ZEN and the art of CLEAN ENERGY SOLUTIONS

A Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in the Maritimes

In partnership with:

Dunsky Energy Consulting
& Redrock Power Systems

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Project Sponsors

EXECUTIVE SUMMARY

> *Hydrogen can become an essential part of the region's energy mix to reach net-zero carbon emissions by 2050 and increase energy independence.*

This study provides an assessment of the role hydrogen can play in the Maritimes' energy transition towards a net-zero-emission future. Opportunities for hydrogen have been identified that support the region's broad energy policy objectives related to climate change, inclusive economic development, and sustainable development of energy resources. Hydrogen opportunities were evaluated through the full value chain from production, storage, distribution and through to end use applications, integrated together into an end-to-end hydrogen ecosystem. Hydrogen shows the potential to be an essential part of the 2050 energy mix, closing gaps in hard-to-abate sectors. However, the region faces challenges that must be addressed for hydrogen to reach its potential and critical policy and infrastructure investments need to be made in the near-term to initiate action in the region.

The study was initiated in July 2020, and to date has been focused on the Maritimes region, looking both at unique provincial considerations in New Brunswick, Nova Scotia, and Prince Edward Island (PEI), and at opportunities enabled by a holistic view of the region. It was recognized that it would be beneficial to expand the scope to include Newfoundland and Labrador to encompass opportunities that could be unlocked through looking at the broader Atlantic region. This version of the report covers Maritimes only, and an addendum will be released before the end of 2020 to include Newfoundland and Labrador.

The potential of hydrogen to play a role in decarbonizing the energy system is top of mind for many governments and industries around the world. According to the Hydrogen Council, 18 federal governments representing more than 70% of global GDP have developed national strategies for hydrogen.[1] Within Canada, a hydrogen study for British Columbia was completed in 2019 and the Federal Government is currently finalizing its hydrogen strategy. This Maritimes study builds on these prior reports and considers the potential role of hydrogen within the local context.

Stakeholder Engagement

Stakeholder engagement served as an important tool to gather input from across all three provinces, and across a variety of industry sectors, levels of government, academia, and non-profit associations and environmental non-governmental organizations (NGOs). Through the study timeframe, almost 60 stakeholders representing over 40 organizations were engaged through a series of targeted one-hour virtual interviews, three two-hour virtual workshops, and an online survey. While the level of knowledge and experience on hydrogen varied among stakeholders, they all provided important perspectives on how

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[1] Hydrogen Council. (2020). *Path to hydrogen competitiveness: A Cost perspective*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

hydrogen can fit within the Maritimes energy landscape and these perspectives were considered in the opportunity analysis and recommended path forward.

Analysis

The opportunity for hydrogen in the Maritimes was evaluated by forecasting demand under two scenarios meant to represent incremental and transformative change from 2020 to 2050. Neither scenario is intended as a prediction of what will necessarily happen in the region but represent what could happen based on a number of assumptions including technology advancement, policy adoption, and consumer preferences. In both cases, hydrogen is assumed to be one of several key components to a larger decarbonization strategy. Other factors, such as increased low-carbon electrification, energy efficiency improvements, and biofuels are also likely to play large roles in reaching emissions targets in the region. The transformative scenario assumes highly favourable adoption of hydrogen technology and is built around achieving net-zero-emissions in 2050. The incremental scenario incorporates more conservative assumptions relating to the adoption of hydrogen and emissions reduction.

With today's policy framework and lack of strategy or coordinated approach regarding how hydrogen fits into a net-zero future for the Maritimes, the region is more on the path of the incremental scenario. This scenario offers little benefit to the region in terms of decarbonization potential and economic growth and is likely not a scenario that is worth pursuing from a cost benefit perspective. Inaction that allows 'business as usual' to progress will result in crucial time being wasted as other regions recognize the role hydrogen is best suited to play and take necessary actions to create a regulatory and policy framework to maximize the opportunities for hydrogen. A number of recommendation themes are included in the report that could position the region to be on the path of the more compelling transformative scenario, including:

- Developing a holistic **Clean Energy Roadmap for the region** that looks at how hydrogen fits with other low-carbon energy vectors and technology options to achieve a net-zero overall energy mix.
- Working as a region to develop **aligned action plans and policies** related to hydrogen.
- Implementing a **strong regulatory framework complemented with incentives** to drive the transformation and decarbonization of the region's energy systems and encourage end use adoption of alternative fuels.
- Getting started now with high profile **lighthouse projects** that encourage local industry participation.

Key Findings

1. Increasing awareness about opportunities for hydrogen is a critical first step

Engagement with stakeholders throughout the study highlighted that many parties in the region are just starting to think about hydrogen and the role it might play. The study started dialogues that should continue for hydrogen opportunities to be realized.

An important step to raise the profile of hydrogen will be to include it as a promising energy vector in the development of a regional Clean Energy Roadmap that looks holistically at the entire energy system in the region, from primary energy supply to end use demand. Hydrogen's role must be understood in the context of other decarbonizing energy vectors to ensure each is deployed where it can offer the greatest potential benefits technically and economically. Local governments can also support industry in raising general awareness about hydrogen safety and end use applications, through supporting outreach initiatives and the development of educational tools.

A Clean Energy Roadmap for the Maritimes would be an effective tool to plan for the transformation that must take place to achieve the region's decarbonization goals. Hydrogen will be an important piece of the roadmap, but it must consider all potential energy vectors and how they can be used in tandem to reach an overall net-zero mix. It is recommended that the roadmap first look at the current energy baseline and consider economics, technical maturity, and effectiveness of available low-carbon options to determine near-, mid-, and long-term viability to ultimately decarbonize the region. Energy consumption across all economic sectors should be considered including transportation, heating, electricity generation, and industry. The roadmap should be data driven and nonbinary given the range of forecast uncertainties, but can inform a rollout strategy by identifying which low-carbon energy vectors are best suited to specific end use applications under a range of scenarios, to inform policy and infrastructure decisions.

2. Producing hydrogen via electrolysis with renewable wind power is the most promising pathway in the region

The production pathways analysis uncovered both opportunities and challenges for producing hydrogen in the Maritimes. There is global consensus that development of new hydrogen supply must be focused on low carbon intensity (CI) pathways. Hydrogen production via electrolysis powered by renewable wind, often referred to as 'green hydrogen', shows the best overall potential in the Maritimes when looking both at bulk production costs and CI levels. Production of hydrogen via natural gas combined with carbon capture utilization and sequestration (CCUS), referred to as 'blue hydrogen', can also be cost competitive and low CI. It should be noted though that the region currently relies primarily on imported natural gas and delivered commodity prices are high relative to other parts of Canada given the region is at the 'end of the line' on import pathways. Unless more domestic natural gas is produced from local reserves, like the Nova Scotia Offshore, or the McCully Field in New Brunswick, this introduces risk for future pricing and does not provide the added benefit of increasing energy independence. Integrating hydrogen production into wind farms can improve the economics of both energy vectors, and ultimately enable greater development of intermittent renewable resources for both decarbonizing the grid and producing hydrogen as a replacement for carbon emitting transportation and heating fuels.

A challenge in the Maritimes is that electricity grids are still reliant on carbon emitting fossil fuels for a significant portion of the grid electricity generation mix, resulting in higher CI than is viable for producing hydrogen via grid connected electrolysis. Over the longer-term, hydrogen is seen as an energy vector that can help reduce the CI of the grid. The nuclear power plant in New Brunswick offers potential for regional hydrogen production, whereby nuclear power at off peak times when electricity demand is low could be used to produce low CI hydrogen. This warrants further study and is dependent on local opportunities for bulk hydrogen storage and requires a more in-depth analysis of daily and seasonal electricity demand and supply fluctuations in the region.

Import of hydrogen from nearby regions like Quebec with established green hydrogen production and liquefaction assets can be an important bridge for getting early deployments off the ground and should not be discounted as a longer-term option as an alternative to importing refined petroleum products.

3. Hydrogen can play an important role in grid scale energy storage, an important enabler for the region to increase energy independence

Intermittency is a significant problem with renewable energy sources, and hydrogen can provide utility-scale storage solutions. For example, PEI has been adding wind generation capacity; however, the amount produced exceeds demand in the summer, requiring the province to export electricity during these months and import electricity during the winter when production doesn't meet demand due to high electric space heating loads. Hydrogen can be produced via electrolysis during off-peak times and converted back to electricity at peak times. Batteries are a mature alternative technology that are being used globally but cannot currently provide economically viable long-duration storage solutions. Hydrogen, when coupled with bulk storage options such as salt caverns, depleted wells, or gas pipeline systems, provides the most economical utility scale energy storage option available today. Hydrogen offers additional flexibility as an energy storage medium, as it can be both used to generate electricity or can alternatively be stored and transported in pipelines either as pure hydrogen or as a blend with natural gas and used for peak heating demands and / or as a transportation fuel. Energy storage technology is developing quickly, and more analysis is necessary to predict the long-term costs and benefits of competing technologies such as hydrogen and batteries.

4. Hydrogen-powered long-range and heavy-duty transportation can become increasingly important to the region as hydrogen infrastructure matures

Transportation accounts for approximately 32% of greenhouse gas (GHG) emissions in the region and is reliant today primarily on refined petroleum products. To meet long-term decarbonization objectives, the region will ultimately have to make the shift to zero-emission vehicles (ZEVs).

The Government of Canada has set federal targets for zero-emission vehicles to reach 10% of light-duty vehicles sales per year by 2025, 30% by 2030 and 100% by 2040. Canada considers battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs), and plug-in hybrid electric vehicles (PHEVs) to qualify as zero-emission vehicles. Provinces in the Maritimes have not adopted a ZEV mandate to further catalyze the transition to ZEVs in the region, and currently there is a struggle to attract BEVs given the lack of regulatory incentives. This will likely continue and limit adoption of FCEVs as well. Ultimately both regulations and incentives for vehicle purchases as well as infrastructure development would help to accelerate the transition in the region.

While BEVs are anticipated to dominate the light-duty vehicle market, FCEVs will provide a choice in the light-duty market for consumers looking for larger vehicles such as sport utility vehicles (SUV) and pickup trucks, where the longer range and fast fueling times demonstrate the greatest advantages. Similarly, the biggest differentiation between FCEVs and BEVs will be in the medium- and heavy-duty trucking sector where FCEVs currently provide the only technically viable solution for the most energy intensive applications. Failing a technological breakthrough in battery technology, fuel cells are likely to play a significant role in heavy-duty trucking applications in the region over time. Hydrogen / diesel co-combustion technology can also provide a transitional technology option in the near term as FCEV commercial rollout is advancing.

5. There is a unique opportunity for Marine applications in the region, but driving change in that sector will be challenging and is not expected to lead hydrogen adoption

The marine sector is of particular interest in the Maritimes due to its cultural and economic importance in the region. While it only represents 4.2% of the overall transportation sector GHG emissions, it presents a bigger challenge in terms of decarbonization compared to land-based transport using other low-carbon energy vectors such as direct electrification with batteries, posing an opportunity for hydrogen to close the gap.

The study looked at potential for ferries, tugs, and fishing vessels, and ferries show the most promise for hydrogen. In comparison to battery electric technology, hydrogen is well suited to vessels that travel longer routes, have high energy requirements, and shorter duration opportunities for refueling that make charging batteries operationally difficult. Ferries also travel on predictable routes which simplifies fueling logistics and infrastructure requirements.

There are no initiatives in the region currently creating pull for zero-emission options. The ferries in the Maritimes are primarily owned by government (Transport Canada, crown corporations, or provincial Departments of Transportation and Infrastructure) but are operated by private industry. The purchasing process for ferries is an important factor to consider, as the procurement process can take years and is largely influenced by government policies. Two ferries (*MV Holiday Island* & *MS Madeleine*) are planned to be replaced over the next few years, and one of these could be targeted for first introduction of hydrogen as a marine propulsion fuel. One of the big challenges for the marine sector is the long lifetime of the vessels – sometimes greater than 50 years. To make significant progress toward Canada's and the International Maritime Organization's (IMO) 2050 emissions reduction goals, pilot projects should be considered as soon as possible in order to demonstrate feasibility as the rest of the sector looks to replace the fleet between 2030 and 2050.

6. Hydrogen as a feedstock for low-carbon fuel production will drive demand and development of supply in the near- and mid-term

Saint John, New Brunswick is home to Canada's largest refinery operated by Irving Oil. Irving already uses significant amounts of hydrogen in upgrading processes in the refinery, and they have started to take steps to reduce the carbon intensity of feedstock hydrogen to lower the carbon intensity of conventional liquid fuels like gasoline and diesel. The federal Clean Fuel Standard (CFS) which is designed to reduce Canada's greenhouse gas emissions through the increased use of lower-carbon fuels, is expected to come into force for liquid fuels in 2022. This anticipated regulation will drive fuel producers like Irving to continue to develop lower CI hydrogen pathways for their refinery feedstock as a compliance pathway. Establishing an increased supply of low CI hydrogen as a feedstock for the refinery can benefit the broader hydrogen sector, through development of lower-cost at-scale production of hydrogen.

Energy companies like Irving can play a financing role with project developers, as CFS credit deficits from conventional fuel production can be offset through purchasing credits generated through hydrogen projects where it is used as a transportation fuel. This has been an effective mechanism in British Columbia where the provincial Low-Carbon Fuel Standard (BC-LCFS) has been instrumental in establishing the network of hydrogen fueling retail stations for light duty vehicles. Energy companies can also generate credits via hydrogen themselves should they choose to produce low CI hydrogen as an alternative fuel.

Longer-term, liquid synthetic fuels will complement pure hydrogen as a fuel where energy density shows preference for liquid fuels or where conversion from lower efficiency internal combustion engines (ICE) to higher efficiency fuel cells is not practical or economically competitive.

7. The largest potential demand for hydrogen by 2050 is expected to be for heating, and natural gas distribution networks and new hydrogen pipelines can be the most effective delivery option

Hydrogen and renewable natural gas (RNG) can be used as a substitute for natural gas in the grid. However, the supply of RNG is limited by feedstock availability, thus limiting the potential to incorporate a large amount into the grid. The Maritimes are a particularly attractive region for hydrogen blending in the natural gas grid because the infrastructure is relatively new and primarily based on polyethylene piping that is compatible with hydrogen, so implementation is easier. Moreover, the gas distribution system is relatively small compared to other provinces; incorporating even a small amount of hydrogen will move the needle toward reaching GHG emission reduction targets, and there is potential to future proof to enable pure hydrogen regions as the grid grows.

With electricity delivered in the region being relatively high carbon emitting, there is strong potential for electricity and natural gas utilities to work collaboratively to develop regionally optimized integrated energy systems with hydrogen as the carbon free energy vector connecting the two. Utilities of the future may have blurred lines with a focus on energy rather than a single commodity.

8. Successful adoption of hydrogen will depend on a regionally coordinated effort

The Maritimes is a small yet diverse region. Hydrogen presents an opportunity for the Atlantic Provinces to coordinate efforts and align policy when planning for a net-zero future, and the success of hydrogen adoption depends on it. Coordination is needed to align policies and regulation, as well as develop common codes and standards to facilitate deployments and trade across provincial boundaries. Including hydrogen for consideration in the Clean Energy Roadmap for individual provinces as well as in a common integrated roadmap for the region would be a concrete step to align actions and policies.

A joint interprovincial hydrogen working group that is tied into the federal Strategic Steering Committee for hydrogen to be led by Natural Resources Canada (NRCan) would be an effective way to work together on a go-forward basis. Through joint development and sharing lessons learned, as well as hard infrastructure assets where appropriate, a more cost-effective introduction of hydrogen can be achieved. This will provide benefit for the region which has invested so heavily in renewables on a per capita basis and continues to struggle with regional energy poverty.

9. Enabling policies and regulations are needed to drive action

Successful deployments of hydrogen have been in regions with a combination of supporting policies and regulations. The Maritimes currently lacks concrete regulations and complementary incentives needed to de-risk industry investment and drive activity in the sector. A number of specific potential policies and actions have been identified for consideration, including those that support the use of hydrogen and other low-carbon technologies, such as ZEV and renewable gas mandates combined with incentives for related infrastructure development. Policies to disincentivize the use of incumbent technologies are also encouraged, such as road taxes or creation of local emission free or combustion free zones. Policy and regulation at the federal level will help guide the way but will likely be slower than what is needed to position for successfully reaching decarbonization goals. Provincial leadership is needed, and municipalities can also play an important role.

10. Regional deployment hubs driving use at scale are needed

There is very limited rollout of hydrogen in the Maritimes region today. To realize the long-term potential benefits, regional deployments must start in the near-term. Development of the full value chain spanning from production, to distribution and storage, through to end use will need to be developed in regional hubs that can facilitate supply and demand growing concurrently at scale. Provincial and Municipal governments will play an important role in supporting local developments and contributing to end use demand, for example by being an anchor tenant with adoption of fleet vehicles or other end use applications that provide financeable demand certainty.

One of the best opportunities to drive awareness is to deploy hydrogen domestically in projects that are high profile. The Port of Saint John, which is located close to the Irving Oil Refinery and hosts multiple end use equipment types that could be converted to hydrogen, and the City of Halifax, have been identified as two promising locations worthy of further study.

11. Established industry and utilities will play an important role

Utilities in the Maritimes are already leading the way in exploring opportunities for hydrogen and understanding the role it can play in solving problems and growing market share in a carbon constrained future. Both natural gas and electric utilities are anticipated to be champions for early demonstration projects, and longer-term broader adoption. Regulated utilities will face some unique challenges and must invite regulatory bodies to the table early to avoid barriers to entry. Energy companies including Irving Oil and Repsol are also well positioned to play an important role but are risk adverse and may be more focused on hydrogen's role in lowering CI of conventional fuels in the near-term.

12. Economic growth and job creation can be realized through fostering a hydrogen cluster approach, Innovation Hub, and supporting local deployments

The supply chain for hydrogen in the Maritimes will evolve as the sector grows and as competition enters the industry and as more services and differentiated production pathways are added. At the same time, the global supply chain will be evolving at an accelerated pace and certain roles and functions will be integrated, consolidated, and commodified by large outside players. It will be important for the Maritime Provinces to build out the supply chain for hydrogen in a deliberate and integrated way to form a critical mass of companies, academic institutions, talent pools, and related services. The cluster approach to industrial development has been successful in many regions around the world including Northern Italy for the textile industry, South Korea for steel production, and South-western Germany for precision manufacturing and may work well for the Maritimes as a new hydrogen economy is developed.

The Maritimes have a long history of resource extraction and other heavy industry, road/rail/marine transport, shipbuilding, and international trade. There are also many opportunities for organizations, skilled technicians, academic institutions, and other local services to pivot and/or participate in the hydrogen supply chain. There are several gaps in the supply chain where local players currently do not operate or are not well suited to transition to hydrogen. These areas will be filled by local product and service providers if they can find innovative ways to operate and stay competitive.

There are a number of innovative start-ups in the region with a focus on hydrogen production technologies. There are also activities in adjacent sectors like nuclear small modular reactors (SMR) that are complementary to hydrogen. Creating a cluster approach to encourage collaboration and consortium-based projects in the region will position the sector for long-term success.

13. The next 10 years should be focused on domestic use rather than export due to supply limitations

While the Maritimes region is strategically located close to several large potential demand markets for hydrogen, it is unclear at this time whether there will be sufficient production capacity for low-carbon hydrogen to satisfy both domestic requirements and export markets.

The region currently relies on imports to meet energy needs, and acts as a gateway for liquid natural gas (LNG) imports converted to natural gas and exported to the Eastern US market. Ultimately there could be potential to transition this export channel to provision of low CI hydrogen rather than natural gas, continuing to use imported LNG as the feedstock and leveraging the region's CCUS potential, or by leveraging other local pathways for producing low CI hydrogen, or most likely some combination of the two. With Europe looking to import large quantities of hydrogen as they move to net zero, the Maritimes could also act as Canada's export gateway to that region. This approach would require infrastructure to transport hydrogen from high capacity, low cost production regions to a port hub, and would also require liquefaction or hydrogenation processing capability as well as bunkering capacity. This is a concept that warrants further study and discussion with European counterparts.

It is recommended that potential for export be considered secondary to first establishing a domestic market for hydrogen that can benefit the region in meeting decarbonization goals, and longer-term position for export.

14. Challenge of being a small region can be turned into an advantage

The Maritimes is a small region in the context of national energy use and economics. This can be both a challenge and advantage in embarking on transformation of energy systems. The federal government will be looking to support lighthouse projects and regional deployment hubs as the *Hydrogen Strategy for Canada* moves into the execution phase. Being a small region, the size of deployments needed to make a significant impact are more manageable. As a small region, industry players are well acquainted and used to collaboration. Certain aspects of the energy system, such as the fact that the natural gas network is reasonably new and positioned for growth, position the region to lead in bold strategies to adopt hydrogen. The key will be finding local champions to develop integrated projects.

15. In a transformative scenario, hydrogen can make up 22% of delivered energy in the Maritimes by 2050, contributing to 6.5 Mt-CO2e emissions reduction or 21% of the region's overall GHG challenge.

In a transformative scenario in which the Maritimes is successful in transitioning to a net-zero carbon energy system by 2050 and adoption of hydrogen technology is aggressively driven by a strong policy and regulatory environment, hydrogen's decarbonization potential shows the greatest opportunity in the following areas:

- As a fuel for electricity production, contributing to decarbonization of the electricity grid through displacing power generation that is today reliant on natural gas and coal
- By providing heat for buildings/industry and replacing natural gas as a feedstock for industry through displacing combustion of carbon emitting natural gas or fuel oil with non-carbon emitting hydrogen
- As a transportation fuel in fuel cell electric vehicles, that are zero-emission at the tailpipe and are double the efficiency of internal combustion engine vehicles

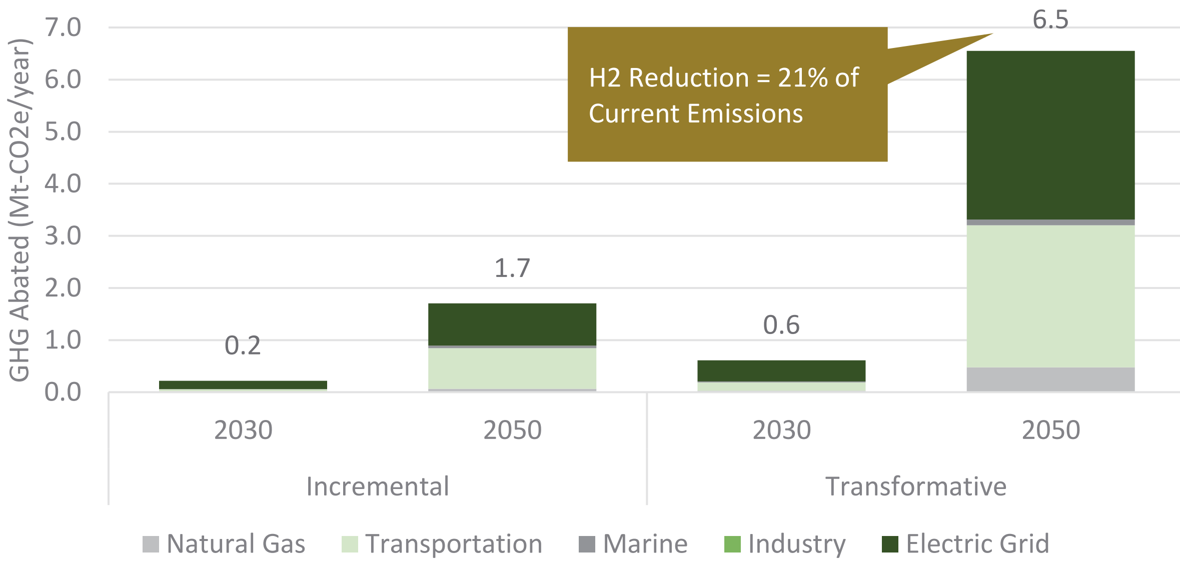

Figure 1 – GHG emissions reduction potential from hydrogen 2030 and 2050

The size of the opportunity is significant, and hydrogen is seen as an essential carbon-free energy vector in the Maritimes future 2050 energy mix.

Recommendations

A number of detailed recommendations are provided throughout the study to drive adoption of hydrogen in the region. Broader recommendations focused on closing near-term knowledge gaps relating to economic and technical challenges, as well as provide actionable next steps to move into the deployment phase, are broken into seven theme areas. These generally align with recommendation pillars in the federal Hydrogen Strategy for Canada that is under development, as ultimately coordination and alignment with national efforts is an important lever for success. The recommendation themes are as follows:

Theme 1: Strategic Partnerships
1. Develop regional working group to align provincial approaches to developing hydrogen sector.
2. Encourage leading industry players to participate in national strategy working groups in relevant sector – e.g. utilities, low-carbon fuel producers, emerging transportation.
Theme 2: Hydrogen Awareness
1. Include hydrogen in provincial and regional integrated Clean Energy Roadmap.
2. Support hydrogen outreach initiatives.
Theme 3: Infrastructure and De-Risking of Investments
1. Initiate studies to determine options and magnitude of investment for hydrogen infrastructure build out, both in individual provinces and as a regional approach.
2. Implement policies that support demand for zero emission and low carbon alternatives, as a mechanism to de-risk private sector investments.
Theme 4: Innovation and Hydrogen Cluster Development
1. Foster collaborative efforts between industry and academia by supporting consortium-based projects for fundamental research priority areas important to the region.
2. Form Maritimes chapter of Canadian Hydrogen and Fuel Cell Association or like industry association to encourage regional cluster development.
Theme 5: Codes and Standards
1. Adopt Canadian Hydrogen Installation Code and like standards to facilitate new technology and infrastructure adoption in early markets.
2. Develop and adopt common standards and practices across the region to facilitate inter-provincial trade.
Theme 6: Policy and Regulation
1. Ensure regional policy framework developed to meet decarbonization targets does not unintentionally preclude hydrogen as a pathway for compliance through narrow definitions.
2. Establish policy frameworks that provide long-term certainty for the sector and that are technology-neutral, performance-based, and non-prescriptive.
Theme 7: Regional Deployment Hubs
1. Identify champions and hosts for regional deployment hubs.
2. Provide support for feasibility studies to advance projects from conceptual to implementation phase.

GLOSSARY

ACI	Association of Chief Boiler and Pressure Vessel Inspectors
ACOA	Atlantic Canada Opportunities Agency
AHI	Atlantic Hydrogen Inc.
AHJ	Authority Having Jurisdiction
ARB	Air Resources Board
ASD	Azimuth Stern Drive
AZETEC	Alberta Zero-Emissions Truck Electrification Collaboration
BC	British Columbia
BC-LFS	British Columbia Low-Carbon Fuel Standard
BEB	Battery Electric Bus
BEV	Battery Electric Vehicle
CAD	Canadian Dollars
CapEx	Capital Expenditure
CCSNS	Carbon Capture and Storage Research Consortium of Nova Scotia
CCUS	Carbon Capture Utilization and Sequestration
CER	Canada Energy Regulator
CFS	Clean Fuel Standard
CH4	Methane
CHIC	Canadian Hydrogen Installation Code
CHP	Combined Heat and Gas
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
CO2-EOR	Carbon Injection to Enhance Oil Recovery
CP	Canadian Pacific Railway
CR	Canadian National Railway
CSA	Canadian Standards Association
CTMA	Coopérative de Transport Maritime et Aérien
CUTA	Canadian Urban Transit Association
CUTRIC	Canadian Urban Transit Research & Innovation Consortium
DTI	Department of Trade and Industry
ECCC	Environment and Climate Change Canada
EER	Energy Efficiency Ratio
EU	European Union
EV	Electric Vehicle
FCEB	Fuel Cell Electric Buses
FCEV	Fuel Cell Electric Vehicle
GDP	Gross Domestic Product
GH2	Gaseous Hydrogen
GHG	Greenhouse Gas
H2	Hydrogen
H2O	Water
HD	Heavy-duty
HENG	Hydrogen Enriched Natural Gas
ICE	Internal Combustion Engine

ICT	Innovative Clean Technology
IEA	International Energy Agency
IGAC	Interprovincial Gas Advisory Council
IMO	International Maritime Organization
IP	Intellectual Property
LD	Light-duty
LH2	Liquid Hydrogen
LNG	Liquid Natural Gas
M&NP	Maritimes and Northeast Pipeline
MCH	Methylcyclohexane
MHD	Medium- and Heavy-duty
MOU	Memorandum of Understanding
N2	Nitrogen
NGOs	Non-Governmental Organizations
NOx	Oxides of Nitrogen
NRCan	Natural Resources Canada
OERA	Offshore Energy Research Association
OpEx	Operating Expenditure
OSV	Offshore Support Vessels
PE	Polyethylene
PEI	Prince Edward Island
PEIFA	Prince Edward Island Fishermen's Association
PEM	Proton Exchange Membrane
PHEV	Plug-in Hybrid Electric Vehicle
PSA	Pressure Swing Absorption
RNG	Renewable Natural Gas
RPPs	Refined Petroleum Products
SDGA	Sustainable Development Goals Act
SEOP	Sable Offshore Energy Project
SMR	Steam Methane Reformer
SOx	Oxides of Sulphur
SUV	Sports Utility Vehicle
TRL	Technology Readiness Level
UK	United Kingdom
US	United States
ZEB	Zero-emission Bus
ZEV	Zero-emission Vehicle

TABLE OF CONTENTS

Acknowledgements ... i

Project Team ... i

Project Sponsors ... i

Executive Summary ... ii

Glossary ... xii

Table of Contents ... xiv

Table of Figures ... xvi

List of Tables ... xix

1. Introduction ... 1

Objectives and Scope ... 1

Project Methodology ... 1

Energy Consumption and GHG Emissions in the Maritimes ... 2

Current Uses and Applications of Hydrogen in the Maritimes ... 8

2. Hydrogen Production ... 11

Electrolysis ... 13

SMR with CCUS ... 17

Thermal Pyrolysis ... 19

Biomass Gasification ... 21

Cost and Carbon Intensity Comparison Summary ... 22

3. Hydrogen Storage ... 24

Physical Storage ... 24

Materials Based Storage ... 25

Chemical Carrier Storage ... 25

Chemical Hydrogen Storage ... 26

Large Scale Geological Storage ... 26

Salt Caverns ... 27

4. Hydrogen Transport ... 30

Hydrogen Transport by Road ... 30

Gaseous Hydrogen by Pipeline ... 32

5. Potential Hydrogen End Uses 33

Decarbonizing the Natural Gas System 33

Heating Buildings 46

Transportation 50

Marine 71

Industrial Applications 83

Electricity Generation 85

Aggregated End-Use Applications 91

6. Hydrogen Production for Export 94

Global Demand and Market Potential for Hydrogen 94

Export opportunity 99

7. Supply Chain Capability Assessment 100

Hydrogen Supply Chain Overview 100

Opportunities and Challenges for Local Service Providers 105

8. Carbon Capture and Sequestration 110

CCUS Technology Description 110

Opportunities and Challenges for CCUS in the Maritimes 112

Recommendations for Further Study 115

9. National Potential for Hydrogen 116

Current Hydrogen Related Activity Across Canada 116

Alignment with the National Strategy 117

10. Regulation and Policy 119

Current Hydrogen Related Policies and Regulations in the Maritimes 119

Recommended Regulations and Policies to Promote Hydrogen 126

11. Summary Recommendations 131

Appendix A. Summary of Stakeholder Engagements 132

Context 132

Key Findings 132

Stakeholder Table 137

TABLE OF FIGURES

Figure 1 – GHG emissions reduction potential from hydrogen 2030 and 2050 x
Figure 2 – End use energy demand in the Maritimes by sector and fuel 3
Figure 3 – GHG emissions in the Maritimes 3
Figure 4 – End use energy demand in the New Brunswick by sector and fuel 4
Figure 5 – Electricity generation in New Brunswick[4] 4
Figure 6 – GHG emissions in New Brunswick 5
Figure 7 – End use energy demand in the Nova Scotia by sector and fuel 6
Figure 8 – Electricity generation in Nova Scotia 6
Figure 9 – GHG emissions in Nova Scotia 7
Figure 10 – End use energy demand in the Nova Scotia by sector and fuel 7
Figure 11 – GHG emissions in PEI 8
Figure 12 – Electricity generation in PEI 8
Figure 13 – PEI wind village project 9
Figure 14 – PEI H2 Shuttle 9
Figure 15 – CarbonSaver demonstration plant 10
Figure 16 – Hydrogen production pathways 12
Figure 17 – Hydrogen production cost – electrolysis 14
Figure 18 – Hydrogen carbon intensity – electrolysis 15
Figure 19 – Electrolyzed hydrogen sensitivity to electricity carbon intensity 16
Figure 20 – Hydrogen production cost sensitivity to electricity cost and scale - electrolysis 16
Figure 21 – Nu:Ionic infographic 17
Figure 22 – Hydrogen production cost – SMR + CCUS 17
Figure 23 – Hydrogen carbon intensity – SMR + CCUS 18
Figure 24 – Hydrogen production cost sensitivity to natural gas feedstock cost – SMR +CCUS 18
Figure 25 – Hydrogen production cost – methane pyrolysis 19
Figure 26 – Hydrogen carbon intensity – methane pyrolysis 20
Figure 27 – Hydrogen production cost sensitivity to NG feedstock cost – methane pyrolysis 20
Figure 28 – Hydrogen production cost – biomass gasification 21
Figure 29 – Hydrogen carbon intensity – biomass gasification 22
Figure 30 – Hydrogen production cost sensitivity to biomass feedstock cost – biomass gasification 22
Figure 31 – Hydrogen production cost at 100 tonnes-H2/day – all pathways 23
Figure 32 – Hydrogen carbon intensity at 100 tonnes-H2/day – all pathways 23
Figure 33 – Hydrogen storage classifications 24
Figure 34 – H2 Ammonia Pathway 26
Figure 35 – Segmentation of electrical energy storage by time and size 27
Figure 36 – Salt cavern creation 28
Figure 37 – Salt caverns in the Maritimes 28
Figure 38 – Alton salt deposit project 29
Figure 39 – CI of compressing and liquefying hydrogen 30

Figure 40 – Compressed H2 tube trailer 31
Figure 41 – Liquid H2 trailer 31
Figure 42 – Estimate cost of gaseous and liquid hydrogen delivery 32
Figure 43 – Natural gas demand per total energy demand in provinces in the Maritimes 33
Figure 44 – Maritimes' end-use NG demand by sector (2018) 33
Figure 45 – Historical annual NG demand per year and province in the Maritimes 34
Figure 46 – Natural gas production (PJ/day) in NB and NS from 2008 – 2018 35
Figure 47 – Maritimes & Northeast Pipeline (M&NP) transmission network map (orange line) 37
Figure 48 – M&NP average daily export & import throughput and capacity from 2008 - 2020 37
Figure 49 – Heritage Gas H2 schematic 39
Figure 50 – Leeds Pipes 40
Figure 51 – Forecasted annual NG demand by province in the Maritimes (2020-2050) 42
Figure 52 – Natural gas incremental scenario – H2 demand 43
Figure 53 – Natural gas incremental scenario - GHG emission abatement 43
Figure 54 – Natural gas transformative scenario - H2 demand 44
Figure 55 – Natural gas transformative scenario - GHG emission abatement 45
Figure 56 – Residential heating system stock (2017) 46
Figure 57 – Commercial space heating demand for Atlantic Canada (1997-2017) 47
Figure 58 – Residential and commercial GHG emissions by fuel excluding electricity 48
Figure 59 – Transportation GHG emissions in the Maritimes by subsector (2018) 50
Figure 60 – Percent of transportation GHG emissions in the Maritimes by subsector(2018) 51
Figure 61 – LD vehicle registrations per year and province in the Maritimes. 52
Figure 62 – New LD vehicle registrations per year and province in the Maritimes. 52
Figure 63 – MHD vehicle registrations per year and province in the Maritimes. 53
Figure 64 – New MHD vehicle registrations per year and province in the Maritimes. 53
Figure 65 – Hydrogen transportation options 54
Figure 66 – Forecasted annual new LD vehicle registrations per year and province in the Maritimes 58
Figure 67 – FCEVs on the road and hydrogen demand - incremental 59
Figure 68 – GHG abated from LD FCEVs - incremental 59
Figure 69 – FCEVs on the road and hydrogen demand – transformative 60
Figure 70 – GHG abated from LD FCEVs - transformative 61
Figure 71 – Forecasted Annual New MHD Vehicle Sales per Year and Province in the Maritimes 63
Figure 72 – Projected MHD FCEVs on-the-road and hydrogen demand 64
Figure 73 – Projected GHG abated from MHD FCEVs 64
Figure 74 – Projected new sales of buses in the Maritimes per year 66
Figure 75 – Projected FCEBs on-the-road and hydrogen demand 67
Figure 76 – Projected GHG abated from FCEBs 68
Figure 77 – On-road transportation H2 demand scenarios 69
Figure 78 – GHG abated scenarios from hydrogen adoption in on-road transportation 69
Figure 79 – Incremental and transformative transportation hydrogen demand by on-road vehicle type 70
Figure 80 – Marine GHG emissions by subsector 71
Figure 81 – RoPax ferry, Nesvik 74

Figure 82 – “Greenpilot” Methanol powered pilot vessel........75
Figure 83 – MV Holiday Island........76
Figure 84 – Atlantic Elm, 2.6MW Tug........76
Figure 85 – Saint John Ferry Terminal........78
Figure 86 – Marine incremental scenario – H2 demand........80
Figure 87 – Marine incremental scenario – GHG emission abatement........80
Figure 88 – Marine transformative scenario – H2 demand........81
Figure 89 – Marine transformative scenario – GHG emission abatement........81
Figure 90 – Marine transformative and incremental scenarios - H2 demand........82
Figure 91 – Marine transformative and incremental scenarios – GHG emissions abatement........82
Figure 92 – Electricity generating capacity CI by province........85
Figure 93 – Utsira wind-hydrogen power plant........86
Figure 94 – Forecasted electricity demand in the Maritimes........88
Figure 95 – Hydrogen penetration of electricity market – incremental and transformative........88
Figure 96 – Annual electricity hydrogen demand - incremental........89
Figure 97 – Annual electricity hydrogen demand - transformative........89
Figure 98 – Annual electricity emissions reduction - incremental........90
Figure 99 – Annual electricity emissions reduction - transformative........90
Figure 100 – Aggregated hydrogen demand forecast by sector........91
Figure 101 – Aggregated GHG emissions reduction Forecast by sector........91
Figure 102 – Hydrogen as part of the Maritimes energy mix in 2050 – transformative scenario........92
Figure 103 – Electricity and natural gas requirements to meet 2050 H2 demand – transformative........93
Figure 104 – Liquid H2 transport ship........94
Figure 105 – Forecasted worldwide hydrogen demand........95
Figure 106 – Sources of electricity production in Norway........96
Figure 107 –Forecasted hydrogen demand in France........97
Figure 108 – Port of Rotterdam Pipeline Infrastructure........98
Figure 109 – Historical Natural Gas Export Price from M&NP to USA........99
Figure 110 – Maritimes Pipeline Network (2016)........99
Figure 111 – Hydrogen supply chain overview........101
Figure 112 – Hydrogen pathway archetypes........103
Figure 113 – Stages of cluster-based industrial supply chain development........105
Figure 114 – Current and potential local service providers........106
Figure 115 – Overview of Geological Storage Options........110
Figure 116 – Map of large industrial emission sources in the Maritimes........112
Figure 117 – Potential CCUS sites in the Maritimes........113
Figure 118 – Windsor Group test facility........113
Figure 119 – Map of five potential CCUS sites identified by RPS Energy and the CCSNS#1 test well site 114
Figure 120 – Map of basins in the Maritimes........115
Figure 121 – Hydrogen activity across Canada........117

LIST OF TABLES

Table 1 – Hydrogen production pathway key parameters 13
Table 2 – Price for residential natural gas use per gigajoule ($/GJ) in NB and NS for February 2018..... 38
Table 3 – Percent H2 blended into NG pipelines - Incremental and transformative scenarios 41
Table 4 – Natural gas modelling constant assumptions 42
Table 5 – Natural gas incremental scenario - H2 demand and GHG abatement by year and region..... 44
Table 6 – Natural gas transformative scenario - H2 demand and GHG abatement by year and region..... 45
Table 7 – Transportation subsector categories 50
Table 8 – Maritimes public transit bus inventory 54
Table 9 – BC ZEV mandate targets by year and %FCEV of EV sale assumptions 57
Table 10 – Key vehicle modeling assumptions 57
Table 11 – LD FCEV H2 demand and GHG abatement summary - incremental 60
Table 12 – LD vehicle FCEV H2 demand and GHG abatement summary - transformative 61
Table 13 – % FCEV sales of total annual MHD vehicle sales model assumptions..... 62
Table 14 – Key MHD vehicle modeling assumptions 62
Table 15 – MHD FCEV demand and GHG abatement summary 65
Table 16 – % ZEB sales projected to be FCEBs..... 65
Table 17 – Key bus modeling assumptions..... 66
Table 18 – Buses FCEB H2 demand and GHG abatement summary..... 68
Table 19 – Marine transportation subcategories 71
Table 20 – Maritimes ferry routes and vessels..... 72
Table 21 – Hydrogen marine vessels adoption assumptions..... 79
Table 22 – Assumed ERR Values 79
Table 23 – SWOT analysis 109
Table 24 – Cost of carbon capture and storage..... 111
Table 25 – Worldwide capacity of potential CO2 storage sites 112
Table 26 – Recommendation themes from Hydrogen Strategy for Canada..... 118
Table 27 – Relevant federal legislation, policies, and programs 120
Table 28 – Gas industry codes 123
Table 29 – Federal programs impacting emissions and clean fuels in transportation 124

1. INTRODUCTION

Objectives and Scope

The Maritimes Hydrogen Feasibility Study was commissioned by the Offshore Energy Research Association (OERA) in partnership with Heritage Gas Limited, the Atlantic Canada Opportunities Agency, Liberty Utilities, and the Nova Scotia Department of Energy & Mines to assess the economic opportunities and technical challenges of hydrogen production, storage, distribution, and use in the Maritimes. This work is in support of the region's broad energy policy objectives related to climate change, inclusive economic development, and sustainable development of energy resources.

The objective of the study is to provide a technical and economic assessment of the role that hydrogen *could* play in the Maritimes' energy transition. All aspects of this resource were considered from creation to end-use and the economic and technical constraints and opportunities were evaluated as hydrogen use and production scales up over time in the Maritimes. The study seeks to identify the role(s) hydrogen could play in the Maritimes from 2020 through 2050 and includes recommendations for instruments and policies to enable hydrogen to have an important role in decarbonizing the economy.

Project Methodology

There are a large variety of factors which will impact how the hydrogen sector evolves in the Maritimes between 2020 and 2050, including technological advancements, implementation of supporting policy and regulations, as well as social and economic factors. A collaborative approach was used to generate relevant and actionable results using a combination of stakeholder engagement, online surveys, market and technology reports, internet research, and leveraging of the project team's expertise in the field.

A broad collection of stakeholders was consulted to ensure a complete view of the hydrogen sector. Three public workshops were completed focused on the following broad topics:

- End Uses for Hydrogen in the Maritimes
- Utilities' Role in the Hydrogen Economy & Hydrogen Energy Storage Opportunities in the Maritimes
- Hydrogen Supply Chain in the Maritimes

Additional outreach was conducted using online surveys and one-on-one interviews. A complete description of stakeholder engagement activities is available in Appendix A.

The cost and carbon intensity (CI) of hydrogen produced by various pathways was evaluated using the best available data for capital and operating expenditure (CapEx and OpEx). The results are intended to represent large scale (100 tonnes-H2 per day) production in 2030, accounting for expected improvements in efficiency, reductions in capital costs, and decarbonization of the electric grid. Data was leveraged from local utilities and public documents such as the International Energy Agency's (IEA) G20 Future of Hydrogen report.

Hydrogen storage and transportation options were assessed based on the current state of development of existing technologies and through analyzing technological trends and the natural strengths and resources of the Maritimes. Information included in these sections are mainly derived from literature reviews and insights drawn from discussions with key stakeholders.

Two scenarios were modeled to estimate end-use demand in the Maritimes by sector. In both cases, assumptions in the analysis were based on available data from leading markets, input from stakeholders, review of technology options and readiness level, existing and potential targets and policies, and an understanding of specific opportunities and constraints in the region. The transformative scenario assumes the most favourable future regulations and technological developments and adoption growth rates that will lead to net-zero-emissions by 2050. This represents the total size of the potential opportunity for hydrogen. The incremental scenario assumes lower-end hydrogen demand based on known regulations, technologies, and less optimistic growth trends. Neither scenario represents a prediction of what will occur but serve to demonstrate the potential outcomes given certain assumptions about adoption.

The potential for export of hydrogen was also considered at a high level by investigating forecasted hydrogen demand from reputable sources in key regions. Countries that are likely to be net importers as well as those that could be competitors in the export market were both considered.

The future hydrogen supply chain in the Maritimes was considered including organizations that are likely to be major contributors to the sector and where there are gaps. The report considers qualitatively where opportunities exist to build out the supply chain network in the region and how it may evolve over time.

Finally, the analysis, feedback, and data gathering were synthesized to create actionable recommendations to help build and bolster the hydrogen economy in the Maritimes. The emphasis was on achieving decarbonization targets, building the economy, and improving energy independence in the region.

Energy Consumption and GHG Emissions in the Maritimes

In 2017, The Maritimes total end-use demand was 3.6% of Canada's total of 11,489 PJ. The top three sources of demand were the industrial, transportation, and residential sectors. To meet its energy requirements, The Maritimes relies heavily on refined petroleum products (RPP), as well as electricity and natural gas. Figure 2 shows total energy demand in the Maritimes by end use sector and fuel type.

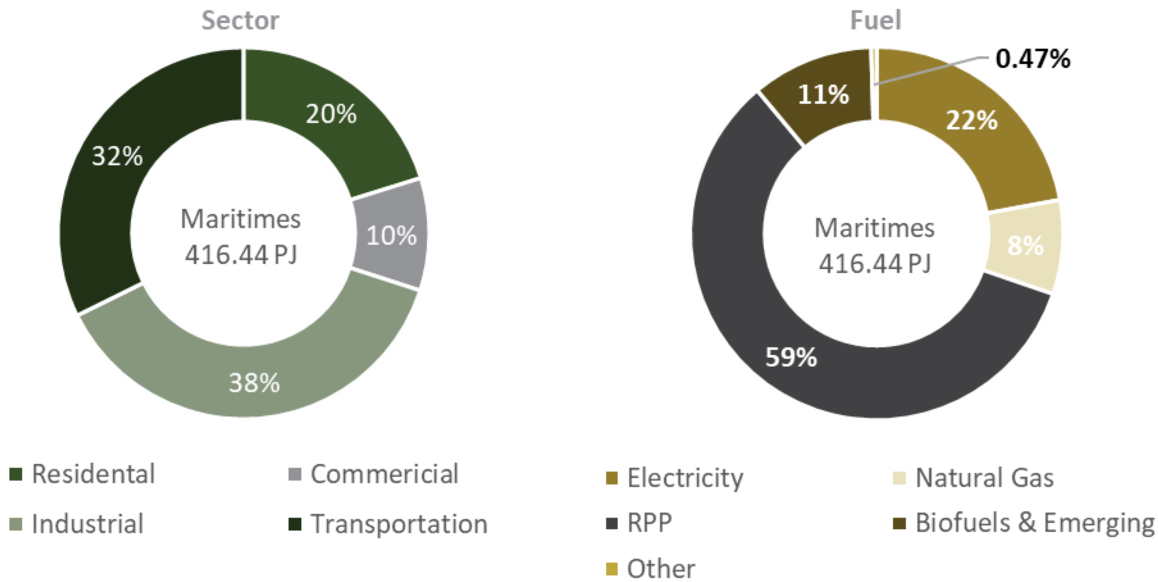

Figure 2 – End use energy demand in the Maritimes by sector and fuel[2]

The high use of fossil fuels in the form of liquid petroleum and natural gas present a significant challenge for decarbonization. Electricity accounts for only 22% of total energy demand, and the carbon intensity of the grid is relatively high. Decarbonization through electrification will require massive growth in low-carbon electricity generation.

Transportation and electricity generation were the two largest contributors to greenhouse gas (GHG) emissions. Nova Scotia's GHG emissions make up 53% of the Maritimes total of 31.93 Mt in 2017, which is mainly due to its larger population, high carbon intensity electricity and transportation demands.

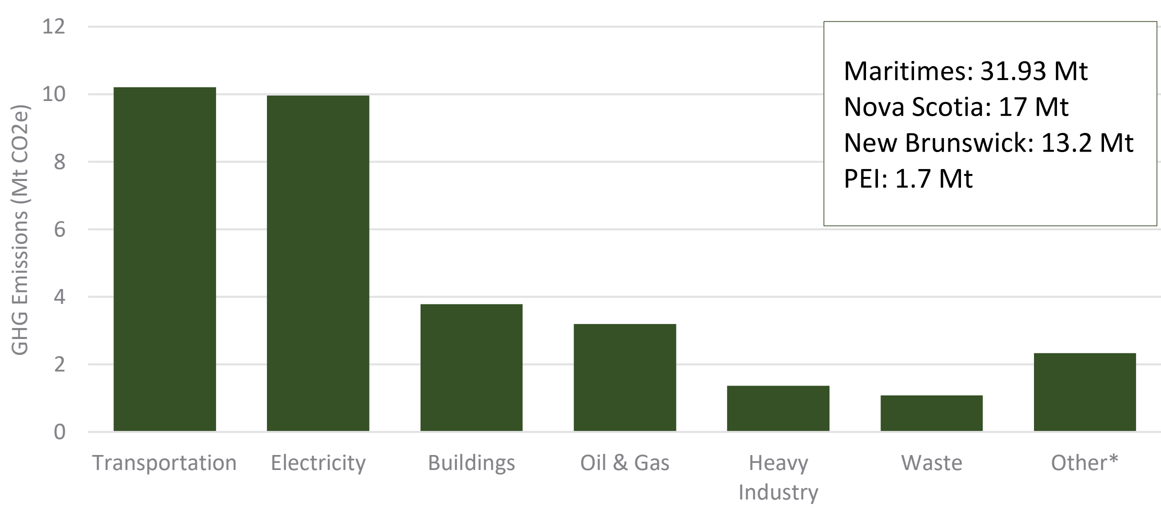

Figure 3 – GHG emissions in the Maritimes[3]

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[2] Canada Energy Regulator. (2019). Canada's Energy Future 2019. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html

[3] Environment and Climate Change Canada (2020). Canada's Official Greenhouse Gas Inventory. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b

New Brunswick

New Brunswick (NB) was the largest energy consumer of the three Maritime provinces, with total end use demand of 225 PJ. The largest share of demand is attributed to the industrial sector, with the majority of RPPs originating from Irving Oil.

