Carbon Storage – A Summary of Experience and Lessons Learned from Publicly Supported Projects

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Abstract

Within Alberta, carbon capture, utilization, and storage (CCUS) will be an important part of the portfolio of technologies that include alternative energy sources, energy efficient systems and other measures needed to achieve climate and energy goals. CCUS provides Alberta and Canada, by extension, with an opportunity to improve its reputation as a clean oil and gas producer and take a leadership role in helping global climate efforts while strengthen our economy as an exporter of CCUS technology and knowledge and eventually hydrogen-based energy and carbon-based products. This has become particularly relevant today as the Government of Alberta is advancing a strategic hub concept where private companies can effectively plan, enable, and undertake carbon sequestration of captured carbon dioxide from various emissions sources. Confidence in pursuing the hub concept has been underpinned by the Alberta Government support for studies into geological storage of CO_2 in the Alberta sedimentary basin as early as 1991. Over the last two decades, Alberta Innovates has supported comprehensive studies and participated in CO_2 storage projects that have made contributions to all three of the major components of geological storage: capacity, injectivity and containment. Given the over two decades of engagement of Alberta Innovates in the area of CO_2 geological storage, the financial support, projects and studies have provided valuable contributions to the development of regulatory and standards associated with the carbon capture and storage more generally and specifically, the geological storage of CO_2. Through direct financial support from Alberta Innovates and the involvement of Alberta researchers and geoscience professionals, major contributions have been possible in international initiatives on the geological storage of CO_2, such as contributions to and support of the North American Geological Storage Atlas and characterization of the Basal Aquifer in the prairie regions of Canada.

1 Introduction

This paper has been published as part of a series of papers on work completed on various aspects of CCUS with recommendations regarding how to advance CCUS in the future. This paper shares the lessons learned from a portfolio of Alberta Innovates, InnoTech Alberta, C-FER and ERA supported projects related specifically to the geological storage of CO_2 completed over the past two decades. These organizations work very closely to ensure the most efficient development and deployment of promising solutions occurs within Alberta. This paper serves to summarize the body of knowledge developed and supported by these organizations, and to identify the remaining gaps that need to be addressed with recommendations regarding how to help enable widespread use of CCUS both in Alberta and around the world. This paper is not intended to be a policy position paper, but it may be used to inform policy decisions as required. It is primarily focused on technology and knowledge development, identifying technology gaps, insights, and priority focus areas for further investment to de-risk CCUS technologies for widespread deployment to support emissions reductions targets.

2 Geological Storage of CO_2 in Alberta

CO_2 sequestration occurs in a sequestration complex containing multiple geological formations with impermeable seals (caprocks). CO_2 is held in the pore spaces present in the sequestration formation, and seals will ensure that the CO_2 stays permanently in place. Sequestration formations include saline formations, depleted oil and natural gas reservoirs, and unmineable coal seams. Alberta legislation requires that sequestration must take place at a depth of more than 1000 metres below the surface. Alberta's oil and natural gas resources were formed and have been held underground by geological seals for millions of years. The same type of geology that has resulted in the province's rich oil and gas reserves also makes the province suitable for CCS. Exploration and production of oil and natural gas has also provided industry and government with knowledge of the subsurface geology of the province. This knowledge will enable the most suitable sites to be chosen for CO_2 sequestration.

Alberta Government support for studies into geological storage of CO_2 in the Alberta sedimentary basin began as early as 1991 with a CO_2 disposal study (TCA Reservoir Engineering Services, 1991) commissioned by the Alberta Oil Sands Technology and Research Authority (AOSTRA), which focussed primarily on enhanced oil recovery and was followed with a three-year study to assess the technical and economic feasibility of aquifer disposal of CO_2 in the sedimentary rocks of the Alberta Basin (Gunter, et al., 1996). It is remarkable that these studies pre-dated the start of the first saline aquifer storage project in Norway – the Sleipner Project – which began injection in 1996. And since this time, research and innovation in Alberta have continued to be at the forefront on CO_2 geologic storage research, demonstration and commercial operations. In general, the key questions for any CO_2 storage project are: how much CO_2 can be injected?; can it be stored safely?; what are the most suitable sites for storage? and ultimately, can storage be done cost-effectively? These general questions underpin the three main storage issues and operational or project level concerns:

- **Capacity**—is there room for the required CO_2 storage volume over the project lifetime?
- **Injectivity**—will we able to inject the CO_2 at a sufficient rate using the available injection wells?
- **Containment**—will the CO_2 remain in the geological storage complex or could it migrate to another geological formation or even leak out?

These three key storage issues are of course important throughout all the phases, but in terms of focus, the capacity issue tends to be foremost in the site selection phase, the injectivity issue dominates in the site operation phase, while containment is the essential question for the site closure and post-closure phases (Ringrose, 2020).

1.1. AB Innovates Support of Technical Innovation for Geological Storage of CO_2 in Alberta

Over the last two decades, AI has supported comprehensive studies and participated in CO_2 storage projects that have made contributions to all three of the major components of geological storage: capacity, injectivity and containment. The following sections provide a summary of these contributions.

1.1.1. Containment

For CO_2 sequestration to contribute to mitigating climate change, long term isolation of the injected CO_2 from the atmosphere must be ensured. A well-chosen sequestration site safeguards against future loss of containment - the sequestration complex must have adequate seals to contain all injected and displaced fluids. This process would also include a review of all wells within the area of review that penetrate the sequestration complex.

The main mechanisms for long-term CO_2 trapping in geological media are (a) structural and stratigraphic trapping, in which the upward and lateral movement of continuous free-phase mobile CO_2 (liquid, gas, or supercritical) in response to buoyancy and/or pressure forces within the storage unit (reservoir or aquifer) is prevented by low-permeability primary and secondary seals; (b) residual-saturation trapping, in which discontinuous free-phase CO_2 is immobilized in individual pores by capillary forces; (c) dissolution trapping, in which mobile and/or immobile CO_2 dissolves in aquifer formation water or reservoir oil; and (d) mineral trapping, in which CO_2 dissolved in formation water reacts with the dissolved substances in the native pore fluid and with the minerals making up the rock matrix of the storage complex, with the result that CO_2 is incorporated into the reaction products as solid carbonate minerals (Canadian Standards Association (CSA), 2012).

For the Alberta Basin in western Canada, an early evaluation of these trapping mechanisms was undertaken by the Alberta Research Council (Bachu, Gunter, & Perkins, 1994) in a study assessing hydrodynamic (stratigraphic) and mineral trapping in aquifer disposal of CO_2. This basin-wide assessment built on previous Alberta Research Council studies exploring the aquifer disposal of CO_2 -rich gases in the vicinity of coal-fired power plants (Gunter, et al., 1993). Subsequent studies also examined how hydrogeological and geochemical trapping mechanisms contribute to secure geological storage at the basin-scale (Gunter, Bachu, & Benson, 2004).

