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ScienceDirect
Energy Procedia 63 (2014) 3553 – 3562
Energy Procedia

GHGT-12

Assessment of CO_2 storage capacity and injectivity in saline aquifers – comparison of results from numerical flow simulations, analytical and generic models

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Abstract

Methodologies for the basin-scale evaluation of industrial-scale CO_2 geological storage in saline aquifers can include the use of analytical tools, generic reservoir simulations, as well as basin-specific flow modelling studies. The selection of appropriate tools is dependent on the scale of investigation. Comparison of the results from these methods for the assessment of basin-scale CO_2 geological storage in the Gippsland and Otway basins in Australia suggests that, at this scale, a combination of analytical tools in the form of equations for calculating injection pressure, radius of impact and storage capacity with generic numerical simulations may provide useful first-order predictions for storage capacity and injectivity. However, the development of multiple resources (petroleum, groundwater, coal) in the Gippsland Basin and regional compartmentalisation in the Otway Basin necessitates an additional, coarsely discretised basin-scale numerical model.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: CO_2 geological storage; brine displacement; reservoir simulations; pressure impacts

1. Introduction

Individual storage projects, from pilot to demonstration scale, require comprehensive, finely discretised static and reservoir models to account for detailed heterogeneity and constrain operational parameters (completion intervals,

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1876-6102
Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.384

injection rates) within a higher level of confidence than required for basin-scale assessments. However, basin scale assessments based on limited geological data are a useful tool for identifying target storage intervals and overall capacity. Building numerical models is time consuming and requires significant amounts of input data, which for many basins is limited. Evaluating these models can likewise be time consuming and difficult. Analytical tools can provide first-order results of, for example, maximum bottomhole injection pressure, reservoir capacity and radius of influence, from which to make comparisons and constrain more detailed numerical simulations.

To investigate the application of analytical tools, results from numerical and analytical models were compared for two basins. Both basins have numerical models available, of varying complexity. The Latrobe Group of the Gippsland Basin has been producing hydrocarbon (predominantly oil) since the 1960s and is known to be experiencing regional pressure decline [1]. Consequently, there is a large amount of geological and production data available and the numerical model reflects this level of complexity. The Paaratte Formation of the Otway Basin is suitable in places for CO_2 storage and is not a hydrocarbon target, however, it is highly faulted and the overall capacity of the basin is constrained by the volume of these compartments.

2. Modelling approaches

2.1. Analytical and semi-analytical models

In this study, we used MonteCarbon [2], software for estimating CO_2 injectivity into saline formations. It uses several analytical equations developed to predict the bottom-hole pressure of CO_2 injection wells in saline formations with various boundary conditions [2, 3]. The maximum injectivity is determined by setting the maximum bottom-hole pressure below the formation fracture pressure. Using the analytical models, a map of the pressure distribution in the formation can be generated and displayed using the visualisation module. It has several built-in correlations for calculations of CO_2 and brine properties. It also contains a database of maximum injectivity for different saline formation properties generated by the analytical solutions. The database covers different numbers of wells and a wide range of formation properties such as formation permeability, relative permeability, porosity, thickness, depth, area, wells' perforation ratio, etc.

The MonteCarbon software is also used to analyse the effect of uncertainty on CO_2 injectivity. The software will perform a Monte Carlo analysis based on the probability distribution of formation properties and different injection rates and uses a non-linear interpolation within an internal database to produce a probability distribution of required number of wells. CO_2 is injected at constant rate into a homogeneous and horizontal saline formation of constant thickness through fully- or partially-penetrating wells. The solutions are found for rectangular formations with either closed, infinite or constant pressure boundary conditions. They also include the effect of pressure relief wells on the formation pressure. The top and bottom boundaries of the formation are treated as closed. The viscosity and compressibility of the fluids are assumed constant. The effects of gravity and capillary pressure on flow are neglected. The analytical models developed in MonteCarbon were compared and validated with numerical simulations [3, 4].

