A review of non-condensable gases (NCGs) reinjection within the geothermal industry and a comparison with other carbon capture and storage (CCS) technologies

Aston Carmichael* and Sadiq J. Zarrouk

Department of Engineering Science, The University of Auckland, Private Bag 92019, Auckland, New Zealand

*rcar585@aucklanduni.ac.nz

Keywords: *Non-condensable gas, Reinjection, Geothermal field, Carbon capture and storage*

ABSTRACT

Greenhouse gases (GHGs), including carbon dioxide (CO_2), are the primary drivers of global warming and climate change. To combat this urgent issue, there have been global efforts to reduce GHG emissions from energy production through initiatives like the Paris Agreement and national carbon taxes. In the geothermal, oil and gas, and coal bed methane (CBM) industries, various strategies have been explored to mitigate emissions. This report reviews the current status of Non-Condensable Gas (NCG) reinjection within the geothermal industry and compares the techniques used with other carbon capture and storage (CCS) methods.

The geothermal industry has shown promise in reducing GHG emissions by reinjecting NCGs. Pilot projects in multiple countries have successfully demonstrated NCG reinjection, primarily through basaltic mineralization and residual trapping. However, further research is needed to assess the potential of NCG reinjection in different geothermal reservoir geologies.

In the oil and gas, and Coal Bed Methane (CBM) industries, various CCS methods have been investigated. These include CO_2-enhanced oil recovery (CO_2-EOR), CO_2-enhanced gas recovery (CO_2-EGR), CO_2-enhanced coal bed methane (CO_2-ECBM), and CO_2 storage in saline aquifers and depleted oil and gas fields. CO_2-EOR has extensive project experience but is primarily an enhanced oil recovery technique rather than a climate change mitigation method. CO_2-ECBM faces challenges such as coal swelling and decreased permeability. CO_2-EGR is still in development and has limited project experience. Saline aquifers and depleted oil and gas fields are seen as long-term storage solutions, but uncertainties remain regarding modelling and cap rock integrity, and there is also a current lack of financial incentive for these methods.

In summary, these approaches contribute to global efforts to reduce GHG emissions. These methods differ significantly in their strategies. Further research and development are necessary to optimise these methods and address their limitations for effective climate change mitigation.

1. INTRODUCTION

Internationally, there has been a push towards reducing GHG emissions in the energy sector. Primarily CO_2 emissions. In 2015, 194 parties ratified the Paris Agreement, agreeing to limit global warming by a maximum of +2°C from pre-industrial times and to aim for only a 1.5°C increase (United Nations, 2015; World Bank, 2022). This movement has further been implemented through policies outlined in the numerous climate change conference of parties which aim to reduce fossil fuel use by 2030 (Manfrida et al., 2019). To meet 2050 targets, the emissions intensity of power production must be below 300gCO_2e/kWh by 2030, 100gCO_2e/kWh by 2035 and 50gCO_2e/kWh by 2050 (Nicholson et al., 2010). Additionally, for a power generation project to be considered a sustainable economic activity as part of the Regulation (EU) 2020/852 taxonomy regulation, it must have an emission intensity below 100gCO_2e/kWh (McLean et al., 2020). Many countries with geothermal resources are now turning to geothermal power as a reliable and sustainable baseload power source as an alternative to fossil fuels.

For geothermal power to remain a competitive baseload power source, it will have to reduce its GHG emissions to remain economically and sustainably efficient. NCG reinjection provides the opportunity to reduce GHG emissions, maximise profit within the geothermal industry, and store CO_2 from other industries (Kaya and Zarrouk, 2022). The introduction of carbon pricing within countries and states that utilise geothermal power (Iceland, New Zealand, Costa Rica, Mexico and the USA) has continued to drive the development of NCG reinjection technologies. In countries like New Zealand, the national climate change authority also recommends that geothermal plants with high emissions be closed by 2030 (Choudhary et al., 2021). This report will review geothermal NCG reinjection as well as other technologies, including CO_2-EOR, CO_2-EGR, CO_2-ECBM, and CO_2 storage within saline aquifers and depleted oil and gas formations. A comparative assessment between these technologies will then be completed.

2. NCG REINJECTION IN THE GEOTHERMAL INDUSTRY

Initially, brine and condensate produced from geothermal power plants were disposed into rivers, oceans, or seas. In the 1980's, reinjection of separated fluid and condensate was introduced. Make-up water from external sources is also injected for higher enthalpy systems. Reinjection allows for both the disposal of brine, which contains impurities unsafe for natural water sources, and the recharging and pressure support for the geothermal reservoirs (Kamila et al., 2020; Manfrida et al., 2019). More recently, active NCG reinjection into geothermal reservoirs has been trialled and implemented in some cases. This allows for the storage of NCGs within the subsurface whilst reducing geothermal GHG emissions. In most cases, NCGs are firstly separated from the geothermal fluid and dissolved into some form of water, either brine, condensate, makeup water or a combination of the three. Supercritical CO_2 has also been reinjected into some reservoirs (Choudhary et al., 2021; Yücetaş et al., 2018).

