

USING CARBON DIOXIDE AS A CUSHION GAS IN NATURAL GAS
STORAGE IN DEPLETED HYDROCARBON RESERVOIRS

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

ÖZLEM BÜYÜKEKİNCİ

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

DECEMBER 2024

Approval of the thesis:

**USING CARBON DIOXIDE AS A CUSHION GAS IN NATURAL GAS
STORAGE IN DEPLETED HYDROCARBON RESERVOIRS**

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ABSTRACT

USING CARBON DIOXIDE AS A CUSHION GAS IN NATURAL GAS STORAGE IN DEPLETED HYDROCARBON RESERVOIRS

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Master of Science, Petroleum and Natural Gas Engineering

Supervisor: Assist. Prof. Dr. Betül Yıldırım

December 2024, 163 pages

Underground gas storage (UGS) technology is critical for meeting fluctuations in natural gas demand, requiring efficient and safe storage processes while also considering its environmental impact. In this context, the thesis study aimed to numerically model (using Computer Modelling Group (CMG)) the effects of using carbon dioxide (CO₂), a greenhouse gas with a significant share in emissions, as cushion gas in depleted oil/gas formations for natural gas storage. The modelling study assessed the effects of different cushion gas injection ratios (0%, 20%, 30%, 40%) at different times (1st, 5th, and 10th years), based on natural gas and CO₂ production data, as well as the molar fractions of these gases in the reservoir. The results obtained from the study indicated that using CO₂ as cushion gas at optimal ratios in underground gas storage projects could provide a more efficient gas storage and recovery process, offering higher natural gas recovery rates compared to only natural gas injection. Furthermore, the study proposed that using CO₂ as cushion gas at a 30% ratio might also contribute to the recovery of CH₄ gas in place that could not be produced from the reservoir.

Keywords: Underground Gas Storage, Cushion Gas, Carbon Dioxide, Working Gas, Methane, Depleted Hydrocarbon Reservoirs, Field-Scale Data Analysis

ÖZ

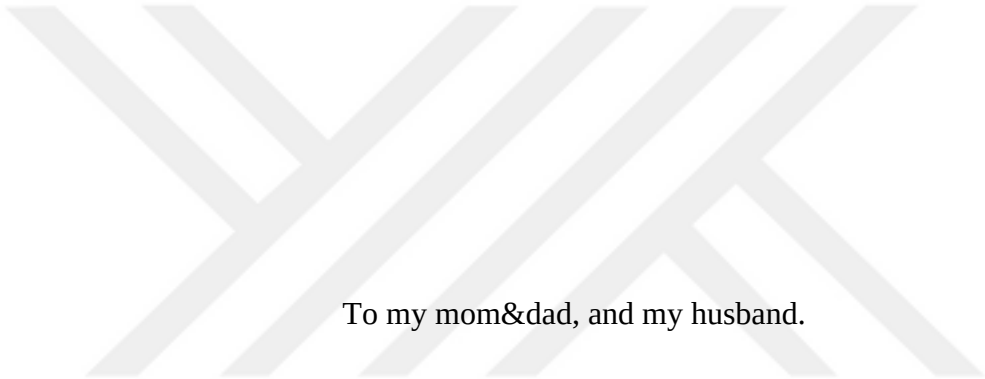
TÜKENMİŞ HİDROKARBON REZERVUARLARINDA DOĞAL GAZ DEPOLAMADA KARBONDİOKSİTİN YASTIK GAZI OLARAK KULLANIMI

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Aralık 2024, 163 sayfa

Yeraltı gaz depolama (UGS) teknolojisi, doğal gaz talebindeki dalgalanmaları karşılamak için kritik olup, çevresel etkilerini de göz önünde bulundurarak, verimli ve güvenli depolama süreçleri gerektirir. Bu bağlamda gerçekleştirilen tez çalışması; sera gazı emisyonlarında büyük payı olan karbondioksit gazının (CO_2) tükenmiş petrol/gaz formasyonlarında doğal gaz depolamada yastık gazı olarak kullanımının etkilerini numerik modelleme ile (Computer Modelling Group (CMG)) incelemeyi hedeflemiştir. Modelleme çalışmasında farklı yastık gazı enjeksiyon oranlarının (0%, 20%, 30%, 40%) zamana bağlı (1., 5., ve 10. senelerdeki) etkileri, doğal gaz ve karbondioksit üretim verilerinin yanı sıra bu gazların rezervuardaki mol fraksiyonları ışığında değerlendirilmiştir. Çalışmadan elde edilen sonuçlar, CO_2 'nin yeraltı gaz depolama projelerinde belirlenen optimum oranlarda yastık gazı olarak kullanımının, yalnızca doğal gaz enjeksiyonuna kıyasla daha yüksek oranlarda doğal gaz kurtarımı sağlayarak verimli bir gaz depolama ve geri üretim süreci sunabileceğini göstermiştir. Buna ek olarak, çalışma, %30 oranında CO_2 'nin yastık gazı olarak kullanılmasının, rezervuardan üretilmeyen CH_4 gazının yerinden geri kazanılmasına da katkı sağlayabileceğini öne sürmüştür.

Anahtar Kelimeler: Yeraltı Gaz Depolama, Yastık Gazı, Karbondioksit, Çalışma Gazı, Metan, Tükenmiş Hidrokarbon Rezervuarı, Saha Ölçeğinde Veri Analizi



To my mom&dad, and my husband.

ACKNOWLEDGMENTS

I am grateful to my thesis advisor, Assist. Prof. Dr. Betül Yıldırım, for her guidance, sharing her knowledge, and providing valuable suggestions throughout my study. I would like to thank her for believing in me from the beginning to the end of the thesis process and for her constant support in every circumstance.

I would like to express my endless gratitude to my mother, who has always supported me, did everything she could for my education, taught me what it means to love unconditionally, and shaped who I am today, as well as to my father, who, even though he is no longer with me, has always been by my side in spirit.

I want to thank my husband for his unwavering love, patience, and support throughout my academic journey. His encouragement and understanding have been invaluable, and I am truly grateful for his presence in my life. Without his constant support, this achievement would not have been possible.

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CHAPTER 1

INTRODUCTION

1.1 Underground Gas Storage

Underground gas storage (UGS) can be defined as the storage of gas in underground reservoirs such as depleted gas fields, aquifers, and salt caverns.

Underground gas storage aims to establish a delicate balance between the fluctuations in supply and demand within the natural gas market. Beyond merely serving a storage function, UGS functions as part of a strategy to enhance energy security, ensure price stability, and bolster the resilience of consumers and industries dependent on this indispensable energy source. Underground gas storage facilitates the management of gas supply to cope with the uncertainty of fluctuating demand. During periods of declining demand, excess natural gas is carefully injected into these underground storage facilities to create reserves for future use. Conversely, during times of increased demand, such as seasonal variations, sudden spikes in consumption, or unforeseen circumstances, the stored gas is rapidly withdrawn to ensure the uninterrupted continuity of the supply chain. Additionally, the significance of underground gas storage goes beyond merely maintaining a supply-demand balance. Due to their capacity to store large quantities of natural gas, underground storage facilities ensure preparedness for supply disruptions arising from geopolitical instabilities, infrastructure failures, or natural disasters. During times of crisis, the timely release of stored gas prevents potential shortages. Furthermore, it plays a critical role in controlling price fluctuations, thereby bringing stability to the natural gas market. (Eren, 2013).

1.2 Natural Gas Production, Consumption and Storage in Türkiye

Türkiye's energy landscape is dominated by natural gas, with natural gas consumption increasing rapidly over the past few years. As of December 31, 2023, the population residing in Türkiye increased by 92,824 individuals compared to the previous year, reaching a total of 85,372,377 people (TÜİK,2024). In parallel with this, natural gas consumption in February 2024 increased by 5% compared to the same period of the previous year, reaching 6.4 billion cubic meters. Consumption in February 2024 increased by approximately 112 million cubic meters compared to the previous month (GAZBİR, 2024).

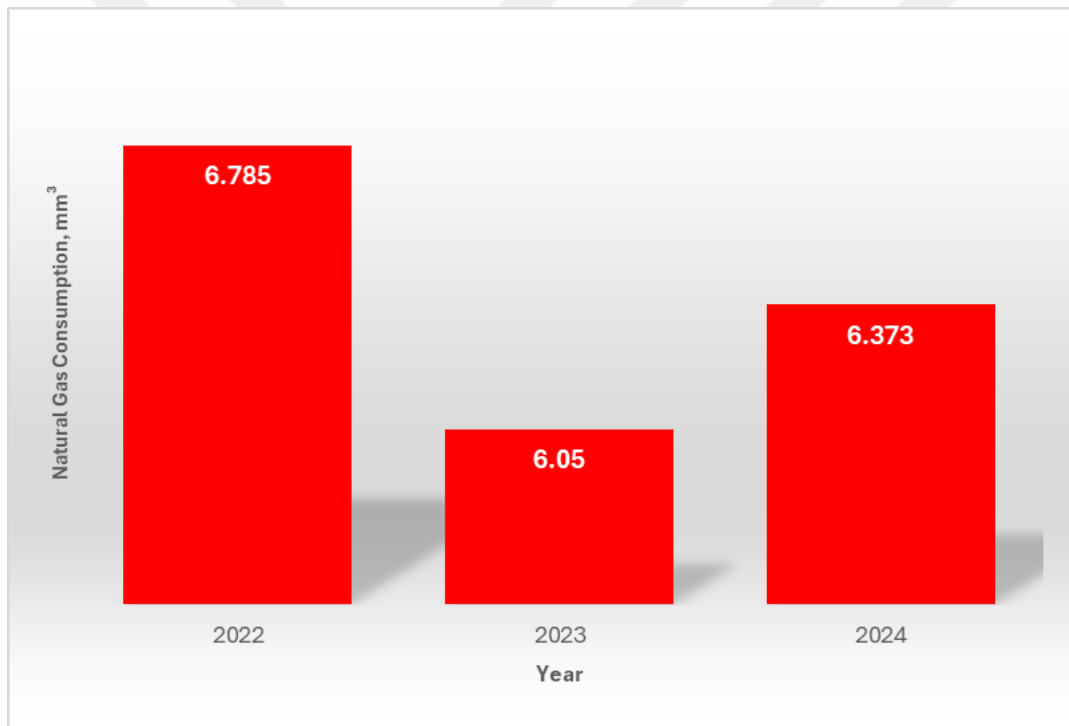


Figure 1.1: Total Natural Gas Consumption in February 2022-2024 (GAZBİR,2024)

The production of natural gas in February 2024 increased by 88 million cubic meters compared with the same period last year as a result of the gradual initiation of production in the Sakarya Natural Gas Production Field (GAZBİR, 2024).

In February 2024, the amount of natural gas produced increased by 6 million cubic meters in comparison with the previous month. According to the forecasts for the Sakarya field, it is expected that there will be an increase in daily production quantity over the coming period. At the end of February 2024, it is estimated that the total amount of stored natural gas in the country has increased by 12% in comparison to the same month last year. In the second month of 2024, the stored natural gas has increased by 143 million cubic meters compared to the previous month. It has been reported that the amount of natural gas stored in underground storage facilities has increased by about 11% in comparison with the same period of the previous year and that the amount of natural gas stored in LNG terminals has increased by 18% in comparison with the same period of the previous year (GAZBIR, 2024).

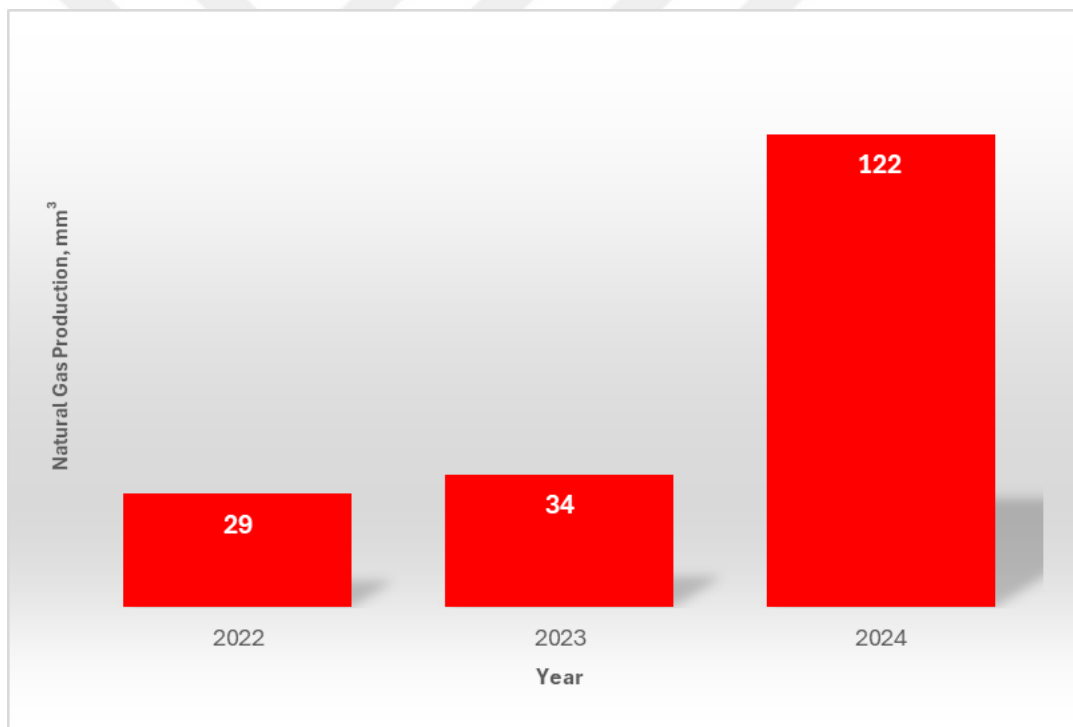


Figure 1.2: Total Natural Gas Production in February 2022-2024 (after GAZBIR, 2024)

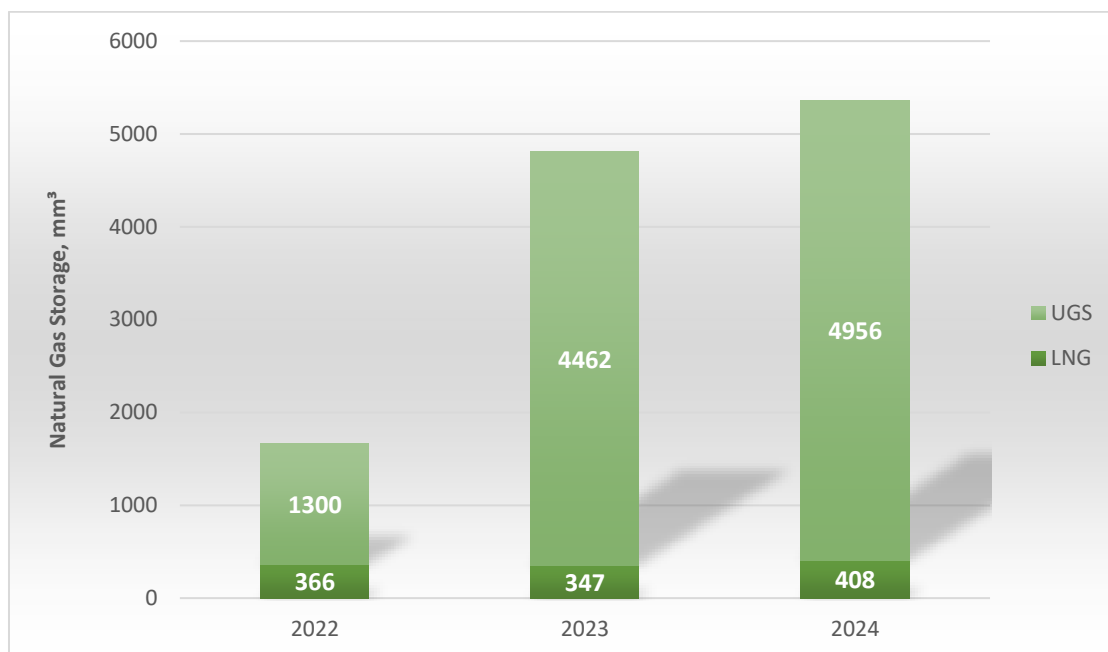


Figure 1.3: Natural Gas Production in 2022-2024 (GAZBIR, 2024)

CHAPTER 2

LITERATURE REVIEW

2.1 Underground Gas Storage

Underground natural gas storage serves a critical role in maintaining energy security by balancing fluctuations in supply and demand, so offering a dependable source of natural gas for emergencies. This storage method involves the injection and withdrawal of natural gas into various underground geological formations, with the most common types of aquifers, salt caverns, and depleted hydrocarbon reservoirs as shown in Figure 2.1.

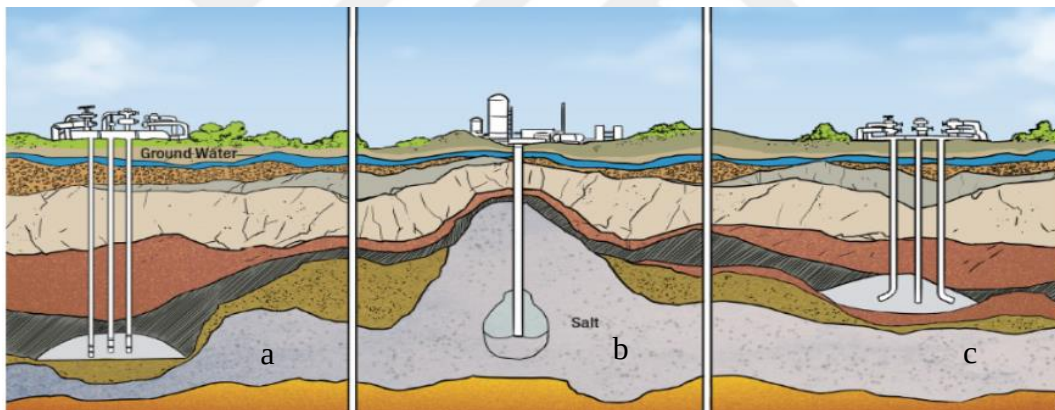


Figure 2.1: Different Underground Gas Storage Methods a) Depleted Reservoir b) Salt Dome c) Aquifer (Gungor, 2019)

2.1.1 Aquifers

Aquifers are geological formations that possess the capability to hold underground water and are utilized for natural gas storage. These structures enable the storage of natural gas within porous rock layers. The primary advantages of aquifers are their

considerable storage capacity and vast coverage areas. However, there are several disadvantages:

- When gas is injected into an aquifer, it displaces water, resulting in pressure losses.
- Keeping gas and water pressures in balance and preventing unwanted water movement can be challenging.
- The presence of water during withdrawal can lead to it coming out with the gas, which will require additional processing and costs.

Aquifers were once used for underground storage but are now rarely chosen for new projects due to their physical characteristics, issues with facility reliability, and higher costs compared to salt caverns and depleted hydrocarbon reservoirs (Güngör, 2019).

2.1.2 Salt Caverns

Salt caverns are underground spaces that are formed when salt deposits are dissolved. These caverns are well-suited for gas storage due to their ability to withstand high pressures and extremely low permeability, preventing gas leakage. To create a salt cavern, water is injected into the salt deposits to dissolve them, and the resulting brine solution is removed, leaving behind a hollow space that can be utilized for gas storage. Famous salt caverns are located in the Gulf of Mexico basin in the United States, Mexico, and Cuba, while other salt formations are found in the Middle East, Europe, and Russia (Güngör, 2019). In Türkiye, BOTAŞ (Petroleum Pipeline Corporation of Türkiye) established the Tuz Gölü Underground Natural Gas Storage Facility in 2021, which utilizes salt structures for natural gas storage. It consists of a total of 52 caverns, which were created by injecting fresh water into salt wells drilled 1500m underground to dissolve the salt. After completion, the project achieved a working gas capacity of 1.2 billion cubic meters and a daily production capacity of 40 million cubic meters (Botaş, 2022).

2.1.3 Depleted Hydrocarbon Reservoirs

Depleted hydrocarbon reservoirs are significant underground structures commonly used for natural gas storage. After extraction of producible hydrocarbons, such as natural gas or oil, reservoirs may become unsuitable for further production due to various reasons. However, these depleted reservoirs are well-suited for gas storage as they already possess the necessary porosity, permeability, and pressure conditions. One of the significant advantages of utilizing depleted reservoirs for gas storage is the presence of existing wells and the familiarity with the underground structure (Lungu et al., 2021).

The BOTAŞ Silivri Underground Natural Gas Storage Facility, one of the existing underground natural gas storage sites in Türkiye, was established in 2007 in a depleted hydrocarbon field. This facility stores natural gas transported to depleted hydrocarbon wells in the Marmara region from the transmission network and has reached a storage capacity of 4.6 billion m³ today (Botaş, 2022).

2.2 Historical Development of Underground Gas Storage

Underground gas storage is a critical process for the storage and management of natural gas. The increase in energy demand and challenges such as mitigating climate change have heightened the significance of underground gas storage systems.

The history of underground gas storage dates back to 1915, when the initial gas storage experiment was conducted in the Welland Gas Field in Ontario, Canada. In 1916, the United States established underground gas storage in the depleted Zoar Gas Field near Buffalo, New York. The first utilization of an oil field for gas storage occurred in 1954 in the CALG Gas Field, New York City, followed by the first gas storage in an aquifer in Kentucky, USA, in 1958. In 1959, the Soviet Union constructed the first underground gas storage in a salt bed, and in 1961, the United States utilized a salt cavern for gas storage for the first time. By 1963, gas was being stored in an abandoned mine near Denver, Colorado. By 1945, there were only 75

underground gas storage facilities, and the type of storage was relatively rudimentary. However, due to the development of the gas market, the increased gas production rate, and the expansion of pipelines, the types and number of underground gas storage facilities developed rapidly. The construction of various types of underground gas storage facilities reached its peak during 1970–1980, resulting in a total of 120 underground gas storage facilities (Ma et. al., 2021).

Table 2.1 Properties of Different UGS Systems

Storage Type	Salt Cavern	Aquifer	Depleted Reservoir
Depth, m	500-2000m	800-2000m	1000-4000m
Pressure, kPa	High (>1500)	Moderate (5000-15000)	Moderate to High (5000-30000)
Temperature, °C	Low (10-30)	Moderate (20-60)	Moderate (20-80)
Porosity, %	Low (1-3)	Moderate to High (10-30)	Moderate (5-20)
Permeability, mD	Very Low (<1)	Moderate to High (10-500)	Moderate (5-100)
Advantages	Short withdrawal time	Large reservoir capacity	Large gas storage and peaking capacity for seasonal peaking and strategic reserves
Disadvantages	Long construction period	Higher leakage risk	Potential gas contamination

Global Examples	Tuz Gölü Underground Gas Storage Facility, Türkiye	Saint-Clair-sur-Epte Field, France	Kuzey Marmara Underground Gas Storage Facility, Türkiye
Sources	(Chen et al., 2018), (Jahanbakhsh et al.,2024), (Minougou et al., 2023), (Michalski et al.,2017), (Liu et al., 2015), (Ozturk, 2004), (Zamani et al., 2024)	(Jahanbakhsh et al.,2024), (Uliasz- Misiak et al., 2024), (Lord, 2009) (Yan et al., 2023) (Zeng et al., 2023)	(Lord, 2009), (Yan et al., 2023) (Zeng et al., 2023), (Zhao et al., 2022),

According to the CEDIGAZ Report (2024), recently, a substantial increase in underground gas storage (UGS) capacity has been observed (see Figure 2.2). By the conclusion of 2022, the working gas capacity attained 429 billion cubic meters, representing a 1.3% increase compared to the preceding year. This growth has been significantly contributed to by China and Europe. Moreover, the maximum withdrawal rate has also increased by 1.7%. Depleted hydrocarbon fields constitute 81% of the global working gas volume, while salt caverns, comprising only 8% of global capacity, play a crucial role in accessibility by providing 26% of the global withdrawal rate. Presently, 76 storage projects are under construction worldwide, contributing an additional capacity of 55 billion cubic meters. Furthermore, 99 additional projects are in the planning phase, indicating potential for further expansion.

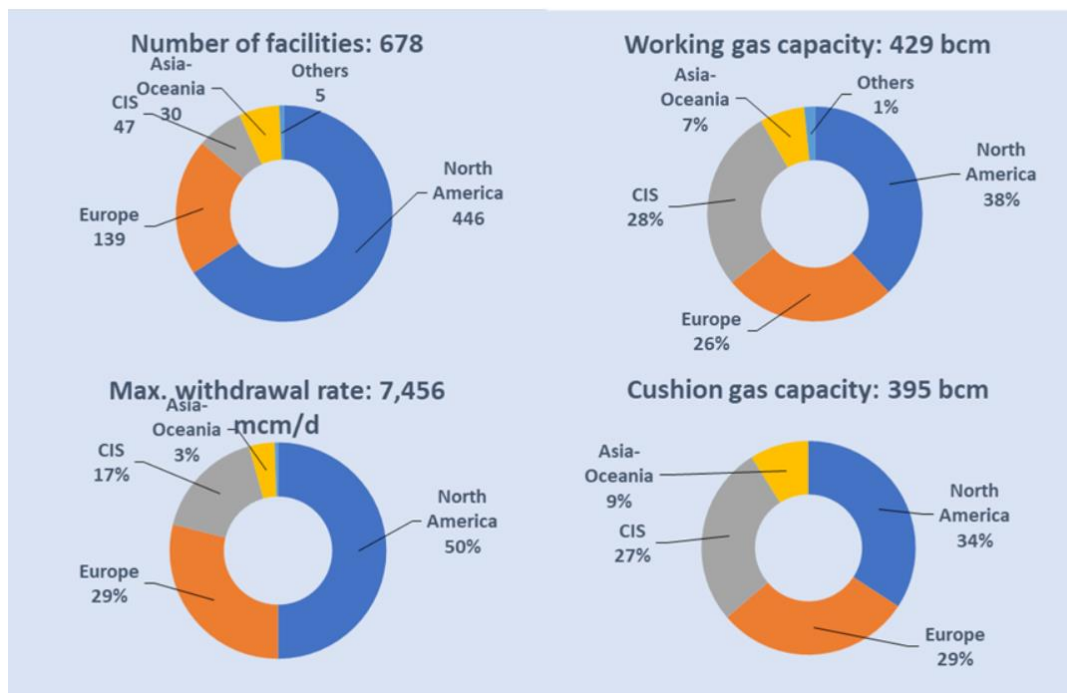


Figure 2.2: Global Underground Gas Storage by Region at the end of 2022 (CEGIGAZ, 2024).

2.3 Working and Cushion Gas Usage in Underground Gas Storage Wells

Underground natural gas storage is essential in balancing the supply and demand of natural gas. Two types of gases play a critical role in underground storage facilities: working gas and cushion gas. The working gas is the gas that is injected into the storage facility based on its content and withdrawn during periods of increased demand. Its volume is dynamic and adjusted according to market consumption needs, making it crucial for managing seasonal and market-driven changes in gas usage. Cushion gas, on the other hand, serves a different purpose. It remains permanently in the reservoir and is not withdrawn. Its primary function is to maintain the necessary pressure in the storage reservoir, which is essential for the efficient injection and withdrawal of working gas. Without sufficient cushion gas, the pressure in the reservoir may drop, leading to operational challenges and inefficiencies in the gas storage process. Therefore, cushion gas ensures the stability

and structural integrity of the reservoir, allowing the storage facility to operate effectively and efficiently (EIA,2015)

The growing demand for energy globally, in addition to environmental and economic concerns, has led to extensive research on various cushion gases utilized in underground gas storage systems. Studies (Kim et al.,2015 & Al-Shafi et al.,2023 & Shoushtari et al.,2023) have been conducted on the storage of gases such as carbon dioxide (CO₂), hydrogen (H₂), and natural gas (CH₄). Due to economic factors and environmental considerations, including reducing the greenhouse gas effect, CO₂ injection into underground formations have gained significant attention. However, the effectiveness of this approach depends on the properties of the reservoir, including permeability, porosity, and reservoir temperature and pressure. These factors directly influence the feasibility and efficiency of using CO₂ as a cushion gas. As a result, each reservoir must be evaluated individually to determine the suitability of CO₂ injection.

Many countries use natural gas as cushion gas in underground gas storage systems. However, since cushion gas is used to balance pressure within the reservoir and cannot be withdrawn, it results in high costs. Consequently, research (Yang et al., 2024) has been conducted on using inert gases or nitrogen as alternatives to natural gas for cushion gas. The notable benefits associated with utilizing CO₂ as a cushion gas is numerous. Among these is its high compressibility, which is particularly pronounced near its critical pressure, allowing for the maintenance of reservoir pressure with great efficiency. Moreover, CO₂'s high viscosity and density contrast with the working gas contributes to enhanced separation and decreased mixing issues. The environmental advantages of employing CO₂ are also considerable, as its sequestration contributes to the reduction of greenhouse gases (Oldenburg et al., 2002). Furthermore, economic benefits can be realized through the acquisition of carbon credits and tax savings associated with CO₂ utilization (Abhishek et al., 2023). Laille et al. (1988) worked on the real case history of the underground aquifer gas storage at Saint-Clair-sur-Epte, France. Initial studies carried out in 1978 and 1979 confirmed the practical viability and economic advantages of injecting a

considerable volume of inert gas (20% of the cushion gas) before filling the storage with natural gas. Oldenburg et al. (2002)'s simulations showed that the injection of CO₂ into depleted gas reservoirs that are heterogeneous can lead to a marked increase in the production of natural gas. The high viscosity and density of CO₂ restrict the mixing of gases, while changes in density and viscosity at critical pressures further limit the degree of mixing that can occur. By injecting CO₂ into the deep reservoir levels, which are located away from production wells, it is possible to recover additional gas for approximately eight years. Kim et al. (2015) compared the use of nitrogen and CO₂ as cushion gases in underground gas storage. Their findings show that replacing 20% of the cushion gas with N₂ or CO₂ increases the productivity index, as both gases are denser than CH₄ under reservoir conditions. However, N₂ reduces productivity by 10%, while CO₂ reduces it by 5%. CO₂ may cause more loss than N₂ due to its higher risk of leakage and expansion tendency. N₂ is more suitable for slightly inclined and flat reservoir models, whereas CO₂ has different effects in sharply inclined reservoirs. According to Ma et al. (2019) utilization of carbon dioxide as a cushion gas in subsurface geological reservoirs for Power-to-Gas (PtG) systems, which convert surplus renewable energy into methane for storage, contributes to maintaining reservoir pressure and diminishing methane emissions. The thickness, dip angle, and temperature of the reservoir impact on the area where gas mixing occurs, thereby maximizing storage efficiency.

Shoushtari et. al. (2023) has categorized the advantages and disadvantages of using nitrogen (N₂) and carbon dioxide (CO₂) as cushion gas based on data from previous studies. According to the results, the high density and viscosity of CO₂ result in a reduced mixing zone during production cycles, which is advantageous for controlling the mixing process as seen in Fig 2.3. Furthermore, the isothermal compressibility of carbon dioxide provides enhanced storage capacity compared to nitrogen. When integrated with carbon capture and storage processes, carbon dioxide offers substantial advantages both operationally and environmentally.

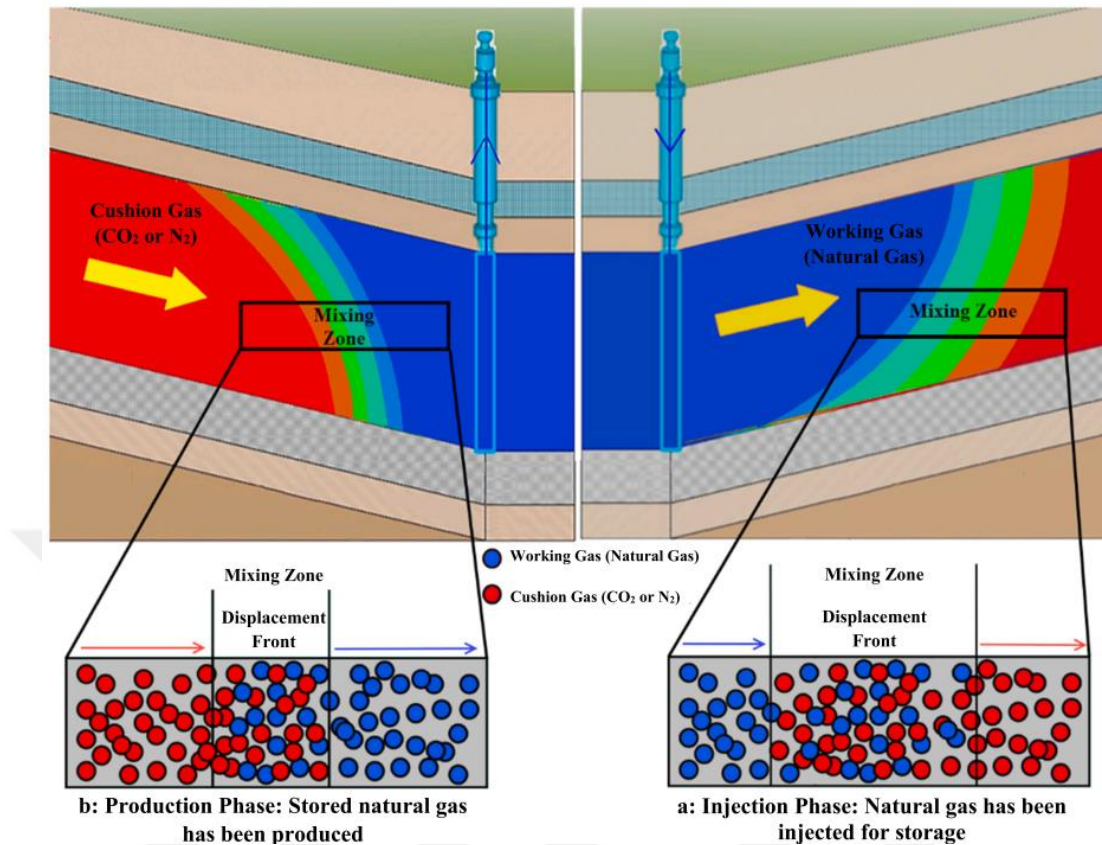


Figure 2.3: Dependence of mixing zone on the viscosity of working gas and cushion gas, a: during the injection phase and b: during the production phase (Shoushtari et. al., 2023)

Due to differences in the physical properties of CO_2 and CH_4 (such as density, viscosity, and compressibility), gas mixing rates in underground natural gas storage are low. CO_2 's higher viscosity reduces migration rates and increases sweep volume, enabling greater storage capacity. CO_2 naturally settles at the bottom of the storage facility due to gravity, inhibiting mixing and providing sufficient driving force for working gas. Elevated temperatures increase gas diffusion but have limited impact. Thick geological structures and steep inclination angles are more suitable for using CO_2 as a cushion gas. Injecting CO_2 from the bottom of the edge well is optimal, with a preferred ratio of 19.5% to 32.5%. (Du et al., 2024).

In supercritical conditions, fluids display unique characteristics that differ from those of liquids or gases. These include a high density similar to liquids and the ability to

fill the entire available space like gases. As depth increases underground, both temperature and pressure rise. While the increase in pressure elevates the density of CO₂, the increase in temperature produces an effect that reduces CO₂ density. As illustrated in Figure 2.5, CO₂ transitions to the supercritical phase as temperature and pressure increase. The critical point for CO₂, when it reaches a supercritical state, is 31.1°C and 7.38 MPa (Voormeij et. al., 2002).

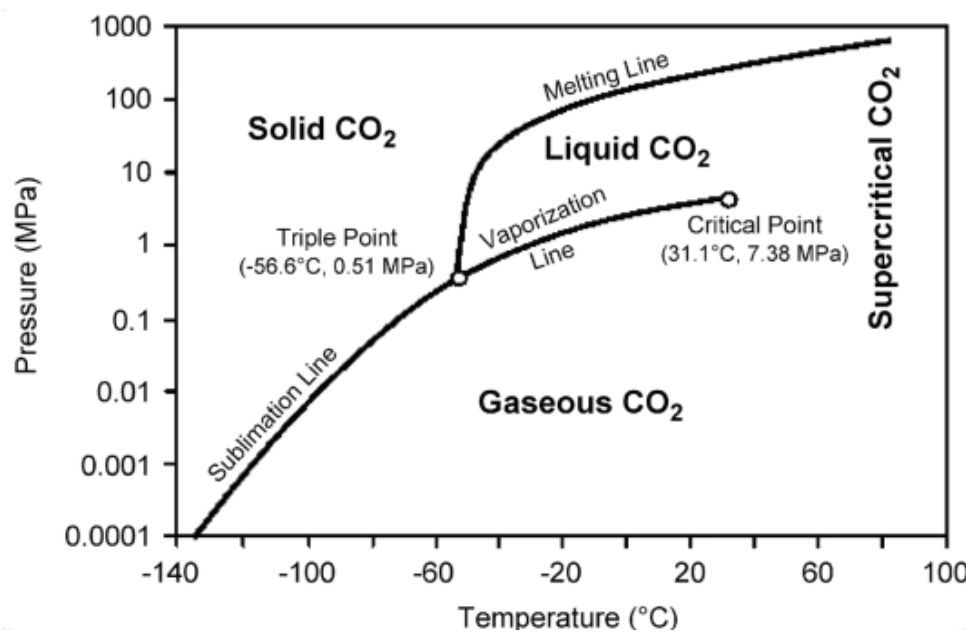


Figure 2.4: Phase Diagram of CO₂ (Bachu et. al., 2008)

2.4 Carbon Capture

Carbon capture refers to the process of capturing carbon dioxide (CO₂) emissions produced from the utilization of fossil fuels in electricity generation and industrial processes, thereby preventing the gas from entering the atmosphere. According to the International Energy Agency (2023), "*Carbon capture, utilization, and storage (CCUS) is a critical technology for achieving net-zero emissions*" emphasizing its significance in mitigating climate change. Technology involves capturing CO₂ at its source, transporting it to a storage site, and sequestering it underground in geological

formations. As the U.S. Department of Energy states (2016), "*CCUS can enable the continued use of fossil fuels while dramatically reducing emissions,*" indicating its potential to reconcile energy requirements with environmental stewardship. The integration of carbon capture into energy systems represents a substantial advancement toward a more sustainable future.

2.4.1 CO₂ Emissions and CCS Activities in Türkiye

Carbon Capture and Storage (CCS) is considered one of the most significant technologies in addressing global climate change. This technology, which aims to mitigate CO₂ levels in the atmosphere, demonstrates substantial potential for minimizing the environmental impacts of industrial activities and energy production. The Marmara Region holds particular significance for carbon capture projects, as it represents an area of critical importance for Türkiye's industrial and energy production sectors.

Million tons CO₂ equivalent, 2018, large regions

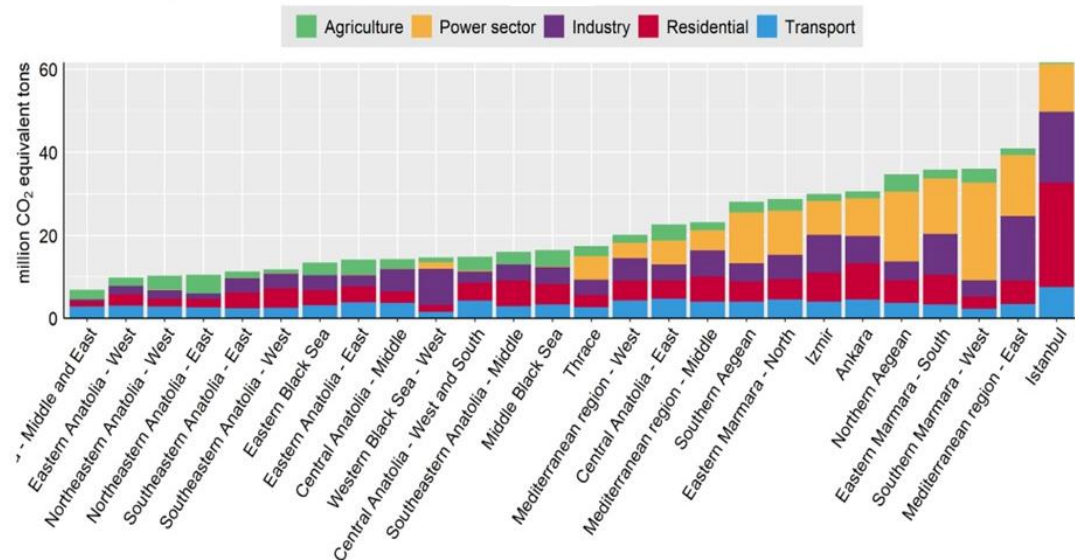


Figure 2.5: CO₂ Emissions by Regions in Türkiye (OECD,2021)

The Marmara Region accommodates a substantial proportion of Türkiye's economic and industrial activities. Metropolitan areas such as Istanbul, Tekirdağ, and Kocaeli,

along with the industrial zones concentrated in these urban centers, consume significant quantities of energy and contribute to carbon emissions (Figure 2.5). Figure 2.7 shows the average carbon footprint map of Türkiye.

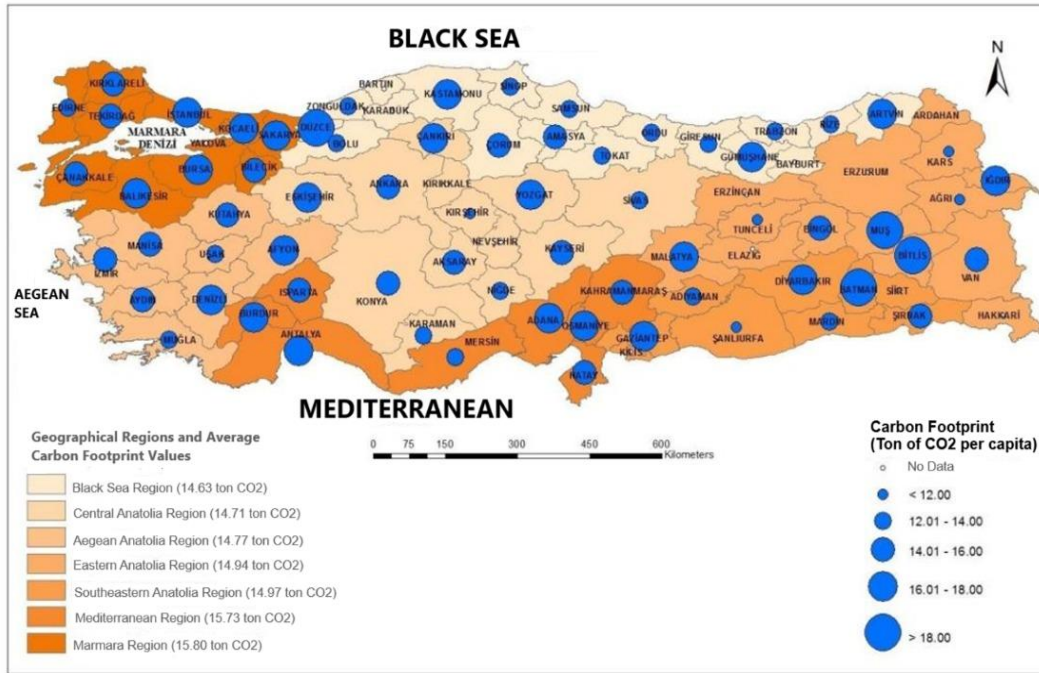


Figure 2.6: Türkiye Geographical Regions Average Carbon Footprint Map (Sarıtürk et al., 2015)

According to TÜİK (2022), total greenhouse gas emissions in Türkiye decreased by 2.4% compared to the previous year, amounting to 558.3 million tons CO₂ equivalent. As shown in Figure 2.7, CO₂ emissions over the period 1990–2022 demonstrate significant increase. In earlier years, emissions were generally lower, however; peaking in certain years due to increased industrial activities, urbanization, and energy demands. The largest proportion of these emissions originated from the energy sector at 71.8%, followed by agriculture at 12.8%, industrial processes and product use at 12.5%, and the waste sector at 2.9%. This data highlights the importance of adopting such technologies in the Marmara Region due to its industrial and energy-intensive nature. The energy sector accounts for 86.6% of Türkiye's total carbon emissions (Figure 2.8). This percentage underscores

the potential efficacy of carbon capture and storage technologies in energy production. Although per capita greenhouse gas emissions decreased to 6.6 tons of CO₂ equivalent in 2022, this represents an increase of over 61% since 1990.

