D geological model of characteristic gas-condensate reservoir from Drava Basin was modeled in Petrel. The reservoir consists of Lower Miocene limestone and Triassic dolomite. The model was populated with porosity data based on real field seismic and well logging data as shown in Figure 3-2 together with three wells (B-6, B-8 and B-9) used in the simulation model. Considering the porosity distribution, reservoir properties around the deepest well (B-6) seem to be more favorable than the reservoir properties around other two wells. The original model of 569 800 cells was upscaled to 7560 cells (NX x NY x NZ = 28 x 30 x 9) in order to reduce the runtime while keeping the reliability of the model. Volume of the reservoir is approximately 300 x 10^6 m^3. After several test runs with different cell number it was determined that a satisfactory history match could be achieved with smaller models.

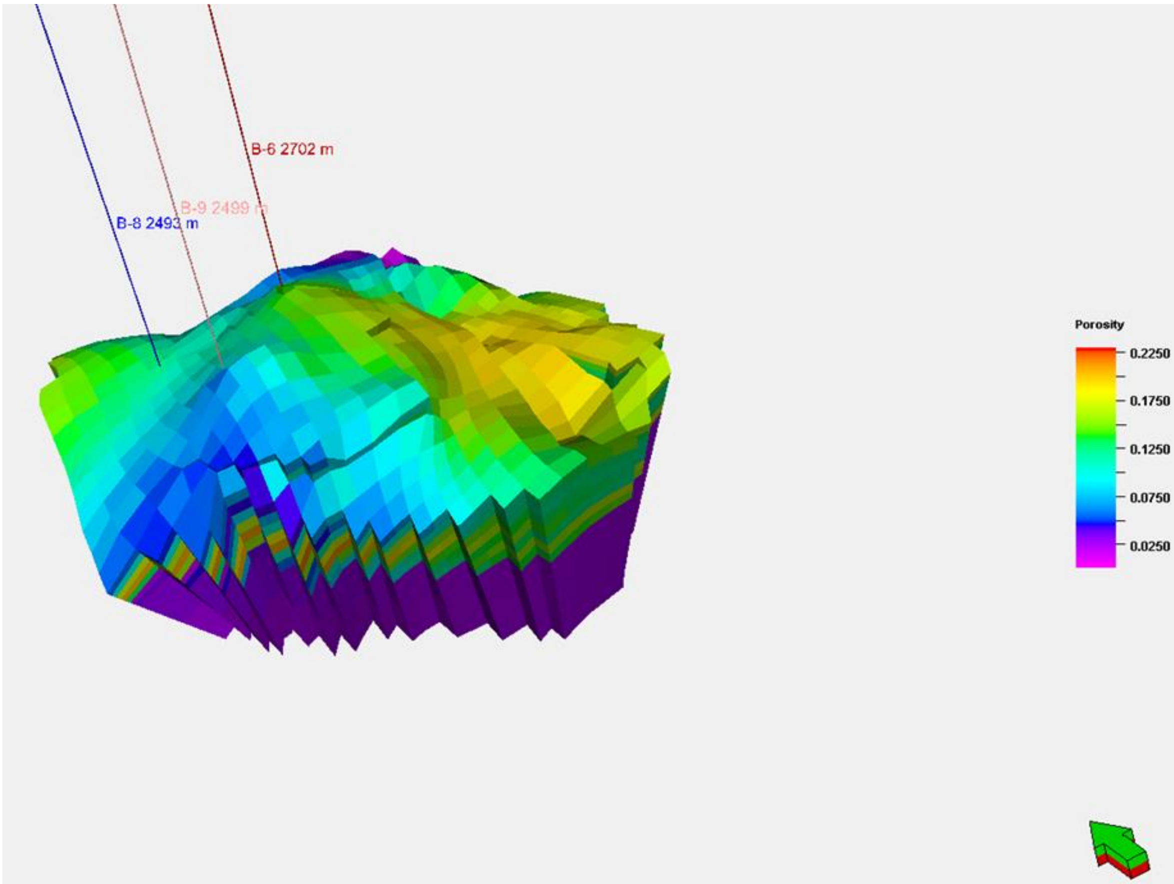

Figure 3-2 Spatial distribution of reservoir porosity

For the dynamic model requirements, a function was set to populate the model with permeability data and incorporate permeability anisotropy. Given the limited core measurements obtained from only two wells, the horizontal permeability in both the x and y directions was set as a log-normal distribution with a mean of 5 mD and a standard deviation of 1 mD. Vertical permeability (z-direction) was assumed to be 10 times smaller than the horizontal. For rock compaction, the correlations were used due to a lack of experimentally-tested data. Relative permeability curves, common for all dynamic models, are tuned to improve the accuracy of history matching.

The capillary pressure was set at 0 at the contact depth. The brine properties were obtained through correlations associated with the provided salinity of 30 000 ppm, and the system's compaction was assessed using the Newman correlation for a consolidated limestone as defined by Newman (1973).

The depth of the gas-water contact is at an absolute depth of -2525 m, which is determined based on interpretation of well-logs data. Other data for initialization are shown in Table 3-1.

Table 3-1 Reservoir reference depth, pressure, and temperature data

Depth of the gas/water contact	2525 m
Initial reservoir pressure at the reference depth (gas/water contact)	396 bar
Reservoir temperature	147 °C

During CO_2 injection, phase changes occur in the system due to different pressure and temperature conditions. For this reason, compositional simulation was used - it takes into account the composition of natural gas and the phase changes, which results in a more realistic distribution of the injected and original reservoir fluid and their mixture. The saturation-related effects in the observed reservoir are particularly interesting since the original reservoir fluid is a gas condensate with a CO_2 content of about 50%. A sample from one of the wells, collected before production started, was used for fluid characterization (Table 3-2).

Table 3-2. Reservoir gas composition

Component	**y_i, %mol**
N_2	1.98
CO_2	48.95
C_1	45.41
C_2	1.66
C_3	0.36
iC_4	0.13
nC_4	0.22
iC_5	0.07

Component	**y_i, %mol**
nC_5	0.07
C_6	0.16
C_7	0.15
C_8	0.11
C_9	0.10
C_{10+}	0.63
sum	100.00

3.3. History matching

Simulated results need to be matched with the production history of the actual reservoir. This is a procedure that can be characterized as an iterative approach including numerous simulation scenarios. Nevertheless, it includes the necessary modifications of the 3D geological model in order to reduce uncertainty (Varga, 2019).

Actual field historical production data was used to validate the geological model by simulating gas production and pressure decline for the first 16.5 years. A satisfactory history match of cumulative gas production was achieved (Figure 3-3) for all three base scenarios by changing the production rates in the producing wells in order to satisfy the material balance recorded in history of the reservoir.