2.2. Numerical multi-phase flow simulations

The numerical flow simulations were performed with the TOUGH2-ECO2N modeling software [5] using the PetraSim interface provided by RockWare. The simulation outputs for the Otway Basin were imported into the Roxar RMS package to allow visualisation of the CO_2 and pressure plume relative to the faults.

3. Case studies

3.1. Gippsland Basin

The Gippsland Basin in southeastern Australia has been identified as a potential candidate for large-scale geological storage of carbon dioxide [1]. The Latrobe Group forms a major freshwater aquifer in the onshore Gippsland Basin and contains hydrocarbon reservoirs in the offshore parts of the basin up to 6000 m below the seafloor. The Latrobe aquifer covers a total area of up to 40,000 km^2, of which approximately 7500 km^2 in the centre of the basin are located within an appropriate depth range for storing CO_2 as a supercritical fluid and are confined by the shales of the Lakes Entrance Formation. The thickness of the Latrobe aquifer in the Central Basin ranges between 400 and 2000 m, comprising variable amounts of sandstone, siltstone, shale and coal. Although aquifer permeability is highly variable and heterogeneous, the wide distribution of highly-productive petroleum fields, reservoir data and pressure history provide evidence that the Latrobe Group forms a hydraulically well-connected aquifer system with good reservoir quality. Due to the multiple usage of the Latrobe aquifer, one challenge for assessing carbon storage in the Latrobe aquifer is to account for the cumulative impacts of CO_2 injection and petroleum production on regional groundwater flow [6].

The Gippsland Basin simulations were described previously by Michael et al [4]. The 14 layer (heterogeneous) model covering the injection aquifer, overlying seal and overburden consists of approximately 50,000 cells with 3 km x 3 km cells of variable thickness. A simple, linear function for the relative permeability of CO_2 and water was used with minimum and maximum water saturation values of $S_{lmin} = 0.2$ and $S_{lmax} = 0.9$, respectively. Saturation limits for CO_2 were assumed to be $S_{gmin} = 0.1$ and $S_{gmax} = 0.7$. All vertical model boundaries and the bottom layer of the model were treated as no-flow boundaries, whereas the top layer was set to fixed pressure, salinity and temperature conditions.

Parameter ranges for the analytical model of CO_2 injection into the Latrobe aquifer are summarised in Table 1 and an example of a Monte Carlo simulation results assessing injectivity is shown in Figure 1. Only a few parameters that were deemed the most uncertain were changed for this example to demonstrate capabilities and outputs of the model. This specific example shows that for the modeled Latrobe aquifer parameters in 90% of the cases an injectivity of 1.25 Mt/year could be achieved with a mean single well injectivity of approximately 20 Mt/year (Fig. 1). The actual injection rate for a single well may need to be smaller depending on operational constraints related to compressor and pipeline capacity.

Table 1 Analytical modeling parameters for CO_2 injection into the Latrobe aquifer and assumed P90 and P10 values (normal distribution) for Monte Carlo simulations.

Parameter	Average value	P90	P10
Irreducible water saturation	0.3		
Gas endpoint relative permeability	0.4		
Corey's exponent for gas	3		
Corey's exponent for water	3		
Injection period (years)	20		
Formation initial pressure (MPa)	25	10	35
Brine salinity (g/l)	30		
Formation length (km)	120		
Formation width (km)	62.5		
Porosity (%)	20	10	30
Permeability (mD)	100	10	200
Thickness (m)	400	200	600
Rock compressibility (1/bar)	5e-05		