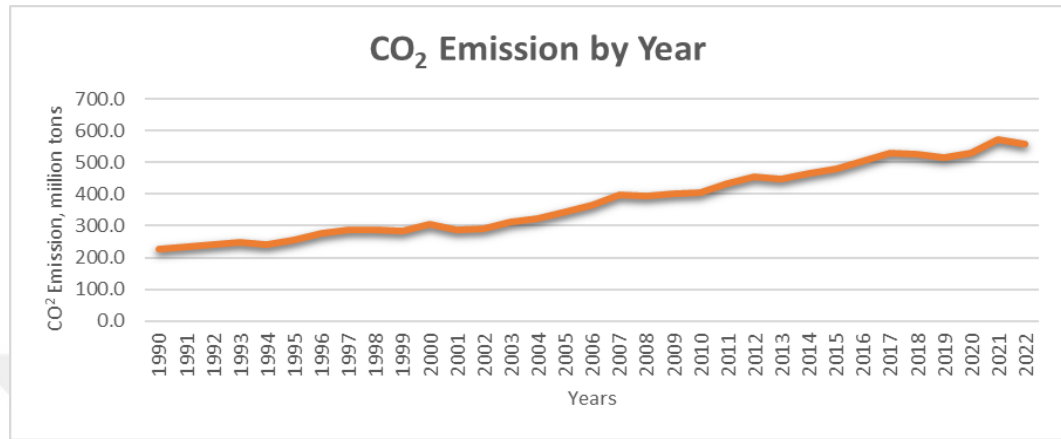


Figure 2.7: CO₂ Emission Between Years 1990-2022 (TÜİK, 2022)

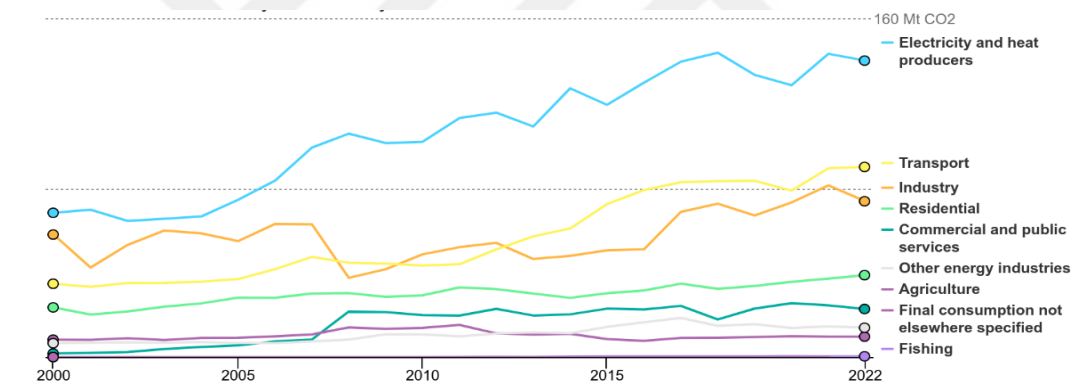


Figure 2.8: Evolution of CO₂ Emissions by Sector in Türkiye Between 2000-2022 (IEA,2022)



Figure 2.9: Türkiye's Potential Carbon Capture Facilities (Sayman et al., 2024).

In Türkiye, 133 large facilities account for approximately half of the country's total emissions. These facilities are anticipated to play a significant role in the potential implementation of carbon capture and storage (CCS) technologies in Türkiye. Moreover, the emissions in Türkiye are expected to continue rising in the near future, primarily driven by cement production. In contrast to the cement industry, Türkiye's iron and steel sector is concentrated in a limited number of provinces, and its emissions are also experiencing an upward trend (Sayman et al., 2024)

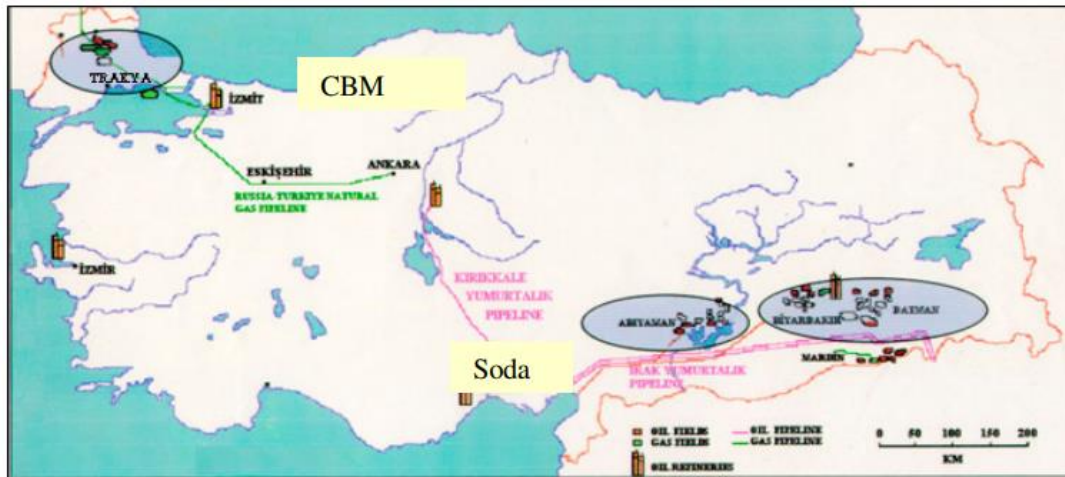


Figure 2.10: Possible CO₂ storage sites in Türkiye (Okandan et al., 2011)

Figure 2.9 and Figure 2.10 comprehensively explore Türkiye's carbon capture and storage (CCS) potential by mapping CO₂ emission sources, such as steel production, cement manufacturing, refineries, and electricity generation, alongside storage sites. Figure 2.9(Sayman et al. 2024), highlights the locations of potential carbon capture facilities, including cement factories and steel production plants, thereby emphasizing industrial regions with significant CO₂ emissions. Additionally, Figure 2.10 (Okandan et al. 2011), illustrates the maps geological formations across Türkiye that are suitable for long-term CO₂ storage. These figures effectively demonstrate the spatial alignment between CO₂ emission sources and storage opportunities, providing a strategic framework for implementing CCS projects in Türkiye.

To facilitate the storage of captured CO₂, it must first be transported to appropriate storage sites. This transportation process can be executed via pipelines, roads, or sea. The existence of an established pipeline infrastructure in proximity to industrial facilities in the Marmara Region could potentially reduce carbon transportation costs and enhance efficiency. Pipelines provide a reliable solution for safely transporting carbon over long distances to storage sites.



CHAPTER 3

STATEMENT OF PROBLEM

Natural gas serves as a crucial energy source for diverse sectors, including electricity generation, industrial processes, and residential consumption. However, natural gas consumption is not constant throughout the year and fluctuates depending on the seasonal and economic conditions. In order to meet the demand fluctuations, underground gas storage (UGS) facilities have been widely implemented as a strategic solution. These facilities utilize depleted hydrocarbon reservoirs, aquifers, or salt caverns to store excess natural gas during periods of low demand and render it available during periods of high demand. However, while UGS technology is an effective and established method, optimization, particularly in terms of cushion gas selection and management, remains a significant challenge.

Cushion gas is a critical component in UGS operations, as it facilitates the maintenance of the necessary reservoir pressure for efficient withdrawal of working gas. Conventionally, natural gas is used as cushion gas; however, this approach presents economic and environmental challenges. The utilization of large volumes of natural gas as cushion gas constrains the amount of working gas that can be stored, thereby reducing the storage efficiency. Furthermore, as natural gas is a finite and valuable resource, its application in non-recoverable contexts increases the operational costs. Using alternative gases instead of natural gas for cushion gas could help lower operational costs and aid in reducing greenhouse gas emissions. In this context, the use of carbon dioxide (CO₂) as an alternative cushion gas potentially offers both environmental and operational benefits. Despite a comparatively longer period of experience on underground gas storage in depleted hydrocarbon fields of Türkiye, a number of questions regarding the effects of cushion gas on the efficiency and effectiveness of gas storage process remain to be addressed.

This thesis aims to numerically model the use of CO₂ in depleted hydrocarbon reservoirs. Using Computer Modelling Group (CMG) software, the effects of different CO₂ injection rates (0%, 20%, 30%, and 40%) over various time periods (1, 5, and 10 years) are investigated. Key parameters such as natural gas recovery rates, CO₂ storage, and the molar fractions of gases in the reservoir are analyzed to assess the effectiveness of this approach.



CHAPTER 4

MATERIALS AND METHODS

4.1 Kuzey Marmara and Degirmenkoy Fields

Similar to other developing countries, Türkiye experiences seasonal variations in natural gas consumption. As a result, the Turkish Petroleum Corporation (TPAO) & BOTAŞ decided to convert the production of two gas fields, Kuzey Marmara (offshore) and Degirmenkoy (offshore), into underground gas storage facilities to account for these seasonal fluctuations. The Kuzey Marmara offshore gas field is situated in the Marmara Sea, approximately three kilometers off the coast of Silivri, Türkiye as shown in Figure 4.1 and Figure 4.2. The Degirmenköy field, on the other hand, is located 16 kilometers northwest of the Kuzey Marmara field. When compared to the Kuzey Marmara field, the Degirmenkoy field is much smaller (Sahin et al., 2012).

The Northern Marmara natural gas field was chosen for its relatively high permeability compared to other gas reservoirs in the region and its strategic location near industrial facilities, major gas-consuming cities, and key transmission lines. (Tureyen et al., 2000).

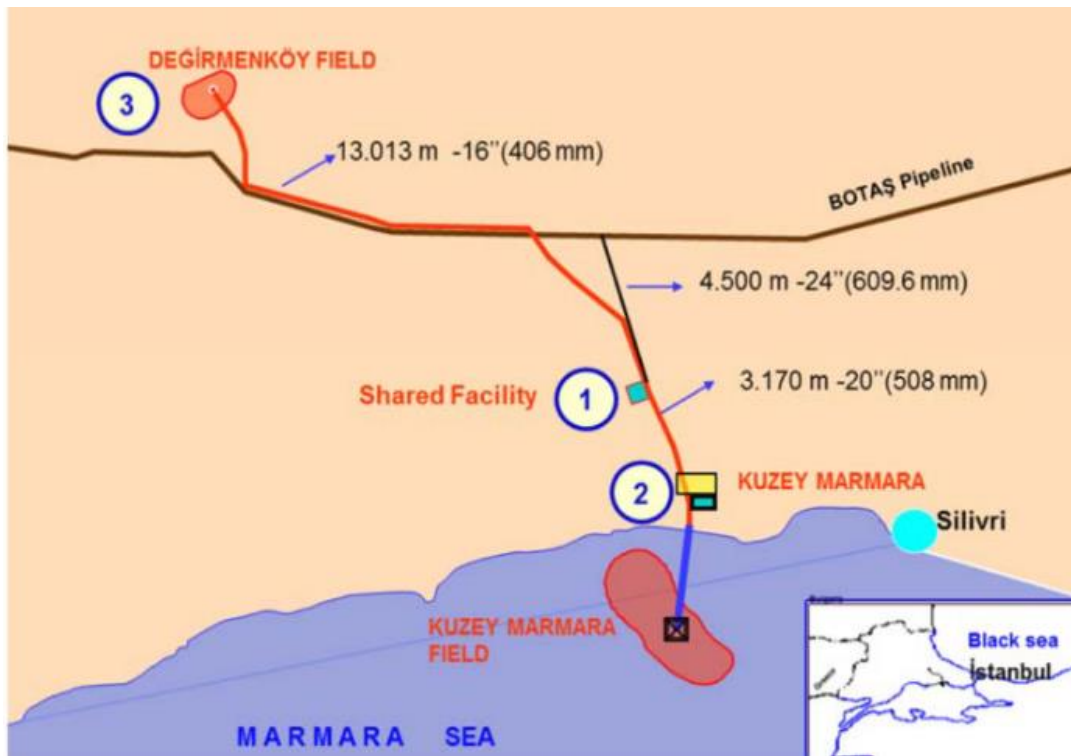


Figure 4.1: Project Layout of Kuzey Marmara and Degirmenkoy Field Underground Gas Storage Project (Sahin et al.,2012)

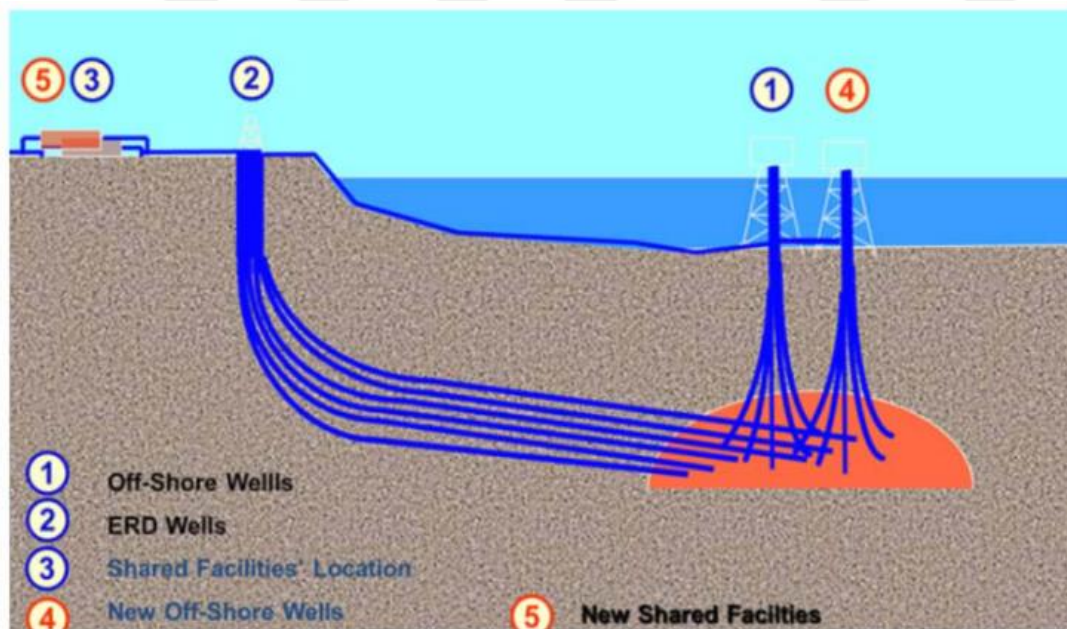


Figure 4.2: Development of Kuzey Marmara for UGS (Sahin et al.,2012)

4.2 Field Development History of Kuzey Marmara Field

The Kuzey Marmara and Degirmenköy fields, situated in the Thrace region in the north of Türkiye, are two major natural gas fields that hold immense importance for Türkiye's energy security and infrastructure. These fields are among the pioneering facilities used for underground natural gas storage. TPAO's hydrocarbon exploration activities in the Sea of Marmara began in 1975 with the drilling of the Marmara-1 well. From 1975 to 1995, a total of five shallow marine exploration wells were drilled in the Sea of Marmara. In 1988, the Kuzey Marmara-1 well revealed the presence of gas, leading to the discovery of the Kuzey Marmara gas field (Kaptanoğlu et al., 1988). Subsequently, as the gas in the field was depleted, it was transformed into Türkiye's first gas storage field in 2007 (BOTAS, 2022). The Degirmenköy Field, similar to the Kuzey Marmara Field, is located near Istanbul (Figure 4.1). This field was also used as a natural gas production site and, after the depletion of the reservoir, was assessed as an underground gas storage area. The Degirmenköy Field, along with the Kuzey Marmara Field, augments Türkiye's natural gas storage capacity and significantly contributes to the country's energy supply security (Sahin et al., 2012).

The first Turkish offshore commercial gas discovery occurred in 1988 with the drilling of the first exploration well, KM-1, in the North Marmara field as part of Phase-1 work. This significant milestone marked the beginning of Türkiye's offshore natural gas industry. The KM-1 well was drilled vertically as part of Phase 1. This initial well proved to have a good gas production capacity, and it was shut-in for further evaluations in the future. Following the success of KM-1, TPAO decided to drill the second well from land in 1988 due to the proximity of the field. The KM-2 well, intended to test the northern section of the field in the north-west direction, faced significant challenges. Due to poor rig performance and errors in selecting the correct kick-off point (KOP), the desired well-path could not be achieved. The directional drilling resulted in only 421 meters of lateral displacement, far short of the desired 1200 meters needed to reach the gas-bearing zones of the Sogucak limestone formation. Consequently, the KM-2 well was logged and permanently

abandoned as a dry hole. Based on the negative experience with KM-2 and the lack of expertise in extended-reach drilling (ERD), TPAO decided to suspend further plans for drilling wells from land until a detailed study could be completed. By the end of 1995, detailed studies on well designs and paths were completed, and a budget for the project was prepared. These preparations led to the decision to drill five new offshore wells to initiate production. TPAO embarked on Phase-2 work, drilling five wells over two years starting in 1995. This included the KM-3, KM-4, and KM-5 wells. KM-3, the first well drilled during Phase 2, was planned to test the southeastern portion of the field and to determine the boundaries of the existing reservoir. Production began in October 1997 with an average output of 0.5 million cubic meters per day (MMm³/d), although the designed production capacity was 1.9 MMm³/d. With the rapid depletion of the field, TPAO evaluated alternative scenarios, including using the reservoir as an underground gas storage facility. This evaluation was part of Phase-3 work and aimed to enhance Türkiye's energy security by providing a buffer against supply disruptions and balancing seasonal demand fluctuations (Kaptanoğlu et al., 1998).

As of 2020, The North Marmara Storage Facility, which currently has a storage capacity of 2.84 billion cubic meters (BCM) and a daily withdrawal capacity of 25 million cubic meters (MMCM), aims to reach a storage capacity of 4.6 BCM and a daily withdrawal capacity of 75 MMCM and injection capacity 45 MMCM with the North Marmara Natural Gas Storage Expansion (Phase-3) Project. Additionally, two fixed offshore platforms have been installed in the Sea of Marmara, with nine wells drilled on each platform (Kolin, 2024).

4.3 Reservoir Properties and Evaluating Kuzey Marmara Field as a Depleted Reservoir for Underground Gas Storage

The Kuzey Marmara field, located in the northwest of Türkiye, has historically been a significant source of natural gas production. As the field approaches its economic

limit for gas production, it offers a promising opportunity for repurposing as an underground gas storage facility. By utilizing depleted reservoirs for gas storage, this approach allows for effective management of seasonal demand fluctuations, ensuring energy security, and maximizing resource utilization.

4.3.1 Reservoir Properties

According to Sahin et al. (2012), Degirmenköy Field's gas reservoir is primarily composed of the Sogucak formation, with the reservoir top situated at 1080 meters. The cap rock, which is the layer of rock above the reservoir, mainly consists of the Mezardere formation, characterized by shale, thin sandstone, and limestone layers. The field has an average porosity of 15%, which allows for efficient gas storage and flow within the reservoir. The average permeability of the reservoir is 55 millidarcies (mD), which is crucial for efficient gas extraction. The original reservoir conditions include a pressure of 13100 kPa and a temperature of 65 °C. The absence of a water drive enhances gas mobility within the reservoir. The average production from two wells is 300,000 m³/day, with a cumulative production reaching 587 MMm³. The field has a working gas volume of 0.3 MMm³ and a cushion gas volume of 0.28 MMm³. Gas injection and withdrawal rates are 2.3 MMm³/day and 3.5 MMm³/day, respectively.

The Kuzey Marmara (KM) field has a maximum reservoir thickness of 65 meters, with the gas-bearing formation also identified as the Sogucak formation. The porosity of the reservoir ranges from 9.5% to 21.4%, accommodating varying gas storage capacities. The permeability ranges from 10 to 70 millidarcies (md), with higher values observed when porosity exceeds 20%. The original reservoir conditions are characterized by a pressure of 143 bar and a temperature of 68.8 °C, optimizing gas retention and flow dynamics. The field boasts a working gas volume of 1.6 billion cubic meters, supporting substantial gas storage capabilities. The maximum injection rate reaches 9.5 million cubic meters per day, while the maximum withdrawal rate is 11.5 million cubic meters per day. During injection, the

maximum wellhead pressure is 138 bar, reducing to 45 bar during withdrawal. Sahin et al. (2012) summarized the reservoir properties based on their latest calculations in Table 4.1.

Table 4.1: Kuzey Marmara (KM) Field Reservoir Properties (After Sahin et al., 2012)

Reservoir top, m	-1150
Reservoir thickness, m	65
Average porosity, %	20
Average permeability, md	50
Average water saturation, %	10
Original reservoir pressure, kPa (psi)	14300 (2074)
Original reservoir temperature, °C (°F)	68.8 (115.3)
Initial gas in place, bcm	*5.5
True vertical depths (TVD), m	1200-1270
All measured depths (MD), m	1280-3650
Final tangential section	74-86°
Working gas volume, bcm	*2.25
Max. withdrawal capacity, million Nm ³ /d	*13
Max. Injection capacity, million Nm ³ /d	*12
Connection pipeline length & dimension; m, inch (mm)	3170, 20" (508)
*Most updated / recalculated figures according to Sahin, Abravcı & Tirek (2012)	

Kuzey Marmara (KM) field has been reported to have several characteristics by Gumrah et al. (2005), which include permeability ranging from 15-60 md, porosity of 10-20%, gas density of 0.1109 lb/cuft, water compressibility of 3×10^{-6} 1/psi, viscosity of 1.0 cp, water saturation of 0.1, gas saturation of 0.9, reservoir temperature of 57 °C, and original water in place of 16 MMSTB, original gas in place of 128 MMSCF, and formation thickness of 214 ft.

As stated in the study of Tureyen et al. (2000), the well structure is elongated and has a regular shape, oriented from northwest to southeast. The structure is bound by two normal faults on its east and west sides. The reservoir rock is located in the Sogucak formation, characterized by reefal and bioclastic limestone. The top of the reservoir is at a depth of 1150 meters and porosity of 20%. An average water

saturation of 10%, with an average permeability of 50 md and max thickness of 65 meters (213 feet). There are no indications of aquifer support or a gas water contact, making the field more desirable for conversion to storage. The original pressure of the reservoir was recorded at 14258 kPa, and the temperature is approximately 57 °C (134.6 °F). The Ceylan formation acts as the caprock, composed mostly of marl and tuff with a thickness ranging from 10 to 60 meters (32.8 to 196.8 feet). Commercial gas production commenced in 1997, with an unmanned facility located 43 meters below sea level.

As Bağcı et al. (2007) stated the reservoir is composed of reefal and bioclastic limestone, with its top located at a depth of 1150 meters. The porosity and average water saturation of the reservoir rock are 15% and 10%, respectively, while its average permeability is 45 md, and its thickness measures 65 meters (213 feet). There is no indication of aquifer support or a gas-water contact, which makes the field more suitable for conversion to storage. The original pressure of the reservoir was recorded as 14306 kPa, and the temperature is approximately 68 degrees Celsius. The caprock comprises mostly marl and tuff and has a thickness that varies between 10 and 60 meters (32.8 to 196.8 feet). Commercial gas production commenced in 1997. Based on data obtained from well logs and reservoir core measurements of six wells, the initial gas in place was estimated to be 4.425 MMM m³. In the KM field, six wells were drilled, and five were utilized solely for production from 1997 to 2002. The producers were perforated in all reservoir layers in the field. The initial production gas rates from separate wells range from 73.625 m³/day to 396.435 m³/day. The formation pressure at the end of the production period reached 8963 kPa, whereas the total gas volume produced from the gas field at the end of the production period was 1.514 MMM-m³ leaving the total gas storage capacity of 2.998 MMM-m³ in the KM field.

4.4 Reservoir Modelling

CMG (Computer Modelling Group) is a widely used reservoir simulation software company founded in 1978 in Canada. Today, it collaborates with leading energy companies, including 90% of the top 10 national oil companies and 75% of the world's top 25 largest oil companies. (CMG, 2024).

CMG has different reservoir simulators which are IMEX (Black Oil and Unconventional Simulator), GEM (Compositional & Unconventional Simulator) and STARS (Thermal & Advanced Processes Simulator). In this study, the GEM (Compositional & Unconventional Simulator) was utilized due to its ability to precisely simulate subsurface fluid dynamics and interactions, aiding in field optimization and maximizing hydrocarbon recovery. GEM is extensively employed for modelling unconventional shale liquid production and is regarded as the leading simulator for CO₂ and H₂ storage processes (CMG, 2024). All scenarios were assumed to take place under isothermal conditions.

Kuzey Marmara (KM) field model was created in Computer Modelling Groups software (CMG). The contour map of Kuzey Marmara Field was taken from Kaptanoğlu et al. (1998) (Figure 4.3) was digitized using Golden Surfer trial version and imported to CMG Builder module to create a reservoir model. As the preliminary model, 43x52x4 cartesian grid and block widths 43x75 in I direction & 52x75 in J direction was created and NM-1, NM-3, NM-4, NM-5, and NM-6 wells were added.

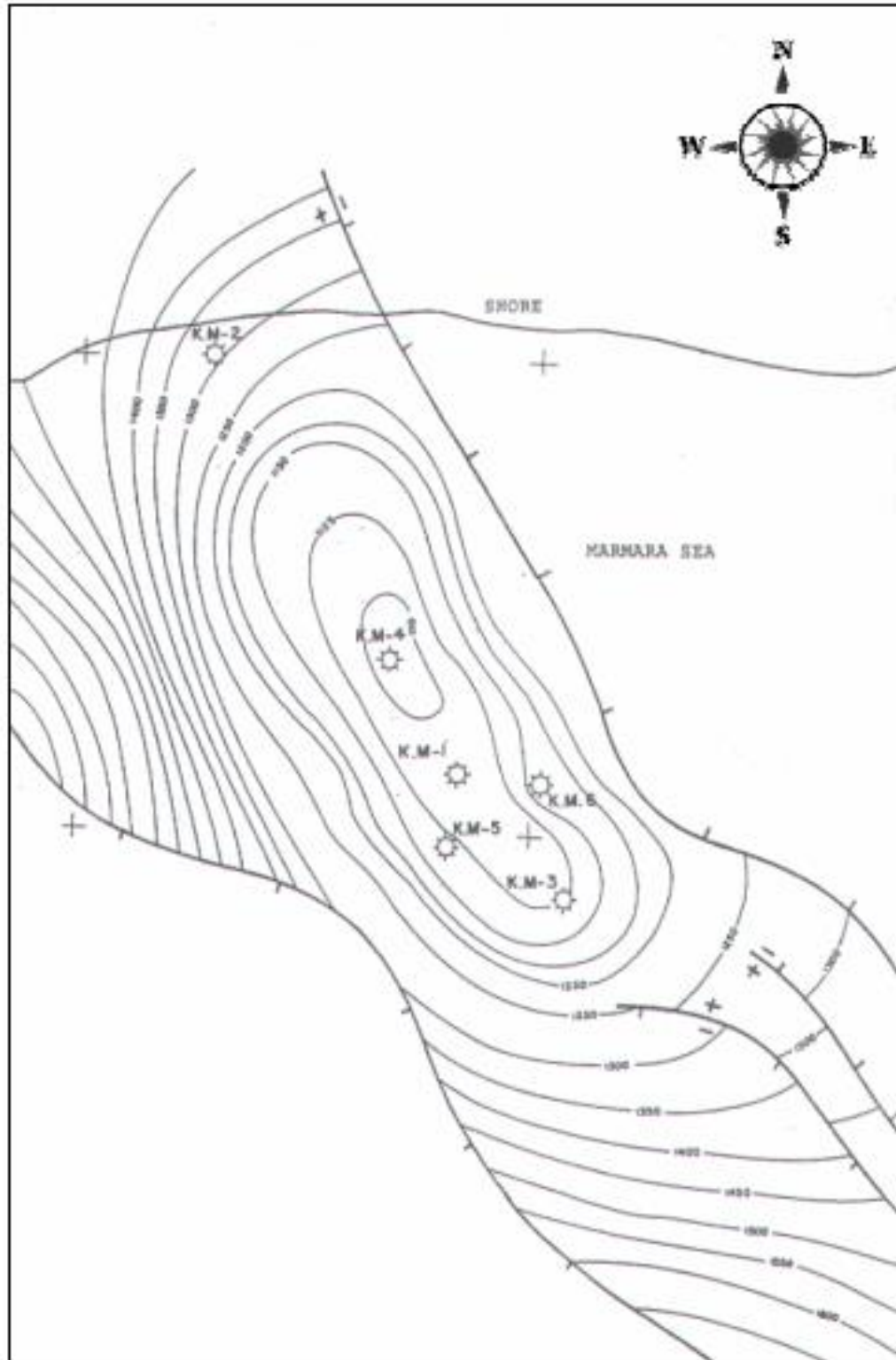


Figure 4.3: Kuzey Marmara Field Contour Map (Kaptanoğlu et al., 1998)

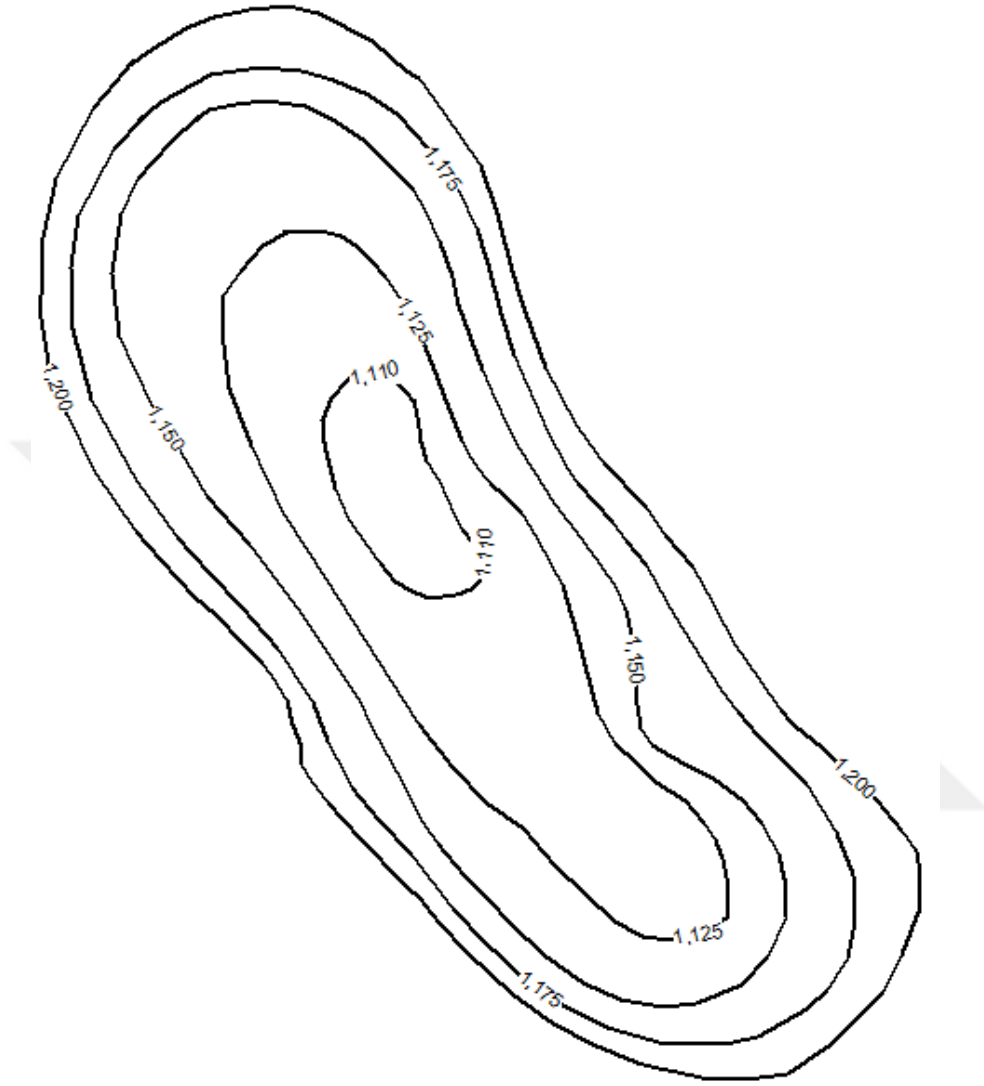


Figure 4.4: Kuzey Marmara Contour Map Created in Golden Surfer Software

The reservoir porosity and permeability maps were taken from Özkılıç (2005)'s study, digitized in Golden Surfer, and imported to the CMG Builder module and they are shown in Figure 4.4.

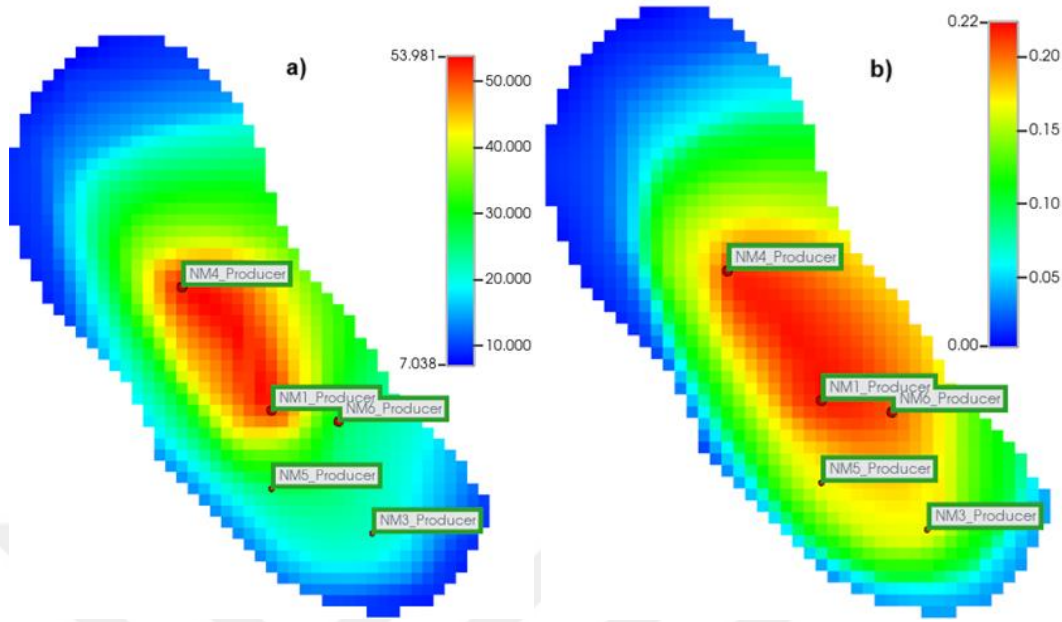


Figure 4.5: a) Permeability and b) Porosity Maps used in Model

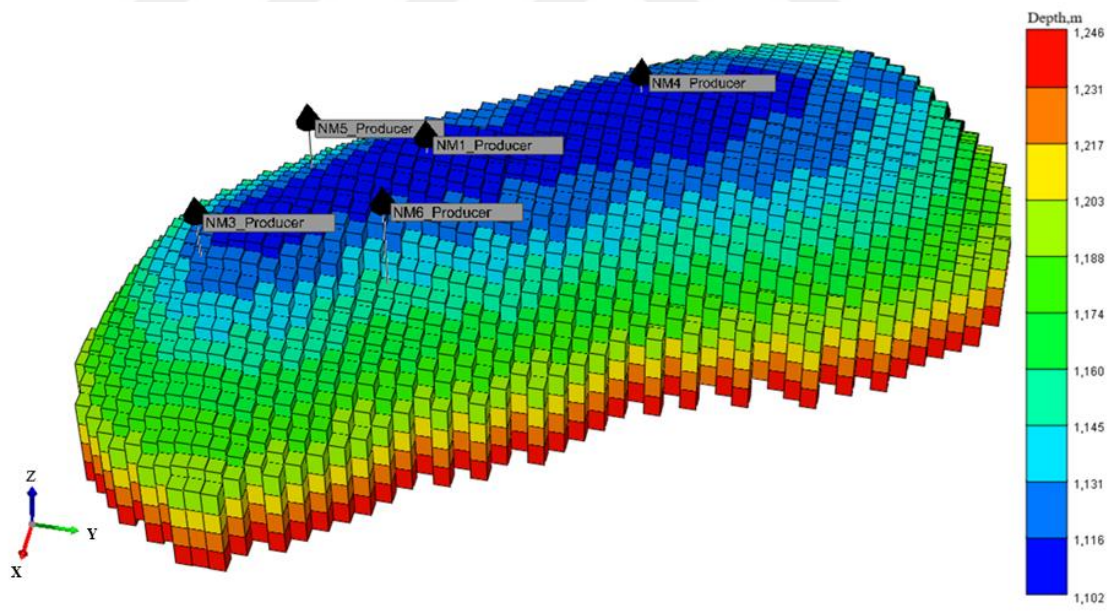


Figure 4.6: Kuzey Marmara Field Preliminary CMG Reservoir Model 3D View

4.4.1 CMG History Matching

Several studies have been conducted in the literature regarding the capacity of the North Marmara field. The OGIP recalculated in Şahin's study (2012) as 5.5 billion m³ is considered the most current OGIP estimate in the literature and has been utilized as 5.5 billion m³ in the model. Gürsel (2022) summarized the molar fractions of the gas stored in the North Marmara field in Table 4.2

Table 4.2: Gas Composition in Kuzey Marmara Field (Gürsel, 2022)

Component	Mole Fraction, %
C1	91.45
C2	3.21
C3	1.21
iC4	0.24
nC4	0.30
iC5	0.09
nC5	0.07
CO2	2.28
N2	1.15

Reservoir properties were optimized using the trial-and-error method, and history matching was conducted based on the production data from 1997 to 2002 as presented in Gürsel's study (2012). Different reservoir thickness has been reported in the literature. Bağcı and Öztürk (2007) stated that the reservoir thickness is a constant 65 meters, whereas Şahin et al. (2012) indicated that the maximum reservoir thickness is 65 meters. In the model developed in this study, the reservoir thickness was assumed as 15 meters each layer, leading to the total thickness of 60 meters. The history matching results obtained with the model are consistent with the reservoir

data and are presented in Table 4.3. Well head pressure and cumulative gas production of each well, field cumulative gas production, field average reservoir pressure and field cumulative water production history matching results are shown in Figure 4.8, Figure 4.9, Figure 4.10, Figure 4.11 and Figure 4.12.

Table 4.3: Model Reservoir Properties

ITEM	UNITS	VALUE
Total Bulk Reservoir Volume	Res m ³	3.77x10 ⁸
Total Pore Volume	Res m ³	3.48x10 ⁷
Total Hydrocarbon Pore Volume	Res m ³	3.90x10 ⁷
Original Gas in Place	STD m ³	5.56x10 ⁹
Wellhead Temperature (Şahin et, al. 2012)	°C	15
Bottomhole Temperature (Şahin et, al. 2012)	°C	68.8
Reservoir Pressure (Şahin et, al. 2012)	kPa	14300
Well Radius (Gürsel, 2021)	m	0.2032
Rad (Gürsel, 2021)	m	0.0762
Relative Roughness (Özkılıç, 2005)	-	0.000742
Critical Water Saturation	%	1
Initial Water Saturation (Öztürk, 2004)	%	13

$$Relative\ Roughness = \frac{Inside\ Pipe\ Roughness}{Inside\ Pipe\ Diameter} \quad (4.4.1.1)$$

$$Inside\ Pipe\ Diameter = 1.50919 \times 10^{-4}\ ft$$

$$Inside\ Pipe\ Diameter = 0.20342\ ft$$

$$Relative\ Roughness = \frac{1.50919 \times 10^{-4} ft}{0.20342 ft} = 0.000742$$

(Özkılıç, 2005)

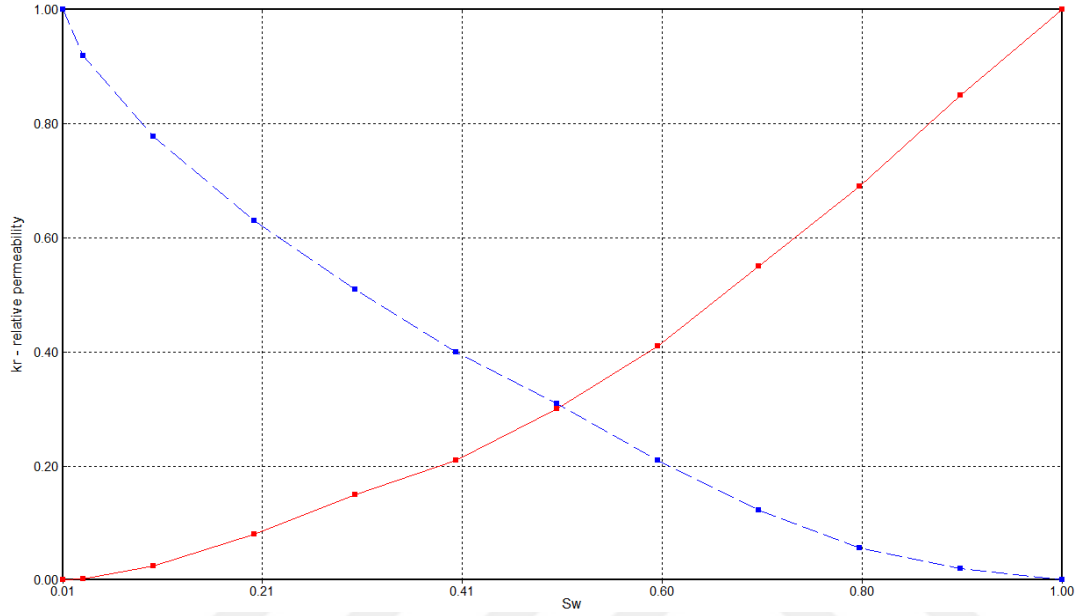


Figure 4.7: Relative Permeability Graph used in model (k_r vs S_w)

Root Mean Square Error (RMSE) is a widely used error method to measure the accuracy of a model. It represents the standard deviation of the differences between the predicted and actual values in the sample (BYJUS,2023). The RMSE of the well head pressure of each well is summarized in Table 4.4.

$$Root\ Mean\ Square\ Error(RMSE) = \frac{\sqrt{\sum (P_{simulator} - P_{field})^2}}{N} \quad (4.4.1.2)$$

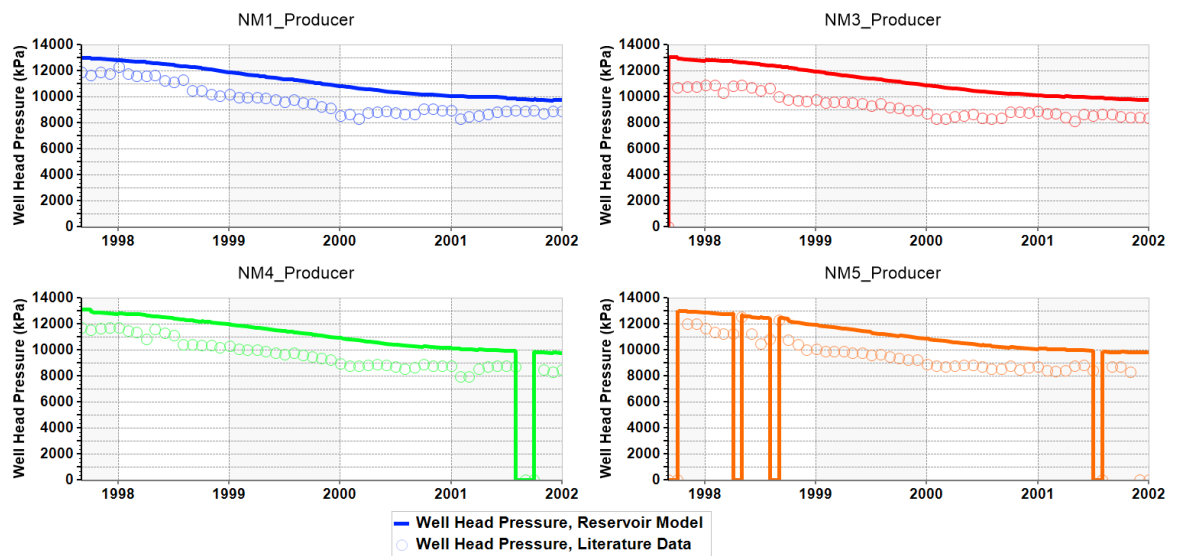
Where N = number of data

(Gümrah et. al, 2005)

Table 4.4: RMSE Wellhead Pressure for Each Well

Well Name	Well Head Pressure RMSE, kPa
NM-1	207.72
NM-3	270.29
NM-4	222.48
NM-5	282.37
NM-6	402.53
Average	277.08