For the addition of NCGs to the injectate to be deemed successful, multiple criteria must be met to ensure maximal power production while minimizing emissions and hazardous risks. Firstly, NCGs must be stored within the reservoir and must not increase the NCG content of the produced fluid or NCG flux through the surface. Secondly, the additional pressure support from NCGs should not affect the enthalpy of the produced fluid or damage the reservoir (Kaya et al., 2018). Thirdly, it must be ensured that additional scaling in the wells or reservoir does not adversely affect the well's injectivity, porosity, permeability, and productivity (Ghafar et al., 2022). Finally, the NCG-injectate must recharge the reservoir whilst ensuring that the thermal head of the NCG-injectate does not prematurely breakthrough into the reservoir and reduce the overall enthalpy of the produced fluid (Kamila et al., 2020; Kaya et al., 2018; Kaya and Zarrouk, 2017).

2.1 Projects

In 1989, the Coso power plant in California was the first geothermal field to capture, compress, and reinject H_2S-brine into the reservoir (Schoonmaker and Maricle, 1990; Adams et al., 2000). In 1993, Coso began switching to H_2S removal through liquid reduction-oxidation due to high compressor maintenance costs and gas breakthroughs to the production wells (Kolar et al., 2015; von Hirtz, 2016). The 2nd NCG reinjection project started at Puna, Hawaii, in 1993, where the technology developed at Coso was used to minimise H_2S emissions and silica scaling. Reinjection at Puna has been in operation for over 20 years. However, the NCG reinjection process used at Coso and Puna could not be transferred to flash plants due to the required anoxic conditions only present in ORC systems combined with a back-pressure turbine (von Hirtz, 2016).

In 2012, in the CarbFix1 project, the first industrial-scale active NCG reinjection project to reduce emissions began. The 2 phases of the project began at the 303 MWe Hellisheiði power plant in Iceland. 175 tons of CO_2 and 73 tons of H_2S were captured in an absorption column and injected and stored within the basaltic target formation (Sigfússon et al., 2018; Gunnarsson and Sigfússon, 2013). Orkuveita Reykjavikur (OR) began the CarbFix2 project in 2014 at Hellisheiði where the storage of CO_2 and H_2S was increased to 12,000 tons per annum (tpa) of CO_2 and 6,000 tpa, accounting for 1/3rd of the CO_2 emissions and 3/4 of the H_2S emissions (Andersen et al., 2021).

The GECO project started in 2018 to expand and advance the technology developed in the CarbFix2 project. The aim is to reduce NCG emissions from geothermal power plants internationally through NCG reinjection or CO_2 utilisation through CO_2 purification. GECO project plants include Hellisheiði and Nesjavellir, Iceland (Andersen et al., 2021), both flash plants. The conceptual model at Castelnuovo, Italy (later replaced by Hverageroi, Iceland) (Manfrida et al., 2019). A test site at Bochum, Germany (Erstling et al., 2019), Hverageroi, Iceland; and Kızıldere, Turkey (Senturk and Akin, 2020; Tut Haklidir et al., 2011; Garg et al., 2015; Akin et al., 2016), all binary plants. Plants in Iceland and Italy represent high-temperature reservoirs, while Bochum represents low-temperature systems (Erstling et al., 2019). A range of geological, NCG content, and thermodynamic conditions were selected to determine optimal approaches for each condition (Andersen et al., 2021; Erstling et al., 2019).

Outside of the GECO project, active NCG reinjection projects were trialled between October and December 2017 at Umurlu, Turkey (Yücetaş et al., 2018) and between October 2021 to June 2022 at Ngatamariki, New Zealand (Ghafar et al., 2022) to investigate active NCG reinjection in different reservoir geologies. 2 active CO_2 reinjection systems are also currently operating at the Te Huka plant in New Zealand with a reinjection rate of 2,000 tpa of CO_2 (Contact Energy, 2023). In 2002, NCG reinjection into hot dry rock (HDR) systems was also investigated at Hijiori, Japan (Yanagisawa, 2010) and Ogachi, Japan (Kaieda et al., 2009).

2.2 Results

There is a large variability in the success of the storage of NCGs within geothermal reservoirs. Industrial integration of NCG reinjection was completed successfully at the Hellisheiði and Nesjavellir flash plants. Both plants reduced their CO_2 and H_2S emissions whilst concluding that mineralisation was occurring within the reservoir. 50% of CO_2 and 76% of H_2S mineralised within 130-176 days at Hellisheiði (Sigfússon et al., 2018; Gunnarsson et al., 2018). Whilst venting still occurred at Hellisheiði, the increased absorption pressure at 11bar at Nesjavellir proved that >90% absorption of CO_2 and >99% absorption of H_2S could be achieved (Andersen et al., 2021). There was also no increase in the CO_2 concentration of the produced fluid at Kızıldere. However, it was concluded that the NCG content of the injectant would need to be increased for conclusive results to be drawn (Sevindik et al., 2023).

For binary projects, in the three months of NCG injection at Ngatamariki no significant change in the injectivity or productivity was observed. Also, no scaling or changes in NCG content were observed at the production well, indicating that the NCGs did not break out of the solution (Ghafar et al., 2022). Reactive modelling at Te Huka also predicted that the increased NCG content of the injectant led to increased porosity, permeability, and pressure support within the reservoir's life (Castillo Ruiz et al., 2021). No NCG breakout has been detected through the production wells at Puna over 20 years of NCG injection (von Hirtz, 2016; Akin et al., 2016). In HDR systems, the presence of calcite in the produced fluid at Hijiori and the increased level of Ca in the production fluid at Ogachi indicated that mineralisation could occur in carbonate HDR environments (Yanagisawa, 2010; Kaieda et al., 2009).

