A TECHNO-ECONOMIC ANALYSIS OF THE POTENTIAL FOR THE CAPTURE AND TRANSPORTATION OF CARBON DIOXIDE FOR UTILIZATION AS AN INDUSTRIAL FEEDSTOCK IN NOVA SCOTIA

By

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Abstract

Hydrogen, ammonia, and CO_2 are three precursors for creating new industries in Nova Scotia. Methanol can be produced by combining hydrogen and carbon dioxide, a versatile chemical used in various applications, including sustainable aviation fuels. Fertilizers such as urea can be produced with ammonia from the combination of hydrogen and nitrogen. Producing methanol and urea requires a source of carbon dioxide. The missing precursor is carbon dioxide, perhaps, the source of the carbon dioxide still needs to be determined.

The thesis performs a techno-economic analysis of the potential for capturing and transporting carbon dioxide for utilization as an industrial feedstock in Nova Scotia. The analysis involves identifying CO_2 point sources, evaluating capture technologies, proposing onsite storage, recommending transportation methods, and exploring the utilization of captured CO_2 to produce value-added products like methanol and urea. The research identifies and explores three power stations using either biomass, natural gas, or coal as a feedstock. The choice of the power plants covers the three energy sources of interest.

This research shows that about 32kt per year of biogenic carbon dioxide could be captured from the Port Hawkesbury biomass plant, about 0.94MtCO_2 per year from Tufts Cove, and about 2.3MtCO_2 per year from the Lingan power plant. The captured 32kt/yr from the biomass plant would require 4.3kt/yr of green hydrogen to produce around 23kt/yr of green methanol and 44kt/yr of green urea. The total cost of delivering green CO_2 from Port Hawkesbury to the EverWind plant was about 206 USD per tonne of CO_2 captured.

Furthermore, combining 177kt/yr of green hydrogen with 1.3Mt of non-renewable CO_2 could yield about 0.9Mt of blue methanol. Additionally, utilizing 1Mt/yr of green ammonia could produce about 1.8Mt of blue urea when mixed with 1.3Mt of non-green CO_2. This demonstrates the substantial opportunity for CO_2 utilization in methanol and urea production. The total cost of delivering CO_2 to the EverWind plant from Tufts Cove and Lingan plants was about 153 USD and 101 USD per tonne of CO_2 captured respectively.

Overall, the available volume of CO_2 in the province could use the expected volume of green hydrogen to make non-green methanol, or green ammonia for non-green urea.

Index Terms – Hydrogen, Ammonia, Methanol, Urea, CO_2 capture, CO_2 transportation, Value-added products, Economic growth.

Glossary

ACTL	Alberta Carbon Trunk Line
ATRI	American Transportation Research Institute
BECCS	Bioenergy with carbon capture and storage
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization, and Storage
CF	Capacity Factor
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of Energy
DAC	Direct Air Capture
DME	Dimethyl ether
DOC	Direct Ocean Capture
eDiesel	Electro Diesel
eFuels	Electro Fuels
eGasoline	Electro Gasoline
eKerosene	Electro Kerosene
eMethanol	Electro Methanol
eSAF	Electro Sustainable Aviation Fuel
EOR	Enhanced oil recovery
Excl. T&S	Excluding Transport and Storage
FECM	Fossil Energy and Carbon Management
FG+	Flue Gas Plus
FT	Fischer-Tropsch
GCCSI	Global Carbon Capture and Storage Institute
GHGRP	Greenhouse Gas Reporting Program
HHV	Higher Heating Value
IEAGHG	International Energy Agency Greenhouse Gas
IECM	Integrated Environmental Control Model
Kt	Thousand Tonnes
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MDEA	Methyl Diethanolamine
MEA	Monoethanolamine
MOGD	Mobil's Olefins to Gasoline and Distillate
Mt	Million Tonnes
MTJ	Methanol-to-Jet
MTO	Methanol-to-olefins
Mtpa	Million Tonnes per annum
NETL	National Energy Technology Laboratory
Nm^3/hr	Normal cubic meters per hour
NSPI	Nova Scotia Power Incorporated
O&M	Operations and Maintenance
OPEX	Operational Expenditure
ROW	Right of Way
SAF	Sustainable Aviation Fuel
TCM	Technology Centre Mongstad
TSA	Temperature Swing Adsorption
UOP	Universal Oil Products
$	All currencies in US Dollars unless otherwise stated

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1 Introduction

By 2030, Nova Scotia intends to become a major player in the global hydrogen market (Global Affairs Canada, 2023), by producing green hydrogen and green ammonia using renewable electricity (EverWind, 2023). This is in keeping with Canada's policy to achieve net-zero emissions by 2050 (NRCan, 2023). Two of the key components of this policy are the production of clean hydrogen and the use of various carbon capture technologies (NRCan, 2021).

On April 3, 2024, EverWind Fuels announced the completion of the Front-End Engineering Design (FEED) for the first phase of its green hydrogen to green ammonia project in Point Tupper, Port Hawkesbury municipality, Nova Scotia (GlobeNewswire, 2024). This initial phase aims to produce around 240,000 tonnes of green ammonia annually (EverWind Fuels, 2024), requiring approximately 42,000 tonnes of green hydrogen, which accounts for about 17.6% of ammonia's mass (Zumdahl & DeCoste, 2017). The second phase targets over one million tonnes of green ammonia (EverWind Fuels, 2024), which could require about 177,000 tonnes of green hydrogen. If contracts can be signed, the resulting ammonia produced is to be shipped to Germany (Uniper, 2022; PR Newswire, 2023).

The production of 1Mt of ammonia and 177kt of hydrogen presents significant opportunities for the creation of value-added products in Nova Scotia, particularly methanol and urea (Patil, et al., 2024; Ding, et al., 2023). Methanol production requires a combination of hydrogen and carbon dioxide (Patil, et al., 2024), while urea production requires ammonia and carbon dioxide (Ding, et al., 2023). With ammonia and hydrogen, Nova Scotia could produce about 0.9 Mt of methanol and 1.8 Mt of urea annually, which would require about 1.3 Mt of carbon dioxide. Methanol and urea production require a source of carbon dioxide, however, there is still the question of where the carbon dioxide will come from to be answered.

If Nova Scotia has access to sufficient quantities of green hydrogen and green ammonia, it will need to find sources of carbon dioxide to produce value-added products such as methanol for green fuels (Sollai, Porcu, Tola, Ferrara, & Pettinau, 2023; ExxonMobil, 2022; Adeli, Nachtane, Faik, Saifaoui, & Boulezhar, 2023), and urea for green fertilizers (Mao, Byun, MacLeod, Maravelias, & Ozin, 2024).

One way of obtaining the carbon dioxide is to identify point-source emitters (emitters which are stationary sources or locations where pollutants or greenhouse gases are emitted into the atmosphere (Shi, et al., 2023)). DAC (Direct Air Capture) and CCUS (Carbon Capture, Utilization, and Storage) are both technologies that capture carbon dioxide, but they operate in distinct ways (IEA, 2021). DAC is one of the carbon capture techniques, that captures CO_2 directly from the atmosphere (which is a diffuse source), making it less concentrated and more energy-intensive to capture (IEA, 2022). However, the CCUS technology captures CO_2 emissions from point sources, either utilized, or transported, and stored for future use (IEA, 2021). If emissions are captured before they are emitted, there will be a reduction in overall atmospheric emissions (Schluter & Geitner, 2020). Point emitters refer to emission sources such as thermal power stations, biomass generating plants, cement manufacturing, and steel production (Rabia, Muhammad, Ayesha, & Muhammad, 2021). Nova Scotia has many examples of point carbon sources, including facilities as small as the Port Hawkesbury biomass power plant with a capacity of 60MW, and the Lingan coal-fired power plant with a capacity of 620MW (ECCC, 2023).

This research presents a techno-economic analysis of the potential for the capture and transportation of carbon dioxide for utilization as an industrial feedstock in Nova Scotia. The analysis includes identifying CO_2 sources, assessing capture technologies, proposing onsite storage methods, recommending methods of transporting CO_2 and utilization of captured CO_2 to create value added products such as methanol and urea. The objective of this thesis is five-fold.

First, the thesis identifies specific point-source emitters from power generation plants in the province. Since 2004, the Greenhouse Gas Reporting Program GHGRP has collected data on greenhouse gas emissions from facilities across Canada (ECCC, 2023). The GHGRP mandates facilities, emitting 10,000 tonnes (10 kt) of CO_2e or more annually, to report their emissions for accurate tracking of GHG emissions (ECCC, 2023). This reporting program enables small, medium-sized, or large carbon emitters to report their emissions. The GHGRP data is accessible through multiple channels, including an online data search tool, data tables in Excel and CSV formats, and an interactive map available online (ECCC, 2023). Once these emission sources have been identified, the next step is how to capture, store, transport, and utilize the carbon.

Second, the thesis will examine the necessary technologies required to capture carbon dioxide emissions from point-source emitters. The technologies used to capture CO_2 are categorized into post-combustion, precombustion, and oxyfuel combustion systems (Yusuf & Ibrahim, 2023). Post-combustion carbon capture involves separating CO_2 from other gases produced after the fuel has been burned or during combustion, typically from the flue gases of power plants or industrial facilities (NETL, nd). Pre-combustion carbon capture involves converting the fuel into a synthesis gas (syngas) through processes like gasification, where CO_2 can be separated before combustion occurs (NETL, nd). Oxyfuel combustion is a technology where a fuel is burned using pure oxygen instead of air. This results in a flue gas predominantly consisting of carbon dioxide and water vapor, which makes it easier to capture CO_2 for storage or utilization (NETL, nd). This study will focus on post-combustion carbon capture by retrofitting existing biomass and fossil fuel power plants with carbon capture technologies.

Third, the thesis will estimate the volume, capacity, safety, and costs associated with onsite CO_2 storage. The onsite storage is employed to mitigate the mismatch between CO_2 production and its utilization by providing a buffer that balances supply and demand. Onsite storage tanks come in various types, each designed for specific applications and capacities such as aboveground tanks, underground tanks, horizontal tanks, vertical tanks, cylindrical tanks, and spherical tanks each with distinct advantages and limitations. The choice of tank depends on the application and volume needed, and proper installation and maintenance are crucial for safe operation.

Fourth, the thesis will analyze different methods of transporting CO_2 from emitting sources to industrial facilities to produce value-added products. The research will also analyze the economic feasibility of different combinations of facility size, capture technologies, and methods of the transportation of CO_2. The transportation of CO_2 has a significant impact on the total project cost (Dong, Jiang, Ye, Xia, & Zhang, 2023). The implementation of CCUS will necessitate the development of new infrastructure to transport captured CO_2 to the storage facilities either via pipeline or trucks (Ahmad, Hamidreza, & Shakiba, 2022). CO_2 transport costs depend on geographic, geologic, and institutional factors (Smith, et al., 2021). The main factors contributing to variability in CO_2 transport cost estimates include the distance traveled (from emission sources to utilization or storage points), the scale of CO_2 transportation (quantity involved), and the underlying assumptions regarding transport costs, notably the capital costs related to pipeline design (thickness and diameter of the pipes) (Leeson, Dowell, Shah, Petit, & Fennell, 2017). The use of pipelines to transport CO_2 has been a mature technology for decades (Tara, 2017), and the diameter and thickness of the pipeline diameter depend on the quantity of CO_2 and flow rate (Peletiri, Rahmanian, & Mujtaba, 2018). In pipeline design, determining the route and length is paramount. This process involves assessing alternative paths and acquiring the Right of Way (ROW) for the chosen route, which may not necessarily be the shortest (Peletiri, Rahmanian, & Mujtaba, 2018). When selecting the route, prioritizing safety, and avoiding populated areas are crucial factors. The objective is to minimize pipeline length, costs, ecological impact, and interference with existing infrastructure. Overall, pipelines are the favored choice for conveying substantial volumes of CO_2 over distances of approximately up to 1,000 km. When dealing with quantities smaller than a few million tonnes of CO_2 annually or for longer distances across seas, employing ships, where feasible, might present more economically viable options (IPCC, 2005).

Fifth, the thesis will demonstrate how adding value to green hydrogen and ammonia in the province can be achieved by combining them with captured carbon dioxide to produce methanol and urea. Methanol can also be synthesized from hydrogen and carbon dioxide (Noerma J. Azhari, 2022) while urea can be synthesized from ammonia and carbon dioxide (Ding, et al., 2023). Sustainable methanol or green methanol is produced from green hydrogen H_2, and green carbon dioxide also known as biogenic CO_2 (Michael, 2019; IRENA, 2021). Methanol from natural gas is known as blue methanol when carbon capture is involved, while methanol produced from coal is termed brown methanol (IRENA, 2021). Methanol is a crucial feedstock to produce several valuable products, making it a versatile and valuable intermediate chemical (Bozzano & Manenti, 2016). It can be used to manufacture plastics, adhesives, solvents, paints, pharmaceuticals, and fuels. Furthermore, methanol-to-jet MTJ technology is used to produce sustainable aviation fuels SAF, as an alternative to the existing Fischer-Tropsch process (ExxonMobil, 2022). MTJ technology is undergoing research, and the aviation industry is striving to enable commercial flights using 100% SAF by 2030 (Honeywell, 2023). Ammonia NH_3 combined with carbon dioxide will produce urea widely used in the production of fertilizers, playing a crucial role in global agriculture. The process of converting ammonia into fertilizer involves the synthesis of various nitrogen-based compounds, such as ammonium nitrate NH_4NO_3 or urea $CO(NH_2)_2$.

This research is important because it determines and ascertains the quantity of CO_2 available from different emission sources in the province that can be utilized as a feedstock for industrial purposes. The captured carbon dioxide, along with green hydrogen and green ammonia, will serve as raw materials for valuable products including sustainable aviation fuels and green fertilizers for agricultural use. This research aligns with Canada's sustainability goals and positions Nova Scotia to be a leader in innovative and environmentally conscious practices, making significant contributions to a cleaner planet. Nova Scotians stand to gain from this research, as the capture of carbon dioxide will not only reduce the province's emissions, but its utilization with provincially produced hydrogen and ammonia will create employment opportunities and foster economic benefits for Nova Scotians.

Overall, the thesis evaluates the feasibility of utilizing carbon dioxide as an industrial feedstock in Nova Scotia through a techno-economic analysis. Chapter 2 will review literature on point source emitters, carbon capture and storage techniques, transportation methods, and utilization. Chapter 3 focuses on methodologies and data collection by determining the quantity of CO_2 available from point source emitters, evaluating CCS techniques, analyzing transportation methods, and calculating the amount of CO_2 required to produce methanol or urea. Chapters 4 and 5 focus on data analysis and discussion by examining emission trends, CCS efficiency, and transportation options to industrial plants for utilization. The final chapters of the thesis will comprise the conclusion and recommendations based on our findings, followed by the references and appendices sections.

2 Background

Carbon Capture, Utilization, and Storage or CCUS is part of several Canadian government initiatives, valued at $8 billion, aimed at capturing and sequestering 15 million tons of carbon dioxide annually by the year 2030 (CSIS, 2022). As of September 2022, the annual global combined capacity of upcoming commercial CCS projects stood at 244 million tonnes, marking a 44% increase compared to the preceding 12 months (Wang, 2024) and approximately 40 commercial facilities in operation (IEA, 2023). The global CCS projects have demonstrated robust yearly expansion for the past six years, achieving a compound growth rate exceeding 35% annually since 2017 (GCCSI, 2023). In July 2023, the CCUS projects in the pipeline comprised 392 facilities, marking a 102% increase compared to the previous year (GCCSI, 2023). Among these, 41 facilities are operational, capable of capturing and storing 49 million tonnes per annum (Mtpa), while 351 facilities are in various stages of development (GCCSI, 2023).

This chapter will examine relevant literature on carbon emission sources, carbon capture and storage (CCS) techniques, carbon transportation methods, and carbon dioxide utilization. Section 2.1 will review CO_2 point emission sources to ascertain the quantity of CO_2 available in the province, as well as determine the distance from emission sources to industrial plants. Section 2.2 will explore various CCS techniques to assess their efficiency and cost-effectiveness in carbon capture. Section 2.3 will review on-site carbon dioxide storage methods. Section 2.4 will review diverse carbon transportation methods, considering factors such as safety, costs, and environmental impacts. Section 2.5 addresses carbon utilization, focusing on the production of methanol for Sustainable Aviation Fuel (SAF) and urea for green fertilizer. Lastly, Section 2.6 will discuss the use of the integrated environmental control model IECM software for simulation for post-combustion carbon capture.

Overall, the schematic diagram in Figure 1 provides an overview of the focal points examined during the literature review.

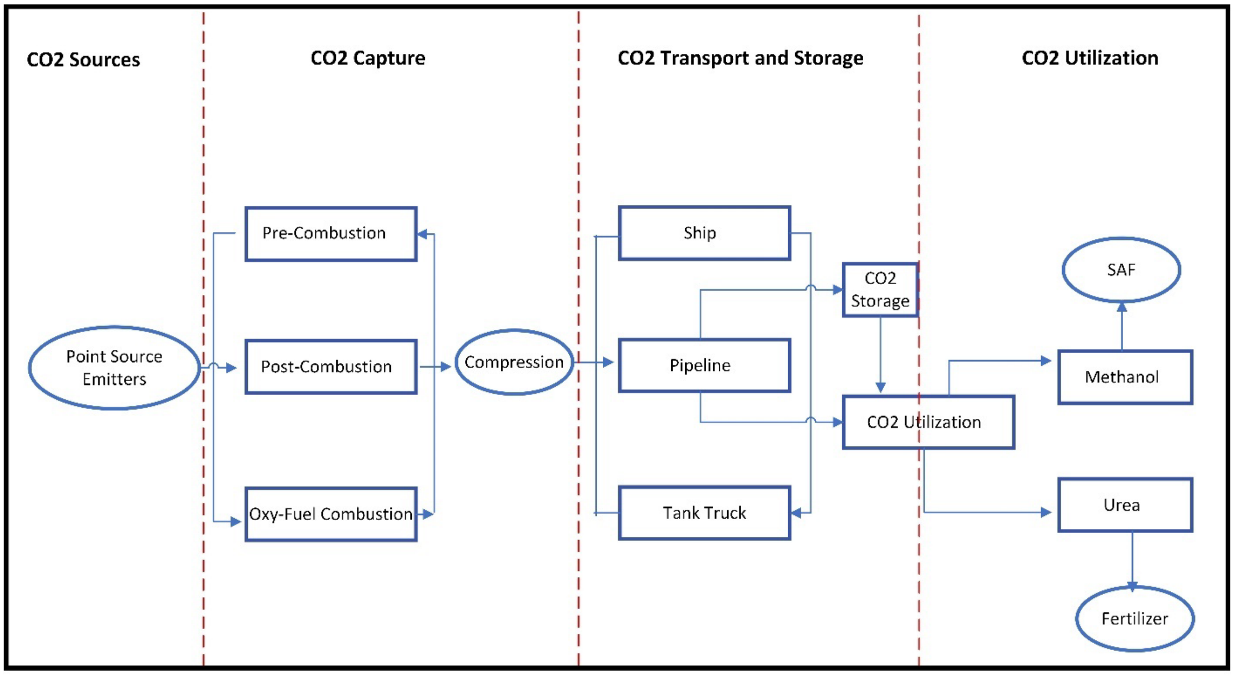

Figure 1: The schematic diagram illustrating the various processes involved in Carbon Capture, Utilization, and Storage (CCUS) as reviewed in the literature (Simonsen, Hansen, & Pedersen, 2024).

2.1 Carbon Dioxide Point Emitters

Carbon dioxide point emitters are specific sources or facilities where carbon dioxide emissions are released directly into the atmosphere, distinct from diffuse sources such as vehicles or agricultural fields (Tianqi Shi a, et al., 2023). Consequently, the initial step in any CCUS project involves identifying and quantifying these emissions (Rabia, Muhammad, Ayesha, & Muhammad, 2021).

In 2021, Halifax had the largest number of industrial facilities contributing to the province's point source greenhouse gas emissions (ArcGIS, 2022). The energy sector, with five facilities, has the highest number of companies emitting GHGs in Nova Scotia, followed by tire manufacturing and waste treatment centers, each having three plants (ArcGIS, 2022). Nova Scotia Power Incorporated (NSPI), situated in the Regional Municipality of Cape Breton, stands as the foremost contributor to GHG emissions in the province, with an approximate emission of 2500 kilotons of carbon dioxide, followed by other NSPI facilities located in other municipalities (ArcGIS, 2022).

The thesis identifies the point sources of carbon dioxide using the GHGRP database (ECCC, 2024). Table 1 shows the number of facilities by categorizing the point emitters based on facility name, facility size, and range of CO_2 emission per annum. It shows a distinct distribution of facilities in Nova Scotia based on four categories: very-small, small, medium, and large, each with specific emission ranges and examples. Very-small facilities emit less than 25Kt of CO_2 per annum; small facilities emit between 25Kt and 100Kt of CO_2 annually; medium-sized facilities emit between 100Kt and 1.2Mt of CO_2 per annum, and large facilities emit above 1.2Mt of CO_2 annually. This categorization helps in understanding the scale of CO_2 emissions across different types of facilities within Nova Scotia's industrial landscape.

Table 1: Summary of Point Emission Sources in Nova Scotia in 2022 (ECCC, 2024)

Facility Size	Range of CO_2 Emissions per annum	Number of Facility	Examples
Very small	less than 25Kt	6	Dalhousie Biomass Energy Plant, Touquoy Mine, East River Mill, CKF – Hantsport, Pictou County Plant and Bridgewater Plant
Small	between 25Kt and 100Kt	6	NSPI's Port Hawkesbury Biomass Cogeneration Power Plant, Highway 101 Landfill, GFL Environmental Inc., CFB/ BFC Halifax - Parc Windsor Park, Otter Lake Landfill, and Waterville Plant
Medium	between 100Kt and 1.2Mt	5	NSPI's Tufts Cove Generating Station, Donkin Mine, NSPI's Point Tupper and Point Aconi Generating Stations, and Brookfield Cement Plant.
Large	above 1.2Mt	2	NSPI's Lingan and Trenton Generating Stations

2.2 Carbon Dioxide Capture Technology

Carbon dioxide capture technology refers to methods designed to capture carbon dioxide either after its release or prior to its release into the atmosphere (IEA, 2022), these include Direct Air Capture DAC and Bioenergy with Carbon Capture and Storage or BECCS.

