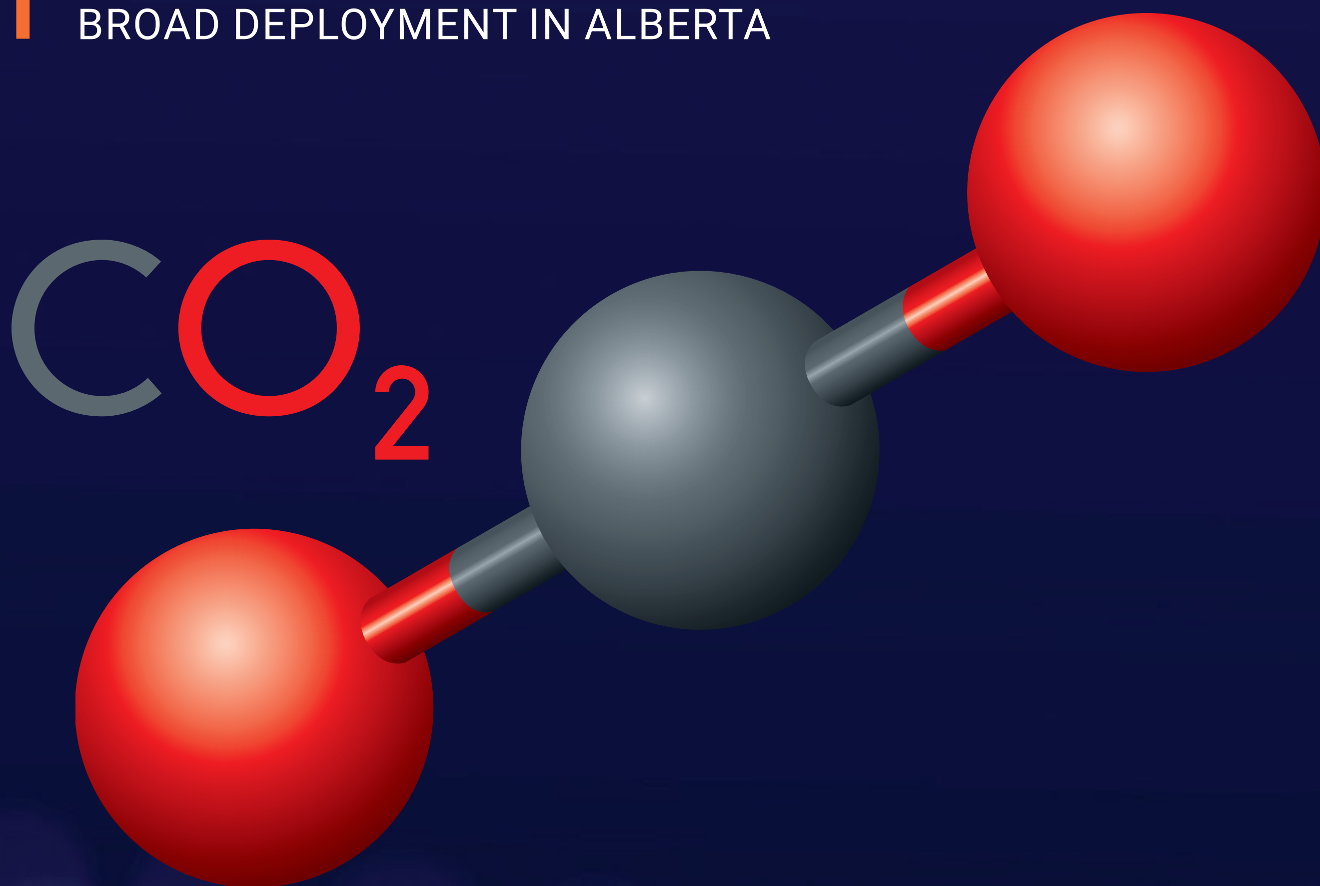
CARBON CAPTURE, UTILIZATION, AND STORAGE (CCUS)

TECHNOLOGY INNOVATION TO ACCELERATE BROAD DEPLOYMENT IN ALBERTA



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ALBERTA INNOVATES

About Alberta Innovates

ALBERTA INNOVATES IS THE PROVINCE'S LARGEST AND CANADA'S FIRST PROVINCIAL RESEARCH AND INNOVATION AGENCY. For a century we have worked closely with researchers, companies and entrepreneurs – trailblazers who built industries and strengthened communities. Today we are pivoting to the next frontier of opportunity in Alberta and worldwide by driving emerging technologies across sectors. We are a provincial corporation delivering seed funding, business advice, applied research and technical services, and avenues for partnership and collaboration.

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FOREWARD

Alberta is a significant centre of energy production and expertise. It is also a growing centre of clean tech expertise, focused on transforming its key energy resources and managing them more sustainability.

Getting to net-zero GHG emissions is one of the greatest challenges of our time and carbon capture, utilization, and storage (CCUS) is an important tool to achieve the goal. As we transition to new fuels and energy sources, oil and gas will continue to be in demand over the near term, but how we utilize the resource will change.

CCUS is an important pathway for Alberta and its oil and gas industries to meet 2030 to 2050 emissions reductions targets. CCUS is also integral to unlocking the potential of low-emission hydrogen production from natural gas.

Alberta will lead the way to greater opportunities as we move to a net-zero world.

We are well-positioned with enormous CO_2 storage capacity – estimated to be more than 100 billion tonnes. Alberta is home to commercial projects and demonstrated CCUS technologies backed by years of research and operating experience. CCUS can enable a low-emissions hydrogen industry using Alberta's massive natural gas reserves.

More importantly, we have the capacity and the ability to do more, using the expertise that exists across the whole of the value chain.

We can build on our resources and experience to accelerate the development of next-generation technologies and the broad commercial deployment of CCUS. We can advance the carbon tech sector, transform the energy industry and export Alberta technologies and know-how around the world.

Laura Kilcrease, *CEO*
Alberta Innovates

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In addition, comments were sought from external organizations and individuals to review the summary, analysis, and recommendations, in the early draft of the paper and to bring additional perspectives. All comments from external reviewers were considered but not necessarily reflected in the final version.

Alberta Innovates is solely responsible for the content of this discussion paper. Reviewers' willingness to provide comments does not represent their consent and/or endorsement of ideas, assumptions, conclusions, and recommendations in this paper. Still, Alberta Innovates sincerely acknowledges and thanks the many organizations and individuals for providing valuable comments and suggestions, including:

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EXECUTIVE SUMMARY

Governments and corporations around the world have been making pledges to reduce greenhouse gas (GHG) emissions to net zero. One of the most important pathways to achieve net-zero emission (NZE) is carbon capture, utilization, and storage (CCUS). Globally, the number of CCUS projects and their capacity have grown rapidly in recent years. CCUS is considered to be a key pathway for Canadian governments and industry to reach their net-zero ambitions.

Alberta Innovates (including its subsidiaries InnoTech Alberta and C-FER Technologies) and Emissions Reduction Alberta (ERA) have invested approximately $140 million in more than 100 CCUS projects in the last 25 years. These investments have contributed to Alberta's international leadership and reputation in carbon capture, utilization, storage, and measurement, monitoring, and verification.

This white paper focuses on technology innovation required for broad commercial-scale deployment of CCUS in Alberta. Other drivers such as public policy, tax incentives, and infrastructure requirements are not discussed here, although their support in improving the economics of CCUS projects is recognized. This paper is Alberta-focused, with consideration to Alberta's industry structure, emission profile, climate conditions, and electric grid carbon intensity. Key learnings from Alberta Innovates' and ERA's CCUS projects are summarized, knowledge gaps are identified, and recommendations are made.

Industry GHG Emissions in Alberta

In 2019, total *industrial* GHG emissions in Alberta were 155 million tonnes (Mt CO_2e). Of 696 industrial facilities, 136 facilities emitted 100,000 tonnes or more CO_2e annually, accounting for more than 126 Mt. Of these, approximately 17 Mt CO_2e of emissions are from high CO_2 concentration sources that can use commercially available carbon capture technologies most economically. Over 109 Mt are from large low to medium-CO_2 concentration sources, primarily from natural gas combustion including natural gas combined cycle (NGCC), once through steam generation (OTSG), and cogeneration. Carbon dioxide concentration from natural gas combustion ranges from 3.5 to 9 per cent, allowing the use of commercially available carbon capture technologies but at a higher cost. Applying CCUS technology to these CO_2 sources more cost-effectively is the greatest GHG emissions reduction opportunity and challenge in Alberta.

Carbon Capture

Carbon capture makes up 80 per cent of the total cost in carbon capture and storage (CCS). It is also the first step required for almost all utilization technologies. Cost reduction has been a key focus in carbon capture technology development. Alberta Innovates and ERA have supported 18 carbon capture technologies including chemical and physical solvents, solid sorbents, and membranes (polymer, solid, and electrochemical).

With proven technologies such as aqueous amines, significant cost reduction can be achieved through “learning by doing” and by continuous incremental improvement in all aspects of these processes. Experience from the Shell Quest project will enable significant cost reduction for similar projects in the future, including carbon capture from the process streams that contain the highest CO2 concentrations and partial pressures. These sources include hydrogen plants at upgrading and refinery plants, especially the syngas and pressure-swing units, fertilizer plants, petrochemicals such as monoethylene glycol, and cement and lime plants. Newly announced blue hydrogen and net-zero ethylene production projects will all benefit from the Quest project experience (e.g., Air Products Blue Hydrogen Hub, Suncor/ATCO Blue Hydrogen Facility, Dow Net-zero Ethylene Plant, Shell Polaris, etc.). Similarly, learnings from the Boundary Dam project should help future CCUS at lime, cement, and steel plants with similar flue gas/off gas concentrations, although the balance of compounds in the exhaust will be different for these applications. Learning by doing can also apply to large emission facilities with low-medium CO_2 concentration such as OTSG and NGCC facilities. CCS is important for both oil sands and power industries.

Incremental improvements to these technologies can give significant improvements in efficiency and cost over time. Areas of improvement include mechanical innovations to reduce equipment size and cost, and chemical innovations to enhance the kinetics of CO_2 capture and reduce the energy for amine solution regeneration. InnoTech Alberta’s Alberta Carbon Conversion Technology Centre (ACCTC) provides an ideal demonstration facility for such improvements.

> **Recommendation #1:** Leverage Alberta’s experience in commercial-scale CCS projects to develop more commercial projects in high CO_2 concentration facilities.

