Reservoir Simulation of CO_2 Sequestration in Deep Saline Reservoir, Citronelle Dome, USA

S.Alireza Haghighat[1], Shahab D. Mohaghegh[1], Najmeh Borzouei[2], Daniel Moreno[1], Alireza Shahkarami[1]; 1:West Virginia University, 2: Shell Exploration and Production Co

Abstract:
CCS (Carbon Capture and Storage) is a fast growing method for mitigation of CO_2 emissions. Carbon storage in underground geological formations is one of the applicable approaches of CCS. The main concern for a geologic carbon dioxide (CO_2) sequestration is sustained confinement of the injected CO_2 over long time periods (hundreds of years). For selection of the proper underground storage site, monitoring the CO_2 plume movement and predicting the behavior of the reservoir pressure (indicator of potential leakage in the system), it is essential to use an appropriate multiphase flow dynamic reservoir model. The Numerical Reservoir Simulator is the most appropriate tool for accomplishing this task.
Data collected from an ongoing saline storage pilot, Citronelle Dome, located in Mobile County (Alabama, US), was considered for this study. This project is a part of a CO_2 storage research project funded by the U.S. Department of Energy (DOE) and conducted by the Southeast Regional Carbon Sequestration Partnership, which is primarily comprised of the Southern States Energy Board, Electric Power Research Institute, Southern Company, Advanced Resources International and Denbury Offshore, to demonstrate commercial-scale storage of CO_2 captured from an existing coal-fired power plant.
A commercial reservoir simulation model (CMG's GEM) for CO_2 sequestration at the Citronelle Dome was developed. The model is based on a comprehensive geological study that included data from more than 40 well logs. The presence of PDGs (Pressure Down-hole Gauge) was considered in the reservoir model at the observation well.
Relative permeability curves, hysteresis, rock type, vertical permeability, boundary condition and brine density as well as compressibility are several uncertain variables for multiple reservoir simulations and parametric studies. 500 years is the time frame of interest for assessing the effect of each parameter (within a typical range) on the CO_2 plume extension and reservoir pressure behavior (in observation well). The results are analyzed to investigate the uncertainty of CO_2 behavior and risk of leakage. Also this analysis provides a framework to be used for history matching the reservoir model in presence of actual field data (real time pressure from observation well).

Introduction
It has been documented that the biggest source of global CO_2 emissions is the combustion of fossil fuels. This emission is one of the main causes of climate change with serious impacts on a variety of issues. It seems to be widely accepted that a comprehensive switch from fossil fuels to green fuels will take several decades to be completed; other CO_2 emission mitigation options like CCS (Carbon Capture and Storage) must be implemented to bridge the gap.
There are different potential sites for geological CO_2 sequestration such as: depleted oil and gas reservoirs, deep saline reservoirs, deep un-mineable coal seams, and storage in association with

CO_2/EOR. Deep saline reservoirs are estimated to have enough volumetric capacity to sequester enormous amount of CO_2. Despite the limited locations of oil and gas reservoirs, deep saline formations are wide spread geographically, providing more chances to store CO_2 from many emission sources [2]. Based on predictions, the retention time for CO_2 to be stored in saline reservoir can be up to thousands of years, representing the best storability amongst the other geological options [2].

Geological storage of CO_2 is associated with different type of potential risks, such as leakage of CO_2 or brine from the target zone. This risk can be managed with careful site selection, with an emphasis on well integrity, reservoir modeling, appropriate monitoring, and the establishment of a remediation strategy [5]. For long term CO_2 storage, it is necessary for the target reservoir to be sealed by an impervious cap rock. Under some unfavorable conditions, the integrity of the cap rock can be damaged by improperly cemented wells, unsealed faults, high permeable regions, and fractures. In order to quantify the risk of CO_2 leakage, it is necessary to determine CO_2 plume extension to see if the injected CO_2 reaches and contacts existing leakage pathways. Additionally, CO_2 injection into saline reservoirs generates pressure build up (which might go much further than the CO_2 plume), resulting in a higher risk of seal integrity damage (creating fractures or activating faults) and displacement of brine into the underground drinking water sources. Therefore, determining the magnitude and location of pressure build up in the reservoir is extremely important for operators and regulators to evaluate the pressure induced risks.

In this work, we study and model CO_2 injection in a deep saline reservoir (Citronelle Dome, Alabama) with a conventional reservoir simulator (CMG's GEM). The main objective is to focus on reservoir pressure build up and CO_2 plume extension behavior subject to variation of uncertain reservoir parameters (sensitivity analysis). The results of the sensitivity analysis can be used in CO_2 injection risk assessment.