Brine compressibility (1/bar)	4.196e-05
Brine viscosity (cp)	0.423

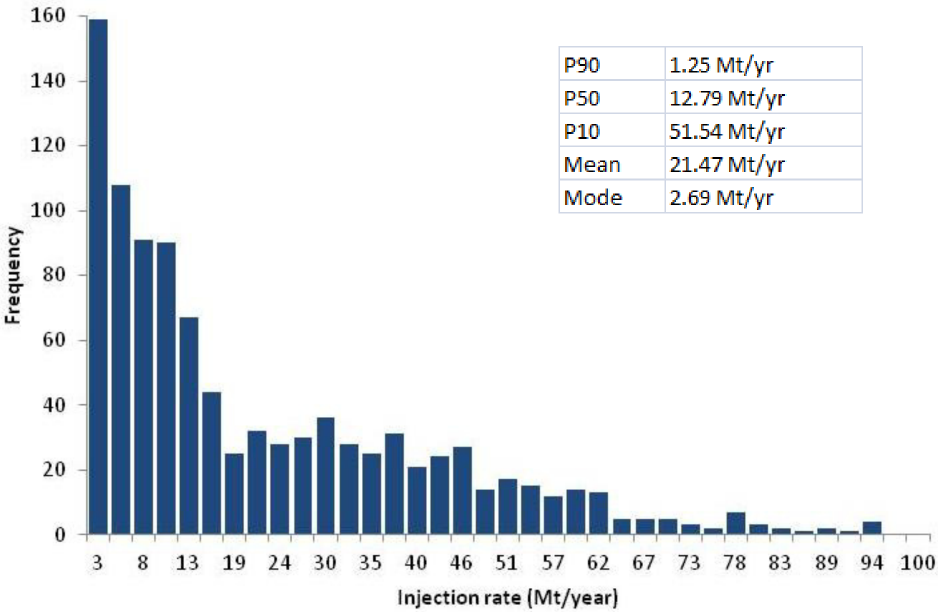

Fig. 1.Example of frequency plot for injectivity from Monte Carlo simulations (1000 trials) using parameters listed in Table 1 and assuming a fracture pressure gradient of 18 kPa/m.

Two-dimensional models were run for assessing the pressure impacts of industrial-scale CO_2 injection through multiple well locations. Figure 2 shows the simulated pressures in response to a combination of injection and production scenarios using the average values for aquifer parameters in Table 1. CO_2 is injected at five locations at a rate of 20 Mt/year into an aquifer from which petroleum is being produced. Petroleum production is modelled as volume-equivalent water production using volumes representative for production values in the Gippsland Basin. Simulated pressure after 50 years of production through 6 well locations and a production rate of 40,000 m^3/year at each location are shown for laterally unconfined conditions (Fig. 2a) and for a semi-closed aquifer (Fig. 2b). Maximum pressure decrease from the initial formation pressure of 25 MPa directly at the producers is approximately 1.5 MPa and 2 MPa for open and semi-confined conditions, respectively. However, the far-field pressure draw down of more than 1 MPa is more extensive in the semi-confined case, particularly in the east where there is no fluid flow and pressure equilibration across the boundaries.

The difference in pressure changes between the two cases of boundary conditions is less pronounced for concomitant CO_2 injection and petroleum production (Fig. 2c,d). The results show pressures after 20 years, but to account for the historical pressure decline, production rates per well are 100,000 m^3/year over this time period. The maximum simulated overpressure at the injection wells is approximately 1.5 MPa above initial conditions for both scenarios. Overpressures of more than 0.5 MPa do not extend farther than 20 km away from the centre of the injection wells and there is a noticeable cone of underpressures in the northeast corner of the model around producers 4, 5 and 6 (corresponding to the locations of the Snapper, Marlin and Tuna fields in Figure 3).

The analytical modeling results for the semi-confined conditions match reasonably well the numerical simulation results shown in Figure 3. A comparison of Figures 2b and 3a suggests that the assumption of closed flow boundaries along the northern, eastern and southern edges of the analytical model is representative of the Gippsland Basin conditions. Also, patterns and magnitudes of over- and underpressures are comparable, pressure in the TOUGH2 simulations (Fig. 3b) ranging from 2 MPa below initial conditions around the Snapper, Marlin and Tuna fields to 2 MPa above initial conditions in the area of CO_2 injection.