> **Recommendation #2:** Conduct CCS FEED studies and build commercial-scale projects at both an oil sands facility and a NGCC power plant using commercial aqueous amines and leverage this experience to improve the learning curve for future projects while creating near-term GHG reductions.

> **Recommendation #3:** Continue efforts to enhance aqueous chemical absorption technologies for ongoing cost reduction.

New second-generation technologies have the potential to significantly reduce costs and to integrate efficiently with some large emitters. The most promising group includes molten carbonate fuel cell (MCFC), solid sorbent, and facilitated transport membranes. The performance of these newer carbon capture technologies needs to be evaluated against the learnings made in the last 15 years with consideration of Alberta-specific climate conditions.

> **Recommendation #4:** Advance the most attractive second-generation technologies to commercial demonstration.

Carbon Storage

IEA estimates that geological storage or sequestration will be responsible for 90 per cent of captured CO_2 (International Energy Agency, 2020). Carbon storage requires a stratigraphic column with a porous formation to hold CO_2 and overlying formations to contain CO_2. The porous formation needs to have sufficient storage capacity and allow good injectivity, and the overlying formations need to provide permanent containment. Research and studies supported by Alberta Innovates over the last 25 years have provided significant knowledge and confidence for large-scale geologic storage of CO_2.

Alberta has world class expertise and experience in carbon storage. The province also has vast carbon storage resources, with the total capacity in Alberta's deep saline aquifers and oil and gas reservoirs estimated to be over 100 billion tonnes. The development of major hubs for storage of CO_2 requires analysis of maximum injection pressure, pressure interference between injection wells/hubs and overall pressure change within these dynamic systems. Internationally recognized CO_2 storage site selection criteria and site characterization, developed in Alberta, should be used to identify the most promising formations for CO_2 storage. Alberta's scientists have also developed methods and assessment tools that can be applied to estimate CO_2 injectivity in various geological formations and assess the effectiveness of seals to contain all injected and displaced fluids. With these tools, pressure interactions between injection wells within a hub or between adjacent hubs can be reliably predicted. However, a large-scale regional dynamic reservoir pressure model of proposed hub interactions has not been completed. This type of model would be beneficial to assess the impacts on long-term effective and practical capacity predictions as per the Techno-Economic Resource-Reserve pyramid (Bachu, et al., 2007) in this dynamic system.

> **Recommendation #5:** Use analysis tools developed in Alberta to assess potential storage hubs for CO_2 and develop a regional large-scale model to assess potential interactions between hubs.

For storage efficiency and safety, Alberta legislation requires that storage must take place at a depth of more than 1,000 metres below the surface. Significant oilsands facilities in the northeast region of Alberta have no deep aquifers for geological storage of CO_2. Shallow aquifer storage may offer a significant quantity of CO_2 storage capacity in the region. It is recognized regulatory changes will be required for geological storage of CO_2 in shallow aquifers.

> **Recommendation #6:** Explore the feasibility of shallow aquifer storage in northeast Alberta.

Carbon Utilization

Carbon utilization includes CO_2-enhanced oil recovery (CO_2-EOR), enhanced gas recovery (CO_2-EGR), mineralization, chemical conversion, and biological conversion. CO_2-EOR has the potential to use and permanently sequester about one billion tonnes of CO_2 in Alberta. Depleted CO_2-EOR reservoirs would also provide further CO_2 storage capacity beyond the CO_2-EOR stage. The role of carbon utilization outside of CO_2-EOR is modest, in terms of total emissions abatement capacity. However, the application of carbon capture technologies is foundational to building the potential for utilization solutions in Alberta and other regions.

CO_2 mineralization is a viable technology for CO_2 utilization and represents a modest near-term opportunity for GHG reduction in Alberta. Two mineralization technologies have been successfully completed, and provide a good benchmark for new mineralization technologies.

Chemical conversion of CO_2 into materials, chemicals, and fuels is thermodynamically challenging. The conversion process itself requires a large amount of energy and often emits more CO_2 if natural gas or natural gas-fired electricity is used as energy input for conversion. Therefore, chemical conversion processes won't reduce life-cycle CO_2 emissions based on the current electricity grid GHG intensity in Alberta. However, CO_2-converted materials and chemicals may have lower GHG intensities than those made from conventional processes. More importantly, some CO_2-converted materials (such as carbon nanotubes, carbon nanofibres, and CO_2-treated fly ash) may be used to displace part of GHG-intense materials in end products (e.g., displacing part of the cement in concrete).

Photosynthesis by plants and algae is an important pathway for fixing atmospheric CO_2. Biomass from agriculture and forestry can be used for making renewable fuels, chemicals, and materials, for storage into soil and biomass, and potentially for carbon capture and storage from biomass utilization. When sunlight is used for engineered bioreactors to make biofuel from captured CO_2, cost is a key challenge and water use intensity is also a concern. The challenge for indoor bioreactors using electrically powered (even renewable) lighting is almost insurmountable. Future research on biological conversion should focus on improving the biomass yields and properties using natural sunlight.

Life cycle assessment (LCA) can be used to assess GHG impacts across the entire carbon utilization process. It is an important tool for screening CO_2 utilization technologies. Alberta has strong LCA expertise, creating an advantage for technology developers, industry, and government. Additionally, the ACCTC managed by InnoTech Alberta, provides a critical testing facility in carbon capture and utilization technology development and is one of only a few such facilities globally. Technoeconomic analysis of promising technologies includes assessments of capex, opex (fixed and variable), as well as the economic environment in which the technology is to be deployed. Minimizing the size and energy usage of the CO_2 capture and utilization solutions will support cost-reduction efforts. New carbon utilization technologies will benefit from the combination of rigorous LCA, systematic testing, and technoeconomic analysis to give a clear indication of feasibility and carbon storage potential.

> **Recommendation #7:** Focus carbon utilization development on large-scale EOR projects, mineralization, and conversion to materials that can replace or displace high-GHG incumbent materials and could have additional life-cycle GHG benefits when in use.

> **Recommendation #8:** Perform technoeconomic analyses of promising carbon utilization technologies.

Carbon Dioxide Removal (CDR) and Negative Emission Technologies

Carbon dioxide removal (CDR) refers to mechanisms where CO_2 is removed from the atmosphere and stored in plants, trees, soil, lakes, oceans, and rock formations deep underground, or in durable products that embody carbon. Nature-based processes (such as forest and soil carbon storage) have significant potential for removing CO_2 from the atmosphere and are outside the scope of this paper. The potential of CCUS-based CDR technologies in Alberta remains to be quantified.

Bioenergy with CCS (BECCS) has modest near-term potential for negative emissions reduction in Alberta. Alberta has 350 MW of bioelectricity capacity emitting 3.2 Mt of CO_2e annually. Existing and planned ethanol production from wheat in Alberta is projected to be 385 million litres per year. Fermentation of sugars from the wheat starch to ethanol in these plants releases 0.3 Mt of CO_2e per year. If all CO_2 emissions from the production of bioethanol and bioelectricity are captured and stored, it would result in 3.5 Mt of negative emission annually. This would be a far more economic negative emission reduction solution for Alberta than direct air capture. For BECCS applications, consideration must also be given for freshwater use and land use when considering life cycle impacts.

Direct air capture (DAC) is energy intensive and needs low-emission energy sources for the capture process. For DAC applications, consideration needs to be given for location near storage fields and power sources. DAC should be considered as a longer-term solution in a high carbon price environment. Alberta's large CO_2 storage capacity may become an enabler for DAC technologies. Over the short and medium terms, DAC units may be co-located with intermittent emitting facilities (e.g., peaking power plant), providing a means for carbon capture at an intermittent emitting facility when the facility is in use and emitting. It can also improve the overall efficiency of DAC and provide learning experiences.

> **Recommendation #9:** Adopt a phased approach on CO_2 removal technologies, with BECSS as the near- and medium-term priority and DAC as a longer-term solution.

Clean tech Entrepreneurship in Alberta

While Alberta has an active technology ecosystem supporting the development of geological carbon storage, there is a gap in innovation for carbon capture and carbon storage. Most carbon capture and utilization (CCU) technologies supported by and demonstrated in Alberta are from other Canadian provinces and countries. The establishment and growth of Alberta-based CCUS companies can contribute to CCUS deployment in Alberta and help develop a clean-tech industry in the province.

Recommendation #10: Identify ways to develop more clean-tech talent and entrepreneurs in the province and help existing small clean-tech companies to grow.

INTRODUCTION

More governments and companies are making pledges to reduce greenhouse gas (GHG) emissions to net-zero emissions (NZE). Achieving net-zero means the economy would either emit no GHG emissions or completely offset its emissions with reductions. It will require a total transformation of the energy systems that underpin our economies. Dozens of countries, organizations, and corporations have developed, or will be developing strategies, pathways, and milestones to reach NZE. The International Energy Agency (IEA) has set out 400 milestones spanning all sectors and technologies – for what needs to happen, and when – to transform the global economy to NZE (IEA, 2021).

One of most important pathways to enable achievement of NZE is carbon capture, utilization, and storage (CCUS). Globally, CCUS projects and capacity are growing rapidly in recent years (GCCSI, 2021a). The federal government's Strengthened Climate Plan (December 2020) and Emissions Reduction Plan (ECCC, 2022) call for the development of a comprehensive CCUS strategy for Canada, which will establish a vision and a set of recommended federal actions to accelerate the CCUS industry in Canada and realize its GHG reduction and commercial potential. In addition, Budget 2022 further solidified an investment tax credit for capital invested in CCUS projects. The $319-million RD&D program led by Natural Resources Canada (NRCan) to improve. the commercial viability of CCUS technologies is advancing with strategy development (NRCan, 2022) and an early priority for these funds to support the development of front-end engineering and design (FEED) studies for CCUS projects across Canada.

The Government of Alberta has invested over one billion dollars in CCUS, contributing to Alberta's position as a global leader in CCUS and support for two megaton-scale projects which have stored more than seven million tonnes of CO_2 since 2015. The government continues to invest in CCUS through funds raised through its Technology Innovation and Emissions Reduction (TIER) program. More recently, the province issued a request for proposals from companies interested in building, owning, and operating a carbon storage hub that will primarily ensure storage services for emissions from Alberta's industrial heartland region.

