INTRODUCTION

This review results from directed studies at the University of Victoria by the senior author and it covers the main technical aspects of the Greenhouse Gas Sequestration methodology.

The Kyoto Agreement may or may not be ratified, however, the following text highlights those options that British Columbia will have if a need for geological, mineral or deep ocean sequestration arises. Of the six greenhouse gases covered by the Kyoto protocol, carbon dioxide (CO₂) is the greatest contributor to Canada’s total GHG emissions (Table 1). Fossil fuel combustion is the main source of anthropogenic CO₂, and it currently supplies over 85% of the global energy demand (Figure 1). The main engineering effort for reduction of CO₂ emissions is therefore aimed at increased efficiency of fossil energy usage, development of energy sources with lower carbon content and increased reliability on alternative energy sources such as wind, solar, geothermal and nuclear. It is not likely that the reduction of CO₂ emissions, in an order of magnitude similar to the Kyoto agreement, could be met using these measures alone.

CO₂ sequestration methods that are currently considered, or being evaluated by industrialized countries, are part of the global plan. Each method has its weaknesses and strengths. The methods that we will cover in this review are:

- Storage in Oil and Gas Reservoirs
- Storage in Deep Coal Seams
- Storage in Deep, Saline Aquifers
- Storage in Deep Ocean
- Storage in Salt Caverns
- Mineral Carbonation

Since all geological and mineral CO₂ sequestration methods involve the capture and extraction of CO₂ from flue-gases or industrial streams, transportation of CO₂ and its disposal in an appropriate sink, the next stage of our study will identify the main stationary point sources of CO₂ emissions and the main potential carbon or CO₂ sinks in British Columbia.

Geographic relationships between the main stationary point CO₂ sources and sinks is an essential piece of the puzzle for CO₂ sequestration planning in British Columbia since transportation is one of the important cost factors.

PHYSICAL PROPERTIES OF CARBON DIOXIDE

It is important to know the main properties of carbon dioxide to understand carbon sequestration methods. Carbon dioxide (CO₂) is an odourless, colourless gas that occurs naturally in the atmosphere. Current ambient atmospheric CO₂ concentrations are approximately 390 parts per million (ppm), but levels have increased by over 15% since pre-industrial times due to increased fossil fuel combustion.

<table>
<thead>
<tr>
<th>CANADIAN GREENHOUSE GAS EMISSIONS</th>
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<tbody>
<tr>
<td><strong>Carbon Dioxide (CO₂)</strong></td>
</tr>
<tr>
<td><strong>Methane (CH₄)</strong></td>
</tr>
<tr>
<td><strong>Nitrous Oxide (N₂O)</strong></td>
</tr>
<tr>
<td><em><em>Other (HFCs</em>, PFCs+ and SF₆⁻)</em>*</td>
</tr>
</tbody>
</table>

*Hydrofluorocarbons
Perfluorocarbons
As Carbon Dioxide Equivalent
Sulphur hexafluorides

(Source: Environment Canada, 2002)

Figure 1. Global energy demand. Fossil fuels supply over 85% of the world’s energy. (Source: McKee, 2002)
spheric concentrations of CO₂ are around 370 ppm (0.037%). Benson et al. (2002) summarizes the effects of high concentrations of CO₂ on humans and other life forms.

Depending on pressure and temperature, CO₂ can take on three separate phases (Figure 2). CO₂ is in a supercritical phase at temperatures greater than 31.1°C and pressures greater than 7.38 MPa (critical point). Below these temperature and pressure conditions, CO₂ will be either a gas or a liquid. Depending on in situ temperature and pressure, CO₂ can be stored as a compressed gas or liquid, or in a supercritical (dense) phase.