Direct air capture (DAC) technology is one way of capturing CO_2 emissions directly from the atmosphere, in contrast to carbon capture methods, which are typically implemented at the source of emissions (IEA, 2022). Capturing carbon dioxide from the air is the costliest form of carbon capture due to the lower concentration of CO_2 in the atmosphere compared to point emitters. Consequently, DAC requires more energy and incurs higher costs compared to other carbon capture methods. On the other hand, the CCUS technology captures CO_2 from point sources like power generation or industrial facilities that use either fossil fuels or biomass as fuel, either utilize or store it for future use (IEA, 2021). If the captured carbon is not utilized at the capture site, the CO_2 is compressed and conveyed via pipeline, ship, rail, or truck for various applications or injected into subsurface geological formations. The carbon could be sequestered in depleted oil and gas reservoirs or saline formations, where it is securely stored permanently (IEA, 2021).

Carbon emissions resulting from the direct combustion of biomass for energy generation, a process known as bioenergy with carbon capture and storage (BECCS), involve capturing and storing carbon dioxide generated during the conversion of biomass into energy (IEA, 2023). BECCS is unique among carbon dioxide removal methods in that it not only removes CO_2 but also generates energy (IEA, 2023).

Carbon dioxide capture technologies can be categorized into different types, notably post-combustion capture, pre-combustion capture, and oxy-fuel combustion capture (Lipei, et al., 2022). Post-combustion capture involves capturing CO_2 from flue gases emitted from power plants and industrial facilities after combustion. Pre-combustion capture involves capturing CO_2 from fuel before combustion occurs. Oxy-fuel combustion capture involves burning fuels in oxygen-rich environments to produce flue gases with higher concentrations of CO_2, making capture easier. Pre-combustion capture and oxy-fuel combustion capture require specific materials and conditions to meet high-temperature demands, which has limited their research and development. On the other hand, post-combustion capture stands out as a widely adopted and well-established technology in the industry, offering excellent CO_2 selectivity and capture efficiency (Zhao, Zhang, C., Wang, & Lin, 2021). The advantages and disadvantages of different CO_2 capture technologies are summarized in Table 2.

Table 2: Summary of the Pros and Cons of Carbon Capture Technologies (Lipei, et al., 2022).

Capture method	Advantages	Disadvantages
Pre-combustion capture	Less regenerative energy. Small capture equipment is required.	High investment cost. Operation is limited.
Oxy-fuel combustion capture	High concentration of captured CO_2. Less NOx formation.	The high oxygen demand increases investment costs and energy consumption when located near a facility that doesn't produce oxygen as a by-product.
Post-combustion capture	Comparatively low investment cost. Fast technology introduction. Flexible operation to reduce operating costs.	Lower CO_2 partial pressure in flue gas increases capture energy consumption. Large capture equipment required

These technologies often employ various processes such as chemical absorption, adsorption, membrane separation, and cryogenic separation to capture CO_2 from gas streams as shown in Figure 2 (Srinu, Jatin, & Damodaran, 2023). The chemical absorption process involves dissolving CO_2 in a solvent or absorbent material, separating it from other gases (Anusha, 2010). The absorbed CO_2 can then be released from the solvent for storage or utilization. In the adsorption process, CO_2 molecules adhere to the surface of a solid material called an adsorbent (Raganati, Miccio, & Ammendola, 2021). The CO_2 is then desorbed from the adsorbent for storage or use. The membrane separation process utilizes semi-permeable membranes to selectively allow CO_2 molecules to pass through while blocking other gases (Srinu, Jatin, & Damodaran, 2023). This separates CO_2 from gas streams, allowing for storage or further processing.

Lastly, the cryogenic separation process involves cooling the gas mixture to very low temperatures to separate CO_2 from other gases based on differences in boiling points (Srinu, Jatin, & Damodaran, 2023). The CO_2 is then collected as a liquid for storage or use. These methods play crucial roles in carbon capture processes, each with its advantages and limitations depending on the specific application and requirements Figure 2 (Srinu, Jatin, & Damodaran, 2023).

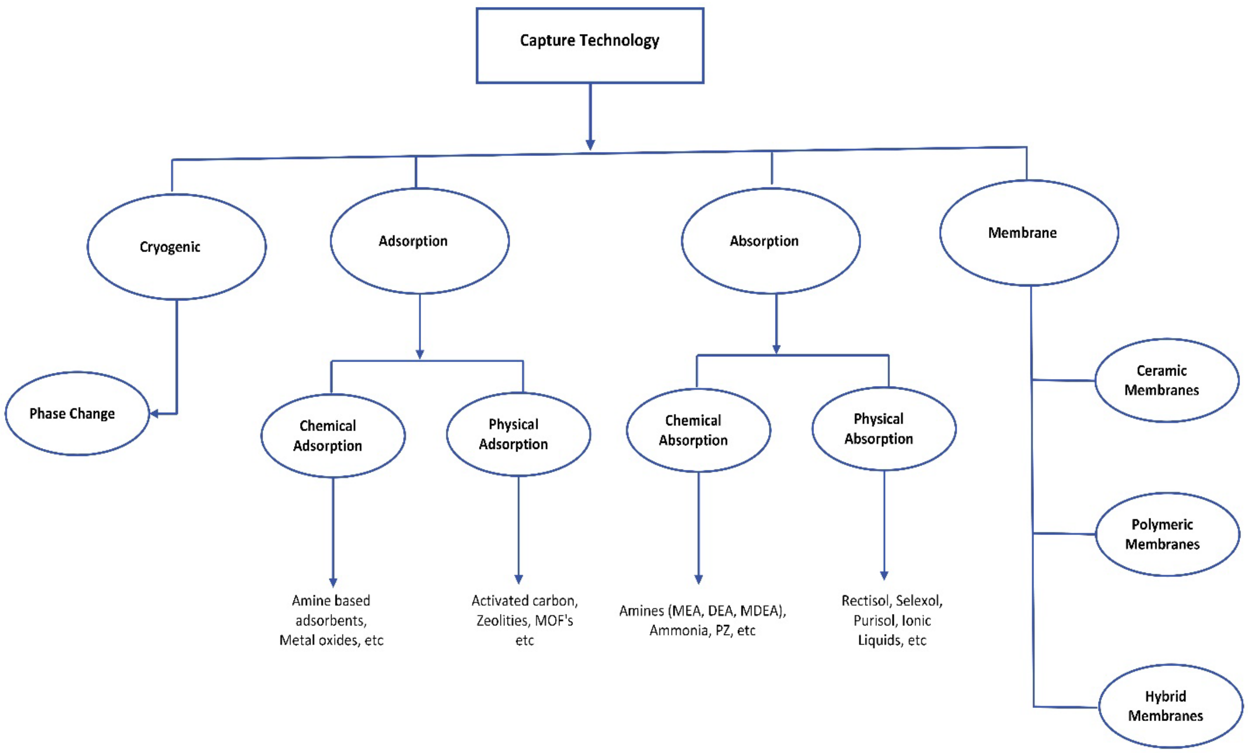

Figure 2: Carbon Capture Techniques (Srinu, Jatin, & Damodaran, 2023).

Post-combustion capture systems provide a technically and economically feasible solution, though with cost pressures (Zanco, et al., 2021). Their economic feasibility is enhanced by the potential to generate carbon credits through reduced emissions, which can support decarbonization efforts across various sectors. These sectors include primary industrial emitters like power generation, steel making, and cement production, as well as secondary emitters such as waste incinerators and chemical plants. Additionally, emitters with the potential for negative emissions, like bioenergy with carbon capture and storage (BECCS), are included (Zanco, et al., 2021). Retrofitting existing plants with post-combustion capture units could be a cost-effective method to reduce emissions at the source without disrupting upstream processes, thus facilitating the transition towards industrial sectors with net-zero CO_2 emissions (Lucquiaud & Gibbins, 2011).

A review of the existing CCS projects was conducted to assess the progress in the commercialization of carbon capture technologies. The CO_2-enhanced oil recovery (EOR) has been practiced in the United States and Canada since the 1960s, with Chevron initiating the world's first large-scale CO_2-EOR project in Scurry County, Texas, in January 1972 (Nath, Mahmood, & Yousuf, 2024). The CO_2 is sourced from natural carbon fields in Colorado and transported via pipelines to the oilfield for flooding, with over 175 million tonnes of natural CO_2 injected into the SACROC project between 1972 and 2009 (Ma, et al., 2022). However, projects utilizing CO_2 directly sourced from natural CO_2 fields for flooding and storage are not classified as carbon emission reduction initiatives and therefore do not fall under the category of CCS projects.

The Sleipner CCS project was initiated in 1996 (Furre, Eiken, Alnes, Vevatne, & Kiær, 2017), and the Weyburn Project launched in 2000 (NRCan, 2016), marked the pioneering international demonstrations of large-scale CCS of anthropogenic CO_2 emissions. The Sleipner CCS project captures CO_2 extracted during natural gas purification and injects it into deep saline aquifers for storage, successfully storing over 20 million tonnes of CO_2 since its inception in 1996. The Weyburn Project stands as the world's most comprehensive multidisciplinary scientific investigation into geological CO_2 storage, spanning 12 years and storing over 35 million tonnes of CO_2 since October 2000. The Weyburn Project takes place at the most extensive geoscience testing location globally, established within the Weyburn field situated in Southern Saskatchewan, Canada. The success of the Weyburn Project highlights three key achievements in CCS technology. First, it pioneered large-scale capture and transportation of high-concentration CO_2 from coal usage for EOR and storage, showcasing the feasibility of reducing coal-generated CO_2 emissions at a rate of 1.8 million tonnes per year (Ma, et al., 2022). Second, it demonstrated the viability of CCS technology establishing a successful commercialization model lasting over 20 years. Third, the project expanded its scope to capture and store low-concentration CO_2 from coal-fired power plants, notably establishing the world's first post-combustion CO_2 capture facility at the SaskPower boundary dam power station (Saskatchewan.ca, 2021).

There are various classification methods for CCS projects, and the Global CCS Institute (GCCSI) categorizes projects that capture, transport, and store 400 $kt \cdot a^{-1}$ CO_2 from industrial emission sources, or those capturing and storing 800 $kt \cdot a^{-1}$ CO_2 from coal-fired power plants, as meeting the criteria for large-scale pilot testing, demonstration, or commercialization projects (Ma, et al., 2022). More so, CCS projects can be categorized based on the origin of CO_2, such as CO_2 sourced from natural gas extraction (like Sleipner), carbon capture at coal chemical plants (such as Great Plains Coal Gasification Plant), hydrogen production in oil refining (for example, Shell Quest and Tomakomai (IEA, 2021)), coal-fired power plants (like SaskPower Boundary Dam and Petra Nova (Giannarisa, et al., 2021; EIA, 2017)), carbon capture at steel mills (such as Al Reyadah (Energy.Gov, 2017)), and biomass energy capture (for instance, Decatur (CarbonBrief, 2016)).

Recently, the concepts of clusters and hubs have emerged as potential solutions in CCS (Wang, 2024). A CCS cluster refers to a geographic concentration of interconnected CO_2-emitting sources within a specific industry sector (Wang, 2024). The size of CCUS hubs under development has significantly increased, with an additional 210 Mt of new storage capacity specifically declared throughout the year (OGCI, 2023). Clusters are formed due to various factors like access to transportation options, and storage proximity. On the other hand, a hub serves as a central point for CO_2 collection or distribution, which may be shared among multiple clusters. These hubs often include storage facilities where CO_2 from various sources is injected. They can be situated at either end of a multi-user pipeline or at both storage points. Both clusters and hubs aim to encourage shared resources and facilitate the expansion of CCUS applications. One notable advantage is cost-sharing, where participants can reduce infrastructure costs by connecting low-cost industrial sources with storage sites. This approach lowers barriers to entry for CCS projects. Another key benefit is stable operation, addressing the mismatch between CO_2 emission sources and storage sites (Wang, 2024). Several CCUS hubs are in the planning or construction stages, primarily located in North America, Europe, and the Asia-Pacific region. Notable hubs include the Ship Channel CCUS hub in the Gulf of Mexico with an annual capacity of 100 million tonnes, the Summit Carbon Solution CCS hub with 10 million tonnes per annum, the Aramis CCS hub with 20 million tonnes per annum, the Acorn CCS hub with 5 million tonnes per annum, and the Longship CCS hub with 5 million tonnes per annum. In China, major corporations like China Petrochemical Corporation, Shell, Baosteel, and BASF are collaborating to establish the country's first ten-million-tonnes CCUS project in East China, aiming to decarbonize industries and develop a low-carbon product supply chain. Additionally, the China National Offshore Oil Corporation, Guangdong Development and Reform Commission, Shell Group, and ExxonMobil are launching China's first offshore 10-million-tonnes CCS cluster demonstration project. Furthermore, PetroChina Southern Petroleum Exploration and Development Company and BP (China) Investment Co., Ltd. have initiated a memorandum to promote CCUS industrialization, focusing on Hainan's storage strategic plan of 1 million tonnes initially and 10 million tonnes in the long term (World-Energy, 2023). Pathways Alliance has put forward a plan for a carbon capture and storage network to capture CO_2 from over 20 oil sands facilities and transport it 400 kilometers by pipeline to a terminal in the Cold Lake area, where it will be stored underground in a shared carbon storage hub (Alberta, nd).

In 2013, Shell Catalysts and Technologies developed the first commercial post-combustion CO_2 facility (Singh, 2014), a state-of-the-art CO_2 capture technology (Shell CANSOLV) incorporating a regenerable amine (Shell Catalysts & Technologies, 2019), offering benefits like low energy consumption, fast kinetics, and minimal volatility. This solution enables industries to lower their carbon footprint, comply with environmental regulations, reduce harmful emissions, generate revenue from CO_2 by-products, and mitigate environmental liabilities. Two plants licensed by CANSOLV are commercially operational, with one being among the largest post-combustion facilities globally (Shell Catalysts & Technologies, 2019). Additionally, multiple other units are currently in advanced engineering phases. Shell's carbon capture technology enables the effective removal of over 90% of CO_2 in exhaust gases. The system operates independently as a standalone facility and is thus well-suited for retrofit situations. The key process steps involve several stages: First, the feed gas undergoes quenching and saturation in a circulated water pre-scrubber. Next, the gas contacts the lean amine solution in a counter-current mass transfer packed absorption column, where CO_2 is absorbed, and the treated gas exits into the atmosphere. Midway through the column, partially loaded amine is extracted, cooled, and reintroduced over a layer of mass transfer packing. The CO_2-rich amine from the absorption column is then pumped through a lean-rich amine heat exchanger and onto the regeneration column. In this column, rising low-pressure saturated steam regenerates the lean amine solution, and CO_2 is recovered as a pure, water-saturated product. The CO_2 and water mixture are directed to a separation unit where CO_2 is separated from the water through condensation. The lean amine is subsequently pumped from the stripper reboiler back to the absorption column for reuse in capturing CO_2. Finally, the CO_2 is directed to by-product management systems. The technology is highly versatile and can be adapted to various industrial applications and gas flow rates, with CO_2 concentrations ranging from 3.5 to 25%. Licensed units treating gas flow rates from 11,000 to 685,000 Nm^3/h and CO_2 concentrations from 9 to 12.5% are currently operational (Shell Catalysts & Technologies, 2019).

Two recent publications highlight opportunities for enhancing energy efficiency, cost reduction, and the overall performance of capture facilities (TCM, 2023). The Technology Centre Mongstad (TCM DA) in Norway investigated CO_2 capture performance using the non-proprietary CESAR1 solvent for flue gases resembling those from steam methane reforming (SMR) furnace at Equinor's SMR unit in Tjeldbergodden methanol plant (Akhter, 2022). The study reported specific reboiler duty (SRD) for 90% CO_2 capture from flue gases with 10 and 15 vol% (dry) CO_2 content, employing absorber packing heights of 12 and 18 meters. Tests at 10 vol% (dry) CO_2 content demonstrated achievable SRD levels below 4 GJ/tonne CO_2 with a 12-meter absorber packing height, while lower SRD values were obtained with an 18-meter absorber packing height. Despite unfavorable overall absorber conditions, precipitation was observed in the absorber packing during the tests, mitigated using anti-foam to address foaming in the stripper. There is a need to study and evaluate predictive models for the TCM carbon capture facility which could potentially reduce operational costs and enhance efficiency (Lars, Audun, & Bjørn, 2022). The study used multivariate data analysis to develop predictive models for CO_2 content (total inorganic carbon) and amine functionalities (total alkalinity) in the amine solvent, demonstrating the potential for real-time reporting of solvent parameters to improve capture process control (Lars, Audun, & Bjørn, 2022).

Table 3 provides a summary of CCUS operational projects in Canada and its associated hub (IEA, 2023). It showed CCUS projects and hubs in Canada, highlighting key details such as operational dates, capacities, and whether they are part of larger CCUS hubs. Notable projects include the Alberta Carbon Trunk Line (ACTL) for CO_2 transport, Boundary Dam CCS in the power sector, and Clive CO_2-EOR for carbon storage. Together, these operational projects represent a significant step towards mitigating carbon emissions and advancing sustainable practices in Canada's industrial landscape. The comprehensive list showing a mix of operational, planned, and under-construction projects, indicating ongoing efforts to implement CCUS technologies can be found in Appendix A. Projects span a wide range of sectors, including power generation, heat production, cement manufacturing, biofuels, and others, underlining the broad application of CCUS solutions across the economy. Capacities vary significantly among projects, reflecting the scalability and flexibility of CCUS infrastructure to accommodate different project sizes and requirements. Moreover, many projects are integrated within CCUS hubs, fostering collaboration, cost-sharing, and efficiency gains within regional carbon capture and storage networks. Table 3 shows the presence of numerous planned projects which suggests continued investments and commitments to expanding CCUS capabilities in Canada, underscoring a long-term strategy to mitigate carbon emissions and achieve environmental sustainability objectives.

Table 3: Summary of CCUS operational projects and hubs in Canada (IEA, 2023).

Project name	Operation Date	Sector	Announced maximum capacity (Mt CO_2/yr)	Part of CCUS hub
Alberta Carbon Trunk Line (ACTL)	2020	CO_2 transport	14.6	Alberta Carbon Trunk Line (ACTL)
Boundary Dam CCS (Saskatchewan)	2014	Power and heat	1	
Clive CO_2-EOR (ACTL) (Alberta)	2020	CO_2 storage	1.12	Alberta Carbon Trunk Line (ACTL)
Horizon H_2 capture tailings CCS (Alberta)	2009	Other fuel transformation	0.438	
NWR CO_2 Recovery Unit (Sturgeon Refinery) (ACTL) (Alberta)	2020	Other fuel transformation	1.3	Alberta Carbon Trunk Line (ACTL)
Quest (Alberta)	2015	Other fuel transformation	1.2	
WCS Redwater CO_2 Recovery Unit (formerly nutrien) (ACTL) Alberta phase 1	2019	Other industry	0.3	Alberta Carbon Trunk Line (ACTL)

2.3 Carbon Dioxide On-site Storage

The carbon dioxide storage tank is designed for long-term storage of liquefied CO_2 (LCO_2) at pressures between 1.14 MPa and 2.41 MPa, with systems to maintain preset conditions, safety, and integrity (Chart, 2013). It consists of a steel inner tank within an outer carbon steel vacuum shell, insulated with composite layers and a high vacuum for extended retention. Liquid CO_2 (LCO_2) storage tanks are made of steel or other durable materials that safely store CO_2 in liquid form under high pressure and low temperatures to ensure efficiency (Whatispiping, 2020).

An LCO_2 tank with model number EN13445PED was designed to operate in an ambient temperature range of -50°C to 50°C, and a working pressure of 22 bar (Cryoteknik, 2023). It was made from carbon steel and featured vacuum insulation. The Liquid CO_2 vacuum-insulated storage tank used vacuum insulation and stainless steel for storing CO_2 (Cryoteknik, 2023). These tanks were constructed with perlite insulation, a cooling unit, an under-tank evaporator, and condensed vapor using the refrigeration unit. In contrast, Liquid CO_2 polyurethane-insulated storage tanks, made from carbon steel, featured expanded polyurethane insulation protected by a stainless steel or aluminum coating and included refrigeration units for gas condensation. It could either store CO_2 in vertical or horizontal tanks (Cryoteknik, 2023).

A technical spec sheet showed an LCO_2 storage tank with a design temperature of -40ºC/+40ºC, featured a differential pressure liquid level indicator with an overfill safety switch, optional load cells for horizontal tanks, a double-mounted safety relief valve with a change-over valve, and essential valves and fittings (Pentair, 2017). They also included a manhole for inspection, which comes in various sizes.

A study examined the essential aspects to consider when assessing the total cost of purchasing above-ground storage tanks (Directank, 2023). Although the upfront capital cost may appear high, the long-term advantages of its operations can make these tanks a valuable investment. Above-ground tanks offer financial and operational benefits by minimizing environmental and safety risks, reducing maintenance requirements, and extending the lifespan of your storage equipment. Storage tanks constructed with fiberglass and polyethylene are more costly, estimated at US$100,000 per 189 m^3 (Directank, 2023).

A double-wall cryogenic tank made of vacuum powder insulation with model number JSAA100-L/2.16 was designed for carbon dioxide storage at a temperature of -50°C with a 95% filling rate (Jianshentank, 2019). The tank operates at a pressure range of 0.2 - 3.0 MPa with an effective volume of 100m^3. It has an inner tank having a diameter of 3000 mm, a length of 13,820 mm, and a thickness of 24 mm. The outer tank measures 3500 mm in diameter, 14,600 mm in length, and has a uniform thickness of 14 mm. The overall dimensions are a diameter of 3528 mm and a length of 16,933 mm, with a net weight of 59,580 kg. Key benefits include a compact design, less space requirements, and ease of maintenance. The tank is available as both vertical and horizontal fixed tank or transport tanker type (Jianshentank, 2019).

The technical specification of a 200 m^3 liquid CO_2 storage tank was based on the ASME SEC VIII DIV-2 ED 2021 design and fabrication code (Startech, 2024). It was designed for a pressure of 22 kg/cm^2 including a safety margin, with a maximum operating pressure of 25.35 kg/cm^2. The tank's design temperature ranged from -46°C to -17°C, and it was tested at a pressure of 32 kg/cm^2. Radiography inspection was performed at 100% to ensure quality, and the tank includes a corrosion allowance of 1.5 mm. The tank was designed to withstand environmental factors following ASCE 7 for wind speed and seismic zone. The horizontal cylindrical has a hemispherical dish end. Overall, the engineering design, procurement, construction, inspection, testing, and supply of the 200 m^3 liquid CO_2 storage tank was about US$150,000 (Startech, 2024).

2.4 Carbon Dioxide Transportation Methods

Carbon dioxide transportation options primarily include ships, pipelines, trains, and trucks as shown in Table 4 (Baroudi, Awoyomi, Patchigolla, Jonnalagadda, & Anthony, 2021).

