THE NET ZERO PROJECT

Carbon Capture, Utilization and Storage Offshore Newfoundland and Labrador

A Net Zero Project White Paper

February 2023

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Energy NL

OILCO NEWFOUNDLAND AND LABRADOR

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This research was led by Energy NL, OilCo, and econext as part of their partnership, The Net Zero Project

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List of Acronyms

Acronym	**Meaning**
ACC	Aker Carbon Capture
AFC	Allam-Fetvedt Cycle
ALE	Asset Life Extension
BdN	Bay du Nord
C-CORE	Centre for Cold Ocean Resources
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CEPA	Canadian Environmental Protection Act
CFD	Computational fluid dynamics
CFR	Clean Fuel Regulations
CFS	Clean Fuel Standards
CGS	Concrete gravity structure
CI	Carbon intensity
CNLOPB	Canada-Newfoundland Offshore Petroleum Board
CSA	Canadian Standards Association
DAC	Direct air capture
DES	Derrick equipment set
DNV	Det Norske Veritas
ECCC	Environment and Climate Change Canada
EEZ	Exclusive Economic Zone
EOR	Enhanced oil recovery
EPC	Engineering, procurement, and construction
ESG	Environmental, social and governance

Acronym	Meaning
FEED	Front-end engineering and design
FLNG	Floating liquified natural gas
FPSO	Floating production, storage and offloading
GBS	Gravity base structure
GGPPA	Greenhouse Gas Pollution Pricing Act
GHG	Greenhouse gases
GHGRP	Greenhouse Gas Reporting Program
GNL	Government of Newfoundland and Labrador
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ITC	Investment Tax Credit
kt	Kilotonnes
kTPA	Kilotonnes per annum
LCCA	Levelized cost of carbon abatement
LNG	Liquified natural gas
LPG	Liquified petroleum gas
MAPI	MA Procense Inc.
MMV	Monitoring, measurement, and verification
MODU	Mobile offshore drilling unit
MOF	Metal-organic frameworks
Mt	Million tonnes
MW	Megawatts
NEA	Norwegian Environmental Agency
NL	Newfoundland and Labrador
NOx	Nitrogen oxides
NRCan	Natural Resources Canada
NZP	Net Zero Project
OBPS	Output-Based Pricing System
OilCo	Oil Corporation of Newfoundland and Labrador
OLS	Offshore loading system
OOIP	Original oil in place
PCOR	Plains CO_2 Reduction
RAM	Rotating adsorption machines
RFP	Request for proposals
RPB	Rotating packed bed
SDP	SNC-Lavalin- Dragados-Pennecon General Partnership
TIER	Technology Innovation and Emissions Reduction
tpd	Tonnes per day
TRL	Technology readiness level
UPM	Utility process module
USD	United States dollars
WAG	Water-alternating-gas
WWRP	West White Rose Project

Executive Summary

The province of Newfoundland and Labrador (NL) has abundant natural resources including oil and gas reserves offshore. Oil production has provided the province and its people with substantial revenues to meet its socio-economic needs.

The NL offshore is responsible for approximately 17% of the total provincial emissions, 1.2% of Canada's oil and gas sector emissions and just 0.3% of the national total of all industries. The GHG emissions discussed above consist of scope 1 emissions and it is these emissions that are the focus of decarbonization efforts in the NL offshore. The current carbon intensity of the oil produced in The NL offshore is one third of the national average with future projects expected to be even less.

Signatories to the Paris Agreement, including Canada, have collectively pledged to reduce GHG emissions to limit the global temperature increase to below 2.0 degrees Celsius, and to pursue efforts to limit to 1.5 degrees Celsius to reduce the severity of climate impacts. For its part, the Government of NL committed in May 2020 to achieve net zero GHGs by the year 2050.

The Net Zero Project was formed in early 2022 with a primary objective is to ensure the long-term sustainable future of the NL offshore oil and gas industry by embracing a lower-emissions greenfield future in line with broader provincial and national objectives of achieving net zero by 2050. With respect to CCUS the NZP's objectives will be to provide:

1. Technical and economic analysis;
2. Policy and regulatory analysis; and
3. Development of a roadmap to advance CCUS as an option for reducing offshore emissions

CCUS has the potential to significantly reduce emissions in the NL offshore in the near to medium term should technical advances continue at their current pace. This will require concerted research and development effort as CCUS has never **been applied in an offshore context before.**

Building on the success of the Carbon Capture, Utilization and Storage (CCUS) Workshop in September 2022, the Net Zero Project is focusing on related action items and facilitating collaboration with various stakeholders in CCUS technology. Economic modeling, policy investigation, and technical feasibility analysis will help drive priorities in this regard. This area presents an opportunity for the development of and investment attraction for a major innovation project.

The world will continue to rely on oil and gas even in an aggressive decarbonization scenario. The recent invasion of Ukraine by Russia has renewed the importance of energy security in resource development decision making.

There is significant opportunity for growth in the NL offshore. Seismic data collected thus far suggest that while only a fraction of the province's offshore area has been assessed, world class resources remain untapped.

In April 2022, the Canadian government indicated that proponents of new oil and gas projects will be required to demonstrate "best in class" low emissions performance. The NL offshore already has a reputation for low emitting oil production facilities and thus may attract future economical oil and gas development to meet this requirement.

CCUS is a technology that captures CO_2 and permanently stores it deep in the ground. The technology, which is proven and has existed for decades, captures CO_2 emissions that come from a plant or industrial site and stops them from being released into the atmosphere.

CCUS technology is primarily being used in onshore applications in Canada and around the world but there are no examples of CCUS projects which capture turbine exhaust gases to reduce emissions from offshore production facilities, such as what is required in the NL offshore.

The three main combustion capture technologies are post-combustion, oxyfuel combustion and pre-combustion. In the NL offshore where space and weight are at a premium, the process that is least complicated, requires less energy, and involves minimal equipment installation may be the favoured approach. Post-combustion carbon capture emerging technologies that are less complex, do not introduce new chemicals and prioritize a compact design with a small footprint may be the most practical solutions. There are several technologies advancing but not fully commercialized that may meet the challenge of implementing carbon capture in offshore NL.

Transport is the stage of carbon capture and storage that links capture sources and storage sites. Commercial-scale transport uses pipelines and/or ships for gaseous and liquid carbon dioxide transport. There is no indication that the problems for carbon dioxide pipelines are any more challenging than those set by hydrocarbon pipelines in similar areas, or that they cannot be resolved. Carbon dioxide is already transported by ships, but on a small scale because of limited demand.

Enhanced Oil Recovery (EOR) is a tertiary oil production recovery method that can utilize CO_2 through miscible displacement to enhance oil production and is often used in the later stages of production. To date, only primary and secondary recovery methods have been implemented in the NL offshore. Accessing the required amounts of CO_2 needed for a full CO_2-EOR scheme would be challenging in the NL offshore. A more likely scenario for utilizing CO_2 offshore is alternating CO_2 injection with water injection.

NL offshore has all the geologic requirements needed for safe CO_2 storage as demonstrated by a long history of storing hydrocarbon gas within the reservoirs. Newfoundland and Labrador's offshore CO_2 storage potential could be in the Gigatonne range given the vast lateral extent of the sedimentary basins. A planned technical storage assessment by OilCo will add much-needed quantification to the perceived CO_2 storage opportunity in Newfoundland and Labrador's offshore.

In the long term, NL offshore shows significant potential to act as a regional (or even national) storage hub for carbon with storage potential in the gigatonne range, however more investigation is required.

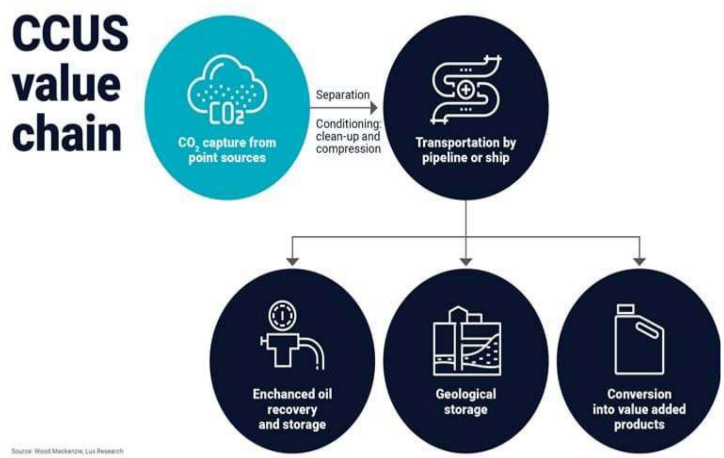
After the CO_2 has been injected into the subsurface reservoirs, it is important to monitor the CO_2 plume and ensure that it remains in an acceptable area, and at an acceptable pressure, so that it does not compromise the storage complex and subsequently escape. A monitoring, measurement, and verification plan (MMV) will be a requirement for any CO_2 storage project offshore Newfoundland and Labrador.

There is currently no regulatory framework in place for the implementation of CCUS projects in the NL offshore. The regulation of offshore air emissions , under the management of the Greenhouse Gas Act, to an authorized work or activity that is carried out within the offshore area, falls under provincial jurisdiction since the amendments made to the Atlantic Accord in 2018.,while the storage of CO_2 in the offshore would fall under federal jurisdiction. Offshore CCUS projects are therefore the ideal scope to be regulated by the C-NLOPB, as a joint federal-provincial regulatory body. The C-NLOPB may consider an application for an amendment to an existing authorization if an operator proposed injection of CO_2 into an oil-producing geological formation.

As with any emerging clean technology, credit issuance has become a significant incentive and a means to create more value in emissions reductions efforts. In terms of satisfying the ITC and CFR credit requirements for storage regulations, it is necessary to work with the Province and the C-NLOPB to identify where gaps in regulation may exist.

The economic viability of CCUS projects is challenging for several reasons, including technological challenges and high capital costs. These challenges are exacerbated in the offshore environment where space constraints and harsh working conditions add to the cost and present technical challenges, the main challenge, however, stems from the lack of associated revenue. Developers may have to rely on sources of "revenue" that are regulatory-driven and include the ability to lower the costs of carbon taxes and other levies.

Given the uncertainty and unknowns involved with installing CCS units offshore, cost estimates are indicative rather than being viewed as absolutes. It is the directional changes in the levelized cost of carbon abated (LCCA) which is worth noting and the relative impacts that the key drivers have on the LCCA of CCS as well as the impact that government incentives and initiatives can have on moving this industry forward.



1 Introduction

Since the start of oil production in late 1997 the NL offshore has produced approximately 2.1 billion barrels of oil. The province has indicated that approximately 25 per cent of provincial Gross Domestic Product (GDP) and 41 per cent of exports over the past 20 years can be attributed to the NL offshore oil industry.

Natural gas, which is produced along with oil, is either used as fuel for offshore operations or reinjected back into the reservoir to be used as pressure support. The gas used as fuel is combusted in turbines to create electricity and power compressors on the offshore operating facilities. As a result of this combustion, carbon dioxide gas (CO_2) is released into the atmosphere as part of the exhaust gas (or flue gas) from the various turbines on the offshore facilities. The flue gas typically contains 3-5% CO_2 by volume, and it's release into the atmosphere is the source of most of the offshore greenhouse gas (GHG) emissions. These emissions are typically referred to as "scope 1 emissions" which are emissions that originate from the production of oil and gas. Other smaller volumes of GHG emissions are generated from routine and emergency flaring which are part of the normal facilities operating design.

The future holds no single solution to meet net-zero requirements. The transition to using clean burning hydrogen for fuel and the use of hydro, wind, and solar energy to create electricity will all have an important role to play. Carbon Capture, Utilization and Storage (CCUS) is another technological option for reducing CO_2 ***emissions and will be essential to achieving the goal of net-zero emissions.***

The overarching objective of The Net Zero Project is to pursue energy resilience with a primary objective that is aimed at ensuring the long-term sustainable future of Canada's growing offshore oil and gas industry by embracing a lower-emissions greenfield future in line with broader provincial and national objectives of achieving net zero by 2050.

Central to all objectives, the Net Zero Project produces analysis and evidence from which project leaders can then use to inform their own priorities and initiatives, pursing activities through technical, economic, policy, and innovation lenses as per the structure of the team.

The three main objectives for The Net Zero Project are as follows:

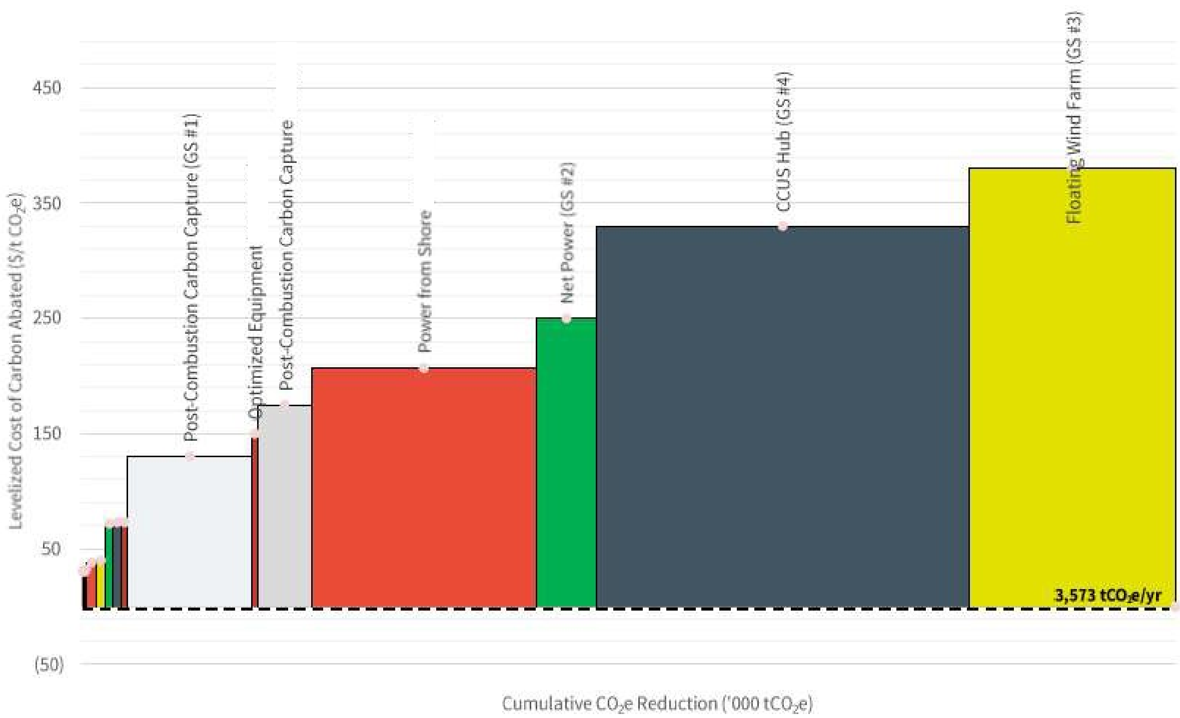
1. Progressing technical and economically viable pathways to achieve net zero offshore NL
2. Advancing policy solutions to facilitate these pathways
3. Develop a network for sharing information on pathways that will help inform potential investors in the offshore energy industry

As part of these objectives, The Net Zero Project plans to implement and provide awareness on CCUS and continue stakeholder engagement on this transformational pathway.

CCUS has emerged as an important area of interest from the perspectives of brownfield, greenfield, and mass storage in a hub concept. Building on the success of the recently CCUS Workshop in September 2022, the project is focusing on related action items and facilitating collaboration with various stakeholders in CCUS technology. Continued economic modeling, enabling/restricting policy investigation, and technical feasibility analysis will help inform priorities in this regard. This area presents an opportunity for the development of and investment attraction for a major innovation project.

As shown in the report *Net Zero Pathways for Canada's Offshore Oil and Gas Industry,* (Figure 1 below), CCUS (i.e., post-combustion carbon capture) offers a lower levelized cost of carbon abated (LCCA) compared to some other decarbonization technologies such as "power from shore" or "floating wind". Implementation of CCUS (via post combustion carbon capture) provides a substantial reduction in CO_2 emissions.

Figure 1 - Marginal Abatement Cost Curve (MACC) for Transformational Pathway, Net Zero Pathways for Canada's Offshore Oil Industry, page 153



CCUS has the potential to significantly reduce emissions in the NL offshore in the near to medium term should technical advances continue at their current pace. This will require concerted research and development effort as CCUS has never been applied in an offshore context before. Also evident is that policy and regulatory frameworks need to be in place to enable process.

2 Background

Signatories to the Paris Agreement, including Canada, have collectively pledged to reduce GHG emissions to limit the global temperature increase to below 2.0 degrees Celsius, and to pursue efforts to limit to 1.5 degrees Celsius to reduce the severity of climate impacts. To support its commitment, Canada has introduced a wide range of measures ranging from putting a national price on carbon to creating tax credit incentives for clean tech investments. For its part, the Government of NL committed in May 2020 to achieve net zero GHGs by the year 2050.

Industries worldwide are facing immense pressure to do their part to help fight climate change. Oil and gas production is a significant contributor to GHG emissions. In the Canadian context, oil and gas is the country's highest emitting sector – accounting for approximately 27% of total GHGs in 2020. Stakeholders agree that GHG emissions reductions are a top priority, however the path forward can be complex.

Canada is the world's fourth largest producer of oil and gas with regional and provincial economies heavily reliant on the revenues and jobs generated by the industry. The world will continue to rely on oil and gas even in an aggressive decarbonization scenario. Infrastructure and processes around the world are built around fossil fuel use and the changes required will take many years. Furthermore, the recent invasion of Ukraine by Russia has renewed the importance of energy security in resource development decision making. These factors suggest that oil and gas production will continue to be a part of the lives of Canadians for many years to come.

Decreased emissions intensity associated with its upstream oil and gas activities will provide benefits to the downstream end user. While Canada cannot control global demand it can supply the market with a low emission intensity product.

Since the start of oil production in late 1997 the NL offshore has produced approximately 2.1 billion barrels of oil.[1]. The province has indicated that approximately 25 per cent of provincial Gross Domestic Product (GDP) and 41 per cent of exports over the past 20 years can be attributed to the NL offshore oil industry.[2]

Canada's oil and gas sector accounted for approximately 179 Mt (or 27%) of the country's total greenhouse gas emissions in 2020. The NL offshore was responsible for 1.8 Mt (or 1.2%) of Canada's oil and gas sector and just 0.3% of the national total of all industries[3]. GHG emissions from the NL offshore contribute just 1.2% of Canada's total oil and gas industry emissions. The current carbon intensity of the oil produced in The NL offshore is one third of the national average. In fact, by 2030, Canada's average will still be approximately 33% higher than current NL offshore emissions[4]. The carbon intensity of future projects in the NL offshore is expected to be even less.

[1] https://www.cnlopb.ca/information/statistics/#rm

[2] https://www.gov.nl.ca/iet/files/advance30-pdf-oil-gas-sector-final-online.pdf

[3] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/oil-gas-emissions-cap/Oil%20and%20Gas%20Emissions%20Cap%20Discussion%20Document%20-%20July%2018%202022_EN.pdf Table 3

[4] Environment and Climate Change Canada, "2030 Emissions Reduction Plan", *publications.gc.ca*, Gatineau, Environment and Climate Change Canada, 2002, p. 48, https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf (accessed 14 November 2022)

The GHG emissions discussed above consist of scope 1 and 2 emissions and it is these emissions that are the focus of decarbonization efforts in the NL offshore. According to the "Greenhouse Gas Protocol" greenhouse gas emissions are categorized as follows:[1]

- Scope 1 emissions include direct emissions a company's owned or controlled sources. This includes on-site energy like natural gas and fuel, refrigerants, and emissions from combustion in owned or controlled boilers, and furnaces as well as emissions from fleet vehicles (e. g. cars, vans, trucks, helicopters for hospitals). Scope 1 emissions encompass process emissions that are released during industrial processes, and on-site manufacturing (e.g., factory fumes, chemicals).
- Scope 2 emissions include indirect greenhouse gas emissions from purchased or acquired energy, like electricity steam, heat, or cooling, generated offsite and consumed by the reporting company. For example, electricity purchased from the utility company is generated offsite, so they are considered indirect emissions.
- Scope 3 emissions includes all indirect emissions that occur in the value chain of a reporting company. To make a clear distinction between Scope 2 and Scope 3 categories the US Environmental Protection Agency (EPA) describes the Scope 3 emissions as "the result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain." Even though these emissions are out of the control of the reporting company, they can represent the largest portion of its greenhouse gas emissions inventory.

Since there is uncertainty about the end use of oil produced scope 3 emissions are not considered when pursuing net zero in the NL offshore.

On a global scale, The NL offshore features some of the lowest production emissions in the world, 30% below the global average since 2016. In a world that will continue to demand oil and gas, the supply of lower emissions intensity fuel is a very meaningful contribution to the fight against climate change.

The fact remains that the production of oil and gas results in significant GHGs. Within NL, the offshore oil and gas industry contributes 17% of the total provincial GHG emissions therefore the continuous pursuit of emissions reduction within the offshore oil industry along with the generation of potential negative emission streams is vital to the province's net zero by 2050 ambitions. It is also noted that 3 existing brownfield assets will likely be offline in 2050, driving this percentage down as a result, while proposed greenfield projects in the growth of the industry will be required to have net zero emissions, complementing that trend.

2.1 Offshore Project Descriptions

At the time of writing this paper, NL has 4 producing oil projects (Hibernia, Terra Nova, White Rose and Hebron) and 1 proposed oil project (Bay du Nord). There are no existing gas projects either producing or proposed.

A summary of the key attributes of each producing project is listed in Table 1 below.

Table 1 – NL Oil Projects Attribute Summary

Attribute	Hibernia	Terra Nova	White Rose	Hebron
Discovery year	1979	1984	1984	1980
Facility type	GBS	FPSO	FPSO	GBS
First oil year	1997	2002	2005	2017
Production to date (MB)[1]	1,239	425	323	217
Remaining reserves (MB)[2]	750	115	245	758
Estimated year of decommissioning	2047	2033	2037	2057
Emissions (kT CO_2e)[3]	527	572	326	541
Carbon intensity (kg CO_2e/bbl)*	13.0	50.8	39.8	14.1

[1] Up to Dec 31, 2022
[2] Proved, probable & possible at Dec 31, 2022
[3] Average of previous 3 years emissions when facility was producing (Terra Nova was shut down in 2020)

Below are brief descriptions of the current offshore oil projects.

2.1.1 Hibernia

Hibernia is in the Jeanne d'Arc Basin, 315 km east of St John's, Newfoundland and Labrador, Canada, in a water depth of 80 m. The field consists principally of two early Cretaceous reservoirs, Hibernia and Avalon, located at average depths of 3,700 m and 2,400 m respectively.