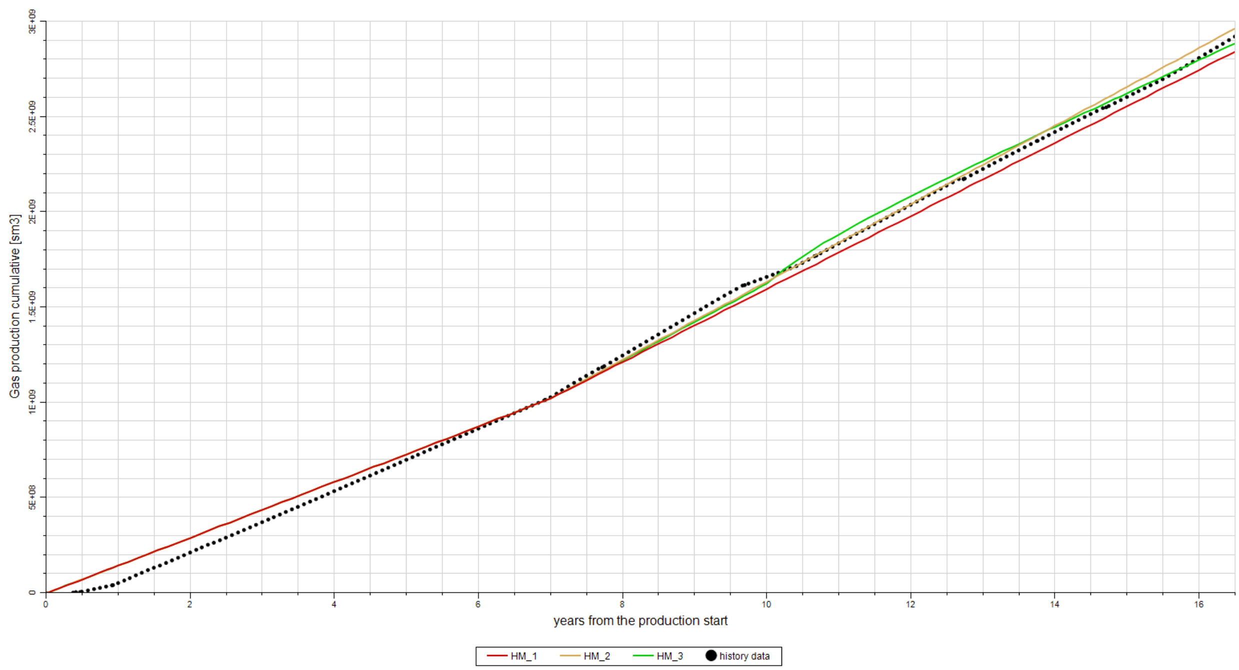

Figure 3-3 History matching for the base cases

After adjusting the reservoir parameters in the test runs and thus proving the reliability of the model by history matching, the model can finally be used to simulate prediction cases with different parameters set (injection/production well selection, injection start time, and production and injection rates).

3.4. Scenarios definition

Prior to simulation start, it was necessary to define the base (business as usual, BAU) cases and injection strategies. Three different base scenarios were defined, since there were three possible combinations of the existing wells. Two wells were used to simulate the production (history matching was achieved by adjusting the production rate constraint, as described in the previous chapter), while the third well was used for CO_2 injection after the production period.

The base cases (HM_BAU_STORE) consist of:

- production phase that follows historical data and at the same time serves to confirm the reliability of the input parameters (history matching, HM),

- predictive production phase which follows the production trend (production rate constraint) as historically recorded (business as usual, BAU),
- storage phase that begins after the end of production.

Theoretically, all wells could have been used for injection in the storage period, but it was decided to keep the same well pattern in HM_BAU_STORE cases and the corresponding simultaneous production and injection scenarios to be comparable. After a satisfactory history match of HM_BAU_STORE cases, each of them was used to create predictive injection scenarios that differ by the start of the injection – e.g. in CCS1_2000, the injection started at the same time as the production (Table 3-3).

Table 3-3. List of all simulated cases

	nomenclature according to the position of the injection well		
Years since the production start (start of the injection)	Injection well B-9	Injection well B-8	Injection well B-6
0	CCS1_2000	CCS2_2000	CCS3_2000
5	CCS1_2005	CCS2_2005	CCS3_2005
8	CCS1_2008	CCS2_2008	CCS3_2008
16	CCS1_2016	CCS2_2016	CCS3_2016
20	CCS1_2020	CCS2_2020	CCS3_2020
25	CCS1_2025	CCS2_2025	CCS3_2025
30	CCS1_2030	CCS2_2030	CCS3_2030
35	CCS1_2035	CCS2_2035	CCS3_2035
40	*HM1_BAU_STORE*	*HM2_BAU_STORE*	*HM3_BAU_STORE*

It is important to note that in all CCS1 cases the injection well is B-9, while B-6 and B-8 are producers. In CCS2 cases B-8 is the injector, while in CCS3 cases it is B-6.

Although an attempt was made to control the CO_2 injection by constraining the bottom hole pressure in the injection well, the approach of volumetric fluid replacement at the reservoir level was chosen for the period of simultaneous production and CO_2 injection. This was done primarily to avoid excessive increase in the reservoir pressure. Production constraints were selected to correspond the production of the base cases as closely as possible. Gas production ends after 40 years in all cases (which is a reasonable lifetime for reservoirs of such kind). Subsequently, a dedicated ('pure') CO_2 storage was simulated for the period of 60 years. In the 'pure' storage period, the injection rate was set to 150 000 Sm^3/day (surface conditions, as opposed to previously used reservoir rate in the period of simultaneous gas production and CO_2 injection) as a realistic injection rate for 1 well in a depleted reservoir.

3.5. Storage potential indicators

The efficiency of permanent storage of CO_2 in the reservoir for each scenario is quantified through retention (Equation 3-1) and storability (Equation 3-2), parameters based on the total injected and produced amounts of CO_2 in the production period with simultaneous injection. Retention is calculated as difference between the CO_2 injected and the CO_2 produced, while the storability is calculated as the ratio of the retention and CO_2 produced (Arnaut et al., 2021). The primary objective of this thesis is to focus on the permanent storage of CO_2, rather than emphasizing the enhancement of hydrocarbon recovery. Therefore, positive values of both parameters are required while high values are desirable in order to achieve carbon-negative scenarios (more CO_2 is injected than produced).

$$Retention = injected\ CO_2\ volume - produced\ CO_2\ volume\ in\ the\ injection\ period,\ (\mathrm{m}^3) \tag{3-1}$$

$$Storability = \frac{Retention}{Produced\ CO_2\ volume\ in\ the\ injection\ period},\ (\text{-}) \tag{3-2}$$

4. RESULTS AND DISCUSSION

To compare the results of all cases, the following parameters were analyzed: natural gas cumulative production without CO_2, CO_2 cumulative production, retention, storability, and pressure behavior.

