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Numerical Simulation of Enhancement in CO2 Sequestration with Various Water Production Schemes under Multiple Well Scenarios

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by
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of Washington University in St. Louis in partial fulfillment of
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I would also like to acknowledge many who have helped me with the thesis. Their continuous efforts have been very important to this research. Thanks to Dr. Danqing Liu for her patient guidance and for continuous discussions her about the model establishment. Thanks to Shuyang Liu for the advice on various numerical issues as well as on feasibility analysis related to this research. Finally, I want to express my appreciation to all my CFD lab colleagues for their continuous help and encouragement.

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Li Chen

Washington University in St. Louis

May 2017

I dedicate this thesis to my parents (Wenxue Chen and Huiru Jia) for their life-time guidance, love and support.

ABSTRACT OF THESIS

Numerical Simulation of Enhancement in CO_2 Sequestration with Various Water Production Schemes under Multiple Well Scenarios

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CO_2 geological sequestration simultaneously combined with water production from deep saline aquifers can effectively address the challenge faced by the modern energy systems for reducing the CO_2 emissions and water intensity while providing reliable, affordable, and secure energy. However, little attention has been paid to date in the literature on determining the best CO_2 injection strategy for achieving both the optimal water production and the optimal CO_2 space storage capacity while maintaining operational safety. This research first establishes three injection-extraction scenarios based on the typical geological parameters of the Junggar Basin in China to analyze the effect of CO_2 injection on water extraction and the effect of water extraction on the CO_2 storage. The three injection scenarios considered are sole CO_2 injection, sole water production, and combined CO_2 enhanced water recovery (CO_2 - EWR). For the combined CO_2 enhanced water recovery scenario, both the co-injection of brine and pre-injection of brine are considered. It is found that in the allowable range of pressure perturbations, pre-injection of brine could result in longer injection time with more CO_2 injected and stored. The influence of number of pumping wells is also analyzed. Although increasing the number of wells can enhance the CO_2 storage, however having more wells may not be an economically desirable option considering the cost of well drilling; this aspect requires the techno-economic analysis. It can be concluded from

this work that the CO_2 enhanced water recovery technology can effectively manage the pressure perturbation caused by the CO_2 injection as well as the water production while significantly enhancing the CO_2 storage capacity, security and water production efficiency; however, the injection strategy is essential to the efficiency of CO_2 enhanced water recovery. The well-known multi-phase flow solver TOUGH2/Petrasim is used for the analysis of injection scenarios.

Chapter 1: Introduction

Over past several hundred years, atmospheric carbon dioxide (CO_2) concentrations have steadily increased. Increase in atmospheric carbon dioxide (CO_2) concentrations is mainly caused by burning fossil fuel such as coal, oil and natural gas for electrical power generation, transportation, industrial and domestic uses. United States is the second biggest CO_2 emitter with 3.05 metric tons of CO_2 emission, which are 14.34% of global emissions. [4] Figure 1.1 shows the greenhouse gas (GHG) emissions in millions of metric tons of CO_2 equivalent. Figure 1.2 shows the GHG emissions by various sectors of the economy worldwide.

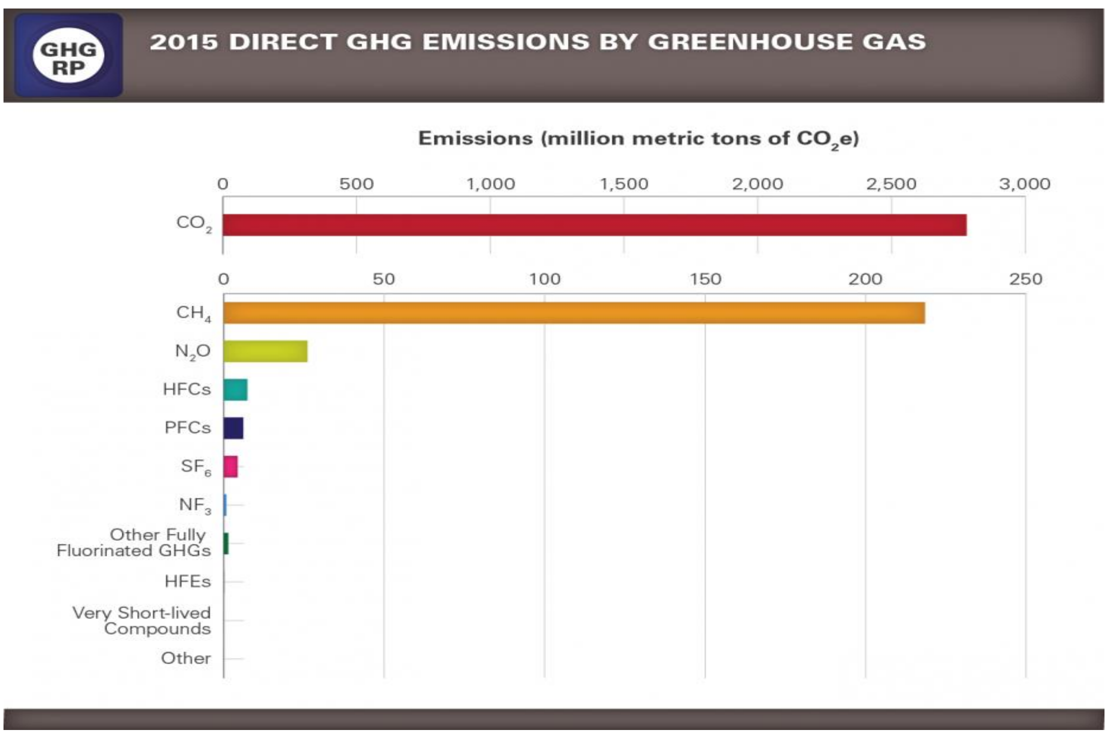

Figure 1. 1 GHG emissions, by Greenhouse Gas Report, United States Environmental Protection Agency

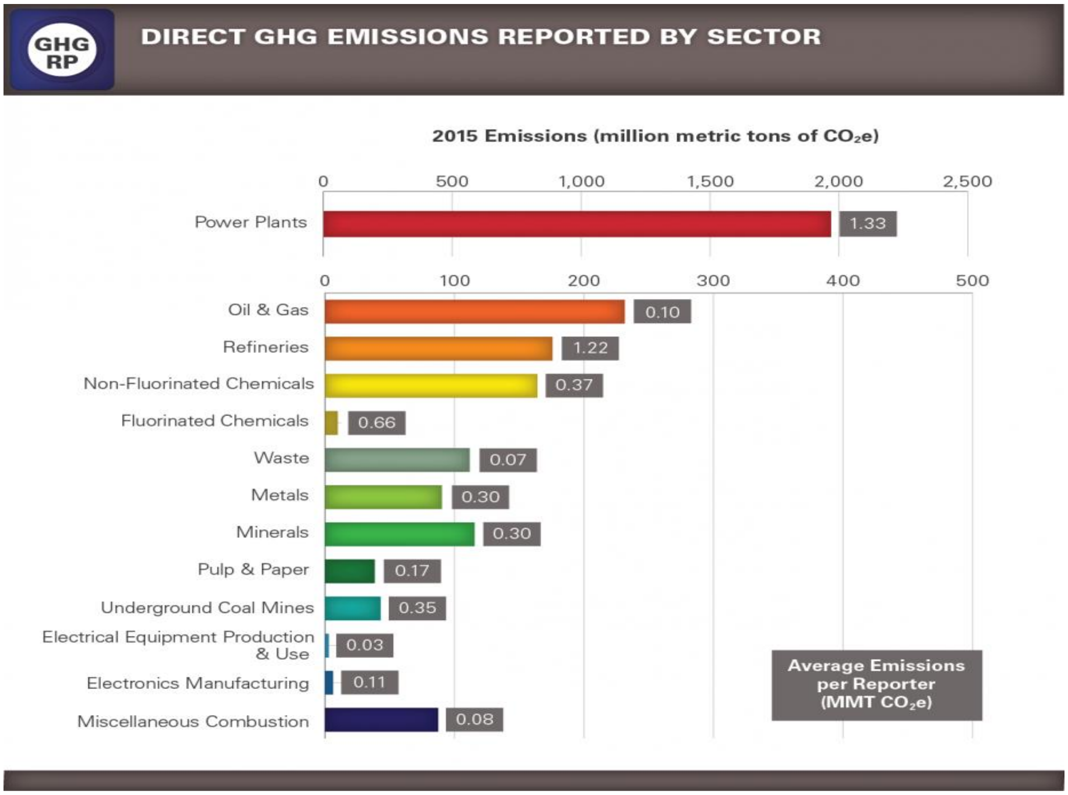

Figure 1.2 GHG emissions by sector, by Greenhouse Gas Report, United States Environmental Protection Agency

It is well established that the increase in CO_2 concentration will significantly influence climate system and ecosystem. Therefore, there is urgency to figure out a way to stabilize the CO_2 concentrations in the atmosphere within next few decades. At today's emission rate, atmospheric CO_2 concentration will continue to grow rapidly and lead to significant consequences to climate system. For example, scientists have predicted that in 50 years, due to global warming, the low-lying coastal areas may be flooded. To address the challenge of global warming, pragmatic long-term approach is needed to reduce the CO_2 emissions. Employing solar power, wind energy and other renewable energy sources to replace fossil fuels is an important step in the direction. But unfortunately, in the near future, most of the World energy needs will be met by fossil fuels. Carbon Capture and Storage (CCS) is an effective way to decrease the CO_2 concentrations into the atmosphere. Recently, a novel geoengineering approach for CO_2 geological utilization and storage, wherein CO_2 geological storage is combined with the deep saline water/brine recovery (CO_2-EWR) has been proposed for CO_2 sequestration as well as to produce underground water. This thesis analyzes both CCS and CO_2-EWR under different CO_2 injection and water production scenarios considering multiple wells and determines a scenario that could store more CO_2 while producing water simultaneously.

1.1 CCS and CO_2-EWR Preview

Carbon capture and storage (CCS) is a technology that can capture up to 90% of the carbon dioxide (CO_2) emissions produced from the use of fossil fuels in electricity generation and industrial processes, preventing the carbon dioxide from entering the atmosphere. The basic idea of CCS includes three parts: capturing the carbon dioxide from the power plant, transporting the carbon dioxide to a sequestration site and storing the carbon dioxide in the aquifer. Carbon capture technologies allow the separation of carbon dioxide from gases produced in electricity generation and industrial processes by several methods: pre-combustion capture, post-combustion capture and oxy-fuel combustion. After capture, carbon dioxide is transported by pipeline or by ship for safe storage. The carbon dioxide is then stored in carefully selected geological rock formation where it would remain for thousands of years or longer. The idea of CCS was first developed in the late 1970s but was paid little attention until 1980s. Since then, more and larger scale industrial projects are being established. Earliest example is the Sleipner gas field in the North Sea, operated by Norway's largest oil company Statoil. This is the first commercial example of CO_2 storage in a deep saline aquifer where over 1 million tons of CO_2 is being stored annually. CO_2 can also be used for enhanced of recovery (EOR) and enhanced gas recovery (EGR). The Weyburn oil field is situated in Canada near the USA border. In 1997, all the waste gas (96% CO_2) from its Great Synfuels Plant was sent to the Weyburn oil field through a pipeline for application in CO_2-EOR. Several more commercial projects are in the advanced stage of planning, for example, the In-Salah project in Algeria, the Gorgon Project in Australia, and the Snohvit Project in the continental shelf offshore of Norway.

