



13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18
November 2016, Lausanne, Switzerland

Security of storage in carbon dioxide enhanced oil recovery

R Jamie Stewart,^a Gareth Johnson,^a Stuart Haszeldine,^a Peter Olden,^b Eric Mackay,^b
Bernhard Mayer,^c Maurice Shevalier,^c Michael Nightingale.^c

^a*School of GeoSciences, University of Edinburgh, Kings Buildings, Edinburgh, EH9 3FE*

^b*Heriot-Watt University, Edinburgh Campus, Edinburgh EH14 4AS*

^c*Applied Geochemistry Group, University of Calgary, 2500 University Drive NW, Calgary, Alberta, Canada T2N1N4*

Abstract

The Pembina Cardium CO₂ Monitoring Pilot was used as a test site to determine the relative roles of trapping mechanisms. Two methods to assess this distribution are presented. A geochemical approach using empirical data from the site was used to determine the phase distribution of CO₂ at a number of production wells that were sampled monthly during a two-year CO₂ injection pilot. In addition, a simplified reservoir simulation was performed. Results indicate that significant amounts of CO₂ are stored in the oil phase thus reducing the amount of CO₂ available as a buoyant free phase and hence increasing storage security.

© 2017 The Authors. Published by Elsevier Ltd. This is an open access article under the CC BY-NC-ND license (<http://creativecommons.org/licenses/by-nc-nd/4.0/>).

Peer-review under responsibility of the organizing committee of GHGT-13.

Keywords: CO₂ Enhanced Oil Recovery, CO₂ Storage Security, CCS, CO₂ solubility, trapping mechanisms

1. Introduction

Preliminary studies from Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) in Canada have suggested that, in CO₂-EOR settings, solubility trapping takes place within both aqueous and hydrocarbon phases. As such it is postulated that CO₂-EOR may provide a greater quantity of securely stored CO₂ than a purely non-EOR storage operation. This study's principal objective was to quantify how much solubility trapping takes place within both aqueous and hydrocarbon phases in CO₂-EOR settings.

1.1. Trapping mechanisms

The fate of CO₂ is an important consideration when injecting CO₂ into the geological subsurface. CO₂ can be trapped structurally and stratigraphically, by residual trapping, solubility trapping, and by mineral trapping [1]. Although in a well selected storage complex a combination of each of these trapping mechanisms should lead to extremely high confidence in storage security, certain geological risks will always exist [2]. What is known, however, is that the highest geological storage risks exist when CO₂ is in free phase and is reliant on structural and stratigraphic trapping and on well integrity. Increased security of CO₂ storage will be achieved if the primary storage mechanism changes from structural and stratigraphic trapping to solubility trapping in the time frame of injection operations and thereafter.

1.2. Pembina Cardium CO₂ Monitoring Pilot

The Pembina Cardium CO₂ Monitoring Pilot (PCCMP) was used as a test site to determine the relative roles of trapping mechanisms. The PCCMP site is located near the town of Drayton Valley, west of Edmonton, (Fig. 1) in the Pembina Field. The Pembina oilfield is the largest individual and one of the oldest onshore oilfields in Canada [3]. The pilot consists of two five-spot injection patterns, with two of the production wells being shared by the two injector wells. This results in a configuration with two CO₂ injectors surrounded by six producers (Fig. 1). These wells are located in the middle of the Pembina field in an area that has been water flooded since 1962 [4]. CO₂ injection started in 2005 with approximately 75,000 tons of truck delivered liquid CO₂ being injected between March 2005 and March 2008. Between March 2005 and March 2007 CO₂ was continuously injected through the two injection wells. After this period the pilot switched to Water Alternating Gas (WAG) injection with injected CO₂ being periodically alternated with water injection [5]. A detailed description of the geology of the field can be found in Dashtgard et al. [4], Hitchon [5], Krause et al. [6], and Plint et al. [7].