The field contains approximately three billion barrels of oil-in-place, of which 1.2B bbls have already been produced, and remaining recoverable reserves are estimated to be 750 million barrels.

The Hibernia field was first discovered in 1979. Development began in 1986 and construction started in 1991. First oil was achieved in November 1997 and since that time Hibernia has produced over 1.2 billion barrels of crude oil. With remaining reserves of over 750 M bbls, Hibernia is expected to continue producing oil well into the 2040's and potentially beyond.

The Hibernia platform is made of three components: Topsides, Gravity Base Structure (GBS), and an Offshore Loading System (OLS). The topsides facilities on the Hibernia platform accommodate drilling, producing, and utility equipment and provide living quarters for platform workers.[5]

2.1.2 Terra Nova

Discovered in 1984, the Terra Nova oil field was the second field to be developed on the Grand Banks offshore Newfoundland. Production from the field began in 2002, using the Terra Nova Floating, Production Storage and Offloading (FPSO) vessel. This was the first development in North America to use FPSO technology in a harsh weather environment featuring sea ice and icebergs. One of the largest FPSO vessels ever built, the Terra Nova is 292.2 metres long and 45.5 metres wide. It is located approximately 350 kilometres off the east coast of Newfoundland.

In 2021, Suncor and the Terra Nova joint venture owners finalized an agreement to move forward with the Asset Life Extension (ALE) Project which is expected to extend the production life by approximately 10 years and produce an additional 70 million barrels of oil. The Asset Life Extension Project has the potential to provide many benefits to the economies of both Newfoundland and Labrador and Canadian in the

[5] Hibernia Management and Development Company Ltd., *Hibernia.ca* (website), https://www.hibernia.ca/about-hibernia/, (accessed November 8 2022).

form of taxes, royalties and employment.[6] The ALE project is nearing completion with FPSO expected to resume production in 1Q2023.

2.1.3 White Rose

Discovered in 1984, the White Rose Field is located approximately 350 kilometres east of St. John's, Newfoundland and Labrador. The field is operated by Cenovus (formally Husky Oil) and is located on the northeastern margin of the Jeanne d'Arc Basin, has one principal reservoir: the Ben Nevis-Avalon reservoir. The field is being produced with a FPSO (Sea Rose) and to date has been supported by MODU units.[7]

Cenovus, on behalf of the other West White Rose Project (WWRP) proponents, Suncor Energy Inc. (Suncor) and OilCo, is leading the development of the WWRP. The White Rose field and satellite extensions are in the Jeanne d'Arc Basin, 350 km east of Newfoundland and Labrador in approximately 120 m of water.

The West White Rose Project will be developed through a fixed drilling platform consisting of a concrete gravity structure (CGS), built by the SNC-Lavalin- Dragados-Pennecon General Partnership (SDP), and an integrated topsides facility. SDP is constructing the CGS in the Argentia Graving Dock, located on the Argentia Peninsula approximately 130 km from St. John's, NL.[8]

2.1.4 Hebron

The Hebron oil field is located offshore Newfoundland and Labrador, Canada in the Jeanne d'Arc Basin 340 kilometres southeast of St. John's. The field was first discovered in 1980 and is estimated to produce more than 700 million barrels of recoverable resources. The water depth at the Hebron field is 93 metres (Mean Sea Level).

The GBS consists of a reinforced concrete structure designed to withstand sea ice, icebergs, and meteorological and oceanographic conditions. The GBS is designed to store approximately 1.2 million barrels of crude oil. The Bull Arm site was the primary construction site for the GBS. The GBS supports an integrated Topsides deck that includes a living quarters and facilities to perform drilling and production.

A substantial portion of the Topsides was engineered and fabricated in Newfoundland and Labrador, and the integration was performed at the Bull Arm Site. Fabrication of the Derrick Equipment Set (DES) and the Utilities/Process Module (UPM) of the topsides occurred in Ulsan, Korea. The project includes offshore surveys, engineering, procurement, fabrication, construction, installation, commissioning, development drilling, production, operations and maintenance and decommissioning.

Hebron is a major project that is delivering significant benefits to Newfoundland and Labrador: engineering, fabrication and construction, employment and training of a diverse workforce, research, and development opportunities, along with significant royalty and tax revenues.[9]

2.1.5 Bay du Nord

The Bay du Nord field (BdN) consists of several oil discoveries in the Flemish Pass basin, some 500 km northeast of St. John's. The first discovery was made by Equinor in 2013, followed by additional discoveries in 2014, 2016 and 2020.

Confirmed discoveries in 2020 in adjacent exploration licence EL1156 (Cappahayden and Cambriol) are potential tie-ins in a joint project

[6] https://www.suncor.com/en-ca/what-we-do/exploration-and-production/east-coast-canada/terra-nova
[7] https://en.wikipedia.org/wiki/White_Rose_oil_field
[8] http://westwhiteroseproject.ca/about/
[9] https://www.hebronproject.com/about-hebron/

development. The Bay du Nord discovery is at a water depth of approximately 1170 metres whilst the new discoveries are at approximately 650 water depth.

Equinor is considering developing the Bay du Nord field using a FPSO, which also is a solution for tie-back of adjacent discoveries and future prospects. [10]

The optimization of the Bay du Nord development project is ongoing to make it more robust for future market and evaluation to include confirmed new discoveries in adjacent licence EL1156 (Cappahayden and Cambriol).

The BdN Project was granted environmental approval by the Government of Canada in March 2022. A final investment decision by Equinor and its partners is the last hurdle before project sanction. First oil is expected to be produced in the late 2020s.

The proposed Bay du Nord development is designed to optimize energy efficiency. It is expected to produce approximately half of the GHG emissions of the current lowest emitting production facility offshore Newfoundland and Labrador[11]. Mitigation measures to be employed to achieve this include no routine flaring, the use of high efficiency burners when flaring may be required, evaluation of a pilotless flare ignition system, and the recovery of low-pressure flare gas and the use of combined cycle turbines. BP is Equinor's partner in the Bay du Nord, Cappahayden and Cambriol discoveries.

2.1.6 Additional Developments

There is significant opportunity for growth in the NL offshore. In the IEA's net zero scenario, oil and gas would still supply approximately 15% of the world's energy needs in 2050..[12] In the next 30 years oil production will continue and should be produced in jurisdictions that focus on the lowest carbon emissions, such as the NL offshore. Seismic data collected thus far suggest that while only a fraction of the province's offshore area has been assessed, world class resources remain untapped.

Future projects in offshore NL are predicted to produce the lowest carbon oil in Canada and are expected to operate some of the lowest emitting oil production facilities in the world. These projects may be considered "best in class" based on their lower predicted carbon intensities.

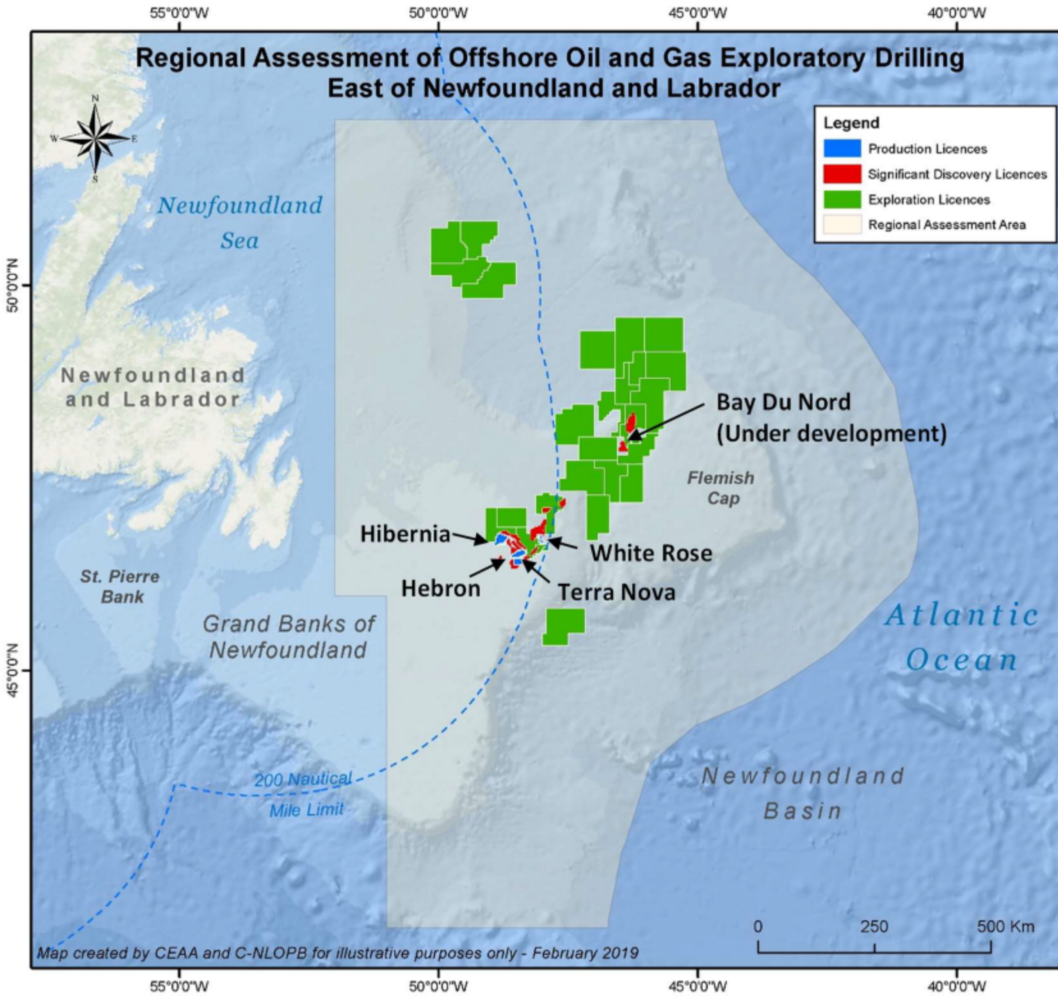
The Canadian government has announced that future oil and gas projects will need to meet higher standards and be subject to the federal impact assessment regulations. The amount of GHG emissions will be required to be best-in-class and net zero by 2050. Also, if projects are approved under the impact assessment process they will be required to fit in under an emissions cap.

With the expectation for world's future demand for oil in the near term and beyond 2050, Canada is well positioned to be a world leader in energy security, safety, and low emission production all while meeting it's ESG obligations.

Figure 2 on the following page shows the regional assessment area for oil and gas development in offshore NL including major projects.

[10] https://www.equinor.com/where-we-are/canada-bay-du-nord
[11] Bay du Nord Development Project Environmental Impact Statement, Table 8.21
[12] https://www.canadianenergycentre.ca/oil-and-gas-demand-to-stay-strong-through-2050-a-building-block-of-our-world/

Figure 2 - Impact Assessment Agency of Canada (location of NL Offshore Major Oil and Gas Projects added)



In April 2022, the Canadian government indicated that proponents of new oil and gas projects will be required to demonstrate "best in class" low emissions performance[13]. The fact that The NL offshore already has a reputation for low emitting oil production facilities may attract future economical oil and gas development that could meet this "best in class" requirement and help meet the world's energy needs.

[13] Draft guidance for best-in-class GHG emissions performance by oil and gas projects. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/best-class-draft-guidance.html

2.2 Offshore Emissions Description

In 2019, the province's total GHG emissions were approximately 11MT / year. Of that offshore emissions are 1.9 MT / year accounting for approximately 17% of the total provincial emissions.[14]

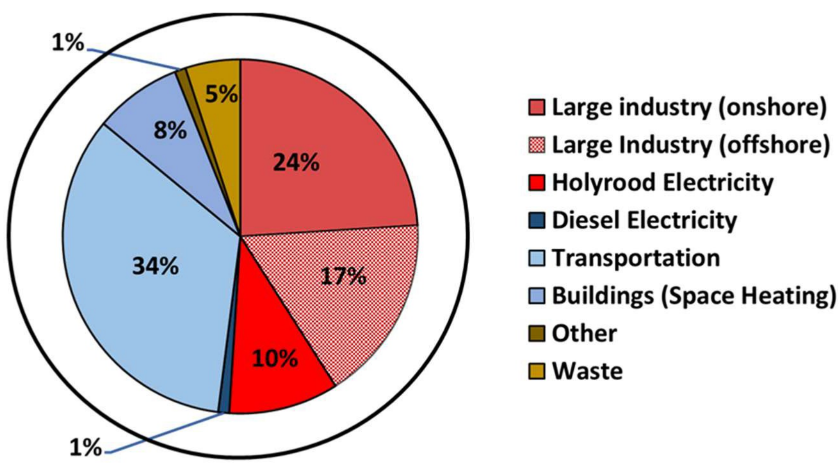
For perspective, The NL offshore emissions make up only 1.2% of Canada's oil and gas sector and just 0.3% of the national total when considering emissions from all sources. Some of The NL offshore oil production facilities (such as the Hibernia platform) are among the lowest emitting of their type in the world. Further driving down The NL offshore emissions will become increasingly important to making energy products more attractive as the world transitions to net-zero.

Offshore oil and gas facilities need significant amounts of electricity for their operational needs. The facilities in offshore NL generally use simple cycle turbines to create the electricity and power compressors. The turbines generally have a power output between 20 MW and 40 MW. A turbine generating 20 MW of power will emit approximately 100 kTPA of CO_2. Most of the emissions in offshore NL come from the exhaust of these turbines that burn natural gas as fuel. Emissions also result from flaring and other fugitive emissions.

The ability to capture and permanently store CO_2 emissions from turbine exhaust combined with reduced flaring and fugitive emissions will be important factors in the decisions to further develop The NL offshore oil and gas resources and ensure the existing projects remain ESG competitive.

Figure 3 below shows the breakout of GHG emissions in the province of NL for the year 2019 (2019 data is presented because 2020 was an anomaly with Covid-19 shutdowns) including 17% total emissions from the offshore oil and gas industry. Further GHG data for 2022 will be released in April 2023.

Figure 3 - Sources of GHG Emissions in NL (2019)



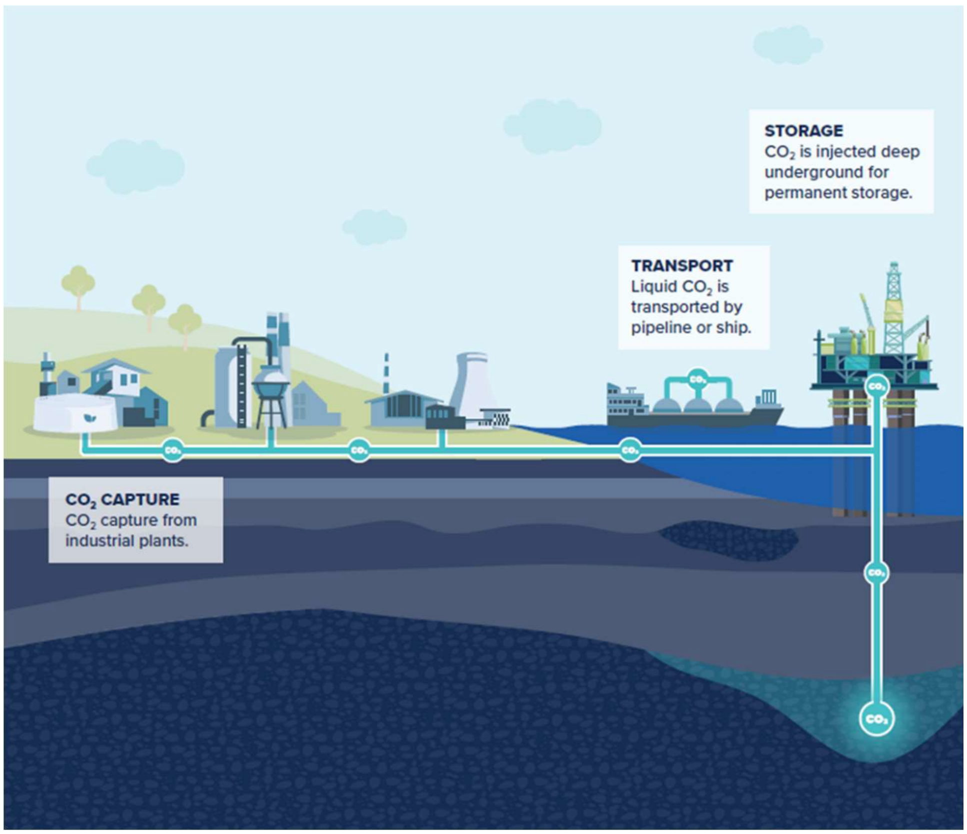
[14] Credit: NL Provincial Government - source C-NLOPB Annual reports

2.3 CCUS as a pathway to Net Zero for the NL Offshore

CCUS is a technology that captures CO_2 and permanently stores it deep in the ground. The technology, which is proven and has existed for decades, captures CO_2 emissions that come from a plant or industrial site and stops them from being released into the atmosphere. The captured emissions are then transported and stored underground in deep geological formations, typically one kilometer or more below the surface. CO_2 can also be recycled and used in a variety of innovative ways.

Carbon capture and storage (CCS) involves three steps – capture, transport, and storage. As shown in Figure 4 below.

Figure 4 – Illustrative Example of a CCS Process[15]



CO_2 is captured at its source and transported (normally by pipe or ship), to be permanently stored in rock formations at least a kilometre under the ground.

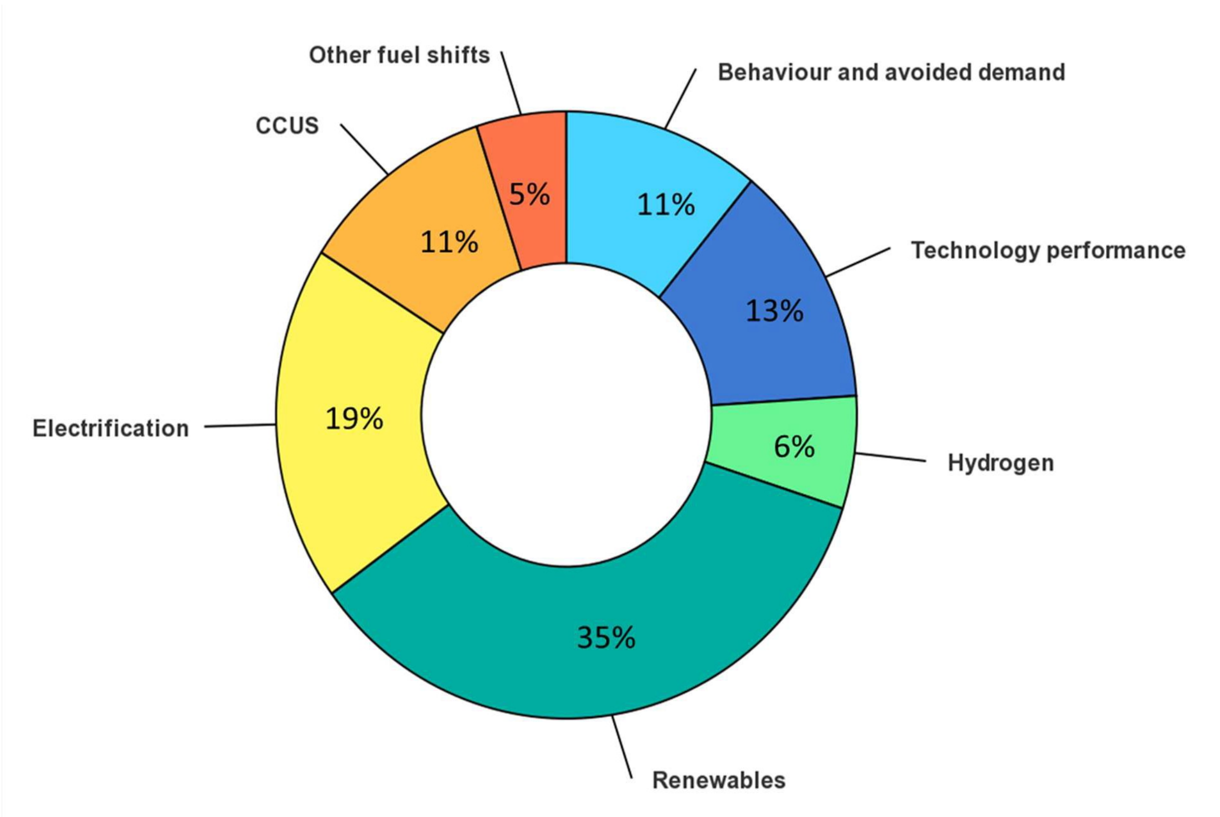
CCUS is in use onshore in other parts of Canada and is critical to meeting the country's long-term energy needs and climate goals. The IEA and other sources have stated that without substantial support to further develop and employ CCUS technology, it will be difficult for Canada (and the rest of the world) to meet its emission reduction targets.

[15] Global CCS Institute - Understanding Carbon Capture and Storage (CCS) 101

Figure 5 below was developed by the IEA and shows the various emission-reduction mitigation measures and the estimated contribution each will make to a 2050 net zero scenario. As shown, CCUS will play a significant role in global decarbonization efforts.

CCUS technology is primarily being used in onshore applications in Canada and around the world. While there are examples of CCS in the offshore in Norway, there are no examples of CCUS projects which capture turbine exhaust gases to reduce emissions from offshore production facilities, such as what is required in the NL offshore.