4.1. Production indicators

All prediction cases were compared with respect to the total amount of the hydrocarbon component of the produced gas to determine the injected CO_2-breakthrough at the production wells, i.e., to what extent CO_2 injection degrades the composition of the original reservoir fluid. In this way, the success of each scenario in terms of enhancing hydrocarbon production can be evaluated (Figure 4-1, Figure 4-2, and Figure 4-3), which is especially interesting since a high content of CO_2 is already present in the original reservoir fluid.

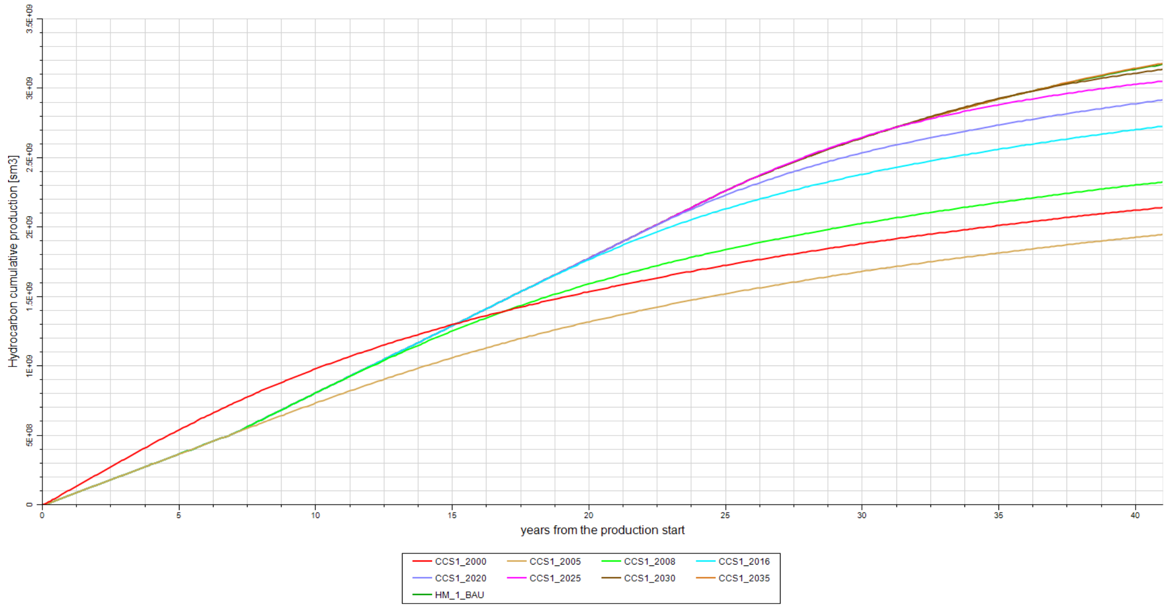

Figure 4-1 Natural gas cumulative production without CO_2 in the gas composition for CCS1 scenarios (B-9 is injector)

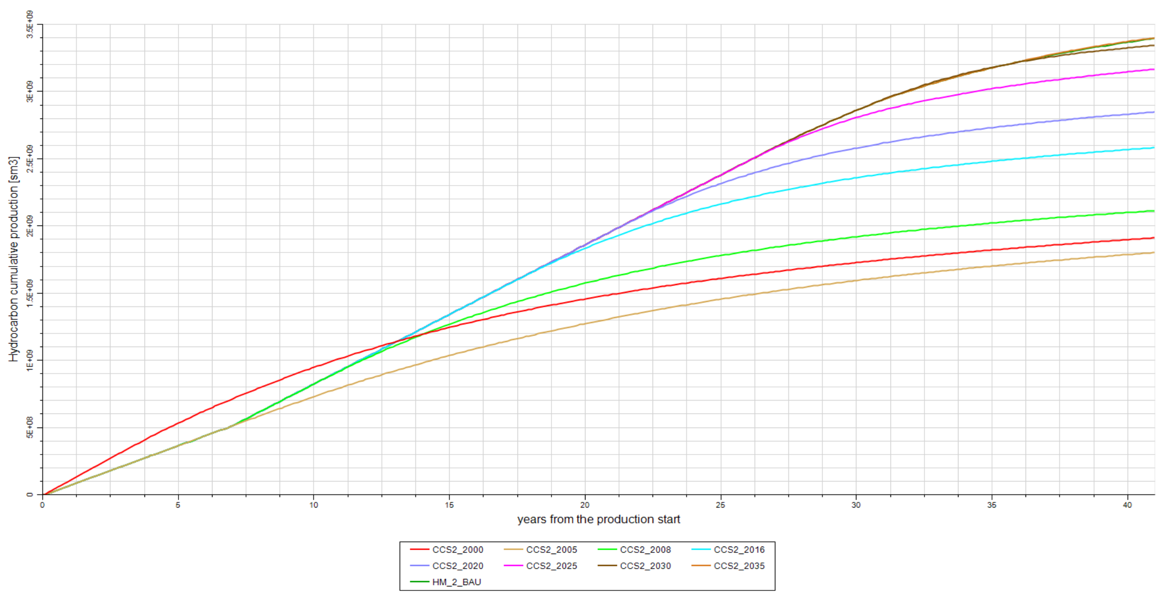

Figure 4-2 Natural gas cumulative production without CO_2 in the gas composition for CCS2 scenarios (B-8 is injector)