Well Head Pressure 1



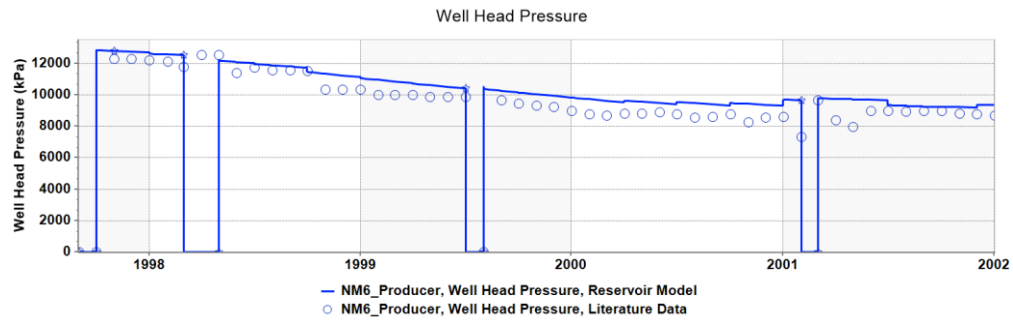


Figure 4.8: History Matching Results of Well Head Pressures

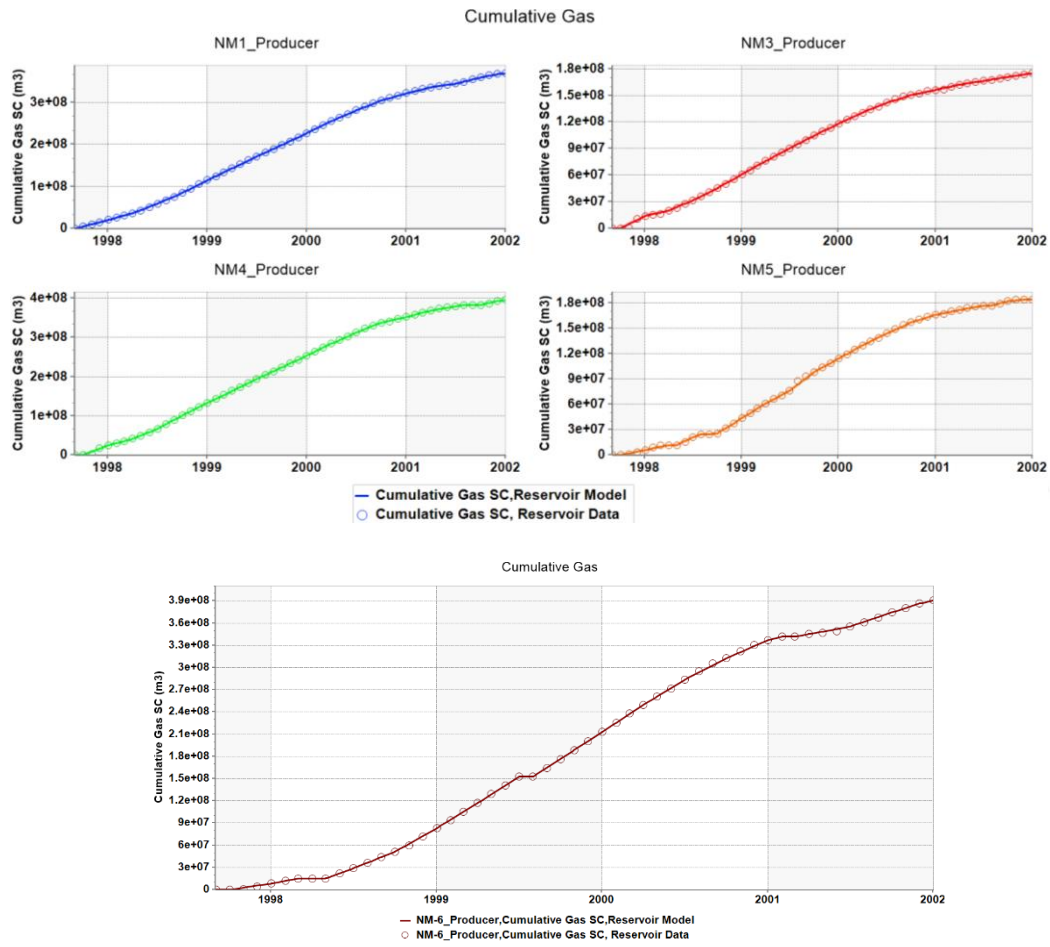


Figure 4.9: History Matching Results for Cumulative Gas Production

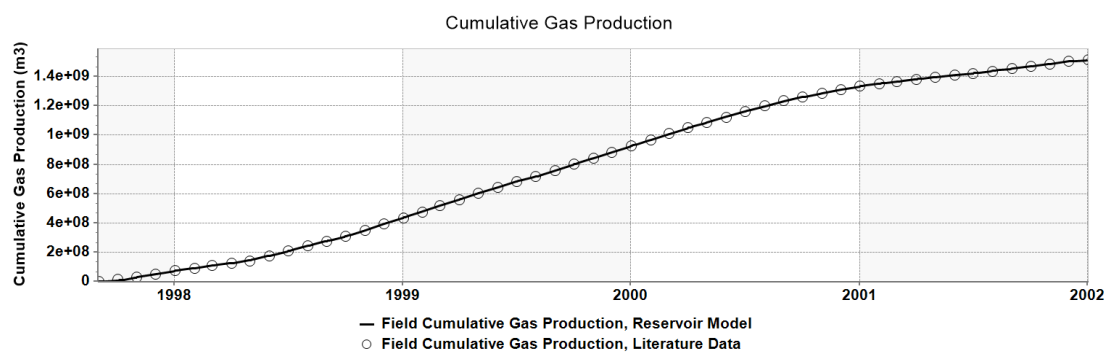


Figure 4.10: History Matching Results of Field Cumulative Gas Production

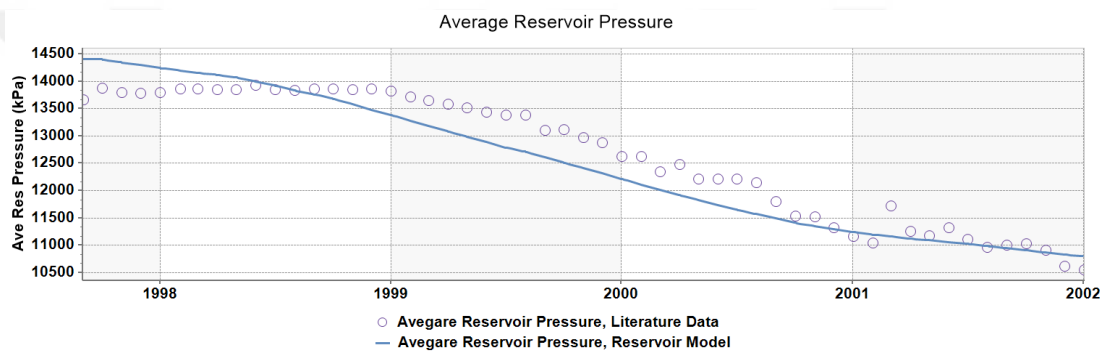


Figure 4.11: History Matching Results of Field Average Reservoir Pressure

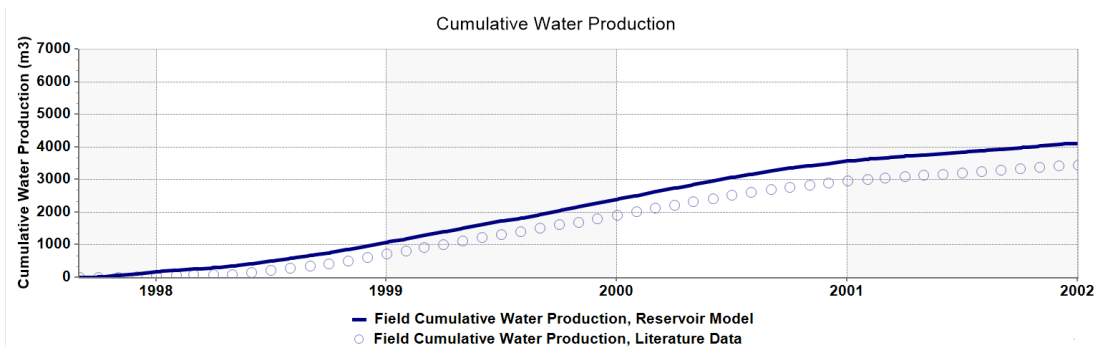


Figure 4.12: History Matching Results of Field Cumulative Water Production

History match is a process aimed at aligning the model with empirical production data. In this phase, the historical production data from the field, including wellhead pressure (Figure 4.8) and cumulative produced gas for each well (Figure 4.9), field cumulative gas production (Figure 4.10), average reservoir pressure (Figure 4.11), and field cumulative water production (Figure 4.12), were compared. Adjustments were made to the unknown reservoir properties such as reservoir thickness, to ensure that the production and pressure data corresponded with the modeled field. In this regard, optimizations were meticulously examined on the production data in the model and the defined parameters to achieve optimal congruence with the historical production data. The resulting calibrated model serves as a foundation for simulating future scenarios for the gas storage process.

Due to the absence of published studies in the literature regarding wells drilled after 2002 to 2024, the well locations have been incorporated into the model by referencing the work of Gumrah et al. (2005). The final reservoir model is presented in Figure 4.14.

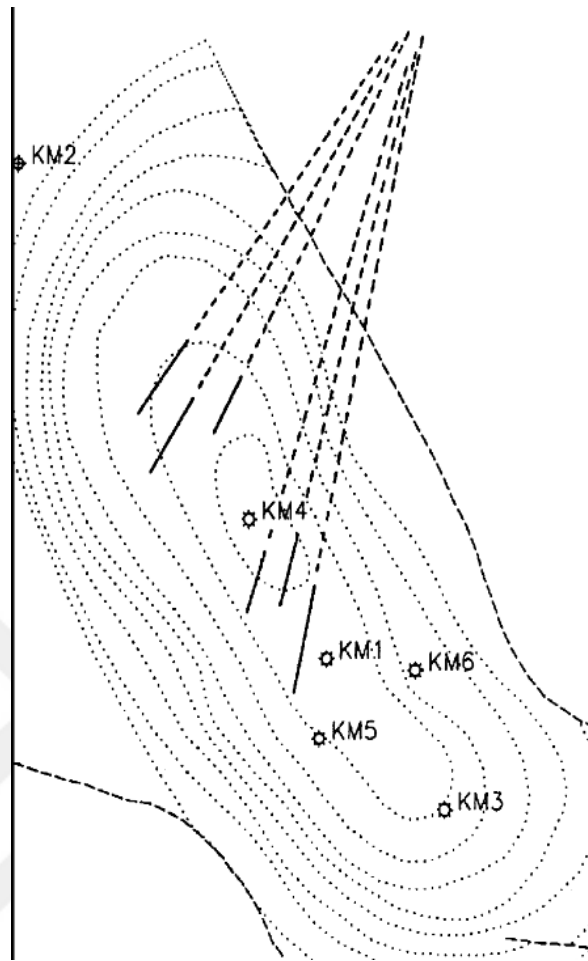


Figure 4.13: Wells Drilled 2002-2005 (Gumrah et al., 2005)

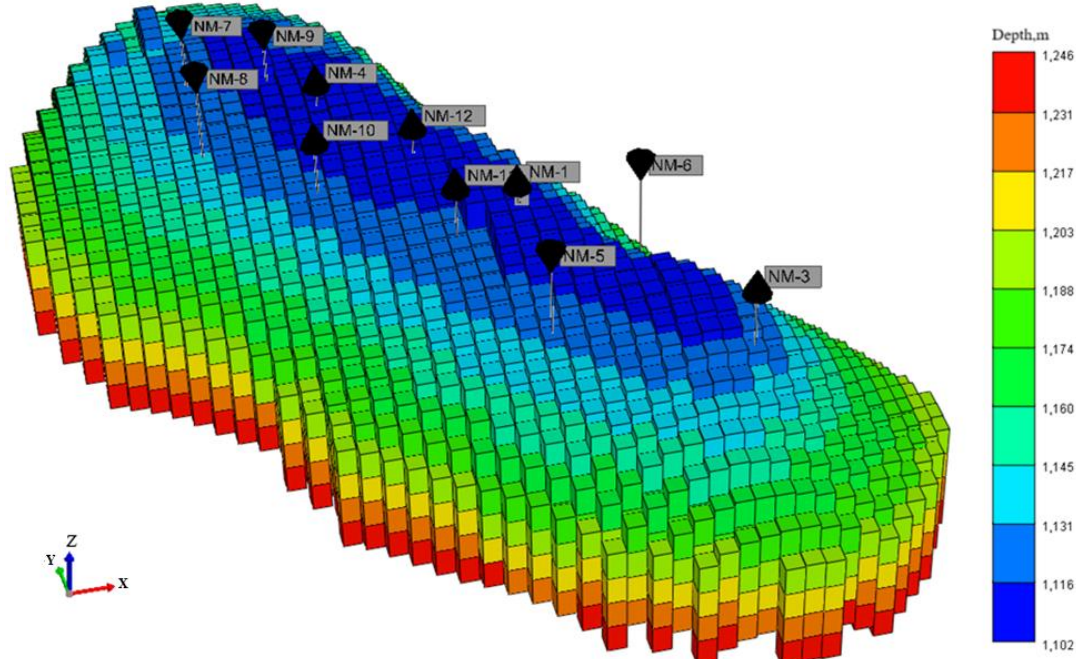


Figure 4.14: Final Reservoir Model

4.5 Model Cases

Since there is no production data available for the wells drilled after 2002, it is assumed that the wells were produced until 2002 and then shut in. Additionally, it is assumed that the wells drilled after 2002 did not produce any gas until the simulation start date in 2024.

To maintain the CO₂ in supercritical condition, the minimum reservoir pressure is constrained to 7800 kPa. Furthermore, the reservoir pressure is limited to 15730 kPa, which does not exceed 10% above the original reservoir pressure of 14300 kPa.

Since the production amount up to 2002 is 1.5 billion m³ and no production is assumed after this year in the model, the total injected gas in the first year is optimized to not exceed 1.5 billion m³.

Injection was performed from wells located near the reservoir boundaries, while the center wells, which have high porosity and permeability, were used for production.

As stated by Shoushtari et al. (2023), the peripheral injection approach resulted in reduced mixing between the cushion gas and the working gas (See Figure 4.15). To this end, a peripheral flooding pattern was implemented in the CMG model. On the other hand, the well trajectories are not considered in the model. The well locations are taken from contour maps and do not represent actual coordinates. The reservoir thickness is assumed to be constant at 60 meters.

To understand the long-term effects of using CH₄ as a cushion gas on production, three scenarios for 1 year, 5 years, and 10 years were examined as summarized in Table 4.5 Comparison of Model Cases. The injection, shut-in, and production periods, as well as the injection and production wells, were kept the same in all simulated scenarios.

Table 4.5 Comparison of Model Cases

Case No	Description	Time (Years)	CH₄ Ratio (%)	CO₂ Ratio (%)
Case-1	100% CH ₄ injection	1, 5, 10	100	0
Case-2	80% CH ₄ and 20% CO ₂ injection	1, 5, 10	80	20
Case-3	70% CH ₄ and 30% CO ₂ injection	1, 5, 10	70	30
Case-4	60% CH ₄ and 40% CO ₂ injection	1, 5, 10	60	40

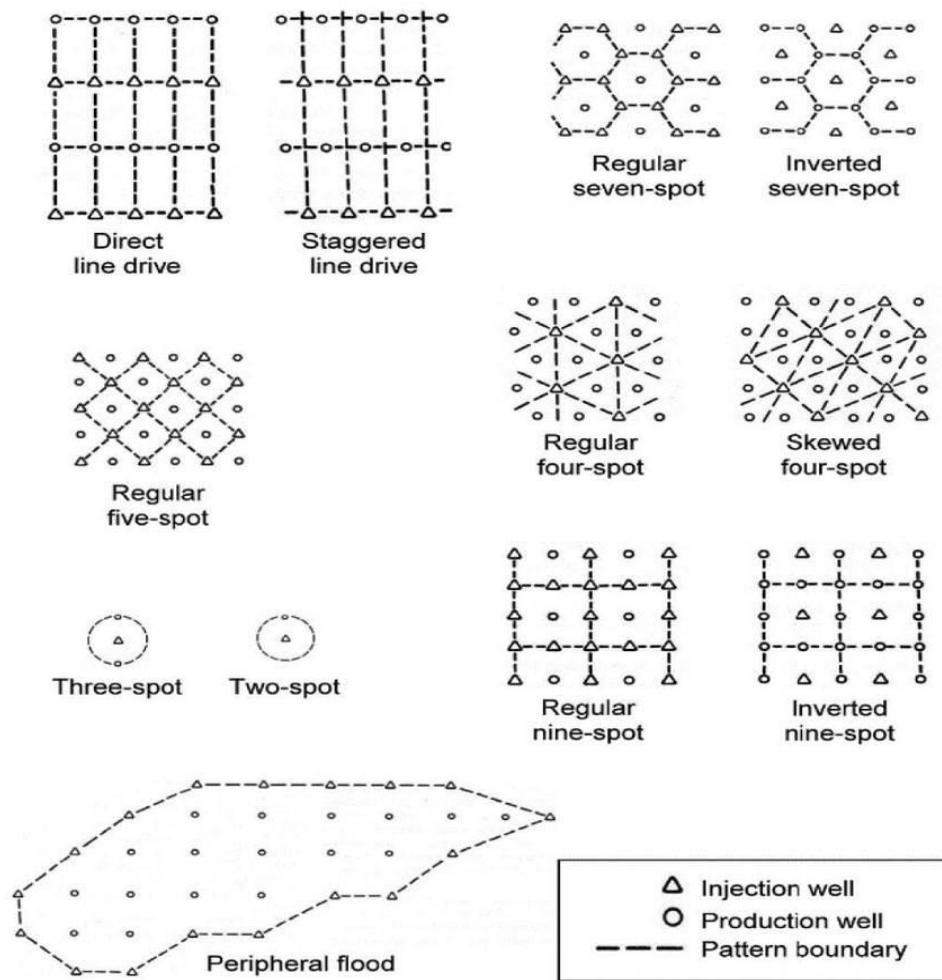


Figure 4.15: Different Injection and Production Well Patterns (Temizel et al., 2017).

4.5.1 Case-1: Injection of 100% CH₄

This case was studied as the base case, and the efficiency of injecting CH₄ as cushion gas in terms of gas recovery was used as a reference for comparison with the other cases.

Table 4.6: Injection and Production Wells Used in Case-1

Well Name	Well Type
NM-1	CH ₄ Injection and Production
NM-3	Only CH ₄ Injection
NM-4	CH ₄ Injection and Production
NM-5	Only CH ₄ Injection
NM-6	Only CH ₄ Injection
NM-7	Only CH ₄ Injection
NM-8	Only CH ₄ Injection
NM-9	Only CH ₄ Injection
NM-10	CH ₄ Injection and Production
NM-11	CH ₄ Injection and Production
NM-12	CH ₄ Injection and Production

Table 4.7: Injection and Production Periods for Case-1

YEAR	STATUS	PERIOD
1	CH₄ INJECTION	2024-Jan & 2024-Feb
	SHUT-IN	2024-Mar
	CH₄ INJECTION	2024-Apr & 2024-May & 2024-June & 2024 July
	SHUT-IN	2024-Aug
	CH₄ PRODUCTION	2024-Sep & 2024-Oct & 2024-Nov
	SHUT IN	2024-Dec
2	CH₄ INJECTION	2025-Jan & 2025-Feb
	SHUT-IN	2025-Mar
	CH₄ INJECTION	2025-Apr & 2025-May & 2025-June & 2025 July
	SHUT-IN	2025-Aug
	CH₄ PRODUCTION	2025-Sep & 2025-Oct & 2025-Nov

	SHUT IN	2025-Dec
3	CH₄ INJECTION	2026-Jan & 2026-Feb
	SHUT-IN	2026-Mar
	CH₄ INJECTION	2026-Apr & 2026-May & 2026-June & 2026-July
	SHUT-IN	2026-Aug
	CH₄ PRODUCTION	2026-Sep & 2026-Oct & 2026-Nov
	SHUT IN	2026-Dec
4	CH₄ INJECTION	2027-Jan & 2027-Feb
	SHUT-IN	2027-Mar
	CH₄ INJECTION	2027-Apr & 2027-May & 2027-June & 2027 July
	SHUT-IN	2027-Aug
	CH₄ PRODUCTION	2027-Sep & 2027-Oct & 2027-Nov
	SHUT IN	2024-Dec
5	CH₄ INJECTION	2028-Jan & 2028-Feb
	SHUT-IN	2028-Mar
	CH₄ INJECTION	2028-Apr & 2028-May & 2028-June & 2028 July
	SHUT-IN	2028-Aug
	CH₄ PRODUCTION	2028-Sep & 2028-Oct & 2028-Nov
	SHUT IN	2028-Dec
6	CH₄ INJECTION	2029-Jan & 2029-Feb
	SHUT-IN	2029-Mar
	CH₄ INJECTION	2029-Apr & 2028-May & 2028-June & 2028 July
	SHUT-IN	2029-Aug
	CH₄ PRODUCTION	2029-Sep & 2029-Oct & 2029-Nov
	SHUT IN	2029-Dec
7	CH₄ INJECTION	2030-Jan & 2030--Feb
	SHUT-IN	2030-Mar
	CH₄ INJECTION	2030-Apr & 2030-May & 2030-June & 2030 July
	SHUT-IN	2030-Aug

	CH₄ PRODUCTION	2030-Sep & 2030-Oct & 2030-Nov
	SHUT IN	2030-Dec
8	CH₄ INJECTION	2031-Jan & 2031-Feb
	SHUT-IN	2031-Mar
	CH₄ INJECTION	2031-Apr & 2031-May & 2031-June & 2031-July
	SHUT-IN	2031-Aug
	CH₄ PRODUCTION	2031-Sep & 2031-Oct & 2031-Nov
	SHUT IN	2031-Dec
9	CH₄ INJECTION	2032-Jan & 2032-Feb
	SHUT-IN	2032-Mar
	CH₄ INJECTION	2032-Apr & 2032-May & 2032-June & 2032-July
	SHUT-IN	2032-Aug
	CH₄ PRODUCTION	2032-Sep & 2032-Oct & 2032-Nov
	SHUT IN	2032-Dec
10	CH₄ INJECTION	2033-Jan & 2033-Feb
	SHUT-IN	2033-Mar
	CH₄ INJECTION	2033-Apr & 2033-May & 2033-June & 2033-July
	SHUT-IN	2033-Aug
	CH₄ PRODUCTION	2033-Sep & 2033-Oct & 2033-Nov
	SHUT IN	2033-Dec

The months of injection and production were considered only in terms of duration, without taking seasonal requirements into account.

4.5.2 Case-2: Injection of 80% CH₄ and 20% CO₂

In this case, CO₂ was injected as cushion gas, followed by the injection of CH₄ for storage. The total gas injected consisted of 20% CO₂ and 80% CH₄.

4.5.3 Case-3: Injection of 70% CH₄ and 30% CO₂

In this case, CO₂ was injected as cushion gas, followed by the injection of CH₄ for storage. The total gas injected consisted of 30% CO₂ and 70% CH₄.

4.5.4 Case-4: Injection of 60% CH₄ and 40% CO₂

In this scenario, CO₂ was injected as cushion gas, followed by the injection of working gas, i.e. the CH₄ for storage. The total gas injected consisted of 40% CO₂ and 60% CH₄. As summarized in Table 4.8, some of wells were used solely during the cushion gas (only CO₂) injection period and were subsequently shut in. After the cushion gas injection period, wells that were used for working gas (only CH₄) injection were also utilized for production purposes after the shut-in period. During this time, no production was made from the wells where CO₂ injection had been performed. The injection and production periods are also listed in Table 4.9.

Table 4.8: Injection and Production Wells Used in Case-2, Case-3, and Case-4

Well Name	Well Type
NM-1	CH ₄ Injection and Production
NM-3	Only CO ₂ Injection
NM-4	CH ₄ Injection and Production
NM-5	Only CO ₂ Injection
NM-6	Only CO ₂ Injection
NM-7	Only CO ₂ Injection
NM-8	Only CO ₂ Injection
NM-9	Only CO ₂ Injection
NM-10	CH ₄ Injection and Production

NM-11	CH ₄ Injection and Production
NM-12	CH ₄ Injection and Production

Table 4.9: Case-2, Case-3 and Case-4 Injection and Production Periods

YEAR	STATUS	PERIOD
1	CO₂ INJECTION	2024-Jan & 2024-Feb
	SHUT-IN	2024-Mar
	CH₄ INJECTION	2024-Apr & 2024-May & 2024-June & 2024 July
	SHUT-IN	2024-Aug
	CH₄ PRODUCTION	2024-Sep & 2024-Oct & 2024-Nov
	SHUT IN	2024-Dec
2	CO₂ INJECTION	2025-Jan & 2025-Feb
	SHUT-IN	2025-Mar
	CH₄ INJECTION	2025-Apr & 2025-May & 2025-June & 2025 July
	SHUT-IN	2025-Aug
	CH₄ PRODUCTION	2025-Sep & 2025-Oct & 2025-Nov
	SHUT IN	2025-Dec
3	CO₂ INJECTION	2026-Jan & 2026-Feb
	SHUT-IN	2026-Mar
	CH₄ INJECTION	2026-Apr & 2026-May & 2026-June & 2026-July
	SHUT-IN	2026-Aug
	CH₄ PRODUCTION	2026-Sep & 2026-Oct & 2026-Nov
	SHUT IN	2026-Dec
4	CO₂ INJECTION	2027-Jan & 2027-Feb
	SHUT-IN	2027-Mar
	CH₄ INJECTION	2027-Apr & 2027-May & 2027-June & 2027 July
	SHUT-IN	2027-Aug
	CH₄ PRODUCTION	2027-Sep & 2027-Oct & 2027-Nov
	SHUT IN	2024-Dec
5	CO₂ INJECTION	2028-Jan & 2028-Feb
	SHUT-IN	2028-Mar
	CH₄ INJECTION	2028-Apr & 2028-May & 2028-June & 2028 July
	SHUT-IN	2028-Aug
	CH₄ PRODUCTION	2028-Sep & 2028-Oct & 2028-Nov
	SHUT IN	2028-Dec

6	CO₂ INJECTION	2029-Jan & 2029-Feb
	SHUT-IN	2029-Mar
	CH₄ INJECTION	2029-Apr & 2028-May & 2028-June & 2028 July
	SHUT-IN	2029-Aug
	CH₄ PRODUCTION	2029-Sep & 2029-Oct & 2029-Nov
	SHUT IN	2029-Dec
7	CO₂ INJECTION	2030-Jan & 2030--Feb
	SHUT-IN	2030-Mar
	CH₄ INJECTION	2030-Apr & 2030-May & 2030-June & 2030 July
	SHUT-IN	2030-Aug
	CH₄ PRODUCTION	2030-Sep & 2030-Oct & 2030-Nov
	SHUT IN	2030-Dec
8	CO₂ INJECTION	2031-Jan & 2031-Feb
	SHUT-IN	2031-Mar
	CH₄ INJECTION	2031-Apr & 2031-May & 2031-June & 2031-July
	SHUT-IN	2031-Aug
	CH₄ PRODUCTION	2031-Sep & 2031-Oct & 2031-Nov
	SHUT IN	2031-Dec
9	CO₂ INJECTION	2032-Jan & 2032-Feb
	SHUT-IN	2032-Mar
	CH₄ INJECTION	2032-Apr & 2032-May & 2032-June & 2032-July
	SHUT-IN	2032-Aug
	CH₄ PRODUCTION	2032-Sep & 2032-Oct & 2032-Nov
	SHUT IN	2032-Dec
10	CO₂ INJECTION	2033-Jan & 2033-Feb
	SHUT-IN	2033-Mar
	CH₄ INJECTION	2033-Apr & 2033-May & 2033-June & 2033-uly
	SHUT-IN	2033-Aug
	CH₄ PRODUCTION	2033-Sep & 2033-Oct & 2033-Nov
	SHUT IN	2033-Dec

CHAPTER 5

RESULTS AND DISCUSSION

5.1 CMG Model Results

5.1.1 Case-1: Injection of 100% CH₄

This case was chosen as the base case for the study, meaning it served as the starting point or reference scenario for evaluating the performance of the reservoir. In this scenario, CH₄ was injected as cushion gas instead of CO₂, and its efficiency in enhancing the gas recovery was carefully analyzed. The performance of this injection strategy was then used as a benchmark to compare against the results of other alternative cases, allowing for a clearer understanding of how different gas injection methods might influence overall gas recovery and production outcomes.

To better comprehend the long-term effects of using CH₄ as a cushion gas, several scenarios with different time frames were considered. These time frames included 1 year, 5 years, and 10 years, each representing a different stage in the reservoir's production life. By examining these different periods, the study aimed to capture the evolving impact of CH₄ injection on the reservoir over both the short and long term, allowing for a more comprehensive assessment of how this method could sustain or improve gas production throughout the life of the reservoir.

5.1.1.1 1-Year Cycle Injection 100% CH₄

For the first 2 months, CH₄ gas was injected into the reservoir at an injection rate of 8 MMm³/day. Afterward, the wells were shut-in for a period of 1 month. Following the 1-month shut-in period, CH₄ was injected into the wells for storage purposes at the same injection rate of 8 MMm³/day for 4 months, and then the wells were shut-in again for another month. After the second 1-month shut-in period, the gas withdrawal phase was initiated. The production rates were as follows: in the first month, 29,942,418 m³/day; in the second month, 16,007,951

m³/day; and in the third month, 10,686,991 m³/day. The injection and production rates from the wells were maintained at equal rates.

Table 5.1: Case-1 Injection and Production Summary for 1-Year Cycle

OGIP, m³	5.56 MMM-m ³
Produced gas until 2002, m³	1.51 MMM-m ³
Remained gas after 2002, m³	4.04 MMM-m ³
OGIP, CH₄ after 2002, m³	3.70 MMM-m ³
Total Injected CH₄, m³	1.46 MMM-m ³
Total Produced Gas, m³	1.72 MMM-m ³
Produced CH₄ in 1 year, m³	1.63 MMM-m ³
Produced reservoir CH₄, m³	0.17 MMM-m ³
Reservoir CH₄ Recovery, %	4.61

As summarized in Table 5.1, only 4.61% of the initial CH₄ in the reservoir was produced during the 1-year period of 100% CH₄ storage. The average reservoir pressure fluctuated between 10,750 and 14,250 kPa throughout the year.

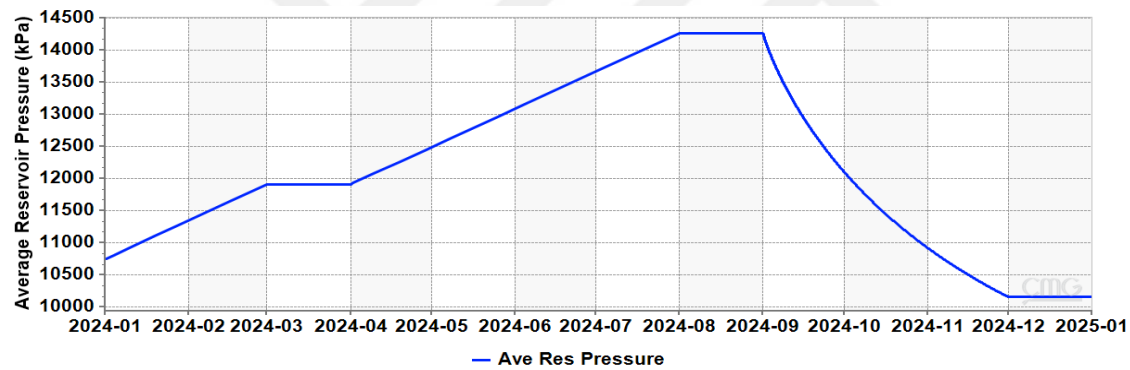


Figure 5.1: Case-1: 1-Year Average Reservoir Pressure

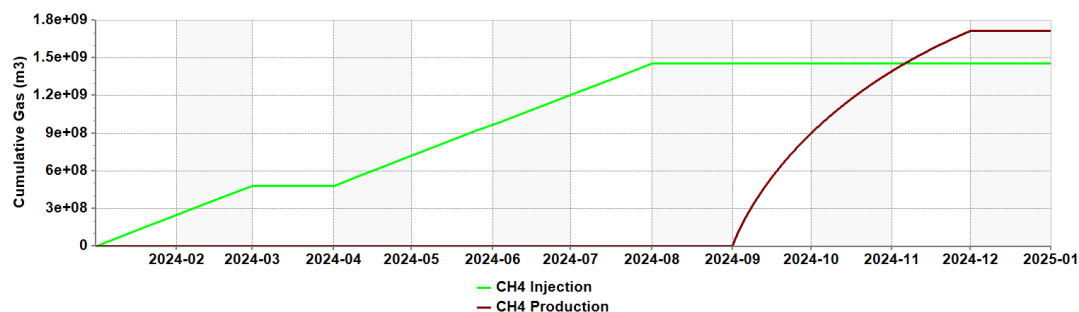


Figure 5.2: Case-1: 1-Year Period Cumulative Injection and Production Gas

The initial reservoir gases, as indicated in Table 4.2, are as follows before the start of CH₄ injection. During the first injection period, CH₄ injected as cushion gas and accumulated rapidly around wells injection NM-7, NM-8, and NM-9. In the second injection period which is working gas injection period, the CH₄ accumulated during the previous phase increased reservoir pressure, causing the gas to spread in the reservoir (Figure 5.3). Since CH₄ is light gas, it has shown homogeneous distribution in the upper and lower layers as seen in the Figure 5.4.

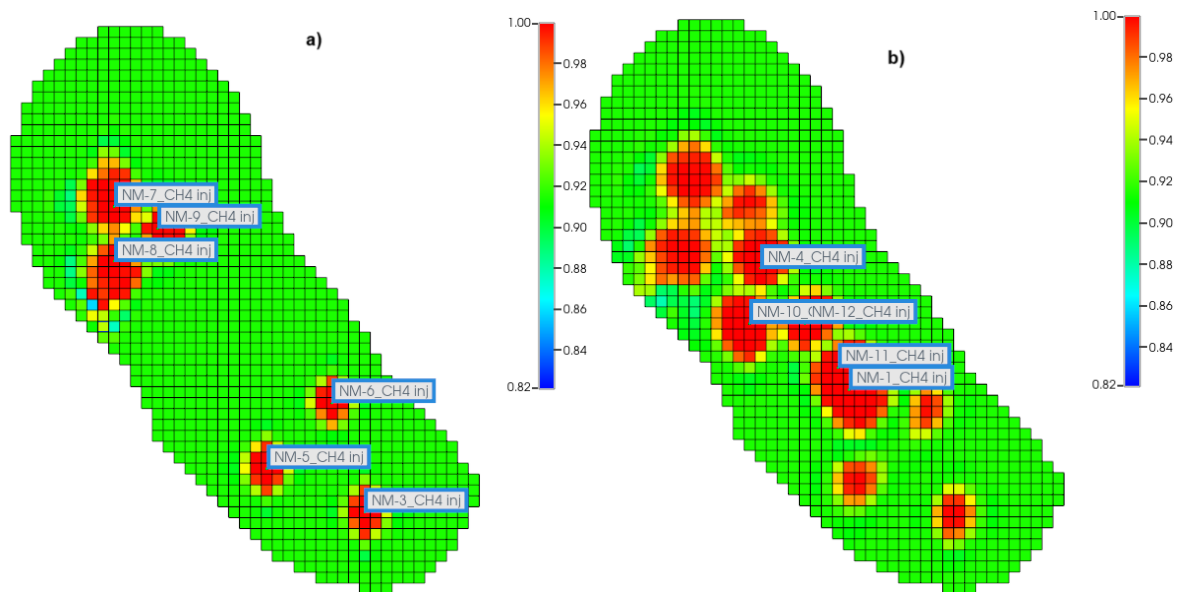


Figure 5.3: Case-1 1-Year Cycle; CH₄ Mole Fraction in First Layer a) End of First CH₄ Injection Period and b) at the End of Second Injection Period

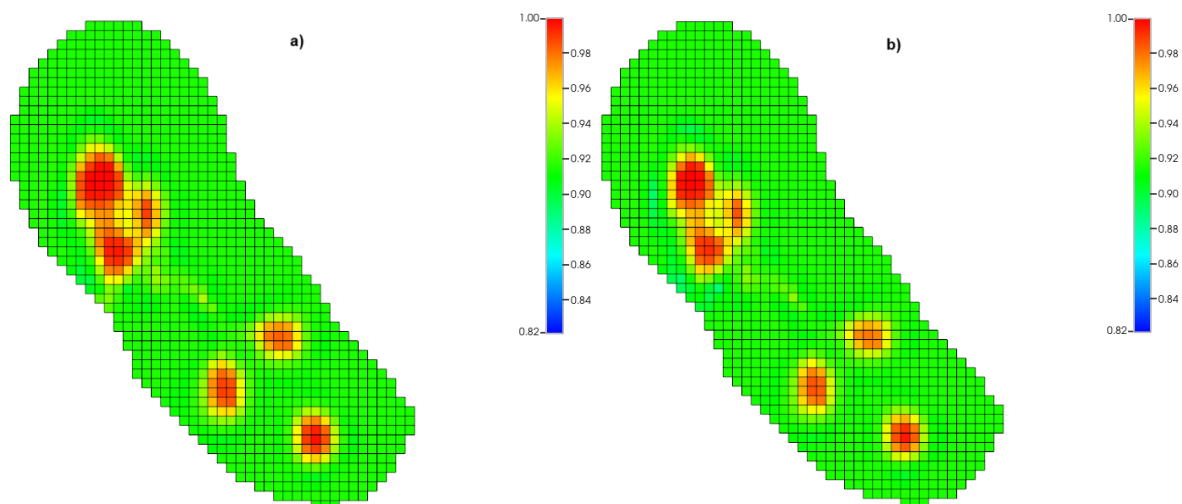


Figure 5.4: Case-1 1-Year Cycle; CH₄ Mole Fraction at the end of production period a) First Layer and b) Last Layer

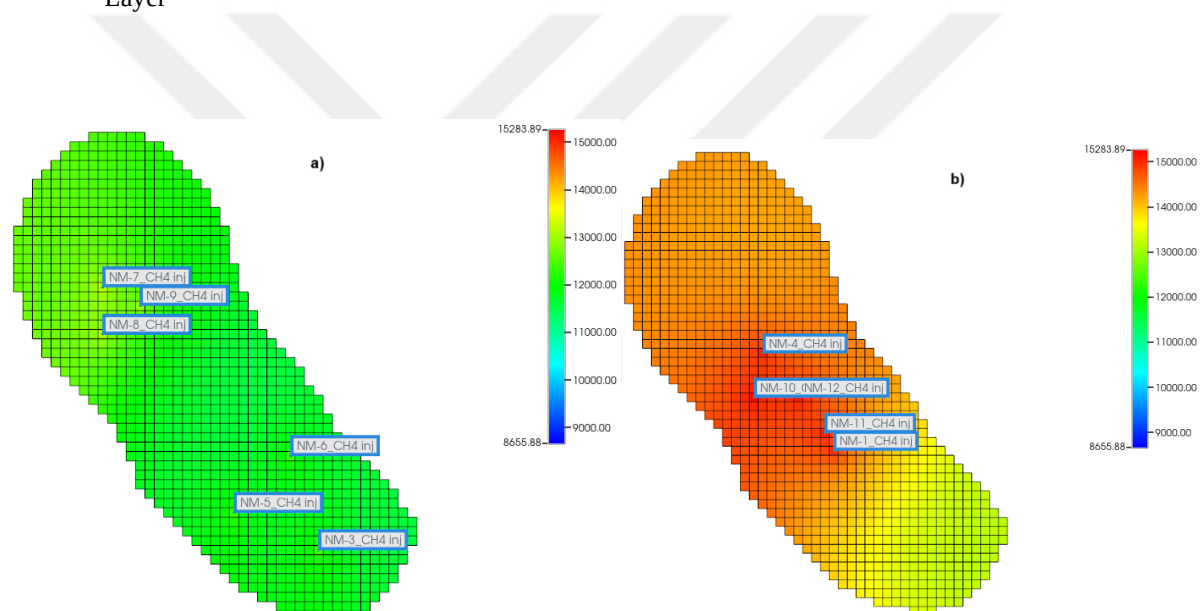


Figure 5.5: Case-1: 1-Year Cycle; Reservoir Pressure (in kPa) a) at the end of First CH₄ Injection Period b) at the End of second CH₄ Injection Period

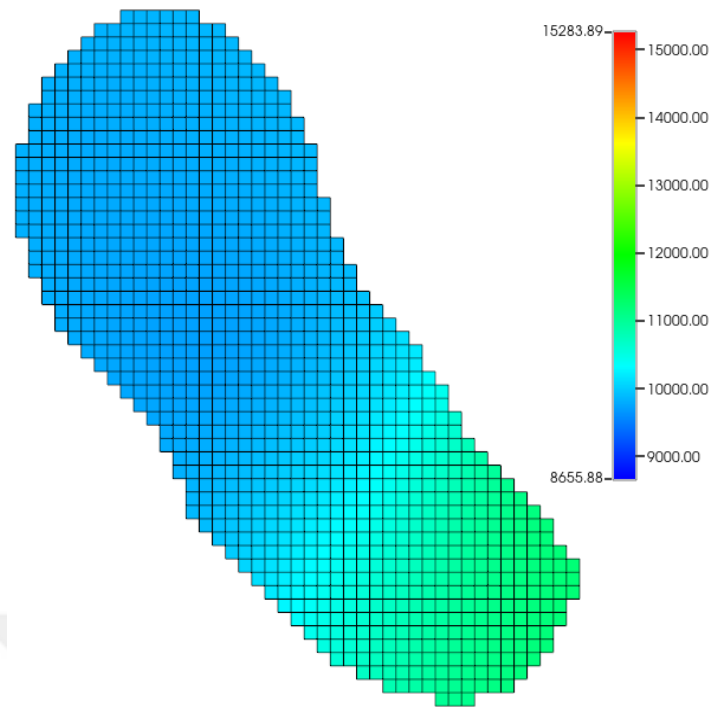


Figure 5.6: Case-1: 1-Year Cycle; Reservoir Pressure (in kPa) at the End of Production Period

5.1.1.2 5-Year Cycle Injection 100% CH₄

As in the previous case, CH₄ injection was carried out at a rate of 8 MMm³/day for the first 2 months, followed by a 1-month shut-in period. After this 1-month shut-in period, CH₄ was injected into the wells at the same injection rate of 8 MMm³/day for 4 months. Then, the wells were shut-in again for another month. After the second 1-month shut-in period, the gas withdrawal phase was initiated. The production rates for 5 years were summarized in Table 5.2.

Table 5.2: Case-1 Gas Production Rate for 5-Year Cycle

Year	Month	Gas Prod Rate (MMm ³ /day)
1	1	20.16
	2	12.78
	3	8.92
2	1	18.13
	2	11.52
	3	8.06
3	1	17.48
	2	11.10
	3	7.76
4	1	17.26
	2	10.96

	3	7.66
5	1	17.24
	2	10.94
	3	7.64

Injection was performed for the first 2 months, followed by a 1-month shut-in period. Then, CH₄ gas was injected for storage purposes over a period of 4 months, after which another 1-month shut-in period was applied. Subsequently, CH₄ gas was withdrawn from the wells for 4 months. After the withdrawal phase, another 1-month shut-in period was initiated. This cycle was studied over a 5-year period.

Table 5.3: Case-1 Injection and Production Summary for 5-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	7.26
Total Produced Gas, MMM m³	7.66
Produced CH₄ in 5 years, MMM m³	7.42
Produced reservoir CH₄, MMM m³	0.17
Reservoir CH₄ Recovery, %	4.55

As summarized in Table 5.3, only 4.55% of the initial CH₄ in the reservoir was produced during the 5-year period of 100% CH₄ storage. The average reservoir pressure fluctuated between 9,860 and 14,260 kPa throughout the 5-years.