During the sequestration process in an aquifer, a large-scale CO_2 injection will lead to significant increase in reservoir pressure. The increase in pressure may result in overlying cap-rock to fracture, giving rise to CO_2 leakage. Considering some of the problems faced by the traditional CCS including cost, an alternative geoengineering approach for carbon capture, utilization and storage has been proposed in recent years while combining the CO_2 geological storage with saline water recovery (CO_2-EWR). The basic idea of CO_2-EWR technology is to inject CO_2 into a deep saline aquifer for CO_2 sequestration and simultaneously produce water/brine that can be used for domestic and industrial use. Compared to the traditional CO_2 geological storage, CO_2-EWR has two main advantages: (1) it allows better control of the reservoir pressure and water production to provide a more secure and stable environment for CO_2 injection; and (2) it can collect and utilize the water/brine extracted for drinking after some treatments, as well as for industrial and agricultural use. Thus, CO_2-EWR technology could be considered as a clean technology for decreasing CO_2 concentrations in the atmosphere as well as for alleviating the water shortage crisis.

1.2 Scope of the Thesis

CO_2 geological storage combined with deep saline water recovery (CO_2-EWR) could not only achieve secure environment for CO_2 storage due to lower injection pressure but also enhance the saline water recovery for industrial or agricultural use. This method is therefore a win-win choice for enhancement of both environment and energy security. A three-dimensional injection-extraction model is established and numerically analyzed using the DOE TOUGH2/Petrasim code employing the typical parameters from a coal chemical industry in the Xinjiang Uyghur Autonomous Region of China. Various water production and CO_2 injection schemes as well as multiple well scenarios are considered in order to determine the advantages and disadvantages of each for achieving the goal of maximum possible CO_2 storage with simultaneous production of brine.

Chapter 2: Methodology

In this chapter, the simulation model, the boundary conditions and, the initial settings, for the simulation are provided. The methodology used in flow field calculation is discussed. Some relevant aspects of CFD simulation methodology are described. The theory behind the simulations is discussed.

2.1 Methodology of Simulation

PetraSim is a graphical interface for the DOE TOUGH2 family of simulators. Developed at Lawrence Berkeley National Laboratory, PetraSim integrates the TOUGH family of codes into a user interface that allows the analyst to focus on the analysis of the model, while automatically handling the complex details of simulator input and output. TOUGH2 and its derivatives have been recognized for their powerful simulation capabilities for fluid flow and heat transfer in porous and fractured media. The 3D model used in this thesis was provided by Dr. Danqing Liu of China University of Geosciences and was established in Petrasim. The details of the model are presented later.

2.2 Methodology of Geometry Modeling

2.2.1 Geological Background

Junggar Basin is located in the Uygur Autonomous Region of Xinjiang, northwestern China, covering an area of 130,000 square kilometers (Figure 2.1). The Junggar Basin is a multicycle superimposed basin formed from the late Paleozoic to the Mesozoic and Cenozoic periods. Hydrocarbon generation sags characterized by multiple hydrocarbon-generation centers and hydrocarbon accumulation zones have been found in the northwestern, northern, central, eastern and southern parts of the basin. However, this region experiences the worst water shortage problem in China. The oldest layer of bedrock in the eastern region is Silurian, followed by Devonian, Carboniferous, Permian, Triassic, Jurassic, Tertiary and Quaternary, from the bottom up, in turn. The Permian, Triassic and Jurassic with lithology-fine sandstone and siltstone, locally coarse sandstone or large-coarse sandstone, are considered the best reservoir due to their wide distribution and large thickness. Thus, applying CO2-EWR at this place is a very feasible and reliable choice. In this thesis, the exact geological parameters of this basin are chosen as initial inputs to the numerical model for CO2-EWR analysis.

Figure 2.1 Geological map of Junggar basin

2.2.2 Model Description

Three three-dimensional models were established for analysis, including two wells model (one injection well and one production well), three wells model (one injection well and two production wells) and five wells model (one injection well and four production wells). The baseline model was established by Dr. Danqing Liu as described in her publication [5] The size of all these models is the same: 21.5 km from east to west, 10.5 km from north to south and a vertical thickness of 150 m, with a total volume of 33.8625 km^3 as shown in Figure 2.2. (Axis scale: x = 1, y = 1, z = 20)

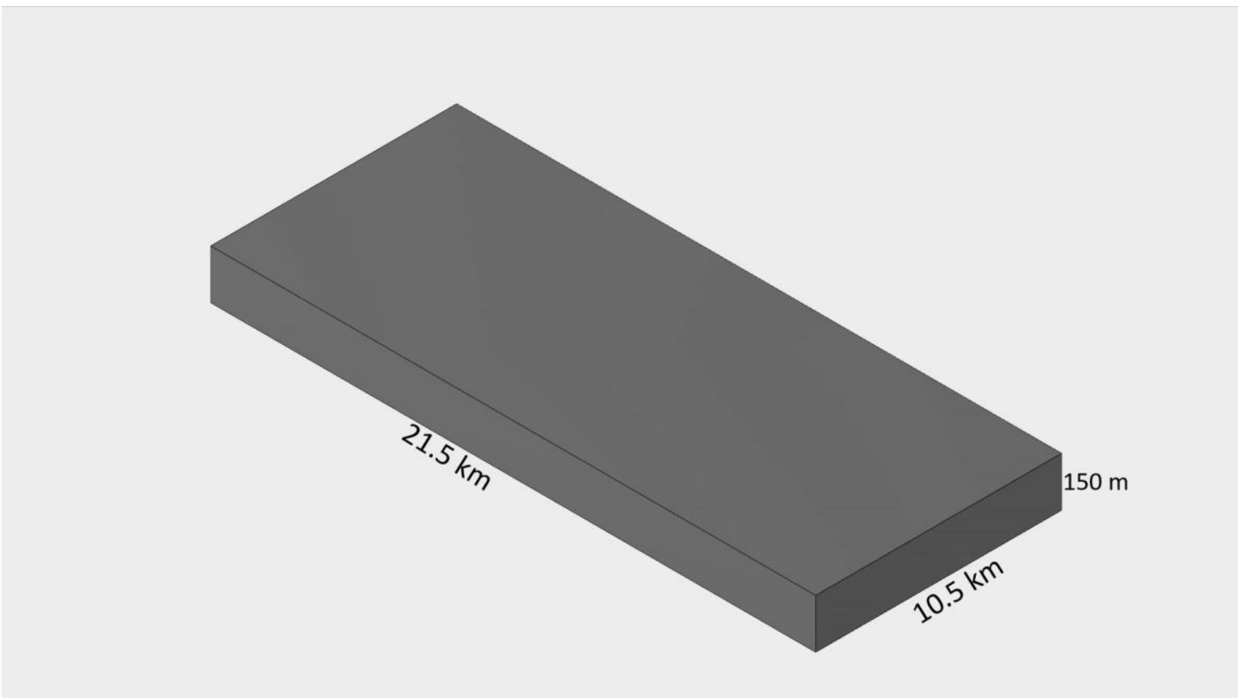

Figure 2.2 Geological model of Junggar basin

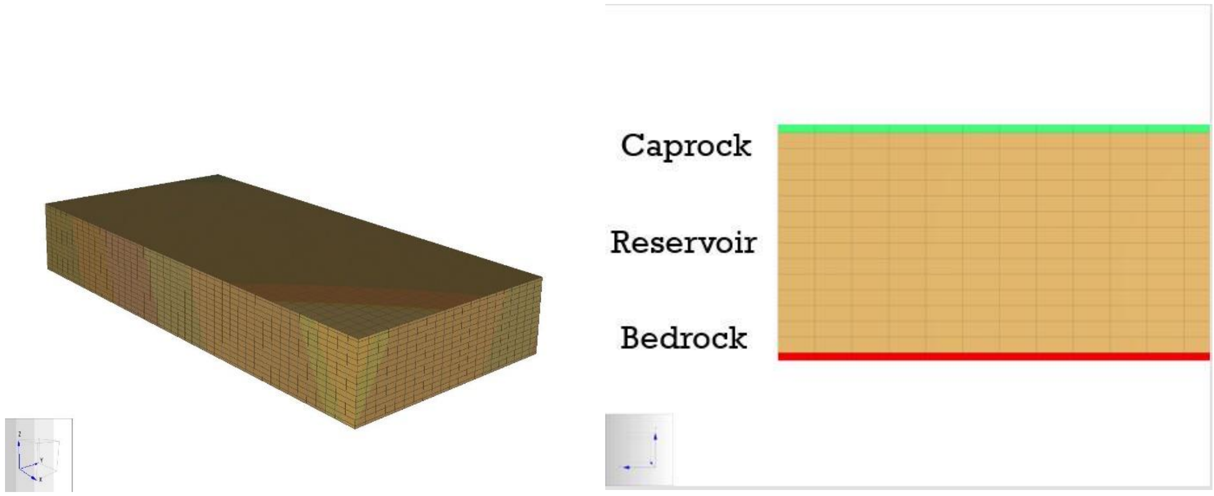

Figure 2.3 3D model of Junggar basin with model

Uniform meshes were created inside the model whom in Figure 3. In order to enhance the calculation speed, a grid-block of size 500 m * 500 m was created in X-Y plane. Along x-axis, 43 cells were created and along the y-axis, 21 cells were created. The model was divided into 7 layers along z-axis. From top to bottom, there are three layers of caprock (0 ~ -5m), the CO_2 reservoir layer (-5 ~ -145m) and three layers of bedrock (-145 ~ -150m). Each layer is shown in Figure 2.4.