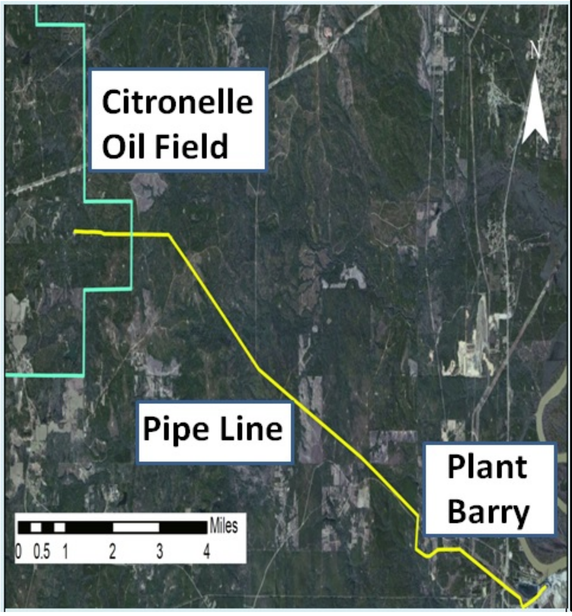
Site Description

Injection and storage of CO_2 in Citronelle, AL is the third phase of Southeastern Regional Carbon Sequestration Partnership. It aims to demonstrate commercial-scale storage of CO_2 captured from an existing coal-fired power plant. Alabama Power Company's Plant Barry is the source of the CO_2, which is approximately 12 miles from the Anthropogenic Test Site (located within Denbury Onshore's Southeast Citronelle operating unit). The project will be capable of capturing approximately 185,000 tons of anthropogenic CO_2 per year. A pipeline was constructed from Plant Barry to the test site (Figure 1.a), and the CO_2 is injected into saline Paluxy sandstones at depths of approximately 9,500 feet. Injection is planned to continue for three years and at the end of injection, the sequestered CO_2 will be monitored for an additional four years in order to determine how well the CO_2 has been contained.

The Paluxy formation (proposed injection zone) is located at a depth of about 9,450 to 10,500ft (TVD). This formation represents a coarsening-upward succession of variegated shale and sandstone [3]. Based on the logs from the injection well, twenty seven individual sandstones in the Paluxy formation were identified as potential storage reservoirs for CO_2. Ten sand layers that are the thickest and most extensive, were selected for injection.

Citronelle Dome, a broad, gently dipping salt pillow, provides the Citronelle Field with structural closure at all stratigraphic horizons of the Jurassic through Tertiary age, including the Paluxy formation. Moreover, there is an apparent lack of faulting at the Citronelle Dome structure [3].

The proposed confining zone for this CO_2 injection test is the basal shale of the Washita-Fredericksburg interval, which has an average thickness of 150 ft. (Figure 1.b). The aquifers on top and bottom of this confining unit (including the Paluxy) represent extremely low groundwater velocities [3].



Formation Tops	Depth (ft bgs)	Interval Thickness (ft)
Bottom of Fresh Water (<1,000 mg/l)	~1,000	
Base of USDW (<10,000 mg/l)	~1,200	
Selma Chalk Group (seal)	4,560	1,310
Eutaw	5,870	150
Tuscaloosa Group		
Upper Tuscaloosa	6,020	720
Middle Tuscaloosa (seal)	6,740	210
Lower Tuscaloosa	6,950	410
Washita-Fredericksburg (seal)	7,360	2,040
Paluxy Formation (target)	9,400	1,110
Mooringsport Formation	10,510	240
Ferry Lake Anhydrite	10,750	190
Rodessa Formation (oil reservoir)	10,940	-

Figure 1:(a) Location of power plant and injection well (b): Stratigraphic layers in the Citronelle Dome [3]

Reservoir Simulation Model

Based upon interpretation and evaluation of geophysical well logs, a comprehensive picture of the subsurface geology has been developed for the reservoir simulation modeling. The reservoir models were built in the Computer Modeling Group's (CMG) numerical simulation software. The geological structure of the model includes 17 sand layers representing 51 simulation layers. A Cartesian grid has been used with a dimension of 150*150*51 grid cells (Δx and Δy equal to 133 ft). Well logs from 40 offset wells that are within the area of study have been acquired and interpreted in order to generate porosity maps. Also, porosity-permeability cross plots that were obtained from core analysis provide reasonable estimates for the permeability distribution within the reservoir. Relative permeability curves from the history-match of the injection pilot test at the Mississippi Test Site were used in this simulation (trapped gas saturation was considered value of 7.5 percent). Other reservoir properties are summarized in Table 1. This is considered as a base case model in the following sections.

Table 1: Reservoir parameters and properties (base case model)

Parameter	Value	Parameter	Value
Permeability(md)	$0.824e^{28.18\varphi}$	Water density(lb/ft^3)	62
Temperature(°F)	230	Water viscosity(cp)	0.26
Salinity(ppm)	100000	Water compressibility(1/psi)	3.2E-6
Residual gas saturation	0.35	K_v/K_h(permeability ratio)	0.1
Residual water saturation	0.6	Pressure reference@9415ft(psi)	4393

For the reservoir simulation, the injection well was operated with maximum bottom-hole pressure limit of 6,300 psi and injection rate constraint of 9.45 million standard cubic feet per day. The injection starts at the beginning of 2012 and takes 3 years. For post-injection site care analysis, the simulation run goes over 500 years.

