Abstract

CO₂ storage in depleted oil and gas reservoirs is considered to be one of the most practical options for reducing CO₂ emissions in the atmosphere and has been practiced in different locations worldwide. It is commonly believed that the sealing capacity of the caprock, which had successfully sealed the original hydrocarbon in the reservoirs for a geological time, is sufficient to prevent the injected CO₂ from escaping into the upper formations. However, the sealing capacity of the caprock is significantly reduced due to the much lower interfacial tension of the CO₂/water system than that of the hydrocarbon/water system when the hydrocarbons in a reservoir are replaced with the injected CO₂. As a result, the injected CO₂ may migrate through the caprock into the upper formations by volume flow. This paper examines the occurrence of the volume flow and measures the gas effective permeability for selected Weyburn Midale caprock samples after the caprock was broken through by the injection of CO₂. Calculations based on the measured gas effective permeabilities show that CO₂ leakage by volume flow is disastrous once it occurs. To avoid the volume flow, the caprock sealing pressure should be determined before the outset of a CO₂ storage project, and it should not be exceeded during the CO₂ injection process. The calculated storage capacity for a given void reservoir volume shows that once the reservoir pressure reaches a certain high level, a continuous increase in pressure is not effective in enhancing the storage capacity. However, much more capacity can be achieved by removing a portion of the remaining water in the reservoir.

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Keywords: Carbon dioxide sequestration; Depleted reservoir; Caprocks; Sealing pressure; Storage capacity

1. Introduction

It has been well accepted that the emissions of greenhouse gases due to booming fossil energy consumption since the last century has led to, or at least is related to, global warming. Among the various greenhouse gases, CO₂ is the greatest contributor, accounting for about 64% of the total greenhouse effects [1]. Therefore, reducing the concentration of CO₂ in the atmosphere is a major challenge in any greenhouse gas mitigation strategy.
Many approaches are already available for reducing CO₂ emissions to the atmosphere, such as increasing the efficiency of energy usage, increasing the utilization of CO₂ in industry and developing alternative energy resources, including wind, solar and nuclear energy. However, it is unlikely that these methods are sufficient to meet the target of CO₂ mitigation agreed on through the Kyoto Protocol. Therefore, new approaches, although more costly, have to be considered. One of these is CO₂ capture and sequestration [1,2], a process of removing CO₂ accumulated in the atmosphere by storing it permanently, or at least for a geological time scale, in places isolated from the atmosphere.

So far, the major sequestration methods being considered by the industrialized countries include deep ocean and geological sequestrations [1,2]. Of these, geological sequestration is believed to be the better option at this time and has already been practiced in different locations worldwide, such as the North Sea in Norway [3], the Weyburn in Canada [4] and the San Juan in the USA [1]. Geological sites that can be used for CO₂ sequestration mainly include depleted oil and gas reservoirs, deep saline aquifers, deep coal seams and salt caverns.

Deep saline aquifers probably have the largest potential in volume for CO₂ storage in geological media [1]. Nonetheless, they are not the best option at present from an economic standpoint because the necessary infrastructure, such as injection wells, surface equipment and pipelines, is nonexistent and developing them appears to be expensive. Currently, depleted or nearly depleted oil and gas reservoirs are the most appealing geological storage sites for CO₂ sequestration for the following reasons. First, the depleted oil and gas reservoirs have been extensively investigated during the oil exploitation stage. Second, the underground and surface infrastructure (wells, equipment and pipelines) is already available and could be used for CO₂ storage injection with minor or even without modifications [1,2]. Third, the injection of different gases, including CO₂, into oil and gas reservoirs as a technique to enhance oil or gas recovery has been widely practiced in the oil and gas industry. The experience gained can be adapted to guide the CO₂ sequestration injection. The sequestration of CO₂ in nearly depleted or even developing oil and gas reservoirs can simultaneously reduce greenhouse gas emissions and increase oil recovery. Such a project, the IEA GHG Weyburn CO₂ Monitoring and Storage Project, is being conducted in the Weyburn reservoir, Saskatchewan, Canada [4].

