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Stochastic and global sensitivity analyses of uncertain parameters affecting the safety of geological carbon storage in saline aquifers of the Michigan Basin

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ABSTRACT

Geological carbon storage (GCS) has been proposed as a favorable technology to reduce carbon dioxide (CO_2) emissions to the atmosphere. One of the main concerns about GCS is the risk of CO_2 escape from the storage formation through leakage pathways in the sealing layer. This study aims at understanding the main sources of uncertainty affecting the upward migration of CO_2 through pre-existing "passive" wells and the risk of fissuring of target formation during GCS operations, which may create pathways for CO_2 escape. The analysis focuses on a potential GCS site located within the Michigan Basin, a geologic basin situated on the lower Peninsula of the state of Michigan. For this purpose, we perform a stochastic analysis (SA) and a global sensitivity analysis (GSA) to investigate the influence of uncertain parameters, such as: permeability and porosity of the injection formation, passive well permeability, system compressibility, brine residual saturation, and CO_2 end-point relative permeability. For the GSA, we apply the extended Fourier amplitude sensitivity test (FAST), which can rank parameters based on their direct impact on the output, or first-order effect, and capture the interaction effect of one parameter with the others, or higher-order effect. To simulate GCS, we use an efficient semi-analytical multiphase flow model, which makes the application of the SA and the GSA computationally affordable. Results show that, among model parameters, the most influential on both fluid overpressure and CO_2 mass leakage is the injection formation permeability. Brine residual saturation also has a significant impact on fluid overpressure. While influence of permeability on fluid overpressure is mostly first-order, brine residual saturation's influence is mostly higher-order. CO_2 mass leakage is also affected by passive well permeability, followed by porosity and system compressibility through higher-order effects.

1. Introduction

The Earth's atmosphere is experiencing global climate change caused by increasing greenhouse gas concentrations. Carbon dioxide (CO_2) is the most important greenhouse gas produced by human activities (Solomon et al., 2007). In the last decade, geological carbon storage (GCS) has been identified as a promising technology for reducing CO_2 emissions to the atmosphere. Candidate storage formations include depleted oil and natural gas reservoirs, unmineable coal seams, and deep saline aquifers (Bergman and Winter, 1995; Ruether, 1998; Bachu, 2003). The latter represent potential alternatives to the lack of petroleum fields and constitute 60% of the estimated storage capacity worldwide (International Energy Agency, 2008). GCS in saline aquifers involves the injection of supercritical CO_2 into deep brine-saturated formations. Supercritical CO_2 is less dense and less viscous than the brine residing in saline formations, which causes gravity override as well as viscous fingering. Thus, supercritical CO_2 tends to migrate upwards driven by buoyancy unless low-permeable layers, or caprock, stops its vertical movement. However, if the injected CO_2 finds a potential leakage pathway through the caprock, it may adversely affect shallow fresh groundwater resources or even reach the land surface.

Sealing features of the caprock overlying the injected formations are critical elements for the effectiveness and safety of GCS operations. Nevertheless, unlike petroleum reservoirs, saline aquifers have never contained oil or gas. Consequently, there are less data

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associated with saline aquifers than petroleum reservoirs. In addition, information about the sealing properties of the caprock might be scarce or nonexistent. Typically, physical properties of potential candidate GCS sites are highly uncertain. Host rock permeability, spatial distribution of potential leakage pathways, and increase of fluid pressure in the injected formations may directly influence CO_2 leakage. Leakage pathways may also be created during the CO_2 injection process due to caprock fracturing associated with increased pore pressure and the ensuing reduction in effective stress. Therefore, assessing the risk of CO_2 leakage given the uncertainty on these parameters is vital prior to the implementation of GCS systems.

Carbon injection into deep saline aquifers involves complex processes of two-phase flow in confined geological formations, which make its modeling a demanding endeavor. Complexities associated with multiphase flow and transport processes, such as non-linearity, induced fingering, and convective mixings, create the need for computationally efficient assessment approaches. Several analytical and semi-analytical solutions have appeared in the literature (e.g., Saripalli and McGrail (2002); Nordbotten et al. (2005a); Gasda et al. (2008); Dentz and Tartakovsky (2009); Vilarrasa et al. (2010); Mathias et al. (2011)), which rely on a number of simplifying assumptions. The main advantage of analytical and semi-analytical models is that they allow simulations to be performed in a very short central processor unit (CPU) time (of the order of seconds), which makes stochastic analyses (SAs), and global sensitivity analyses (GSAs) requiring on the order of thousands of model runs computationally viable.

Risk assessment is an important tool for decision making during the initial stages of GCS projects. Some algorithms have been developed to predict performance and risk of GCS systems (e.g., LeNeveu, 2008; Stauffer et al., 2008; Oldenburg et al., 2009; Dobossy et al., 2011), in which potential candidate sites are selected for evaluation of their safety and effectiveness. Several studies have been published that statistically analyze the uncertainty of leakage associated with parameters of the injected aquifer in a GCS system. For example, Celia et al. (2009) investigated the influence of the injection depth on leakage risk and showed that this risk decreases when injection depth increases.