Based on the initial studies, maximum CO_2 plume extension occurs in the top and sixth layer. The plume area has the approximate major diameter of 4,933 ft, 500 years after the injection (Figure 2).

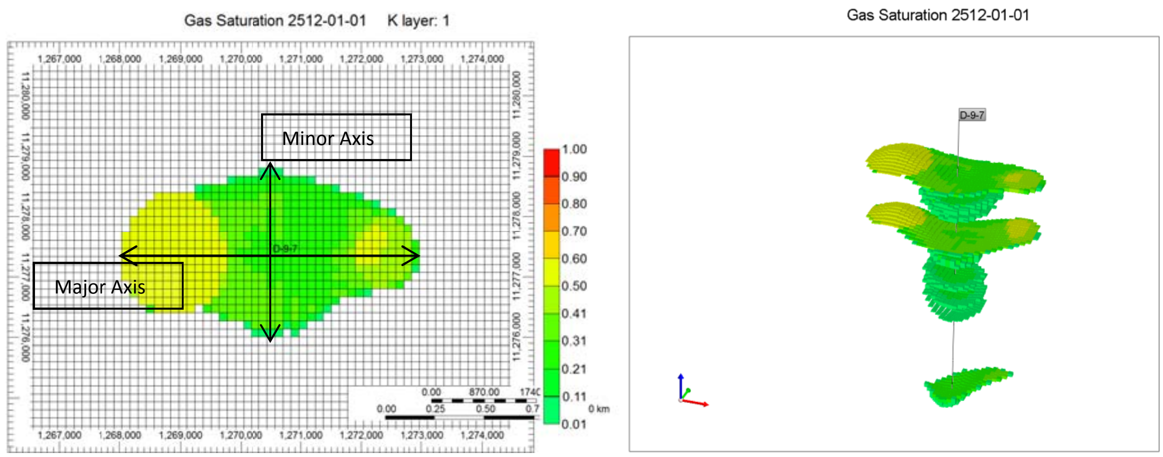


Figure 2: Plume extension in the first layer (left) and all layers 500 years after injection

Two Pressure Down-hole Gauges (PDG) are installed in the project's observation well (D-9-8#2), which is located 820 ft at the east side of the injection well. These PDGs can provide real time pressure and temperature measurements. The actual pressure data can be used for reservoir monitoring (especially CO_2 leakage detection) in addition to history matching. Therefore, the main focus of this study is to analyze the reservoir simulation pressure behavior at the grid block that corresponds to the exact location of the PDG in the observation well. Pressure in the observation well rises from 4,400 psi to 4,727 psi (or "maximum pressure) during the 3 years injection period (2012 to 2015). After the injection is stopped, the pressure decreases gradually to 4,660 psi after 1 year (stabilized pressure). Finally the reservoir pressure in the observation well follows a very gentle decline and stable trend from 4,660 to 4,653 psi over 500 years (Figure 3).

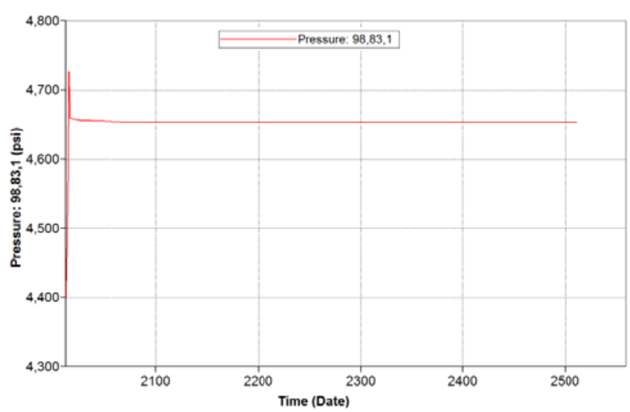


Figure 3: pressure behavior in the observation well (base case model)

Sensitivity Analysis

In this section, simulation model predictions are presented considering uncertainty in some reservoir properties. The sensitivity analysis procedure was to change one parameter at a time (within the uncertainty range) to investigate the corresponding effects on the reservoir pressure (at the observation well) and CO_2 plume extension. The reservoir parameters that we analyzed in this study are permeability (rock type), gas relative permeability, maximum residual gas saturation (hysteresis), vertical to horizontal permeability ratio, boundary condition, brine compressibility, and density. Since the CO_2 plume extension shape is elliptical, the magnitude of the major and minor axis (Figure 2) can characterize the underground

CO_2 distribution 5, 50 or 500 years after the injection. Additionally, to analyze the reservoir pressure behavior, we focused on maximum (at the end of injection) and stabilized pressures.

Permeability

From here on, the contribution of each parameter to the reservoir pressure and plume extension would be identified. In the Citronelle reservoir model, porosity originates from maps that are generated by the interpretation of 40 well logs. Figure 4 shows porosity-permeability cross-plots of the Geological Survey of Alabama's southwestern Dataset [3]. In order to have reliable porosity-permeability correlation, the data points are clustered into 5 different rock types, ranging from very tight to very conductive. The initial porosity-permeability data gathered from well D-9-8 (observation well) core analysis, represents a conductive rock type (this is used in the base model). Average ($K = 0.64e^{21.87\varphi}$) and Very Conductive ($K = 9.964e^{21.74\varphi}$) rock types are introduced to the reservoir simulation model.