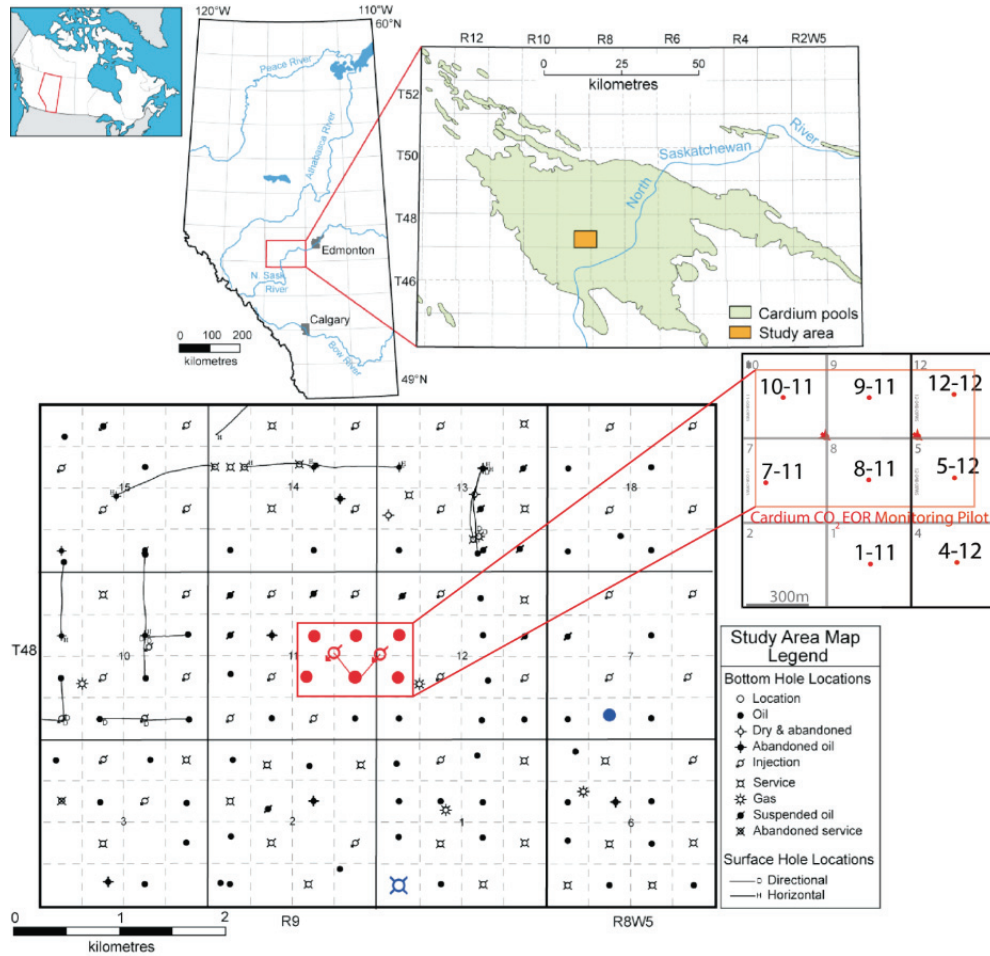


Figure 1. Location Map of the PCCMP in the Cardium pool, Pembina Field, adapted from Dashtgard et al. [4]. The lower map illustrates the location of all wells within the study area. Wells 10-11, 9-11, 7-11 and 8-11 are production wells in the classic 5 spot pattern with a CO₂ injector in the middle. Using wells 9-11 and 8-11 wells 12-12 and 5-12 form a second 5 spot pattern with another CO₂ injector in the middle. Wells 1-11 and 4-12 are also production wells which sit further to the south.

1.3 Solubility of CO₂ at Pembina reservoir temperatures and pressures

The solubility of CO₂ in oil is controlled predominantly by reservoir pressure, temperature and to a smaller extent the oil API gravity [8,9,10,11]. Generally, solubility increases with pressure and oil API gravity (i.e. higher in lighter oils) but decreases with temperature. The solubility of CO₂ in aqueous fluids is primarily dependent on temperature, pressure and much like the solubility of CO₂ in oil, the solubility of CO₂ in brine decreases with temperature but increases rapidly with increasing pressures up to the saturation pressure [12].

CO₂ solubility in brine at pressures and temperatures nearest to those at Pembina field reservoir conditions of 50°C and 190 bar (19MPa) and 0.085M NaCl, a solubility of 2.3 mole % CO₂ (1.25 mol/L) is predicted [12].

