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Analysis Of The Use Of Superposition For Analytic Models Of CO2 Injection Into Reservoirs With Multiple Injection Sites

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Summary

Large scale CCS is crucial to reduce the cost associated with minimizing climate change. Energy system models should thus include CCS at regional or global scale with a proper evaluation of pressure limitations and injectivity, which are currently ignored. To this aim, the use of simplified analytical solutions is highly useful because they provide fast evaluation of pressure and plume evolution without the computational costs of the numerical models. Application of these solutions to assess storage capacity has been extended to cases of multiple well injection. In these cases, the pressure build-up is evaluated as the superposition of the analytical solutions for pressure associated with each individual well. In this study we investigate the validity of the superposition procedure, given the non-linearity of the multiphase flow. We quantify the error associated with the application of superposition to estimate reservoir pressurisation in different scenarios of.multi-site CO2 injection in a large regional aquifer. We find that the error associated with the adoption of this procedure increases with time and with the number of wells in proportion to the area invaded by CO2 in the reservoir.

Introduction

The widespread adoption of large scale carbon capture and storage (CCS) is crucial to reduce the cost associated with minimizing climate change (Pye *et al*., 2017). The evaluation of costs at the regional or global scale requires the introduction of CCS into energy systems models. Current systems models with CCS ignore pressure limitations and injectivity. Full 3D numerical models of injection and plume migration are too computationally expensive. However, the use of simplified analytical solutions poses a significant advantage because they allow for a rapid assessment of the pressure response and the plume evolution to varying geological conditions and injection scenarios at multiple sites.

A number of analytical solutions have been proposed to calculate pressure build-up and plume evolution in response to CO_2 injection into a single well (e.g., Nordbotten *et al*., 2005; Mathias *et al*., 2008, 2011; Dentz and Tartakowski, 2009; Azizi and Cinar, 2013). Application of these solutions to assess storage capacity has been extended to cases of multiple well injection (Ghaderi *et al*., 2009; Joshi *et al*., 2016). In these cases, the pressure build-up is evaluated as the superposition of the analytical solutions for pressure associated with each individual well.

However, the adoption of such simplified models may incur two principal errors. The first is related to the accuracy of analytical solutions in predicting the pressure increase for single well injection. This depends on the characteristics of the problem – reservoir permeability, injected flow rate, etc. For example, the solution proposed by Nordbotten *et al*. (2005) - and further developed by Mathias *et al*. (2008) – is accurate when the pressure front is far ahead of the CO_2 front, applicable for most potential CO_2 storage sites. The second error involves the applicability of the superposition principle. This is theoretically invalid in the case of multiphase flow because of the non-linearity of the flow process. Even under the circumstance where CO_2 plumes are not interacting, i.e., when injection wells are sufficiently distant from each other, superposition applicability implicitly assumes that the reservoir is brine-saturated outside of a single CO_2 plume. This is of course untrue for the case of interest, of multiple plumes dispersed throughout the reservoir.

In this paper, we investigate and quantify the error associated with the application of superposition to estimate reservoir pressurisation in different scenarios of.multi site CO_2 injection in a large regional aquifer.

Methodology

We quantify the error due to the application of superposition using numerical simulations. In one group of simulations, we simulate the injection of CO_2 in N wells. We also simulate the injection into a single well and estimate the pressure field in the case of N wells by superposing this result on to itself. The comparison of the two pressure fields allows the estimation of the error associated with superposition application.

We assume a Cartesian configuration with a columns and rows of n wells, such that the total number of wells, $N=n^2$ (Fig.1). The distance between wells is assumed constant and equal to 200 m. We explore the error in the superposition approach for different scenarios with values of n changing from 2 to 5.

We use a square domain of 10 km on each side with the well pattern in the middle. The domain was chosen such that the pressure front does not reach the outer boundary over the duration of injection, i.e., simulating an infinite reservoir. The reservoir is considered homogeneous and isotropic with a constant thickness of 10 m, intrinsic permeability of 10 mD, porosity of 0.1 and rock compressibility of 10^{-10} Pa^{-1}. A constant flow rate of 50 m^3/d is injected into each well starting at the same time and lasting for 120 days. In the central part of the domain the grid dimension is 5m×5m, whereas a coarser grid with squared elements of 100 m a side is adopted for the external portion of the domain. A sensitivity analysis was performed on the gridding to ensure minimal numerical artifacts. Fluid density and viscosity are set as constant for both CO_2 and brine. Simulations are performed by means of the Eclipse 100 simulator.

Results

We analyse the difference between the numerical and the superposed solution by observing the maximum pressure build-up, which always occurs at the most inner well (Fig.1 – top panel).

The generation of multiple CO_2 plumes within the reservoir increases the fluid mobility in the reservoir because of a reduction in the average viscosity of the fluids. This is not captured using superposed analytic solutions which thus over estimate the pressure buildup in response to multiple well injection.