**CO₂ STORAGE IN OIL AND GAS RESERVOIRS**

Both depleted and active fossil fuel reservoirs are potential storage space for CO₂ in underground formations. CO₂ may be injected directly into a depleted or inactive reservoir without expectation of any further oil production, or the CO₂ injection may result in enhanced oil/gas recovery and simultaneous CO₂ sequestration. CO₂ may also be injected into producing oil and gas reservoirs, where CO₂-enhanced oil recovery (EOR) and CO₂-enhanced gas recovery (EGR) will offer an economic benefit. Typically, oil reservoirs have undergone a variety of production and injection processes during primary and secondary recovery (e.g. gas, water or steam injection), as described by Jimenez and Chalaturnyk (2002). As a tertiary recovery process, CO₂ can be injected into the reservoir to improve the mobility of the remaining oil (van der Meer, 2002), thereby extending the production life of the reservoir. Injection of CO₂ into producing gas reservoirs for EGR was previously believed to risk contaminating the natural gas reserve (Stevens et al., 2000). However, recent studies by Oldenburg and Benson (2002; 2001) suggest that mixing of the CO₂ and methane (CH₄) in a gas reservoir would be limited due to the high density and viscosity of CO₂ relative to the natural gas. Furthermore, significant quantities of natural gas can be produced by repressurization of the reservoir. According to Davison et al. (2001), it is possible that improved oil and gas recovery could more than offset the cost of CO₂ capture and injection.

For the purpose of this paper, the term “depleted fossil fuel reservoirs” refers to abandoned oil and gas reservoirs. These reservoirs have undergone primary and secondary recovery and CO₂-enhanced oil recovery is not currently envisaged to generate positive cashflow.

**ACTIVE OIL RESERVOIRS**

The petroleum industry has been injecting CO₂ into underground formations for several decades (Gentzis, 2000) to improve oil recovery from light and medium oil reservoirs, even before climate change became an issue (Bachu, 2000a). CO₂ injected into suitable oil reservoirs can improve oil recovery by 10-15% of the original oil in place in the reservoir (Davison et al., 2001). When CO₂ is injected into a reservoir above its critical point (typically a reservoir depth greater than 800 m), the gas acts as a powerful solvent. If the pressure is high enough and the oil gravity is greater than 25° API (Bachu, 2001), the CO₂ and oil become completely miscible. According to Aycaguer et al. (2001), the miscible flood reduces the oil’s viscosity thereby enabling the oil to migrate more readily to the producing wells (Figure 3). At lower pressures CO₂ and oil are not completely miscible, however some fraction of the CO₂ will dissolve in the oil. This is known as immiscible displacement and also enhances oil recovery. CO₂ enhanced oil recovery is now considered as a mature technology (Gentzis, 2000). If EOR is the main objective of CO₂ injection, then the operation is optimized to minimize the cost of CO₂ used and maximize the oil recovery. CO₂ sequestration differs from EOR by CO₂; its main objective is to sequester as much CO₂ in the reservoir as possible for geological time (van der Meer, 2002; Benson, 2000).

A life cycle assessment study on EOR with injection of CO₂ in the Permian Basin of West Texas (Aycaguer et al., 2001) suggests that the amount of CO₂ injected, not includ-
DEPLETED OIL AND GAS RESERVOIRS

Following more than a century of intensive petroleum exploitation, thousands of oil and gas fields are approaching the ends of their economically productive lives (Davison et al., 2001). Some of these exhausted fields could act as storage sites for CO2. As in the case of producing fields, the general concept of CO2 disposal in depleted oil and gas reservoirs is that the hydrogeological conditions that allowed the hydrocarbons to accumulate in the first place will also permit the accumulation and trapping of CO2 in the space vacated by the produced hydrocarbons (Hitchon et al., 1999; Gentzis, 2000). The caprock that prevented the escape of oil and gas over geological time, should retain the sequestered CO2 for thousands of years (Bachu, 2001), as long as it is not damaged as a result of overpressuring during the CO2 injection (van der Meer, 1993), by the presence of unsealed, improperly completed or abandoned wells (Hitchon et al., 1999), tectonic activity or pH change.