Studies on CO₂ storage in depleted oil and gas reservoirs have been extensively conducted in different aspects, such as underground migration simulation, geochemical modeling, long-term integrity and risk assessment, through which many questions have been addressed and answered [4]. However, investigations concerning the criteria of selection of the storage injection pressure for CO₂ sequestration in depleted oil and gas reservoirs have not been adequate even though the injection pressure has to be decided prior to implementation of any CO₂ sequestration project. Generally, the original reservoir pressure is often taken as the primary criterion, and the sequestration is considered to be safe as long as the pressure of the injected CO₂ is lower than the original reservoir pressure. This criterion is based on the assumption that the sealing capacity of the caprock that retained the oil and gas in the first place should be adequate to prevent the injected CO₂ from escaping through the caprock [1,2]. However, when the hydrocarbons (gas and oil) are replaced by the injected CO₂, the lower interfacial tension (IFT) of the CO₂/brine system relative to that of the original hydrocarbon/brine system results in a lower capillary sealing pressure of the caprock. Consequently, the sealing capacity of the same caprock is compromised in CO₂ storage and needs to be re-evaluated. Another criterion for the selection of CO₂ storage injection pressure is the fracture pressure of the reservoir rock or the caprock. This criterion assumes that the injection is safe provided that the fracture pressure is not exceeded. This is risky in practice when the sealing pressure of the caprock is lower than the fracture pressure. In such a case, the injected CO₂ will breakthrough the caprocks and leak into the upper formations before the fracture pressure is reached. Experimental results for different pelitic caprocks by Hildenbrand et al. [5] have shown that even for nitrogen, the breakthrough pressure is lower than the fracture pressure or the minimum principal stress. Given that, it may not be proper to use the fracture pressure as the maximum CO₂ storage injection pressure for reservoirs with pelitic caprocks.

Investigations of gas leakage through caprocks have been reported in the literature [5,6]. Two mechanisms were found responsible for gas migration into the adjacent formations [6]. One is compressible flow of the free gas phase, called volume flow or slow Darcy flow, and the other is molecular diffusion [6]. Between them, the volume flow would be more efficient once it occurs and, thus, more dangerous in CO₂ storage. The prerequisite for the occurrence of volume flow is for the pressure difference across the caprock to exceed the breakthrough pressure of the caprock. Although the volume flow could be prevented through selecting a proper storage...
injection pressure, further quantitative estimations of the migration rate caused by volume flow are important in understanding the basic scenarios and the related risks when the caprock is broken through. In other words, this may give answers to the following questions. Is the caprock sealing pressure worthy of consideration in CO₂ storage injection? What if the caprock is broken through? To these ends, this paper first elucidates that the sealing capacity of the same caprock may not be sufficient to seal the injected CO₂ in place. Then, the CO₂ volume flow when the pressure exceeds the caprock breakthrough pressure is examined, and the gas flow rate and the gas effective permeability are measured. Based on the measured effective permeability, calculations are made to evaluate the gas leakage through the caprock by volume flow. CO₂ leakage caused by molecular diffusion is also calculated and compared with the Darcy flow.

It should be mentioned that the possible leakage of the injected CO₂ may also occur through wellbores [4], but the focus of this paper is on caprocks only. How to maximize an oil or gas reservoir capacity for CO₂ storage is also discussed.

2. Caprock sealing capacity for CO₂

The sealing capacity of a caprock is indicated by the magnitude of the breakthrough pressure (or sealing pressure), defined as the differential pressure across the caprock that just exceeds the capillary pressure of a series of interconnected pore throats with an arbitrarily large size, thus causing the non-wetting phase to flow through these pore throats. In essence, the capillary pressure within the arbitrarily large pore throats determines the breakthrough pressure. Thus, the capillary pressure correlation can be used to analyze the breakthrough pressure [7]. The capillary pressure $P_c$ in a pore throat can be expressed as

$$P_c = \frac{2\sigma}{r_p} \cos \theta,$$

where $\sigma$ is the interfacial tension (IFT) between the non-wetting phase (gas or oil) and the wetting phase (water); $r_p$ is the radius of the pore throat and $\theta$ is the contact angle, the angle between the tangents of the two boundaries of gas/liquid and solid/liquid. Eq. (1) shows that for a given caprock, the capillary pressure of the largest interconnected channels or, eventually, the breakthrough pressure depends on the IFT and the contact angle. The contact angles would be close for CO₂ and other gases such as CH₄ and N₂ based on our previous measurements [7]. As a result, the breakthrough pressure is primarily determined by the IFT of the gas/water system for a given caprock. The ability of oil and gas to be retained in the reservoir over a geological time span is mainly attributed to the high sealing pressure of the caprock due to the high IFT and extremely small size of the caprock pore throats, especially for those abnormally high pressure oil and gas reservoirs (with reservoir pressure in excess of the hydrostatic pressure).