CCUS is also a key strategy for Alberta's industries in their pursuit of NZE. It is a key pathway in the Oil Sands Pathways to Net-Zero, an initiative led by six oil sands producers who represent 95 per cent of total bitumen production in Alberta to achieve net-zero emissions by 2050. The electric power, cement, refinery, petrochemical, hydrogen, and fertilizer industries in Alberta are all developing CCUS projects for their emissions reduction.

Alberta Innovates (including InnoTech Alberta and C-FER Technologies) and Emissions Reduction Alberta (ERA) have invested approximately $140 million in more than 100 CCUS projects in the last 25 years. Alberta's innovation organizations and research universities have strong programs and international reputations in carbon captures, utilization, storage, and measurement, monitoring, and verification (MMV). These include:

- Pioneering and ground breaking research in carbon storage, including contribution to the “Underground Geological Storage” Chapter in the seminal IPCC 2005 Report whose authors were awarded the 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;
- World class MMV research at the Universities of Alberta and Calgary, CMC Research Institutes, and InnoTech Alberta including participation in a major international research initiative “IEAGHG Weyburn-Midale CO_2 Monitoring & Storage Project”;
- Support for the Government of Alberta’s CCS program in early 2000 that led to the 1.5 million tonnes per year Alberta Carbon Trunk Line (ACTL) project and the 1.0 million tonnes per year Quest project.
- Support for 18 distinctive carbon capture technologies from across Canada and internationally;
- Launch of CCEMC (ERA) Grand Challenge in carbon utilization in 2013, which reached more than 400 innovators and supported 25 top technologies from around the world;
- Support for a life-cycle analysis (LCA) study of 95 carbon utilization pathways to gauge the potential of carbon utilization technologies in emission reduction;
- Support for the Canadian Clean Power Coalition whose work provided the foundation for SaskPower’s Boundary Dam project; and
- Establishment of Alberta Carbon Conversion Technology Centre (ACCTC) and hosted awardees from COSIA/NRG Carbon X-PRIZE.

Despite investment made and progress achieved, significant barriers still exist for broad deployment of CCUS in Alberta. To meet Canada’s 2030 and 2050 GHG targets and Alberta CCUS ambitions, existing technologies need to be deployed broadly, and new technologies need to be developed, demonstrated, and deployed.

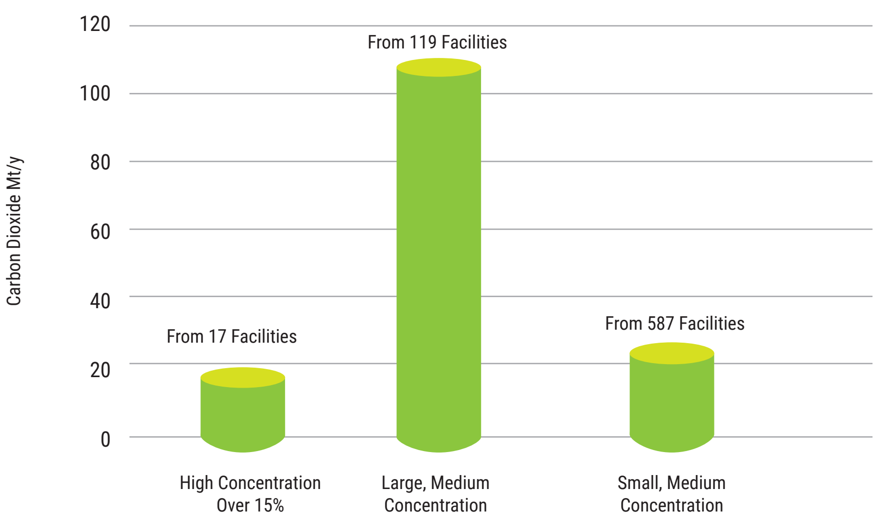
This white paper summarizes the key learnings from past investments and projects, identifies key knowledge gaps, and offers our insights to accelerate CCUS technology development and deployment in Alberta. Many of the learnings are derived from the 106 projects supported by Alberta Innovates (including its predecessors and subsidiaries) and ERA. These projects and studies are summarized by Chalaturnyk (2022) (carbon storage), Lawton (2022) (MMV), Butler (2022) (carbon capture), Meikle et. al. (2022) (carbon utilization), and Wagg (2022) (transportation). Carbon storage and MMV studies are very much focused on Alberta and the Western Canadian Sedimentary Basin (WCSB). Carbon capture and utilization technologies are sourced from across Canada and around the world. Knowledge gaps and key barriers across the CCUS value chain were identified and those specific to Alberta are highlighted. Insights were developed from the learnings from these projects and the understanding of specific CCUS challenges in Alberta. Based on these insights, recommendations are made to accelerate CCUS deployment in Alberta.

MAJOR INDUSTRIAL EMISSION SOURCES IN ALBERTA

Understanding the characteristics of emission sources is the first step in developing effective CCUS strategies and pathways. The Government of Canada tracks all greenhouse gas emissions including CO_2, methane, N_2O, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. CO_2 comprises 95 per cent of the totals provided below, with methane providing 4 per cent and others comprising the balance. Consequently, the portion of Alberta's industrial GHG emissions that are relevant to CCUS discussions was 148 Mt in 2019, or 20 per cent of the total national emissions of 730 Mt in 2019 (Government of Canada, 2022). Potential CCUS on these sources depends on the concentration, or more specifically the partial pressure, of CO_2, the size of the source, and the ease of retrofitting existing equipment for carbon capture or fuel substitution. The scale of CO_2 emissions from three categories of sources in Alberta is shown in Figure 1

Figure 1

Industrial CO_2 Emissions in Alberta by Capture-Readiness



(2019 data for emissions from Government of Canada, 2021, allocated by concentration based on Layzell et al. 2020)

The facilities listed in Figure 1 are divided into three groups:

1. Facilities with CO_2 concentration streams or flue gases greater than 15 per cent, including those in hydrogen production (especially the syngas stream), fertilizer manufacturing, mono ethylene glycol plants, cement, and lime manufacturing facilities. Concentrations range from 15 to 100 per cent on a dry basis. 2.5 Mt of CO_2e from this group are already being captured and stored annually.

2. Large emission sources in the low to medium range, from 3.5 to 15 per cent CO_2, including oil sands in-situ facilities, natural gas power generation, other power production, chemical manufacturing, oil sands mining and upgrading facilities and petroleum refineries. At the low end of the range, natural gas in combined cycle and co-generation plants have circa 3.5 per cent CO_2 in their flue gas, while at the high-end boilers fired with petroleum coke can have 15 per cent CO_2 on a dry basis.

3. Smaller (under 100,000 t/y), dispersed facilities with flue gas/exhaust CO_2 concentration greater than 3.5 per cent, including compressor stations, batteries, smaller gas plants, pipelines, distribution systems, agriculture, waste management and other facilities.

The distinction between streams of different concentration is important because CCUS for higher concentration CO_2 streams has been deployed on commercial scale in Alberta and elsewhere in the world but CCUS for medium concentration CO_2 streams carries a higher cost and is less commonly found on a commercial scale. At low concentrations of CO_2 (Kazemifar, 2021) below 3.5 per cent, such as direct capture from air, carbon capture is much more expensive due to the large volumes of gas that must be handled and the low efficiency of the capture step, regardless of the technology.

Our analysis indicates that as of 2019, 17 Mt CO_2e emissions were from 17 high-concentration sources. Since that time, CCUS has reduced this amount by 1.6 Mt/y, and commercially available capture technologies can process a large portion of the high concentration streams available from these sites Note that after 2019, the base GHG reductions were 2.5 Mt/y due to an increased number of projects coming online. A significant fraction of these emissions is expected to be captured by 2030. The Alberta Hydrogen Roadmap (2021) proposes a dramatic increase in the production of hydrogen coupled with CCUS by 2030. The Transformative Scenario in this roadmap includes significant exports of blue hydrogen, ammonia derived from blue hydrogen, increased CO_2 capture from existing hydrogen plants, and use of hydrogen as fuel in industrial facilities and in natural gas networks as methane-hydrogen blends.

109 Mt/y are from low to medium CO_2 concentration sources for those emitting greater than 100,000 t/y. These emissions are expected to decline to 86 Mt/y due to conversion of coal-fired plants and increased use of hydrogen as fuel in industrial operations and natural gas distribution networks. As Alberta phases out coal, natural gas combustion will dominate the low to medium concentration sources. Once through steam generation (OTSG), gas-fired boilers, and high-temperature furnaces have CO_2 concentrations in flue gases from 5 to 9 per cent. Combined cycle and cogeneration power plants have CO_2 concentration in flue gases at circa 3.5 to 4 per cent, making them the most challenging large industrial sources for cost-effective carbon capture.

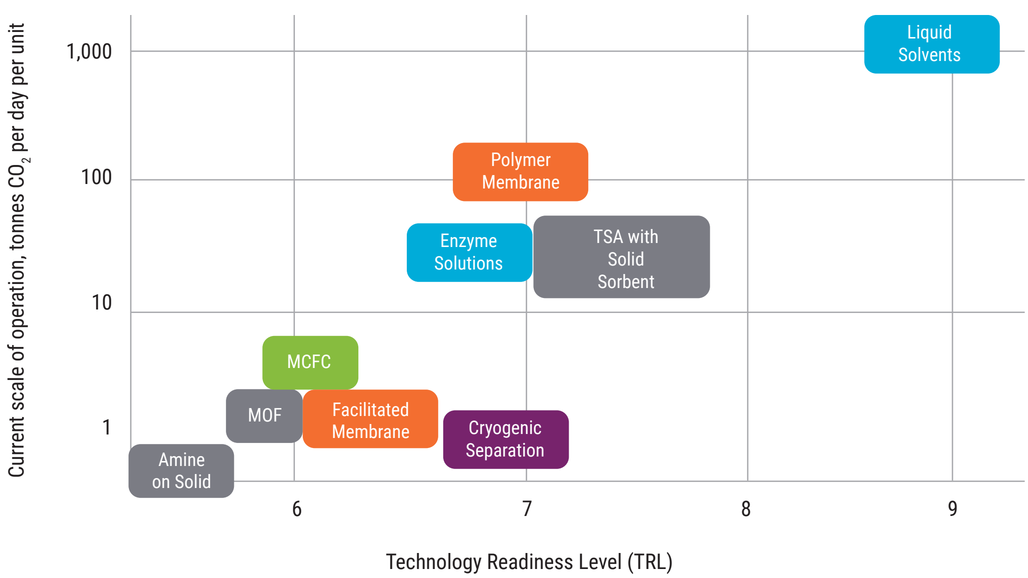
Smaller industrial sources, below 100 kt/y, are widely distributed so that emissions from these 587 sites generate 22 Mt/y (15 per cent of Alberta's total). These will be more challenging to cost-effectively capture and transport to appropriate storage sites, so may be harder to abate than larger point sources. Applying CCUS technology to the large-scale, low to medium-concentration CO_2 sources is the greatest opportunity and challenge in Alberta. However, due to the large number of these facilities locally and globally, there may be potential technology export opportunities if capture technology can be economically scaled to these facilities.