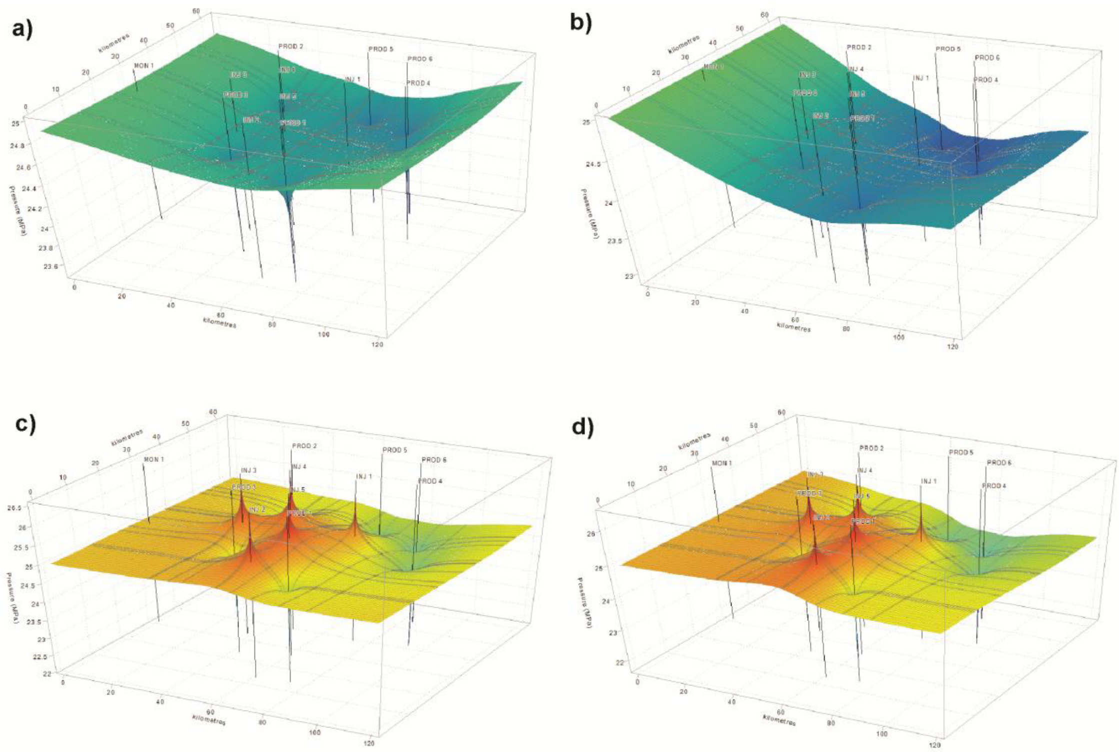

Fig. 2. Analytical simulation results of pressure response to fluid production and injection for open and closed lateral boundary conditions after: a) 50 years of production – infinite reservoir, b) 50 years production – closed N, E, S boundaries and constant pressure along the west boundary, c) 20 years of concurrent CO_2 injection and petroleum production – infinite reservoir, and d) 20 years of concurrent CO_2 injection and petroleum production - closed N, E, S boundaries and constant pressure along the west boundary.