Once an oil reservoir has undergone a CO₂ injection process, a supercritical CO₂ phase will replace the original hydrocarbon and stay at the top of the reservoir formation in contact with the caprocks. The breakthrough pressure changes owing to the change of IFT at the interface of the non-wetting/wetting phase. Table 1 summarizes the literature results [8–11] of IFTs between different non-wetting/wetting phases at conditions close to those of typical oil and gas reservoirs. It is seen from Table 1 that the IFT of the CO₂/water system is much lower than that of oil/water systems and even lower than that of methane (or nitrogen)/water systems. Accordingly, the breakthrough pressure of the same caprock is to be reduced proportionally when

<table>
<thead>
<tr>
<th>Systems</th>
<th>Conditions</th>
<th>IFT (mN/m)</th>
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<tbody>
<tr>
<td>Medium oil/water [10]</td>
<td>&gt;6.9 MPa, 54.4–81.1 °C</td>
<td>30–35</td>
</tr>
</tbody>
</table>
**3. Characterization of gas flow through caprocks**

When the differential pressure across the caprock exceeds the breakthrough pressure because CO$_2$ injection has raised the reservoir pressure, a continuous gas volume flow will finally occur. In this section, the volume flow of gas through caprocks was investigated with caprock samples collected from the Weyburn oilfields. Then both the gas absolute permeability and the effective permeability when water exists were determined, and calculations were made with the measured permeability values.
3.1. Description of caprock samples

Weyburn Midale Evaporite caprock samples collected from two wells, 14-17-6-13 W2M and 14-3-6-13 W2M, were used in the measurements. The Midale Evaporite is the major caprock in the Weyburn reservoir that essentially works as a barrier to prevent the injected CO₂ from escaping into the overlying formations. Stratigraphically, it is the lowermost unit of the Mississippian Ratcliffe beds and sits conformably on the uppermost unit of the Midale beds from which most of the previous oil production was obtained [4]. The sample analysis showed that: the porosity of the collected samples varies from 0.2% to 8%; the bulk density is in the range of 2.50–2.95 g/cc; and the grain density varies from 2.87 to 2.95 g/cc. The porosity of the caprock changes dramatically with depth. In the vicinity of the reservoir/caprock contact region, the porosity is as high as about 8%. In the middle of the Midale Evaporite, the caprock samples are extremely tight, with porosities as low as 0.2–0.5%. This lowest porosity region of the caprock, with a thickness of about 5 m, determines the sealing capacity of the Weyburn Midale Evaporite caprocks. Samples from this region were used in both the previous breakthrough pressure measurements [7] and the effective permeability measurements in this work.

3.2. Experimental setup for permeability measurement

The same experimental setup as that for the breakthrough pressure measurement [7] was used for the gas flow measurement, as shown in Fig. 1. It primarily includes: (1) an air bath to maintain the test temperature; (2) a Hassler type high pressure core holder with a thick lead sleeve to contain the core sample; (3) a high pressure piston cylinder to contain the test fluid sample; (4) two high pressure pumps to pressurize the fluid sample and provide the confining pressure of the core sample in the core holder; (5) a backpressure regulator (BPR) to provide the back pressure at the outlet of the core sample; (6) a set of metering capillary tubes (with fine scales) to measure the gas flow rate; and (7) a two-channel, high pressure, digital Heise gauge to monitor the pressure. More details concerning the sample preparations and the experimental procedure have been reported elsewhere [7].

3.3. Absolute gas permeability

The single-phase permeabilities were measured using the steady-state method with nitrogen. The pressures at the two ends of the core sample were recorded once they were stable. The flow rate was measured with the metering capillary tube. The permeability was calculated with Darcy’s law. For the gas flow in tight caprock
rock samples, the permeability can be significantly affected by slip effects. In order to eliminate the slip effect, a backpressure was applied downstream of the core sample. In a measurement, the backpressure was increased gradually until the measured apparent permeability reached a certain value that did not change with further increase of backpressure. This non-slip permeability was taken as the absolute gas permeability. More details concerning the measurement of non-slip gas permeability have been given previously [16]. The measured permeabilities for the selected caprock samples are given in Table 3.