Recognizing that acid-gas injection operations represented a commercial-scale analogue to geological storage of CO_2, a study was completed in 2003 that described the subsurface characteristics of acid-gas operations in western Canada (Bachu, Adams, Buschkuehle, Haug, & Michael, 2003). Similar to CO_2 geological storage, it was shown that for a safe acid-gas injection operation, proper characterization, and selection of the subsurface injection zone (reservoir or aquifer) is important. Critical elements are containment and prevention of leakage and/or migration through natural or man-made conduits, such as fractures ("cracks") and abandoned wells ("punctures"). It is essential to maintain the integrity of the confining aquitard (or caprock), which is subjected to physical and chemical stresses. It was recommended that the technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., design, materials, leakage prevention and safety) could be easily adopted for large-scale operations for CO_2 geological storage. Additionally, the subsurface information about aquifer and reservoir rocks and fluids may provide a wealth of information as to what characteristics a suitable CO_2 -storage site should possess (Bachu, Buschkuehle, Haug, & Michael, 2004).

Alberta Innovates support for and participation in the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project (Hawkes & Gardner, 2012) (Sakuta, Young, & Worth, 2015) from its inception in 2000 has also provided valuable insight to issues related to containment. Research undertaken in this study demonstrated that geological characterization is critical for CO_2 storage, not least in defining the storage complex, and that identification of seals is of paramount importance. The Weyburn study also demonstrated that reservoirs where CO_2-EOR is practiced will invariably have secure hydrodynamic (vertical) containment of the remaining hydrocarbon accumulation and secure lateral containment ensured by well-characterized structural controls, despite the presence of production and injection wells. However, in the context of CO_2 storage, long-term containment is by no means assured, given what is known now about well integrity. Further, many aquifers in which CO_2 may be injected are laterally unconfined. Hence, long-term integrity of natural seals represents the most important constraint on isolation performance. Accurate long-term forecasting of reservoir integrity was also deemed critical. Predicting the long-term changes in permeability of reservoir seals during CO_2-EOR and CO_2 storage requires first identifying, then quantifying, its dependence on key parameters and processes. The most important factors influencing this change were subdivided into three groups: (1) intrinsic seal properties, (2) chemical conditions at the reservoir–seal interface, and (3) the pressure perturbation associated with CO_2 injection.

Alberta Innovates supported several field studies in the mid to late 2000's that embodied research activities related to containment assessment for geological storge of CO_2.

An analysis of the potential for CO_2 leakage along wells at the Penn West CO_2-EOR pilot operation in a local-scale study area defined by 12 sections of land around the site was completed as part of a research program set up to study the fate of the injected CO_2 at the pilot operation (Bachu & Haug, 2006). Assessment of the potential for CO_2 leakage through existing wells is especially important in mature sedimentary basins that have been intensively explored and exploited for hydrocarbon production, such as the Alberta Basin. A scheme for evaluating the risk for CO_2 leakage along wells was developed based on the analysis of all the wells with surface casing vent flow and gas migration in the province. The scheme was based on well characteristics alone and did not take into account the geology and hydrostratigraphy of the strata around a well. This scheme was subsequently applied to the 169 wells in the 12 sections of the local-scale study area that encompasses the Penn West CO_2-EOR pilot in the Pembina oil field. All but four wells intersect the Cardium Formation that is targeted for expanding the CO_2-EOR if the pilot operations prove successful. The results of the analysis showed newer drilled wells scoring in the low-risk category, older producing wells scored in the medium-risk category and three old, abandoned wells were identified as high-risk wells.

The Heartland Redwater Leduc Reef Saline Aquifer CO_2 capture and geologic storage project (Gunter W. , et al., 2009), supported by AERI and initiated by the Alberta Research Council was structured to investigate the technical and economic feasibility of injecting significant volumes of CO_2 into the water-bearing portion of the Leduc Reef underlying the Redwater oil pool, to evaluate:

- the ability to permanently store a substantial volume of CO_2;
- injection strategies and storage capacity;
- the long-term CO_2 containment; and
- monitoring strategies.

Simulation studies to estimate CO_2 injectivity and storage capacity will be discussed §1.1.2 and §1.1.3, respectively. From the perspective of containment, this study revealed that the primary seal of the Ireton aquitard, encasing the reservoir, appears to be a competent seal considering its entrapment of hydrocarbons dating to approximately 60 million years ago (Stoakes & Foellmer, 2008). The suitability and capacity for long-term geological storage of CO_2 in the Redwater reef was shown to be largely dependent on its hydrogeology and flow characteristics and processes inside the reef (Palombi, Gunter, & Brydie, 2008). The study also showed the value of hydrochemistry as a technique for identifying salinity and compositional variations between aquifers.

In 2009, the IEA GHG commissioned the Alberta Research Council to conduct a review of storage site selection criteria and site characterisation methods in order to produce a synthesis report (International Energy Agency, 2009). This study was underpinned by the three major requirements of any storage site:

1. capacity to store the intended volume of CO_2 over the lifetime of the operation,
2. injectivity, to accept/take CO_2 at the rate that it is supplied from the emitter(s), and
3. containment, to ensure that CO_2 will not migrate and/or leak out of the storage unit (safety and security of storage).

A major outcome from this study was the development of a set of qualifiers and threshold values that can be used to quantify a site's suitability for storage compared to other sites, both for saline storage (Figure 1) and CO_2 storage in CO_2-EOR operations (Figure 2). This result is notable because it is the same set of qualifiers that Shell Canada used in the development of their Quest project in Alberta.

Criterion Level	No	Criterion	Eliminatory or unfavourable	Preferred or Favourable
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)
	2	Pressure regime	Overpressured: pressure gradients greater than 14 kPa/m	Pressure gradients less than 12 kPa/m
	3	Monitoring potential	Absent	Present
	4	Affecting protected groundwater quality	Yes	No
Essential	5	Seismicity	High	Moderate and less
	6	Faulting and fracturing intensity	Extensive	Limited to moderate
	7	Hydrogeology	Short flow systems, or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow
Desirable	8	Depth	< 750-800 m	>800 m
	9	Located within fold belts	Yes	No
	10	Adverse diagenesis[+]	Significant	Low to moderate
	11	Geothermal regime	Gradients ≥ 35 °C/km and/or high surface temperature	Gradients < 35 °C/km and low surface temperature
	12	Temperature	< 35 °C	≥ 35 °C
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa
	14	Thickness	< 20 m	≥ 20 m
	15	Porosity	< 10%	≥ 10%
	16	Permeability	< 20 mD	≥ 20 mD
	17	Caprock thickness	< 10 m	≥ 10 m
	18	Well density	High	Low to moderate

Figure 1 Site selection criteria for ensuring the safety and security of CO_2 storage

Reservoir Parameter	Miscible CO_2-EOR
Size (ROIP in MMstb; or $MtCO_2$)	≥1 (whichever condition is met first)
Depth (ft/m)	>1500 (>450)
Temperature (ºF/ºC)	82 to 250 (28 to 121)
Pressure	> MMP and < P_f
Porosity (%)	≥3
Permeability (mD)	≥5
Oil Gravity (API)	27 to 45
Oil Viscosity (cP/mPa·s)	≤6
Remaining Oil Fraction in the Reservoir	≥0.30

Figure 2 Characteristics of oil reservoirs suitable for miscible CO_2-EOR (metric values are given in brackets)

Alberta Innovates was also an early supporter of the Shell Quest CCS project from 2008 to 2011 through grant funding provided by AI-EES for drilling and testing the first three CCS appraisal wells to be drilled in Alberta (Crouch, 2011). The project provided valuable drilling and operational experience in the local area of interest in order to engineer injection wells suitable for long term CO_2 injection into a saline aquifer and to ensure mechanical integrity and containment. The core attained in the Cambrian section through the AI-EES Project helped to develop the current geologic understanding on the entire BCS storage complex and therefore provide support for containment. The project data collected from the three wells confirmed that the geology, fluid, pressure and well integrity were consistent with regional data and support the BCS as a safe and effective formation for commercial scale CO_2 storage.