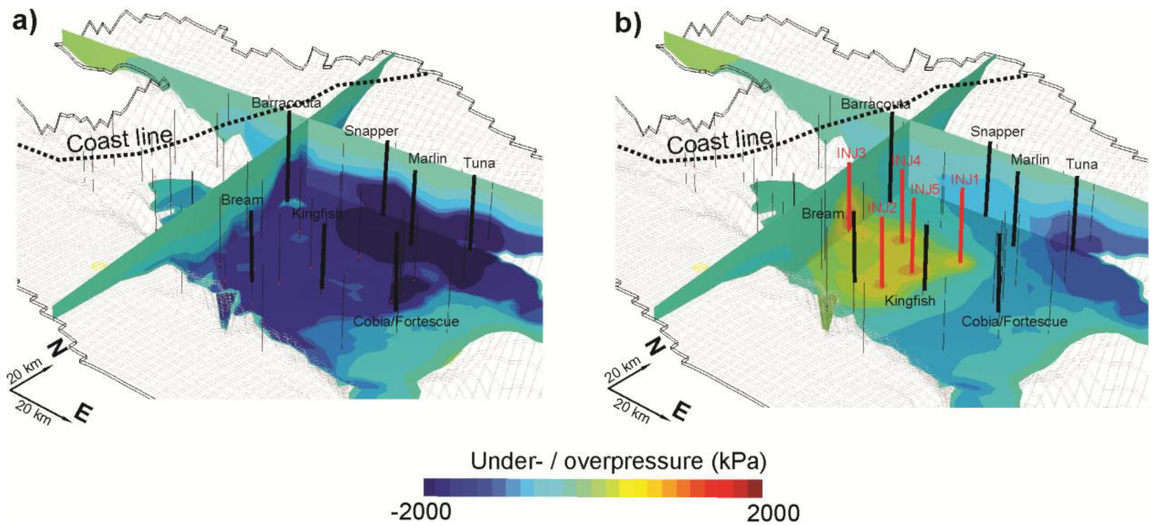

Fig. 3. Reservoir simulation results showing change in formation pressure in response to a) 50 years of petroleum production and b) 20 years of CO_2 injection after 50 years of petroleum production and 10 years injection/production overlap. Note: lateral scale and directions are only approximate due to model tilt; 10x vertical exaggeration.

3.2. Otway Basin

The Paaratte Formation of the Otway Basin is highly faulted however, the regional hydrodynamic assessment shows that the individual compartments are connected to the greater aquifer and that flow occurs either across or around faults [7]. The Paaratte Formation is a thick succession of interbedded fine- to coarse-grained quartzose sandstones and carbonaceous mudstones deposited in marine to coastal plain environments [8]. The Paaratte Formation is overlain by the Timboon Formation, a marine transgression, consisting of quartz sand, gravel and carbonaceous mudstone, generally unconsolidated [9]. Seal is provided by either intraformational shales or the Pebble Point Formation. Neither the Paaratte nor the Timboon formations are hydrocarbon targets and both contain low salinity water. Consequently, there is little data available to assess either the permeability or porosity. However, the deeper, Waarre Formation is an active hydrocarbon reservoir with many small fault bound accumulations and there is a significant amount of seismic data mapping the larger faults across the basin.

The numerical model we used of the Otway Basin consists of six homogeneous layers, 168 x 81 km and contains 82,236 active cells. Each cell is one square kilometre with the thickness of each layer varying from 50 m to over 1200 m, producing a wedge shaped basin, with depths up to 4500 m. The faults were imported from the geological model as separate facies and their properties assigned independently with the permeability set at either 0.01 mD (closed) or 500 mD (open). The top of the model is bound by the Dilwyn Formation, which is set as a fixed boundary with the low permeability Skull Creek Formation set as the lower boundary. The Otway Basin pinches out to the north, so the northern boundary is set as a no flow boundary. The east and west boundaries are approximately 50 km distant from the edge of the basin and are set as infinite acting, the southern boundary is approximately 100 km from the edge of the basin and is set accordingly. The temperature and salinity are constant. The total CO_2 injected was 1200 Mt injected through 6 wells over 30 years into the Paaratte Formation with vertical migration allowed into the Timboon Formation.

The inputs for the analytical and numerical models are shown in Table 2, and the injection and modelling wells located at the same coordinates. In the numerical software the radius of the well is represented by the area of the cell or cells through which injection occurs, in this case the cells were 1 km^2 with variable thickness. The analytical model used a well radius of 0.1m. In both models the injection interval was set at 50 m. Consequently, it is not possible to directly compare the bottom hole pressure (BHP) predicted by the analytical and numerical models with the numerical value being underestimated. To allow a reasonable comparison to be made between the two models, four monitoring wells were included at some distance from the injection wells (Fig. 4).

Similarly, the Otway Basin is wedge shaped and the depth varies across 4500 m with the pressure increasing hydrostatically. The numerical model is able to account for this variation in depth and the associated pressure changes. The analytical solution considers a flat, rectangular box with uniform pressure and requires input of an average thickness. The average thickness was estimated from the volume of the injection layer and taking into account the wedge shape of the model. However, this required an understanding of the structure of the injection layer across the basin, which in this case, came from the numerical model.