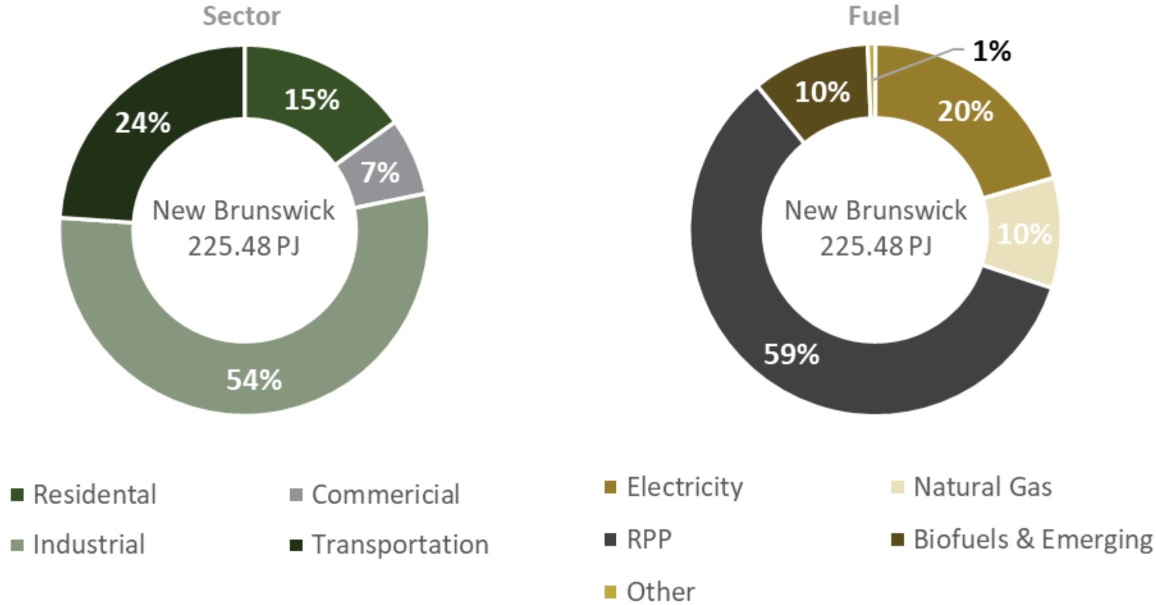


Figure 4 – End use energy demand in the New Brunswick by sector and fuel[2]

Irving Oil Limited: [4]

Irving Oil, headquartered in **Saint John**, New Brunswick, operates **Canada's largest oil refinery** and more than 900 fueling locations within Eastern Canada and New England. Irving Oil also owns the only oil refinery in Ireland located in the town of Whitegate.

The Saint John Refinery has the capacity to refine over **320,000 barrels/day (1.94 PJ/day)** and employs over **1,600 people**. The refinery produces **gasoline, diesel, heating oil, jet fuel, and propane** for retail and wholesale markets. More than half of the refinery's products are exported to the Northeast US.

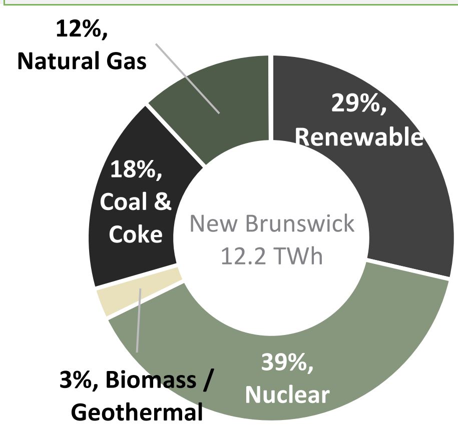


Figure 5 – Electricity generation in New Brunswick[4]

RPPs made up the greatest share of energy demand, accounting for 59% of total consumption in 2019. This fuel is primarily used for transportation as well as a heating fuel.

Electricity accounted for 20% of energy consumption in 2019. As shown in Figure 5, low-carbon electricity generating sources (renewable, nuclear, and biomass/geothermal) represent 70% of electricity produced in New Brunswick. Fossil fuel sources (coal/coke and natural gas) accounted for the remaining 30%. These sources will

[4] Operations | Irving Oil (2020). Retrieved from https://www.irvingoil.com/en-CA/discover-irving/operations
[5] Canada Energy Regulator. (2018). Provincial and Territorial Energy Profiles – New Brunswick. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/nb-eng.html

need to be transitioned to low- carbon sources if the province is to reach its decarbonization targets.

Figure 6 shows New Brunswick's 2018 GHG emissions. Transportation was the largest contributor, producing 3.7 Mt-CO2e. Fuel usage for the transportation sector was dominated by diesel and motor gas. Electricity was the next largest sector, accounting for 3.2 Mt-CO2e and was most prominent in the residential and industrial sectors. Oil and Gas was the third largest emitter, contributing 3.0 Mt-CO2e to total emissions in 2018, which is mostly due to production of RPP's within the province.

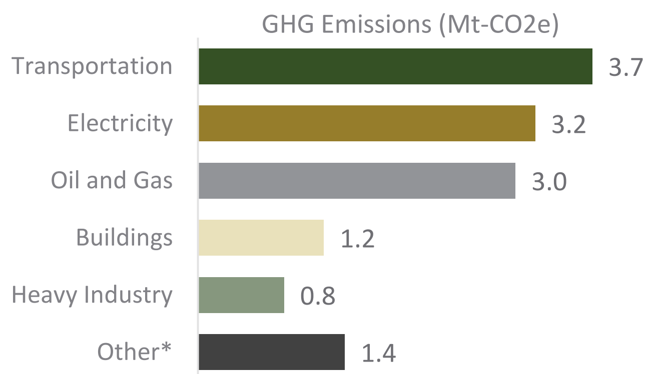
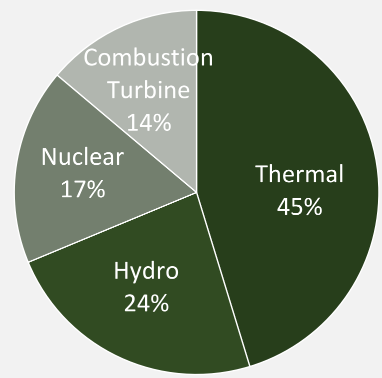


Figure 6 – GHG emissions in New Brunswick[6]

*Other refers to of waste, agriculture, light manufacturing, construction & forest resources.

New Brunswick Power Corporation (NB Power)

NB Power is New Brunswick's primary electricity generator and distributor, providing over 88% of the province's generating capacity.[4] In 2019/2020, NB Power had a net generating capacity of 3,790 MW produced from a variety of non-emitting and renewable sources.

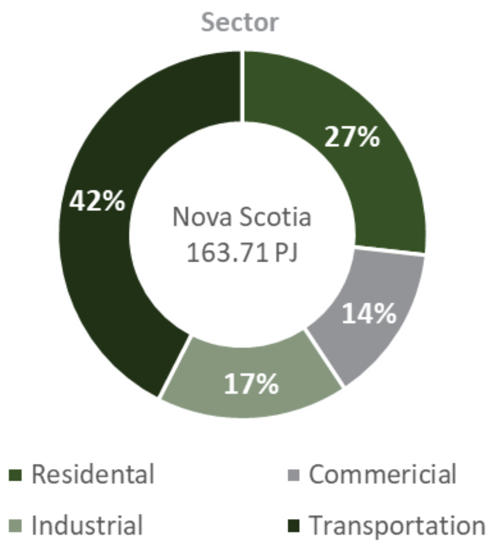


Nova Scotia

In 2018, Nova Scotia's (NS) total end-use demand was 163.7 PJ, second to New Brunswick in the Maritimes.

Figure 7 shows energy demand in 2019 by sector and fuel. Contrasting sharply with New Brunswick, the greatest demand came from the transportation sector, which accounted for 42% of the total. The residential sector was second largest component with 27% of total energy demand.

[6] Environment and Climate Change Canada (2020). Canada's Official Greenhouse Gas Inventory. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b



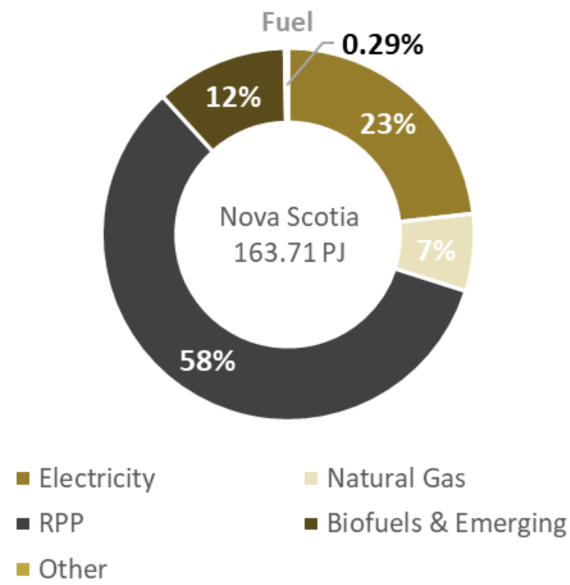


Figure 7 – End use energy demand in the Nova Scotia by sector and fuel[7]

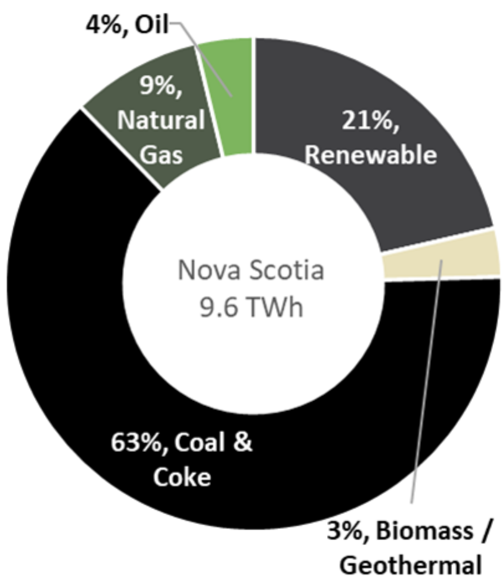


Figure 8 – Electricity generation in Nova Scotia[9]

Energy consumption in Nova Scotia is similar to New Brunswick. In 201, RPPs made up the largest share of energy demand, representing 58% of total energy consumed, followed by electricity at 23%.

The Nova Scotia electric grid is among the highest emitting in Canada. Only Alberta, Nunavut, and Saskatchewan have higher emitting electricity grids.[8] 21% of Nova Scotian electricity is generated from renewable sources, mainly hydro and wind, but 63% is derived from heavy emitting coal & coke.[9]

Nova Scotia Power, the major electrical utility in the province is committed to decarbonizing the grid and is undergoing a major integrated resource planning exercise to outline a path for the future. Hydrogen could play a role in enabling greater penetration of intermittent renewables in the province due to its energy storage capabilities.

[7] Canada Energy Regulator. (2019). Canada's Energy Future 2019. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html
[8] Canada Energy Regulator. (2018). Canada's Renewable Power Landscape 2017. Retrieved from https://www.cer-rec.gc.ca/nrg/sttstc/lctrct/rprt/2017cndrnwblpwr/ghgmssn-eng.html?=undefined&wbdisable=true
[9] Canada Energy Regulator (2020). Provincial and Territorial Energy Profiles – Nova Scotia. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/ns-eng.html

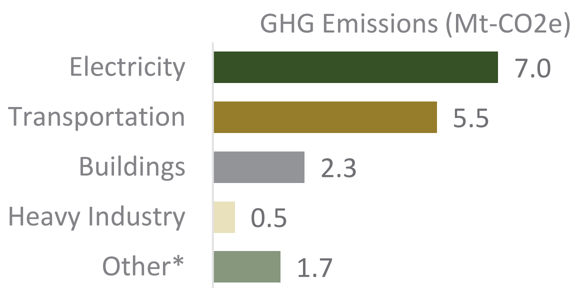


Figure 9 – GHG emissions in Nova Scotia[10]
*Other refers to of waste, agriculture, light manufacturing, construction & forest resources.

Figure 9 shows the source of GHG emissions in Nova Scotia in 2018. The four key sectors which dominate Nova Scotia's GHG emissions are electricity, transportation, buildings, and heavy industry. Electricity is the largest contributor to GHG emissions due to the composition of Nova Scotia's electricity generation mix.

Prince Edward Island

Total end-use energy demand in Prince Edward Island (PEI) was 27.3 PJ in 2018, the lowest of the three Maritimes provinces. Figure 10 shows energy demand in 2018 by sector and fuel. Similar to Nova Scotia, the transportation sector was responsible for the largest demand, accounting for 40% of the total.

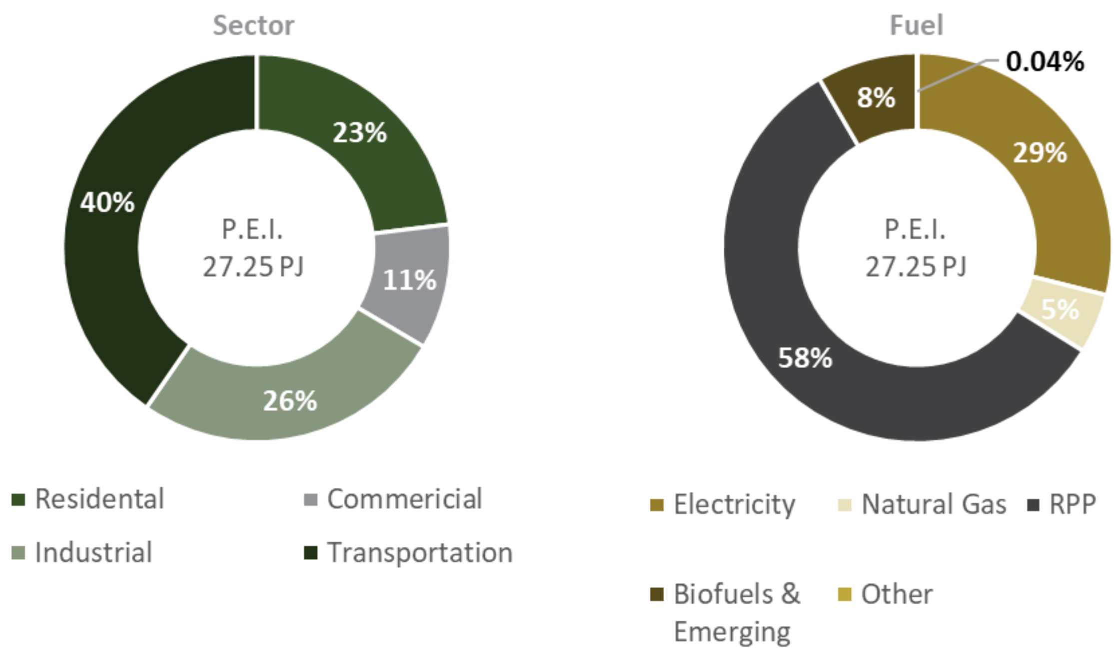


Figure 10 – End use energy demand in the Nova Scotia by sector and fuel[11]

[10] Environment and Climate Change Canada (2020). Canada's Official Greenhouse Gas Inventory. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b
[11] Canada Energy Regulator. (2019). Canada's Energy Future 2019. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html

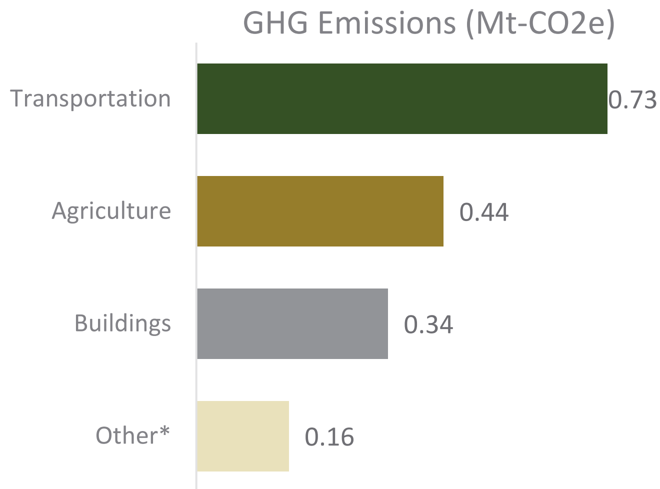


Figure 11 – GHG emissions in PEI[12]
Other refers to of waste, agriculture, light manufacturing, construction & forest resources.

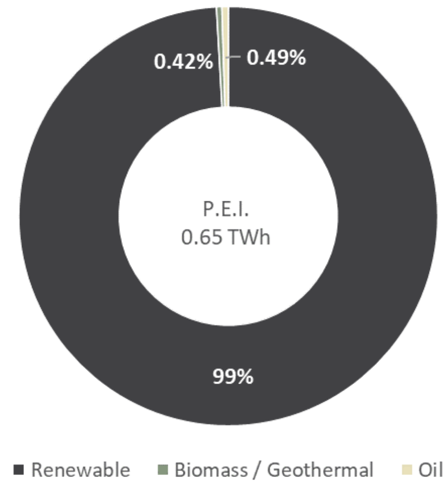


Figure 12 – Electricity generation in PEI[13]

The electrical generating capacity in PEI is almost entirely wind power; however, approximately 60% of electricity on the island is met through imported electricity from New Brunswick.[13] This is due to a combination of limited capacity and intermittency of the power source. Since wind is so variable, additional dispatchable power is required to meet demand. Similarly, there are times when the power generated from wind exceeds demand and the load must be curtailed.

Energy storage is required to substantially grow and improve the wind power resources in the province, and hydrogen presents a viable option for this purpose.

PEI's GHG emissions total 1.67 Mt-CO2e, with the usage in transportation, agriculture, and buildings making up more than 90% of total emissions.

Current Uses and Applications of Hydrogen in the Maritimes

Hydrogen use in the Maritimes is currently limited. The biggest use of hydrogen today is at the Irving Oil Refinery, where hydrogen is used as a feedstock in the crude oil refining process. Irving uses substantial amounts of hydrogen, at approximately 215 tonnes-H2/day. At this facility, hydrogen is produced on site through a combination of naphtha reforming and steam methane reforming. Irving has taken on initiatives to lower the CI of hydrogen produced on site. Pressure swing absorption systems (PSA) captures a portion of the by-product CO2 from the SMR plant, and the CO2 is piped to a nearby industrial park where it is used as a carbonation feedstock at a beverage manufacturing facility and a greenhouse. With some of the CO2 captured, this hydrogen can be considered 'blue' hydrogen. The Federal Clean Fuel Standard, once

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[12] Environment and Climate Change Canada (2020). Canada's Official Greenhouse Gas Inventory. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b
[13] Canada Energy Regulator (2020). Provincial and Territorial Energy Profiles – PE. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/pe-eng.html

adopted, is expected to drive more activity to reduce the CI of hydrogen used in upgrading.

There have also been a number of hydrogen related pilot projects in the region, some of which have not been very successful and all of which occurred years ago. The history of hydrogen projects in the Maritimes may have left some negative perceptions of hydrogen in the region, which will need to be addressed with education and outreach about the current state of the industry. Future projects will benefit from advancement in technology over the past 5-10 years, cost reductions that have been achieved, the adoption of climate action plans from each of the region's Provinces and developing worldwide interest that has advanced maturity and expanded supply chains in the sector. Future projects would benefit from a coordinated effort to build demand regionally to leverage hydrogen supply and expertise. Clear targets and allocated resources will enable collaboration and foster long-term planning to build up the industry. Previous pilot projects include:

Wind-Hydrogen Village Project (PEI)

The Prince Edward Island Wind-Hydrogen Village Project was undertaken by a consortium of industry and government partners, including Hydrogenics and the Government of PEI. The project was initially conceptualized in 2005, with a stated budget of $10.3 million CAD. The project's purpose was to generate clean hydrogen from electricity generated by the North Cape Wind Farm utilizing electrolysis technology. The original scope included an electrolyzer system, hydrogen storage depot, and a wind-hydrogen and wind-diesel integrated control system to power the North Cape Interpretive Center Complex as well as homes and buildings within North Cape. The generated hydrogen would also supply hydrogen powered utility vehicles and a fuel cell tour boat.

Figure 13 – PEI wind village project[14]

The project was eventually scaled back after only receiving one-third of its original funding target of $10.3 million CAD, and the focus shifted to piloting and experimentation instead of the full-scale demonstration. The updated scope involved integrating an electrolyzer directly to a wind turbine. The produced hydrogen was compressed and stored in pressurized tanks to later be burned in a generator to produce electricity on non-windy days. It was among the first electrolyzer projects in North America to directly draw electricity from a wind turbine.

Hydrogen Shuttle Bus (PEI)

Figure 14 – PEI H2 Shuttle[15]

In 2007 a hydrogen fueling station was constructed in PEI to support the demonstration of two hydrogen powered shuttle buses provided by Ford of Canada and Industry Canada. The pilot project was jointly funded by the Government of Canada, PEI, and Air Liquide. The shuttle buses were operated by Charlottetown Transit, and the hydrogen fuel was delivered by truck to a storage tank in PEI. The project was discontinued in 2011,

[14] CBC. (2009). PEI Makes Moves Towards Hydrogen Future. Retrieved from https://www.cbc.ca/news/canada/prince-edward-island/p-e-i-makes-moves-towards-hydrogen-future-1.844785

when the Province's request for additional funding to extend the project for two more years was denied. The shuttles were well received by customers and provided the transit operator a valuable opportunity to familiarize its staff with the fuel cell shuttle, and hydrogen storage and fueling equipment.

NB Power Hydrogen Generation Project (New Brunswick)

The New Brunswick Power Hydrogen Generation Project was an ambitious project to utilize Joi Scientific's proprietary technology to generate hydrogen from sea water. New Brunswick Power paid Joi Scientific $13 million to license the Florida company's "Hydrogen 2.0" technology for use in its Belledune generation station, which is planning to phase out coal by 2030. In 2019, the project was discontinued when a technical audit revealed inconsistencies in Joi Scientific's energy calculations and the technology's conversion efficiencies. This is a high-profile project that has led a negative perception in the region around the viability of hydrogen technology.

Greening Gas at the City Gate (New Brunswick)

Atlantic Hydrogen Inc. (AHI), a New Brunswick-based company, planned to demonstrate its CarbonSaver technology, a plasma process for on-site removal of carbon from natural gas and generation of hydrogen-enriched natural gas (HENG), through a pilot scale demonstration project. This was an $8 million project which began in 2008 and had an estimated three-years to completion timeline. Targeted HENG specifications range from 5-12% hydrogen by volume and decreases the carbon intensity of the fuel and decreases harmful oxides of nitrogen (NOx) emissions by 50-90%. The project's scope included the design, construction, and operation of a pilot plant using the CarbonSaver technology to process gas fed to compressors in a gas gathering station. In 2015, Atlantic Hydrogen Inc. HI filed for bankruptcy after being unable to secure funding to continue operations.

Figure 15 – CarbonSaver demonstration plant[16]

Despite challenges with early deployment projects, there are a number of encouraging local policy signals that have generated some renewed interest in hydrogen, including the Sustainable Development Goals Act and Climate Change Plan for Clean Growth in Nova Scotia. These are discussed in more detail in Section 10.0.

The uneven results of project demonstrations in the Maritimes to date suggests that future demonstration and deployment activities must be:

- Aligned with a regional strategy
- Focused on areas where there is a clear value proposition for Maritime stakeholders, with the ability to scale the enterprise
- Initiated only when there is a strong and unwavering commitment from both public and private sector partners

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[15] CBC. (2011). Hydrogen Bus Experiment on PEI Ends. Retrieved from https://www.cbc.ca/news/canada/prince-edward-island/hydrogen-bus-experiment-on-p-e-i-ends-1.986683

[16] Atlantic Hydrogen. (2010). Greening the Gas Status Update. Retrieved from https://www.csaregistries.ca/files/projects/prj_6763_931.pdf

2. HYDROGEN PRODUCTION

Although hydrogen is the most abundant element in the universe, it is rarely available on Earth in its pure molecular form – H2. In order to produce pure hydrogen, it must be separated from other molecules such as water (H2O), methane (CH4), or more complex hydrocarbons. There are a variety of pathways that can be employed to generate hydrogen from these feedstocks, and the cost of production and CI of the resulting hydrogen will depend on the utilized method.

Figure 16 outlines the low-carbon pathways that were found to be the best suited for the Maritimes. Each pathway is described in more detail in the sections below. High emitting pathways were not considered in this report because widespread use of high CI hydrogen will not contribute to achieving the region's decarbonization targets.

All pathways considered in this report are low-carbon, but not all pathways are renewable. Clean renewable hydrogen, sometimes referred to as "green hydrogen," is hydrogen generated from renewable power sources. This is limited to electrolyzed hydrogen produced using renewable electricity, and hydrogen produced from biomass. Low-carbon non-renewable hydrogen, sometimes referred to as "blue hydrogen," is produced from fossil fuel sources that employ carbon capture and utilization/storage (CCUS)

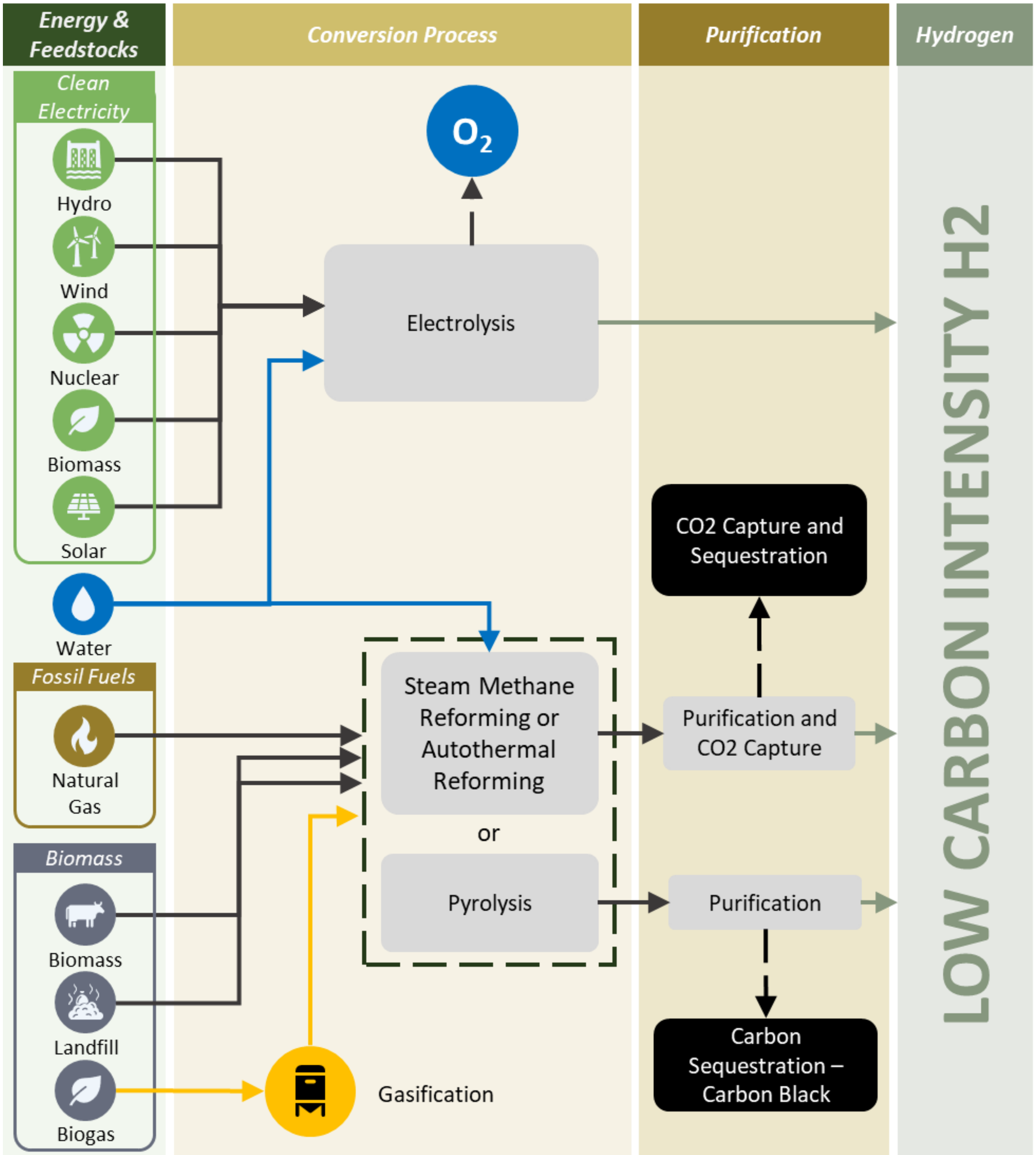

Figure 16 – Hydrogen production pathways

To compare each pathway, it was necessary to estimate cost and CI of each pathway at a consistent scale of production. Some pathways are easily scaled, while others only become viable at a larger scale. *A production plant of 100 tonnes-H2/day was selected as the basis for comparison.* In the case of electrolysis, smaller scales were analyzed for comparison purposes. In order to be forward looking, the analysis seeks to estimate costs for a facility operating in 2030.

There are several key variables which remain consistent across the various pathways which impact the estimated cost and CI of hydrogen. These variables are summarized in Table 1. In some instances, additional analysis has been conducted to investigate the sensitivity of hydrogen price to these variables.

Table 1 – Hydrogen production pathway key parameters

Parameter	Province		
	NS	*NB*	*PE*
Electricity **Demand** Charge ($/kW)	$12.00[17]	$14.55[18]	$14.50[19]
Electricity Energy Charge ($/kWh)	$0.0865[17]	$0.0538[18]	$0.0714[19]
Effective Natural Gas Cost ($/GJ)[20]	$12.63[21]	$12.71[22]	n/a
Electricity Carbon Intensity in 2030 (g-CO2e/kWh)[23, 24, 25]	391[26, 27]	229[28]	139
Natural Gas Carbon Intensity (g-CO2e/MJ)[29]	62		
Equipment Amortization Period (years)[30]	25		
Cost of Capital[30]	8%		

Electrolysis

Electrolysis uses electrical energy to split water molecules and produces hydrogen gas and an oxygen gas by-product. There are three primary types of electrolysis technologies: proton exchange membrane (PEM), alkaline, and solid oxide electrolyzers. PEM electrolyzers have become more common in recent years due to breakthroughs in membrane cell density and because they are capable of high turndown ratios and fast ramping response times, allowing the system to be used for electrical load following

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[17] Nova Scotia Power. Large Industrial Tariff. Retrieved from https://www.nspower.ca/about-us/electricity/rates-tariffs/large-industrial

[18] Énergie New Brunswick Power. (2019). Rates: Business Rates. Retrieved from https://www.nbpower.com/en/products-services/business/rates

[19] Maritime Electric. (2019). Rates and General Rules and Regulations. Retrieved from https://www.maritimeelectric.com/about-us/regulatory/rates-and-general-rules-and-regulations/

[20] Includes transmission and distribution costs for large industrial customers assuming a 100% load factor as well as the commodity price of natural gas which was estimated to be $10/GJ.

[21] Heritage Gas. (2020). Heritage Gas Rate Table. Retrieved from https://www.heritagegas.com/wp-content/uploads/2020/08/HGL-Rate-Table-August-2020-FINAL.pdf

[22] Liberty Utilities. (2020). Current Natural Gas Distribution Rates & Charges. Retrieved from https://naturalgasnb.com/en/for-home/accounts-billing/customer-rate-classes/#current-natural-gas-distribution-rates-charges

[23] Calculated to account for electricity imported from other jurisdictions and an assumed reduction in carbon intensity of the grid based on published targets and/or analysis conducted by the utilities.

[24] Canada Energy Regulator. (2020). Provincial and Territorial Energy Profiles. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/index-eng.html

[25] Canada Energy Regulator. (2020). Canada's Renewable Power Landscape 2017 - Energy Market Analysis. Retrieved from https://www.cer-rec.gc.ca/nrg/sttstc/lctrct/rprt/2017cndrnwblpwr/ghgmssn-eng.html

[26] Nova Scotia Power. Air Emissions Reporting. Retrieved from https://www.nspower.ca/clean-energy/air-emissions-reporting

[27] NS Power. (2020). NS Power 2020 IRP Modeling Results Release. Retrieved from https://irp.nspower.ca/files/supporting-documents/IRP-Modeling-Results-2020-06-26.pdf

[28] NB Power. (2019). NB Power - An Emission Reductions Leader. Retrieved from https://www.nbpower.com/blog/en/posts/2019/april/nb-power-an-emission-reductions-leader-by-gaetan-thomas/

[29] Environment and Climate Change Canada. (2019). Clean Fuel Standard Proposed Regulatory Approach. Retrieved from https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/pricing-pollution/Clean-fuel-standard-proposed-regulatory-approach.pdf

[30] IEA. (2019). IEA G20 Hydrogen Report: Assumptions. Retrieved from https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

operations and easily integrating with intermittent power generation systems. Alkaline electrolyzers are a mature technology and historically the technology of choice for commercial scale plants but require a more consistent power supply to operate efficiently, and they lack the flexibility of a PEM electrolyzer's high turndown ratio and fast response times. The required capital investment and production efficiencies of PEM and alkaline electrolyzers are comparable. Solid oxide electrolyzers are currently under development but have not yet been commercially deployed. They must operate at very high temperatures but have the potential to be more efficient than PEM or alkaline electrolyzers.

Figure 17 shows the estimated cost to produce hydrogen via PEM electrolysis in the three Maritime provinces using grid and wind power directly for a 200 MW, 100 tonnes-H2/day facility. The cost of onshore and offshore wind was estimated to be $66/MWh and $150/MWh respectively based on modelling from Nova Scotia Power.[31] The impact of varying the cost of electricity is discussed later in this section.

At a scale of 100 tonnes-H2/day, the electrolyzer equipment costs were estimated to be $910/kW and annual plant operation and maintenance was assumed to be 1.5% of capital expenditure (CapEx).[30] A conversion efficiency of 81% was used based on the higher heating value of hydrogen.[30]

The figure compares the cost of hydrogen produced via electrolysis. In each province, the cost was evaluated in two scenarios in which the electrolyzer is fully utilized: assuming that 100% of the input power is sourced from grid electricity, and assuming a combination of grid and onshore wind electricity such that 40% of the electrolyzer input power comes from onshore wind and 60% from the electric grid. Additionally, the cost of off-grid electrolysis was considered in which 100% of the power is sourced from onshore or offshore wind power and the electrolyzer is only generating hydrogen at 40% capacity to account for intermittency. The calculated CapEx only includes capital equipment costs for the electrolyzer. The CapEx of wind turbines is factored into the wind power electricity cost that is included in the operating expense (OpEx).

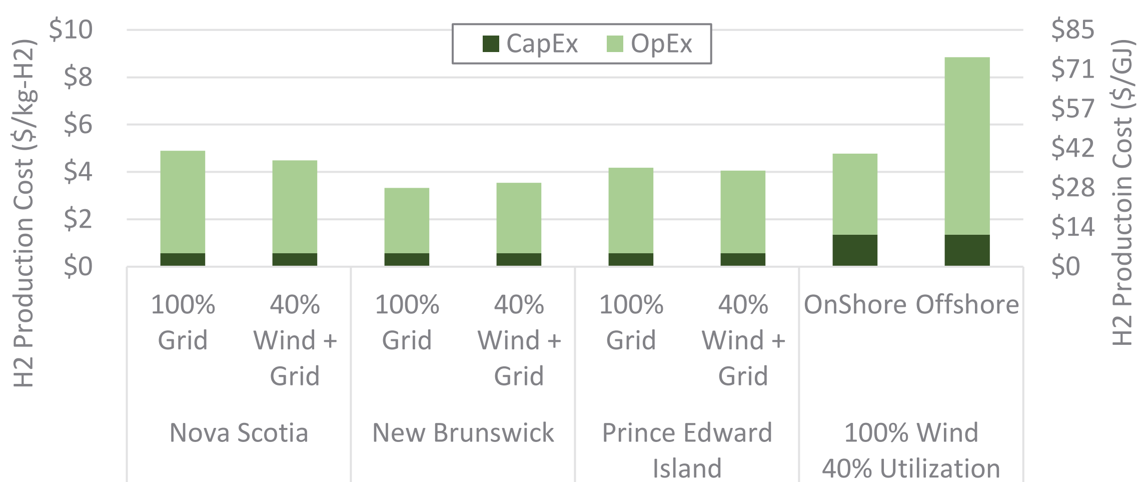

Figure 17 – Hydrogen production cost – electrolysis

[31] Nova Scotia Power. (2020). 2020 Integrated Resource Plan (IRP): Draft Assumptions Addendum/Update. Retrieved from https://irp.nspower.ca/files/key-documents/assumptions/20200203-IRP-Assumptions-Set-just-updates.pdf

The principal cost of producing hydrogen via electrolysis is the cost of electricity, which makes up 93%-97% of the OpEx and 67%-86% of the total production cost depending on the province and penetration of wind power. The CapEx is greater per kg-H2 in the off-grid wind power scenarios because the electrolysis equipment is underutilized due to the intermittency of operations.

The offshore wind scenario assumes that electricity is transmitted back to shore and hydrogen is produced on land. Alternatively, hydrogen could be produced offshore with the wind turbines, removing the necessity to install a costly transmission line between the offshore turbines and the mainland. This alternative scenario could be attractive and requires further research.

The CI of the produced hydrogen will depend heavily on the CI of the electricity used in the generation process. Figure 18 shows the estimated CI for hydrogen produced via the same pathways shown in Figure 17. Incorporating renewable electricity such as wind power greatly reduces the resulting hydrogen CI which is critical to achieving decarbonization targets. To be considered low-carbon, the CI of the resulting hydrogen should be below 36.4 g-CO2e/MJ, which is the threshold outlined by the European CertifHy standard.[32]

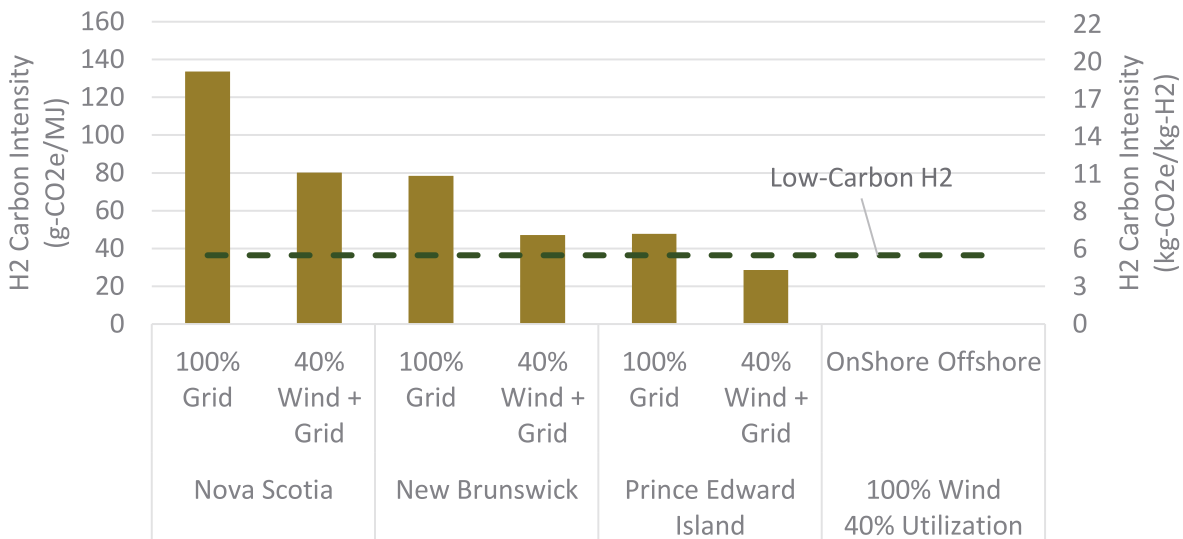

Figure 18 – Hydrogen carbon intensity – electrolysis

Hydrogen generated using 100% grid electricity does not meet the threshold for low-carbon hydrogen in any of the Maritime provinces based on projected electricity grid carbon intensities in the 2030 timeframe. If the electrolyzer is tied directly to renewable or low-carbon electricity generation, then the CI can be greatly reduced. Incorporating intermittent renewables like wind can also improve the utilization of the electrical generating equipment because it can provide load for the equipment to limit curtailment. This can serve to improve the value proposition of the renewable generation.

Figure 19 shows the CI of hydrogen produced via electrolysis relative to the CI of the input electricity. To be low-carbon hydrogen, the electricity needs to be below approximately 100 g-CO2e/kWh.

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[32] Fuel Cells and Hydrogen 2 Joint Undertaking (2019). Hydrogen Roadmap Europe: A Sustainable Pathway for the European Energy Transition. Retrieved from https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

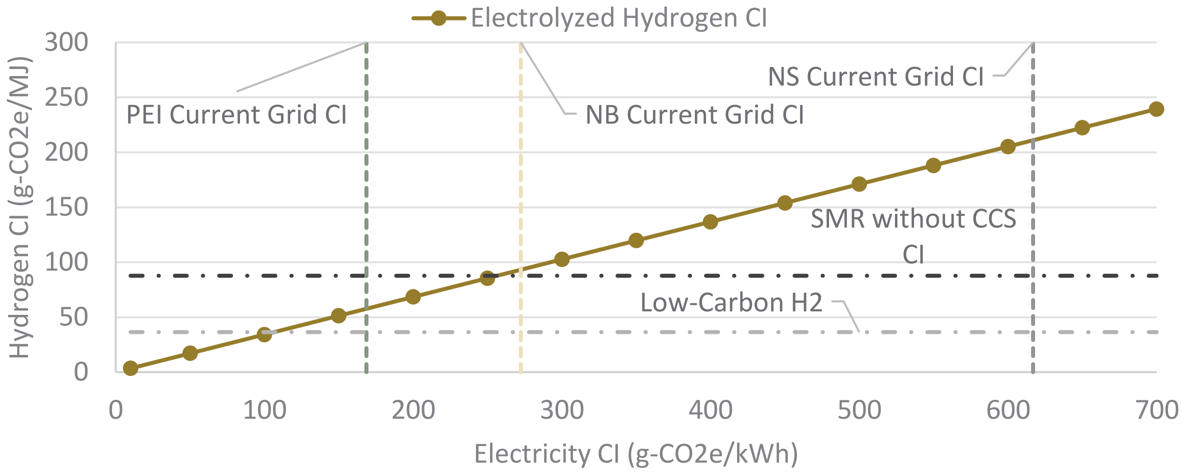

Figure 19 – Electrolyzed hydrogen sensitivity to electricity carbon intensity

Figure 20 shows the sensitivity of overall hydrogen production costs to the price of electricity for a 1 MW, 10 MW, and 200 MW electrolyzer. Unsurprisingly, the resulting cost is strongly linked to electricity price. The cost of renewable electricity is expected to drop significantly in the coming decades. In a 2019 report, BloombergNEF forecasted the cost of wind energy to drop 36% from current levels by 2030 and 48% by 2050 to around $30/MWh.[33] Analysis conducted by Lazard in 2019 shows electricity from wind generation can already reach as low as $28-54/MWh under certain conditions.[34] The relationship between cost and system size is weaker because the technology is readily scalable, so the efficiency is not greatly improved by scale. Cost savings at larger scale are primarily due to reductions in capital costs. At electricity costs of $30-40/MWh, hydrogen produced via electrolysis can be cost competitive against baseline fuels in many applications.

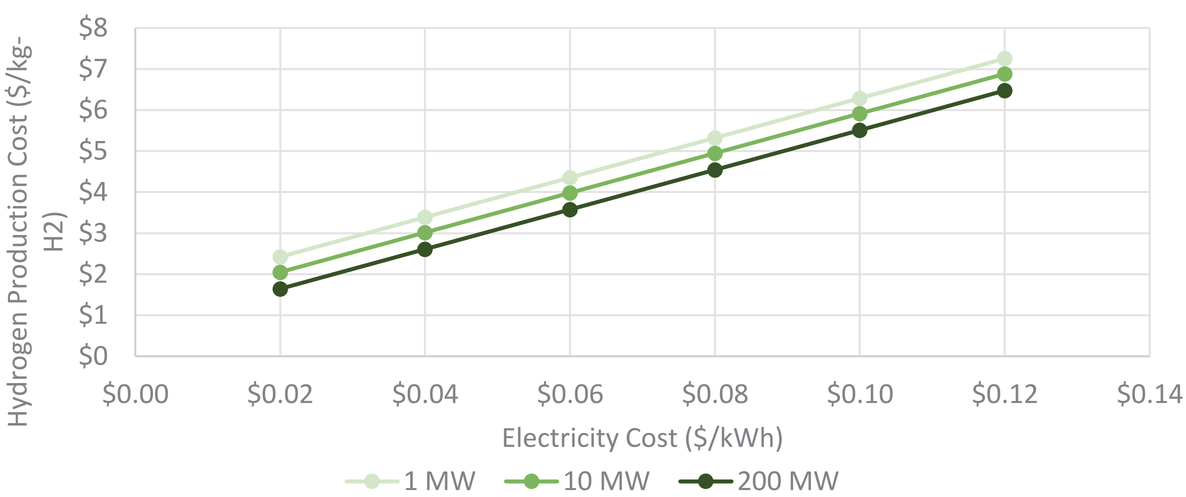

Figure 20 – Hydrogen production cost sensitivity to electricity cost and scale - electrolysis

[33] BloombergNEF. (2019). New Energy Outlook 2019. Retrieved from https://about.bnef.com/new-energy-outlook/#toc-download

[34] Lazard. (2019). Levelized Cost of Energy and Levelized cost of Storage 2019. Retrieved from https://www.lazard.com/perspective/lcoe2019/

SMR with CCUS

Steam methane reforming (SMR) is a process which utilizes high temperature steam and a methane source such as natural gas to produce hydrogen. SMR is currently the most common method of producing hydrogen worldwide. In addition to hydrogen, this process also generates CO2 as a by-product, which necessitates an additional carbon capture and utilization/sequestration (CCUS) process in order to create low-carbon hydrogen. CCUS is described in detail in the *Carbon Capture and Sequestration* section.

Figure 22 shows the estimated cost to produce hydrogen via SMR + CCUS in the Maritimes for a 100 tonnes-H2/day facility. The capital cost requirements were estimated to be $1,502/kW and the operations and maintenance were assumed to be 3% of the CapEx.[36] Based on the higher heating value of hydrogen, it requires 1.37 GJ-NG to produce 1 GJ-H2.[36] This accounts for conversion losses and the loss of chemical potential energy of the carbon atoms which formed CO2. The bulk of the production cost is from the cost of natural gas, which represents 87%-89% of OpEx and 71% of the total hydrogen cost.

NU:IONIC HYDROGEN PRODUCTION

Based in Fredericton, NB, Nu:Ionic has developed an innovative technology that uses microwave catalytic reforming to produce hydrogen. The process can reduce the required natural gas consumption by 25-30%, and outputs hydrogen suitable for use as a feedstock for industrial processes or as a transportation fuel.

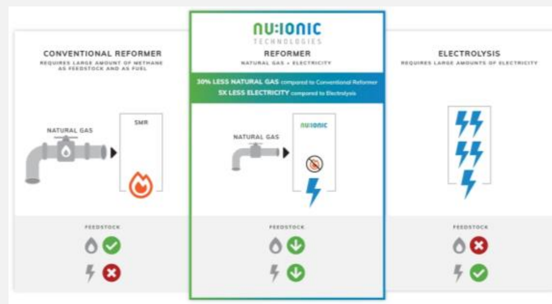

Figure 21 – Nu:Ionic infographic[35]

The system is designed for small scale hydrogen production that could be deployed on-site at the point of use. This removes the need for liquefaction and distribution, which can be costly and increases emissions.

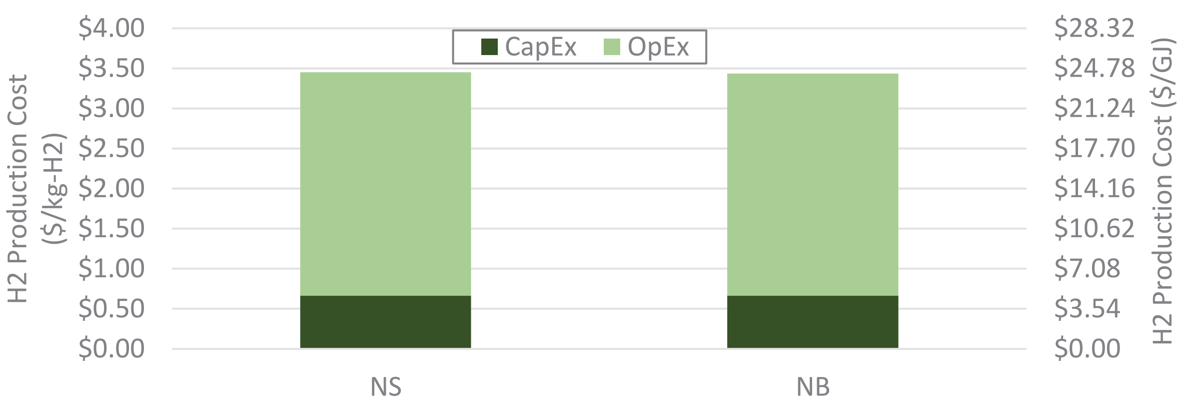

Figure 22 – Hydrogen production cost – SMR + CCUS

[35] Nu:Ionic. Technology. Retrieved from https://www.nuionic.com/pages/technology-new
[36] IEA. (2019). IEA G20 Hydrogen Report: Assumptions. Retrieved from https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

The CI of the resulting hydrogen is largely driven by the CCUS efficiency, which was assumed to be 90%.[36] There are also emissions related to upstream natural gas extraction and transportation as well as electricity consumed in the process. The resulting emissions are below the 36.4 g-CO2e/MJ threshold for low-carbon hydrogen.

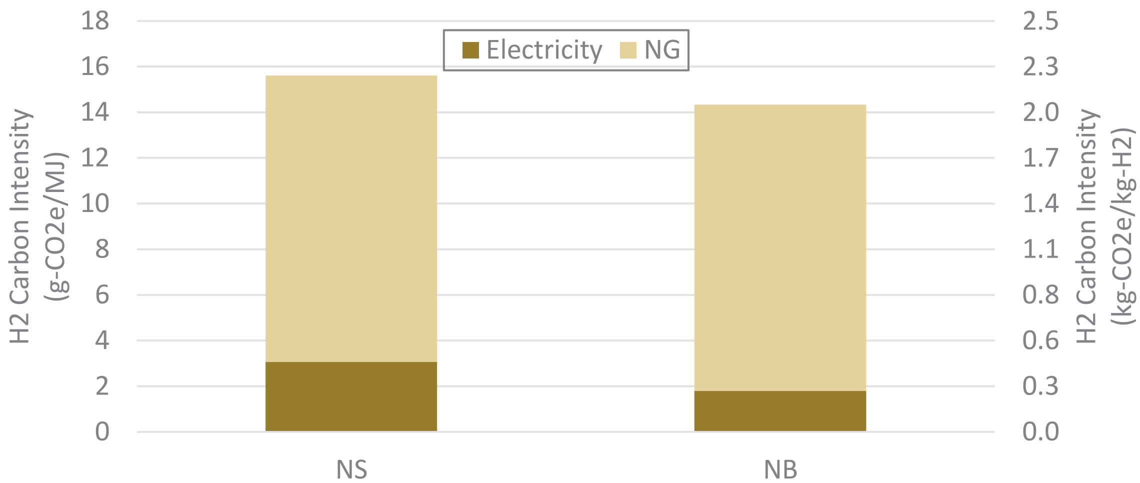

Figure 23 – Hydrogen carbon intensity – SMR + CCUS

Though SMR + CCUS is cost competitive and produces relatively low-carbon hydrogen, further analysis is required to ensure this pathway is feasible in the Maritimes at a large scale. Production of 100 tonnes-H2/day would require 7 PJ of natural gas annually and CCUS of 0.3 Mt-CO2/year. This represents roughly 20% of total natural gas demand of the Maritimes in 2019. The production facility would also need to be located in close proximity to a site which enables large scale CCUS. This pathway is expected to play a large role in hydrogen production nationally and may be a source of hydrogen supplied by other provinces and delivered to the Maritimes.

Figure 24 shows the sensitivity of hydrogen price to the cost of the natural gas feedstock. The price of hydrogen from this pathway is strongly linked to the price of natural gas.