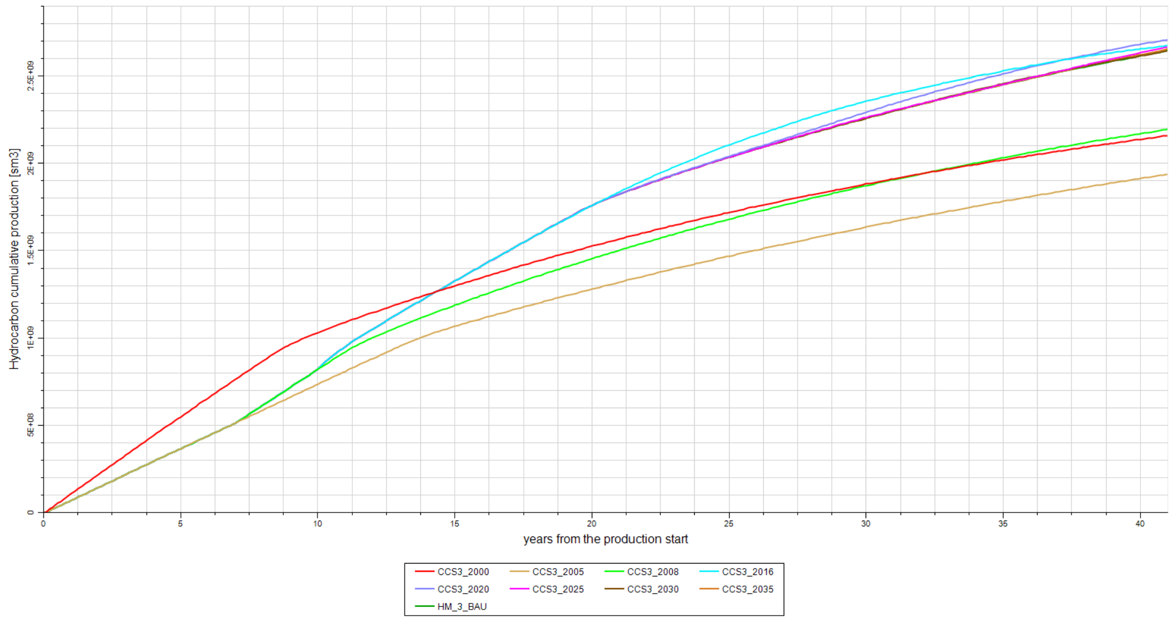

Figure 4-3 Natural gas cumulative production without CO_2 in the gas composition for CCS3 scenarios (B-6 is injector)

For all CCS1 and CCS2 scenarios, the base cases without CO_2 injection (HM_1_BAU and HM_2_BAU) produce cumulatively the greatest amount of 'clean' natural gas (without CO_2 in the composition) compared to all injection scenarios, except for the latest injection start (35 after the production start), which can be explained by the minimum original fluid contamination. However, if the injection starts simultaneously with the start of production (i.e., strategies CCS1_2000 and CCS2_2000), production of 'clean' natural gas is higher compared to the base cases, but only for the first fifteen years. The total produced amount is still lower than the base cases, which is explained by CO_2-breakthrough in the production wells. Nevertheless, the total produced quantities very close to those of the base cases are observed in the cases where the injection starts when the reservoir is already depleted (CCS1_2030, CCS1_2035, CCS2_2030, and CCS2_2035). Similar results were obtained by Clemens and Wit (2002), whose simulations show that it is advisable to deplete the gas reservoir as much as possible before injecting CO_2 if the goal is to maximize the total amount of natural gas recovered. The same conclusions were reached by Jikich et al. (2003), whose research examined the influence of different EGR timings and found that a later start of injection leads to the maximal ultimate recovery.

The aforementioned phenomenon can be observed in the third arrangement of wells (CCS3), where well B-6 is converted to injector. In this set of scenarios, more cases yield a higher cumulative production of ‘clean’ gas than the base one. Such results can be explained by the positioning of injection and production wells. In the cases where the deepest well (B-6) is the injector, pure gas production is notably lower compared to other two arrangements. This could mean that this well has the best productivity (cumulatively produced pure gas amounts are higher in cases where B-6 is one of the producers), and also the best injectivity considering that the cases where B-6 is the injector yield the best retention (CO_2 injected minus CO_2 produced), probably due to the most favorable position on the structure. Further optimization of enhanced gas production would be achieved by varying the injection and production rates considering the optimal position of the injection well and later injection start (less contamination).

It is possible to conclude that later injection starts increase the ultimate gas recovery. However, a later start of injection has a different effect on the CO_2 storability within the reservoir. Aside from the preceding criterion of ultimate recovery, which impacts the economic profitability of the project, it is essential to take into account other elements that indicate the reservoir's suitability for simultaneous production and storage.

The produced amounts of CO_2 follow the same trend for all three well placement options (Figure 4-4). The base cases (HM_1_BAU_STORE, HM_2_BAU_STORE, and HM_3_BAU_STORE) have the lowest production of CO_2 since there is no injection – the produced CO_2 comes only from the composition of the reservoir fluid. The highest production of CO_2 is achieved in strategies with earlier injection start, which confirms that CO_2-breakthrough is inevitable to a certain extent but can be mitigated with different strategies in terms of production and injection rate.

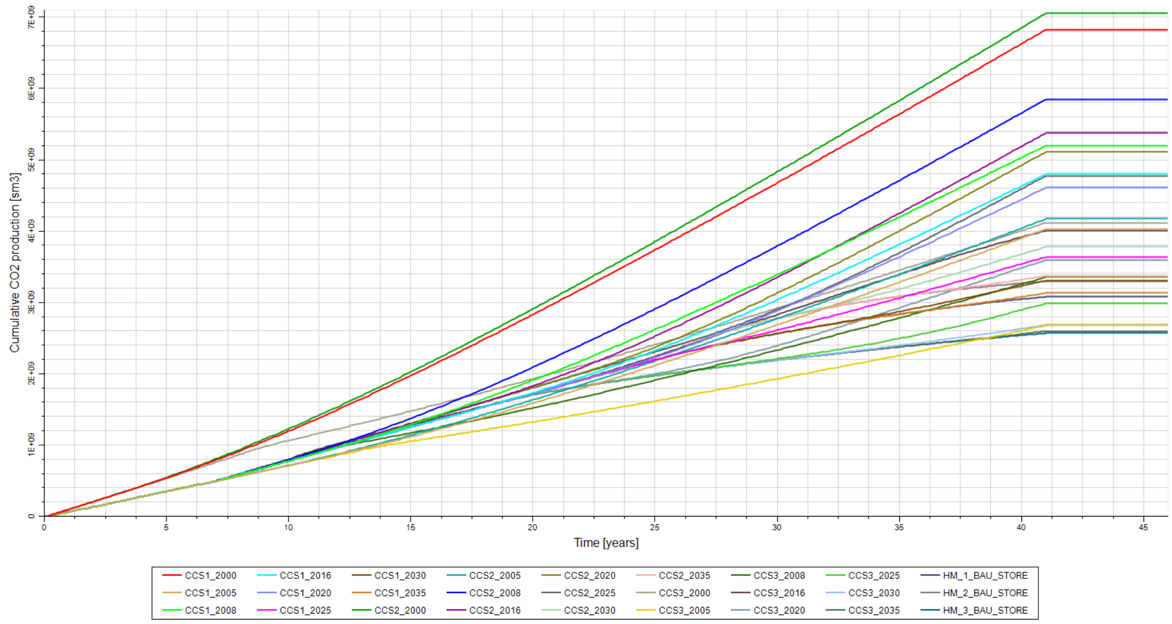

Figure 4-4 CO_2 cumulative production for all scenarios

4.2. Retention

Contrary to the previously evaluated parameters, retention should be observed not only in the production stage of the field (the first 40 years) but also in the period when the reservoir is repurposed for 'pure' CO_2 storage (the last 60 years) (Figure 4-5). A positive retention value (more CO_2 injected than produced) is required to confirm that permanent CO_2 storage has been achieved.