The solubility of CO₂ in oil at Pembina reservoir temperatures and pressures is predicted to be 0.67 mole fraction. If the molecular weight and density of the oil is known this solubility can be converted to molality (mol L⁻¹). The Pembina oil has a molecular weight of 191g mol⁻¹ and a density of 0.8338 kg L⁻¹ [5]. Therefore, at equilibrium saturation 0.67 mole fraction equates to 8.5 mol L⁻¹ of oil. Therefore the solubility of CO₂ in oil at Pembina reservoir conditions is approximately seven times greater than in brine.

2. Methods

Two methods were used to determine the relative of trapping mechanisms. Firstly a geochemical method using empirical production data from the project. was used to determine the phase distribution of CO₂ (dissolved or free phase) at a number of production wells during the two-year CO₂ injection pilot at the Pembina field. Secondly a reservoir modelling approach was used to also estimate the phase distribution of CO₂ in the reservoir over the 2 year injection period. This would allow for the comparison of results between the two methods.

2.1 Geochemical method

Using the calculated equilibrium solubility coefficients (section 1.3), the partitioning of CO₂ that is dissolved in the oil, brine or present as a free phase gas can be estimated for the first two years of CO₂ injection at the PCCMP. To do this, the relative volumes of brine, oil and CO₂ in the reservoir must also be known. At the Pembina field monthly production volumes of gas, oil and brine are available and are here used as a proxy for the relative reservoir saturations. As observed in Figure 2 significant volumes of CO₂ were produced at wells 7-11, 8-11, 9-11 and 12-12. Using this production data the relative mole % of CO₂ dissolved in the oil, brine and as a free phase gas was calculated for the same 2 year injection period.

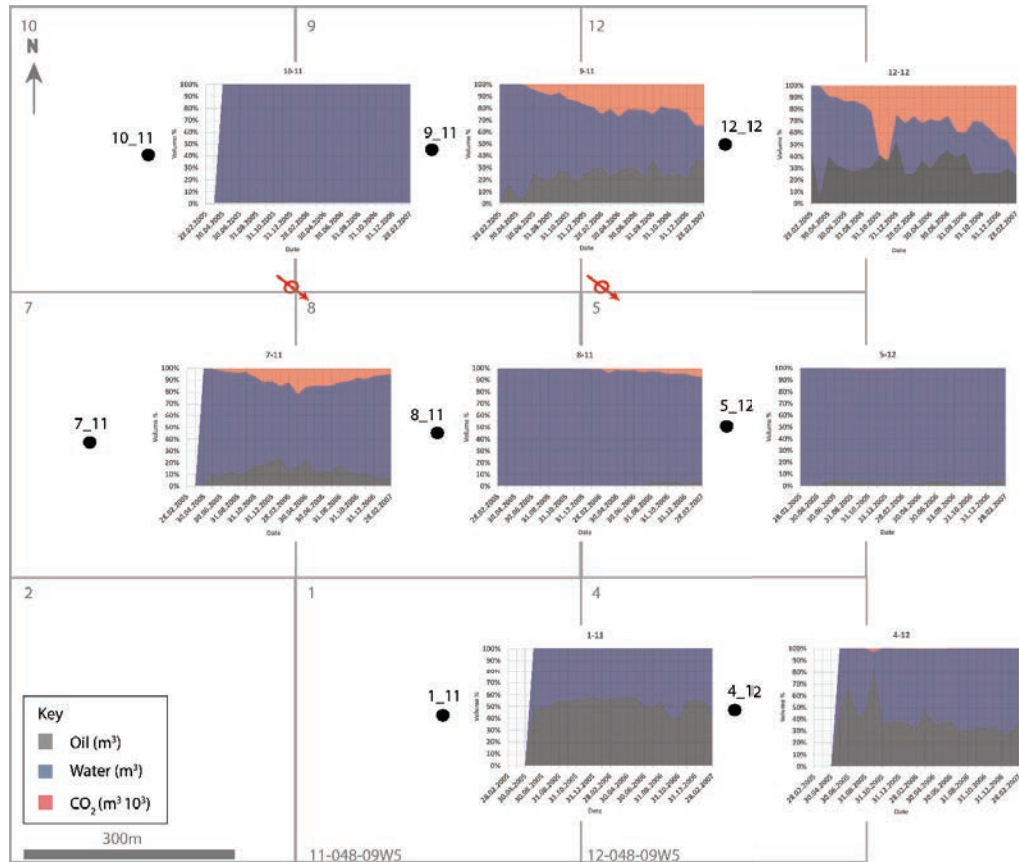


Figure 2. Produced fluids over the two year injection interval at each of the sampled wells. Production data from Alberta Innovates. [13,14,15].