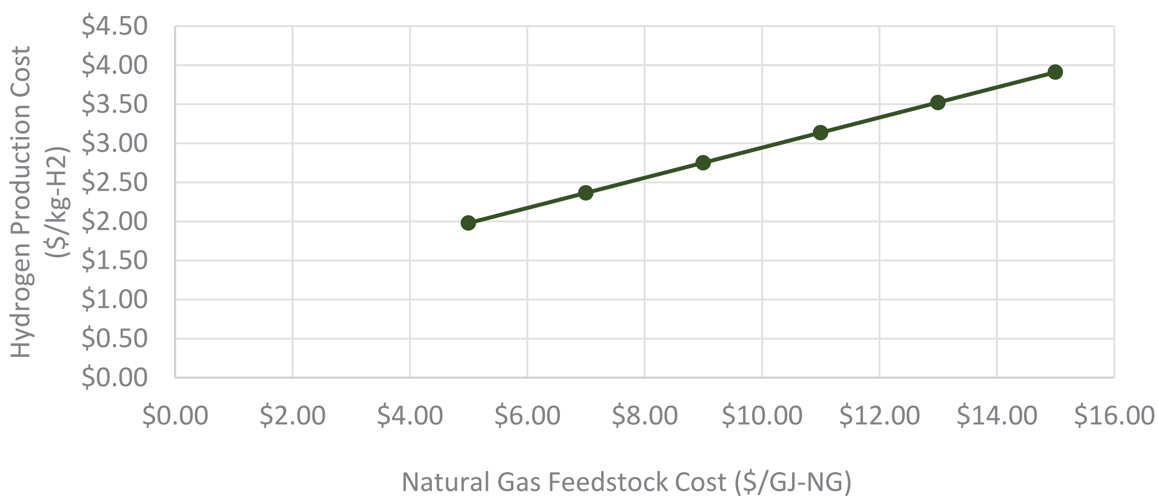

Figure 24 – Hydrogen production cost sensitivity to natural gas feedstock cost – SMR +CCUS

Thermal Pyrolysis

Thermal pyrolysis is the process of decomposing natural gas without oxygen into its two constituents: hydrogen, which is output as a gas, and carbon black, which is output as a solid. Since no CO2 is produced, there is no need to store it in a sealed underground location, but the carbon black must be stored or utilized. Pyrolysis has been used for the purposes of carbon black production in Alberta since the early 1900s but has not been used commercially for hydrogen production.

Figure 25 details the estimated cost for hydrogen produced via pyrolysis at a 100 tonnes-H2/day facility. It was assumed that the capital investment would be $1,477/kg-H2/day and operations and maintenance would be 5% of the CapEx.[37] Based on the higher heating value of hydrogen, it requires 2.27 GJ of natural gas per GJ of hydrogen, which is less efficient than the SMR + CCUS pathway, but similarly accounts both for conversion losses and the loss of chemical potential energy of the carbon atoms. The bulk of the production cost is from the cost of natural gas, which represents 95% of OpEx and 87% of the total hydrogen cost.

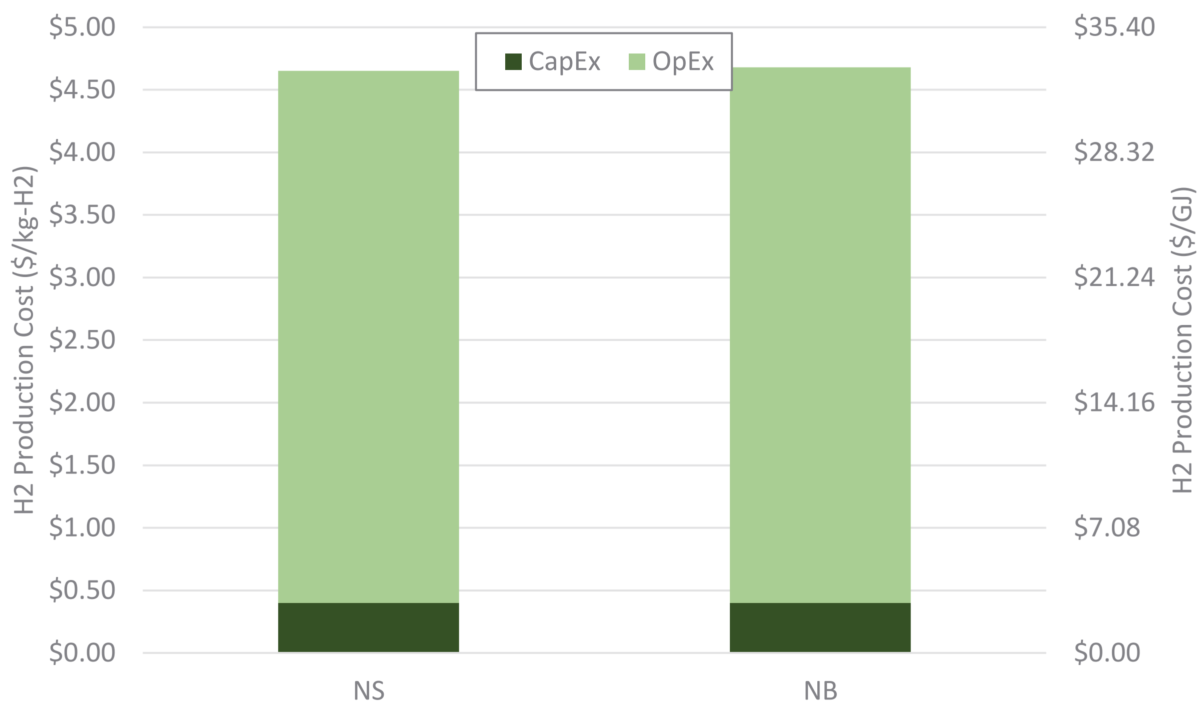

Figure 25 – Hydrogen production cost – methane pyrolysis

The CI of the produced hydrogen results from upstream natural gas emissions and the natural gas that is burned to provide energy for the process. Emissions are below the threshold of 36.4 g-CO2e/MJ for low-carbon hydrogen.

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[37] Zen and the Art of Clean Energy Solutions. (2019). British Columbia Hydrogen Study. Retrieved from http://zenenergysolutions.com/

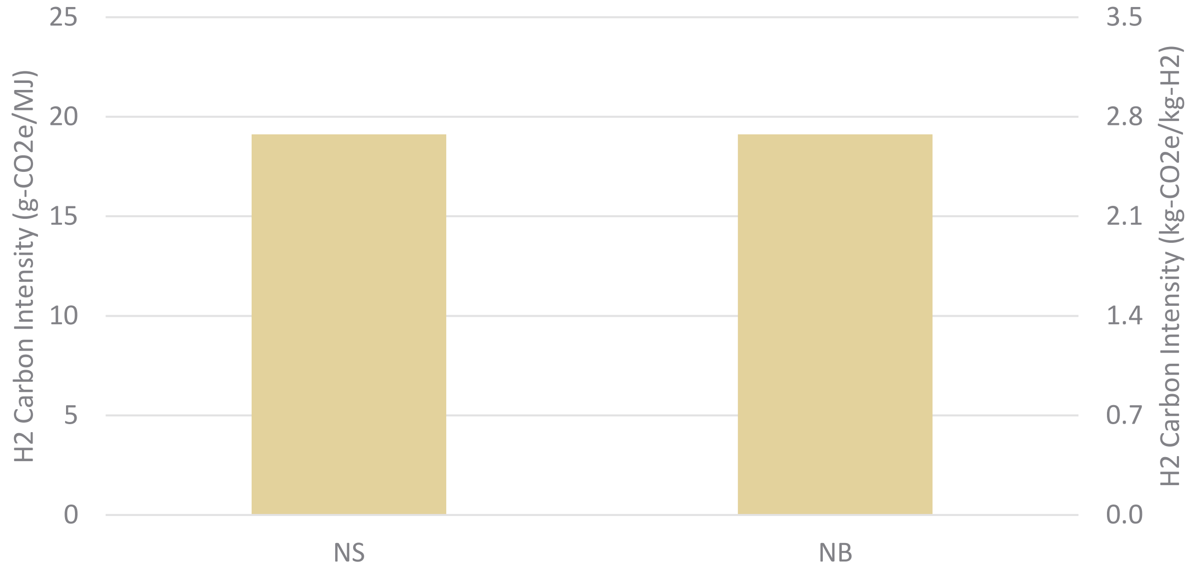

Figure 26 – Hydrogen carbon intensity – methane pyrolysis

Figure 27 shows the sensitivity of hydrogen price to the cost of the natural gas feedstock. The price of hydrogen from this pathway is strongly linked to the price of natural gas.

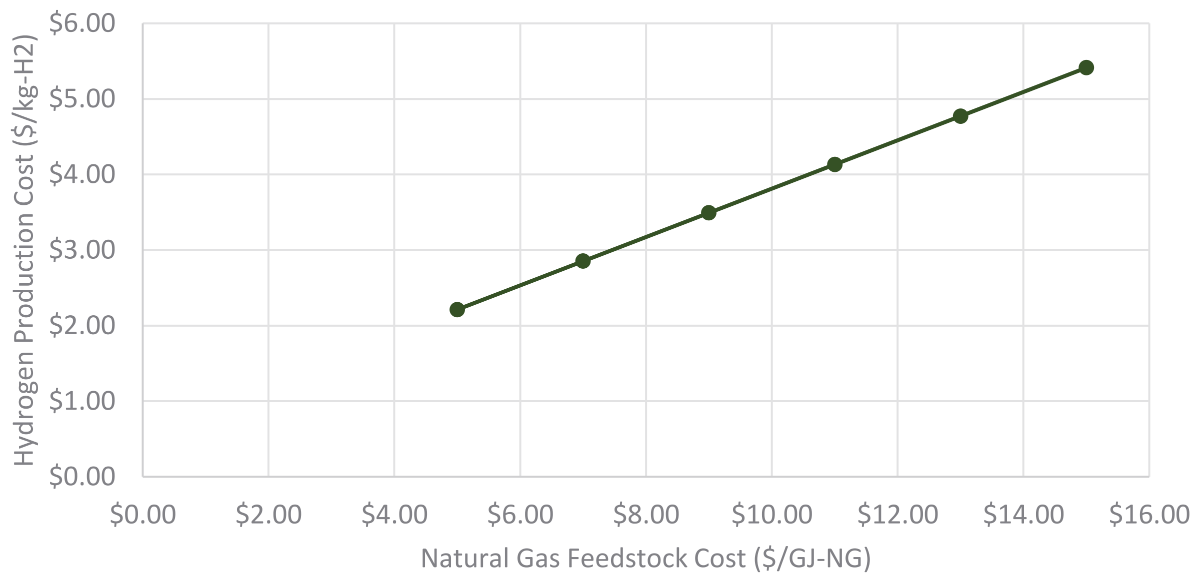

Figure 27 – Hydrogen production cost sensitivity to NG feedstock cost – methane pyrolysis

Biomass Gasification

Biomass gasification is the process of producing hydrogen from renewable organic biomatter. In essence, heat and steam are used to convert the biomass at temperatures > 700 °C into hydrogen gas and CO2. This pathway is considered low-carbon even without CCUS the CO2 that is released from the biomass was first removed from the atmosphere during the growing cycle and will be removed again through future growth. If CCUS is used, the resulting hydrogen can be carbon negative, though this pathway was not considered in this analysis.

Hydrogen production at this scale would require nearly 500,000 tonnes of woody biomass per year. The transportation costs associated with sourcing and delivery of biomass to a facility in the Maritimes may be cost prohibitive. A more distributed model may be more feasible but would reduce the economies of scale and increase the total CapEx.

Figure 28 shows the estimated cost for hydrogen produced via biomass gasification at a 100 tonnes-H2/day facility. It was assumed that the capital investment would be $1,070/kg-H2/day and operations and maintenance would be 8.7% of the CapEx.[38] Based on the higher heating value of hydrogen, it requires 13.5 dry-tonnes of woody biomass per GJ of hydrogen. It was assumed that biomass costs $70/tonne plus $30/tonne for transportation to the processing facility.[38] The biomass feedstock cost represents the bulk of the production cost, accounting for 79%-80% of OpEx and 67%-68% of the total hydrogen cost.

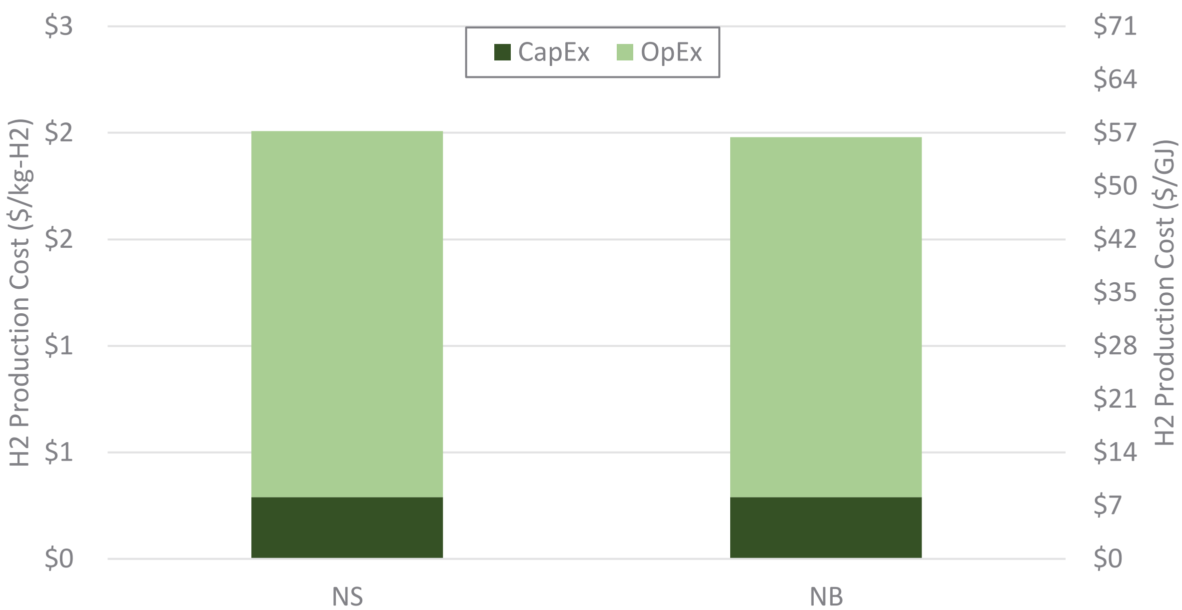

Figure 28 – Hydrogen production cost – biomass gasification

The CI of the produced hydrogen results from upstream emissions from the procurement of woody biomass and electricity consumed in the process. Emissions are below the threshold of 36.4 g-CO2e/MJ for low-carbon hydrogen.

[38] Nova Scotia Innovation Hub. (2015). Feedstock Assessments by County and Mobilization of Biomass Supply.

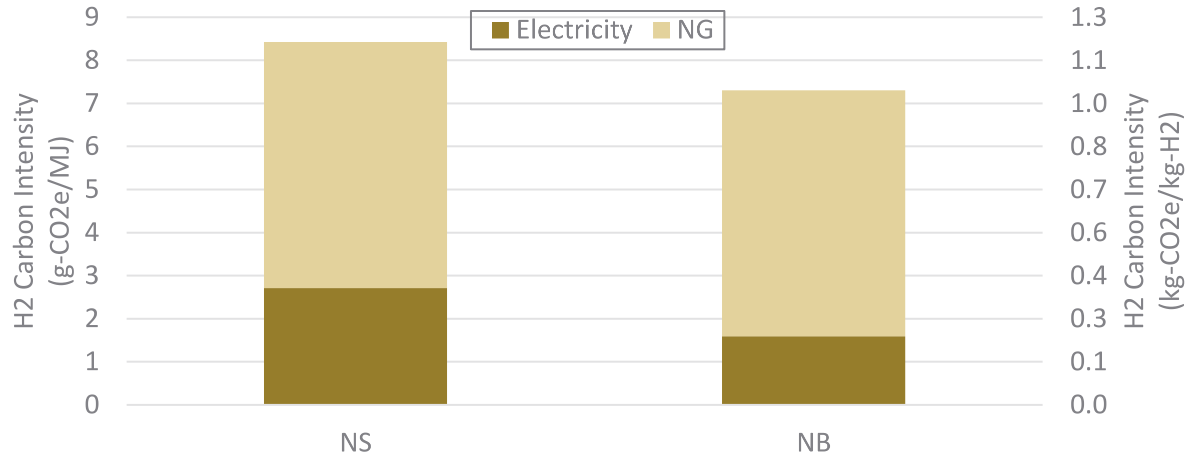

Figure 29 – Hydrogen carbon intensity – biomass gasification

Figure 30 shows the sensitivity of hydrogen price to the cost of the biomass feedstock including transportation costs. The price of hydrogen from this pathway is strongly linked to the price of biomass.

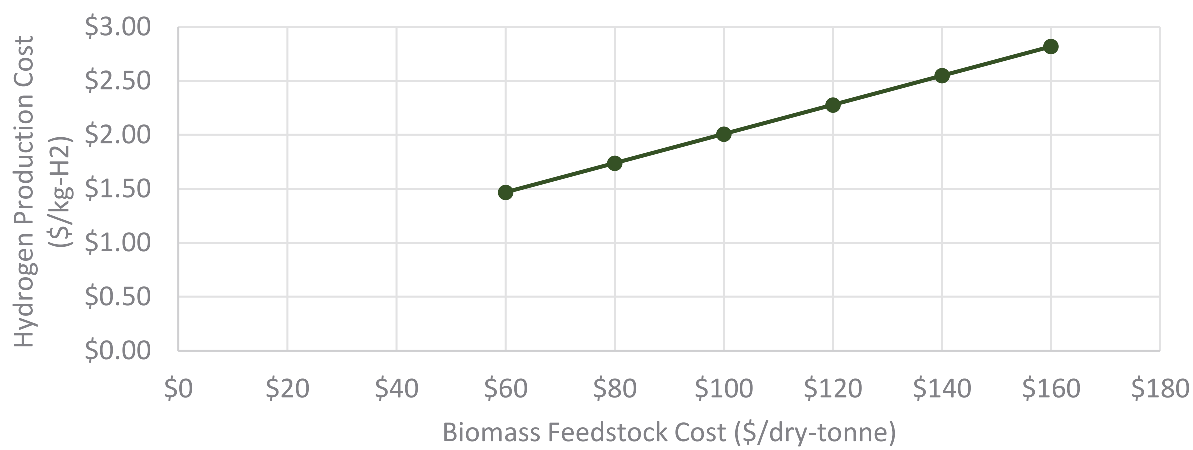

Figure 30 – Hydrogen production cost sensitivity to biomass feedstock cost – biomass gasification

Cost and Carbon Intensity Comparison Summary

Figure 31 and Figure 32 summarize the projected 2030 cost and CI of hydrogen production for each of the pathways described above. The natural gas and electrolysis pathways are of comparable costs (excluding offshore wind) but the carbon intensities vary considerably. Beyond 2030, the grid electricity CI is expected to continue to drop through decarbonization efforts and as more renewable generation is implemented. As a result, the CI of electrolyzed hydrogen will continue to drop in the future. The fossil fuel pathways will be less suspectable to change as the majority of emissions come from the consumption of natural gas.

Due to the lack of natural gas production in the region and the relatively high cost, and magnitude of production via SMR + CCUS or pyrolysis, these pathways may offer limited potential in the Maritimes.

Hydrogen produced from electrolysis is a viable pathway, especially in PEI, where it can be paired with renewable electricity generation to produce a low CI product.

Biomass gasification offers a low-carbon and relatively low-cost pathway, but the production capacity of hydrogen will be limited by feedstock availability and location.

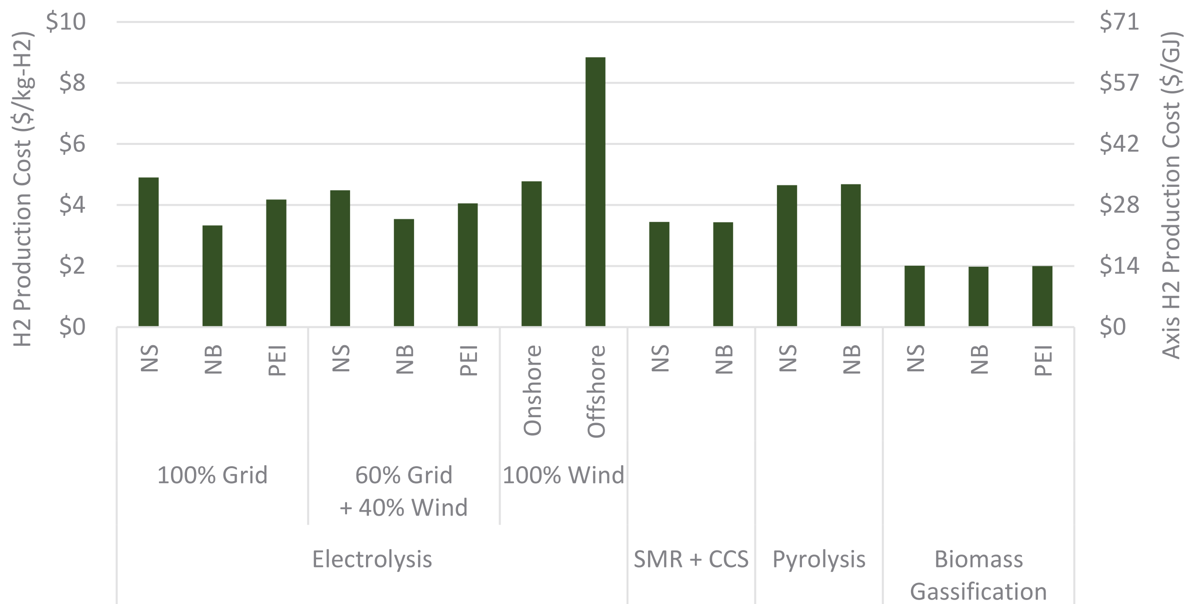

Figure 31 – Hydrogen production cost at 100 tonnes-H2/day – all pathways

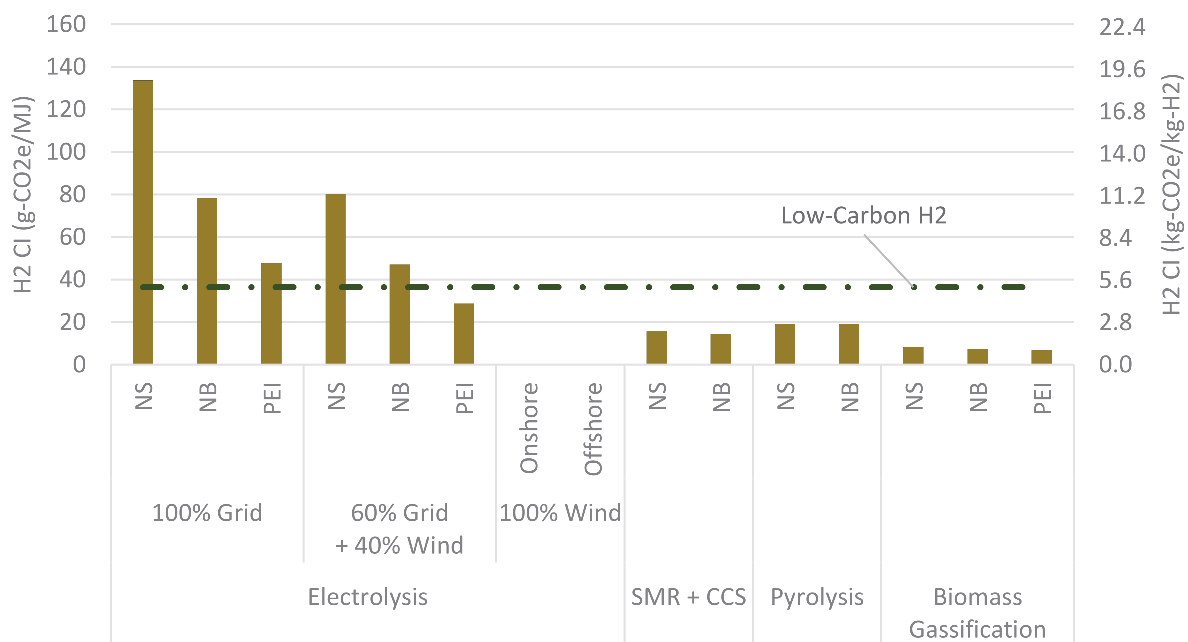

Figure 32 – Hydrogen carbon intensity at 100 tonnes-H2/day – all pathways

3. HYDROGEN STORAGE

Hydrogen has a particularly high gravimetric energy density, but a relatively low volumetric energy density. Per kilogram, hydrogen contains three times the energy of gasoline, but under atmospheric conditions it exists as a very light gas. Therefore, hydrogen must be stored either as a compressed gas, cryogenic liquid, or as part of or attached to another molecule. Figure 33 details the various methods of hydrogen storage, which are broadly categorized as physical and material-based technologies.

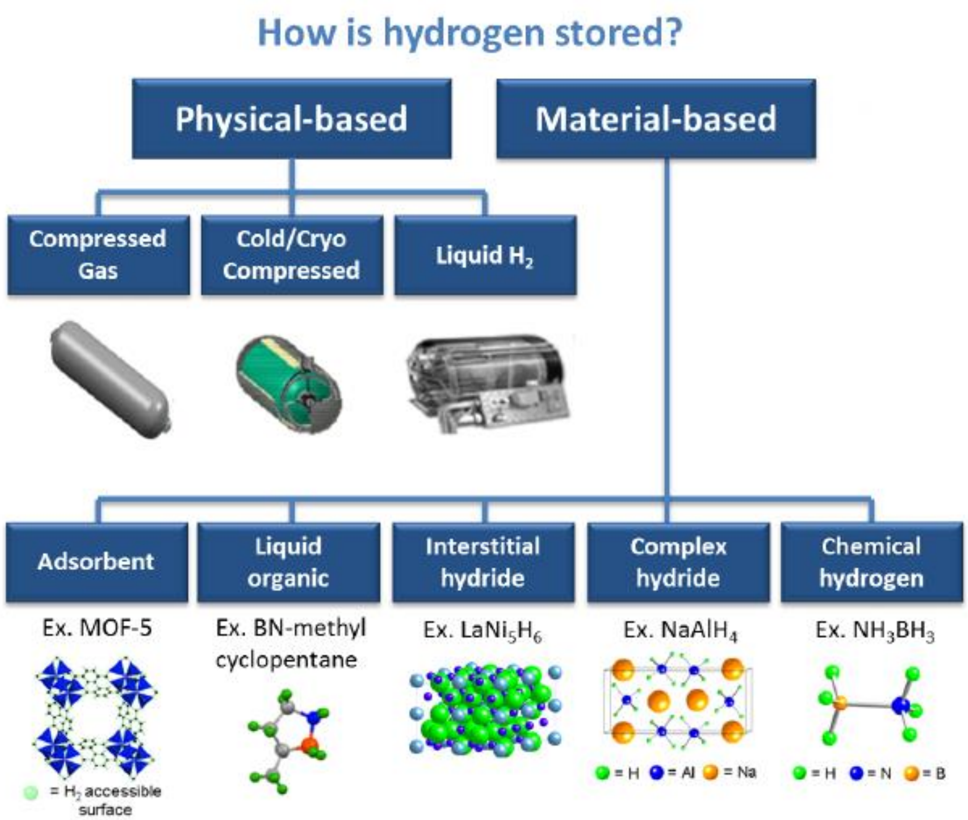

Figure 33 – Hydrogen storage classifications[39]

Physical Storage

Physical hydrogen storage is the most widely used method and consists of either compressing the gas and storing it in high pressure cylinders or pipelines, or liquefaction where hydrogen is stored as a liquid. Gaseous hydrogen compression is typically utilized up to 700 bar in light-duty transportation applications. As the pressure increases, the cost and weight of the storage tank increases with diminishing returns.[40]

[39]United States Department of Energy, Fuel Cell Technologies Office. Hydrogen Storage. Retrieved from https://www.energy.gov/eere/fuelcells/hydrogen-storage

[40] Dr. Müller, K., and Prof. Arlt, W. (2013). Status and Development in Hydrogen Transport and Storage for Energy Applications.

Hydrogen tanks in heavy-duty vehicle applications typically use 350 bar storage to reduce costs where volumetric density is less import than in passenger vehicles.[41]

Pipelines, including natural gas pipelines, can both store and transport hydrogen. Existing pipeline networks inherently enable storage of natural gas and incorporating hydrogen into the network as a blend would allow for significant storage potential. A blended natural gas-hydrogen mixture could be used in many end use applications that are traditionally fueled by natural gas alone. Different blending rates up to approximately 20% are being trialed around the world. Pipelines that incorporate hydrogen could either come from retrofitting existing infrastructure or building new hydrogen compliant infrastructure. This opportunity is discussed further in the Decarbonizing Natural Gas Section.

Hydrogen liquefaction occurs by cooling gaseous hydrogen below -250 °C. Liquefaction is an energy intensive process, with roughly 30% of the energy content of the hydrogen being consumed in the process. Additionally, slow evaporative losses, referred to as “boil-off,” occur due to the temperature differential between the inner storage tank wall and the environment. When transported over long distances, liquid hydrogen is stored in super-insulated cryogenic tanker trucks and dispensed onto storage tanks at the point of use. Before it is transferred to hydrogen powered vehicles, the liquid is converted back into gaseous form to be stored in high pressure tanks and consumed in a fuel cell. High volume applications tend to utilize liquid hydrogen transport and storage due to its lower $/kg cost, for example, most of the fuel cell electric buses and lift truck fleets in North America use delivered liquid hydrogen.

Materials Based Storage

The required volume to store hydrogen can be reduced drastically if the hydrogen molecules are bound to other molecules, thereby increasing the volumetric energy density at a given temperature and pressure. Adsorption materials include carbon-based materials such as activated carbon and graphite, porous polymers, and zeolites. Since the adsorption process is exothermic, the process needs to be held at low temperatures, but not as low as cryogenic liquid hydrogen (-196 °C compared to -240 °C for liquefied H2).[40]

Chemical Carrier Storage

Reversible metal hydrides are alloys which absorb hydrogen under temperature and pressure, the process is reversible when the temperature/pressure is decreased. The mechanism involves adsorption of hydrogen onto the surface, dissociation of H2 molecule, and dissolution of the hydrogen atoms into the metal lattice.[42] For example, magnesium alloys can absorb up to ~5% of hydrogen by weight. This storage method offers great volumetric density benefits but can be a heavier option than other technologies.

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[41] Zen Clean Energy Solutions (2019). British Columbia Hydrogen Study. Retrieved from https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf

[42] Stetson, N., and Blair, L. (2011). Materials Challenges in Alternative and Renewable Energy. Hydrogen Storage Technologies – A Tutorial with Perspectives from the US National Program

Chemical Hydrogen Storage

Hydrogen can be stored via strong chemical bonds and released by thermal decomposition or chemical reaction. The reaction by-products are then regenerated back into the hydrogenated form through another reaction. Two materials under development are methylcyclohexane (MCH) and ammonia (NH3). MCH is a liquid at atmospheric pressure with a chemical formula of C7H14 and can be handled by chemical tankers. Three H2 molecules can be liberated from MCH, which transforms it into toluene through a reversible reaction. Ammonia (NH3) can be dehydrogenated, yielding 0.176 tonnes of hydrogen per tonne of NH3. This is a very promising technology, especially for the export of H2 to international markets but is still in an early stage of development.

Large Scale Geological Storage

Hydrogen presents a unique opportunity to store large quantities of energy over long periods using favourable geologic formations. The stored supply may be used to buffer intermittent renewable electricity production by wind and solar or may be reserved for use during unexpected shutdowns or plant outages. Underground geological storage of natural gas is an established practice to account for natural gas shortages, plant shut-downs, and seasonal fluctuations. Germany and France have reserves of fossil fuels that cover approximately 2 months of demand.[46] As intermittent renewable electricity generation makes up an increasing percentage of the electric grid in the Maritimes, energy storage will be critical. Electricity generation from wind is inherently intermittent, and for the region to generate a significant portion of electricity from wind, it will require a long-term and high capacity energy storage buffer solution.

SAUDI ARABIA AMMONIA PRODUCTION FACILITY

In July 2020, Air Products & Chemicals Inc. announced the signing of an agreement for a $5 billion hydrogen-based ammonia plant powered by wind and solar renewable energy with partners ACWA Power International and NEOM. The project will be sited in Neom, Saudi Arabia, and will draw from over 4 GW of renewable power to produce 1.2 million tons per year of green ammonia.[43]

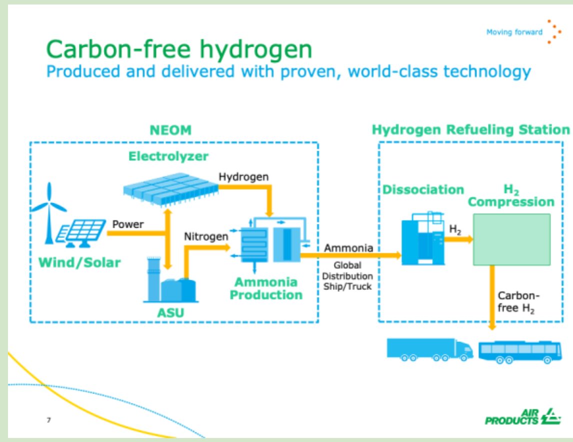

Figure 34 – H2 Ammonia Pathway[44]

To synthesize the ammonia product, hydrogen will be produced via electrolysis and nitrogen through air separation. The process to synthesize ammonia involves a high temperature catalytic reaction which occurs at 200 – 400 atm.[45] Air Products will be the exclusive offtaker of the ammonia, which it plans to distribute globally for cracking to green hydrogen. The projected commissioning date is 2025.

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[43] Air Products. (2020). News Release. Retrieved from http://www.airproducts.com/Company/news-center/2020/07/0707-air-products-agreement-for-green-ammonia-production-facility-for-export-to-hydrogen-market.aspx
[44] Air Products. (2020). Carbon-Free Hydrogen: The Energy Source of the Future. Retrieved from https://investors.airproducts.com/static-files/b0595961-b2ac-45ff-89c5-7d9d8837a363
[45] U.S Department of Energy (2006). Potential Roles of Ammonia in a Hydrogen Economy. Retrieved from https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf
[46] Crotogino, F., and Bünger, U. (2010). Large-Scale Hydrogen Underground Storage for Securing Future Energy Supplies. Retrieved from https://www.researchgate.net/publication/48693439_Large-Scale_Hydrogen_Underground_Storage_for_Securing_Future_Energy_Supplies

Different mechanisms for energy storage are best suited for particular applications. Figure 35 shows the conditions for which different energy storage options provide the greatest potential based on scale and duration. The figure is approximate, and the exact regimes for each technology will evolve as technologies improve; however, the general trends are expected to be maintained barring technology breakthroughs. Hydrogen geological storage has the greatest comparative advantage at high power over long durations, which is applicable for seasonal energy storage. This trend shown in the figure below was echoed during the stakeholder workshops and interviews conducted as part of this study.

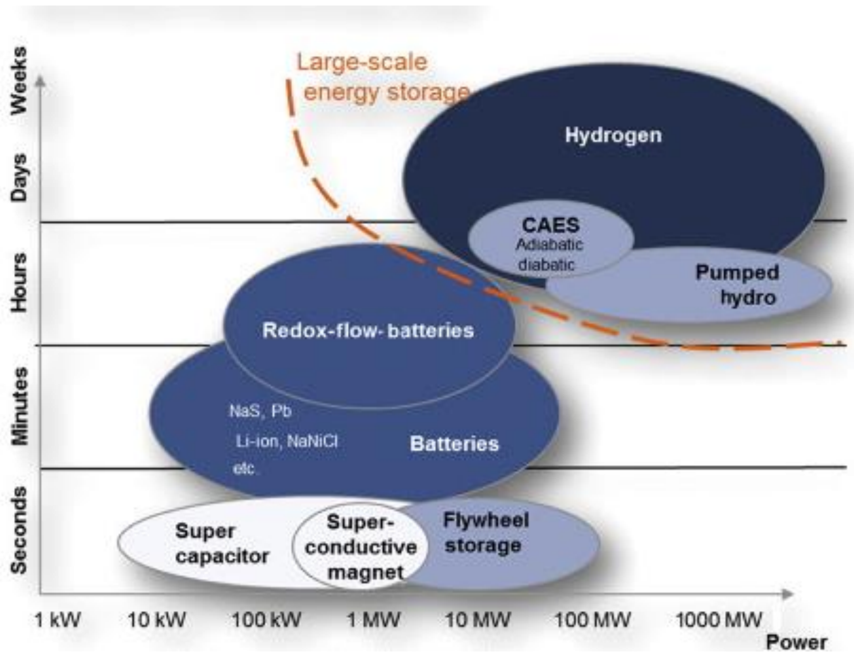

Figure 35 – Segmentation of electrical energy storage by time and size[47]

Salt Caverns

The most commonly employed storage techniques for natural gas utilize depleted gas fields and geological formations such as natural aquifer formations. These solutions are not as suitable for large scale hydrogen storage since hydrogen may react with microorganisms or mineral content inside these structures, depleting the hydrogen over time and decreasing overall storage volume by plugging microporous spaces. Engineered salt caverns are an ideal option, since the compacted salt is inert and also forms a tight seal which traps the stored hydrogen molecules.

As shown in Figure 36, human engineered salt caverns are created by boring a hole to storage depths and creating the storage space through the process of solution mining. This process creates a cavern by pumping in fresh water to slowly dissolve the salt while simultaneously extracting the brine stream. The brine may be disposed through a wastewater treatment process or released into a nearby water source if it is determined the rate and concentration of brine introduction has no harmful environmental effects. Alternatively, the brine stream may be utilized for salt production or as a feed stream in chlor-alkali plants.

[47] Siemens AG (2014). Hydrogen Energy Storage. Retrieved from https://www.sciencedirect.com/topics/engineering/hydrogen-energy-storage

Hydrogen can be transported to the storage site either by truck or through a direct pipeline from the production source. The delivered hydrogen must be compressed to the cavern's storage pressure and dried before being injected through the borehole.

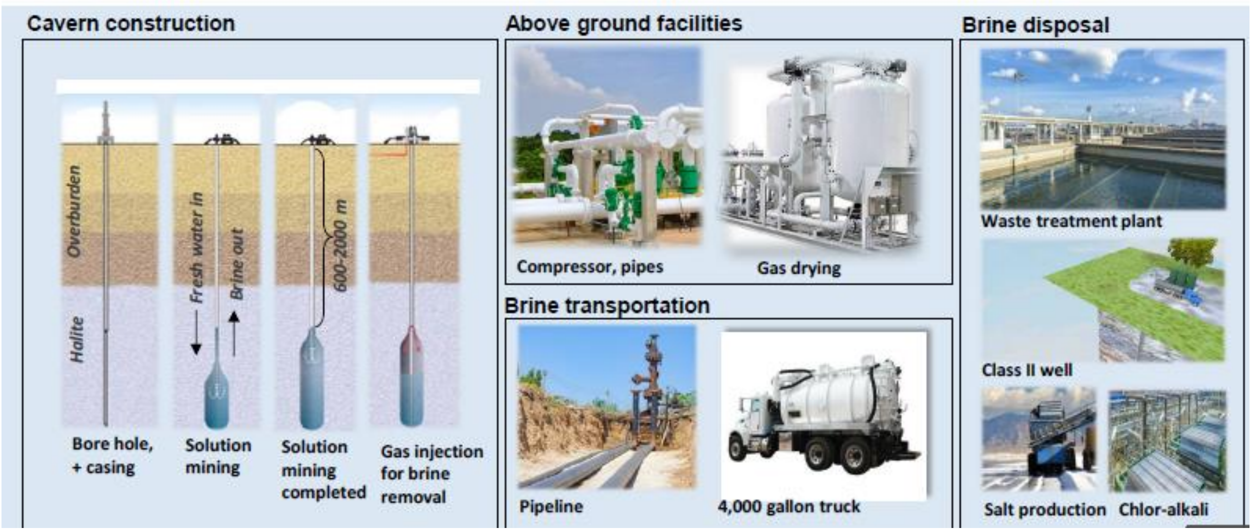

Figure 36 – Salt cavern creation[48]

All the salt deposits in the Maritimes region lie in the Maritimes Basin, which is shown in Figure 37. The basin is considered low risk for seismic activity, which makes it a good candidate for long-term and large-scale hydrogen storage.

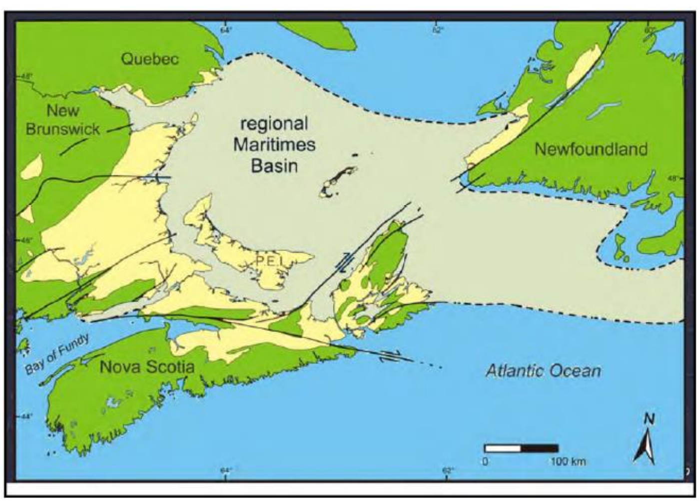

Figure 37 – Salt caverns in the Maritimes[49]

[48] Ahluwalia, R.K., Papadias, D.D., Peng, JK., and Roh, H.S. (2019). System Level Analysis of Hydrogen Storage Options. Retrieved from https://www.hydrogen.energy.gov/pdfs/review19/st001_ahluwalia_2019_o.pdf

[49] W.G. Shaw & Associates Ltd. Consulting Geoscientists (2012). Salt Cavern Storage Potential in Atlantic Canada.

Safety and Regulatory Considerations

The compact structure and composition of salt rock formations make the structures inherently gas tight, and the cavern's only surface access is the borehole, which is plugged to prevent leakage. The storage pressure is also designed to be lower than the cavern's formation pressure to minimize the risk of fracturing. Currently, none of the Maritimes provinces have legislation allowing for storage and recovery of industrial wastes in geological media, but there is legislation allowing for the storage and recovery of hydrocarbons in salt caverns.[49] These are the "Underground Hydrocarbons Storage Act" in Nova Scotia and the "Underground Storage Act" in New Brunswick.

A 2012 survey of potential sites performed by the Newalta Corporation recommended five storage sites based on the following 5 main attributes[51]:

1. Size, shape, and depth
2. State of development existing
3. Capacity of salt cavern to provide safe, long-term storage
4. Proximity to waste generators and transportation logistics
5. Permit approval ease

The recommended sites in Nova Scotia were:

- Alton Salt Deposit
- Kingsville Salt Deposit
- Orangedale Salt Deposit

The recommended sites in New Brunswick were:

- Salt Springs Salt Deposit
- Dorchester Salt Deposit

ALTON SALT DEPOSIT

At the Alton Salt Deposit in Nova Scotia, a project is underway to create an underground hydrocarbon storage facility in a series of engineered salt caverns at depths over 700m. The solution mining process will be utilized to develop the storage space. [50]

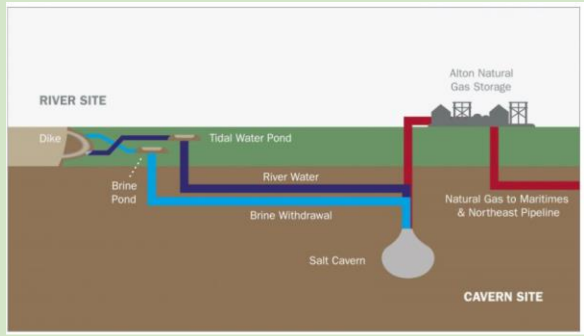

Figure 38 – Alton salt deposit project[50]

The project was originally scheduled to commence construction in mid-2008 with four caverns being formed over 18-24 months. The plan is to connect the gas storage facility with the region's Maritimes and Northeast pipeline. Phase 1 will be the construction of 1-4 caverns each with a volume of approximately 226,000 cubic metres. The site has the potential to incorporate 10-15 caverns of this size.

While surface facilities for the project have been constructed, the project has not yet begun the solution mining of the salt caverns. A March 2020 decision of the Nova Scotia Supreme Court overturned one of the project's environmental approvals, ordering further consultation with the neighbouring Sipekne'katik First Nation. If this project is completed, it could become an ideal location to pilot and demonstrate large scale hydrogen storage.

[50] Alton. The Project. Retrieved from https://altonnaturalgasstorage.ca/the-project/
[51] Newalta Corporation (2012). Salt Cavern Storage Potential in Atlantic Canada.

4. HYDROGEN TRANSPORT

Transportation is an essential piece of the hydrogen supply chain. The cost and carbon intensity of transporting hydrogen can be considerable, so it is ideal to co-locate hydrogen production with demand wherever possible. This is especially true when hydrogen is to be used in cost sensitive applications like blending into the natural gas network. It may also be possible to utilize on-site generation of hydrogen for some transportation applications using small scale electrolysis, but due to the distributed nature of hydrogen refueling stations, some degree of transportation will be required.

Hydrogen in its pure form can be transported as a gas or cryogenic liquid. There are alternative hydrogen transportation options involving adsorption onto a storage medium, conversion into another chemical such as ammonia or methanol, or using liquid organic hydrides however these are at a lower technology readiness level (TRL) and would not be cost effective for distribution around the Maritimes. This report will only describe transportation of hydrogen in its pure form as a gas or liquid. Some of these alternatives offer benefits over very long distances and would be applicable to international shipping. These would be important if the export market develops.

Hydrogen Transport by Road

Hydrogen is commonly transported in trucks as both a compressed gas and a cryogenic liquid. Compressing or liquifying the hydrogen requires energy which comes at a cost as well as increasing the carbon intensity of the fuel. Compressing hydrogen for transport requires approximately 4 kWh/kg-H2 while liquefying it requires approximately 10 kWh/kg-H2. In the Maritimes, this electricity would cost approximately \$0.22-\$0.35/kg-H2 for compression or \$0.55-\$0.87/kg-H2 for liquefaction depending on the province. The CI of the hydrogen is dependent on the electric grid CI. Figure 39 shows the CI impact of compressing or liquefying hydrogen relative to the grid CI. In the Maritimes, this can have a significant impact on the CI of delivered fuel since the grid CI is relatively high, especially in Nova Scotia.

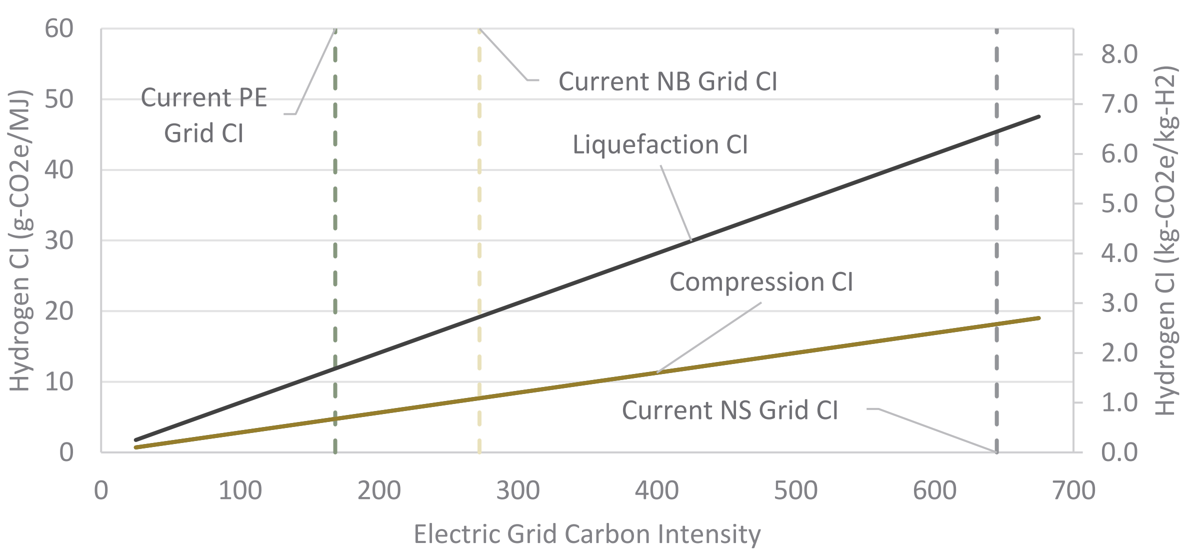

Figure 39 – CI of compressing and liquefying hydrogen

Figure 40 – Compressed H2 tube trailer[52]

When transported by road as a compressed gas hydrogen (GH2), the hydrogen is typically stored in a tube trailer as shown in Figure 40. This is a conventional heavy-duty truck equipped with compressed gas cylinders that store the hydrogen at ~ 250 bar. Typically, they are diesel powered trucks and transportation emissions must be considered in lifecycle analyses.

Since hydrogen has a low volumetric density, the amount of hydrogen stored in a tube trailer is typically limited to approximately 500 kg. The pressure in the vessels can never go below atmospheric pressure, so not all of the hydrogen in the cylinders can be removed from the trailer upon delivery.

When transported by road as a cryogenic liquid hydrogen (LH2), hydrogen is carried in a liquid hydrogen trailer as shown in Figure 41. These trucks use highly insulated containers called dewars to maintain the temperature at approximately -253°C. These trailers do not use a cooling system to keep the temperature low, so some hydrogen will be lost to evaporation, referred to as 'boil-off' at a rate of 0.3-0.6% per day. [53]

Figure 41 – Liquid H2 trailer[53]

Because of the improved density in a liquid state, liquid trailers can carry much more hydrogen per trailer. Some trailers transport as much as 7,500 kg-H2 in a single load. This improved transportation efficiency makes liquid hydrogen more suitable for long-range and high-volume operations.

The cost to transport hydrogen as a gas and liquid via trucks was estimated including the full cost of equipment (including liquefaction and compression, trailers, and balance of plant), operational expenses (including labour, electricity, and fuel). Cost assumptions were taken from available reports, regional electricity and fuel costs, and industry knowledge. Since gaseous delivery is typically viable at lower scale than liquefaction, it was assumed that the gaseous delivery operation outputs approximately 4,000 kg-H2/day (equivalent to a 10 MW electrolyzer) and the liquid operation outputs approximately 20,000 kg/day.

Figure 42 shows the estimated cost of delivery for gaseous and liquid delivery over distances of 100 km and 500 km. The figure represents an overall average for the Maritimes assuming an electricity price of $0.087/kWh. The cost of gaseous hydrogen delivery is much more sensitive to the distance travelled since much less hydrogen is transported each trip. Although the cost of delivered gaseous hydrogen is lower over short distances, it is considered at a smaller scale. Increasing the size of the plant would greatly complicate logistics and increase the required size since a large number of trucks would be required to transport the gaseous hydrogen produced.

