Case study: trapping mechanisms at the pilot-scale CO\textsubscript{2} injection site, Nagaoka, Japan

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Abstract

In this paper, we present the results of geophysical and geochemical observations at the Nagaoka site, where the first Japanese project on CO\textsubscript{2} geological storage is currently underway. We collected formation water and rock samples from the reservoir, and conducted laboratory experiments to investigate the seismic wave response and geochemical reactions due to the CO\textsubscript{2} injection under simulated in situ conditions. The results of time-lapse crosswell seismic tomography indicate an area of P-wave velocity decrease due to CO\textsubscript{2} saturation, and the CO\textsubscript{2}-bearing zone near the injection well expanded clearly along the formation up dip direction during CO\textsubscript{2} injection. The presence of CO\textsubscript{2} was also identified by induction, sonic and neutron logging at the observation wells. The results of geochemical reactions demonstrated the potential of reservoir sandstones at the Nagaoka site for the effective solubility, ionic, and mineral trapping of CO\textsubscript{2}.

Keywords: Trapping Mechanisms, Geochemical Reaction, Residual Gas Saturation, Saline Aquifer Storage, X-ray CT

1. Introduction

Sequestration of CO\textsubscript{2} into saline aquifers has been proposed as one of the most practical options for reducing CO\textsubscript{2} emissions into the atmosphere. A number of pilot and commercial CO\textsubscript{2} storage projects are underway or proposed. The Sleipner project, operated by Statoil in the North Sea about 250 km off the coast of Norway, is the first commercial scale project dedicated to geological CO\textsubscript{2} storage in a saline formation (IPCC, 2005). The CO\textsubscript{2} from Sleipner West Gas Field is separated, then injected into a large, deep, saline formation 800 m below the seabed of the North Sea. The saline formation into which the CO\textsubscript{2} is injected is a unconsolidated sandstone reservoir about 800–1000 m below the sea floor. The formation also contains secondary thin shale layers, which influence the internal movement of injected CO\textsubscript{2}. The top of the formation is fairly flat on a regional scale, although it contains

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numerous small, low-amplitude closures. The overlying primary seal is an extensive, thick, shale layer. This commercial-scale project was established to monitor and research the storage of CO2.

In comparison to the offshore location of the Sleipner Project, the Japanese Nagaoka project undertaken looks at the geophysical monitoring of CO2 injection in an onshore saline aquifer. The CO2 was injected into a thin permeable zone of the reservoir at 20-40 tonnes per day. The CO2 injection started on July 2003 and ended on January 2005. The total amount of injected CO2 is about 10,400 tonnes. The pilot-scale demonstration allowed an improved understanding of the CO2 movement in a porous sandstone reservoir (Xue et al., 2006). The Nagaoka pilot project demonstrated that CO2 can be injected into a deep saline aquifer without adverse health, safety or environmental effects. The Nagaoka project also provides unique data to develop economically viable, environmentally effective options for reducing carbon emissions in Japan. Several key questions need to be answered when the CO2 storage is to be undertaken worldwide (IPCC, 2005). Such as how is CO2 stored underground? What happens to the CO2 when it is injected? What are the physico-chemical and chemical processes involved? Injection of CO2 into the pore space and fractures of a permeable formation can displace the in situ fluid or the CO2 may dissolve in or mix with the fluid or react with the mineral grains or there may be some combination of these processes. This paper presents the results obtained from both field and laboratory to examine these processes and their influence on geological storage of CO2 at the Nagaoka site.

2. Geology and CO2 Injection

The pilot CO2 injection site is located at the Minami-Nagaoka gas and oil field, where Teikoku Oil Co. produces natural gas from the deep reservoirs (4700 m). The upper 1000 m of the geological section at the CO2 injection site consists of the Pliocene-Pleistocene Uonuma Group and Haizume Formation. The Uonuma Group is represented by two types of depositional cycles (Hoyanagi et al., 2000). One is shallowing-upward successions deposited on shelf to shoreface environments of wave-dominated delta system and is accompanied with transgressive lag at the base. The other is repetition of fluvial-estuary sediments. Depositional systems of the Uonuma Group changed from delta to estuary in the early Pleistocene. The Haizume Formation consists of shallowing-upward successions, which resulted from deposition in margin of wave-dominated delta system.