A technical report prepared by the International Energy Agency Greenhouse Gas IEAGHG Program reviewed the status and challenges of carbon dioxide shipping infrastructures (IEAGHG, 2020). The study indicates that transporting carbon dioxide of about 1-2 Mtpa over long distances by ship presents a cost-effective option. To estimate the time required to ship carbon dioxide over a distance, several factors must be considered, including the speed, capacity, and any potential delays or handling times (IEAGHG, 2020). An article showed how the speed of a ship is measured and the economic importance to the operator of the vessel (Marine Insight, 2019). The term knot originated as a maritime measurement of a ship's speed, where one knot is equivalent to 1.852 kilometers per hour, or one nautical mile equals 1.852 kilometers (Tai & Wang, 2022). Different types of ships have varying service speeds: bulk carriers typically range from 13 to 15 knots, container ships from 16 to 24 knots, and oil and chemical tankers from 13 to 17 knots (Marine Insight, 2019).

Globally, the use of pipelines for CO_2 transport is a mature technology, especially in the United States with over 5000 miles of pipelines in operation (Erin, et al., 2021). Pipeline transportation can be either onshore pipeline or offshore pipeline (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). CO_2 pipelines require thicker pipes than natural pipelines due to higher pressure demands. The use of natural gas pipelines for large-scale CO_2 transport over long distances is impractical due to these differences in pressure requirements. Offshore pipelines, though similar in cost factors to onshore ones, tend to be more expensive due to the complexities of construction in offshore environments. Transportation by ship, although established for liquefied natural gas (LNG) and liquefied petroleum gas (LPG), is not commonly used for CO_2 transport (Erin, et al., 2021). LPG tankers serve as a closer analogy for CO_2 transport via ship due to the necessity of transporting liquefied CO_2 at elevated pressures (Erin, et al., 2021). While repurposing LPG tankers is feasible, specially designed CO_2 tankers offer better optimization for capacity and investment costs (Erin, et al., 2021). Transport via train or truck may be economical for short distances and small CO_2 quantities but is not anticipated to play a significant role in large-scale CCS deployment due to cost considerations (Erin, et al., 2021). Pipelines and ships are deemed more cost-effective for transporting megatons of CO_2 annually, owing to economies of scale (Erin, et al., 2021). An overview of CO_2 transportation methods, considering projected transport capacities and operational conditions in each system are outlined in Table 4 (Baroudi, Awoyomi, Patchigolla, Jonnalagadda, & Anthony, 2021).

Table 4: Carbon dioxide CO_2 transportation methods (Baroudi, Awoyomi, Patchigolla, Jonnalagadda, & Anthony, 2021).

Transportation method	Conditions	Capacity	Comments
Ships	0.65–4.5 MPa, 221–283 K	>70 $MtCO_2$/year	High operating costs. Low capital costs. Transportation equipment requires low temperatures and high pressure.
Pipelines	4.8–20 MPa, 283–307 K	~100 $MtCO_2$/year	High capital costs. Low operating costs. Large transportation volume.
Tank Trucks	1.7–2 MPa, 243–253 K	>1 $MtCO_2$/year	High transportation cost. Affected significantly by weather and traffic conditions. High fuel and labor costs. Not economical for large-scale CCUS projects.
Railway	0.65–2.6 MPa, 223–253 K	>3 $MtCO_2$/year	Need to be close to the railway. High requirement for gas source and destination. More advantageous over medium and long distances

Carbon dioxide can be transported in various states: gaseous, liquid, dense, or supercritical, as shown in Figure 3.

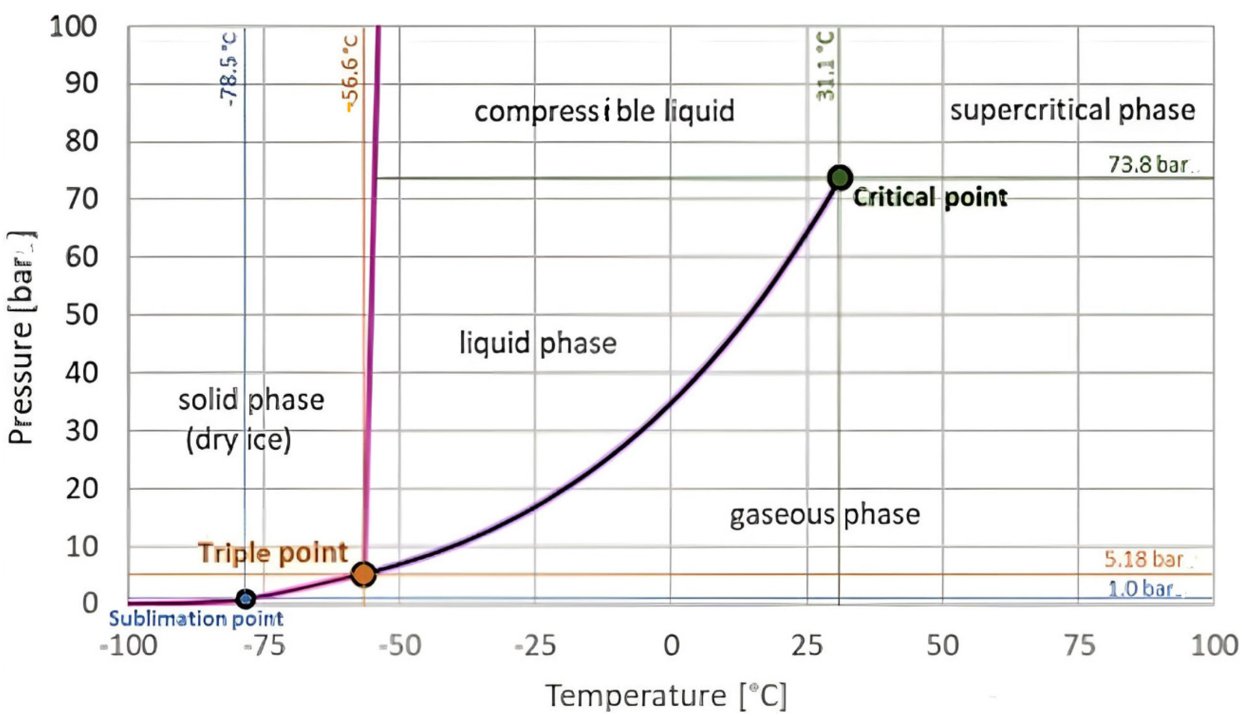

Figure 3: The CO_2 phase diagram illustrates its states under varying temperature and pressure conditions (Engineeringtoolbox, 2018)

Gaseous transport is deemed the least efficient and economical due to its lower volume flow rate (Peletiri, Rahmanian, & Mujtaba, 2018). Consequently, CO_2 is typically transported either as a liquid via ships, or trucks, or as a supercritical fluid through pipelines (Onyebuchi Victor, 2018). In its supercritical state, CO_2 exhibits properties of both liquid and gas, with the density of a liquid and the compressibility and viscosity of a gas. Liquid CO_2 transport operates below the critical point but above the triple point (−56.6°C to 31°C and 5.2 to 73.8 bar), while pipeline transportation is conducted above the critical pressure to prevent phase changes (Simonsen, Hansen, & Pedersen, 2024). Achieving high CO_2 density is crucial in pipeline transport, where density increases with decreased temperature or increased pressure. Dense and supercritical CO_2 enables greater mass transport with smaller pipeline dimensions, reducing material costs. However, transporting dense CO_2 requires pipelines with adequate wall thickness to withstand increased pressure. Liquid CO_2 transport is more economical and efficient than gas transport but demands strict safety measures to prevent phase changes and ensure structural integrity (Simonsen, Hansen, & Pedersen, 2024). Overall, transporting carbon dioxide in the liquid phase typically involves compressing it into a supercritical state rather than a true liquid state, hence the CO_2 exhibits both gaseous and liquid properties (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). This compression is necessary to ensure that the CO_2 can be moved in significant quantities over long distances through pipelines. The pipeline's diameter will range from 12 inches for the 2.5 Mtpa volume over a 10 km length to 32 inches for the 20 Mtpa volume covering a 1,500 km length as shown in table 2.5 below (Sandrine Decarre, 2011). Table 5 presents a comparison of the diameter of the CO_2 pipeline based on different volumes and distances. As the volume of CO_2 increases, the diameter of the pipeline also increases to accommodate higher flow rates and longer distances. More so, longer distances and higher volumes necessitate larger pipeline diameters to maintain the required flow rate and pressure, providing essential insights for designing and planning CO_2 transport infrastructure (Sandrine Decarre, 2011).

Table 5: Pipeline dimensions as a function of volume and distance (Sandrine Decarre, 2011).

CO_2 Volume	10 km	180 km	500 km	750 km	1,500 km
2.5 Mtpa	12''	12''	-	-	-
10 Mtpa	20''	24''	24''	24''	24''
20 Mtpa	24''	32''	32''	32''	32''

The CCUS industry is still emerging, and transportation costs vary from project to project, representing approximately 25% of total CCUS project expenses (Simonsen, Hansen, & Pedersen, 2024). There are about 65 announced projects in Europe that aim to become operational before 2030 using either pipeline or shipping as a mode of transportation (Simonsen, Hansen, & Pedersen, 2024). Some of the projects have determined to use either pipeline or shipping; or both. Table 6 presents the ongoing European cross-border network initiatives for CO_2 transportation, such as the Belgian project Antwerp@C, which lacks suitable geological storage facilities, necessitating collaboration across borders (Simonsen, Hansen, & Pedersen, 2024). For instance, CO_2 captured in Antwerp is transported either by pipeline to Rotterdam in the Netherlands or shipped to storage sites like Norway's Northern Lights. Other projects like Carbon Connect Delta and Dartagnan aim to assess the feasibility of CCUS between the Netherlands, Belgium, and France, with Dartagnan exploring the potential of a hub exporting CO_2 from Dunkirk harbor to Rotterdam for North Sea storage. Carbon Connect Delta focuses on CCUS feasibility across the North Sea Port, extending from Belgium to the Netherlands, and explores connections with projects like Northern Lights and ARAMIS. These projects highlight the growing emphasis on CO_2 transportation in the CCUS industry, particularly in countries lacking national storage capacity, albeit they are all still in the developmental phase (Simonsen, Hansen, & Pedersen, 2024).

Table 6: Cross-border networks for the transportation of carbon dioxide (Simonsen, Hansen, & Pedersen, 2024).

Project name	Countries involved	Transport	Injection capacity
Dartagnan	The Netherlands, France	Pipeline and ship	3 Mt CO_2 /yr
Carbon Connect Delta	The Netherlands, Belgium	Pipeline	1 Mt CO_2 /yr
CO_2TransPorts	The Netherlands, Belgium	Pipeline	10 Mt CO_2 /yr
Northern Lights	Norway, The Netherlands, (Expected to expand to several European countries)	Pipeline and ship	1.5 Mt CO_2 /yr
ARAMIS	The Netherlands, Belgium, France, Germany	Pipeline and ship	2.5 Mt CO_2 /yr

Globally, the largest carbon dioxide transportation infrastructure is in Canada, known as the Alberta Carbon Trunk Line (ACTL) with a 240-kilometer pipeline that transports CO_2 from capture sites to locations where it is utilized for Enhanced Oil Recovery EOR (Simonsen, Hansen, & Pedersen, 2024), as illustrated in Figure 4.

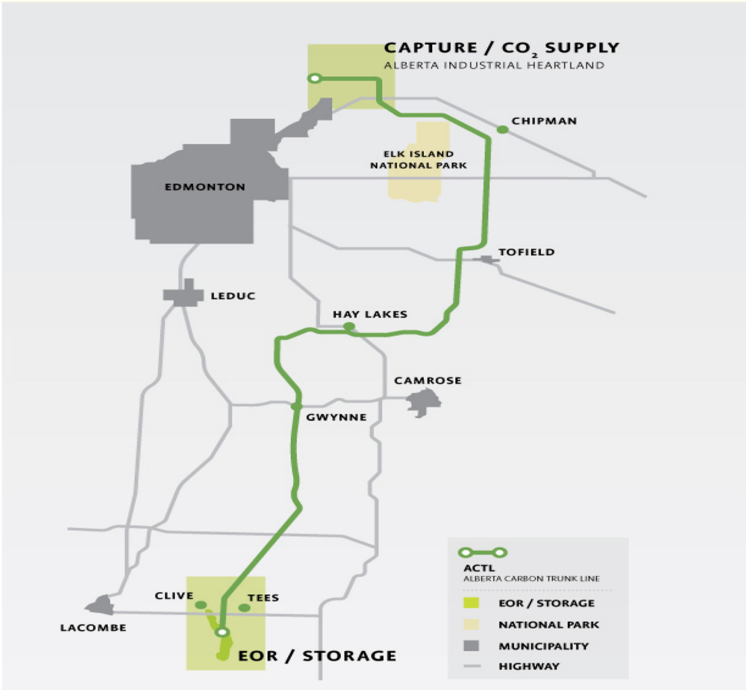

Figure 4: Map of the Alberta Carbon Trunk Line Pipeline system (Canadian Energy Centre, 2021).

The ACTL pipeline is designed to accommodate 15 million tons of CO_2 annually, although only about 1.8 million tons are currently being utilized (NRCan, 2016). The project, which is worth US$1.24 billion, adopts a CCUS cluster concept where the transportation system is oversized to accommodate the needs of multiple users (Simonsen, Hansen, & Pedersen, 2024). This strategy aims not only to reduce the footprint of individual pipeline systems but also to reduce costs by sharing infrastructure, thereby expediting the commercialization of CCUS. Following the ACTL project concept, another CO_2 transport initiative involving a 1,000 km offshore pipeline from Belgium to Norway is set to be operational by the end of the decade. This pipeline will enable emitters from Belgium and neighboring countries to access CO_2 storage facilities in Norway. In contrast, the Norwegian Northern Light project will ship compressed CO_2 from Southeast Norway to the West coast, where a temporary storage facility holds the CO_2 before it is piped offshore into a reservoir 1 to 3.3 km beneath the seabed for permanent storage. The Northern Light project aims to evolve into a commercial CO_2 transport system across European capture plants for storage on the Norwegian continental shelf (west coast of Norway). The Northern Lights project embarked on the world's first cross-border, open-source network for CO_2 transport and storage infrastructure (IEA, 2021).

A study compared the costs of transporting liquids using pipelines, trucks, and ships based on the hypothetical construction of a pipeline in the UK (William & Stephen, 2019). The paper offers an analysis of the energy and environmental advantages of pipelines in contrast to trucking and shipping alternatives. Manchester Airport was selected as the destination terminal, with Felixstowe, a major port, as its supply terminal. The distances for each respective transportation route between Felixstowe and Manchester are as follows: 336 kilometers via pipeline, 386 kilometers by road, and 1,230 kilometers by ship (William & Stephen, 2019). For the pipeline option, there is either a single continuous 12-inch line spanning 336 kilometers, costing $278 million; or two segments of 12-inch lines, each covering 50% of the 336-kilometer distance, along with an intermediate pumping station, costing $280 million (William & Stephen, 2019). The analysis conducted in the paper demonstrates that the energy usage and emissions generated by pipelines are lower compared to those of trucks and ships (William & Stephen, 2019).

More so, research was done to estimate the cost per tonne of transporting CO_2 over a range of distances in the United States (McCoy & Rubin, 2008). The study developed an engineering-economic model to analyze CO_2 transport via pipelines. This model incorporates a probabilistic analysis feature, allowing for the quantification of transport cost sensitivity to input parameter variability and uncertainty (McCoy & Rubin, 2008). The results of the study indicate that constructing a 100 km pipeline in the Midwest to handle five million tonnes of CO_2 annually costs approximately US$1.16 per tonne. The study showed that costs vary across regions, with the Central US being US$0.39 per tonne cheaper and the Northeast US being US$0.20 per tonne more expensive under the same assumptions (McCoy & Rubin, 2008). The pipeline's design capacity and length significantly influence costs, reducing the Midwest pipeline's capacity to two million tonnes per year increases costs to US$2.23 per tonne for a 100 km pipeline and US$4.06 per tonne for a 200 km pipeline. A probabilistic analysis assigns uncertainty distributions to a range of factors, revealing a 90% probability that the transportation cost per tonne of CO_2 falls between US$1.03 and US$2.63 in the Midwest US (McCoy & Rubin, 2008).

A study systematically examined the advancement of carbon dioxide transportation through pipelines, focusing on five key aspects: pipeline design, processes, risk and safety, specifications, and cost (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). The paper evaluated various factors to be considered during CO_2 pipeline design such as length, pipe diameter, thickness, pressure, and construction route. The study shows a direct correlation between pipeline length and required pressure, which necessitates long-distance pipelines to adopt a stepwise pressurization approach, requiring the establishment of multiple booster stations along the route. The study grouped pipelines into high, medium, and low-capacity categories due to varying distances between the point emitters and utilization plant (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). High-capacity pipelines have lengths ranging from 657 to 808 kilometers, with a transport capacity of 10 to 37 million tonnes per year and initial booster power of 43 to 68 megawatts (Kara, Lessly, Matthew, & Robert, 2014). Medium-capacity pipelines typically span from 116 to 380 kilometers in length, with a transport capacity of 2.8 to 7.2 million tonnes per year and initial booster power of 15 to 17 megawatts (Kara, Lessly, Matthew, &

Robert, 2014). Low-capacity pipelines are considerably shorter, ranging from 1.9 to 97 kilometers, with a transport capacity of 0.06 to two million tonnes per year and initial booster power of 0.2 to 8 megawatts (Kara, Lessly, Matthew, & Robert, 2014). The next factor, which is pipe diameter was considered while selecting CO_2 pipelines. Calculating the pipe diameter is very important as it not only directly impacts transportation capacity but also affects investment decision (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). Typically, larger pipe diameters entail greater investment costs. Thus, the most optimal approach is to minimize the pipe diameter while meeting transmission requirements (Lin & Xin-Rong, 2011). Additionally, factors such as pressure, flow rate, and fluid flow must be considered when determining pipe diameter. The proposed pipe diameter design or optimization formula based on different considerations is shown in Equation 1.

$$\mathbf{D} = \sqrt[5]{\frac{\mathbf{2.25Lf\rho Q_m^2}}{\mathbf{\Delta p}}}$$

Equation 1: The pipe diameter (IEAGHG, 2014).

Where D represents pipe diameter (m)

f = the friction factor

ρ = fluid density (kg/m^3)

L = pipe length (m)

Δp represent pressure drop (Pa)

p_1 represents the inlet pressure of the pipeline (Pa)

p_2 represents the output pressure of the pipeline (Pa)

Q_m represents mass flow rate (m^3/s)

Another factor that was considered in selecting the CO_2 pipeline was the wall thickness of the pipe. The pipe wall serves to withstand both internal and external pressure exerted on the pipe. A greater wall thickness enhances the pipeline's ability to bear pressure, albeit at the expense of increased investment (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). High-capacity pipelines have diameters ranging from 600 to 921 millimeters, with wall thicknesses between 19 and 27 millimeters. Medium-capacity pipelines typically feature diameters ranging from 305 to 508 millimeters, with wall thicknesses between 10 and 13 millimeters. Low-capacity pipelines are characterized by diameters ranging from 152 to 270 millimeters, with wall thicknesses between 5.2 and 9.5 millimeters. These parameters are crucial design considerations that directly influence the performance and cost of CO_2 pipeline systems. The mathematical expression for the pipeline wall thickness is shown in Equation 2.

$$\mathbf{t} = \frac{\mathbf{p_{max}\,D_0}}{\mathbf{2SL_fET}}$$

Equation 2: Pipeline wall thickness (Kang, Seo, Chang, Kang, & Huh, 2015).

Where t represents pipe wall thickness (m)

p_{max} = maximum pressure (Pa)

S = yield strength (Pa)

D_o = outer diameter of the pipeline(m)

F = the design factor

E = the longitudinal joint factor

T = the temperature factor

L_f = the location factor

More so, temperature and pressure were considered because they play a direct role in determining the state of CO_2 transport within the pipeline (Serpa, Morbee, & Tzimas, 2011). For the CO_2 to be transported under supercritical conditions, the temperature should range from 12 to 44 degrees Celsius, while the pressure should fall within the range of 8.5 to 15 megapascals (MPa) (Serpa, Morbee, & Tzimas, 2011). Throughout CO_2 transport, both temperature and pressure vary within a defined range and are not constant. High-capacity pipelines have a maximum pressure range of 15.1 to 20.0 megapascals (MPa) and a minimum pressure range of 7.2 to 15.1 MPa. Medium-capacity pipelines typically exhibit a maximum pressure range of 9.8 to 14.5 MPa and a minimum pressure range of 3.1 to 3.5 MPa. Low-capacity pipelines are characterized by a maximum pressure range of 2.1 to 4.0 MPa and a minimum pressure range of 0.3 to 1.0 MPa (Serpa, Morbee, & Tzimas, 2011). These pressure ranges are crucial pipeline selection parameters that dictate the operational capabilities and safety margins of CO_2 pipeline systems.

Additionally, the pipeline construction route was considered, which is determined by the source and destination of the carbon dioxide. This decision not only impacts the length of the pipeline but also influences the design specifications regarding pressure, temperature, and the choice of pipeline material. When the long-distance CO_2 pipeline traverse different regions, the design and construction considerations vary. These considerations encompass economic factors as well as any special areas such as urban or pre-existing infrastructures (Luo, Wang, Oko, & Okezue, 2014). The possibility of acquiring the right of way (ROW) is a crucial prerequisite of construction consideration before route selection (Serpa, Morbee, & Tzimas, 2011). In urban settings, it is advisable to minimize pipeline routes due to potential increases in construction expenses, extended construction timelines, and heightened operational risks (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020). However, employing trenchless technology during pipeline installation can mitigate urban pavement damage to some extent without disrupting traffic flow. Areas characterized by steep slopes and unstable soil layers, including regions prone to landslides and seismic activity, should be avoided. Whenever feasible, utilize pre-existing infrastructure to streamline pipeline installation and minimize environmental impact. Areas designated as nature reserves or possessing sensitive ecological attributes should be avoided whenever possible, respecting conservation principles. Linear features such as rivers, highways, and railways may necessitate trenchless technology for crossing to minimize disruption (Hongfang, Xin, Kun, Lingdi, & Mohammadamin, 2020).

A comparative study of CO_2 pipeline safety regulations was done by analyzing various levels of stringency and safety measures, suggesting the need for harmonized global standards to improve safety within CCUS projects (El-Kady, Amin, Khan, & El-Halwagi, 2024). The 2020 rupture of a CO_2 pipeline near Satartia, Mississippi, highlighted the severe safety hazards associated with CO_2 pipelines, as the release of CO_2 gas formed a fast-moving cloud that displaced air and suffocated individuals and animals over a wide area. CO_2, being an asphyxiant, poses serious health risks if a leak occurs (Permentier, Vercammen, Soetaert, & Schellemans, 2017), necessitating strict safety protocols such as automatic shutoff valves (US DOT, 2022) and continuous leak detection and monitoring systems (Sun, Yan, Zhang, & Shao, 2024), which could increase project costs (CRS, 2022). Additionally, regulatory requirements, including minimum setback distances from occupied dwellings (AER, 2022) and comprehensive environmental risk and safety assessments (Vitali, et al., 2021), may further drive up costs due to the need for compliance.