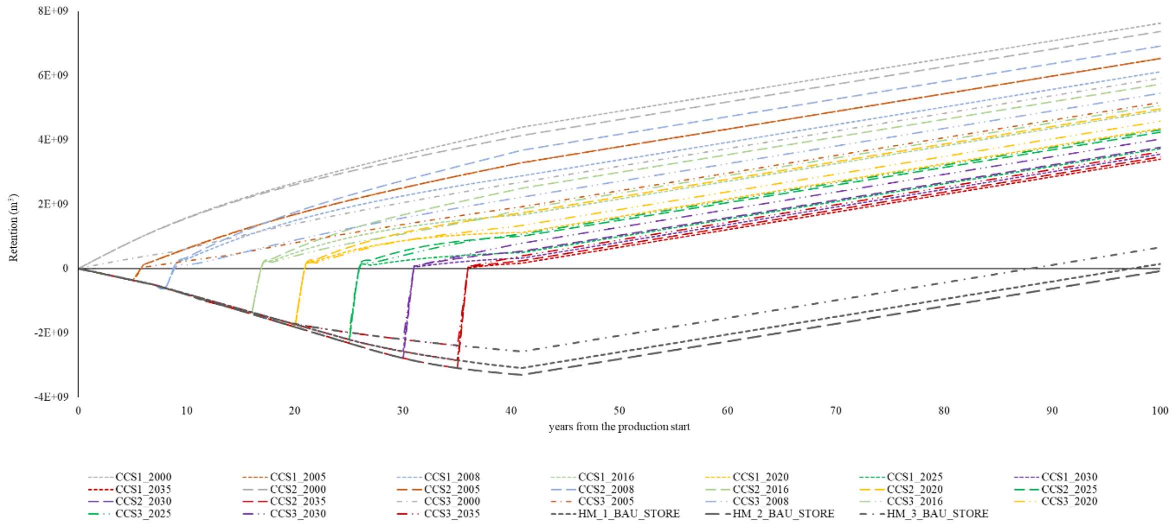

Figure 4-5 Retention for all scenarios

All scenarios generally follow the same retention trend but differ in amounts due to the different amounts of CO_2 injected and produced. In scenarios with simultaneous production and injection, from the injection start onwards, all scenarios have achieved positive retention values.

In the CCS3 scenarios, for earlier injection starts significantly lower retentions were achieved compared to the CCS1 and CCS2 scenarios. This effect is reversed as the injection starts later, so for the latest injection start (35 years after the production start), strategies CCS3 yield the highest retention.

Comparing individual cases of each well placement version, the highest final retention is generally achieved in cases with earlier injection start since the total injected amounts of CO_2 are the highest. However, it can be observed that in CCS2 and CCS3, cases starting with the injection 8 years after the production start yield cumulatively better retention compared to those starting 5 years after the production start (CCS2_2005 has lower retention compared to CCS2_2008 and CCS3_2005 has lower retention compared to CCS3_2008).

Considering the base cases, the final retentions are rather low. The obtained results show that simultaneous injection and production increase reservoir's capacity for permanent CO_2 storage.

Negative values of retention imply that the case is not carbon-negative (i.e., more CO_2 is produced than injected), and for this specific field negative retention is inevitable as the original reservoir fluid has high CO_2 content, meaning that the only way to achieve carbon-negativity is to inject CO_2.

4.3. Storability

Storability is also observed throughout the production stage of the field as well as through the period when it is converted to 'pure' storage.

The analysis of storability for CCS1 scenarios (Figure 4-6) showed that better results were achieved for earlier injection start if only the production period is considered. This is in line with retention results (these cases have the highest retention as well). A trend of decreasing storability over time (in the production period) was also observed for each injection scenario, which can be explained by the increasing CO_2-breakthrough over time.

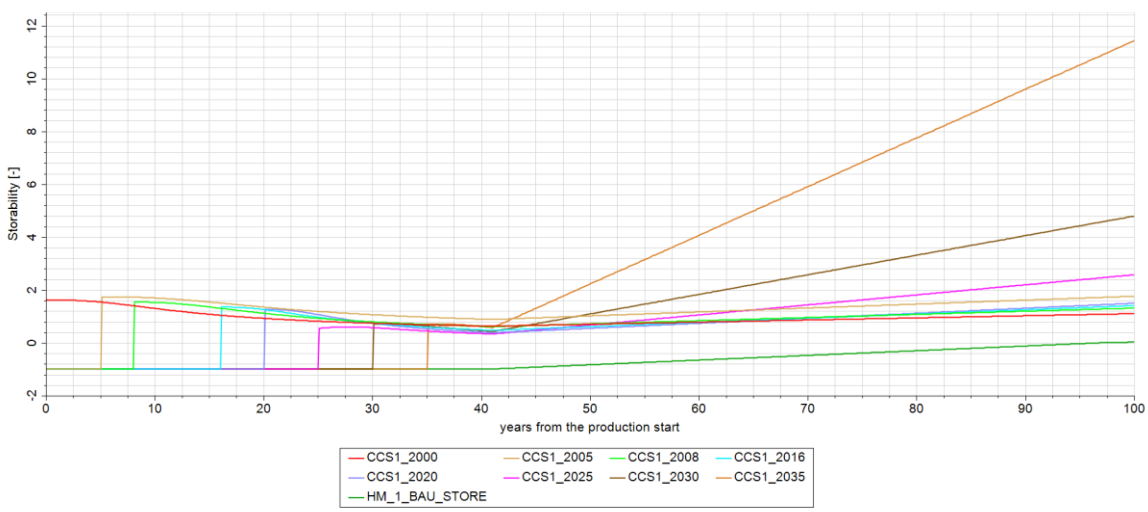

Figure 4-6 Storability for CCS1 scenarios (B-9 is injector)

In CCS2 (Figure 4-7) and CCS3 (Figure 4-8) scenarios, slightly different storability results are obtained than in CCS1.