2.2.3 Model Setup and Boundary Conditions

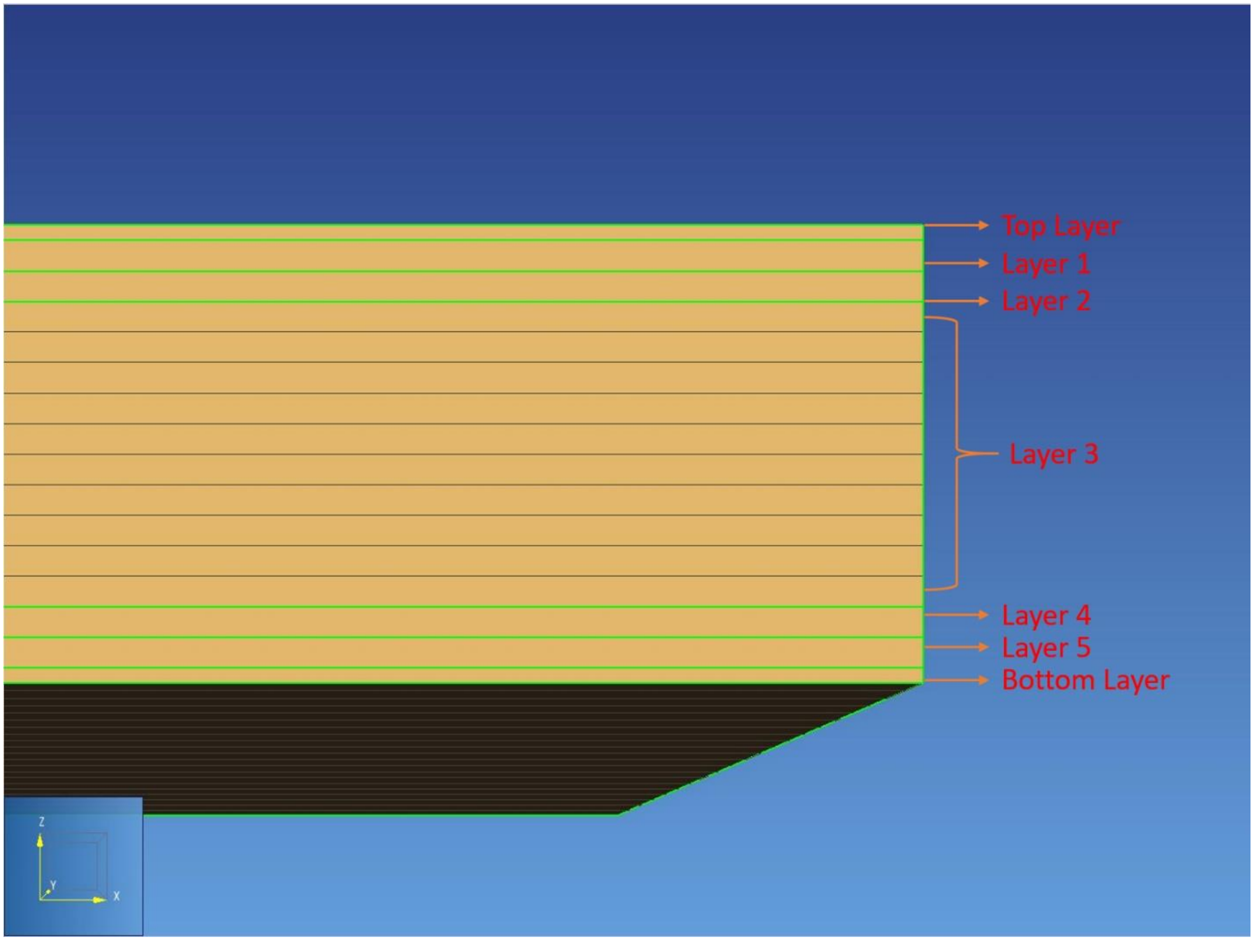

Figure 2.4 Seven layers of the model

From Figure 2.4, one can see that the material of the top three layers and the bottom three layer is all shale and the middle layer (Layer 3) is all sand. Consequently, there are 14,448 total elements included in this model. The total simulation period is 15 years (4.73354E8 s). The time step is selected to be 100.0 s and automatic time step adjustment is enabled. Relative Error Criterion is set at 1.0E-5 and the Absolute Error Criterion is set at 1.0. The surrounding boundaries of the model are assumed to be closed, and the other boundaries are treated as no flow boundaries by setting the permeability at 0 m^2. The pressure monitoring point named as "monitoring point" is at the center of the horizontal plane, z = -25m below the caprock. There is only one injection well in all three models. In the three wells model, the injection well is located at the center of the horizontal plane (10750, 5250), and the injection depth is 30 m from -95 m to -125 m. In the two wells model, the injection well is located at (14250, 5250) and the production well, are located at (7250, 5250). Every production well is kept at the same distance (7 km) from the central injection well. In the three wells model, two production wells are located at (3750, 5250) and (17750, 5250). The five wells model, is slightly different than the traditional five wells model. In traditional five wells model, the injection well is located at the center and four production wells are located at four corners of a square around the injection well. In the present model, with 14 km distance between the injection and production wells, it is not possible to design the traditional five wells model due to distance along the y-axis. Therefore, a rectangular five-wells model is designed which has the injection well located at the same place as in the three wells model, and four production wells are located at (4460, 2178), (4460, 8322), (17040, 2178), and (17040, 8322) respectively. The CO_2 storage and water production is determined for all these three models.

Figure 2.5 shows the two wells model, which has one injection well and one production well. Figures 2.6 and 2.7 represents the three wells model and the five wells model respectively. (Axis scale: x = 1, y = 1, z = 20). To keep only one variable in the simulation, the distance between each injection well and production well is keep as constant (7 km). For each well, the injection and water extraction point is assigned at 90 m to 120 m below the caprock.

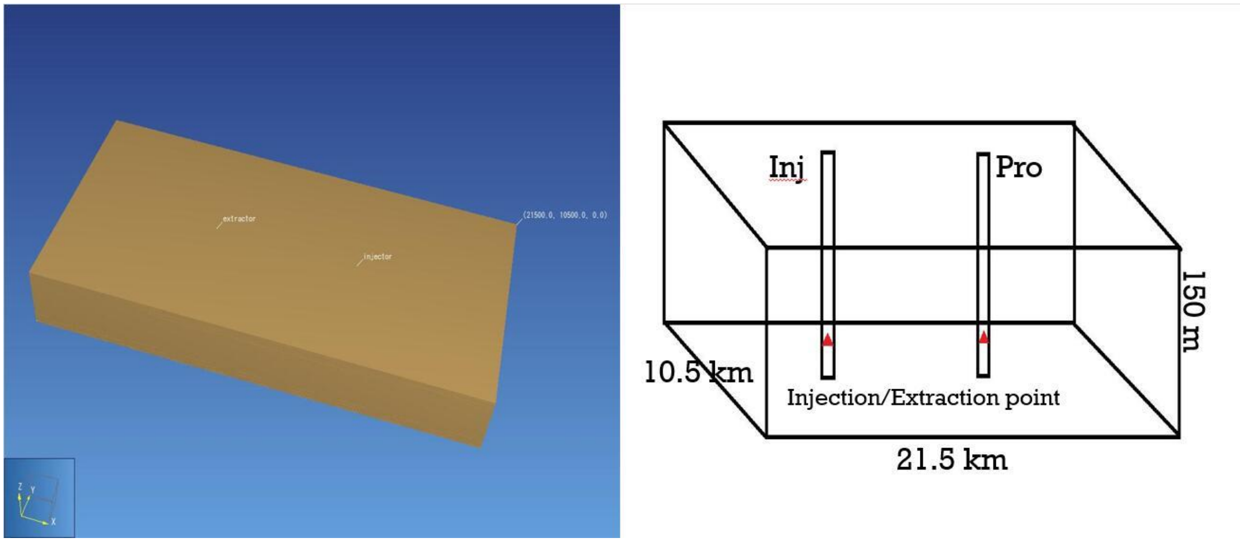

Figure 2.5 Two wells model

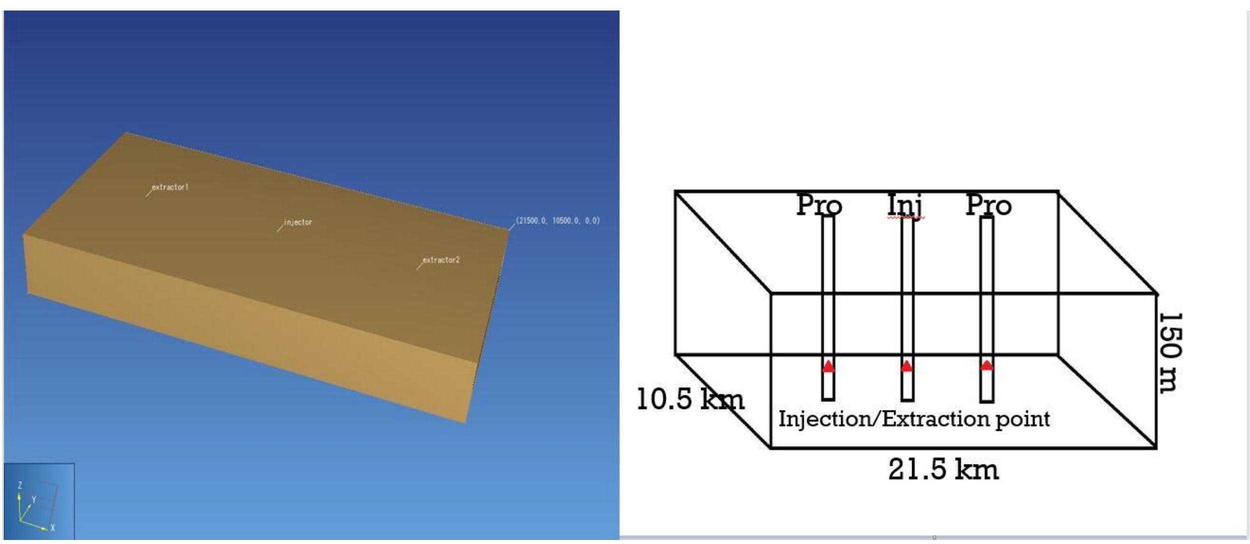

Figure 2.6 Three wells model

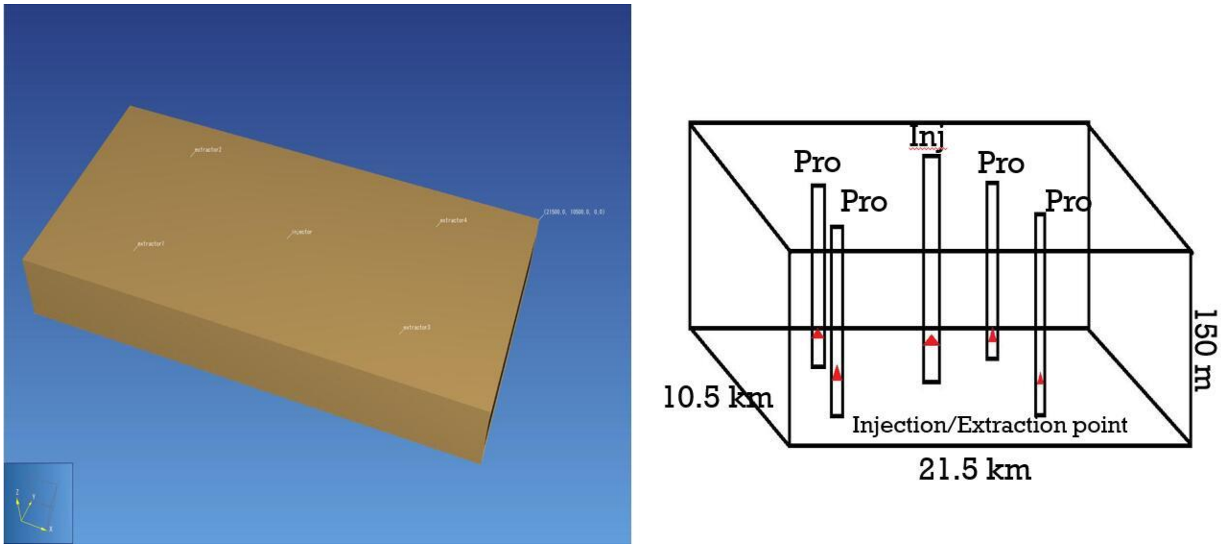

Figure 2.7 Five wells model

2.2.4 Initial Conditions and Simulations

The initial conditions used in the simulations are in Table 2.1.