A preliminary review of the design and risks associated with CO_2 pipelines was done to ensure comprehensive risk assessments are conducted and that standard practices are applied in both the design and operation stages (John, Ken, Peter, & Schellhase, 2005). The CO_2 pipeline engineering design considerations include operating pressure, ambient and operating temperatures, corrosivity, routing topography, and pipeline monitoring systems. Other design considerations for CO_2 pipelines involve appropriate valve materials, compressors, and seals, to ensure reliable operation. Routine safety inspection of the operating pipeline is important with any incident documented and analyzed, with corrective measures implemented to mitigate failures (John, Ken, Peter, & Schellhase, 2005).

A study considered the costs of pipeline transportation and showed that total costs are determined based on project size, distance, system design, and geographical locations (Myers, Li, & Markham, 2024). The NETL CO_2 transportation cost models (NETL, 2023) to compute the overall cost of the transport infrastructure. It encompasses the capital expenditure for materials $Cost_{capital}$, the operational and maintenance expenses ($Cost_{O\&M}$), and the energy consumption costs associated with equipment operation $Cost_{energy}$. The total transportation cost model is shown in Equation 3.

$$\mathbf{Cost_{total} = Cost_{capital} + Cost_{O\&M} + Cost_{energy}}$$

Equation 3: Total transportation cost (Mohammad, Farzad, Ali, & Yuri, 2019).

The capital cost for the pipeline comprised the costs associated with the pipe itself and the booster stations. Compute the capital cost using Equation 4.

$$\mathbf{Cost_{capital} = Cost_{pipe} + Cost_{booster}}$$

Equation 4: Pipeline Capital Cost (Mohammad, Farzad, Ali, & Yuri, 2019).

The cost of the pipe is contingent on factors such as its diameter, length, wall thickness, and the materials used. The pipeline material cost was computed using Equation 5.

$$\mathbf{Cost_{pipe} = \frac{1.025\pi\rho_p L\{(D + t_p)^2 - (D)^2\}}{4}}$$

Equation 5: Pipeline material cost (Mohammad, Farzad, Ali, & Yuri, 2019).

Where, ρ_p in kg/m^3 is the density of the pipeline

t_p = in meter is the wall thickness of the pipeline $= \frac{P_{max}\, D}{2SFE}$

P_{max} = the maximum operational pressure (e.g., 15MPa)

S = the minimum yield stress (e.g. 483 MPa)

F = the design factor (e.g. 0.72)

E = the longitudinal joint factor (e.g. 1.0)

The booster cost depends on the pump capacity and terrain. The cost of the booster station is given by Equation 6.

$$\mathbf{Cost_{booster} = F_L \; x \; (7.82W_p + 0.46) \; x \; 10^6}$$

Equation 6: Cost of the booster station (Mohammad, Farzad, Ali, & Yuri, 2019).

Where, W_p in (MW) is the pump capacity $= \frac{\dot{m}}{\rho} \frac{(P_{out} - P_{in})}{\eta_{booster}}$

$\dot{m}$ = the mass flow rate in kg/s

ρ = the density of the pumping fluid in kg/m^3

P_{out} = Pump output pressure in MPa.

P_{in} = Pump inlet pressure in MPa.

F_L = Geographic location factor

The flow rates of CO_2 transportation have a significant correlation with the cost of the pipeline. The indicative costs of pipelines influenced by CO_2 flow rate are shown in Figure 5 (Dziejarski, Krzyżyńska, & Andersson, 2023).

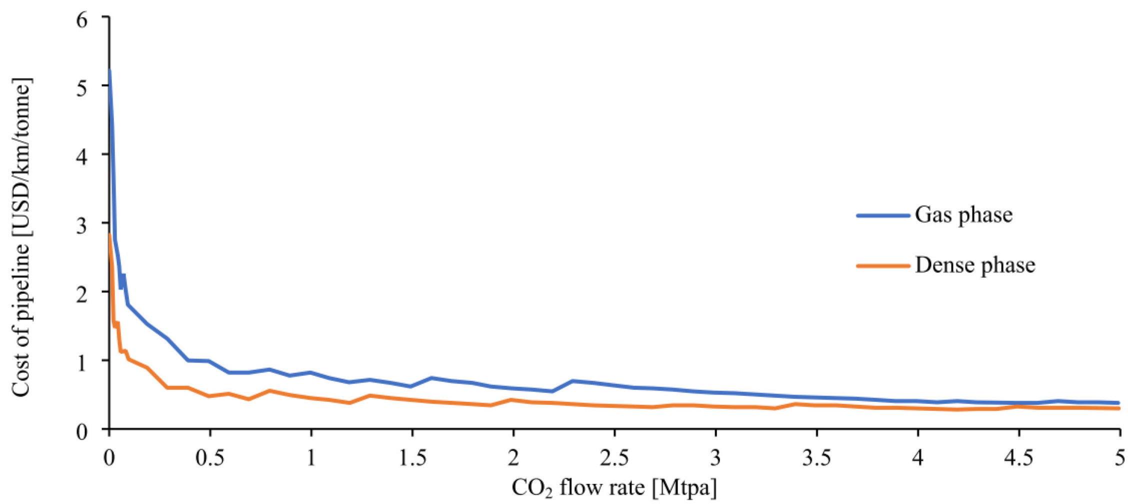

Figure 5: Impact of CO_2 flow rate on cost (Dziejarski, Krzyżyńska, & Andersson, 2023).

Overall, the chart in Figure 6 shows the linear relationship between compression power and flow rate.

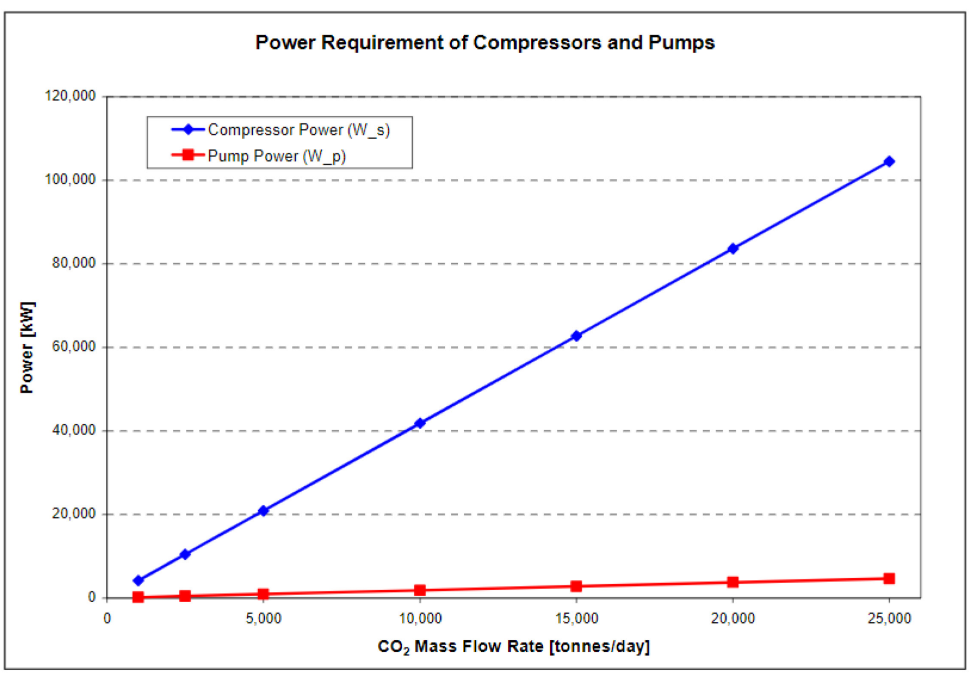

Figure 6: Power Requirement of Pumps and Compressors (Dziejarski, Krzyżyńska, & Andersson, 2023).

The operation and maintenance cost of the pipeline includes expenses for operating and maintaining both the pipeline itself and its pump stations. The calculation was performed using Equation 7.

$$\mathbf{Cost_{O\&M} = O\&M_{pipe} + O\&M_{pump}}$$

Equation 7: Total Operation and maintenance cost (McCollum & Ogden, 2006).

The annual operation and maintenance cost of the pipeline $O\&M_{pipe}$ was computed using Equation 8

$$\mathbf{O\&M_{pipe} = 1.6407 \text{ x } 10^6 D + 1.7342L - 2.6010 \text{ x } 10^5}$$

Equation 8: Operation and maintenance cost of the pipeline (McCollum & Ogden, 2006).

Where D (meters) is the internal diameter of the pipeline and L (km) is the length of the pipeline.

The annual operation and maintenance cost of the pump $O\&M_{pump}$ was computed using Equation 9.

$$\mathbf{O\&M_{pump} = -176.864 W_p{}^2 + 671.665 W_p + 159.292}$$

Equation 9: Operation and maintenance cost of the pump (McCollum & Ogden, 2006).

Where W_p (MW) represents the pump power.

The energy consumption cost is due to the booster pumps on each booster station which was calculated using Equation 10.

$$\mathbf{Cost_{energy} = COE \text{ x } \{\sum_{i=1}^{N} (W_p \text{ x } CF_i) \text{ x } 8760}$$

Equation 10: Energy consumption cost (McCollum & Ogden, 2006).

Where N is the number of active pumps.

CF is the capacity factor of the pump (e.g. 0.8)

COE is the electricity price (e.g. \$/(MWh))

The capacity factor CF of a power plant is the ratio of the actual megawatt-hours (MWh) generated to the maximum potential MWh that could be generated, usually measured over the course of a year (Ferrari, 2021). For planning purposes, utility planners typically assume capacity factors for different technology types based on experience, which is derived from the interaction of loads, net loads, and supply over a given period (Ferrari, 2021).

Overall, the goal was to analyze the total cost of pipeline transportation CO_2 from its source to the destination. To ensure efficiency in long-distance pipeline transportation, booster stations are necessary along the pipeline route to maintain the required pressure of CO_2 in a supercritical liquid state.

The operation and maintenance costs for fleet transportation are determined based on a survey of freight trucking logistics, the average fuel consumption of the fleet, and its historical trend of fuel efficiency (ATRI, 2022).

2.5 Carbon Dioxide Utilization for Methanol and Urea Production

In December 2020, Canada introduced its Hydrogen Strategy, a plan to position the country as a global supplier of green hydrogen and associated technologies for a net-zero future (Canada, 2022). In March 2021, Canada and Germany signed an energy memorandum of understanding and joint declaration of intent on establishing a Canadian-German Hydrogen Alliance to facilitate the export of hydrogen from Canada to Germany beginning in 2025 (NRCan, 2022). Nova Scotia plans to become a major player in the global hydrogen market (Global Affairs Canada, 2023) by producing green hydrogen and green ammonia using renewable electricity (EverWind, 2023). One way to add value to the green hydrogen to be produced in Nova Scotia is through the creation of two distinct output streams: the conversion of green hydrogen into methanol, and the other stream used to produce urea.

First, value can be added to green hydrogen in the province by utilizing it to produce methanol, which can serve as a precursor for various other product streams. Sustainable methanol or renewable methanol synthesis is a process where a chemical compound can be synthesized from green hydrogen H_2 and green carbon dioxide also known as biogenic CO_2 (Michael, 2019; IRENA, 2021). Methanol produced from renewable sources and biogenic CO_2 is called green methanol (Mærsk, 2024). Methanol from natural gas is known as blue methanol when carbon capture is involved, while methanol produced from coal is termed brown methanol (IRENA, 2021). This conversion process involves combining hydrogen with CO_2, resulting in the formation of methanol. Methanol is a crucial feedstock to produce several valuable products, making it a versatile and valuable intermediate chemical (Bozzano & Manenti, 2016). It can be used to manufacture plastics, adhesives, solvents, paints, pharmaceuticals, and fuels. Methanol can also be transformed into olefins, formaldehyde, and dimethyl ether DME (Jens, 2019). The production of gasoline, kerosene, and diesel from renewable methanol can be achieved via methanol-to-olefins MTO using Mobil's Olefins to Gasoline and Distillate MOGD syntheses technology (Ruokonen, et al., 2021). Furthermore, methanol-to-jet MTJ technology is used to produce sustainable aviation fuels SAF, as an alternative to the existing Fischer-Tropsch process (ExxonMobil, 2022). ExxonMobil has produced synthetic jet fuel components using the MTJ technology at the pilot plant scale (ExxonMobil, 2023). The MTJ technology used to produce electrofuels (eFuels), like Honeywell UOP eFining, is available today. However, eFuels are not being produced at a commercial scale, research indicates industrial-scale production will be reached by 2030 (Honeywell, 2023). Besides eMethanol, other examples of eFuels are eDiesel, eGasoline, and eSAF (eKerosene) (Honeywell, 2023). Honeywell's Universal Oil Product (UOP) eFining is an MTJ processing technology used to transform methanol to SAF with an 88% reduction in greenhouse gas (GHG) emissions compared to conventional jet fuel (Honeywell, 2023). MTJ technology is undergoing research, and the aviation industry is striving to enable commercial flights using 100% SAF by 2030 (Honeywell, 2023). The chemical equations to produce methanol CH_3OH using green hydrogen H_2 and carbon dioxide CO_2 are shown in Equation 11.

$$\mathbf{CO_2 + H_2 \leftrightarrow CO + H_2O \qquad \Delta H300\ K = 41.2\ kJ\ per\ mol\ CO_2}$$

$$\mathbf{CO + 2H_2 \leftrightarrow CH_3OH \qquad \Delta H300\ K = -\ 90.4\ kJ\ per\ mol\ CO_2}$$

Equation 11: Methanol production (Kumar, Bhardwaj, & Choudhury, 2023).

Second, the other valuable output stream from green hydrogen is used to produce green ammonia, which can be used as a precursor for fertilizer or urea (The Royal Society, 2020). Green ammonia-based fertilizers are produced from green hydrogen through Haber-Bosch synthesis, which combines hydrogen and nitrogen to produce ammonia (Ghavam, Vahdati, I., & Styring, 2021). Ammonia NH_3 is widely used in the production of fertilizers, playing a crucial role in global agriculture. The process of converting ammonia into fertilizer involves the synthesis of various nitrogen-based compounds, such as ammonium nitrate NH_4NO_3 or urea $CO(NH_2)_2$. The Haber-Bosch process is shown in Equation 12.

$$\mathbf{N_2 + 3H_2 \rightarrow 2NH_3 \quad (\Delta H = -92.4\ kJ \cdot mol^{-1})}$$

Equation 12: Ammonia production (Chemguide, 2013).

The chemical equation to produce ammonium nitrate NH_4NO_3 involves the reaction between ammonia NH_3 and nitric acid HNO_3 (James, 2017). In this reaction, one molecule of ammonia reacts with one molecule of nitric acid to form one molecule of ammonium nitrate. The balanced equation is shown in Equation 13.

$$\mathbf{NH_3 + HNO_3 \rightarrow NH_4NO_3 \quad (\Delta H = -112.3\ kJ \cdot mol^{-1})}$$

Equation 13: Ammonium nitrate (James, 2017).

The chemical equation to produce urea $CO(NH_2)_2$ involves the reaction between ammonia NH_3 and carbon dioxide CO_2 in the presence of a catalyst (Ding, et al., 2023). In this reaction, two molecules of ammonia react with one molecule of carbon dioxide to form one molecule of urea and one molecule of water. The balanced equation for urea is shown in Equation 14.

$2NH_3 + CO_2 \rightarrow CO(NH_2)_2 + H_2O$ ($\Delta H = -133.6$ kJ·mol^{-1})

Equation 14: Urea production (James, 2017).

Overall, the chemical equations above will be used to determine the quantity of green methanol and urea that will be produced from a given quantity of green hydrogen, green ammonia, and carbon dioxide. For example, the quantity of methanol could be determined using the stoichiometric coefficients of the balanced chemical equation as shown in Equation 11 (Leonzio, Zondervan, & Foscolo, 2019). Next, find the molar masses of the reactants, and convert the masses to moles (Halpern, 2024). Identify the limiting reactant by comparing the mole ratios from the balanced equation (Libretexts, nd). Use the amount of the limiting reactant to calculate the moles of methanol produced, and then convert these moles to mass using the molar mass of methanol.

2.6 Integrated Environmental Control Model IECM

The integrated environmental control model (IECM) is a software tool used for the simulation and analysis of the cost and performance of various power plant types and emission control systems (IECM, 2021). The latest version of IECM software (V.11.5) enables users to simulate different technology options for carbon capture including pulverized coal plants, integrated gasification combined cycle (IGCC) with GE and Shell technologies, and natural gas combined cycle (NGCC) (IECM, 2021). The current version of the IECM does not explicitly support biomass, however, the custom coal could be used to create biomass specifications and simulated as a biomass plant (IECM, 2021).

A study presented a techno-economic analysis of carbon capture systems in pulverized coal-fired power plants using the Integrated Environmental Control Model IECM (Borgert & Rubin, 2017). The study used the IECM software to conduct case studies comparing the overall performance and cost of electricity generation between oxy-combustion and amine-based post-combustion processes for capturing and sequestering 90% of flue gas CO_2 from various US coals. The result of this study showed that the oxy-combustion carbon capture was not cost-effective (Borgert & Rubin, 2017). Oxy-combustion is not cost-competitive for the New Source Performance Standard (NSPS) in the U.S. because the required CO_2 capture levels are much lower than what current oxy-combustion technology can achieve. Meeting these strict standards would require significant additional investment, making it economically unfeasible. However, if alternative policies, like a CO_2 emissions tax, were implemented, they could make oxy-combustion more attractive by providing financial incentives for higher levels of CO_2 capture.

A systematic evaluation of the performance and cost of two-stage polymeric membrane systems for CO_2 capture at coal-fired power plants was done using IECM software (Zhai & Rubin, 2012). The analyses showed that multi-stage membrane systems for CO_2 capture can achieve 90% CO_2 capture and 95%

purity with a two-stage membrane system. However, the cost of electricity generation nearly doubles, and the energy penalty can reach up to 30% of the plant's gross electrical output. Additionally, improving membrane properties could further lower capture costs and enhance the practicality of membrane technology (Zhai & Rubin, 2012).

A study analyzed the role of carbon capture and storage projects in the energy sector using IECM (Echevarria & Lourenco, 2015). The research explored the potential for advancement in carbon capture, utilization, and storage in fossil fuel power plants, highlighting its role in reducing future carbon emissions as part of the global effort to combat climate change. This paper reviewed CO_2 separation methods and their advantages and challenges, focusing on large-scale integrated projects (Echevarria & Lourenco, 2015).

In IECM software (IECM, 2021), a reference plant is referred to plant that does not employ CO_2 capture technology and emits a certain amount of CO_2 into the atmosphere for each kilowatt hour of electricity generated. The cost of electricity COE for the reference plant is also determined using the IECM framework by dividing the total annualized plant cost by the net electricity produced each year. In contrast, for a power plant retrofitted with CO_2 capture technology, the term CO_2 emitted refers to the amount of carbon dioxide released into the atmosphere per kilowatt-hour of electricity produced. Meanwhile, CO_2 captured refers to the quantity of carbon dioxide captured per kilowatt-hour generated. The net plant efficiency can be calculated using the net electrical output and the total plant input. The formula for net plant efficiency based on the Higher Heating Value (HHV) is shown in Equation 15.

$$\textbf{Net Plant Efficeincy (HHV) \%} = \frac{\textbf{Net Electrical Output}}{\textbf{Total Energy Input}} \; \boldsymbol{x}\,\mathbf{100}$$

Equation 15: Net Plant Efficiency (IECM, 2021).

The costs of CO_2 captured and avoided are shown in Equation 16 and Equation 17, which are used to measure the economic impact of CO_2 control systems in power plants or industrial facilities (IECM, 2021). The cost per tonne of CO_2 captured is the expense of capturing and removing one tonne of CO_2 from the flue gas or emissions stream. It accounts for the cost of the capture technology, including equipment, operation, and maintenance. Meanwhile, the cost per tonne of CO_2 avoided measures the cost of emissions that are not released into the atmosphere due to the installation of a CO_2 capture system. Unlike the cost per tonne of CO_2 captured, this considers the reduction in net CO_2 emissions relative to the electricity produced (IECM, 2021). When the costs associated with CO_2 transport and storage are excluded, this is referred to as the cost of CO_2 avoided excluding transport and storage (T&S).

$$\textbf{Cost of CO}_2\textbf{ Captured} = \frac{\textbf{Cost of Electricity Excluding T\&S}_{\textbf{cap}} - \textbf{Cost of Electricity}_{\textbf{ref}}}{\textbf{CO}_2\textbf{ Emissions}_{\textbf{cap}}}$$

Equation 16: Cost of CO_2 captured (IECM, 2021).

$$\textbf{Cost of CO}_2\textbf{ Avoided} = \frac{\textbf{Cost of Electricity}_{\textbf{cap}} - \textbf{Cost of Electricity}_{\textbf{ref}}}{\textbf{CO}_2\textbf{ Emissions}_{\textbf{ref}} - \textbf{CO}_2\textbf{ Emissions}_{\textbf{cap}}}$$

Equation 17: Cost of CO_2 avoided (IECM, 2021).

Where: ref = reference plant

cap = plant with carbon capture.

Overall, the literature review covered several key aspects of CCUS such as carbon dioxide point source emitters, CO_2 capture technology, storage, transportation, utilization, and IECM simulation software used. The review started with the identification of various carbon dioxide point emitters, such as industrial facilities and power plants, and the technologies used to capture CO_2 from these sources. It then discussed on-site storage options for captured CO_2 and explored the methods for transporting CO_2 utilization plants, such as pipelines, trucks, ships, and rail. Additionally, the review highlighted the utilization of captured CO_2 for producing valuable chemicals like methanol and urea. Finally, it described the Integrated Environmental Control Model (IECM), a software tool for evaluating the techno-economic performance of carbon capture. The next chapter, Chapter 3, will discuss the methods used in this thesis.

3 Methods

This research examines the technical and economic aspects of capturing and transporting carbon dioxide for industrial use. The study is divided into the stages of the CCS value chain to analyze the costs involved: capturing, storing, and transporting carbon dioxide. The following steps are undertaken to achieve the objectives.

First, obtain datasets that provide information on point source carbon emitters from power generating plants. Key data required for the analysis include the quantity of CO_2 emissions per point source, emission trends over time, and geographical location of the power plant. Once the data is collected, group the point source emitters based on the quantity of CO_2 emission.

Second, explore methods of retrofitting the point emitters with post-combustion capture equipment using the Integrated Environmental Control Model (IECM). This research evaluates post-combustion CO_2 capture technologies to assess their efficiencies and cost-effectiveness without interrupting the upstream processes of the base plant.

