Pressure History Matching for CO2 Storage in Saline Aquifers: Case Study for Citronelle Dome

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Abstract
Carbon Capture and Storage (CCS) projects are subject to monitoring and verification programs to insure the storage is operating safely. Among different verification techniques, Reservoir Simulation and Modeling has proved to be a powerful tool for predicting underground storage behavior and consequently quantifying the risks associated with CO2 storage process. Reliability of the reservoir simulation models is highly dependent on how accurately simulation results can represent the actual field measurements. This article presents a workflow aimed at history matching a reservoir simulation model for a CO2 storage project.

In this study a saline reservoir which is located in Citronelle Dome at Mobile County (Alabama, US) is considered for history matching. This project is part of a CO2 storage research plan, conducted by the U.S. Department of Energy (DOE) and some industrial partners to demonstrate viability of commercial-scale storage of CO2 captured from an existing coal-fired power plant.

A Reservoir Simulation model for CO2 injection into the Citronelle saline aquifer was built using commercially available software (CMG-GEM). Field measurements of CO2 injection rates are assigned as the operational constraint to the model. In addition to the Injection rates, high frequency, real-time pressure data from two downhole pressure gauges imbedded in an observation well (833 ft. away from the injection well) is also provided. Several uncertain reservoir properties were tuned within reasonable ranges in order to find proper match between simulated pressure results and actual field measurements.

Introduction
Different types of potential risks (like leakage of CO2 or brine from the target zone) are generally associated with geological storage of CO2. Reservoir simulation and modeling in addition to implementation of appropriate monitoring techniques are considered to be expedient tools for CO2-risk management.

Reservoir pressure/temperature measurement (by down-hole gauge) has been widely used in the oil and gas industry for reservoir monitoring, well test analysis and history matching. In CO2 sequestration projects, real time reservoir pressure can deliver CO2 migration/leakage indications. Meckel et al. [11] interpreted permanent down-hole gauges (PDGs) data collected from single well at injection and above zone monitoring interval for CO2 injection at Cranfield field. They suggested almost no inter-formational communication (vertical) at the site based on analysis of pressure changes that were due to seven injection and nine production wells’ activities. Tao et al. [15] analyzed the same pressure and temperature data (collected from the monitoring well at Cranfield) and concluded very small leakage had occurred from the injection interval to the overlying formation. PDG data can also provide valuable information for reservoir simulation models.

Reservoir models can be used for assessment of CO2 storage capacity, well injectivity, CO2 trapping mechanisms, CO2 plume extension, and reservoir pressure build up. Sifuentes et al. [14] studied the effect of different physical parameters on the CO2 trapping in Stuggart formation (Germany). In order to determine the contribution of each parameter on CO2 trapping, they used reservoir simulation coupled with experimental design to perform sensitivity analysis. Torn et al. [16] carried out almost the same study (sensitivity analysis) on Mt. Simon sandstone (USA).
model to assess storage capacity and safety issues. Senel et al. [13] performed a reservoir simulation and uncertainty analysis study on CO\textsubscript{2} injection in the same formation (Mt. Simon sandstone -USA) incorporating more geophysical and petro-physical data. They investigated the effect of uncertainty on trapping mechanisms and CO\textsubscript{2} area of extension by providing probabilistic estimates. Masoudi et al. [10] coupled a geo-mechanical and simulation model in order to study feasibility and risks associated with CO\textsubscript{2} injection in M4 Field (East Malaysia). They determined maximum allowed reservoir pressure considering cap rock integrity for different CO\textsubscript{2} injection scenarios.

Reservoir simulation performance must be validated by checking if the model is able to regenerate the past behavior of a reservoir. History matching of oil and gas reservoir models are much more achievable (compared to CO\textsubscript{2} storage models) due to availability of large amount of production or/injection data. For CO\textsubscript{2} storage projects (especially in saline formations), reservoir history data are limited to injection rate in addition to down-hole injection/observation well pressure. Mantilla et al. [9] used probabilistic history matching software (Pro-HMS) which incorporated injection data from active (injection) and inactive (observation) wells. They implemented Pro-HMS to a synthetic model (CO\textsubscript{2} storage in aquifer with one/three injection and one observation wells) to obtain high permeability streaks by use of only injection and pressure data. In another history matching attempt, Krause et al. [7] conducted core flooding (brine/CO\textsubscript{2}) followed by numerical simulation of the experiment. They matched Simulation results with experimental data by calculation of permeability, using porosity and capillary pressure data. Xiao et al. [17] studied numerical simulation of CO\textsubscript{2}/EOR and storage in a pilot-5spot pattern unit of SACROC field. Since the target storage field had long term production/injection history, they performed history matching for five wells’ gas, oil and water production. They also predicted reservoir performance for three enhanced oil recovery (EOR) (injection) schemes and analyzed CO\textsubscript{2} storage capacity considering different CO\textsubscript{2} trapping mechanisms.

This study is one of the very few of its kind that aims to history match reservoir simulation model of CO\textsubscript{2} injection in Citronelle Dome (saline formation). The available field data for history matching are ten months of CO\textsubscript{2} injection rate as well as pressure data coming from two gauges installed in the observation well.