We estimate the relative error related to the application of superposition as the difference between the superposed and the numerical solution normalized with respect to the numerical solution (Fig. 1 – bottom panel). The error is zero for small time until the pressure front originating in a well of interest intercepts a neighboring CO_2 invaded area. After that, the error increases with time scaling with the increase in area invaded by CO_2. The relative error increases with the number of injection wells, *n,* because the area of increased mobility (the area invaded by CO_2) increases with *n*.

Conclusions

The application of the superposition principle to estimate pressure build-up in the case of multiple well injection is valid only for small time. When the pressure front generated by each injecting well intercepts the CO_2 plumes generated by the other injecting wells the superposition principle fails. The error associated with the adoption of this procedure increases with time and with the number of wells in proportion to the area invaded by CO_2 in the reservoir. Evaluation of this error, appropriately scaled with respect to the characteristics of the problem, may correct the pressure build-up calculated by simplified superposed solutions.

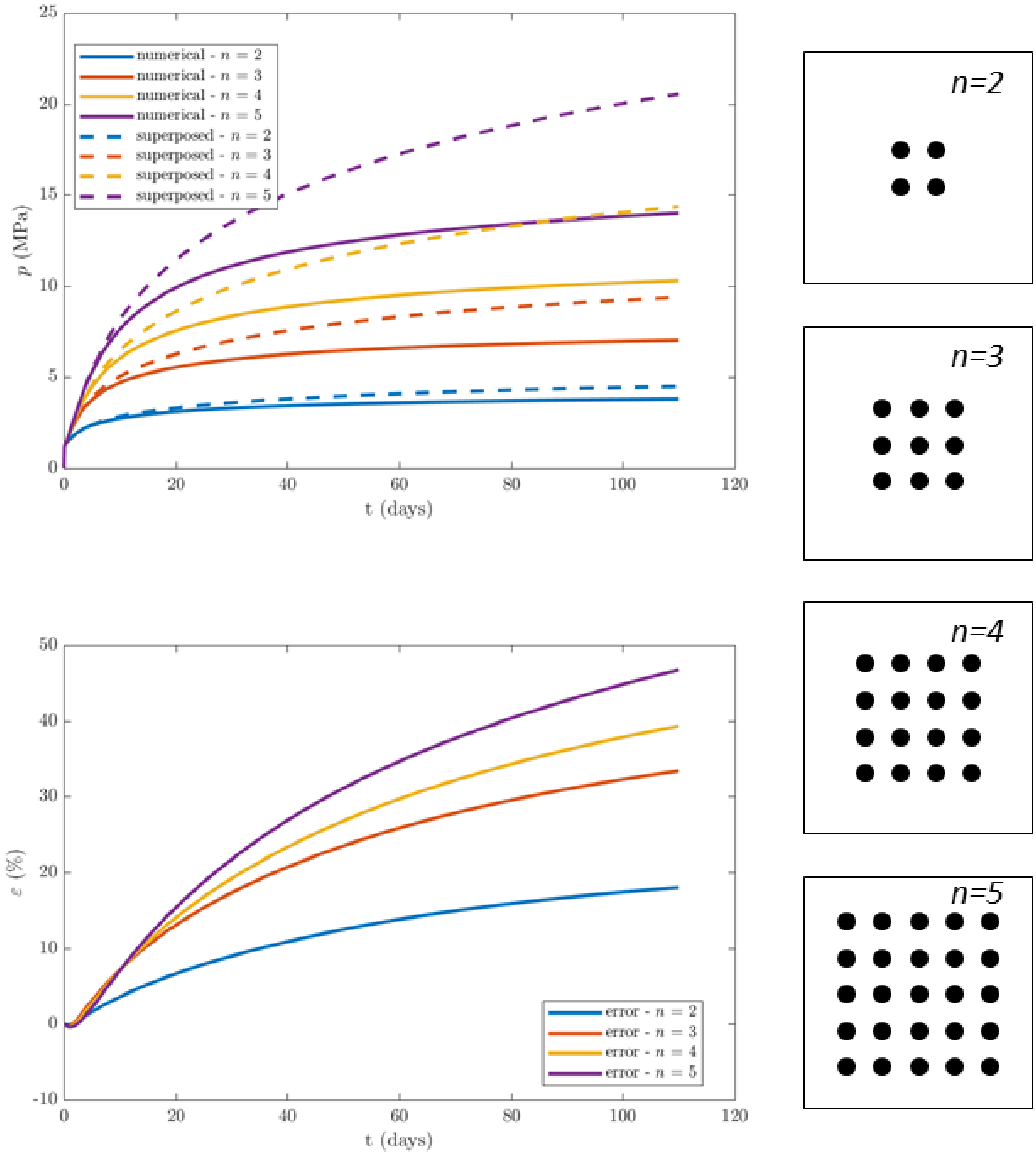

Figure 1 *Temporal evolution of pressure at the most inner well for different number of wells n. Solid lines represent the numerical solution with n injecting wells whereas the dashed lines represent the solution calculated as the superposition of n solutions of one injecting well. Relative error in the bottom panel is calculated as the difference between the superposed and the numerical solution normalized with respect to the numerical solution, i.e.,* $\varepsilon=(p_{sup}-p_{num})/p_{num}$.

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