Third, evaluate the cost of possible storage of CO_2 at the source plant using an on-site storage tank. This involves the calculation of tank capacity and associated costs with CO_2 storage tanks.

Lastly, evaluate various carbon transportation methods and determine the distance from emission sources to industrial plants using, for example, Google interactive maps, aiming to identify the most cost-effective option.

3.1 Carbon Dioxide Sources

This section examines gathering, structuring, and analyzing data regarding emissions from various facilities. It includes the type of fuel-generating emissions, the volume of emissions measured hourly, daily, weekly, monthly, or yearly, and their geographic distribution. The following procedures are employed to accomplish this objective.

First, obtain the point source emission dataset and filter relevant information such as facility name, geographic locations, and annual CO_2 emissions for at least five years. This helps to select only the emission data from any given location needed for the analysis.

Second, calculate total emissions from each facility over specified years using Equation 18.

$$\textbf{Total Emissions} = \sum_{i}^{j} (\mathbf{e_{ij}})$$

Equation 18: Total emissions from each facility.

Where, e_{ij} represents the emission datasets to the time interval from the i-th year to the j-th year.

Third, calculate the average emissions over an n-year period using Equation 19.

$$\textbf{Average Carbon Emissions}_{\mathbf{ij}} = \frac{\sum_{i}^{j} (\mathbf{e_{ij}})}{\mathbf{n}}$$

Equation 19: Average emissions.

Fourth, calculate the average annual energy production of each power plant over an n-year period using Equation 20.

$$\textbf{Average Annual Energy Output} = \frac{\sum_{i}^{j} (\mathbf{E_{ij}})}{\mathbf{n}}$$

Equation 20: **Annual energy output.**

Where, E_{ij} represents the actual energy production of each power plant from year i to year j.

Fifth, calculate the emission intensity using Equation 21.

$$\textbf{Emission Intensity} = \frac{\textbf{Average Annual Emissions}}{\textbf{Average Annual Energy Production}}$$

Equation 21: Emission Intensity of the plants (Tim, Pershing, & Baumert, 2005).

Lastly, group and tabulate the emissions from each identified facility. The facilities are classified into distinct sizes based on the average CO_2 emissions for the years 2018 to 2022 shown in Table 7.

Table 7: Facility Categories (ECCC, 2023).

Facility Type	Minimum Annual Emissions	Maximum Annual Emissions
Very Small	≤1Kt	<25Kt
Small	≤ 25Kt	< 100Kt
Medium	≤ 100Kt	< 1.2Mt
Large	≥ 1.2Mt	-

3.2 Cost of capturing the CO_2 at the source

The blueprint on how to retrofit an existing plant with new carbon capture technology using the Integrated Environmental Control Model (IECM) is shown below (IECM, 2021).

First, using the IECM interface version 11.5, create a new session, select the type of power plant to be retrofitted, and name the plant, as shown in Figure 7.

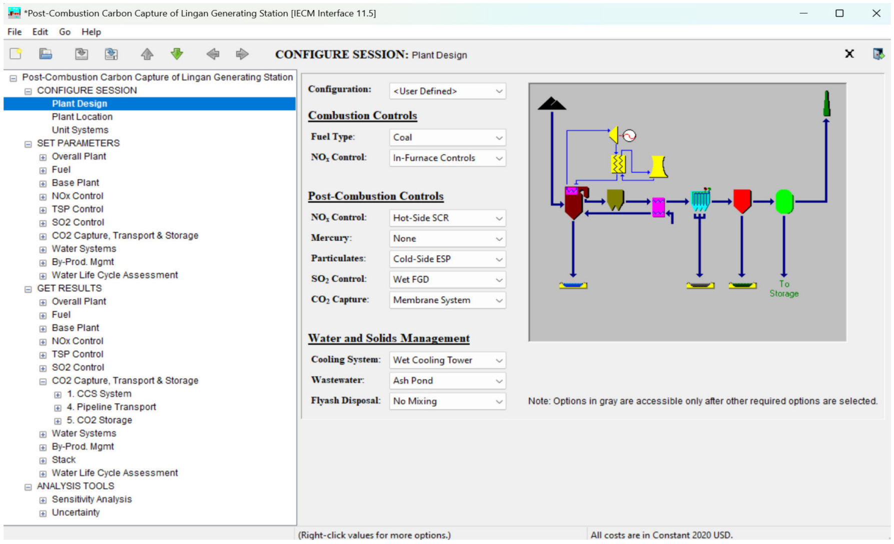

Figure 7: Post-combustion carbon capture at Lingan generating station IECM Version 11.5 (IECM, 2021)

Second, configure the base plant by choosing the fuel type, plant location, and unit systems. Add post-combustion control systems such as NOx control, particulate collector, SO_2 control, CO_2 capture system, and the type of water and solid management systems.

Third, set the system parameters by adjusting the input parameter values of the base plant for each case study: such as gross power (MW), estimated lifespan (Yrs.), capacity factor (%), thermal efficiency (%), capture rate (%) emission limits, and financial structure ($). The technical specifications and characteristics of an assumed model scenario are shown in Table 8 and Appendix A.

Table 8: IECM Set Parameters for a Post-Combustion Carbon Capture Plant (IECM, 2021; NSPI, 2019).

Activity	Set Parameter
Fuel	Coal
Base Plant Capacity	620MW
Type of Power Plant	Pulverized coal power plant
Capacity Factor	85%
Thermal Efficiency	40%
Type of Capture System	Amine
Capture Efficiency	95%
Project Lifespan	20 years

Fourth, use the IECM software to perform technical and economic analyses of three case studies notably biomass, natural gas, and coal-fired plants respectively. Simulate different capture technologies and boiler types in each case study to determine the net plant efficiency, quantity of CO_2 captured and emitted, and cost of CO_2 captured and avoided.

Fifth, calculate the quantity captured by multiplying the total energy produced (kilowatt-hours) by the CO_2 captured per kilowatt-hour.

Sixth, calculate the current cost by comparing cost over time using the consumer price index CPI (BOC, nd). The new cost will account for the inflation that has occurred over the years. Use Equation 22 to compute the current cost. Convert the total CCS costs from US$ to C$ using a currency converter (Xe, 2024).

$$\mathbf{Cost_2 = Cost_1 \ x \ \frac{CPI_2}{CPI_1}}$$

Equation 22: Compute the current cost (BOC, nd).

Lastly, tabulate the results of the simulations for each case study. Analyze the plant performance by interpreting the efficiency, costs, and quantity of CO_2 captured. Discuss the impact of the retrofit on net power output, plant efficiency, and overall costs.

3.3 On-site CO_2 Storage

The construction of a CO_2 tank onsite is necessary for temporary storage, especially when there is a mismatch between the quantity of CO_2 captured and the quantity in demand (IPCC, 2006). The following procedures are followed to conduct a techno-economic evaluation of on-site CO_2 storage.

First, using the quantity of CO_2 captured in the IECM simulation results, determine the mass of CO_2 captured from each case study of carbon-capturing systems. Assume a day on-site storage capacity to handle at least 24 hours of mismatch between the production and demand. The onsite storage capacity should be sized to minimize operational impacts, with space allocated for future expansion.

Second, use the captured mass of CO_2 and a density of approximately 1077 kg/m³ to calculate the volume of each tank (Engineeringtoolbox, 2018). The density of CO_2 in liquid form will reduce the volume of CO_2, reducing the number of on-site storage tanks required (TechieScience, 2024).

Third, calculate the volume of the tank using Equation 23. Select a double-wall cryogenic LCO_2 tank made of vacuum powder insulation, designed to withstand temperatures of about -50°C, a 95% filling rate, a pressure range of 0.2-3.0MPa, and a maximum volume of 200m^3 (Jianshentank, 2019). Use a diameter of 3100mm, length of 26500mm, and thickness of 24mm.

$$\textbf{Density}\ (\boldsymbol{\rho}) = \frac{\textbf{Mass}\ (\textbf{m})}{\textbf{Volume}\ (\textbf{v})}$$

Equation 23: Relationship between density, mass, and volume of fluid (Das, Das, Saidulu, & Dhakane, 2017).

Where:

ρ = density of fluid (kg/m^3)

m = mass of fluid (kg)

v = volume of fluid (m^3)

The relationship between the volume, diameter, and length of a cylindrical tank is shown in Equation 24.

$$\mathbf{V} = (\boldsymbol{\pi}\ \mathbf{x}\ \boldsymbol{d}^{2}\ \mathbf{x}\ \boldsymbol{l})/\mathbf{4}$$

Equation 24: Relationship between the volume, diameter, and length of a cylindrical tank (Sexton J., nd).

Where:

V (cubic meters or liters) = tank volume

d (meters) = tank diameter

l (meters) = length of the horizontal tank.

Lastly, calculate the construction costs of each tank based on a rate of $150,000 per 200 m^3 tank (Startech, 2024).

3.4 Carbon Transportation Methods

In this study, three transport modes will be considered: pipeline, ship, and tank trucks (ASCO, 2021). The Costs will be determined based on the quantity of captured CO_2, distance, and geographical locations (Myers, Li, & Markham, 2024). The following methods were adopted:

First, measure the distance between the emission point and the utilization plant using geographic measurement systems.

Second, calculate the total cost of the pipeline transport infrastructure, accounting for factors such as distance, terrain, pipeline materials, labor, and regional cost variations.

Third, calculate the costs of fleet transportation such as fuel costs, truck purchase or lease costs, repair and maintenance, insurance premiums, permits and licenses, tire and toll expenses, as well as driver wages and benefits

3.5 Carbon Dioxide Utilization

To determine the quantity of CO_2 required to produce methanol and urea for a given amount of green hydrogen and ammonia the following steps are taken.

First, determine the quantity of methanol that could be produced from the given hydrogen using the stoichiometric coefficients of a balanced chemical equation. Then, calculate the quantity of carbon dioxide required for this methanol production. Calculate the amount of SAF that would be produced from the methanol.

Second, determine the quantity of urea that could be produced from the given ammonia using the stoichiometric coefficients of a balanced chemical equation. Then, calculate the quantity of carbon dioxide required for this urea production.

Lastly, show whether the volume of CO_2 available from each site is adequate for the given quantity of hydrogen and ammonia.

3.6 Summary

The methods are structured around the main stages of the CCS value chain: capturing, storing, and transporting CO_2. First, carbon emissions from the Greenhouse Gas Reporting Program (GHGRP) database are analyzed to assess emissions from three facilities. Second, the IECM software would be used to retrofit base plants with post-combustion capture units to determine the estimated CO_2 that could be produced from the facilities. The capture technologies are evaluated for efficiency and cost-effectiveness. Third, the study conducts a cost assessment for on-site storage of CO_2, including procurement logistics, installation, maintenance, and safety measures. Fourth, various transportation methods are evaluated to identify the most cost-effective option, considering factors such as pressure, pipe diameter, and construction route. Lastly, the quantity of CO_2 required to produce methanol and urea for a given amount of green hydrogen and ammonia was determined.

4 Case Study - Nova Scotia

In this chapter, the methods outlined in Chapter 3 are applied to analyze the technical and economic possibility of capturing, storing, and transporting carbon dioxide for industrial applications in Nova Scotia. The findings of the case study across the various stages of the CCS value chain are discussed to ascertain the cost-effectiveness of these processes within the province. Three case studies namely Port Hawkesbury Cogeneration Power Plant, Tufts Cove Generating Station, and Lingan Generating Station were chosen for this analysis. These power plants covered the three energy sources of interest: biomass, natural gas, and coal.

4.1 Point source emissions

The availability of carbon dioxide is categorized into actual and estimated sources based on data origins. Emissions reported by the Canadian Greenhouse Gas Reporting Program (GHGRP) are considered the actual point sources of CO_2. In contrast, CO_2 availability derived from the integrated environmental control model (IECM) is regarded as an estimated source. This distinction ensures clarity in data analysis, with actual sources reflecting verified emissions and estimated sources providing modeled future projections for the potential scaling of quantities.

4.1.1 The actual point source emissions

The actual point sources of carbon dioxide were identified in Nova Scotia using the GHGRP dataset. Table 9 shows emission categories, facility names, energy sources, power capacities, and annual emissions from 2018 to 2022 (ECCC, 2024). The emission dataset of the three selected facilities over five years shows distinct trends based on energy source and plant capacity. This selection allows us to study emission trends across fuel types such as biomass, natural gas, and coal. The selected plants represent a range of energy sources with varying carbon footprints and technological characteristics, allowing for a comprehensive analysis. For example, the Port Hawkesbury biomass facility displays relatively low but increasing emissions, suggesting variability in usage or the need to increase output due to the phaseout of coal. In 2022, all the coal-fired plants show significant emission reductions due to policy shifts to reduce coal use and shifts towards less emissions-intensive energy practices.

Table 9: Examples of carbon dioxide point emitters in Nova Scotia (ECCC, 2024; NSPI, 2023)

Facility Emission Size	Name of Facility	Energy Source	Capacity (MW)	Annual Emissions ($ktCO_2$)				
				2018	2019	2020	2021	2022
Small	Port Hawkesbury Biomass Cogeneration Power Plant	Biomass	60	29.21	26.72	38.51	39.82	40.19
Medium	Tufts Cove Generating Station	Nat Gas	500	879.13	775.75	1022.93	994.24	1065.43
Large	Lingan Generating Station	Coal	620	2385.32	2497.67	2464.93	2636.78	2111.50

Table 10 shows emissions data from the three selected energy facilities in Nova Scotia over five years, calculating the average annual emissions and emission intensity using trend emission data (ECCC, 2024; NSPI, 2019; CEEDC, 2024; Emera Incorporated, 2023). The average annual energy output (GWh) was calculated based on NS Power's annual production volumes from 2020 and 2022 (Emera Incorporated, 2023). Port Hawkesbury biomass cogeneration power plant demonstrates a very low emission intensity, indicative of efficient biomass utilization, lower carbon fuel source, or possibly optimized cogeneration process, which makes better use of the fuel input by producing both electricity and useful heat. The Lingan coal-fired power station emits significantly more CO_2 than other types of power stations. However, employing CO_2 capture technologies can reduce its CO_2 emission intensity. Emission intensity is essential for assessing the efficiency of power plants, enabling comparisons between different energy sources and technologies, and identifying areas for efficiency improvements (Chen, Seiner, Suzuki, & Lackner, 2017).

Table 10: Facility Annual Emissions (ECCC, 2024; NSPI, 2019; CEEDC, 2024; Emera Incorporated, 2023).

Facility Size	Name of Facility	Installed Capacity (MW)	Average Annual Emission ($ktCO_2$/yr)	Average Annual Energy Output (GWh)	Emission Intensity ($ktCO_2$/GWh)
Small	Port Hawkesbury Biomass Cogeneration Power Plant	60	34.89	131	0.26
Medium	Tufts Cove Natural Gas Generating Station	500	947.50	1,732	0.55
Large	Lingan Coal Generating Station	620	2,419.24	2,102	1.15
Totals for selected sites		1,180	3,401.62	3,965	0.86

4.1.2 The estimated point source emissions

The point sources of carbon dioxide were estimated using IECM simulation. This section provides an overview of the set parameters and assumptions used to generate the results shown in Appendix A.

The IECM set parameters include plant name, location, base plant capacity, fuel type, carbon capture technology, boiler technology, capture efficiency and capacity factor. The IECM output parameters include base plant net electricity output, net plant efficiency, CO_2 captured, CO_2 emitted, cost of CO_2 captured, and cost of CO_2 avoided. The costs used in the IECM model are given in constant year 2020 US dollars.

To assess the techno-economic feasibility of carbon capture and utilization in Nova Scotia, this analysis employs the IECM to simulate three distinct case studies: a biomass power plant, a natural gas power plant, and a coal power plant. These case studies were selected to represent various fuel types and technologies prevalent in NS Power electricity generation, each with unique challenges. While the current version of the IECM does not have biomass fuel specifications, a custom coal module was used to create biomass fuel specifications (IECM, 2021). The biomass plant's performance was simulated by using the fuel specifications of a grade A2 wood chip (NRCan, 2017). Grade A2 is chipped and delivered to the plant, like the wood biomass fuel used by Nova Scotia Power. The biomass fuel could be sourced from stem wood and residues from milling and logging operations (NRCan, 2017)**,** which might be easier to obtain and the possibility of their use for generating electricity (Pokharel, et al., 2019).

Section 4.2 will detail each case study simulated, showing the CO_2 captured, CO_2 emitted, cost of CO_2 captured, and cost of CO_2 avoided. The IECM software uses financial assumptions of a constant dollar rate of 2020 USD per tonne.

4.2 Cost of capturing the CO_2 at the source

After the federal regulation to phase out coal for electricity generation, Nova Scotia Power has committed to phasing out coal usage which supplies about 35% of the province's electrical demand, reducing its emissions below 4.5 megatonnes and achieving 80% of renewable energy by 2030 (Hughes, 2024). Instead of shutting down coal-fired plants, retrofitting them with carbon capture technology can be a viable option to reduce emissions and carbon taxes. This approach will extend the life of these plants (IEA, 2012), providing Nova Scotia Power Incorporated (NSPI) adequate time to achieve the province's clean power plan. More so, there is potential for reducing emissions by retrofitting biomass and natural gas plants with carbon capture technology.

Therefore, the IECM modeling tool was utilized with set parameters highlighted in Appendix A and B to simulate the performance and cost of capturing CO_2 for possible utilization as feedstock. To obtain the results of possible CO_2 available, Nova Scotia Power's average annual energy generation from 2020 to 2022 was used, as shown Table 10 (Emera Incorporated, 2023). In the IECM software interface, a capacity factor of 85% was used for biomass, in line with Nova Scotia Power's biomass capacity factor

(NSPI, 2019). The emission intensity results of each plant were used as the input parameter for the reference plant in the IECM simulation. The annual CO_2 captured ($ktCO_2/yr$) was calculated by multiplying the annual average energy output (kWh) by the results of CO_2 captured (kg/kWh) using IECM software. IECM-simulated CO_2 capture rate (kg/kWh).

The three case studies were analyzed using the IECM software to show the quantity of CO_2 available from those sources as possible industrial feedstock in the province.

4.2.1 Case Study 1: Techno-Economic Analysis of Biomass Power Plant

Case study 1 simulates the Port Hawkesbury biomass plant retrofitted with carbon capture equipment using the IECM software. Grade A2 wood chip fuel specifications were used in the simulation (NRCan, 2017). The base plant's emission intensity of 0.26 $ktCO_2$/GWh and biomass levelized cost of energy LCOE of biomass (2019 CAD $140/MWh) was used for the simulation (NSPI, 2019). The LCOE for biomass remains stable from 2020 to 2040 due to the slow reductions in capital costs.

The simulation analyzed three different carbon capture systems (amine, solid sorbent, and membrane) with a subcritical boiler type. The result showed that the membrane system had the lowest cost of CO_2 captured followed by the amine system, while the solid sorbent had the highest cost of capture. To analyze the potential performance of the existing plant if more advanced boilers were used, the base plant's subcritical boiler was repowered with more advanced boilers, such as supercritical and ultra-supercritical boilers. The advanced boiler types, although cost-prohibitive, had improved efficiency across all systems, with the membrane system emerging as the most efficient option. Considering the cost-effectiveness and efficiency of CO_2 captured, the subcritical boiler emerges as the optimal solution for various CO_2 capturing system performances.

Overall, the biogenic CO_2 with carbon capture from the Port Hawkesbury biomass plant is expected to be a cost-effective source relative to other sources. However, the plant's limited capacity makes it more expensive to produce CO_2 compared to larger facilities, which could benefit from economies of scale. The results of the techno-economic analysis of the Port Hawkesbury biomass plant are shown in Table 11.

Table 11: Techno-Economic Analysis of Biomass Power Plant (60MW).

CO_2 Capture System	Amine			Solid Sorbent TSA			Membrane		
Boiler Type	**Subcritical**	**Super Critical**	**Ultra-Super Critical**	**Subcritical**	**Super Critical**	**Ultra-Super Critical**	**Subcritical**	**Super Critical**	**Ultra-Super Critical**
Average Annual Energy Output (GWh)	131	131	131	131	131	131	131	131	131
Net Electricity Output (MW)	53.79	54.29	54.79	52.92	53.57	54.19	53.60	53.98	54.49
Electricity used for capture (MW)	3.86	3.44	3.12	2.34	2.14	1.91	2.46	2.31	2.11
Net Plant Efficiency HHV (%)	31%	34%	38%	26%	28%	32%	33%	36%	39%
CO_2 Captured (kg/kWh)	0.28	0.26	0.24	0.35	0.32	0.28	0.27	0.25	0.28
CO_2 Captured ($ktCO_2$/yr)	36.68	34.06	31.44	45.85	41.92	36.68	35.37	32.75	36.68
CO_2 Emitted (kg/kWh)	0.03	0.02	0.02	0.04	0.04	0.03	0.03	0.03	0.02
CO_2 Emitted ($ktCO_2$/yr)	3.93	2.62	2.62	5.24	5.24	3.93	3.93	3.93	2.62
Cost of CO_2 Captured (US$/$tCO_2$)	$198.4	$243.8	$284.0	$461.5	$512.4	$562.5	$159.0	$209.1	$251.5
Cost of CO_2 Avoided Excl T&S (US$/$tCO_2$)	$250.7	$283.6	$292.9	$789.0	$779.6	$740.8	$231.3	$272.5	$287.8

4.2.2 Case Study 2: Techno-Economic Analysis of Natural Gas Power Plant

In the second case, the Tufts Cove natural gas generating station is retrofitted with carbon capture and simulated using the IECM software. The base plant's emission intensity of 0.55 $ktCO_2/GWh$ was used for the simulation. All currencies are in USD.

The analysis includes CO_2 capture systems such as FG+ amine, MEA, CANSOLV, and ammonia. These systems are specifically designed to work with the flue gas characteristics of natural gas-fired power plants, which typically have lower CO_2 concentrations compared to coal-fired plants. The selected systems are designed to handle flue gas with higher particulates and SOx, maximizing CO_2 capture while minimizing energy penalties.

The study demonstrated that the FG+ amine system is the most efficient and cost-effective option, offering the highest net plant efficiency of 44% and the lowest costs for CO_2 capture of about \$72/tCO_2 and avoidance cost of about \$59/tCO_2. The MEA and CANSOLV systems provided moderate efficiency and higher costs. The MEA system has a moderate efficiency of 42% and relatively higher costs for CO_2 capture at \$87/tCO_2 and for CO_2 avoidance at \$73/tCO_2. It is less efficient and more costly than FG+ amine but still viable compared to CANSOLV and ammonia. The analysis of CO_2 emissions across different CO_2 capture systems showed that the amine FG+ system is the most efficient, with the lowest cost of CO_2 avoided. The ammonia system, however, recorded the highest emissions at 0.05 kg/kWh, making it the least efficient of the systems analyzed. The ammonia system, despite capturing the most CO_2 per kWh, was the least efficient of other systems and had the highest costs at \$121/tCO_2 for capture and \$107/tCO_2 for avoidance, making it the least favorable option. Overall, FG+ amine stands out as the optimal choice for CO_2 capture in terms of both efficiency and cost. The results of the technical and economic evaluations of the Tufts Cove natural gas generating station are shown in Table 12.