To estimate partitioning, the equilibrium solubilities of 8.5 mol/L in oil and 1.25 mol/L in brine were multiplied by the number of liters of brine and oil produced at monthly intervals. This provided an estimate of the volume of CO₂ that would be needed to saturate both the brine and the oil. The volume of CO₂ in the system was calculated by multiplying the produced gas volume by the CO₂ concentration (mole %). When the volume of CO₂ in the system was in excess of the volume needed to saturate the brine and the oil, it was assumed that free phase CO₂ was present. When the volume in the system was less than the saturation volume it was assumed that both the brine and oil phase would be under-saturated with respect to CO₂. An assumption was made that the ratio of partitioning of CO₂ in brine and oil would remain constant in both under-saturated and saturated conditions. However this ratio was adjusted to represent the relative volumes of oil and brine by multiplying the saturated mole fractions by the fraction change in volume relative to a 1:1 oil water ratio. This leads to the solubility molalities (moles /L) in oil and brine remaining constant but the total number of moles in oil in relation to that in brine being different compared to that if the oil:water ratio was 1:1.

2.2 Reservoir modelling

A simple box compositional reservoir simulation model of the PCCM was developed to test results derived from the empirical site data. The primary purpose of the model developed here was not to match any project specific injection and production history, but rather to use it as a test-bed to investigate various CO₂ injection scenarios with a model having some of the salient features of the pilot project. In particular, the question posed was the differentiation between the proportions of CO₂ that is dissolved in water and CO₂ dissolved in oil, as well as CO₂ in the mobile and residual in the free gas phase, under various injection scenarios, such as could be reasonably envisaged for such a site.

The model was developed using CMG GEM compositional reservoir simulation software [16]. The model was constructed with a 21 × 21 × 15 grid with 20 m × 20 m cells in the areal plane. The solubility of CO₂ (and the other hydrocarbon components) dissolved in water was calculated using Henry's Law with Harvey's correlation used for CO₂, which makes the constant a function of pressure, temperature and salinity [17]. For the simulations reported here the water salinity was taken to be zero.

3. Results

Table 1 shows the phase distribution of the CO₂ at the end of the two-year injection interval. On average across all wells 74% of the CO₂ remains as a free phase with 14% and 12% dissolved into the oil and brine phase respectively. However the range of values vary from 55-91% for CO₂ in a free phase and from 8-84% and 1-100% for CO₂ in oil and brine respectively at individual wells. Thus one must be careful to not over interpret any one well in isolation of considering the production volumes.

Table 1. Mole % CO₂ in each reservoir fluid phase for each sampled well at the end of the two year CO₂ injection interval.

Well	moles CO ₂		moles CO ₂		moles CO ₂		SUM (moles)
	in brine	as %	in oil	as %	free phase	as %	
12_12	13163	1	156060	8	1694668	91	1863891
7_11	100100	50	61880	31	37633	19	199613
8_11	411950	34	126140	10	663962	55	1202052
9_11	30100	2	264180	21	935451	76	1229731
1_11	33	16	180	84	0	0	213
10_11	379	100	0	0	0	0	379
4_12	50	20	206	80	0	0	256
5_12	138	79	38	21	0	0	176
TOTAL	555913		608684		3331713		4496310
% Total		12		14		74	100