Specific caprock integrity studies for assessing containment of CO_2 were explored in an Alberta Research Council study involving thermo-poro-mechanical simulations of a synthetic CO_2 storage case (Soltanzadeh & Jafari, 2013). The detailed study was conducted to characterize the behaviour of this model and to identify the mechanisms of interaction between the fluid flow, heat transfer, and geomechanical effects on the modeling results. It was observed that the low temperature of CO_2 has a major influence on the geomechanical response of the model. It was observed that the low temperature of CO_2 has a dominant effect on the geomechanical response of the model and showed that a temperature decrease can lead to severe reduction in the values of in-situ stresses and, consequently, it increases in the potential of induced fracturing in the aquifer and the caprock. Nevertheless, this potential is smaller in the caprock than in the aquifer as a result of lower temperature decrease in the caprock. Sensitivity analyses showed that injection of CO_2 with a temperature closer to the temperature of the aquifer reduces the potential for tensile fracturing in the caprock and aquifer to a great extent. This potential is also highly reduced by injecting CO_2 at greater depths within the aquifer and farther away from the caprock.

In 2014, AI-EES supported the Alberta CO_2 Purity Project (Petroleum Technology Alliance Canada, 2014) which examined the effect of CO_2 purity and contaminants on the following 4 components of CCS systems:

1. Capture of CO_2 emissions from large industrial facilities;
2. Transportation of the CO_2 through pipelines;
3. Permanent storage of the CO_2 in oil reservoirs where CO_2 is utilized for enhanced oil recovery (EOR); and
4. Permanent storage of the CO_2 in deep saline aquifers (sequestration).

Issues of containment were only addressed in the 4th component – deep saline aquifer storage - and was mostly concerned with the performance of the storage formation and focused on better understanding the effect that impurities have on a sequestration scheme's containment, pore space use efficiency and capacity, plume extent, trapping capability, and injection scheme performance. Through mostly a desktop numerical study performed with synthetic simplified cases and generalized models of actual reservoirs, this project revealed an important observation controlling all study results: viscosity and density of the mixtures considered were lower than those of pure CO_2 at the same temperatures and pressures. For a plume of CO_2 with impurities, moving updip with no barrier, will migrate farther from the point of injection but will be trapped through residual saturation sooner than will a plume of pure CO_2 and possibly enhance dissolution, primarily because it is exposed to more rock / brine volume. A larger plume, however, means that a larger area must be defined and monitored for leakage pathways, such as faults and wells, but the faster trapping translates into a shorter monitoring period. Equally important is that contrasts of viscosity and density between pure CO_2 and a CO_2 mixture decrease with depth, suggesting that differences in flow behavior and storage capacity are proportionally reduced with depth.

Well integrity is a primary concern for storage integrity (CO_2 containment) because wellbores can act as conduits for fluid migration from the storage reservoir to protected resources or the surface. Well leakage can occur in active or inactive wells, new or old. Old, abandoned wells are of particular concern because they likely were plugged using procedures and materials that are antiquated by today's standard. In addition to earlier work on a review of failures for wells used for CO_2 and acid gas injection in Alberta (Bachu & Watson, 2009), Alberta Innovates has also supported research into sealing technologies for permanent sealing of wells that penetrate geologic formations being used for CO_2 geological storage. A CCEMC project in 2015 assessed the use of certain bismuth-based metal alloys as a sealant material (Spencer, 2015). The studies that comprised this project were divided into three main milestones:

1. comprehensive measurement of corrosion of this alloy and steel well casing immersed in saltwater as a function of temperature, pressure, and pH from alkaline to acidic levels which showed that plugs in wells molded from this alloy should have a service life measured in thousands of years;
2. design and construction of full-scale physical models into which bismuth alloy was deployed using electrically heated purpose-designed tools under physical conditions similar to those encountered in most Alberta oil and gas wells. The resulting plugs were tested successfully to pressures exceeding Alberta regulatory requirements; and
3. field testing the deployment of bismuth alloy plugs in eight wells with known gas leaks that established procedures directly applicable to the repair of the very large number of leaking wells in Alberta (Bachu & Watson, 2009) and to the permanent sealing of CO_2 sequestration wells.

1.1.2. Injectivity

As stated previously, injectivity is an issue that dominates in the site operation phase of a CO_2 storage project. Given the limited number of fully operational CO_2 storage sites in Alberta, studies supported by Alberta Innovates that examined issues of injectivity are typically numerical simulation studies and have focussed primarily on CO_2-EOR projects. AI contributions to CO_2-EOR related issues are discussed in (Meikle, et al., 2022) but an outstanding example of long-standing support for studies that explored issues of injectivity includes the very early studies completed in 1991 for the Alberta Oil Sands Technology and Research Authority (AOSTRA) to quantify the potential for CO_2 capture and use for enhanced oil recovery at a scale sufficiently large to have an impact on the rate of growth of CO_2 emissions (TCA Reservoir Engineering Services, 1991). This numerical simulation-based reservoir engineering study of CO_2 enhanced oil recovery was conducted for a selection of five reservoirs with a prediction of performance for operating conditions and for alternative CO_2 injection strategies aimed at determining an optimal recovery scheme in terms of oil recovery and efficient CO_2 utilization. With respect to injectivity, this very early study observed significant variability in injectivity profiles across the completion intervals – a challenge that is faced by today's geological storage projects.

The processes of CO_2 injectivity and migration within the storage unit, and the sequestration of CO_2 in the pore space all depend on the relative permeability of CO_2 and formation water systems and on the CO_2-brine capillary pressure character. Furthermore, numerical models for predicting the fate of the injected CO_2 also need information about these two important parameters. Within the Alberta Innovates ecosystem, support has been provided for a series of interfacial tensions (IFT) and relative permeability measurements performed on core plugs taken from several sandstone, carbonate and shale formations in Alberta (Bennion & Bachu, 2005); (Bennion & Bachu, 2006a), (Bennion & Bachu, 2006b) and (Bachu & Bennion, 2008)). This series of tests has proven to be invaluable to the CO_2 geological storage community as the relative permeability curves (Figure 3), in particular, are used widely for simulation studies. Simulation studies within the IEAGHG Weyburn project and more recently, the Aquistore Project (Movahedzadeh, Shokri, Chalaturnyk, Nickel, & Sacuta, 2021) have adopted these curves.