CO_2 injection performance and sequestration efficiency have also been investigated. For example, Celia et al. (2011) found that CO_2 injection rates are reduced by higher brine residual saturations and are influenced by the relative permeability of CO_2. Gupta and Bryant (2011) found that more CO_2 trapping is achieved when the gravity number (i.e., the ratio between buoyancy and viscous forces) is low, leading to enhanced lateral displacement of the CO_2 plume. On the other hand, high gravity numbers lead to stronger gravity override, resulting in both less trapping of CO_2 and less contact between the CO_2 plume and ambient brine. Middleton et al. (2012) showed that uncertainties from permeability, porosity, and formation thickness significantly affect capacity and cost calculations.

Studies that analyze the uncertainty of leakage associated with abandoned wells can also be found. Kopp et al. (2010) conclude that increased risk of leakage is produced by a longer injection time, smaller distance between injection wells and leaky wells, higher permeability anisotropy, higher geothermal gradient, and shallower depth. In order to show that potential leakage depends on formation properties, as well as the location and the number of leaky wells, Nogues et al. (2012) conducted a Monte Carlo simulation where the main uncertainty was the effective well permeability.

Alternative methods for quantifying uncertainty by stochastic simulation can be found, for example, in the works of Oladyshkin et al. (2011) and Walter et al. (2011). Both studies used an integrative probabilistic collocation method (Wiener, 1938; Li and Zhang, 2007) to reduce the computational cost associated with stochastic approaches. Specifically, Oladyshkin et al. (2011) compared the probabilistic collocation method to a Monte Carlo approach as a risk assessment tool of CO_2 storage. Walter et al. (2011) used this method to study the pressure increase in a channel system during injection of CO_2.

Mathias et al. (2013) applied a local sensitivity analysis of permeability, porosity, and relative permeability parameters based on data drawn from the literature on 25 formations. The sensitivity analysis addressed the impact of these parameters on the ratio between the CO_2 injection rate and the down-hole fluid overpressure – or injectivety – at the end of a prescribed injection period that is likely to cause fissuring of the formation. They showed that relative permeability parameters have a significant impact on aquifers of large extent, whereas, the impact of compressibility and porosity is more important in “closed” compartmentalized aquifers. A local sensitivity analysis on the long-term behavior of CO_2 in a multilayered aquifer was conducted by Kano and Ishido (2011), who showed that, in the long-term, the most influential parameters are geothermal gradient, layer thicknesses, capillary pressure, relative permeability, and permeability. Aoyagi et al. (2011) presented an example of a local sensitivity analysis of productivity index and fault permeability affecting the leakage of CO_2 through wells or faults. They found that the fault permeability value is more relevant when leakage starts. Zhao et al. (2010) determined that CO_2 dissolution increased when the vertical-to-horizontal permeability ratio, critical gas saturation, or brine salinity are decreased, and when brine saturation is increased.

GSA (Saltelli, 2008) differs from the local sensitivity analysis in that GSA explores the whole parameter space and is able to rank parameters according to their importance. GSA methods include methods, such as Fourier amplitude sensitivity test (FAST) (Cukier et al., 1978; Saltelli et al., 1999; Saltelli, 2008), Morris analysis (Morris, 1991), and Sobol’ indices (Sobol’, 2001). These last two methods have been applied recently by Wainwright et al. (2013) to investigate the complementarity of GSA and local sensitivity analysis in a hypothetical GCS site located in the Southern San Joaquin Basin in California, USA. Another option to compute sensitivity measures when observations are available is the Generalized Likelihood Uncertainty Estimation (GLUE) (Beven, 1993). One example of the use of GLUE to produce sensitivities measures for each parameter based on Kolmogorov–Smirnov statistic can be found in McIntyre et al. (2005).

All these studies investigate uncertainties of multiple factors to aid the decision making of best injection strategies. The aim of this study is to provide an understanding of the main sources of uncertainty that affect leakage through potential escape pathways and fluid overpressure variability, thereby, identifying where data collection efforts should be directed to improve the characterization of a candidate site for GCS. With this purpose, we conduct SAs and GSAs to investigate the effect of several parameters – such as permeability and porosity of injection formations, passive well permeability, system compressibility, brine residual saturation, and CO_2 end-point relative permeability – on (i) the maximum fluid overpressure produced by carbon injection and (ii) the mass of CO_2 that migrates into overlying formations through passive wells in relation to the total mass of injected CO_2. The main goal of the SA is to estimate the probability of fracturing the caprock, and the probability of leaked mass to exceed predefined threshold values. In carrying out the GSA, we apply the extended FAST method (Saltelli et al., 1999), which captures not only the uncertain parameters having more influence on the model output, but also the interaction effect among these parameters. In all analyses, CO_2 injection is simulated using ELSA–IGPS, a semi-analytical model developed by Cody (2014), which builds upon the semi-analytical solution of Celia and Nordbotten (2009) and Nordbotten et al. (2009). These