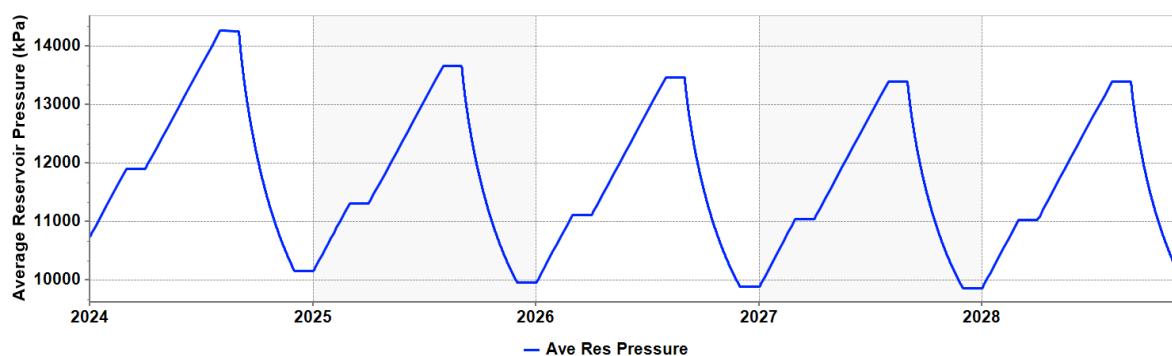


Figure 5.7: Case-1 5-Year Average Reservoir Pressure

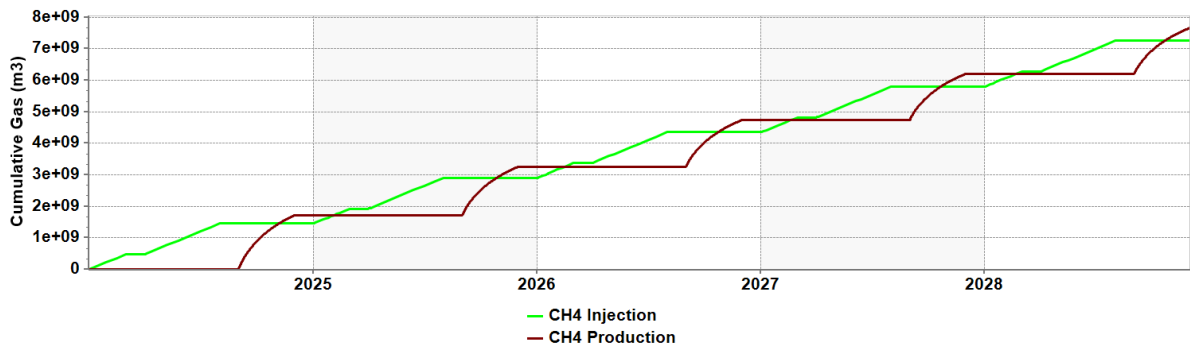


Figure 5.8: Case-1 5-Year Period Cumulative Injection and Production Gas

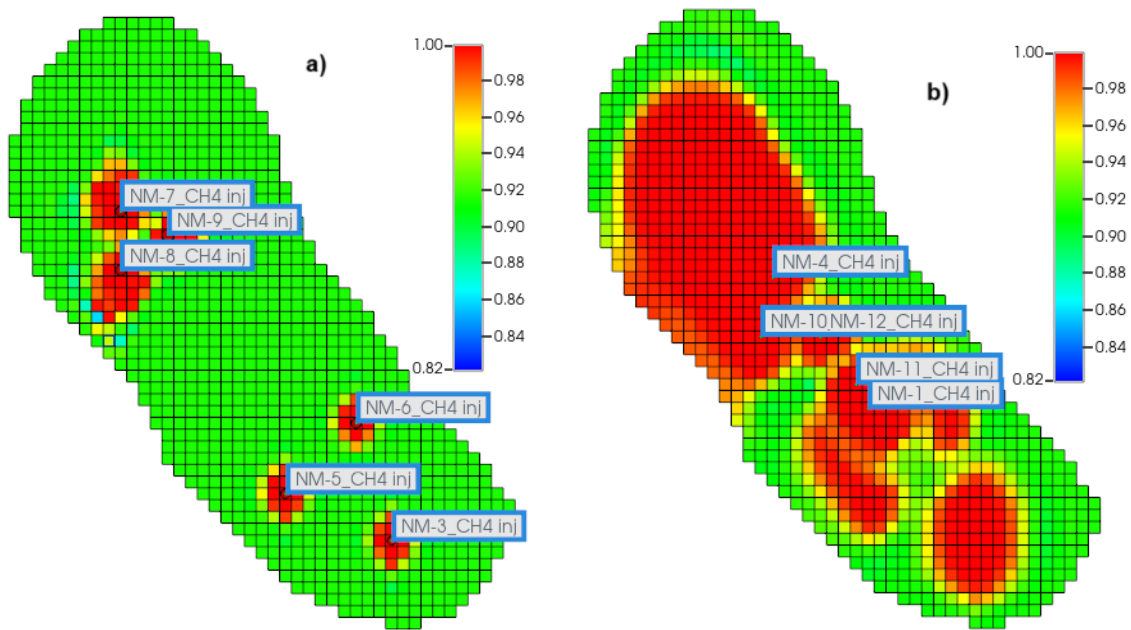


Figure 5.9: Case-1 5-Year Cycle; CH₄ Mole Fraction in First Layer a) End of First CH₄ Injection Period and b) at the end of Last Injection Period

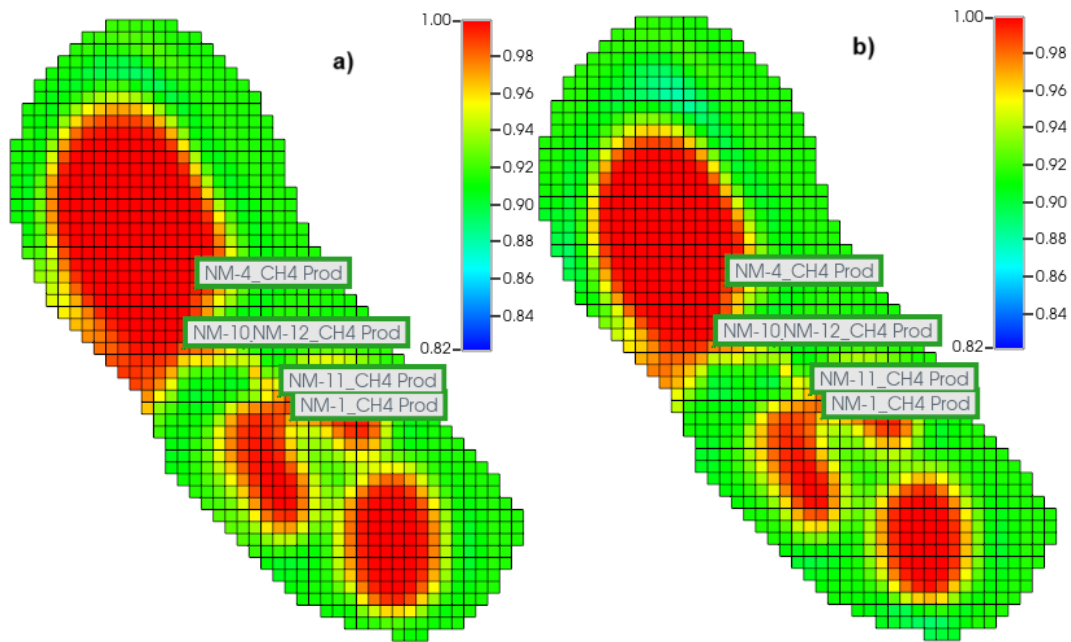


Figure 5.10: Case-1 5-Year Cycle; CH₄ Mole Fraction at the end of 5-Year production period a) First Layer and b) Last Layer

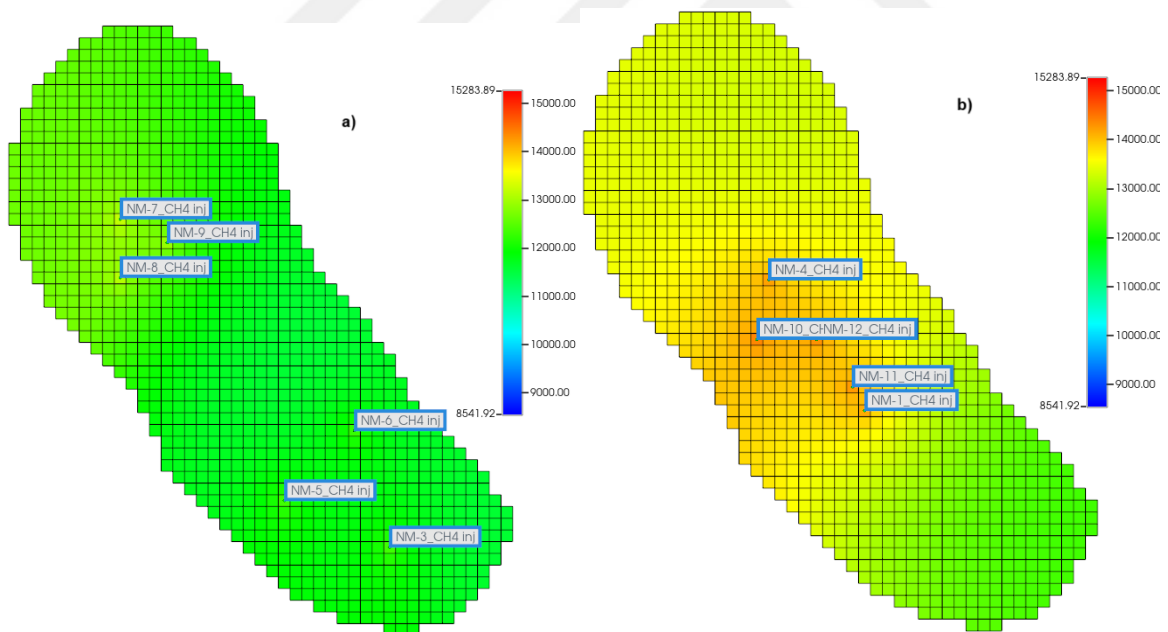


Figure 5.11: Case-1 5-Year Cycle; Reservoir Pressure a) at the End of First CH₄ Injection Period b) at the End of Last CH₄ Injection Period

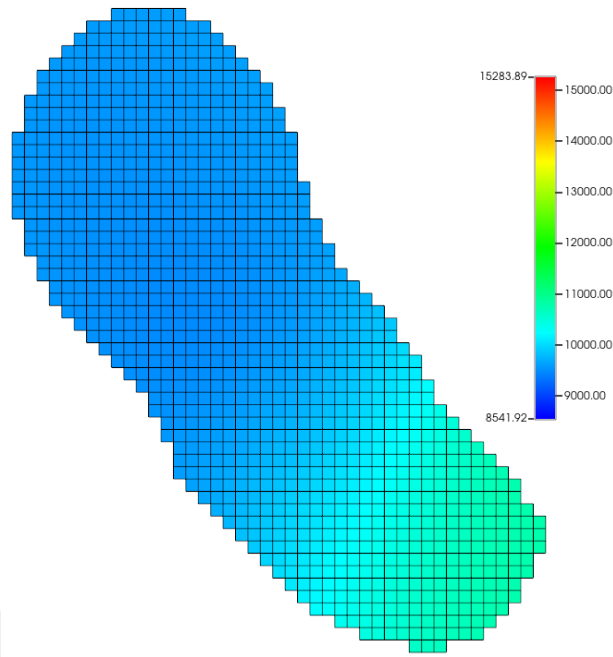


Figure 5.12: Case-1 5-Year Cycle; Reservoir Pressure (in kPa) at the End of Production Period

5.1.1.3 10-Year Cycle Injection 100% CH₄

CH₄ injection was carried out at a rate of 8 MMm³/day for the first 2 months, followed by a 1-month shut-in period. CH₄ was then injected for 4 months at the same rate, followed by another 1-month shut-in period. After the second shut-in, the gas withdrawal phase began. The production rates for 10 years were summarized in Table 5.4.

Table 5.4 Case-1 Gas Production Rate for 10-Year Cycle

Year	Month	Gas Prod Rate (MMm ³ /day)
1	1	29.94
	2	16.00
	3	10.68
2	1	26.78
	2	14.41
	3	9.64
3	1	25.78
	2	13.89
	3	9.29
4	1	25.45
	2	13.71
	3	9.16
5	1	25.43

	2	13.69
	3	9.15
6	1	25.31
	2	13.63
	3	9.10
7	1	25.28
	2	13.61
	3	9.09
8	1	25.26
	2	13.60
	3	9.08
9	1	25.36
	2	13.65
	3	9.11
10	1	25.29
	2	13.61
	3	9.08

As summarized in Table 5.5, only 2.36% of the initial CH₄ in the reservoir was produced during the 10-year period of 100% CH₄ storage. The average reservoir pressure fluctuated between 9,860 and 14,260 kPa throughout the 10 years.

Table 5.5: Case-1 Injection and Production Summary for 10-Year Cycle

OGIP	5.56
Produced gas until 2002, MMM-m³	1.51
Remained gas after 2002, MMM-m³	4.04
OGIP, CH₄ after 2002, MMM-m³	3.70
Total Injected CH₄, MMM-m³	14.50
Total Produced Gas, MMM-m³	14.94
Produced CH₄ in 5 year, MMM-m³	14.60
Produced reservoir CH₄, MMM-m³	0.10
Reservoir CH₄ Recovery, %	2.36

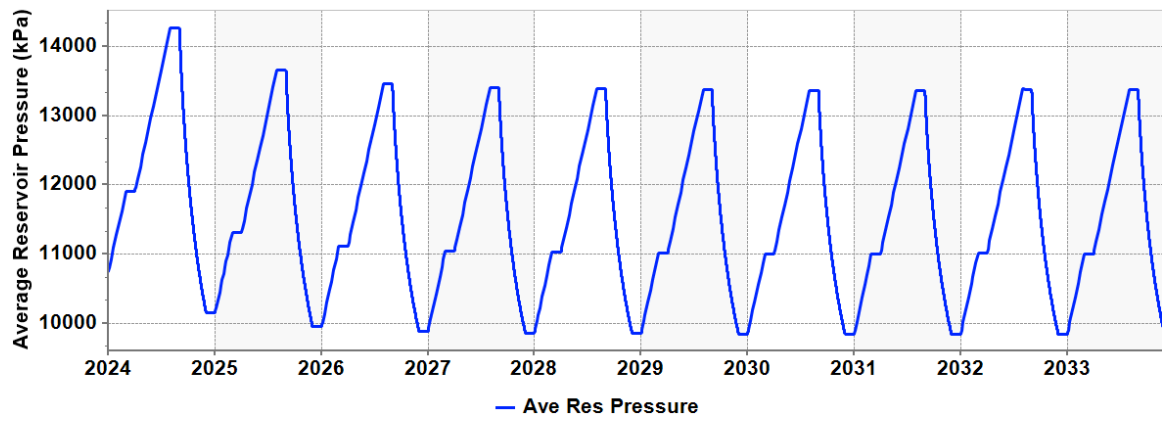


Figure 5.13: Case-1 10-Year Average Reservoir Pressure

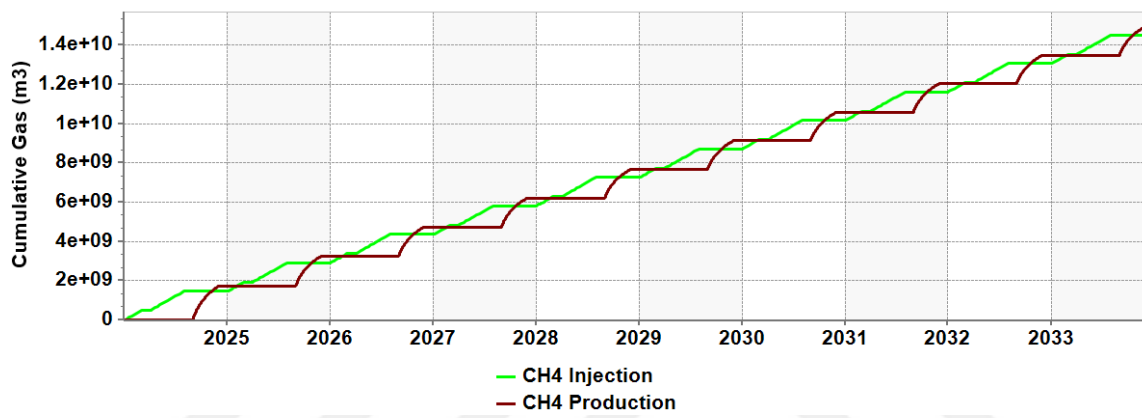


Figure 5.14: Case-1 10-Year Period Cumulative Injection and Production Gas

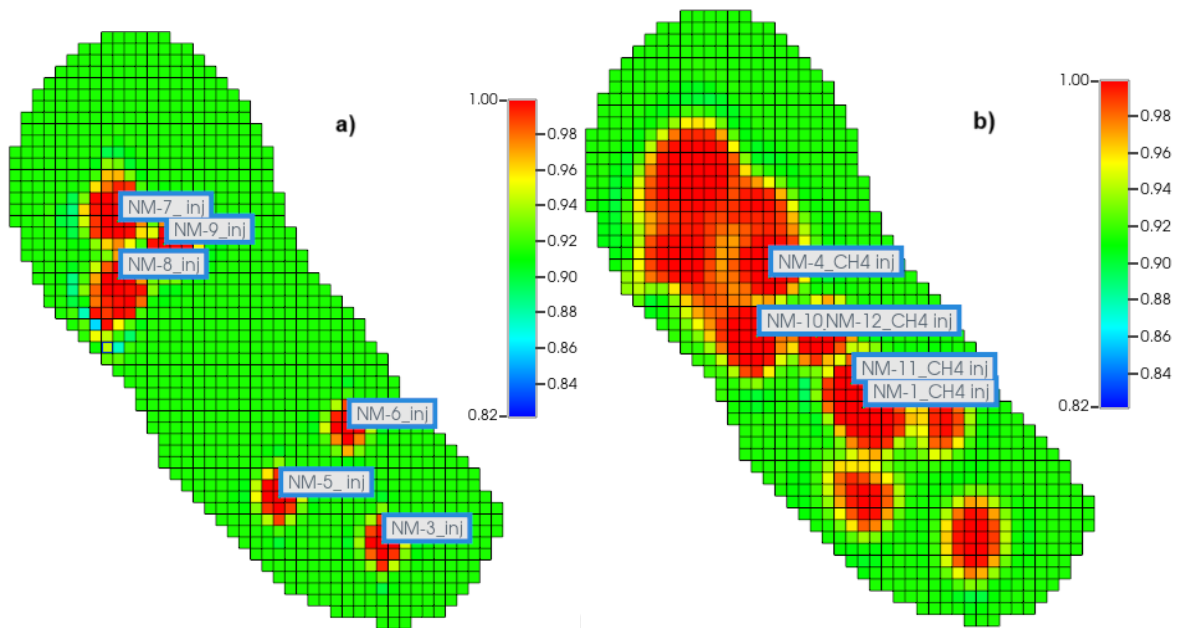


Figure 5.15: Case-1 10-Year Cycle; CH₄ Mole Fraction in First Layer a) at End of First CH₄ Injection Period and b) at the End of Last Injection Period

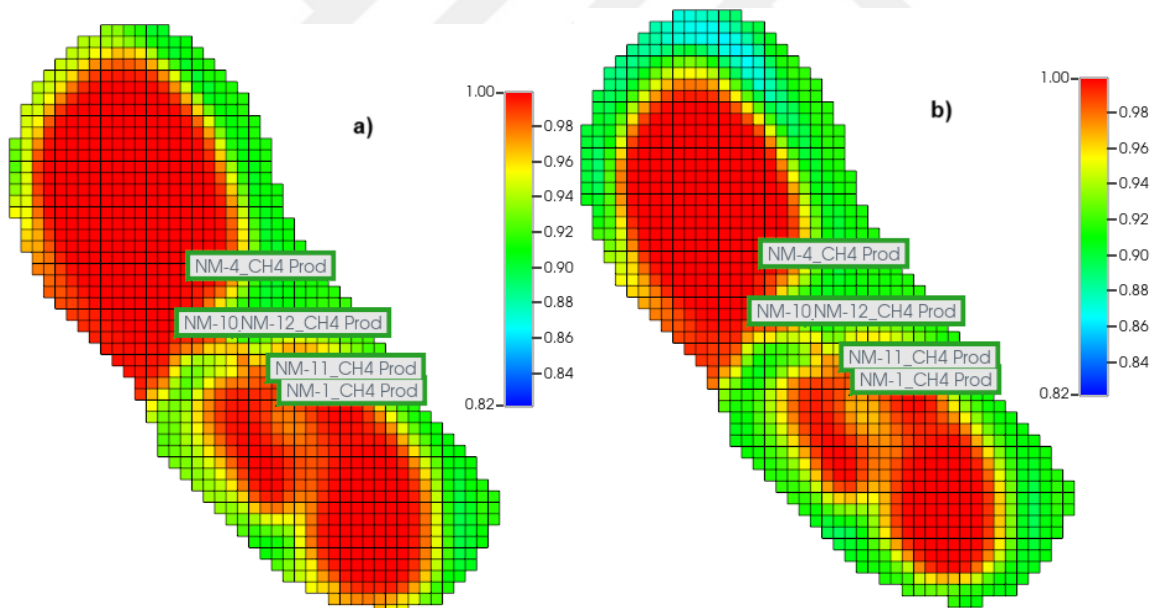


Figure 5.16: Case-1 10-Year Cycle; CH₄ Mole Fraction at the end of 10-Year production period a) First Layer and b) Last Layer

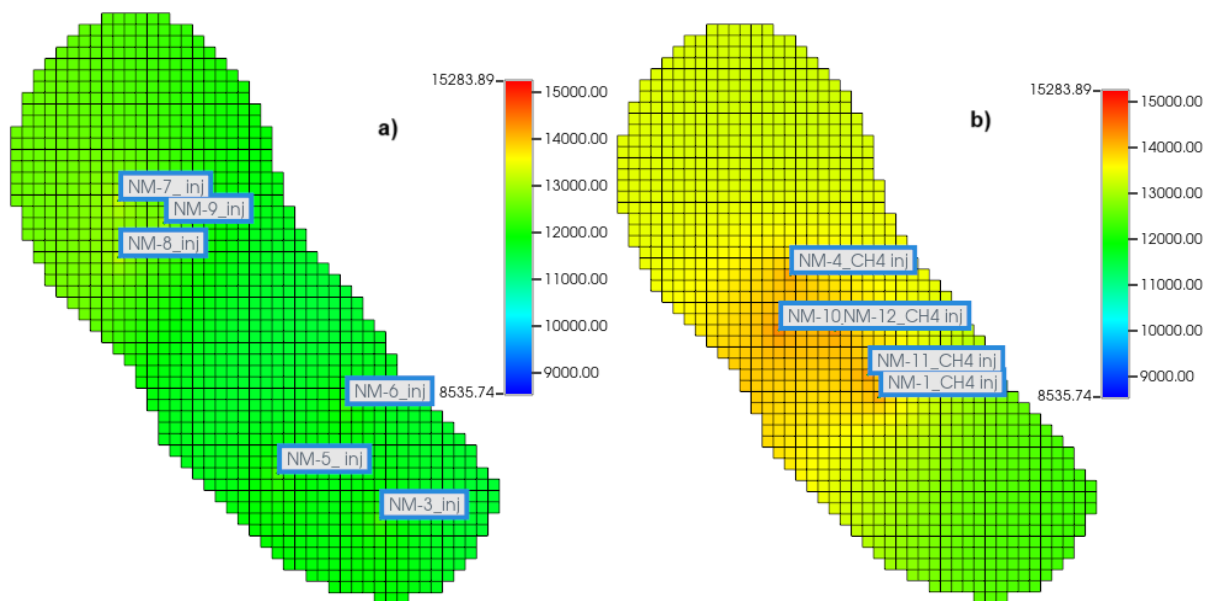


Figure 5.17: Case-1 10-Year Cycle; Reservoir Pressure a) at the End of First CH₄ injection Period b) at the End of Last CH₄ Injection Period

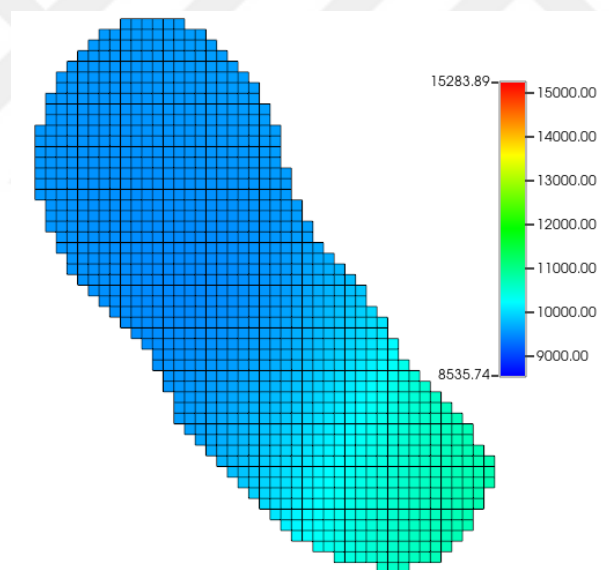


Figure 5.18: Case-1 10-Year Cycle; Reservoir Pressure(in kPa) at the End of Production Period

5.1.2 Case-2 Injection of 80% CH₄ and 20% CO₂

In this case, CO₂ was initially injected into the storage field as cushion gas, which served to maintain the pressure and stability of the reservoir during the subsequent injection of CH₄ for storage. The total volume of gas injected into the field was composed of 20% CO₂ and 80% CH₄, with the goal of evaluating the performance and long-term behavior of this mixed gas injection strategy. To analyze the effects of using CO₂ as cushion gas, the production and storage scenarios were evaluated over three distinct timeframes: 1 year, 5 years, and 10 years. These timeframes allowed for a comprehensive assessment of how the storage field would respond to the different phases of gas injection, shut-in periods, and production cycles.

In each of these scenarios, it was assumed that the fundamental parameters governing the injection and production processes remained consistent. Specifically, the injection and shut-in periods, as well as the production periods, were maintained at fixed intervals, ensuring a uniform comparison across the different durations. Furthermore, the locations of the injection and production wells were kept constant throughout the analysis. This consistency was crucial to isolating the effect of CO₂ cushion gas on overall production and storage efficiency, without the confounding influences of variable well placement or operational changes. Through this approach, the study aimed to provide insights into the long-term viability and effectiveness of using CO₂ as a cushion gas in natural gas storage projects.

5.1.2.1 1-Year Cycle Injection of 80% CH₄ and 20% CO₂

For the first 2 months, CO₂ was injected into the reservoir at an injection rate of 4.7 MMm³/day. Afterward, the wells were shut-in for a period of 1 month. Following the 1-month shut-in period, CH₄ was injected into the wells for storage purposes with an injection rate of 9.7 MMm³/day for 4 months, and then the wells were shut-in again for another month. After the second 1-month shut-in period, the gas withdrawal phase was initiated. The production rates were as follows: in the first month, 19.37 MMm³/day; in the second month, 12.27 MMm³/day; and in the third month, 8.64 MMm³/day. The injection and production rates from the wells were maintained at equal levels. As summarized in Table 5.6, 11.13 % of the initial CH₄ in the

reservoir was produced during the 1 year of 80% CH₄ storage. The average reservoir pressure fluctuated between 10,150 and 14,040 kPa throughout the year.

Table 5.6: Case-2: Injection and Production Summary for 1-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	1.16
Total Injected CO₂, MMM m³	0.30
Total Injected Gas, MMM m³	1.46
Total Produced CH₄, MMM m³	1.57
Total Produced CO₂, MMM m³	0.03
Total Produced Gas, MMM m³	1.65
Total Produced Other Gases*, MMM m³	0.05
Produced reservoir CH₄, MMM m³	0.41
Produced reservoir CH₄, MMM m³	0.41
Reservoir CH₄ Recovery, %	11.13

* Other Gases represent initial reservoir gases stated in Table 4.2.

Table 5.7: Gas Mole Fractions of Produced Gas

Time	C₂H₆	C₃H₈	CH₄	CO₂	iC₄	iC₅	N₂	nC₄	nC₅
1 st Month	0.0079	0.003	0.9781	0.0064	0.0006	0.0002	0.0028	0.0007	0.0002
2 nd Month	0.0196	0.0074	0.9336	0.0281	0.0015	0.0006	0.007	0.0018	0.0004
3 rd Month	0.0262	0.0099	0.9007	0.0482	0.002	0.0007	0.0094	0.0024	0.0006

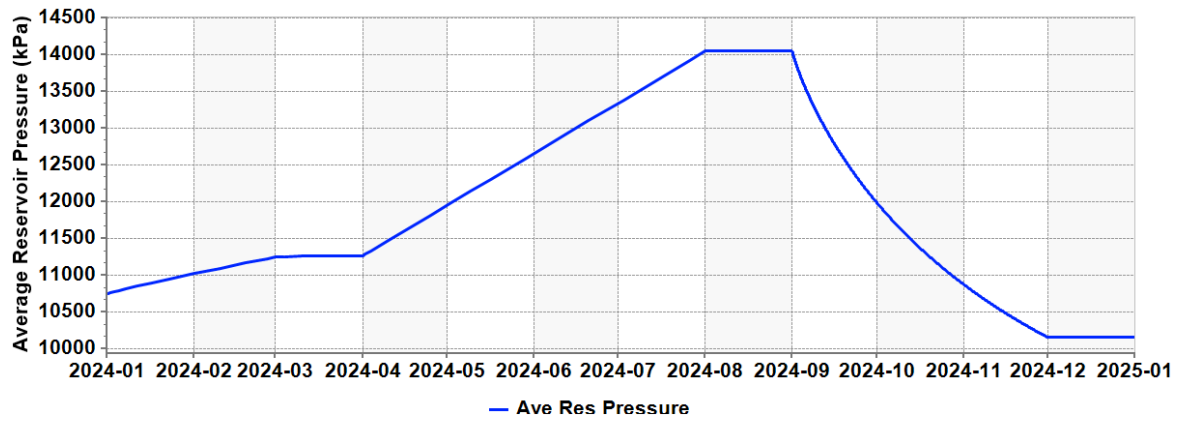


Figure 5.19: Case-2 1-Year Average Reservoir Pressure

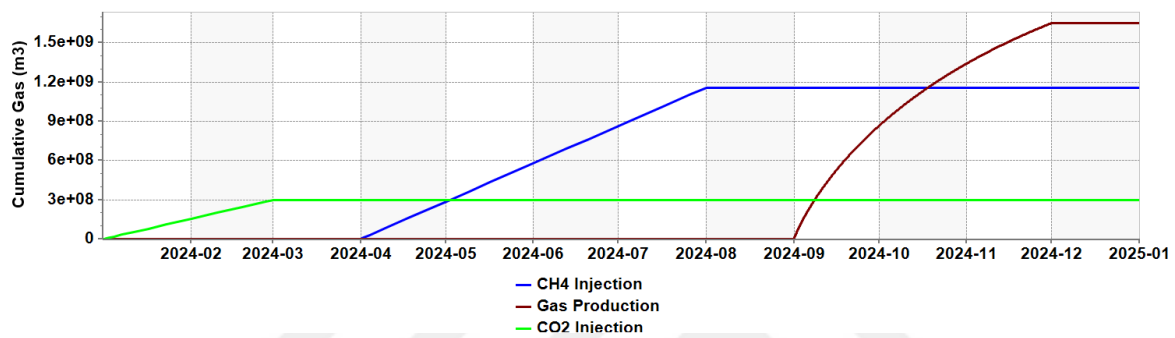


Figure 5.20: Case-2 1-Year Period Cumulative Injection and Production Gas

Considering that both Case-1 and Case-2 have the same shut-in periods and CO₂ is controlled to remain in a supercritical phase, CO₂'s higher density compared to methane result in slower movement within the reservoir and accumulation in the lower zones due to gravity as seen in Figure 5.21, while methane exhibits a more uniform distribution and faster progression.

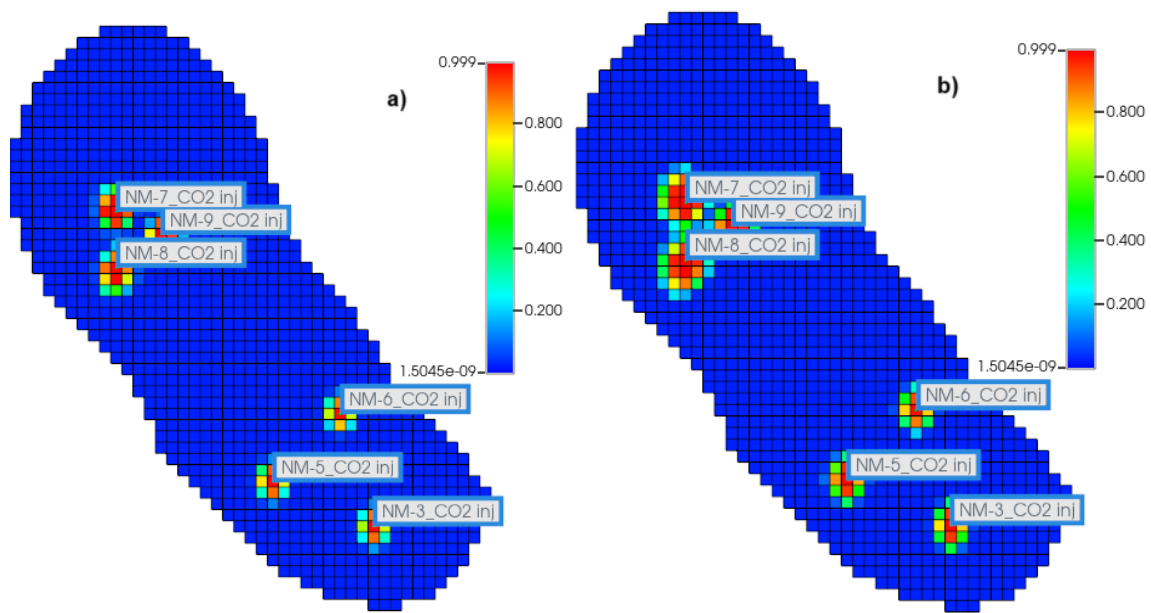


Figure 5.21: Case-2 1-Year Cycle; CO₂ Mole Fraction in a) First Layer b) Last Layer After First CO₂ Injection

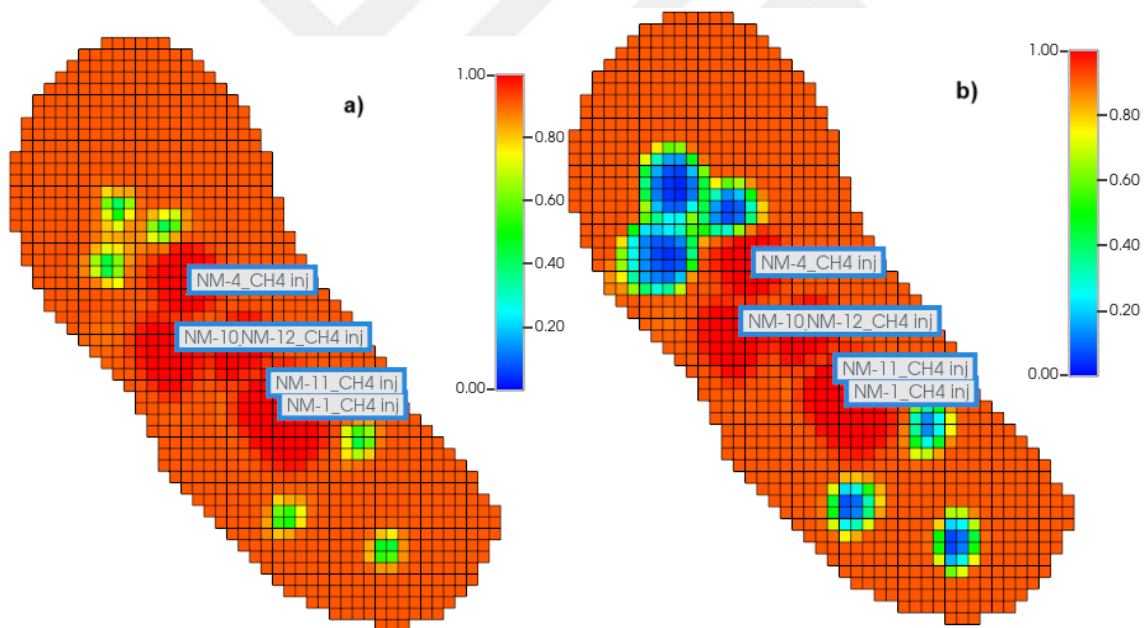


Figure 5.22: Case-2 1-Year Cycle; CH₄ Mole Fraction in a) First Layer b) Last Layer After First CH₄ Injection

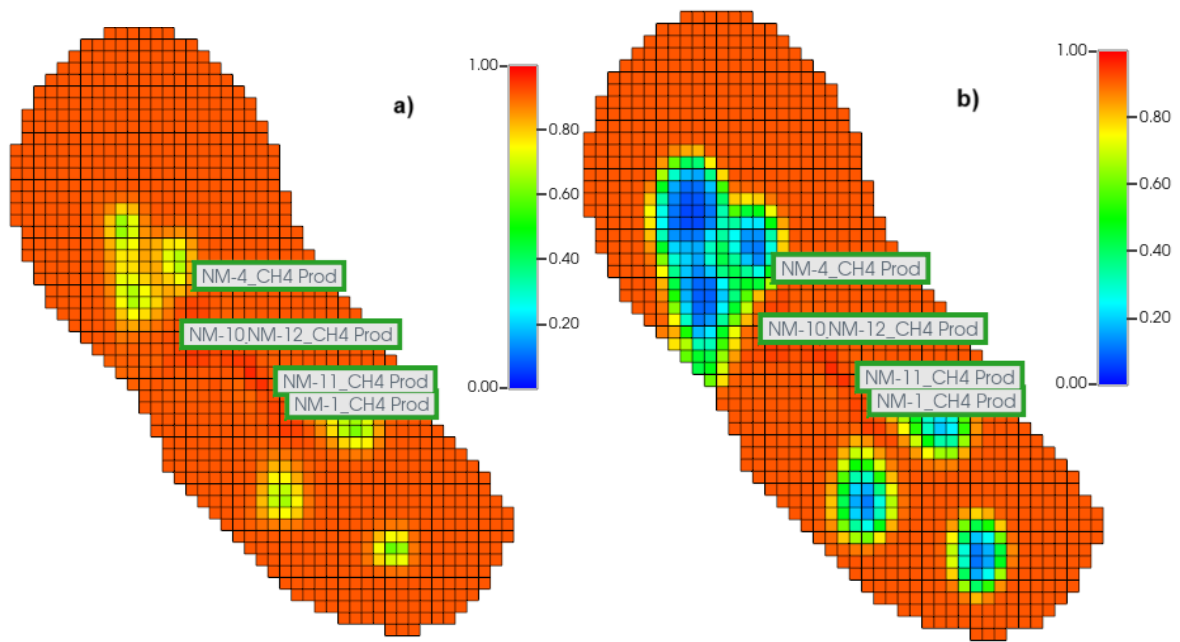


Figure 5.23: Case-2 1-Year Cycle; CH₄ Mole Fraction at the End of 1-Year Production Period a) First Layer and b) Last Layer

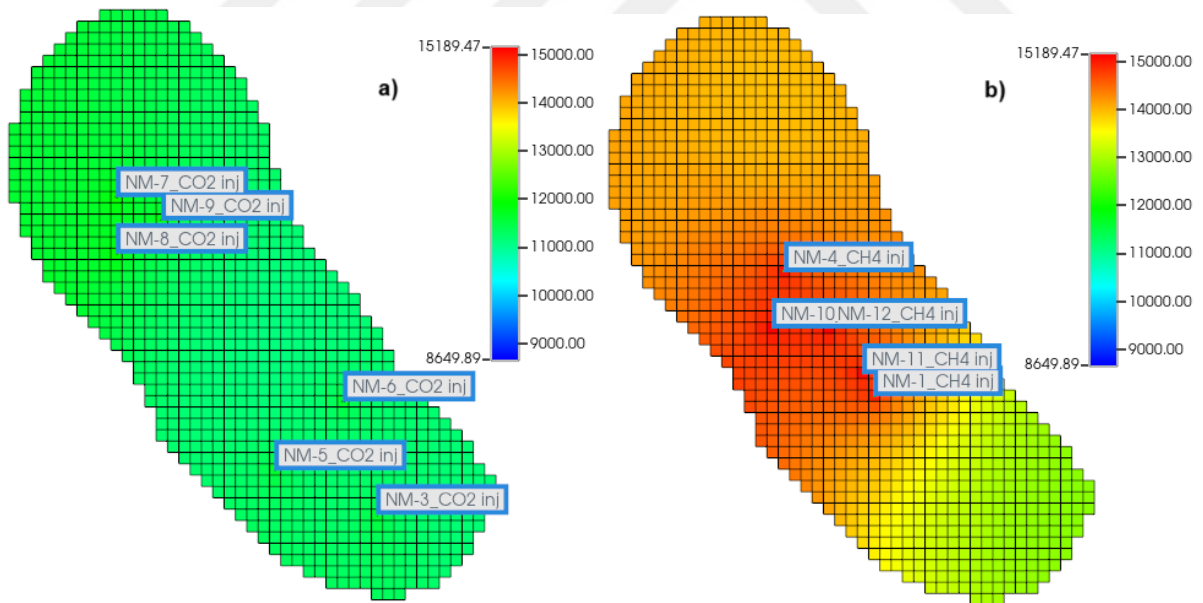


Figure 5.24: Case-2 1-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period

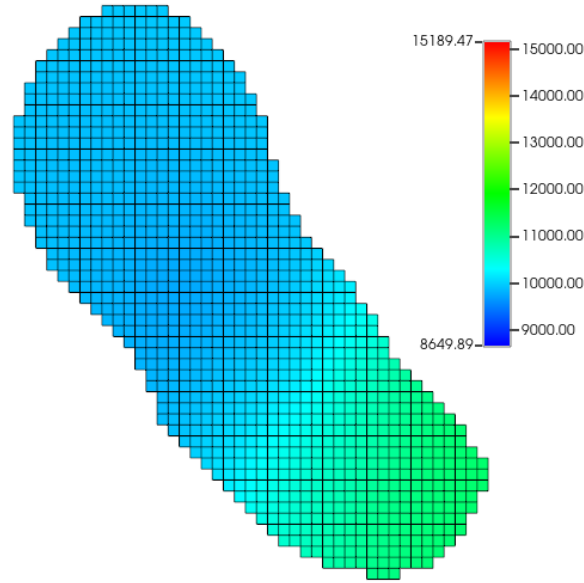


Figure 5.25: Case-2 1-Year Cycle; Reservoir Pressure at the End of Production Period

5.1.2.2 5-Year Cycle Injection of 80% CH₄ and 20% CO₂

For the first 2 months, CO₂ was injected into the reservoir at an injection rate of 4.7 MMm³/day . Afterward, the wells were shut-in for a period of 1 month. Following the 1-month shut-in period, CH₄ was injected into the wells for storage purposes with injection rate of 9.7 MMm³/day for 4 months, and then the wells were shut-in again for another month. After the second 1-month shut-in period, the gas withdrawal phase was initiated. The production rates for 5 years were summarized in Table 5.8. As summarized in Table 5.9, 25.41 % of the initial CH₄ in the reservoir was produced during the 1-year period of 80% CH₄ storage. The average reservoir pressure fluctuated between 10,000 and 14,070 kPa throughout the year.