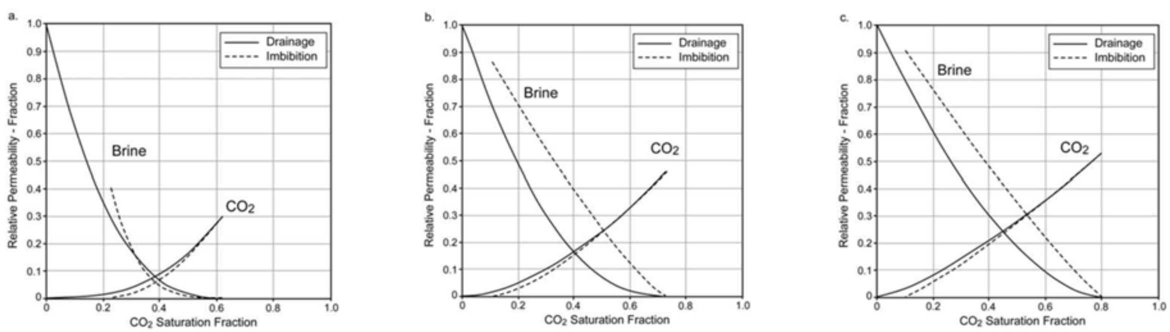

Figure 3 Relative permeability curves (drainage and imbibition) for a core sample from the Cardium Formation in Wabamun Lake area, Alberta, Canada, for CO2 -brine systems at in-situ temperature of 43°C and water salinity of 27,096 ppm, and for various IFT: a) 56. 2 mN/m, b) 33.5 mN/m, and c) 19.8 mN/m, that corresponds to increasing pressures of 1,378 kPa, 6,890 kPa and 20,000 kPa, respectively.

The Heartland Redwater Leduc Reef Saline Aquifer CO_2 Capture and geological storage project undertook simulation studies to assess CO_2 injectivity in the Redwater Leduc reef (Mattar, Hong, Pooladi-Darvish, & Hughes, 2008). It was notable that the injection rate of CO_2 chosen for the study was 50,000 Tonnes/day over a period of 30 years, which amounts to an expected storage capacity of 550 MT. This is a very ambitious target when you consider that the current Quest CCS Project only injects approximately 3,000 Tonnes/day. The Redwater Leduc reef simulation studies illustrated how geological factors within the reef can limit the dynamic storage capacity when the maximum reservoir pressure is reached prematurely, and lateral migration of CO_2 reaches adjacent aquifers. One outcome from the study was a demonstration that the reef had the potential to achieve its CO_2 injectivity expectations, but that the injection scheme would require a concurrent water withdrawal scheme. Over a decade later, this study outcome is in fact a key element of Chevron Australia's Gorgon liquefied natural gas (LNG) facility where naturally occurring CO_2 is taken from offshore gas reservoirs and injected into a giant sandstone formation two kilometres beneath Barrow Island, where it remains permanently trapped. This however requires that subsurface pressures be regulated by reinjecting water produced from the injection horizon into overlying formations.

Injectivity constraints were also identified in the comprehensive characterization study conducted by Michael et al. (2009) for a central Alberta site where capacity estimates for CO_2 storage within the Devonian Nisku carbonate aquifer could be achieved only if multiple injection wells are used to maintain bottomhole injection pressures below the rock fracturing threshold.

AI-EES support and participation in the CO_2 Sequestration in Basal Cambrian Sands study conducted between 2008 and 2011 by Shell in support of their Quest CCS project has provided valuable learnings with respect to injectivity (Crouch, 2011). The results of the two water injectivity tests support the conclusion that the BCS reservoir is of sufficient quality to inject a daily rate of up to 1.2Mt/a of CO_2 for a minimum of ten years. Of value from this study for future CO_2 geological storage projects was the decision to complete a water injectivity test instead of a CO_2 injectivity test. While each potential site will have its own subsurface characteristics, the rationale for not completing a CO_2 injectivity test included:

- injectivity (K_h & skin) could be attained more accurately through a water injection test;
- determining connected volume would have a low probability of success with a short injection test;
- determining non-Darcy skin would require a long enough CO_2 test to attain stable flow which is not feasible;
- Special core analysis work performed at in-situ conditions to determine the relative permeability behaviors of mineral oil can be used to sufficiently characterize the BCS reservoir in-situ CO_2 relative permeability behaviors and
- proof of feasibility of time-lapse seismic (detectable CO_2 plume) is not possible in a reasonable test time frame due to the amount of CO_2 required (10-60MMt CO_2) which would equate to approximately 600-4000 trucks for transport. This would not be in the best interest of the stakeholders nor would it be possible without approval to dispose of large quantities of CO_2.

1.1.3. Capacity

Over the last two decades, estimation of CO_2 capacity has been a major focus for many studies examining the geological storage of CO_2. These studies have mapped potential storage formations and used that information to estimate CO_2 storage capacity. These efforts have typically happened at the national level to help prepare nations for future large-scale CO_2 storage projects. Within North America, the combined efforts of Canada, the United States and Mexico have culminated in the generation of a North American Geological Storage Atlas (NETL, 2016) that identifies major stationary sources of carbon dioxide emissions and potential geological storage reservoirs for CO_2. The atlas can be used to develop a comprehensive understanding of the potential for carbon capture and storage in North America. To map the CO_2 sources and geological storage reservoirs, the three countries agreed on a common methodology for estimating geological reservoir capacities, an appropriate scale and resolution for the data, a data-sharing protocol, and a process for treating common cross-border areas.

The availability of CO_2 storage capacity is critical to CCUS. Globally, it is anticipated that 95% of all CO_2 captured will need to be permanently stored to achieve net-zero emissions (IEA, 2021a). Canada is rich in geology that is suitable for CO_2 storage, including sedimentary basins, saline formations, and oil and gas reservoirs. The capacity of saline aquifers alone is estimated at over 100 billion tonnes.

Alberta Innovates has contributed to storage capacity estimation through the support for Alberta researchers' participation in the Carbon Sequestration Leadership Forum (CSLF, 2007) and AITF initiatives to refine and progress our understanding of the factors that affect CO_2 storage capacity and storage efficiency in deep saline aquifers (Bachu, et al., 2007); (Bachu S. , 2015). An important classification methodology termed the Techno-Economic Resource- Reserve pyramid (Figure 4) was introduced by (Bachu, et al., 2007). In this methodology, CO_2 storage capacity is classified into theoretical capacity (the maximum amount of CO_2 that the system can ultimately store), effective storage capacity, which represents the CO_2 storage capacity constrained by the physical and chemical characteristics of the system; practical storage capacity, which represents the CO_2 storage capacity further constrained by technical, economic and regulatory considerations, and matched storage capacity, which represents CO_2 storage capacity in actual projects that link CO_2 sources with CO_2 storage sites.

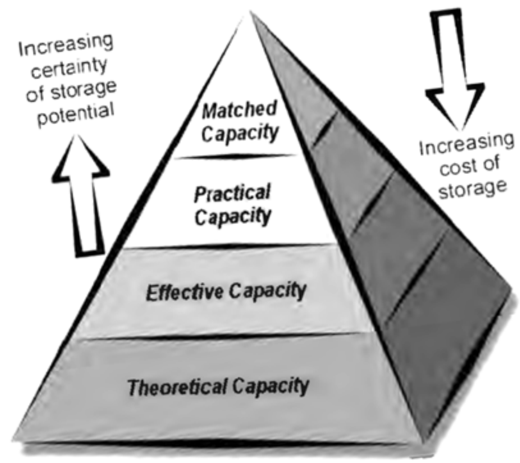

Figure 4 Techno-Economic Resource-Reserve pyramid for CO_2 storage capacity in geological media within a jurisdiction or geographic region (CSLF, 2007); (Bachu, et al., 2007). The pyramid shows the relationship between Theoretical, Effective, Practical and Matched capacities.