Table 2.1 Initial conditions

Reservoir initial pressure (MPa)	22
Reservoir initial temperature (Celsius Degree)	62.5
Salt mass fraction	0.006

The following relative permeability and capillary pressure functions are used in the simulation, Van Genuchten-Mualem (IRP = 7) model is used for relative permeability function. The Van Genuchten function (ICP = 7) is used as the capillary function.

(a) Relative Permeability Function:

$$RP_{liq} = S_*^{\frac{1}{2}}(1 - \left(1 - S_*^{\frac{1}{\lambda}}\right)^{\lambda})^2 \ when\ S_l < S_{ls} \tag{1.1}$$

$$RP_{liq} = 1 \ when\ S_l \geq S_{ls} \tag{1.2}$$

$$RP_{gas} = 1 - RP_{liq} \ when\ S_{gr} = 0 \tag{1.3}$$

$$RP_{gas} = (1 - S_*)^2\left(1 - S_*{}^2\right) \ when\ S_{gr} > 0$$

$$where\ S_* = \frac{(S_l - S_{lr})}{(S_{ls} - S_{lr})} \ and\ S_\# = \frac{(S_l - S_{lr})}{(1 - S_{ls} - S_{lr})} \tag{1.4}$$

(b) Capillary Pressure Function:

$$CP = -P_0\left(S^{*\,-1-\lambda} - 1\right)^{1-\lambda}$$

$$where - P_{max} \leq CP \leq 0 \ and\ S^* = \frac{(S_l - S_{lr})}{(S_{ls} - S_{lr})} \tag{1.5}$$

Parameters used in the model are listed in Table 2.2.

Table 2.2 Parameters used in the model

Model dimension (m)	21500*10500*150
Rock density (kg/m^3)	2600
Rock porosity	0.12
Horizontal permeability for sand (m^2)	5.9E-14
Vertical permeability for sand (m^2)	5.9E-15
Horizontal permeability for shale (m^2)	5.9E-19
Vertical permeability for shale (m^2)	5.9E-20
Wet heat conductivity (W/(m*K))	2.51
Specific heat (J/(kg*K))	920
Residual liquid saturation S_{lr}	0.3
Maximum liquid saturation S_{ls}	1.0
Residual gas saturation S_{gr}	0.05
Index λ	0.457
Pressure coefficient P_0	19.58
P_{max}	1.0E7
Liquid relative permeability RP_{liq}	See above
Gas relative permeability RP_{gas}	See above
Pore compressibility	4.5E-10 1/Pa

2.3 Injection and Production Schemes

Three different injection and production schemes are used in this thesis. They are injection only scheme, pre-injection brine production scheme and co-brine brine production scheme.

2.3.1 Sole Injection Scheme

The sole injection scheme is the scheme in which injection well injects CO_2 underground at the beginning of the simulation. Production wells are disabled in the whole simulation. This scheme is used to compare the CO_2 storage and other variables such as pressure in the reservoir with the other two schemes.

2.3.2 Pre-Injection Brine Production Scheme

Brine extraction could be scheduled before CO_2 injection, during CO_2 injection and after CO_2 injection. Pre-injection brine production is the scheme which schedules the brine production before CO_2 injection. In this scheme, CO_2 is injected where pressure drawdown is greatest, It is the location from which the brine has already been extracted. This concept was first proposed by Buscheck [6]. This method has multiple benefits compared to sole injection scheme. First, it can be used as a pressure management strategy. In this case, the brine extraction is scheduled before CO_2 injection, which can lower the reservoir pressure, in other words, the reservoir has more room for CO_2 storage resulting in less overpressure for a given storage quantity of CO_2. In the reservoir, the overpressure is defined as the fluid pressure that exceeds the original pressure of the reservoir before CO_2 in injected. Second, the brine produced could be used for industrial and agricultural purposes, and even for drinking after appropriate treatments. Furthermore, when the brine is extracted before CO_2 injection, the resulting pressure drawdown provides direct and specific information about the potential CO_2 leakage through the caprock as well as the CO_2 storage performance and security.

2.3.3 Co-Injection Brine Production

Co-injection brine production scheme is another effective method for injecting more CO_2 under the same geological condition. It has all the advantages mentioned in section 2.3.2, for the pre-injection brine production scheme since it also has the brine extraction schedule. The difference between the two schemes is the brine extraction time. Basically, the co-injection method involves brine production and CO_2 injection at the same time. In chapter 3, the details of how these three different schemes are applied and their results are given.

Chapter 3: Numerical Solution and Validation of Buscheck's Baseline Cases

Thomas A. Buscheck conducted a simulation to determine the potential of brine removal for a real geological setting: Tubåen Fm. at Snøhvit. He employed the NUFT code to generate the reservoir model and performed the simulations. His results showed good agreement with the experiment results provided by Statoil. More details can be found in his paper [6]. In this thesis, in order to test the validity of present simulation, Buscheck's baseline cases are completed.

3.1 Validation Test Case

3.1.1 Buscheck's Test Cases

Thomas A. Buscheck published his research results a few years ago [6]. In order to improve the physical and economic performance of CO_2 capture, utilization and storage in saline reservoirs, he compared different injection-production schemes based on Snøhvit CO_2 storage project. A brief result is given below, more detail of his research can be found in [6].

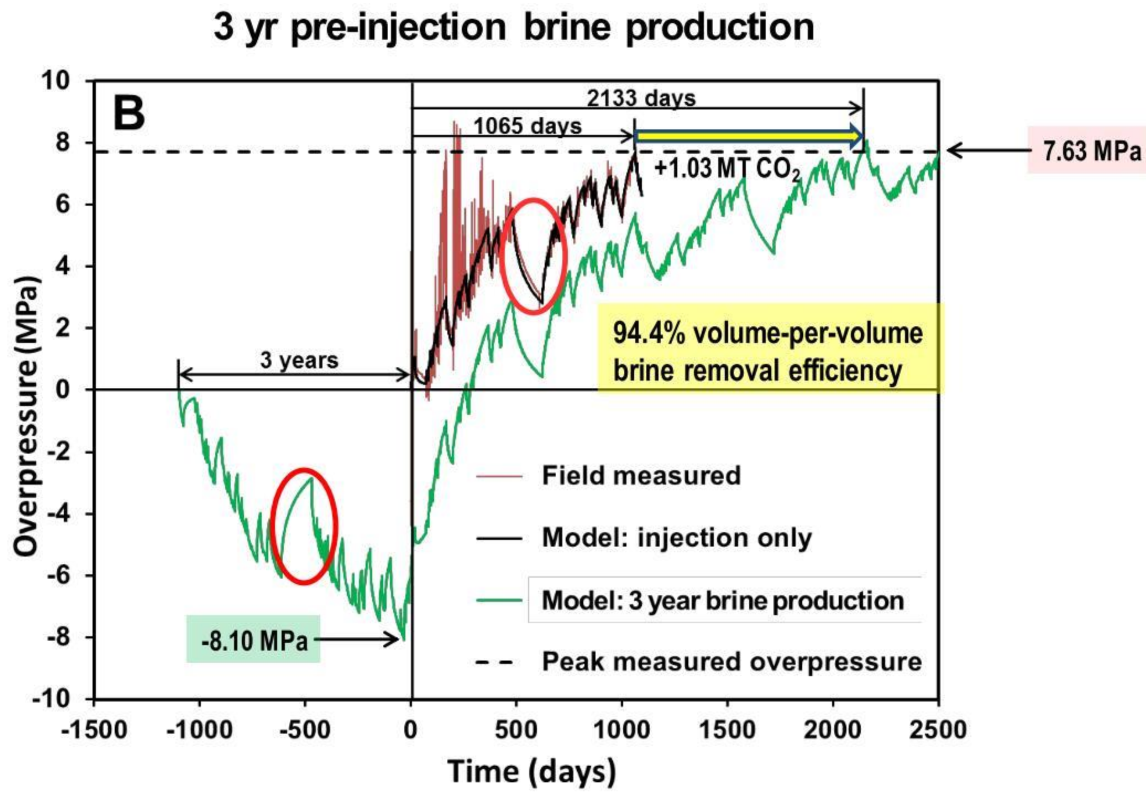

Figure 3.1 Pre-injection brine production compared with sole injection [6]

In Figure 3.1, the black line is the experimental results provided by Statoil. A total of 1.09 MT of CO_2 was injected into Tubåen Fm for 3 years. From Figure 3.1, one can see that after three years of brine production, the overpressure drops down to -8.1MPa and the CO_2 injection begins. According to the geological information, the injector pressure cannot reach the peak overpressure (7.63 MPa). From the red line, one can tell that the sole injection scheme reaches peak pressure after 1065 days injection. In contrast, the pre-injection brine production scheme has longer injection time (It takes 2133 days to reach the peak pressure). Consequently, 1.03 MT of CO_2 was injected into the geological formation. Apparently, this scheme is much better than the sole injection scheme, significantly increases enlarge the CO_2 storage capacity.

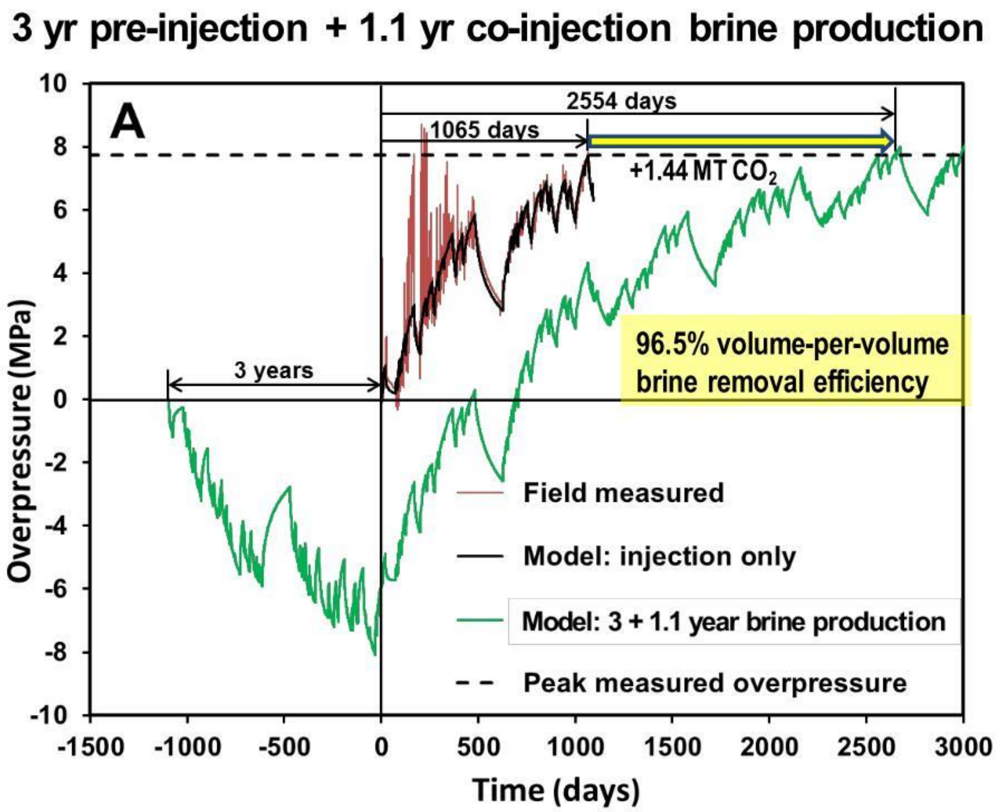

Figure 3.2 Co-injection brine production compared with sole injection [6]

In Figure 3.2, one can find that with 1.1 years of co-injection brine production after 3 years of pre-injection, 1.44 MT more of CO_2 was injected in the reservoir compared with sole injection scheme. This method therefore can be used to inject more CO_2 even compared to the pre-injection brine production scheme mentioned above.