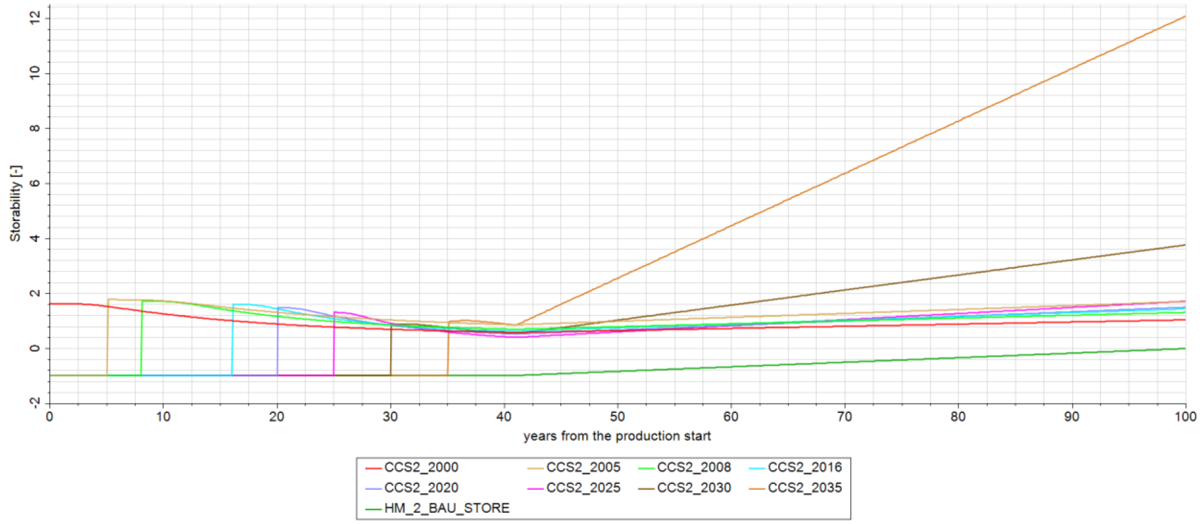

Figure 4-7 Storability for CCS2 scenarios (B-8 is injector)

Overall, scenarios when the injection starts later give the best storability results in 'pure' storage period, which can be explained by faster decrease trend of CO_2 production compared to the retention increase trend. The highest storability value is reached in the cases in which the injection started 35 years after the production start (CCS1_2035, CCS2_2035, and CCS3_2035) and has by far the highest amount compared to the other years of the injection start.

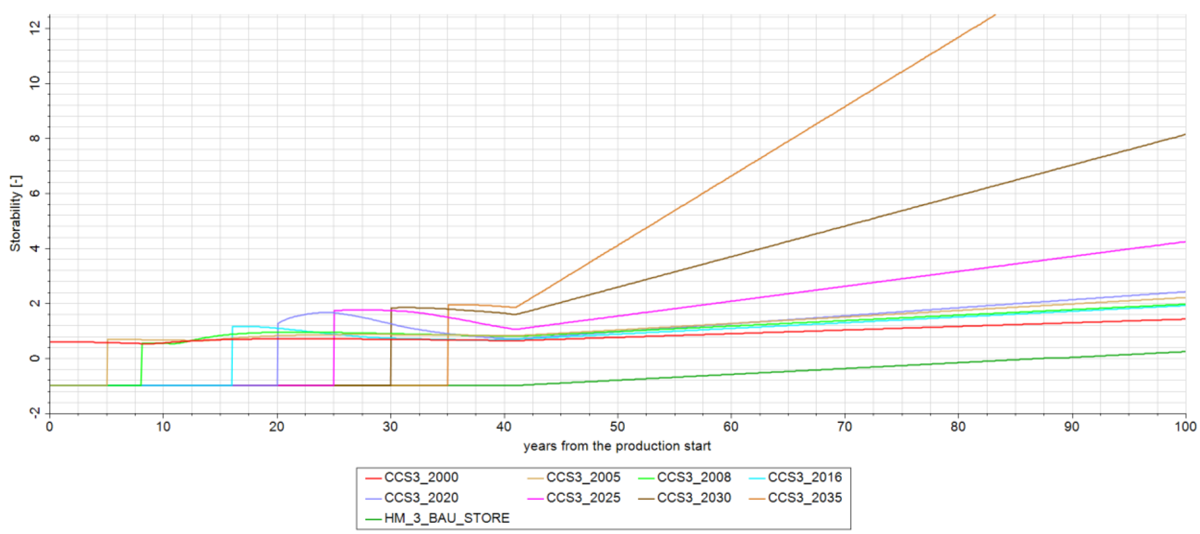

Figure 4-8**.** Storability for CCS3 scenarios (B-6 is injector)

The base cases exhibit the lowest storability, and this should not be taken as the main criterion in storage potential assessment as these low values can be attributed to the fact that the period without any injection whatsoever is very long in the base cases so it is virtually impossible to inject so much CO_2 (with the given rate) in the 60 years of pure storage to offset the amounts of CO_2 produced during the 40-year-long production period. As storability is not a representative indicator for the base case scenarios, the cumulatively injected amounts of CO_2 were observed because all CO_2 injected will be retained, i.e., permanently stored (Figure 4-9) considering there is no production. It can be observed that the injected amount of CO_2 is the same in all base cases due to the injection constraint (150 000 Sm^3/day).