**Site Description and reservoir model**

CO\textsubscript{2} sequestration in the Citronelle Dome, AL, which is the third phase of Southeastern Regional Carbon Sequestration Partnership, aims at commercial-scale storage of CO\textsubscript{2} captured from Alabama power plant Barry (2,657 MW coal-fired with capture rate capacity of up to 550 tons per day ). Captured CO\textsubscript{2} is transferred through a 12 miles pipeline to the injection site which is located within Denbury onshore’s southeast Citronelle operating unit. Saline Paluxy sandstone (inter-bedded sandstone and shale formation), which is located at depths of about 9,450 to 10,500ft (TVD) is the target injection zone. CO\textsubscript{2} was planned to be injected at the rate of 500 tons per day for a maximum of three years.

There are two extensive shale layers that separate Paluxy formation from a saline reservoir at Washita Fredericksburg sand (at the top), and an oil reservoir at the Donovan sand (at the bottom). Stratigraphic horizons of the Jurassic through Tertiary age, including the Paluxy formation was provided with structural closure by Citronelle Dome (broad, gently dipping salt pillow)[3]. Well log analysis for the injection well (D-9-7) showed 17 sand layers as potential CO\textsubscript{2} storage and ten out of them (most extensive and thickest ones) were selected for the injection. The thickness of each sand body varies from 10 to 80 ft with total sand thickness of about 470 ft [5].

In order to generate reservoir simulation model, a comprehensive geological study was performed based on well log interpretation. This model includes 51 layers vertically (Each geological layers was divided into three simulation layers). Each layer includes 156625 grid cells with the dimension of each grid block is 133 ft by 133 ft in each XY direction. The process of building the geological and simulation model is described in detail in previous work [4].
History match

Locations of injection and observation wells are shown in Figure 1. CO₂ injection started on August 20th, 2012 with the rate of 918 Mcf/day. After that time, the injection rate increased with an oscillating trend (because of operative difficulties) until the end of September (2012) when it reached 9 Bcf/day (targeted rate). Then, the injection continued until August (2013) with a stable rate although periodic shut downs occurred. The daily injection rate from the beginning up to August 2013 is shown in Figure 2. These injection rates were used in the reservoir simulation model as operational constrains.

![Figure 1: Locations of the CO₂ injection, observation and backup injection wells in Citronelle Dome](image)

In the observation well (D-9-8#2) at Citronelle field (Figure 1), two Pressure Down-hole Gauges (PDG-5108/5109) are installed at different depths (9416 and 9441 ft TVD) in order to provide real time pressure and temperature readings during and after injection period. The pressure data is available from Mid-August of 2012 until August 1st 2013, recorded at every minute, listed in 1440 records daily. It should be mentioned that there were some gaps in the pressure records due to onsite computer failure. Since history matching the data on a minute basis was computationally expensive and time consuming, the pressure data was summarized by averaging over each day. The results of actual pressure data on a daily basis are illustrated in Figure 3.

![Figure 2: CO₂ injection rate history](image)  ![Figure 3: Daily pressure data from PDGs @ observation well](image)

Initially a base case reservoir model was developed considering reservoir properties that are summarized in Table 1. Porosity maps for each simulation layer were acquired by interpretation of 40 well logs. In this model, operational constrains were the actual CO₂ injection rates in addition to maximum bottom-hole pressure limit of 6,300 psi. The solubility of CO₂ in the brine was not considered in the base model. Block pressure for the grids corresponding to the PDGs were compared with the actual data. Simulated pressure data using the base model are plotted against actual pressure history in Figure 4.
Table 1: Reservoir parameters and properties (base model)

<table>
<thead>
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<th>Parameter</th>
<th>Value</th>
<th>Parameter</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Permeability (md)</td>
<td>460</td>
<td>Water density (lb/ft³)</td>
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</tr>
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<td>Water viscosity (cp)</td>
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<td>Kv/Kh (permeability ratio)</td>
<td>0.1</td>
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<tr>
<td>Residual water saturation</td>
<td>0.6</td>
<td>Pressure reference@9415 ft (psi)</td>
<td>4393</td>
</tr>
</tbody>
</table>

Figure 4: Actual pressure vs. simulated pressure in the base model.

The simulation data were matching neither the start point, nor the difference between the values of two gauges. Initial reservoir pressure was adjusted by changing the reference pressure to 4370 psi at the datum depth of 9416 ft. Pressure gradient between the PDGs was 0.62 psi/ft while between the simulation grids was 0.43 psi/ft. Based on this, it was concluded that the brine density should be set at a higher value in order to mimic the same pressure gradient. Brine density at the reservoir conditions can be calculated using the following equation:

\[
\tilde{\rho}_{br} = \rho_{br}^{0} \left[ 1 + c_{br} \left( p - p^{0} \right) \right]
\]

Keeping the brine compressibility unchanged, density of brine should be altered to 87 lb/ft³.