[52] City Machine & Welding, inc. Hydrogen Tube Trailer – 9 Tubes. Retrieved from https://cmwelding.com/configuration/hydrogen-h2-tube-trailer-9-tubes-dot-3aax-2400psi-40-ft
[53] Brown, A. (2019). The Chemical Engineer. Hydrogen Transport. Retrieved from https://www.thechemicalengineer.com/features/hydrogen-transport/

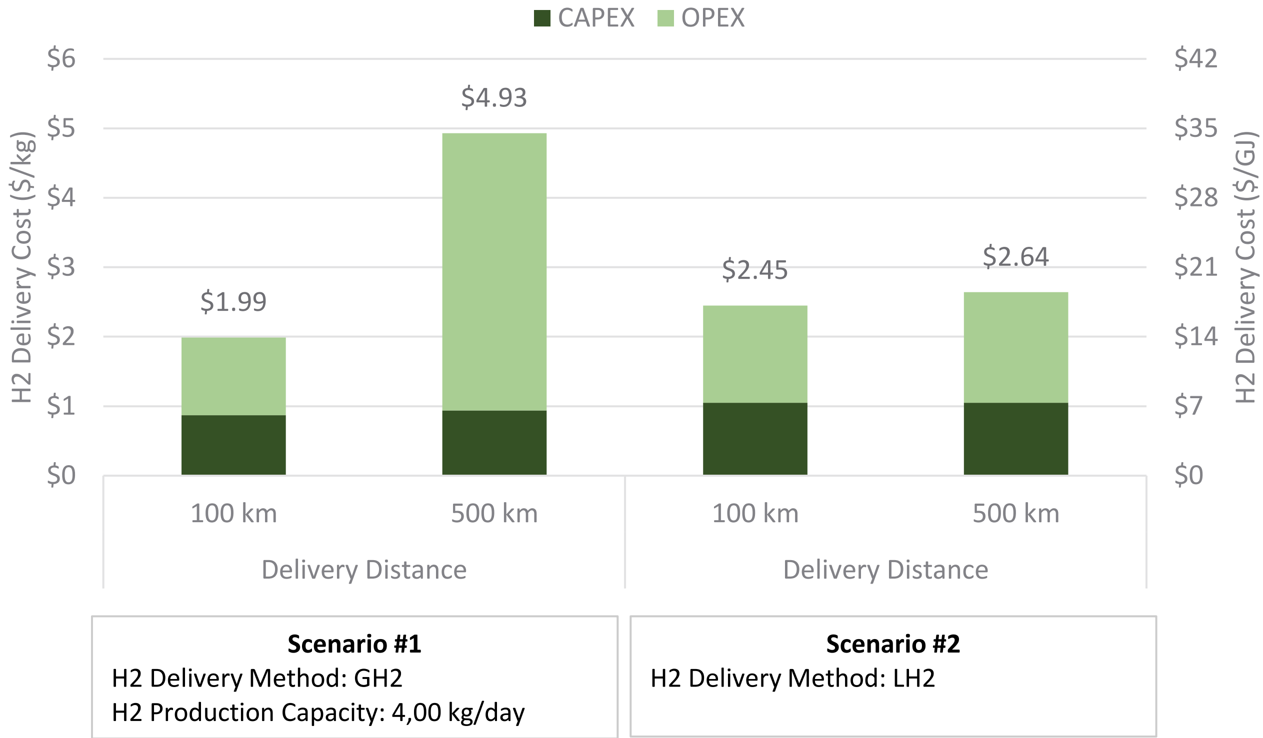

Figure 42 – Estimate cost of gaseous and liquid hydrogen delivery

Gaseous Hydrogen by Pipeline

Gaseous hydrogen can also be transported through a pipeline in a similar fashion to natural gas. This is described in more detail in the Decarbonizing Natural Gas Section. Transporting H2 via pipeline is the most efficient and inexpensive method of moving hydrogen but requires significant capital expenditure and support to install the infrastructure.

A critical difference between transporting natural gas and hydrogen via pipeline is the type of pipes that are required. Hydrogen acts to embrittle steel and welds that are used to fabricate conventional pipelines. This can lead to permeation and leaks. Fiber reinforced polymer pipelines or other plastic based pipes do not suffer from the same embrittlement problem and are a good alternative to steel for transporting hydrogen. Most of the natural gas infrastructure in the Maritimes is made from these hydrogen-compatible materials, which will make adoption more straightforward than in other provinces with older infrastructure.

5. POTENTIAL HYDROGEN END USES

Decarbonizing the Natural Gas System

Baseline

End-Use Energy Demand

End-use demand for natural gas in the Maritimes represents a varying percent of total energy demand for each province. As shown in Figure 43, natural gas in New Brunswick, Nova Scotia, and PEI accounted for only 7%, 10%, and 5% of total energy consumption in 2019, respectively.[54]

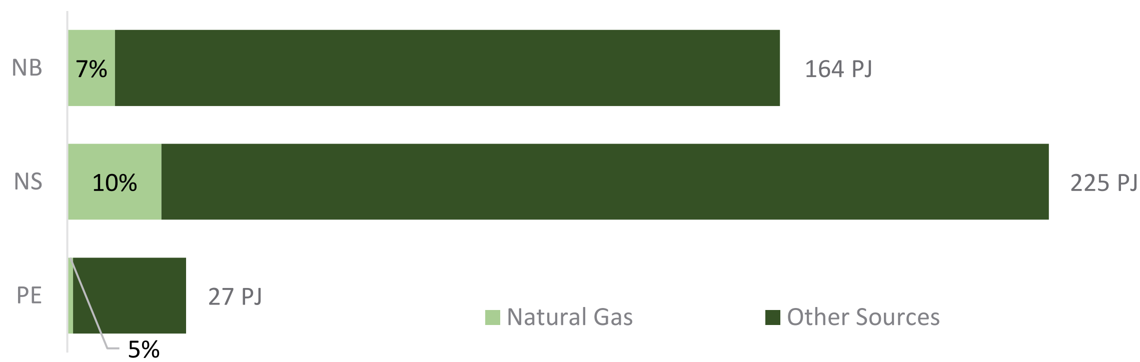

Figure 43 – Natural gas demand per total energy demand in provinces in the Maritimes[54]

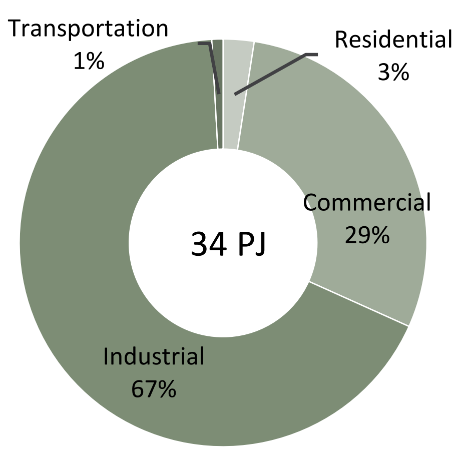

Figure 44 – Maritimes' end-use NG demand by sector (2018)[54]

Despite natural gas making up a relatively small amount of total energy demand in the Maritimes, natural gas plays a vital role in the industrial sector. As shown in Figure 44, the industrial sector accounts for the majority of natural gas demand, consuming 67% of the 34 PJ of natural gas consumed in the Maritimes in 2018. The commercial sector, which uses natural gas for heating buildings and water as well as to operate equipment such as refrigeration, cooling, and gas for stoves, accounts for 29% (9.9 PJ) of the total demand. The residential and transportation sector consumed only 3% (0.8 PJ) and 1% (0.3 PJ) of total demand, respectively.

The annual demand of natural gas across each province in the Maritimes is displayed in Figure 45 and is based on historical data from the Canada Energy Regulator (CER).[54]

[54] Canada Energy Regulator (2017). End – Use Demand. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

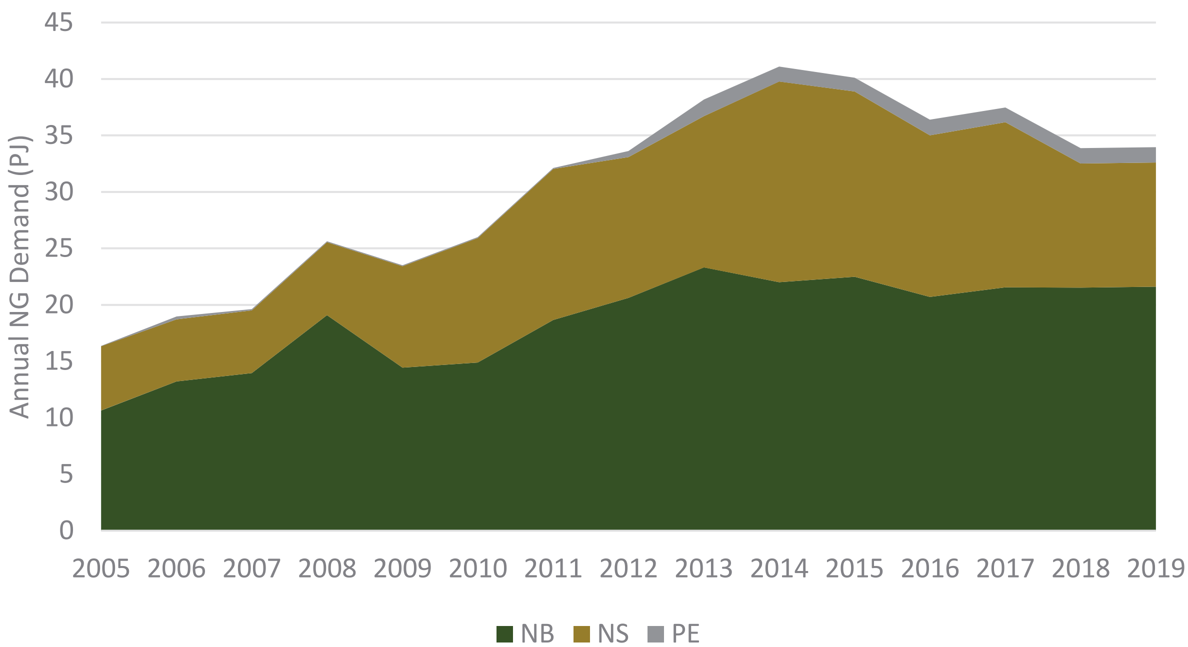

Figure 45 – Historical annual NG demand per year and province in the Maritimes[54]

New Brunswick has the largest NG demand of the Maritime provinces, accounting for 21.52 PJ in 2018. The largest consuming sector for natural gas in New Brunswick is the industrial sector, which consumed 85% of all natural gas demand. The largest industrial consumer is Irving Oil, which uses of natural gas for its oil and gas operations. Commercial and residential sectors accounted for 13% and 2%, respectively.

Nova Scotia's natural gas demand in 2018 was 11 PJ, accounting for less than 1% of total Canadian demand. The commercial sector in Nova Scotia consumed 65% of all natural gas demand in 2018, followed by the industrial, residential, and transportation industries accounting for 30%, 3%, and 2% respectively.

PEI uses minimal natural gas, with 100% of the 1.36 PJ consumed in 2018 being used for industrial processes which are all brought to the island via truck.

Production and Existing Infrastructure

The production of natural gas in the Maritimes has been decreasing over the past 10 years due to the closure of Exxon Mobil's Sable Offshore Energy Project and Ovintiv's (formerly Encana) Deep Panuke offshore reserve. PEI does not have any natural gas production and uses minimal amounts for end-use. Natural gas used in PEI is transported via trucking and private companies, as there are no pipeline networks. Figure 46 displays annual natural gas production in the Maritimes from the past 10 years.[55]

[55] Canada Energy Regulator (2017). Natural Gas Production. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

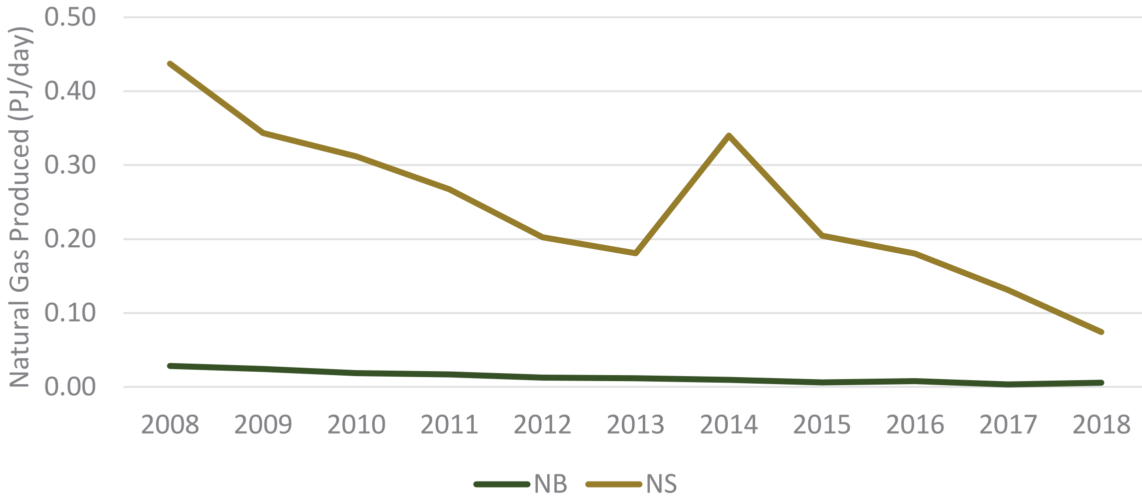

Figure 46 – Natural gas production (PJ/day) in NB and NS from 2008 – 2018[56]

Between 2008 and 2018, natural gas production decreased by 80% and 83% in New Brunswick and Nova Scotia, respectively. New Brunswick experienced a linear decrease in production over time, with a value of 2 PJ/year in 2018. Nova Scotia's production increased after its initially declining in 2008 – 2013, before falling back down to a production value of 27 PJ/year in 2018.

New Brunswick

In 2018, New Brunswick produced only 2 PJ of natural gas, representing less than 0.1% of Canadian production. Natural gas in New Brunswick is produced from the McCully Field, which is believed to have 63.7 trillion cubic feet of in-place shale gas resources.[56] The completion of five hydraulic fracturing operations in the summer of 2014 by Corridor Resources led to an additional 48 wells of natural gas production.[56] However, in December 2014, hydraulic fracturing was banned in New Brunswick until further research concerning health, water, and environmental risks is performed. As of 2017, McCully Field has shut-in natural gas production in the summer to align production with peak demand in the winter.

New Brunswick has been exporting natural gas to the northeastern United States since 2007, via the Maritimes and Northeast Pipeline (M&NP), which goes through Nova Scotia and crosses the border in Maine. The M&NP currently imports more natural gas than it exports. The M&NP is discussed in further detail in the following section. Liberty Utilities is the primary provider of natural gas, covering over 1,200 km of natural gas pipeline throughout southern New Brunswick.[57]

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[56] Natural Resources Canada (2017). New Brunswick's Shale and Tight Resources. Retrieved from https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/natural-gas/shale-and-tight-resources-canada/new-brunswicks-shale-and-tight-resources/17698

[57] Canada Energy Regulator (2020). Provincial and Territorial Energy Profiles – New Brunswick. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/nb-eng.html

Liberty Utilities is a regulated water, natural gas and electric transmission and distribution utility. Within New Brunswick its distribution network includes over 1,200 kilometres of pipeline. Natural gas service is provided to over 12,000 customers in the Fredericton, Moncton, and Saint John area.

Nova Scotia

Production of natural gas in Nova Scotia was 27 PJ in 2018, representing approximately 0.4% of the total output in Canada. The decrease in natural gas production from 2008-2018 is mostly attributable to the closing down of offshore natural gas projects in December 2018. Before 2018, the majority of natural gas was produced from the Sable Offshore Energy Project (SOEP) and Deep Panuke Offshore Gas Development Project.

SOEP, located near Sable Island, 160km off the coast of Nova Scotia, began in 1999, making it Canada's first offshore natural gas project. The SOEP was the largest supplier of natural gas in the Maritimes producing a total of 60 billion cubic metres of natural gas from five offshore fields before shutting down permanently in December 2018.[58] Deep Panuke Offshore Project, located just southeast of Halifax, began production in 2013 and was another major natural gas supplier in Nova Scotia. The project operated on a seasonal basis through 2015-2018, with operations only running during winter months when natural gas prices and demand were higher. The sudden increase in natural gas production in 2014, as displayed in Figure 46, is due to the opening of Deep Panuke. The project was projected to have a lifespan of 13 years; however, the project officially shut down in 2018 after producing a total of 4.2 billion cubic metres of natural gas from four wells.[59] Nova Scotia currently has very minimal natural gas from small onshore production projects. During production years, Nova Scotia's offshore production exported natural gas to the Northeast United States (US) via the M&NP.

Heritage Gas is the sole natural gas distribution utility in Nova Scotia, operating in seven counties in in the Province including the Halifax Regional Municipality. Heritage Gas provides energy to some of the largest industries, institutions, and employers in the province. Deliveries utilize both pipelines and Compressed Natural Gas (CNG) trailers to natural gas customers that are not adjacent to existing infrastructure. Over 90% of the utilities pipelines are polyethylene (PE) and are well suited to high blends of hydrogen with natural gas.

[58] CNSOPB. Deep Panuke Offshore Gas Development Project. Retrieved from https://www.cnsopb.ns.ca/offshore-activity/current-activity/deep-panuke

[59] CNSOPB. Sable Offshore Energy Project. Retrieved from https://www.cnsopb.ns.ca/offshore-activity/current-activity/deep-panuke

Maritimes & Northeast Pipeline

The M&NP was commissioned in 1999 alongside the SOEP to transport natural gas through Nova Scotia, New Brunswick, and the Northeast of the US. Additional connections to the pipeline were made in 2007, connecting the McCully natural gas field and in 2013 to the Deep Panuke project.[60] An overview of the M&NP's transmission network is displayed in Figure 47.

Figure 47 – Maritimes & Northeast Pipeline (M&NP) transmission network map (orange line)[60]

The MN&P is bi-directional, allowing for the import of natural gas during peak season when domestic supply is insufficient. Due to the closing of the SOEP and Deep Panuke, the Maritimes gets the majority of their natural gas from the Northeast US. As such, since the conclusion of offshore projects in 2018, imports from the Northeast of the US have surpassed exports, supported by Figure 48, which displays the average daily throughput for natural gas imports and exports for the M&NP. The M&NP has a total capacity of 13.33 million cubic metres per day for exports and imports, which is much more than current throughput.

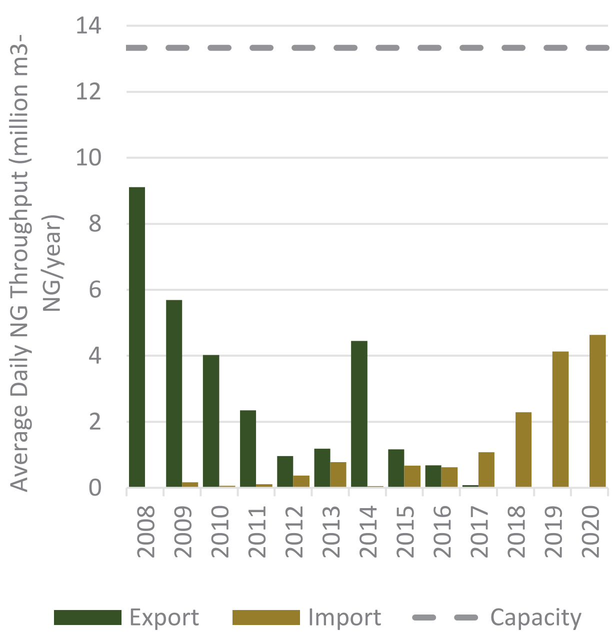

Figure 48 – M&NP average daily export & import throughput and capacity from 2008 - 2020[60]

GHG Emissions

Based on the national average carbon intensity for natural gas usage of 62 gCO2e/MJ, GHG emissions associated with the end-use of natural gas in 2018 for New Brunswick, Nova Scotia, and PEI was 1.3, 0.7, and 0.08 Mt-CO2e respectively.[61]

Cost of Natural Gas

The cost of natural gas in the Maritimes is high in comparison to western Canadian provinces that have an abundance of natural gas resources and developed pipeline infrastructure. The region has less developed pipeline infrastructure, making it more

[60] Canada Energy Regulator (2020). Pipeline Profiles: Maritimes & Northeast. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/pplnprtl/pplnprfls/ntrlgs/mnp-eng.html
[61] Environment and Climate Change Canada (2019). Clean Fuel Standard Proposed Regulatory Approach. Retrieved from https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/pricing-pollution/Clean-fuel-standard-proposed-regulatory-approach.pdf

costly to transport and use. Table 2 displays the cost of natural gas in New Brunswick and Nova Scotia for residential customers from February 2018 based on an average household natural gas consumption of 7.87 GJ per month.

Table 2 – Price for residential natural gas use per gigajoule ($/GJ) in NB and NS for February 2018.[62]

Cost Type	NB	NS
Commodity Price ($/GJ)	$9.0	$9.4
Variable Charges ($/GJ)	$9.8	$8.7
Fixed Charges ($/GJ)	$2.4	$3.0
Total ($/GJ)	**$21.2**	**$21.1**

Opportunities and Challenges for Hydrogen

Hydrogen's Role in Decarbonizing the Natural Gas Grid

Hydrogen can be integrated into natural gas grids blended with natural gas or in 100% hydrogen pipelines. One of the most attractive benefits of blending hydrogen into natural grids is its ability to lower the GHG emissions of the gas network. Lighthouse projects have been explored over the past decade around the world. When blended with relatively low concentrations of 5-20% of hydrogen by volume, there are minimal risks associated with using the blend in end-use devices for public safety or the durability and integrity of existing natural gas network infrastructure.[63, 64]

Blending hydrogen into natural gas pipelines can also be used to deliver pure hydrogen to markets. Purification and separation technologies could separate hydrogen after injection points to provide pure hydrogen closer to end-users.

Hydrogen has a lower volumetric energy density (heating value) than natural gas, so blending it into natural gas networks will result in a mixture containing a less energy on a volume basis. As such, the flow rate of the blended gas will need to be increased. To accomplish this, pipelines and distribution networks will need to increase their system pressure and gas mixture density flowing through their pipelines to adhere to the increased flows. Thus, the pressure rating of pipelines may constrain the amount of hydrogen that can be injected into the network. Similarly, as discussed prior, when concentrations of hydrogen mixed into the system exceeds 20%, the mixture may not be suitable for end-user applications without equipment upgrades. Constraints associated with hydrogen injection limits can be combatted by isolating and/or localizing portions of the natural gas network or end customers who have equipment and end-uses suitable for higher hydrogen concentrations.

[62] Canada Energy Regulator (2020). Market Snapshot: What is in your residential natural gas bill? Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/07-04rsdntlntrlgsbll-eng.html
[63] Melania MW., et al. (2013). Blending Hydrogen into Natural Gas Pipeline Networks A Review of Key Issues. Retrieved from https://www.nrel.gov/docs/fy13osti/51995.pdf
[64] Yoo Y., et al., (2017). Review of Hydrogen Tolerance of Key Power-to-Gas (P2G) Components and Systems in Canada. NRC-EME-55882. Retrieved from https://nrc-publications.canada.ca/eng/view/fulltext/?id=94a036f4-0e60-4433-add5-9479350f74de

Since the natural gas pipeline infrastructure is fairly centralized within the Maritimes, there is an opportunity to purposefully expand the network to use hydrogen. A large portion of the population does not currently have access to natural gas and use heating oil or high CI electricity from the grid. New infrastructure can be future proofed to enable high concentrations or even 100% hydrogen pipelines to residential, commercial, and industrial customers. In the near-term, this approach could be used to create a hydrogen community with a 100% hydrogen pipeline network used for heating, transportation, and energy storage.

Challenges and Barriers

When blending hydrogen into natural gas networks, pipe composition, material compatibility, pressure, appliance operation, and at times hydrogen extraction needs to be considered to enable a successful project. The Canadian Gas Association is currently working to develop industry standards to help address some of these challenges.

Embrittlement

The embrittlement of certain metals used in pipelines must be considered for high-pressure natural gas pipelines when they are exposed to high concentrations of hydrogen or mixtures of natural gas and hydrogen for long periods.

Natural gas transmission pipelines are typically made from high-strength steels wrapped or coated and protected against corrosion. These high strength steels can be subject to embrittlement under high-pressure operations. The MN&P, which is the primary natural gas transmission pipeline in the Maritimes, is built from high-strength carbon steel, coated with fusion-bonded epoxy to protect the steel from corrosion and provide cathodic protection.[66] As such, hydrogen concentration injected into the network may be constrained by embrittlement. However, injections of hydrogen at 5-20% by volume into natural gas grids still accounts for a considerable amount due to the high pressure and large throughput of gas in transmission networks.[67]

HERITAGE GAS PILOT PROJECT

Heritage Gas is pursuing funding to develop a clean hydrogen pilot project through the 'Green Infrastructure Projects that Reduce Greenhouse Gas Emissions' Program. The objective would be to construct a 4 MW electrolyzer facility connected directly to a new wind farm. The hydrogen generated would be distributed through the natural gas pipeline at a low blending rate for use in conventional natural gas equipment. It's estimated that the project would generate and distribute 40,000 GJ of hydrogen annually.

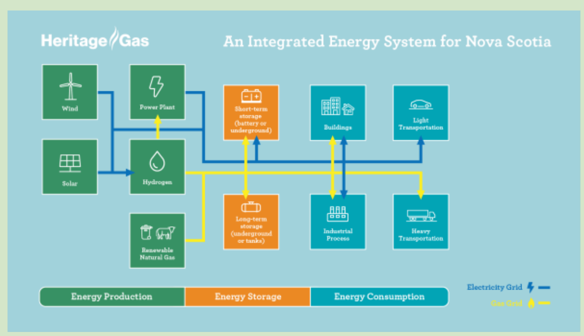

Figure 49 – Heritage Gas H2 schematic[65]

[65] Heritage Gas. An Integrated Energy System for Nova Scotia. Retrieved from https://www.heritagegas.com/wp-content/uploads/2020/06/HGAS-4579-01-Campaign-Execution-and-Production-Technical-Diagram-HG.png
[66] Maritimes & Northeast Pipeline. Safety. Retrieved from https://mnpp.com/us/operations/safety
[67] Zen Clean Energy Solutions (2019). British Columbia Hydrogen Study.

The majority of natural gas distribution systems are composed of steel and polyethylene (PE). Metallic distribution grids are commonly made from low-strength steels. Low-strength steels are generally not susceptible to hydrogen-induced embrittlement under normal operating conditions.[63] Additional metallic pipes that are sometimes used in natural gas pipelines include iron (ductile, cast, or wrought) and copper, and are generally free from hydrogen-induced embrittlement. Most pipes in the Maritimes are made of polyethylene, which do not suffer from the same embrittlement issue.

Recent studies have determined that transmission pipelines can operate with minimal risk with injected hydrogen concentration of 20% by volume.

Pipeline Standards and Policy

Country-specific standards and regulations limit hydrogen concentration allowed in current natural gas infrastructure. International standards currently range from allowing hydrogen injection values of 0.1% (vol.) in the United Kingdom (UK) and Belgium to 12% (vol.) in Holland.

There are currently no hydrogen injection standards in the Maritimes or anywhere throughout North America. However, individual pipelines require shippers on their system to adhere to specific limits. The MN&P currently requires gas on its system to have a total heating value between 957 – 1110 Btu/cubic-foot and limits non-methane gas to 4%.

Future injection limits and regulations will need to be considered due to the M&NP's connection through New Brunswick, Nova Scotia, and the Northeast of the US. The Canadian Gas Association interviewed for British Columbia's (BC) hydrogen strategy anticipated future reports advising that hydrogen blending of up to 5% (vol.) is acceptable in the near-term.[67]

Pipeline Capacity

Hydrogen production capacity must coincide with existing natural gas pipeline capacity for hydrogen blending to occur. Detailed studies

H21 LEEDS CITY GATE PROJECT

In 2019, the United Kingdom (UK) announced its goal to reach net zero-emissions by 2050. As such, to reduce the emissions associated with heating, the UK has developed long-term plans to convert the Northern England energy grid to 100% hydrogen. The H21 Leeds City Gate project was initiated in 2016 to determine the feasibility of converting the UK's gas grid to hydrogen. The project takes place in the city of Leeds in Northern England and includes the conversion of 3.7 million homes and businesses from natural gas to hydrogen.

Figure 50 – Leeds Pipes[68]

Total demand for the project is expected to be 6.4 TWh and the hydrogen will be provided by four SMR facilities incorporating CCU/S in Teesside. It's estimated that 1.5 Mt-CO2e will be sequestered annually.

[68] Australian Gas Networks. (2017). H21 Leeds City Gate Film. Retrieved from https://www.youtube.com/watch?v=eR5oZHRCouM

concerning pipeline capacity and injection location must be conducted to optimize hydrogen injection efforts.

Appliances

Appliances that use natural gas must be able to operate without interruption from the hydrogen-blended natural gas. Despite most devices being compatible with hydrogen concentrations up to 10% (vol.), combustion turbines, compressors (that may contain natural gas but leak hydrogen), and CNG tanks may not be suitable under these hydrogen concentration conditions.

Hydrogen concentrations of 30% and higher may cause performance issues among engines, burners, boilers, and stoves.[67] Appliance testing and validation for all product models and makes are necessary before implementing higher hydrogen concentration values.

Gas Metering

Hydrogen blends can influence the accuracy of existing gas meters. However, studies have shown that gas meters would not need to be tuned for low hydrogen blend levels under 50% hydrogen volume.

Contaminants

Further investigation concerning the impact of contaminants associated with hydrogen injection into the natural gas network needs to be completed. However, hydrogen production methods producing relatively pure hydrogen, such as electrolysis methods would not be as impacted by contaminants.[67]

Adoption Scenarios

Hydrogen demand was estimated for two scenarios based on incremental and transformative adoption of hydrogen as a substitute for natural gas in the pipeline system. Both scenarios assume that provinces will comply with targets for low CI hydrogen. The incremental scenario assumes a slower adoption rate of hydrogen in the natural gas system while adhering to existing policies and legislations. The transformative scenario provides the ambitious goal of reaching a near carbon-neutral system by 2050 with a more aggressive blending rate.

The hydrogen blending amounts per volume and energy for the incremental and transformative cases in 2030 and 250 are displayed in Table 3.

Table 3 – Percent H2 blended into NG pipelines - Incremental and transformative scenarios

Parameter	Province	Incremental		Transformative	
		2030	2050	2030	2050
%Volume of NG Demand from H2	NB/NS	5%	20%	10%	78%
	PEI	5%	20%	10%	100%
%Energy of NG Demand from H2	NB/NS	2%	7%	3%	53%
	PEI	2%	7%	3%	100%

In the transformative scenario, PEI was assumed to have substituted 100% of natural gas consumption with hydrogen by 2050. PEI is a smaller market and has no current natural gas pipeline infrastructure. Natural gas brought to the island via truck is relatively expensive and the volume is low so it would be possible to replace this source with hydrogen produced on island via electrolysis using wind power.

Table 4 displays the constants that were used to estimate energy and the Greenhouse Gas (GHG) abatement potential of blending hydrogen into the natural gas grid.

Table 4 – Natural gas modelling constant assumptions

Parameter	Value	Unit	Source
Natural Gas Volumetric Energy Density	37.3	MJ/m^3	https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA#1-4
Natural Gas Carbon Intensity	62	gCO2e/ MJ	https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/pricing-pollution/Clean-fuel-standard-proposed-regulatory-approach.pdf
Hydrogen Volumetric Energy Density	12	MJ/m^3	https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA#1-4
Hydrogen Higher Heating Value	142	MJ/kg	https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels
Hydrogen Carbon Intensity	36.4	gCO2e/ MJ	https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

Forecasted NG Demand

The forecasted natural gas demand in the Maritimes is shown in Figure 51. It is based on data from the CER through 2040, after which it was assumed to remain constant.[69]

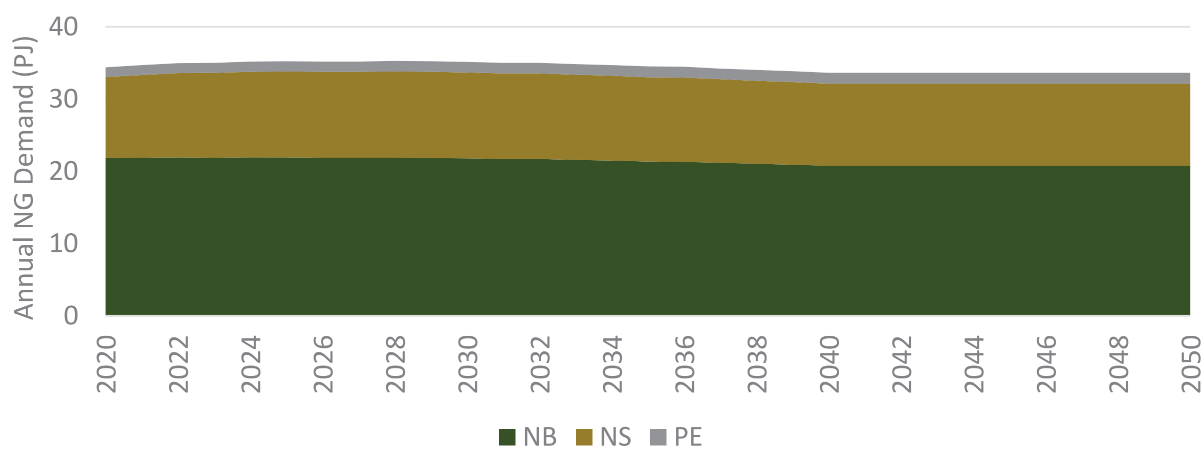

Figure 51 – Forecasted annual NG demand by province in the Maritimes (2020-2050)[69]

[69] Canada Energy Regulator (2017). Primary Energy Demand. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

While these adoption scenarios leverage CER forecasts for NG demand in the region and identify opportunities for hydrogen to displace a proportion of that energy demand projected to be delivered by NG, the CER does not account for potential fuel switching to hydrogen in a wide range of applications that could drive demand for gaseous fuels in the region. The Maritimes pipeline infrastructure could be expanded significantly in the future, with hydrogen making up a significant portion of delivered energy through the expanded network.

Forecasted Hydrogen Demand & GHG Reduction

Incremental Scenario

The amount of hydrogen blended into the natural gas grid for the incremental scenario is significantly lower than the transformative case with the maximum amount of hydrogen accounting for only 7% (energy) of the entire network. The resulting annual hydrogen demand for 2020 – 2050 is presented in Figure 52.

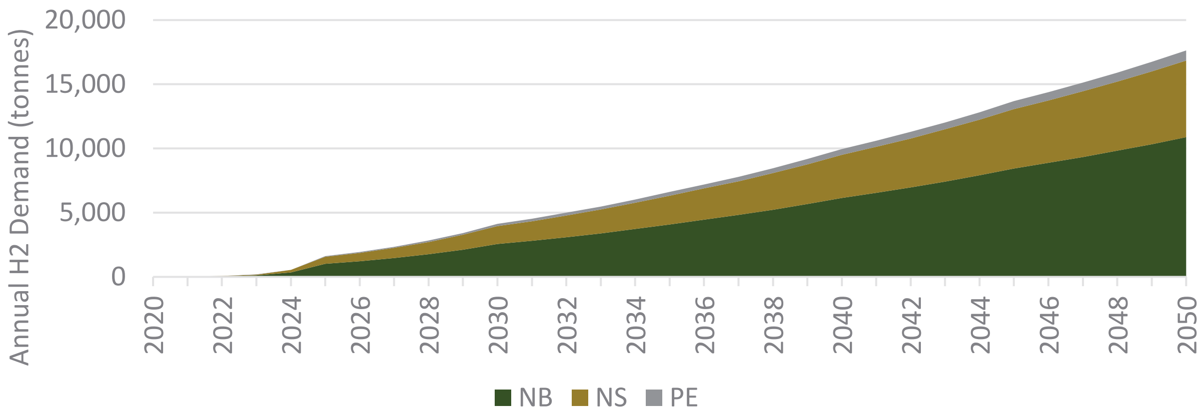

Figure 52 – Natural gas incremental scenario – H2 demand

Using the difference between CI values for natural gas and low CI hydrogen displayed in Table 4, the potential GHG reduction was determined and is shown in Figure 53.

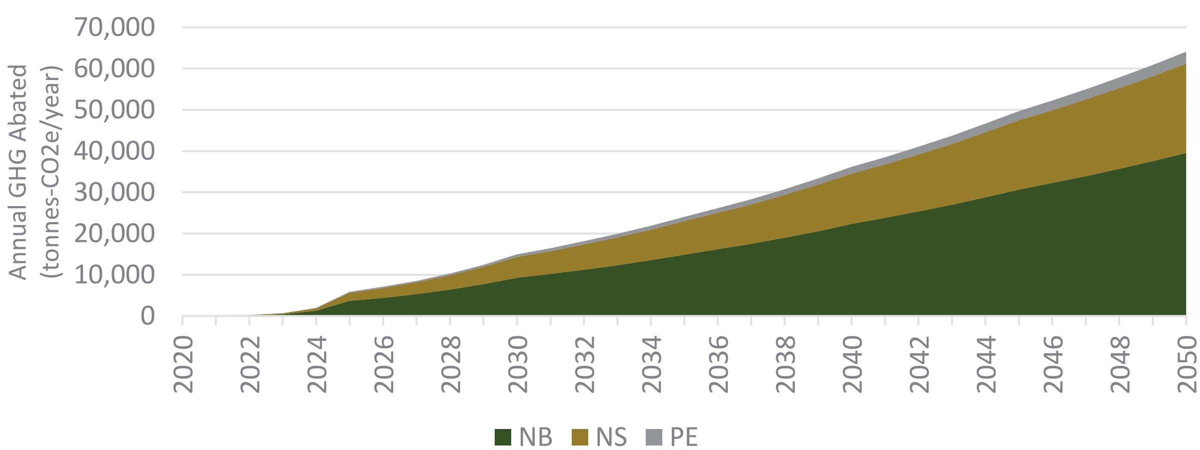

Figure 53 – Natural gas incremental scenario - GHG emission abatement

Table 5 summarizes the potential hydrogen demand and GHG reductions associated with the incremental natural gas model for each province in the Maritimes.

Table 5 – Natural gas incremental scenario - H2 demand and GHG abatement by year and region

Year	Region	H2 Demand (tonnes H2/year)	GHG Abatement (tonnes-CO2e/year)
2025	NB	1,007	3,660
	NS	547	1,989
	PE	65	235
	All	**1,619**	**5,885**
2030	NB	2,555	9,288
	NS	1,392	5,060
	PE	172	627
	All	**4,119**	**14,974**
2040	NB	6,144	22,335
	NS	3,368	12,244
	PE	444	1,614
	All	**9,956**	**36,193**
2050	NB	10,883	39,562
	NS	5,966	21,687
	PE	786	2,859
	All	**17,635**	**64,108**

Transformative Scenario

In the transformative natural gas scenario, hydrogen accounts for 58% (energy) and 100% (energy) within the natural gas pipeline mixture for New Brunswick/Nova Scotia and PEI by 2050, respectively. The resulting annual hydrogen demand for each province in this scenario is displayed in Figure 54.

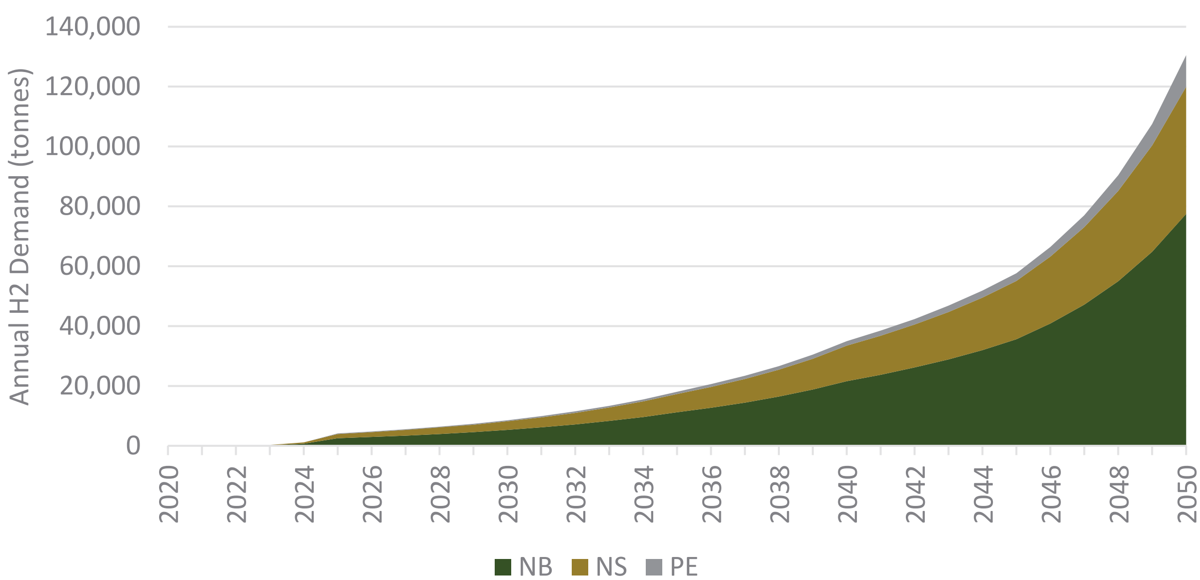

Figure 54 – Natural gas transformative scenario - H2 demand

The GHG emissions abated annually during the transformative natural gas scenario was determined using the same method described in the incremental case and is displayed in Figure 55.

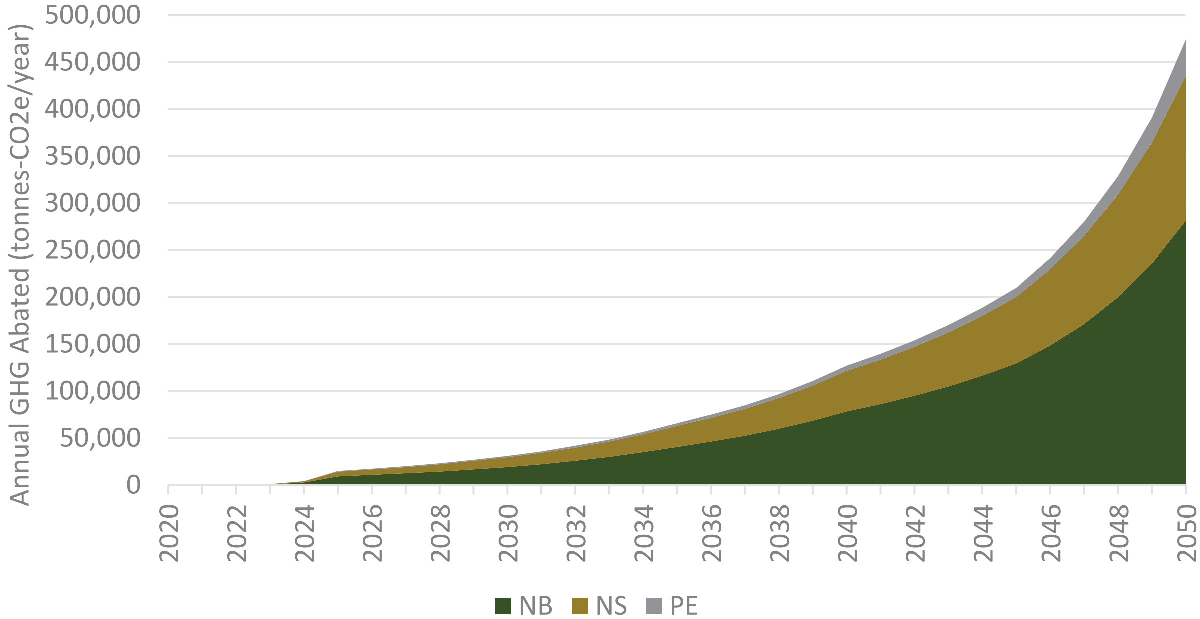

Figure 55 – Natural gas transformative scenario - GHG emission abatement

The resulting hydrogen demand and GHG abatement for the transformative natural gas scenario for each province in the Maritimes are displayed in Table 6.

Table 6 – Natural gas transformative scenario - H2 demand and GHG abatement by year and region

Year	Region	H2 Demand (tonnes H2/year)	GHG Abatement (tonnes-CO2e/year)
2025	NB	2,570	9,343
	NS	1,397	5,077
	PE	165	601
	All	**4,132**	**15,021**
2030	NB	5,296	19,252
	NS	2,885	10,487
	PE	357	1,299
	All	**8,538**	**31,038**
2040	NB	21,587	78,471
	NS	11,833	43,016
	PE	1,560	5,670
	All	**34,979**	**127,157**
2050	NB	77,478	281,648
	NS	42,471	154,391
	PE	10,563	38,400
	All	**130,512**	**474,438**

Recommendations

Key Natural Gas Sector Recommendations

- Ensure codes and standards allow for hydrogen blending in the natural gas grid
- Support pilot project to incorporate low-carbon hydrogen into the natural gas grid
- Consider studying the technical feasibility of converting a portion of existing pipeline network or a new area of expansion to 100% hydrogen and converting all end-use appliances

Heating Buildings

Baseline

Residential Space Heating

Energy sources and space heating systems vary vastly between each province in the Maritimes due to available resources and infrastructure in each province. Figure 56 shows the residential heating systems stock used in New Brunswick, Nova Scotia, and PEI in 2017.

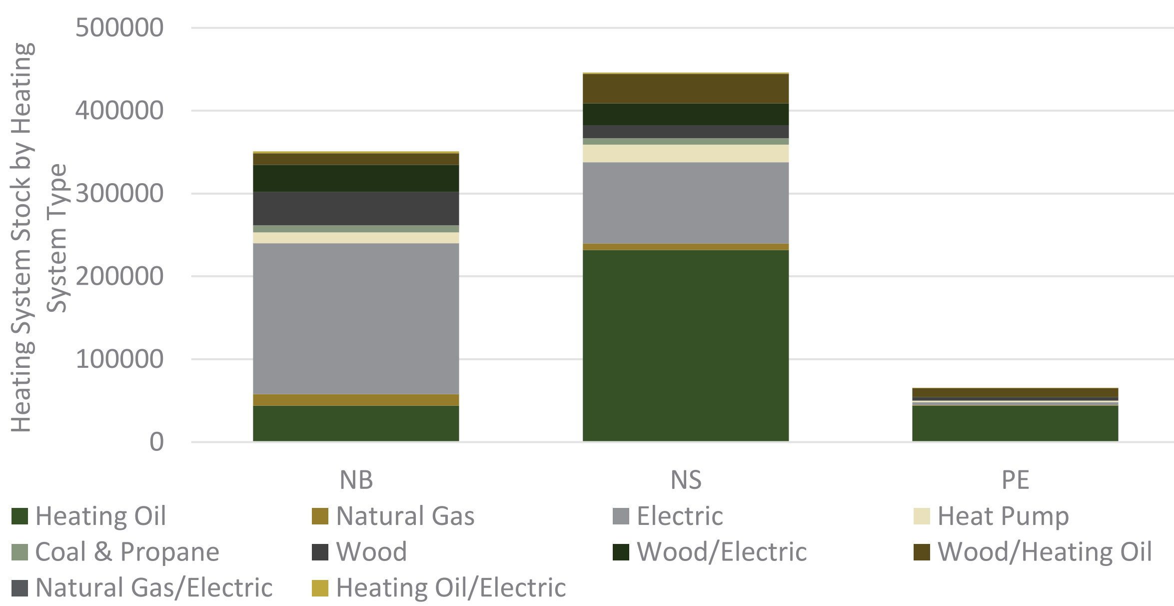

Figure 56 – Residential heating system stock (2017)[70]

The majority of residences in New Brunswick (52%) are heated with electricity through electric floorboard heating and small electric heaters. Natural gas distribution infrastructure in the Maritimes is fairly limited resulting in fairly low penetration of natural gas heating systems, which are installed in only 4% of homes in the region. Heating oil is still used by itself or as part of a dual system with electricity and wood. Most

[70] NRCan (2017). Comprehensive Energy Use Database. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

older houses were designed to use oil furnaces and are sometimes used in those homes as a backup to other systems. Heating oil accounted for 12.6% of residential heating systems and 4.0% of dual heating systems involving heating oil. A total of 11% of homes are heated by solely by wood and are also used in dual systems with heating oil and electricity (4% and 9% of homes respectively). Wood accounted for the most energy demand among space heating demand with a value of 29.5 PJ despite its presence in space heating homes due to the lower efficiency of wood burning heating.[70] A small percent of houses (3.7%) use heat pumps to warm their houses.

Nova Scotia has the largest population and the most heating systems in the Maritime provinces. Heating oil is the main contributor to space heating, accounting for 52% of all residences in the province. Despite the relatively high-emitting electric grid in Nova Scotia, 22% of homes in the province in 2017 solely used electric heating. Natural gas and coal/propane were used in 1.8% and 1.7% of residences in 2017 respectively. Wood heating systems were used in 17.4% of residences, including dual fuel systems, and accounted for 37.1% of residential space heating demand in 2017. The use of heat pumps for space heating has increased over time, being used in 4.7% of residences by 2017.

PEI does not have a natural gas network; thus, only a small percent (1.7%) of residences use gas for heating which is brought to the island by private companies. Heating oil is the most common heating system and was used in 67% of residences in 2017. Wood and dual fuel heating systems were the second most common heating system, accounting for 22.9% of homes. The remaining heating systems included electric (4.9%), heat pump (2.4%), coal and propane (1.0%).

Commercial Space Heating

Figure 57 shows the commercial space heating energy demand for Atlantic Canada from 1997 to 2017.

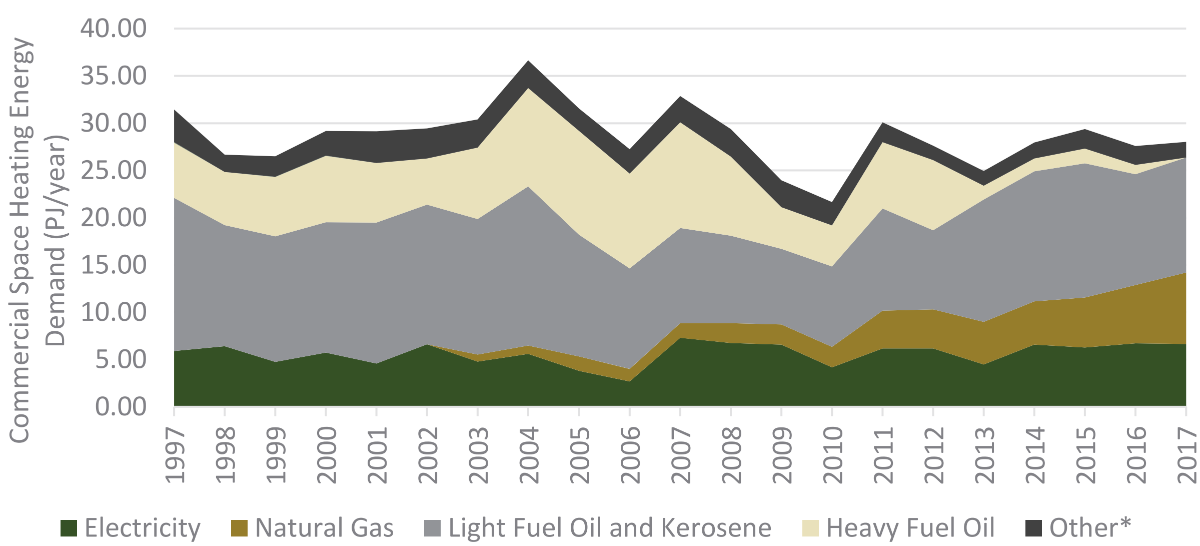

Figure 57 – Commercial space heating demand for Atlantic Canada (1997-2017)[71]
*Other includes Coal and Propane

[71] NRCan. (2017). Table 24: Space Heating Secondary Energy Use and GHG Emissions by Energy Source. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=com&juris=atl&rn=24&page=0

Light fuel oil and kerosene accounted for 43% of energy demand and was the primary source of energy used to heat commercial buildings in Atlantic Canada. Following the start of operations at SOEP and construction of the MN&P in late 1999, natural gas began to be used for commercial space heating and has since increased to 27% of Atlantic Canada's demand in 2017. Currently minimal natural gas is used for commercial heating in PEI due to their lack of resources and natural gas distribution system. Electricity made up 24% of energy demand and remained relatively consistent from 2014-2017. The remaining energy demand was from coal and propane which consumed 6% of energy demand.