A commercially relevant classification system for geological storage resources has been developed by the Society of Petroleum Engineers (SPE, 2017). The SPE Storage Resources Management System (SRMS) is based on the SPE Petroleum Resource Management System (PRMS) used widely to classify oil and gas reserves and resources. The SRMS sets out standardized definitions to describe the maturity of, and level of uncertainty or confidence in, storage resource assessments. It supports commercial CCS investment decisions in the same way that the PRMS does for oil or gas resources and with the recent announcement by the Government of Alberta that they will issue carbon sequestration rights through a competitive process, it is likely the SRMS will be a classification scheme adopted by hub proponents. This is relevant from an Alberta Innovates perspective because the capacity estimation framework developed by Bachu et al. (2007), with the support from AI, is used as a basis for the development of the SRMS.

The extensive study on CO_2 storage characterization of the Basal Aquifer in the prairie regions of Canada, which was supported by AI-EES and AITF, along with Natural Resources Canada and Total E&P Canada Ltd., embeds much of the detail on the methodology for estimating CO_2 storage capacity that is described in (Bachu, et al., 2007) (Bachu, et al., 2012).

This review for estimating the CO_2 storage capacity in an aquifer indicates that a storage efficiency coefficient varies from less than 1% to a few percentages of aquifer pore volume, depending on aquifer, aquitard, and displacement characteristics. In addition, the review showed that the following data types are required for a proper evaluation of CO_2 storage capacity at the regional scale:

1. Aquifer pore volume, as defined by:
   - Area A
   - Thickness h (isopach)
   - Porosity ϕ
2. Aquifer characteristics, as defined by:
   - Lithology, and if possible the depositional environment
   - Depth
   - Pressure p
   - Temperature T
   - Rock fracturing threshold, or rock fracturing gradient
3. CO_2 density, which depends on pressure p and temperature T; and
4. Characteristics of the overlying and underlying aquitards (caprock) to determine if the storage aquifer is open, semi-open or closed.

Critically, the review also showed that the choice of the value of the storage efficiency coefficient E has the most significant impact on the regional-scale estimation of CO_2 storage capacity in an aquifer. A detailed assessment for the current status of computing storage efficiency coefficients is provided in Bachu (2015).

Beyond storage capacity estimates for saline aquifers within Alberta, Alberta Innovates studies have also examined the CO_2 storage capacity of hydrocarbon reservoirs. Reference to potential storage volumes associated with CO_2-EOR activities in Alberta have been provided in (Meikle, et al., 2022) but for completeness, the following sections will briefly summarize the storage capacity estimates provided in four AI supported studies.

1.1.3.1. CO2 Enhanced Hydrocarbon Recovery: Incremental Recovery and Associated CO_2 Storage Potential in Alberta (2009)

This summary report (Danielson, et al., 2009) of a more extensive report prepared by AITF for the Alberta Department of Energy (ADOE), presents the results of a detailed reservoir and development analysis to quantify the potential for incremental oil recovery and associated CO_2 capture and storage for five horizontal miscible CO_2 flood target pool types (prototypes) in Alberta. The ultimate objective of this project was to provide critical technical information and data to accelerate the pace of EOR and Carbon Capture and Storage (CCS) demonstration and field projects in Alberta. This study adopted detailed reservoir technical evaluations for five CO_2-EOR prototype fields within Alberta which differs from previous studies that were based on high-level reservoir parameter screening or on element of symmetry simulations. For the Beaverhill Lake, Redwater Reef and Pembina Cardium prototypes, it was estimated that storage capacities could range from 933 MT (no risk factors considered in development) down to 253 MT (considering incremental recovery, storage risk and processing considerations). The study concludes with recommendations that clearly identify the linkage of CO_2-EOR potential and ultimately, CO_2 storage to the economics associated with these developments. For instance, the report noted that the study was restricted to the field characteristics for CO_2 flooding and did not consider the proximity to suitable CO_2 sources and the cost to deliver CO_2 to the field. Recommendations were provided that it would be useful to build on the results of the study by evaluating potential sources and estimate transportation costs to deliver the CO_2 to the fields so economics can be run to quantify the size of the "gap" between the cost to capture, purify, compress and transport the CO_2.

1.1.3.2. Identification of Oil Reservoirs in Alberta Suitable for CO_2 Enhanced Oil Recovery (CO_2-EOR) and Evaluation of their Potential Incremental Oil Recovery and CO_2 Storage Capacity (2016)

The AITF report by Bachu and Jafari (2016) was motivated by the need to perform a province-wide assessment of the potential for miscible CO_2-EOR of oil reservoirs in the province and of the potential incremental oil recovery and associated CO_2 storage capacity to provide policy and decision makers with necessary information in developing and establishing policies and course of action for increasing conventional oil production in the province while reducing CO_2 emissions from large emitters. The report completed three steps to estimate potential incremental oil recovery and associated CO_2 storage capacity from CO_2-EOR:

1. analyze the state of the art and establish, technical criteria of successful CO_2-EOR operations;
2. review methodologies that can be applied to a very large number of oil reservoirs to estimate their potential incremental oil recovery and associated CO_2 storage capacity; and
3. application of screening criteria to the approximately 13,000 oil reservoirs in Alberta.

From a ranking of the oil reservoirs based on recoverable oil-in-place ≤ 5MMSTB, the potential associated CO_2 storage capacity for 264 oil reservoirs was estimated to be in excess of 900 MT, with a variability dependent on the water injection strategy associated with the CO_2-EOR operations. More discussion on technical details for CO_2-EOR can be found in (Meikle, et al., 2022).

1.1.3.3. The Capacity for Carbon Dioxide Storage in Oil and Gas Pools in Northeastern Alberta (2006)

This AERI report provides insight into CO_2 storage in the Athabasca-Cold Lake region in northeastern Alberta (Bachu S. , 2006). The Alberta Basin, which underlies Alberta, provides a very large capacity for CO_2 storage in oil and gas reservoirs. However, the Athabasca-Cold Lake region in northeastern Alberta has less potential for CO_2 storage because it is shallow, being close to the zero edge of the basin. There are only 15 oil pools in northeastern Alberta, with insignificant CO_2 storage capacity compared with the ~609 Mt CO_2 potential capacity in ~5,300 gas pools. Most of the gas pools are small, with only less than 900 gas pools having CO_2 storage capacity greater than 100 kt CO_2, for a total of ~504 Mt CO_2. Of these, 76 gas pools have capacity greater than 1 Mt CO_2 each, for a total of 292 Mt CO_2. These gas pools are distributed almost evenly across northeastern Alberta, and are found at depths that vary between ~200 and 950 m. Upon depletion, these gas pools can be used for storing the CO_2 emitted by oil sands plants in the Athabasca area, allowing for a few decades of oil production with reduced atmospheric CO_2 emissions.