Figure 5 – Cumulative Emissions Reduction by Mitigation Measure in the Net Zero Scenario, 2021-2050. [16]



[16] https://www.iea.org/data-and-statistics/charts/cumulative-emissions-reduction-by-mitigation-measure-in-the-net-zero-scenario-2021-2050

3 Carbon Capture

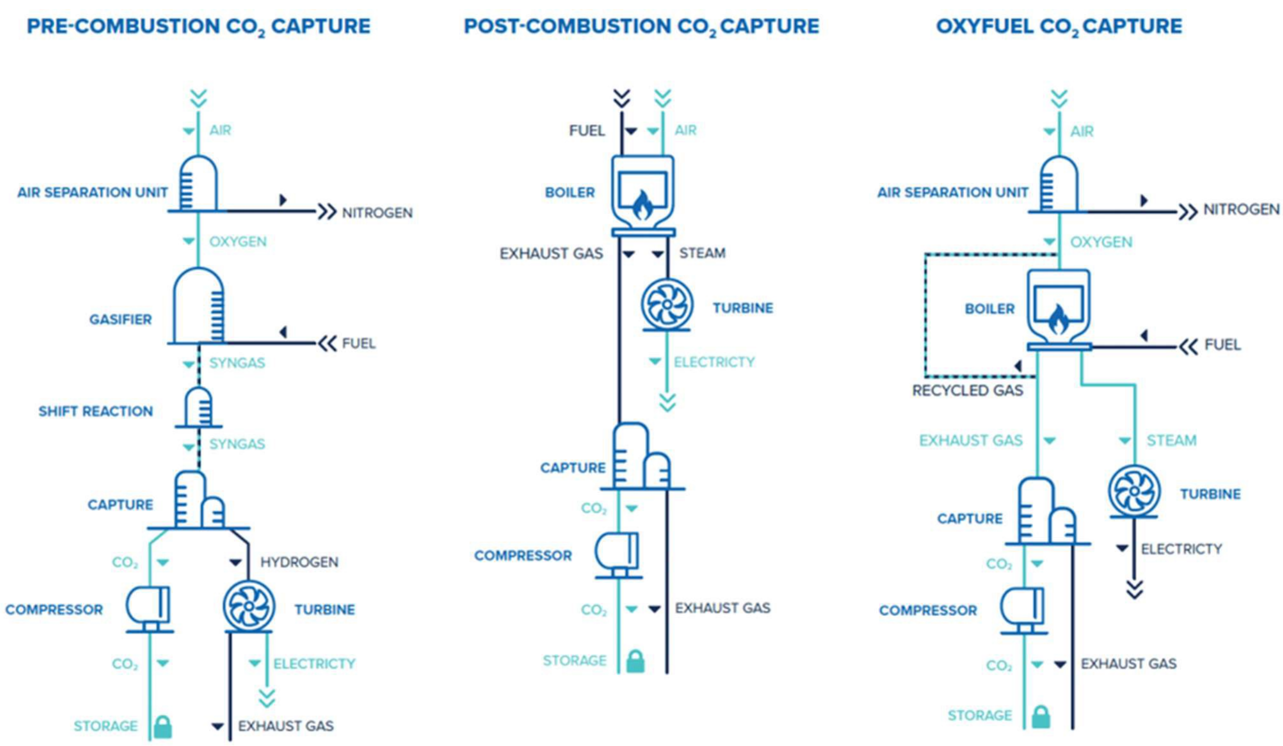
This section of the white paper explains the carbon capture process and the leading technologies commercially available and in development, with a focus on applicability to the NL offshore oil and gas industry. While the application of carbon capture technologies to the offshore oil and gas industry are relatively rare, they have been applied in various onshore industries since the 1970's.

3.1 Capture Technologies

Carbon capture technology can be used on any large source of CO_2 but is most often associated with the capture of CO_2 from industrial processes where fossil fuels are combusted for power generation. Currently, offshore NL production facilities use natural gas and diesel (i.e., fossil fuels) to fuel turbines and generate electricity and power compressors to meet their energy needs. Capturing and removing carbon from the turbine exhaust gases are key to reducing GHG emissions in the NL offshore. The flue gas typically contains 3-5%[17] CO_2 by volume, and it's release into the atmosphere is the source of most of the offshore emissions.

Three main combustion capture technologies are shown in Figure 6 below.

Figure 6 – Illustrative Example of Carbon Capture Technologies[18]



17 https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/decarbonizing-gas-turbines-ccus-gea34966.pdf Figure 8

18 https://www.globalccsinstitute.com/ccs-explained-capture/

The selection of technology is dependent on many factors, so there is no consensus on which technology is the right one for the future. In the NL offshore where space and weight are at a premium, the process that is least complicated, requires less energy, and involves minimal equipment installation may be the favoured approach. However, the least complicated process may be the least efficient at capturing carbon therefore trade offs between cost, efficiency and space constraints need to be evaluated.

There are other "carbon negative" capture technologies and processes that may be utilized for removing CO_2 directly from the atmosphere including Direct Air Capture (DAC), enhanced weathering, ocean fertilization, afforestation, and reforestation[19]. According to the IEA and the IPCC, the potential capacity of negative emission technologies remains highly uncertain. It depends on many factors, the most important one being the emission reduction trajectories the world will follow. These technologies may be utilized in the future to complement capturing CO_2 from combustion to achieve net zero emissions.

In addition, capture technologies can be utilized to abate carbon emissions when producing hydrogen from natural gas via steam methane reforming. Clean burning hydrogen fuel can be then substituted for fossil fuels and utilized to power industrial processes without carbon emissions.

The primary focus of this paper pertains to abating carbon emissions due to combustion of fossil fuels since combustion is how most of the primary energy contained in fossil fuels is transformed into energy and is the largest source of CO_2 emissions in the NL offshore.

3.1.1 Post-Combustion Carbon Capture

Post-combustion carbon capture is emerging as a key technology focus area for the near to medium term and appears to have the best chance of being successfully applied to NL offshore with potential for brownfield and greenfield adoption and it can be considered one of the most cost-effective options to achieve net zero emissions compared to other solutions. It involves capturing carbon after combustion when CO_2 is more concentrated in the flue gas. Using this technology does not require making any changes to the base design of turbines or other power plants. It is a fundamental difference with the other families of capture technologies, Oxyfuel Combustion and Pre-Combustion Capture, which is discussed separately below.

3.1.1.1 Amine Solvents

Amine solvents are used extensively in post-combustion carbon capture in the onshore industries (such as cement and steel making) and the technology has been in use since the 1970's. In the offshore oil and gas industries, amine plants are very rare, and to date none are used to capture carbon from turbine exhaust.

Some gas fields contain natural gas (i.e., methane) mixed in high proportions with carbon dioxide. An example of this is the Sleipner oil field in Norway. The raw produced gas from this field contains approximately 9% carbon dioxide and is separated from other gases prior to combustion using standard gas processing with an amine solvent. This done to so the natural gas can be purified to meet pipeline specifications and be commercialised. This is where decades of experience with these technologies come from, which have been adapted in the last decade for combustion gases.

Generally, in a post-combustion carbon capture plant, the liquid amine solvent (or absorbent)

[19] https://www.iea.org/commentaries/going-carbon-negative-what-are-the-technology-options

flows from the top of the absorber tower via a liquid distributor, like a shower head, and trickles down on the structured packing, where it is collected at the bottom.

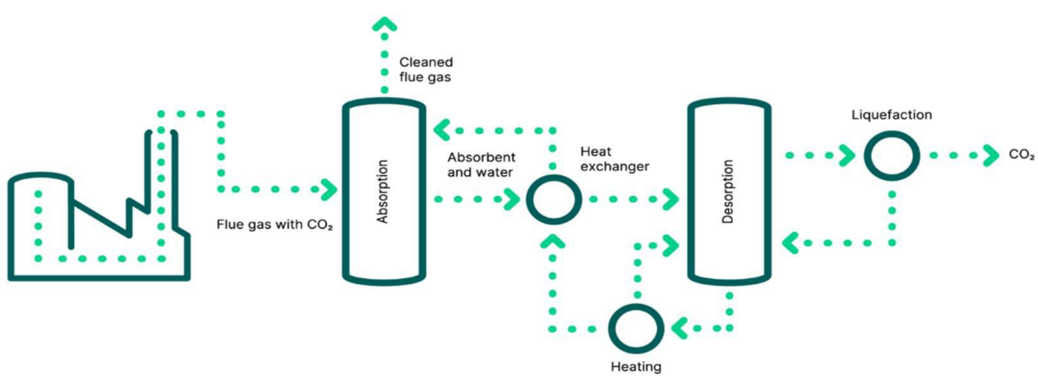
Packing is a material used in the gas processing industry to increase the contact surface area between the gas and the liquid amine solvent so that impurities (such as CO_2) can be effectively removed. Packing can be made of various materials such as metal, plastic or ceramic and come in different geometric shapes such as cylindrical tubes (i.e., raschig rings). The larger surface area is needed between the combustion gas and the chemical solvent to allow for the chemical reaction to take place.

Exhaust gas (or flue gas) enters via a gas distributor and flows upwards in the opposite direction to the liquid. The chemical reaction happens at the interface between the gas and the liquid film spread on the packing. In a typical post-combustion capture process, the solvent at the bottom is rich with CO_2 and is then sent away to be heated up to reverse the chemical reaction. The CO_2 is released as a gas again and is compressed for transport and geological storage. The solvent meanwhile has recovered its ability to absorb CO_2, is cooled down and returns to be contacted again with more CO_2.

Because post-combustion carbon capture can be added to existing power plants when there is ample space and no weight restrictions, it also makes sense to ensure that new power plants are located, designed, and engineered to facilitate a retrofit with CCS: this is a concept called 'CCS-Readiness'. Again, this is primarily an onshore CCS development. The challenges with using amine plants in the offshore will be discussed in a later section.

The Figure 7 below illustrates a typical post-combustion carbon capture process using an amine-based solvent.

Figure 7 – Post-Combustion Carbon Capture Process Utilizing Amine[20]



[20] Aker Solutions. "Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry", 2022.

3.1.1.2 Emerging Post-Combustion Carbon Capture Technologies

There are multiple research programs ongoing around the world to develop and evaluate alternative technologies for CCS including chemical looping combustion, membrane separation and cryogenic separation among others. Companies continue to better refine existing amine technologies that are more efficient at capturing carbon, less toxic to the environment and require less energy. Since CCUS provides an important pathway to lower emissions the government of Canada is investing significantly to incentivize research, development, and demonstrations to advance the commercial viability of additional CCUS technologies.[21]

The technologies that enable CCS are evolving. As the world's ambition to lower emissions increases, considerable research and development into better and more cost-effective CCS technologies are underway. Technology breakthrough will play an important role in reducing the costs of CCS. Improvements in technology are currently underway that are both incremental (improvements of existing technologies) and breakthrough (new developments in form and/or function).

A qualitative scale known as the Technology Readiness Level (TRL) defines the maturity of technologies within an increasing scale of commercial deployment; see Table 2 below.

Table 2 – Simplified definitions of Technology Readiness Level (TRL) (IEAGHG 2014) for CCS technologies.[22]

CATEGORY	TRL	DESCRIPTION
Demonstration	9	Normal commercial service
	8	Commercial demonstration, full-scale deployment in final form
	7	Sub-scale demonstration, fully functional prototype
Development	6	Fully integrated pilot tested in a relevant environment
	5	Sub-system validation in a relevant environment
	4	System validation in a laboratory environment
Research	3	Proof-of-concept tests, component level
	2	Formulation of the application
	1	Basic principles, observed, initial concept

[21] https://www.nrcan.gc.ca/science-and-data/funding-partnerships/funding-opportunities/funding-grants-incentives/energy-innovation-program/energy-innovation-program-carbon-capture-utilization-and-storage-stream/23815
[22] https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf

The emerging technologies described in the following subsections are not considered ready for normal commercial service. They range from research and development (such as gas separation using nozzle geometry) to subscale demonstration (such as using nano-materials and modularization).

It is important to note that in the offshore oil and gas industry with space and weigh constraints at the forefront, emerging carbon capture technologies that are less complex, do not introduce new chemicals and prioritize a compact design with a small footprint may be the most practical solutions. There are several technologies advancing but not fully commercialized that may meet the challenge of implementing carbon capture in offshore NL. Some of these are discussed below.

3.1.1.2.1 Modulization

Aker Carbon Capture (ACC) has designed a "Just Catch Offshore" module which is shown in Figure 8 opposite.[23] It is perhaps the only carbon capture system to date that is targeted for use in the offshore and specifically for FPSOs. It holds some promise for application in the NL offshore, especially for greenfield FPSOs and potentially other brownfield facilities.

ACC's solution has recently been qualified by DNV and is now ready to be deployed in offshore oil and gas fields where the firm's solution can significantly reduce emissions from offshore power generation.[24]

According to DNV's qualification, the offshore facility is considered fit for harsh weather conditions with severe motions. The solution is now ready for a traditional field development project path, including a FEED phase, EPC delivery and operational support.

The solution is based on a modularized design with multiple capacity options. ACC believes that the capacity can be increased and adjusted in accordance with the specific requirements by combining modules, providing significant flexibility towards capture capacity and power demand.

The modules can be prefabricated and lifted onto an FPSO (for example) at the fabrication yard for hook-up to the gas turbine stacks. They can fit into any type of application where gas turbines are present, including bottom-fixed (i.e., GBS) as well as floating production facilities, such as FPSOs, FLNG, power hubs and offshore power gas plants.

A proprietary amine solvent has been developed by ACC for use in the Just Catch Offshore module and has attributes such as low degradation, low emissions, and low toxicity.

ACC indicates that after feasibility, concept and FEED studies are completed, delivery time is estimated to be 20-24 months, with expectations to improve the timeline once optimization of the fabrication line is completed.

Figure 8 – Aker Carbon Capture: Just Catch Carbon Capture Modular Unit

[23] https://akercarboncapture.com/offerings/just-catch-offshore/

[24] https://www.offshore-energy.biz/aker-carbon-captures-modularized-offshore-facility-wins-dnvs-stamp-of-approval/

3.1.1.2.2 Using Nozzle Design and Geometry to Separate Gases

A local NL company, MA Procense Inc. (MAPI) along with the Centre for Cold Ocean Resources Engineering (C-CORE) has progressed the first phase of a comprehensive research project exploring a compact solution for carbon capture offshore NL.[25] They are investigating the use of supersonic nozzles to separate CO_2 from offshore turbine exhaust flue gases.

The first phase of the project is now completed with the objective to optimize the design and performance of the nozzles for offshore applications where weight and footprint are at a premium. MAPI and C-CORE explored nozzle design through a combination of computational fluid dynamics (CFD) simulations and physical experiments in a laboratory set up at C-CORE. Manufacturing capabilities for precise machining and 3D printing of metal components were also developed during this phase.

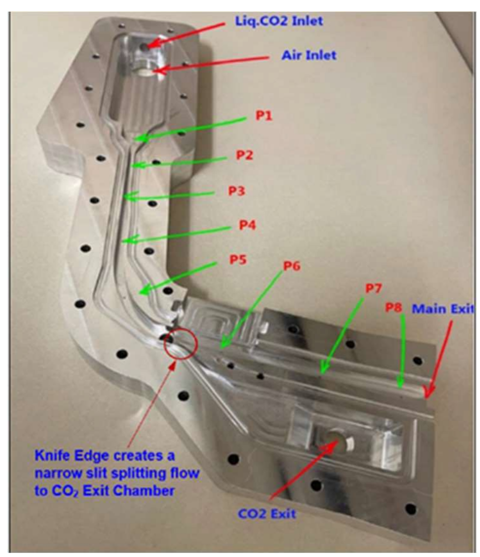
The technology is based on the use of supersonic nozzles in which flue gas is accelerated in converging-diverging (de Laval) nozzles (see Figure 9). The flue gas is accelerated to extremely high velocities (i.e., greater than Mach 2), such that the gas is expanded and cooled to extremely low temperatures. Under these flow conditions and very low temperatures, CO_2 is frozen out of the flue gas mixture and then separated using centrifugal acceleration. The frozen CO_2 particles are then separated into a chamber in which they may be pressurized and transferred to downstream processes for subsequent transport to a subsurface reservoir.

The Phase 1 scope also included studying the electromagnetic separation of charged particles and how this could optimize carbon capture. This method could potentially eliminate the need for a curved nozzle (L- or J-shaped) and thereby minimize energy requirements to drive the flue gas through the proposed nozzle system.

The project also tested the feasibility of applying the technology as a retrofit on an existing offshore floating production storage and offloading (FPSO) vessel. This brownfield application was not considered feasible at this time and would more likely be better suited to be designed into a new facility.

While the first phase of the project was considered successful, more study is required. The next phase of the project would focus on improving the Technology Readiness Level (TRL), complementary design and modelling.

Figure 9 – Post-Combustion Carbon Capture – Nozzle Technology (MA Procense)



[25] Developing Compact Capture Technology for Removal of CO_2 from NL Offshore Oil and Gas Production Facilities, MAPI, C-CORE, Aker Solutions, Professor Vlasta Masek, August 2022

3.1.1.2.3 CO_2 Capture Using Nano-Materials

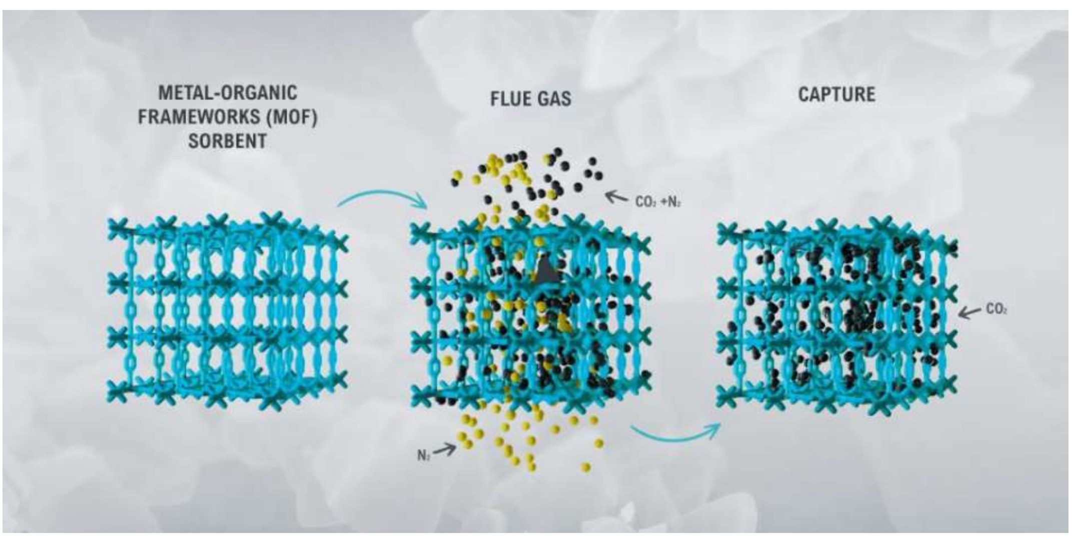
There are emerging post-combustion carbon capture technologies that use solid adsorbent materials (like filters) that can remove CO_2 without any or minimal amine solvents. These new types of materials have the potential to transform carbon capture.

Dr. Michael Katz from Memorial University is exploring materials that can separate CO_2 from other gas by allowing it to pass through the material's pores but restricting and catching larger molecules such as nitrogen and methane.

Other researchers have developed similar very small nano-materials collectively called metal-organic frameworks, or MOFs. These MOFs could help capture more than 90% of the carbon dioxide produced by natural gas power plants when they generate electricity.

MOFs have very large internal surface areas and are highly customizable. Unfolded, a gram of the material, roughly the weight of a paper clip, could cover an entire football field. The MOF's honeycomb structure of nano-sized pores (as shown in Figure 10 below) can capture CO_2emissions like a sponge, and the high surface area-to-volume ratio makes it a potentially ideal compact material to support and improve current CCS technology. This technology holds great promise for locations such as offshore NL that have significant space and weight constraints. At very low temperatures, the molecules in the MOF form a solid bond with the CO_2. Moderate heat then strips the CO_2 molecules away to be collected and stored. Once cleared of the CO_2, the MOF returns to its original state, making the material reusable even after repeated contact with the heat and steam that sweeps out the captured emissions. The MOF's pores can also be lined with specific amine molecules that grab CO_2 selectively. The capture process is also energy efficient, since collecting the CO_2 off the material only requires steam that is already widely available in natural gas-fired power plants.

Figure 10 – MOF sorbent material capturing CO_2 gas molecules[26]



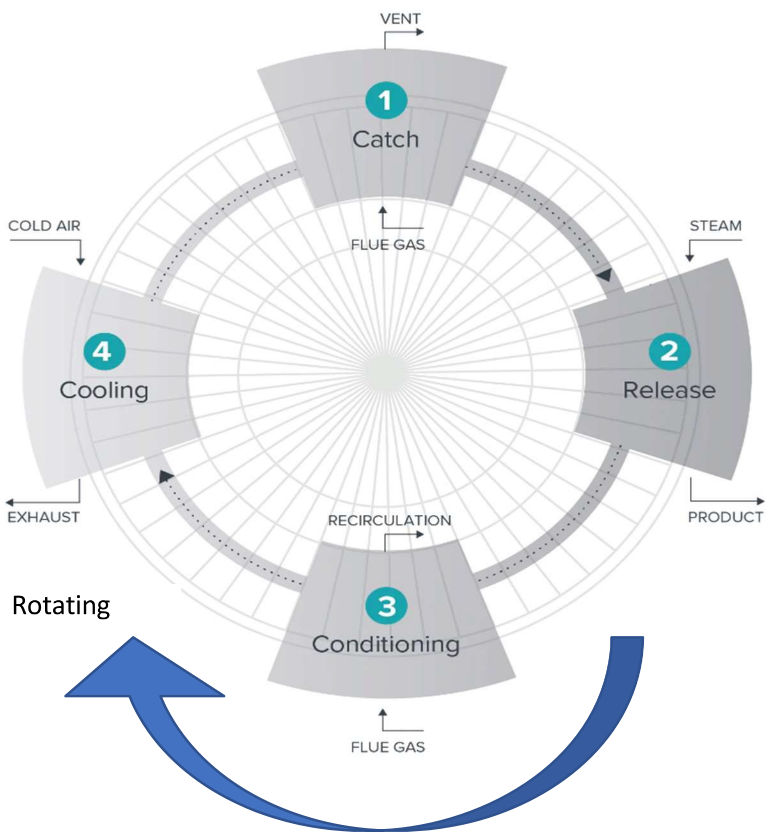
[26] https://svanteinc.com/2021/12/16/a-scalable-solution-for-carbon-capture/

Companies such as Canadian-based Svante are working on commercializing their MOF technology for carbon capture. Svante has a pilot plant in operation in Lloydminster, SK at one of Cenovus oil fields where they are testing the technology on turbine exhaust gas.

Svante is trying to increase the carbon capture capacity of their MOF by manufacturing the materials in sheets and using rotating adsorption machines (RAMs) shown in Figure 11. Currently, Svante offers carbon capture solutions that can capture up to 1,000 tonnes per day (tpd). Future development will allow Svante to scale-up to about 3,000 tpd to meet the needs of large emitters.

While promising, the MOF work is in its early stages and is part of longer-term research into the fundamental science to support lower-emission technologies.

Figure 11 – Post-Combustion Carbon Capture – Rotating Adsorption Machine (Svante)



3.1.1.2.4 Combining Amines and Rotating Packed Beds

Another developing technology that may be suitable for offshore NL uses a combination of amines and rotating packed beds to capture carbon more efficiently than just using amines alone. This allows a more compact design with smaller equipment requiring less space than just using amines alone.