CARBON CAPTURE

Carbon capture is the first step in the CCUS process, and the most expensive. The high cost of carbon capture has been a key barrier for CCUS deployment to date. The Global CCS Institute has provided an overview of carbon capture technologies in use and under development (GCCSI, 2021b). Alberta Innovates and ERA have been supporting the development of carbon capture technologies since 2010. Our focus has been to bring the most promising carbon capture technologies into Alberta to enable CCUS development in the province. These technologies include physical and chemical solvents, solid sorbents, membranes, and others. The lessons learned in these developments are summarized below. A summary of the relative advancement of different carbon capture technologies expressed as maximum volumes that have been successfully captured and technology readiness level (TRL) level is provided in Figure 2.

Figure 2

Carbon Capture Technologies by Volume Captured and Technology Readiness Level (TRL)



Chemical and Physical Solvents

Liquid solvents, both chemical and physical, have been used for carbon capture for decades. Physical solvents such as glycol and methanol are suitable for CO_2 capture from process gas streams that contain higher CO_2 concentrations (>25 per cent) under higher-pressure conditions. Two commercial examples of physical solvents are Selexol™ and Rectisol®. These solvents are used at gasification plants using coal, petroleum coke, and biomass feedstocks. Northwest Refining's (NWR's) Sturgeon Refinery uses Rectisol® for CO_2 capture from its gasification unit.

Chemical solvents such as amines in aqueous solutions are widely used in the natural gas industry to separate CO_2 and hydrogen sulfide from methane (Alberta Government, 2018). In amine-based capture systems, CO_2 in incoming gas is absorbed by amines at low temperature and pure CO_2 is separated at higher temperature (Alberta Government, 2018). Aqueous amine systems have also been used for large-scale CO_2 capture from a steam methane reforming (SMR) hydrogen production facility (Quest) and a coal-fired electric power plant (Boundary Dam).

The cost for amine-based carbon capture systems is high. Both Quest and Boundary Dam projects cost more than \$100/tonne CO_2 avoided, and approximately 80 per cent of this cost is attributed to capture. For CO_2 capture from low CO_2 concentration flue gases such as with natural gas combustion, the cost could be even higher because carbon capture cost is inversely correlated to CO_2 concentration in flue gas (GCCSI, 2021a). There has been a global effort to improve amine-based CO_2 capture systems. Alberta Innovates and ERA have supported several such projects including:

- **HTC Purenergy (now Delta Clean)**. This is an amine system with both enhanced solvent composition and physical packing. The HTC system had the promise to capture CO_2 from OTSG (once through steam generator) flue gas for \$70/tonne. A demonstration was conducted at a steam-assisted gravity drainage (SAGD) oil sands facility. Operation of the demonstration plant was unreliable due to several process and mechanical issues, not all related to the CO_2 technology itself. Many of the problems, including foaming of the solvent, were hypothesized to be linked to reuse of legacy equipment.

- **CO2 Solutions Inc (CSI)**. CSI developed an enzyme that accelerates the kinetics of CO_2 dissolution in aqueous carbonate solutions, which can then be regenerated at low temperature to release pure CO_2. Because of their ability to accelerate CO_2 uptake into a carbonate solution, enzymes have the potential to reduce both the capital cost (smaller plant size) and operation cost (lower regeneration temperature) of CO_2 capture. CSI estimated they could reduce the amount of energy required for regeneration of the carbonate solution by 88 per cent by using waste energy streams. CSI's technology has been demonstrated at 30 tonnes/day of CO_2 capture. The company was funded in part by NRCan as well (NRCan, 2018). The company has been acquired by Italian-based energy company Saipem. The technology continues to hold promise.

Recent advancements that have been made in amine capture systems could offset the capture cost impacts of lower CO_2 concentration in flue gas as advanced chemical solvents and process modifications are being developed to more cost-effectively capture CO_2 concentrations from flue gases at 5 per cent or less (Wang & Song, 2020).

Solid Sorbents

Carbon capture using solid sorbents is based on the interaction between gas molecules and the sorbent surface. Adsorption can be characterized as either chemical or physical. Chemical adsorption results in a strong interaction between the gas molecule and sorbent, and physical adsorption has a weaker interaction between the gas molecule and sorbent. Regeneration is typically accomplished using a thermal swing adsorption (TSA) or pressure swing adsorption (PSA) mechanism, although vacuum swing adsorption (VSA) can also be used. Alberta Innovates and ERA have supported several solid sorbent projects including:

- **Svante's (formerly Inventys) VeloxoTherm™**. The VeloxoTherm™ system is a physical adsorption process with a rapid-cycle thermal swing adsorption (TSA). It captures CO_2 from flue gas (generated by boilers, heaters, cement kilns, steel plants, petrochemicals, and hydrogen) using activated carbon in a rotary mechanical contactor to capture, release, and regenerate the sorbent in a single unit. Supported by ERA, the technology has been demonstrated at 30 tonnes per day from an OTSG at Husky's (now Cenovus') thermal oil facility in Lashburn, Saskatchewan and Lafarge's cement plant in Richmond, BC. Svante's VeloxoTherm™ was tested on flue gas at 16 per cent concentration from a cement plant (Ghaffari-N, et al., 2021) to generate CO_2 of 95 per cent purity using the CALF-20 metal-organic framework (MOF) described below (Lafarge, 2021). This technology is currently being tested at a Chevron NGCC facility with flue gas concentrations between 4 and 14 per cent at a 25 tonnes per day capture rate to determine the economic viability of the technology (NETL, 2021a), and at a Linde steam methane reforming facility to determine if it can achieve a 90 per cent capture rate with 95 per cent purity (NETL, 2021b). A key lesson from the development of the VeloxoTherm™ technology is that an effective solid adsorption system requires not only a high-performance sorbent but also a medium to support it.

- **The University of Ottawa and Pacific Northwest National Laboratory (PNNL)**. Many proposed solid sorbents are based on solids coated with amines. Compared with aqueous solutions, amines on solids can perform the same function as aqueous amines but save energy in regeneration. The University of Ottawa's solid sorbent was ranked as one of the top-performing solid sorbents in the world in 2010 (Sjostrom & Krutka, 2010). Alberta Innovates supported a joint project using University of Ottawa's sorbent and PNNL's sorbent bed system. The lab scale work showed that the solid sorbents tested can achieve high CO_2 loading capacities and rapid adsorption/regeneration cycles could be achieved with the structured bed. However, scale-up estimates identified that the use of vacuum pressure to remove the CO_2 could not be scaled up. Scale-up to commercial size can be a significant barrier for many CO_2 capture technologies that show early promise.

- **Metal Organic Framework (MOF)**. MOFs are porous solids based on customizable metal ions and organic linkers. Modifications to the MOF structure allow for the development of highly selective adsorption properties, in this case for CO_2, and may also be tuned to maintain greater robustness with exposure to humidity and other feed gas impurities compared to other solid sorbents. Alberta Innovates supported a project at the University of Calgary to develop a zinc-based, CO_2 capture-specific MOF, called Calgary Framework 20 (CALF-20) (University of Calgary, 2021) intended for eventual integration with commercial scale CO_2 capture processes. The CALF-20 MOF can preferentially adsorb CO_2 at up to 40 per cent relative humidity and maintains its performance under flue gas conditions of 150°C, with resistance to steam and acid gas conditions for greater than 450,000 cycles (Lin, et al., 2021) using a 17 per cent CO_2 concentration flue gas stream from a cement facility (Ghaffari-N, et al., 2021). Beyond its CO_2 selectivity properties, CALF-20 has also been confirmed to have a low enthalpic regeneration penalty, validating its potential to reduce the overall cost of capture. The CALF-20 material was tested in conjunction with Svante, who demonstrated the material's viability for use as an adsorbent in its VeloxoTherm ™ technology and Svante has successfully tested the material in an industrial cement plant setting, with a capture capacity of one tonne per day.

Membranes

Three types of membrane system have been used for CO_2 capture: polymeric membranes, electrochemical membranes, and solid membranes. Alberta Innovates and ERA have invested in the development of all three membrane types for applications in Alberta.

Gas separation through polymeric membranes can be achieved by solution-diffusion mechanisms or facilitated transport processes. (Han et al. (2020) provide a good overview of recent developments in polymeric membranes for CO_2 capture. In the solution-diffusion process, gas molecules diffuse through a polymer at different rates, achieving separation. In the facilitated transport process, a reactive amine group is fixed onto the polymeric chain and promotes CO_2 transport through the membrane. The two most important intrinsic properties of polymeric membranes are permeability and selectivity. The selectivity of facilitated transport membranes often is an order of magnitude higher than solution-diffusion membranes. Polymeric membranes can be flat or hollow fibre. Hollow fibre membranes can significantly increase the surface area for separation and therefore increase the efficiency. Alberta Innovates supported two world-leading polymeric membrane developments:

- **The Norwegian University of Science and Technology (NTNU)**. NTNU's fixed-site carrier (FSC) membrane (a type of facilitated transport membrane) has exceptional permeability and selectivity for CO_2. The selectivity of CO_2/N_2 is greater than 1000, more than 10 times that of solution-diffusion membranes. Alberta Innovates supported the development of the NTNU membrane in partnership with oil sands producers and the global membrane manufacturer Air Products. A process simulation was created using pilot testing results. The simulation confirmed the technical feasibility of using a two-staged membrane system to achieve 95 per cent captured CO_2 purity at 80 per cent capture. A more commercially viable design considered a three-stage membrane system to achieve 50 to 70 per cent capture (depending on feed CO_2 composition) to yield a stream of 95 per cent CO_2 purity. A 90 per cent capture case was determined to be unrealistic at commercial scale due to the membrane area required. The NTNU membrane was advanced to technology readiness level (TRL) 6 through the project. Air Products has signed an exclusive license agreement with NTNU for the membrane technology for CO_2 capture (Phys.org, 2017).
- **Membrane Technology and Research (MTR) Polaris™ membrane**. Alberta Innovates supported MTR's membrane technology demonstration at the Advanced Energy Research Facility. MTR combined its Proteus membrane for H_2 separation and Polaris membrane for CO_2 separation. The design was too complicated, and the project terminated before completion. MTR has, however, been advancing its Polaris membrane technology since the project termination with Alberta Innovates. In its latest US Department of Energy (DOE) project, MTR is conducting a 140 tonnes per day demonstration (NETL, no date). The designed CO_2 capture rate is at 70 per cent.