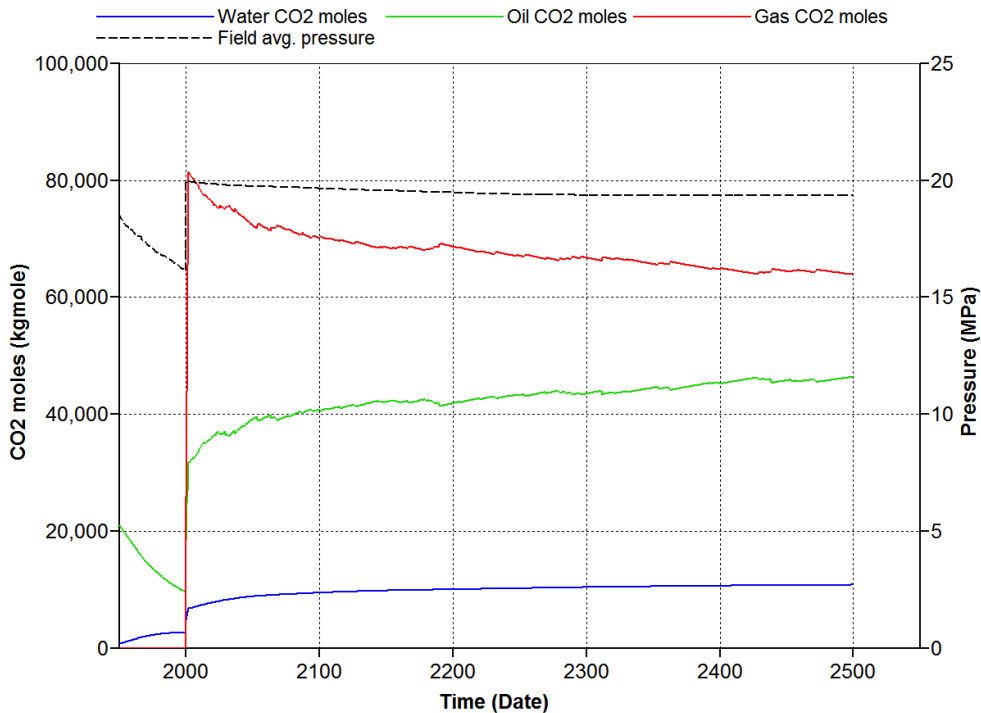


Figure 3. Initial simulation results showing the partitioning of CO₂ moles in the water, oil and gas phases and the average field pressure during water-flooding, CO₂ injection and subsequent equilibration stages.

Simulation results are shown in Figure 3. At time 2002, the final post CO₂ injection, CO₂ distributions were 68% in the free (gas) phase, 26% in the oil phase and 6% in the water phase. This compares to an average of 74% in free phase, 14% in the oil phase and 12% in the water phase at the wells sampled during the operations (See table 1) which is considered a good fit given the uncertainty in the oil:water ratio at the start of CO₂ injection.

4. Discussion and Conclusions

Using a number of different correlations equilibrium solubility constants were calculated to be 8.5 mol/L for CO₂ in oil and 1.25 mol/L for CO₂ in brine at the PCCMP. Thus the presence of oil provides an additional sink for CO₂ that, dependent on conditions and relative oil:water saturations may have significantly higher CO₂ solubility than in saline aquifers alone. Using an empirical method based on production data and the solubility coefficients noted above it was found that 74% of the CO₂ remains as a free phase with 14% and 12% dissolved into the oil and brine phase respectively (on average across all wells). A previous assessment, which used an isotopic approach to estimate reservoir pore space saturations, gave similar partitioning results at the individual wells at the end of 2 years [18]. This study improves on this by accounting for pore-space away from wells and through comparison with a reservoir simulator.

The initial reservoir simulation modelling presented in this study also closely matches the average CO₂ distribution and relative trapping contributions derived from the geochemical approach. A slightly higher fraction of CO₂ dissolves in the oil and slightly lower fraction dissolves in the water when comparing the reservoir model to the

average values of the geochemical data. However, the numbers thus calculated are well within the ranges of the geochemical data giving additional confidence in the empirical data method and the representativeness of the reservoir model itself.

We therefore conclude that security of storage can be greater in EOR settings where an oil phase permits additional solubility trapping and therefore less structural/stratigraphic trapping. However, it is noted that in EOR settings there may be more wells and therefore potential leakage pathways for CO₂ to migrate from than in virgin saline aquifer settings. Nonetheless these potential migration pathways should be well known and can be easily instrumented to ensure the security of the storage site.

Acknowledgements

Members of the Applied Geochemistry group at the University of Calgary are thanked for collecting and help with interpreting the geochemical data. The work was funded by the SCCS EOR JIP. Reservoir modelling work was completed by Heriot-Watt University and all other work was undertaken by the University of Edinburgh. CMG Ltd are thanked for use of the GEM reservoir simulation software.