Carbon Clean's "CycloneCC" unit (see Figure 12 below) is a solution that combines their proprietary amine solvent and a process technology called rotating packed beds (RPBs). When utilized together it is expected to be more efficient than conventional carbon capture methods, reducing the size of the equipment needs and the costs while meeting performance requirements.

Built on a skid, each CycloneCC unit will be self contained and modularized, ready to install. It is a scalable solution that can be cost effective. Standardized designs allow users to add units to increase capacity.

The RPB contactor consists of packing material mounted on a horizonal (or vertical) shaft, casing, and a liquid distributor. The rotation of unit creates centrifugal force that helps the amine liquid solvent better utilize the packing, contact the exhaust gas and capture CO_2.

The CycloneCC unit's current capacity for carbon capture is in the range of 10 - 300 tpd of CO_2.

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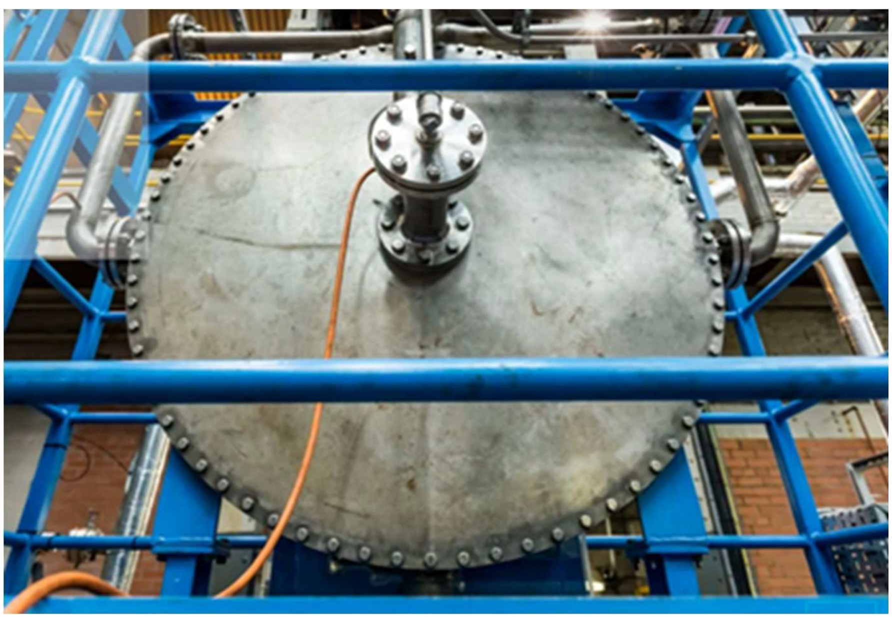
Figure 12 – Post-Combustion Carbon Capture – Amine solvent with Rotating Packed Beds (Carbon Clean)



3.1.2 Oxyfuel Combustion

Oxyfuel combustion carbon capture processes use pure oxygen rather than air for combustion of fuel. When oxygen in used in combustion rather than air it produces exhaust gas that is mainly water vapour and CO_2 that can be easily separated to produce a high purity CO_2 stream.

This process requires modifications of the base design of turbines, however. This is typically done by adding equipment and processes upstream of the turbine where combustion takes place.

An example of a type of oxyfuel combustion is the NET Power technology. [27] NET Power describes their technology as a Allam-Fetvedt Cycle (AFC), which is essentially a specialized Brayton cycle in which the combustor is supplied with three flows: fuel gas, which is compressed in the fuel compressor; oxygen, which is produced in an air separation unit and then compressed; and a carbon dioxide working fluid that is heated in the multi-flow regenerator. [28]

The CO_2 is recycled in the NET power process, but some excess is left over. The excess CO_2 which is not recycled is captured and is ready for transport. It can either be sequestered and stored in geological formations or sold to industries such as the medical, agricultural, and industrial sectors.

In addition, other companies such as Aker Solutions are developing a high pressure oxyfuel combustion solution such as the Zeus Project which involves developing an underwater power station that burns natural gas to create electricity all on the seabed. CO_2 is captured and stored as part of generating zero emission energy.[29]

Some of the main advantages of the oxyfuel combustion is the ability to capture up to 100% of the CO_2, which is higher than the capture rates for post-combustion carbon capture, and there are no other emissions released into the atmosphere (including no NOx). Some of the main disadvantages are that air separation equipment needs to be added to the process and the process is quite energy demanding.

Oxyfuel combustion carbon capture is generally used in the onshore where ample space is available. The retrofit of an oxyfuel combustion carbon capture process on an existing brownfield offshore facility would require not only space but significant modifications and redesign (likely replacement) of the turbine and auxiliary systems. Even for a new greenfield facility, implementing an oxyfuel combustion solution may be economically prohibitive compared to other post-combustion capture caption options.

3.1.3 Pre-Combustion Carbon Capture

During pre-combustion carbon capture CO_2 is removed from the fuel prior to combustion. This is done by converting the fuel that the turbine burns into hydrogen.

Generally, pre-combustion carbon capture uses a process called steam methane reforming to create hydrogen and CO_2 from natural gas. The hydrogen is then used by the turbine and the CO_2 is collected and transported to storage or utilized elsewhere. Some turbines can burn a blended mixture of natural gas and hydrogen which would help reduce emissions. However, most existing turbines in the NL offshore would likely be unable to burn 100% hydrogen. Research is underway by the various turbine manufacturers to develop turbines that can reliably utilize

[27] https://netpower.com/technology/
[28] https://www.powermag.com/net-powers-first-allam-cycle-300-mw-gas-fired-project-will-be-built-in-texas/
[29] https://www.upstreamonline.com/focus/zeus-to-take-gas-to-power-technology-to-poseidons-realm/2-1-1201911

hydrogen as a primary fuel. In addition, introducing hydrogen into existing facilities would require a review to determine what modifications are necessary for their fuel gas systems.

Even though hydrogen is a very clean burning fuel with no emissions other than water, the energy requirements needed for pre-combustion carbon capture process may be significantly more than required for post-combustion carbon capture.

There are currently no large-scale commercial CCS power plants using pre-combustion capture in operation offshore.

Pre-combustion carbon capture may not be practical for NL offshore since the process is most complex and requiring more equipment. Significant additional space and structural supports may be required.

A summary of the attributes of the main types of capture technology are summarized in Table 3 below.

Table 3 – Advantages and Challenges of Capture Technologies

Technology	Advantages	Challenges
Post-Combustion Carbon Capture	• Minimal changes to base turbine design • Least complicated integration to existing facilities • Likely most cost-effective option	• Requires further study to optimize for space and weight constraints • Trade offs between cost versus capture effectiveness
Oxyfuel Carbon Capture	• CO_2 capture effectiveness up to 100% • Smaller capture equipment required due to less flue gas volume	• Requires air separation equipment to generate pure oxygen for combustion • High demand for energy
Pre-Combustion Carbon Capture	• Creates clean burning hydrogen fuel for turbines with no emissions	• Requires steam methane reforming, electrolyzer or other supply of hydrogen • Requires hydrogen storage and handling facilities

3.1.4 NL Offshore Installation Implications

Even though post-combustion carbon capture may be considered the most feasible capture technology option for offshore NL, it has many challenges for offshore implementation. While it may be one of the relatively lower cost technologies to capture emissions from turbine exhaust, it still remains a high-cost endeavor on an absolute basis.

3.1.4.1 Environmental

A significant issue with the current commercialized post-combustion carbon capture technology is that it introduces potentially new chemicals (i.e. amine-based solvents) into the offshore environment that are used for CO_2 absorption. These new chemicals may complicate the offshore processes. Amines generally degrade over time and must be cleaned by reclamation. Reclamation will generate waste which may need to be transported onshore for disposal. Some amines are more toxic to the ocean than others. Suppliers have developed amines that have very low degradation rates and minimal impact on sea life. These amines should be selected for offshore use, even if they have a slightly higher heat consumption. The use of MOFs with no chemicals is likely a better approach from an environmental stand point.

3.1.4.2 Safety

The resulting concentrated CO_2 from the capture plant will have safety implications for an offshore facility. CO_2 is an inert gas and will not present a fire risk to a platform. However, CO_2 is toxic at high concentration and will also cause asphyxiation if oxygen concentrations are too low. The issues presented by CO_2 are familiar to facility operators processing natural gas and oil and therefore the safety level of the facility is not expected to be significantly affected by CO_2 systems.

3.1.4.3 Regulatory

A retro-fit of an existing facility would result in a high cost, large scale, muti-year project requiring significant engineering, procurement, execution, and commissioning activities. A project such as this would almost certainly result in a development plan amendment involving the regulator and statutory certification. Downtime and deferred production would need to be considered in the economics of the project (see Section 8 for a discussion of the economics of CCUS in the offshore).

3.1.4.4 Space and Weight Constraints

In a retrofit project, a critical balance would need to be found between the target carbon capture efficiency, available space, weight considerations, and electrical power demands. Potentially it may only be feasible to capture a portion of the CO_2 emissions for a given facility.

Installation of carbon capture equipment is a challenging process when designing around the constraints of an existing offshore facility. Existing facilities, and in particular, floating facilities typically have weight and space optimized during their original design. The considerable space, electrical power and structural supports demands for the additional infrastructure required for carbon capture would not typically be available on an existing facility.

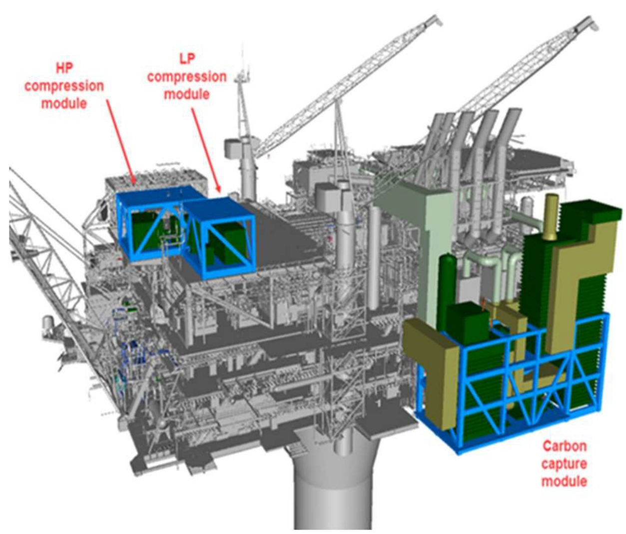
A technology that utilizes a small footprint and has low energy needs would be desirable and installation on a new (greenfield) facility that could be originally designed to include a capture plant would be more feasible and cost effective than a retrofit of a brownfield facility.

3.1.4.5 Energy Requirements

In a retrofit project, a critical balance would need to be found between the target carbon capture efficiency, available space, weight considerations, and electrical power demands. The heat is required to regenerate the absorbent. The electrical power is mainly required for CO_2 compression. There are also numerous smaller consumers including fans, pumps and heaters. In many cases, these utilities may not exist on the facility and therefore modifications will be required.

Figures 13, 14 and 15 below illustrate how a carbon capture processes could theoretically be added to existing fixed facilities (GBS and FPSO).

Figure 13 – Platform Modified for Carbon Capture[30]



[32] Aker Solutions., Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry, Study Report, Document No.: 90001-21L01-G-SY-00001-001, Revision No.: E2

Figure 14 – FPSO Lay Out with Post-Combustion CO_2 Capture [31]

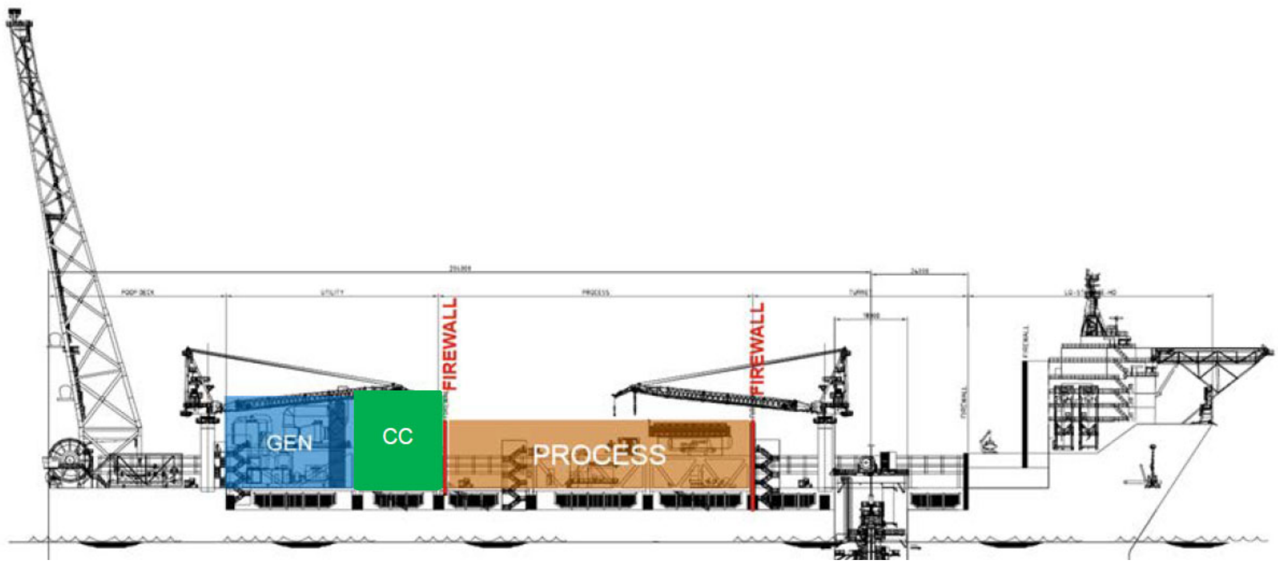
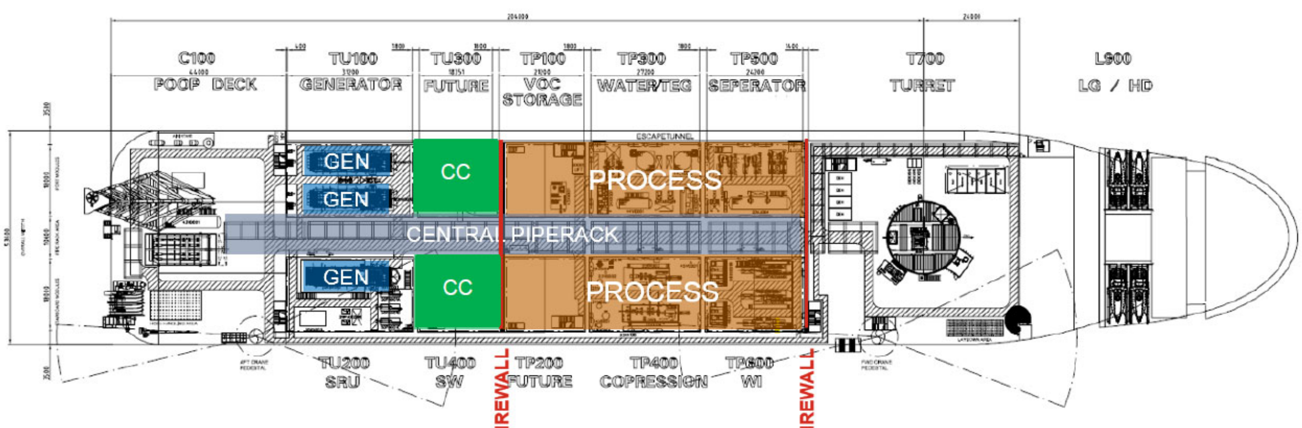


Figure 15 – FPSO Plan With Post-Combustion CO_2 Capture [32]



[31] Aker Solutions., Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry, Study Report, Document No.: 90001-21L01-G-SY-00001-001, Revision No.: E2

[32] Aker Solutions., Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry, Study Report, Document No.: 90001-21L01-G-SY-00001-001, Revision No.: E2

4 Transport

Transport is the stage of carbon capture and storage that links capture sources and storage sites.

CO_2 can be transported in three states: gas, liquid and solid. Commercial-scale transport uses pipelines and/or ships for gaseous and liquid carbon dioxide transport. Tanks are sometimes used for temporary storage.

Gas transported at close to atmospheric pressure occupies such a large volume that very large facilities are needed. Gas occupies less volume if it is compressed, and compressed gas can be transported by pipeline. Volume can be further reduced by liquefaction and is an established technology for gas transport by ship.

Transport is covered by its own regulatory framework, whether it is pipelines or shipping and will require established minimum product specifications as may be determined by a storage operator or by the end user.

4.1 Pipelines

Pipelines routinely carry large volumes of natural gas, oil, condensate, and water over distances of thousands of kilometres, both on land and in the sea. Pipelines are used in many different environments and climates including deserts, the artic, mountain ranges, heavily populated areas, and in the ocean. Pipelines can be utilized in ocean depths up to 2,200 m.

In the context of long-distance movement of large quantities of carbon dioxide, pipeline transport is part of current practice. Existing CO_2 pipelines (see Figure 167 on the following page) extend over more than 2,500 km in the western USA, where they carry 50 $MtCO_2$ / year from capture sites to enhanced oil recovery projects in west Texas and elsewhere.

Existing natural gas pipelines can be converted to transport CO_2 but that comes with technical challenges. CO_2 travels most efficiently through pipelines at higher pressures compared to natural gas, therefore if existing pipelines are to be used the operating pressure may need to be lower than optimal or pipeline reinforcements need to be installed.

Design of a CO_2 pipeline should consider water content, hydrogen sulphide content, other contaminants, overpressure protection and leak detection. These are all factors which can be accommodated with existing pipeline design, fabrication, and installation techniques.

With respect to offshore NL, there is additional risk of an iceberg impact with subsea pipeline and appropriate risk assessment would need to be completed and risk mitigation measures implemented. C-CORE has experience mitigating operational risk in ice/iceberg-prone waters and has modelled a safe pipeline route to shore.[33] In addition, offshore operators have developed ice management expertise and have systems in place to monitor icebergs and pack ice.

There is no indication that the problems for carbon dioxide pipelines are any more challenging than those set by hydrocarbon pipelines in similar areas, or that they cannot be resolved.

[33] Aker Solutions., Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry, Study Report, Document No.: 90001-21L01-G-SY-00001-001, Revision No.: E2 Appendix A

4.2 Shipping

The properties of liquefied carbon dioxide are not greatly different from those of liquefied petroleum gases, and the technology can be scaled up to large carbon dioxide carriers (see Figure 16). Liquefied natural gas and petroleum gases such as propane and butane are routinely transported by marine tankers. Carbon dioxide is already transported in the same way, but on a small scale because of limited demand. Liquefied gas can also be carried by rail and road tankers, but it is unlikely that they be considered attractive options for large-scale carbon dioxide capture and storage projects.

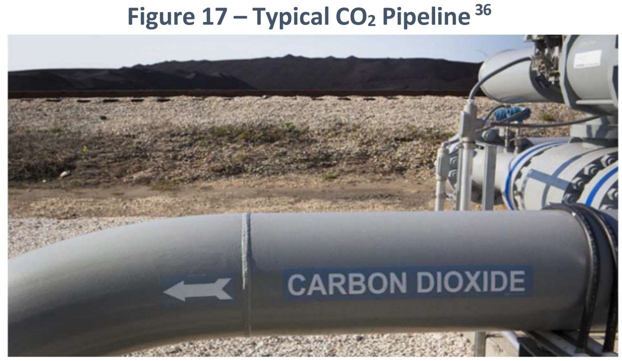
Marine transportation systems typically include temporary storage on land and a loading facility as well as the ship itself.

Carbon dioxide tankers are constructed using the same technology as existing liquefied gas carriers. The latest LNG carriers reach more than 200,000 m3 capacity (such a vessel could carry 230 kt of liquid CO_2)[34] The same type of yards that today build LPG and LNG ships can carry out the construction of a CO_2 tanker.

What happens at the delivery point depends on the CO_2 storage system. If the delivery point is onshore, the CO_2 is unloaded from the ships into temporary storage tanks. If the delivery point is offshore – as in the ocean storage option – ships might either unload to a platform, to a floating storage facility (similar to a floating production and storage facility routinely used in offshore petroleum production), to a single-buoy mooring or directly to a storage system.

Figure 16 – Northern Lights CO_2 Carrier [35]

Figure 17 – Typical CO_2 Pipeline [36]



[34] https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_chapter4-1.pdf
[35] *https://norlights.com/what-we-do/*
[36] *http://stellaeenergy.com/energy-solutions/ccs/carbon-dioxide-transportation*

5 Carbon Storage Hub Concept

In the long term, NL offshore shows significant potential to act as a regional (or even national) storage hub for carbon with storage potential in the gigaton range. More investigation is required, such as the storage assessment being undertaken by OilCo[37], to better define this opportunity and to begin to conceptualize technical and economic design.

A storage hub would collect carbon from various sources and after capture and transport, would inject the carbon into common infrastructure for permanent geological storage or otherwise provide the carbon for utilization in industry.

An offshore CCUS storage hub in the NL offshore may include existing offshore oil production facilities and have future capacity for other emitters as the oil and gas industry grows as well as other industrial emitters. The hub may attract onshore industrial activity that would have an available storage location for any carbon that would be emitted.

In addition, any blue hydrogen development utilizing NL natural gas resources and implementing carbon capture may utilize a carbon storage hub offshore as described in a feasibility study completed by Aker Solutions [38]

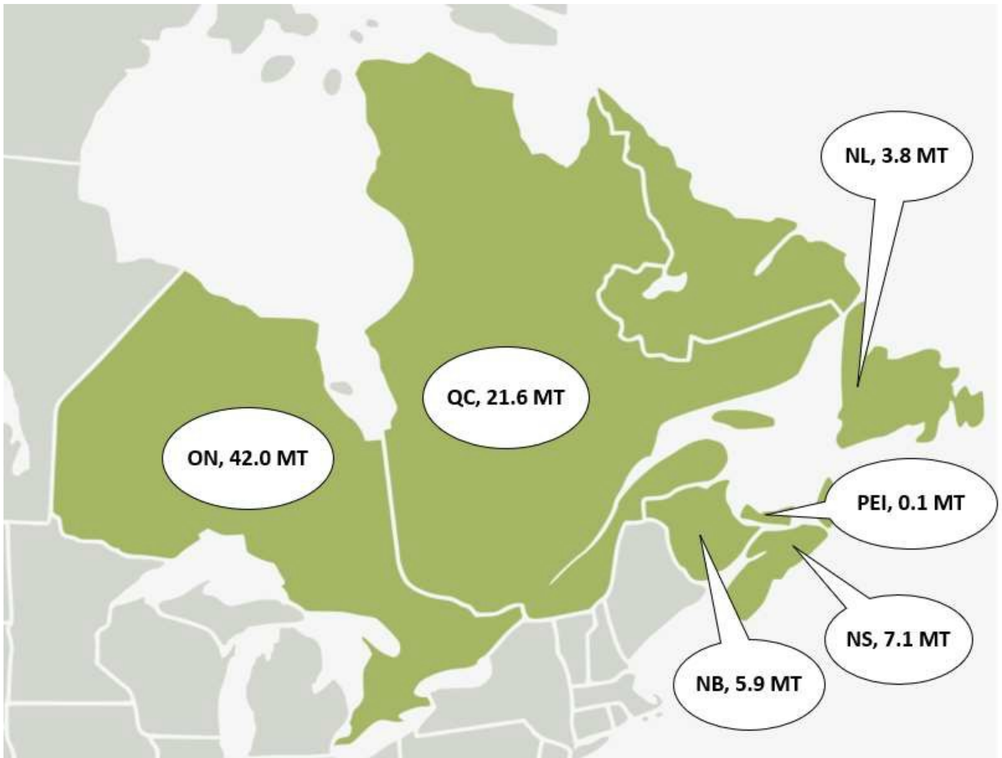
The significant natural gas resource base included in the Aker study combined with the associated scalable hydrogen production with CCS could create the foundation for a large scale project as noted within the Hydrogen Strategy for Canada and the regional deployment hub theme discussed in the Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in Newfoundland & Labrador.