The results in Table 3 show that the gas absolute permeability for the selected caprock samples is in the range of $3 \cdot 10^{-14} - 6 \cdot 10^{-19}$ md (or $3 \cdot 10^{-18} - 6 \cdot 10^{-20}$ m²). These results are about one order larger than those water permeabilities measured for the different pelitic caprocks ($3 \cdot 10^{-21} - 5.5 \cdot 10^{-19}$ m²) by Hildenbrand et al. [5].

### 3.4. Effective permeability of CO₂

The migration of CO₂ through caprocks by volume flow is a two-phase (gas/water) flow in tight porous media coupled with capillary effects, which can be predicted once the two-phase relative permeability curve is measured. However, due to the extremely low permeability of the caprock samples, determination of the relative gas/water permeability curves appears to be difficult. Since only the gas migration through the caprock is of concern in CO₂ storage, a shortcut is to measure directly the effective gas permeability after a water-saturated rock sample is broken through and then apply the measured gas effective permeability to predict the gas migration through the caprock.

Before a gas effective permeability measurement, the water-saturated caprock sample was first broken through by CO₂ with a stepwise increase of gas pressure until a continuous liquid flow, followed by a gas bubble flow, was observed at the outlet of the core sample. Then, the flow rate was measured as a function of time until a steady gas flow was reached. The effective permeability was calculated from the measured flow rate. Physically, this experiment simulated well the process of CO₂ breaking through the caprock and then migrating into the upper layers. Two samples from the Weyburn Midale Evaporite caprock were selected for the flow measurements, A7 and B8 with a porosity of 1.5% and 0.7%, respectively. The gas broke through the samples at about 2.9 MPa (A7) and 1.1 MPa (B8). The measured effective permeability was plotted against time in Figs. 2 and 3, respectively.

Figs. 2 and 3 show that the gas flow can be divided into two regions after the gas broke through. The early region is characterized by an extremely low and fluctuating gas flow, probably because the gas phase in some channels is not continuous in this period and, thus, the resistance to gas flow is relatively high. As well, the water phase (wetting phase) may be re-distributed due to the inhibition effect, thus blocking the gas from flowing through the caprock. So, in this early region, both the water and the gas phase are mobile. After a significant amount of time, all the mobile water in the channels where the gas flow prevails is carried out by the gas so that the gas forms a continuous phase and the water phase becomes immobile or irreducible. The gas effective permeability reaches its maximum value and remains stable.

It is seen that the measured effective permeabilities are significantly reduced compared with the absolute gas permeability. The ultimate effective gas permeability is about $1 \times 10^{-14}$ md for sample A7 and $4 \times 10^{-14}$ md for sample B8, only about 10% of the corresponding absolute gas permeability. This might be attributed to the

<table>
<thead>
<tr>
<th>Sample No.</th>
<th>Porosity (%)</th>
<th>Non-slip gas permeability (md)</th>
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<tbody>
<tr>
<td>A5</td>
<td>0.3</td>
<td>$3.94 \times 10^{-4}$</td>
</tr>
<tr>
<td>A7</td>
<td>1.5</td>
<td>$1.11 \times 10^{-3}$</td>
</tr>
<tr>
<td>A8</td>
<td>0.7</td>
<td>$1.24 \times 10^{-3}$</td>
</tr>
<tr>
<td>A15</td>
<td>0.3</td>
<td>$1.90 \times 10^{-3}$</td>
</tr>
<tr>
<td>B8</td>
<td>0.5</td>
<td>$5.24 \times 10^{-3}$</td>
</tr>
<tr>
<td>B5</td>
<td>2.7</td>
<td>$1.42 \times 10^{-3}$</td>
</tr>
<tr>
<td>B10</td>
<td>2.8</td>
<td>$3.50 \times 10^{-4}$</td>
</tr>
</tbody>
</table>

* A: samples collected from Well 14-17-6-13 W2M; B: samples collected from Well 14-3-6-13 W2M.
extremely narrow pore throats in the tight caprocks, i.e. a large amount of the pore throats that allow single gas flow are completely blocked by the water slugs when water exists; the immobile water film occupies a significant portion of the channels broken through by the gas; and the gas only flows as fine filaments in these channels. Based on the observed reduction of the gas effective permeability compared with the measured absolute gas permeability, the effective permeability for Weyburn caprocks is estimated to be in the range of $3 \times 10^{-10}$ to $6 \times 10^{-11} \text{ md}$ (or $3 \times 10^{-20}$ to $6 \times 10^{-21} \text{ m}^2$). This range is just covered by the results measured by Hildenbrand et al. [5] for Boom Clay caprocks, which have effective permeabilities ranging from $2.4 \times 10^{-21}$ to $1 \times 10^{-18} \text{ m}^2$.