GHG Emissions

Figure 58 display the GHG emissions excluding electricity associated with space heating in the Maritimes and Atlantic Canada, respectively.

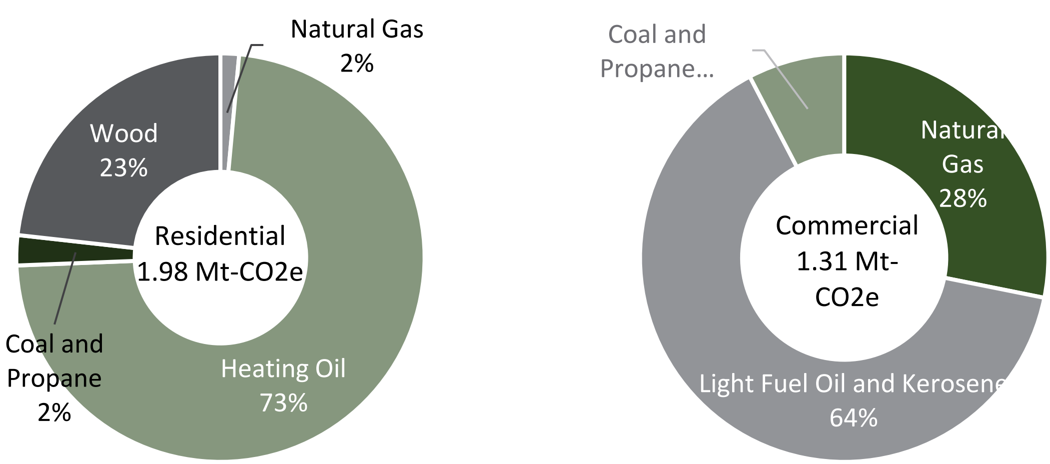

Figure 58 – Residential and commercial GHG emissions by fuel excluding electricity[72]

Opportunities and Challenges for Hydrogen

The primary opportunity for hydrogen as a heating fuel is as a part of the natural gas pipeline or acting as energy storage for the generation of clean electricity. Hydrogen is an attractive heating fuel in the Maritimes because of the relatively high cost and carbon intensity of the alternatives. Natural gas prices are high in the Maritimes because the fuel is imported, primarily from the US. Transforming the energy system to replace existing imported heating fuels with low-carbon hydrogen generated through electrolysis has a better value proposition in the Maritimes than other regions where the cost of natural gas is lower.

Hydrogen could be used as a heating fuel blended with natural gas distributed through the pipe network or in a 100% hydrogen grid. It could be burned directly in a conventional heating system or consumed in a fuel cell to generate combined heat and power at a residential scale. In either case, the main difficulty is the limited infrastructure which currently prohibits widescale adoption. However, the limited gas

[72] NRCan (2017). Comprehensive Energy Use Database. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

distribution in the Maritimes offers an opportunity to implement 100% hydrogen distribution in communities currently not served by gas, as the complications associated with converting natural gas pipelines and blending will not be present. As the gas network grows, it could decarbonize through the increasing penetration of hydrogen into the network.

Hydrogen can also work in tandem with electric heat pumps, which are becoming increasingly popular in the Maritimes. When used as an energy storage medium, hydrogen helps to reduce the carbon intensity of the grid, which will reduce emissions from heat pumps as well as electric resistive heaters. Hydrogen could also be used in a dual fuel scenario with heat pumps during particularly cold weather when heat pump efficiency drops. Further study should be conducted to determine the financial feasibility of a hydrogen dual fuel system.

Adoption Scenarios

The major opportunities for hydrogen as a heating fuel are accounted for in the adoption scenarios outlined in the Natural Gas and Electricity end use demand sections. They have not been replicated here so as to not be double counted.

Recommendations

Key Heating Buildings Sector Recommendations

- Support demonstration projects to trial hydrogen used for heating applications including blending in the natural gas grid and isolated systems
- Study the feasibility for dual fuel hydrogen: heat pump heating systems

Transportation

Baseline

Transportation is the largest contributor to GHG emissions in the Maritimes, accounting for 32% of all emissions.[73] The sector can be divided into several categories as described in Table 7.

Table 7 – Transportation subsector categories

Category	Description
Light-Duty Vehicle	Light-duty vehicles registered in the Maritimes and licensed to operate on roads. Includes personal transport in vehicles and light-duty trucks
Heavy-Duty Vehicles	Heavy-duty vehicles registered in the Maritimes and licensed to operate on the roads. Include medium-duty trucks, heavy-duty trucks, and buses
Off-Road Vehicles	Vehicles not licensed to operate on roads. Including vehicles associated with oil & gas, heavy industry, agriculture, manufacturing, construction, and forest resource services
Domestic Railway and Marine	Locomotives operating in the Maritimes and marine vessels registered and fueled in the Maritimes
Pipeline Transport	Transportation and distribution of crude oil, natural gas, and other products
Domestic Aviation	Canadian registered aircrafts flying domestically within Canada and originating in the Maritimes including commercial, private, and agricultural flights

The emissions per transportation category for each province in the Maritimes in 2018 is displayed in Figure 59.

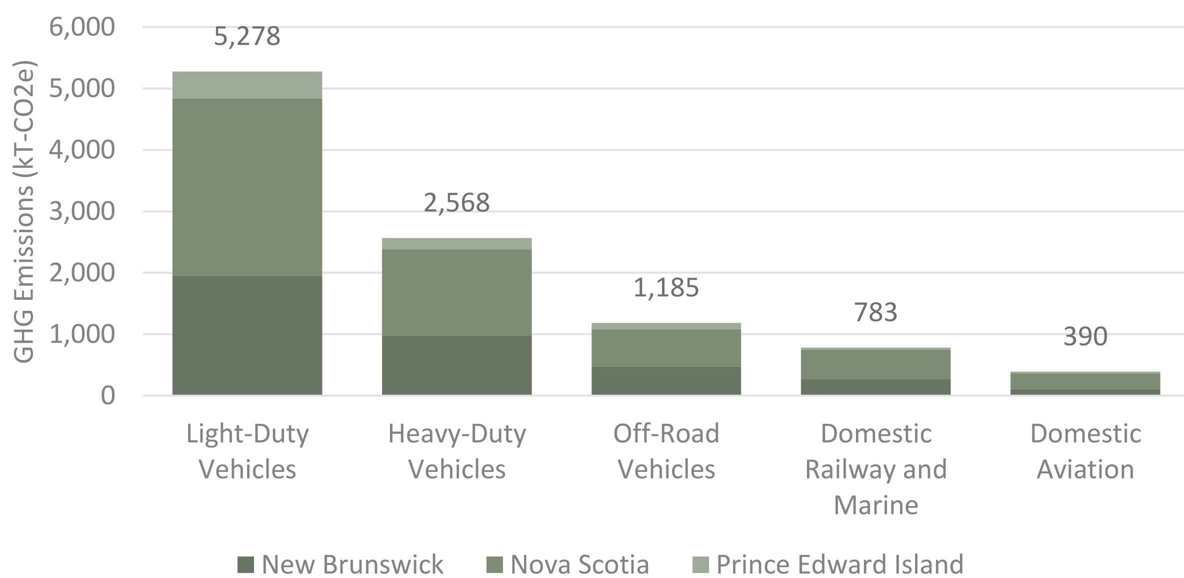

Figure 59 – Transportation GHG emissions in the Maritimes by subsector (2018)[73]

[73] Environment and Climate Change Canada (2020). Canada's Official Greenhouse Gas Inventory. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b

As shown in Figure 59, on-road transportation of light-duty (LD) vehicles and heavy-duty (HD) vehicles has an immense emission impact in the Maritimes. Figure 60 represents the percent of total transportation GHG emissions attributable to each transport category in 2018 for the Maritimes, indicating that on-road transportation is responsible for 76% of transportation emissions and 24% of all emissions released in 2018.

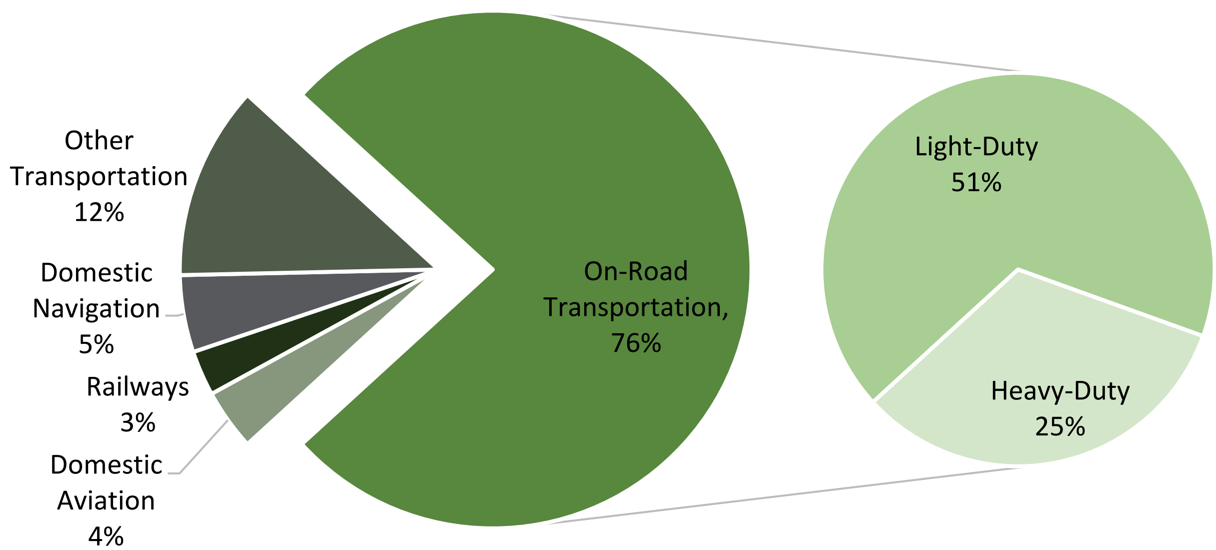

Figure 60 – Percent of transportation GHG emissions in the Maritimes by subsector(2018)[73]

Light and Heavy-Duty Vehicle Baseline

Within the transportation sector, this study focuses on light-duty (LD) vehicles and heavy-duty (HD) vehicles as they represent the majority of GHG emissions in the Maritimes. Marine applications are described in a separate section of this report.

Light-Duty Vehicles

LD vehicles accounted for 39% of total emissions in the Maritimes, making it the largest contributing subsector to GHG emissions. LD vehicles include passenger vehicles and light trucks such as minivans, sport-utility vehicles, and vans under 4,500 kg in weight. The number of LD vehicle registrations, i.e., number of vehicles on the road, and new LD vehicle registrations per year, i.e., new vehicle sales, by province in the Maritimes are displayed in Figure 61 and Figure 62, respectively.

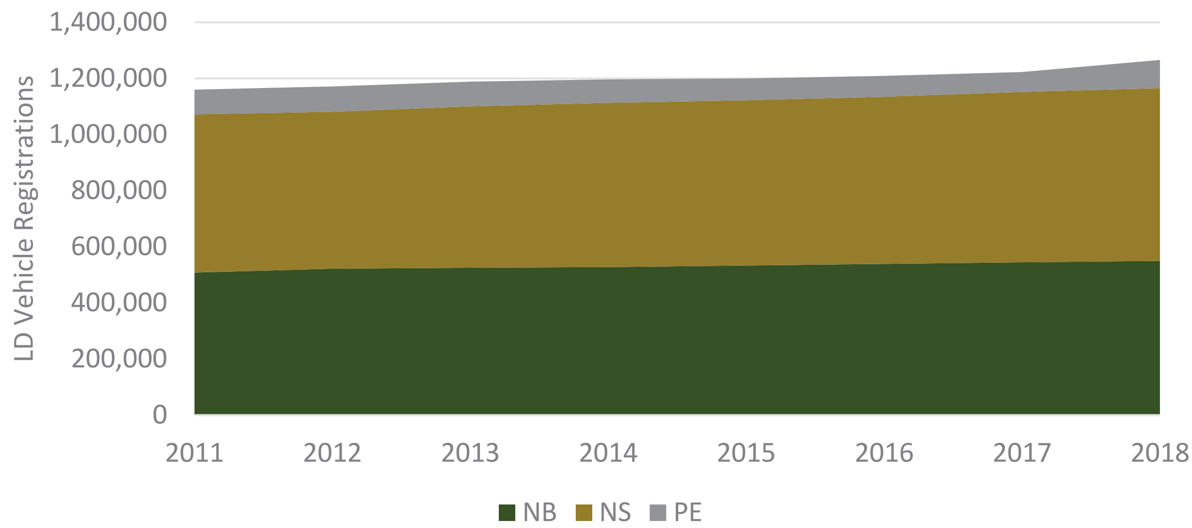

Figure 61 – LD vehicle registrations per year and province in the Maritimes.[74]

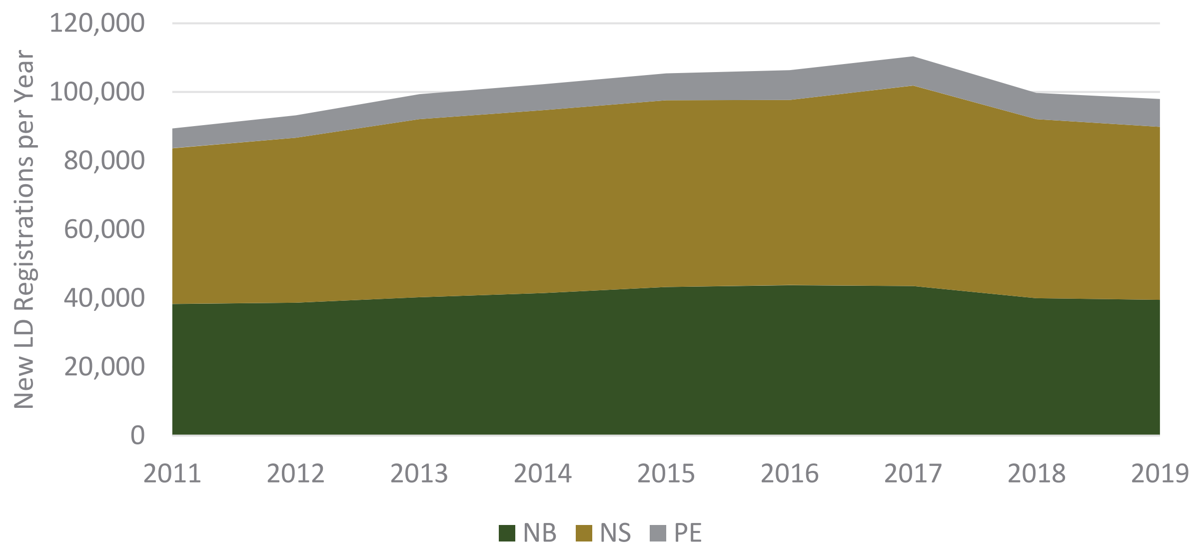

Figure 62 – New LD vehicle registrations per year and province in the Maritimes.[75]

The total registrations for LD vehicles in the Maritimes have slowly been increasing from 2011 to 2018. However, new LD vehicle registrations have started decreasing as of 2017.

Nova Scotia and New Brunswick account for most LD vehicles in the Maritimes due to their larger populations in comparison to PEI. Nova Scotia's 615,897 total LD vehicle registrations in 2018 made it the largest market in the Maritimes closely followed by New Brunswick, which had 549,514 registrations. In PEI there were 100,276 LD vehicle registrants in 2018.

[74] Statistics Canada (2020). Vehicle registrations, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701

[75] Statistics Canada (2020). New motor vehicle sales, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201

Medium- & Heavy-Duty Vehicles – Excluding Buses for Public Transit

Medium- and heavy-duty vehicles (MHD) vehicles include trucks weighing over 4,500 kg. Medium-duty vehicles (MDV) vehicles and HDVs in this study are classified as being trucks greater than 4,500 kg but less than 15,00 kg and greater than 15,000 kg, respectively. Buses used for public transport are not included in the MHD vehicle analysis of transportation and are looked at separately for this study. The number of new and total MHD vehicle registrations per year in each province are displayed in Figure 63 and Figure 64, respectively.

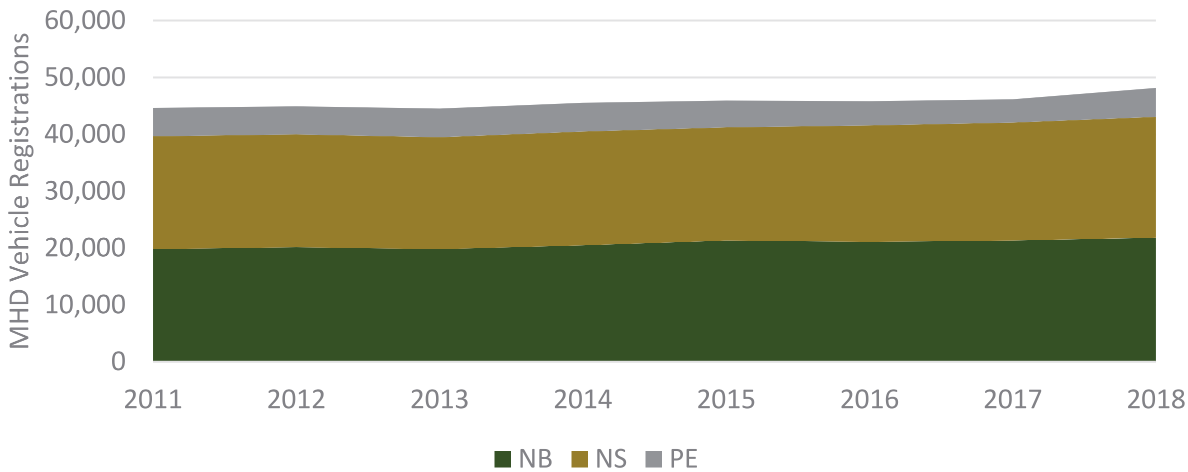

Figure 63 – MHD vehicle registrations per year and province in the Maritimes.[74]

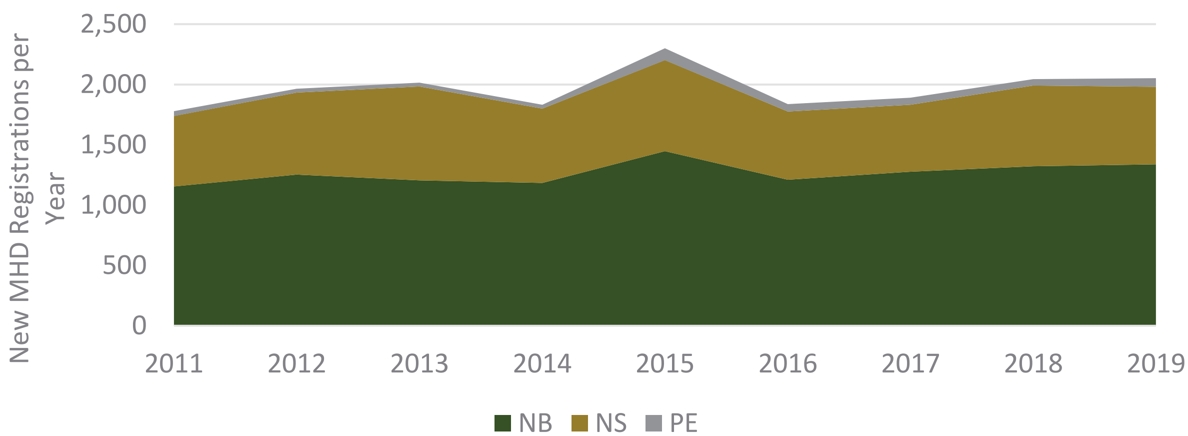

Figure 64 – New MHD vehicle registrations per year and province in the Maritimes.[75]

Total MHD vehicle registrations in the Maritimes between 2011 and 2018 have shown a slight increase over time. New Brunswick had the most MHD vehicle registrations with 21,778 due to their large industrial sector requiring transportation for the movement of goods. Nova Scotia had the next largest MHD vehicle sector including 21,269 vehicles. In comparison, PEI had a significantly smaller number of MHD vehicles at a value of 5,099 ion 2018.

Public Transport

The Maritimes has a relatively small number of public transit buses in comparison to bigger cities and provinces throughout Canada. Based on data collected by the Canadian Urban Transit Association (CUTA) and stakeholder conversations, the following number of buses displayed in Table 8 in each province was assumed.

Table 8 – Maritimes public transit bus inventory[76]

Bus Type	New Brunswick (2018)	Nova Scotia (2020)	PEI (2018)
Transit Bus (>=27'6", 2 doors)	144	364	30
Articulated Bus (>=55')	2	47	0

Transportation Hydrogen Baseline

The Maritimes sole project involving hydrogen in transportation was a hydrogen shuttle bus project conducted in PEI in 2007. The project involved the construction of a hydrogen fueling station to support two hydrogen powered shuttle buses. The project lasted four years before being discontinued in 2011.

In December 2019, Halifax Regional Council ordered a staff report investigate the potential uses of hydrogen fuel cell technology focusing on applications such as the Regional Municipality's transit buses and ferries.

Opportunities and Challenges for Hydrogen

Hydrogen technologies can significantly reduce GHG emissions from the transportation sector. Hydrogen use as a fuel for fuel cell electric vehicles (FCEV) is quickly becoming an attractive zero-emission alternative for transportation methods, especially heavy-duty vehicles and transit buses that require energy dense fuels. Hydrogen fuel does not emit any emissions at its point-of-use, enabling it to vastly reduce pollution and GHG emissions associated with the transportation sector. Figure 65 shows how hydrogen can be used as a fuel in the transportation sector.

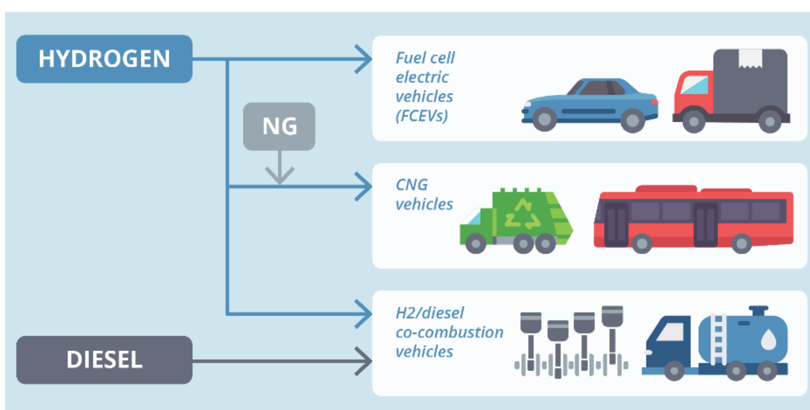

Figure 65 – Hydrogen transportation options

To fully decarbonize the transportation sector, battery electric vehicles (BEV) and FCEVs will need to be deployed in parallel. BEVs and FCEVs offer complementary benefits depending on the transportation application. Batteries provide a better "well-to-wheel" efficiency for transportation than fuel cells. However, they have a lower

[76] Adapted from: Canadian Urban Transit Association (2020). NRCan 2014 – 2018 Vehicle Data.xlsx. Received on June 29, 2020

energy storage density than compressed or liquid hydrogen tanks. As such, batteries are well-suited for light-duty vehicle applications and heavy-duty vehicles operating on short routes.

One of the main advantages of FCEVs when compared to BEVs is their ability to be fueled at a quick rate, similar to the way conventional cars are fueled today. Whereas BEVs require a relatively longer duration to charge, even using state of art fast-charging systems.

Light-Duty Vehicles

The future LD vehicle market will consist both BEVs and FCEVs. However, FCEVs have greater range capabilities and faster fueling times, which offer performance similar to conventional vehicles. However, due to the FCEV market being approximately 10 years behind BEVs, the BEV market already has widespread commercialization, and is expected to dominate the LD vehicle market in the short-term.

FCEVs will likely be more attractive for drivers in multi-unit residential buildings (condominiums, apartments, townhouses with shared garages, etc.) where cost and strata law barriers can make retrofits of home charging stations expensive and difficult.[77] The average percent of households who live in apartments in the Maritimes is 19%, which could potentially make FCEVs important in the future.[78]

One of the greatest challenges facing the FCEV market in Canada today is the lack of production of LD FCEVs from manufacturers. The lack of LD FCEVs available on the market make it hard to attract funding to develop hydrogen fueling infrastructure. The scarcity of FCEVs also makes FCEVs more expensive than conventional internal combustion engines (ICE) and BEVs.

BC and Quebec have introduced ZEV mandates that will require to have specific percentages of their sales attributed to ZEVs. The addition of a similar ZEV mandate in the Maritimes could help stimulate adoption of FCEVs. A 2020 study commissioned by the Ecology Action Centre investigating ZEV adoption in Nova Scotia conducted by Dunsky concluded that a, “ZEV mandate combined with provincial incentives will be critical in getting Nova Scotia to 30% [ZEV sales] by 2030”.[79]

Medium- and Heavy-Duty Vehicles

In most instances, MHD trucks are better suited to hydrogen technology than batteries. There will be opportunities for battery powered trucks for applications with a limited daily range, like parcel distribution, but the heavy loads and long distances required of most applications are better suited to hydrogen fuel cells. A fuel cell truck would end up roughly the same weight as a conventional diesel truck, whereas a battery for a 40-ton truck would add about 3 tonnes of payload.[80]

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[77] Zen Clean Energy Solutions (2019). British Columbia Hydrogen Study. Retrieved from https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf

[78] Canada Energy Regulator (2017). Comprehensive Energy Use Database. Retrieved from https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[79] Dunsky Energy Consulting for Ecology Action Centre. (2020). Electric Vehicle Adoption in Nova Scotia 2020-2030. Retrieved from https://ecologyaction.ca/sites/default/files/images-documents/EAC%20EV%20Adoption%20Study%20-%20Final%20%28Embargo%29%20%281%29.pdf

[80] Fuel Cells and Hydrogen Joint Undertaking (2019). Hydrogen Roadmap Europe. Retrieved from https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

MHD FCEVs have been demonstrated around the world but have yet to be widely deployed. Government encouragement in near-term zero-emission vehicle (ZEV) adoption in applications that have central fueling locations, could help stimulate hydrogen development in these segments.

Public Transit

Public transit agencies around the world are shifting towards low and ZEVs. Low-emission technology includes compressed natural gas (CNG) and renewable natural gas (RNG) as a fuel. Zero-emission transit includes battery electric buses (BEBs) and fuel cell electric buses (FCEBs). Like LD vehicles, BEBs are the most cost effective on short routes. Whereas FCEBs offer better value on longer routes that have higher power requirements.

Hydrogen powered buses are more easily scaled than battery electric buses. Fuel cell buses can be refueled at comparable speeds and in a similar way as conventional diesel buses, whereas battery electric buses require much longer charging times. Battery electric buses are either charged over several hours, typically overnight in a depot, or through opportunity charging on-route. Opportunity charging typically requires a bus to be recharged over a shorter period several times a day. It allows for less onboard battery power, and therefore less weight, but increases the operational complexity and constraints. Feedback from transit authorities has been that while longer bus charging times are not an issue at demonstration scale, challenges of cost and complexity increase significantly at fleetwide scale.

The state of California has instated an innovative clean technology (ICT) mandate, which requires a percentage of new bus purchases by transit agencies to be zero-emission. The percent of ZEB purchases required per year for a large transit agency is as follows:

- ZEBs make up 25% of new bus sales for the first 3 years after introduction
- ZEBs make up 50% of new bus sales for the 4-6 years after introduction
- All new ZEBs seven years after the adoption of the mandate

Developing a similar framework in the Maritimes could help stimulate ZEB and FCEB adoption.

The commercial maturity of ZEB's is high relative to other applications, with New Flyer Industries, the North American leader for transit buses, offering both BEB and FCEB options manufactured at their Winnipeg, Manitoba facility.

Adoption Scenarios

Light-Duty Vehicles

Hydrogen demand was estimated for incremental and transformative adoption scenarios of LD FCEVs based on the assumption that the Maritimes will instate a ZEV mandate like the ones developed in BC and Quebec. The number of ZEVs purchased per year were based on targets set in the BC Provincial ZEV mandate. The number of FCEVs sold per year was estimated using an assumption for the percent of electric vehicles (EV) that will be FCEVs, resulting in values comparable to other studies.[81,82] Table 9 shows the structure of the ZEV mandate and target percent of FCEVs out of total sales used for the adoption scenarios.

Table 9 – BC ZEV mandate targets by year and %FCEV of EV sale assumptions

Year	%FCEV of EV Sales[82]		British Columbia ZEV Mandate[83]	
	Incremental	Transformative	ZEV Mandate Year	ZEV Sales % Related to Compliance Ratios
2025	8%	10%	6	10%
2030	6%	8%	11	30%
2040	13%	19%	16	100%
2050	15%	26%	21	100%

Projections for light-duty FCEV adoption in BC based on current hydrogen deployments and the details of the BC ZEV mandate displayed in Table 9 were used as a baseline for the adoption scenarios in the Maritimes.

In the incremental scenario, FCEVs are assumed to begin to be deployed in 2030 whereas in the transformative scenario they begin in 2023. In both cases it was assumed that deployment is supported by strong government policies such as a ZEV mandate. The transformative scenario is designed to achieve the Federal Government's target that all new vehicle sales will be zero-emission in 2040.

Fuel Consumption & Property Assumptions

The parameters shown in Table 10 were constants and assumptions used to determine annual hydrogen demand and GHG abatement for the incremental and transformative cases.

Table 10 – Key vehicle modeling assumptions

Parameter	Value	Unit	Source
Energy Efficiency Ratio (EER) H2:Gasoline	2.5	-	http://www.bclaws.ca/civix/document/id/complete/statreg/394_2008
Daily Hydrogen Consumption per Vehicle	0.40	kg-H2/day /vehicle	Calculated using ratio of LD trucks to vehicles and values from: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=ca&rn=32&page=0

[81] Cambridge Econometrics. (2018). Fuelling Europe's Future: How the Transition from Oil Strengthens the Economy. Retrieved from https://europeanclimate.org/content/uploads/2019/12/20-02-2018-fuelling-europes-future-how-the-transition-from-oil-strengthens-the-economy-summary-report.pdf

[82] McKinsey & Company (2019). Road to a US Hydrogen Economy. Retrieved from https://cafcp.org/sites/default/files/Road-map-to-a-US-hydrogen-economy_Executive-Summary.pdf

[83] Government of British Columbia (2019). B.C. Zero-Emission Vehicles Act: Regulations Intentions Paper. Retrieved from https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/zev_act_regulations_intentions_paper-1-final_-_updated_29oct2019.pdf

Parameter	Value	Unit	Source
Hydrogen Higher Heating Value	142	MJ/kg	https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels
Hydrogen Carbon Intensity	36.4	gCO2e/MJ	https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf
Gasoline Carbon Intensity	96.4	g-CO2e/MJ	https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/regulatory-approach.html

Forecasted New LD Vehicles per Year

Based on historical data of the number of new LD vehicle registrations per year in New Brunswick, Nova Scotia, and PEI from 2011 – 2019, forecasted registrations of LD vehicles from 2020-2050 were estimated as shown in Figure 66.

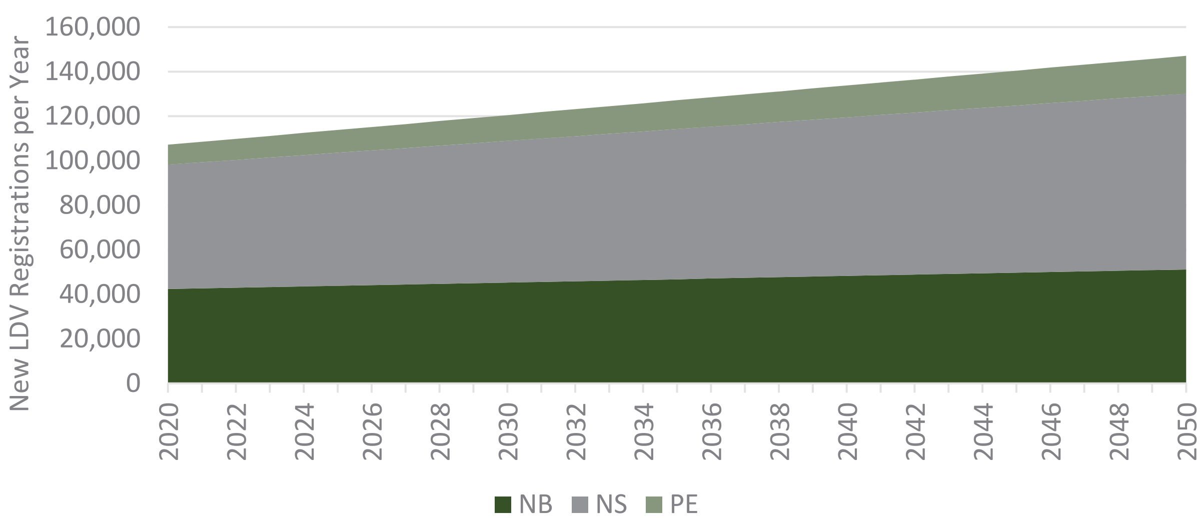

Figure 66 – Forecasted annual new LD vehicle registrations per year and province in the Maritimes[84]

Incremental Scenario

In the incremental scenario, adoption of FCEVs was assumed to begin in 2030. The uptake of FCEVs takes the same trajectory as the targets outlined in the BC ZEV mandate. This type of adoption is expected if the provincial governments adopt strong policies to support ZEV deployments such as a mandate. Since adoption begins much later, the forecasted numbers of FCEVs on-the-road and annual hydrogen demand are significantly lower when compared to the transformative case.

[84] Statistics Canada (2020). New motor vehicle sales, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201

The hydrogen demand per FCEV on the road was determined using the average annual LD vehicle distance travelled, fuel economy, and energy equivalence ratio (EER). Using the difference in CI for the low CI hydrogen and gasoline, the GHG abated per year was calculated. The resulting projected number of FCEVs on-the-road and coinciding annual hydrogen demand and GHG abated in the incremental scenario is displayed in Figure 67 and Figure 68, respectively.

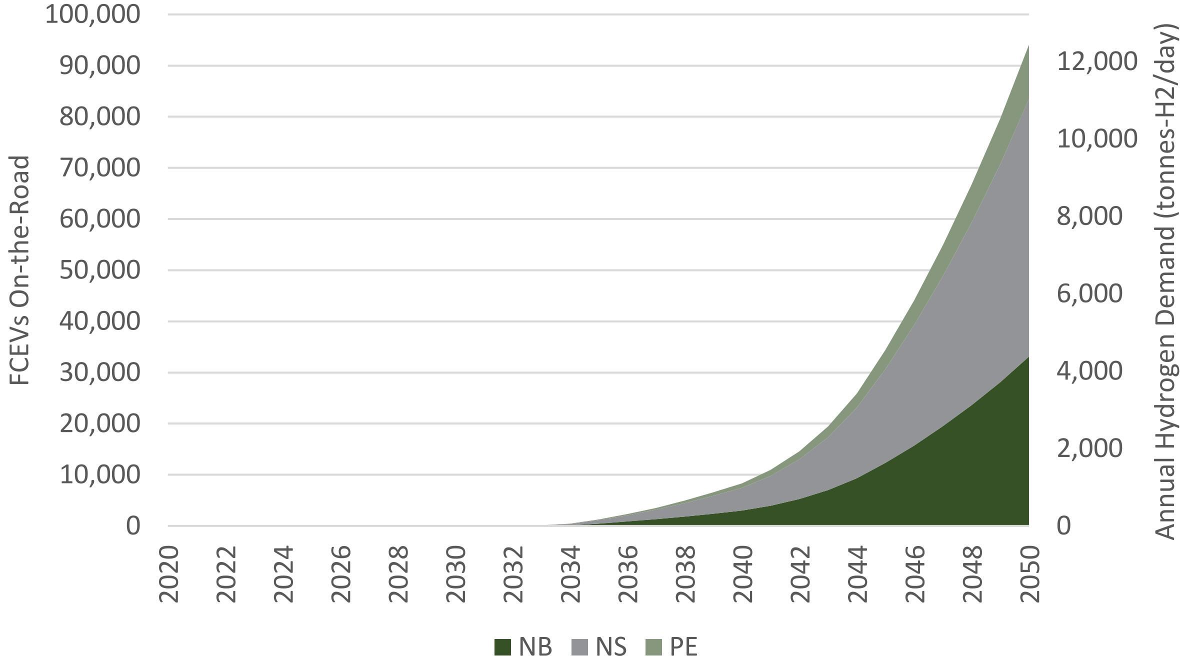

Figure 67 – FCEVs on the road and hydrogen demand - incremental

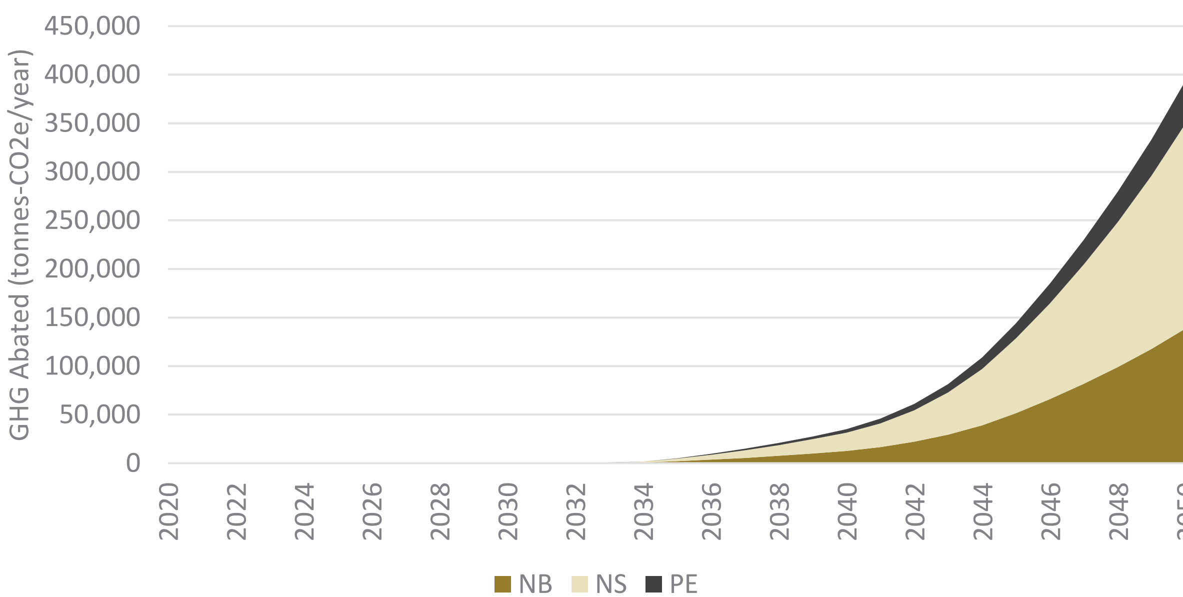

Figure 68 – GHG abated from LD FCEVs - incremental

Table 11 summarizes the number of FCEVs on-the-road, hydrogen demand, and GHG abatement for each region within the Maritimes associated with the incremental adoption scenario.

Table 11 – LD FCEV H2 demand and GHG abatement summary - incremental

Year	Region	FCEVs On-the-Road	H2 Demand (tonnes H2/year)	GHG Abatement (tonnes-CO2e/year)
2030	NB	1	0	4
	NS	2	0	8
	PE	0	0	0
	All	**3**	**0**	**13**
2040	NB	3,039	446	12,731
	NS	4,441	652	18,605
	PE	872	128	3,653
	All	**8,352**	**1,227**	**34,990**
2050	NB	33,104	4,863	138,685
	NS	50,389	7,402	211,098
	PE	10,586	1,555	44,349
	All	**94,079**	**13,819**	**394,132**

Transformative Scenario

The transformative scenario is built off the assumption that the Maritimes will enact a ZEV mandate that is on pace with the mandate in place in BC and Quebec. Since the mandate is already in place in these regions, the Maritimes mandate would have to begin with a larger initial sales targets in order to catch up. This scenario achieves the Federal Government's target of 100% new vehicle ZEV sales in 2040. The first FCEV is assumed to be deployed in 2023. Using the same method described that was described in the incremental scenario, the number of FCEVs on-the-road and hydrogen demand and GHG abated was calculated and is displayed in Figure 69 and Figure 70, respectively.

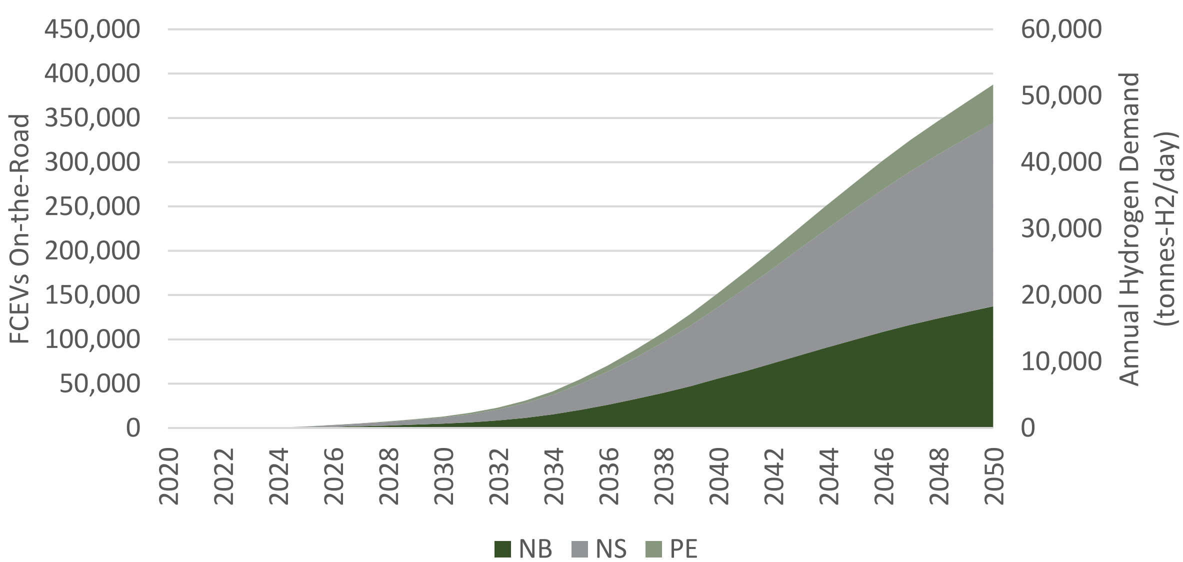

Figure 69 – FCEVs on the road and hydrogen demand – transformative

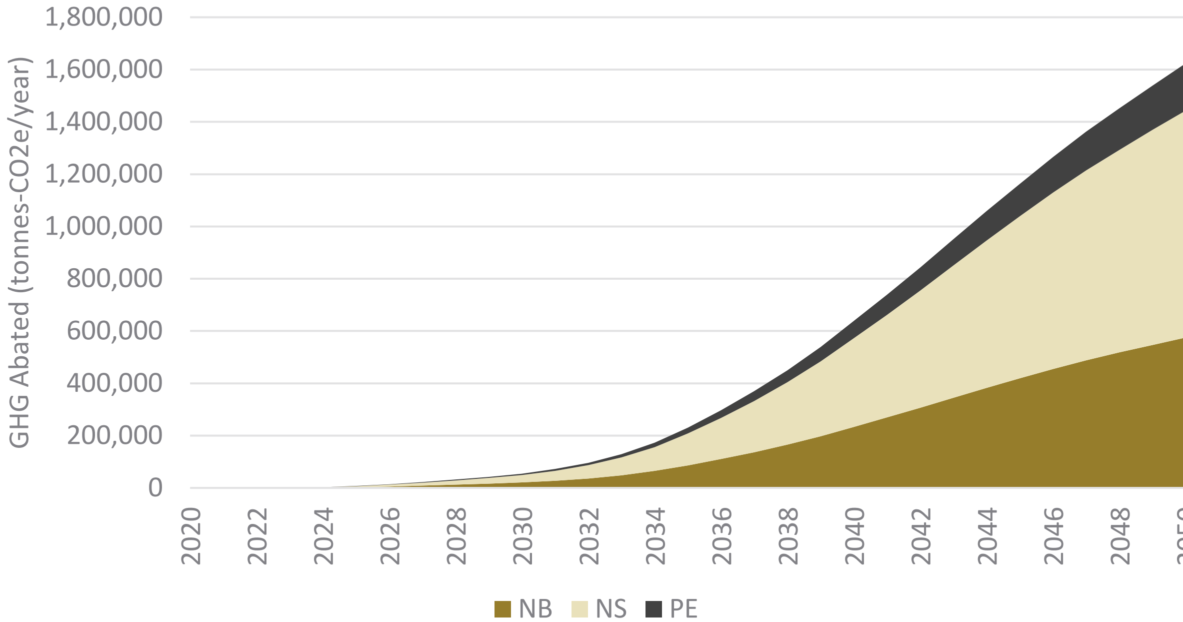

Figure 70 – GHG abated from LD FCEVs - transformative

The resulting number of FCEVs on-the-road, hydrogen demand, and GHG abated for the transformative scenario for each province in the Maritimes are displayed in Table 12.

Table 12 – LD vehicle FCEV H2 demand and GHG abatement summary - transformative

Year	Region	FCEVs On-the-Road	H2 Demand (tonnes H2/year)	GHG Abatement (tonnes-CO2e/year)
2025	NB	699	103	2,928
	NS	947	139	3,967
	PE	161	24	674
	All	**1,807**	**265**	**7,570**
2030	NB	4,951	727	20,742
	NS	6,849	1,006	28,693
	PE	1,217	179	5,098
	All	**13,017**	**1,912**	**54,533**
2040	NB	55,698	8,181	233,339
	NS	80,847	11,876	338,698
	PE	15,723	2,310	65,869
	All	**152,268**	**22,366**	**637,907**
2050	NB	137,318	20,170	575,276
	NS	207,286	30,448	868,397
	PE	42,998	6,316	180,134
	All	**387,602**	**56,934**	**1,623,807**

Medium-Heavy-duty Vehicles

Adoption of FCEVs in the MHD vehicle sector was calculated assuming annual FCEV sales as a percent of MHD vehicle sales are consistent with the values used in the US Hydrogen Roadmap written by McKinsey & Company in 2019.[85] The resulting percent of FCEV sales for the incremental and transformative adoption scenarios is displayed in Table 13. In practice, this would include targeted trucking operations as early adopters.

Table 13 – % FCEV sales of total annual MHD vehicle sales model assumptions

Year	%FCEV Sales of MHD Vehicle Sales	
	Incremental	Transformative
2030	4%	12%
2050	12%	25%

The following constants and fuel properties displayed in Table 14 were used to determine hydrogen demand and GHG abatement in the MHD vehicle analysis.

Table 14 – Key MHD vehicle modeling assumptions

Parameter	Value	Unit	Source
Energy Efficiency Ratio (EER) H2:Diesel	1.9	-	http://www.bclaws.ca/civix/document/id/complete/statreg/394_2008
Heavy-Duty Diesel Vehicle Carbon Intensity	3.55	kg-CO2e /L-diesel	https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/methodology/2018-pso-methodology.pdf
Hydrogen Carbon Intensity	36.4	g-CO2e/MJ	https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf
Hydrogen Higher Heating Value	142	MJ/kg	https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels
Diesel Energy Density	36.7	MJ/L	https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA#1-4
Daily Hydrogen Consumption per HD Vehicle	23.3	kg-H2/day /vehicle	Calculated from HD Vehicle Data Collected by ARB, Nikola
Daily Hydrogen Consumption per MD Vehicle	17.7	kg-H2/day /vehicle	Calculated from MD Vehicle Duty Data Collected by ARB, Nikola

[85] McKinsey & Company (2019). Road to a US Hydrogen Economy. Retrieved from https://cafcp.org/sites/default/files/Road-map-to-a-US-hydrogen-economy_Executive-Summary.pdf

Forecasted New MHD Vehicle Registrations

The number of new MHD vehicle registrations per year in the Maritimes from 2020-2050 was forecasted based on historical data of new MHD vehicle registrations as shown in Figure 71.

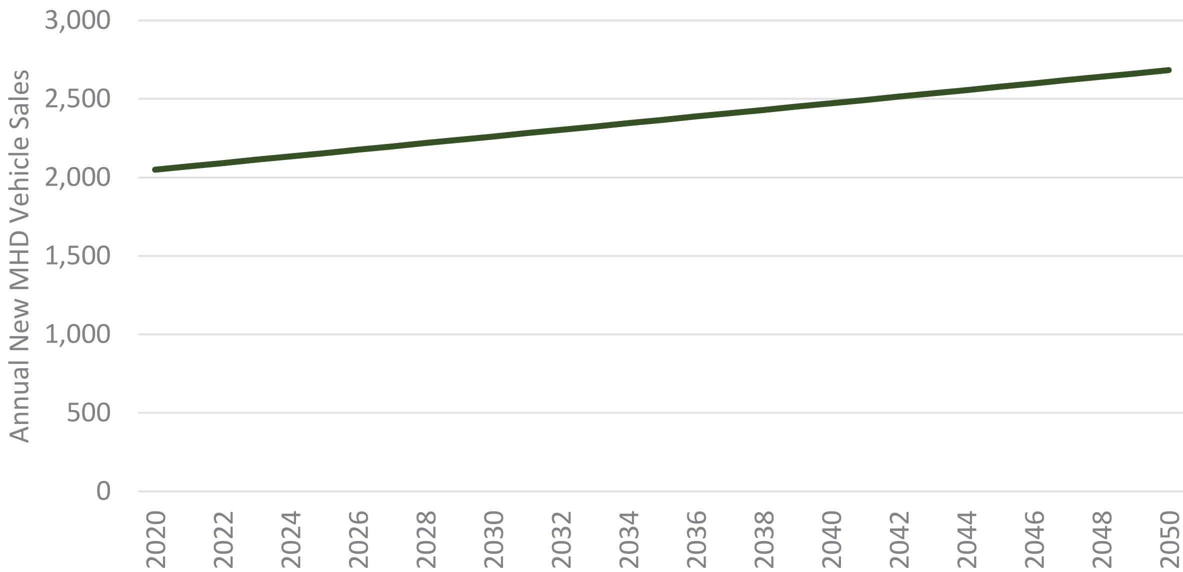

Figure 71 – Forecasted Annual New MHD Vehicle Sales per Year and Province in the Maritimes[86]

Model Results

The incremental scenario for FCEV adoption in the MHD vehicle sector assumes that adoption begins in 2025 and accounts for 2% of all MHD vehicle purchases that year ramping up to 12% in 2050. The scenario depends on provincial governments implementing strong policies to drive adoption for ZEV MHD vehicles. The transformative scenario assumes fuel cell vehicles make up a greater share of ZEV sales than in the light duty scenario. By 2050, the transformative scenario assumes that 25% of all MHDV purchases will be FCEVs. As such, the hydrogen demand required for the transformative scenario is significantly greater than the incremental adoption scenario.

Hydrogen demand per vehicle was determined using the average values for annual distance travelled by a medium-duty and heavy-duty distance travelled per year, fuel economy, and EER. The GHG abated for each scenario was calculated from the difference of CI between low CI hydrogen and diesel fuel. The projected number of MHD FCEVs on-the-road and coinciding hydrogen demand and GHG abated for both scenarios is displayed in Figure 72 and Figure 73, respectively.