Table 5.8: Case-2 Gas Production Rate for 5-Year Cycle

Year	Month	Gas Prod Rate (MM m ³ /day)
1	1	19.48
	2	12.33
	3	8.67
2	1	17.19
	2	10.97
	3	7.81
3	1	16.45
	2	10.55
	3	7.59
4	1	16.21
	2	10.44
	3	7.57
5	1	16.17
	2	10.45
	3	7.64

Table 5.9: Case-2 Injection and Production Summary for 5-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	5.92
Total Injected CO₂, MMM m³	1.40
Total Injected Gas, MMM m³	7.31
Total Produced CH₄, MMM m³	6.86
Total Produced CO₂, MMM m³	0.33
Total Produced Gas, MMM m³	7.31
Total Produced Other Gases, MMM m³	0.13
Produced reservoir CH₄, MMM m³	0.94
Reservoir CH₄ Recovery, %	25.41

Table 5.10: Molar Fraction of Produced Gas Case-2 5-Year Cycle

Year	Month	C ₂ H ₆	C ₃ H ₈	CH ₄	CO ₂	iC ₄	iC ₅	N ₂	nC ₄	nC ₅
1	1	0.008	0.003	0.979	0.006	0.001	0.000	0.003	0.001	0.000
	2	0.019	0.007	0.936	0.026	0.001	0.001	0.007	0.002	0.000
	3	0.026	0.010	0.904	0.046	0.002	0.001	0.009	0.002	0.001
2	1	0.005	0.002	0.983	0.008	0.000	0.000	0.002	0.000	0.000
	2	0.013	0.005	0.934	0.040	0.001	0.000	0.005	0.001	0.000
	3	0.020	0.008	0.885	0.076	0.002	0.001	0.007	0.002	0.000
3	1	0.003	0.001	0.980	0.013	0.000	0.000	0.001	0.000	0.000
	2	0.010	0.004	0.922	0.059	0.001	0.000	0.004	0.001	0.000
	3	0.016	0.006	0.857	0.111	0.001	0.001	0.006	0.002	0.000
4	1	0.003	0.001	0.975	0.020	0.000	0.000	0.001	0.000	0.000
	2	0.008	0.003	0.906	0.078	0.001	0.000	0.003	0.001	0.000
	3	0.014	0.005	0.828	0.145	0.001	0.000	0.005	0.001	0.000
5	1	0.002	0.001	0.968	0.027	0.000	0.000	0.001	0.000	0.000
	2	0.007	0.003	0.888	0.098	0.001	0.000	0.003	0.001	0.000
	3	0.012	0.005	0.800	0.177	0.001	0.000	0.004	0.001	0.000

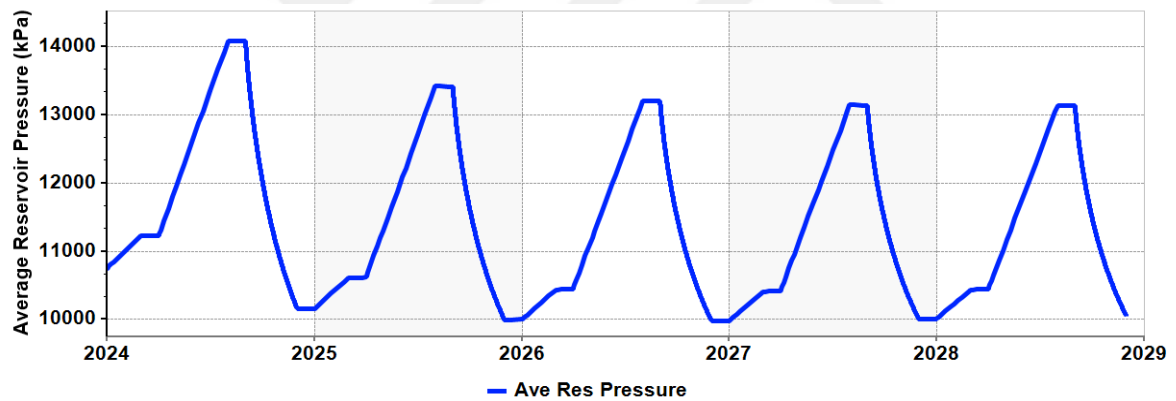


Figure 5.26: Case-2 5-Year Average Reservoir Pressure

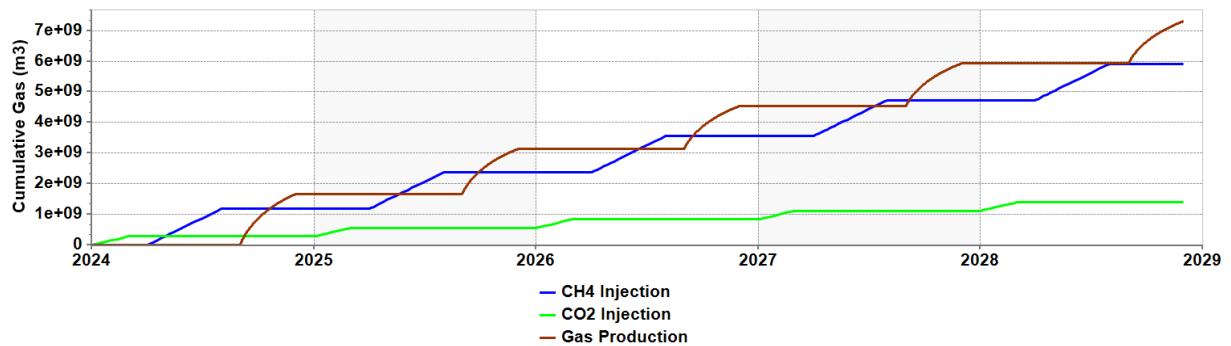


Figure 5.27: Case-2 5-Year Period Cumulative Injection and Production Gas

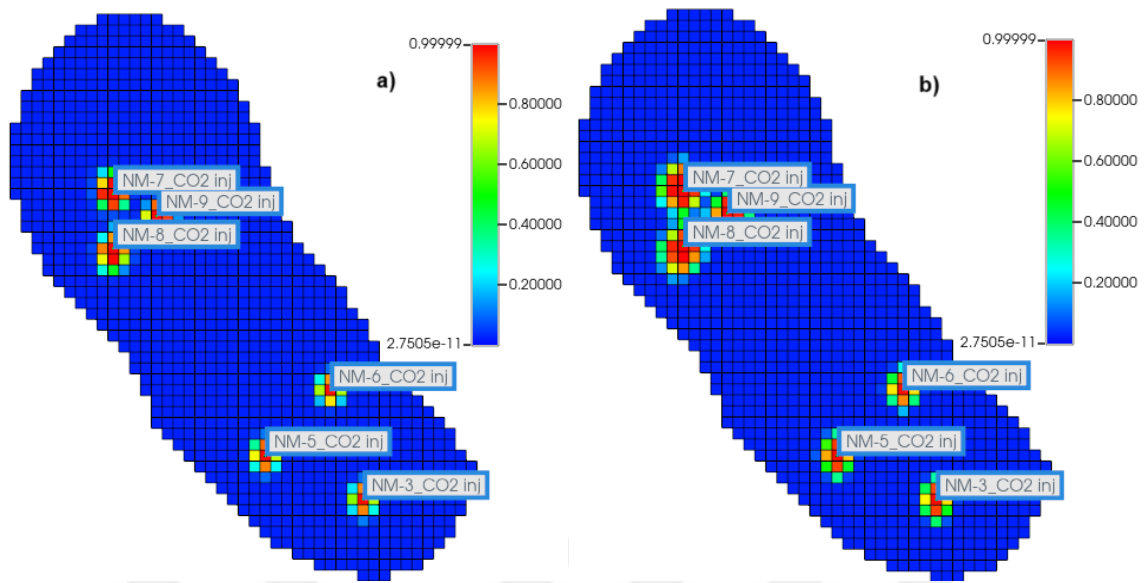


Figure 5.28: Case-2 5-Year Cycle CO₂ Mole Fraction in a) First Layer b) Last Layer after first CO₂ Injection

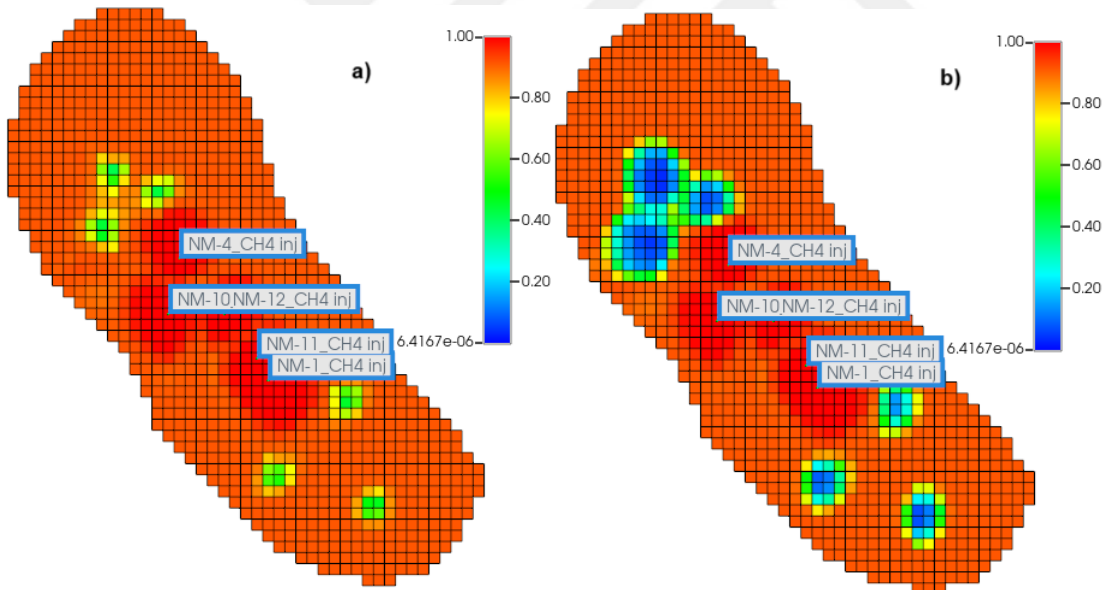


Figure 5.29: Case-2 5-Year Cycle; CH₄ Mole Fraction in a) First Layer b) Last Layer After First CH₄ Injection

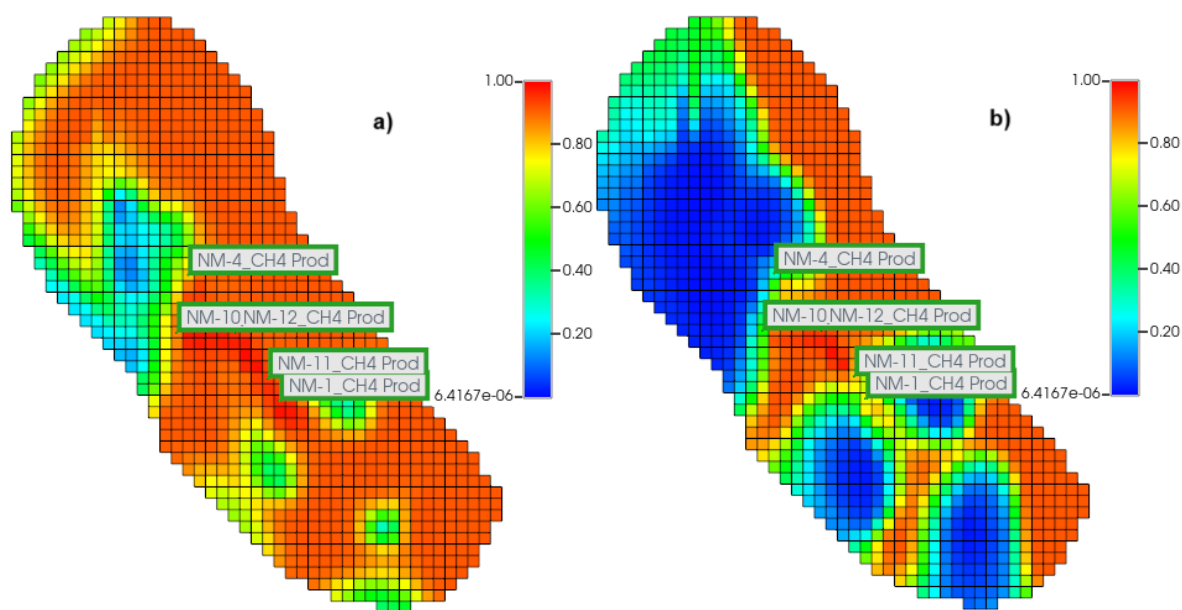


Figure 5.30: Case-2 5-Year Cycle; CH₄ Mole Fraction at the End of 5-Year Production Period a) First Layer and b) Last Layer

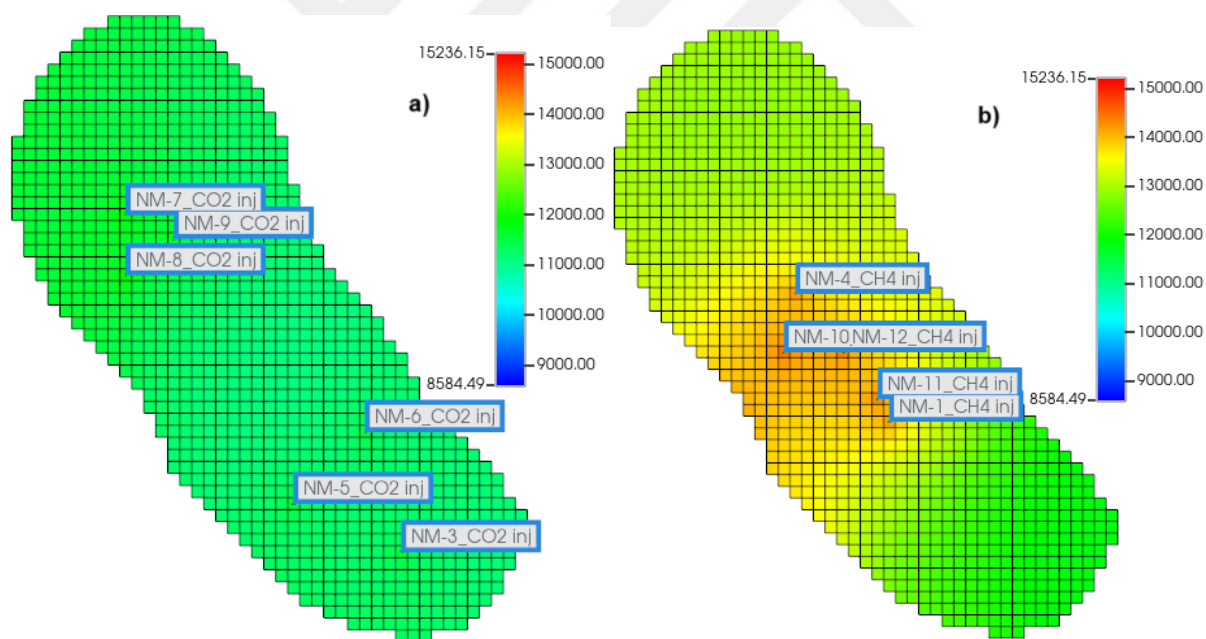


Figure 5.31: Case-2 5-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period

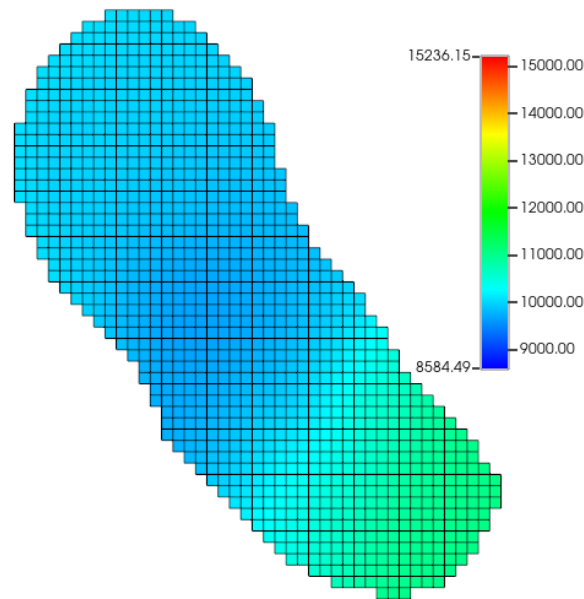


Figure 5.32: Case-2 5-Year Cycle; Reservoir Pressure at the End of 5-Year Production Period

5.1.2.3 10-Year Cycle Injection of 80% CH₄ and 20% CO₂

For the first 2 months, CO₂ was injected into the reservoir at a rate of 4.7 MMm³/day, followed by a 1-month shut-in period. After this, CH₄ was injected at 9.7 MMm³/day for 4 months, and the wells were shut-in again for 1 month. Following the second shut-in period, the gas withdrawal phase began. The production rates for 10 years are summarized in Table 5.11.

As summarized in Table 5.12, 31.76% of the initial CH₄ in the reservoir was produced during the 1-year period of 80% CH₄ storage. The average reservoir pressure fluctuated between 10,000 and 14,100 kPa throughout the year.

Table 5.11: Case-2 Gas Production Rate for 10-Year Cycle

Year	Month	Gas Prod Rate (MM m ³ /day)
1	1	19.48
	2	12.33
	3	8.67
2	1	17.19
	2	10.97
	3	7.81
3	1	16.45
	2	10.55
	3	7.59
4	1	16.21
	2	10.44
	3	7.57
5	1	16.17
	2	10.45
	3	7.64
6	1	16.16
	2	10.49
	3	7.72
7	1	16.18
	2	10.53
	3	7.79
8	1	16.20
	2	10.58
	3	7.86
9	1	16.24
	2	10.64
	3	7.94
10	1	16.25
	2	10.67
	3	7.99

Table 5.12: Case-2 Injection and Production Summary for 10-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	11.83
Total Injected CO₂, MMM m³	2.79
Total Injected Gas, MMM m³	14.62
Total Produced CH₄, MMM m³	13.01
Total Produced CO₂, MMM m³	1.11
Total Produced Gas, MMM m³	14.31
Total Produced Other Gases, MMM m³	0.19
Produced reservoir CH₄, MMM m³	1.17
Reservoir CH₄ Recovery, %	31.76

Table 5.13: Molar Fraction of Produced Gas Case-2 10-Year Cycle

Year	Month	C ₂ H ₆	C ₃ H ₈	CH ₄	CO ₂	iC ₄	iC ₅	N ₂	nC ₄	nC ₅
1	1	0.008	0.003	0.979	0.006	0.001	0.000	0.003	0.001	0.000
	2	0.019	0.007	0.936	0.026	0.001	0.001	0.007	0.002	0.000
	3	0.026	0.010	0.904	0.046	0.002	0.001	0.009	0.002	0.001
2	1	0.005	0.002	0.983	0.008	0.000	0.000	0.002	0.000	0.000
	2	0.013	0.005	0.934	0.040	0.001	0.000	0.005	0.001	0.000
	3	0.020	0.008	0.885	0.076	0.002	0.001	0.007	0.002	0.000
3	1	0.003	0.001	0.980	0.013	0.000	0.000	0.001	0.000	0.000
	2	0.010	0.004	0.922	0.059	0.001	0.000	0.004	0.001	0.000
	3	0.016	0.006	0.857	0.111	0.001	0.001	0.006	0.002	0.000
4	1	0.003	0.001	0.975	0.020	0.000	0.000	0.001	0.000	0.000
	2	0.008	0.003	0.906	0.078	0.001	0.000	0.003	0.001	0.000
	3	0.014	0.005	0.828	0.145	0.001	0.000	0.005	0.001	0.000
5	1	0.002	0.001	0.968	0.027	0.000	0.000	0.001	0.000	0.000
	2	0.007	0.003	0.888	0.098	0.001	0.000	0.003	0.001	0.000
	3	0.012	0.005	0.800	0.177	0.001	0.000	0.004	0.001	0.000
6	1	0.002	0.001	0.961	0.035	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.872	0.116	0.001	0.000	0.002	0.001	0.000
	3	0.011	0.004	0.775	0.204	0.001	0.000	0.004	0.001	0.000
7	1	0.002	0.001	0.955	0.041	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.858	0.130	0.000	0.000	0.002	0.001	0.000
	3	0.010	0.004	0.755	0.226	0.001	0.000	0.004	0.001	0.000
8	1	0.002	0.001	0.950	0.047	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.847	0.143	0.000	0.000	0.002	0.001	0.000
	3	0.009	0.004	0.738	0.244	0.001	0.000	0.003	0.001	0.000
9	1	0.002	0.001	0.945	0.052	0.000	0.000	0.001	0.000	0.000
	2	0.005	0.002	0.836	0.154	0.000	0.000	0.002	0.001	0.000
	3	0.009	0.003	0.722	0.261	0.001	0.000	0.003	0.001	0.000
10	1	0.002	0.001	0.941	0.056	0.000	0.000	0.001	0.000	0.000
	2	0.005	0.002	0.827	0.164	0.000	0.000	0.002	0.001	0.000
	3	0.008	0.003	0.708	0.276	0.001	0.000	0.003	0.001	0.000

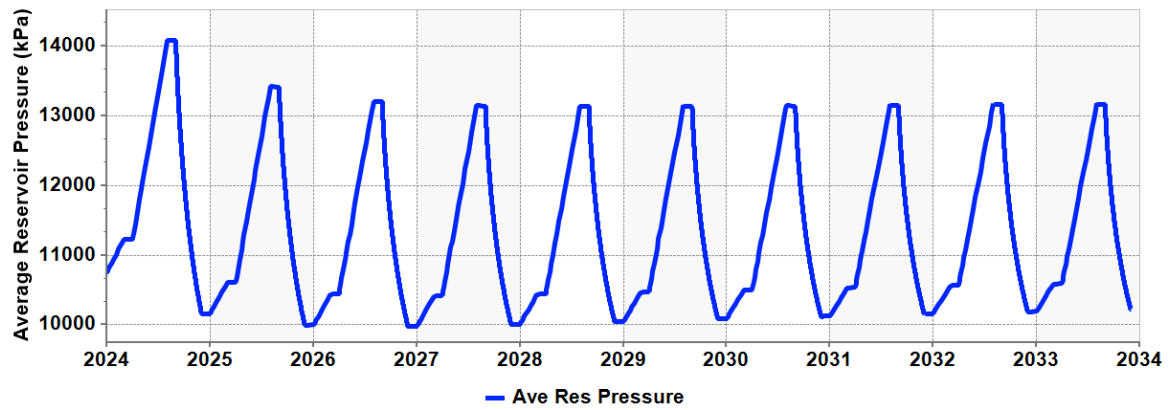


Figure 5.33: Case-2 10-Year Average Reservoir Pressure

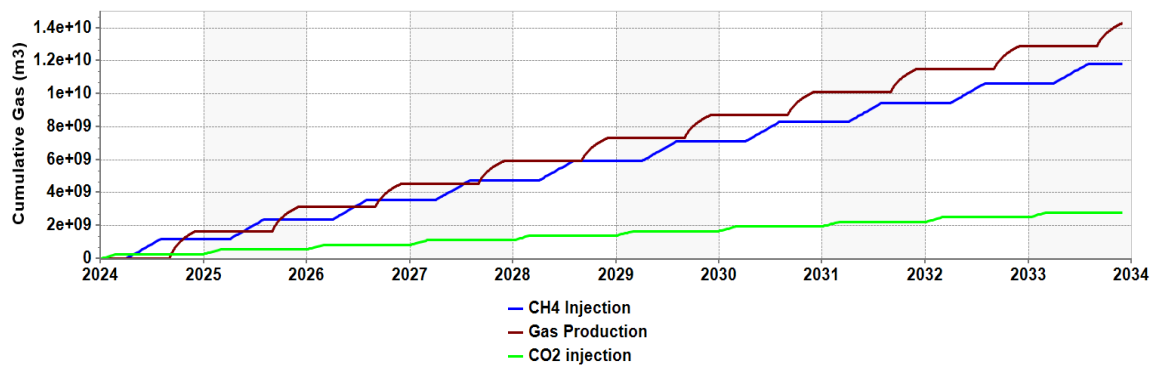


Figure 5.34: Case-2 10-Year Period Cumulative Injection and Production Gas

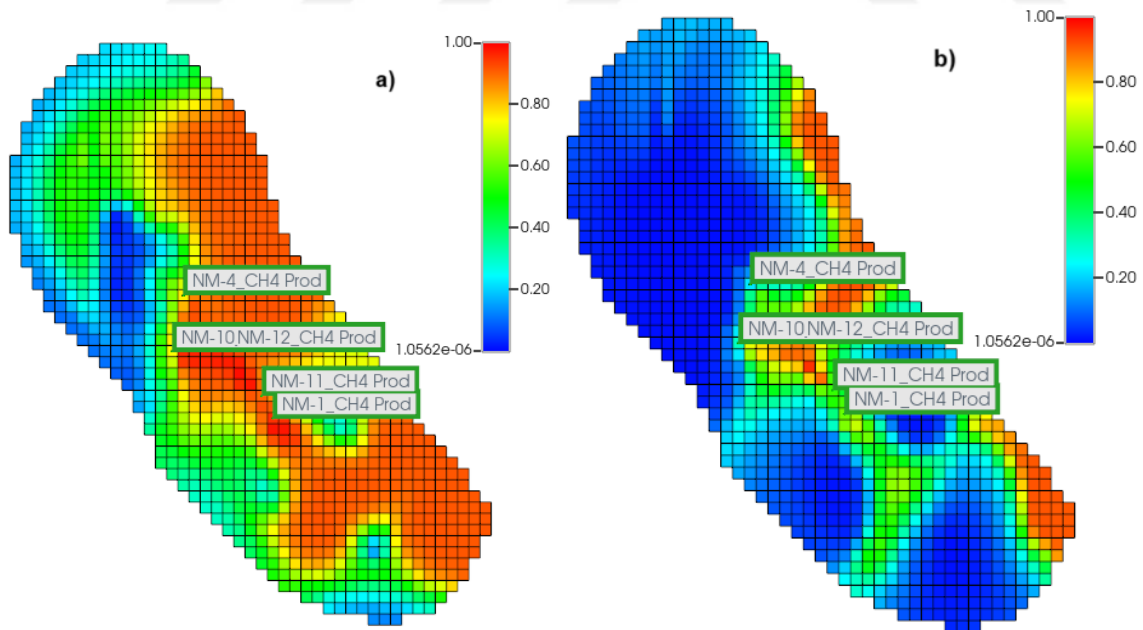


Figure 5.35: Case-2 10-Year Cycle; CH₄ Mole Fraction at the End of 10-Year Production Period a) First Layer and b) Last Layer

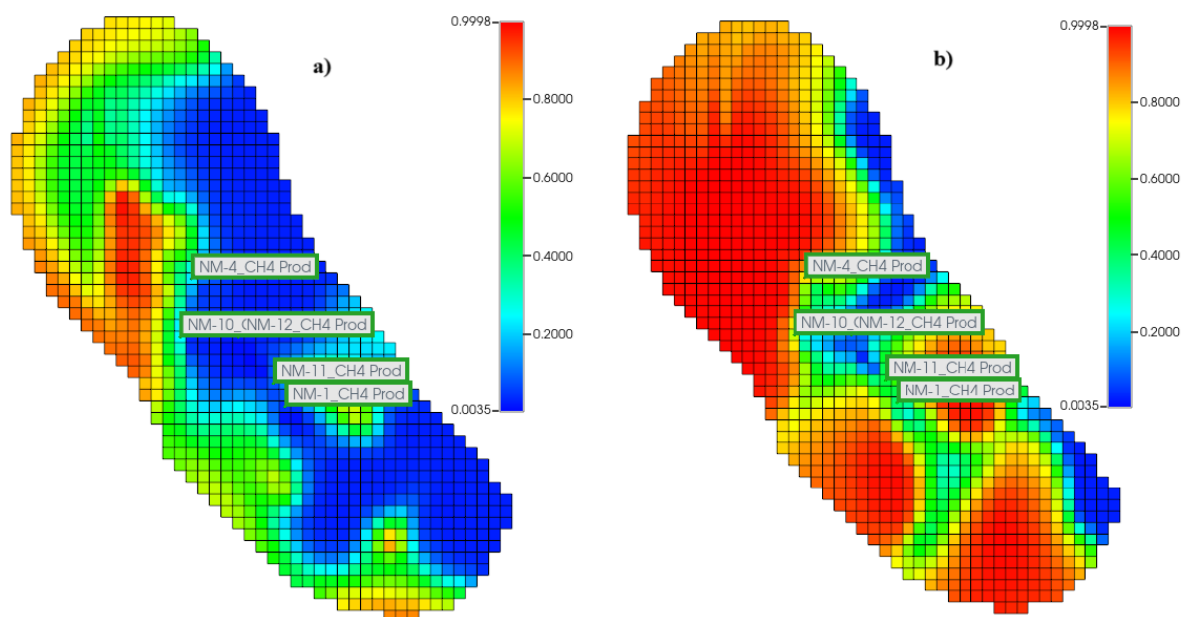


Figure 5.36: Case-2 10-Year Cycle; CO₂ Mole Fraction at the End of 10-Year Production Period a) First Layer and b) Last Layer

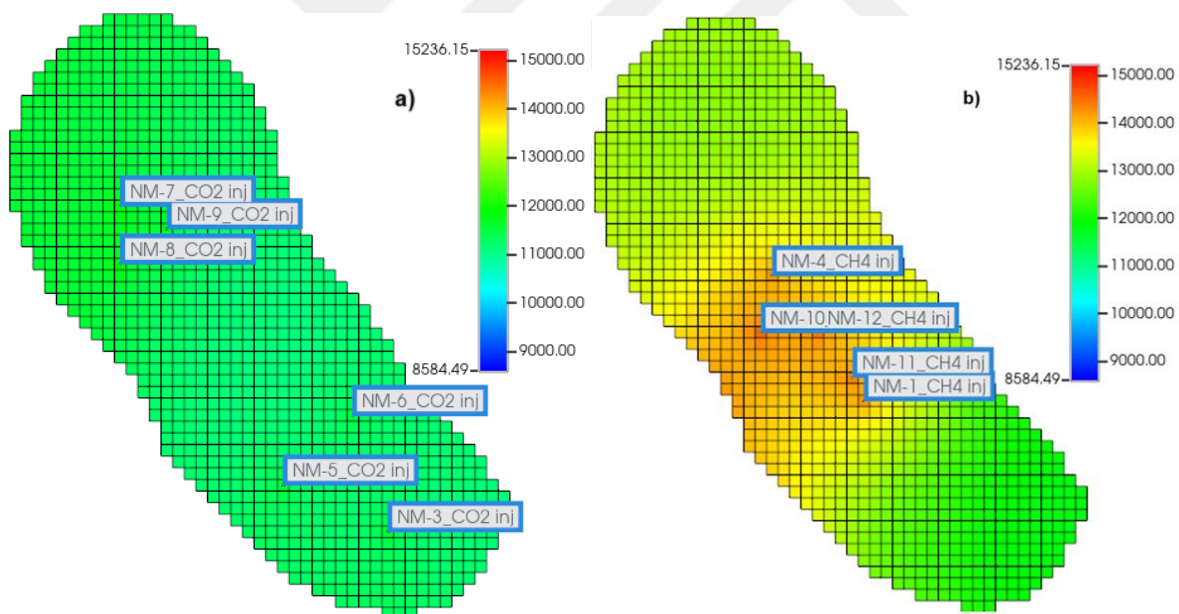


Figure 5.37: Case-2 10-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period

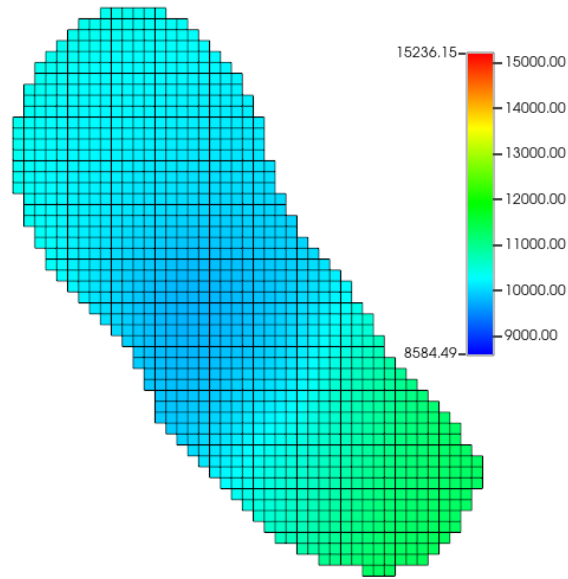


Figure 5.38: Case-2 10-Year Cycle; Reservoir Pressure at the End of 10-Year Production Period

5.1.3 Case-3 Injection of 70% CH₄ and 30% CO₂

In this case, CO₂ was first injected as cushion gas, followed by the injection of CH₄ for storage purposes. The total gas injected consisted of 30% CO₂ and 70% CH₄. This mixture was chosen to understand the long-term performance of the gas storage field. The impact of using CO₂ as cushion gas on production over time was analyzed over different timeframes: 1 year, 5 years, and 10 years. The analysis aimed to assess how the use of CO₂ as cushion gas would influence reservoir pressure management, gas storage, and production efficiency over time.

Throughout all cases, the injection, shut-in, and production periods remained fixed, meaning that each phase was carried out within a set time interval. Additionally, the locations of the injection and production wells were kept constant. This consistency ensured that the analyses were more reliable and comparable, focusing solely on the effects of using CO₂ as cushion gas. No changes were made to the injection or production processes, and all parameters were kept steady. This approach allowed for a more accurate evaluation of how the use of CO₂ as cushion gas would affect the long-term production capacity, gas storage, and efficiency of the reservoir. Overall, this study aimed to provide a comprehensive analysis of how CO₂ could be used as cushion gas in natural gas storage projects, considering its potential impact on efficiency.

5.1.3.1 1-Year Cycle Injection of 70% CH₄ and 30% CO₂

For the first 2 months, CO₂ was injected at 7.2 MMm³/day, followed by a 1-month shut-in. Then, CH₄ was injected at 8.3 MMm³/day for 4 months, with another 1-month shut-in. After the second shut-in, the gas withdrawal phase began. Production rates were: 186 MM-m³/day in the first month, 12 MM-m³/day in the second, and 8 MM-m³/day in the third.

Table 5.14: Case-3 Injection and Production Summary for 1-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	1.01
Total Injected CO₂, MMM m³	0.43
Total Injected Gas, MMM m³	1.44
Total Produced CH₄, MMM m³	1.5
Total Produced CO₂, MMM m³	0.05
Total Produced Gas, MMM m³	1.61
Total Produced Other Gases, MMM m³	0.05
Produced reservoir CH₄, MMM m³	0.49
Reservoir CH₄ Recovery, %	13.26

As summarized in Table 5.14, 13.26 % of the initial CH₄ in the reservoir was produced during the 1-year period of 80% CH₄ storage. The average reservoir pressure fluctuated between 9,970 and 13,890 kPa throughout the year.

Table 5.15: Molar Fraction of Produced Gas Case-3 1-Year Cycle

Time	C₂H₆	C₃H₈	CH₄	CO₂	iC₄	iC₅	N₂	nC₄	nC₅
1st Month	0.004	0.969	0.011	0.001	0.000	0.004	0.001	0.000	0.0002
2nd Month	0.008	0.913	0.043	0.002	0.001	0.008	0.002	0.000	0.0004
3rd Month	0.010	0.876	0.070	0.002	0.001	0.010	0.003	0.001	0.0006

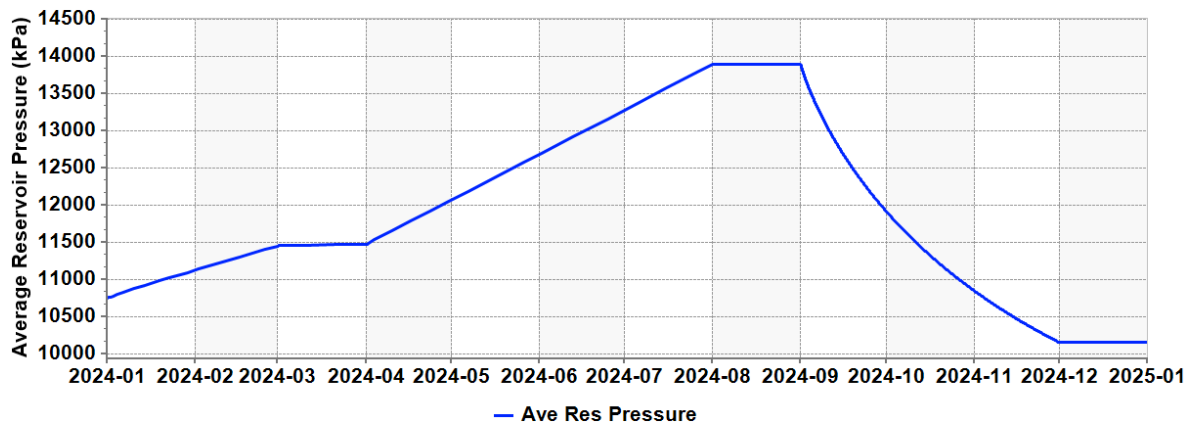


Figure 5.39: Case-3 1-Year Average Reservoir Pressure

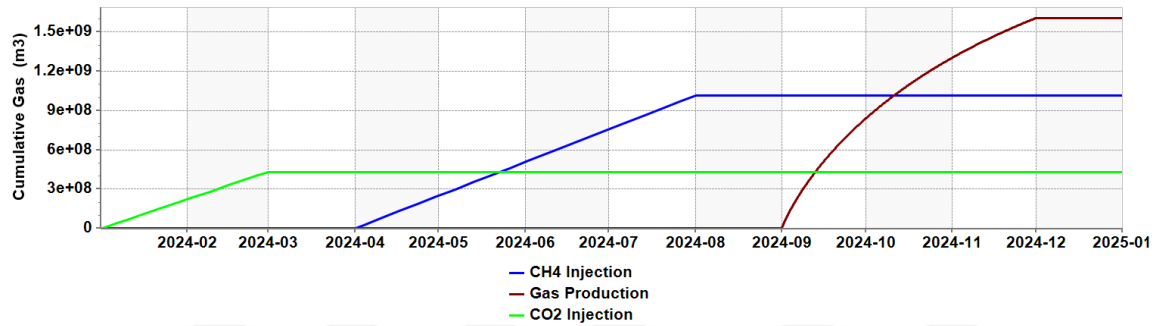


Figure 5.40: Case-3 1-Year Period Cumulative Injection and Production Gas

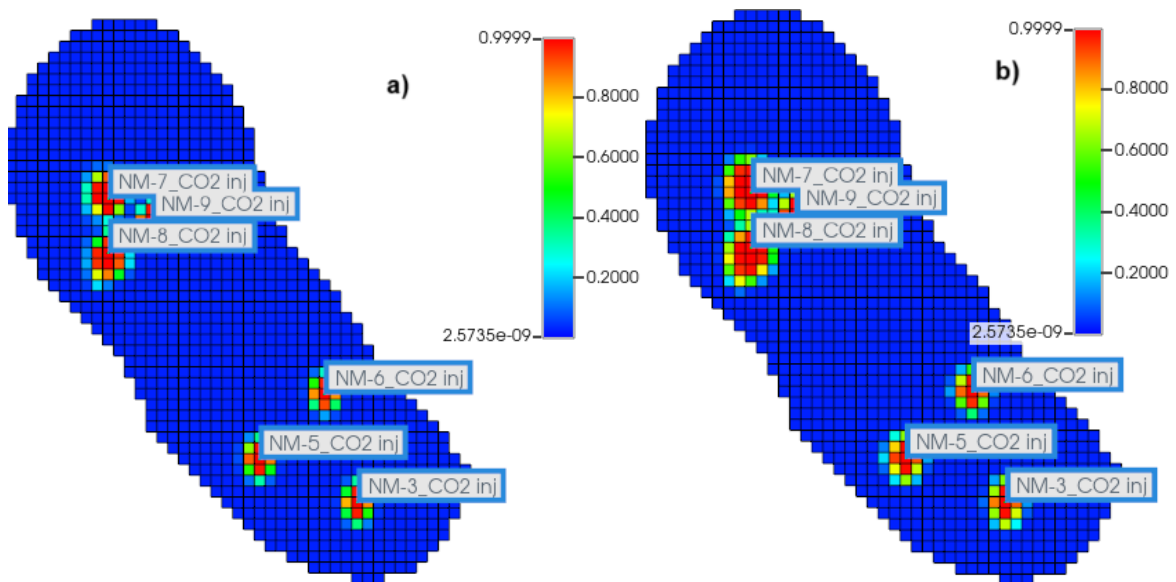


Figure 5.41: Case-3 1-Year Cycle; CO₂ Mole Fraction in a) First Layer b) Last Layer After First CO₂ Injection

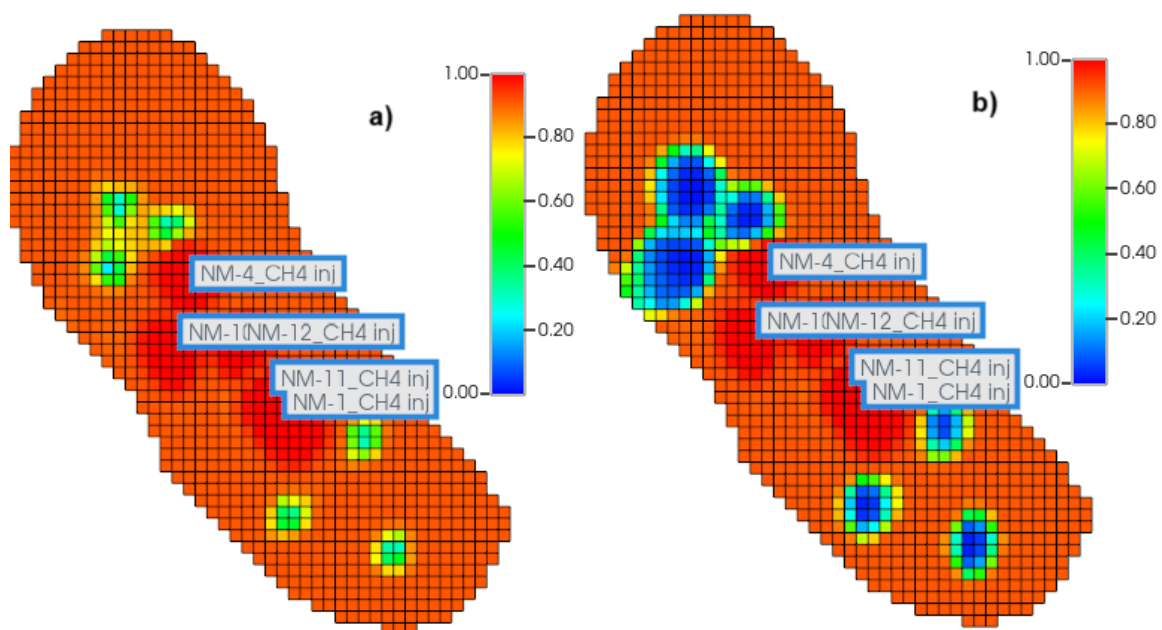


Figure 5.42: Case-3 1-Year Cycle; CH₄ Mole Fraction in a) First Layer b) Last Layer After First CH₄ Injection

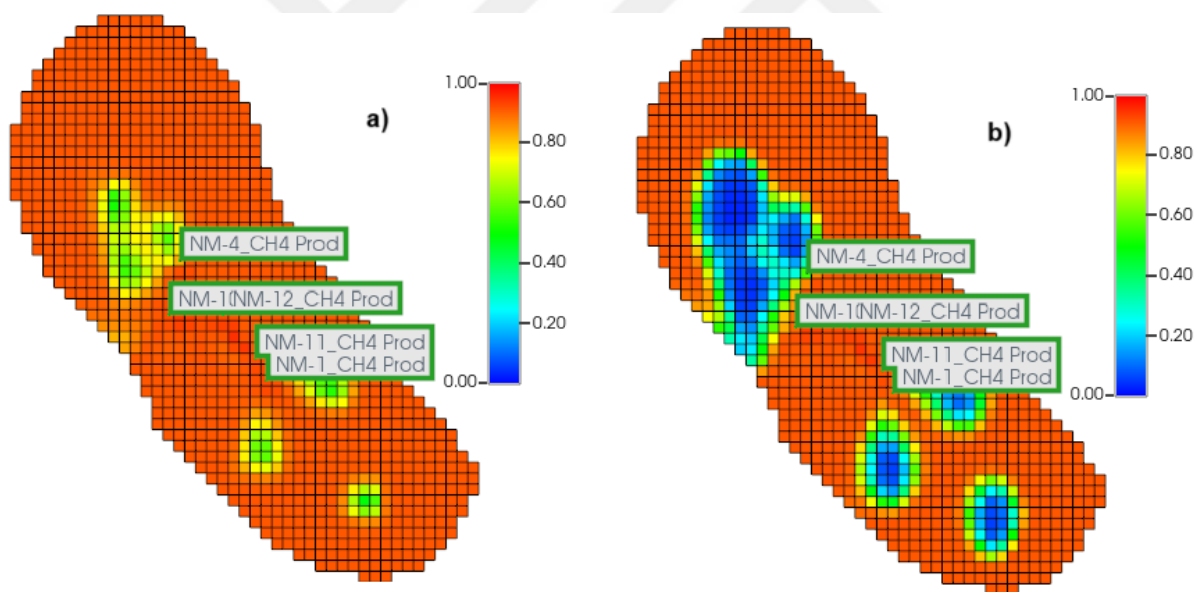


Figure 5.43: Case-3 1-Year Cycle; CH₄ Mole Fraction at the End of 1-Year Production Period a) First Layer and b) Last Layer

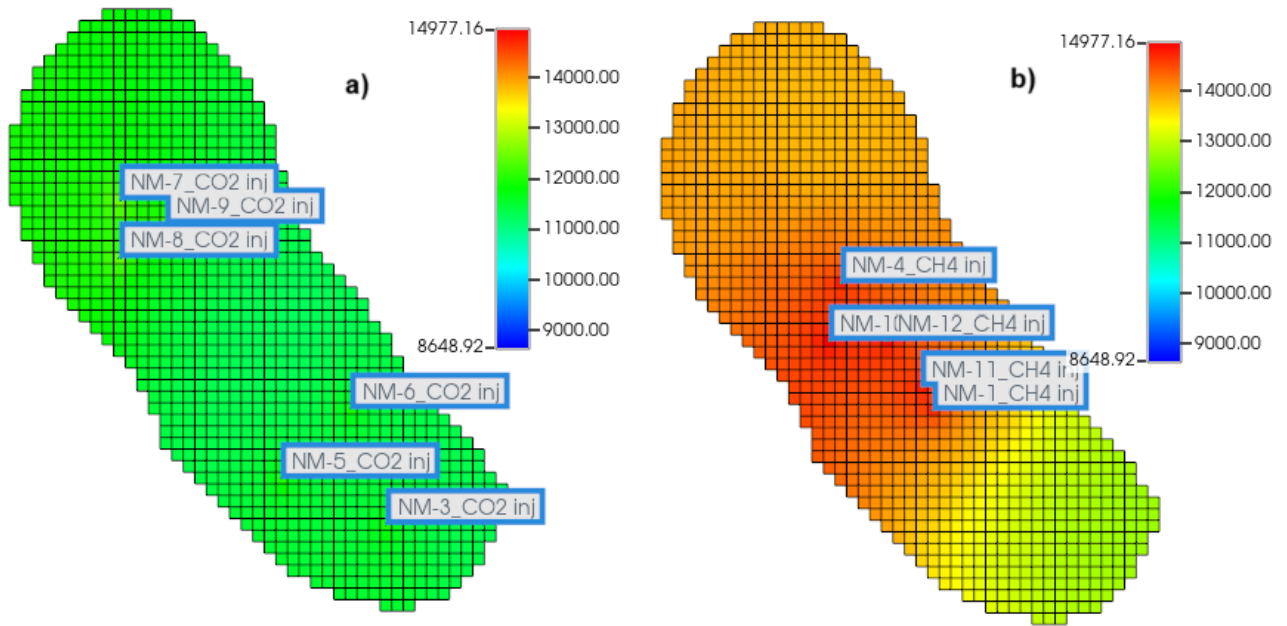


Figure 5.44: Case-3 1-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period

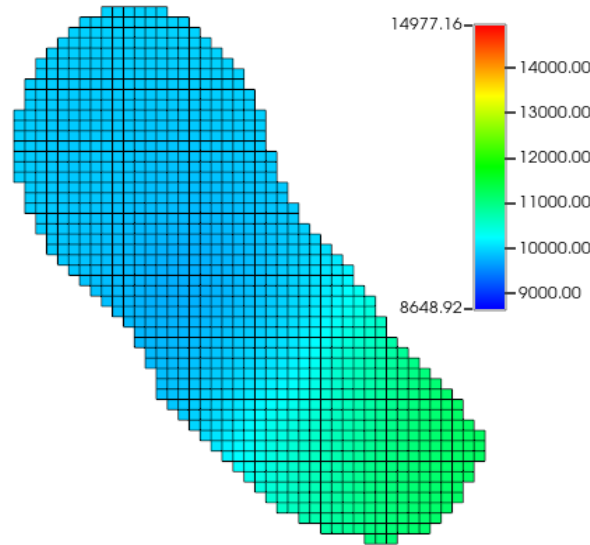


Figure 5.45: Case-3 1-Year Cycle; Reservoir Pressure at the End of 1-Year Production Period

5.1.3.2 5-Year Cycle Injection of 70% CH₄ and 30% CO₂

CO₂ was injected at 7.2 MMm³/day for the first 2 months, followed by a 1-month shut-in. Then, CH₄ was injected at 8.3 MMm³/day for 4 months, with another 1-month shut-in. After the

second shut-in, the gas withdrawal phase began. The production rates for 5 years are summarized in Table 5.16

Table 5.16: Case-3 Gas Production Rate for 5-Year Cycle

Year	Month	Gas Prod Rate (MM m ³ /day)
1	1	18.82
	2	12.02
	3	8.54
2	1	16.32
	2	10.58
	3	7.68
3	1	15.56
	2	10.18
	3	7.53
4	1	15.36
	2	10.14
	3	7.60
5	1	15.38
	2	10.24
	3	7.76

Table 5.17: Case-3 Injection and Production Summary for 5-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	5.06
Total Injected CO₂, MMM m³	2.14
Total Injected Gas, MMM m³	7.20
Total Produced CH₄, MMM m³	6.19
Total Produced CO₂, MMM m³	0.67
Total Produced Gas, MMM m³	7.02
Total Produced Other Gases, MMM m³	0.15
Produced reservoir CH₄, MMM m³	1.13
Reservoir CH₄ Recovery, %	30.62

As summarized in Table 5.17, 30.62% of the initial CH₄ in the reservoir was produced during the 5-year period of 70% CH₄ storage. The average reservoir pressure fluctuated between 10,000 and 13,890 kPa throughout the year.