As a result of Gas-Over-Bitumen disputes between gas and bitumen producers in the Athabasca area, a significant number of gas pools in the McMurray-Wabiskaw sedimentary succession have been shut-in by EUB, or could be affected in the future. These gas pools have significant CO_2 storage capacity, estimated at greater than 185 Mt CO_2. Repressuring these gas pools with CO_2 from oil sands plants would achieve a dual objective of maintaining pressure in these gas reservoirs, thus preserving the ability to produce the underlying bitumen while producing the gas and storing CO_2 from oil sands plants in the Fort McMurray area, thus reducing greenhouse gas emissions and allowing the development of oil sands resources in a responsible manner.

One salient conclusion reached in this study considering the recent announcements of hub and cluster development within the Athabasca-Cold Lake region in northeastern Alberta is related to shallow storage viability. The generally accepted depth for storing CO_2 is greater than 800 m, but this is based on reasons of storage effectiveness, since at depths greater than this CO_2 will likely be in dense supercritical phase, hence more CO_2 will be stored for the same volume of pore space. However, as long as containment is ensured (see discussions in §1.1.1), there is no reason not to store CO_2 at shallower depths where CO_2 would be in less-dense gaseous phase.

1.1.3.4. Evaluation of CO_2 storage capacity in Devonian hydrocarbon reservoirs for emissions from oil sands operations in the Athabasca area, Canada (2014)

While not strictly commissioned by Alberta Innovates, the results of this AITF study (Jafari & Bachu, 2014) financially supported by NRCan, ADOE and four oil sands companies, showed that the potential CO_2 storage capacity in oil and gas reservoirs in Devonian strata west of the Athabasca oil sands area in Alberta is significant. This advancement of the work commissioned by AERI in 2006 (Bachu S. , 2006) is very relevant to the current issue of reducing atmospheric CO_2 emissions is particularly important for oil sands producers in Alberta.

CO_2 storage adjacent to the Athabasca oil sands deposits is not possible because of the shallowness of the basin. There are 790 oil pools, 4 oil pools with a gas cap and 8 heavy oil pools, and 423 gas pools in the Devonian sedimentary succession in a region covering 126,000 km^2 west of the Athabasca oil sands. All but four oil reservoirs are located at depths greater than 1000 m, while 406 gas reservoirs are located at depths shallower than 1000 m. Assuming that, after depletion, CO_2 will be stored in these reservoirs up to the point at which the respective reservoir pressure reaches the initial reservoir pressure, the total CO_2 storage capacity in all the deep reservoirs is estimated to be: ~215 Mt CO_2 in oil reservoirs, ~151 Mt CO_2 in gas reservoirs, and close to 16 Mt CO_2 in oil reservoirs with an associated gas cap.

The CO_2 storage capacity in shallower oil reservoirs is negligible, but the CO_2 storage capacity in shallower gas reservoirs is significant at ~315 Mt CO_2. However, the great majority of both oil and gas reservoirs have low CO_2 storage capacity. Only 9 deep oil reservoirs and 10 gas reservoirs (2 deeper and 8 shallower than 1000 m) have individual CO_2 storage capacity greater than 5 Mt CO_2, for a total of ~447 Mt CO_2, of which ~241 Mt CO_2 storage capacity is at depths greater than 1000 m, and ~206 Mt CO_2 storage capacity is at depths less than 1000 m.

It is important to note that the potential CO_2 storage resource shallower than 1000 m depth is sterilized under current CCS legislation in Alberta.

1.1.4. Regulatory/Standards for Geological Storage

Given the over two decades of engagement of AI in the area of CO_2 geological storage, the financial support, projects and studies have provided valuable contributions to the development of regulatory and standards associated with the carbon capture and storage more generally and specifically, the geological storage of CO_2. The following section provides a summary of several notable regulatory and standards spanning provincial, national, and international jurisdictions that have referenced AI supported studies and engaged AI supported experts in the field of CO_2 geological storage.

1.1.4.1. Regulatory Framework Assessment – Alberta

CO_2 sequestration occurs in a sequestration complex containing multiple geological formations with impermeable seals (caprocks). CO2 is held in the pore spaces present in the sequestration formation, and seals will ensure that the CO2 stays permanently in place. Sequestration formations include saline formations, depleted oil and natural gas reservoirs, and unmineable coal seams. Alberta legislation requires that sequestration must take place at a depth of more than 1000 metres below the surface.

Alberta's oil and natural gas resources were formed and have been held underground by geological seals for millions of years. The same type of geology that has resulted in the province's rich oil and gas reserves also makes the province suitable for CCS. Exploration and production of oil and natural gas has also provided industry and government with knowledge of the subsurface geology of the province. This knowledge will enable the most suitable sites to be chosen for CO_2 sequestration.

The lifecycle of a sequestration project typically will include the periods shown in Figure 5

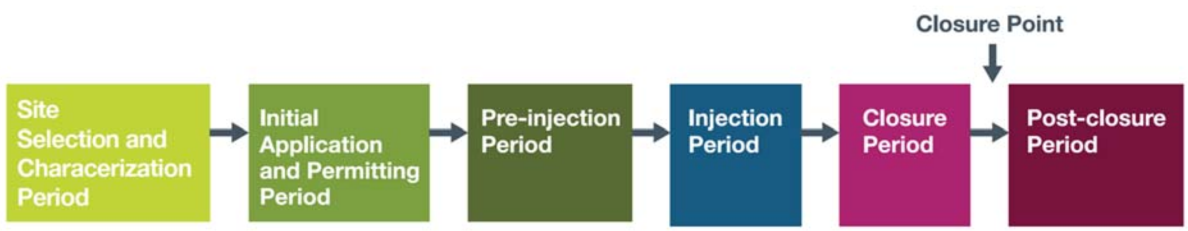

Figure 5 Periods of a CO_2 Sequestration Project (GOA, 2013)

1.1.4.2. CSA Z741-12(2018) – Canadian Standard Association standard for Geological Storage of Carbon Dioxide

In a world-leading effort, the Canadian Standards Association (CSA) worked with the International Performance Assessment Centre (IPAC-CO_2) to develop the first performance standard for geological carbon storage in sedimentary basins. CSA Z741-12(R2018) was released in 2012 and reaffirmed in 2018 (CSA, 2018). Although the standard cannot be enforced by law unless officially adopted by a regulatory agency, including any exceptions or additional requirements, the standard sets out all requirements and guidelines for industrial implementation to effectively manage carbon storage risk. The standard was built upon the vast experience gained through decades of CO_2-EOR operations, as well as pilot and demonstration CCS projects undertaken across North America prior to 2012 and is updated as appropriate thereafter.

The CSA standard provides guidelines for regulators and industry globally for scientific and industrial-scale CCS projects. The standard includes both requirements and recommendations for geological storage to assure safe, long-term containment of CO_2 that minimizes the risk to human health and the environment over the full life cycle of a storage project from pre-injection to closure. It notably does not include anything related to the post-closure period, which is initiated at the point at which the responsibility for the geological storage site is transferred to a designated authority.

Furthermore, the CSA standard does not include CO_2 geologically stored in: unmineable coal beds, basalt formations, shales, or salt caverns; underground storage in the form of containers; operational aspects related to hydrocarbon production at CO_2-EOR or CO_2-EGR operations, including incidental storage of associated CO_2; and disposal of acid gas (which includes significant levels of CO_2).