[86] Statistics Canada (2020). Vehicle registrations, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701

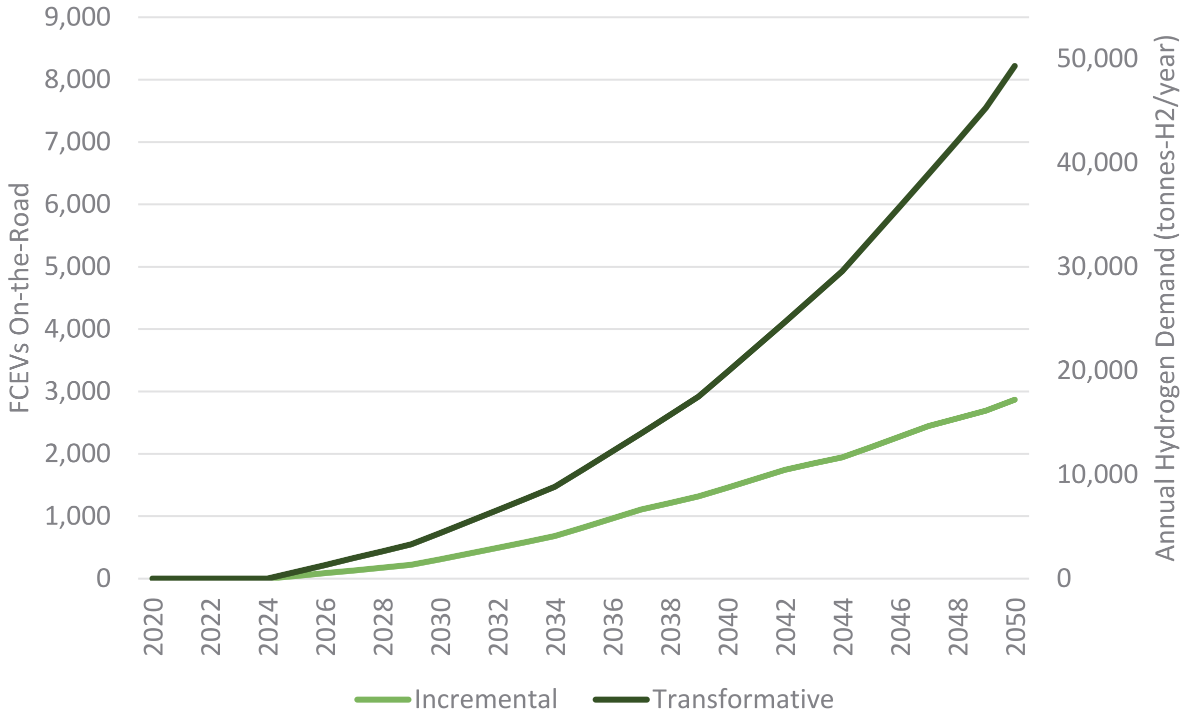

Figure 72 – Projected MHD FCEVs on-the-road and hydrogen demand

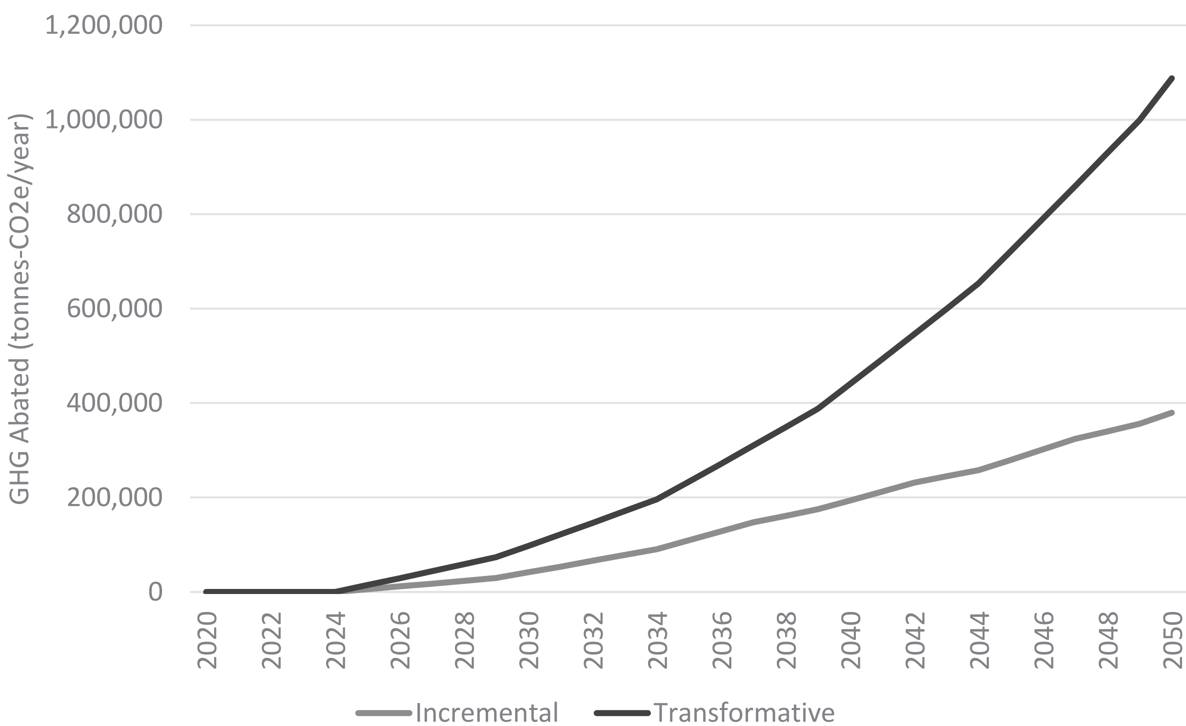

Figure 73 – Projected GHG abated from MHD FCEVs

Table 15 summarizes the number of MHD FCEVs on-the-road, hydrogen demand, and GHG abatement for the incremental and transformative adoption scenarios in the Maritimes.

Table 15 – MHD FCEV demand and GHG abatement summary

Year	FCEVs On-the-Road		H2 Demand (tonnes H2/year)		GHG Abatement (tonnes-CO2e/year)	
	Incremental	Transformative	Incremental	Transformative	Incremental	Transformative
2025	43	108	265	662	5,776	14,440
2030	310	730	1,900	4,472	41,435	97,548
2040	1,458	3,311	8,883	20,176	193,738	440,068
2050	2,868	8,218	17,403	49,870	379,570	1,087,718

Transit Buses

ZEB Mandate

Hydrogen adoption scenarios for buses in the Maritimes assumed that a region-wide ZEB mandate like one developed in California would be introduced. The California ZEB mandate for large transit agencies must adhere to the following guidelines

- ZEBs make up 25% of new bus sales for the first 3 years after introduction
- ZEBs make up 50% of new bus sales for the 4-6 years after introduction
- All new ZEBs seven years after the adoption of the mandate

The incremental scenario assumes that a Maritimes ZEB mandate would be introduced in 2028 leading to all new bus purchases being ZEBs by 2034. The transformative scenario assumes that a Maritimes ZEB Mandate would be introduced in 2026 and all new bus sales would be ZEBs by 2034.

Based on stakeholder interviews and the technology limits for different ZEB technologies, the percent of ZEB sales projected to be FCEBs was estimated and displayed in Table 16.

Table 16 – % ZEB sales projected to be FCEBs

Year	%FCEV of Transit Bus Sales		%FCEB of Articulated Bus Sales	
	Incremental	Transformative	Incremental	Transformative
2030	13%	25%	25%	50%
2050	13%	25%	25%	50%

Fuel Consumption & Property Assumptions

The parameters displayed in Table 17 were constants and assumptions used to determine annual hydrogen demand and GHG abatement for the incremental and transformative cases.

Table 17 – Key bus modeling assumptions

Parameter	Value	Unit	Source
Energy Efficiency Ratio (EER) H2:Diesel	1.9	-	http://www.bclaws.ca/civix/document/id/lc/statreg/394_2008
Annual Hydrogen Consumption per Bus	5,385	kg-H2/bus	Calculated from CARB ACT TCO Assumptions Parameters
Diesel Gas Energy Density	36.7	MJ/L	https://apps.cer-rec.gc.ca/Conversion/conversion-tables.aspx?GoCTemplateCulture=en-CA#1-4
Hydrogen Higher Heating Value	142	MJ/kg	https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels
Hydrogen Carbon Intensity	36.4	gCO2e/MJ	https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf
Heavy-Duty Diesel Carbon Intensity	3.55	kg-CO2e/L-diesel	https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard/regulatory-approach.html

Forecasted Bus Purchases per Year

Based on historical bus purchase data provided by CUTA[76], the average growth rate for the number new bus purchases in the Maritimes over past 5 years (2014-2018) was 0.9%. Using the average growth rate, bus purchases per year were projected out to 2050 as shown in Figure 74.

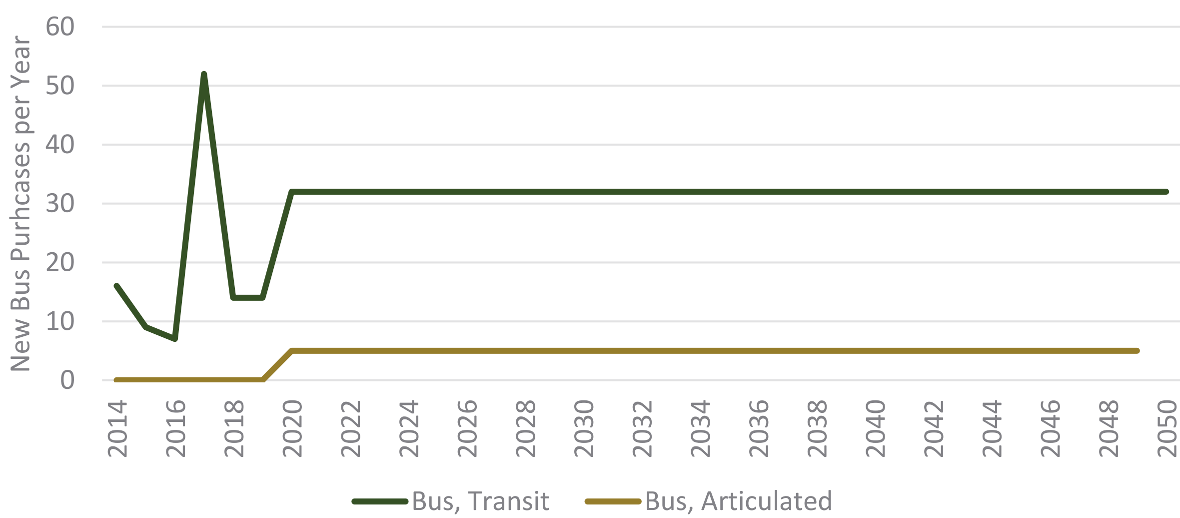

Figure 74 – Projected new sales of buses in the Maritimes per year[87]

[87] Adapted from: Canadian Urban Transit Association (2020). NRCan 2014 – 2018 Vehicle Data.xlsx. Received on June 29, 0

Model Results

In the incremental scenario, adoption of FCEBs was assumed to begin in 2028. The percent of new bus purchases required to be ZEBs followed the same guidelines outlined by the California ZEB mandate. This adoption scenario is expected if the provincial governments in the Maritimes implement policies that promote FCEB adoption such as a ZEB mandate. The first FCEB deployment is projected to be in 2023, giving the Maritimes five-years of experience with FCEB technology prior to the introduction of the ZEB mandate. As the adoption begins slightly later in the incremental scenario, the number of forecasted FCEVs on-the-road and annual hydrogen demand are considerably lower than the transformative scenario.

The transformative scenario assumes that adoption of FCEBs will start in 2026 based on the Maritimes implementing a ZEB mandate with the same ZEB purchase targets per mandate year as the California ZEB mandate. Although introducing the ZEB mandate in 2026 is an aggressive case for FCEB adoption in the Maritimes, the first deployment of FCEBs is projected to be in 2023, allowing the Maritimes to gain some experience with FCEB technology and hydrogen fueling infrastructure.

The hydrogen demand per FCEB on-the-road was determined using the average annual distance buses travel, fuel economy, and EER. The amount of GHG abated for each scenario was calculated based on the difference of CI for the low CI hydrogen and diesel gas. The projected number of FCEBs on-the-road and corresponding hydrogen demand and GHG abated for the incremental and transformative scenarios is displayed in Figure 75 and Figure 76, respectively.

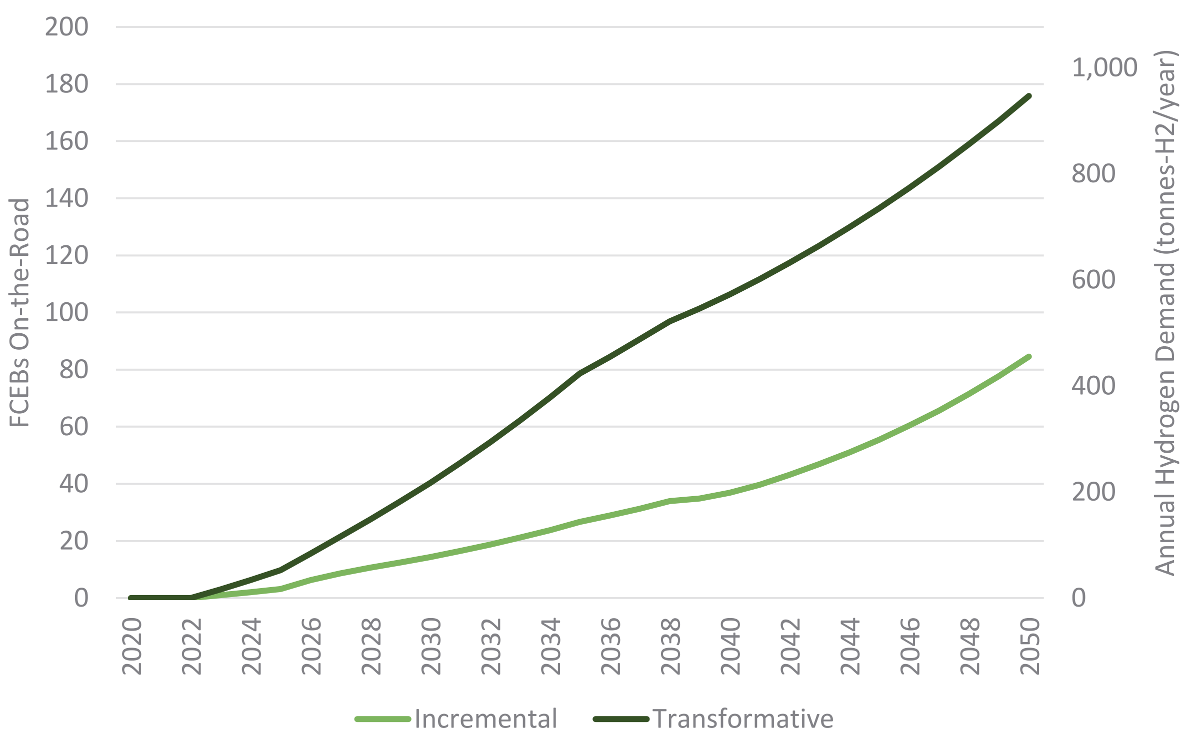

Figure 75 – Projected FCEBs on-the-road and hydrogen demand

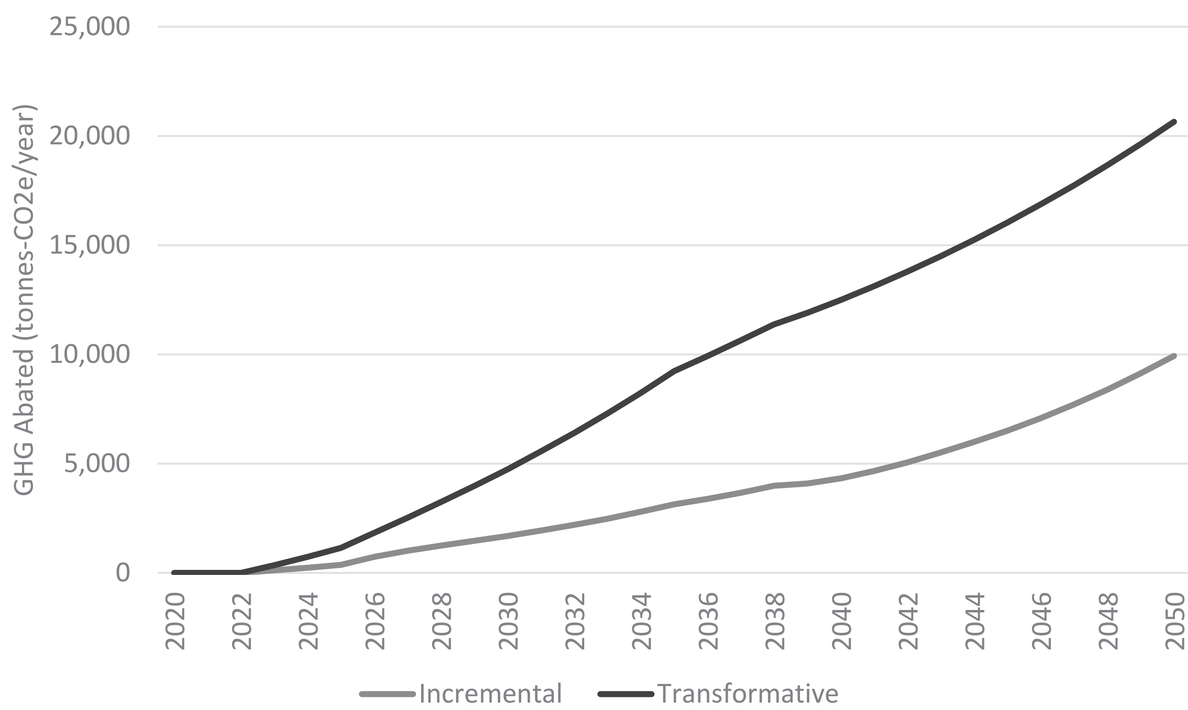

Figure 76 – Projected GHG abated from FCEBs

Table 18 summarizes the number of FCEVs on-the-road, hydrogen demand, and GHG abatement for each region within the Maritimes for the incremental and transformative adoption scenarios.

Table 18 – Buses FCEB H2 demand and GHG abatement summary

Year	FCEBs On-the-Road		H2 Demand (tonnes H2/year)		GHG Abatement (tonnes-CO2e/year)	
	Incremental	Transformative	Incremental	Transformative	Incremental	Transformative
2025	3	10	17	53	366	1,147
2030	14	40	77	217	1,685	4,741
2040	37	106	198	572	4,328	12,487
2050	85	176	455	947	9,930	20,651

On-Road Transportation Summary

The aggregate hydrogen demand and GHG abated for on-road transportation in the incremental and transformative scenario is displayed in Figure 77 and Figure 78, respectively.

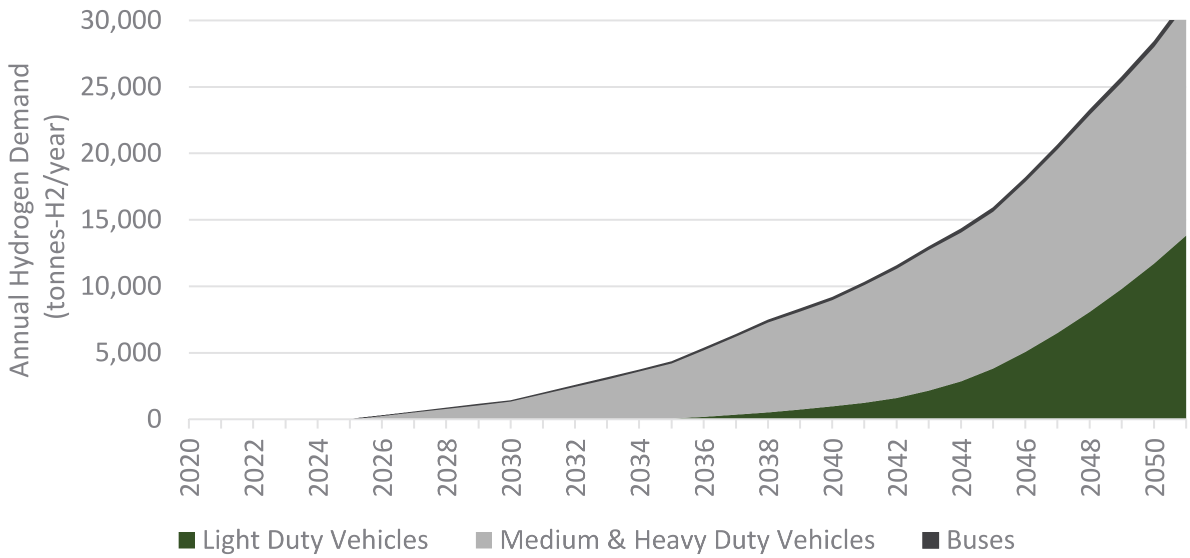

Figure 77 – On-road transportation H2 demand scenarios

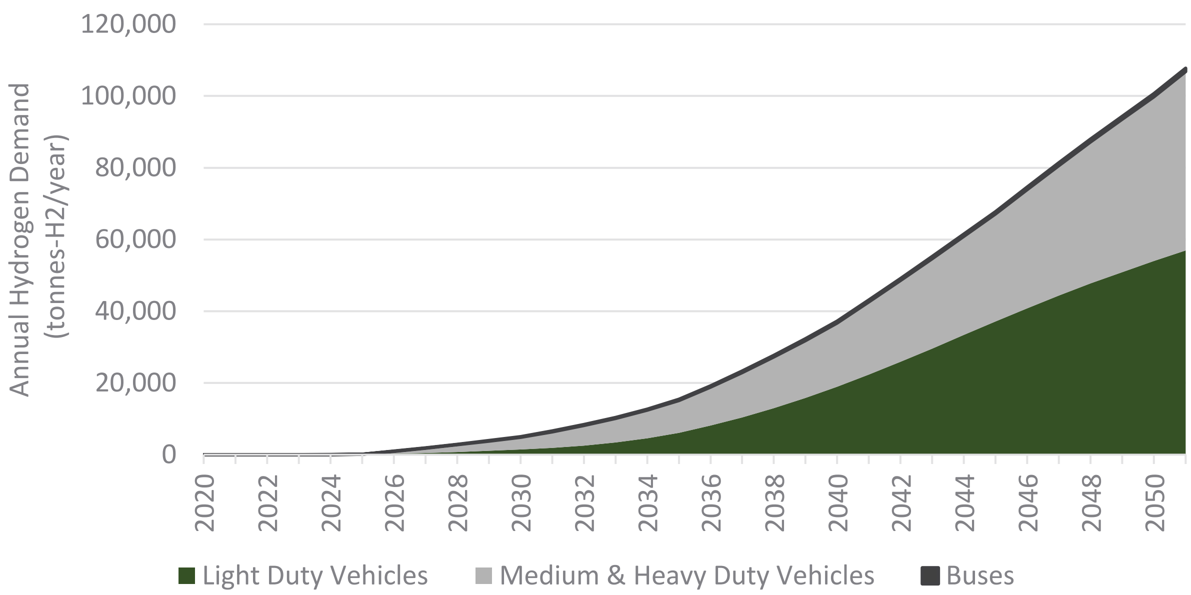

Figure 78 – GHG abated scenarios from hydrogen adoption in on-road transportation

The annual hydrogen demand accounted for by adoption in the LD vehicle, MHD vehicle, and FCEBs sectors for the incremental and transformative scenarios in 2030 and 2050 is provided in Figure 79.

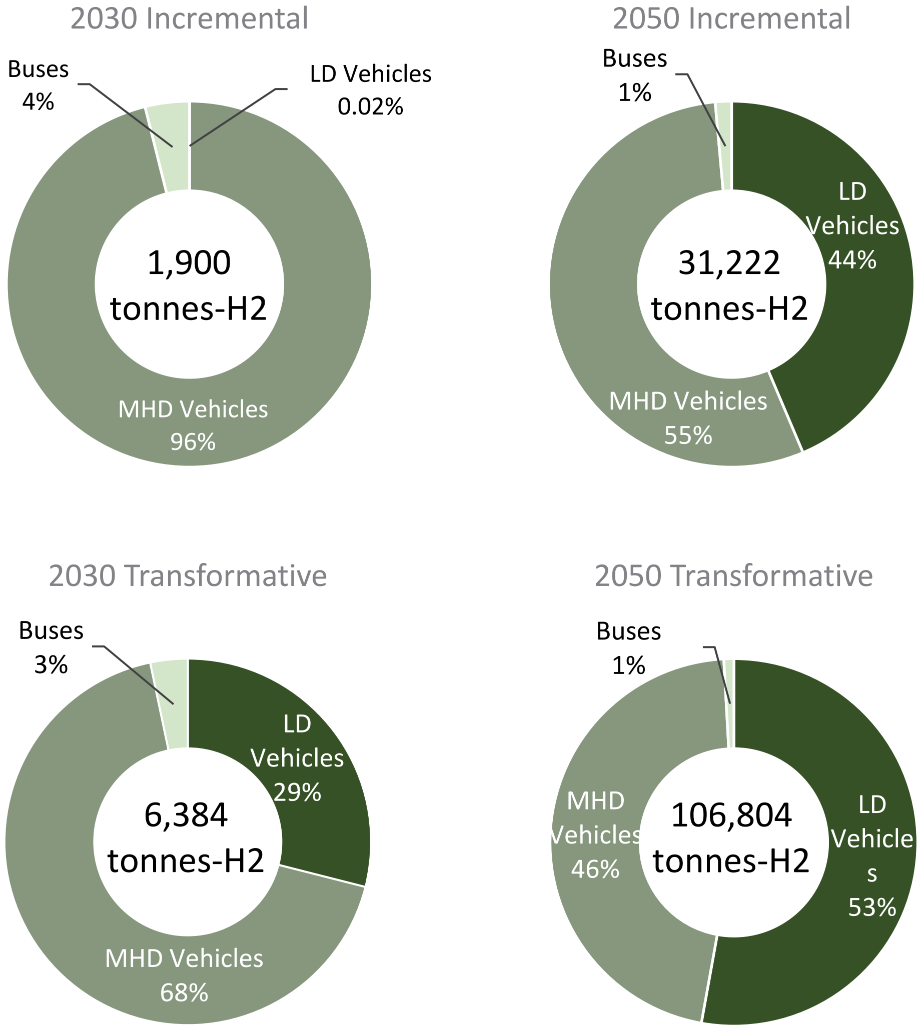

Figure 79 – Incremental and transformative transportation hydrogen demand by on-road vehicle type

Recommendations

Key Transportation Sector Recommendations

- Support near-term projects to deploy fuel cell vehicles and supporting infrastructure
- Enact strong policies to drive adoption of ZEVs, for example ZEV mandates, which will motivate manufacturers to make vehicles available in the region
- Provide financial and non-financial incentives for the adoption of ZEVs

Marine

Baseline

The marine sector is of particular interest in the Maritimes due to its cultural and economic importance in the region. While it only represents 4.2% of the overall transportation sector's GHG emissions, it presents a particular challenge in terms of decarbonization compared to land-based transport. In this report, three marine subsectors were considered as shown in Table 19.

Table 19 – Marine transportation subcategories

Subcategory	# of Vessels Considered	Notes
Fishery	8,946	Primarily <45 ft vessels operating the inshore fishery (lobster, herring, crab, mixed fisheries, etc.)
Ferries	16	Various sizes of vessels operating partially or completely in the maritime region. Numerous government-operated small cable ferries were not considered as candidates for H2 conversion. Only 50% of ferry emissions are considered for routes to locations outside of the Maritimes.
Tugs	18	Primarily Azimuth Stern Drive (ASD) Tugs, with some conventional tugs & Offshore Support Vessels (OSV). Workboats mostly serve the major ports of Saint John and Halifax but may leave the region for some jobs.

Combined, these three subsectors represent approximately 85% of the GHG emissions in the Maritimes within the domestic navigation sector as defined in Figure 60. A further breakdown of the marine sector is shown here in Figure 80.

To date, hydrogen is not being trialed in the Maritimes marine sector. The only major ongoing GHG emissions reduction project is a hybrid diesel-electric tour boat currently being piloted in Halifax[88].

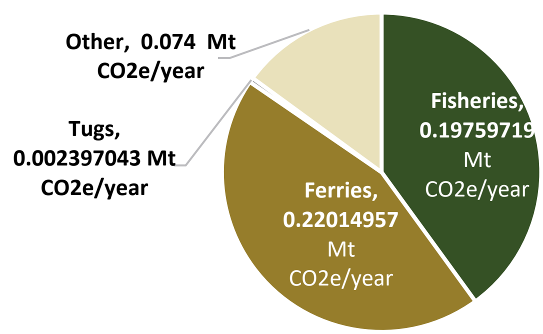

Figure 80 – Marine GHG emissions by subsector

The current GHG emissions by category are shown in Figure 80. The individual emissions profiles per subsector were modeled based on publicly available data on vessel power, speed, and capacity. Several assumptions were made in order to estimate the aggregate fuel consumption per sector.

[88] Glas Ocean Electric. (2020). Navigating to Resilient Energy. Retrieved from http://glasoceanelectric.com/index.html

Fishing

In 2018, the fishing fleet comprised 8,946 vessels[89]. The operation of each vessel is dependent on the predominant species fished, but on average they operate 83 days per year. A large majority (92%) of these vessels are small fishing vessels under 45 ft, serving the inshore fishery.

Small fishing vessels are currently fueled with diesel. There is currently only one diesel - battery hybrid fishing vessel in the region, *Alutasi*, currently being operated in Halifax Harbour for day fishing trips[90]. The Prince Edward Island Fishermen's Association (PEIFA) is looking to pilot nine low-emissions fishing vessels, incorporating three different designs across three different fishing areas. The alternative powertrain designs have not yet been selected, so hydrogen fuel cells could be part of this pilot project.

The International Maritime Organization (IMO) sets emissions standards for marine fuel. The IMO's 2020 MARPOL Annex VI[91], adopted by Transport Canada, reduces allowable NO_X and SO_X emissions for engines over 130kW. This effectively regulates the engine category that may be used on fishing vessels (Tier I, Tier II, or Tier III).

Ferries

In the Maritimes, there are six major ferry routes operated by Northumberland Ferries, Marine Atlantic, and Coopérative de Transport Maritime et Aérien (CTMA). Of these routes, four are only partially in the Maritimes. As such, only half the carbon footprint for these routes was considered in this analysis. There are also several small ferry operators in New Brunswick, as well as two ferry routes operated as part of the Halifax Transit system.

Table 20 shows the routes currently operated in the Maritimes and the vessels serving each route

Table 20 – Maritimes ferry routes and vessels

Operator	Route	Vessel Name	Year Built	Rated Power [kW]	Maritimes Emissions Fraction
Northumberland Ferries/ Bay Ferries	Wood Islands PEI - Pictou NS	MV Holiday Island	1971	5,406	1
		MV Confederation	1993	4,474	1
	Saint John NB - Digby NS	MV Fundy Rose	1999	12,350	1
	Yarmouth NS - Bar Harbor ME	HST-2 "The CAT"	2004	36,000	0.5

[89] Fisheries and Oceans Management (2020). Vessel Information. Retrieved from https://www.dfo-mpo.gc.ca/stats/commercial/licences-permis/vess-embarc/ve18-eng.htm
[90] Plugboats. (2020). Canada Approves 1st Lithium-ion Commercial Passenger Boat. Retrieved from https://plugboats.com/canada-approves-1st-lithium-ion-commercial-passenger-boat/
[91] International Maritime Organization. Prevention of Air Pollution from Ships. Retrieved from http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx

Operator	Route	Vessel Name	Year Built	Rated Power [kW]	Maritimes Emissions Fraction
Coastal Transport	Grand Manan NB - Blacks Harbour NB	Grand Manan Adventure	2011	4,474	1
		Grand Manan V	1990	1,767	1
CTMA	Souris PEI - Cap-aux-Meules QC	MS Madeleine	1981	13,240	0.5
Marine Atlantic	North Sydney NS - Argentia NL	MV Atlantic Vision	2001	26,550	0.5
	North Sydney NS - Port aux Basques NL	MV Blue Puttees	2006	22,600	0.5
		MV Highlanders	2006	21,600	0.5
		MV Leif Ericson	1991	10,560	0.5
Halifax Transit	Halifax NS - Dartmouth NS (Alderney & Woodside)	Rita Joe	2018	574	1
		Vincent Coleman	2018	574	1
		Viola Desmond	2016	574	1
		Craig Blake	2015	574	1
		Christopher Stannix	2014	574	1

There are currently no projects underway to reduce ferry emissions by incorporating low-emission power trains. One technique under consideration is to reduce the speed of each ferry, which will reduce drag and lower fuel consumption and GHG emissions. Special consideration for this measure must be given to ensure there are not scheduling disruptions since the crossing times will increase.

Tugs

The majority of tugs operated in the Maritimes belong to either Atlantic Towing or Svitzer. Between these two operators, there are 3 conventional tugs, 13 azimuth stern drive (ASD) tugs, and 2 offshore support vessels (OSVs). There are additional tugs registered in the Maritimes that are currently working in other parts of the country or internationally that were not considered. Even among the 18 tugs considered in this study, vessels may occasionally leave the region as part of regular work but for the purposes of this study, this fraction is considered to be negligible.

Overall, the tug subsector is a very small part of the overall carbon footprint of the marine sector due to the infrequent use and large fraction of the vessels' time being spent in low power operations. There are currently no projects in the Maritimes to reduce tug emissions, but consideration is being given to initiatives including speed reduction and incorporation of hybrid electric drives. Internationally, hybrid and even zero-emissions tugs are receiving increased attention.

Opportunities and Challenges for Hydrogen

The cultural importance of marine vessels to the region provides a good opportunity to support a lighthouse project that showcases the benefits of hydrogen in a unique regional framework. Such a project could demonstrate how integrating hydrogen technology into marine vessels would promote its advantages, while concurrently aligning with IMO's 2050 targets to reduce GHG emissions from shipping by 50%[92] in accordance with the Paris Agreement temperature goals. This effort also aims to see a reduction by 70% of CO2 emissions with comparison to 2008 numbers.

In comparison to battery electric technology, hydrogen is well suited to vessels that travel longer routes, have high energy requirements, and shorter opportunities for refueling. Ideally, they would also operate out of fewer locations to simplify fueling operations. This is particularly important in the near- to mid-term since fueling infrastructure will be highly limited.

NORWAY FERRY PROJECT[93]

The Norwegian Public Roads Administration has commissioned the build of a Ropax ferry to operate on the Hjelmeland - Skipavik - Nesvik route in Rogaland County. The *Nesvik* will be incorporate liquid hydrogen storage and a battery. It will be primarily powered by a 400-kW fuel cell system. The ferry is expected to begin operation in 2021.

Figure 81 – RoPax ferry, Nesvik

One of the big challenges for the marine sector is the long lifetime of the vessels – sometimes greater than 50 years. In order to make significant progress toward Canada's (and IMO's) 2050 emissions reduction goals, pilot projects should be considered as soon as possible in order to demonstrate feasibility as the rest of the sector looks to replace the fleet between 2030 and 2050.

A compounding factor to the long lifecycles of marine vessels may be lack of buy-in from the industry. Many of the stakeholders are risk/change-averse, and the transition to hydrogen/zero-emissions powertrains will require championing, especially for the early pilot projects. Lack of awareness is also problematic, as many stakeholders are unaware of the viability of hydrogen as an alternative to BEVs.

Another challenge facing early stage pilot projects is the need for an affordable and reliable fuel supply. Long-term contracts will be required to alleviate the concern of price fluctuations and disruption of supply. Ideally, pilot projects in the marine sector could be located near other end-use projects to build up scale for hydrogen production facilities.

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92 International Maritime Organization. Greenhouse Gas Emissions. Retrieved from http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/GHG-Emissions.aspx

93 Moore, R., (2019). Norway's first hydrogen – powered car ferries take shape. Retrieved from https://www.rivieramm.com/news-content-hub/news-content-hub/norwayrsquos-first-hydrogen-powered-car-ferries-take-shape-55559

Fishing

Fishing is a varied industry with needs that differ depending on the fishing zone and type of fishery. Many fishing zones are within 10 km from shore and could be converted to zero-emissions using batteries or fuel cell technologies.

One of the primary levers for change will be demonstrating operational improvements from the use of hydrogen (or other zero-emissions technologies). If fishing operations can spend less time and money on boat maintenance, it enables more time at sea, which will help enable the transition. This is also true in reverse – until the technology is seen as a reliable option, there will be minimal uptake. Consider the financial impact of propulsion equipment failure related to novel technology. A protracted repair process would significantly decrease revenues, given the short fishing seasons. Propulsion failures at sea are also a significant safety hazard.

Early pilots that showcase the benefits of zero-emission technology will be key, and word of mouth amongst the fishing communities will drive the speed at which new technologies are adopted.

Another potential avenue for operational improvements may be to increase vessel size but decrease the overall number of vessels in the fleet. This could lead to greater efficiency on a fleet-wide basis for the same catch.

SINGAPORE FERRY PROJECT[94]

The GreenPilot project involved the conversion of a pilot boat to operate on renewable methanol fuel, demonstrating the improvements to environmental and operational performance that can be achieved for this fuel. Methanol is a clean-burning alcohol which burns with very low NOX, SOX, and particulates. Hydrogen is a feedstock for green methanol. The vessel first began operating in Singapore in 2019.

Figure 82 – "Greenpilot" Methanol powered pilot vessel

If vessel electrification is not viable, another route to GHG reduction could be through the use of synthetic fuels, incorporating H_2 as a feedstock, while retaining combustion engine technology. One such option is green methanol which is effectively an alternative vector for hydrogen. Methanol-fueled marine engines have been demonstrated in Sweden[95], and could adapted for fishing vessels. Battery hybridization would further reduce the required engine size and fuel consumption. Such a combustion engine-based option may be more appealing as an intermediate step for the fishing industry. This could also enable potential synergies to produce local green methanol from biogas – derived hydrogen (e.g. at wastewater treatment plants).

[94] The Maritime Executive. (2019). Nanyang Technological University Evaluates Methanol Fuel. Retrieved from https://www.maritime-executive.com/article/nanyang-technological-university-evaluates-methanol-fuel
[95] Research Institute of Sweden. (2018). New Methanol Engine Ready for the Market. Retrieved from https://news.cision.com/rise/r/new-methanol-engine-ready-for-the-marine-market,c2646904

Ferries

Ferries offer a unique opportunity for technology adoption. The ferries in the Maritimes are primarily owned by government (Transport Canada or provincial Departments of Transportation and Infrastructure) but are operated by private industry. The long lifecycle of ferries is an important factor to consider, as the procurement process can take years and is largely influenced by government policies. Currently, two ferries (*MV Holiday Island* & *MS Madeleine*) are in the process of being replaced over the next few years. Ideally, one or both of these would be used as pilot projects to demonstrate the potential for a fuel cell ferry or other zero-emission technology. Because Transport Canada owns and specifies the vessels, they have the power to lead by example and test out these options before a large majority of the ferry fleet requires replacement between 2030 and 2050.

Figure 83 – MV Holiday Island

For the large ferries that were the focus of this study, hydrogen is likely the better candidate for zero-emission conversion as compared to batteries due to the long range and heavy loads required. The advantages of hydrogen are especially important in the summer months, as the ferries may need to do several crossings a day, meaning the faster refuel time and better overall energy storage are important for operations. For smaller regional ferries, batteries or fuel cells may be appropriate depending on operational requirements and recharge/refuel requirements of the specific routes.

Tugs

Tugs are a small part of the overall emissions profile in the region. Tug operators are able to pass operating costs directly on to their clients, and tug fees are small compared to the value of the cargo being shipped. Therefore, carbon pricing incentives are not likely to significantly influence a shift towards GHG reductions. Regulations may be more impactful.

The tug duty cycle lends itself well to hybridization. Tugs require very high peak power for short duration, and long periods of low power. Hybridization could be battery/fuel cell, battery/diesel, or some other combination. Either Halifax or Saint John could serve as viable locations for a pilot project, although Saint John has additional potential to combine project elements with the ferry and Irving Oil.

Figure 84 – Atlantic Elm, 2.6MW Tug

Adoption Scenarios

For each of the three sectors considered – fishery, ferries, and tugs – two scenarios were created to estimate hydrogen demand and GHG emissions reduction potential. The transformative scenario represents aggressive adoption of hydrogen fuel cell vessels in the marine sector driven by strong policies, stakeholder buy-in, and technology development. The incremental scenario assumes more conservative demand and a slower transition to zero-emission vessels.

For all cases, the transformative scenario is guided heavily by the IMO's Marine Environment Protection Committee (MEPC) resolution MEPC.304(72). This strategy is based on studies of GHG emissions in shipping, with emission reduction targets that span 2012 through 2050.[96] The IMO Strategy aims to reduce CO_2 emissions by 40% in 2030, and 70% by 2050.[91] The IMO identified the need for industry to invest in and adopt alternative low-carbon and zero-carbon fuels, as well as to research and improve technological efficiencies. In particular, the IMO Strategy intends to:

- Reduce shipping energy consumption via tightening requirements of the energy efficiency design index
- Reduce the carbon intensity (CO_2 emitted per unit of transport work) by 40% by 2030; and by 70% by 2050 compared to 2008 levels.
- Reduce overall shipping sector emissions by 50% by 2050 compared to 2008 levels.

This strategy is in accordance with the Paris Agreement and its mission to reduce the climate change through 2050 by 1.5°C[97]. If MEPC.304(72) evolves into an IMO regulation, Canada will be obligated to meet these targets as an IMO signatory.

Fishery

In the transformative adoption scenario, small pilots for fuel cell fishing boats are launched in key industries (lobster & scallop) by 2025.

The fishery is the second largest emitter of GHGs in the maritime sector, but due to its high amount of diversity, not all of the fleet is well suited to hydrogen. For the inshore lobster fishery, part of the fleet may be better suited to hybridization or battery electric over fuel cell operation. A potential pilot partnership with the PEIFA could highlight the potential strength of FCEV technology for vessels travelling further offshore. Another large part of the Maritime fishing industry is the scallop fishery in the Bay of Fundy. This fishery has a longer season compared to lobster (180 days at sea vs 50-80), meaning that there is potential for a faster payback period due to fuel savings.

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[96] International Maritime Organization. Third IMO GHG Study 2014. Retrieved from http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Greenhouse-Gas-Studies-2014.aspx
[97] International Chamber of Shipping. (2018). Reducing CO2 emissions to Zero: The 'Paris Agreement for Shipping.' Retrieved from https://www.ics-shipping.org/docs/default-source/resources/reducing-co2-emissions-to-zero-the-paris-agreement-for-shipping.pdf

The difficulty in this industry is that each vessel is privately owned by individual operators. There will need to be a strong business case in order to justify switching, as well as buy-in from early adopters to act as champions for hydrogen (or other clean tech) in the industry.

Ferries

Ferries have the greatest potential to both increase hydrogen demand and reduce GHG emissions in the maritime sector. They have high power requirements, predictable operating conditions, and simple point-to-point operation which makes them ideal candidates for a fuel cell drive system. Most of the large ferries in the region are owned by Transport Canada, giving them the power to mandate electrification upon the end of life of the current vessels.

In the aggressive scenario, it is assumed that when the *MV Holiday Island* is replaced, it will be with a fuel cell ferry as a pilot project. If this pilot is successful, Transport Canada could mandate that the rest of the fleet be replaced with fuel cell vessels or other zero-emissions options. This would result in an additional seven fuel cell ferries being introduced to the fleet by 2050. A strong mandate from Transport Canada to electrify its ferry fleet may also encourage New Brunswick's Department of Trade and Industry (DTI) to consider fuel cells for the Grand Manan ferry when it is due to be replaced. There are additional ferries owned by the New Brunswick DTI which are not as well suited to fuel cells due to shorter routes and lower power requirements.

SAINT JOHN HYDROGEN PORT

Saint John is an ideal place to start a lighthouse program focused on the marine sector and heavy-duty vehicles.

Figure 85 – Saint John Ferry Terminal[98]

In Saint John Harbour there are multiple potential hydrogen end-users that could form a cluster of demonstration projects. This could include the ferry from Saint John-Digby ferry, harbour tugs, and material handling equipment at Port of Saint John.

Saint John is also home to the Irving Oil Refinery which currently produces hydrogen for its own consumption.

Conversely, the incremental scenario assumes Transport Canada not introduce a mandate to electrify their ferry fleet until forced from external pressure such as IMO regulations or pressure from the United Nations after Canada fails to meet its 2030 climate targets, which is likely without strong new incentives to decarbonize the transportation and energy sectors.[99]

[98] Huddle. (2017). Ottawa Invests $5-Million in Saint John Ferry Terminal. Retrieved from https://huddle.today/ottawa-invests-saint-john-ferry-terminal/

[99] Government of Canada. (2020). Progress Towards Canada's Greenhouse Gas Emissions Reduction Target. Retrieved from https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/progress-towards-canada-greenhouse-gas-emissions-reduction-target.html

Tugs

Tugs make up a small piece of the overall emissions profile but are well suited to hybridization. There are few tug operators, so the adoption of hydrogen technology is likely to be fairly binary – either they are trialed and accepted or not. In the transformative case, it was assumed that a successful pilot demonstration project of a single hydrogen fuel cell tug leads to product acceptance and all new tug purchases are hydrogen powered from 2030 to 2050. Tugs were assumed to have a useful life of 40-50 years, so by 2050, there would be 11 hydrogen tugs in the region. In the incremental case, the first deployment does not begin until 2040.

Forecasted Hydrogen Demand & GHG Reduction

Table 21 shows the number of hydrogen powered vessels deployed per year for each subsector in the incremental and transformative scenarios.

Table 21 – Hydrogen marine vessels adoption assumptions

Year	Ferry		Fishery		Tug	
	Incremental	Transformative	Incremental	Transformative	Incremental	Transformative
2020	0	0	0	0	0	0
2025	0	1	0	4	0	1
2030	0	2	1	18	0	2
2035	0	3	12	46	0	3
2040	1	4	45	111	1	5
2045	2	6	140	282	2	7
2050	4	9	282	543	3	11

Determining the GHG reductions associated with technology adoption requires assumptions regarding the energy effectiveness ratio (EER) for fuel cell propulsion systems compared to conventional marine combustion engines. Assumed EER's are given in Table 22.

Table 22 – Assumed ERR Values

Marine Sub-Sector	Fuel Cell Shaft Efficiency	Diesel Shaft Efficiency	EER
Fishing	50%	30%	1.67
Tug	50%	40%	1.25
Ferry	50%	45%	1.11

Incremental Scenario

Figure 86 and Figure 87 show the forecasted hydrogen demand and emissions reduction from the marine sector by year and subsector. Ferries are assumed to make up the vast majority of hydrogen demand and emissions reduction potential because of their large energy demand and the ability of the government to directly control the transition.