About 80% of the world’s hydrocarbon fields are at depths greater than 800m (IEA, website), thus meeting the criteria for the pressure and temperature needed to efficiently store CO2 as a supercritical fluid (van der Meer, 1993). Existing infrastructure and reservoir properties make storage of CO2 in depleted oil and gas reservoirs a simpler option than other forms of CO2 sequestration (Bachu, 2000a).

Closed, underpressured oil reservoirs that have not been invaded by water should have good sequestration capacity (Bachu, 2001). Oil field primary recovery varies from 5% to 40% (van der Meer, 2002), thus, depending on the extraction technology used and economic conditions that prevailed during the active life of the reservoir (Bachu et al., 2000), significant oil reserves may remain in the reservoir. Therefore, if exhausted oil fields were used for CO2 storage, substantial amounts of oil could be recovered (van der Meer, 2002). Depleted hydrocarbon reservoirs that are filled with connate water (fully water-saturated reservoirs) offer limited storage capacity. The injected CO2 would have to displace the connate water of the reservoir. Storage of CO2 in water-saturated reservoirs would in practice amount to aquifer storage (Bachu, 2000a; van der Meer, 2002) as described later in this paper.

Closed, underpressured, depleted gas reservoirs are excellent geological traps for CO2 storage. Firstly, primary recovery of gas fields usually removes as much as 95% of the original gas in place (Bachu, 2001), creating large storage potential. Secondly, the injected CO2 can be used to restore the reservoir to its original pressure (Bachu et al., 2000), thereby preventing possible collapse or man-induced subsidence. Thirdly, the trapping mechanism that retained hydrocarbons in the first place should ensure that CO2 does not reach the surface (Bachu et al., 2000). And lastly, the existing surface and down-hole infrastructure used for production of gas is ideally suited for transportation and injection of supercritical CO2.

Spatial association between hydrocarbon production and the presence of reservoirs suitable for CO2 sequestration may result in shared infrastructure and reduction of transportation costs. Furthermore, depleted hydrocarbon fields commonly have an established geological database and as such, reservoir characteristics are well known. Currently, the petroleum industry is reluctant to consider storage of CO2 in depleted hydrocarbon reservoirs, because abandoned fields will still contain oil and gas resources (US Dept of Energy, 2002), which potentially have economic value if oil prices were to rise enough or new EOR technologies were developed in the future (Davison et al., 2001; Bachu et al., 2000). Today, sequestration of CO2 in depleted oil reservoirs offers little or no economic benefit for the oil companies, however these reservoirs may become a base of the future CO2 disposal industry.

CO2 STORAGE IN COALBEDS

Coalbeds are a potential storage medium for CO2. British Columbia has abundant coal resources; some of them lie at depths too great to be considered for conventional mining. CO2 can be injected into suitable coal seams where it will be adsorbed onto the coal, stored in the pore matrix of the coal seams, and locked up permanently. An alternative to CO2-only storage is injection of flue gas, a mixture of CO2 and nitrogen (N2) into coalbeds. According to Reeve (2000), flue gases account for 80% of CO2 emissions in western Canada. Although in British Columbia flue gases represent much smaller percentage of total emissions, the injection of flue gas may avoid the high cost of CO2 separation (Law et al., 2002).
CO2-ENHANCED COALBED METHANE RECOVERY

CO2 sequestration in coal seams has the potential to generate cashflow through enhanced coalbed methane (CBM) recovery, a process similar to the practice of CO2-EOR. Recovery of CBM is a relatively well-established technology used in several coalfields around the world (Schraufnagel, 1993; Ivory et al., 2000). A number of companies are looking at producing CBM in British Columbia. Primary CBM recovers about 20-60% of the gas in place (Gentzis, 2000; van Bergen, 2001); some of the remaining CBM may be further recovered by CO2 enhanced CBM recovery.