A thorough sensitivity analysis was performed to study the effect of several uncertain reservoir parameters on pressure behavior in the observation well [4]. The results of sensitivity analysis showed that permeability (rock type) significantly contributed to injectivity, CO₂ plume extension and reservoir pressure. Using available core data (not taken from Citronelle field) [4], porosity-permeability cross-plot was generated for the Paluxy formation (Figure 5). Available data from the core samples taken from injection well demonstrated the dominancy of conductive rock type in the vicinity of the injection area [5]. Also, vertical to horizontal permeability ratio was calculated to be 0.58 using core data analysis. Modification of pressure reference, brine density and permeability in addition to setting zero transmissibility between the sand and shale layers resulted in pressure predictions illustrated in Figure 6.
By Implementation of modified parameters in the model, prediction results resembled initial pressure and pressure gradient similar to the actual data. However, model pressure predictions didn’t follow PDGs pressure trend correctly. As shown in Figure 6, reservoir simulation results underestimated actual data during first four months after the injection, and overestimated the rest of pressure history. Additionally, simulation pressure drawdowns reached a stable trend much faster, compare with actual data. This behavior can be explained by the fact that higher permeability (in the model) resulted in lowering the time for pressure drawdown to reach a steady trend. Therefore, it was necessary to decrease the permeability in the model to adjust pressure drawdown behavior. On the other hand, lowering the permeability led to CO$_2$ injectivity reduction [4]. As results, reservoir model was divided into two regions: (a) grids in the vicinity of the injection zone (20*20 grids around the injection well) and (b) grids outside the injection zone (Figure 7). To correct model’s pressure drawdown trend, dual modification in reservoir permeability was done by decreasing permeability in region “a” and increasing permeability in region “b”.

As shown in Figure 8, although modifications in the model’s permeability improved pressure drawdown behavior, pressure predictions were overestimated considerably (compare with the actual PDG data). To lower pressure results, solubility of CO$_2$ in the brine (aqueous phase) was incorporated in the model [1]. More importantly, volume modifier was assigned to the grids at the east boundary of the reservoir (Figure 9). This accounted for the fact that reservoir boundary and volume might be bigger than what was assigned to the model. To develop the geological model, top and thickness of sand layers were picked for log data of 14 wells (crossing at injection well) and then correlated (Figure10). Due to the limited amount of information (just two well logs) at east side of the injection well, it was not possible to estimate the extension of the sand layer on that area. Therefore it was probable that more reservoir volume existed outside the boundary of the geological model. Adding more volume to the reservoir (sand layers) resulted in lowering the pressure prediction. After activating CO$_2$ solubility in the brine phase and tuning “volume modifier” a very good match between model results and actual pressure data with less than 0.001% average error was achieved (Figure 11).
Model Validation

History matched model showed very good precision in generating ten months of pressure results which resembled the actual field measurements. In order to study predictability of reservoir model, last three months (from August 1st to October 30th, 2013) of actual injection/pressure was unused in history matching and set aside for forecast validation (Figure 12 and Figure 13). During these three months, CO₂ was injected steadily according to targeted rate (9.48 Bcf/day). Injection experienced few shutdowns resulted in average rate to be 7.98 Bcf/day. Consequently, reservoir pressure increased during August 2013, followed by some drawdowns (due to no injection) in September 2013 and gentle buildup during the last month.
Considering the last three months of injection rate profile as the model’s operational constraints, simulation pressure predictions were obtained. Pressure prediction result has been plotted versus actual data in Figure 14. The prediction has precisely captured actual data trend such that the average errors for gauges 5109 and 5108 are 0.12% and 0.073% respectively which is quite satisfactory.

**Conclusion**

Ten months of CO$_2$ injection in the Citronelle’s Dome saline formation (Paluxy) was modeled by numerical reservoir simulation. The presence of two PDGs (Pressure Down-hole Gauge) at the observation (monitoring) well was considered in the model. A comprehensive sensitivity analysis was performed to assess the effect of uncertainty of several reservoir parameters on model’s pressure (at observation well) behavior. The analysis was used to match the history of actual field pressure data with model’s prediction by tuning reservoir parameters. By modification of brine density, permeability (in two reservoir regions), vertical to horizontal permeability ratio, CO$_2$ solubility in brine...
and reservoir volume, a reasonable match (less than .001% error) between actual and model’s pressure data was achieved. This model was validated using the last three months pressure-injection profiles and showed acceptable predictability. However, history matching of the numerical model is a non-unique solution to a complex problem; other combinations of reservoir parameter modification may possibly result in the same match between actual and model’s data.

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Symbols
\[ c_{br} = \text{brine compressibility, 1/psi} \]
\[ K = \text{Permeability, md} \]
\[ p = \text{reservoir pressure, psi} \]
\[ p^0 = \text{reference pressure, 14.7 psi} \]
\[ \rho_{br} = \text{brine density, lb/ft}^3 \]
\[ \rho_{br}^0 = \text{brine density @ reference pressure, lb/ft}^3 \]
\[ \phi = \text{porosity, \%} \]

References
1. CMG software, Technical Manual
2. Cooper C.:” A Technical Basis for Carbon Dioxide Storage”, CO₂ Capture Project, 2010