Less successful results have been observed in other projects. CO_2 broke through to the production wells in the near vicinity of the injection wells at Umurlu. Profound effects on the behaviour were also observed around these wells. This may be due to the supercritical injection of CO_2 as structural/stratigraphic trapping was relied on as the entrapment mechanism (Yücetaş et al., 2018). NCG reinjection reservoir modelling at Wairakei, New Zealand, also predicted a CO_2 breakthrough in the production wells and a large build-up of CO_2 within the production zones. However, as reactive modelling was not completed as part of the study, there may be an overestimation in the CO_2 volume as mineralisation effects were not accounted for (Kaya et al., 2018).

3. ENHANCED OIL RECOVERY/ ENHANCED GAS RECOVERY

CO_2 reinjection into oil reservoirs is an enhanced oil recovery (EOR) technique known as CO_2-EOR. CO_2 reduces the emissions intensity of oil production by changing the viscosity of the oil in the reservoir, which increases productivity whilst reducing lifecycle emissions by as much as 50%, and in turn, the carbon tax of production is reduced (Akin et al., 2016; Hannis et al., 2017). CO_2 reinjection can also be injected into gas formations (especially shale formations) to enhance gas recovery whilst geologically storing the CO_2 (Khosrokhavar, 2016).

CO_2-EOR is now being used worldwide and can recover an additional 15-20% of the oil initially in place whilst reducing emissions through CO_2 storage. The oil industry has the highest demand for CO_2 obtained from external sources and the largest number CCS projects. In 2018, 0.3-0.6 tons of CO_2 were injected per barrel of oil produced (IEA, 2019). Reservoir simulations, experimental studies, and pilot projects have provided preliminary evidence of the technical feasibility of CO_2-EGR. However, the technology is not yet fully developed or commercially viable (Liu et al., 2022).

3.1 Projects

The first commercial CO_2-EOR project began at SACROC in 1972 and is still operating in 2023. As a result, SACROC increased their oil recovery by 10% (Contek Solutions, n.d.). SACROC's success has incentivised other oil and gas producers to adopt CO_2-EOR/EGR. As a result, approximately 73% of the annual global CO_2 captured is utilized for EOR projects (Robertson and Mousavian, 2022). Recently, CO_2-EOR has been utilised to improve recovery and reduce emissions and the associated carbon tax. The first project to incorporate CO_2-EOR for increased production as well as CO_2 storage was in 2000 at the Weyburn field, Canada (Liu and Riu, 2022). As of 2023, there are more than 150 CO_2-EOR projects worldwide. The USA makes up about 25% of CO_2 storage through operational and planned CO_2-EOR projects (Global CCS Institute, 2023). The largest current project is the Lula project, part of the Petrobras Santos Basin CCS project with a total storage capacity of 8.7Mtpa of CO_2. It is also the first offshore CO_2-EOR project (Global CCS Institute, 2023).

The first CO_2-EGR demonstration project was in 2002 at the Long Coulee Glauconite F pool gas field, in Canada (Pooladi-Darvish et al., 2008). Since then, two other demonstration projects have taken place at the K12-B gas field project, Dutch North Sea (Vandeweijer et al., 2018) and the Otway project, Australia (Jenkins et al., 2012). The CASTOR pilot project in the Atzbach-Schwanestadt gas field, Austria was supposed to inject 8.2Mton CO_2 over 30 years but was cancelled due to permitting issues. The ROAD CCS pilot project in the P18-4 field, Dutch North Sea has also been postponed due to decreases in carbon pricing. This project proposed to inject 8Mton CO_2 over 10 years. The CLEAN project in the Altmark natural gas field, Germany, also proposed to inject 0.1Mton CO_2 over 3 years but was postponed due to the expensive re-completion of wells required (Kühn et al., 2013).

3.2 Results

The sustainability and appropriateness of CO_2 for oil and gas decarbonisation is a largely disputed topic. It is commonly believed that CO_2-EOR/EGR will prolong production from the emission-intensive oil and gas industry (Núñez-López et al., 2019). Núñez-López et al. (2019) concluded that the retention of CO_2 within the subsurface offsets the emissions from the final product, i.e., gasoline. In turn, this can lead to carbon-negative oil and gas production. However, comparing the life cycle analysis of different CO_2-EOR/EGR projects can be challenging as the boundaries for accounting for GHG emissions across different studies tend to be highly varied. Additionally, the source of CO_2 for CO_2-EOR has a large impact on the emission intensity of CO_2-EOR. When CO_2 is sourced from anthropogenic sources, it will reduce the emissions intensity of CO_2-EOR. However, as 70% of CO_2 in the USA is sourced from natural CO_2 sinks, this source of CO_2 leads to no reduction in emission intensity (IEA, 2019).