For the Average rock type, due to the lower permeability values, CO_2 injectivity decreases. Thus, it is not possible to store the all the CO_2 according to planned target (Figure 5.a). Injectivity of CO_2 is the same for both Conductive and Very Conductive rock types equal to the target values. We can see the results for pressure in Figure 5.b (since the stabilized reservoir pressure changes very gently during 500 years, we show the results for 20 years after the injection to be able to see more detail). By decreasing the permeability (average rock type), CO2 injectivity decreases to 60% of target value, resulting in reduced reservoir pressure (compared with base case). For higher permeability (Very Conductive), stabilized reservoir pressure is 42 psi less than the base case, due to the higher conductivity that prevents more pressure build up. Additionally, an increase in the permeability enhances CO_2 and brine displacement, which leads to larger CO_2 plume extensions, according to Table 2.

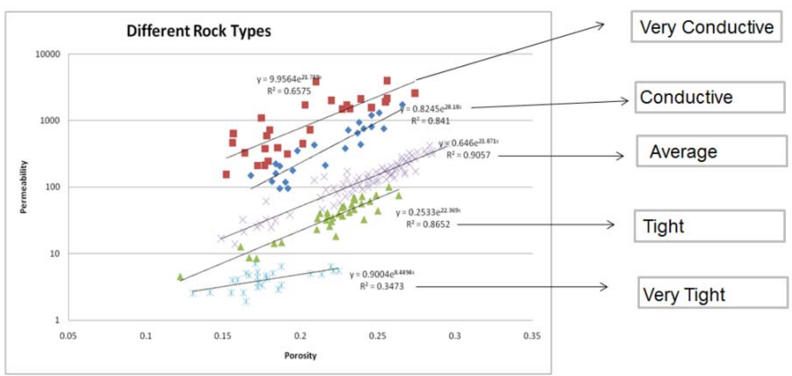


Figure 4: Porosity-permeability cross-plot

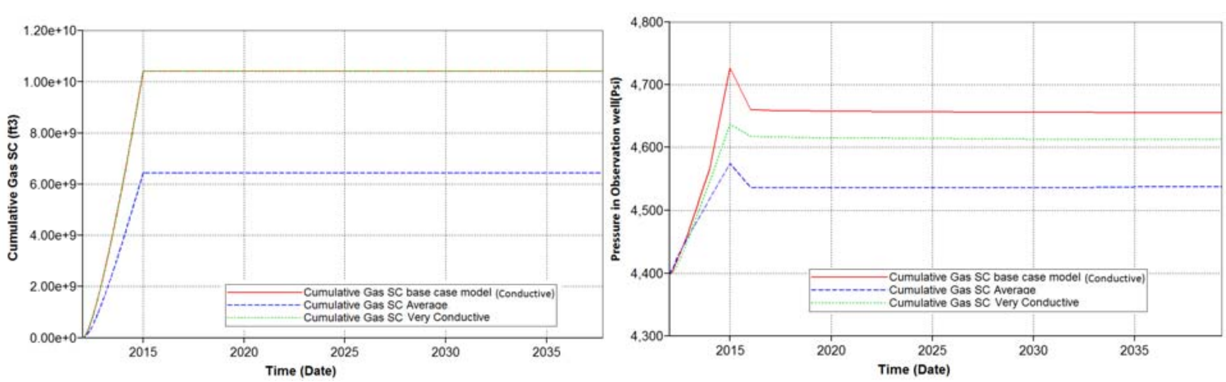


Figure 5: (a) CO_2 injectivity for different rock types (b) Reservoir pressure in observation well for different rock types

Table 2:CO_2 Plume extension size over time (in the first layer) for different rock types

			Permeability		
			Base Case (K=0.824e^28.18 φ)	Average (K=0.64e^21.87 φ)	Very Conductive (K=9.964e^21.74φ)
CO_2 Plume Extension	5 Years after Injection	Minor Axis(ft)	2133	1600	2533
		Major Axis(ft)	2400	1733	3200
	50 Years after Injection	Minor Axis(ft)	2533	1867	2800
		Major Axis(ft)	4000	2133	4667
	500 Years after Injection	Minor Axis(ft)	2667	2133	2667
		Major Axis(ft)	4933	3733	5067

Vertical permeability

Typically, vertical permeability is determined as a ratio to horizontal permeability. In this study, for the base case model, K_v/K_h is considered to be 0.1. For the sensitivity analysis; we assigned values of 0.3, 0.5, and 0.7 to the K_v/K_h. As shown in Figure 6, an increase in the K_v/K_h generates less pressure build up during the injection. However, after the transition time, the higher vertical to horizontal permeability ratio, the higher the stabilized pressure value is. Also, the size of the CO_2 plume slightly increases for higher K_v/K_h , especially for 5 and 50 years after injection (Table 3).