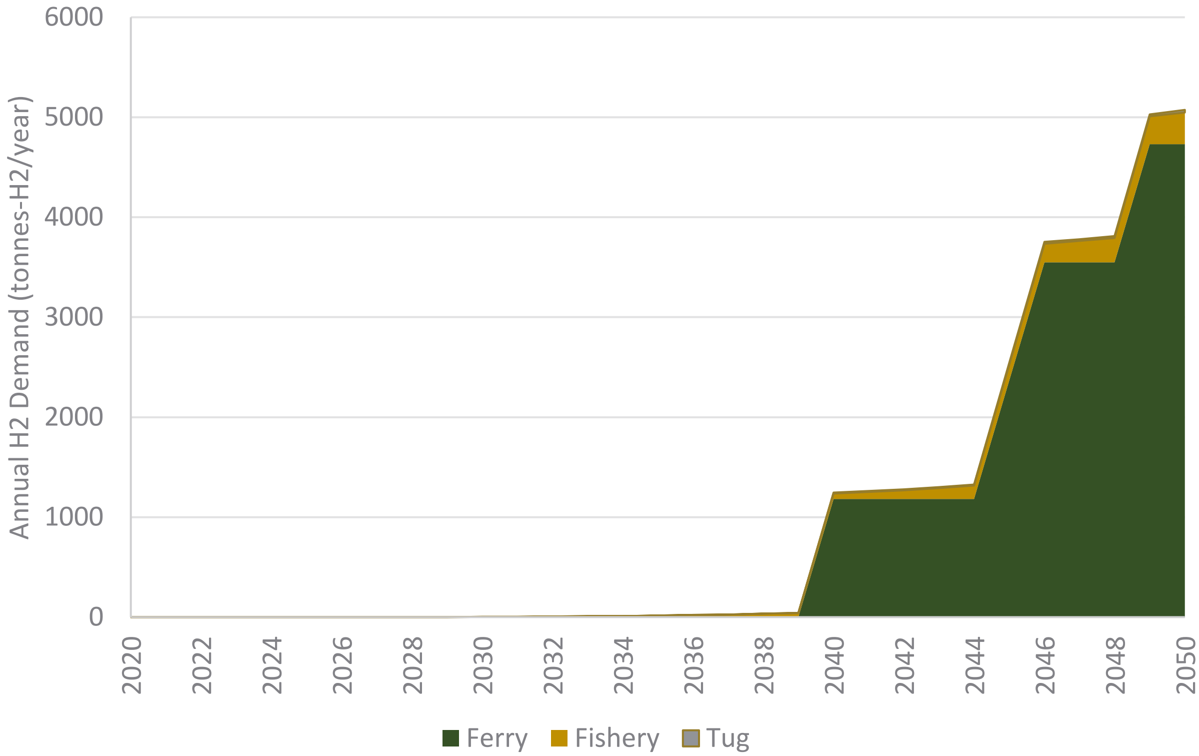

Figure 86 – Marine incremental scenario – H2 demand

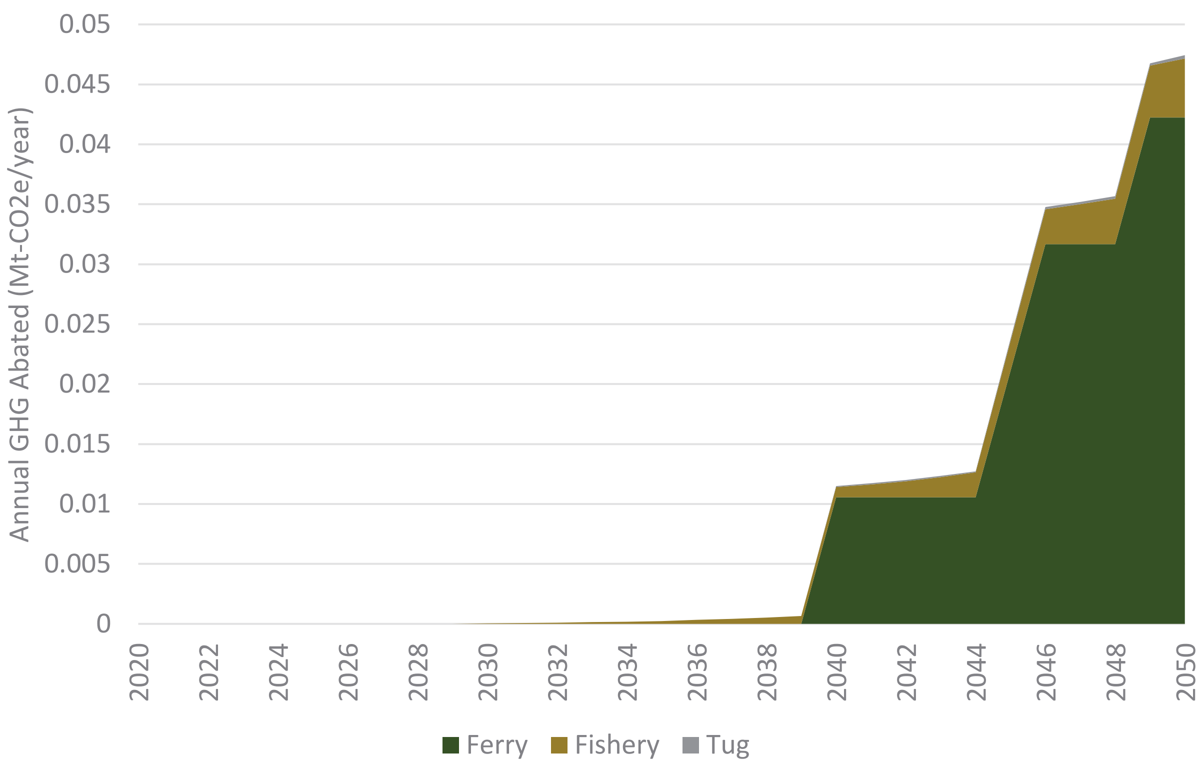

Figure 87 – Marine incremental scenario – GHG emission abatement

Transformative Scenario

Figure 88 and Figure 89 show the forecasted hydrogen demand and emissions reduction from the marine sector by year and subsector. As in the incremental scenario, ferries dominate

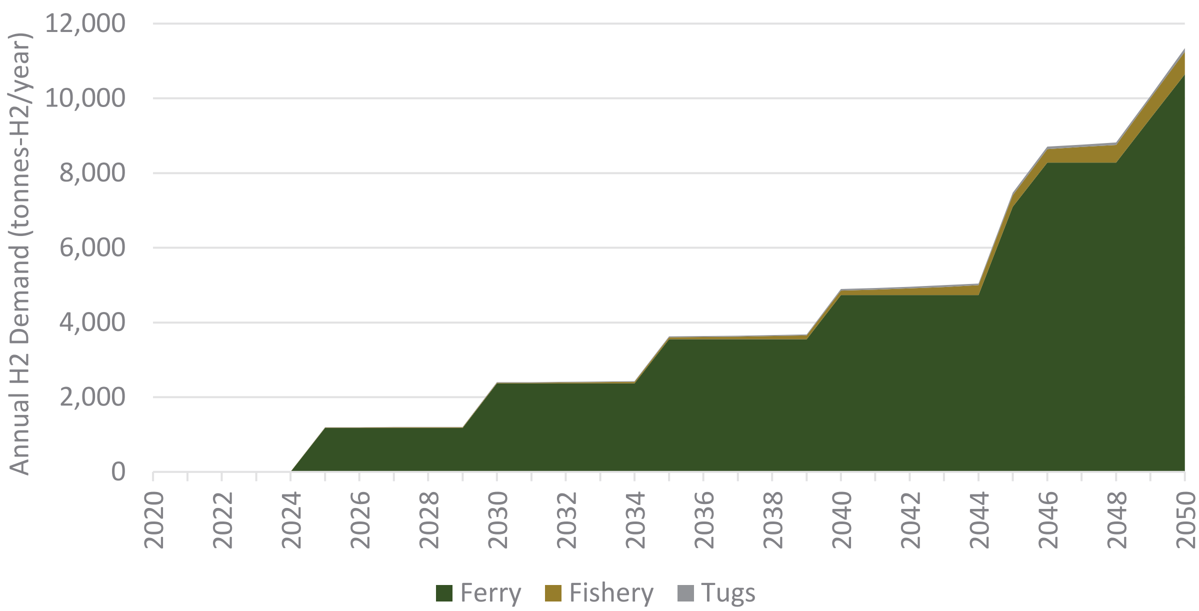

Figure 88 – Marine transformative scenario – H2 demand

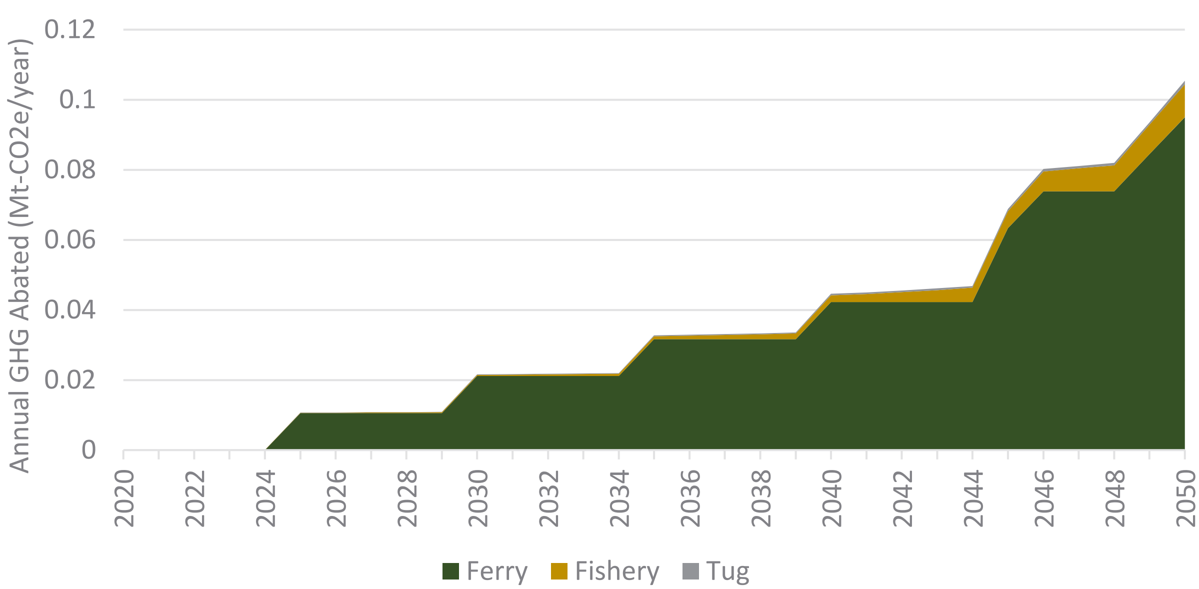

Figure 89 – Marine transformative scenario – GHG emission abatement

Figure 90 and Figure 91 show the annual hydrogen demand and potential GHG emissions reduction for both the conservative and aggressive scenarios for the three marine subsectors combined.

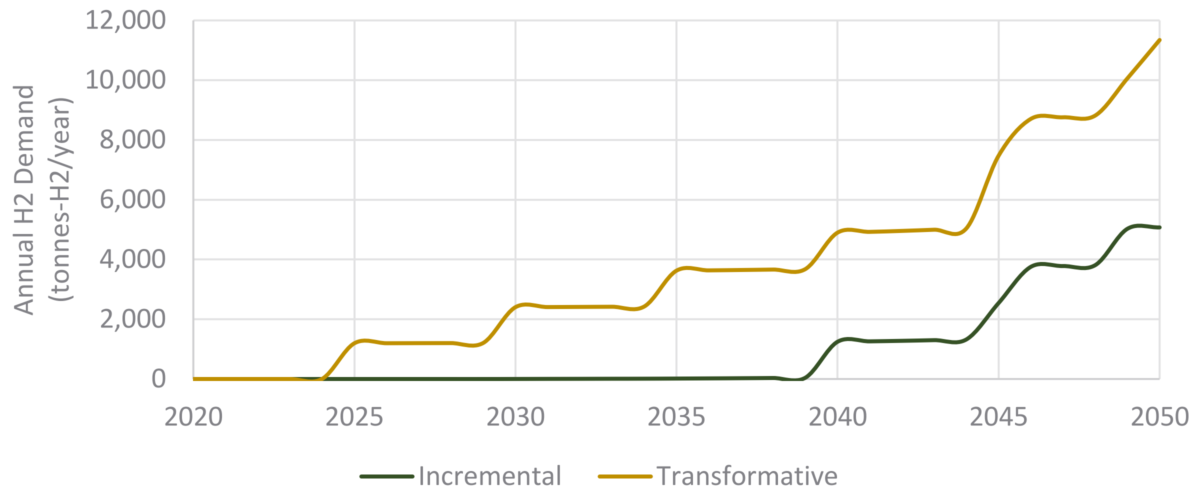

Figure 90 – Marine transformative and incremental scenarios - H2 demand

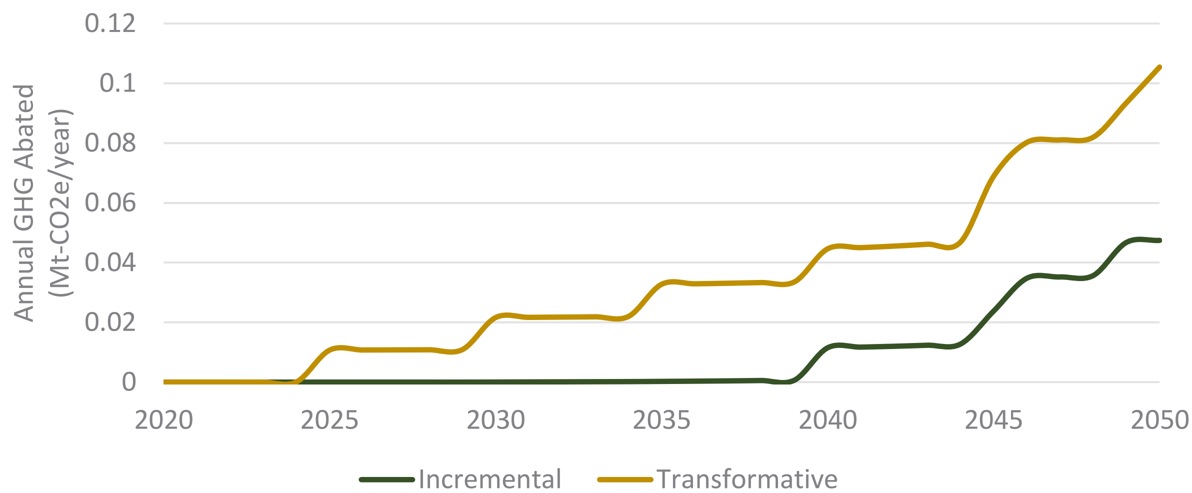

Figure 91 – Marine transformative and incremental scenarios – GHG emissions abatement

Recommendations

Key Marine Sector Recommendations

- Adopt government policy to procure zero-emission ferries
- Build out hydrogen infrastructure to facilitate early demonstration projects
- Support pilot projects with private industry (tugs/fishing)
- Educate industry about benefits of transitioning to zero-emission
- Adopt policies that align with wider decarbonization goals and regulations (e.g., IMO for fisheries)

Industrial Applications

Baseline

The industrial sector is a broad category of organizations that encompass highly varied businesses and services. This sector makes up the largest component of energy demand in the Maritimes, representing 54% of demand across the three provinces.[100] Much of that demand is included in other end-use classifications in this report such as transportation, natural gas, and electricity.

The greatest opportunity for hydrogen as a large industrial load is at the Irving Oil Refinery in Saint John. This facility is the largest refinery in Canada, processing more than 320,000 barrels of crude oil per day and supplying fuel to more than 900 fueling locations across Eastern Canada and New England.

Hydrogen is produced as a by-product of the rheniforming process through which naphtha is upgraded to higher value fuels such as gasoline. The Irving Oil Refinery in Saint John produces approximately 96 tonnes of hydrogen daily through this process. Hydrogen is a required input for several other refining processes. The by-product hydrogen via the naphtha rheniforming process accounts for approximately 45% of total demand within the refinery. The remainder of hydrogen consumed is produced via SMR. Most of the hydrogen produced is high emitting, but CCUS is being used to reduce emissions by using the CO2 in a nearby greenhouse facility and to carbonate beverages.

Opportunities and Challenges for Hydrogen

Irving Oil could play a significant role in building the hydrogen economy in the Maritimes. It already has infrastructure and institutional knowledge to produce and use hydrogen, which positions the organization well to participate in the sector. Irving Oil could act both as a large end-use consumer of low-carbon hydrogen (to replace the high-emitting hydrogen currently used in their processes) or expand production and become a supplier for other end-use applications in the region.

A major challenge to the incorporation of low-carbon hydrogen into the refining process is the relatively high cost of the fuel compared to the incumbent high-emitting hydrogen. The additional cost may be reduced through policies like the Carbon Tax and the proposed Canadian Clean Fuel Standards, which raise the cost of emissions and incentivize low-carbon technologies.

There are opportunities for other industrial companies to become involved in the hydrogen sector. Industries in decline, like the pulp and paper industry, can look to incorporate hydrogen generation into their facilities to be sold for end use applications like transportation or for their own consumption. This would enable them to leverage existing electrical transmission infrastructure which may be currently underutilized. The Canaport liquid natural gas (LNG) terminal could also present an opportunity for the hydrogen import/export market. However, conversion of equipment from LNG to hydrogen and to manage exports instead of imports would require significant capital investment.

[100] Canada Energy Regulator. (2019). Canada's Energy Future 2019. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html

Adoption Scenarios

The industrial demand considered in this report is solely for hydrogen consumed at the Irving Oil Refinery in Saint John. It was assumed that low-carbon hydrogen could be incorporated into the process to replace the current high-emitting supply. This could come through expansion of the CCUS operations currently at the facility or by constructing electrolyzers tied to renewable or low-carbon electricity generation.

The portion of hydrogen currently generation from SMR on site is included in the Natural Gas Demand End-Use section. The portion generated through naphtha reformation is not likely to be substituted with hydrogen from another pathway because it is a by-product and therefore much lower cost than alternatives. It was assumed that the amount of naphtha refined via this method will remain constant, and therefore the amount of hydrogen produced is constant at 96 tonnes/year from 2020-2050.

Recommendations

Key Industry Sector Recommendations

- Promote a pilot project to incorporate low-carbon hydrogen into the existing refining processes at Irving Oil
- Foster partnerships that can match end-use demand from multiple applications to a single supply point to grow scale, in particular in Saint John where Irving Oil could play a role
- Seek to leverage existing infrastructure to lower the cost of hydrogen production and consumption

Electricity Generation

Baseline

The electric grid in each Maritime province was described in Section 1. Due to the relatively high prevalence of generation from fossil fuel resources in Nova Scotia and New Brunswick, the grid CI is high in the region, as shown in Figure 92.

New Brunswick generates the most electricity of the three provinces and exports power to both Nova Scotia and PEI. New Brunswick also imports a small percentage of its electricity from Quebec and New England.

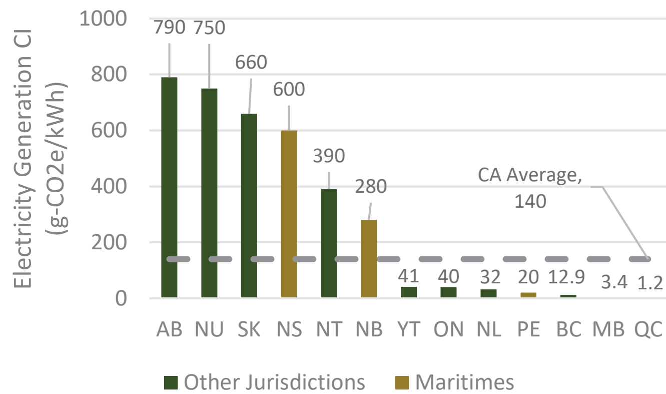

Figure 92 – Electricity generating capacity CI by province[101]

The electric utilities in Nova Scotia and New Brunswick are both committed to reducing the emissions from electricity generation grids and phasing out coal and other heavy emitting generation. Nova Scotia Power's 2020 Integrated Resource Plan seeks to outline a long-term strategy to provide the minimize rate increases while meeting the province's environmental regulations. As part of the exercise, they are modelling scenarios to reach lower carbon intensity levels out to 2045. New Brunswick power has been retiring fossil fuel infrastructure including the coal-fired Grand Lake facility in 2010 and the fossil-fuel-fired facility at Dalhousie in 2012. They have also refurbished low emitting nuclear resources and expanded wind generation. In PEI, almost all of the electricity generated is through wind, so the primary source of emissions in the electrical grid is through imported energy.

The electricity market in the Maritimes is also highly seasonal. Demand is greatest in the winter because of the prevalence of electric heating. Since electrical utilities have an obligation to provide power at all times, the electrical system is sized to deliver electrical capacity equal to peak winter demand. Much of this generating capacity remains unused in the summer months.

Opportunities and Challenges for Hydrogen

The key to reducing emissions from electricity generation will be to increase generating capacity of low emitting and/or renewable resources. Wind power represents the greatest opportunity for this in the region. However, since wind does not provide consistent power, the electrical grid will increasingly face intermittency issues as the percent of wind power grows.

[101] Canada Energy Regulator. (2018). Canada's Renewable Power Landscape 2017. Retrieved from https://www.cer-rec.gc.ca/nrg/sttstc/lctrct/rprt/2017cndrnwblpwr/ghgmssn-eng.html?=undefined&wbdisable=true

Mismatch of demand and renewable power production causes surplus energy production when renewable power exceeds grid load and insufficient power when renewable power cannot meet grid load necessitating alternative sources. The ratio of peak to average power is roughly between 3:1 and 4:1

depending on the specific location. If wind power makes up 50% of grid electricity, it's estimated that 15% of the power generated cannot be put to direct use.[103] Hydrogen could be used to store this energy and act as a buffer for electricity generation and demand. This would limit curtailed energy and enable wider adoption of intermittent renewable resources.

While energy storage is a necessary component of an electric grid with a high penetration of renewables, it is not clear whether hydrogen offers the best value proposition. Other storage technologies such as batteries or pumped hydro may be more cost-effective ways to meet storage requirements due to daily fluctuations in electricity production and demand. Further analysis is required to fully assess the costs and benefits of each potential storage option.

Hydrogen can also play a role in providing seasonal energy storage. Electrolyzers could be used to generate hydrogen during the summer months when electricity demand is low, and assets are underutilized. This would require massive storage reservoirs designed for long durations. The most appropriate storage mechanism would be salt caverns, so the hydrogen generating facility would need to be located near these geological resources. In the winter, when demand is high again, this hydrogen would be used to generate electricity either through a fuel cell or hydrogen turbine. This configuration would pair well with intermittent or base load generation such as nuclear power.

UTSIRA WIND-HYDROGEN PROJECT

The Utsira wind power and hydrogen plant is the world's first full-scale combined wind power and hydrogen project. Ten households were directly supplied with energy generated from the integrated wind and hydrogen system. When the wind power exceeded household demand, the excess was used to produce hydrogen through electrolysis, then compressed and stored on-site. During periods of low wind, the stored hydrogen was used to generate energy from either a hydrogen internal combustion engine or fuel cell.

Figure 93 – Utsira wind-hydrogen power plant[102]

The project started up in 2004 and was operated continuously for four years. The electrolyzer had a peak load of 48 kW, a 5 kW Hofer compressor was used, and the gaseous hydrogen was stored at 200 bar in a 2,4000 Nm3 vessel.

[102] Nakken T., et al. (2006). The Utsira Wind-Hydrogen System – Operational Experience. Retrieved from http://www.globalislands.net/greenislands/docs/norway_135_Ewec2006fullpaper.pdf
[103] Steinberger-Wilckens, R. (2012). Wind Power in Power Systems, Second Edition. Hydrogen as Means of Transporting and Balancing Wind Power Production. Retrieved from https://www.wiley.com/en-us/Wind+Power+in+Power+Systems%2C+2nd+Edition-p-9780470974162

Hydrogen is likely to be the best option for long-term seasonal energy storage if the right geographical conditions are met. Batteries are better suited for smaller scale and shorter duration cycles of energy storage. The mass of battery that would be required to deliver seasonal energy storage would be massive and likely cost prohibitive.

Hydrogen could also be used as energy storage from daily or seasonal peaks in electricity generation without being converted back to electricity during periods of high electricity demand. In this scenario, the hydrogen would be consumed in other end use applications where there may be more favourable economic factors. For example, off-peak wind electricity could be used to generate hydrogen that is then injected into the natural gas pipeline or used in a fuel cell vehicle. More work is needed to develop a detailed techno-economic model for the use of hydrogen for dispatchable power generation.

Adoption Scenarios

The opportunity for energy storage in the electrical grid in the Maritimes is large. The electric grid is relatively high emitting and a transition to low-carbon sources of generation is likely to include a high penetration of intermittent renewables, primarily wind power. Additionally, the relatively low penetration of natural gas for heating purposes has resulted in a large amount of electrical heating that causes a large seasonal fluctuation in energy demand.

Hydrogen could act as the energy storage mechanism for both daily and seasonal storage requirements, but more study is required to understand economics and technical viability of large scale energy storage and opportunities to supply dispatchable power using hydrogen as a fuel in the region. Consultation with electrical utilities in the region suggested that as much of 80% of the electric grid could be decarbonized relatively easily, but the final 20% could be more difficult. It was assumed that the total opportunity for an energy storage mechanism in the Maritimes was 20% of electrical demand.

In this analysis it was assumed that hydrogen turbines would be used to generate the electricity. It would also be possible to use fuel cells, which would offer a significant efficiency improvement. However, the best opportunity for fuel cells for electricity generation would be in distributed residential scale systems that also provide heating for domestic hot water. These type of system have been deployed at large scale across Japan. Developing the infrastructure for this would be a major project but may become feasible as the natural gas grid transitions to hydrogen.

Figure 94 shows the estimated electricity demand in each Maritime province from 2020-2050. These data are based on forecasts from the CER.

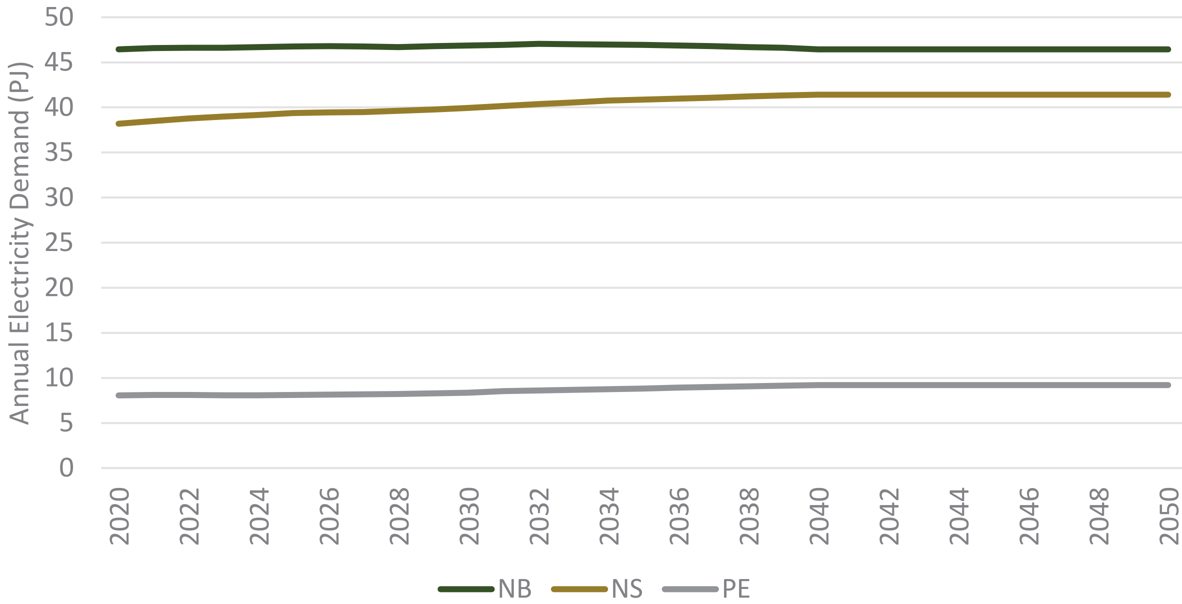

Figure 94 – Forecasted electricity demand in the Maritimes[104]

In the transformative scenario, it was assumed that hydrogen makes up the entire energy storage opportunity and comprise 20% of electrical demand. This represents an aggressive scenario that provides an upper bound for the total size of the potential opportunity in which hydrogen proves to be the most economical energy storage mechanism in most applications. In the incremental scenario, hydrogen accounts for 5% of energy demand, largely driven by seasonal energy storage. Figure 95 shows the increase of hydrogen as a source of electricity generation over time in the two scenarios.

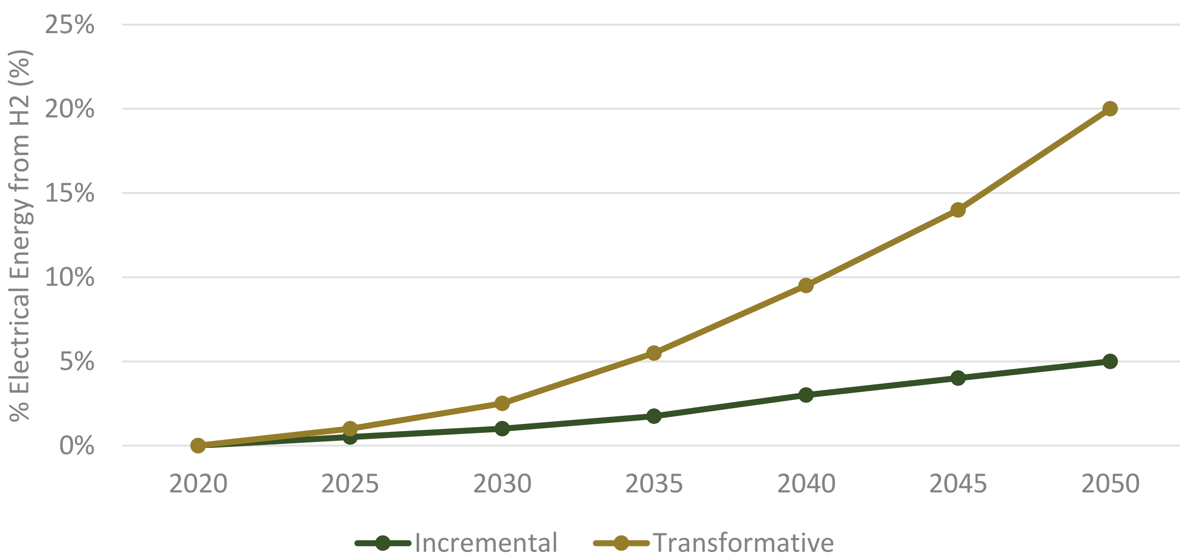

Figure 95 – Hydrogen penetration of electricity market – incremental and transformative

[104] Canada Energy Regulator (2017). End – Use Demand. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Figure 96 and Figure 97 show the annual demand for hydrogen in the incremental and transformative scenarios for each province in the Maritimes over time.

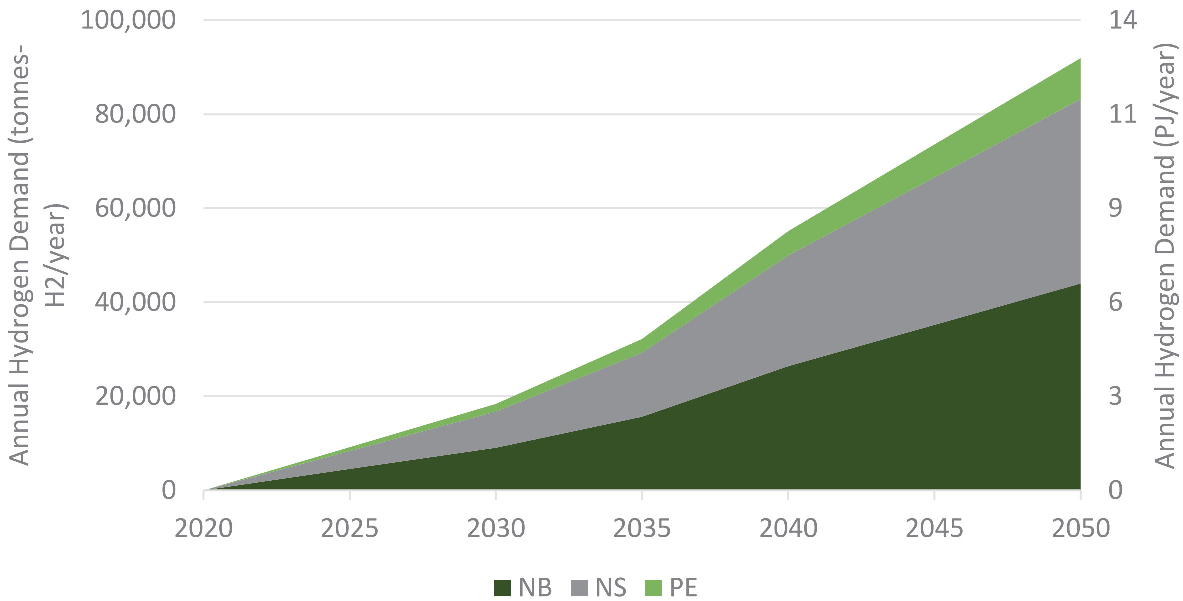

Figure 96 – Annual electricity hydrogen demand - incremental

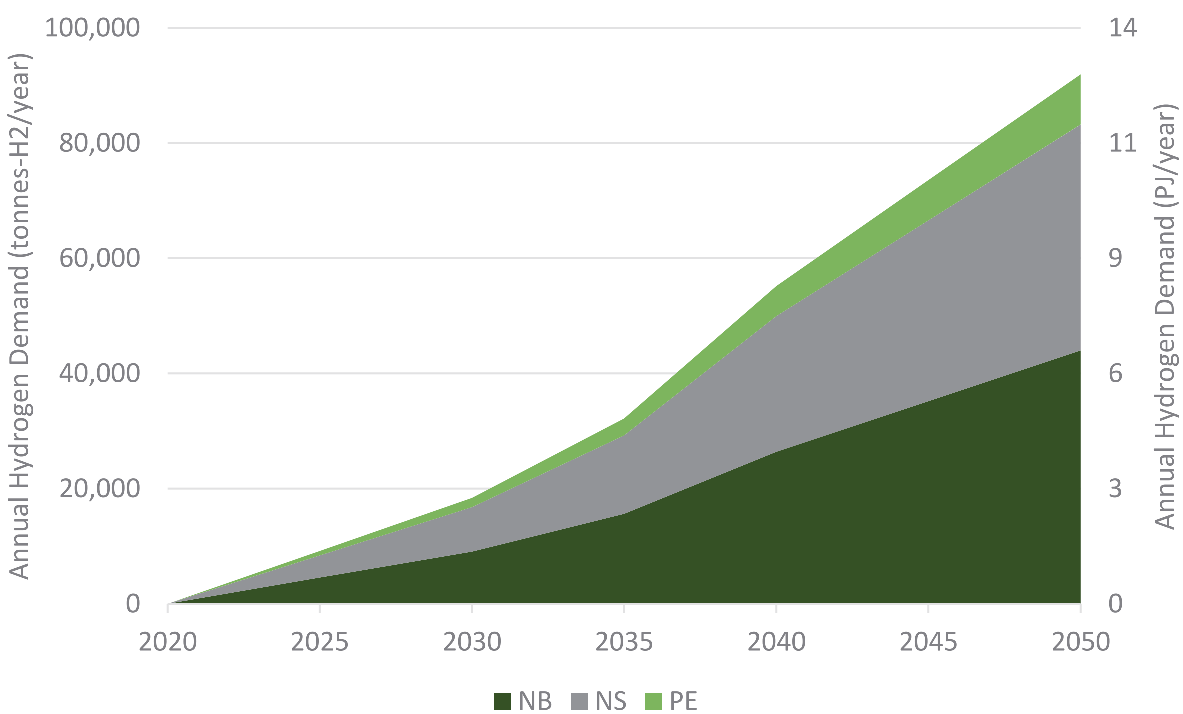

Figure 97 – Annual electricity hydrogen demand - transformative

Figure 98 and Figure 99 show the resulting emissions reduction from incorporating hydrogen into the electricity generation mix in the incremental and transformative scenarios.

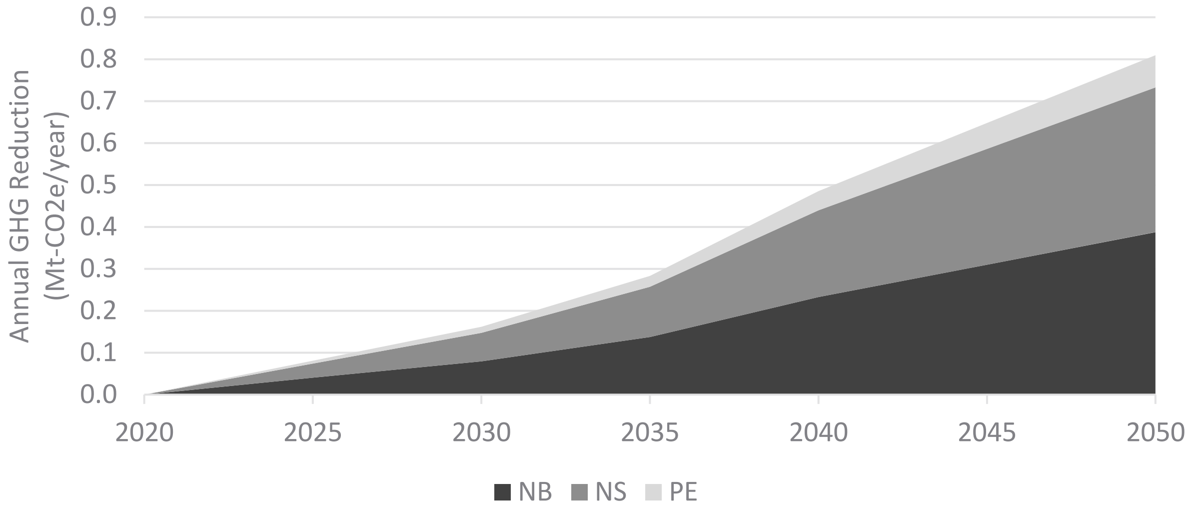

Figure 98 – Annual electricity emissions reduction - incremental

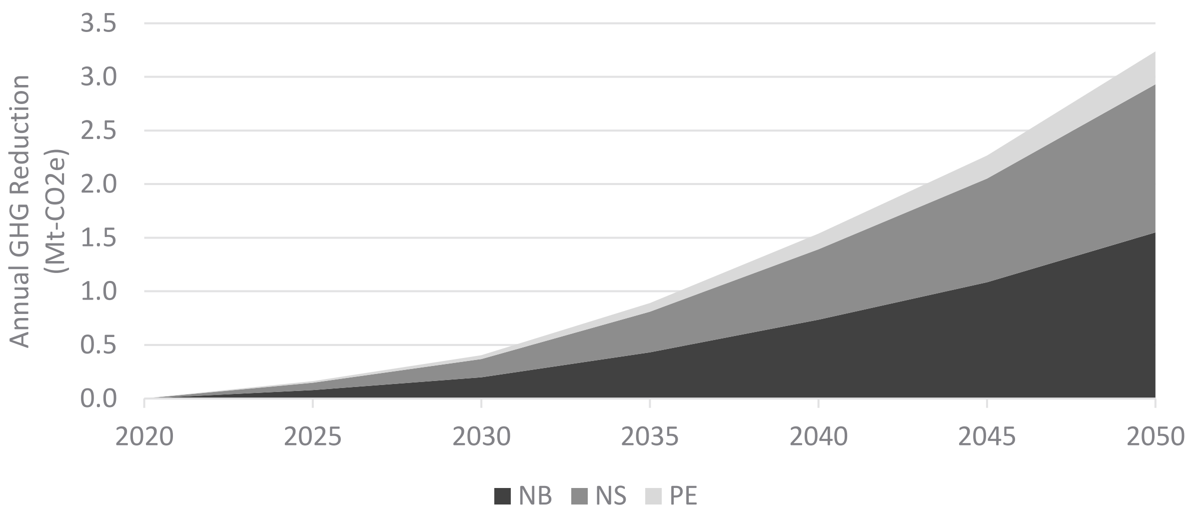

Figure 99 – Annual electricity emissions reduction - transformative

Recommendations

Key Electricity Sector Recommendations

- Further explore economics of alternative energy storage mediums including hydrogen and utility scale batteries for both daily and seasonal storage
- Support a pilot project to demonstrate hydrogen as an effective energy storage medium and build demand
- Ensure codes and standards allow for the short- and long-term storage of hydrogen including in salt caverns

Aggregated End-Use Applications

Figure 100 and Figure 101 show the aggregated hydrogen demand and emissions reduction potential from all the end-use sectors considered in this report. The aggregate hydrogen demand in the transformative case is 0.65 Mt-H2/year, which would reduce emissions by 6.5 Mt-CO2e/year. This represents an optimistic scenario in which hydrogen adoption is driven by technological advancement and strong support from all levels of government and industry. The specific assumptions are outlined in the preceding sections.

Hydrogen used to generate electricity represents the largest share of hydrogen demand and emissions reduction in the transformative scenario. This sector will be heavily dependent on the evolution of energy storage technologies. The transformative scenario represents the total opportunity, but in all likelihood, the sector will be further split between hydrogen and other energy storage technologies. Further study is required to fully assess the economic costs and benefits.

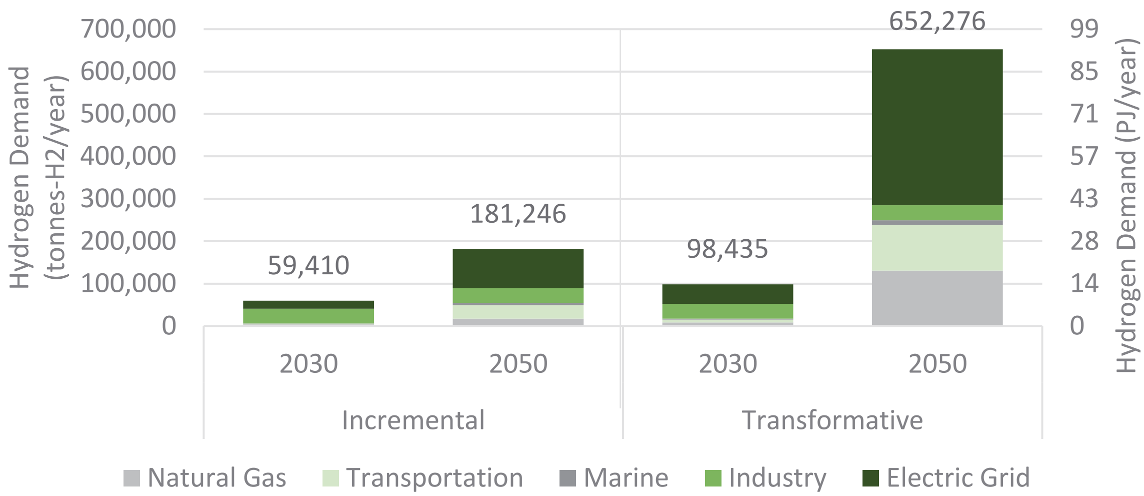

Figure 100 – Aggregated hydrogen demand forecast by sector

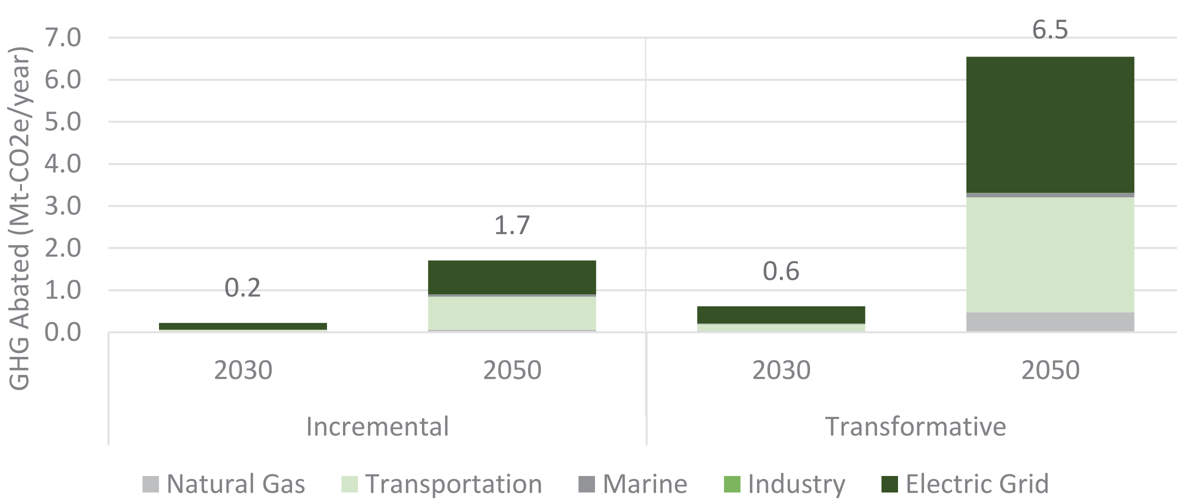

Figure 101 – Aggregated GHG emissions reduction Forecast by sector

In the transformative scenario, hydrogen accounts for 22% of total delivered (secondary) energy demand in the Maritimes in 2050, as shown in Figure 102. The remaining 78% of delivered energy will come from other low-carbon sources such as renewable electricity and biofuels. It may also include the use of conventional fossil fuels that have been offset by CCUS or through other negative emissions activities such as tree planting.

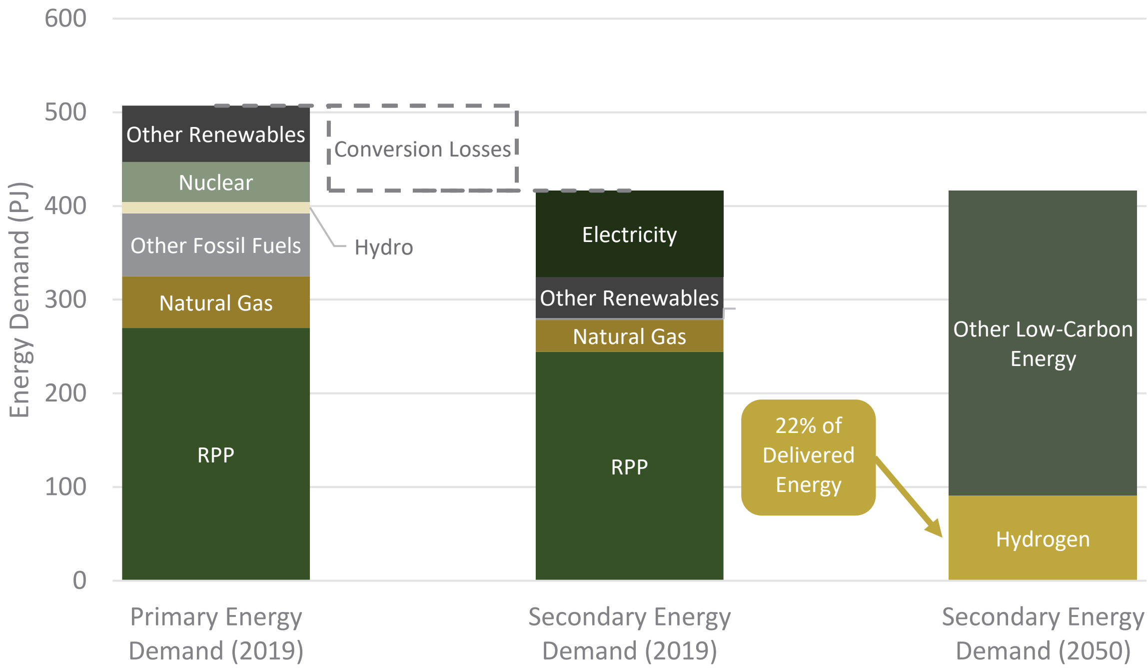

Figure 102 – Hydrogen as part of the Maritimes energy mix in 2050 – transformative scenario[105]

Generating this much hydrogen will require significant electricity and/or natural gas feedstocks. Figure 103 shows the inputs required if 100% of the hydrogen was generated via electrolysis or SMR+CCUS. The hydrogen could either be generated within the region or imported from neighbouring jurisdictions.

[105] Source of primary and secondary energy demand (2019): Canada Energy Regulator. (2019). Canada's Energy Future 2019. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html

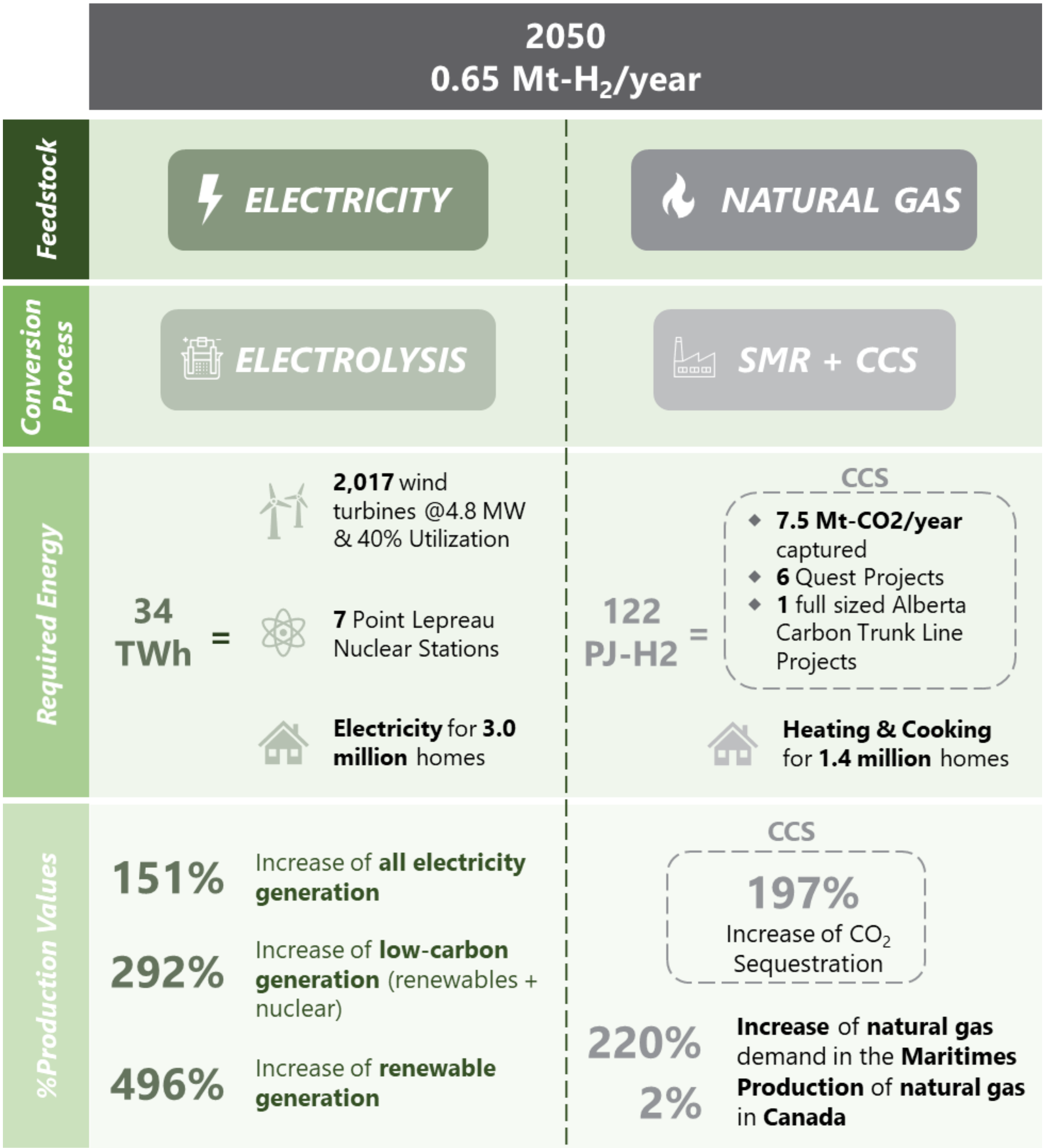

Figure 103 – Electricity and natural gas requirements to meet 2050 H2 demand – transformative

6. HYDROGEN PRODUCTION FOR EXPORT

Global Demand and Market Potential for Hydrogen

The Maritimes region is a key international gateway into Canada. The Port of Halifax achieved a throughput of 282,990 TEUs in 2019, while The Port of Saint John's, another major port in Atlantic Canada, achieved a throughput of 68,901 TEUs.[107,108] The region may capitalize on its unique geographical advantages by serving as a central export nexus for both locally produced hydrogen and hydrogen produced in other provinces which may be transported to the export points via pipeline. Through the region's ports, hydrogen may be directly exported to countries across the European Union (EU) such as Netherlands, Germany, and France, as well as states along America's eastern seaboard. Liquid hydrogen may be transported on specially constructed ships, utilizing similar design principles as used in LNG transport. The world's first special-purpose liquid hydrogen transport ship was launched in 2019.[109] Other options for transport include the material storage techniques outlined in the Storage Technologies section of this report.

The European Union states are collaborating to position themselves as a world leader in hydrogen production and end-use technologies, with the vision laid out in its "Hydrogen Roadmap for Europe" which was released in 2019. They presented a "business as usual" scenario, which would not achieve the EU's 2-degree target and an

KAWASKI HEAVY INDUSTRIES

In December 2019, the world's first liquefied hydrogen carrier was commissioned by Kawasaki Heavy Industries Ltd. The vessel named the Suiso Frontier will transport liquefied hydrogen using a 1,250 m3 vacuum-insulated double-shell structured liquefied hydrogen storage container and is slated for completion by late 2020.

Figure 104 – Liquid H2 transport ship[106]

The ship is equipped with a hybrid electric-diesel engine and will transport liquefied hydrogen produced in the Latrobe Valley in Victoria, Australia 9000 km to Japan. This pilot program will demonstrate the viability of the design and its potential as a key method of transportation in the future global hydrogen economy.