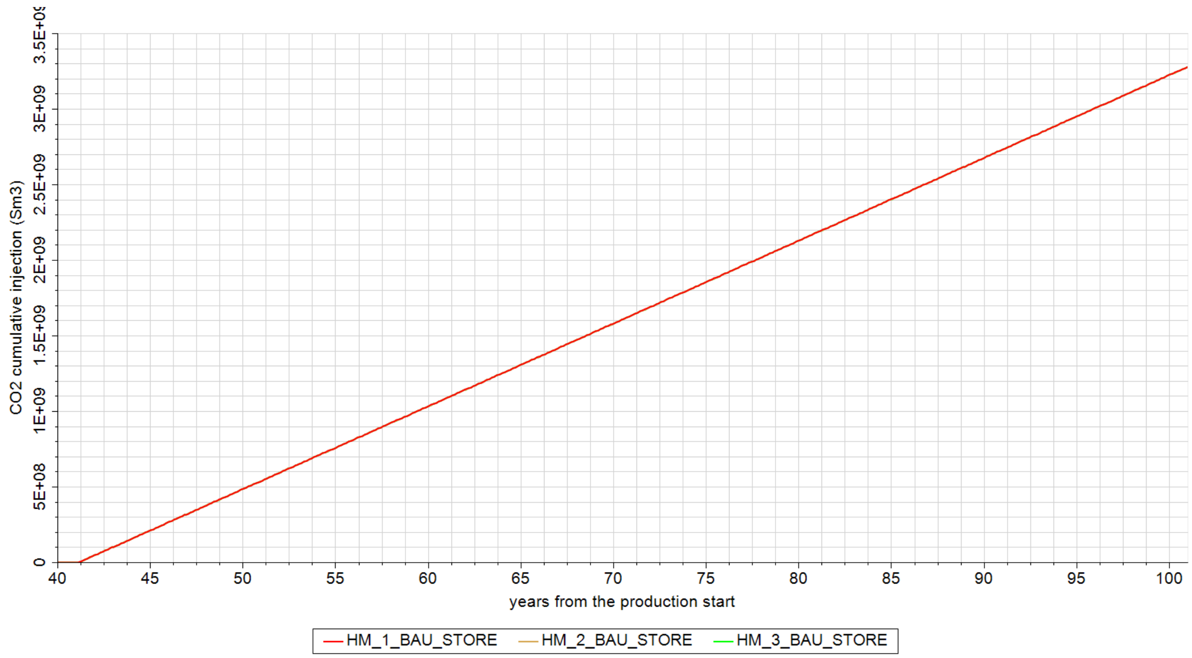

Figure 4-9 Cumulatively injected (stored) CO_2 in the ‘pure’ storage scenarios

4.4. Pressure behavior

The amounts from Figure 4-5 do not represent the maximum storage capacity of the reservoir since the reservoir pressure does not reach the initial reservoir pressure even after 60 years of injection (Figure 4-10), which implies that there is still room in the reservoir for CO_2 injection in ‘pure’ storage scenarios.

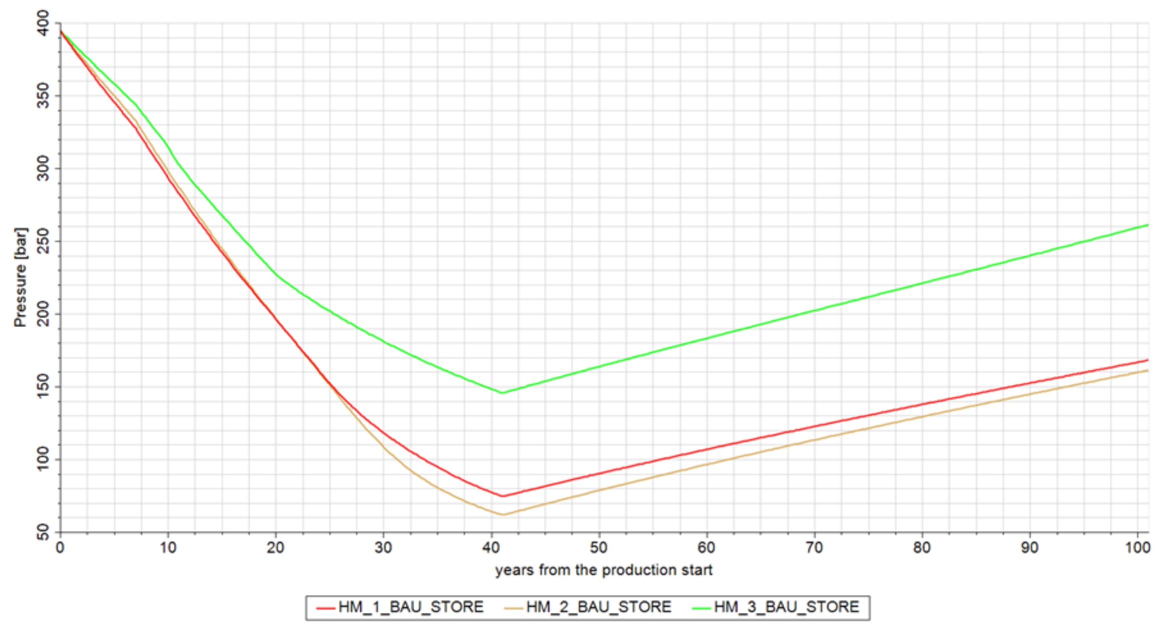

Figure 4-10 Average reservoir pressure in 'pure' storage scenarios

It is observed that in some CCS cases, the reservoir pressure would increase above the initial reservoir pressure (Figure 4-11) relatively shortly after converting the reservoir to storage. However, in most cases, the reservoir could be used as storage for a long period after the production ends.

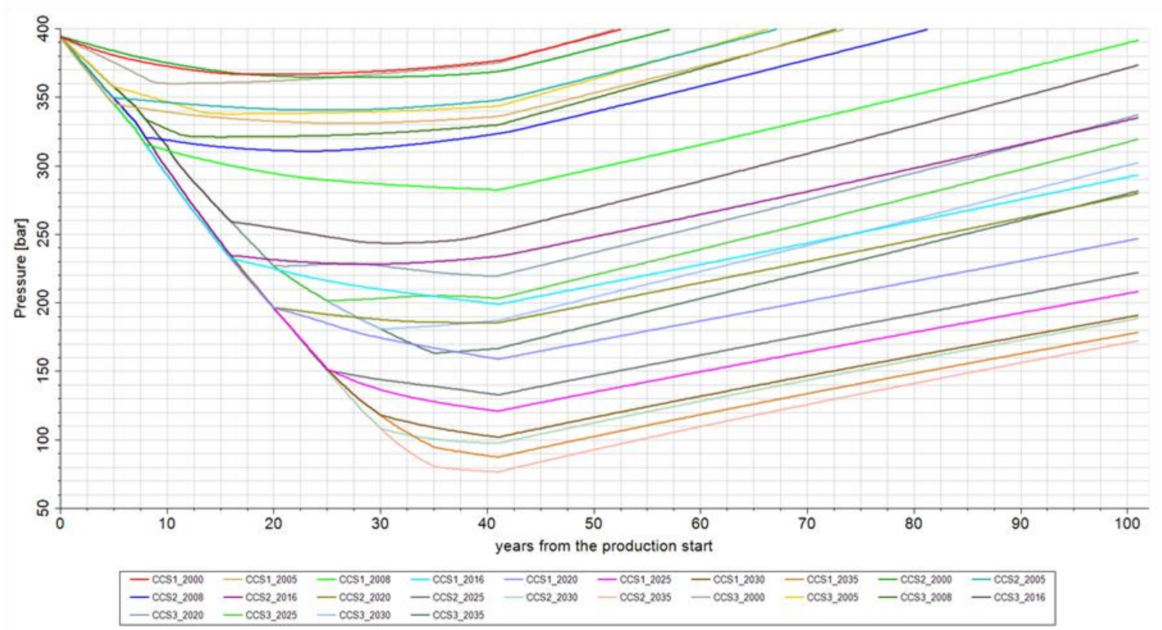

Figure 4-11 Reservoir pressure for all CCS cases

Examining the relationship between retention and pressure for each scenario is advantageous as it facilitates a comprehensive assessment of the reservoir's potential for CO_2 storage. Because of high content of CO_2 in original natural gas composition, in BAU_STORE scenarios retention decreases (becomes negative) until the CO_2 injection starts (Figure 4-12). It could be seen that pressure and retention increase with injection in all cases.