The disposal of CO2 in these methane-rich coalbeds, where applicable, is expected to increase drive pressure and the CBM recovery rate (Hitchon et al., 1999). Thus, injection of CO2 should enable more CBM to be extracted, while at the same time sequestering CO2. CO2-enhanced CBM production could be achieved by drilling wells into the coal deposits, typically a five-spot pattern, with the centre well as the injector and the four corner wells as the producing wells (Wong et al., 2001). After discharging formation waters from the coal, CO2 is injected into the coal seam. CO2 has a higher affinity with coal, about twice that of methane (Figure 4), just below the critical point (~7.38 Mpa). Limited data at pressures exceeding the critical point of CO2 indicate that the extrapolation of the CO2 adsorption curve above 7.38 Mpa is not justified (Krooss et al., 2002). In theory, injected CO2 molecules displace the adsorbed methane molecules (Wong et al., 2001; Ivory et al., 2000; Hitchon et al., 1999), which desorb from the coal matrix into the cleats (Figure 5) and flow to the production wells. CO2 enhanced CBM can achieve about 72% recovery (Wong et al., 2000). A CO2 enhanced CBM production project terminates at CO2 breakthrough in one or more of the production wells (Wong et al., 2001).

Flue gas injection may enhance methane production to a greater degree than CO2 alone (Ivory et al., 2000). However, N2 has a lower affinity for coal than CO2 or methane (Figure 5). Therefore, injection of flue gas or CO2-enriched flue gas results in rapid nitrogen breakthrough at the producing wells (Macdonald et al., 2002; Law et al., 2002). In such cases, N2 waste could be reinjected into the coal seam (Macdonald et al., 2002; Wong and Gunter, 1999).

Sequestration of CO2 in coal seams, while enhancing CBM recovery, is an attractive option, but the physical characteristics of the coals, for the purpose of CO2-enhanced coalbed methane recovery (ECBM), are largely unknown. Recent studies (Fokker and van der Meer, 2002; Reeves, 2002) have shown that continued injection of CO2 in coalbeds induced a decrease in the permeability of the cleat system surrounding the injection well area. In general, desorption of the methane causes shrinkage of the coal matrix, which in turn, causes the cleats to open, thereby allowing the CO2 injection rate to increase and the methane to flow to the producing well. At the same time, replacement of the methane by the injected CO2 is believed to cause the coal matrix to swell. This swelling will partially block the cleat system and negatively affect the main flow parameters. The fracturing of the coal and the swelling have opposite effects on the CO2 injectivity (Fokker and van der Meer, 2002). One possible solution to achieve an acceptable CO2 injection rate would be to allow the near-well gas pressure in the cleat system to exceed the hydraulic fracturing pressure (Fokker and van der Meer, 2002; Shi et al., 2002). However, if repeated hydraulic fracturing is necessary to maintain connectivity between the well bore and the permeable areas of the coal seam, this in turn may result in over/under burden fracturing (Gale, 2002), and CO2 leakage.

The Alberta Research Council (ARC) has done extensive applied research in this field and some of the outstanding contributions were published by Wong et al. (2000), Law et al. (2002), and Mavor et al. (2002). There are currently several CO2-ECBM recovery field projects studying sequestration of CO2 and flue gas in deep coal seams. These projects range in depth from 760 to 1100 metres.

- Alberta Research Council under an international project, facilitated by the IEA Greenhouse gas R&D Programme, has established a pilot site at Fenn-Big Valley, Alberta, Canada. The project is looking at the enhancement of CBM production rates in low permeability CBM reser-
CO2 is injected into a suitable aquifer, due to buoyancy (Gunter et al., 1997). Thus, from a capacity perspective, deep, unmineable coal seams using enhanced CBM recovery technology (Reeves, 2002).

- In October 2000 a three-year government-industry project in the San Juan Basin (USA), known as the Coal-Seq project, was launched. The project studies the feasibility of CO2-sequestration in deep, unmineable coal seams using enhanced CBM recovery technology (Reeves, 2002).
- In November 2001, the RECOPOL project (Reduction of CO2 emission by means of CO2 storage in coal seams in the Silesian Coal Basin of Poland), funded by the European Commission, started with aims to develop the first European field demonstration of CO2 sequestration in subsurface coal seams (van der Meer et al., 2002).