1.1.4.3. ISO 27914 - Carbon dioxide capture, transportation and geological storage — Geological storage (2017)

Using CSA Z741-12 as a seed document, the International Standards Organization (ISO) developed ISO 27914 to provide recommendations for the safe and effective storage of CO_2 in subsurface geologic formations through all phases of a storage project life cycle. The life cycle of a CO_2 geological storage project covers all aspects, periods, and stages of the project, from those that lead to the start of the project (including site screening, selection, characterization, assessment, engineering, permitting, and construction), through the start of injection and proceeding through subsequent operations until cessation of injection and culminating in the post-injection period, which includes a closure period. ISO 27914 applies to injection of CO_2 into geologic units for the sole purpose of storage and does not apply to CO_2 injection for hydrocarbon recovery, or storage of CO_2 that occurs in association with carbon dioxide enhanced hydrocarbon recovery. ISO 29716, discussed below, has been developed address carbon dioxide storage using enhanced oil recovery (CO_2-EOR). ISO 27914 contains similar exclusions as CSA Z741-12 concerning what is not covered by the standard:

- the post-closure period,
- injection of CO_2 for enhancing production of hydrocarbons or for storage associated with CO_2-EOR,
- disposal of other acid gases except as considered part of the CO_2 stream,
- disposal of waste and other matter added for purpose of disposal,
- CO_2 injection and storage in coal, basalt, shale and salt caverns, or
- underground storage using any form of buried container.

1.1.4.4. ISO 27916 - Carbon dioxide capture, transportation and geological storage — Carbon dioxide storage using enhanced oil recovery (2019)

ISO 27916 was developed by ISO to address one of the major exclusions in ISO 27914, namely carbon dioxide storage using enhanced oil recovery (CO_2-EOR). ISO 27916 applies to quantifying and documenting the total CO2 (and optionally the anthropogenic portion of the CO_2) that is stored in association with CO_2-EOR. The document recognizes that CO_2-EOR is principally an oil recovery operation but associated with this oil recovery, however, safe and long-term CO_2 storage occurs. The purpose of ISO 27916 is to facilitate the exchange of goods and services related to the increased use and emissions reductions through associated storage by providing methods for demonstrating the safe, long-term containment of, and determining the quantity of CO_2 stored in association with CO_2-EOR. ISO 27916 does not address the following items:

- financial consequences that may or may not result from documenting storage of CO_2 in association with CO_2-EOR operations;
- requirements for the selection, characterization or permitting of sites for CO_2-EOR projects; and

- specifications for environment, health and safety protections or corrective action and mitigation requirements that are provided by the regulations and standards applicable to all hydrocarbon production operations.

1.1.4.5. NETL Best Practices Documents

One of NETL's main initiatives to promote information and knowledge sharing is the development of a series of best practice manuals (BPMs) that outline uniform approaches to address a variety of CCS-related issues and challenges. Developing best practices (or reliable and consistent standards and operational characteristics for CO_2 collection, injection, and storage) is essential for providing the basis for a legal and regulatory framework and encouraging widespread global CCS deployment. These BPMs provide recommended approaches for monitoring, verification, accounting (MVA), and assessment; public outreach and education; geologic storage formation classifications; site screening, selection, and characterization; simulation and risk assessment; well construction, operations, and closure; and terrestrial sequestration.

Sharing of lessons learned and best practices from the research and development (R&D) projects sponsored by the U.S. Department of Energy (DOE) Carbon Storage Program is essential for the deployment of carbon capture and storage (CCS). BPMs are one of the key ways in which DOE promotes information sharing among all of the projects it sponsors, including the Advanced Storage R&D and Regional Carbon Sequestration Partnership (RCSP) activities. The BPMs are focused on establishing uniform approaches for carrying out essential activities common to the success of all CCS projects, including site selection and characterization, monitoring, modeling, risk assessment, field operations, and public outreach and education. Lessons learned and best practices contained in the BPMs are integral to the successful progress of the development of the infrastructure needed for the planned field activities and future commercial deployment of CCS technology.

The full range of best practice manuals can be accessed at https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/best-practices-manuals (NETL, no date).

1.2. AB Innovates Contributions Beyond Alberta's Borders

Through direct financial support from AI and the involvement of Alberta researchers and geoscience professionals, major contributions have been possible in international initiatives on the geological storage of CO_2. Examples include participating in the authorship of the "Underground Geological Storage" Chapter in the seminal IPCC 2005 Report (Benson, et al., 2005) where Alberta's CCS efforts were recognized in the awarding of a 2007 Nobel Peace Prize; contributions to and support of the North American Geological Storage Atlas (NETL, 2016) and characterization of the Basal Aquifer in the prairie regions of Canada. The following sections provide a brief summary of the outcomes from each of these contributions.

1.2.1. IPCC Chapter on Underground Geological Storage

In 2005, the Intergovernmental Panel on Climate Change (IPCC) released its special report on carbon dioxide capture and storage (IPCC, 2005), which consisted of 9 chapters covering sources of CO_2, the technical specifics of capturing, transporting and storing it in geological formations, the ocean, or minerals, or utilizing it in industrial processes. It also assesses the costs and potential of CCS, the environmental impacts, risks and safety, its implications for greenhouse gas inventories and accounting, public perception, and legal issues. In 2007, the IPCC received the Nobel Peace Prize for the 2005 report. Alberta's contribution to the report, specifically the chapter on underground geological storage (Chapter 5), was recognized by Dr. Stefan Bachu as a Lead Author and Dr. Bill Gunter as a Contributing Author. The depth and breadth of their contribution demonstrates Alberta's standing as home to world-class experts in the geological storage of CO_2 and reflects their influence on the scientific and technical understanding of the role of geological storage in combatting climate change.

1.2.2. North American Geological Storage Atlas - Fifth Edition (2015)

The U.S. Department of Energy's (DOE) Carbon Storage Atlas – Fifth Edition (NETL, 2016) provides a high-level, quantitative estimate of carbon dioxide (CO_2) storage resource available in subsurface environments of their regions. Environments considered for CO_2 storage have been categorized into the following major geologic systems: oil reservoirs, gas reservoirs, unmineable coal, saline formations, shale basins, and basalt formations. Where possible, CO_2 storage resource estimates have been quantified for oil reservoirs, gas reservoirs, saline formations, and unmineable coal. Shale and basalt formations are presented as future opportunities and are not assessed.

The project facilitated the gathering and sharing of data on stationary CO_2 sources and storage reservoirs among the three countries (Canada, United States and Mexico) in support of a uniform geographic information system. It accomplished the objective of creating a common portal, where data from different states, provinces or organizations in the three countries can be accessed in a similar format. As noted in Table 1, AI were participants in the development of the atlas.

Table 1 List of proponents and partners involved with NA Geological Storage Atlas

Government/department	Other participants
Natural Resources Canada - Office of Energy R&D - Geological Survey of Canada - Mapping Information Branch	Alberta Innovates – Technology Futures (formerly Alberta Research Council)
U.S. Department of Energy	Plains CO_2 Reduction (PCOR) Partnership
U.S. Department of Energy National Energy Technology Laboratory	Southeast Regional Carbon Sequestration Partnership (SECARB)
U.S. Geological Survey	West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Secretaría de Energía de México (Mexican Department of Energy)	Southwest Regional Carbon Sequestration Partnership (SWP)
Comisión Federal de Electricidad (Federal Electricity Commission)	Midwest Regional Carbon Sequestration Partnership (MRCSP)
	Midwest Geological Sequestration Consortium (MGSC)
	West Virginia University
	IEA Greenhouse Gas R&D Programme (IEAGHG)

The Western Canada Sedimentary Basin that spans from British Columbia (BC), across Alberta (AB) and Saskatchewan (SK), to Manitoba (MB) offers the largest known capacity to store CO_2 in Canada and is the most characterized (Figure 6). Also spanning AB and SK, the Williston Basin has storage potential, as do sites in BC, Ontario and Quebec. Further characterization of the storage potential in Canada is needed to better understand regional opportunities in areas with less mature CO_2 storage options.