Table 12: Techno-Economic Analysis of Natural Gas Power Plant (500MW).

CO_2 Capture System	Amine			Ammonia
	FG+	MEA	CANSOLV	
Average Annual Energy Output (GWh)	1,732	1,732	1,732	1,732
Net Electricity Output (MW)	468	452	450	423
Electricity used for capture (MW)	23.33	37.97	40.28	66.92
Net Plant Efficiency HHV (%)	44%	42%	41%	39%
CO_2 Captured (kg/kWh)	0.38	0.39	0.39	0.42
CO_2 Captured ($ktCO_2$/yr)	658.16	675.48	675.48	727.44
CO_2 Emitted (kg/kWh)	0.04	0.04	0.04	0.05
CO_2 Emitted ($ktCO_2$/yr)	69.28	69.28	69.28	86.6
Cost of CO_2 Captured (US$/$tCO_2$)	$71.73	$86.75	$119.01	$121.30
Cost of CO_2 Avoided Excl T&S (US$/$tCO_2$)	$59.41	$73.03	$98.36	$107.02

4.2.3 Case Study 3: Techno-Economic Analysis of Coal Power Plant

The IECM software was used to simulate the Lingan coal power plant with a gross electricity output of 620 MW retrofitted with carbon capture equipment. The results in Table 13 illustrate the performance efficiency and costs of various CO_2 capture systems integrated with the coal plant. The systems evaluated include amine, solid sorbent, and membrane technologies. The study initially considered a sub-critical boiler and later expanded to include analyses of supercritical and ultra-supercritical boilers to evaluate their economic impact. Key performance indicators such as net electricity output, net plant efficiency, CO_2 captured per kWh, cost of CO_2 captured, and cost of CO_2 avoided are presented. All currencies are in USD.

The analysis indicated that the ultra-supercritical amine system provides the highest net electricity output, making it the most efficient among the systems studied. While the net plant efficiency of the amine system significantly improves, it remains lower than the highest efficiency achieved by the membrane system. In terms of CO_2 capture per kilowatt-hour, the membrane system captures the least average CO_2, but it also achieves the highest efficiency. The cost of CO_2 capture is lowest for the amine system, suggesting it might be the most economically viable compared to other options. Meanwhile, the solid sorbent system has the highest cost of CO_2 capture, indicating it may not be as cost-effective compared to the other systems. Overall, while each system has its strengths, the amine system appears to strike a balance between high electricity output, moderate efficiency, and lower CO_2 capture costs.

Table 13: Techno-Economic Analysis of Coal Power Plant (620MW)

CO_2 Capture System	Amine			Solid Sorbent TSA			Membrane		
Boiler Type	**Subcritical**	**Super Critical**	**Ultra-Super Critical**	**Subcritical**	**Super Critical**	**Ultra-Super Critical**	**Subcritical**	**Super Critical**	**Ultra-Super Critical**
Average Annual Energy Output (GWh)	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102
Net Electricity Output (MW)	508.6	518	528.1	495	507	519.2	487.6	495.2	506
Electricity used for capture (MW)	59.70	55.05	49.26	77.91	70.00	61.87	88.91	83.99	76.53
Net Plant Efficiency HHV (%)	26%	29%	33%	22%	25%	29%	31%	33%	37%
CO_2 Captured (kg/kWh)	1.11	1	0.88	1.29	1.14	0.98	0.82	0.76	0.68
CO_2 Captured ($MtCO_2$/yr)	2.33	2.10	1.85	2.71	2.40	2.06	1.72	1.60	1.43
CO_2 Emitted (kg/kWh)	0.12	0.11	0.1	0.14	0.13	0.11	0.2	0.18	0.16
CO_2 Emitted ($MtCO_2$/yr)	0.25	0.23	0.21	0.29	0.27	0.23	0.42	0.38	0.34
Cost of CO_2 Captured (US$/$tCO_2$)	$28.15	$29.44	$31.33	$72.97	$73.84	$76.24	$35.32	$38.80	$42.41
Cost of CO_2 Avoided Excl T&S (US$/$tCO_2$)	$32.99	$30.89	$28.44	$96.30	$85.01	$74.55	$32.87	$32.96	$31.37

Overall, retrofitting existing plants with CCS is technically feasible, however, the quantity that can be captured depends on the technology and capacity of the base plant. For example, the quantity of captured CO_2 from the biomass plant was lower due to the capacity of the plant. The CCS electrical load demand increases the operational and maintenance costs of the existing plant due to the additional energy required to capture and compress CO_2. For example, retrofitting any of the plants (biomass, natural gas, or coal) reduced the gross electricity output of the base plant as some energy would be required to power the CCS process. This reduction in efficiency leads to higher fuel consumption and operational costs. Advances in CCS technology could reduce capture costs and improve the energy efficiency of capture processes, making retrofits more economically viable in the future.

4.3 On-site CO_2 storage

This thesis proposed on-site CO_2 storage before transportation to ensure a reliable supply and enhance process efficiency for CO_2-dependent industries. To support this, a day storage autonomy was assumed for the on-site storage capacity. A horizontal cylindrical storage tank was chosen for on-site CO_2 storage due to its ease of operations and maintenance. A horizontal tank is easier to transport because it can be loaded onto a truck more efficiently (Anticor, 2022). More so, horizontal storage tanks are designed for more efficient cooling of liquids, ensuring that the proper temperature is maintained during storage. All currencies are in USD.

First, the mass of CO_2 captured was determined by leveraging optimal solutions from each case study in the techno-economic analysis of carbon-capturing systems, specifically detailed in Table 11, Table 12, and Table 13, respectively.

Second, the density of 1077 kg/m³ was used, which reflects the state of CO_2 as a liquid when cooled and compressed to -30 degrees Celsius at 1.5 Mpa (Engineeringtoolbox, 2018). This transformation into liquid form significantly increased its density and reduced the volume for efficient storage purposes.

Third, the volume and diameter of each storage tank are calculated using Equation 24 from Chapter 3. A double-wall cryogenic tank made of vacuum powder insulation was proposed. The proposed tank has similar specifications to the LCO_2 tank model JSAA100-L/2.16, designed for a temperature of about -30°C, a 95% filling rate, a pressure range of about 1.5 MPa, a diameter of 3100mm, a length of 26500mm, thickness of 24mm and a maximum volume of 200m³ (Jianshentank, 2019). The 95% filling rate showed the maximum safe capacity at which the tank can be filled to accommodate the adiabatic expansion of the contents and pressure changes. This helps prevent overfilling, reduces the risk of leaks or spills, and ensures safe operation under varying conditions. The maximum volume of 200m³ was chosen to facilitate easier transportation of the tank from the manufacturing facility to its installation site. The tank was designed to withstand a lower temperature of about -50°C and a higher pressure of about 3MPa to ensure safety and provide a buffer above the normal operating conditions. Under typical storage conditions, the liquid CO_2 would be maintained at -30°C and 1.5 MPa to reduce the refrigeration requirements. The design temperature and pressure margins could accommodate variations, such as unexpected cooling or pressure increases, ensuring the tank can safely store the liquid CO_2. This safety margin minimizes the risk of tank failure, ensuring reliable containment of the CO_2 across a range of possible scenarios, which also increases the storage cost.

Lastly, the engineering design, procurement, construction, inspection, testing, and supply of the 200 m^3 liquid CO_2 storage tank was about US$150,000 (Startech, 2024).

Table 14 shows that coal being the highest emitter, necessitates the largest storage infrastructure, requiring about 5937m^3 of daily storage spread across 30 tanks. In contrast, biomass and natural gas emit significantly less CO_2, with biomass requiring about 90 m^3 of one storage tank while natural gas requires 1674 m^3 across 9 tanks. The coal plant had the lowest storage cost per tonne of CO_2 captured in a year at about $1.93, due to economies of scale. The natural gas plant would have a slightly higher storage cost at about $2.05 per tonne, followed by the biomass plant, which had the highest storage cost at $2.12 per tonne.

Table 14: On-site CO_2 storage per day (All Costs in USD).

Parameters	Biomass	Natural Gas	Coal
Net Electricity Output (MW)	53.6	467	508
Annual Energy Output (GWh)	131	1732	2,102
CO_2 Captured (kg/kWh)	0.27	0.38	1.11
CO_2 Captured ($ktCO_2$/yr)	34.37	658.16	2333.22
Mass of CO_2 Captured per day ($ktCO_2$/day)	0.097	1.80	6.39
Total Volume of CO_2 Storage Tank (m^3)	90	1674	5937
Volume of each Storage Tank (m^3)	100	200	200
Number of On-Site Storage Tanks	1	9	30
Total Storage Cost of CO_2 Captured (M$)	$0.075	$1.35	$4.50
Storage Cost per tonne of CO_2 Captured per day (US$/tonne)	$773.19	$750	$704.22
Storage Cost per tonne of CO_2 Captured per yr (US$/tonne)	$2.12	$2.05	$1.93

4.4 Carbon Transportation Methods

The study evaluated three modes of carbon dioxide transportation: pipelines, ships, and tankers. Rail was not considered because of the lack of infrastructure in the province. Each mode presents unique advantages and challenges, making them suitable for different cases, depending on distance, cost, and infrastructure. Large amounts of CO_2 are typically transported over long distances via pipelines, while smaller amounts are transported over similar distances via ships. However, for shorter distances and smaller quantities, CO_2 is transported by truck (IEA, 2020). The distances from the capturing locations to the industrial plant of utilization, the EverWind plant, are measured using Google Maps. The CO_2 transportation analysis for this study is threefold.

First, the pipeline was chosen for transporting carbon dioxide from the Lingan coal-fired plant to the CO_2 utilization plant, about 155 km. The FECM/NETL CO_2 Transport Cost Model, an Excel-based tool, was utilized to estimate transportation costs (NETL, 2023). In these calculations, CO_2 was assumed to be transported in supercritical form, with one booster pump installed to maintain the required pressure. The analysis used an average annual CO_2 mass flow rate of 2.3 Mt/yr., to determine the required pipe diameter. For the financial assumptions, a base year dollar rate of 2011 USD per tonne and a 2.8% annual escalation rate (Bank of Canada, 2024) were used to calculate the capital and operating costs of the pipeline. The pipeline transportation system for the Lingan coal plant was evaluated using the equations from four cost estimators (Parker, 2004; McCoy & Rubin, 2008; Rui, Metz, Reynolds, Chen, & Zhou, 2011; Brown, Reddi, & Elgowainy, 2022). The equation from Parker gave the highest costs, which was quite a large spread compared to other estimates. The results from the Parker equation were not used for this analysis considering the year and cost margin. The average of the cost estimates from 2008 to 2022 was calculated for this analysis as shown in Table 15. Rui gave the lowest costs, and the equations from Brown et al. are based on the most recent pipeline capital cost data. Capital expenditures ranged from $59.73M to $75.44M, with an average contribution of $68.96M. Operational expenditures over 20 years ranged from $38.98M to $45.81M, averaging $42.99M. Total costs ranged from $98.71M to $121.24M, averaging $111.95M. Costs per tonne of CO_2 transported ranged from 42.92$/tonne to 52.71$/tonne. The average pipeline transportation cost was about 49 USD per tonne.

Table 15: CO_2 Pipeline Transportation Studies (All Costs in USD)

Parameters`	CASE STUDY - Lingan Coal Plant				
	Parker (2004)	**McCoy & Rubin (2008)**	**Rui et al. (2011)**	**Brown et al. (2022)**	**Average (2008 – 2022)**
Avg. Annual Energy Output (GWh)	2,102	2,102	2,102	2,102	2,102
Avg. CO_2 Mass Flow Rate (Mt/yr)	2.3	2.3	2.3	2.3	2.3
Nominal Pipe Diameter (mm)	254	254	254	254	254
CAPEX (M$)	$128.08	$71.71	$59.73	$75.44	$68.96
OPEX (M$) for 20yrs.	$68.69	$44.19	$38.98	$45.81	$42.99
Total Costs (M$)	$196.77	$115.90	$98.71	$121.24	$111.95
Total Costs per km of pipeline (M$/km)	$1.27	$0.75	$0.64	$0.78	$0.72
Total Costs per tonne ($/tonne)	$85.55	$50.39	$42.92	$52.71	$48.67

Second, considering the recommended day storage tank on site and the relatively short distance of about 2.3 kilometers between the Port Hawkesbury biomass plant and the CO_2 utilization plant, two tank trucks were used to transport the captured carbon dioxide. The specifications of the tank trucks are shown in Appendix C. Transporting smaller quantities of CO_2 over shorter distances is more cost-effective. CO_2 tanker was chosen to provide flexible and scalable solutions for transporting CO_2 which is ideal for shorter distances. Additionally, tankers offer mobility advantages and are suitable for impractical pipeline construction. However, their capacity is significantly lower than pipelines, making them less efficient for transporting large CO_2 volumes over long distances. The cost of transportation via tank truck includes capital costs for purchasing truck heads and demountable tanks, as well as operation and maintenance costs. Operation and maintenance costs for the fleet transportation are determined based on a survey of freight trucking logistics conducted by the American Transportation Research Institute, updated in June 2023 (ATRI, 2023).

The operations costs survey from 2018-2022 included components such as fuel costs, repair and maintenance, truck insurance premiums, permits and licenses, tires and tolls, driver wages, and benefits. These costs are US dollars per kilometer (US$/km) and tabulated as shown in Table 16. The average marginal costs per kilometer for trucks have fluctuated over the last five years. In 2018, the cost was $1.132 per kilometer, which slightly decreased to $1.056 in 2019 and further to $1.02 in 2020. However, in 2021, the costs rose to $1.2 per kilometer, indicating an increase in operational expenses. This upward trend continued significantly in 2022, with costs reaching $1.4 per kilometer. This substantial rise could be attributed to various factors such as higher fuel prices, increased maintenance costs, or other economic influences shown in Table 16.

Table 16: Tank truck operational costs (ATRI, 2023).

Parameters	Average Marginal Costs per km (US$/km) 2018 - 2022				
	2018	**2019**	**2020**	**2021**	**2022**
Fuel Costs	$0.269	$0.239	$0.191	$0.259	$0.398
Truck Lease	$0.165	$0.159	$0.168	$0.173	$0.206
Repair & Maintenance	$0.106	$0.093	$0.092	$0.109	$0.122
Truck Insurance Premiums	$0.052	$0.044	$0.054	$0.053	$0.055
Permits & Licenses	$0.015	$0.013	$0.010	$0.010	$0.009
Tires & Tolls	$0.042	$0.046	$0.050	$0.045	$0.045
Driver Wages and Benefits	$0.482	$0.462	$0.458	$0.503	$0.564
TOTAL	$1.132	$1.056	$1.023	$1.153	$1.399

The data in Table 17 shows that diesel trucks are the least expensive at $0.27 per kilometer but produce the highest CO_2 emissions at 932 grams per kilometer (MIT, 2024). Hydrogen, though significantly more expensive at $0.62 per kilometer, has the lowest emissions at 249 grams per kilometer, making it the cleanest option. The hydrogen trucks do not emit carbon dioxide directly from their exhaust. However, there are indirect CO_2 emissions associated with hydrogen production and distribution. Efforts are underway to minimize these indirect emissions using renewable energy to produce green hydrogen. Battery electric trucks strike a balance, costing $0.50 per kilometer and emitting 510 grams of CO_2 per kilometer. The emission from the electric truck was due to a non-renewable grid, which will improve as the grid is decarbonized in the future. Therefore, choosing between these energy sources depends on prioritizing either cost efficiency or environmental impact, with diesel being the most cost-effective, hydrogen being the most environmentally friendly, and battery electric offering a moderate compromise.

Table 17: CO_2 Emissions from powering the truck (MIT, 2024).

Energy Source	Tank Truck Transportation	
	Fuel/Electricity Cost (US$/km)	**CO_2 Emissions from powering the truck (grams/km)**
Diesel	0.27	932
Hydrogen	0.62	249
Battery Electric	0.50	510

The data highlights the variability in operational costs of tank trucks over the five years, with a notable increase in the most recent year as shown in Figure 8.

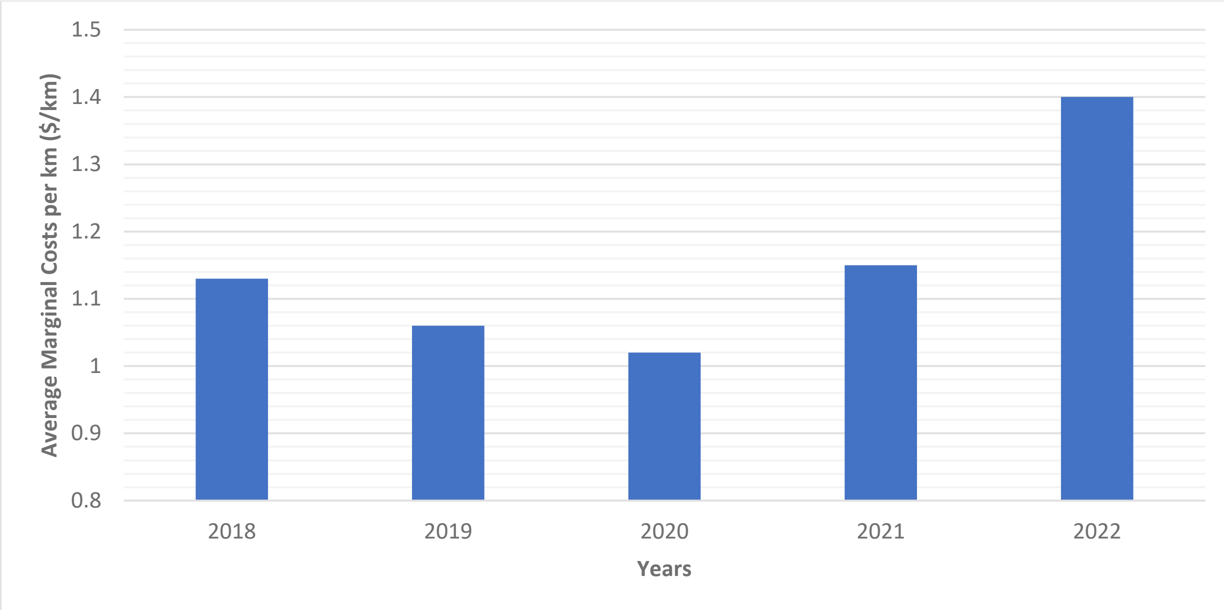

Figure 8: Average Marginal Costs per km (US$/km)

Overall, Table 18 summarised the total cost of transportation by two tank trucks, including both capital and operational expenses, expressed in US dollars per tonne of CO_2, along with a 10% contingency to handle unexpected risks. The total transportation cost via tank trucks amounts to about $15.65 per tonne of CO_2.

Table 18: Tank truck transportation costs

Cost Component	Total Cost (US$/t$CO_2$)
Capital Costs	
Tank Truck Head Purchase x 2	$5.37
30 m^3 LCO_2 Demountable Trailer Tank x 2	$3.10
Operations Costs	
Operation & Maintenance x 2	$5.76
Contingency (10%)	$1.42
Total Cost	$15.65

Third, considering the recommended day storage tank on site, two ships were chosen to transport carbon dioxide from the Tufts Cove natural gas plant to the EverWind plant at approximately 289 kilometers or about 156 nautical miles. The recommended 2000 m^3 liquefied CO_2 carrier has an average speed of about 15 knots or 27.78 km/hr (Marine Insight, 2019). Based on this speed, it would take approximately 10.4 hours to cover the required distance and about 21 hours for a round trip. To ensure continuous operation, a day on-site storage tank and two ships are required: one ship would be in transit while the other would be loading.

The data utilized for cost analysis was sourced from the IEA, as illustrated in Table 19 (IEA, 2020). The table provides information on the costs of transporting CO_2 by ship based on different quantities. The cost per tonne generally decreases as the quantity increases, indicating economies of scale. The cost of transporting CO_2 by each ship was approximately 28 US$/t$CO_2$.Therefore, leasing two ships would cost about 56 US$/t$CO_2$. The quantity of carbon dioxide that would be transported is approximately 0.94 ktCO_2/yr.

Table 19: The costs of transporting CO_2 by ship based on different quantities and distances (IEA, 2020).

Quantity (Mt/yr)	Cost (US$/t$CO_2$)	Annual Cost (US$ million)
0.5	$30	$15
1	$28	$28
2	$26	$52
5	$24	$120
10	$24	$240

Overall, the choice of transportation method depends on various factors such as the quantity of CO_2 to be transported, the distance between the source and destination, and the existing infrastructure, with each method: pipeline, ship, or tanker offering its benefits and limitations.

4.5 Cost Breakdown of Capture, Storage and Transport

Overall, the inflation-adjusted cost breakdown of the CCS project was calculated as shown in Table 20. All the currency conversions were done on the 20th of September 2024 (Xe, 2024).The results showed that the biomass plant's carbon capture cost was higher than other plants. The costs decrease significantly with higher volumes of captured CO_2, especially in capture and storage, suggesting economies of scale in these processes. Transportation costs, however, are higher in the Tufts Cove and Lingan plants, due to transportation infrastructure and distances covered.

Table 20: Cost Summary of CCS

Parameter	Port Hawkesbury Plant			Tufts Cove Plant			Lingan Plant		
	Capture	Storage	Transportation	Capture	Storage	Transportation	Capture	Storage	Transportation
Captured CO_2 ($MtCO_2$)	0.032			0.94			2.3		
Costs (US$/$tCO_2$)	$159.00	$2.12	$15.65	$71.73	$2.05	$56.00	$28.15	$1.93	$48.67
Inflation-adjusted average cost (US$/$tCO_2$)	$187.86	$2.12	$16.00	$84.75	$2.05	$66.16	$33.26	$1.93	$65.75
Total Costs (US$/$tCO_2$)	$205.98			$152.96			$100.94		
Total CCS Costs (C$/$tCO_2$)	$279.65			$207.60			$137.06		

4.6 Summary

This chapter presents the results of the technical and economic possibility of capturing, storing, and transporting carbon dioxide for industrial applications in Nova Scotia. Using the IECM software, a techno-economic analysis of post-combustion carbon capture was simulated for the Port Hawkesbury biomass power plant, the Tufts Cove natural gas generating station, and the Lingan coal generating station. This analysis evaluated the performance, costs, and feasibility of implementing carbon capture technology at each facility, providing insights into the benefits and challenges of carbon capture across different power generation methods. This site selection allowed us to determine CO_2 availability across different fuel types such as biomass, natural gas, and coal. The efficiency of each technology, its scalability, and financials were assessed. More so, the results showed the cost analysis of on-site CO_2 cylindrical storage tanks and evaluated the cost of different transportation methods using the FECM/NETL CO_2 transport cost model.