The industry and scientific community will carefully scrutinize the results from these field tests, particularly since they may provide empirical data on CO2 adsorption behaviour above its critical point (7.38 Mpa). The outcome from these tests will probably determine where new research will be oriented.

CO2 STORAGE IN DEEP AQUIFERS

Worldwide, deep saline aquifers have larger geological storage capacity than hydrocarbon reservoirs and deep coal seams (Table 2). Deep aquifers are found in most of the sedimentary basins around the world (Bachu, 2001) and typically contain high-salinity connate water that is not fit for industrial and agricultural use, or for human consumption. Deep saline aquifers have been used for injection of hazardous and nonhazardous liquid waste (Bachu, 2001), ensuring that the injected CO2 will be stored in supercritical state. No single bed or strata will be stored in supercritical state. No single bed or strata (Gale, 2002).

Suitable aquifers must be capped by a regional aquitard (e.g. shale), which should not contain any fractures or incompletely closed wells (Bachu et al., 1994). The top of the aquifer must be located at a minimum depth of 800 meters (van der Meer, 2002), ensuring that the injected CO2 will be stored in supercritical state. No single bed or stratigraphic interval is likely to be a potential injection aquifer across an entire basin (Hitchon et al., 1999), thus near-well permeability should be high for injection purposes, but regional-scale permeability should be low, to ensure long-term disposal of CO2 (Bachu et al., 1994). When the CO2 is injected into a suitable aquifer, due to buoyancy effects, it will rise up and gradually spread out forming a layer of CO2 under the cap rock (Gale, 2002). In the early stages of geochemical reaction, dissolution is expected to be the predominant process (Gunter et al., 1997). The surface area of CO2 in contact with the formation water will control the rate of dissolution. It is believed that during an injection period of 25 years, between 10 and 25% of the CO2 will be dissolved (Gale, 2002). The undissolved portion of the injected CO2 will segregate and form a plume at the top of the aquifer results from density differences (Bachu, 2001). The CO2 plume will be driven by both hydrodynamic flow and by buoyancy (Bachu et al., 2000). The greater the density and viscosity differences between CO2 and the formation fluid, the faster the undissolved CO2 will separate and flow updip in the aquifer in a process similar to oil and gas migration (Bachu, 2001). Thus, CO2 should be injected under high pressures to ensure high density of the CO2 and high CO2 solubility rate in formation water.

Once outside the radius of influence of the injection well, both the dissolved and immiscible CO2 will travel with the natural velocity of the formation water (Gunter et al., 1997). On the regional scale, the velocity of formation waters in these aquifers is expected to be of the orer of 1 to 10cm/year (Bachu et al., 1994), suggesting that CO2 residence time in a deep, low-permeability aquifer could be of the order of tens to hundreds of thousands of years (Gunter et al., 1997). The geological time-scale trapping of CO2 in deep regional aquifers, caused by very low flow velocity, is termed hydrodynamic trapping, because it depends on the hydrodynamic regime of formation waters (Bachu et al., 1994).

Injection of CO2 into a siliclastic formation may lead to precipitation of carbonate minerals, in effect storing CO2 in a stable form. This is referred to as mineral trapping (Bachu et al., 1994; Gunter, Bachu and Benson, in review) and is based on the same principle as mineral carbonation that will be discussed in the last section. The following chemical reaction is an example of mineral trapping of CO2 (Bachu et al., 1994):

\[
\text{CaAl}_2\text{Si}_2\text{O}_8 \text{[Ca-feldspar]} + \text{CO}_2 + 2\text{H}_2\text{O} \rightarrow \\
\text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4 \text{[kaolinite]} + \text{CaCO}_3 \text{[calcite]}
\]

Experiments carried out to test the validity of mineral trapping of CO2, by Gunter et al. (1997), concluded that these reactions are expected to take hundreds of years or more to complete. Due to the long residence time of CO2-charged formation waters within the aquifer, these reactions may eventually trap over 90% of the injected CO2 (Gunter et al., 1997). Mineral trapping will not greatly increase the CO2 storage capacity of the aquifer; rather its advantage over the hydrodynamic trapping resides in the permanent nature of CO2 disposal (Bachu et al., 1994).