Figure 18 shows the amount of GHG emissions produced in the eastern Canadian provinces for the year 2020. There is potential for collaboration among the eastern Canadian province to develop a CO_2 transport cluster(s) for onshore emitters and a storage hub in offshore NL utilizing pipelines and shipping. Emitters that are based onshore could utilize pipelines to transport their CO_2 to a terminal where it could be delivered via ship to a offshore storage hub. In the event eastern Canada becomes a hydrogen producer, it could be exported to other foreign markets (i.e. Europe) via ship and on the return trip bring CO_2 back to the hub for storage. This could kick start another industry in eastern Canada.

A hub concept would potentially lower the cost of storage infrastructure versus single-point storage solutions. The hub concept may attract government support and reduce risk for individual emitters. It could decrease the development time for other emitters that would only need to provide capture and transport segments of CCUS.

[37] https://www.merx.com/govnl/govnl1/solicitations/CO2-Storage-Assessment-Offshore-Newfoundland-and-Labrador-Canada/0000231738
[38] Aker Solutions., Feasibility of Blue Hydrogen Production in Canada's Offshore Oil and Gas Industry, Study Report, Document No.: 90001-21L01-G-SY-00001-001, Revision No.: E2

Figure 18 – Eastern Canadian Facility GHG Emissions by Province, 2020 [39]



[39] Map created from Greenhouse Gas Reporting Program (GHGRP) - Facility Greenhouse Gas (GHG) Data - Open Government Portal (canada.ca)

6 CO_2 Utilization: Enhanced Oil Recovery (EOR)

Enhanced Oil Recovery (EOR) is a tertiary oil production recovery method often used in the later stages of production. In the first stage of production, the natural pressure from the earth is the only mechanism supporting production. This is referred to as primary production and the recovery can be as much as 20%[40] of the original oil in place (OOIP).

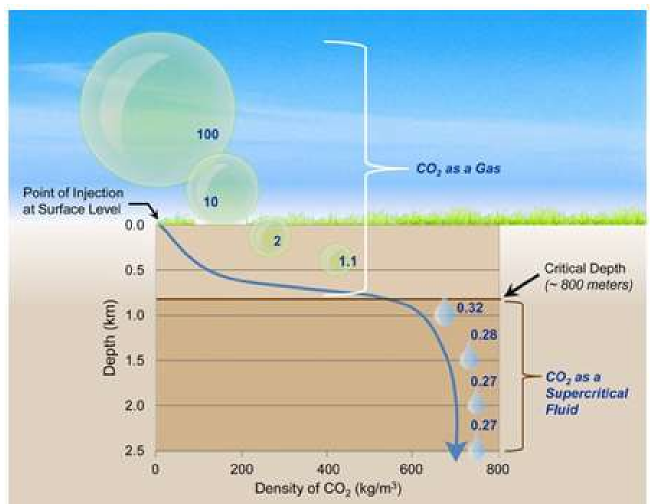
Next, pressure is added to the system through injecting water or gas. In the case of water injection (or water flooding) the water is usually injected into the aquifer below the oil accumulations; similarly, for gas injection (or gas flooding), the gas is injected into the gas cap at the top of the oil accumulation. This injection helps to slow pressure decline and forces more oil up through the production well. This is known as secondary production. Through secondary recovery mechanisms, the production can increase by 15-20%[41] of the OOIP. At this point, up to 40% of the oil has been recovered but significant resource (~60%) remains.

To further maximize oil production, enhanced oil recovery (EOR) mechanisms can be implemented. Research is underway in this area by Dr. Lesley Janes at Memorial University of Newfoundland.[42] There are three main types of EOR operations[43]:

1. Chemical flooding (alkaline flooding or micellar-polymer flooding
2. Thermal recovery (steam flood or in-situ combustion)[44]
3. Miscible displacement through gas injection (CO_2 or hydrocarbon)

In this paper we will focus on miscible displacement through CO_2 injection. CO_2 EOR enhances oil recovery by miscible displacement. Miscibility is the process by which liquids can fully mix. At atmospheric conditions, CO_2 and oil are immiscible, but at supercritical conditions (temperatures of 31.1° C and pressures of 7.38 MPa), the density of CO_2 increases to that of a liquid, but the viscosity remains similar to a gas. At this point, CO_2 becomes miscible with oil. These conditions are associated with geological depths greater than 800 metres as shown in Figure 19 and are represented by the blue numbers which show the volume of CO_2 compared to the volume of CO_2 at the surface (100).[45].

Figure 19 – Graphical Depiction of the Effects of Depth on CO_2 Density



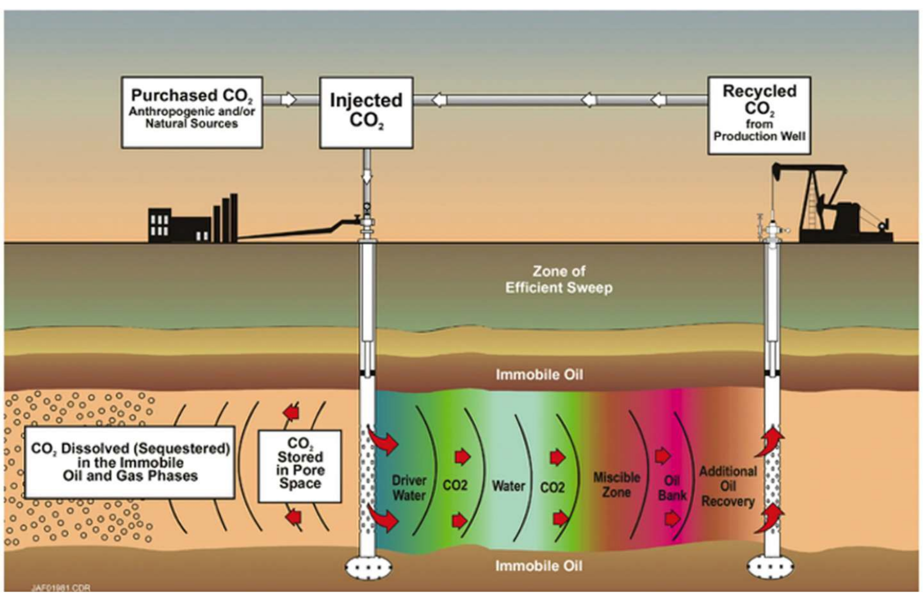
40 https://www.globalenergyinstitute.org/sites/default/files/020174_EI21_EnhancedOilRecovery_final.pdf
41 https://www.globalenergyinstitute.org/sites/default/files/020174_EI21_EnhancedOilRecovery_final.pdf
42 https://www.engr.mun.ca/research/eor/?_ga=2.35153634.2100802294.1673877228-1577032880.1673464305
43 https://glossary.slb.com/en/terms/e/enhanced_oil_recovery
44 Chemical flooding and thermal recovery do not utilize CO_2 and therefore will not be discussed in this paper.
45 https://netl.doe.gov/carbon-management/carbon-storage/faqs/carbon-storage-faqs

With the oil and CO_2 mixed in liquid phase, the pressure increases, and the viscosity decreases resulting in an increased mobility of the oil towards the production well. Also, when CO_2 dissolves in water it forms carbonic acid which can dissolve calcite that may exist in the reservoir increasing the porosity and permeability and potentially increasing the recovery factor. This tertiary recovery mechanism can result in another 15-20%[46] of the OOIP.

CO_2 EOR was initially intended as a mechanism for increasing production from mature fields; however, as the world focusses on emissions reductions, CO_2 EOR is being considered as a means of CO_2 sequestration. CO_2 EOR is not considered permanent sequestration unless it is separated at the surface and reinjected in a close loop as shown in Figure 20[47]. This figure shows recycled CO_2 from the production well reinjected into the subsurface. When the wells are abandoned, the pressure would need to remain constant as lowering the reservoir pressure would release CO_2 from the closed system.

CO_2-EOR has the potential to decrease emission intensity (amount of CO_2 produced per barrel of oil) due to the retention of CO_2 within the reservoir. When CO_2 is injected into a reservoir, approximately 30-40% will be retained in the subsurface as the molecules become trapped within the pores or adhered to mineral surfaces[48]. Since this acts as a form of storage, CO_2-EOR increases the produced barrels of hydrocarbons while decreasing the CO_2.

Figure 20 – Schematic Diagram Illustrating a Closed System CO_2 EOR Scheme Utilizing Water Alternating Gas (WAG)



[46] https://www.globalenergyinstitute.org/sites/default/files/020174_EI21_EnhancedOilRecovery_final.pdf
[47] Lake et al., 2019, https://www.sciencedirect.com/science/article/pii/B9780128127520000022
[48] https://www.globalccsinstitute.com/archive/hub/publications/118946/technical-aspects-co2-enhanced-oil-recovery-and-associated-carbon-sto.pdf

To date, only primary and secondary recovery methods have been implemented offshore Newfoundland and Labrador. The Hibernia Enhanced Oil Recovery Laboratory at Memorial University of Newfoundland and Labrador has partnered with Hibernia (amongst other organizations) to research EOR opportunities for the field including CO_2 integration[49].

There are several factors that make CO_2 EOR implementation challenging in the offshore environment. As mentioned in section 3.1.5, weight and space is constrained on an offshore facility making it difficult to accommodate additional compression and capture technology. Also, separating and compressing CO_2 requires added electricity which, for offshore Newfoundland and Labrador, is currently generated by combustion of natural gas. In the case of brownfield assets, retrofitting the facilities for carbon capture and CO_2 injection would be required adding a significant capital expenditure. For greenfield assets, CO_2 capture, and reinjection would have to be considered at the design phase with the risk that technology (or regulatory conditions) may change over the course of the assets life. Similar considerations would be required for subsea infrastructure and well designs.

Also, access to additional CO_2 would challenge the economics of any offshore CO_2 EOR project. According to the U.S. Department of Energy, National Energy Technology Laboratory, 2014[50], the required CO_2 demand (kg) per barrel of oil is ~200-400 in the offshore. Similarly, the IEA[51] references 300-600 kg CO_2 per barrel of oil (in the United States). In Newfoundland and Labrador's offshore, the average CO_2 produced per barrel of oil is ~18-20 kg (2019-2021 excluding Terra Nova). This means that CO_2 would need to be transported to the offshore to develop a full CO_2 EOR scheme which poses challenges due to lack of existing infrastructure and the added capital costs associated with building it.

A more likely scenario for utilizing CO_2 offshore is alternating CO_2 injection with water injection. This is commonly referred to as miscible water-alternating-gas or WAG and is depicted in Figure 20 above. WAG would require two separate injection wells (one for water and one for CO_2 gas) that would alternate injection between the two, essentially creating carbonaceous water. In this scenario, the CO_2 becomes miscible with oil and makes it mobile (as mentioned above) while the water creates pressure to force the oil towards the production well. CO_2 WAG would require less CO_2 compared to CO_2 injection alone, thus making it more practical for the Newfoundland and Labrador offshore.

To summarize, there are financial and environmental benefits to incorporating CO_2 EOR in the late stages of an asset; however, the technical challenges associated with these projects in an offshore environment like Newfoundland and Labrador, make the economics and associated risks more challenging than onshore assets that have access to additional space for equipment and ample CO_2 supply.

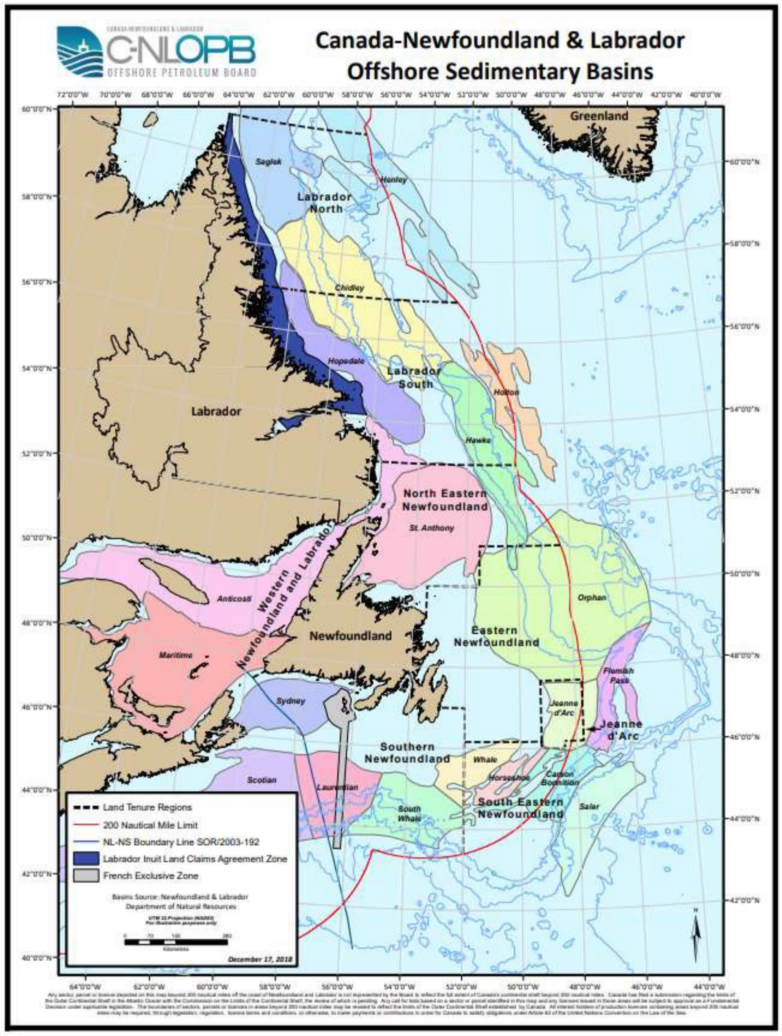
[49] https://www.mun.ca/engineering/research/eor/research/
[50] https://www.netl.doe.gov/projects/files/FY14_CO2-EOROffshoreResourceAssessment_060114.pdf
[51] https://www.iea.org/commentaries/can-co2-eor-really-provide-carbon-negative-oil

7 CO_2 Storage

Although Newfoundland and Labrador's onshore geology is unique and diverse, it does not provide suitable storage for traditional CO_2 injection. Much of the Avalon peninsula and St. John's area is underlain by sedimentary rocks; however, these rocks have low porosity and permeability due to their age and compaction history. The remainder of the onshore geology is dominated by igneous and metamorphic rocks in contrast to sedimentary rocks[52]. Igneous and metamorphic rocks lack the connected void, or pore, space required to hold fluids or gases such as hydrocarbons, water, or other gases like CO_2. Some mafic and ultramafic rocks onshore Newfoundland and Labrador can store CO_2 long-term by converting it into carbonate rocks through a process known as CO_2 mineralization. This process happens naturally but can be enhanced by increasing the exposed surface area of these mafic and ultramafic rocks. There is active research being conducted at Memorial University of Newfoundland and Labrador regarding CO_2 mineralization. Dr. Penny Morrill and the Diverse Environmental Laboratory Terrestrial Analogue Studies (DELTAS) Research Group[53] are investigating the CO_2 mineralization potential in Newfoundland and Labrador including the ultramafic rocks in the western region of the island portion of the province. Although their research has provided insights into the potential of CO_2 storage onshore, CO_2 mineralization has not been regarded as having as much storage potential as sedimentary rocks such as those found in abundance offshore NL.

The sedimentary rocks found offshore Newfoundland and Labrador contain varying pore space depending on the type of sedimentary rock – shale, silt, sandstone, or limestone. The offshore region of Newfoundland and Labrador is comprised of multiple Mesozoic and Paleozoic sedimentary basins as seen in Figure 21. Current producing assets (Hibernia, Hebron, Terra Nova and White Rose) are shown in the Jeanne d'Arc Basin (light green) and the proposed Bay du Nord field is in the Flemish Pass Basin (purple).

Figure 21 – Map of East Coast Canada's Offshore Sedimentary Basins[54]



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[52] https://www.gov.nl.ca/iet/files/mines-investments-geology-map-nl.pdf

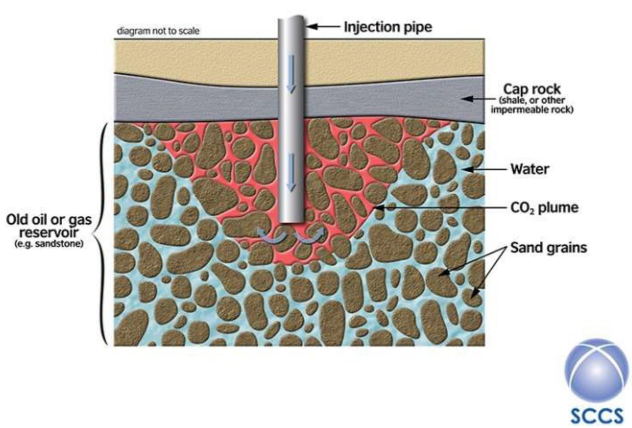
[53] https://www.esd.mun.ca/wordpress/deltasresearch/

[54] C-NLOPB, https://www.cnlopb.ca/wp-content/uploads/maps/nlsb.pdf

The calculation of storage potential in a particular geological formation is assessed in the same manner that hydrocarbon accumulation potential is assessed. The basic principles of containing a fluid or gas are the same regardless of what that fluid or gas is. First, a reservoir is needed – this reservoir contains sand grains and in between those sand grains is the pore space, or porosity. The connectivity of those pore spaces (i.e. the permeability) is also needed so that there is connected volume available for storage. Reservoirs suitable for storage can contain saline water (aquifer) or can be hydrocarbon reservoirs that have been depleted. These saline aquifers are well below the surface of the ocean and do not connect to ground water onshore Newfoundland and Labrador.

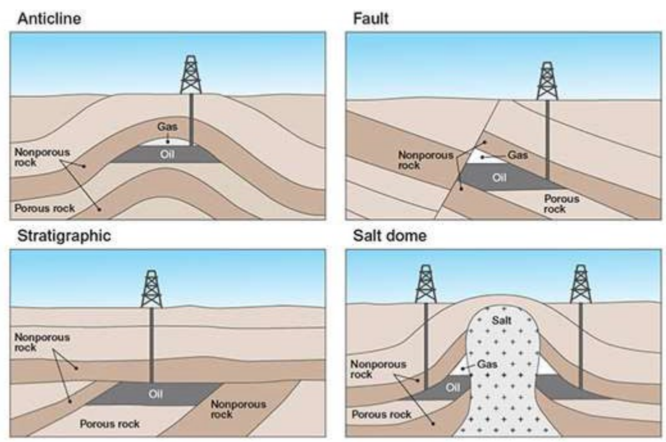
Figure 22 highlights the key geological features required for CO_2 storage. The carbon dioxide (red) displaces water (blue) from between the sand grains (brown) while the cap rock (grey) prevents the CO_2 from moving vertically.

Figure 22 – Schematic Diagram Illustrating Required Geological Parameters Needed for CO_2 Injection[55]



Another important attribute is the existence of a cap rock (or top seal). A cap rock is an impermeable rock (little to no permeability) and is often a shale. It is required to keep the fluid or gas from rising vertically to the surface. A final important attribute is a trapping mechanism which is required to contain the fluid or gas laterally. As shown in Figure 23, there are several different geological configurations possible to form a physical trap. While this image illustrates physical traps for oil (illustrated in grey), the same configuration is required for CO_2.

Figure 23 – Schematic Diagram Illustrating Different Physical Trapping Configurations Possible To Contain Hydrocarbons or CO_2 (Anticline, Fault, Stratigraphic and Salt Dome) [56]



Although structural and stratigraphic traps will contain the significant portion of CO_2 at the onset of CO_2 injection, there are other secondary trapping mechanisms at play. These include residual trapping, solubility or dissolution trapping, and mineral trapping or CO_2 mineralization.

Residual trapping occurs when CO_2 becomes immobile within the microscopic pore spaces. CO_2 moves through the pore spaces within the rock formation when injected. It is then displaced by other fluids; however, some of the CO_2 becomes disconnected and left behind (residual). These droplets become permanently trapped thus securing the residual CO_2 in the subsurface.

Solubility or dissolution trapping occurs when CO_2 is dissolved in the formation water. Similar

[55] www.wsccs.org.uk
[56] https://www.open.edu/openlearn/mod/oucontent/view.php?id=101227&section=_unit3.8

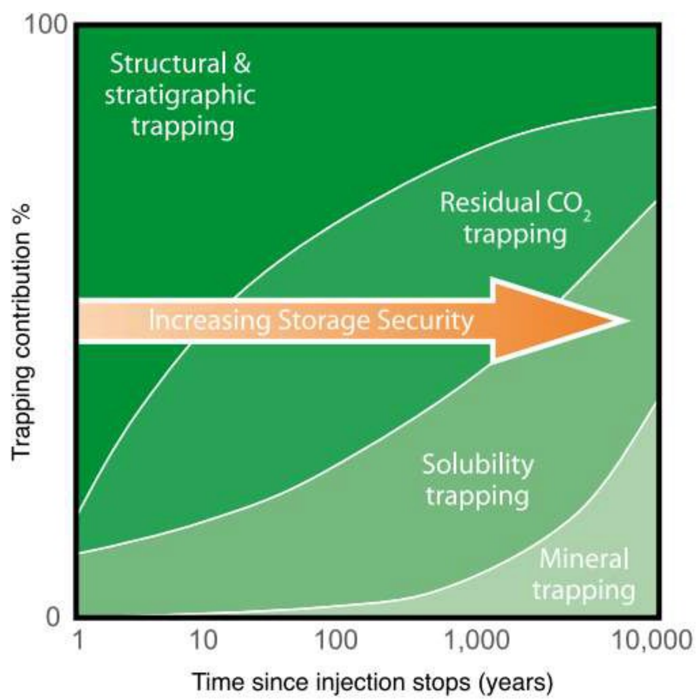
to sugar dissolving in tea, when CO_2 is in its gaseous phase, it dissolves in other fluids such as the water within the rock formations. This salt water with dissolved CO_2 is heavier than the surrounding fluids and subsequently sinks thus trapping the CO_2 more securely at the bottom of the formation.