3.1.2 Validation of Junggar Basin Model

The validation test was conducted on a two wells model (one injection well and one production well as shown in Figure 2.4). By keeping a constant rate CO_2 injection speed and brine production speed at 31.71 kg/s. The results of validation are shown in Figure 3.3.

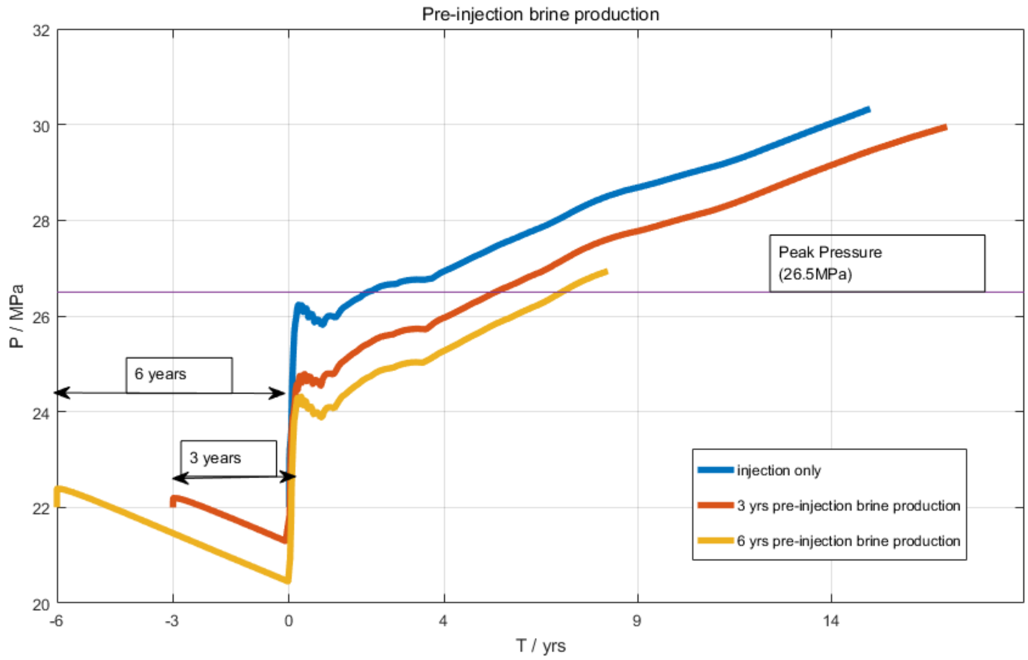

Figure 3.3 Validation case for pre-injection brine production scheme

From Figure 3.3 one can see that the injection well pressure reach peak pressure in 2 years in sole injection scheme. But in 3 years pre-injection brine production scheme, the injection well pressure reaches peak pressure much later than the sole injection scheme, which provides more time for injecting CO_2. Also, one can notice that the 6 years pre-injection brine production scheme has much larger capability for CO_2 storage, which due to large pressure drop after producing brine. Thus, one can conclude that with more time used in producing brine before injecting CO_2 into the reservoir, one can enhance the CO_2 storage capability significantly. This result perfectly matches with the conclusions of Buscheck [6].

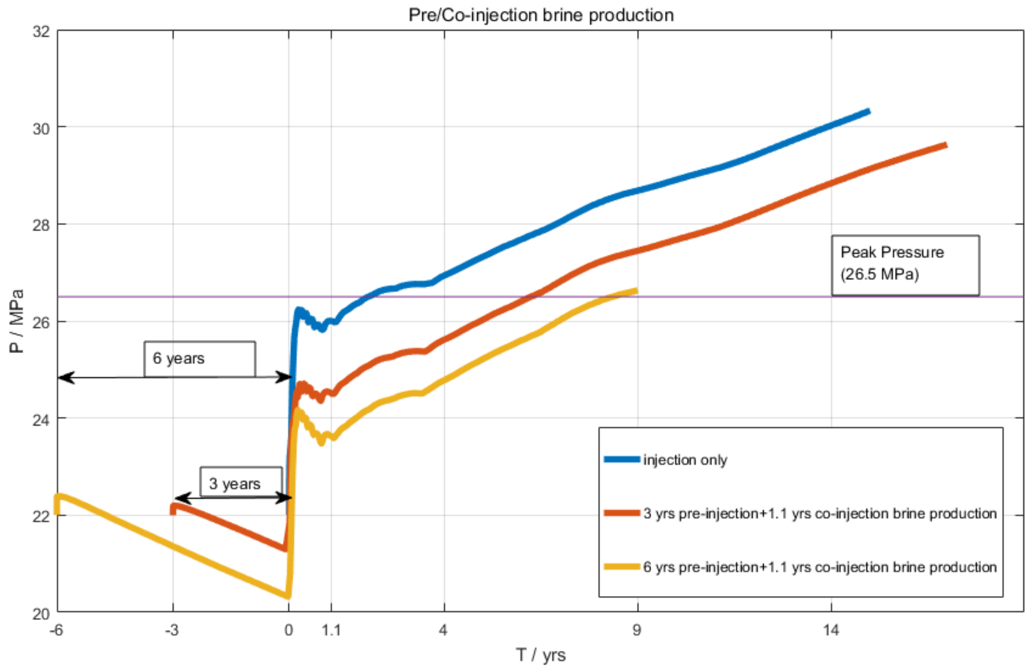

Figure 3.4 Validation case for pre/co-injection brine production scheme

It is obvious that the co-injection brine production scheme is much better than the sole injection brine production scheme for storing CO_2. One can also notice that with more time used in pre-injection, more CO_2 could be injected in the reservoir, matches the result of Buscheck [6].

3.2 Simulation Results and Discussion

3.2.1 Analysis of Pressure Perturbation in Various Schemes

From the validation cases, one can find that increasing the time of pre-injection enhance the storage ability of CO_2. In order to find a best way to store more CO_2, one need to determine how the co-injection brine production time affects CO_2 storage. The results of pressure perturbation for various co-injection brine production schemes, for two, three and five wells are shown in Figures 3.5, 3.6 and 3.7 respectively.

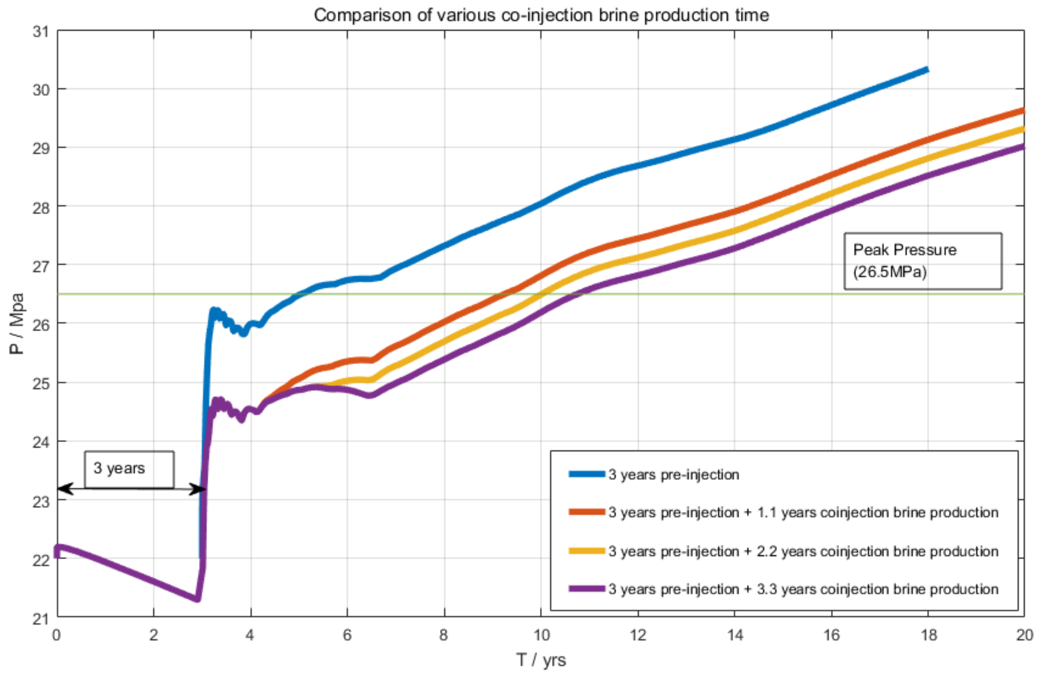

Figure 3.5 Comparison of pressure perturbation in various co-injection brine production time for two wells model

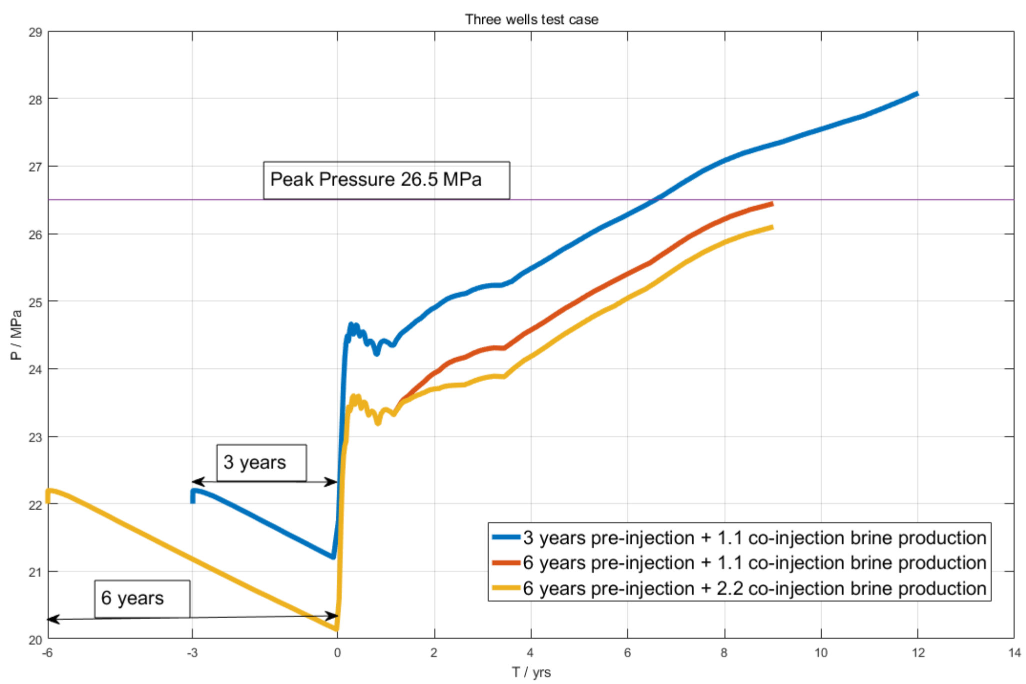

Figure 3.6 Comparison of pressure perturbation in various co-injection brine production time for three wells model