In early injection scenarios, it could be concluded that the reservoir is almost full and there is no more room for further injection. The main advantage of early injection should be favorable discounted cash flow, since the revenues from gas production are higher, and in ‘pure’ storage period no capital investments are needed. Nonetheless, if a greater amount of CO_2 is aimed to be stored even 60 years after reservoir conversion to a ‘pure’ storage project, it is advisable to postpone the injection start until the end of the reservoir production lifecycle.

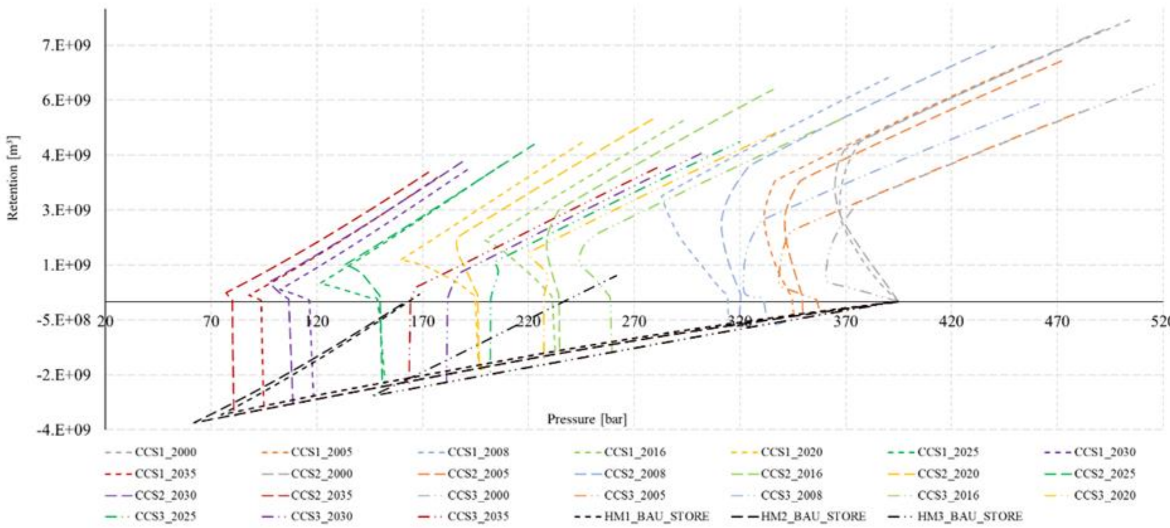

Figure 4-12 Retention vs. pressure for all CCS cases

5. CONCLUSION

A total of 27 cases were simulated and in all scenarios production stops after 40 years, after which the reservoir is converted into CO_2 storage site ('pure' storage). The hypothesis is confirmed - by carefully selecting the position of the injection well and accurately identifying the appropriate start time for injection, it is feasible to attain the optimum conditions for permanent carbon dioxide storage in accordance with the retention criterion. The conclusions derived from the analysis of simulation strategies are:

- starting CO_2 injection at an early stage leads to increased retention of CO_2, regardless of the well pattern adopted. This is particularly beneficial due to the high CO_2 content in the original gas, resulting in a reduced CO_2 footprint of the gas-producing reservoir,
- all scenarios with simultaneous production and injection achieved carbon negativity very soon after the injection start, and only in one of the BAU cases larger amounts of CO_2 were produced than injected (negative retention), but this can be explained by the already mentioned high content of CO_2 in the initial composition of natural gas,
- the project involving the simultaneous storage of CO_2 and gas production in the specific field may prove to be successful due to the abundant availability of CO_2, which is the primary cost factor. This availability is particularly noteworthy as it may be sourced from nearby reservoirs that also have a high concentration of CO_2.

The choice of the optimal strategy depends on the desired goal - to increase the recovery, a better option is later injection start times, and for storage, better results are achieved by starting injection as early as possible. This can be further optimized by varying CO_2 rates and setting different production constraints.

It is important to note that due to the representation of realistic conditions, there is no investment in drilling new wells, and the thesis only analyzed options with the existing infrastructure in the form of wells and technology.

The thesis presents the results of the simulation and analysis of the CO_2 flow on a realistic (heterogeneous and complex) model of a real reservoir. It is shown that despite the extremely unfavorable composition properties (typical for gas-condensate fields in the observed area; over 50% of CO_2 is initially found), the entire system can be carbon-negative using the right time of

CO_2 injection. This gives reason for optimism, because the results would be far more favorable if it were injected into reservoirs with less CO_2 in the initial composition. Also, scenarios in which CO_2 is injected and stored during production are completely justified, since this concept adds value to the production field. Furthermore, in the context of CCS, technology is available immediately, which overcomes the problem of standard estimates, in which injection would start within five years after the depletion of hydrocarbon reservoirs (whose production end also has to wait). Also, in case of deep saline aquifers, the first new projects are expected only within ten years after the initial assessments of the storage capacity.

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IZJAVA

Izjavljujem da sam ovaj rad izradila samostalno na temelju znanja stečenih na Rudarsko–geološko–naftnom fakultetu služeći se navedenom literaturom.

STATUTORY DECLARATION

I declare that I wrote this Thesis and performed the associated research myself, using the knowledge gained at the Faculty of Mining, Geology and Petroleum Engineering and the literature cited in this work.

Valentina Kružić

Valentina Kružić

KLASA: 602-01/23-01/206
URBROJ: 251-70-12-23-2
U Zagrebu, 07.12.2023.

Valentina Kružić, studentica

RJEŠENJE O ODOBRENJU TEME

Na temelju vašeg zahtjeva primljenog pod KLASOM 602-01/23-01/206, URBROJ: 251-70-12-23-1 od 24.11.2023. priopćujemo vam temu diplomskog rada koja glasi:

OPTIMAL CONDITIONS FOR CO_2 PERMANENT STORAGE IN A PRODUCING GAS RESERVOIR

Za mentora ovog diplomskog rada imenuje se u smislu Pravilnika o izradi i obrani diplomskog rada prof. dr. sc. Domagoj Vulin nastavnik Rudarsko-geološko-naftnog-fakulteta Sveučilišta u Zagrebu i komentoricu dr. sc. Lucija Jukić.

Mentor:

Vulin

(potpis)

prof. dr. sc. Domagoj Vulin

(titula, ime i prezime)

Predsjednica povjerenstva za završne i diplomske ispite:

(potpis)

izv. prof. dr. sc. Karolina Novak Mavar

(titula, ime i prezime)

Jukić

(potpis)

dr. sc. Lucija Jukić

(titula, ime i prezime)

Prodekan za nastavu i studente:

(potpis)

izv. prof. dr. sc. Borivoje Pašić

(titula, ime i prezime)