Table 5.18: Molar Fraction of Produced Gas Case-3 5-Year Cycle

Year	Month	C ₂ H ₆	C ₃ H ₈	CH ₄	CO ₂	iC ₄	iC ₅	N ₂	nC ₄	nC ₅
1	1	0.011	0.004	0.969	0.011	0.001	0.000	0.004	0.001	0.000
	2	0.022	0.008	0.913	0.043	0.002	0.001	0.008	0.002	0.000
	3	0.028	0.010	0.876	0.070	0.002	0.001	0.010	0.003	0.001
2	1	0.007	0.003	0.964	0.023	0.000	0.000	0.002	0.001	0.000
	2	0.016	0.006	0.884	0.085	0.001	0.000	0.006	0.002	0.000
	3	0.022	0.008	0.816	0.141	0.002	0.001	0.008	0.002	0.000
3	1	0.005	0.002	0.949	0.042	0.000	0.000	0.002	0.000	0.000
	2	0.012	0.005	0.844	0.132	0.001	0.000	0.004	0.001	0.000
	3	0.018	0.007	0.756	0.210	0.001	0.000	0.006	0.002	0.000
4	1	0.004	0.002	0.932	0.060	0.000	0.000	0.001	0.000	0.000
	2	0.010	0.004	0.807	0.174	0.001	0.000	0.004	0.001	0.000
	3	0.015	0.006	0.704	0.267	0.001	0.000	0.005	0.001	0.000
5	1	0.004	0.001	0.915	0.078	0.000	0.000	0.001	0.000	0.000
	2	0.009	0.003	0.773	0.209	0.001	0.000	0.003	0.001	0.000
	3	0.013	0.005	0.662	0.313	0.001	0.000	0.005	0.001	0.000

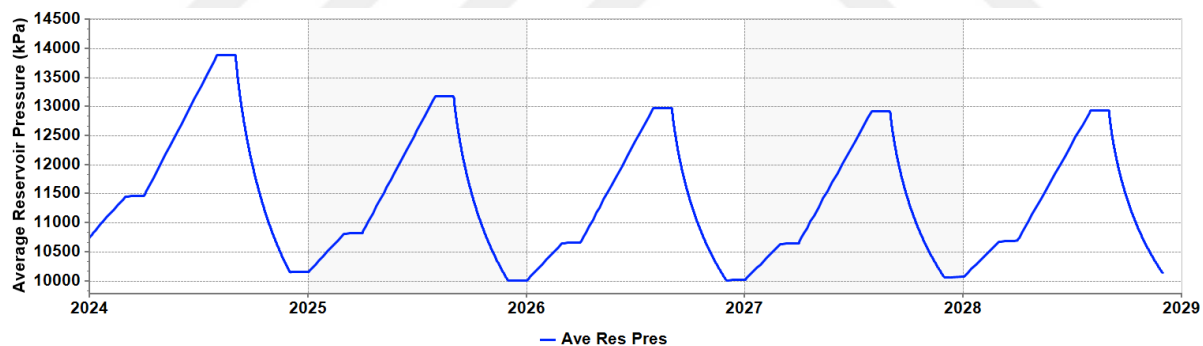


Figure 5.46: Case-3 5-Year Average Reservoir Pressure

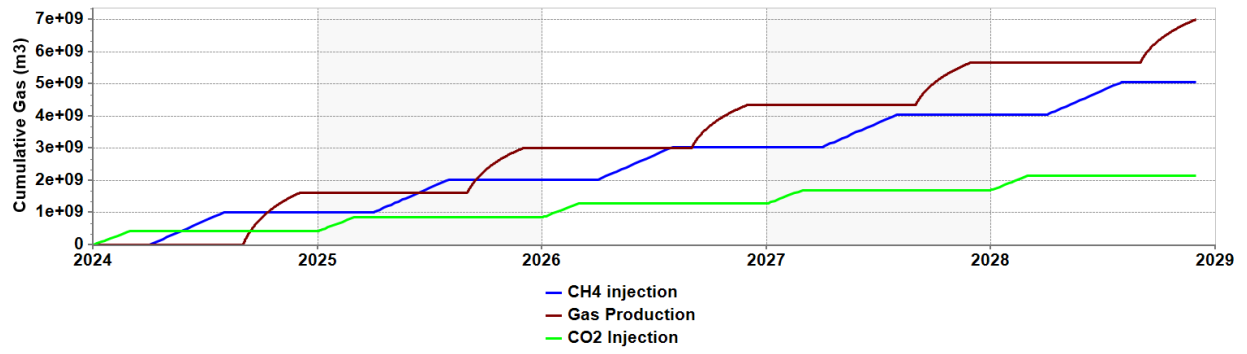


Figure 5.47: Case-3 5-Year Period Cumulative Injection and Production Gas

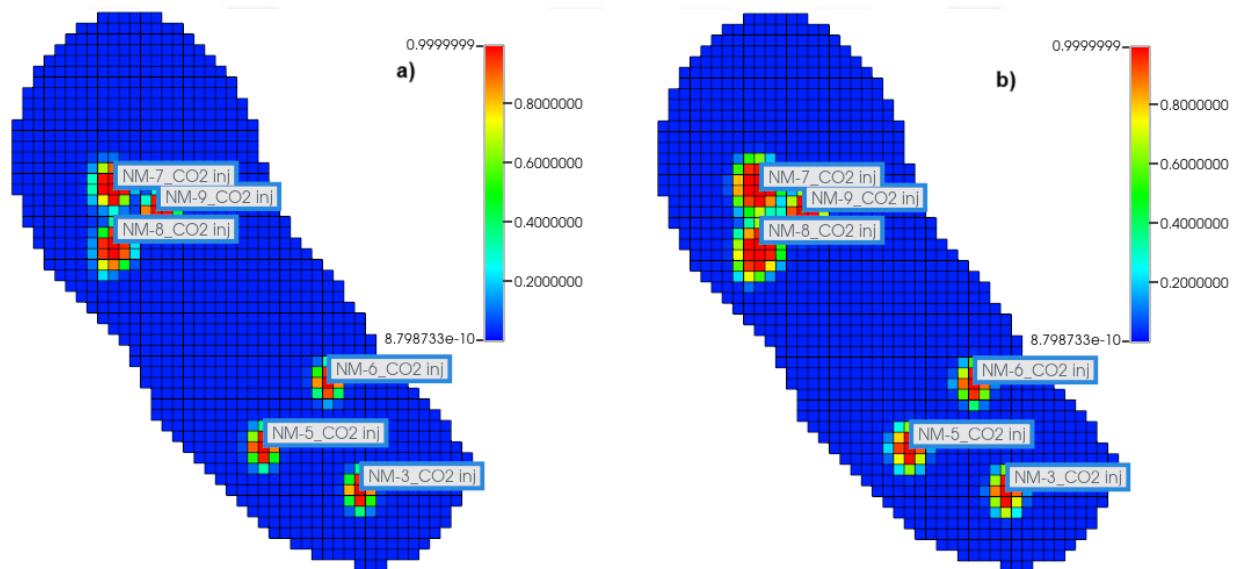


Figure 5.48: Case-3 5-Year Cycle; CO₂ Mole Fraction in a) First Layer b) Last Layer After First CO₂ Injection

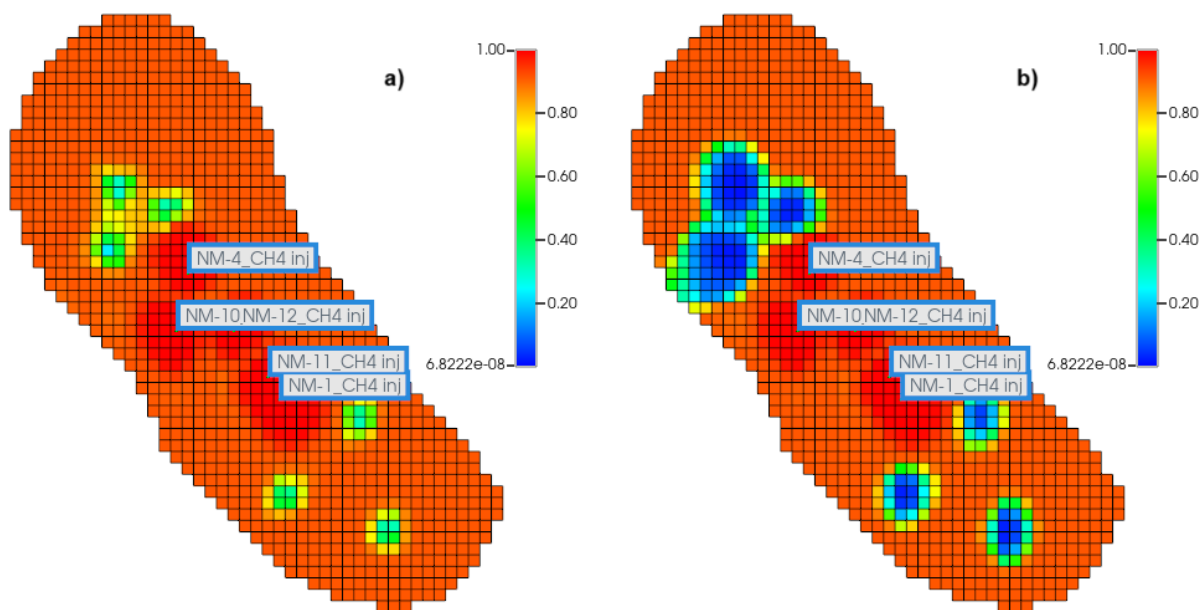


Figure 5.49: Case-3 5-Year Cycle; CH₄ Mole Fraction in a) First Layer b) Last Layer After First CH₄ Injection

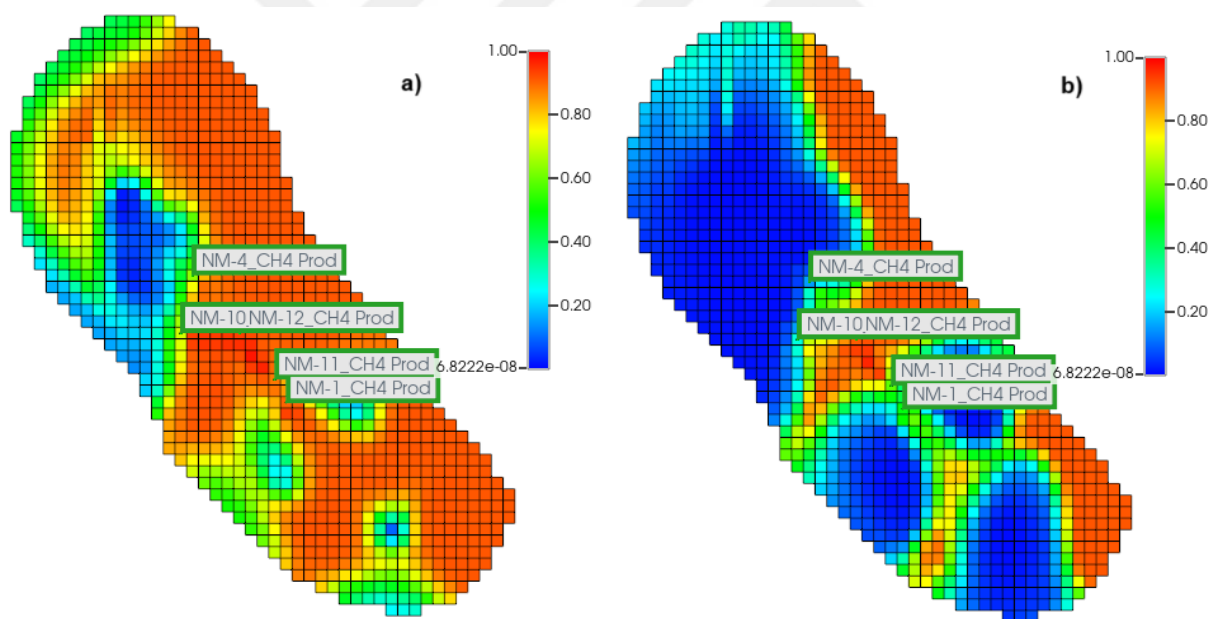


Figure 5.50: Case-3 5-Year Cycle; CH₄ Mole Fraction at the End of 5-Year Production Period a) First Layer and b) Last Layer

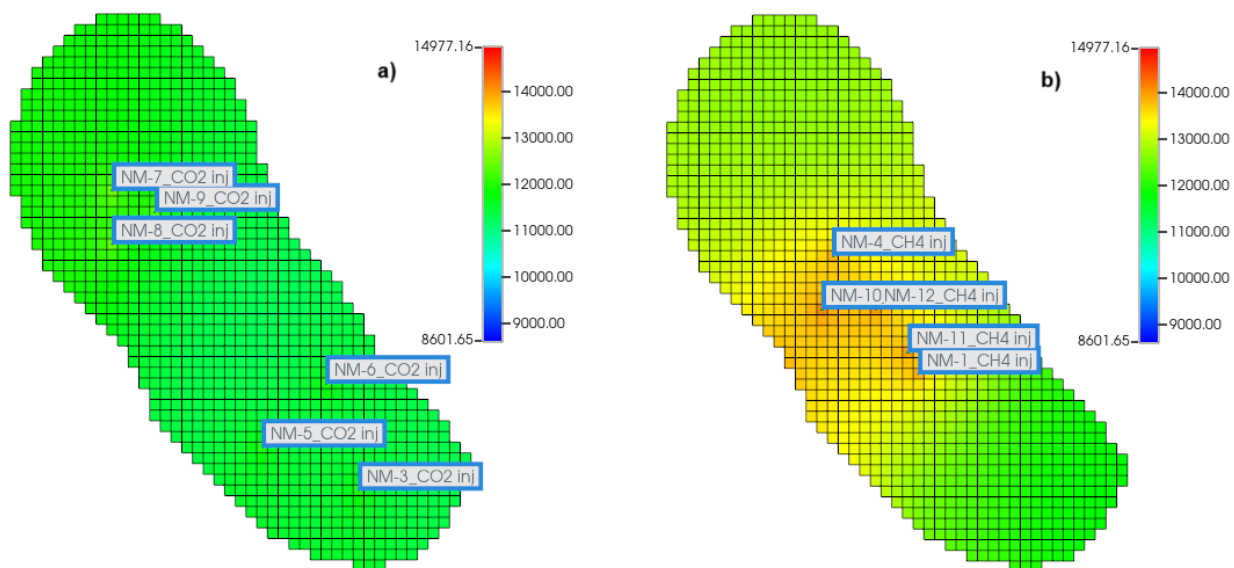


Figure 5.51: Case-3 5-Year Cycle; Reservoir Pressure a) at the end of first CO₂ injection Period b) at the End of Last CH₄ Injection Period

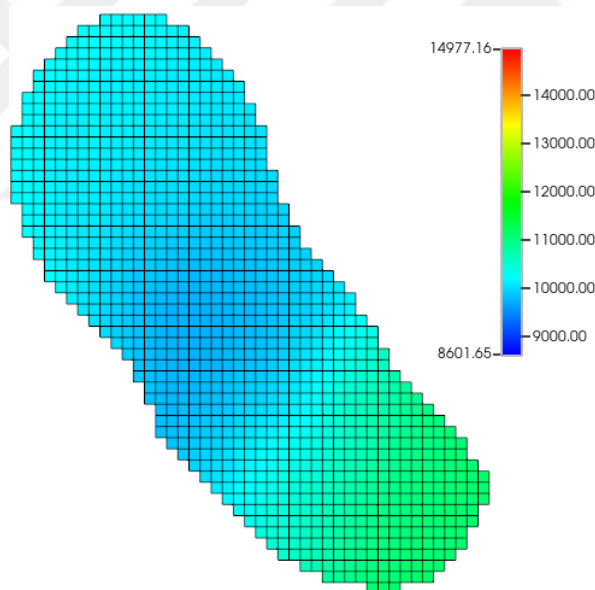


Figure 5.52: Case-3 5-Year Cycle; Reservoir Pressure at the End of 5-Year Production Period

5.1.3.3 10-Year Cycle Injection of 70% CH₄ and 30% CO₂

Same as 5-Year Case, CO₂ was injected at 7.2 MMm³/day for the first 2 months, followed by a 1-month shut-in. Then, CH₄ was injected at 8.3 MMm³/day for 4 months, with another 1-month shut-in. After the second shut-in, the gas withdrawal phase began. The production rates for 10 years are summarized in Table 5.19.

Table 5.19: Case-3 Gas Production Rate for 10-Year Cycle

Year	Month	Gas Prod Rate (MM m ³ /day)
1	1	18.82
	2	12.02
	3	8.54
2	1	16.32
	2	10.58
	3	7.68
3	1	15.56
	2	10.18
	3	7.53
4	1	15.36
	2	10.14
	3	7.60
5	1	15.38
	2	10.24
	3	7.76
6	1	15.41
	2	10.32
	3	7.88
7	1	15.46
	2	10.40
	3	7.99
8	1	15.50
	2	10.47
	3	8.09
9	1	15.56
	2	10.55
	3	8.19
10	1	15.58
	2	10.60
	3	8.27

As summarized in Table 5.20, 35.02% of the initial CH₄ in the reservoir was produced during the 10-year period of 70% CH₄ storage. The average reservoir pressure fluctuated between 10,000 and 13,890 kPa throughout the year.

Table 5.20: Case-3 Injection and Production Summary for 10-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	10.13
Total Injected CO₂, MMM m³	4.27
Total Injected Gas, MMM m³	14.40
Total Produced CH₄, MMM m³	11.42
Total Produced CO₂, MMM m³	2.14
Total Produced Gas, MMM m³	13.79
Total Produced Other Gases, MMM m³	0.22
Produced reservoir CH₄, MMM m³	1.29
Reservoir CH₄ Recovery, %	35.02

Table 5.21: Molar Fraction of Produced Gas Case-3 10-Year Cycle

Year	Month	C₂H₆	C₃H₈	CH₄	CO₂	iC₄	iC₅	N₂	nC₄	nC₅
1	1	0.011	0.004	0.969	0.011	0.001	0.000	0.004	0.001	0.000
	2	0.022	0.008	0.913	0.043	0.002	0.001	0.008	0.002	0.000
	3	0.028	0.010	0.876	0.070	0.002	0.001	0.010	0.003	0.001
2	1	0.007	0.003	0.964	0.023	0.000	0.000	0.002	0.001	0.000
	2	0.016	0.006	0.884	0.085	0.001	0.000	0.006	0.002	0.000
	3	0.022	0.008	0.816	0.141	0.002	0.001	0.008	0.002	0.000
3	1	0.005	0.002	0.949	0.042	0.000	0.000	0.002	0.000	0.000
	2	0.012	0.005	0.844	0.132	0.001	0.000	0.004	0.001	0.000
	3	0.018	0.007	0.756	0.210	0.001	0.000	0.006	0.002	0.000
4	1	0.004	0.002	0.932	0.060	0.000	0.000	0.001	0.000	0.000
	2	0.010	0.004	0.807	0.174	0.001	0.000	0.004	0.001	0.000
	3	0.015	0.006	0.704	0.267	0.001	0.000	0.005	0.001	0.000
5	1	0.004	0.001	0.915	0.078	0.000	0.000	0.001	0.000	0.000
	2	0.009	0.003	0.773	0.209	0.001	0.000	0.003	0.001	0.000
	3	0.013	0.005	0.662	0.313	0.001	0.000	0.005	0.001	0.000
6	1	0.003	0.001	0.902	0.092	0.000	0.000	0.001	0.000	0.000
	2	0.008	0.003	0.748	0.236	0.001	0.000	0.003	0.001	0.000
	3	0.012	0.004	0.629	0.348	0.001	0.000	0.004	0.001	0.000
7	1	0.003	0.001	0.891	0.104	0.000	0.000	0.001	0.000	0.000
	2	0.007	0.003	0.728	0.258	0.001	0.000	0.003	0.001	0.000

	3	0.011	0.004	0.603	0.376	0.001	0.000	0.004	0.001	0.000
8	1	0.003	0.001	0.882	0.113	0.000	0.000	0.001	0.000	0.000
	2	0.007	0.003	0.711	0.276	0.000	0.000	0.002	0.001	0.000
	3	0.010	0.004	0.581	0.400	0.001	0.000	0.004	0.001	0.000
9	1	0.002	0.001	0.873	0.123	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.694	0.294	0.000	0.000	0.002	0.001	0.000
	3	0.009	0.003	0.558	0.424	0.001	0.000	0.003	0.001	0.000
10	1	0.002	0.001	0.865	0.131	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.679	0.310	0.000	0.000	0.002	0.001	0.000
	3	0.009	0.003	0.539	0.444	0.001	0.000	0.003	0.001	0.000

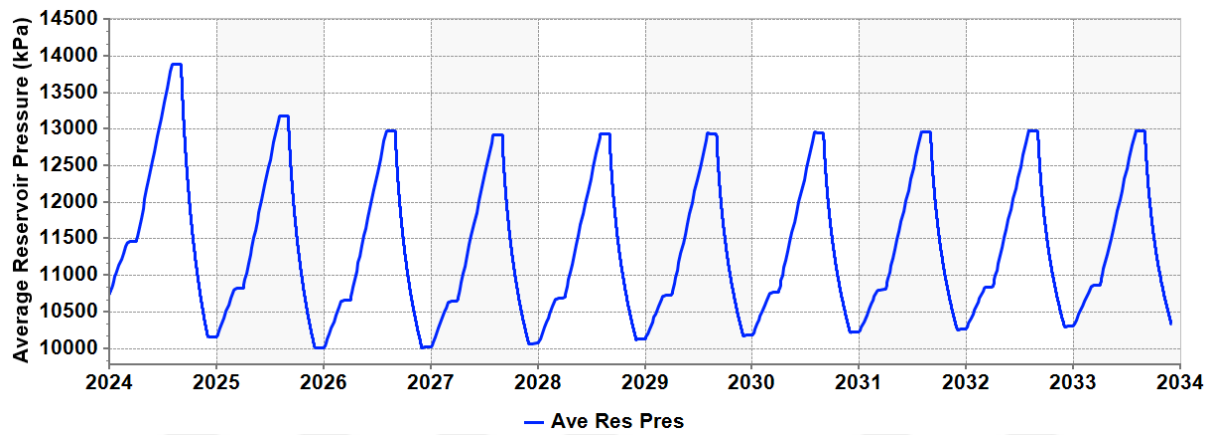


Figure 5.53: Case-3 10-Year Average Reservoir Pressure

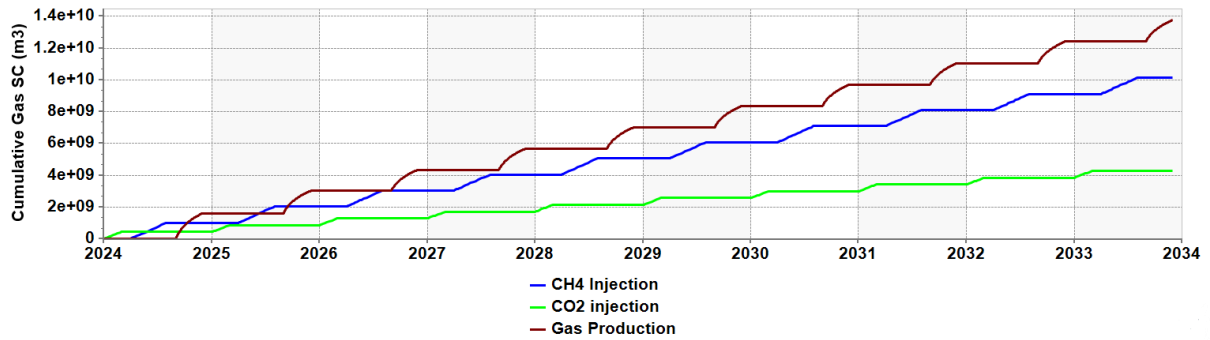


Figure 5.54: Case-3 10-Year Period Cumulative Injection and Production Gas

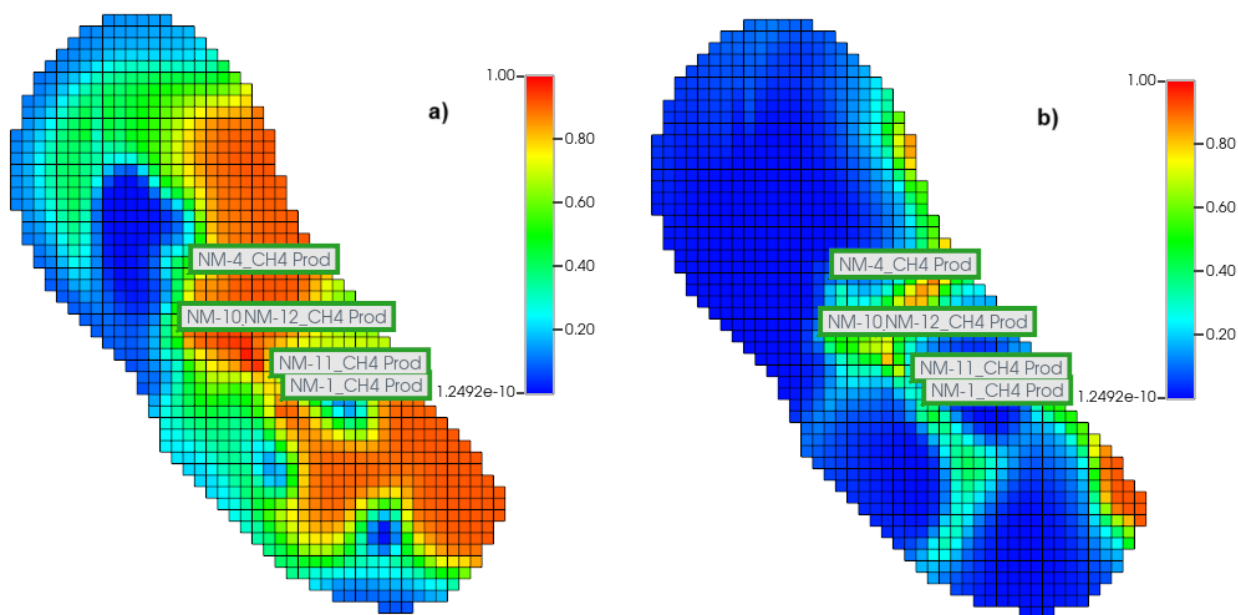


Figure 5.55: Case-3 10-Year Cycle; CH₄ Mole Fraction at the end of 10-Year Production Period a) First Layer and b) Last Layer

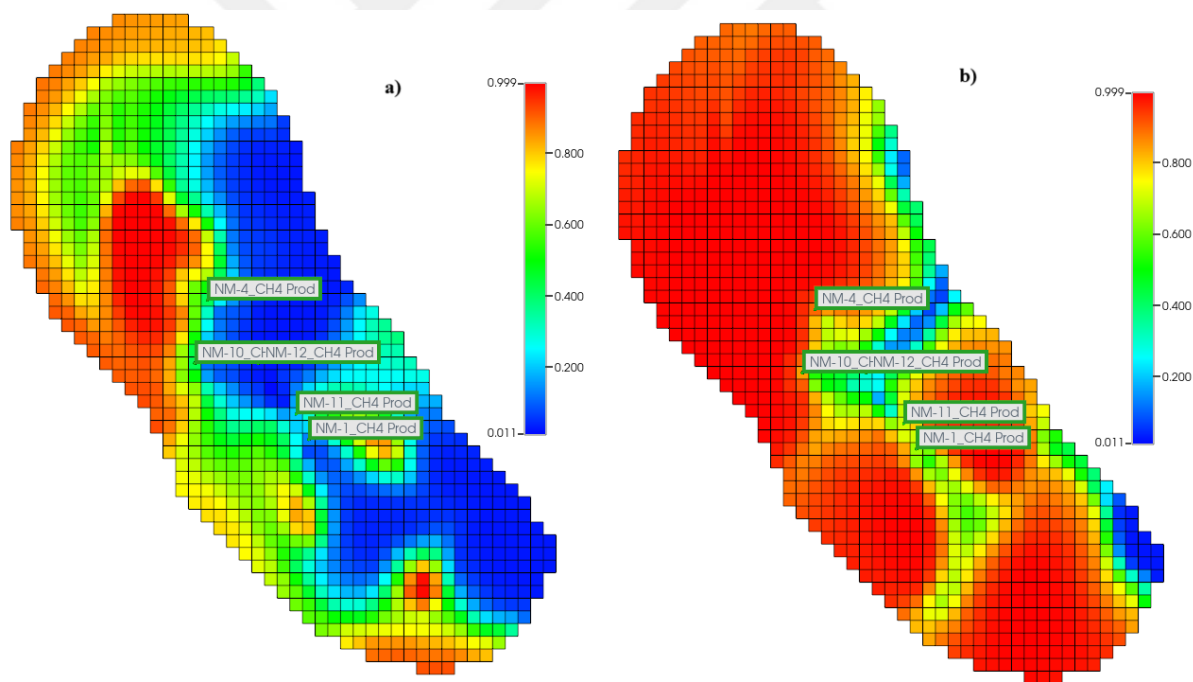


Figure 5.56 Case-3 10-Year Cycle; CO₂ Mole Fraction at the end of 10-Year Production Period a) First Layer and b) Last Layer

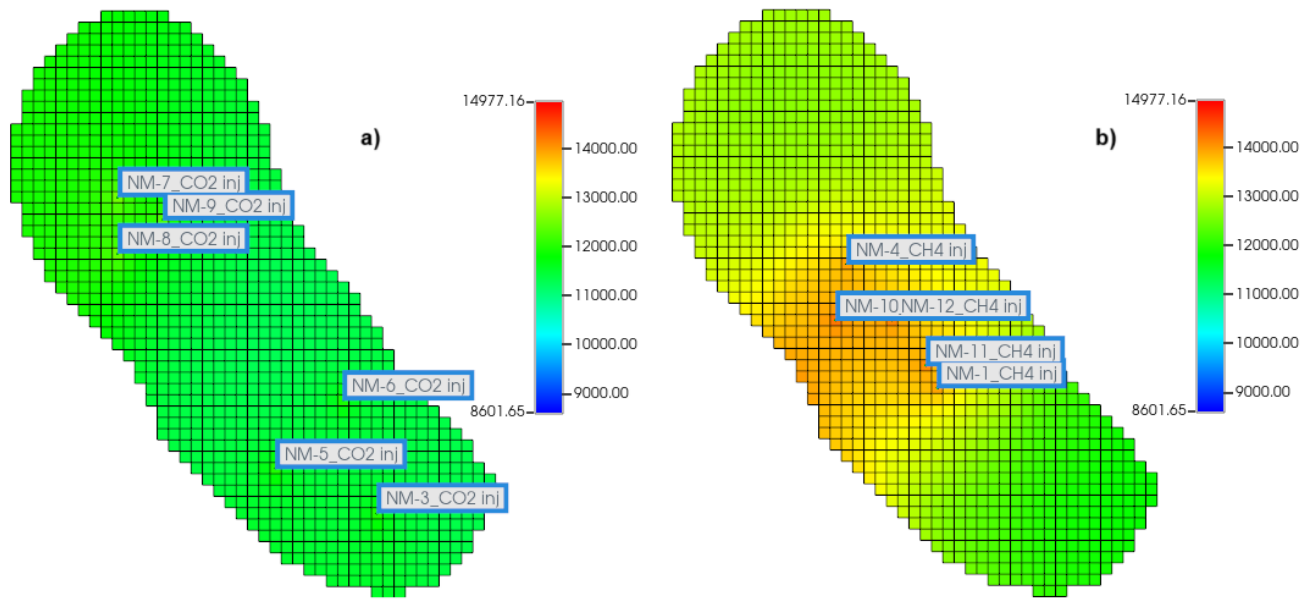


Figure 5.57: Case-3 10-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period

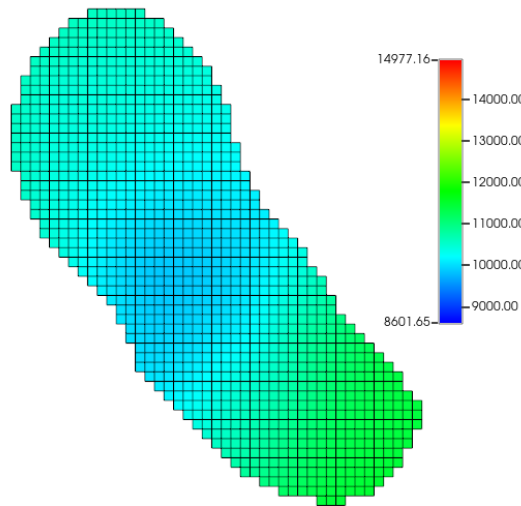


Figure 5.58: Case-3 10-Year Cycle; Reservoir Pressure at the End of 10-Year Production Period

5.1.4 Case-4 Injection of 60% CH₄ and 40% CO₂

In this case, CO₂ was initially injected into the reservoir as cushion gas, which plays a critical role in maintaining the pressure and stability of the storage field. Following the CO₂ injection, CH₄ was subsequently injected for storage purposes. The total volume of gas injected into the reservoir consisted of 40% CO₂ and 60% CH₄, forming a specific gas mixture ratio. This ratio was chosen to examine how the varying proportions of CO₂ and CH₄ affect the storage process

and long-term production performance. The study aimed to assess the impact of using CO₂ as cushion gas over different periods of time, specifically analyzing the production dynamics over three distinct timeframes: 1 year, 5 years, and 10 years. These time periods were selected to observe the short-term and long-term effects of the injection strategy, providing insights into how the reservoir's performance and production efficiency evolve over time.

Throughout all the scenarios considered in this study, several key operational parameters were held constant to ensure a fair and accurate comparison. The injection periods, shut-in periods (when the wells are sealed to allow pressure to stabilize), and production periods were all kept consistent across the different timeframes. This allowed for a focused evaluation of the impact of CO₂ as cushion gas without any interference from varying operational conditions. In addition, the locations of both the injection and production wells were fixed for the duration of the analysis, ensuring that the results were not influenced by changes in well placement. By maintaining these constants, the study aimed to isolate and understand the specific effects that the use of CO₂ as cushion gas would have on gas storage, pressure management, and overall production over time, while minimizing the potential confounding factors. Through this approach, the research sought to provide a clearer understanding of the long-term viability and efficiency of using CO₂ as cushion gas in natural gas storage projects.

5.1.4.1 1-Year Cycle Injection of 60% CH₄ and 40% CO₂

For the first 2 months, CO₂ was injected into the reservoir at an injection rate of 9.5 MMm³/day. Afterward, the wells were shut-in for a period of 1 month. Following the 1-month shut-in period, CH₄ was injected into the wells for storage purposes with injection rate of 7.2 MMm³/day for 4 months, and then the wells were shut-in again for another month. After the second 1-month shut-in period, the gas withdrawal phase was initiated. The production rates were as follows: in the first month, 18.37 MM m³/day; in the second month, 11.84 MM m³/day; and in the third month, 8.48 MM m³/day. The injection and production rates from the wells were maintained at equal levels.

Table 5.22: Case-4 Injection and Production Summary for 1-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	0.88
Total Injected CO₂, MMM m³	0.57
Total Injected Gas, MMM m³	1.45
Total Produced CH₄, MMM m³	1.44
Total Produced CO₂, MMM m³	0.07
Total Produced Gas, MMM m³	1.57
Total Produced Other Gases, MMM m³	0.06
Produced reservoir CH₄, MMM m³	0.56
Reservoir CH₄ Recovery, %	15.19

As summarized in Table 5.22, 15.19% of the initial CH₄ in the reservoir was produced during the 10-year period of 60% CH₄ storage. The average reservoir pressure fluctuated between 10,160 and 13,770 kPa throughout the year.

Table 5.23: Molar Fraction of Produced Gas Case-4 1-Year Cycle

Time	C₂H₆	C₃H₈	CH₄	CO₂	iC₄	iC₅	N₂	nC₄	nC₅
1 st Month	0.014	0.005	0.955	0.018	0.001	0.000	0.005	0.001	0.000
2 nd Month	0.025	0.009	0.889	0.063	0.002	0.001	0.009	0.002	0.001
3 rd Month	0.028	0.011	0.847	0.098	0.002	0.001	0.010	0.003	0.001

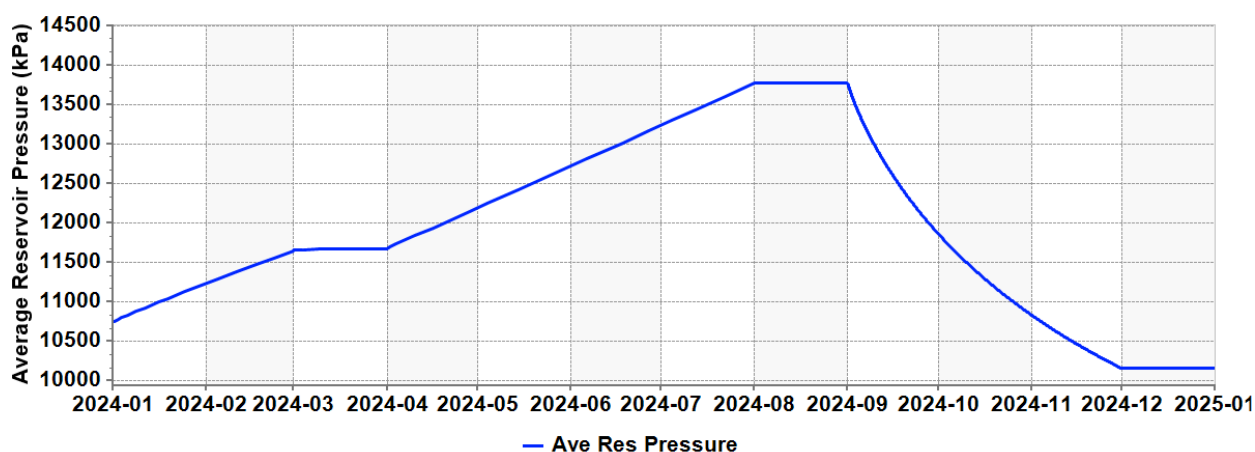


Figure 5.59: Case-4 1-Year Average Reservoir Pressure

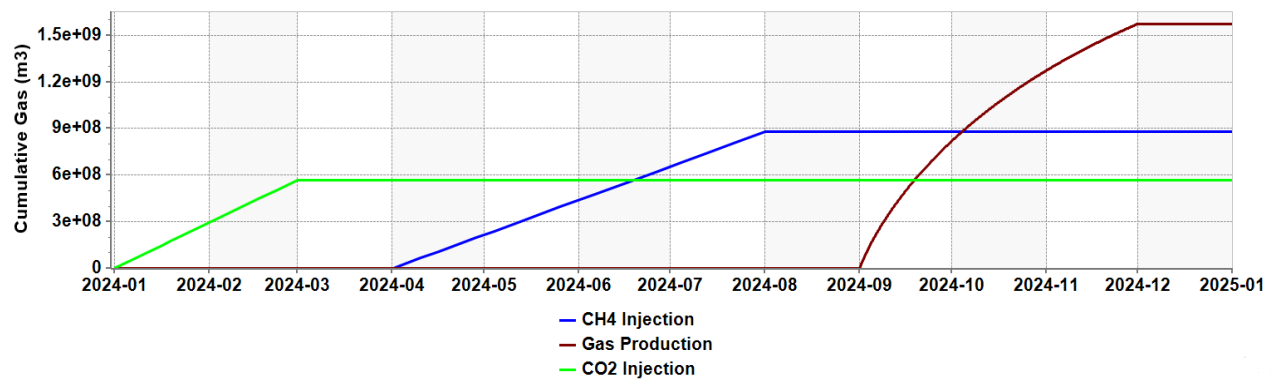


Figure 5.60: Case-4 1-Year Period Cumulative Injection and Production Gas

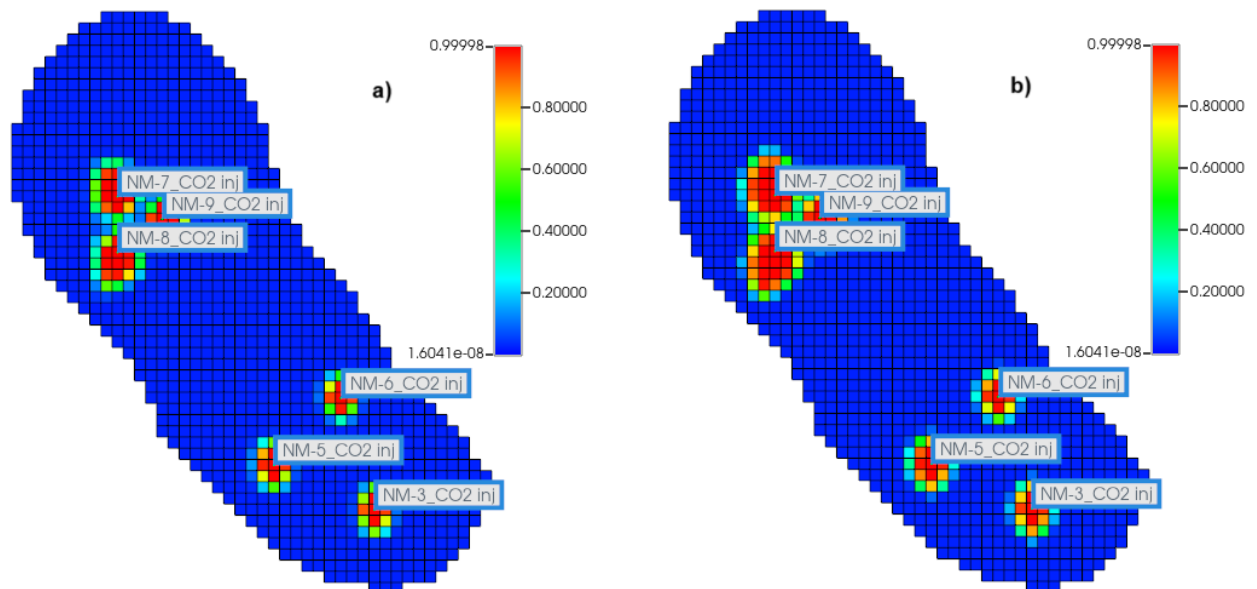


Figure 5.61: Case-4 1-Year Cycle; CO₂ Mole Fraction in a) First Layer b) Last Layer After First CO₂ Injection

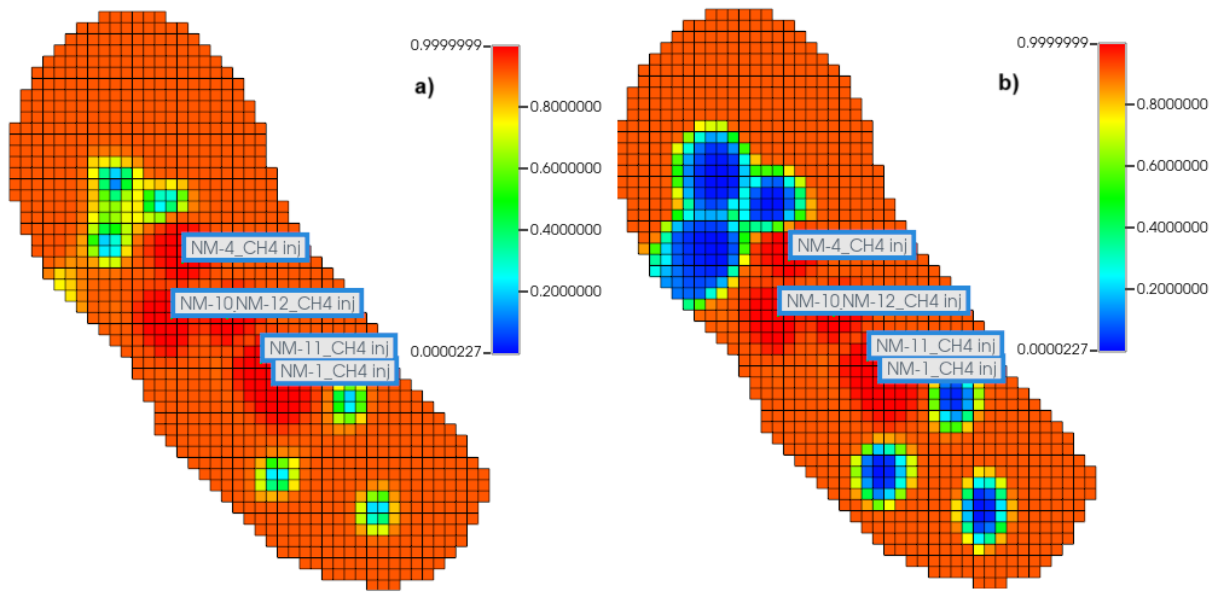


Figure 5.62: Case-4 1-Year Cycle; CH₄ Mole Fraction in a) First Layer b) Last Layer After First CH₄ Injection

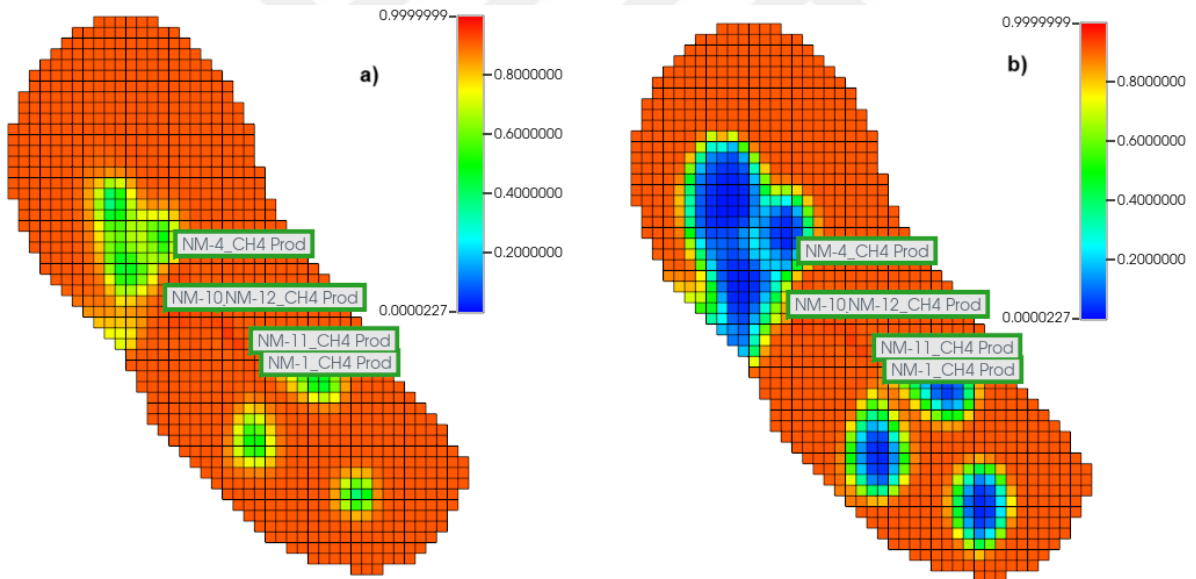


Figure 5.63: Case-4 1-Year Cycle; CH₄ Mole Fraction at the End of 1-Year Production Period a) First Layer and b) Last Layer

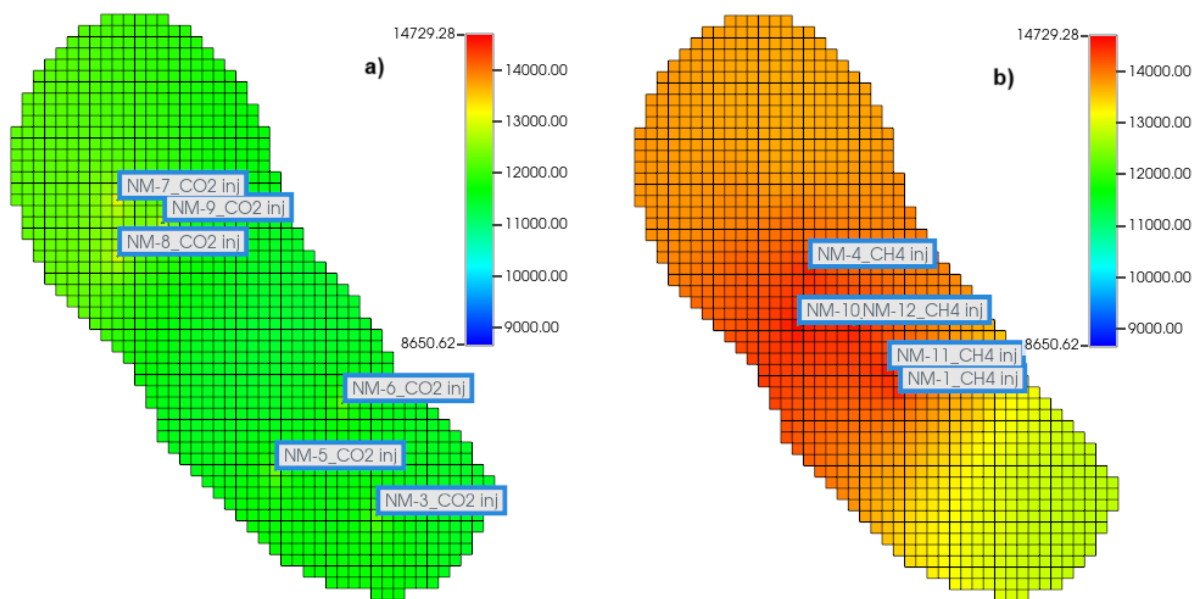


Figure 5.64: Case-4 1-Year Cycle; Reservoir Pressure a) at the End of First CO₂ injection Period b) at the End of Last CH₄ Injection Period

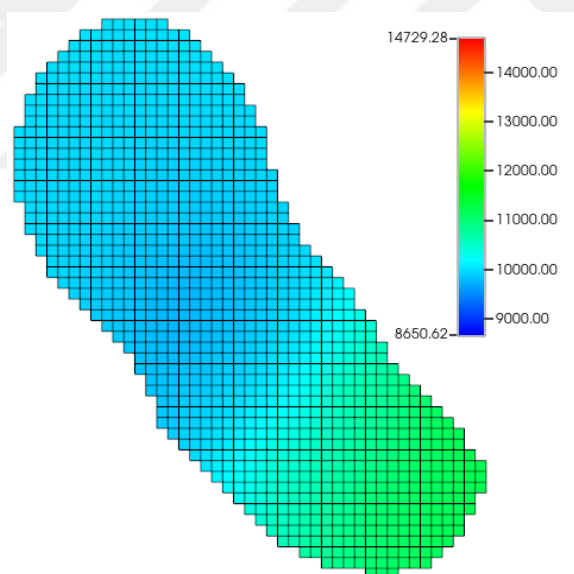


Figure 5.65: Case-4 1-Year Cycle; Reservoir Pressure at the End of 1-Year Production Period

5.1.4.2 5-Year Cycle Injection of 60% CH₄ and 40% CO₂

CO₂ was injected at 9.5 MMm³/day for the first 2 months, followed by a 1-month shut-in. Then, CH₄ was injected at 7.2 MMm³/day for 4 months, with another 1-month shut-in. After the

second shut-in, the gas withdrawal phase began. The production rates for 5 years are summarized in Table 5.24.