Polymeric membrane development is still very active. However, as shown in Han et al. (2020), many polymeric membranes cannot achieve high capture rates and high CO_2 concentrations at the same time. To Alberta Innovates' knowledge, the NTNU membrane is the only one that has the potential to achieve 80 per cent capture from post-combustion flue gas and achieve 95 per cent concentration in CO_2 stream at the same time. For new membranes to be competitive, they will need to cost-effectively capture similar amounts of post-combustion flue gases from a range of flue gas concentrations and achieve at least a 95 per cent concentration CO_2 stream. To help improve competitiveness, high pressure environments are more amenable to the use of membranes as the pressure provides a driving force on the membrane.

Electrochemical membranes (ECM) have significant potential for combined CO_2 separation and power generation. ECMs utilize chemical potential for gas separation. The best example is molten carbonate fuel cells (MCFC). MCFC is an established technology but have not been used for carbon capture application. In carbon capture application, carbon dioxide from an external flue gas is catalyzed at the cathode into carbonate ions. Carbonate ions then travel through a membrane and react with hydrogen on the anode side, generating electric power and releasing CO_2 at a higher concentration than the flue gas. Natural gas is reacted in the anode side to provide the hydrogen to drive the separation within the cell. The advantage of the MCFC for carbon capture in SAGD operations is the synergy between steam generation, power generation, and carbon capture.

Alberta Innovates introduced the MCFC technology to oil sands producers in Alberta and led multiple studies of MCFC application for CO_2 capture in SAGD application. Technoeconomic analysis indicates that MCFC can capture 90 per cent of CO_2 from SAGD facilities at a cost significantly lower than liquid amine processes per Jacobs Consultancy et. al. (2013) and Hill et al. (2016) although this is based on several assumptions that may no longer be valid. Still, the cost of using MCFC for carbon capture in SAGD facility would be significantly lower than amine-based processes per Jacobs Consultancy et. al. (2013). An "MCFC for carbon capture" project is being advanced through a 1.4 MW demonstration at Canadian Natural/Shell Scotford facility, partially funded by ERA and the Clean Resources Innovation Network. The technology is also being pursued by US DOE and ExxonMobil.

Alberta Innovates and ERA also supported the development of solid membrane technologies. This includes a zeolite membrane for hydrogen separation with GE and the University of Alberta and an oxygen membrane with Air Products, US DOE and Canmet ENERGY, etc. These technologies all fell short of expectations and therefore no further efforts are being made. Effective membrane technologies will need to have high capture rates from low concentration post-combustion streams and be able to produce high concentration CO_2 streams cost-effectively.

Other Carbon Capture Technologies

Alberta Innovates and ERA have also supported several other carbon capture technologies including:

- **Oxyfuel combustion.** Oxyfuel combustion is the process of adding a stream of pure oxygen and recycled exhaust gases (mainly CO_2) into the combustion process, resulting in an exhaust stream highly concentrated in CO_2 (Nemitallah, et al., 2017). The concentrated, heated CO_2 stream that results from this process improves CO_2 capture capability. An evaluation conducted by Jacobs Consultancy (2013) for Alberta Innovates through the Canadian Clean Power Coalition determined that the addition of post-combustion carbon capture equipment to an oxyfuel facility increased the capital costs by 53 to 65 per cent at power generation facilities, compared to post-combustion capture equipment cost increases of 40 per cent at a natural gas combined cycle plant. Significant capital cost reduction will be required for oxyfuel combustion to be a competitive carbon capture option.

- **Chemical looping.** Chemical looping uses solid carriers to shuttle oxygen, nitrogen, or CO_2 between pairs of chemical reactors to produce products such as hydrogen and ammonia, with an additional loop to concentrate CO_2 (Jacobs Consultancy, 2010) (Joshi, et al., 2021). This complex process can be used for coal gasification to form syngas or hydrogen, or to use natural gas to produce hydrogen, ammonia and other products (Joshi, et al., 2021). Capital costs and system reliability are challenges to be overcome to provide a cost-effective solution, and include: extensive capital infrastructure, multiple chemical inputs and reactor beds, the need for robust carriers that resist attrition, system resistance to volume expansion and contraction of the carriers and reactor beds, abrasive forces from physical movement of solids, and channeling through the fluidized bed reactors (Joshi, et al., 2021). Additional development efforts would be required to address these issues to provide a cost-effective solution.

- **Solid oxide fuel cells.** Solid oxide fuel cells (SOFCs) convert fuel (e.g. methane) into power and heat through oxygen transfer across an electrolyte from a cathode to an anode which then reacts with the fuel, producing power and releasing CO_2 and water (as steam) from the anode (Jacobs; Scott, S; Lamprecht, D; Butler, D, 2013) (Jacobs Consultancy; Dave Butler & Associates, 2014). SOFCs are in "early adopter" stages of commercial readiness but have not yet experienced broad market deployment. SOFCs with carbon capture have low cost of capture due to the low cost of purification required and therefore lower capture equipment costs. However, SOFCs have high capital costs and energy usage to operate (Jacobs; Scott, S; Lamprecht, D; Butler, D, 2013), (Jacobs Consultancy; Dave Butler & Associates, 2014). Future versions of SOFCs will need to address capital cost and energy inputs to be competitive.

- **Ionic liquids.** Ionic liquids are a class of solvent that typically consist of a large ionic cation and an inorganic or organic anion. These compounds have negligible vapour pressure at room temperature and are stable over a wide range of temperatures. An early study funded by Alberta Innovates concluded that ionic liquids do not have an advantage over amines in natural gas sweetening (Mather & Jou, 2004). Advancement has been made more recently (Shukla, Khokarale, Bui, & Mikkola, 2019) (Aghaie, Rezaei, & Zendehboudi, 2018). However, ionic liquids are still at early stages of development, and significant additional work is required to advance towards commercial implementation.

- **Cryogenic carbon capture (CCC).** In CCC the flue gas is cooled to the point where CO_2 is solidified for easier separation, coincidentally removing mercury and SO_2 as well. CO_2 purities have been verified as high as 99 per cent from the CCC process (Sustainable Energy Solutions, 2015). Sustainable Energy Solutions (SES) was supported by ERA in the development of their CCC process, which was combined with an energy storage module. Using natural gas as a refrigerant, SES simulated storing energy in condensed natural gas during off peak hours at a power generation facility. The stored energy could then be used to run the CCC process during peak hours, virtually offsetting the parasitic load of carbon capture. SES has been acquired by global manufacturing company, Chart Industries. Heat transfer efficiency and cold temperature solids management remain key challenges, however, the technology remains promising. Several different cryo-capture technologies have been demonstrated in multiple jurisdictions internationally.

- **Direct air capture (DAC).** Direct air capture involves separation of CO_2 from ambient air and concentrating it for either use or storage. The separation mechanisms can vary from direct mineralization to solvents and others. Carbon Engineering completed a project with funding from ERA to test their solution absorption mechanism for direct air capture. The solution involved a closed loop cycling of potassium hydroxide reacting with ambient CO_2 to form potassium carbonate, which was reconstituted back to potassium hydroxide and a pure CO_2 stream using heat (Carbon Engineering, 2016). The heat and power used by the facility was provided by natural gas for the study. Due to the low concentration of CO_2 in the ambient air relative to other sources such as flue gas exhaust, higher volumes of air need to be processed, requiring significant additional energy and infrastructure to drive the process. This results in a more energy intensive and expensive capture process over other carbon capture methods using more concentrated CO_2 streams (Wang & Song, 2020). When energy used to run the process is obtained from a carbon-emitting source, the benefits of ambient CO_2 capture are reduced. Carbon Engineering (2018) has calculated that the energy intensity of the process is 8.8GJ (thermal) per tonne of CO_2 captured. Keith et. al. (2018) estimated that capture costs vary from USD $94/t to $232/t. Efforts to reduce energy intensity will be necessary for this technology to compete at commercial scale with CO_2 capture from other sources. Leveraging waste heat sources such as expended SAGD fields may improve the energy balance and potentially improve the economics of this option. Carbon Engineering is currently developing a commercial-scale pilot in Texas to validate its unit costs (IEEE, 2021).

With the renewed interest in carbon capture and the specialized expertise needed to assess, test, implement and operate carbon capture systems as well as advance next generation technologies, a significant increase in high quality and specialized personnel will be needed to advance cost-effective solutions to meet increasingly stringent federal and provincial regulations. Alberta already has a wealth of expertise in this field, but additional new and seasoned experts will need to be focused on providing solutions to the oil and gas and power markets to maximize the deployment of carbon capture solutions into the market to meet aggressive net-zero targets.

CARBON STORAGE

Carbon dioxide storage or sequestration is a process placing CO_2 in geological formations with impermeable seals (caprocks). CO_2 is held in the pore spaces present in the storage formation, and seals will ensure that the CO_2 stays permanently in place. Storage formations include saline formations, depleted oil and natural gas reservoirs, and un-mineable coal seams. Globally, it is anticipated that 90 per cent of all CO_2 captured will need to be permanently stored to achieve net-zero emissions (International Energy Agency, 2020).

Alberta's oil and natural gas resources were formed and have been trapped 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 storage.

Over the last two decades, Alberta researchers and geoscience professionals have been at the forefront of the geological storage of CO_2. The contribution of Alberta Innovates, including its predecessors (Alberta Research Council, Alberta Innovates Technology Futures, Alberta Energy Research Institute, and Alberta Innovates Energy and Environment Solutions) and subsidiaries (InnoTech Alberta), in carbon storage has been summarized recently (Chalaturnyk R. , 2022).

Capacity

The availability of CO_2 storage capacity is critical to CCUS. Estimation of CO_2 capacity has been a major focus for many studies examining the geological storage of CO_2. Canada, the United States and Mexico have collaborated to produce a North American Geological Storage Atlas (NETL, 2016). The Atlas identifies major stationary sources of CO_2 emissions and potential geological storage reservoirs. 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 in Alberta.