The final phase of trapping is CO_2 mineralization. Mineralization trapping is a very slow process that occurs when dissolved CO_2 in water creates a weak acid that reacts with minerals in surrounding rock and creates solid carbonate minerals. These minerals are permanently trapped thus securing the CO_2 in the subsurface.

Over time, the trapping contribution by structural and stratigraphic traps decreases while the trapping contribution by these secondary mechanisms increases (Figure 23). As such, if CO_2 were to escape from the storage complex, it would happen in the early years post CO_2 injection and over time, assuming no more CO_2 is being injected, there would be an increase in storage security.

Figure 24 illustrates how the storage security of CO_2 increases over time as CO_2 that was originally trapped structurally or stratigraphically (time 1 year) is converted to residual or geochemical trapping (solubility and mineral).

Figure 24 – Effects of Time on CO_2 Storage Security[57]



[57] https://repository.ubn.ru.nl/bitstream/handle/2066/230961/230961.pdf?sequence=1

Another important geological requirement for CO_2 storage is the depth of the reservoir. The deeper the reservoir, the greater the pressure and temperature of the fluids within the reservoir. As the pressure and temperature of the CO_2 gas increases, it turns from a gas into a liquid. Since liquid takes up less space than gas, more CO_2 can be stored in liquid phase. Also, CO_2 as a liquid can mix with water and other compounds which helps to keep the CO_2 underground through dissolution/solubility trapping as mentioned above. The favourable depth to the reservoir as suggested by the International Energy Association CCS Site Characterization Criteria[58] (Table 4) is greater than 800m.

Table 4 - Site Selection Criteria for Ensuring the Safety and Security of CO_2 Storage[59]

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

58 https://www.globalccsinstitute.com/archive/hub/publications/95881/ccs-site-characterisation-criteria.pdf
59 https://www.globalccsinstitute.com/archive/hub/publications/95881/ccs-site-characterisation-criteria.pdf

7.1 Implication for CO_2 Storage Offshore NL

Newfoundland and Labrador's producing assets (Hibernia, Hebron, Terra Nova and White Rose) have helped to demonstrate that the geology offshore Newfoundland and Labrador has the necessary components (reservoir, top seal, and trap) and the appropriate depths (>800 m) to contain fluids and gas over millions of years (see Table 5 below).

Table 5 - Properties of Oil-Bearing Reservoirs Within the Jeanne d'Arc Basin[60]

CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD

Properties of Oil Bearing Reservoirs[1]
(Updated February 21, 1997)

Field	Wells Drilled	Water Depth (m)	Oil Reservoir	Average Depth (m)	Net Oil Pay (m)	Porosity (%)	Average Perm (Ko) (mD)	Oil Gravity (°API)	GOR (Sm³/Rm³)	Test Rate (max) (m³/d)	Productivity Index (m³/d/kPa)	Pressure (kPaa)	Temp (°C)
Hibernia	10	80	Hibernia	3768	41	16	640	30.2-40.3	216-264	1,166	1.0447	39500	95
			Ben Nevis/Avalon	2338	23	20	148	29.0-32.7	79-114	1,054	0.0199	26766	66
			Catalina	3235	15	15	75	32.5	120	568	0.0359	34165	92
			Jeanne d'Arc	4124	13	9	8	33.5	87	90	0.0029	68471	107
			Lower Avalon	2673	5	21	441	36.2	125	511	0.0385	30265	N/A
			Hibernia Stray	3710	6	9	31	35.4	169	663	0.0327	56203	N/A
Terra Nova	9	93	Terra Nova	3346	36	17	950	33.7	126	1400	0.8079	34686	96
			Beothuk	3258	8	17	1330	33.7	126	1300	0.7397	34415	94
Hebron	1	94	Jeanne d'Arc	4375	5	12	245	36.1	215	605	0.0338	47430	117
			Fortune Bay	3850	5	12	520	31.4	101	848	0.0513	45484	100
			Hibernia	2941	31	15	266	28.8	105	418	0.0356	30569	72
			Ben Nevis	1892	36	20	650	19.8	36	177	0.1169	19414	49
Whiterose	4	119	Ben Nevis/Avalon	3012	23-87	15	56	30.7	110	755	.0125-0.14	30662	110
			Hibernia	3617	8	15	7	32.8-38.3	132-351	83	0.0026	49700	125
			Rankin	3813	8	12	3	32.8	262	43	0.0014	71362	N/A
West Ben Nevis	1	96	A Marker	2426	15	20	182	22.8	60	238	0.0419	24502	82
			Ben Nevis	2008	4	18	146	28.1	59	98	0.0167	20093	69
Mara	1	88	Otter Bay	2406	3	20	258	21.5	72	124	0.0263	24230	72
			South Mara	1855	5	27	548	21.6	38	97	0.0410	18533	57
Ben Nevis	1	100	Ben Nevis	2420	6[2]	<15	5	22.3	N/A	33	0.0120	25140	82
North Ben Nevis	2	100	Ben Nevis/Avalon	3082	19	17	168	31.5	128	872	0.0776	30624	100
Springdale	1	99	Ben Nevis	1488	6	33	7280	14.4	24	64	0.0265	15021	54
Nautilus	1	84	Ben Nevis	3326	5	12	28	30.8	172	391	0.0145	53423	105
South Tempest	1	158	Lower Tempest	4117	7	13	739	42	652	216	0.0402	74183	117
			Upper Source	3840	4	13	7	39.7	N/A	24	0.0013	55366	N/A
Fortune	1	113	Hibernia	3996	7	11	19	36	309	150	0.0115	39190	110
South Mara	1	97	Ben Nevis/Avalon	2954	6	17	-	34.7	244	274.8	0.7015	29460	97

[1] Properties quoted are average for the wells drilled through the oil zone. Where properties vary significantly, a range is provided.

[2] Estimated average for field.

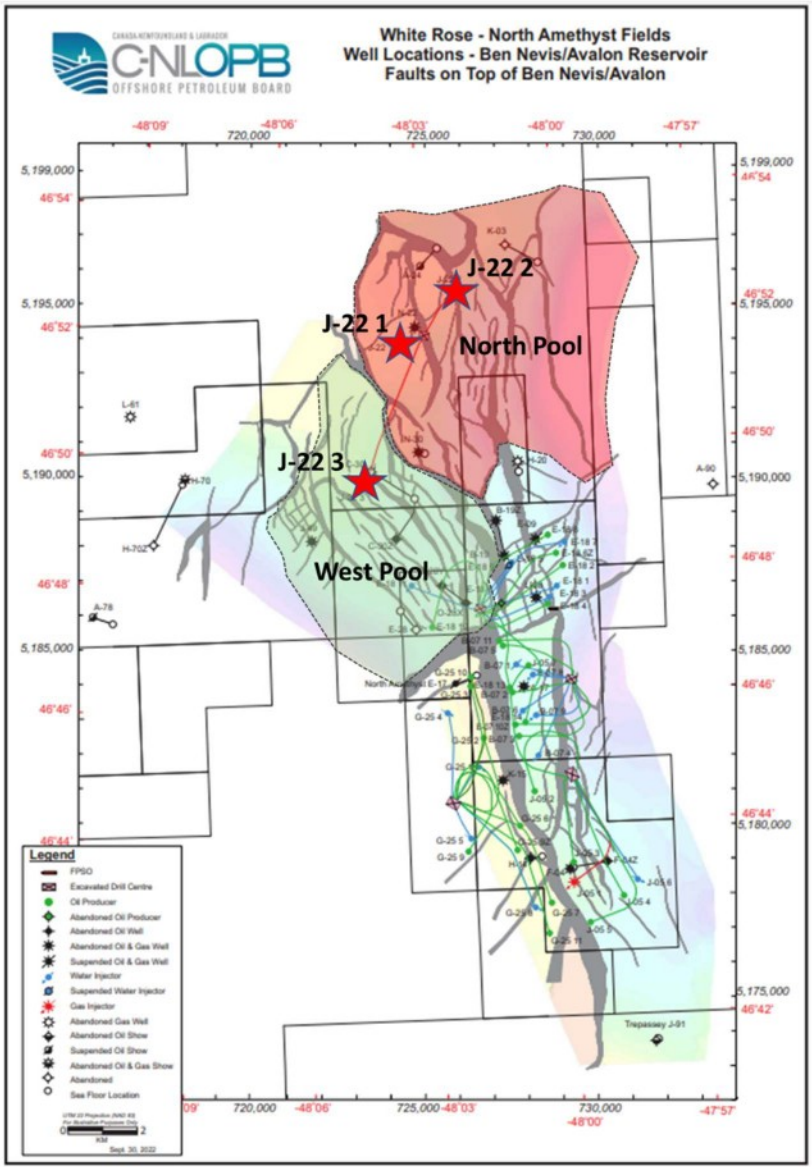
N/A - Not available.

Table 5 above illustrates that the depths, porosities and permeabilities of oil-bearing reservoirs suggest that the geology in offshore NL has all the required elements to store CO_2.

The storage potential offshore Newfoundland and Labrador is also demonstrated by the storage of hydrocarbon gas. There are four wells in two fields (White Rose and Hebron) that exclusively store produced gas (not pure CO_2) for which the C-NLOPB has issued subsurface storage licenses. Wells J-22 1, J-22 2, and J-22 3 located in the White Rose North and West pools are gas injectors which were only used to store produced gas from other areas of the White Rose field for gas-conservation purposes (Figure 25). The gas cap of the North pool was identified as the ideal location for gas storage in the White Rose development plan[61]; however, at present, these wells are no longer used for gas injection.

[60] C-NLOPB, https://www.cnlopb.ca/wp-content/uploads/oil_prop.pdf
[61] C-NLOPB, https://www.cnlopb.ca/wp-content/uploads/news/sawrxdevplan.pdf

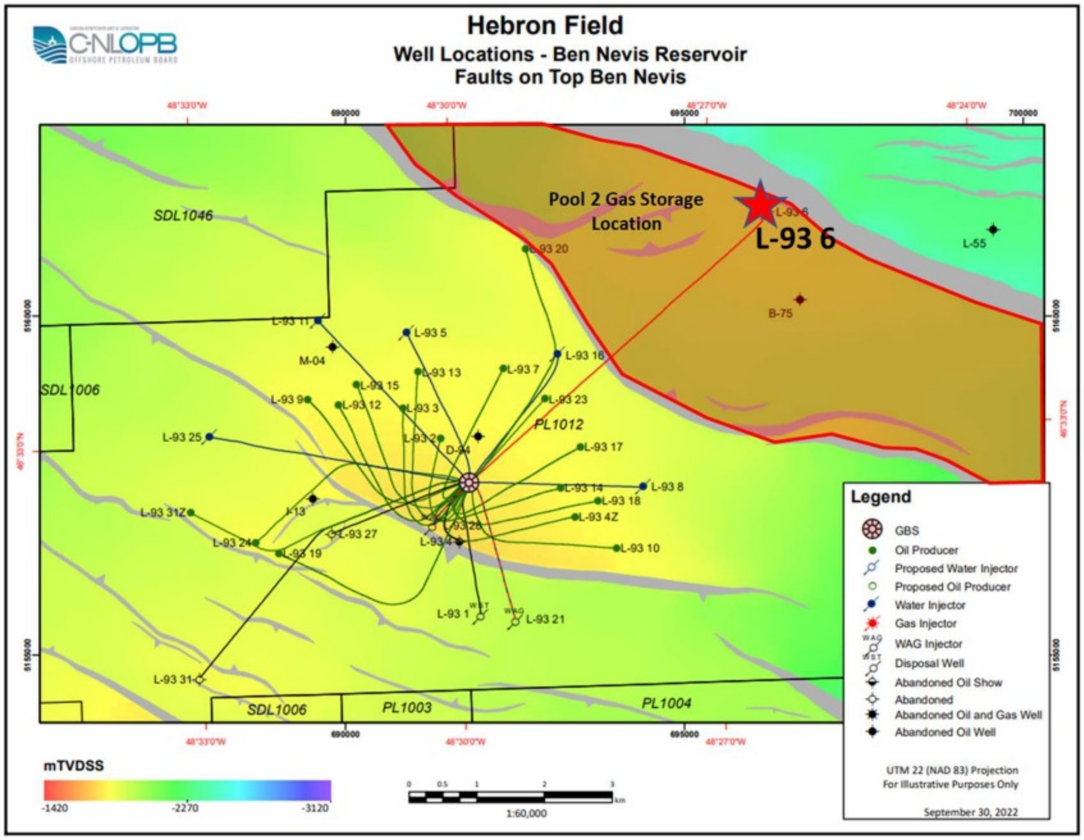
Figure 25 – Map of the White Rose Field at the Top of the Ben Nevis/Avalon Reservoir. [62]



At Hebron, the L-93 6 well located in Pool 2 (Figure 26), is being used for gas storage with the intent of accessing that gas in the future to be used for fuel by the platform as indicated in the Hebron development plan[63]. The three red stars show the locations of the current wells (J-22 1, J-22 2, and J-22 3) that are being used for gas storage. These wells clearly demonstrate that the geology exists offshore Newfoundland and Labrador for the safe storage of gas and CO_2.

[62] C-NLOPB, https://www.cnlopb.ca/wp-content/uploads/maps/wrbna_dev.pdf
[63] C-NLOPB, https://www.cnlopb.ca/wp-content/uploads/news/sahebdevplan.pdf

Figure 26 – Map of the Hebron Field at the Top of the Ben Nevis Reservoir[64]



The red star in Figure 26 above shows the location of the current well L-93 6 that is being used for gas storage and the red outline area is Pool 2.

To summarize, offshore Newfoundland and Labrador has all the geologic requirements needed for safe CO_2 storage as demonstrated by a long history of storing hydrocarbon gas within the reservoirs. Newfoundland and Labrador's offshore CO_2 storage potential could be in the Gigatonne range given the vast lateral extent of the sedimentary basins and multiple stacked reservoirs within those basins; however, no known technical storage assessment for CO_2 has been completed. To address this deficiency, a Request for Proposals (RFP) was issued in September 2022 by OilCo for a CO_2 storage assessment offshore Newfoundland and Labrador. This analysis will add much-needed quantification to the perceived CO_2 storage opportunity in Newfoundland and Labrador's offshore.

While the above description of CO_2 storage requirements is relatively simplified, it is important to note that choosing a CO_2 storage site is a complex technical process supported by geoscientists, Petro-physicists and engineers. It involves the integration and interpretation of many different types of data to ensure the safe storage of CO_2 including, but not limited to, geomechanical, geophysical, well log and fluid data.

[64] C-NLOPB, https://www.cnlopb.ca/wp-content/uploads/maps/hebbn_dev.pdf

7.2 CO_2 Storage Monitoring

After the CO_2 has been injected into the subsurface reservoirs, it is important to monitor the CO_2 plume and ensure that it remains in an acceptable area, and at an acceptable pressure, so that it does not compromise the storage complex and subsequently escape. Developing and executing a monitoring, measurement, and verification plan (MMV) will be a requirement for any CO_2 storage project offshore Newfoundland and Labrador.

There are several guidelines or best practices for the storage and monitoring of CO_2. Some of the most well-known guidelines and best practices include:

1. Canadian Standards Association: Geological storage of carbon dioxide[65]
2. International Organization for Standardization: Carbon dioxide capture, transportation, and geological storage – Geological Storage[66]
3. Plains CO_2 Reduction (PCOR) Partnership: Best Practices Manual – Monitoring for CO_2 storage[67]
4. U.S. Department of Energy: Best Practices – monitoring, verification, and accounting for geologic storage projects[68]
5. Alberta Department of Energy (Carbon Capture & Storage: Summary Report of the Regulatory Framework Assessment)[69]
6. DNV-RP-J203: Geological storage of carbon dioxide – Recommended Practice[70]
7. Alberta Department of Energy (Monitoring, measurement and verification principles and objectives for CO_2 sequestration projects)[71]
8. London Protocol: Specific Guidelines for the Assessment of Carbon Dioxide Streams for Disposal into Sub-Seabed Geological Formations[72]

Neither of these guidelines are prescriptive about the technology or techniques needed to monitor CO_2 as the techniques used will vary based on the technical feasibility for any given site. According to DNV's "Best Practices for Geological Storage of CO_2", the technical feasibility will be determined by factors such as:

1. Location (onshore/offshore)
2. Terrain and land use (onshore)
3. Water depth and seafloor conditions (offshore)
4. Depth of the Injection zone
5. Lithology (geology) of the storage complex and overburden
6. Sensitivity and reliability of a given technique

It is also important to assess the risk associated with a specific storage site as this will need to be factored into the monitoring plan. As such, there is no universal monitoring plan developed with regards to the chosen techniques.

[65] https://www.csagroup.org/store/product/Z741-12/
[66] https://www.iso.org/standard/64148.html
[67] https://undeerc.org/pcor/assets/PDFs/PCOR-BPM-Monitoring-for-CO2-Storage.pdf
[68] https://netl.doe.gov/sites/default/files/2018-10/BPM-MVA-2012.pdf
[69] https://open.alberta.ca/dataset/5483a064-1ec8-466e-a330-19d2253e5807/resource/ecab392b-4757-4351-a157-9d5aebedecd0/download/6259895-2013-carbon-capture-storage-summary-report.pdf
[70] https://www.dnv.com/oilgas/download/dnv-rp-j203-geological-storage-of-carbon-dioxide.html
[71] https://open.alberta.ca/dataset/46a0eba9-e435-4c7a-88aa-d80bb17d15ce/resource/dd0455d9-e543-445d-9ece-faf32300a701/download/energy-mmv-principles-objectives-for-co2-sequestration-projects-version-1.pdf
[72] https://www.gc.noaa.gov/documents/gcil_imo_co2wag.pdf

The techniques that can be used to monitor CO_2 are often the same as techniques used in the discovery and production of oil and gas reservoirs. These techniques can be categorized into 7 types (U.S. Department of Energy, 2017) as shown in Table 6. Many of these techniques are already being used offshore Newfoundland and Labrador for hydrocarbon exploration and development (U.S. Department of Energy, 2017). It is important to note that these techniques, including data collection and interpretation, is not new to offshore Newfoundland and Labrador.

Table 6 - Summary of Subsurface Techniques that Can Be Used in the Monitoring of CO_2 Storage Sites[73]

Subsurface Technique	Examples	Technology Maturity w.r.t CO2 storage	Technology Deployed offshore NL w.r.t petroleum exploration/development
Wireline Deployed Well Logging Tools	Acoustic and resistivity logs	Mature	✓
Wellbore Deployed Pressure and Temperature Gauges	-	Mature	✓
Wellbore-Based Fluid Monitoring Tools	-	Mature	✓
Emerging Wellbore Tools	Harmonic pulse testing, modular borehole monitoring, novel tracers	Moderately mature	Tracers
Seismic Geophysical Methods	4D seismic, vertical seismic profiles	Mature	✓
Gravity Methods	-	Moderately mature	✓
Electrical Methods	Electrical resistance tomography (ERT), electromagnetic tomography (EM), controlled-source electromagnetic (CSEM) surveys	Immature	✓

For example, four dimensional (4D) seismic surveys have been conducted and interpreted at several fields offshore Newfoundland and Labrador. Four dimensional seismic is simply three dimensional (3D) seismic data acquired at different times (usually at the beginning of production or injection and subsequent times in the future) over the same area, collected with the same parameters, to assess the changes in the reservoir with time. Figure 27 shows seismic images of the Sleipner field (North Sea) in 1994 (baseline) and in 2001, 2004, and 2006 post CO_2 injection[74]. The changes in the seismic response (top) demonstrate the movement and accumulation of CO_2 in the subsurface.

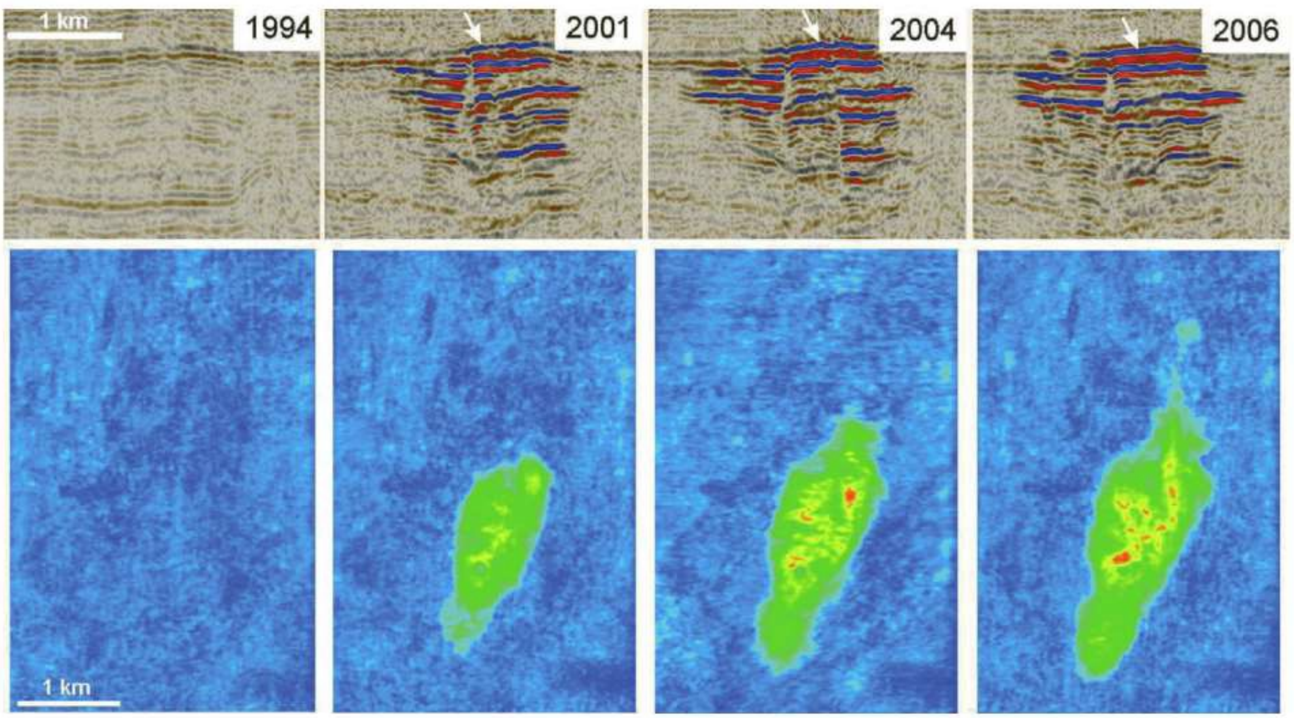
Having a robust monitoring plan before, during and after CO_2 injection will be crucial to the safe and permanent storage of carbon dioxide offshore Newfoundland and Labrador. Fortunately, the offshore industry has significant experience in monitoring oil and gas fields and this expertise can be adapted for the

[73] https://www.dnv.com/oilgas/download/dnv-rp-j203-geological-storage-of-carbon-dioxide.html
[74] R.A. Chadwick et al., 2009, https://www.sciencedirect.com/science/article/pii/S1876610209002756

purpose of CO_2 storage monitoring in future CCUS projects. Also, Newfoundland and Labrador is recognized for its cluster of private sector and research institution capacity and technology development around environmental sensing, characterization, and monitoring that could be deployed in support of CO_2 monitoring.