Table 5.24: Case-4 Gas Production Rate for 5-Year Cycle

Year	Month	Gas Prod Rate (MM m ³ /day)
1	1	18.37
	2	11.84
	3	8.48
2	1	15.77
	2	10.40
	3	7.69
3	1	15.04
	2	10.09
	3	7.65
4	1	14.92
	2	10.14
	3	7.80
5	1	15.00
	2	10.31
	3	8.02

As summarized in Table 5.25, 33.71% of the initial CH₄ in the reservoir was produced during the 10-year period of 60% CH₄ storage. The average reservoir pressure fluctuated between 10,070 and 13,770 kPa throughout the year.

Table 5.25: Case-4 Injection and Production Summary for 5-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	4.39
Total Injected CO₂, MMM m³	2.82
Total Injected Gas, MMM m³	7.21
Total Produced CH₄, MMM m³	5.64
Total Produced CO₂, MMM m³	1.06
Total Produced Gas, MMM m³	6.86
Total Produced Other Gases, MMM m³	0.17
Produced reservoir CH₄, MMM m³	1.25
Reservoir CH₄ Recovery, %	33.71

Table 5.26: Molar Fraction of Produced Gas Case-4 5-Year Cycle

Year	Month	C ₂ H ₆	C ₃ H ₈	CH ₄	CO ₂	iC ₄	iC ₅	N ₂	nC ₄	nC ₅
1	1	0.014	0.005	0.955	0.018	0.001	0.000	0.005	0.001	0.000
	2	0.025	0.009	0.889	0.063	0.002	0.001	0.009	0.002	0.001
	3	0.028	0.011	0.847	0.098	0.002	0.001	0.010	0.003	0.001
2	1	0.009	0.003	0.933	0.050	0.001	0.000	0.003	0.001	0.000
	2	0.018	0.007	0.823	0.142	0.001	0.001	0.006	0.002	0.000
	3	0.022	0.008	0.746	0.211	0.002	0.001	0.008	0.002	0.000
3	1	0.007	0.002	0.900	0.087	0.000	0.000	0.002	0.001	0.000
	2	0.014	0.005	0.756	0.217	0.001	0.000	0.005	0.001	0.000
	3	0.018	0.007	0.662	0.304	0.001	0.000	0.006	0.002	0.000
4	1	0.005	0.002	0.870	0.119	0.000	0.000	0.002	0.000	0.000
	2	0.011	0.004	0.703	0.275	0.001	0.000	0.004	0.001	0.000
	3	0.015	0.006	0.598	0.373	0.001	0.000	0.005	0.001	0.000
5	1	0.005	0.002	0.845	0.147	0.000	0.000	0.002	0.000	0.000
	2	0.010	0.004	0.661	0.320	0.001	0.000	0.004	0.001	0.000
	3	0.013	0.005	0.550	0.425	0.001	0.000	0.005	0.001	0.000

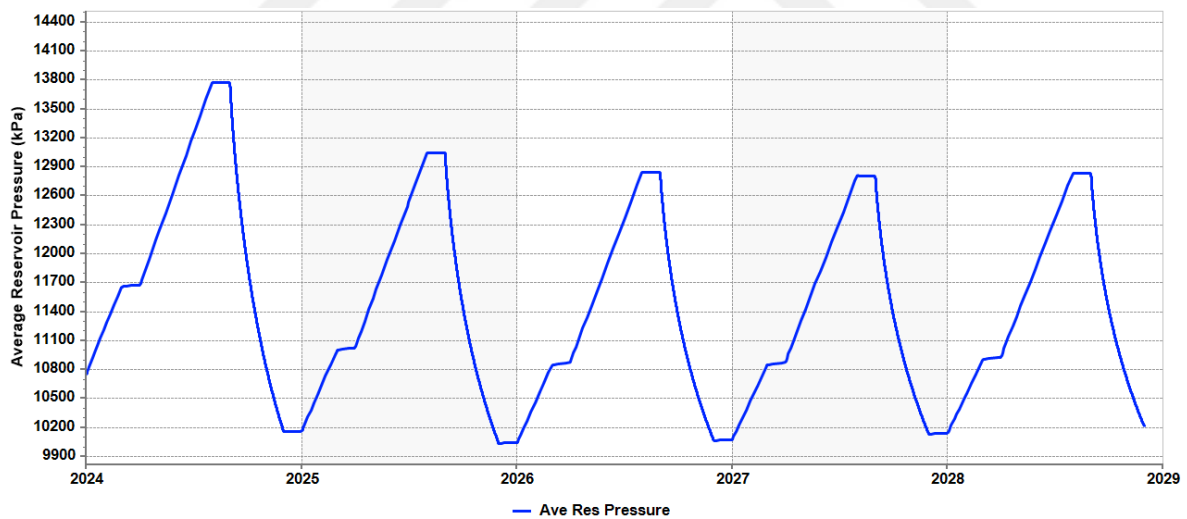


Figure 5.66: Case-4 5-Year Average Reservoir Pressure

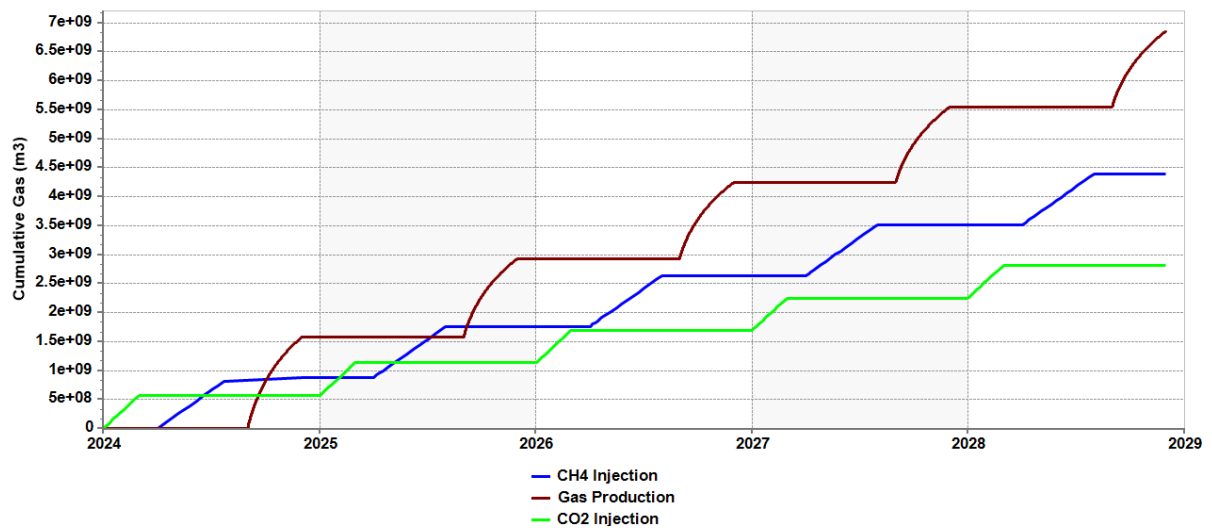


Figure 5.67: Case-4 5-Year Period Cumulative Injection and Production Gas

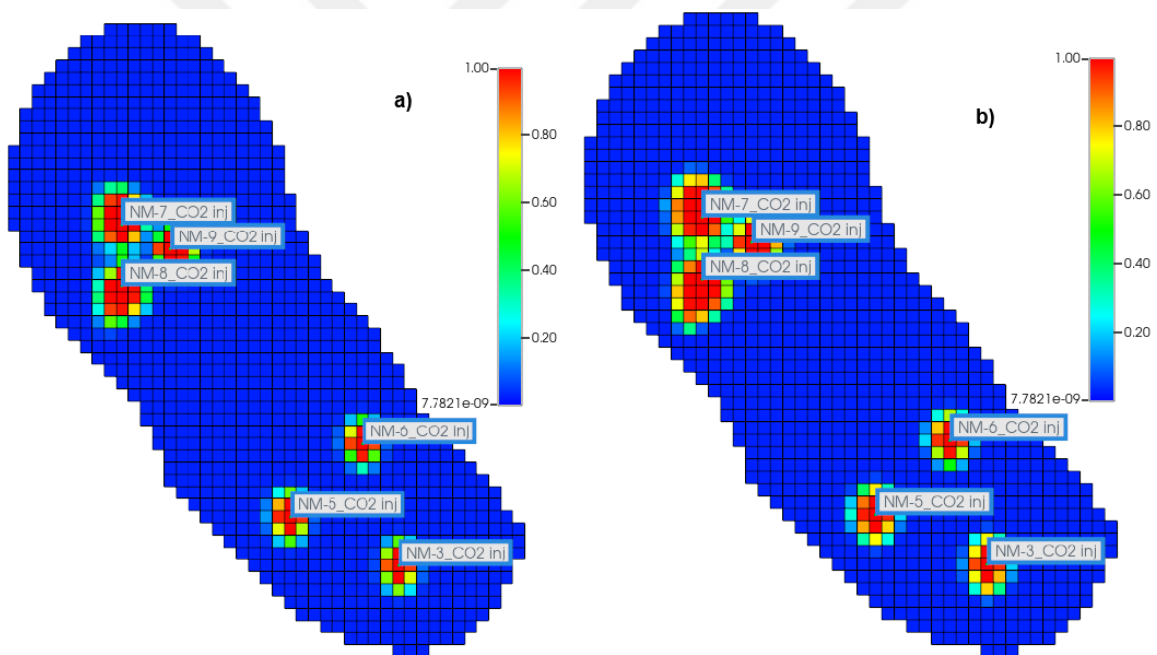


Figure 5.68: Case-4 5-Year Cycle; CO₂ Mole Fraction in a) First Layer b) Last Layer After First CO₂ Injection

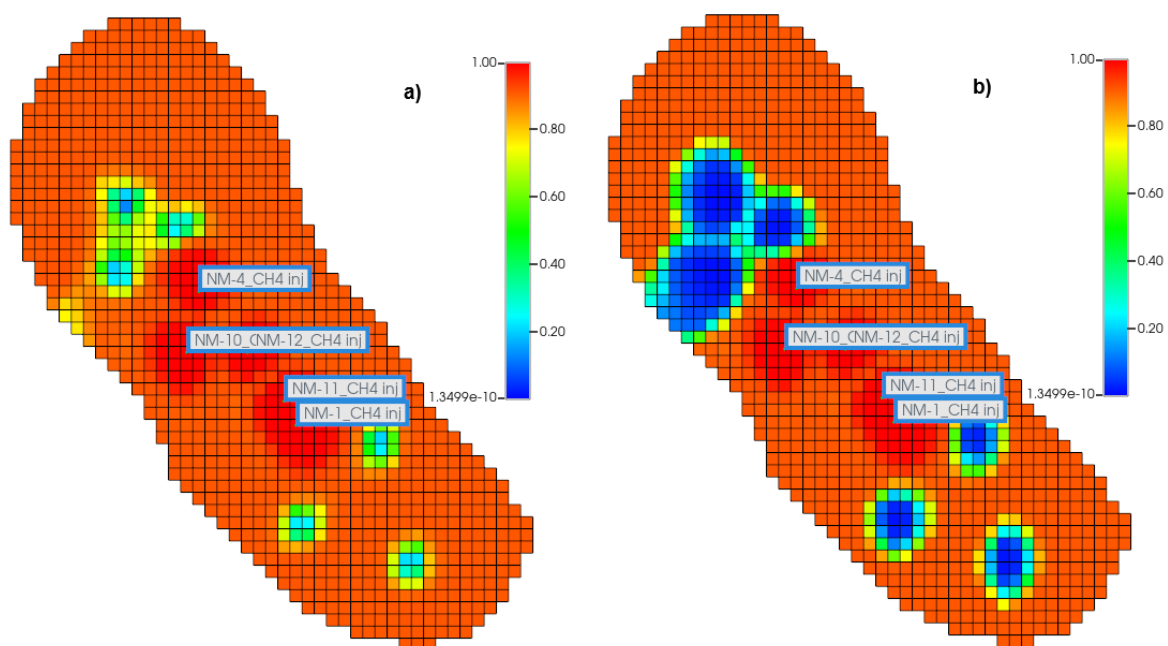


Figure 5.69: Case-4 5-Year Cycle; CH₄ Mole Fraction in a) First Layer b) Last Layer After First CH₄ Injection

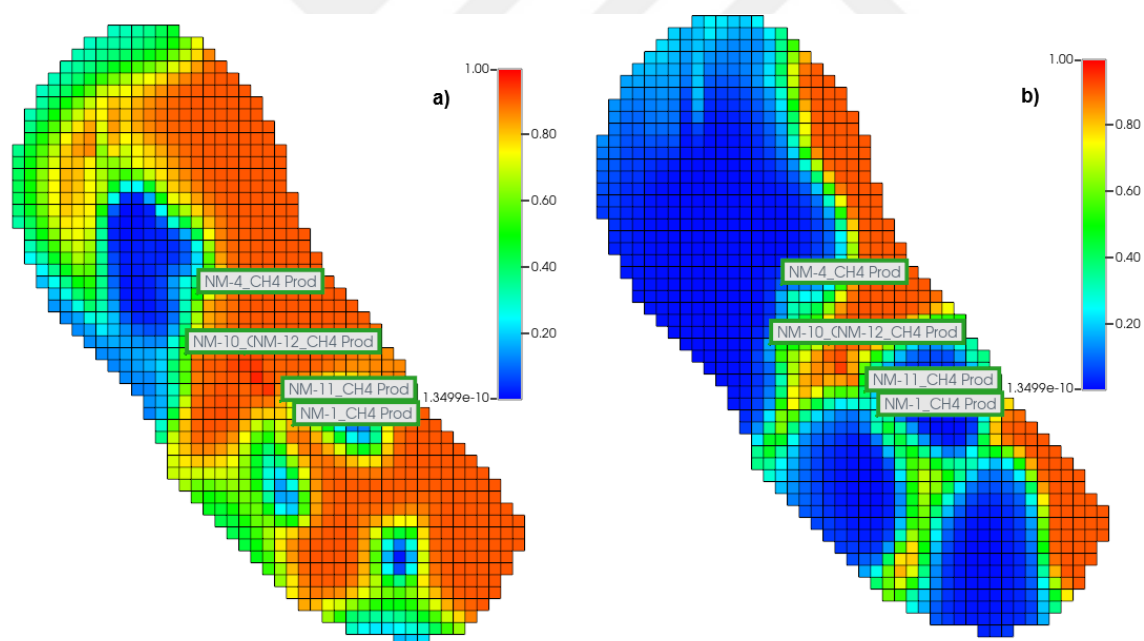


Figure 5.70: Case-4 5-Year Cycle; CH₄ Mole Fraction at the end of 5-Year Production Period a) First Layer and b) Last Layer

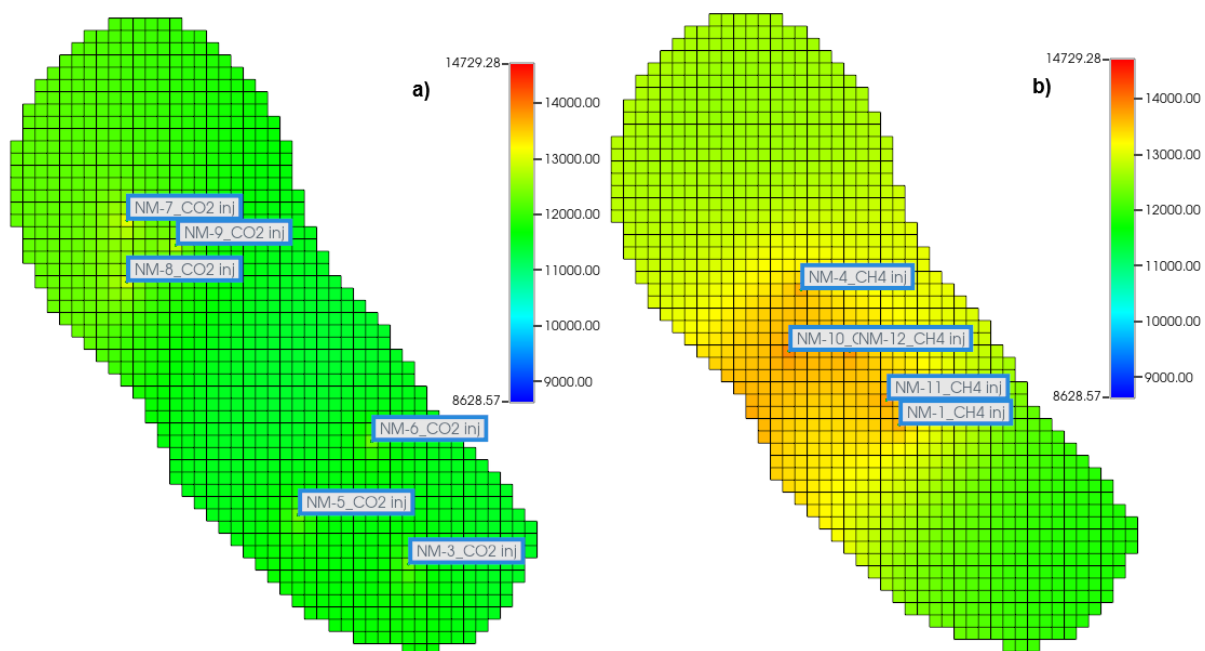
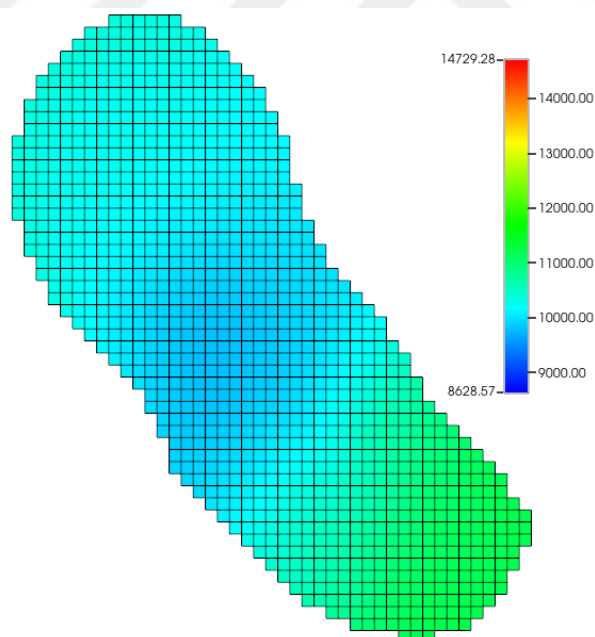


Figure 5.71: Case-4 5-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period



5.72: Case-4 5-Year Cycle; Reservoir Pressure at the End of 5-Year Production Period

5.1.4.3 10-Year Cycle Injection of 60% CH₄ and 40% CO₂

CO₂ was injected at 9.5 MMm³/day for the first 2 months, followed by a 1-month shut-in. Then, CH₄ was injected at 7.2 MMm³/day for 4 months, with another 1-month shut-in. After the second shut-in, the gas withdrawal phase began. The production rates for 10 years are summarized in Table 5.27.

Table 5.27: Case-4 Gas Production Rate for 10-Year Cycle

Year	Month	Gas Prod Rate (MMm ³ /day)
1	1	27.24
	2	14.68
	3	10.03
2	1	23.33
	2	12.71
	3	8.93
3	1	22.24
	2	12.21
	3	8.77
4	1	22.01
	2	12.17
	3	8.88
5	1	22.10
	2	12.30
	3	9.07
6	1	22.15
	2	12.39
	3	9.21
7	1	22.19
	2	12.47
	3	9.33
8	1	22.24
	2	12.55
	3	9.45
9	1	22.34
	2	12.65
	3	9.58
10	1	22.34
	2	12.70
	3	9.66

As summarized in Table 5.28, 35.31% of the initial CH₄ in the reservoir was produced during the 10-year period of 60% CH₄ storage. The average reservoir pressure fluctuated between 10,040 and 13,700 kPa throughout the year.

Table 5.28: Case-4 Injection and Production Summary for 10-Year Cycle

OGIP, MMM m³	5.56
Produced gas until 2002, MMM m³	1.51
Remained gas after 2002, MMM m³	4.04
OGIP, CH₄ after 2002, MMM m³	3.70
Total Injected CH₄, MMM m³	8.78
Total Injected CO₂, MMM m³	5.63
Total Injected Gas, MMM m³	14.42
Total Produced CH₄, MMM m³	10.09
Total Produced CO₂, MMM m³	3.23
Total Produced Gas, MMM m³	13.56
Total Produced Other Gases, MMM m³	0.24
Produced reservoir CH₄, MMM m³	1.31
Reservoir CH₄ Recovery, %	35.31

Table 5.29: Molar Fraction of Produced Gas Case-4 10-Year Cycle

Year	Month	C₂H₆	C₃H₈	CH₄	CO₂	iC₄	iC₅	N₂	nC₄	nC₅
1	1	0.014	0.005	0.955	0.018	0.001	0.000	0.005	0.001	0.000
	2	0.025	0.009	0.889	0.063	0.002	0.001	0.009	0.002	0.001
	3	0.028	0.011	0.847	0.098	0.002	0.001	0.010	0.003	0.001
2	1	0.009	0.003	0.933	0.050	0.001	0.000	0.003	0.001	0.000
	2	0.018	0.007	0.823	0.142	0.001	0.001	0.006	0.002	0.000
	3	0.022	0.008	0.746	0.211	0.002	0.001	0.008	0.002	0.000
3	1	0.007	0.002	0.900	0.087	0.000	0.000	0.002	0.001	0.000
	2	0.014	0.005	0.756	0.217	0.001	0.000	0.005	0.001	0.000
	3	0.018	0.007	0.662	0.304	0.001	0.000	0.006	0.002	0.000
4	1	0.005	0.002	0.870	0.119	0.000	0.000	0.002	0.000	0.000
	2	0.011	0.004	0.703	0.275	0.001	0.000	0.004	0.001	0.000
	3	0.015	0.006	0.598	0.373	0.001	0.000	0.005	0.001	0.000
5	1	0.005	0.002	0.845	0.147	0.000	0.000	0.002	0.000	0.000
	2	0.010	0.004	0.661	0.320	0.001	0.000	0.004	0.001	0.000
	3	0.013	0.005	0.550	0.425	0.001	0.000	0.005	0.001	0.000

6	1	0.004	0.002	0.826	0.166	0.000	0.000	0.001	0.000	0.000
	2	0.009	0.003	0.631	0.352	0.001	0.000	0.003	0.001	0.000
	3	0.012	0.004	0.514	0.463	0.001	0.000	0.004	0.001	0.000
7	1	0.004	0.001	0.811	0.182	0.000	0.000	0.001	0.000	0.000
	2	0.008	0.003	0.606	0.378	0.001	0.000	0.003	0.001	0.000
	3	0.010	0.004	0.484	0.496	0.001	0.000	0.004	0.001	0.000
8	1	0.003	0.001	0.797	0.197	0.000	0.000	0.001	0.000	0.000
	2	0.007	0.003	0.584	0.402	0.001	0.000	0.003	0.001	0.000
	3	0.010	0.004	0.457	0.524	0.001	0.000	0.003	0.001	0.000
9	1	0.003	0.001	0.783	0.211	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.562	0.425	0.000	0.000	0.002	0.001	0.000
	3	0.009	0.003	0.431	0.552	0.001	0.000	0.003	0.001	0.000
10	1	0.003	0.001	0.772	0.223	0.000	0.000	0.001	0.000	0.000
	2	0.006	0.002	0.544	0.444	0.000	0.000	0.002	0.001	0.000
	3	0.008	0.003	0.410	0.575	0.001	0.000	0.003	0.001	0.000

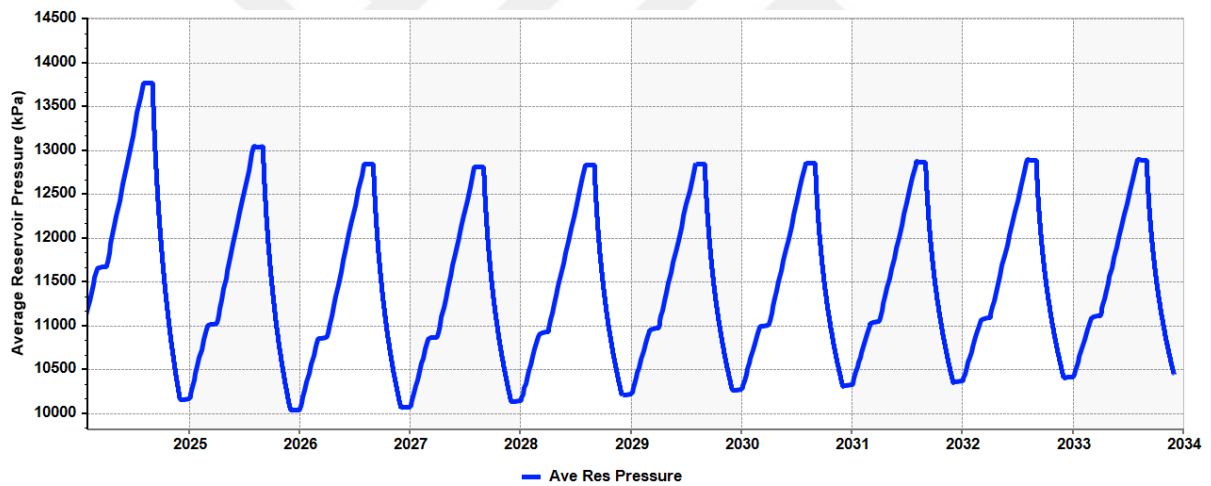


Figure 5.73: Case-4 10-Year Average Reservoir Pressure

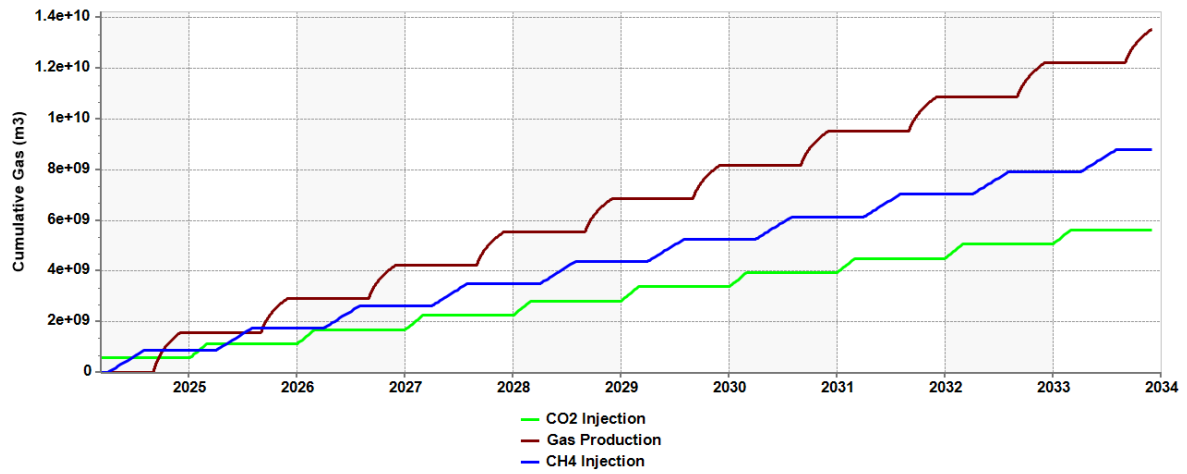


Figure 5.74: Case-4 10-Year Period Cumulative Injection and Production Gas

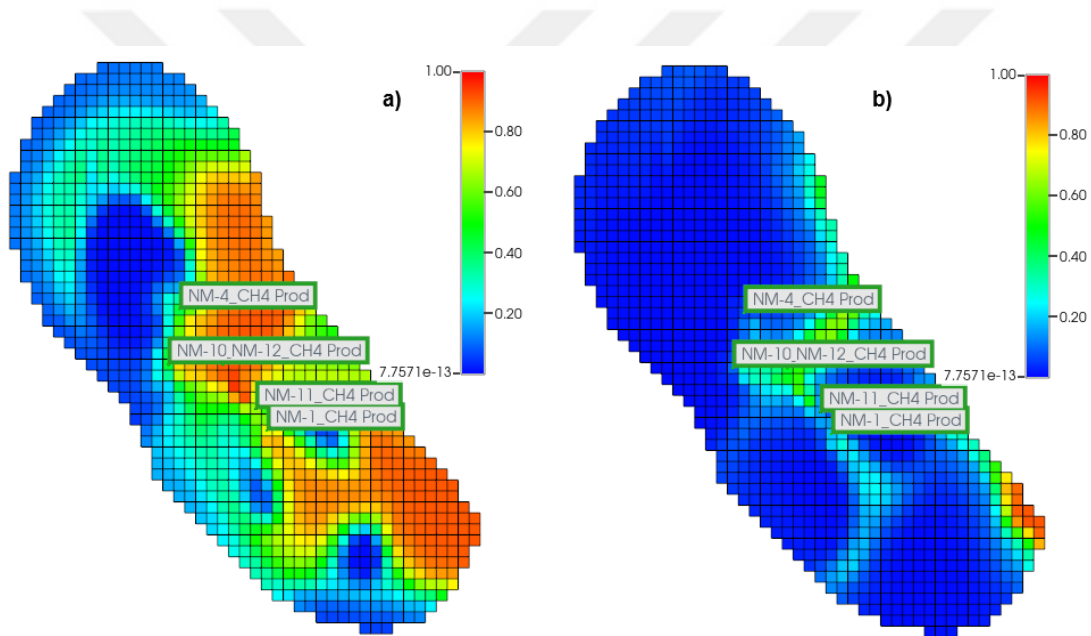


Figure 5.75: Case-4 10-Year Cycle; CH₄ Mole Fraction at the End of 10-Year Production Period a) First Layer and b) Last Layer

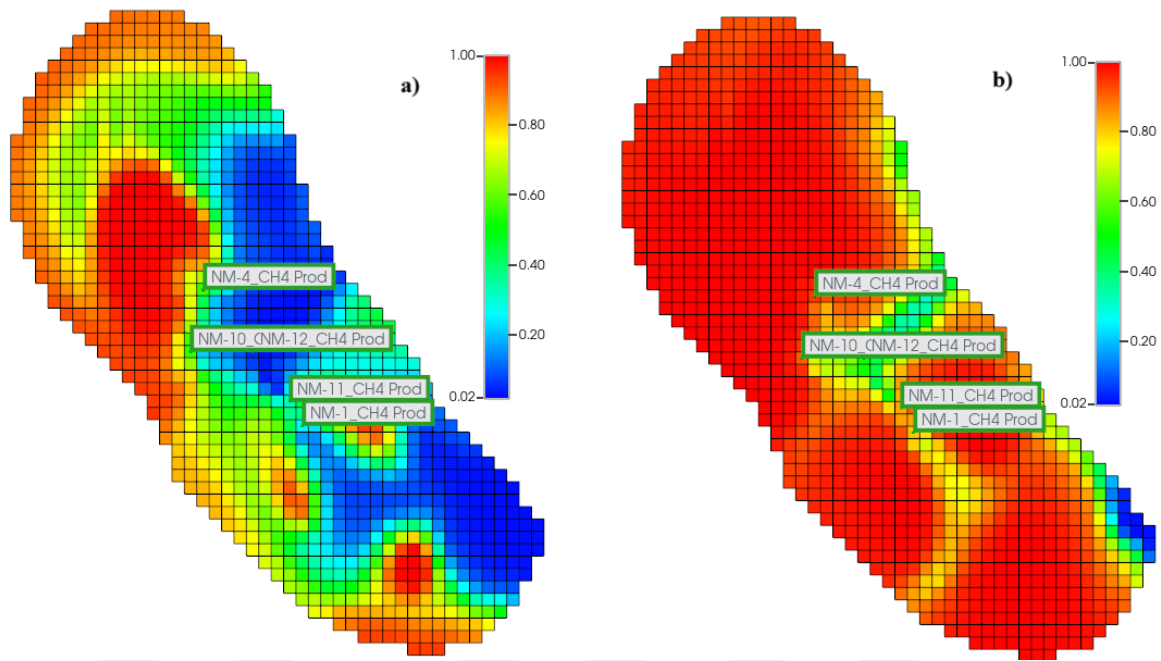


Figure 5.76 Case-4 10-Year Cycle; CO₂ Mole Fraction at the End of 10-Year Production Period a) First Layer and b) Last Layer

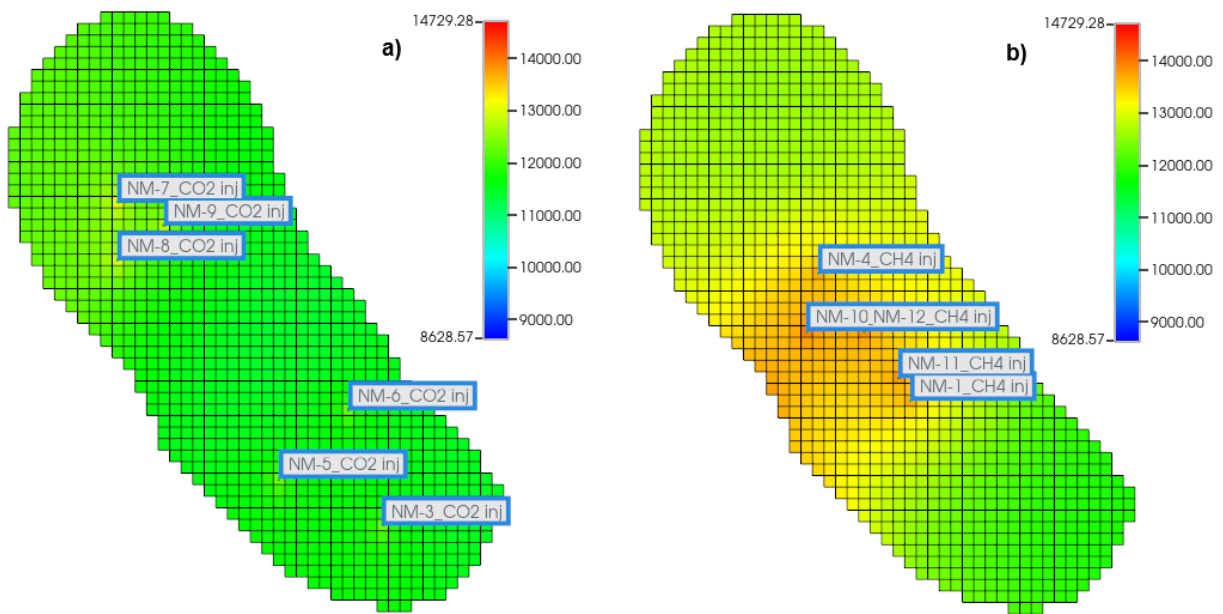
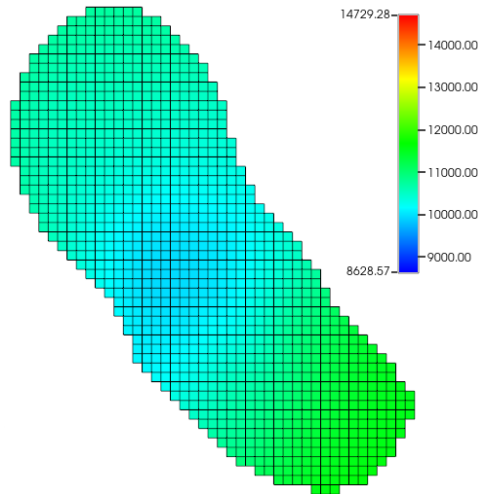


Figure 5.77: Case-4 10-Year Cycle; Reservoir Pressure a) at the End of First CO₂ Injection Period b) at the End of Last CH₄ Injection Period



5.78: Case-4 10-Year Cycle; Reservoir Pressure at the End of 10-Year Production Period

5.2 Competitive Model Results

To better understand how CO₂ acts as a cushion gas compared with CH₄ gas, four cases with different working and cushion gas ratios (Case-1: 100% CH₄, Case-2: 80% CH₄ - 20% CO₂, Case-3: 70% CH₄ - 30% CO₂, and Case-4: 60% CH₄ - 40% CO₂) have been simulated. The effects of injecting different gas ratios were evaluated at different time intervals (1 year, 5 years, and 10 years) accordingly.

When CH₄ was used as cushion gas (Case-1), the amount of CH₄ recovered from the reservoir increased in the short term, but in the long term, its effect on CH₄ production from the reservoir was limited. The amount of CH₄ recovered from the reservoir was calculated based on the assumption that all the CH₄ gas injected for storage purposes was produced.

In cases where CO₂ was injected as cushion gas at different ratios (Case-2, Case-3, and Case-4), an increase in the CO₂ ratio resulted in a higher CH₄ recovery from the reservoir for the 1-year and 5-year cycles. However, in the 10-year cycle, the injection of 30% CO₂ and 40% CO₂ as cushion gas had the same effect on reservoir CH₄ recovery, with both cases contributing to a 35% recovery of the reservoir CH₄ as seen Figure 5.81.