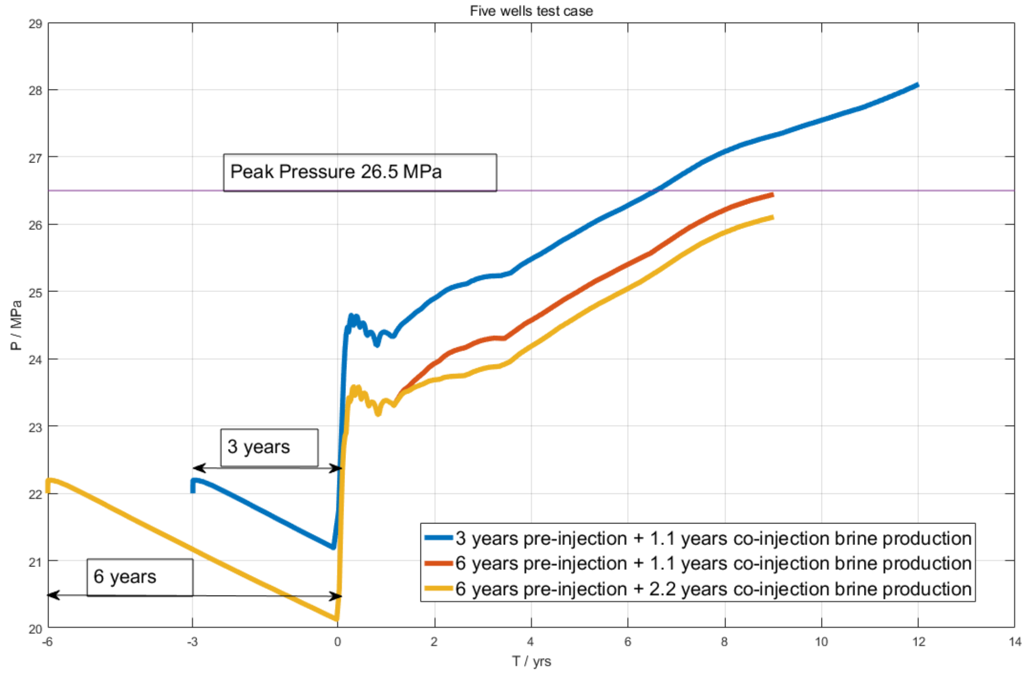

Figure 3.7 Comparison of pressure perturbation in various co-injection brine production time for five wells model

From Figures 3.5, 3.6 and 3.7, one can see that the results from the three wells model and the five wells model are match perfectly with Buscheck's results [6]. Prolonging the pre-injection brine production time can significantly enhance the CO_2 storage capacity in reservoir and co-injection brine production scheme can increase the CO_2 storage capacity significantly. Figures 3.8, 3.9 and 3.10 show the pressure contour for two, three and five wells model respectively. One can find that the pressure builds up close to the injection well is much larger than that at the production wells. Pressure drops continuously from injection well to each of the production wells. Once the CO_2 is injected into the reservoir, the reservoir pressure will increase, which can be a series of problem for the caprock if it exceeds the fracture pressure. From the results, one can see that two wells model has the largest peak pressure. In order to keep producing brine and injecting CO_2 in a safe manner, the pressure must be kept as low as possible. It is clear that the three wells model and five wells model provide a better security guarantee than the two wells model.

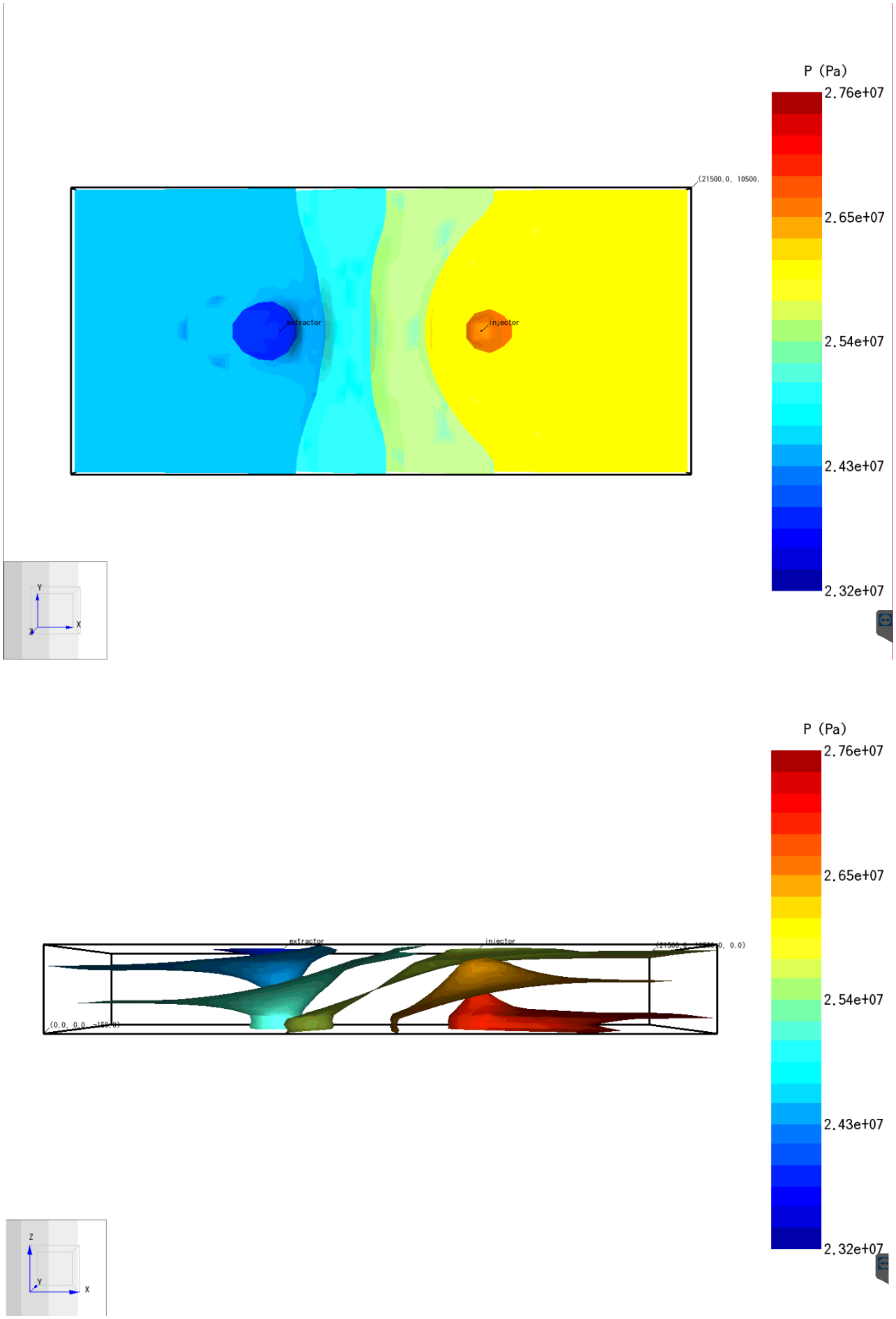

Figure 3.8 Pressure contours in two wells model at the end of simulation (top and front view)

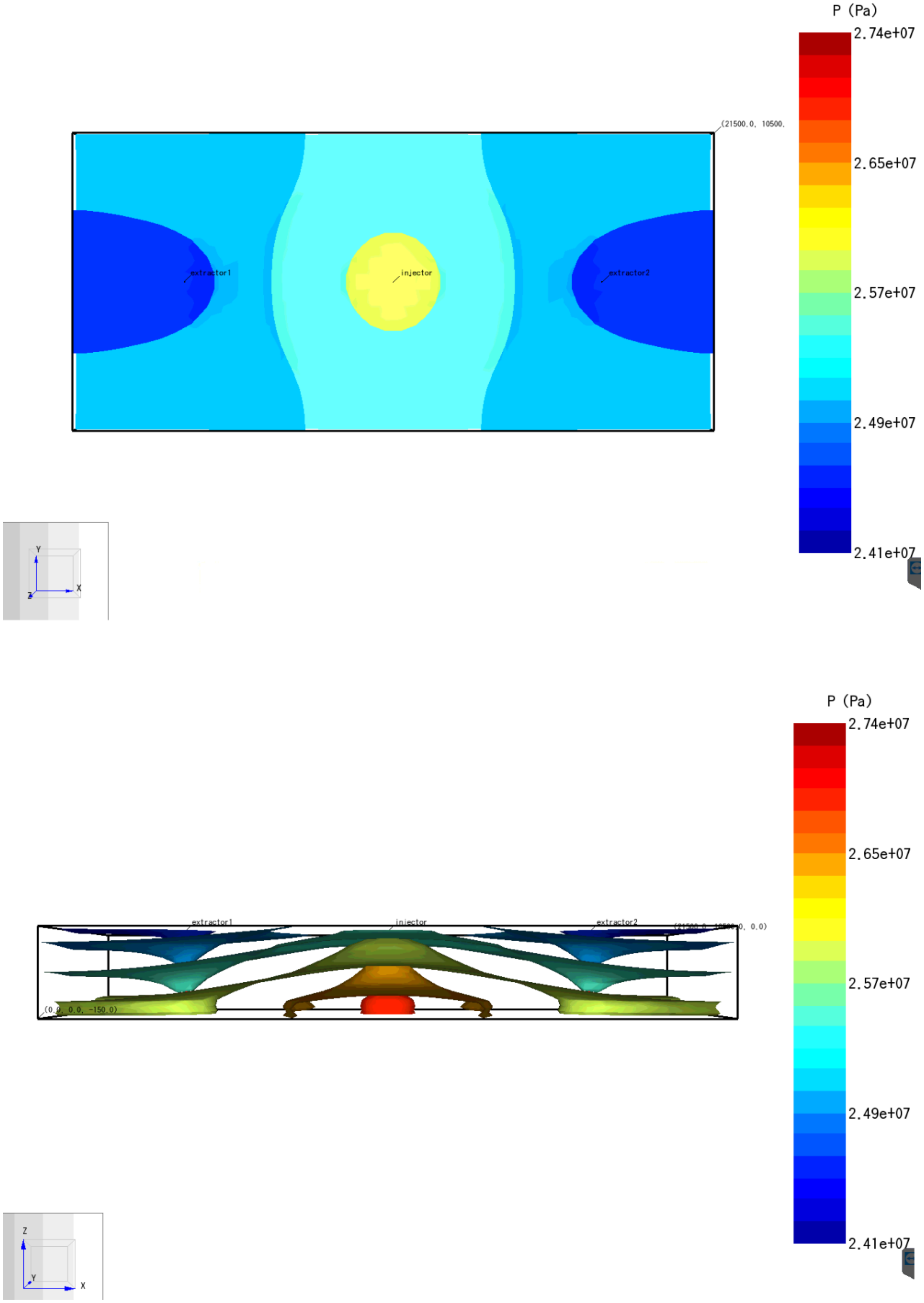

Figure 3.9 Pressure contours in three wells model at the end of simulation (top and front view)