This 4D seismic data such as that used to produce the images in Figure 27 can be used to monitor CO_2 storage offshore, including offshore Newfoundland and Labrador.

Figure 27 – Seismic Data, Taken at Four Different Points in Time, Demonstrating the CO_2 Plume Response[75]



[75] R.A. Chadwick et al., 2009, https://www.sciencedirect.com/science/article/pii/S1876610209002756

8 Regulations and Policy

It is widely recognized that carbon capture, utilization and storage is required to meet the targets set out in the Paris Agreement. At the end of 2020, the global carbon capture and storage capacity in operation was approximately 40 million tonnes (Mt) CO_2/year. Currently, projects being planned between 2025–2030 will add less than 300 Mt CO_2/year, which is about 50 percent of what is needed in the IEA Sustainable Development Scenario (SDS)[76].

While the need for CCUS projects and the policy direction of governments is clear, there is currently no regulatory framework in place for the implementation of CCUS projects in Canada's offshore. The regulation of offshore air emissions under the management of the Greenhouse Gas Act, to an authorized work or activity that is carried out within the offshore area, falls under provincial jurisdiction since the amendments made to the Atlantic Accord in 2018,while the storage of CO_2 in the offshore would occur on federal lands, under federal jurisdiction. Offshore CCUS projects are therefore the ideal scope to be regulated by the C-NLOPB, as a joint federal-provincial regulatory body, similar to current oil and gas industry oversight.

Under existing legislation, the C-NLOPB may consider an application for an amendment to an existing authorization if an operator proposed injection of CO_2 into an oil-producing geological formation. Under Section 86 (1) of the Canada–Newfoundland and Labrador Atlantic Accord Implementation Act:

"The Board may, subject to any terms and conditions the Board considers appropriate, issue a licence for the purpose of subsurface storage of petroleum or any other substance approved by the Board in portions of the offshore area at depths greater than twenty metres."

However, approved storage licences must fit within the overall mandate of the C-NLOPB to ensure conservation of resources, and therefore proponents must:

- verify the capacity of the reservoir to hold the volume of injected gas
- demonstrate retention from migration by an effective monitoring and surveillance system as per Section 86.3 of the Drilling and Production Guidelines, and
- provide assurance of deliverability when the gas is needed for future development.

Within the context of this paper, it is important to recognize the distinction between gas storage for future development and permanent storage of CO_2 associated with CCS. The following sections therefore present the regulatory context associated with long-term ownership of a dedicated carbon storage site and the continuation of monitoring and surveillance past the life of a hydrocarbon production project.

8.1 Regulatory Considerations

8.1.1 Federal

The primary pieces of federal legislative review necessary to enable a CCS project approval in the offshore, are the *Canadian Environmental Protection Act*, 1999 and the *Impact Assessment Act*, 2019.

Ocean Disposal under CEPA

As Party to the London Protocol, an international agreement intended to prevent waste disposals at sea, Canada has a disposal at sea regime administered by ECCC under the *Canadian Environmental Protection Act*, 1999 (CEPA). CEPA

[76] Carbon Sequestration Leadership Forum 2021 https://www.cslforum.org/cslf/sites/default/files/CSLF_Tech_Roadmap_2021_final_0.pdf

currently does not allow subsea CO_2 storage in Canadian waters and prohibits the import and export of CO_2 destined for sub-seabed storage. The London Protocol was amended in 2006 to authorize storage of CO_2 streams in sub-seabed geological formations, and again in 2009, to allow cross-border transport of CO_2 for the purpose of geological storage. The 2009 amendment, while not yet ratified, has being provisionally applied since a resolution was adopted in 2019. In Canada, changes to CEPA are required to adopt these amendments and to add CO_2 to the list of substances to be permitted under the Ocean Disposal Regulations of CEPA.

Under the CEPA, a substance can only be disposed of in Canada's territorial sea or Exclusive Economic Zone (EEZ) if "the substance is waste or other matter" of a type listed in Schedule 5 of the Act. Carbon dioxide is currently not listed on Schedule 5 of CEPA, but can be added by an Order in Council, rather than requiring a legislative change to the Act. Likewise, and perhaps concurrently, Schedule 6 of CEPA which governs the assessment of waste, may be amended to include the conditions for CO_2 subsea injection from the London Protocol[77].

Having CO_2 listed on Schedule 5 would allow an application for disposal, but it would be within the current limitations of Ocean Disposal Regulations. For example, an ocean disposal permit can only be issued for a maximum of one year, at which time a renewal application is required. Existing Ocean Disposal Regulations allow for the approval of the waste disposal site. In the case of CCS, it would mean the CO_2 disposal well location could be approved and presumably no other approvals would be required for use of federal seabed lands under *Federal Real Properties and Federal Immovables Act*.

Part 7, Division 3 of the CEPA regulates the "disposal" of materials at sea. The term "disposal" is defined broadly to include, among other things, "the storage on the seabed, in the subsoil of the seabed or on the ice in any area of the sea of a substance that comes from a ship, an aircraft, a platform or another structure." This definition would encompass the injection of CO_2 into sub-seabed geologic formations where the CO_2 "comes from a . . . structure." If pipelines are excluded from the list of structures, offshore CO_2 storage would not be regulated as a form of "disposal" if a pipeline system were used to transport the CO_2 from shore and deposit it into the sub-seabed, without the use of any ship, platform, or similar facility. However, a project capturing CO_2 on an offshore platform and injecting it into the sub-seabed from that or another platform, or a ship, would be captured by regulation if it constitutes disposal. Injection of CO_2 for the purposes of enhanced oil recovery is not captured by CEPA since section 122 (1) of Part 7, Division 3 of CEPA, the definition of what is disposal and what is not disposal is provided; one item that is not considered disposal is 122 (1)(k):

> "*a discharge or storage directly arising from, or directly related to, the exploration for, exploitation of and associated offshore processing of seabed mineral resources*."

Discharge or storage of a substance related to an oil and gas operation is not covered under the Disposal at Sea Regulations of CEPA; instead, it would fall under the jurisdiction of the relevant offshore petroleum board. Since Division 3 does not apply to disposal resulting from offshore exploration and processing of seabed mineral resources, as regulated under the Canada Oil and Gas Act, then storage of CO_2 that is generated

77 https://www.gc.noaa.gov/documents/gcil_imo_co2wag.pdf

directly from those operations could be exempt from the definition of "Disposal", similar to EOR.

Projects proposing CO_2 reinjection from a source outside Canada's EEZ may also not be captured by the Ocean Disposal Regulations, since the area outside the EEZ is not included explicitly in the Acts definition of "sea" in Section 122(2). However, an area of the sea adjacent to the EEZ may be designated by Governor in Council based on a recommendation of the Minister, under Section 135 (1) (g) of CEPA.

Impact Assessment Act

Although CCS projects are not explicitly listed as a designated project requiring a federal impact assessment, if a proposed CCS project were to use existing oil and gas infrastructure, there is room for interpretation. The following sections of the Physical Activities Regulations (SOR/2019-285) will require interpretation as they relate to an offshore CCS project:

> ***Section 36*** - The decommissioning and abandonment of an existing offshore floating or fixed platform, vessel or artificial island used for the production of oil or gas that is proposed to be disposed of or abandoned offshore or converted on site to another role.
>
> ***Section 40*** - The construction, operation, decommissioning and abandonment of a new offshore oil and gas pipeline, other than a flowline as defined in subsection 2(1) of the Canada Oil and Gas Installations Regulations.
>
> ***Section 41*** - The construction, operation, decommissioning and abandonment of a new pipeline, as defined in section 2 of the Canadian Energy Regulator Act, other than an offshore pipeline, that requires a total of 75 km or more of new right of way.

Specifically, if existing offshore platforms were converted for the purpose of CO_2 injection and if pipelines were repurposed or constructed to carry CO_2 for the purposes of reinjection and storage, they would not be considered a designated project. Governments could consider implementing a new mechanism to expedite projects that are offering to capture and store emissions by excluding CCUS-related projects from requiring assessment under the *Impact Assessment Act*. Presumably, if a new well were required for CO_2 injection, it also may be excluded from a requirement under the *Impact Assessment Act* via the Regulations Respecting Excluded Physical Activities (Newfoundland and Labrador Offshore Exploratory Wells).

8.1.2 Provincial

Once there is a clear path to federal approval for CCS projects in the offshore, regulations and/or guidance surrounding operation and decommissioning of CCS projects outside the existing mandate of the C-NLOPB will be required. The following sections outline considerations for the development of a CCUS regulatory framework.

8.1.2.1 Alberta

In 2010, the Alberta *Carbon Capture and Storage Statutes Amendment Act*, amended several acts governing the oil and gas industry and had three main objectives:

1) to clarify the ownership of pore space,
2) to transfer to the province, long-term liability for injected CO_2, and
3) to create a stewardship fund to be used for remedial work and ongoing monitoring costs for the stored CO_2.

The Government of Alberta has maintained ownership of pore space in the province, and therefore long-term liability for carbon storage. The provincial government has taken on long-term liability of stored CO_2 once a site is no longer active and will be responsible for assuring that any leaks are fixed and that wellbores are maintained. The Carbon Capture and Storage Statutes Amendment Act allows the government to assume long-term liability for storage sites and makes it mandatory for carbon capture and storage operators to contribute to the Post-Closure Stewardship Fund. The provincial government will use this fund for ongoing monitoring and any required maintenance and remediation. Types of monitoring and measurement:

- Subsurface: monitors the movement of the CO_2 in the storage site and the stability of the cap rock.
- Near surface: monitors soil, well water, and groundwater to ensure CO_2 is not leaking.
- Atmospheric: monitors CO_2 levels in the air around the site

In 2011, the Regulatory Framework Assessment was initiated in response to Alberta's $1.3 billion investment in two commercial-scale CCS projects in the province. In 2013, the resulting report recommended regulatory changes related to the technical, environmental, safety, and monitoring requirements for the safe deployment of CCS.

Also in 2013, Alberta passed the Carbon Capture and Storage Funding Act to encourage and expedite the design, construction and operation of carbon capture and storage projects in Alberta through the provision of funding not to exceed $2 billion.

Land tenure for carbon sequestration in Alberta is issued through a competitive bid process to projects not associated with oil and gas extraction. The intent is to award licenses to hub or cluster projects, where CO_2 is collected from multiple facilities and injected underground.

The first round of land tenure in the Edmonton area resulted in six hub projects being selected to proceed with site evaluation. A second round of land tenure received 40 applications for CO_2 storage projects.

Monitoring Measurement Verification Guidelines establishes principles and objectives for industry during the term of the carbon sequestration lease regarding monitoring, measurement and verification of sequestered carbon emissions, to help ensure long-term public safety and environmental protection. Guidelines for items to be addressed in a monitoring, measurement and verification plan for a CCS project can be found in the Monitoring, Measurement and Verification Principles and Objectives document[78].

Under Alberta's Technology Innovation and Emissions Reduction (TIER) regulations, emission offset credits may be generated by projects that have voluntarily reduced their greenhouse gas emissions, including CCUS and EOR projects. Emission offsets are quantified using provincial protocols and are verified by a certified third-party. These credits may be used for compliance obligations for emissions reduction in Alberta.

A CCS operator will be responsible for the CCS operation until it substantiates that the stored carbon dioxide is "contained", and a closure certificate has been issued. Thereafter, the Alberta government will be the owner of the sequestered CO_2 and, on an indefinite basis, will assume the monitoring and other post-closure responsibilities.

8.1.2.2 Saskatchewan

All EOR projects, including those using CO_2, are eligible to receive a production incentive that lowers the royalty rate until the cost of capital is recovered. Under the current EOR royalty regime, a project pays a Crown Royalty equaling one per cent of the project's gross revenue until payout, and up to 20 per cent of the operating (net) revenue after payout. Saskatchewan's EOR

[78] https://open.alberta.ca/publications/mmv-principles-objectives-for-co2-sequestration-projects

royalty approach is now roughly two decades old. The Government of Credit Mark

8.2 Credit Market

As with any emerging clean technology, credit issuance has become a significant incentive and a means to create more value in emissions reductions efforts. Credits can be the tipping point that makes a project feasible and therefore a key factor in attracting project investment. Under the right conditions, credit-based revenues support a case to attract private investment capital to execute emission reduction projects which would otherwise not be feasible. However, in the absence of price certainty within each of these credit examples, there is inherent risk in using the projected value of credits in any economic model.

Provincially, there is no jurisdiction to do any credit market associated with CEPA as it appears outside of the scope of the province under the Management of Greenhouse Gas Act. There are options around a equivalency agreement process, but such agreements are rare and complex.

8.2.1 Offset Credits

Alberta is currently the only jurisdiction within Canada where offsets credits can be earned for a regulated facility installing a CCUS unit. Alberta has developed carbon offset protocols for both carbon capture and storage as well as for enhanced oil recovery methods. These technology-based offset credits generate a premium price in the regulated market and are sold to other facilities within the province. Offset credits registered in Alberta cannot currently be used for federal compliance and are non-transferable outside the province.

On June 8, 2022, the Government of Canada enacted the Canadian Greenhouse Gas Offset Credit System Regulations (Offset Regulations) under Part 2 of the *Greenhouse Gas Pollution Pricing Act* (GGPPA). Offsets are generated by preventing GHG emissions or removing GHGs from the atmosphere over and above "business as usual" or legal requirements to reduce GHGs. They also must not be incentivized by legal requirements already in place, nor can they be subject to any policy or other risk management instrument placing a price on carbon pollution. Once generated, offset credits can be used by facilities subject to the Output-Based Pricing System (OBPS) for compliance purposes. Alternatively, they can be used to meet corporate net-zero commitments or conditions of an *Impact Assessment Act* approval. However, there are currently no plans for a CCS protocol for industrial emissions, either on the federal or provincial side.

A regulated facility may explore the option of producing offset credits for the voluntary market, although the uncertainty of credit price and risk of low demand would increase compared to the regulated offset market, making this option less practical or feasible. Furthermore, many voluntary credit buyers currently prefer nature-based solutions that provide significant ESG co-benefits at values significantly below those required to decarbonize an industrial asset using CCUS.

8.2.2 Performance Credits

Emissions reduction beyond regulatory requirements for offshore facilities will currently earn performance credits under the provincial Management of Greenhouse Gas Regulations. A CCS project on an offshore installation would potentially introduce hundreds of thousands of additional credits into a market with a limited number of potential buyers. The province is proposing a minimum pricing structure for credits created by Newfoundland and Labrador

Hydro[79] which would likely translate to credits produced by all other facilities. A maximum 10 per cent discount rate for these credits below the regulated carbon price in 2023 is proposed. It would be reduced by one percentage point per year until it reaches five per cent in reporting year 2027, and it will be maintained at five per cent in future years.

Thus two items must be considered when it comes to performance credits, based on current observations:

1. The existing credits generated by NL Hydro and the Seal Cove Thermal Generation plant will no longer be available by 2042.
2. There is an unknown surrounding the use of performance credits at this time due to the ongoing discussion around sectoral hard cap emissions.

The Discussion Document on 'Options to Cap and Cut Oil and Gas Sector Greenhouse Gas Emissions to Achieve 2030 Goals and Net-Zero by 2050' describes how performance credits may no longer be available to oil and gas facilities[80], but there is no timeline for the potential phasing out. In the absence of an option to use performance credits or offset credits for compliance, offshore operators will be left with a choice between direct emissions reduction or paying into the provincial Greenhouse Gas Reduction Fund, at the federal carbon price per tonne of emissions.

8.2.3 Investment Tax Credits

Currently, the government of Canada is offering a 60 percent tax credit for eligible capture equipment, a 50 percent tax credit on other eligible capture equipment and a 37.5 percent tax credit on eligible transportation storage and use equipment. Enhanced oil recovery projects are not eligible. Each of these CCUS tax credits are to be only available to projects in jurisdictions where there are sufficient regulations to ensure that the CO_2 is permanently stored as determined by Environment and Climate Change Canada. Initially, the Investment Tax Credit (ITC) will only be available to CCUS projects that store the CO_2 in Saskatchewan or Alberta, since there is currently no regulatory framework explicitly dedicated to CO_2 storage and long-term liability in other provinces or territories.

ECCC will lead a review by federal departments of provincial/territorial CCUS regulatory frameworks as they come forward to consider if their regulations generally meet best practices globally to ensure permanent storage of CO_2. The requirements of CO_2 storage regulations were outlined in a recent presentation by NRCan[81] as:

- ECCC and its federal partners (*e.g.*, NRCan) intend to review a jurisdiction's CCUS regulatory protocols to ensure that regulatory requirements are met:
    - Support environmental integrity and safety across the project lifecycle
    - Ensure CO_2 leaks are prevented, monitored and contained

79 https://www.gov.nl.ca/ecc/files/Carbon-Pricing-Systems-Federal-Benchmark-NL-Response-Detailed.pdf
80 https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/options-discussion-paper.html
81 From a presentation by Savis Mortazavi at the 2022 NL CCUS Workshop in St. John's on September 28, 2022

- Ensure permanence of CO_2 storage post-closure

- Criteria that will be considered include aspects across the CCUS storage project lifecycle such as: site characterization, risk assessment, long-term monitoring and verification, site care and post-closure obligations and considerations.

- Once a provincial regulatory framework is determined to be sufficient, ECCC will advise Finance Canada to begin administering the CCUS-ITC in that province.

According to international best practice, a site determined to have the geological potential for CO_2 storage requires further assessment to characterize the properties of the formation, confirm its suitability (e.g., temperature, pressure, injectivity, containment, and capacity), and identify potential liabilities. Monitoring technologies are required to ensure robust data are available to provide a baseline of the site pre-injection, verify the amount stored once CO_2 is injected, and to ensure permanence.

8.2.4 Clean Fuel Credits

Similar to the qualification requirements for the ITC, CCUS projects are required to demonstrate existing provincial or territorial regulations to ensure permanent storage to earn credits under the Clean Fuel Regulations (CFR). The Minister of Environment and Climate Change Canada may decline projects in province(s) or territory(ies) if it can not be demonstrated that they have relevant regulations to ensure permanent storage. This includes, but is not limited to, requirements for site characterization, well construction and operation, injection monitoring and well abandonment.

Once the Minister is satisfied that CO_2 storage regulations are adequate, offshore projects may be eligible to earn CFS credits under compliance category 1, which are actions throughout the lifecycle of a liquid fossil fuel that reduce its carbon intensity (CI), by carrying out a Carbon Dioxide Equivalent (CO_2e) emission-reduction projects in respect of fossil fuels. Credit eligibility is determined based on the proportion of the quantity of crude oil that is not exported from Canada and that has a reduced carbon intensity as a result of the activities carried out for the project. Carbon intensity of crude may be reduced according to the Carbon, Capture and Storage Quantification Method[82], and Enhanced Oil Recovery Quantification Method[83] in order to earn credits. Credits may also be earned on the portion of crude sold domestically under the Generic QM and may include, but are not limited to energy efficiency, electrification, fuel switching, combined heat and power and methane reductions beyond regulatory requirements. Low intensity crude from the offshore may realize increasing demand as refineries within Canada are required to reduce lifecycle carbon intensity of liquid fossil fuels under the Clean Fuel Regulations.

[82] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/clean-fuel/regulations/Quantification-Method-Enhanced-Oil-Recovery-CO2-capture-permanent-storage.pdf

[83] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-regulations/compliance/quantification-method-enhanced-oil-recovery-co2-capture-permanent-storage.html

8.3 Regulatory Gaps

Outside the authority of the offshore petroleum boards to approve gas injection by an operator on an existing production licence, Canada does not have a regulatory framework for offshore CCS or ocean-based CO_2 sequestration[84]. There are no statutes able to grant interest on the continental shelf for activities unrelated to oil and gas development, outside a waste disposal site under the Disposal at Sea Regulations (see Section 7.1.1).

In terms of satisfying the ITC and CFR credit requirements for storage regulations, it is necessary to work with the Province and the C-NLOPB to identify where gaps in regulation may exist.

The CSA Group has developed a standardized approach for Geological Carbon Storage (GCS) projects consistent with industry best practices and regulatory requirements. It establishes requirements and recommendations to:

- Help promote environmentally safe and long-term containment of CO_2 in a way that minimizes risks to the environment and human health.
- Guide management documents, community engagement, risk assessment and risk communication.
- Cover the project life cycle, from injection through to subsequent operations until cessation of injection. The standard does not specify post-closure period.

In general, a site determined to have geology potentially suitable for CO_2 storage via feasibility studies requires further assessment to characterize the properties of the formation, confirm its suitability (e.g., temperature, pressure, injectivity, containment, and capacity), and identify potential liabilities. Site-specific risk assessments are also required and permits from the responsible regulator. Monitoring technologies are required to ensure robust data are available to provide a baseline of the site pre-injection, verify the amount stored CO_2 once it is injected, and to ensure permanence.

Further guidance is available from the Quantification Methods for Enhanced Oil Recovery with CO_2 Capture and Permanent Storage and Enhanced Oil Recovery with CO_2 Capture and Permanent Storage in terms of how to establish a baseline, quantification of storage, monitoring and verification.