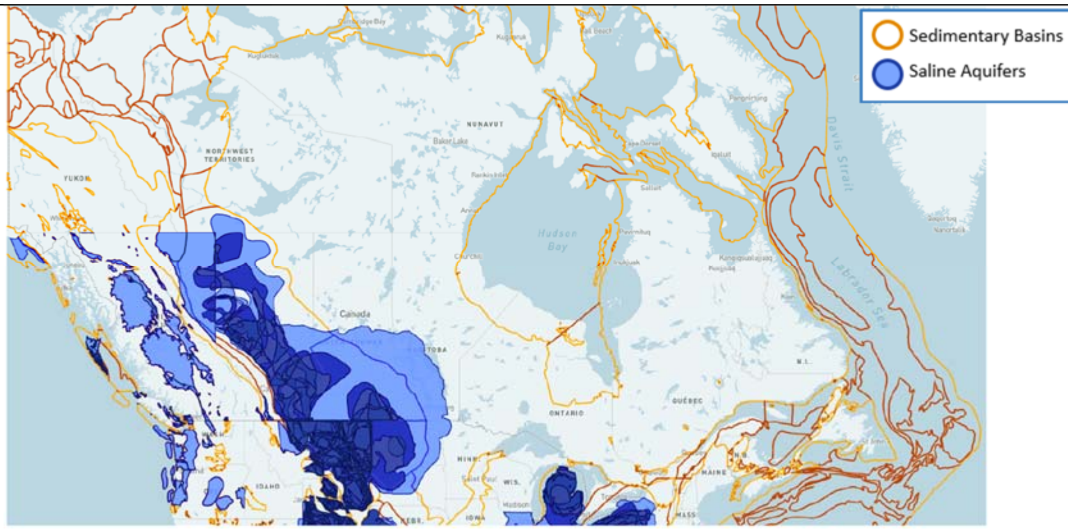

Figure 6 Map of Canada showing saline formations and sedimentary basins with higher volume shown with darker colours (North American Carbon Storage Atlas)

Through the work on the atlas, CO_2 storage resource estimates for Alberta were determined and Table 2 provides these estimates for each major class of reservoir considered in the atlas.

Table 2 Storage resource estimates for Alberta - NA Geological Storage Atlas

State/Province	Oil and Natural Gas Reservoirs Storage Resource			Unmineable Coal Storage Resource			Saline Formation Storage Resource			Total Storage Resource		
	Billion Metric Tons			Billion Metric Tons			Billion Metric Tons			Billion Metric Tons		
	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate	Low Estimate	Medium Estimate	High Estimate
ALBERTA	0.60	1.49	3.57	0.03	0.03	0.03	38.17	76.74	140.30	38.80	78.26	143.90

1.2.3. Basal Aquifer CO_2 Storage Characterization for Prairie Region of Canada

At the base of the sedimentary succession with the prairie regions of Canada, immediately overlying the crystalline Precambrian basement, a series of sandstones, comprising Cambrian- and Ordovician-age units that extend from west-central Alberta into Saskatchewan, southwestern Manitoba and then south into the North and South Dakotas and adjacent states, forms an extensive Basal Aquifer generally devoid of hydrocarbon resources. A project initiated by Alberta Innovates – Technology Futures and the Energy and Environmental Research Centre at the University of North Dakota in 2010 characterized the Basal Aquifer and evaluated its potential for, and effects of, CO_2 storage in this aquifer.

Subsurface mapping of the aquifer and the primary caprock comprising mainly shales, but also tight carbonates and evaporites was completed in the project. Properties across the study area such as mineralogy, depth-thickness, temperature, porosity, pore pressure and salinity were also determined. The storage capacity in the Basal Aquifer suitable for CO_2 storage was estimated using aquifer thickness, porosity, and CO_2 density calculated at in-situ conditions using equations of state, and a storage efficiency coefficient of 2%. The results show an average porosity of 14.4% in the area suitable for CO_2 storage, with a total capacity of 92.5 Gt CO_2 (19.2 Gt in Alberta, 72 Gt in Saskatchewan and 1.3 Gt in Manitoba). This storage capacity will last for ~300 and ~3785 years of CO_2 emissions from locations in Alberta and

Saskatchewan with emissions greater than 1 Mt CO_2/year, respectively, or for ~113 years and ~163 years, respectively, assuming a 5% annual rate of increase in CO_2 emissions at these locations.

1.3. Gaps and Recommendations – Geological Storage

AI supported efforts in defining storage capacity within the WCSB has provided significant confidence in the availability of sufficient pore space to support the deployment of CCUS projects. The Government of Alberta's current interest in identifying suitable CO_2 storage hubs within the province is fundamentally based on this pore space availability. But to deliver on these expectations, it is important to recognize that geological storage capacity is a dynamic variable and may be significantly impacted by sustainable CO_2 injection rates for any particular sequestration site. Quantifying the factors that determine injectivity for a range of early geological storage sites within Alberta will be important for refining forecasts of capacity in future CCS deployment. Quantifying these dynamic characteristics will also provide an opportunity to refine the storage efficiency coefficient in capacity equations and provide direct linkage to the SPE storage resources management system.

From an operations perspective, the development of storage hubs or smaller, more focussed storage projects will require a better understanding of the dynamic pressure limits to ensure induced seismic and containment related risks are managed effectively. These limits will also help manage the interaction of multiple, simultaneous injection projects that may be developed within the same aquifer or depleted hydrocarbon reservoir. Collectively, this knowledge can potentially lead to the development of injection strategies that maximize CO_2 storage and exploit natural geological heterogeneity within the storage horizon.

The presence of fault and fracture systems within the target storage reservoirs or adjacent bounding layers may represent a significant containment risk and are a key element in the assessment of induced seismicity risk. This will be particularly relevant as shallower storage horizons may be considered for CO_2 storage projects. Improvements in site characterization techniques to detect, map, and assess faults and fractures, both within target reservoirs and in surrounding rocks—especially critically stressed crystalline basement faults – will ensure that unsuitable sites are not developed, monitoring programs are appropriate in scale to the expected risk and public confidence is maintained for a rapidly emerging CCUS industry.

For Alberta, CO_2-EOR remains an effective utilization option for CO_2 and while AI has supported numerous studies examining both opportunity and reservoir suitability for CO_2-EOR, recognition of the permanence of associated CO_2 storage remains challenging. Recent investment tax credit policy discussions in Canada, for instance have clearly identified some hesitation in linking CO_2 storage with CO_2-EOR operations. Consequently, it is important to continue demonstrating, through projects and robust MMV programs, how CO_2-EOR can be treated equally with deep saline aquifer storage.

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