Table 2 Parameters used for analytical and numerical modelling

Parameter	Numerical Input	Analytical Input
Irreducible water saturation	0.4	0.4
Gas endpoint rel perm		0.4
Corey's exponent for gas		3
Corey's exponent for water		3
Residual Gas Saturation	0	0
Injection Period (years)	30	30
Injection Rate	210 kg/sec distributed across the perf. interval	40 M tonnes/year
No. of wells	6	6
Temperature (°C)	25-isothermal	25-isothermal
Basin Dimensions (km^2)	13608	13608
Anisotropy	0.1	0.1
Thickness (m)	Variable	500
Perforation Interval (m)	50 at top of formation	50 from bottom
Permeability (mD)	500	500
Porosity	0.1	0.1
Salinity	0	0
Well Radius (m)	1000	0.1
Boundaries	Infinite	Infinite
Rock compressibility (Pa^{-1})		$5x10^{-9}$
Rock density	2600 kg/m^3	
Brine compressibility (Pa^{-1})		$4.445x10^{-9}$
Brine viscosity (Pa.s)		$0.867x10^{-3}$
Dry gas zone rel. perm.		0.8

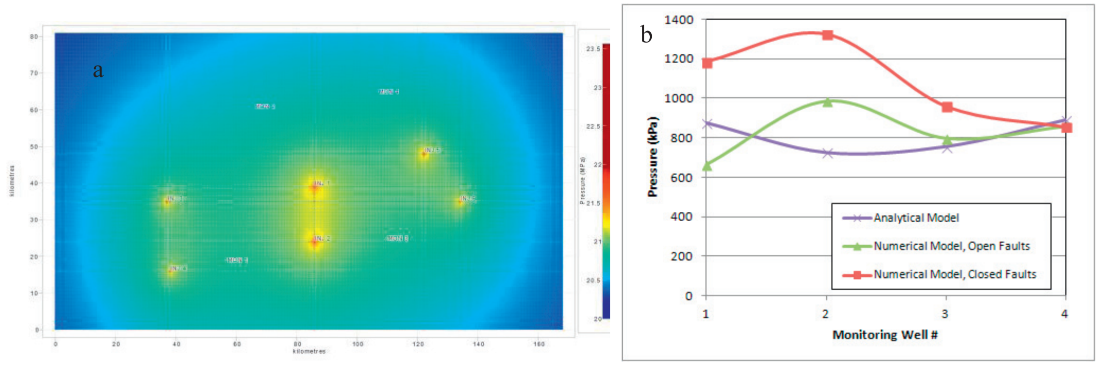

Fig. 4 a) Distribution of pressure and location of injection and monitoring wells post injection, analytical model. The cut-off pressure is 22 MPa and is therefore equivalent to the pressure difference of 2 MPa in Fig. 5. b) Comparison of the pressure measured at each monitoring well