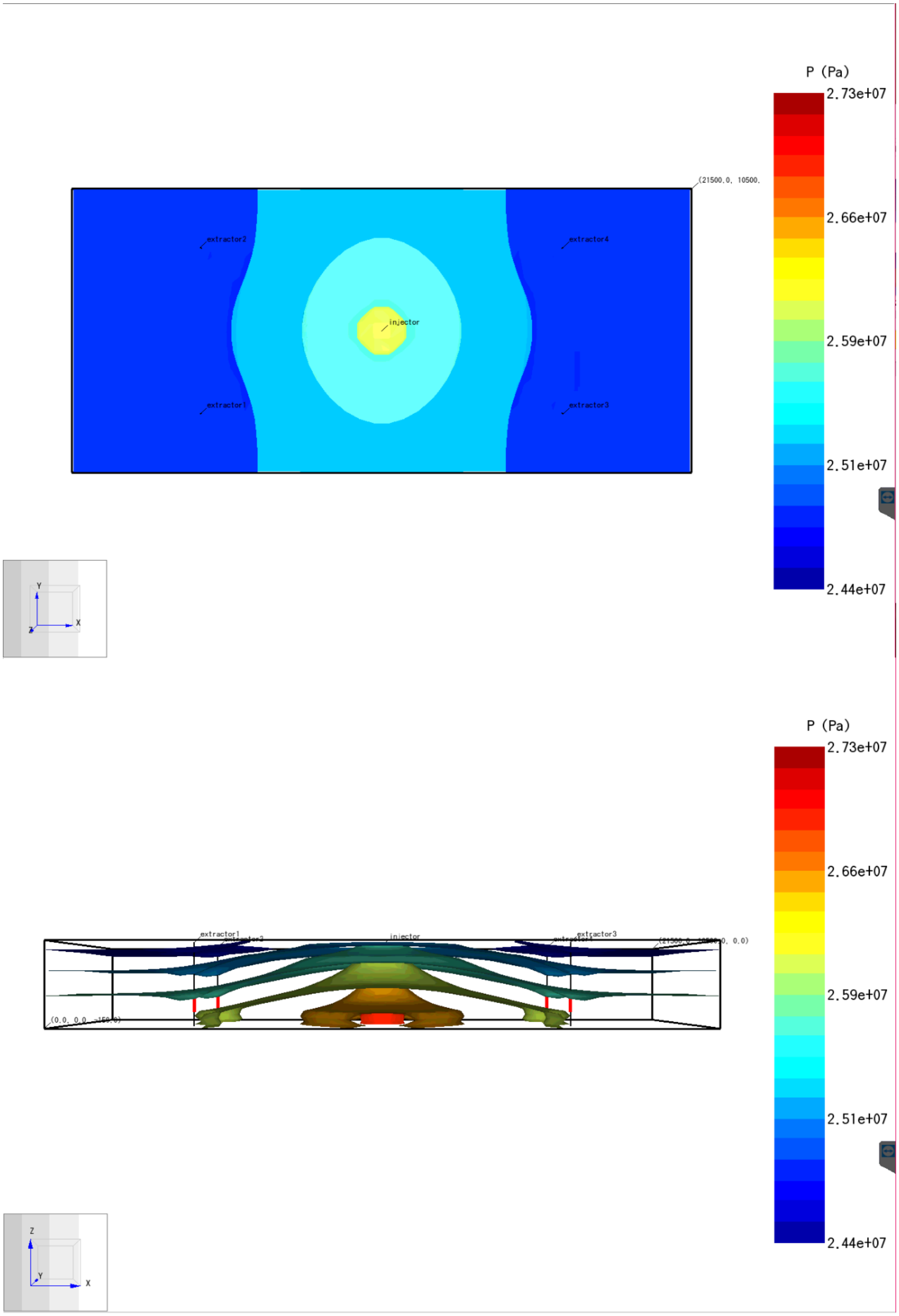

Figure 3.10 Pressure contours in five wells model at the end of simulation (top and front view)

Figure 3.11 shows the saturation of CO_2 (SG) for each model. In the two wells model, the saturation of CO_2 is concentrated more on the injection well, which leads to an imbalance in CO_2 saturation. In contrast, the three wells model and five wells model have symmetric CO_2 saturation due to symmetric model. In symmetric models, the pressure and CO_2 could spread continuously from injection well to production wells, which could maintain a relative balance in the reservoir. Because of this reason, three wells model and five wells model provide more safety compared to the two wells model.

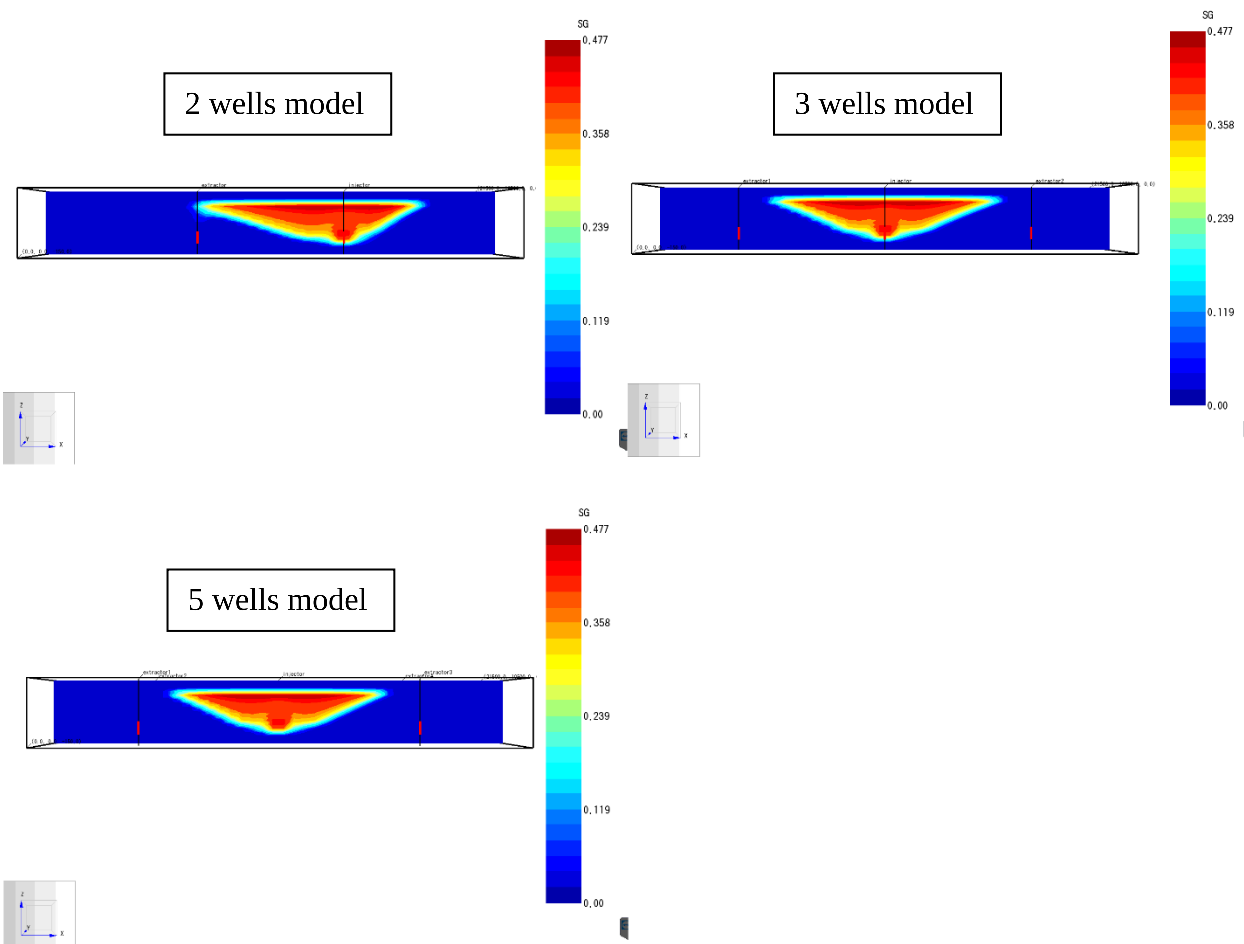

Figure 3.11 Saturation of CO_2 (SG) for each model at the end of simulation (XZ cross-section view, y=5250 m)

3.2.2 Discussion of CO_2 Storage Ability in Various Schemes and Models

From the validation case and other computed test cases, one can notice that pre-injection scheme has much larger pressure dropdown and longer time for injecting CO_2 after brine production compared to the sole injection scheme, which implies that this is a better way for injecting more CO_2 in the reservoir. And one can also find that 6 years pre-injection brine production scheme has much larger pressure dropdown and longer time for injecting CO_2 after brine production compared to 3 years pre-injection scheme, which enables much larger CO_2 storage. In other words, with longer time for pre-injection brine production, more CO_2 could be injected. The conclusions are applicable for two wells model, three wells model and also five wells model. Next, the maximum CO_2 storage ability of all the three well models are evaluated. Considering the reservoir stability, one cannot keep on injecting CO_2, due to large and lasting pressure perturbation which may cause the caprock fracture. Thus, pressure limits on the reservoir pressure must be applied. The simulation is run for pressure limits from 17.5 MPa to 26.5 MPa. The pre-injection and co-injection brine production schemes are applied to determine the maximum CO_2 storage ability for each well model.

After many simulations, It was found that the injection well pressure will reach the peak overpressure (- 4.5 MPa) after 4.5E8 s (14.27 years) of brine production, and different models have different CO_2 storage capacities as shown in Figures 3.12, 3.13 and 3.14.