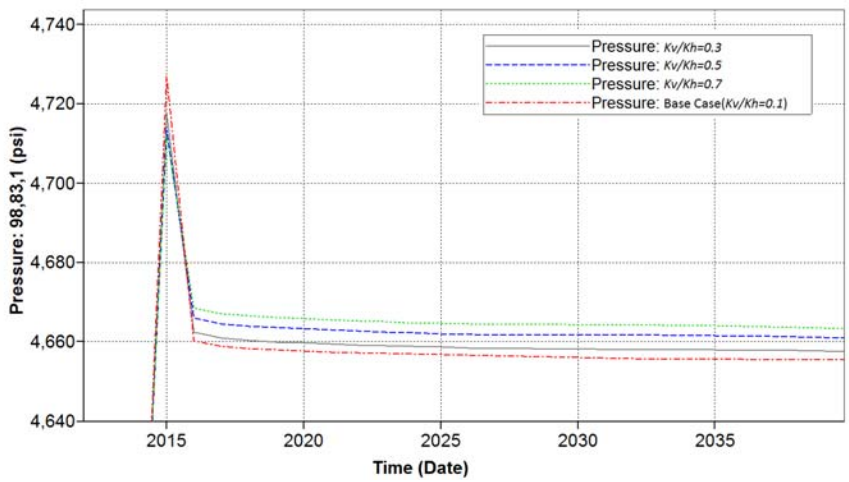


Figure 6: Reservoir pressure in observation well for different permeability ratios

Table 3:CO_2 Plume extension size over time (in the first layer) for different permeability ratios

			Vertical to Horizontal Permeability Ratio			
			Base Case	Kv/Kh=0.3	Kv/Kh=0.5	Kv/Kh=0.7
CO_2 Plume Extension	5 Years after Injection	Minor Axis(ft)	2133	2133	2133	2267
		Major Axis(ft)	2400	2533	2667	2800
	50 Years after Injection	Minor Axis(ft)	2533	2667	2667	2667
		Major Axis(ft)	4000	4133	4267	4400
	500 Years after Injection	Minor Axis(ft)	2667	2667	2800	2800
		Major Axis(ft)	4933	4933	5067	5067

Gas Relative Permeability Curves

Four different gas relative permeability curves were generated so that two of them represent higher (at any given gas saturation) and two represent lower values of relative permeability, compared with the base case (Figure 7.a). It is worth mentioning that the curves with the higher gas relative permeability values have lower residual gas saturations and vice versa. The results are shown in Table 4 and Figure 7.b. Higher gas relative permeability curves represent lower residual gas saturation that can mobilize CO_2 phase earlier (at lower gas saturations). Therefore, CO_2 moves further resulting in larger CO_2 plume extension. Additionally, higher gas relative permeability increases the stabilized reservoir pressure. Reversely, lower gas relative permeability leads to less extensive plum and lower stabilized reservoir pressure

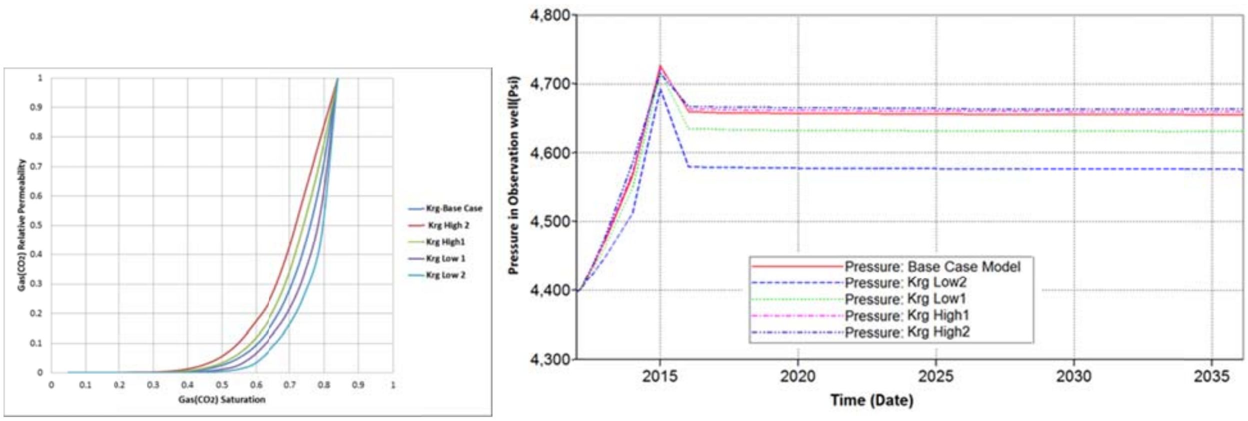


Figure 7:(a) Different gas relative permeability curves (b) Reservoir pressure in observation well for different gas relative permeability curves

Table 4: CO_2 Plume extension size over time (in the first layer) for different gas relative permeability curves