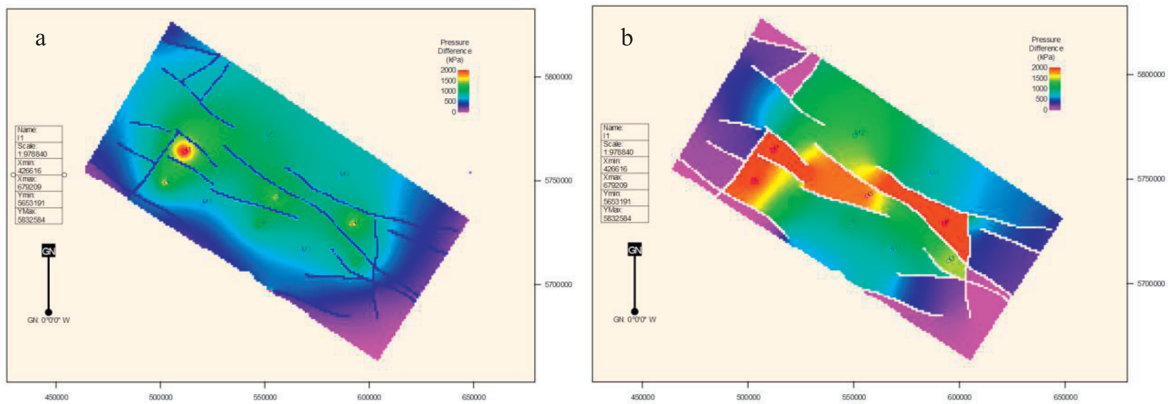

Fig. 5 Distribution of pressure from the numerical simulations a) fault permeability 500 mD b) fault permeability 0.01 mD

Table 3 Comparison of pressure buildup at the four monitoring wells (relative to the initial pressure). The thickness of the injection layer is included.

Monitoring Well	**Actual Thickness (m)**	**Analytical Model (kPa)**	**Numerical Model, Open Faults (kPa)**	**Numerical Model, Closed Faults (kPa)**
M1	556	875	663	1185
M2	113	725	984	1323
M3	975	755	797	960
M4	304	890	857	855

The pressure buildup at the monitoring wells for the analytical (Fig. 4a) and the numerical solution with no faults (Fig. 5a) is in good agreement, with the maximum difference 259 kPa at M2 (Table 3, Fig. 4b). M2 also has the thinnest reservoir thickness relative to the analytical model. Both models indicate that the Otway Basin could contain 1200 Mt of CO_2 with a small pressure build up away from the injection wells. However, the geological model of the Otway Basin shows a difference in thickness across the injecting units of up to 1000m. Consequently, the pressure build up at any individual point (or well) is dependent on the relative difference between the pressure (depth) and thickness. The thickness of the permeable layers, although it also has large error bars, is more constrained in the numerical version than in the analytical. In addition, although the permeability of the surrounding sealing units was assumed at $1x10^{-5}$ mD these layers experienced a degree of pressure build up in the numerical model which was not accounted for in the analytical.

The introduction of heterogeneity into the numerical model in the form of faults, changes the pressure distribution across the basin significantly (Fig. 5b). The pressure build up is concentrated around and constrained by the dimensions of the compartments and the pressure change seen in the monitoring wells is higher than predicted for both models without faults. The two wells most exposed to the injection sites, M1 and M2 exhibit the biggest difference when compared to both the analytical and numerical homogeneous models.

Summary and conclusions

The results from the analytical and numerical modelling were comparable for both basin assessments. The Gippsland Basin numerical model accounted for heterogeneity and hydrocarbon production. The analytical predictions were not significantly impacted by the absence of heterogeneity and were able to account, at least partly, for the hydrocarbon production. The Otway Basin model did not contain heterogeneity and the analytical models were able to predict the pressure build-up across the basin within a few hundred kPa. However, when heterogeneity in the form of compartments was added, the analytical models were not suitable for predicting the pressure distribution and build-up.

Advantages the analytical modeling approaches used in this project compared to numerical reservoir simulations for the assessment of CO_2 injectivity and pressure build-up are:

- No gridding necessary or smaller number of grid blocks and simple parameterisation table results in a quick model set up;
- Small computational times allow for effective use of Monte Carlo simulations;
- Easy to change and to test different boundary conditions and model parameters;

Disadvantages of analytical techniques are:

- Cannot represent heterogeneities like varying porosity/permeability distribution or faults;
- Cannot simulate varying stress periods for injection and/or production;
- Simulation of a single, horizontal reservoir layer of uniform thickness;

However, when assessing basin scale storage potential the uncertainty associated with heterogeneity and the locations and injectivity of potential wells suggests that the analytical suite of tools may be a more efficient method to determine the sensitivities and boundaries associated with this scale of investigation. Analytical models may also provide regulators with an effective means for an initial assessment of numerical models results provided by operators without having to perform complicated and time consuming reservoir simulations themselves.

Acknowledgements

We would like to acknowledge the funding provided by the Australian Government through its CRC Program to support this CO2CRC research project.

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