3. Trapping Mechanisms

(1) Physical trapping mechanism

Physical trapping to block upward migration of CO2 is provided by a layer of shale and clay rock above the storage formation. This impermeable layer is known as the “cap rock”. At the Nagaoka site, we collected drilled cores from the injection well and confirmed the effectiveness against the vertical migration of the injected CO2.

Figure 1 Pressure responses obtained at laboratory when injecting artificial formation water (upper) into the wet core sample and the supercritical CO2 (lower) into the saturated core sample under in situ conditions.
(2) Solubility and Ionic trapping mechanisms

Numerical studies for a CO2 injection into a deep aquifer showed that a significant amount of CO2 (up to 29 % of the total injected amount) would dissolve into formation water (solubility trapping) over the life time of the injection operation (Bachu et al., 1994). At the Nagaoka site we sampled the formation fluid by Cased Hole Dynamics Tester (CHDT) at one of the three observation wells where data from well loggings have revealed the occurrence of CO2 breakthrough (Mito et al., 2007). Results of chemical analyses showed the high HCO3-concentration compared to original formation water. The formation water sampling point was just bellow the CO2-bearing zone.

![Figure 2](image-url) Changes in HCO3- concentration of formation water collected pre- and post-CO2 injection stages.

![Figure 3](image-url) Changes in Ca, Mg and Fe concentrations of formation water collected pre- and post-CO2 injection stages (Mito et al., 2007).

(3) Mineral trapping mechanism

Chemical reactions between the dissolved CO2 and rock minerals form ionic species, consequently a fraction of the injected CO2 will be converted to solid carbonate minerals over millions of years. The mechanism is well known as mineral trapping, which is important for the long-term entrapment of the injected CO2 in geological sequestration.

(4) Residual gas trapping mechanism

As the CO2 migrating in the reservoir, the formation water comes back into the CO2 saturated zone. At the pore scale, CO2 is continuous in porous rocks. However, with a decrease in CO2 saturation, the continuous CO2 is disconnected at these points. Once a portion of the non-wetting CO2 is separated from the continuum, it is trapped...
because of capillary pressure. A CO2 bubble that occupies a large pore space can not pass through a pore neck because of the interfacial tension (Figure 4). This trap mechanism is referred to as residual gas or capillary trapping.

Figure 4 (A) Stages of capillary gas breakthrough (drainage), (B) Initially water-saturated sample, (C) Gas breakthrough, (D) Imbibition.

A series of laboratory measurements on residual gas saturation was carried out two sandstones with different porosity and pore geometry (Figure 5).

Figure 5 Pore size distributions in Berea sandstone (left) and Tako sandstone (right) by using Mercury Porosimetry.

Processes of drainage (supercritical CO2 injection) and imbibition (water re-injection) were visualized by a X-ray CT system (RITE, 2006).
4. Conclusions

Saline formations occur in sedimentary basins throughout the world, both onshore and on the continental shelves and are not limited to hydrocarbon provinces or coal basins. To understand the difficulties in assessing CO2 storage capacity in deep saline formations, we need to understand the interplay of the various trapping mechanisms during the evolution of a CO2 plume (IPCC, 2005).
Geochemical reactions observed at an early stage of CO2 storage at the Nagaoka site. Compared to the Sleipner site, the complex mineralogies are expected to enhance chemical reactions in the water-rock system of the reservoir and, as a consequence, have large potential in mineral trapping to fix CO2 as carbonate. Changes in compositions of the formation water sampled by the CHDT tool after the CO2 injection suggested that the solubility trapping is also an important mechanism in geological sequestration of CO2. Dissolution of plagioclase and chlorite has great potential for enhancing neutralization of the acidified formation water.

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REFERENCES
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