			Gas Relative Permeability				
			Base Case	Krg Low 2	Krg Low 1	Krg High1	Krg High2
CO_2 Plume Extension	5 Years after Injection	Minor Axis(ft)	2133	1867	2000	2133	2400
		Major Axis(ft)	2400	2133	2266	2533	2800
	50 Years after Injection	Minor Axis(ft)	2533	2133	2267	2667	2933
		Major Axis(ft)	4000	2800	3467	4267	4533
	500 Years after Injection	Minor Axis(ft)	2667	2400	2533	2800	2933
		Major Axis(ft)	4933	4133	4533	5067	5467

Maximum Residual Gas Saturation

Generally, drainage relative permeability curves are provided for the reservoir simulation model. When the maximum residual gas saturation is introduced, the imbibition gas relative permeability curve can be determined based on the drainage curve [10]. During CO_2 movement in the reservoir, water imbibition causes a portion of gas phase to be trapped in the pores (residual trapping). Therefore, when the maximum residual gas saturation increases, more gas is trapped, resulting in less mobile CO_2 and consequently a smaller CO_2 plume extension (Table 5). Changing maximum residual gas saturation has no significant impact on the reservoir pressure.

Table 5: CO_2 Plume extension size over time (in the first layer) for different maximum residual gas saturations

			Maximum Residual Gas Saturation(Hysteresis)			
			Base Case	0.05	0.1	0.2
CO_2 Plume Extension	5 Years after Injection	Minor Axis(ft)	2133	2133	2133	2133
		Major Axis(ft)	2400	2400	2400	2400
	50 Years after Injection	Minor Axis(ft)	2533	2533	2533	2400
		Major Axis(ft)	4000	4000	3867	3733
	500 Years after Injection	Minor Axis(ft)	2667	2800	2533	2533
		Major Axis(ft)	4933	4933	4800	4533

Brine Compressibility

In a closed geologic system, the amount of CO_2 that can be injected into the saline reservoir is mostly dependent on the availability of the additional pore space that can be provided due to brine compressibility [9]. Additionally, compressibility determines how much injected fluid contributes to reservoir pressure build up or brine volume change (also can be referred to as a change in brine density). As observed in Figure 8, an increase in brine compressibility results in lowering the maximum and stabilized reservoir pressures. For higher brine compressibility, injected CO_2 results in more changes in brine density rather than generating pressure build up in the reservoir. Changing brine compressibility shows no considerable influence on the CO_2 plume extension.

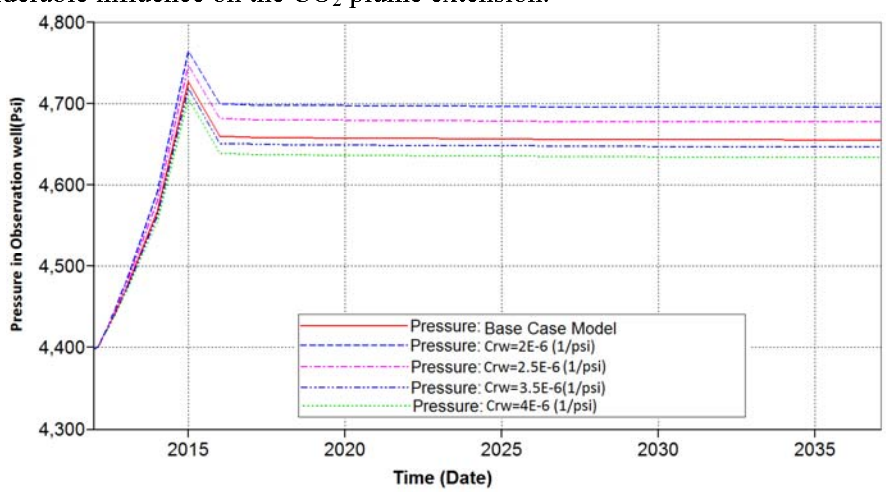


Figure 8: Reservoir pressure in observation well for different brine compressibility

Brine density

The impact of a change in brine density on the reservoir pressure can be analyzed by considering the fact that denser the brine is, the less compressible it is, allowing more pressure build up during and after CO_2 injection. As it is illustrated in Figure 9, the higher brine density contributes to more pressure gain for the reservoir (both maximum and stabilized pressures). The influence of the brine density on CO_2 plume extension is addressed by the driving mechanism that governs fluid movement in the reservoir. During CO_2 injection, viscous forces makes the CO_2 move forward, and after injection, buoyancy would be the dominant driving force. The density difference between brine and CO_2 determines the magnitude of the buoyant force [1]. Higher brine density results greater density differential and consequently, more buoyance force. Therefore an increase in brine density accounts for more buoyant force to be exerted to the CO_2 plume resulting in larger extensions (Table 6).