References

- [1] IPCC, 2005. IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., Davidson, O., de Coninck, H.C., Loos, M., and Meyer, L.A., (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, p.442.
- [2] Worden, R.H. & Smith, L.K., 2004. Geological sequestration of CO₂ in the subsurface: lessons from CO₂ injection enhanced oil recovery projects in oilfields. Geological Society, London, Special Publications, 233, pp.211–224.
- [3] Owen, E.W., 1975. Trek of the oil finders: a history of exploration for petroleum. AAPG Memoir 6, 1647 p.
- [4] Dashtgard, S.E., Buschkuehle, M.B.E., Fairgrieve, B., and Berhane, H., 2008. Geological characterization and potential for carbon dioxide (CO₂) enhanced oil recovery in the Cardium Formation, central Pembina Field, Alberta. Bulletin of Canadian Petroleum Geology, v. 56, n.2, pp.147-164.
- [5] Hitchon, 2009. Pembina Cardium CO₂ Monitoring Pilot: A CO₂-EOR Project, Alberta, Canada - Final Report. Geoscience Publishing, 2009. ISBN 978-0-9680844-5-8.
- [6] Krause, F.F., Deutsch, K.B., Joiner, S.D., Barclay, J.E., Hall, R.L., and Hills, L.V., 1994. Cretaceous Cardium Formation of the Western Canada Sedimentary Basin. In Mossop, G.D., and Shetsen, I., (eds), Geological Atlas of the Western Canada Sedimentary Basin. Canadian Society of Petroleum Geologists. pp.375-385.
- [7] Plint, A.G., Walker, R.G., and Bergman, K.M., 1986. Cardium Formation 6. Stratigraphic framework of the Cardium in subsurface. Bulletin of Canadian Petroleum Geology, v.34, pp. 213-225.
- [8] Chung, F.T.H., Jones, R.A. & Nguyen, H.T., 1988. Measurements and Correlations of the Physical Properties of CO₂/Heavy-Crude-Oil Mixtures. SPE Reservoir Engineering (August) 822.
- [9] DeRuiter, R. A., Nash, L.J. & Singletary, M.S., 1994. Solubility and Displacement Behavior of a Viscous Crude With CO₂ and Hydrocarbon Gases. SPE Reservoir Engineering, 9(May), pp.101–106.

- [10] Simon, R. & Graue, D. 1965. Generalized Correlations for Predicting Solubility, Swelling & Viscosity Behavior of CO₂-Crude Oil Systems. *J. Pet. Techn.* v.17, n.1, 102-106.
- [11] Welker, J.R. & Dunlop, D.D., 1963. The Physical Properties of Carbonated Oils. *J. Pet. Techn.* v.15. pp.873–875.
- [12] Spycher, N., Pruess, K. & Ennis-King, J., 2003. CO₂-H₂O mixtures in the geological sequestration of CO₂. I. Assessment and calculation of mutual solubilities from 12 to 100C and up to 600 bar. *Geochimica et Cosmochimica Acta*, 67(16), pp.3015–3031.
- [13] Alberta Innovates 2005. Penn West Energy Trust Pembina Cardium 'A' Lease - CO₂ Pilot Project Annual Report 2005. Retrieved Dec 2014 from <http://eipa.alberta.ca/resources/co2/pembina.aspx>
- [14] Alberta Innovates 2006. Penn West Energy Trust Pembina Cardium 'A' Lease - CO₂ Pilot Project Annual Report 2006. Retrieved Dec 2014 from <http://eipa.alberta.ca/resources/co2/pembina.aspx>
- [15] Alberta Innovates 2007. Penn West Energy Trust Pembina Cardium 'A' Lease - CO₂ Pilot Project Annual Report 2007. Retrieved Dec 2014 from <http://eipa.alberta.ca/resources/co2/pembina.aspx>
- [16] CMG, 2014. Computer Modelling Group, CO₂ EOR Modelling Using GEM - Course Notes, 2014.
- [17] Harvey, A.H.: “Semi-empirical Correlation for Henry’s Constants over Large Temperature Ranges,” *AICHE J.*, Vol. 42, No. 5 (May 1996), pp. 1491-1494.
- [18] Johnson, G., Mayer, B., Nightingale, M., Shevalier, M., & Hutcheon, I. 2011. Using oxygen isotope ratios to quantitatively assess trapping mechanisms during CO₂ injection into geological reservoirs: The Pembina case study. *Chemical Geology*, 283(3-4), pp.185–193.