4. ENHANCED COAL BED METHANE (ECBM)

Aside from conventional gas reservoirs, natural gas is also stored within the micropores and cleats of CBM reservoirs (Satter and Iqbal, 2016). ECBM involves the injection of CO_2 into coal bed seams with the intention of reducing the GHG emissions from the CBM industry whilst increasing the recovery of CBM and heavier natural gases. For simplicity, these gases will be referred to as CBM, as methane is the most produced gas. 20-60% of CBM recovery occurs during the primary stage of recovery when the coal bed is first drilled (Mukherjee and Misra, 2018). The difference between the reservoir and atmospheric pressure causes the CBM to desorb from the surface of the porous coal particles. The CBM then flows through cleats or fractures to the production wells. Water is then pumped into the reservoir to maintain reservoir pressure, promote CH_4 desorption and increase production. Hydraulic fracturing is commonly used to increase the permeability of the reservoir (Satter and Iqbal, 2016). However, hydraulic fracturing requires large amounts of water and does not significantly improve production efficiency (Liu et al., 2022). CO_2-ECBM has been trialled across a number of international projects to maintain the pressure gradient across the reservoir through the injection of CO_2. CO_2 also reduces the partial pressure of CH_4 and increases the rate of CH_4 desorption. The coal bed grains then absorb and store the CO_2 and reduce the emissions intensity of CBM production. Additionally, displacing CBM can significantly decrease the potential hazard of gas explosions or outbursts in coal mines (Zhang et al., 2023).

Geologically, CBM reservoirs are a lot shallower, typically under 1000m, than previously covered reservoir types (Satter and Iqbal, 2016). However, deep CBM reservoirs, between 1500m-3000m, can also be exploited (Huang et al., 2020). CBM reservoirs hold up to 98% of the CBM in an adsorbed state. The reservoirs' permeability depends on in-situ stress, as CBM reservoirs have a much larger compressibility compared to other reservoir types. Reservoir stress is highly dependent on the elastic modulus of the coal. Increased stress within the reservoir leads to cleat compression and reduced permeability. Porosity reduction through shrinkage during reservoir decompression is also very common within CBM reservoirs and must be controlled to maintain reservoir permeability and production. CO_2 adsorption in CBM reservoirs leads to increased swelling and decreased stiffness, causing decreased permeability within CBM reservoir (Han et al., 2020; Satter and Iqbal, 2016). Langmuir-type curves can be used to mathematically describe the reduction in mechanical strength and stiffness (elastic modulus) due to the saturation pressure of the CO_2 within the reservoir. Therefore, reinjection conditions must be carefully selected to minimise swelling and reservoir stress whilst maximising CO_2 adsorption and CH_4 desorption (Han et al., 2020).

4.1 Projects

CO_2-ECBM has been trialled at a limited number of pilot projects internationally. The Allison and Tiffany units at the San Juan Basin in New Mexico, USA were the first and the only large-scale pilot field test of CO_2-ECBM in 1995. As part of this project, 336,000 tonCO_2 was injected over six years at the Allison unit. At the Tiffany unit, nitrogen was injected to evaluate the potential for ECBM using nitrogen (N_2-ECBM) instead of CO_2 (Pan and Connell, 2012).

Smaller pilot projects have been trialled at Yurabi, Japan (Fujioka et al., 2010), and the Velenje mine, Poland (Wageningen et al., 2009). Whilst the number of field projects is low, reservoir modelling and adsorption experiments have been extensively conducted on ECBM (Mukherjee and Misra, 2018).

4.2 Results

Pilot project results have not shown a lot of promise for ECBM acting as a promising CCS technique. Firstly, CO_2 adsorption within CBM reservoirs has decreased reservoir permeability, e.g., 100mD to 1mD at the Allison unit (Godec et al., 2014). This is due to the coal swelling during CO_2 adsorption (Pan and Connell, 2012). In turn, this led to a large pressure build-up in the area surrounding the production wells, resulting in an overall decrease in injectivity (Mukherjee and Misra, 2018). In most cases, models and pilot projects have shown that CO_2 will break through to the production wells after several years. The time before the breakthrough decreases as the injection rate increases (Zarrouk and Moore, 2009). Where there is no breakthrough of CO_2, e.g., Allison Unit (Godec et al., 2014), it has been believed that the lack of breakthrough was due to the insufficient permeability within the reservoir due to coal swelling. N_2 injection alongside CO_2 is now being trialled to reduce these effects in fields with inadequate permeability and coal rank (Godec et al., 2014). However, results have shown that this results in lower CH_4 recovery and faster breakthrough times, e.g., Huntly Coalfield, New Zealand (Zarrouk and Moore, 2009) (Liu et al., 2022).

5. DEDICATED GEOLOGICAL STORAGE

CO_2 storage in depleted oil and gas reservoirs and CO_2-EOR provides the additional benefit of utilizing existing facilities (prior to their decommissioning) and ultimately addresses the short-term CO_2 storage gap for fast and relatively affordable climate abatement returns (Hannis et al., 2017). Dedicated geological storage reservoirs, unlike CO_2-EOR, are used to only store and remove CO_2 from the atmosphere. Whilst CO_2-EOR has the largest capacity of CO_2 storage out of all CCS projects, most upcoming CCS projects are utilising dedicated geological storage as their storage mechanism (Global CCS Institute, 2023). This is partly because the reliance on oil is declining and partly due to carbon pricing, e.g., 45Q tax credit in the USA provides $50 USD/t$CO_2$ for permanent storage and $35 USD/t$CO_2$ for EOR. Dedicated geological storage is a more stable alternative to CO_2-EOR, particularly during low oil prices (IEA, 2020). Large subsurface rock formations such as sedimentary basins, depleted oil and gas reservoirs, saline aquifers, and basalts are well-suited for carbon storage due to their vast volume and widespread availability (Gunnarsson and Sigfússon, 2013).