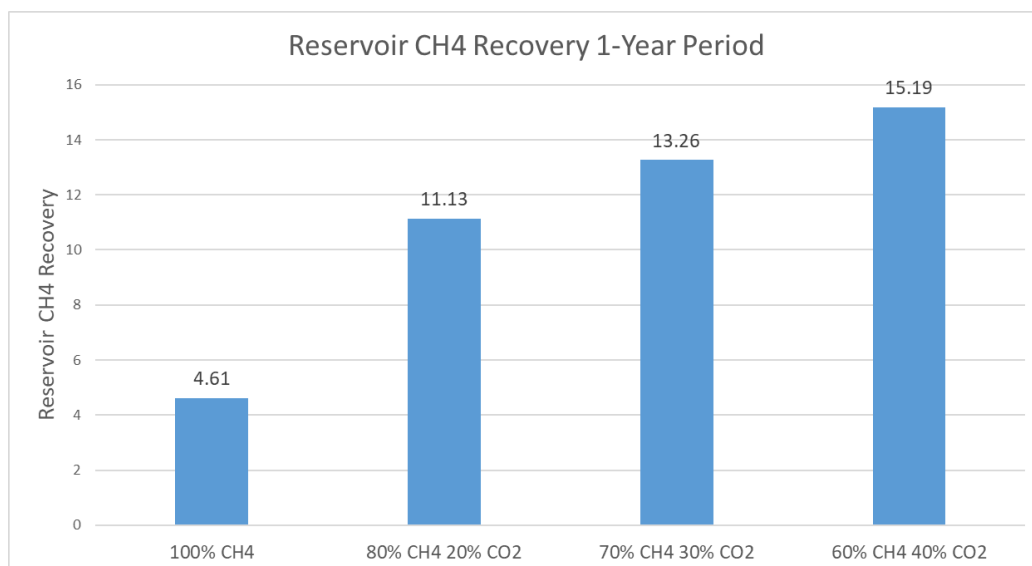


Figure 5.79: Reservoir CH₄ Recovery in 1-Year Period

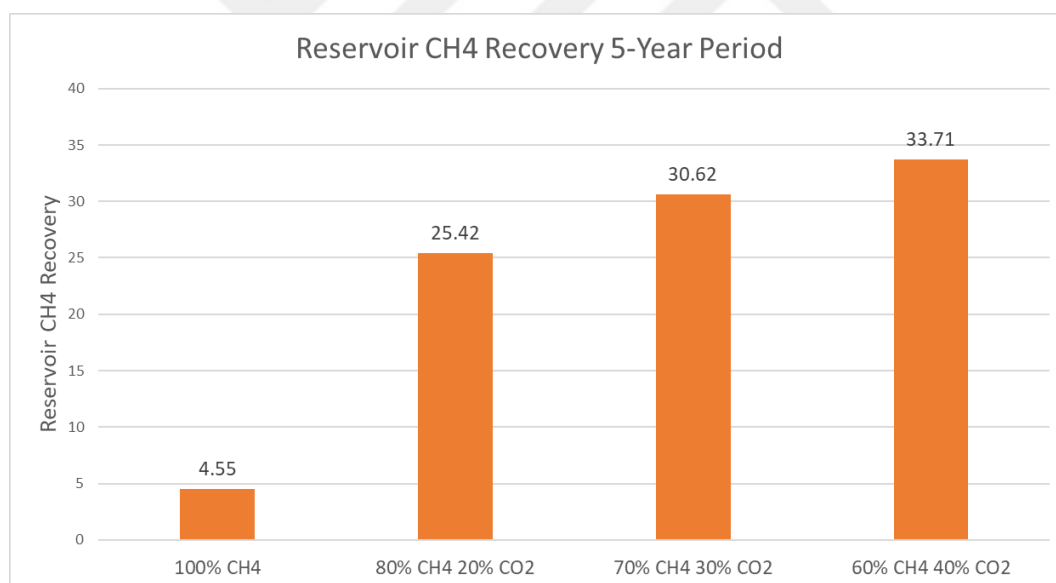


Figure 5.80: Figure 5.76 Reservoir CH₄ Recovery in 5-Year Period

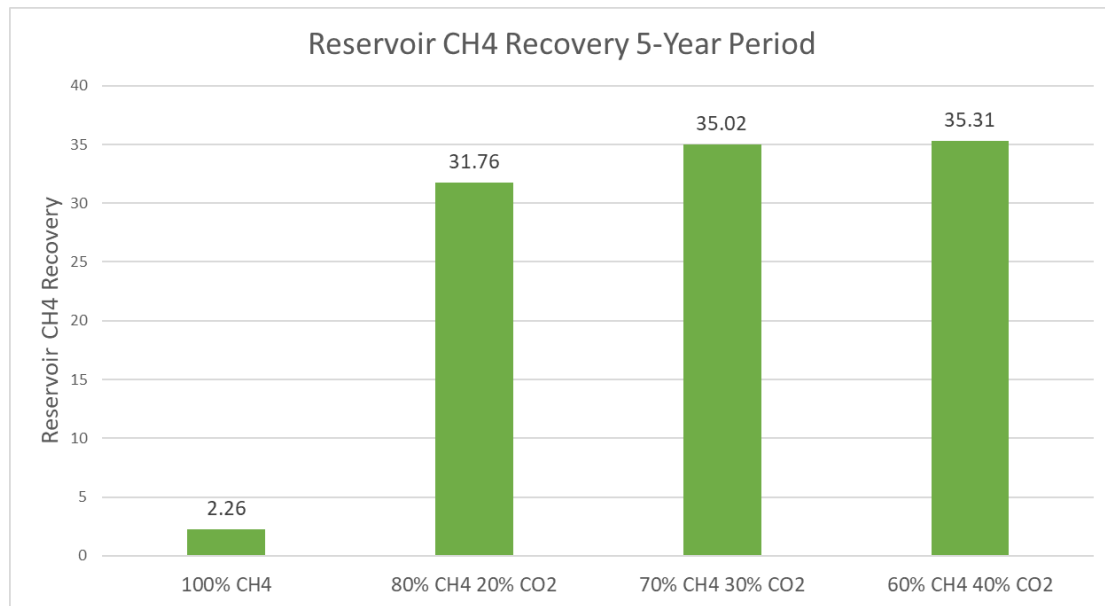


Figure 5.81 Reservoir CH₄ Recovery in 10-Year Period

The CO₂ injected as cushion gas has a higher density (see Figure 5.82) compared to CH₄, which has caused it to accumulate in the lower layers of the reservoir. Since CH₄ is less viscous (See Table 5.30) than both cushion gas CO₂ and the initial reservoir gases, it tends to move towards the upper layers of the reservoir.

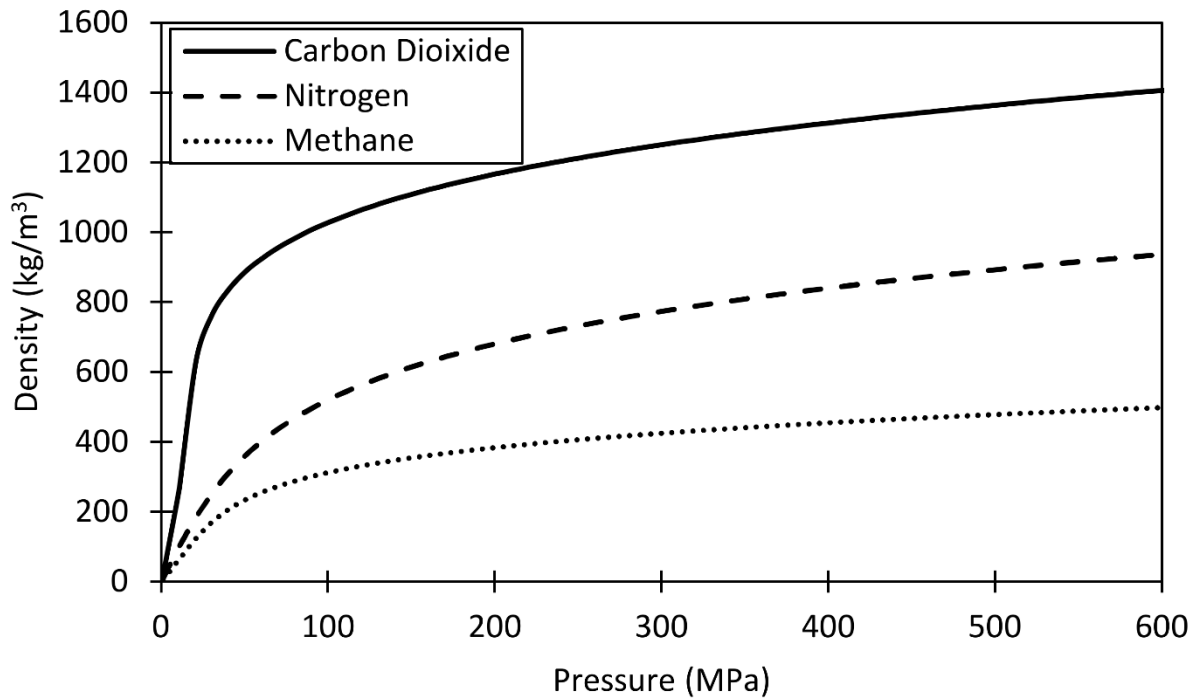


Figure 5.82 Density of CO₂, N₂ and CH₄ at temperature 76°C (Mehana et al., 2020)

Table 5.30 CO₂ and CH₄ Density and Viscosity

CO ₂		CH ₄	
Pressure (kPa)	14500	Pressure (kPa)	14500
Temperature (°C)	68.8	Temperature (°C)	68.8
Density (kg·m ⁻³)	494.8322	Density (kg·m ⁻³)	89.45
Viscosity (Pa·s)	3.67 x 10 ⁻⁵	Viscosity (Pa·s)	1.62 x 10 ⁻⁶
Sources	(EgiChem,2024) & (peacesoftware.de,2007)		

In cases where CO₂ is used as cushion gas, its low viscosity causes it to move more irregularly and slowly through the porous medium. CH₄, on the other hand, progresses more uniformly and moves faster due to its higher viscosity. CO₂ injection from wells close to the reservoir boundaries has caused CH₄ to move toward the production wells. In the medium and long term, the CO₂ injected as cushion gas accumulated near the reservoir boundaries, and the molar

fraction of CH₄ was higher near the production wells (Figure 5.63). This has had a positive effect on the amount of CH₄ recovered from the reservoir.

As stated in Du et al. (2024) study, the optimal ratio of CO₂ used as cushion gas is 19.5%-32.5%. Figure 5.81 shows that the increase in CO₂ ratio in the long-term (10-Year cycle) case had no positive effect on the reservoir CH₄ production. Therefore, it could be concluded that injecting 30% CO₂ as cushion gas yields the most optimal result in the arranged model set-up.





CHAPTER 6

6.1. CONCLUSIONS

This study compares the short-, medium-, and longer-term performances of using CO₂ as cushion gas in the Kuzey Marmara (KM) Field, where the primary aim of cushion gas in natural gas storage projects is to maintain the pressure balance and increase the recovery of stored CH₄. The main objective is to assess how the injection of CO₂ as cushion gas at different proportions affects CH₄ recovery in both the short and long term. To this end, the simulations were conducted with different gas injection ratios (100% CH₄, 80% CH₄ - 20% CO₂, 70% CH₄ - 30% CO₂, 60% CH₄ - 40% CO₂) over three different periods (1 year, 5 years, and 10 years).

In Case-1, where 100% CH₄ was injected, the effect on CH₄ recovery from the reservoir was minimal. On the other hand, in Case-2, Case-3, and Case-4, where CO₂ was used as cushion gas, an increase in the recovered CH₄ ratio was observed in the short and medium term. Over 1-Year and 5-Year cycles, an increase in the proportion of CO₂ injected as cushion gas led to an increase in the amount of CH₄ recovered from the reservoir. However, in the long term (10-year cycle), increasing the CO₂ injection rate from 30% to 40% had little effect on the reservoir CH₄ recovery, with CH₄ recovery in both cases reaching approximately 35%. To this end, it could be concluded that as the proportion of CO₂ injected as cushion gas into the reservoir increases, the amount of CH₄ recovered also shows a parallel increase in short (1-year) and mid-term periods (5-year), whereas further increase in injected CO₂ does not provide a significant additional benefit for CH₄ recovery in the longer terms (10-year). This, in turn, suggests that using CO₂ as cushion gas at a ratio of 30% would be the optimal value for enhancing CH₄ recovery in KM field for the arranged flooding pattern. However, a more detailed techno-economic feasibility study should be conducted by taking into account the well trajectories, other flooding patterns, and surface facility capabilities, such as the separator's capacity to assess the separation of the recovered CO₂.

6.2. RECOMMENDATIONS FOR FUTURE WORK

The study concludes that injecting CO₂ as cushion gas at a proportion of 30% of the total gas stored has a positive effect on the reservoir CH₄ production. However, as no data after 2002 is available in literature is assumed that the wells have been in a shut-in state since that time, whereas these wells have actually continued to be used for gas storage purposes after 2002, with 18 directional wells drilled in 2022. Accordingly, the trajectories of these 18 directional wells should also be incorporated into the study to evaluate the effect of well trajectories on the injection of CO₂ as cushion gas.

On the other hand, the substantial daily gas injection rates were calculated based on the assumption of using all the available storage capacity of KM field for the gas injection and withdrawal periods. However, well injectivities, the presence of sufficient infrastructure, including injection wells, compressors, and pipelines, as well as the reservoir conditions (P, T), and historical, seasonal daily injection rates applied in the field should be evaluated very carefully to arrange more realistic and safer gas injection rates.

Furthermore, the study assumes that all CH₄ injected for storage is fully recovered, leading to the calculation of the reservoir CH₄ recovery percentage. A more detailed analysis could include the inclusion of tracer in the injected CH₄, to investigate the recovery rate of stored CH₄.

In the medium to long term, the accumulation of CO₂ in the lower layers of the reservoir and the upward movement of CH₄ towards the upper layers may require perforation in the existing wells.

The study considers peripheral injection, where CO₂ is injected from wells near the reservoir boundaries, and production is carried out from wells located at the center of the reservoir. The effects of different injection/production patterns on CH₄ recovery could also be further explored.

In summary, the model input parameters (daily injection and production rates, gas injection, shut-in, and withdrawal periods, flooding pattern, and number and trajectories of injection and production wells) assumed in the study should be compared with the actual and/or more realistic field parameters, and accordingly, more comprehensive research should be conducted

to further investigate the impact of using CO₂ as cushion gas on CH₄ recovery in the Kuzey Marmara (KM) Field.





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APPENDIX

A. Field Data

The field data presented in this appendix were published in Özkılıç's study (2005), while the .fhf files were obtained from Gürsel's (2022) thesis.

Average Reservoir Pressure:

2022-01-01

"

1997 09 01

'YYYY/MM/DD'

1

'Ave reservoir pres'

'kPa'

1

'PAVG' *SPECIAL

1997/09/01 13669

1997/10/01 13873

1997/11/01 13796

1997/12/01 13784

1998/01/01 13796

1998/02/01 13860

1998/03/01 13860

1998/04/01 13859

1998/05/01	13859
1998/06/01	13936
1998/07/01	13859
1998/08/01	13834
1998/09/01	13872
1998/10/01	13872
1998/11/01	13859
1998/12/01	13872
1999/01/01	13821
1999/02/01	13719
1999/03/01	13655
1999/04/01	13592
1999/05/01	13516
1999/06/01	13439
1999/07/01	13388
1999/08/01	13388
1999/09/01	13109
1999/10/01	13122
1999/11/01	12969
1999/12/01	12880
2000/01/01	12626
2000/02/01	12626
2000/03/01	12346

2000/04/01	12486
2000/05/01	12219
2000/06/01	12219
2000/07/01	12219
2000/08/01	12143
2000/09/01	11800
2000/10/01	11533
2000/11/01	11520
2000/12/01	11317
2001/01/01	11164
2001/02/01	11037
2001/03/01	11723
2001/04/01	11253
2001/05/01	11177
2001/06/01	11317
2001/07/01	11101
2001/08/01	10961
2001/09/01	10999
2001/10/01	11024
2001/11/01	10910
2001/12/01	10618
2002/01/01	10554

Field Cumulative Production:

'Field Data'

1997 09 01

'YYYY/MM/DD'

3

'Bottom Hole Pressure' 'Cumulative Water SC' 'Cumulative Gas SC'

'kPa' 'bbl' 'MSCF'

1

'FIELD' *SECTOR

1997/09/01	13375.51829	0	16564
1997/10/01	13371.33122	0	441988
1997/11/01	13262.06517	38	1022492
1997/12/01	13222.85566	199	1793724
1998/01/01	13152.98583	353	2582745
1998/02/01	13089.69129	433	3204030
1998/03/01	13037.34873	485	3825728
1998/04/01	12977.87687	526	4414295
1998/05/01	12934.27315	548	4996599
1998/06/01	12890.68985	922	6107228
1998/07/01	12797.62075	1354	7335650
1998/08/01	12709.81352	1781	8546879
1998/09/01	12605.51999	2179	9685019
1998/10/01	12530.60597	2605	10881525
1998/11/01	12415.05378	3138	12260273

1998/12/01	12322.60277	3820	13863407
1999/01/01	12178.15289	4490	15397163
1999/02/01	12065.66783	5110	16806263
1999/03/01	11946.63859	5784	18352047
1999/04/01	11836.80493	6416	19802247
1999/05/01	11708.65343	7070	21302645
1999/06/01	11571.2697	7694	22707735
1999/07/01	11470.57051	8342	24178876
1999/08/01	11369.89576	8883	25410258
1999/09/01	11221.08171	9519	26830608
1999/10/01	11166.2382	10181	28299016
1999/11/01	10992.24325	10599	29722276
1999/12/01	10946.54642	11282	31201410
2000/01/01	10781.72261	11971	32721774
2000/02/01	10644.41219	12638	34176298
2000/03/01	10589.4587	13346	35695980
2000/04/01	10442.97716	13985	37110690
2000/05/01	10333.10683	14593	38388810
2000/06/01	10241.59099	15167	39663622
2000/07/01	10122.62285	15810	41074897
2000/08/01	9976.116863	16442	42475074
2000/09/01	9902.918857	17001	43698963
2000/10/01	9811.403019	17406	44570350

2000/11/01	9683.214864	17836	45449334
2000/12/01	9665.019225	18257	46387084
2001/01/01	9527.757688	18617	47100293
2001/02/01	9482.219713	18942	47700136
2001/03/01	9436.474014	19205	48260896
2001/04/01	9390.838286	19487	48848034
2001/05/01	9354.263721	19733	49361073
2001/06/01	9308.640212	19900	49768038
2001/07/01	9262.992265	20137	50256737
2001/08/01	9244.833283	20425	50778975
2001/09/01	9199.221994	20700	51329113
2001/10/01	9123.777025	20998	51915651
2001/11/01	9096.42247	21289	52517932
2001/12/01	9050.786743	21559	53127939
2002/01/01	9023.468845	21712	53485330

Well Head Pressure:

20022-01-01

'NM Wells Wellhead Pressure'

1997 09 01

'YYYY/MM/DD'

1

'Well Head Pressure'

'kPa'

'NM1_Producer'

1997/09/01	11858.98254
1997/10/01	11652.13982
1997/11/01	11858.98254
1997/12/01	11790.03497
1998/01/01	12272.66798
1998/02/01	11790.03497
1998/03/01	11583.19225
1998/04/01	11583.19225
1998/05/01	11652.13982
1998/06/01	11238.45438
1998/07/01	11100.55924
1998/08/01	11307.40196
1998/09/01	10480.03108
1998/10/01	10480.03108
1998/11/01	10204.24079
1998/12/01	10066.34564
1999/01/01	10204.24079
1999/02/01	9928.450498
1999/03/01	9928.450498
1999/04/01	9928.450498
1999/05/01	9859.502925

1999/06/01	9790.555352
1999/07/01	9583.712633
1999/08/01	9790.555352
1999/09/01	9514.76506
1999/10/01	9445.817487
1999/11/01	9238.974769
1999/12/01	9101.079623
2000/01/01	8549.49904
2000/02/01	8618.446613
2000/03/01	8273.708748
2000/04/01	8756.341758
2000/05/01	8825.289331
2000/06/01	8894.236904
2000/07/01	8756.341758
2000/08/01	8618.446613
2000/09/01	8618.446613
2000/10/01	9032.13205
2000/11/01	9032.13205
2000/12/01	8963.184477
2001/01/01	8928.710691
2001/02/01	8308.182534
2001/03/01	8480.551467
2001/04/01	8549.49904

2001/05/01	8618.446613
2001/06/01	8825.289331
2001/07/01	8894.236904
2001/08/01	8963.184477
2001/09/01	8859.763118
2001/10/01	8963.184477
2001/11/01	8721.867972
2001/12/01	8859.763118
2002/01/01	8894.236904
'NM3_Producer'	
1997/09/01	0
1997/10/01	10686.8738
1997/11/01	10755.82137
1997/12/01	10755.82137
1998/01/01	10893.71652
1998/02/01	10879.927
1998/03/01	10300.76739
1998/04/01	10824.76895
1998/05/01	10893.71652
1998/06/01	10686.8738
1998/07/01	10480.03108
1998/08/01	10617.92623
1998/09/01	9997.398071

1998/10/01	9790.555352
1998/11/01	9721.607779
1998/12/01	9652.660206
1999/01/01	9790.555352
1999/02/01	9514.76506
1999/03/01	9583.712633
1999/04/01	9583.712633
1999/05/01	9514.76506
1999/06/01	9445.817487
1999/07/01	9307.922342
1999/08/01	9445.817487
1999/09/01	9170.027196
1999/10/01	9101.079623
1999/11/01	8963.184477
1999/12/01	8963.184477
2000/01/01	8687.394185
2000/02/01	8273.708748
2000/03/01	8273.708748
2000/04/01	8480.551467
2000/05/01	8549.49904
2000/06/01	8618.446613
2000/07/01	8342.656321
2000/08/01	8273.708748

2000/09/01	8342.656321
2000/10/01	8825.289331
2000/11/01	8825.289331
2000/12/01	8756.341758
2001/01/01	8859.763118
2001/02/01	8721.867972
2001/03/01	8687.394185
2001/04/01	8411.603894
2001/05/01	8101.339816
2001/06/01	8618.446613
2001/07/01	8549.49904
2001/08/01	8618.446613
2001/09/01	8618.446613
2001/10/01	8480.551467
2001/11/01	8411.603894
2001/12/01	8411.603894
2002/01/01	8342.656321

'NM4_Producer'

1997/09/01	11721.08739
1997/10/01	11514.24467
1997/11/01	11652.13982
1997/12/01	11721.08739
1998/01/01	11721.08739

1998/02/01	11445.2971
1998/03/01	11376.34953
1998/04/01	10824.76895
1998/05/01	11583.19225
1998/06/01	11307.40196
1998/07/01	11100.55924
1998/08/01	10411.08351
1998/09/01	10411.08351
1998/10/01	10342.13594
1998/11/01	10342.13594
1998/12/01	10204.24079
1999/01/01	10273.18836
1999/02/01	10066.34564
1999/03/01	9997.398071
1999/04/01	9997.398071
1999/05/01	9859.502925
1999/06/01	9790.555352
1999/07/01	9652.660206
1999/08/01	9790.555352
1999/09/01	9583.712633
1999/10/01	9445.817487
1999/11/01	9376.869914
1999/12/01	9238.974769

2000/01/01	8963.184477
2000/02/01	8756.341758
2000/03/01	8756.341758
2000/04/01	8825.289331
2000/05/01	8894.236904
2000/06/01	8825.289331
2000/07/01	8687.394185
2000/08/01	8549.49904
2000/09/01	8618.446613
2000/10/01	8894.236904
2000/11/01	8756.341758
2000/12/01	8756.341758
2001/01/01	8790.815545
2001/02/01	7928.970884
2001/03/01	7928.970884
2001/04/01	8549.49904
2001/05/01	8687.394185
2001/06/01	8756.341758
2001/07/01	8790.815545
2001/08/01	8687.394185
2001/09/01	0
2001/10/01	0
2001/11/01	8446.07768

2001/12/01 8273.708748

2002/01/01 8480.551467

'NM5_Producer'

1997/09/01 0

1997/10/01 0

1997/11/01 11996.87768

1997/12/01 11996.87768

1998/01/01 11652.13982

1998/02/01 11376.34953

1998/03/01 11238.45438

1998/04/01 11238.45438

1998/05/01 12548.45827

1998/06/01 11238.45438

1998/07/01 10480.03108

1998/08/01 10824.76895

1998/09/01 12272.66798

1998/10/01 10755.82137

1998/11/01 10411.08351

1998/12/01 9997.398071

1999/01/01 10066.34564

1999/02/01 9859.502925

1999/03/01 9859.502925

1999/04/01 9859.502925

1999/05/01	9790.555352
1999/06/01	9790.555352
1999/07/01	9583.712633
1999/08/01	9652.660206
1999/09/01	9445.817487
1999/10/01	9376.869914
1999/11/01	9238.974769
1999/12/01	9238.974769
2000/01/01	8894.236904
2000/02/01	8756.341758
2000/03/01	8687.394185
2000/04/01	8756.341758
2000/05/01	8825.289331
2000/06/01	8825.289331
2000/07/01	8687.394185
2000/08/01	8549.49904
2000/09/01	8549.49904
2000/10/01	8756.341758
2000/11/01	8480.551467
2000/12/01	8618.446613
2001/01/01	8687.394185
2001/02/01	8411.603894
2001/03/01	8342.656321

2001/04/01	8411.603894
2001/05/01	8756.341758
2001/06/01	8825.289331
2001/07/01	8411.603894
2001/08/01	0
2001/09/01	8721.867972
2001/10/01	8687.394185
2001/11/01	8273.708748
2001/12/01	0
2002/01/01	0
'NM6_Producer'	
1997/09/01	0
1997/10/01	0
1997/11/01	12272.66798
1997/12/01	12272.66798
1998/01/01	12203.7204
1998/02/01	12134.77283
1998/03/01	11790.03497
1998/04/01	12548.45827
1998/05/01	12548.45827
1998/06/01	11376.34953
1998/07/01	11721.08739
1998/08/01	11583.19225

1998/09/01	11583.19225
1998/10/01	11514.24467
1998/11/01	10342.13594
1998/12/01	10342.13594
1999/01/01	10342.13594
1999/02/01	9997.398071
1999/03/01	9997.398071
1999/04/01	9997.398071
1999/05/01	9859.502925
1999/06/01	9859.502925
1999/07/01	9859.502925
1999/08/01	0
1999/09/01	9652.660206
1999/10/01	9445.817487
1999/11/01	9307.922342
1999/12/01	9238.974769
2000/01/01	8963.184477
2000/02/01	8756.341758
2000/03/01	8687.394185
2000/04/01	8825.289331
2000/05/01	8825.289331
2000/06/01	8894.236904
2000/07/01	8756.341758

2000/08/01	8549.49904
2000/09/01	8618.446613
2000/10/01	8756.341758
2000/11/01	8273.708748
2000/12/01	8549.49904
2001/01/01	8618.446613
2001/02/01	7308.442727
2001/03/01	9652.660206
2001/04/01	8377.130107
2001/05/01	7963.44467
2001/06/01	8963.184477
2001/07/01	8963.184477
2001/08/01	8928.710691
2001/09/01	8963.184477
2001/10/01	8963.184477
2001/11/01	8790.815545
2001/12/01	8756.341758
2002/01/01	8687.394185

Wells Cumulative Productions:

20022-01-01

'NM Wells Production'

1997 09 01

'YYYY/MM/DD'

1

'Cumulative Gas SC'

'MSCF'

5

'NM1_Producer'

1997/09/01 8116

1997/10/01 165028

1997/11/01 340978

1997/12/01 533488

1998/01/01 723921

1998/02/01 894301

1998/03/01 1069453

1998/04/01 1289186

1998/05/01 1509472

1998/06/01 1790842

1998/07/01 2097959

1998/08/01 2344874

1998/09/01 2668904

1998/10/01 3006580

1998/11/01 3347170

1998/12/01 3713652

1999/01/01 4060077

1999/02/01 4382665

1999/03/01	4736840
1999/04/01	5062610
1999/05/01	5404974
1999/06/01	5730144
1999/07/01	6055494
1999/08/01	6370175
1999/09/01	6688535
1999/10/01	7015213
1999/11/01	7335523
1999/12/01	7673702
2000/01/01	8025862
2000/02/01	8363219
2000/03/01	8717456
2000/04/01	9043856
2000/05/01	9339416
2000/06/01	9628106
2000/07/01	9947127
2000/08/01	10264381
2000/09/01	10533820
2000/10/01	10758446
2000/11/01	10982576
2000/12/01	11188292
2001/01/01	11375462

2001/02/01	11553962
2001/03/01	11735906
2001/04/01	11866636
2001/05/01	11974588
2001/06/01	12096577
2001/07/01	12187243
2001/08/01	12341809
2001/09/01	12522559
2001/10/01	12703227
2001/11/01	12874707
2001/12/01	12987743
2002/01/01	13050095
'NM3_Producer'	
1997/09/01	0
1997/10/01	10584
1997/11/01	23511
1997/12/01	374579
1998/01/01	502454
1998/02/01	535070
1998/03/01	584300
1998/04/01	707000
1998/05/01	829233
1998/06/01	974613

1998/07/01	1125552
1998/08/01	1269423
1998/09/01	1433013
1998/10/01	1599357
1998/11/01	1776837
1998/12/01	1971424
1999/01/01	2159315
1999/02/01	2328687
1999/03/01	2515431
1999/04/01	2686791
1999/05/01	2862716
1999/06/01	3028646
1999/07/01	3198061
1999/08/01	3362485
1999/09/01	3524185
1999/10/01	3696173
1999/11/01	3854663
1999/12/01	4015305
2000/01/01	4174025
2000/02/01	4321896
2000/03/01	4473982
2000/04/01	4613422
2000/05/01	4733602

2000/06/01	4860562
2000/07/01	4998233
2000/08/01	5135811
2000/09/01	5255494
2000/10/01	5306632
2000/11/01	5375862
2000/12/01	5462042
2001/01/01	5514735
2001/02/01	5532480
2001/03/01	5625954
2001/04/01	5718684
2001/05/01	5768132
2001/06/01	5831405
2001/07/01	5870871
2001/08/01	5897579
2001/09/01	5975339
2001/10/01	6030971
2001/11/01	6068587
2001/12/01	6133170
2002/01/01	6173730
'NM4_Producer'	
1997/09/01	8448
1997/10/01	17112

1997/11/01	39225
1997/12/01	640963
1998/01/01	857839
1998/02/01	1055074
1998/03/01	1224514
1998/04/01	1465534
1998/05/01	1705319
1998/06/01	2016629
1998/07/01	2353537
1998/08/01	2780345
1998/09/01	3172265
1998/10/01	3574335
1998/11/01	3930948
1998/12/01	4330166
1999/01/01	4696772
1999/02/01	5046408
1999/03/01	5422376
1999/04/01	5770286
1999/05/01	6135931
1999/06/01	6485881
1999/07/01	6851278
1999/08/01	7191565
1999/09/01	7537705

1999/10/01	7893058
1999/11/01	8239048
1999/12/01	8599051
2000/01/01	8971361
2000/02/01	9330004
2000/03/01	9699245
2000/04/01	10047755
2000/05/01	10366145
2000/06/01	10687325
2000/07/01	11039423
2000/08/01	11388824
2000/09/01	11688481
2000/10/01	11931211
2000/11/01	12055915
2000/12/01	12284726
2001/01/01	12446102
2001/02/01	12654466
2001/03/01	12810338
2001/04/01	13016830
2001/05/01	13232452
2001/06/01	13335124
2001/07/01	13399300
2001/08/01	13533742

2001/09/01	13533742
2001/10/01	13533742
2001/11/01	13653406
2001/12/01	13882992
2002/01/01	13986880

'NM5_Producer'

1997/09/01	0
1997/10/01	0
1997/11/01	23776
1997/12/01	103722
1998/01/01	206992
1998/02/01	304338
1998/03/01	407930
1998/04/01	413044
1998/05/01	413044
1998/06/01	553238
1998/07/01	737084
1998/08/01	865235
1998/09/01	865235
1998/10/01	889950
1998/11/01	1102229
1998/12/01	1321771
1999/01/01	1543886

1999/02/01	1738934
1999/03/01	1956554
1999/04/01	2151434
1999/05/01	2338455
1999/06/01	2490205
1999/07/01	2684544
1999/08/01	3096534
1999/09/01	3278214
1999/10/01	3465361
1999/11/01	3645601
1999/12/01	3832903
2000/01/01	4026250
2000/02/01	4210139
2000/03/01	4403176
2000/04/01	4584136
2000/05/01	4742836
2000/06/01	4896188
2000/07/01	5077104
2000/08/01	5257927
2000/09/01	5423347
2000/10/01	5538667
2000/11/01	5671267
2000/12/01	5787455

2001/01/01	5855615
2001/02/01	5885711
2001/03/01	6015181
2001/04/01	6050765
2001/05/01	6147017
2001/06/01	6191842
2001/07/01	6246572
2001/08/01	6246572
2001/09/01	6311400
2001/10/01	6421884
2001/11/01	6480605
2001/12/01	6480606
2002/01/01	6480607

'NM6_Producer'

1997/09/01	0
1997/10/01	0
1997/11/01	30378
1997/12/01	140972
1998/01/01	291539
1998/02/01	415247
1998/03/01	539531
1998/04/01	539531
1998/05/01	539531

1998/06/01	771906
1998/07/01	1021518
1998/08/01	1287002
1998/09/01	1545602
1998/10/01	1811303
1998/11/01	2103089
1998/12/01	2526394
1999/01/01	2937113
1999/02/01	3309569
1999/03/01	3720846
1999/04/01	4131126
1999/05/01	4560569
1999/06/01	4972859
1999/07/01	5389499
1999/08/01	5389499
1999/09/01	5801969
1999/10/01	6229211
1999/11/01	6647441
1999/12/01	7080449
2000/01/01	7524276
2000/02/01	7951040
2000/03/01	8402121
2000/04/01	8821521

2000/05/01	9206811
2000/06/01	9591441
2000/07/01	10013010
2000/08/01	10428131
2000/09/01	10797821
2000/10/01	11035394
2000/11/01	11363714
2000/12/01	11664569
2001/01/01	11908379
2001/02/01	12073517
2001/03/01	12073517
2001/04/01	12195119
2001/05/01	12238884
2001/06/01	12313090
2001/07/01	12552751
2001/08/01	12759273
2001/09/01	12986073
2001/10/01	13225827
2001/11/01	13440627
2001/12/01	13643429
2002/01/01	13794020

B. CMG Model Code Sample

Since different scenarios were run with multiple models in the study, one of the models used has been shared as an example.

INUNIT SI

WSRF WELL 1

WSRF GRID TIME

INVENTORY-CO2

OUTSRF GRID DENG DENW DPORMNR KRG KRW MOLALITY 'CH4' MOLALITY
'CO2' PERM PH POROS PRES

SG SGDTHY SGHYS SGRHYS SW TGIP Y 'CH4' Y 'CO2' Z 'CH4' Z 'CO2'

OUTSRF RES NONE

OUTSRF WELL LAYER ALL DOWNHOLE

OUTSRF SPECIAL GHGAQU

GHGGAS

GHGLIQ

GHGMNR

GHGSCRIT

GHGSOL

GHGTHY

WPRN GRID 0

OUTPRN GRID NONE

OUTPRN RES NONE

RESULTS SUBMODEL_REFSS 43

**

** Definition of fundamental cartesian grid

**

GRID VARI 43 52 4

KDIR DOWN

DI IVAR

43*75

DJ JVAR

52*75

DK ALL

8944*15

DTOP

2*1200 1208.308 1207.916 1196.18 1203.967 1202.625 120 'CMGTEMP_000.inc'

XOFFSET -1802.2772

YOFFSET 2499.0702

** 0 = null block, 1 = active block

NULL ALL

8*0 6*1 35*0 10*1 32*0 12*1 30*0 14*1 28*0 16*1 26*0 18*1 25*0 19*1

23*0 20*1 23*0 21*1 22*0 21*1 21*0 23*1 20*0 23*1 20*0 23*1 20*0 23*1

20*0 24*1 19*0 24*1 19*0 24*1 20*0 24*1 19*0 24*1 19*0 25*1 19*0 24*1

19*0 25*1 19*0 25*1 18*0 26*1 18*0 26*1 18*0 26*1 18*0 25*1 19*0 25*1

19*0 25*1 19*0 24*1 20*0 24*1 20*0 23*1 20*0 24*1 20*0 24*1 19*0 25*1

19*0 25*1 18*0 26*1 17*0 27*1 17*0 27*1 17*0 26*1 18*0 26*1 18*0 26*1
18*0 25*1 19*0 24*1 20*0 22*1 22*0 21*1 23*0 19*1 25*0 18*1 26*0 16*1
29*0 13*1 32*0 10*1 37*0 3*1 16*0 6*1 35*0 10*1 32*0 12*1 30*0 14*1
28*0 16*1 26*0 18*1 25*0 19*1 23*0 20*1 23*0 21*1 22*0 21*1 21*0 23*1
20*0 23*1 20*0 23*1 20*0 23*1 20*0 24*1 19*0 24*1 19*0 24*1 20*0 24*1
19*0 24*1 19*0 25*1 19*0 24*1 19*0 25*1 19*0 25*1 18*0 26*1 18*0 26*1
18*0 26*1 18*0 25*1 19*0 25*1 19*0 25*1 19*0 24*1 20*0 24*1 20*0 23*1
20*0 24*1 20*0 24*1 19*0 25*1 19*0 25*1 18*0 26*1 17*0 27*1 17*0 27*1
17*0 26*1 18*0 26*1 18*0 26*1 18*0 25*1 19*0 24*1 20*0 22*1 22*0 21*1
23*0 19*1 25*0 18*1 26*0 16*1 29*0 13*1 32*0 10*1 37*0 3*1 16*0 6*1
35*0 10*1 32*0 12*1 30*0 14*1 28*0 16*1 26*0 18*1 25*0 19*1 23*0 20*1
23*0 21*1 22*0 21*1 21*0 23*1 20*0 23*1 20*0 23*1 20*0 23*1 20*0 24*1
19*0 24*1 19*0 24*1 20*0 24*1 19*0 24*1 19*0 25*1 19*0 24*1 19*0 25*1
19*0 25*1 18*0 26*1 18*0 26*1 18*0 26*1 18*0 25*1 19*0 25*1 19*0 25*1
19*0 24*1 20*0 24*1 20*0 23*1 20*0 24*1 20*0 24*1 19*0 25*1 19*0 25*1
18*0 26*1 17*0 27*1 17*0 27*1 17*0 26*1 18*0 26*1 18*0 26*1 18*0 25*1
19*0 24*1 20*0 22*1 22*0 21*1 23*0 19*1 25*0 18*1 26*0 16*1 29*0 13*1
32*0 10*1 37*0 3*1 16*0 6*1 35*0 10*1 32*0 12*1 30*0 14*1 28*0 16*1
26*0 18*1 25*0 19*1 23*0 20*1 23*0 21*1 22*0 21*1 21*0 23*1 20*0 23*1
20*0 23*1 20*0 23*1 20*0 24*1 19*0 24*1 19*0 24*1 20*0 24*1 19*0 24*1
19*0 25*1 19*0 24*1 19*0 25*1 19*0 25*1 18*0 26*1 18*0 26*1 18*0 26*1
18*0 25*1 19*0 25*1 19*0 25*1 19*0 24*1 20*0 24*1 20*0 23*1 20*0 24*1
20*0 24*1 19*0 25*1 19*0 25*1 18*0 26*1 17*0 27*1 17*0 27*1 17*0 26*1

18*0 26*1 18*0 26*1 18*0 25*1 19*0 24*1 20*0 22*1 22*0 21*1 23*0 19*1

25*0 18*1 26*0 16*1 29*0 13*1 32*0 10*1 37*0 3*1 8*0

POR ALL

5*0.001 0.000706801 0.0009545619 0.001925145 0.0030193 'CMGTEMP_001.inc'

PERMI ALL

3*5 4.928558 5.241355 5.764671 6.422454 6.996027 7.465 'CMGTEMP_002.inc'

PERMJ CON 50

PERMK CON 50

** 0 = pinched block, 1 = active block

PINCHOUTARRAY CON 1

PRPOR 14500

CPOR 4E-06

**The following is the fluid component

**property data in GEM format.

**The unit system and fluid compositions should

**be specified in the I/O control section.

**The units and compositions specified in WinProp

**are included here as comments for informational purposes.

** PVT UNITS CONSISTENT WITH *INUNIT *SI

**COMPOSITION *PRIMARY

** 0.02280000 0.03210000 0.00240000 0.01210000 0.00300000

** 0.00090000 0.00070000 0.01150000 0.91450000

**COMPOSITION *SECOND

** 0.00000000 0.00000000 0.00000000 0.00000000 0.00000000

** 0.00000000 0.00000000 0.00000000 0.00000000

** Model and number of components

** Model and number of components

MODEL PR

NC 9 9

COMPNAME 'CO2' 'C2H6' 'IC4' 'C3H8' 'NC4' 'IC5' 'NC5' 'N2' 'CH4'

** The Hydrocarbon component flag values: 1 - Hydro-Carbon, 0 - non Hydro-Carbon

**

** The read-in HC-HC BIN values will be overwritten by the internal GEM calculated

** values for these HC-HC pairs, if the original *HCFLAG values are used.

** This is fine if there is only 1 HC-HC group defined in the original WinProp

** data set. Otherwise, all-zero *HCFLAG will be output here in order to use the

** full read-in BIN values.

** The original WinProp HC-flags:

** *HCFLAG 3 1 1 1 1 1 1 0 0

** all-0 HCFlag values output here for using full BIN and/or BINS

HCFLAG

0 0 0 0 0 0 0 0 0

TRES 68.80000

VISCOR HZYT

TRES 68.80000

VISCOEFF

1.0230000E-01 2.3364000E-02 5.8533000E-02 -4.0758000E-02 9.3324000E-03

MW

4.4010000E+01 3.0070000E+01 5.8124000E+01 4.4097000E+01 5.8124000E+01
7.2151000E+01 7.2151000E+01 2.8013000E+01 1.6043000E+01

AC

2.2500000E-01 9.8000000E-02 1.7600000E-01 1.5200000E-01 1.9300000E-01 2.2700000E-
01 2.5100000E-01 4.0000000E-02 8.0000000E-03

PCRIT

7.2800000E+01 4.8200000E+01 3.6000000E+01 4.1900000E+01 3.7500000E+01
3.3400000E+01 3.3300000E+01 3.3500000E+01 4.5400000E+01

VCRIT

9.4000000E-02 1.4800000E-01 2.6300000E-01 2.0300000E-01 2.5500000E-01 3.0600000E-
01 3.0400000E-01 8.9500000E-02 9.9000000E-02

TCRIT

3.0420000E+02 3.0540000E+02 4.0810000E+02 3.6980000E+02 4.2520000E+02
4.6040000E+02 4.6960000E+02 1.2620000E+02 1.9060000E+02

PCHOR

7.8000000E+01 1.0800000E+02 1.8150000E+02 1.5030000E+02 1.8990000E+02
2.2500000E+02 2.3150000E+02 4.1000000E+01 7.7000000E+01

SG

8.1800000E-01 3.5600000E-01 5.6300000E-01 5.0700000E-01 5.8400000E-01 6.2500000E-
01 6.3100000E-01 8.0900000E-01 3.0000000E-01

TB

-7.8450000E+01 -8.8650000E+01 -1.1850000E+01 -4.2050000E+01 -4.5000000E-01
2.7850000E+01 3.6050000E+01 -1.9575000E+02 -1.6145000E+02

OMEGA

4.5723553E-01 4.5723553E-01 4.5723553E-01 4.5723553E-01 4.5723553E-01 4.5723553E-01
4.5723553E-01 4.5723553E-01 4.5723553E-01

OMEGB

7.7796074E-02 7.7796074E-02 7.7796074E-02 7.7796074E-02 7.7796074E-02 7.7796074E-02
7.7796074E-02 7.7796074E-02 7.7796074E-02

VSHIFT

0.0000000E+00 0.0000000E+00 0.0000000E+00 0.0000000E+00 0.0000000E+00
0.0000000E+00 0.0000000E+00 0.0000000E+00 0.0000000E+00

VISVC

9.4000000E-02 1.4800000E-01 2.6300000E-01 2.0300000E-01 2.5500000E-01 3.0600000E-01
3.0400000E-01 8.9500000E-02 9.9000000E-02

BIN

1.3000000E-01

1.2000000E-01 5.4857876E-03

1.2500000E-01 1.6620489E-03 1.1165976E-03

1.1500000E-01 4.9143360E-03 1.5903506E-05 8.6625350E-04

1.1500000E-01 8.7338646E-03 3.8207590E-04 2.8007353E-03 5.5378054E-04

1.1500000E-01 8.5779330E-03 3.4971119E-04 2.7121325E-03 5.1467786E-04 7.1665797E-07

0.0000000E+00 1.0000000E-02 9.5000000E-02 9.0000000E-02 9.5000000E-02

1.0000000E-01 1.1000000E-01

1.0500000E-01 0.0000000E+00 0.0000000E+00 0.0000000E+00 0.0000000E+00

0.0000000E+00 0.0000000E+00 2.5000000E-02

ENTHCOEF

9.6880000E-02 1.5884300E-01 -3.3712000E-05 1.4810500E-07 -9.6620300E-11
2.0738320E-14

-1.4220000E-02 2.6461200E-01 -2.4568000E-05 2.9140200E-07 -1.2810330E-10
1.8134820E-14

1.4595600E+00 9.9070000E-02 2.3873600E-04 9.1593000E-08 -5.9405000E-11
9.0964500E-15

6.8715000E-01 1.6030400E-01 1.2608400E-04 1.8143000E-07 -9.1891300E-11
1.3548500E-14

7.2281400E+00 9.9687000E-02 2.6654800E-04 5.4073000E-08 -4.2926900E-11
6.6958000E-15

1.7694120E+01 1.5946000E-02 3.8244900E-04 -2.7557000E-08 -1.4303500E-11
2.9567700E-15

9.0420900E+00 1.1182900E-01 2.2851500E-04 8.6331000E-08 -5.4464900E-11
8.1845000E-15

-6.5665000E-01 2.5409800E-01 -1.6624000E-05 1.5302000E-08 -3.0995000E-12
1.5167000E-16

-2.8385700E+00 5.3828500E-01 -2.1140900E-04 3.3927600E-07 -1.1643220E-10
1.3896120E-14

SOLUBILITY HENRY

AQUEOUS-VISCOSITY KESTIN

*AQUEOUS-DENSITY *ROWE-CHOU

ROCKFLUID

RPT 1

** Sw krw krow

SWT

0.01	0	1
0.03	0.003	0.92
0.1	0.025	0.778
0.2	0.081	0.63
0.3	0.15	0.51
0.4	0.21	0.4
0.5	0.3	0.31
0.6	0.41	0.21
0.7	0.55	0.122
0.8	0.69	0.057
0.9	0.85	0.02
1	1	0

** Sg krg krog

SGT

SMOOTHEND QUADGEM

0	0	1
0.03	0.007	0.9
0.1	0.025	0.74
0.2	0.077	0.59
0.3	0.14	0.46

0.4	0.21	0.36
0.5	0.3	0.25
0.6	0.42	0.16
0.7	0.55	0.09
0.8	0.699	0.04
0.9	0.86	0.008
0.99	1	0
BSWCRIT CON		0.1
CEC-IEX CON		0.2
INITIAL		
USER_INPUT		
PRES CON		14300
SW CON		0.1
ZGLOBALC 'C2H6' CON		0.0321
ZGLOBALC 'C3H8' CON		0.0121
ZGLOBALC 'CH4' CON		0.9145
ZGLOBALC 'CO2' CON		0.0228
ZGLOBALC 'IC4' CON		0.0024
ZGLOBALC 'IC5' CON		0.0009
ZGLOBALC 'N2' CON		0.0115
ZGLOBALC 'NC4' CON		0.003
ZGLOBALC 'NC5' CON		0.0007