Together, the CSA standard and the quantification methods, could form the basis of a regulatory framework for offshore carbon storage. On an international scale, alignment of international standards on CCUS could improve confidence for industry and investors as a global CCUS market grows. The International Organization for Standardization is currently developing CCUS standards for this purpose, with a scope including standardization of design, construction, operation, environmental planning and management, risk management, quantification, monitoring and verification, and related activities in the field of CO_2 capture, transportation, and geological storage. Additional regulation would be required for areas not covered such as decommissioning, abandonment and long-term liability.

84 https://climate.law.columbia.edu/content/legal-framework-offshore-carbon-capture-and-storage-canada

9 Economics of CCUS

Making carbon capture and storage projects economically viable is challenging for a number of reasons, including technological challenges and high capital costs. Both of these challenges are exacerbated in the offshore environment where space constraints and harsh working conditions add to the cost and present technical challenges. The main challenge, however, stems from one key factor: there is no direct source of revenue available for capturing and permanently storing emissions. As such, the primary sources of "revenue" are regulatory-driven and include the ability to lower the costs of carbon taxes and other levies. To offset the cost barriers of CCS projects, governments are also implementing incentives that either help to lower the costs of CCUS projects (e.g., investment tax credits) or provide direct payments based on the volume of carbon captured (e.g., production credits).

The costs involved with reducing emissions to avoid the negative impacts of climate change can be considered a global public good. Typically, public goods are defined by the extent to which the benefits accrue to broader society. For most public goods, these benefits are local (e.g., municipal water systems), regional (e.g., provincial highways) or national (e.g., coast guard operations); reducing emissions is a rare case where the benefits are global. The global nature of the problem and consequently the solutions add an additional layer of complexity in the analysis of the economic viability of CCS projects.

According to the Longship Project White Paper[85], there are two sets of market failures which preclude CCS development and deployment:

1. *The first and most important market failure is that the price of emitting greenhouse gases is lower than the socioeconomic costs associated with such emissions. This pricing of emissions, either by way of taxes or a market for emission allowances, is the single most important measure in Norwegian climate policy*
2. *The other market failure is related to the development and scope of new technology. The development of technology may have the characteristics of a public good. This means that the technology is useful to others and not just the actor that developed it. The actors that develop the technology will therefore bear the costs, while the benefits are shared by many. In economics, this is called positive externalities, and a market left to its own devices will create too little of this kind of public good.*

This means that the costs are borne by few, while the benefits are shared by many. From a business economics perspective, it can therefore be profitable to wait until others have borne the costs of development and early application. This is a particular problem for technologies that lead to large positive externalities that are difficult to patent or that are necessary, but do not in themselves provide a significant competitive advantage in the market. CCS is an example of this.

85 https://www.regjeringen.no/contentassets/943cb244091d4b2fb3782f395d69b05b/en-gb/pdfs/stm201920200033000engpdfs.pdf

Another factor which hinders the viability of CCUS in The NL offshore is that there are only four producing oil fields in the NL offshore and thus there is limited potential to achieve economies of scale through shared costs. In addition, two of the fields are nearing the end of their productive life, which makes it even less economically viable to undertake any CCS retrofitting projects. Beyond the four offshore emitters, there are a limited number of large emitters in other sectors of the Province, thereby limiting the ability to share and lower unit transportation and storage costs.

9.1 Determinants of Economic Viability

When determining economic viability of CCUS projects, many factors are considered, including revenues (or cost savings), volume of carbon captured, capital costs, operating costs, transportation costs, storage costs and taxes. In the case of CCUS projects, economic viability is typically determined on a levelized cost of carbon abated (LCCA) basis. In other words, CCUS modelling typically focuses only on costs. The LCCA expresses the total costs of a CCUS project on a per unit of carbon abated basis over the expected life of the project. Because of the various (and changing) types of regulatory-driven incentives or disincentives, the LCCA number allows the comparison of the ultimate cost of capturing and storing carbon to the various incentives available in the prevailing jurisdiction. Typically, if the LCCA is less than the regulatory costs of emitting carbon, then the project is viable.

Many factors are at play in the viability of CCUS projects, further discussed below, include:

- Capture costs
- Transportation costs
- Storage costs
- Technological/efficiency improvements
- Source of emissions (e.g., natural gas fired power generation vs. Cement production, etc.)
- Properties of the CO_2 source (e.g. CO_2 concentration levels
- CO_2 volumes
- Cost of debt and equity (i.e., discount rate)
- Government incentives and costs:
    - Investment Tax Credits (ITC)
    - Production credits (e.g., United States 45Q tax credit)
    - Carbon taxes

9.2 Cost Drivers

Note that most costs in this section reference onshore carbon capture costs. The costs of capturing carbon from retrofitted offshore facilities or on new offshore facilities are expected to be greater than those for onshore facilities. Given that there are no offshore oil and gas production facilities that have carbon capture systems[86], there is limited information available about the costs of installing CCUS units on offshore production facilities (brownfield or greenfield), the costs presented will most likely need to be factored up to reflect the higher costs related to offshore facilities. As shown in Table 7 below, the range for CCS costs vary considerably.

[86] The Sleipner field in offshore Norway utilizes carbon capture, however, it is primarily used to remove excess CO2 from its natural gas stream rather than capturing CO2 for permanent storage

Table 7 - Indicative Costs for CCS (US$/tonne CO_2e)

	Capture		Transport		Storage	
Source	**Low**	**High**	**Low**	**High**	**Low**	**High**
Rystad[1]		150	12	15	9	12
Longship[2]	62	62	40	80	Included in trans cost	
Global CCS Institute[3]	13	23	3	25	3	20
Royal Society[4]	49	114	2	15.3	8	25

Notes:
1) Rystad Energy, "How to bring down the costs of CCUS Projects: White paper", Oct, 2022
2) https://netl.doe.gov/sites/default/files/netl-file/20CCUS_Carpenter.pdf
3) Global CCS Institute, "Technology Readiness and Costs of CCS", Mar, 2021 https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf
4) Royal Society, "Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States", Aug. 2020, "https://royalsocietypublishing.org/doi/10.1098/rsfs.2019.0065

9.2.1 Capture Costs

Capital costs for capturing carbon are the biggest source of total CCUS costs and they vary considerably (as illustrated in Table 6 above) based on several factors, including: the selected technology, the volume of CO_2 to be abated, the properties of the emissions, the type of facility, and the source of the emissions. Given the relatively low levels of CO_2 in the flue streams from natural gas power plants and the high cost of retrofitting existing gas turbines, capture costs for natural gas power plant flue streams are amongst the highest when compared to other types of emitters such as petrochemical facilities and natural gas processing plants[87]. When combined with the challenge of installing carbon capture units on offshore facilities, the potential costs for capturing carbon from offshore facilities is expected to be significant.

Because of these factors, the costs of capturing carbon can range considerably. For example, according to Rystad Energy, the capital cost for capturing carbon from natural gas plants is ~ $85 (USD) per tonne of CO_2 and operating costs are ~ $65 per tonne, for a total cost of capture in the $150 (USD) per tonne range. Meanwhile, the Global CCS Institute places capture cost in the $13-23 (USD) range. To add another level of uncertainty, the costs for capturing carbon from offshore gas turbines can be expected to be significantly higher given the space constraints on existing offshore facilities and the inherent difficulty and added costs associated with working in an offshore environment.

9.2.2 Transportation Costs

After capture costs, transportation costs typically are the next biggest contributor to the overall costs of CCUS projects. Transportation is either accommodated via pipelines, ships, or a combination. The location of the emitters compared to the location of the storage wells determines the choice of transportation selected and is a key driver of the overall costs of transportation.

According to Rystad[88], the costs of transporting via pipelines and ships are equivalent up to a distance of ~ 500 km (~ $15 &US/tonne). For longer distances beyond 500 km, the relative per unit costs of transportation via ships versus via pipelines declines considerably. As with capture costs, unit costs can vary considerably based on the volumes of CO_2 being transported.

[87] Sproule. "Carbon Capture, Utilization and Storage – Market Overview and Project Considerations, October, 2021.
[88] Rystad Energy. "How to Bring Down the Costs of CCUS Projects: White Paper", October, 2022.

9.2.3 Storage Costs

Storage costs are location-dependent but are typically the smallest contributor to the overall costs of CCUS. According to Rystad, storage in depleted offshore oil and gas reservoirs ($9-12 USD/t) is less than the costs of storage in saline aquifers ($12-15 USD/t). As with most aspects of CCUS and the determination of a levelized cost, the expected volumes of CO_2 to be stored is a big determinant in the unit costs.

There is generally less variability in expected unit costs for storage with the primary determining factor being the location of the storage facility. Onshore storage would generally be less expensive than offshore storage.

9.2.4 Discount Rate

The selection of an appropriate discount rate used to present costs in present-dollar values can have a significant impact on the levelized cost calculations. In addition, the choice of how to accommodate "discounting" abated emissions can also have a material impact on the LCCA calculations.

According to DNV in their analysis of the Northern Lights project, there are two options for determining present values. The first is the Investor Perspective, which involves discounting all costs and volumes of CO_2 abated to present values. In the case of the report referenced, both values were discounted at 8%. The other method is used by the Norwegian Environmental Agency (NEA) and involves discounting costs at 4% and not discounting the volumes of carbon abated. The results are profoundly different at 2,600 NOK ($361 CAD) per tonne using the Investor Perspective methodology and 1,000 NOK ($139 CAD) per tonne using the NEA methodology.

9.3 Government Incentives

Government policy and the regulatory environment are critical factors influencing the economic viability of CCUS. Governments can affect economic viability through two primary means: 1) providing tax credits to offset the capital costs of CCUS investments; and 2) placing real costs on carbon that are large enough to place a meaningful value on carbon. In addition, as was the case with the Northern Lights project, the government can directly invest in the industry to kick-start development. For Northern Lights, the government of Norway contributed approximately two-thirds of the project cost.

9.3.1 NL Performance Credits

In the Newfoundland and Labrador context, large emitters are not subject to a carbon tax; rather the GNL has put in place a system that combines annual emission reduction targets with a performance credit system. Section 8.2.2 provides an overview of Newfoundland and Labrador's performance credit system.

9.3.2 Investment Tax Credits

In its 2022 budget, the Government of Canada (GC) introduced an Investment Tax Credit (ITC) for eligible CCUS projects. In its initial iteration, the credit is only applicable to CCUS projects in Alberta and Saskatchewan. The credit is refundable and provides companies with a direct refundable credit of up to 30% of eligible CCUS costs.

For a typical CCUS project, whose costs are very capital-intensive, an effective 30% reduction in capital costs has the opportunity to vastly improve the economics of CCUS projects. Section 8.2.3 provides additional information on the Government of Canada's ITC for CCUS projects.

One of the provincial eligibility requirements is having delineated and confirmed storage capacity. Newfoundland and Labrador, through the Oil and Gas Corporation of Newfoundland and Labrador (OilCo) is addressing this requirement through the issuance of a RFP to undertake a formal storage assessment for the storage of CO_2 in the NL offshore in either depleted reservoirs or in saline aquifers.

9.3.3 Production Credits

Production credits are a government incentive whereby the government pays emitters for storing carbon on a unit basis. This system is in place in the United States and was significantly enhanced under the Inflation Reduction Act, passed in mid-2022. Under this enhanced program, the US government will pay companies up to $85 (USD) per tonne for every tonne of carbon permanently stored. This enhanced refundable credit has been called a game-changer and a "bonanza"[89]

> *"Together with the historic investments made in the Bipartisan Infrastructure Law, this package would provide the most transformative and far-reaching policy support in the world for the economywide deployment of carbon management technologies"*[90]

While the Canadian ITC offers significant potential for cost reductions, it falls well short of the US-based production credit system. According to a September 2022 BMO Capital Markets report, Canada is falling behind the United States in CCUS policy and incentives. A made-in-Canada production credit type of system would go a long way to ensuring that Canada is able to attract the investment required to deploy CCUS at a pace and scale that will help Canada meet its emissions-reduction targets.

9.4 Improving the Viability of CCUS Offshore NL

Given these challenges, there are four main areas which could affect the viability of CCUS projects in the offshore oil and gas industry:

9.4.1 Technological Improvements

As with many cleantech technologies and concepts, the CCUS technical environment is continually evolving with implications for costs. It will be important to keep abreast of emerging technologies that would be a fit for the NL offshore. In addition, nurturing the development of local technologies that are specifically targeted at NL offshore could have direct benefits for carbon capture solutions as well as indirect benefits through the development of a supply chain. While there exist challenges for any novel technology such as the installation of CCS units on existing offshore facilities, there are also significant opportunities with being an early mover. Newfoundland and Labrador has a well-developed cleantech ecosystem with hundreds of small and medium sized enterprises providing products and services throughout the value chain, many of whom are well-positioned to capitalize on this opportunity.

9.4.2 Collaboration

Given the cost challenges and the importance of economies of scale towards reducing unit costs, collaboration is a key means by which the viability of CCUS offshore NL can be improved. In this context, collaboration means operators, regulators, contractors, and government working together to develop shared solutions that would best fit the NL offshore environment. Further discussion of the carbon capture hub concept is provided in Section 5.

9.4.3 Understanding Storage Potential

Assessing the storage potential offshore NL is an important pre-requisite to all CCUS opportunities, whether it be for stand-along projects or for advancing the storage hub concept (see below). The recently issued RFP for a formal storage assessment will help firm up the

[89] https://time.com/6205570/inflation-reduction-act-carbon-capture/
[90] Madelyn Madison, External Affairs Manager, Carbon Capture Coalition

storage potential offshore and will provide certainty for one aspect of the overall CCUS costs offshore NL.

9.4.4 Economies of Scale

A shared hub concept that would accommodate NL emitters as well as have the ability to store CO_2 from industrial emitters (most likely from eastern North America) would have the combined benefits of potentially lower unit costs for The NL offshore projects as well as bring in additional revenue and economic opportunities. Sharing costs is one of the basic tenets of the hub concept, however, even with the sharing of costs, the viability remains challenging. By way of example, two-thirds of the Northern Lights project in Norway was financed by the Norwegian government. In addition, the Northern Lights project business model includes storing CO_2 from other emitters on a fee-for-service basis.

9.4.5 Government Support

Government support includes both tangible actions like the recently announced ITC for CCUS projects in Alberta and Saskatchewan as well as intangible support. This support comes from championing CCUS, ensuring regulatory certainty and stability, assisting with R&D for new technologies and potentially even investing in a hub much like the Government of Norway did with the Northern Lights project.

While the costs of installing a carbon capture unit on an existing offshore facility are uncertain, a reasonable scenario can be developed using some known and some assumed potential costs and amounts of carbon abated from the installation of one carbon capture unit on a fixed platform. These costs are derived from work done by Hatch within the report Net Zero Pathways for Canada's Oil and Gas Industry (Pathways Report) as well as from research undertaken by the NZP team.

9.5 LCCA Scenarios

The primary purpose was to identify a base case and then to determine how the LCCA would be affected by various government incentives as well as how the LCCA is affected by changes in various cost assumptions, including the effect that changes in capital and operating costs would have on the LCCA. The results of this analysis are presented in Table 7 below.

9.5.1 Scenario Descriptions and Results

Base Case - The base case scenario is based on the costs to install one carbon capture unit that would capture 90% of the emissions from one natural gas turbine on an existing platform. The capital and operating costs for the capture unit are from the Pathways report previously referenced. Transport and storage costs were estimated by the NZP team and are based on utilizing an existing wellbore from a brownfield facility and injecting CO_2 into a depleted reservoir. For the tax savings, it was assumed that the operator would save 15% of the capex and opex costs after deducting the costs against its income tax payable. Under the base case, it was assumed that CCS projects in NL are not eligible for the Government of Canada's ITC and that CCS costs are not deductible against revenues for the purposes of calculating royalties. The amount of carbon abated was based on the volume of flue gas used and the carbon intensity of non-marketable gas. In the base case, the LCCA is $240 per tonne of carbon abated, which is considerably higher than the carbon tax in 2030 when it is expected to reach $170 per tonne.

Scenario 1 – Under Scenario 1, it is assumed that the project is eligible for the Government of Canada's refundable ITC at 30% of capital costs. The impact on the LCCA is significant as this ITC effectively reduces the capital costs by 30%, which reduces the LCCA from $240 to $182 per tonne but is still higher than the $170 per tonne carbon tax threshold expected by 2030.

Scenario 2 – Under Scenario 2, it is assumed there is a production credit in place in lieu of an ITC. The production credit is based on the 45Q credit in place in the US and which was enhanced under the recent Inflation Reduction Act to provide payments of $85 (USD) per tonne of carbon captured. The effect of such a credit would lower the LCCA to $155 per tonne, which is less than the $170 per tonne carbon tax threshold expected by 2030. In effect, the production credit provides a direct market price for carbon that is captured and permanently stored.

Scenario 3 – Under Scenario 3, it is assumed that both the capex and opex costs of the CCS project are deductible against revenues for the purposes of calculating royalties. The marginal royalty rate is estimated at 25% and there are no federal credits. Under this scenario, the LCCA is also reduced significantly to below the level of the federal ITC. While this is not a recommendation, it does illustrate that the Government of NL has the ability to incentivize the deployment of CCS technology on existing facilities through adjustments to its royalty regimes.

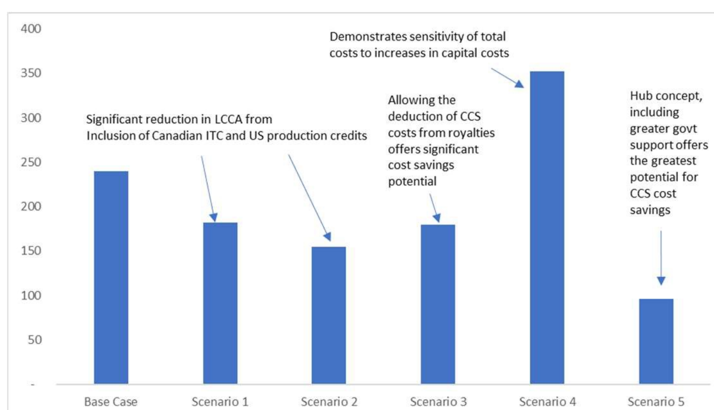
Scenario 4 – Under Scenario 4, the sensitivity of the LCCA to the capital costs were examined. As expected, the LCCA is highly dependent on the capital costs. In this scenario, the capital and operating costs were increased by 50% with a resultant increase in the LCCA by approximately $110 per tonne over the base case.

Scenario 5 – Scenario 5 is a proxy for what a potential government-driven CCS hub could look like and where the cost savings would most likely occur. Under this hub concept scenario, government involvement is assumed to involve an enhanced ITC at 50% for all capital costs and the deduction of CCS costs against royalties. For the transportation and storage costs, a hub concept could potentially reduce the unit costs considerably through shared infrastructure. Under this scenario, it is assumed that through a combination of direct government investment (or enhanced ITC), economies of scale, that the unit transportation and storage costs could come down by one-third. The ability to achieve economies of scale is more pronounced for transportation and storage costs.

9.5.2 Scenario Summary

The scenarios presented above present notional LCCA costs estimates for various CCS scenarios involving the installation of one unit on a brownfield GBS facility. Given the uncertainty and unknowns involved with installing CCS units offshore, these cost estimates are indicative and rather than being viewed as absolutes, it is the directional changes in the LCCA (Figure 28) which are worth noting and the relative impacts that the key drivers have on the LCCA of carbon capture as well as the impact that government incentives and initiatives can have on moving this industry forward.

Figure 28 – Notional CCS LCCA Scenarios



10 Net Zero Project Next Steps

The Net Zero Project continues to collaborate within the energy and environmental industries to drive economic growth, diversification, investment, and awareness through the lens of sustainability and the pursuit of net zero in NL offshore energy sector.

CCUS has emerged as a pathway to net zero, but more investigation is required to better define this opportunity and to begin to conceptualize technical and economic design scenarios. The NZP will continue to develop a comprehensive understanding of the source of CO_2 and how that can frame a strategy for Newfoundland and Labrador, or regionally as a $C0_2$ receiving hub. This will require a concerted research and development effort, and policy and regulatory frameworks will need to be in place to enable progress.

Offshore carbon storage has been successfully implemented in other jurisdictions, most notably offshore Norway, where storage has been ongoing since 1996. Offshore NL has significant CO_2 storage potential given the presence of high porosity and permeability reservoir sands with large pore volumes but this potential has yet to be quantified. OilCo has recently (Sept. 2022) issued a Request for Proposal (RFP) to conduct a resource assessment for CO_2 storage in offshore NL. NZP will assist with the evaluation and delivery of this assessment and help put the CO_2 storage potential of offshore NL in a global context.

The NZP will help to guide and coordinate activities to advance CCUS as a pathway to net zero, informed greatly by the results stemming from its CCUS workshop, which included:

- Confirmation, via engagement by NZP with stakeholders, that CCUS is a technology that will play an important role in the future of the offshore oil and gas industry.
- There is a need for regulatory definition, refinement, certainty, and speed. In addition, there is a perceived uncertainty in industry, government, and regulatory bodies as to ownership with a wide range of overlapping policy, legislation, guidance, and regulation.
- The offshore area has significant known potential for carbon storage, but a formal assessment has not been completed to date.
- There is a need for a roadmap for offshore implementation in asset specific and hub scenarios.
- **NL has an opportunity to be an early front runner in offshore CCUS technology.**

Currently, the NZP is continuing to progress a detailed technical and economic analysis, with increased granularity informed through key stakeholder feedback on CCUS and associated technologies. This analysis will be completed with focus on CCUS investment cases for asset specific and hub scenarios. As this industry develops, detailed policy and regulatory analysis will be performed to identify barriers to advancement and adoption of CCUS technologies, including investigating CO_2 substance status on CEPA and in respect to the London Protocols.

In addition, in collaboration with project partners, a phase 2 of the geological storage assessment will be advanced for specific oilfield(s) or other geologic structures that were high graded in phase 1 of the study that may include an EOR component, potential facility modification requirements and the economics of storing CO_2 considering carbon compliance costs, and the incremental value of additional resources produced.

The NZP will also put develop a CCUS ‘roadmap’ articulating actions required – including prioritization and sequence thereof – to realize NL (and Canadian) potential related to offshore CCUS. The roadmap will show a vision and action plan that can communicate timelines and current requirements in capital investment, technical adoption and regulatory frameworks, creating a sense of urgency around climate impact.

The NZP looks at this CCUS white paper as a beginning, and an introduction to current and potential industry when it comes to CCUS. As this transformational pathway advances in NL and technology evolves, the NZP expects this paper to revised on be a regular basis to capture new developments and help educate and inform stakeholders for the advancement of the industry.