5.1 Saline Aquifers

Whilst saline aquifers have been used for CO_2-EOR projects, e.g., Otway, Australia; Weyburn, USA (Michael et al., 2010), fractures in saline aquifers have the highest CO_2 storing potential at approximately 10,000GtonCO_2 worldwide (Wei et al., 2022). The supercritical CO_2 is injected into these fractures, typically more than 1000m in depth. The high pressure of the reservoir causes the formation of supercritical CO_2 within the reservoir. The buoyant CO_2 then migrates up to the top of the reservoir, trapped by an overlain with a low permeability caprock (Akai et al., 2021).

In 1996, the Sleipner project in the Norwegian North Sea marked the first commercial-scale CCS project into saline aquifers specifically dedicated to the disposal of CO_2 from gas production. Following its success, numerous storage projects within saline aquifers have taken place both on a commercial scale and as pilot projects. The Gorgon project is the largest current CO_2 storage project, with an estimated capacity of 120MtCO_2 and a maximum injection rate of 4Mtpa (Global CCS Institute, 2023).

Currently, 6 saline aquifer projects are in development with an additional estimated storage capacity of 13.575Mtpa. One of the most notable projects is the Lake Charles Methanol facility, USA, with a storage capacity of 4Mtpa (Global CCS Institute, 2023). Saline aquifers also have a wide distribution worldwide, providing generally lower transportation costs that make saline aquifers attractive economically. The lack of financial incentives for saline aquifer CO_2 storage is the main reason for a slow rate of progress. However, financial incentives for saline aquifers will increase with larger carbon prices (Cao et al., 2020).

5.1.1 Results

While these projects successfully proved storage within saline aquifers, pressure accumulation and CO_2 plume migration within the formation have been observed in these projects and reservoir models. As a result, this has proven that saline aquifers exhibit a larger risk of formation fracturing and fault reactivation, increasing the chance of CO_2 leakage (Cao et al., 2020).

5.2 Depleted Oil and Gas Fields

The CO_2 trapping mechanism is the exact same as it is for CO_2-EOR and CO_2-EGR carbon storage. However, the overarching aim of this technique is to permanently store CO_2 as opposed to enhancing oil or gas production when CO_2-EOR/EGR is used. CO_2 is sourced directly from anthropogenic sources. Depleted oil and gas fields provide a very advantageous environment for the storage of CO_2. Firstly, oil and gas reservoirs offer an abundance of existing surface and underground equipment, which can be repurposed with minimal modifications. Secondly, the caprock's seal quality and integrity have been thoroughly assessed and ensured during the exploration and production phases. Thirdly, due to prolonged oil and gas extraction, depleted oil and gas reservoirs experience smaller pressure perturbations and induced stress changes compared to saline aquifers (Orlic, 2016).

0.065Mton of CO_2 was injected at the first and only commercial-scale demonstration project, the Otway Project, Australia, which began in March 2008 (Cao et al., 2022; Hannis et al., 2017). Further project data is required to determine the effectiveness of this CCS technique. 11 projects are now in various stages of development. These projects are expected to provide an additional 12Mtpa of CO_2 storage per year (Global CCS Institute, 2023; Cao et al., 2022; Hannis et al., 2017).

6. COMPARISON BETWEEN GEOTHERMAL NCG REINJECTION AND OTHER CCS METHODS

A summary of each CCS technology is shown in Table 1 below.

6.1 Key findings

Whilst CO_2-EOR is the most established technology, the main priority of CO_2-EOR, as well as CO_2-EGR, and ECBM, is to increase the recovery of oil and gas and not for climate change abatement. For this reason, care should be taken applying lessons learned in these methods to geothermal NCG reinjection, and CO_2 storage in saline aquifers and depleted oil and gas reservoirs. Additionally, geothermal NCG reinjection is the only method that also disposes of H_2S as well as CO_2. These NCGs are sourced directly from the produced fluid for geothermal reservoirs, whereas, in the other CCS methods, the majority of CO_2 is sourced directly from anthropogenic sources. NCGs are also injected dissolved in fluid into the reservoir, whereas in the other CCS techniques, they are injected as a supercritical gas.

6.2 Entrapment and storability

The entrapment mechanism between the methods covered is varied. In geothermal NCG reinjection, the primary method for NCG sequestration is residual trapping and after a period of time, it becomes mineralisation. Stratigraphic trapping has not successfully been utilised in geothermal NCG reinjection despite the efforts at Umurlu, Turkey (Yücetaş et al., 2018). Whereas in all the other methods, apart from ECBM, stratigraphic trapping is the primary initial trapping mechanism. This is because CO_2 is injected into reservoir types that have an impermeable cap rock. In contrast, most geothermal reservoirs do not have a cap rock.