Case study 1 simulated the techno-economic analysis of the Port Hawkesbury biomass plant retrofitted with carbon capture equipment. The volume of CO_2 captured is relatively small, and the cost of capture is quite high, with moderate costs for transportation and minimal costs for storage. As a result, the total cost of capturing, storing, and transporting CO_2 in this case study is the highest. The biogenic CO_2 production from the Port Hawkesbury biomass plant is expected to be a cost-effective source. However, the plant's limited capacity of 60MW makes it more expensive to produce CO_2 compared to larger facilities, which benefit from economies of scale.

Case study 2 simulated the techno-economic analysis of the Tufts Cove natural gas generating station retrofitted with carbon capture. Higher quantity of CO_2 was captured relative to case study 1, leading to a lower cost per tonne for capture, with a slightly lower cost of storage. However, transportation costs were higher than in case study 1. The total cost was moderate compared to case study 1.

Case study 3 simulated the techno-economic analysis of the Lingan coal power plant retrofitted with carbon capture. The analysis found that the amine system is efficient and cost-effective across different boiler types, with the ultra-supercritical boiler performing the best. The solid sorbent system captures more CO_2 but incurs higher costs. In case study 3, the largest volume of CO_2 was captured, which significantly reduces the cost of capture and storage due to economies of scale. Despite higher transportation costs, this scenario results in the lowest overall cost per tonne of CO_2.

5 Discussion

This chapter discusses the results obtained in Chapter 4, emphasizing the technical feasibility, cost analysis, and availability of CO_2 as an industrial feedstock in Nova Scotia. The study begins by examining the technical feasibility and costs of different CO_2 capture methods, exploring their trade-offs, and identifying the most suitable approach for varying-size facilities. It also analyzed the quantity of hydrogen (H_2) needed to effectively utilize the captured CO_2 to produce valuable products such as methanol for sustainable aviation fuel and urea for fertilizer production. These insights provided an understanding of possible CO_2 capture, storage, transport, and utilization in the province.

5.1 Technical Analysis

The technical analysis showed the efficiency of various carbon capture technologies, the quantity of CO_2 captured (CO_2 availability), the required size of the on-site storage tank, and recommended the optimum transportation mode for each case study. This discussion will be divided into three parts based on the case studies presented.

5.1.1 Port Hawkesbury Biomass Plant

The study of biogenic CO_2 capture at the Port Hawkesbury biomass plant considered various capture systems, such as amine, solid sorbent Temperature Swing Adsorption (TSA), and membrane each assessed with different types of boilers using IECM software. The membrane carbon capture system had the lowest electricity consumption, followed by the amine system, with the solid sorbent TSA system consuming relatively more electricity.

The membrane system achieved the highest net plant efficiency of about 39% while the solid sorbent TSA system had the lowest efficiency of 26%. The efficiency of a CO_2 capture system can be evaluated by the amount of CO_2 captured per unit of electricity generated and the residual CO_2 emitted. The solid sorbent TSA system captured the most CO_2, about 0.35 kg/kWh, particularly with subcritical boilers. The amine and membrane systems showed similar trends, with the membrane system performing slightly better in terms of lower CO_2 emissions. Biogenic CO_2 is a renewable feedstock, but its availability is limited to industries that employ biomass in their production processes, restricting its use to specific geographic regions. As a result, there is a need for onsite storage and transportation to the point of utilization which was estimated for a day of CO_2 availability. Tank trucks are recommended in this case, given the quantity and the estimated transportation distance of 2.3km from the Port Hawkesbury biomass plant to EverWind Fuel at Point Tupper where the CO_2 will be utilized. Two CO_2 tankers are recommended to provide flexible and scalable CO_2 transportation solutions, which are ideal for short distances.

5.1.2 Tufts Cove Natural Gas Generating Plant

The simulation of the post-combustion CO_2 capture at Tufts Cove natural gas generating station considered various capture systems, such as amine (FG+, MEA, CANSOLV), and ammonia. The performance metrics was compared such as net electricity output, net plant efficiency, CO_2 captured, and CO_2 emitted. The amine FG+ system had the highest net electricity output of 467MW, while the ammonia system had the lowest net electricity output of 434 MW, indicating the highest energy consumption for CO_2 capture. The FG+ system is the most efficient (44%), while the ammonia system is the least efficient (39%). The ammonia system captured the most CO_2 per kWh (0.42 kg/kWh), while FG+ and CANSOLV captured slightly less (0.38 kg/kWh). MEA also had a relatively high CO_2 capture rate (0.40 kg/kWh). All systems except the ammonia system emitted the same amount of CO_2. The FG+ and CANSOLV systems offer a good balance of high net electricity output and efficiency while maintaining low CO_2 emissions. If the primary goal is to maximize CO_2 capture, the ammonia system could be considered despite its lower efficiency and higher CO_2 capture. If energy efficiency and net electricity output are prioritized, the FG+ and CANSOLV systems are preferable. The technical analysis of tank storage assesses the on-site CO_2 storage capabilities of a natural gas power plant over one day, highlighting the mass of CO_2 captured, tank volume, and diameter. The average CO_2 captured was approximately 0.39 kg/kWh, resulting in a total mass of about 1.8kt for a day storage tank. The total storage tank volume of about 1674m³ allows for effective on-site storage, requiring 9 tanks of 3.1m diameter to enhance operational flexibility. The results indicate that using two ships to transport carbon dioxide from the Tufts Cove natural gas plant to the EverWind plant was the best option, considering the captured quantity and distance of approximately 289 kilometers.

5.1.3 Lingan coal-fired plant

The study of CO_2 capture at the Lingan coal-fired plant examined various capture systems, notably amine, solid sorbent TSA, and membrane each assessed with different types of boilers such as subcritical, supercritical, and ultra-supercritical boilers. This analysis evaluates the performance of the coal power plant using three different CO_2 capture systems (amine, solid sorbent TSA, and membrane) across three boiler types (subcritical, supercritical, and ultra-supercritical). The comparative analysis showed that the net electricity output was highest in amine with ultra-supercritical boiler (528 MW) and lowest in membrane with subcritical (488 MW). The ultra-supercritical boilers consistently provide the highest net output and efficiency across all capture systems. The membrane system showed the highest net plant efficiency of 37% with an ultra-supercritical boiler and solid sorbent TSA had the lowest efficiency of 22% with a subcritical boiler type. The solid sorbent TSA system with a subcritical boiler had the highest captured CO_2 per kWh of about 1.29 kg/kWh. In contrast, the membrane system with an ultra-supercritical boiler captured the lowest carbon of about 0.68 kg/kWh. The CO_2 captured and emitted decreases with more advanced boiler types across all capture systems. The choice of CO_2 capture system and boiler type significantly impacts the technical performance of a coal power plant. Ultra-supercritical boilers consistently enhance efficiency and reduce emissions across all systems. The amine system is optimal for maximizing net electricity output and CO_2 capture, while the membrane system excels in plant efficiency. The study showed that the coal plant produced the highest CO_2, necessitating the largest storage infrastructure, with 6.39kt of CO_2 for one day, requiring 5937m^3 of storage spread across 30 tanks. Considering the large amount of CO_2 captured from the coal plant, a pipeline was recommended for transporting carbon dioxide from the Lingan coal-fired plant to the utilization plant which is about 155km.

5.2 Cost Analysis

The cost analysis provided a cost breakdown across three case studies, highlighting the minimum and maximum CO_2 capture, storage, and transport costs. It also presented the total average costs, adjusted for inflation as of 2024. The current costs were determined using an online inflation calculator provided by the Canadian Bank of Industry (BOC, nd), and currency converter (Xe, 2024). Table 20 showed the costs of the recommended capture system in each case study, onsite storage, and transportation. The cost analysis is threefold: biomass, natural gas, and coal plants.

First, the IECM simulation for the Port Hawkesbury plant showed that the solid sorbent carbon capturing system was the least economically favorable due to significantly higher costs despite capturing more CO_2 per kWh. The membrane system with subcritical boilers offered the lowest inflation-adjusted CO_2 capture cost of C$255/t$CO_2$. The total costs for Case 1, including capture, storage, and transportation and adjusted for inflation, were approximately C$279.25/t$CO_2$. Figure 9 showed the percentage contribution of each component to the total cost.

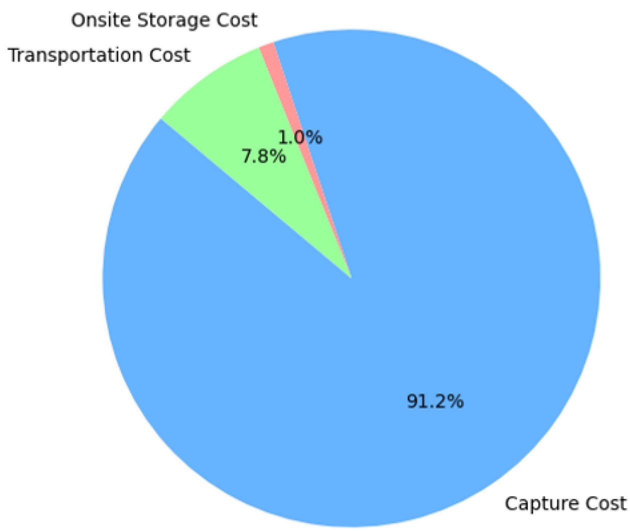

Figure 9: Biomass plant cost distribution.

Second, the IECM simulation of the Tufts Cove natural gas generating station demonstrated that the FG+ amine system was the most cost-effective option, with an inflation-adjusted CO_2 cost of about C$115/t$CO_2$. The storage cost of about C$2.7/t$CO_2$ and the transportation cost of C$89.83/t$CO_2$. The average total costs which include capture, storage, and transportation for the second case study were about C$207.60/t$CO_2$. The percentage contribution of capture, storage, and transportation costs is shown in Figure 10.

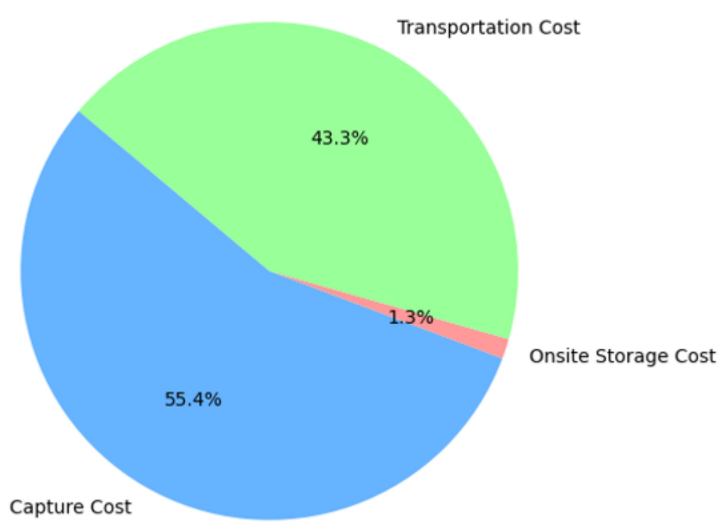

Figure 10: Natural gas plant cost distribution.

Third, the simulation of the Lingan plant using the IECM software showed the amine system had the lowest CO_2 capture cost, about C$45/t$CO_2$. In this case, the average total capture, storage, and transportation cost was approximately C$137/t$CO_2$. Figure 11 illustrates the proportionate contributions of capture, storage, and transportation costs.

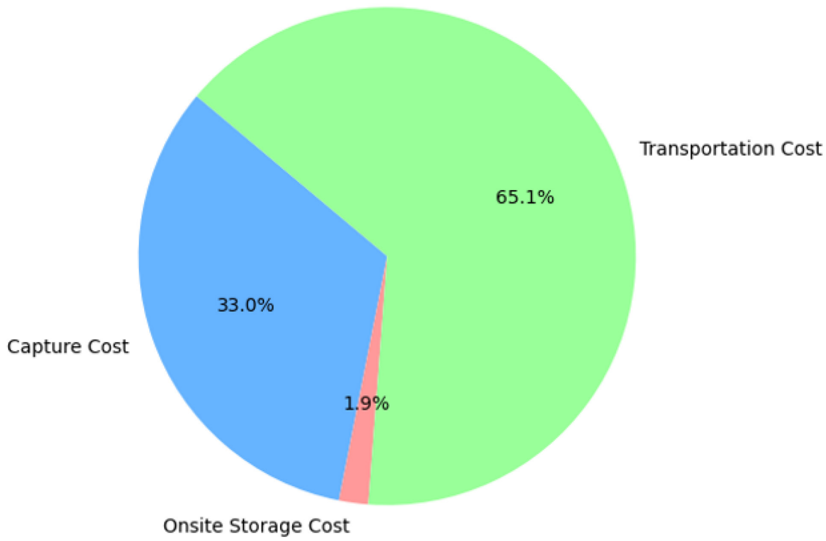

Figure 11: Coal plant cost distribution.

Overall, Table 21 showed the summary of inflation adjusted costs associated with capture, storage, and transportation across three plants notably biomass, natural gas, and coal.

Table 21: Inflation-adjusted cost.

Plant Type	Capture Cost ($C\$/tCO_2$)	Onsite Storage ($C\$/tCO_2$)	Transportation ($C\$/tCO_2$)	Total Cost ($C\$/tCO_2$)
Biomass	$255.06	$2.87	$21.72	$279.65
Natural Gas	$115.07	$2.7	$89.83	$207.60
Coal	$45.15	$2.62	$89.29	$137.06

5.3 Carbon Dioxide Utilization

The first phase of EverWind's production plant is intended to produce approximately 240kt per annum of green ammonia in 2025 (EverWind Fuels, 2024), and then produce over one million tonnes per annum by 2026 (EverWind, 2023). To reach this target, approximately 42kt of hydrogen would need to be produced in 2025, and about 177kt of hydrogen would be required annually from 2026 onward.

One way to add value to the green hydrogen to be produced in Nova Scotia is by converting it into methanol and ammonia. As described in Chapter 2, methanol, synthesized from green hydrogen and carbon dioxide, can be used to produce sustainable aviation fuels. Green hydrogen can also be used to produce ammonia, a key ingredient in fertilizers, through the Haber-Bosch process.

The GHGRP dataset showed on average that the Port Hawkesbury biomass cogeneration power plant could produce about 35ktCO_2/yr, the Tufts Cove natural gas generating station can produce about 940ktCO_2/yr, and the Lingan Coal generating station can produce about 2.4MtCO_2/yr. The IECM simulation results showed that the Port Hawkesbury biomass cogeneration power plant could produce about 32ktCO_2/yr, the Tufts Cove natural gas generating station can produce about 0.66MtCO_2/yr, and the Lingan Coal generating station can produce about 2.3MtCO_2/yr. This highlights the varying quantities of CO_2 available from different types of power plants, with coal plants being the highest source, followed by natural gas, and then biomass.

5.3.1 Methanol production

The carbon footprint of methanol varies based on the source of feedstock used and the method of production. Methanol production from renewable sources like biomass results in a low carbon footprint. However, when methanol is produced from natural gas, it has a lower carbon footprint compared to methanol derived from coal, which has a significantly higher carbon footprint. The methanol production pathways in this study can be categorized into two-fold: renewable (biomass), and non-renewable (natural gas and coal).

5.3.1.1 Biomass Pathway and its Challenges.

Green methanol production requires both green hydrogen, which would be produced by EverWind, and green carbon dioxide, which could be captured from the Port Hawkesbury biomass plant.

The IECM simulation results showed that 32kt/yr of carbon dioxide was captured (which is approximately 94% of the average carbon dioxide reported by the GHGRP) from the Port Hawkesbury biomass plant. This captured quantity of carbon dioxide would require about 4.3kt/yr of green hydrogen to produce around 23kt/yr of green methanol. Since the amount of CO_2 available from the Port Hawkesbury plant is relatively small, only about 10% of EverWind's total green hydrogen production per year would be needed for this green methanol production. The biogenic carbon dioxide is the limiting reagent in this process, meaning that the more quantity of green CO_2 that could be captured, the more methanol that could be produced in the province. The linear relationship between green hydrogen and green carbon dioxide to produce green methanol is shown in Figure 12. The dashed line on the graph represents the projected increase in green methanol production that could be achieved if the amount of captured green carbon dioxide were to increase.

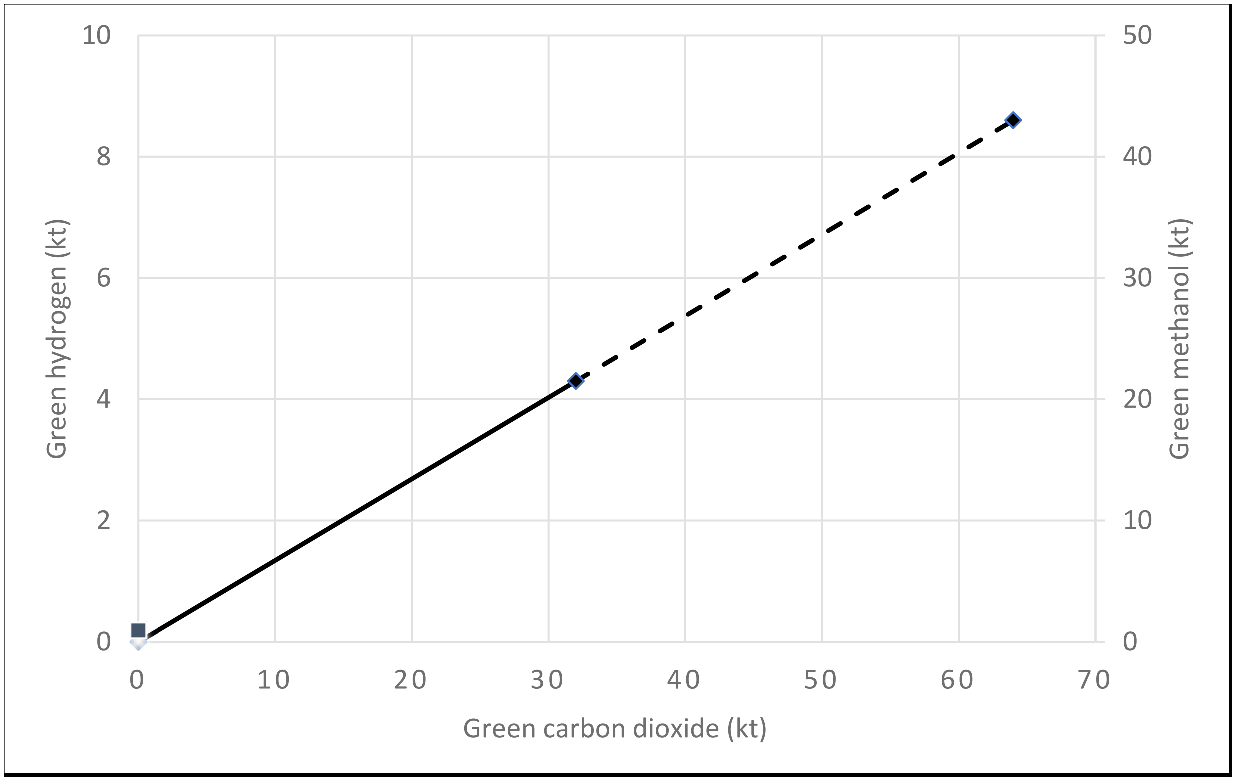

Figure 12: Relationship between Green Hydrogen, Carbon dioxide, and Methanol.

Sustainable aviation fuel SAF can be made from different technological pathways and the maximum theoretical threshold depends on the technology used in the refinery. For example, the Fischer-Tropsch process can yield 25-40% SAF of the total output (IATA, 2024). At present, there is limited research available on the conversion of methanol to jet fuel, although it is anticipated that jet fuel derived from methanol will attain efficiency levels comparable to those of Fischer-Tropsch production methods (Iva & Hamza, 2024).

Using a 40% conversion efficiency of the methanol-to-jet process, the annual green methanol production of 23kt would yield 9.2kt of SAF per year in the province. On the other hand, if we choose a 25% conversion efficiency, a total of about 5.75kt of SAF would have been produced. Overall, the green methanol and SAF production are summarized in Table 22.

Table 22: Green Methanol and SAF production (IATA, 2024).

Activity	Port Hawkesbury
Feedstock	Biomass
CO_2 Emissions and Capture	
- Average Quantity of CO_2 Emitted ($ktCO_2/yr$) - GHGRP	34
- Average Quantity of CO_2 Captured ($ktCO_2/yr$) - IECM	32
- Percentage of CO_2 Captured (%)	94%
Hydrogen Production	
- H_2 Produced by EverWind (kt/yr)	42
- H_2 Required (kt/yr)	4.3
- Percentage of H_2 Required	10%
Methanol Production Potential	
- Possible Methanol Production (kt)	23
SAF Production Potential	
- Possible SAF Production (kt)	9.2

Globally, the use of biomass for energy generation is recognized as a renewable energy source (IEA, 2023). However, ecological critics have raised concerns about its sustainability (Forest Defenders, 2021), particularly in terms of potential environmental impacts such as deforestation, loss of biodiversity, and soil degradation (Qua, et al., 2024).

The use of biomass for energy, as a climate solution in Nova Scotia, had received concerns from forest ecologists as a travesty (Halifax Examiner, 2022). Critics argue that uprooted trees and wood waste during extreme weather events, such as hurricanes, should remain in forests to decay naturally. This process helps replenish soil nutrients, provides critical habitats for wildlife, and contributes to overall forest health. Additionally, Nova Scotia's forests serve as carbon sinks (DNR, 2017), sequestering carbon in both the above-ground biomass and the soil. Cutting forests for biomass disrupts this natural carbon storage (Li, et al., 2022), diminishing the province's ability to mitigate carbon emissions.

However, wood waste from forest products can increase the risk of forest fires in Nova Scotia (Environment, 2023). Accumulated wood waste, including logging residues and unprocessed wood, can create significant fuel loads that increase the risk of wildfires, which had contributed to global warming and a threat to biodiversity (Forest NS, 2023). Managing wood waste through proper utilization strategies is crucial in mitigating fire risks and enhancing forest resilience (Earth, 2022; Forestry, 2024).

5.3.1.2 Fossil Pathway and its Challenges.

Methanol can also be produced using non-renewable carbon dioxide captured from natural gas and coal fired plants. Methanol produced by combining green hydrogen with non-renewable CO_2 is known as blue methanol (IRENA, 2021). Table 23 showed the quantity of methanol produced using non-renewable carbon dioxide.