3.5. Estimation of volume flow and comparison with molecular diffusion

Once the gas effective permeability is determined, the migration of the injected CO$_2$ after the caprock is broken through can be estimated. Calculations of the amount of CO$_2$ migration through the caprock as a function of time at different effective permeabilities $10^{-3}$, $10^{-4}$ and $10^{-5} \text{ md}$ are given in Fig. 4. The effective permeabilities used in the calculation are based on the measurements but are extended to a wider range. In the calculation, the reservoir pressure is assumed at 25 MPa and the pressure above the caprock is 15 MPa, yielding an average pressure within the caprock of 20 MPa. The thickness of the caprock is 10 m. The area in calculation is 1 km$^2$. The viscosity of the CO$_2$ is about 0.06 MPa · s at 59 °C, 20 MPa [17]. The values of the above parameters are set to construct a scenario in the Weyburn CO$_2$ storage project. Here, it is also assumed that both the
reservoir and overburden pressures do not change during the injection and leakage processes. The gas migration is only through the caprock, i.e. the leakage through the wellbore is not considered. It is seen from Fig. 4 that the mass of CO$_2$ migrated into the upper layers increases linearly with time at each effective permeability. The consequence of this leakage rate in CO$_2$ storage injection can be well recognized when it is compared with the actual injection scenario in Weyburn. Based on the available results from the Weyburn project, the ultimate CO$_2$ storage potential in the Weyburn Unit, with an area of 180 km$^2$, is around 54.8 million tonnes over 50 years through CO$_2$-EOR and post-EOR CO$_2$ injection processes [4]. The averaged storage efficiency is about 6.09 $\times$ 10$^4$ tonne/km$^2$/year. If volume flow occurs, the leakage rate is around 3.69 $\times$ 10$^3$ tonne/km$^2$/year even when the gas effective permeability of 10$^{-5}$ md is used. This will cause a migration of 6% of the CO$_2$ that could be stored in the reservoir to the upper formations, which may eventually reach the surface. Fortunately, the high sealing quality of the caprocks in Weyburn, as indicated by the high breakthrough pressure, is capable of preventing the injected CO$_2$ from leaking through a volume flow. However, it is of the first priority to re-evaluate the breakthrough pressure of the caprocks for different reservoirs once they are selected as the injection sites. The sealing pressure of the caprock should be considered as an important constraint in CO$_2$ storage injection.

In addition to the volume flow, the molecular diffusion of CO$_2$ into the adjacent formations would be much larger than that of light hydrocarbons as reported in the literature [6,18,19] due to the higher solubility of CO$_2$ in water than that of hydrocarbons. Using the model of diffusion through a plane sheet [6,20], the diffusion leakage of CO$_2$ through Weyburn caprock (under similar conditions as those for Darcy flow) was also calculated and is plotted in Fig. 4. The caprock porosity used in the calculation is 2%. The solubility of CO$_2$ in brine is about 4.4 kg/m$^3$ (0.001 mol/cc) based on the previous measurements [21]. The effective diffusion coefficient used is 10$^{-9}$ m$^2$/s, which might be a bit larger than the actual effective diffusion coefficient based on our measurements [22]. Despite that, the leakage caused by molecular diffusion is negligible compared with the volume flow once the caprock is broken through. However, since molecular diffusion is a ubiquitous process over geological time, it may have significant impacts on the rock properties due to the mineralogical reactions caused by CO$_2$ in long-term containment.