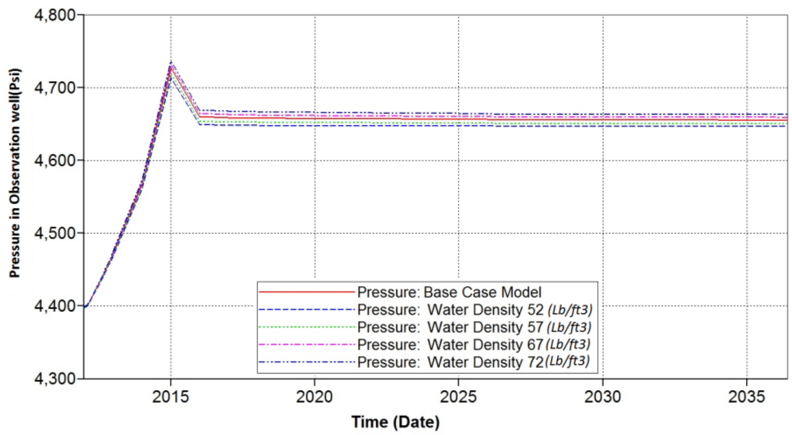


Figure 9: Reservoir pressure in observation well for different brine densities

Table 6: CO_2 Plume extension size over time (in the first layer) for different brine densities

			Brine Density(lb/ft3)				
			Base Case	52	57	67	72
CO_2 Plume Extension	5 Years after Injection	Minor Axis(ft)	2133	2133	2133	2133	2133
		Major Axis(ft)	2400	2267	2400	2533	2667
	50 Years after Injection	Minor Axis(ft)	2533	2533	2533	2533	2667
		Major Axis(ft)	4000	3467	3733	4133	4133
	500 Years after Injection	Minor Axis(ft)	2667	2533	2667	2800	2800
		Major Axis(ft)	4933	4667	4933	4933	5066

Boundary Condition

In this section, we assume that the saline reservoir in the Paluxy formation is not a closed system. A Fetkovich aquifer (which keeps the reservoir pressure constant at the reservoir boundaries) is assigned to the East, East- South and East-South-West edges of the reservoir (Figure 10). As shown in Figure11, reservoir pressure behavior in the open system is significantly different compared to what was observed in the previous sections. First of all, maximum reservoir pressure at the end of injection is much less (almost 200 psi) in the open systems. Secondly, the stabilized pressure reaches initial or native reservoir pressure after particular time.

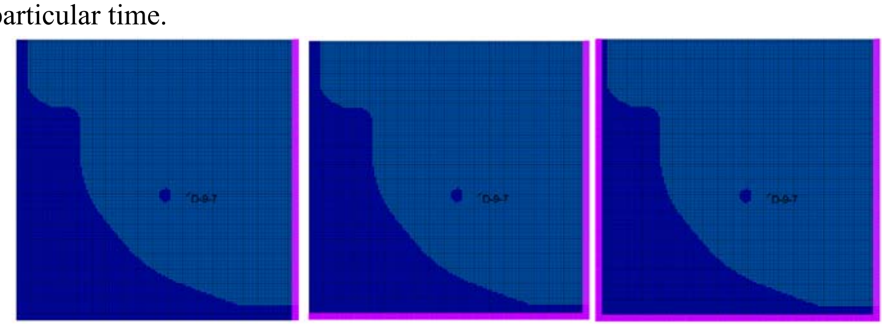


Figure 10: Different locations for constant pressure boundary (Fetkovich aquifer)

As the portion of reservoir boundary that is exposed to the constant pressure (Fetkovich aquifer) increases, less pressure build up is observed at the end of injection. Additionally, when more edges of the reservoir are connected to open aquifer, it takes less time that reservoir pressure reaches to the native conditions. Changing reservoir boundary conditions represents an insignificant effect on the CO_2 plume size (Table 7)

Table 7: CO_2 Plume extension size over time (in the first layer) for different boundary conditions

			Reservoir Boundary(Fetkovich Aquifer)			
			Base Case	East	East+ South	East+ South+ West
CO_2 Plume Extension	5 Years after Injection	Minor Axis(ft)	2133	2133	2267	2267
		Major Axis(ft)	2400	2400	2667	2800
	50 Years after Injection	Minor Axis(ft)	2533	2533	2667	2667
		Major Axis(ft)	4000	4000	4133	4133
	500 Years after Injection	Minor Axis(ft)	2667	2800	2800	2800
		Major Axis(ft)	4933	5066	5066	5066

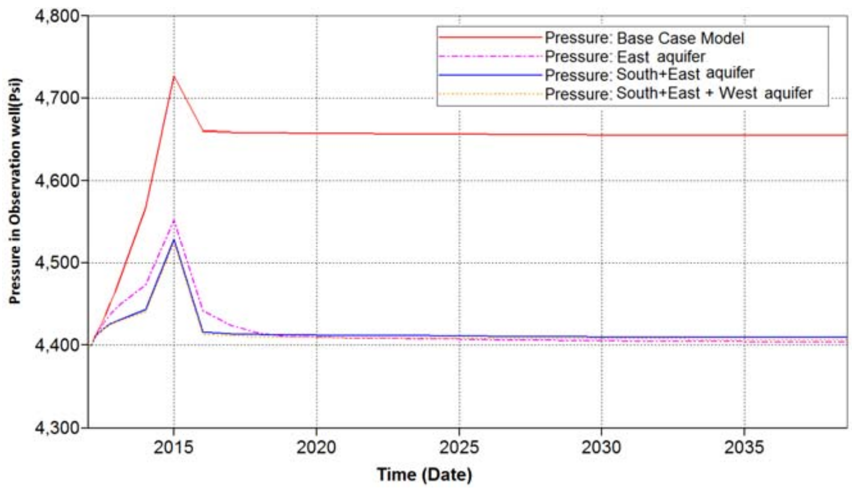


Figure 11: Reservoir pressure in observation well for different boundary conditions