The Western Canada Sedimentary Basin that spans from British Columbia, across Alberta and Saskatchewan, to Manitoba offers the largest known capacity to store CO_2 in Canada and is the most characterized (Figure 2). Also spanning Alberta and Saskatchewan, the Williston Basin has storage potential, as do sites in British Columbia, 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. Carbon dioxide storage resource estimates for Alberta are shown in Table 1.

Figure 2

Map of saline formations and sedimentary basins with higher volume shown with darker contours (NETL, 2016).

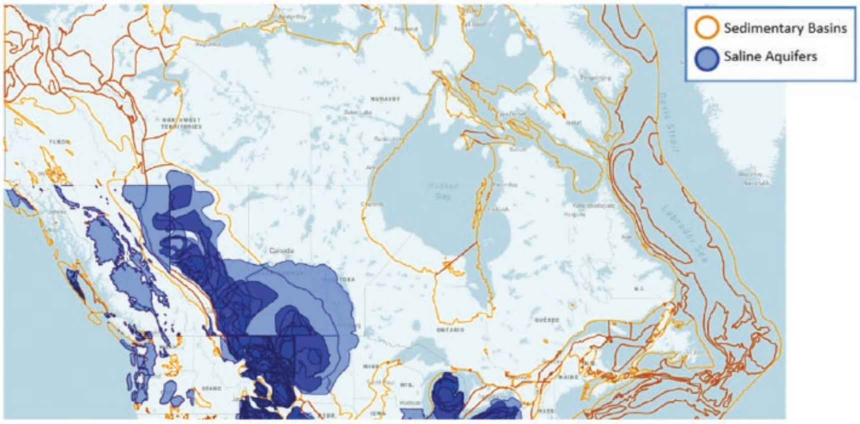


Table 1

Storage resource estimates for Alberta – NA Geological Storage Atlas

Key studies on storage capacity (Bachu, et al., 2007), (Bachu, et al., 2012), (Bachu & Jafari, 2016), and (Bachu S. , 2006) characterize the storage capacity and potential for EOR across Alberta. The studies further established large storage capacity in basal aquifers in Alberta. However, storage capacity in the Athabasca-Cold Lake region in northeastern Alberta is relatively small, though there are approximately 5300 gas pools with approximately 609 Mt CO_2e potential capacity. Of these, 76 gas pools have capacity greater than 1 Mt CO_2e each, for a total of 292 Mt CO_2e. These gas pools are distributed almost evenly across northeastern Alberta, and are found at depths that vary between approximately 200 and 950 metres. Upon depletion, these gas pools can be used for sequestering 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.

Gross storage capacity and usable storage capacity are not the same, therefore Alberta Innovates supported a framework on how to determine actual storage capacity was established through a technoeconomic resource-reserve pyramid (Bachu, et al., 2007) (CSLF, 2007). The Society of Petroleum Engineers (SPE) used this foundation and developed a Storage Resources Management System (SRMS) (SPE, 2017) to set out standardized definitions to describe the maturity of, and level of uncertainty or confidence in, storage resource assessments. It provides a standardized approach to classifying the storage reserves and resources and supports commercial CCS investment decisions. SRMS will likely be used by the Alberta Government in its competitive carbon storage rights process currently underway (Chalaturnyk R. , 2022).

It should be noted that storage efficiency coefficient values are very small, varying from less than 1 per cent to a few per centages of aquifer pore volume. 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 of the current status of computing storage efficiency coefficients is provided in (Bachu S. , 2015).

To date, all estimations of CO_2 storage capacity in aquifers have been done for deep aquifers (deeper than 1000 meters). There are shallow saline aquifers in oil sands region that could also be considered for CO_2 storage and Alberta Innovates is currently supporting a project to investigate this feasibility. Commercial advancement of these potential resources would require updates to the provincial regulatory structure.

Injectivity

As stated previously, injectivity dominates in the site operation phase of a CO2 storage project. Given the limited number of fully operational CO_2 storage sites in Alberta, studies supported by Alberta Innovates that examined injectivity are typically numerical simulation studies and have focused primarily on CO_2-EOR projects. 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).

Since then, numerous studies supported by Alberta Innovates indicate that 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 (Bennion & Bachu, 2005), (Bennion & Bachu, 2006a), (Bennion & Bachu, 2006b) and (Bachu & Bennion, 2008)). The relative permeability curves developed in these studies have been used by the IEAGHG Weyburn project.

Alberta Innovates' 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/y of CO_2 for a minimum of ten years. Currently, the performance of the Shell Quest CCS project has demonstrated safe and effective injectivity, with annual reports made available to the public (Alberta Government, 2021).

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. The sequestration formations must have adequate seals to contain all injected and displaced fluids and consider all wells within the area of review that penetrate it to safeguard against future loss of containment. Alberta Innovates supported several field studies in the 2000s that embodied research activities related to containment assessment for geological storge of CO_2:

- Alberta's industrial acid-gas injection experience indicates that the 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") (Bachu et. al., (2003).

- The IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project (Sakuta, Young, & Worth, 2015) provided valuable insight to containment. Long-term integrity of natural seals represents the most important constraint on isolation performance. 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 Heartland Redwater Leduc Reef Saline Aquifer CO_2 capture and geologic storage project (Gunter, et al., 2009) confirmed that the Ireton aquitard encasing the reservoirs can form a competent seal considering its entrapment of hydrocarbons dating back approximately 60 million years.

- The Pembina-Cardium CO_2-Enhanced Oil Recovery Pilot project provided an assessment model to determine the risk of CO_2 leakage from wells in the storage formation (Bachu & Haug, 2006).

- Additional work was completed on novel sealing technologies for permanent sealing of wells with the support of ERA (Spencer, 2015). This work revealed that the proprietary bismuth alloy used for sealing wells had superior sealing and longevity characteristics to cement.

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 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).

A review of CO_2 storage site selection criteria and site characterization methods was conducted by InnoTech Alberta (International Energy Agency, 2009). The study established 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 3) and CO_2 storage in CO_2-EOR operations (Figure 4). 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.

Figure 3

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

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 4

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

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 (°F/°C)	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

Measurement, Monitoring and Verification (MMV)

An integral part of any commercial CCUS project is a detailed Measurement, Monitoring and Verification (MMV) plan. MMV spans across the geosphere, hydrosphere and atmosphere but technologies specifically designed to monitor the injected CO_2 plume itself reside in the geosphere. The highly successful MMV experiences at Quest and Weyburn are highlighted (Lawton et. al. (2022). Also, a generic MMV plan for monitoring acid gas injection (Chalaturnyk R. J., 2005) was found to be applicable to CCS projects and the recommendations were built into the Government of Alberta's Regulatory Framework Assessment for CCS, published in 2013.

At present, projects at the scale of Quest (approximately 1 Mt/yr) and Enhance Energy's Clive EOR project (approximately 1.5 Mt/year) are operating with well-established MMV. Geophysical and well-based MMV plans have been successful in operational monitoring and groundwater monitoring at established projects indicating that well-selected and carefully constructed CCUS storage complexes exhibit reliable containment of the injected CO_2.

Currently, the Government of Alberta is coordinating the development of CO_2 storage hubs to drive the scale-up of CCS implementation in the province. For regions with multiple CO_2 storage hubs, MMV plans will need to include a method of monitoring data sharing to ensure that pressure and CO_2 plumes from possible adjacent hubs do not interfere with each other. In addition, coordinating MMV plans and sharing data, including groundwater programs, observation wells and surface geophysical surveys, can optimize costs for individual operators.

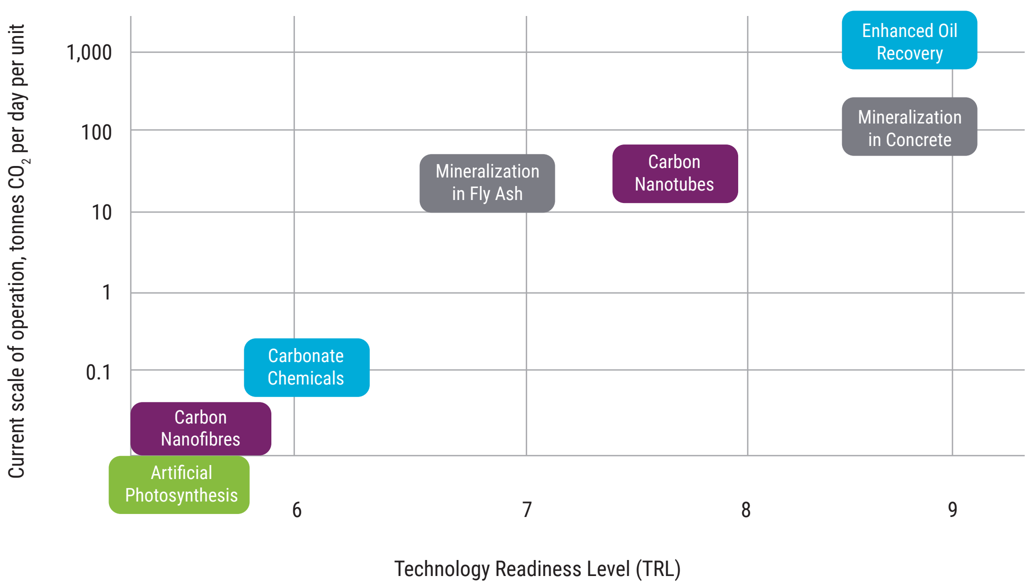
CARBON UTILIZATION

In the context of CCUS, carbon utilization refers to CO_2 utilization or simply 'CO_2 use'. CO_2 can be directly used, mineralized, or converted. Direct CO_2 use for enhanced oil recovery (EOR) is a mature technology and has been practised for decades. CO_2 mineralization in cement and concrete products has received much public funding in the last decade and is quickly approaching commercialization. CO_2 can also be chemically or biologically converted into chemicals, materials, and fuels.

The expectation for the role of CO_2 utilization in GHG emissions reduction has been high (Zimmermann, et al., 2020). However, IEA's projection is more modest and puts carbon utilization as being responsible for 10 per cent of the total CCUS market (International Energy Agency, 2020). Learnings from Alberta Innovates' and ERA's investments in carbon utilization projects are summarized herein to guide future public investments and technology advancements. The range of carbon utilization technology classes as a function of technology readiness level and volumes of CO_2 that have been successfully utilized by these technologies to date is provided in Figure 5.