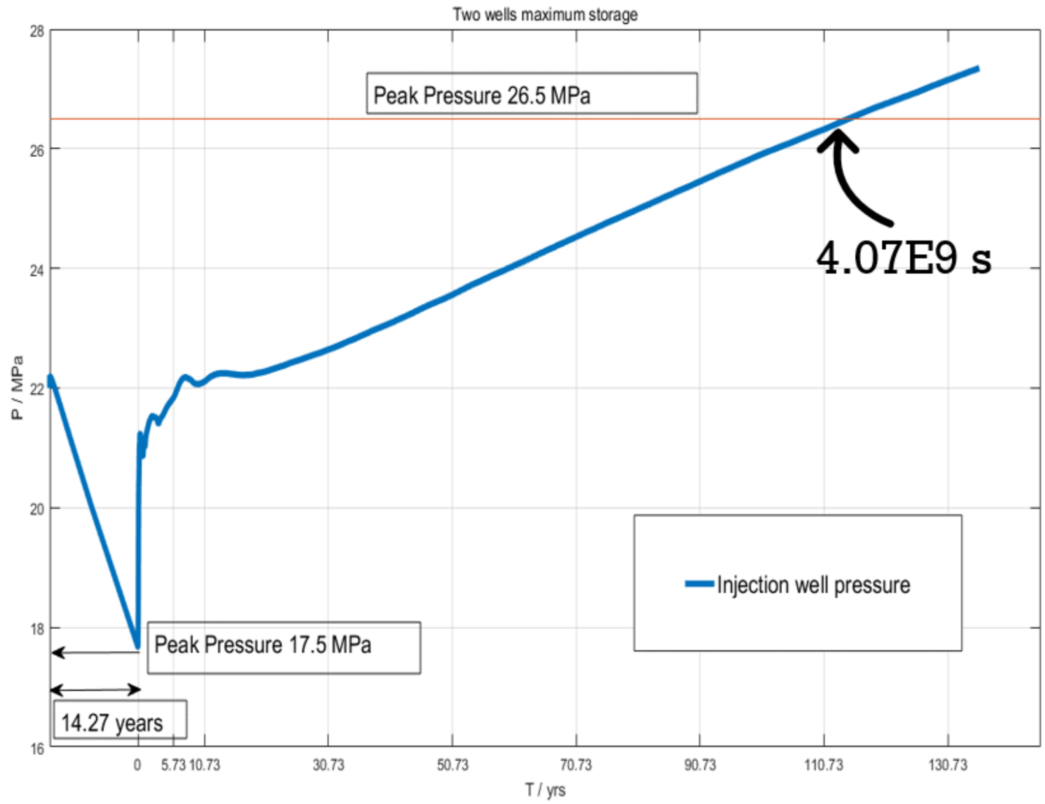

Figure 3.12 Two wells model result

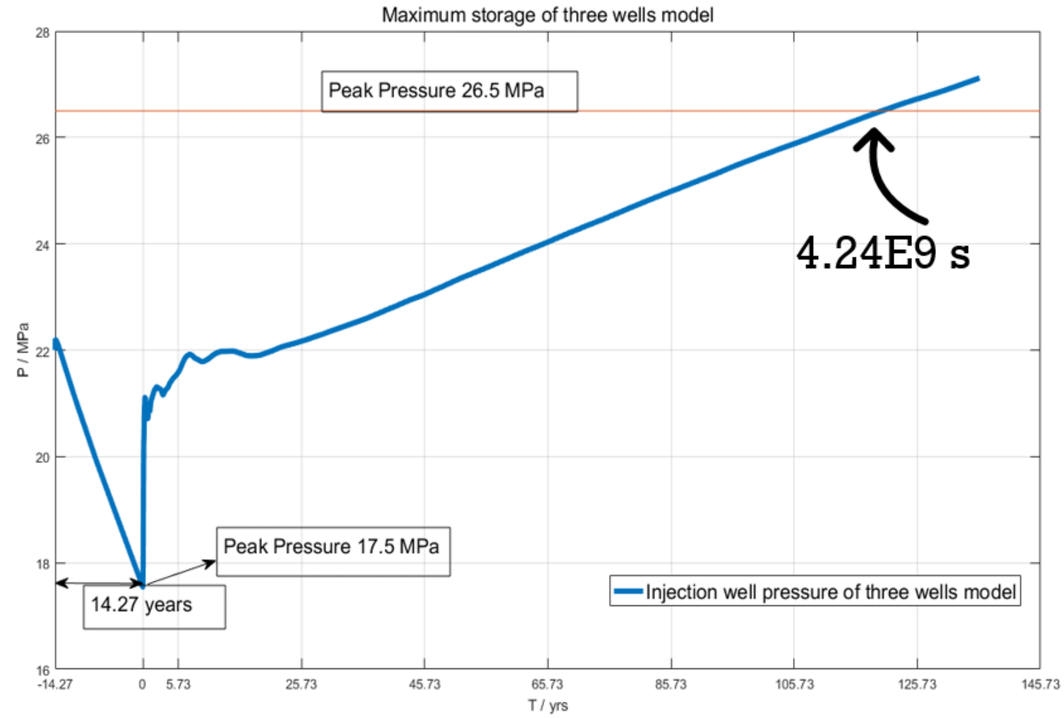

Figure 3.13 Three wells model result

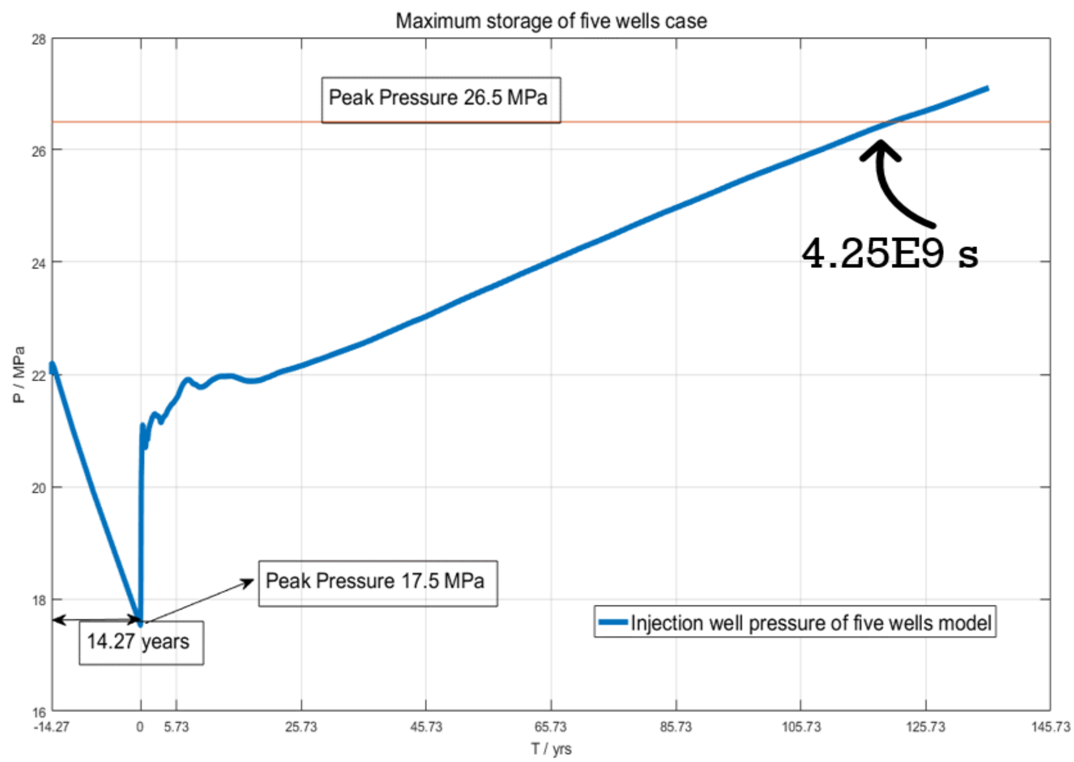

Figure 3.14 Five wells model result

Table 3.1 shows the maximum CO_2 storage capacity for different well models

Table 3.1 Maximum CO_2 storage capacity

	Two wells model	Three wells model	Five wells model
Total brine produced (kg)	129,059,700,000	134,450,400,000	134,767,500,000
Total production time (year)	129.059	~134.45	~134.45
Total CO_2 injected (kg)	114,789,753,016	120,180,788,381	120,500,790,480
Total injection time (year)	114.789	~120.18	~120.18

Figure 3.15 shows the comparison of maximum CO_2 storage capacity with the two, three, and five wells models.

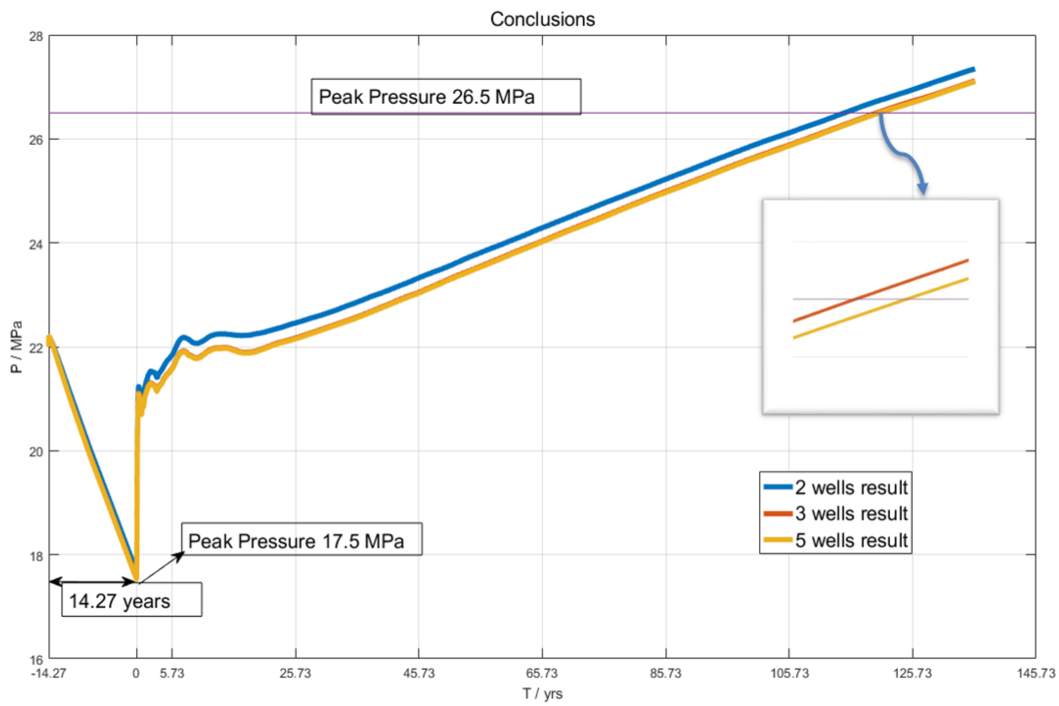

Figure 3.15 Comparison of maximum CO_2 storage capacity in three different well models

From Table 3.1 one can notice that five wells model has the largest CO_2 storage ability of 12 million tons. Three wells model is in second place but the maximum CO_2 storage is very close to the five wells model (~ 12 million tons). In contrast, the two wells model has very limited CO_2 storage ability compared to the three wells and five wells models. Compared to the two wells model, approximately 0.56 million tons more CO_2 has been injected in three and five wells models. The reason for this is that the three wells model distributes the injection pressure effectively and evenly to two production wells. Five wells model also has a really large CO_2 storage, which is very close to three wells' storage. Considering the large cost of building the wells, five wells models may not be adapted in an industry environment.

Chapter 4: Conclusions

In this thesis, numerical simulation of enhancement in CO_2 sequestration are performed for various water production schemes under multiple well scenarios. According to the results, It is found that the pre-injection and co-injection brine production is the most effective way to inject more CO_2 in the reservoir. Compared to the two wells model and three wells model, five wells model has larger CO_2 storage ability (over 12 million metric tons).

Some of the challenges facing today to environment and energy systems require reducing CO_2 emissions in the atmosphere as well as alleviating the water shortage. Simultaneously injecting CO_2 from power plants in deep saline aquifers for storage while producing brine from the same aquifers could address same challenges. Producing brine has lots of operational benefits which include enhancing the CO_2 storage and alleviating the pressure build up in the reservoir during CO_2 injection. Since CCS is a relatively low-cost technology for limit the global CO_2 emissions in atmosphere and Enhancing Water Recovery (EWR) technology is simultaneously used in can we very attractive to the industry and the policy makers.

Chapter 5: Future Work

In this thesis, only constant rate CO_2 injection and water production (31.71 kg/s) are considered. Future work could address for the dependent CO_2 injection and water production. Constant pressure injection and production also could also be researched. Junggar basin model is very simplified model. More complex and accurate models could be employed in the future work. Distance between injection and production wells are fixed at 7 km in my thesis. Future work could evaluate the CO_2 storage and pressure build up in the reservoir by changing the distance between wells.

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