Conclusions

A reservoir simulation model was developed to predict storage performance for CO_2 injection in the Paluxy saline reservoir of the Citronelle Dome. Sensitivity analyses were performed to study the impacts of reservoir uncertainty on the reservoir pressure in the observation well and CO_2 plume extension. The results of sensitivity analysis can be considered for risk assessment in addition to history matching the reservoir simulation model while actual Dome measurements (pressure data) are available. The main findings can be summarized as:

- Rock type (permeability) contributes to CO_2 injectivity, reservoir pressure and CO_2 plume extension significantly. Higher permeability represents more extensive CO_2 plume and less reservoir pressure gain. Also an increase in vertical to horizontal ratio leads to higher stabilized pressure and CO_2 plume extension.
- It is observed that an increase in gas relative permeability results in a higher stabilized pressure and a larger CO_2 plume extension. Additionally, the higher maximum residual gas saturation ends up with more residual trapping, accounting for a lower CO_2 plume extension.

- Brine compressibility plays a role in reservoir pressure build up, especially in a closed geologic system. When brine compressibility rises, we observe a decrease in stabilized reservoir pressure.
- Density of brine is the parameter that affects both reservoir pressure and CO_2 plume extension. Denser brine causes more buoyancy force, which drives CO_2 to move further and distributes in more area. Also higher brine density values contribute to more reservoir pressure build up.
- Changing the boundary condition of the reservoir from closed to constant pressure, affects reservoir pressure behavior significantly. When Fetkovich aquifers are placed at the edges of the reservoir, maximum pressure build up decreases notably. In addition to that, stabilized reservoir pressure comes back to native reservoir pressure after a while when injection is ceased.

Acknowledgment

Authors wish to acknowledge Advanced Resources International (ARI), US DOE, EPRI, and SSEB for providing the field data and Computer Modeling Group for providing the reservoir modeling and simulation software CMG-GEM™ for the case study that were conducted at West Virginia University.

Symbols

Kh= horizontal permeability, md
Kv=vertical permeability, md
φ = porosity

References

1. Charles R. Nelson, James M. Evans, Edward N. Steadman, John A. Harju, " Factors Affecting The Potential for CO_2 Leakage from Geologic Sinks", NETL Report, 2005
2. Cooper C.:" A Technical Basis for Carbon Dioxide Storage", CO_2 Capture Project, 2010
3. Denbury Resources, Incorporated, Plano, Texas,:" SECARB PHASE III ANTHROPOGENIC TEST Volume 1 of 2", Prepared for: Alabama Department of Environmental Management, 2010
4. Koperna G.J, Kuuskraa V.A.,Reistenberg D.E, Rhudy R., Trautz R., Hill G.,Esposito R.A," The SECARB Anthropogenic Test: The First US Integrated Capture, Transportation, and Storage Test" Carbon Management Technology Conference, 7-9 February 2012, Orlando, Florida, USA
5. Kuuskraa V.A.," Cost-Effective Remediation Strategies for Storing CO2 in Geologic Formations", SPE International Conference on CO2 Capture, Storage, and Utilization, 2-4 November 2009, San Diego, California, USA, 2009
6. Kuuskraa V.A., Koperna G.J., Schepers K.C., "CO2-Storage Engineering: Real Solutions to Real Problems", SPE International Conference on CO2 Capture, Storage, and Utilization, 10-12 November 2010, New Orleans, Louisiana, USA
7. Riestenberg D.E, Koperna G.J, Kuuskraa V.A., Esposito R.,Harisson K,Berry R.,Sparks j.,Rhudy R.," CO2 Sequestration Permitting at the SECARB Mississippi Test Site", SPE Americas E&P Environmental and Safety Conference, 23-25 March 2009, San Antonio, Texa
8. Sifuentes W., Blunt M.J., SPE, Giddins M.A.," Modeling CO2 Storage in Aquifers: Assessing the key contributors to uncertainty", Offshore Europe, 8-11 September 2009, Aberdeen, UK
9. Zhou, Q.; Birkholzer, J.; Rutqvist, J.; Tsang, C-F,:" Sensitivity study of CO2 storage capacity in brine aquifers with closed boundaries: Dependence on hydrogeologic properties", DOE Technical Report Server (U.S. Department of Energy), 2008
10. CMG software, Technical Manual