Figure 5

Carbon Utilization Technologies by Volume of CO_2 Captured and TRL



The development and advancement of utilization-based technologies and industry verticals such as the ones shown in Figure 5 will be highly dependent on successful carbon capture technology deployment at scale.

CO_2-Enhanced Oil Recovery (CO_2-EOR)

CO_2-EOR has been in commercial practice for decades, with early applications in the US based on naturally occurring CO_2 reservoirs. In Canada, the focus has been on anthropogenic CO_2, beginning with the Vikor operation supplied by NOVA Chemicals in 1984 (NOVA Chemicals, 2019). The Weyburn project, in operation since 2000, has safely sequestered more than 31 million tonnes of CO_2 sourced from the coal-fired Boundary Dam Power Station in Saskatchewan and a coal gasification plant in North Dakota (Whitecap Resources Inc., 2021). Experience from the Weyburn project indicates that about 190 kg of CO_2 is sequestered for every barrel of oil produced (IEA, 2004), although this number may vary depending on site-specific conditions.

Alberta Innovates and InnoTech Alberta also supported large industry-led pilots in Alberta, at Swan Hills and Penn West (Pembina) as well as the small-scale Medicine Hat Glauconitic Pool. Multiple analysis and modeling studies indicate that the total Alberta CO_2-EOR has the potential to produce 1.5 to 2 billion barrels of oil (Alberta Economic Development Authority, 2009) and store between 131 Mt and 1.3 Gt of CO_2 in Alberta (Hares, 2020) (Alberta Research Council; AERI, 2009).

Commercial CO_2-EOR production has been very limited in Alberta to date. In addition to CO_2 supply cost, the barriers for CO_2-EOR in Alberta include unitization and long-investment cycle compared to quick return, high yield projects (Gunter & Longworth, 2013). CO_2-EOR development in Alberta was also hindered by the US shale oil and gas revolution and crash in the price of oil in 2015. With the construction of the ACTL in 2020, Enhance Energy started to produce oil from their CO_2-EOR project in Clive, Alberta. As of March 2021, Enhance Energy has sequestered 2.5 million tonnes of CO_2 in Central Alberta (Enhance Energy, 2022). Currently, the ACTL is utilized only at 10 per cent capacity, therefore there is potential for considerably more CO_2-EOR projects and storage in saline aquifers in the region. CO_2-EOR continues to represent the greatest volume CO_2 utilization opportunity in Alberta and around the world based on current economics.

Although less studied and developed than EOR, using CO_2 for enhanced gas recovery (EGR) is an area for potential study and development. Preliminary studies (Pooladi-Darvish, et al., 2008) have shown some efficacy with increased gas recovery, but reservoir characteristics and prevention of breakthrough will be important factors to consider when testing and operating CO_2-EGR initiatives and will benefit from additional research and field testing.

Mineralization

Carbon dioxide mineralization is a process in which CO_2 reacts with metal (hydro)oxides or metal (hydro)silicates in cement, fly ash, furnace slags, mafic rocks (e.g., basalt), or mafic rock mining tailings to form carbonate minerals. Alberta doesn't have basalt formations for in-situ mineralization. Therefore, the main opportunity is incorporation of CO_2 in the cement for concrete. In CO_2 mineralization, the carbon remains at an oxidated state and the mineralization process is energetically favorable. Material properties may be enhanced when CO_2 mineralization occurs. Mineralization presents the second largest volume CO_2 utilization opportunity after CO_2-EOR.

Concrete is the world's most abundant man-made material, and its production is responsible for eight per cent of global GHG emissions. Cement, the binding material used to make concrete, is the most carbon-intensive ingredient, and is combined with aggregates to form concrete. Cement and concrete production offer promising avenues for commercial-scale CO_2 utilization and sequestration.

The mineralization pathway is compelling from a life cycle analysis perspective because the mineralization process has the potential to capture more CO_2 than it emits, and no further emissions result during the use of the mineralization end-products. Moreover, in the case of concrete, CO_2 mineralization products can avoid CO_2 by being less CO_2-intensive than the incumbent products they are replacing (i.e. cement). As a result, mineralization technologies can be carbon negative from a lifecycle perspective through both CO_2 utilization (uptake), modest CO_2 emissions resulting from the process, and potential CO_2 avoidance through Scope 3 end use as discussed in Weldeyohannes et. al. (2018).

ERA and Alberta Innovates have supported multiple mineralization technologies, two of which were demonstrated at the ACCTC during the NRG COSIA Carbon X-PRIZE. There are other technologies that are being advanced in this area as well, both Canadian and international. The ACCTC, managed by InnoTech Alberta, is a facility located in Calgary, Alberta, established to advance carbon capture and utilization technology de-risking and demonstration. The ACCTC diverts CO_2 from the adjacent Shepard Natural Gas Energy Centre and provides a steady supply of 25 tonnes of low concentration CO_2/day to five test bays available for technology demonstration. The CO_2 from the flue gas is also concentrated through an amine capture system, enabling users to access CO_2 concentrations ranging from four to just under 99 per cent. Two of the most successful projects are summarized below.

- **CarbonCure's** technology involves injection of CO_2 into concrete during mixing to form calcium carbonate (CaCO3), permanently storing the CO_2. In masonry and ready-mix applications, the added CO_2 reacts with freshly hydrated cement; whereas in wash water and recycled concrete applications, the added CO_2 reacts with hydrated cement. Mineralized CO_2 improves the concrete's compressive strength, which in turn reduces overall cement requirements, resulting in CO_2 avoidance. With this CO_2 mineralization method, a relatively modest quantity of CO_2 is utilized per unit of concrete. The larger CO_2 reduction opportunity results from CO_2 avoidance, due to reduced cement usage in the concrete. CarbonCure's project in Round 2 of the Grand Challenge indicated that approximately 0.3 tonnes CO_2 can be utilized and 2.5 tonnes cement avoided (or 2 tonnes of CO_2) per 1,000 tonnes concrete (Lehigh Heidelberg Cement Group, 2020). Carbon Cure also received NRCan funding to advance its technology (NRCan, 2020). The technology is now considered commercial. Several concrete suppliers in Alberta are contracted to implement the technology and to supply low carbon concrete.

- **Carbon Upcycling Technologies (CUT)'s** technology utilizes CO_2 by reacting it with fly ash, an ingredient of concrete, and avoids CO_2 emissions by reducing cement requirements for concrete production. Fly ash is first chemically activated to reactions with CO_2. Then CO_2 is injected into a 'reactor', or a pressurized ball mill assisted by the presence of catalyst where it reacts to form a solid product. The CO_2-treated fly ash can improve concrete compressive strength at lower cement mixtures. CUT is currently demonstrating at the ACCTC using concentrated CO_2 from derived from an amine capture system adjacent to a natural gas power plant. Their facility was scaled up to 20 tpd of CO_2-embedded fly ash materials in 2021. CUT has several partnerships with concrete producers in Alberta, including Lafarge, Burnco, and CEMEX. Based on production rates at the ACCTC over the past year, CUT utilizes approximately 10 tonnes of CO_2 in 200 tonnes of fly ash for every 1,000 tonnes of concrete, displacing 10 to 15 tonnes of cement (Thomas, 2007), resulting in 8 to 12 tonnes of CO_2 emissions avoided (Carbon Upcycling Technologies, 2021) (Lehigh Heidelberg Cement Group, 2020) when using low carbon energy inputs.

Chemical Conversion

Chemical conversion of CO_2 uses external energy to convert the carbon from oxidized state in CO_2 to reduced state in materials, chemicals, and fuels. The GHG reduction potential of a CO_2 chemical conversion process depends on the nature of the input energy, either indirectly to produce compounds to react with CO_2 or by direct energy input. If fossil fuel is used as input energy, the process will release more CO_2 than the amount of CO_2 converted. However, the products from chemical conversion processes may bring GHG reduction benefits during their use. Therefore, there may be overall lifecycle GHG reduction benefits despite the actual conversion process being GHG positive (CO_2 released is more than CO_2 converted in the conversion process). For example, if CO_2 from a fossil-fuel power plant is captured and on-site electricity is used to make carbon nanotubes, there will be no lifecycle GHG emissions reduction unless the carbon nanotubes are used to reduce cement use in concrete, in which there will be lifecycle GHG benefits.

ERA, Alberta Innovates and InnoTech Alberta have funded over 16 chemical conversion projects. Several promising projects are summarized here to illustrate the potential of chemical conversion for CO_2 utilization.

- **Carbon Corp – CO_2 to Carbon Nanotubes**. Carbon Corp (formerly C2CNT)'s technology, called "Genesis DeviceTM", produces carbon nanotubes (CNTs) and oxygen (O_2) via molten electrolysis. CNTs have excellent thermal and electrical conductivity and can be used as composites in a variety of materials to increase strength and reduce overall material requirements. Carbon Corp is currently demonstrating at the ACCTC utilizing concentrated CO_2. A commercial plant with a capacity of 2,500 tonnes of CNTs per year is being built at Capital Power's Genesee Generating Station (Genesee Carbon Conversion Centre (Phase 1), 2021) with support from ERA. Project estimates show that one tonne of CNTs has the potential to displace up to 940 tonnes of cement, which equates to 770 tonnes CO_2 avoided, assuming general-use Portland Cement (Deeg, 2022) (Lehigh Heidelberg Cement Group, 2020). Due to the emergent nature of CNTs, this has yet to be confirmed by the market.

- **Carbonova – CO_2 to Carbon Nanofibres**. This technology uses a patented catalyst and converts CO_2 and synthesis gas ($CO + H_2$) into carbon nanofibres (CNFs). The synthesis gas is produced from methane. CNFs can reduce cement loading in concrete or resin loading in polymer composite materials. Carbonova' CNFs will likely have lower GHG intensity than commercial carbon fibres, which have a footprint of 20 tonnes of CO_2 per tonne fibre (Toray, 2022). CNF can enable Scope 3 emission reductions. The technology is at an early stage, and a full life cycle analysis of the CO_2 emission reductions is yet to be performed.