<table>
<thead>
<tr>
<th>Storage Option</th>
<th>Global Capacity</th>
<th>% of emissions to 2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depleted oil and gas fields</td>
<td>920</td>
<td>45</td>
</tr>
<tr>
<td>Deep saline aquifers</td>
<td>400-10,000</td>
<td>20-500</td>
</tr>
<tr>
<td>Unmineable coal seams</td>
<td>&gt;15</td>
<td>&gt;1</td>
</tr>
</tbody>
</table>

Source: IEA Greenhouse Gas R&D Programme, 2001

TABLE 2
GLOBAL CAPACITY OF GEOLOGICAL RESERVOIRS
Injection of CO2 into deep, saline aquifers relies on existing technology. Since 1996, Statoil injects about 1 million tonnes of CO2 per year into a deep aquifer offshore Norway (Chadwick et al., 2002). Sequestration of the CO2 waste, a by-product of natural gas production, saves the company from paying a Norwegian CO2 tax (Gentzis, 2000).

DEEP OCEAN DISPOSAL OF CO2

The ocean is the largest sink available for disposal of CO2 with a residence time of four to five hundred years (Gentzis, 2000). The oceans contain a stratified thermocline, which is located between the surface layer and the deep ocean. Its waters circulate between surface and deep layers on varying time scales from 250yrs in the Atlantic Ocean to 1000yrs for parts of the Pacific Ocean (Mignone et al., 2002; Ormerod et al., 2002). The atmosphere and the ocean are in contact over 70% of the globe and there is a continuous exchange of inorganic carbon between them. Oceans are, at present time, removing about six gigatonnes CO2/year from the atmosphere (Ormerod et al., 2002). Disposing anthropogenic CO2 in the deep ocean would accelerate a natural process. CO2 could be injected as a liquid below the thermocline at depths greater than 1500m and be sequestered either by dissolution in the water column or by formation of CO2 hydrates (Figure 6).

STORING CO2 BY DISSOLUTION

One approach involves transporting liquid CO2 from shore by pipeline and then discharging it from a manifold lying on the ocean bottom, forming a droplet plume. Since liquid CO2 is less dense than seawater, the CO2 droplets will rise until they are dissolved into the seawater and the CO2-charged solution spreads laterally into the (stratified) surrounding seawater. The dissolved CO2 may travel in the thermocline, and eventually (after hundreds of years) circulate back into the atmosphere. The deeper the CO2 is injected, the more effectively it is sequestered, but injecting deeper requires more advanced technologies (Ormerod et al., 2002). The oil and gas industry have established technology to construct vertical risers in deep water and to lay seabed oil and gas pipelines in depths down to 1600m (Ormerod et al., 2002), suggesting that this method is technically feasible.

Alternatively, liquid CO2 could be transported by a tanker and discharged from a pipe towed by a moving ship. The Japanese R&D program for ocean sequestration of CO2 is currently in phase II of a large-scale “moving-ship” scheme in the western North Pacific to assess environmental impact and CO2-plume behaviour (Murai et al., 2002). Studies by Ozaki et al. (2001) have shown that CO2 injection would be most effective at relatively slower rates (larger droplet size) and at depths greater than 1500m (Ormerod et al., 2002). Such a depth is well within the capability of present day subsea pipeline technology and CO2 could be transported by a tanker, like those used currently for transportation of liquid petroleum gas (Ormerod et al., 2002).