Additionally, complete storage of CO_2 has not been achieved in CO_2-EOR and CO_2-EGR due to the continued production of the reservoir. It is thereby recommended that stratigraphic trapping is not an optimal primary storage mechanism for the reduction in the emissions intensity of geothermal production. However, recycling and reinjecting the produced CO_2 back into the reservoir does reduce emissions intensity. In the case that CO_2 is to be injected as a supercritical gas into geothermal reservoirs that rely on stratigraphic trapping as the storage mechanism, e.g., carbonate reservoirs in Turkey, then the water and gas injection type should be selected. This is to reduce the effect of viscous fingering and has proven effective in the CO_2-EOR process (Núñez-López et al., 2019). CO_2 mineralisation results from Hellisheiði show that NCG reinjection currently only has a 50% storability (Sigfússon et al., 2018; Gunnarsson et al., 2018). This is much lower than ECBM at 95-98% and 100% for dedicated geological storage (assuming no leakage) (Han et al., 2020; Satter and Iqbal, 2016). However, this is larger than the 6-56% of CO_2 storage that occurs in CO_2-EOR (Farajzahed et al., 2020).

6.3 Modelling

Whilst the modelling processes are similar for all methods covered, i.e., modelling the flow of fluids in the reservoir, there is not a large amount of overlap regarding modelling objectives involved in the other CCS processes and NCG reinjection. This is primarily due to the difference in entrapment mechanism and overarching motivation of the different CCS methods. Geothermal NCG reinjection modelling results rely largely on reactive path and transport modelling to model mineralisation. In the other CCS methods, mineralisation occurs much later, usually at least 100 years, and the CO_2 remains in the gaseous phase inside the reservoir. However, the CO_2-ECBM-TOUGH EOS module developed for ECBM modelling can and has been used for geothermal NCG reinjection modelling (Zarrouk and Moore, 2009; Kaya and Zarrouk, 2017). It is recommended that this EOS module be used for geothermal NCG reinjection reservoir modelling, which can model the main NCG components (Kaya and Zarrouk, 2017).

6.4 Leakage and monitoring

All CCS methods have possible leakage through wells, fractures and faults. The largest risk of leakage through wells is for CO_2-EOR, CO_2-EGR, and depleted oil and gas storage due to the large number of wells in these reservoirs. Results from SACROC show that carbonic acid that forms from the reaction between injected CO_2 and reservoir water has not degraded the cement in the wells over 40 years of storage (CSLF, 2017). CO_2 injection may, however, increase the risk of local seismicity as it has in the geothermal and oil and gas industries, which can increase the chance of leakage through larger fractures and faults. Leakage is detected by monitoring the change in CO_2 production in produced fluids for CO_2-EOR, CO_2-EGR, and geothermal NCG reinjection.

7. CONCLUSIONS

Whilst there is not a lot of overlap between geothermal NCG reinjection and the other covered CCS methods due to the differences in reservoir geologies and overarching motivation, the following comparisons can be made:

- CO_2-EOR, CO_2-EGR and CO_2-ECBM are financially attractive as they increase oil and gas production. However, geothermal NCG reinjection and CO_2 storage in dedicated geological formations lack financial incentives as they are only used for GHG emission reduction.
- All methods become more financially attractive in higher carbon tax scenarios.
- Geothermal NCG reinjection has the lowest cost of technological implementation.
- Mineralisation and solubility trapping is the key storage mechanism for geothermal NCG reinjection. Stratigraphic trapping is the key storage mechanism for CO_2-EOR/EGR and dedicated geological storage. CBM adsorption is the key storage mechanism for CO_2-ECBM.
- Injection of CO_2 dissolved in fluid is primarily used within geothermal NCG reinjection and CO_2 storage in depleted oil and gas fields. Supercritical CO_2 injection is used in the rest of the techniques, and in the storage of NCGs in geothermal reservoirs where stratigraphic trapping is the main storage mechanism.
- CO_2 is supplied directly from the produced fluid for geothermal NCG reinjection, whilst the other methods primarily rely on CO_2 from anthropogenic sources/ natural CO_2 sinks.
- Dedicated geological storage has the highest CO_2 storage percentage at 100%. CO_2-ECBM has the second highest at 95-98%. NCG reinjection has the third highest at ~50% and CO_2-EOR has the lowest between 6-56% (Farajzahed et al., 2020; Sigfússon et al., 2018; Gunnarsson et al., 2018; Han et al., 2020; Satter and Iqbal, 2016).

Table 1. Summary of comparative assessment between geothermal NCG reinjection, CO_2-EOR, CO_2-EGR, ECBM, CO_2 storage in saline aquifers, and CO_2 storage in depleted oil and gas fields.