In the projected phase 1 production, EverWind is expected to produce about 42 kt of green hydrogen per year. This amount of hydrogen requires about 308 kt of non-renewable carbon dioxide to produce about 224 kt of methanol. The amount of carbon dioxide captured from either Tufts Cove plant or Lingan plant is sufficient for this amount of hydrogen, the only limiting feedstock is the amount of hydrogen produced.

During phase 2 production, the green hydrogen production is projected to increase to about 177 kt/yr, requiring 1.3 Mt of carbon dioxide to produce about 0.9 Mt of methanol. The amount of carbon dioxide captured from the Tufts Cove plant is not sufficient to fully utilize all the hydrogen produced. However, the carbon dioxide captured from the Lingan plant, either on its own or in combination with that from Tufts Cove, would provide enough carbon dioxide to fully utilize all the hydrogen produced by EverWind. This combined approach ensures that both plants can supply the required carbon dioxide for hydrogen utilization, supporting the production of methanol.

Table 23: Methanol production using non-renewable carbon dioxide.

Activity	**Tufts Cove**	**Lingan**
Feedstock	Natural gas	Coal
CO_2 Emissions and Capture		
- Average Quantity of CO_2 Emitted ($MtCO_2$/yr) - GHGRP	0.94	2.4
- Average Quantity of CO_2 Captured ($MtCO_2$/yr) - IECM	0.66	2.3
Projected Production Phase 1		
- H_2 available (kt/yr)	42	
- Quantity of CO_2 Required (kt)	308	
- Possible Methanol Production (kt)	224	
Projected Production Phase 2		
- H_2 available (kt/yr)	128	177
- Quantity of CO_2 Required (Mt)	0.94	1.30
- Possible Methanol Production (Mt)	0.68	0.94

The utilization of captured CO_2 from non-renewable sources with green hydrogen produced in Nova Scotia presents an opportunity to contribute to the production of blue methanol. While green methanol is promoted as a decarbonization strategy, using non-renewable CO_2 sources could still produce methanol as an alternative especially where the availability of biogenic CO_2 is a challenge.

5.3.2 Urea production

Green urea synthesis requires both the captured green carbon dioxide and green ammonia. The process starts with green ammonia reacting with green carbon dioxide to produce ammonium carbamate, which decomposes into green urea and is then used to produce fertilizers for agricultural purposes. For example, based on IECM results, if EverWind produces around 240 kt of green ammonia and combines it with approximately 32 kt of CO_2, it could produce about 44 kt of urea as shown in Table 24.

Table 24: Green Urea Production

Activity	**Port Hawkesbury**
Feedstock	Biomass
CO_2 Emissions and Capture	
- Average Quantity of CO_2 Emitted ($ktCO_2$/yr) - GHGRP	34
- Average Quantity of CO_2 Captured ($ktCO_2$/yr) - IECM	32
- Percentage of green CO_2 Utilized (%)	94%
Green Ammonia Production	
- NH_3 Produced by EverWind (kt/yr)	240
Green Urea Production Potential	
- Possible Urea Production (kt)	44

Green urea synthesis requires both the captured green carbon dioxide and green ammonia. Table 25 showed the quantity of urea produced using non-renewable carbon dioxide.

The phase 1 production showed that about 240 kt of green ammonia requires about 308 kt of non-renewable carbon dioxide to produce about 424 kt of urea. The amount of carbon dioxide captured from either Tufts Cove plant or Lingan plant is sufficient, the only limiting feedstock is the amount of ammonia produced.

During Phase 2 production, the green ammonia production is projected to increase to about 1Mt/yr, requiring about 1.3 Mt of carbon dioxide to produce about 1.8 Mt of urea. The carbon dioxide captured from the Tufts Cove plant is insufficient to fully utilize all the ammonia produced. However, the carbon dioxide from Lingan alone, or combined with Tufts Cove, would be enough to fully utilize EverWind's ammonia produced.

Overall, using non-renewable CO_2 with Nova Scotia's green ammonia could produce blue ammonia, offering an alternative to green ammonia where renewable CO_2 is scarce.

Table 25: Urea production using non-renewable carbon dioxide.

Activity	Tufts Cove	Lingan
Feedstock	Natural gas	Coal
CO_2 Emissions and Capture		
- Average Quantity of CO_2 Emitted ($MtCO_2$/yr) - GHGRP	0.94	2.4
- Average Quantity of CO_2 Captured ($MtCO_2$/yr) - IECM	0.66	2.3
Projected Production Phase 1		
-NH_3 available (kt/yr)	240	
- Quantity of CO_2 Required (kt)	308	
- Possible Urea Production (kt)	424	
Projected Production Phase 2		
- NH_3 available (Mt/yr)	1	
- Quantity of CO_2 Required (Mt)	0.94	1.3
- Possible Urea Production (Mt)	1.3	1.8

5.4 Summary

This chapter discussed the technical feasibility, economic viability, CO_2 utilization as an industrial feedstock, and benefits of the project to Nova Scotians.

First, it discussed the IECM technical results of the study such as the efficiency of various carbon capture technologies, the quantity of CO_2 captured (CO_2 availability), the size of the on-site storage tank, and recommended the optimum transportation mode. The results showed that the Port Hawkesbury biomass cogeneration power plant (case 1) could produce about 32 $ktCO_2$/yr, the Tufts Cove natural gas generating station (case 2), about 0.66 $MtCO_2$/yr, and the Lingan coal generating station (case 3), about 2.3 $MtCO_2$/yr. The Lingan plant required the largest storage infrastructure followed by Tufts Cove and Port Hawkesbury plant. The transportation mode was considered based on the distance from the point of CO_2 sources to the point of utilization. Tank truck was recommended for case 1 with a distance of about 2.3km, ship for case 2 with a distance of about 289km, and pipeline for case 3 with a distance of about 155km.

Second, the cost breakdown across the three cases was considered, showing the cost for CO_2 capture, storage, and transport, as well as the inflation-adjusted total cost.

Third, the quantity of hydrogen (H_2) needed to effectively utilize the captured CO_2 to produce valuable products such as methanol for sustainable aviation fuel and the quantity of ammonia for urea production was analyzed. The result showed that if EverWind commences production of about 240kt/yr of green NH_3, it requires approximately 32kt of green CO_2 to produce about 23kt of green methanol and 44kt of green urea.

Fourth, if EverWind produces about 177,000 tonnes of green hydrogen by 2026 and combines the hydrogen with 1.3 million tonnes of non-renewable carbon dioxide, it would produce about 0.9 million tonnes of methanol. This would be slightly less than one percent of global methanol production in 2022. More so, if EverWind produces one million tonnes of ammonia using nitrogen and hydrogen from its facility, this could be combined with approximately 1.3 megatonnes of CO_2 to produce 1.8 megatonnes of urea. This output would represent about one percent of global urea production in 2022.

6 Conclusions

This thesis presented a techno-economic analysis of the potential for the capture, storage, and transportation of carbon dioxide for utilization as an industrial feedstock in Nova Scotia. The research aimed to identify CO_2 point sources in the province, examine technologies for CO_2 capture and storage, recommend transportation methods, and explore the possible utilization of CO_2 for value-added products such as methanol and urea.

The objectives were achieved by first identifying and quantifying three CO_2 point sources of interest, notably the Port Hawkesbury Plant (biomass), the Tufts Cove generating station (natural gas), and the Lingan thermal plant (coal) using the emission dataset from Canadian greenhouse gas reporting program GHGRP database.

Next, the IECM software was used to simulate the three-point sources using various capturing systems such as amine, solid sorbent, and membrane each with subcritical, supercritical, and ultra-supercritical boiler types. The results of the simulations include the net efficiency of each technology, the quantities of carbon captured and emitted, and the costs of CO_2 captured and avoided). The simulation used Nova Scotia Power's average annual energy generation from 2020 to 2022. More so, the model assumed a CO_2 capture efficiency of 95% with the captured CO_2 compressed into liquid form for transportation and storage. Additional specifications of the base plant used in the simulation are detailed in Appendix A.

The study showed the average CO_2 emissions reported by the Greenhouse Gas Reporting Program (GHGRP) and the average CO_2 captured using the Integrated Environmental Control Model (IECM) software.

Based on the quantities of CO_2 available from each plant, a day on-site horizontal cylindrical storage tank was recommended to handle the mismatch between CO_2 production and its demand from the utilization plants.

Various transportation methods, including pipelines, tank trucks, and shipping, were evaluated based on quantity and distance. A tank truck was recommended for the Port Hawkesbury biomass plant due to the CO_2 quantity captured and its short distance to the point of utilization. The larger volumes and distances necessitated a pipeline for Lingan and a ship for Tufts Cove.

The possible use of captured CO_2 as an industrial feedstock was explored by calculating the quantities of CO_2 required to produce methanol and urea. Green hydrogen combined with carbon dioxide will produce methanol which could be converted to SAF via methanol-to-jet or MTJ. More so, green ammonia combined with carbon dioxide will produce urea which could be used to produce fertilizers for agriculture. These value-added products would lead to the creation of new industries in the province.

Overall, this study achieved its objectives.

6.1 Research Contributions

The research identified possible CO_2 point sources, capturing techniques, on-site storage tanks, and methods of CO_2 transportation for utilization. The thesis explored three different power stations using either biomass, natural gas, or coal as a feedstock. These power plants covered the three energy sources of interest.

Table 26 summarized the results of the techno-economic analysis for Port Hawkesbury, Tufts Cove, and Lingan plants. Port Hawkesbury plant has an average renewable carbon dioxide of 0.032 $MtCO_2$/yr, Tufts Cove has an average non-renewable carbon dioxide of 0.94 $MtCO_2$/yr, and Lingan has an average non-renewable carbon dioxide of about 2.3 $MtCO_2$/yr. A day of onsite storage was estimated for the captured CO_2 from the three plants. Two tank trucks are recommended to deliver the captured CO_2 from the Port Hawkesbury biomass plant to the EverWind plant. More so, two ships were recommended for Tufts Cove transportation and a pipeline for the Lingan coal-fired plant. Total costs per tonne of CO_2 captured are highest at Port Hawkesbury ($206) and lowest at Lingan ($101). Hydrogen requirements vary, with Port Hawkesbury needing 4.3 kt H_2 to potentially produce 23 kt of green methanol and 44 kt of green urea.

Combining EverWind's production of 177,000 tonnes of green hydrogen with 1.3 million tonnes of non-renewable carbon dioxide could yield about 0.9 million tonnes of blue methanol. Additionally, utilizing one million tonnes of ammonia could produce about 1.8 megatonnes of urea when mixed with 1.3 megatonnes of carbon dioxide. This demonstrates the substantial opportunity for carbon dioxide utilization in methanol and urea production.

The Port Hawkesbury biomass plant stands out due to its tri-generation benefits: heat, electricity, and green CO_2, positioning it as a key player in the transition towards establishing sustainable industries in the province. The production of green methanol, used for green fuels, depends on the availability of green hydrogen and green carbon dioxide.

Since biogenic CO_2 is required to produce green SAF, the capacity of the Port Hawkesbury plant needs to be increased. Increasing the plant's capacity raises the biogenic CO_2 availability, increasing the quantity of SAF produced and reducing the capture cost by leveraging economies of scale. Alternatively, other sources of green CO_2 such as dedicated cogeneration plants converting wood waste to electricity and CO_2 are needed if the Port Hawkesbury plant cannot be increased.

Overall, the volume of CO_2 available in the province could use green hydrogen to make non-green methanol or green ammonia for non-green urea. The quantities of both green or blue methanol and urea that could be produced from either biogenic or non-renewable carbon dioxide in the province are summarized in Table 26.

Table 26: Techno-Economic Analysis of CCUS in Nova Scotia.

Activity	Port Hawkesbury	Tufts Cove	Lingan
Feedstock	Biomass	Natural Gas	Coal
CO2 source	Renewable	Non-renewable	Non-renewable
Average Quantity of Carbon Dioxide ($MtCO_2$/yr)	0.032	0.94	2.3
On-site Storage Volume (m^3)	90	1,674	5,937
Transportation mode	Tank Truck	Ship	Pipeline
Capture Cost (US$/$tCO_2$)	$188	$85	$33
Transportation Cost (US$/$tCO_2$)	$16.00	$66.16	$65.75
Storage Cost (US$/$tCO_2$)	$2.12	$2.05	$1.93
Total Cost (US$/$tCO_2$)	$205.98	$152.96	$100.94
Total Cost (C$/$tCO_2$)	$279.65	$207.60	$137.06
EverWind's Projected Phase 1 Production			
H_2 production target (kt)	42		
NH_3 production target (kt)	240		
Available CO_2 (kt)	32	308	
H_2 required (kt)	4.3	42	
Possible methanol production (kt)	23	224	
Possible urea production (kt)	44	424	
EverWind's Projected Phase 2 Production			
H_2 production target (kt)	177		
NH_3 production target (Mt)	1		
Available CO_2 (Mt)	0.032	0.94	1.3
H_2 required (kt)	4.3	128	177
Possible methanol production (Mt)	0.023	0.68	0.94
Possible urea production (Mt)	0.044	1.30	1.80

6.2 Limitations

This study aimed to provide a comprehensive techno-economic analysis of possible CO_2 capture and utilization, the known limitations are:

- The IECM software was chosen for its robust framework for evaluating emission control technologies. However, the software is limited to simulating CO_2 emissions from power plants and its permanent storage methods, like geological storage and enhanced oil recovery. The latest software edition was not designed to simulate onsite CO_2 storage.

- This study focused on CO_2 onsite storage infrastructure but did not explore alternative options like salt domes to address the space-time disparity between carbon capture and utilization.
- The analysis considered pipeline, ship, and truck transportation but did not consider alternatives, notably rail, due to the lack of infrastructure in the relevant locations.
- The thesis focused solely on the costs of CO_2 capture, storage, and transport but did not include the costs of green hydrogen, ammonia, methanol, and urea production. The study assumed that EverWind Fuels would produce green hydrogen and ammonia.
- Most of the economic costs are in USD. This may not accurately capture regional economic conditions in Nova Scotia.

6.3 Recommendations for Future Work

This thesis focused on post-combustion carbon capture in three facilities: the Port Hawkesbury biomass plant, the Tufts Cove natural gas generating station, and the Lingan coal-fired plant covering three different energy sources (small, medium, and large CO_2 sources), respectively, in the province.

Based on this research, it is recommended that:

- The provincial government supports the creation of a scalable facility for transforming green hydrogen and ammonia into methanol and urea by providing financial incentives.
- The provincial government conducts studies on the co-location of CO_2 capture, conversion facilities, potential CO_2 hubs, or provincial CO_2 pipelines to reduce transportation costs and enhance overall efficiency.
- Nova Scotia Power explores the possibility of increasing the generating capacity of the Port Hawkesbury biomass plant to produce and capture greater quantities of biogenic CO_2. This will enable the plant to leverage economies of scale, thereby reducing the overall cost of biogenic carbon capture.
- The provincial government reviews the relevant legislation to permit the increased use of waste biomass for the biogenic production of CO_2.
- The provincial government conducts feasibility studies for CO_2 removal from sources including the atmosphere and ocean. This is especially important if existing sources of terrestrial CO_2, such as the

combustion of coal, natural gas, or biomass become unobtainable because of emissions limits or the need to preserve Nova Scotia's forests.

6.4 Nova Scotia's Hydrogen Future

The results of the carbon capture, storage, transportation, and utilization methods represent the critical components of the techno-economic analysis of CCUS in Nova Scotia. The thesis examined the technological feasibility, economic viability, use of CO_2 as an industrial feedstock, and project benefits for Nova Scotians.

The province could enjoy both environmental and economic benefits from the deployment of carbon capture systems. This could reduce CO_2 emissions in the province, which could contribute to the global effort to reduce the impact of climatic change and extreme weather events such as heatwaves, heavy rainfall, and droughts. This could improve public health due to reduced pollution levels and improved air quality. Moreover, the three precursors of sustainable aviation fuel and green urea, notably biogenic CO_2, green hydrogen, and green ammonia will, ideally, contribute to the creation of sustainable industrial development in the province. This will stimulate economic growth by creating wealth and job opportunities, making Nova Scotia a significant player in the global hydrogen market to achieve global net-zero targets.

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Appendix A: Set parameters

CASE 1: Facility Profile for Biomass Power Plant			
Parameter	**Value**	**Unit**	**Source**
Base Plant Name	Port Hawkesbury Biomass		(NSPI, 2023)
Gross Power output	60	MW	(NSPI, 2023)
Capacity Factor	85	%	Assigned
Type of Capture Technology	Amine/Membrane		(IECM, 2021)
Unit Type/Boiler Technology	Subcritical /Ultra-Supercritical		Assigned
Boiler Type	Tangential		(IECM, 2021)
Capture Efficiency	90	%	Assigned
Estimated CO_2 Emission	40.2	$ktCO_2/yr$	(ECCC, 2024)
Distance to CO_2 Utilization Plant	2.3	km	Google Map
Wood Chip Grade	A2		(NRCan, 2017)
Carbon Content	51	wt%	(Grammelis, 2011)
Oxygen Content	31.3	wt%	(Świerzewski & Gladysz)
Moisture Content	8	wt%	(NRCan, 2017)
Ash Content	1.2	wt%	(NRCan, 2017)
Hydrogen Content	7.9	wt%	(Grammelis, 2011)
Nitrogen Content	0.3	wt%	(Świerzewski & Gladysz)
Sulphur Content	0.2	wt%	(Świerzewski & Gladysz)
High Heating Value by Mass	28	(MJ/kg)	(Grammelis, 2011)
SO_2 Control	Wet FGD		(IECM, 2021)
NOx Control	Hot-Side SCR		(IECM, 2021)

CASE 2: Facility Profile for Natural Gas Power Plant			
Parameter	**Value**	**Unit**	**Source**
Base Plant Name	Tufts Cove Generating Station		(NSPI, 2023)
Gross Power output	500	MW	(NSPI, 2023)
Capacity Factor	85	%	Assigned
Unit Type/Boiler Technology	Subcritical /Ultra-Supercritical		Assigned
Type of Capture Technology	Amine/Ammonia		(IECM, 2021)
Capture Efficiency	95	%	Assigned
Estimated CO_2 Emission	0.95	$MtCO_2$/yr	(ECCC, 2024)
Distance to CO_2 Utilization Plant	289	Km	Google Map
Higher Heating Value HHV	5.23E+04	KJ/kg	(IECM, 2021)
Fuel Carbon Dioxide CO_2 Content	1	% vol	(IECM, 2021)
Methane (CH_4) Content	93.1	% vol	(IECM, 2021)
Nitrogen (N_2) Content	1.6	% vol	(IECM, 2021)
Ethane (C_2H_6) Content	3.2	% vol	(IECM, 2021)
Propane (C_3H_8) Content	1.1	% vol	(IECM, 2021)

CASE 3: Facility Profile for Coal Power Plant			
Parameter	**Value**	**Unit**	**Source**
Base Plant Name	Lingan Generating Station	4 Plants	(NSPI, 2023)
Gross Power output	620	MW	(NSPI, 2023)
Capacity Factor	85	%	(IECM, 2021)
Unit Type/Boiler Technology	Subcritical /Ultra-Supercritical		(GEM, 2024)
Boiler Type	Tangential		(IECM, 2021)
Type of Capture Technology	Amine/Membrane		(IECM, 2021)
Capture Efficiency	95	%	Assigned
Estimated CO_2 Emission in 2021	2.63	$MtCO_2$/yr	(ECCC, 2024)
Distance to CO_2 Utilization Plant	155	km	Google Map
Coal Rank	Bituminous		(IECM, 2021)
Coal Flow Rate	0.3208	kg/kWh	(IECM, 2021)
Year Cost Reported	2020	Yr	(IECM, 2021)
Higher Heating Value HHV	3.08E+04	kJ/kg	(IECM, 2021)
Fuel Carbon Content	73.81	wt%	(IECM, 2021)
Fuel Sulphur Content	2.13	wt%	(IECM, 2021)
Fuel Hydrogen Content	4.88	wt%	(IECM, 2021)
Fuel Nitrogen Content	1.42	wt%	(IECM, 2021)
Fuel Ash Content	7.24	wt%	(IECM, 2021)
Fuel Moisture Content	5.05	wt%	(IECM, 2021)
Tower Water Temperature (Inlet & Outlet)	80 & 60	°F	(IECM, 2021)
Air Temperature (Dry Bulb & Wet Bulb)	60 & 51.5	°F	(IECM, 2021)
NOx Control	Hot-Side SCR		(IECM, 2021)
SO_2 Control	Wet FGD		(IECM, 2021)

APPENDIX B: Energy analysis set parameters.

Parameter	Value	Unit	Source
Biomass Fuel Cost	$39. 71	$/tonne	(Statista, 2024)
Carbon Tax (Yr 2024)	$80	$/tonne	(ECCC, 2021)
Emission intensity limit for solid fuels (Yr 2030)	370	tonne/GWh	(Justice Laws, 2024)
Emission intensity limit for Natural Gas	370	tonne/GWh	(Justice Laws, 2024)
CO_2 Pump Capacity	1,415	kW	
Project Life Span	20	Years	Assigned

APPENDIX C: Tank Truck Specifications.

Cost Component	Cost (US$)	Reference
Capital Costs		
Tank Truck Head Purchase	$95,000	(Alibaba, 2024)
30 m^3 LCO_2 Demountable Trailer Tank	$55,000	(Jianshentank, 2019)
Tank Truck Head Specifications		
Brand Name	SINOTRUCK	(Alibaba, 2024)
Gross Vehicle Weight	15000 kg	(HNJJC, 2024)
Fuel Type	Electric	(HNJJC, 2024)
Transmission Type	Automatic	(HNJJC, 2024)
Capacity (Load)	> 50T	(HNJJC, 2024)
Maximum Torque(Nm)	1000-1500Nm	(HNJJC, 2024)
Supplier	Hunan Jujiacheng Automobile Sales Co., Ltd	(HNJJC, 2024)
30 m^3 LCO_2 Demountable Trailer Tank Specifications		
Total Tank Weight	11360 kg	(Jianshentank, 2019)
Dimensions (mm)	13000* 2500 * 3620	(Jianshentank, 2019)
Design Pressure	2.2 MPa	(Jianshentank, 2019)
Work Pressure	1.5 - 2.2 MPa	(Jianshentank, 2019)
Operating temperature (°C)	-35 to -15	(Jianshentank, 2019)
Minimum design metal temperature (°C)	-40	(Jianshentank, 2019)
Insulation form	Polyurethane foam flame retardant Materials and standards of main pressure components:WH590E:Q/EGN132 -2019 16MnDR:GB/T3531-2014 20MnMoDIII: NB/T 47009-2017 16MnDIII: NB/T 47009-2017	(Jianshentank, 2019)

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