4. Options to maximize the storage capacity

Although depleted oil and gas reservoirs are the most attractive geological media for CO$_2$ storage, their total capacity is limited. Therefore, it is crucial to utilize fully the capacity of a given reservoir and thereby maximize the value of the depleted oil and gas reservoirs in reducing CO$_2$ emissions. For CO$_2$ storage in a
depleted oil reservoir, the capacity primarily includes the storage as a free supercritical CO₂ gas phase and its
dissolution in the formation water and residual oil. The trapping through mineralogical reaction is not con-
sidered in the storage injection stage, although it may play an important role in the long-term sequestration.
Since the capacity, both as a free gas phase and dissolution in reservoir liquids, increases with increasing pres-
sure, the most straightforward option to maximize the storage capacity of a given reservoir is to increase the
storage pressure. However, the increase in storage capacity becomes limited after the pressure reaches a certain
level. This was shown in detail in Figs. 5–7, respectively, for three types of storage capacity as a function of
pressure in a 1 m³ void space of a hypothetical reservoir. Both the brine and oil used in the calculations were
collected from the Weyburn reservoir, and their analyses have been given elsewhere [21,23]. A PVT simulator
CMG Winprop [24] with Peng–Robinson equation [25] was used to calculate the amount of CO₂ that can be
stored as a free gas phase and as dissolution in oil. The amount of CO₂ dissolved in brine was based on Refs.
[21,26]. Although all of these three types of storage capacity increase with increasing pressure, the slope of
capacity vs. pressure becomes gradually smaller after the pressure exceeds a certain value. For the reservoir
temperature in the Weyburn field, 59 °C, the amount of CO₂ stored as each of these three types of storage
almost levels off after 20 MPa. The increase of pressure from 20 to 30 MPa gives an increase in storage capac-
ity of less than 10%. This may be of little worth in practical applications, since the resulting risks of the con-
tainment are considerably amplified with such a dramatic increase in pressure.

The above storage capacity calculations based on 1 m³ void reservoir space also show that for a given res-
ervoir volume, the storage capacity as a free gas phase is much larger than that as dissolution in the water and
oil. In depleted oil reservoirs that have undergone secondary and enhanced oil recovery processes, most of the
pore space is filled with water injected to displace oil, maintain reservoir pressure, or improve the sweep effi-
ciency (in the water alternating gas process) during the secondary and tertiary recovery processes. As a result,

Fig. 5. The amount of CO₂ stored as a free gas phase in 1 m³ void space as a function of pressure at different temperatures.

Fig. 6. The amount of CO₂ stored as dissolution in 1 m³ Weyburn formation brine as a function of pressure at different temperatures.
the storage capacity of such reservoirs is mainly determined by the solubility of CO₂ in the remaining water and the residual oil. This has been recognized in the IEA GHG Weyburn CO₂ Monitoring and Storage Project [4], in which the reservoir simulation results demonstrated that at the end of the CO₂ EOR process, most of the CO₂ is stored in the remaining water and oil as solubility trapping, and only about 30% of the CO₂ could be stored as a supercritical gas. The remaining water after CO₂-EOR is estimated to account for over 60% of the total void reservoir space. For such reservoirs, the storage capacity enhancement by simply increasing the storage pressure is limited. However, a significant increase of the capacity can be achieved by removing a portion of the remaining water (or oil if possible) in place. The production of the reservoir water can be operated most economically through natural flowing when the reservoir pressure is sufficiently elevated by CO₂ injection. A key advantage of this option is that the capacity can be substantially increased without additional infrastructure investment. A research project aiming at maximizing the reservoir capacity for CO₂ storage through optimizing the injection (CO₂)/production (water) scheme is in progress.

5. Conclusions

The sealing pressure of caprocks for CO₂ is significantly reduced compared with that for the original hydrocarbons due to the much lower interfacial tension (IFT) of the CO₂/water system. As a result, the sealing capacity of caprocks that retained the oil and gas in the first place may not be sufficient to prevent the injected CO₂ from migrating through the caprocks by volume flow. Therefore, it is crucial to re-evaluate the sealing capacity of the caprock once an oil or gas reservoir is selected as a CO₂ storage site.

The gas effective permeability in the selected Weyburn Midale caprock samples, after the differential pressure exceeds the breakthrough pressure, was measured to be in the range of $3 \times 10^{-5} - 6 \times 10^{-4}$ md. The calculations made with the measured gas effective permeabilities showed that the CO₂ leakage by volume flow is disastrous once it occurs. To avoid volume flow, the CO₂ sealing pressure of the caprock should be considered as a basic constraint in designing and implementing CO₂ storage injection such that the caprock will never be broken through by the injected CO₂.

The leakage of CO₂ through caprock by molecular diffusion is negligible during the short-term injection stage. Investigations should focus on the caprock property changes due to the mineralogical reactions caused by the diffused CO₂ in the long-term containment.

The calculation of the storage capacity for a given reservoir shows that once the reservoir pressure reaches a certain high level, a continuous increase in pressure alone is not effective in enhancing the storage capacity. However, much more capacity can be achieved by removing a portion of the remaining water.

Acknowledgments

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