- **Mangrove Technologies Ltd. – CO_2 to Industrial Chemicals**. This process converts waste gases and saline water to desalinated water, hydrochloric acid, and sodium hydroxide using electric power. The sodium hydroxide can be used to convert CO_2 and other GHGs to carbonate or bicarbonate salts, which can be used in oil and gas operations. Through lifecycle analysis, Mangrove estimates that GHG reductions from a desalination facility of 1,000 m3/day capacity would be 30,660 tonnes CO_2e/year, inclusive of CO_2 utilized and avoided. Mangrove is now finalizing the design of a system that will be demonstrated at Canadian Natural Resources Limited's oil sands mining site in Alberta. Successful commercial rollout of Mangrove's technology could result in an estimated 265 kt CO_2 emissions reductions/year in Alberta (Mangrove Water Technologies, 2019).

- **McGill University – Artificial Photosynthesis**. In the artificial synthesis process, a semiconductor acts like a kind of artificial leaf. Solar energy is captured by the semiconductor, which leads to the generation of electron/hole pairs. The energetic photogenerated electrons can reduce input CO_2 to higher energy carbon-based compounds such as CO and CH4, if the conduction band minimum is more negative than the reduction potential of CO_2. McGill's process uses type III-nitride semiconductor materials, which have large absorption coefficients in the visible range, excellent charge carrier properties, a tunable band via slight variations in the alloy content, all while being able to encompass the redox potentials of water splitting and CO_2 reduction (Mi, 2020). The process is still at laboratory scale; and no system engineering work has been completed to date, but it remains a potential avenue to a fully circular CO_2 ecosystem. McGill researchers are not currently performing any work in Alberta, and CO_2 utilization/avoidance at this stage is negligible.

- **CO_2 to Fuels**. The area of CO_2 to fuels, in which the CO_2-produced fuels are combusted downstream, is a particularly challenging case of carbon utilization from a lifecycle perspective. In many of the previously discussed examples, regardless of whether the core processes themselves are CO_2 positive or negative, the resulting CO_2-derived products do not emit net-new CO_2 themselves and avoid CO_2 emission by displacing more GHG-intensive incumbents at end use. In the case of CO_2-to-fuels, not only is the conversion process energy-intensive and often carbon-positive, but the products also themselves will result in additional emissions as identified in IEA (2019) and Weldeyohannes et al. (2018).

Biological Conversion

Carbon dioxide can also be converted to fuels through biological processes based on photosynthesis. Natural photosynthesis by sunlight is responsible for plant growth and is responsible for almost all the approximately 160 billion liters of biofuels predicted to be produced globally in 2021 (IEA, 2020). There have been many proposed technologies to use captured CO2 to grow algae. In this process, CO2 and energy from light is used to grow algae which stores the energy from the light in chemical form. Many CO_2-to-algae conversion technologies use natural sunlight. Most algae players have exited from the market (Global CO_2 Initiative, 2016) due to challenging economics and high water use intensity.

Life cycle analysis for bioconversion technologies highlights the challenges with logistics and scalability issues, according to Weldeyohannes et. al. (2018), as is evidenced by some CO_2-to-algae technologies are based on indoor growth chamber with LED lights (Canadian Natural Resources Ltd, 2013) (Pankratz, Oyedun, Zhang, & Kumar, no date). From a CO_2 utilization perspective, this concept has uncertain GHG benefits. For example, if this process is powered by renewable electricity, the conversion rate will be one unit of renewable energy for less than 0.02 unit of chemical energy from algae. If the power is from natural gas, the biofuel from algae will have more than three times GHG intensity than petroleum-derived fuel. Alberta Innovates, InnoTech Alberta, and ERA have supported limited work in this area, with no projects advancing along the commercialization pathway in part due to the scalability issues discussed above.

Life Cycle Analysis (LCA) and Technoeconomic Assessment for Carbon Utilization

As discussed above, carbon utilization technologies can use CO_2 to make a variety of end products, but these processes also consume energy and feed materials that can result in CO_2 emissions.

LCA is an essential practice for evaluating the efficacy of carbon utilization technologies in reducing CO_2 emissions. The accepted standard is ISO 14044:2006, which specifies requirements and provides guidelines for LCA. Globally, work is underway to better apply these standards specifically to the nascent field of carbon utilization technologies, largely spearheaded by the Global Carbon Initiative (GCI) (Zimmermann, et al., 2020). Because carbon utilization is a relatively new application of LCA, protocols derived from the ISO standard did not exist until recently and have not yet reached general adoption.

Alberta Innovates and ERA commissioned a team from the University of Calgary and University of Alberta to prepare an Excel-based model framework and corresponding report (Weldeyohannes et. al. (2018). The studies used the boundary conditions relevant for Alberta. Among 95 pathways, CO_2 mineralization, particularly in the concrete industry, shows the highest potential to reduce global GHG emissions. Compared to mineralization, other categories have at best little net impact on global emissions reductions, and in some cases significant adverse net impacts according to this study under the boundary conditions assessed.

As boundary conditions change (e.g., more renewables on the grid), more carbon conversion technologies may become more viable, and LCA will be an effective tool to screen technologies from early technology readiness levels.

Complementary to LCA is technoeconomic analysis, whereby the cost effectiveness of technologies is analyzed through internal factors (capital expenditure, fixed operating expenditure, variable operating expenditure) as well as external factors (carbon pricing, materials and labour cost trends, tax incentives and other policy instruments, etc.). Combining LCA and technoeconomic analysis gives greater understanding of the potential for adoption of a technology in its target market.

CARBON DIOXIDE REMOVAL (CDR) AND NEGATIVE EMISSION TECHNOLOGIES

Carbon dioxide removal (CDR) refers to mechanisms where CO_2 is removed from the atmosphere and stored in plants, trees, soil, lakes, oceans, and rock formations deep underground, or in durable products that embody carbon. Nature-based processes (such as forest and soil carbon storage) have significant potential for removing CO_2 from the atmosphere and are outside the scope of this paper. The potential of CCUS-based CDR technologies in Alberta remains to be quantified.

Bioenergy with CCS (BECCS) has a modest potential in negative emission reduction in Alberta. Alberta has 350 MW bioelectricity capacity and emits 3.2 Mt of CO_2 annually. If this CO_2 is captured, it will constitute negative emissions as the carbon in the biomass originates from the atmosphere minus the CO_2 associated with feedstock cultivation, fuel for transportation, and the BECCS plant operation. Since the majority of bioelectricity in Alberta comes from combustion of biomass byproducts from pulp and paper processing, CO_2 from feedstock processing and fuel transportation is negligible. Biomass-sourced CO_2 emissions are excluded from regular industrial emissions reporting, so their removal is by default a negative emissions activity. This would be a far more economic negative emission reduction solution for Alberta. Carbon LCA and technoeconomic studies will be required to determine the specific cost per tonne from proposed BECCS projects.

Bioethanol production through fermentation of sugar-based feedstock produces a CO_2 stream with small amounts of gas impurities. Existing and planned ethanol production from wheat in Alberta is 385 million litres per year. The bio-sourced emission will be 0.3 Mt of CO_2 annually. This CO_2 stream is in high concentration and low temperature. The capture cost for this fermenter off-gas would be lower than post combustion flue gas and much lower than DAC.

Biogas produced from organic waste such as food waste, manure and other agricultural waste, and wastewater sludge through anaerobic digestion contains 50 to 80 vol per cent methane and 30 to 50 vol per cent CO_2. Methane is separated and purified to form pipeline grade renewable natural gas (RNG) that can be injected into the natural gas pipeline. Carbon dioxide separated from methane resulting from upgrade biogas to RNG can be stored to cause negative emissions. However, the total CO_2 available from this source is small.

Direct air capture (DAC) is energy intensive and needs low-emission energy sources for the capture process. For DAC applications, consideration needs to be given for location near storage fields and power sources. DAC should be considered as a longer-term solution in a high carbon price environment. Alberta's large CO_2 storage capacity may become an enabler for DAC technologies. In the short and medium terms, DAC units may be co-located with intermittent emitting facilities (e.g. peaking power plant). This can provide a means for carbon capture at an intermittent emitting facility when the facility is in use and emitting. It can also improve the overall efficiency of DAC and provide learning experience.

CO_2 TRANSPORTATION

Carbon dioxide transportation is well-established technology and there have been decades of industry experience for safe CO_2 transportation. However, the Alberta CO_2 Purity Project Report (PTAC, 2014) still identified some knowledge gaps to be closed, including:

- Conducting further testing of the impacts of impurities on dense-phase transportation of CO_2;
- Validating models for atmospheric dispersion of CO_2 vapour clouds from pipeline leaks that are used to determine hazard zone extent; and
- Evaluating available fracture arrest assessment methods and models and the toughness requirements they establish for pipeline materials to ensure that they provide levels of fracture propagation control comparable to that achieved for natural gas pipelines.

SUMMARY AND RECOMMENDATIONS

Alberta is a global leader in CCUS. Commercial-scale CCUS projects have been in operation since 2015. Alberta Innovates (including InnoTech Alberta and C-FER Technologies) and Emissions Reduction Alberta (ERA) have invested approximately $140 million in more than 100 CCUS projects in the last 25 years. Key learnings from these CCUS projects are summarized. Key knowledge gaps are identified, and recommendations are made:

Recommendation #1: Leverage Alberta's experience in commercial-scale CCS projects to develop more commercial projects in high CO_2 concentration facilities.

Recommendation #2: Conduct CCS FEED studies and build commercial-scale projects at both an oil sands facility and a NGCC power plant using commercial aqueous amines and leverage this experience to improve the learning curve for future projects while creating near-term GHG reductions.

Recommendation #3: Continue efforts to enhance aqueous chemical absorption technologies for ongoing cost reduction.

Recommendation #4: Advance the most attractive second-generation technologies to commercial demonstration.

Recommendation #5: Use analysis tools developed in Alberta to assess potential storage hubs for CO_2 and develop a regional large-scale model to assess potential interactions between hubs.

Recommendation #6: Explore the feasibility of shallow aquifer storage in northeast Alberta.

Recommendation #7: Focus carbon utilization development on large-scale CO_2-EOR projects, mineralization, and conversion to materials that can replace or displace high GHG incumbent materials and could have additional life cycle GHG benefits when in use.

Recommendation #8: Perform technoeconomic analyses of promising carbon utilization technologies.

Recommendation #9: Adopt a phased approach on carbon dioxide removal technologies, with BECSS as the near-and medium-term priority and DAC as a longer-term solution.

Recommendation #10: Identify ways to develop more cleantech talent and entrepreneurs in the province and help existing small cleantech companies to grow.

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