Method	Geothermal NCG reinjection	CO_2-EOR	CO_2-EGR	ECBM	Saline aquifers	Depleted oil and gas
Number of commercial scale projects	4 active (Hellisheiði and Nesjavellir, Iceland; Puna, USA; Te Huka, New Zealand), 1 inactive (Coso, USA)	150+ combined active and inactive. Mostly in the US.	3 inactive	1 inactive (Allison and Tiffany units, US)	5 inactive	3 inactive
Overarching motivation	Emissions intensity reduction of geothermal power production to increase profit through lower carbon pricing. Also, climate change abatement.	Increase hydrocarbon recovery and reduce emissions intensity to increase profit through larger hydrocarbon production and lower carbon tax. Also, climate change abatement.		Increase CBM recovery and reduce emissions intensity to increase profit through larger CBM production and lower carbon tax. Also, climate change abatement.	Climate change abatement.	
Reinjected gases	CO_2 and H_2S. Reinjected with water.	CO_2. H_2S reinjected at LeBarge, Wyoming. Reinjected with water.	CO_2. Reinjected with water.	CO_2. Sometimes N_2 is used to enhance injectivity	CO_2	CO_2 (SO_2 if the Joule-Thomson effect needs to be reduced.)
Sources of reinjected gases	Produced alongside geothermal fluid.	Mostly from natural CO_2 sink sources (70% in the US). Remaining is from anthropogenic sources.		Anthropogenic sources.		
Modelling objective	Maximise storage of NCGs without reducing production rate and preventing thermal and chemical breakthroughs. Used to predict if NCGs will breakthrough to the wells. Determine optimal water and CO_2 injection rates. Model mineralisation rates. Observe the impact on reservoir geology from the injection of NCGs. Determine the sizing and operating conditions of surface facilities. Model the mixing NCG and water mixing and predict wellbore integrity	Primarily centred around enhancing comprehension of sweep efficiency. Prevent early breakthrough of CO_2 and water through the optimisation water and gas injection ratio and well location.	Primarily centred around enhancing comprehension of sweep efficiency and determining the technical feasibility of the project. Prevent early breakthrough of CO_2.	To assess the effectiveness of CO_2 (and N_2 if it is used) sequestration and ECBM recovery. Adsorption modelling is based upon Langmuir adsorption curves based upon laboratory experiments.	Forecast CO_2 behaviour and estimate capacity and containment. initial predictions are submitted to acquire permits. Model is history matched against previous project results. However, previous project data is limited for saline aquifers.	
Modelling capabilities	Flow of NCGs and water can be modelled. Rock-fluid reactions and mineralisation can be modelled with the conjunction of reaction path and reaction transport modelling. Lack of previous project data, and large number of uncertainties, leads to large uncertainties in the model. Advancements in geochemical modelling is required to determine mineralisation rates.	Black-oil and compositional models (most popular) are available. The presence of residual hydrocarbon saturations can contribute to the complexity of the situation. Large uncertainty in reservoirs' total	Able to model isothermal flow of CO_2, CH_4, and residual water. Different simulators have generated similar results. Very limited project data for history matching.	Ability to model on isothermal flow of CO_2, N_2, CH_4, H_2S. Modelling results successfully replicated results seen in commercial scaled project.	Able to simulate the two-phase behaviour and the precipitation and dissolution of CO_2, H_2O, NaCl, CaCl, and $CaCO_3$. Large uncertainties arise due to intricate geological structure and trapping mechanisms, and lack of previous history	Complex modelling due to residual hydrocarbon saturations, but it can be mitigated by matching it with production data to minimize uncertainty. Geomechanical modelling is employed, incorporating site

		capacity for CO_2 storage.			matching data. Model results have not matched 4d seismic results in several projects.	history, to ensure the integrity of the wellbore and caprock rocks following pressure cycling.
Separation technique	Extracted from the heat exchangers for binary systems using NCG exhaust streams. NCG separation is maximised by extracting at each heat exchanger as the temperature of the produced fluid decreases. Liquid ring vacuum pumps in anoxic conditions are most appropriate for NCG separation in flash systems. H_2S abatement is not required unless utilisation is selected over NCG reinjection.	Either pre-combustion or post-combustion for anthropogenic CO_2 sources. Chemical adsorption is the most common and well-developed technique. However, this is a very energy-intensive process. Membrane separation techniques are now becoming increasingly popular and have proven to provide a much more energy-efficient and sustainable method for separation. H_2S abatement methods are also required when CO_2 is sourced directly from oil and gas reservoirs. Sulphur Recovery Units are most commonly used whereby elemental sulphur is produced and can be sold as a byproduct.				
Injection type	Recommended to dissolve the CO_2 into the injectant either at the surface or down the injection well. Surface mixing using adsorption columns at 11 bar has proved 95% CO_2 and 99%H_2S adsorption. However, this method still requires NCG venting and should only be used on low NCG concentration projects. Binary systems and high NCG content projects should use down well mixing with multiple mixing points. Injection pressure must be above the breakout pressure to ensure NCGs remain dissolved within the injectant and reservoir fluid.	Either CGI, WAG, or SWAG. 90% of projects use WAG as it reduces the effect of viscous fingering and has the greatest potential for increased EOR and CO_2 sequestration. However, WAG injection has led to reduced injectivity, premature water and CO_2 breakthroughs, corrosion, and the formation of hydrates. Injection pressure must be above the MMP so that the CO_2 is miscible within the oil to maximise EOR and CO_2 sequestration.		Supercritical CO_2 injection has proven to increase the adsorption within CBM reservoirs. Pressures are often selected between 40-160 bar. Whilst increased pressure increases CH_4 recovery, it reduces CO_2 breakthrough time. N_2 is also injected in some cases to reduce coal swelling and maximise permeability but it has led to decreased breakthrough times in projects.	Supercritical CO_2 injection.	CO_2 dissolved in fluid.
Entrapment mechanism	In basaltic reservoirs, entrapment is initially solubility trapping within the injectant and reservoir fluid. CO_2 then mineralises to calcite and H_2S mineralises to pyrite. Mineralisation in other geology types is currently being researched.	Initially, structural or stratigraphic trapping where impermeable cap rock prevents CO_2 mitigation to the surface. The CO_2 then sweeps, replaces the oil and gas in the reservoir pores, and is stored through residual trapping. Mineralisation occurs in high-temperature reservoirs at a very slow rate over hundreds of years.		Primarily chemical adsorption. CH_4 desorbs from the coal grains, and CO_2 adsorbs to the coal grains.	Initially, structural trapping. Then, residual trapping after approximately 10 years. Solubility trapping after 100 years.	
Tracing	Inert tracers are used to track NCG-injectant flow. DIC, $CaCO_3$, Ca and SO_4 concentration in a produced fluid is a metric for mineralisation rate.	CO_2 production levels are measured in the production well. Compared with injected CO_2 rates to calculate the storability.		N_2 production is an indication of imminent CO_2 breakthrough in the wells.	Downhole wireline samples.	