STORING CO2 AS CLATHRATES

Another method for ocean disposal of CO2 involves sequestration of CO2 at depths in excess of 3000 metres. At these depths, due to the high pressure and low temperatures (Ozaki et al., 2001), CO2 exists in the form of a clathrate hydrate, an ice-like combination of CO2 and water (Brewer et al., 2000). Pure CO2-hydrate is denser than seawater and will generate a sinking plume, settling on the bottom of the ocean (Brewer et al., 2000). CO2 sequestered in this way would form submarine pools in hollows or trenches in the deep sea. Dissolution of CO2 into the overlying seawater would be reduced significantly due to formation of the CO2-hydrates. Direct disposal of CO2 at great depths is currently not technically feasible, however, it may be possible to send cold CO2 (dry ice) from mid-depth to the ocean floor (Aya et al., 2002). With a density greater than seawa-
ter, cold CO₂ will sink to the ocean bottom and be effectively stored. The Monterey Bay Aquarium Research Institute (MBARI) has recently conducted a series of controlled experiments that involve release of cold CO₂ slurry at depths of 350-500m (Aya et al., 2002).

Yet another method proposes disposal of CO₂ as clathrate blocks. Studies on this disposal method confirm that streamlined blocks have higher terminal velocity and thus reach the seabed faster than equidimensional blocks (Guever et al., 1996). As large as 1000 tons and shaped like a projectile, these blocks could penetrate into the deep seabed where the solid CO₂ would physically and chemically interact with the sediments before reacting with the ocean water. The retention times could, therefore, be significantly increased as compared to the gaseous or liquid CO₂ disposal methods (Guever et al., 1996). According to the IEA this method is currently not economically feasible (Ormerod et al., 2002).

Further studies on ocean disposal of CO₂ include fertilising the oceans with additional nutrients to increase draw-down of CO₂ from the atmosphere (Ormerod et al., 2002). Addition of nutrients such as nitrates and phosphates or iron may increase production of biological material, thereby drawing down additional CO₂ from the atmosphere through photosynthesis of the phytoplankton (Ormerod et al., 2002). Should this method prove to be feasible, the fishing industries may benefit from the resulting increase in the fish population, with atmospheric CO₂ sequestration as a secondary benefit, however the overall impact on the marine ecosystem is not well understood.

All the above described ocean disposal methods could potentially cause at least a local change in pH of the ocean water. Marine communities are, in general, intolerant to changes in the pH. Thus, due to environmental impacts on the marine ecosystem and associated public disapproval, ocean sequestration of CO₂ is not currently considered as an attractive option. The situation may change if the development of extensive CH₄ clathrate deposits along the BC coast takes place.

STORAGE IN SALT CAVERNS

Underground caverns, such as mined salt domes, could be created to store CO₂. Salt is generally found as intrusive (domal or ridge) deposits whereby salt from a major underlying source has been forced up into overlying formations. Salt caverns are created by solution mining, a process in which water is injected down a well, to dissolve the salt, and the brine solution is pumped out, creating large cavities. These caverns can be up to 500 000 m³ in volume (Bachu, 2000a), and since salt is highly impermeable (Murck et al., 1996) these spaces could provide a long-term solution to CO₂ sequestration. Solid CO₂ (dry ice) could also be stored in these repositories, surrounded by thermal insulation to minimise heat transfer and loss of CO₂ gas (Davison et al., 2001). The technology has been developed and applied for salt mining and underground storage of petroleum, compressed air and natural gas (Bachu, 2000a; Crossley, 1998; Istvan, 1983). Although salt and rock caverns theoretically have a large storage capacity, the associated costs are very high and the environmental problems relating to the mined rock and disposal of large amounts of brine are significant (Kolkas-Mossbah and Friedman, 1997). Based on current technology, storage of CO₂ in underground salt caverns is uneconomical for the time being.

MINERAL CARBONATION

Mineral carbonation is a CO₂ sequestration concept where CO₂ is chemically combined in an exothermic reaction with readily available Mg or Ca-silicate minerals to form carbonates and other stable by-products (Seifritz, 1990; Gerdemann et al., 2002; O’Connor et al., 2000). Both Mg and Ca carbonates are stable on geologic time-scale, potentially storing CO₂ for millions of years. Mg-silicates are favoured relative to Ca-silicates because they are more widespread, form larger bodies and contain more reactive material per tonne of rock (Lackner et al., 1997; Kohlmann et al., 2002). Wide variety of Mg-bearing materials, such as enstatite, asbestos tailings (Fauth and Soong, 2001), fly ash and other industrial residues were investigated as potential starting materials for the industrial carbonation process, however, in the light of recent laboratory tests, olivine [(Mg,Fe)SiO₄] and serpentine [Mg₃Si₂O₅(OH)₄] appear as the most promising. The two reactions below illustrate the CO₂:carbonation principle using olivine and serpentine as examples:

\[
\text{Mg}_2\text{SiO}_4\text{[olivine]} + 2\text{CO}_2 \rightarrow 2\text{MgCO}_3\text{[magnesite]} + \text{SiO}_2 \quad (1)
\]

\[
3\text{MgCO}_3\text{[magnesite]} + 2\text{SiO}_2 + \text{H}_2\text{O} \rightarrow \text{Mg}_3\text{SiO}_4\text{[serpentine]} + 3\text{CO}_2 \quad (2)
\]

In nature, carbonation reactions involving silicates are slow (Kohlmann and Zevenhoven, 2001). Currently, a sequestration plant can be visualized as a blender operating at high temperature-pressure conditions (Figure 7). For the
Large-scale CO2 sequestration as mineral carbonates will require enormous amounts of mineral (Kohlmann et al., 2002). For a typical power plant, the mass flows of fuel and carbonated mineral will be of the same order of magnitude. For example, studies suggest that for a single power plant, generating approximately 10 000 tons CO2 per day, over 23 000 to 30 000 tons per day of Mg-silicate ore would be required (Dahlin et al., 2000; O’Connor et al., 2000). If mineral sequestration becomes a reality and serpentine becomes a workhorse of mineral CO2 sequestration, no shortage of starting material is likely to occur in BC. However, if forsterite (Mg-end member of olivine) is used as starting material, supplies are limited and geographically constrained. Under ideal conditions, coal and Mg-silicate mines would be located close to each other. In most cases, serpentine is an unwanted by-product of metal and chrysotile mining, but in some locations, this waste may become a sought after commodity when its potential for CO2 sequestration is realized. Should mineral sequestration of CO2 become an established technology, then new opportunities will arise for potential producers of magnesium silicates and owners of magnesium silicate-rich tailings.

The British Columbia Geological Survey may not participate in the development of mineral sequestration technology, however, the inventory, characterization and documentation of potential sources of Mg-silicates is in the Survey’s interest. It may attract industry to the province, should this technology become accepted.

CONCLUSIONS AND PLANS FOR FUTURE WORK

This review concentrated on the description of the main geological and mineral CO2 sequestration methods that are currently the focus of intensive research by industrialized nations worldwide. At first glance, the most technologically mature methods are storage in active and depleted oil and gas fields, though most of the emphasis lies on maximizing oil and gas recovery rather than sequestration potential. Research relating to injection of CO2 into deep coal seams is rapidly advancing, with CO2-enhanced CBM recovery potentially offsetting sequestration costs. Saline aquifers provide huge storage potential in terms of volume for CO2 sequestration, but they are much more difficult and expensive to characterize than hydrocarbon reservoirs due to the lack of an existing exploration database. The methods, which currently encounter the most resistance from the public, are storage in salt caverns and ocean sequestration. Mineral sequestration is the only method that truly disposes of CO2 on geological time scale, with a minimum risk for an accidental CO2 release.

The next stage of our study will expand and summarize the relative technological maturity of the methods covered in this paper and their potential applicability to British Columbia. Since all geological and mineral CO2 sequestration methods involve the capture and extraction of CO2 from flue-gases or industrial streams, transportation of CO2 and its disposal in an appropriate sink, the next stage of our study will also identify the main stationary point sources of...
CO₂ emissions and the main potential carbon or CO₂ sinks in British Columbia. The relative geographic relationships between the main stationary point CO₂ sources and sinks is also an essential piece of the puzzle for conceptual decision-making and a base for rigorous CO₂ sequestration planning in British Columbia if it becomes a necessity.

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