Leakage and monitoring	There is a high chance of leakage if NCGs come out of solution, as there is usually no cap rock in the geothermal reservoir. Changes in CO_2 flux through surface features and soil can indicate potential CO_2 leakage. Very extensive monitoring is required across the whole field, and there is limited monitoring data outside of the power stations.	Leakage from the reservoir can occur through existing well bores, faults, fractures, seismic activity, lateral migration of CO_2 out of the reservoir, and drilling through CO_2 area. Measurements of oil, water, and CO_2 flow rates as well as aerial surveys, are used to detect leakage from CO_2 reservoirs.		Susceptible to leakage, especially in the high pressure around the well or through high permeability cap rocks or fractures. Monitoring CO_2 concentration around the injection well and in the overlying strata can detect early-stage leakage.	Potential leakage through the opening of fractures and faults through CO_2 injection. 4D seismic can be used to track the movement of the CO_2 plume.	A relatively large source of leakage through existing well bores and the opening of faults and fractures from CO_2 injection. Difficult to detect using seismic tools due to the presence of residual oil and gas.
Impacts on reservoir geology	Reactive modelling indicates that permeability, porosity, and pressure support increased after NCG was reinjected. Potential opening of fractures and faults due to the injection of CO_2, and subsequent increased risk of local seismicity.	Slight mineralisation occurs in high-temperature oil reservoirs, and in gas reservoirs, over 100 years which can reduce permeability. Potential opening of fractures and faults due to the injection of CO_2, and subsequent increased risk of local seismicity.		CO_2 adsorption has resulted in large amounts of coal swelling, causing a substantial reduction in reservoir porosity and permeability.	Potential opening of fractures and faults due to the injection of CO_2, and subsequent increased risk of local seismicity.	
Storability	50% CO_2 and 76% H_2S mineralisation in basaltic reservoir types.	120Gt storage capacity worldwide. 6-56% of injected CO_2 stored.	160-390Gt storage capacity worldwide.	95-98% estimated. 3-200Gt storage capacity worldwide.	100% storability. 10000GtCO_2 worldwide capacity worldwide.	1000Gt worldwide storability. 100% storage
Cost and economics	Capture is the largest expenditure. Single-step separation is relatively cheaper as H_2S abatement methods are not required. Additional cost of the required infrastructure is minimised as capture and reinjection occur on the same site. Depending on CO_2 price, utilisation may be more economically attractive but requires additional energy for 2-step purification methods.	Incentivised during high oil and gas prices, low CO_2 supply prices, and high carbon taxes. Additional transportation infrastructure is required to supply CO_2. Reinjection consumes ~3-10% of the thermal energy produced.		Incentivised during high gas prices and low CO_2 prices. Profit is mainly dependent on carbon tax, capture cost, and pipeline distance. \$2USD/MSCFCO_2 profit recorded in only commercial-scale project. Profitable after \$20USD/tCO_2e carbon tax.	Low financial incentives at low carbon prices. Larger incentives in countries with larger tax credits for permanent storage compared to EOR. Lower respective transport costs due to wide distribution worldwide.	Lower respective installation costs if oil and gas infrastructure is utilised. Additional transportation infrastructure is required to supply CO_2. Larger incentives at higher carbon taxes and in countries with larger tax credits for permanent CO_2 storage.
Future developments	Mineralisation to be trialled in other reservoir types. Developments in reactive modelling to further determine mineralisation rates.	Use of more separation types. Addition of reactants to improve CO_2 solubility in oil	CO_2 storage within tight shale gas reservoir	Potential use of cryogenic injection of CO_2 to increase permeability and therefore improve CO_2 storage and CH_4 production.	Future project data to history match models to and improve their reliability.	
Future projects	Continuation of the GECO research project, and several research projects through the geothermal department at the University of Auckland.	9 projects in development. Additional 15.7Mtpa of CO_2 storage.	No commercial-scale projects are currently in development.	No commercial-scale projects are currently in development.	6 additional projects with a storage capacity of 13.575Mtpa.	11 additional projects with a storage capacity of 12Mtpa.

ISSN2703-4275

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