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[106] Kawasaki Heavy Industries. (2019). World's First Liquefied Hydrogen Carrier SUISO FRONTIER Launches Building an International Hydrogen Energy Supply Chain Aimed at Carbon-free Society. Retrieved from http://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487

[107] Port of Halifax. (2020). Cargo Statistics. Retrieved from https://www.portofhalifax.ca/port-operations-centre/cargo-statistics/

[108] Port of Saint John. (2019). Adapting for the Future: 2019 Annual Report. Retrieved from https://www.sjport.com/wp-content/uploads/2020/05/SJP_annualreport2020_spread-FINAL.pdf

[109] Norwegian Ministry of Petroleum and Energy (2020). The Norwegian Government's hydrogen strategy. Retrieved from https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf

"ambitious" scenario which will. Figure 105 predicts hydrogen usage will grow to 665 TWh in 2030 and 2,251 TWh in 2050 in the "ambitious" scenario.[110] This will entail a growth of hydrogen in Europe's energy mix from less than 2% currently to 13-14% by 2050.[111] The European Commission estimates renewable hydrogen investments in Europe could be €180-470 billion by 2050, and also identifies Canada as a potential international trade partner in the new hydrogen economy.[111]

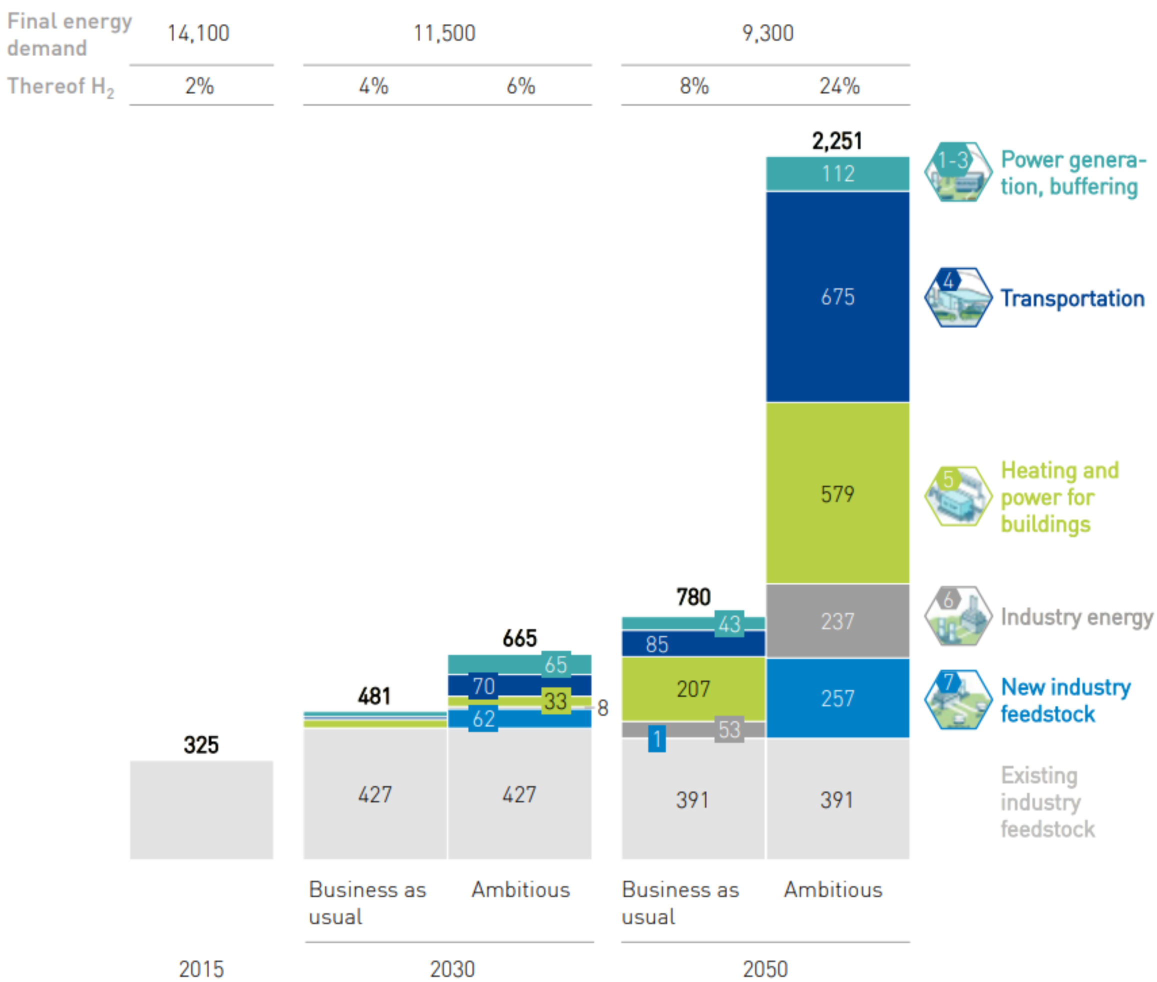

Figure 105 – Forecasted worldwide hydrogen demand[110]

[110] Fuel Cells and Hydrogen Joint Undertaking (2019). Hydrogen Roadmap Europe. Retrieved from https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

[111] European Commission (2020). Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions. Retrieved from https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

Germany

Germany released its "National Hydrogen Strategy" in June 2020, which identified green hydrogen as the only sustainable long-term option. However, it acknowledged blue hydrogen as a potential source during the transition period in the short- and medium-terms.[112] Since renewable generation capacity in Germany is limited, the country expects to be an importer of hydrogen and represents an ideal trade partner for the Maritimes region. The country's current usage of hydrogen is estimated to be 55 TWh, which is predicted to grow to 110 – 380 TWh by 2050 in order to meet its carbon neutrality goal.

Norway

The Norwegian Government released its hydrogen strategy in June 2020. As seen in Figure 117, Norway's electricity generation is primarily from hydro, which positions it to be a key competitor to the Maritimes region for the supply of green hydrogen to the EU.

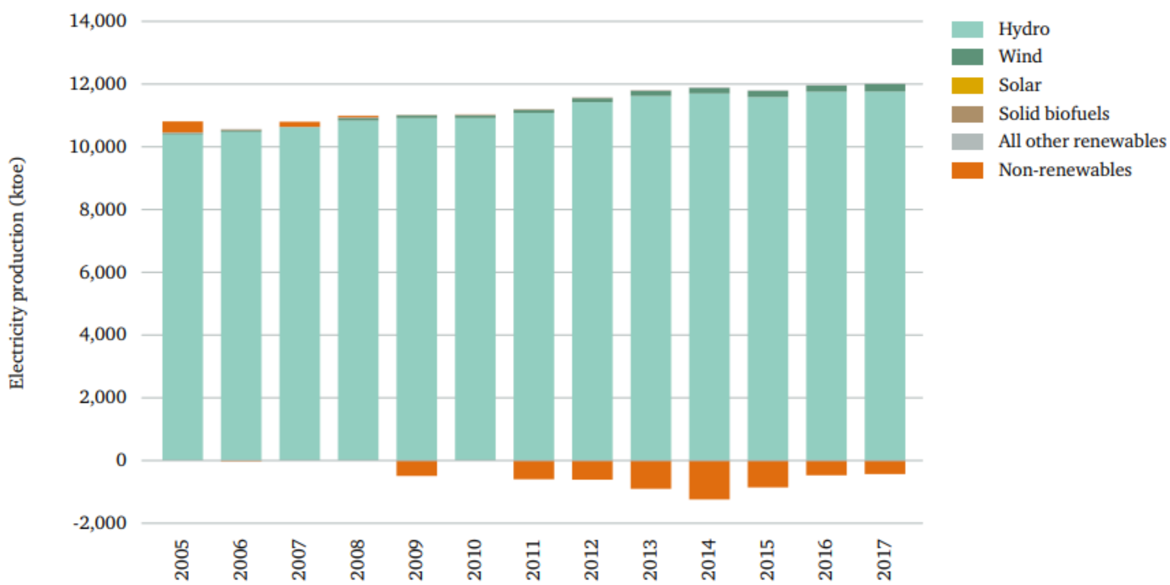

Figure 106 – Sources of electricity production in Norway[109]

France

France has set the target to reduce its CO2 emissions from ~310 Mt in 2015 to ~90 Mt in 2050. A 2018 strategic document prepared for the Minister for Ecological and Solidary Transition predicted France's potential energy demand supplied by hydrogen to grow from 160 PJ in 2020 to 275 PJ in 2030 and 790 PJ in 2050. France has a relatively low-cost electricity grid, with an estimated CI of 50 g-CO2e/kWh compared to 560 g-CO2e/kWh in Germany. The French government also has ambitious targets on renewables production (40% by 2030), which increases the country's potential as a European source of green

[112] Federal Ministry for Economic Affairs and Energy Germany (2020). The National Hydrogen Strategy. Retrieved from https://www.bmbf.de/files/bmwi_Nationale%20Wasserstoffstrategie_Eng_s01.pdf

hydrogen. France could become another exporter of hydrogen to other European nations, competing with potential exports from the Maritimes.

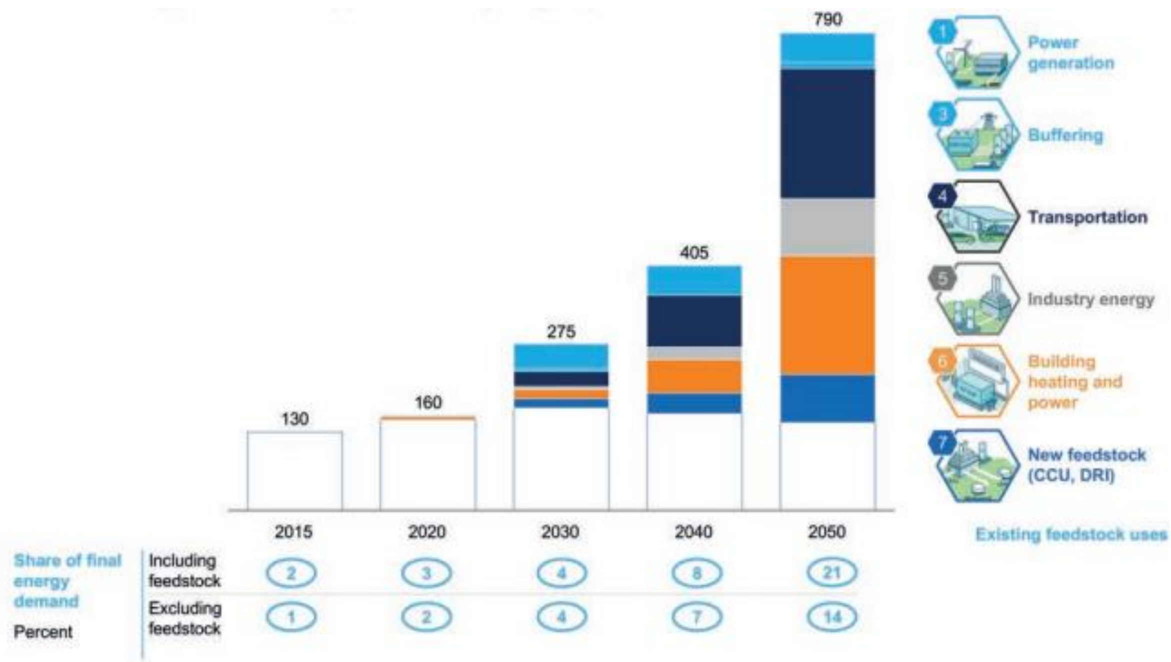

Figure 107 –Forecasted hydrogen demand in France[113]

Netherlands

The Port of Rotterdam is a leading energy cluster in Northwest Europe, with more than half its the total throughput being fossil fuel resources. As a result, the port has existing infrastructure and experience to handle large quantities of liquid fuels, as well as experience receiving and processing them.[114] For large scale transportation of hydrogen over long distances, the most economical and efficient method is delivery via pipelines. Figure 106 below shows the strategic importance of the Port of Rotterdam as an energy importing hub to the surrounding countries, as well as the potential to repurpose the existing natural gas pipelines for hydrogen use. The dotted red line labelled "AL" on Figure 106 are two private hydrogen pipelines operated by Air Liquide and Air Products, which originate from the port. The port is looking to be an early mover in establishing itself as a gateway for the import of green hydrogen into the EU and makes it a potential export location for the Maritimes' hydrogen.

[113]French Minister for Ecological and Solidary Transition (2018). Developing Hydrogen for the French Economy. Retrieved from https://www.afhypac.org/documents/publications/rapports/Afhypac_Etude%20H2%20Fce%20GB_def.pdf(from reference 7)
[114] Hydrogen for the Port of Rotterdam in an International Context (2020). Retrieved from https://www.portofrotterdam.com/sites/default/files/drift-hydrogen-for-the-port-of-rotterdam-in-an-international-context-a-plea-for-leadership.pdf?token=3ySt8rOD

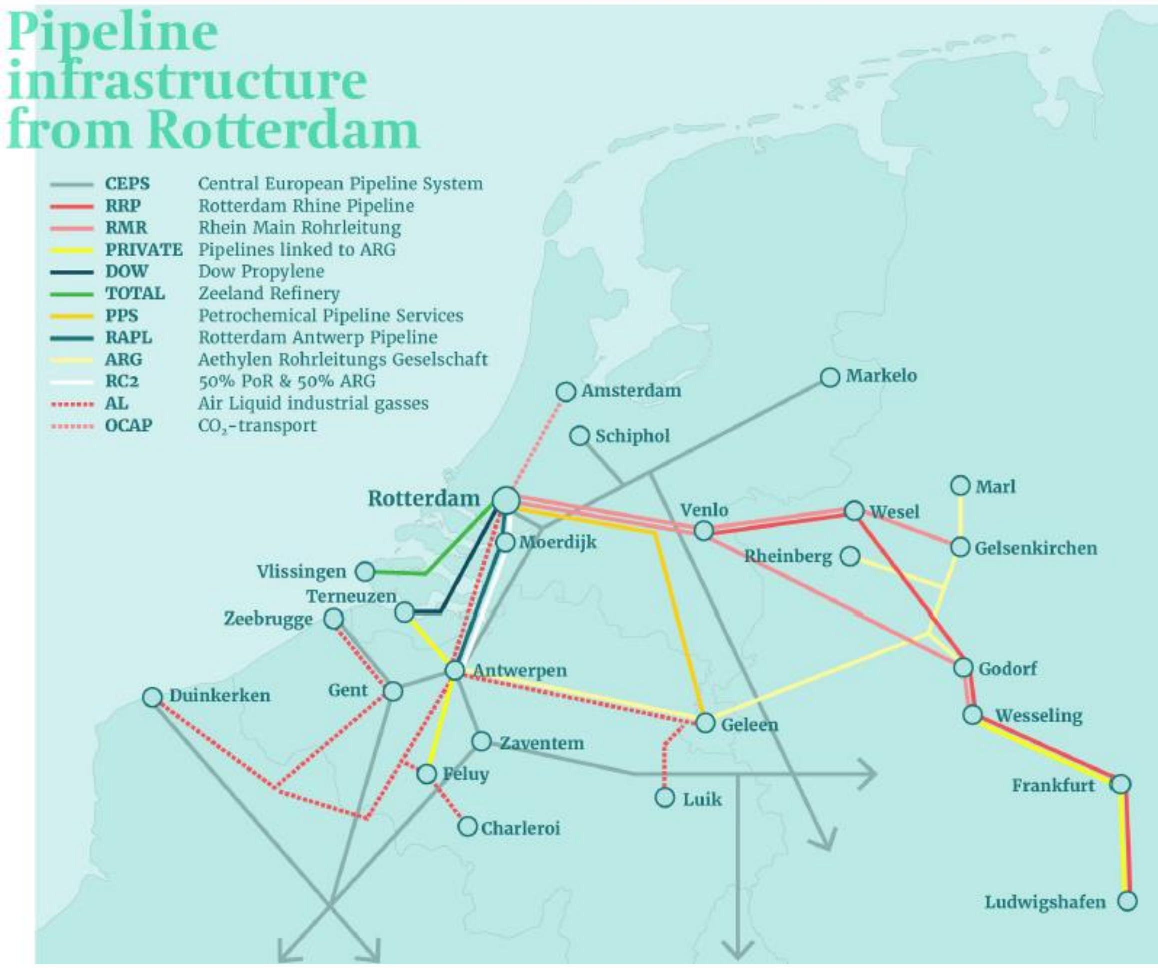

Figure 108 – Port of Rotterdam Pipeline Infrastructure

In July 2020, the Port of Rotterdam Authority and Air Liquide announced the launch of a jointly created initiative which aims to enable 1,000 hydrogen-powered zero-emission trucks, with 500 being based in the Port area, on the roads connecting Netherlands, Belgium, and West Germany by 2025. The project includes 25 high capacity hydrogen stations and electrolysis facilities to produce low-carbon hydrogen by leveraging its location next to the North Sea's abundant wind energy resources.

United States of America

The northeastern US states have been a long-time energy trading partner with the Maritimes. Electricity is currently traded back and forth between the two regions, and natural gas flows into the Maritimes from the US. While demand for hydrogen is currently small in the region, it could become a potential export market for hydrogen from the Maritimes in the future. As shown in Figure 109, since the Deep Panuke and SOEP natural gas projects ceased operations in 2018, the Maritimes and Northeast Pipeline (M&NP) the formerly bi-directional natural gas trade has shifted to one-directional imports into the Maritimes region from the U.S.

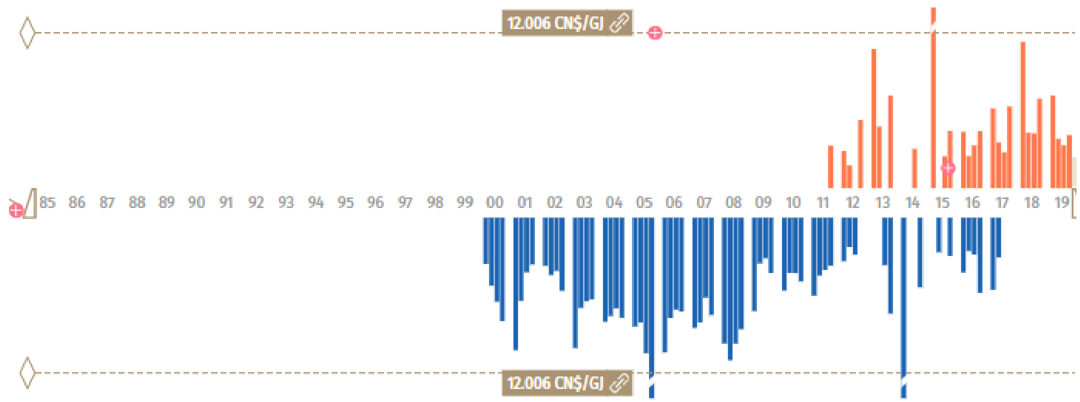

Figure 109 – Historical Natural Gas Export Price from M&NP to USA[115]

The pipeline has the potential to carry 13.33 million m^3/day of natural gas, which may be utilized to export hydrogen to the Northeastern States in the future. The Canaport terminal in Saint John's, NB imports LNG which it stores and regasifies on-site. This presents an opportunity for the development of an SMR facility to produce blue hydrogen by sequestering the carbon in the region's natural geological formations. The Canaport facility is also strategically located along the M&NP, which allows the produced hydrogen to be directly transported to the Northeastern US states.

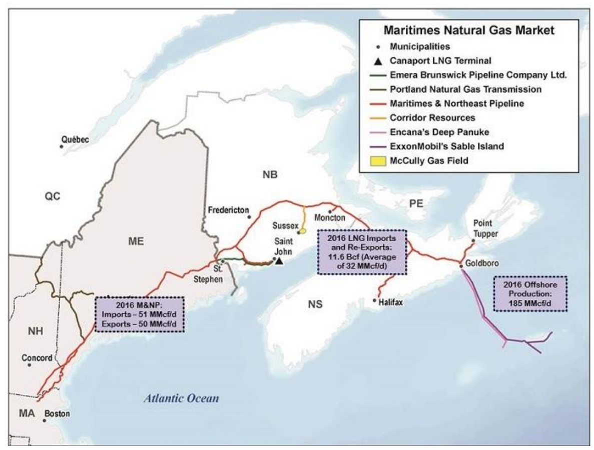

Figure 110 – Maritimes Pipeline Network (2016)[116]

Export opportunity

While the Maritimes region is strategically located close to several large potential demand markets for hydrogen, it is unclear at this time whether there will be sufficient production capacity for low CI hydrogen to satisfy both domestic requirements and export markets.

The region currently relies on imports to meet energy needs, and acts as a gateway for LNG imports converted to natural gas and exported to the Eastern US market. Ultimately there could be potential to transition this export channel to provision of low CI hydrogen rather than natural gas, continuing to use imported LNG as the feedstock and leveraging the region's CCUS potential, or by leveraging other local pathways for producing low CI hydrogen, or most likely some combination of the two. It is recommended that potential for export be considered secondary to first establishing a domestic market for hydrogen that can benefit the region in meeting decarbonization goals, and longer-term position for export.

[115] Canada Energy Regulator (2017). Imports & Exports of Energy Products to and from Canada.
[116] Canada Energy Regulator (2017). Market Snapshot: Maritimes natural gas production and exports decline in 2016. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2017/03-02cdncrlnwhgh-eng.html?=undefined&wbdisable=true

7. SUPPLY CHAIN CAPABILITY ASSESSMENT

Hydrogen Supply Chain Overview

Supply Chain Definition

The hydrogen supply chain includes the entire process from primary energy/feedstock supply through to end-use conversion into electricity, heat, or as a feedstock into another process (e.g. ammonia production). Hydrogen can be produced along a variety of pathways (see earlier sections) and this will affect the supply chain considerations, number of steps, participants, and other factors.

A supply chain is one set of linkages within a greater economic network where value is added to create an increasingly complex and useful product. The core supply chain includes both the material/product itself and the value-adding processes. In addition, supply chains rely on support infrastructure and other industries that extend value vertically (e.g. specialized equipment manufacturers), and horizontally (e.g. value-added service providers, aggregators, marketplaces, and other forms of facilitation). This is sometimes referred to a value chain or value network to highlight the vertical as well as horizontal dimension of the linkages between firms.

The Hydrogen Supply Chain and Value Network

An overview of the hydrogen supply chain is shown in Figure 111, (see next page). Across the horizontal dimension the segments of the core supply chain are shown, starting with the primary energy supply. These are complemented by a range of support services and industries which plan, supply, maintain, monitor, and inform the core supply chain. The system is also supported by hard and soft infrastructure such as the gas and electricity networks, transportation infrastructure and regulatory and policy frameworks (Section 10 Regulations and Policies).

For the hydrogen supply chain, the primary energy or feedstock supply will dictate the rest of the steps along the process. Primary energy supply includes electricity, nuclear energy (heat/electricity), and heat from fossil fuel combustion. Primary feedstock supply includes the raw materials which are used to create the hydrogen for example water in electrolysis and natural gas and water in SMR.

The next stage in the supply chain is the production (conversion) of the energy and feedstocks into hydrogen (as described in the pathways section, e.g. reformation, electrolysis, pyrolysis). The purification, compression and carbon capture steps are usually integrated within the production process, but can be performed by separate entities within the hydrogen supply chain, for example in the case of industrial by-product hydrogen, the purification, compression and storage is more suited to a second party than to the producer itself. Captured carbon involves a separate downstream supply chain, usually consisting of drying, compression, transport to a use or storage site (via truck, pipeline, etc.), and finally use or sequestration.

Once the hydrogen gas, liquid, or blended gas arrives at its point of end-use, it can be further compressed, stored, or dispensed. These stages of the chain will require additional cooling, compression, storage, metering, and other equipment depending on the application.

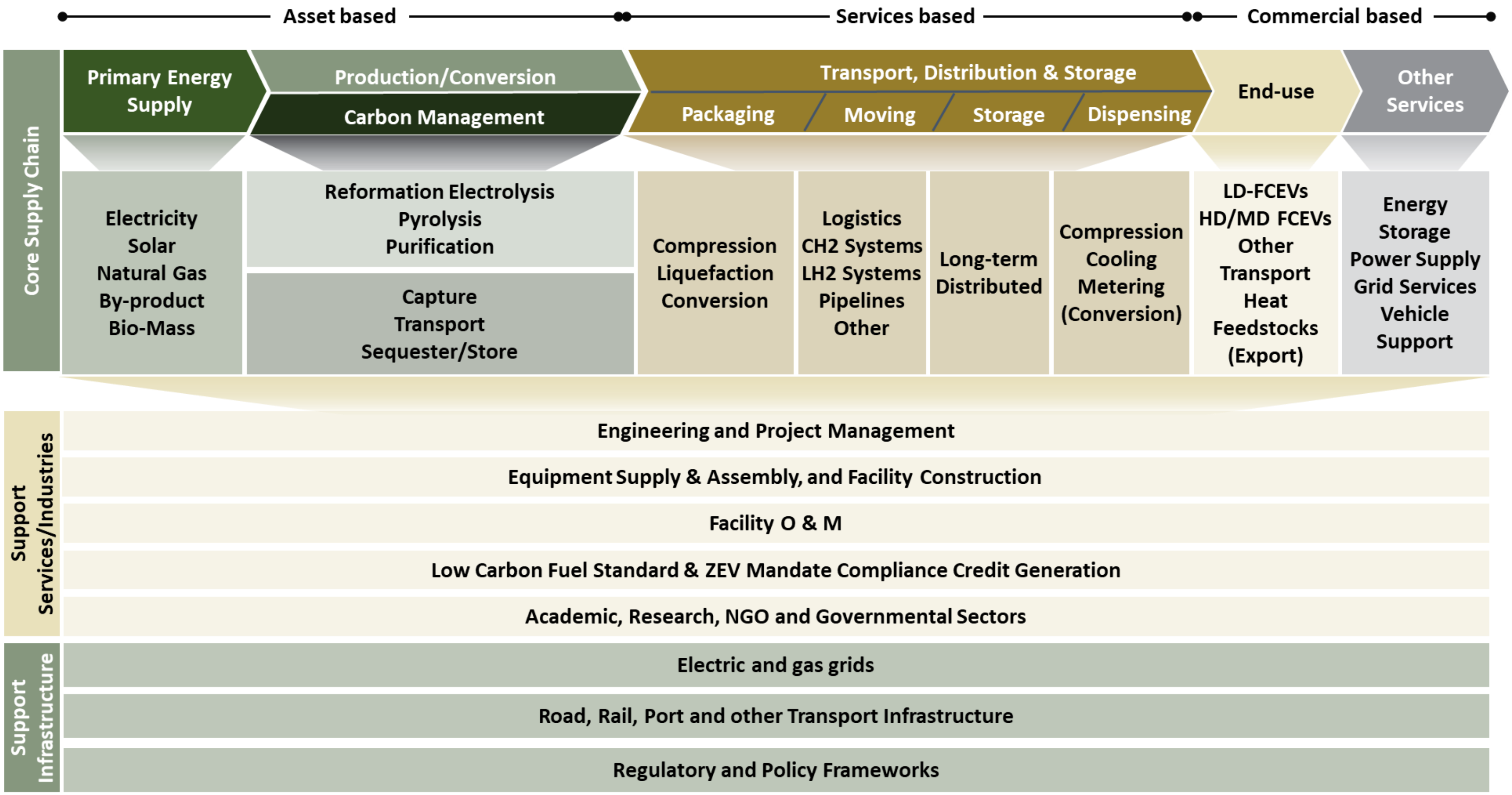

Figure 111 – Hydrogen supply chain overview

The resulting bulk H2 gas can then move through several possible channels on its way to its final conversion and end-use. In the case of Power-to-gas, the hydrogen will be piped to a blending and injection site along the natural gas pipeline. For bulk gas transport and distribution, the hydrogen can be moved via dedicated pipelines to its end-use location. Hydrogen for transportation, export, or other end-uses can either be compressed into gas vessels or, in the case of larger amounts and longer distances, liquefied into a cryogenic liquid and transported via truck, rail or ship. Finally, the bulk gas can be piped or transported to a storage facility for use and distribution in the future.

In addition to the horizontal supply chain of hydrogen delivery, there are many support services, ancillary processes, and underlying infrastructure that go into supporting the overall supply chain. For example,

- Hydrogen produced through electrolysis can provide additional benefits as a source of variable energy demand.
- Engineering and project management support services are required to plan, develop, and build infrastructure such as pipelines, rail networks and roadways.
- Equipment supply, assembly and facility construction services are required to supply the storage, compression, and purification equipment, the specialized transport vehicles, the liquefaction facilities, the temporary storage facilities and many other related components and parts.
- Another set of service providers are required to operate, maintain, monitor, and replace equipment, buildings and infrastructure once it is in place.
- Upstream production and downstream carbon management require their own equipment, buildings, infrastructure, and operating services.

Hydrogen Supply Chain Pathways in the Maritimes

As outlined above, there are numerous feedstocks for hydrogen production, a range of applicable production processes, many options for distributing hydrogen to customers (e.g., by pipeline, by truck or by on-site production), and many possible end-use applications (e.g., for power, heat or mobility, or as a material input to manufacturing processes). The various combinations could easily constitute hundreds of unique pathways, each with its own discrete assessment of value and competitiveness.

To narrow the scope of supply chain analysis and to better communicate the real-world examples that are likely to be seen in the Maritimes, several archetypes have been chosen (Figure 112).

Pathway Archetype	Input Energy System		Hydrogen Production	Distribution	End-use	Description
Elec1	Hydro	Power Lines (200km)	Electrolysis (large, centralized)	Liquid H2 delivered by truck (500km)	Light Duty Transport	Off-peak hydro for retail, LD transport
Elec2	Nuclear				MD/HD Transport	Baseload nuclear for bulk, HD transport
Elec3	Wind			Gaseous H2 delivered by truck (250km)	Light Duty Transport	Zero carbon for retail LD
Elec4	Wind			Gaseous H2 delivered by pipeline (500km)	Building heat	Displacing NG at residential building w/ blended H2
Elec5	Grid Average		Electrolysis (small, local)	Used on site	FCEBs	Transit yard self-generation
Gas1	Natural Gas w/o CCUS		SMR	Gaseous H2 delivered by pipeline (500km)	Industrial heat	Displacing NG at industrial site w/ blended H2
Gas2	Natural Gas w/ CCUS		SMR +CCUS		Building heat	Displacing NG at commercial building w/ blended H2

Figure 112 – Hydrogen pathway archetypes

As the strategy for hydrogen development in the Maritimes evolves, these archetypes can be used to perform a more detailed analysis of specific supply chains. For example, a key pathway in New Brunswick could be the **Elec2** pathway based on nuclear electricity and heat. This supply chain would need to consider the nuclear infrastructure, co-locating vs. remote electrolysis, the trade-offs between gaseous and liquid delivery for each potential market and the most likely end-use segments and their requirements.

Supply Chain Evolution

The supply chain for hydrogen in the Maritimes will evolve over time as more competition enters the industry and as more services and differentiated production pathways are added. At the same time, the global supply chain will be evolving at an accelerated pace and certain roles and functions will be integrated, consolidated, and commodified by large outside players. It will be critical for the maritime provinces to build out the supply chain for hydrogen in a deliberate and integrated way to form a critical mass of companies, academic institutions, talent pools, and related services. The cluster approach to industrial developed has been proven successful in many regions around the world including Northern Italy for the textile industry, South Korea for steel production, and South-western Germany for precision manufacturing.

The initial stages of supply chain development will be regional and will serve the domestic market with limited product and service offerings (Figure 113).

- The focus of the start-up phase will be on satisfying local demand for hydrogen production, distribution and storage, building capacity and improving products and services through innovation. The initial cluster of activity should be formed around a keystone or “anchor tenant” industry that provides a long-term, predictable form of demand for hydrogen. Examples of keystone industries in the Maritimes could include the ports and freight industries.

- The systemization and expansion stage will increase the volume of hydrogen supply available through better integration, higher efficiencies, lower costs, and economies of scale. Smaller players and sources of demand located near keystone consumers can pool their requests to generate higher overall demand.

- As the hydrogen economy develops globally and the maritime provinces become increasing integrated into Canadian and global supply chains for equipment, hydrogen supply and demand, transportation networks, and support service provision, the local supply change will need to restrict and focus on the comparable advantages such as access to transportation infrastructure, local knowledge of codes and standards, and access to aggregate local demand.

- The final phase of supply chain development will focus on developing differentiated product and service offerings that are competitive locally and well-integrated globally[117]

[117] Zailani, Suhaiza. (2012). Global Supply Chain Strategies and Practices: Synthesis from Literature.

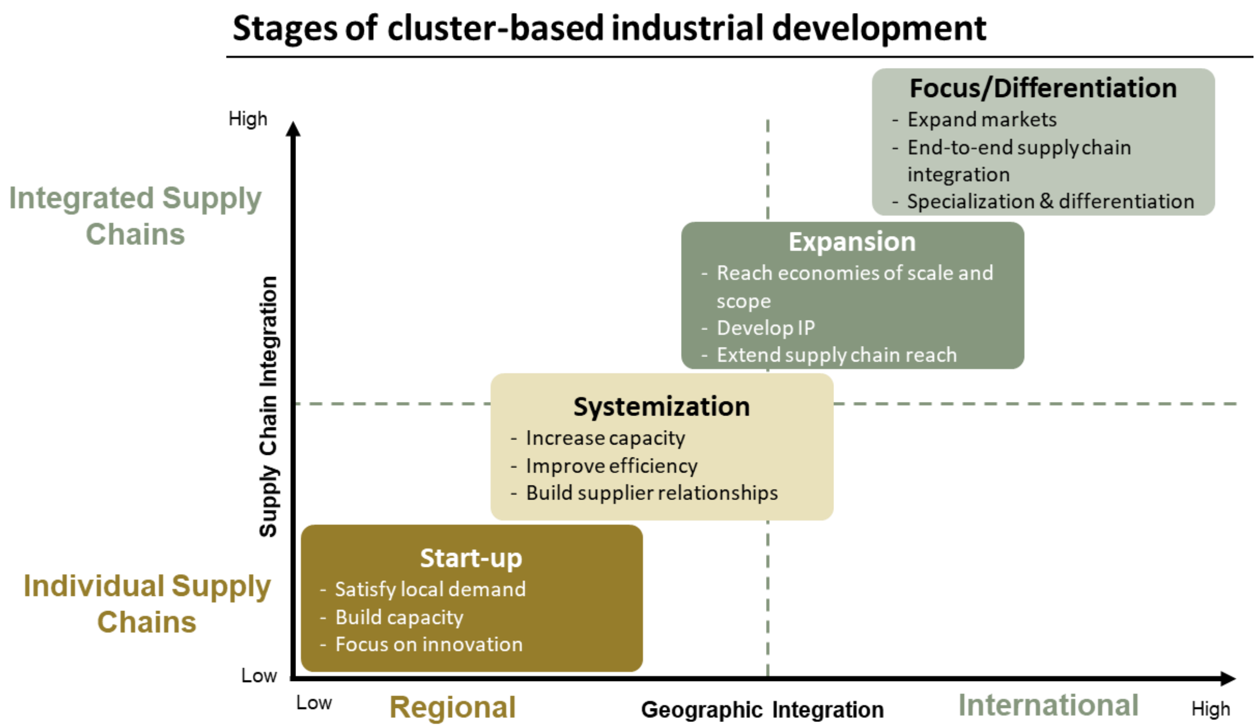

Figure 113 – Stages of cluster-based industrial supply chain development[118]

Opportunities and Challenges for Local Service Providers

This section discusses the areas of the supply chain that can be provided by local service providers and where expertise is lacking, including a SWOT analysis.

Overview of Current and Potential Local Service Providers

The Maritimes has a long history of resource extraction and other heavy industry, road/rail/marine transport, shipbuilding, and international trade. There are also many opportunities for organizations, skilled technicians, academic institutions, and other local services to pivot and/or participate in the hydrogen supply chain.

These companies are shown along the supply chain on the next page. As shown, there are several gaps in the supply chain where local players currently do not operate or are not well suited to transition to hydrogen. These areas will be filled by local product and service providers if they can find innovative ways to operate and stay competitive. Other areas such as specialized equipment manufacturing, and bulk hydrogen production will likely be done outside the region or will be supplemented and complemented by outside companies serving this market through local operations.

[118] Zailani, Suhaiza. (2012). Global Supply Chain Strategies and Practices: Synthesis from Literature.

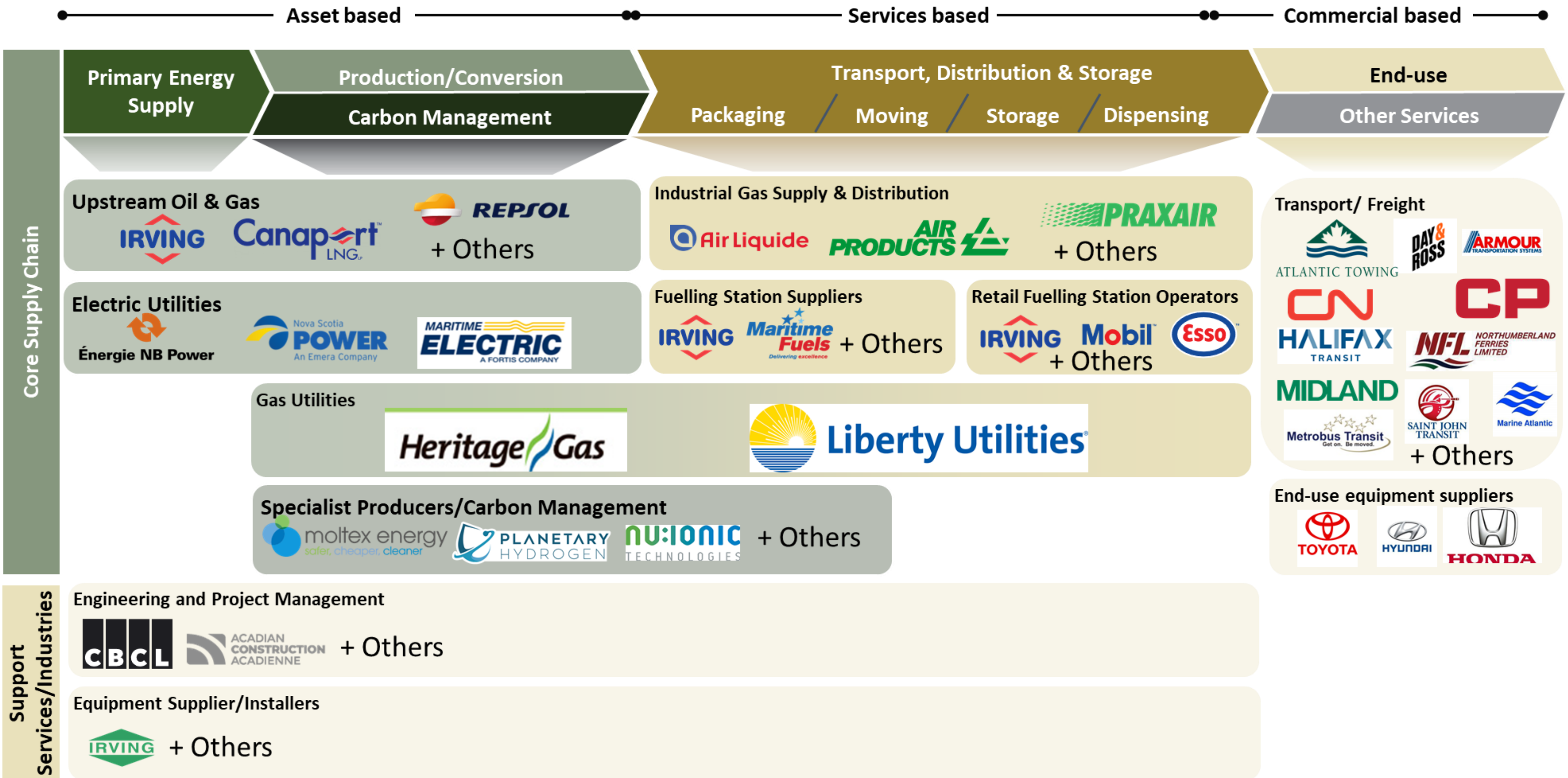

Figure 114 – Current and potential local service providers

Several local companies and players are already involved with the core hydrogen supply chain or would be able to provide equipment and services with minimal changes to their existing operations:

- **Primary Energy Supply & Production/Conversion**

  Primary energy supply in the Maritimes comes from a variety of sources as noted above. The main electricity providers are **Énergie NB Power**, **Nova Scotia Power**, and **Maritime Electric**. These providers are interconnected and would be able to serve electrolyzer loads from their transmission or distribution grids following an established planning process. The main gas utilities, **Heritage Gas** and **Liberty Utilities**, are well-positioned to serve as primary energy/feedstock suppliers to downstream production and conversion processes. The upstream/midstream oil and gas sector produces natural gas and refines imported crude and the two main players in the region are **Repsol** and **Irving Oil**. These companies could potentially produce hydrogen from their own fossil feedstocks or use it as process fuel or upgrading feedstock in their operations. The region is home to several innovative production/conversion technology companies including **Moltex Energy**, **ARC Nuclear**, **Planetary Hydrogen**, and **Nu:Ionic Technologies**. These players are actively involved with the hydrogen supply chain and could be producers or technology suppliers.

  Despite the large potential, there are significant gaps in expertise in hydrogen production and a limited number of companies that could fill this role at the scale required. This, combined with limited local feedstocks, implies a large part of the production segment will be served from outside the region in the near to mid-terms.

- **Transport, Distribution & Storage:**

  The main Industrial Gas Suppliers, **Praxair**, **Air Products** and **Air Liquide**, have operations or could service the Maritime region. As these firms are already well-established and experienced with both gaseous and liquid hydrogen, they could serve the hydrogen supply chain relatively easily. The firms operating in the downstream fuels distribution and retail/commercial fuel sales sector include **Irving Oil**, **Mobil/Esso**, **Shell**, **Maritimes Fuels,** and several others. These players could enter the hydrogen supply chain as fuel distributors and retailers, leveraging their existing infrastructure and real estate assets. The gas utilities mentioned above would be the primary distributors of hydrogen through the natural gas network and would serve as large storage reservoirs for the rest of the system.

  The main gaps in this part of the value chain include expertise working with and transporting high pressure gases, hydrogen retail sales, and fuelling station logistics/servicing.

- **End-use:**

  There are many potential end-users of hydrogen, but the main sources of demand are likely to come from transport/freight, transit, and industrial users. The transport/freight sector including road, rail and marine is a critical part of the region's economy. New Brunswick is the home base for 3 of Canada's top 20 largest trucking companies, including **Day&Ross**, **Armour Transportation**

Systems, and **Midland Transport**[119]. These companies operate hundreds of trucks throughout their coverage zones and could represent a large, near-term demand for hydrogen. For transit fleets, the largest operators are **MetroLink** (Halifax Transit), **Saint John Transit**, and **Metrobus** (St. John's). While these agencies are in their early stages of ZEB transition planning, a local source of hydrogen could make them ideal sites to operate FCEBs. The marine industry includes many potential opportunities for hydrogen especially for passenger ferry services (**Marine Atlantic**, **Halifax Transit**, **Bay Ferries**), and towing (**Atlantic Towing**). The rail industry is dominated by the national carriers (Canadian National Railway [**CN**], Canadian Pacific Railway [**CP**], and **Via**) so demand from this sector will be dependent on their larger national strategies. On the industrial side, the pulp and paper (**J.D. Irving**), cement (**Lafarge**, **Atlantic Ready Mix**, **McInnis Cement**), and fertilizer (**Atlantic Potash**) firms are also potential sources of demand.

The clear gap in this sector is that, while there are many potential end-users for hydrogen, there have been very limited deployments to date. The industry will need to rapidly transition and aggregate demand with and natural gas end-users in order to be viable.

Other companies that operate in adjacent industries include construction, equipment manufacturing, transportation, carbon capture and storage, fuelling station operators, and operations/maintenance companies:

- **Engineering Project Management, & Construction:**

  The engineering, project management, and construction industry is well-established in the Maritimes with a range of international, national, and local firms. As with most parts of the country, specific engineering expertise related to hydrogen production and distribution systems is in its early stages. A more specialized hydrogen-centred engineering sector could eventually evolve in the region, but this expertise is likely to be imported in the near-term.

- **Equipment manufacturing/supply:**

  Similarly, for the equipment manufacturing and supply industry a range of existing international, national, and regional firms serve the Maritimes and could pivot to manufacturing or integrating hydrogen systems from local and international parts. Certain elements of the hydrogen supply chain such as pipes, fittings, compressors, storage vessels and other components are highly transferrable from other industries such pulp and paper, shipbuilding, oil and gas and industrial gas supply. Specialty component such as electrolyzers, fuel cell modules, high pressure storage tanks, and measurement equipment are likely to be dominated by international firms with extensive intellectual property and access to global markets.

[119] Trucknews. (2020). Canada's Top 100 Truck Fleets Topped by TFI International. Retrieved from https://www.trucknews.com/transportation/canadas-top-100-truck-fleets-topped-by-tfi-international/1003141460/

SWOT Analysis

The competitiveness of the region's existing hydrogen supply chain companies and those who could pivot to the new industry will depend on their relative Strengths, Weaknesses, Opportunities and Threats (SWOT) compared to outside players entering the region and/or other countries or regions.

Table 23 – SWOT analysis

Strengths	**Weaknesses**
◆ Strong integrated road, rail and marine transportation networks and established freight, rail and shipping companies ◆ Modern natural gas infrastructure and pipelines that can accept hydrogen blending ◆ Interconnected electrical grid with access to surplus supply via inter-regional trade ◆ Atlantic Canada is ranked among the lowest business-cost locations within G8 countries[120]	◆ Relatively nascent hydrogen industry with limited activity and history ◆ Small, diverse regional demand making aggregation more difficult ◆ Electricity generation is a mix of low-carbon (wind, hydro, nuclear) and high carbon (oil, gas, coal) sources ◆ Limited excess grid capacity and high electricity prices for large baseload electrolysis
Opportunities	**Threats**
◆ a Large regional and international marine sector including port infrastructure and ship building ◆ Well-establish academic and research institutions and nascent clean tech start up industry ◆ Export and transport-focused economy with Canada-leading experience in LNG ◆ Home to more post-secondary graduates per capita than the Canadian and U.S. averages, resulting in a highly skilled labour force[121]	◆ Competition from other regions in Canada, US and globally for access to key markets in North-East US and Europe ◆ Significant differences in provincial policies and priorities could lead to a less cohesive approach

[120] Government of Canada. Clean Energy and Related Industries of Atlantic Canada. Retrieved from https://www.canada.ca/en/atlantic-canada-opportunities/services/clean-energy-and-related-industries-of-atlantic-canada.html
[121] Ibid.

8. CARBON CAPTURE AND SEQUESTRATION

CCUS Technology Description

Geological CCUS technology is an established method for long-term storage of carbon dioxide gas. The technology for CO2 injection was first developed and utilized by the oil and gas industry to enhance oil recovery (CO2-EOR). This process involves CO2 injected into wells to displace oil and gas from porous rocks into wells where the products can be removed. In the 1990s, there were 66 projects in the USA utilizing this process to recover oil through high pressure CO2 injection.[122] Industrially, CO2 injection is also utilized to enhance methane recovery from coal beds. A CO2 and nitrogen (N2) mixture is injected into a coal bed to displace the methane adsorbed onto its pores.[122]

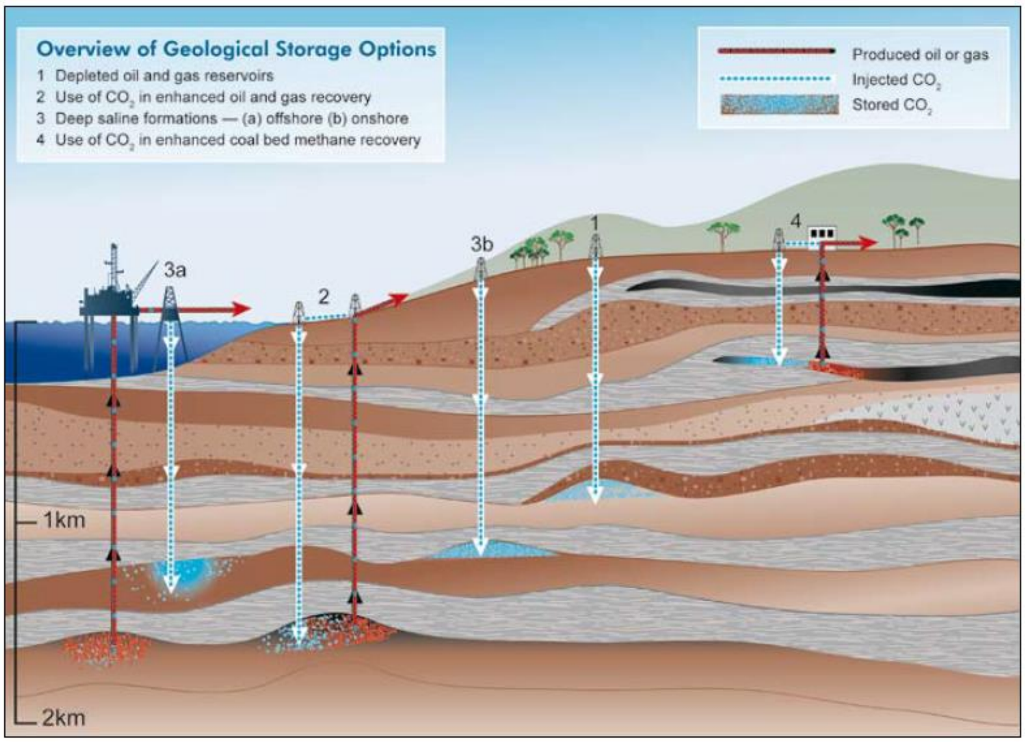

Figure 115 – Overview of Geological Storage Options[123]

In general, CCUS Process involves four main steps:

1. Capture of CO2
2. Compression
3. Transportation
4. Injection

[122] National Academy of Engineering National Research Council. (2002). The Carbon Dioxide Dilemma. Retrieved from https://www.nap.edu/read/10798/chapter/3#16
[123] Intergovernmental Panel on Climate Change. (2005). Carbon Dioxide Capture and Storage. Retrieved from https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_wholereport-1.pdf

The major costs of CCUS are in the capture and compression stages assuming the CCS takes place near the site of production. There are a variety of industrial methods available for capturing and purifying CO2 from industrial effluent streams. Carbon dioxide must then be compressed to its supercritical state, where its density increases by 200x to maximize storage capacity of the reservoir. This requires the storage site must be > 800m below the ground in order to maintain this state. Table 24 below shows cost estimate of each step from a study on Canadian CCUS opportunities performed by the Pembina institute in 2005.

Table 24 – Cost of carbon capture and storage[124]

Activity	Cost ($USD/tonnes-CO2)	Uncertainties
CO2 capture (including compression)	5 to 50 (current) 5 to 30 (future)	♦ Low end for pure streams that only need compression ♦ High end for chemical adsorption from gas-fired combined cycles
CO2 transportation	2 to 20	♦ Depends on scale and distance
CO2 revenues	-55 to 0	♦ No benefits for aquifers; highest benefits for certain enhanced oil recovery projects
Total	-40 to 100	

In addition to these steps, continuous rigorous monitoring of the injection site and storage space is required. Example safeguard procedures include:

- CO2 is heavier than air, which makes it an asphyxiation hazard if large leaks arise. Constant monitoring of CO2 movement within the reservoir and at the surface is required
- Monitoring of groundwater to look for signs of contamination. An increase in CO2 may increase leaching of harmful compounds such as lead and arsenic from the surround rocks
- Monitoring of storage space pressure to detect buildup that could fracture caprock and create major leaks

Carbon sequestration has been successfully demonstrated in many projects worldwide including:

- **Sleipner Project:** started up in 1996 in the North Sea ~240 km off the coast of Norway. Here, CO2 is compressed and pumped into a 200 m thick sandstone layer 1000 m below the seabed. The incremental investment cost was $80 million, with ~1 million metric tons of CO2 (3% of Norway's annual emissions) sequestered annually[125]
- **Weyburn-Midale Project** in Saskatchewan was one of the world's first five fully integrated commercial CCUS projects. The project utilizes CO2 emissions captured in North Dakota, which is

[124] Griffiths, M., Cobb, P., Marr-Laing, T. (2005). Carbon Capture and Storage: A Canadian Primer. Retrieved from https://www.pembina.org/reports/CCS_Primer_Final_Nov15_05.pdf
[125] Herzog, H. (2001). What Future for Carbon Capture and Sequestration? Retrieved from https://pubs.acs.org/doi/pdf/10.1021/es012307j

transported 300 km across the border via pipeline for enhanced oil recovery operations, as well as storage

CO2 storage in underground sedimentary formations are the most mature technique for storage. This has been utilized for two decades globally and store 3.7-4.2 MtCO2/year. This technology requires an impermeable caprock, which seals and traps the injected CO2[126] On a global scale, the prospects for CO2 capture and storage have been estimated by the IEA:

Table 25 – Worldwide capacity of potential CO2 storage sites[124]

Sequestration Option	Worldwide Capacity for CO2
Oceans	1,000 Gt
Deep Saline Formations	100-10,000 Gt
Oil and Gas Reservoirs	100-1,000 Gt
Coal Seams	10-100 Gt
Terrestrial Ecosystems	10 Gt
World Emissions of CO2 for 200	25 Gt

Opportunities and Challenges for CCUS in the Maritimes

CCUS will be critical in mitigating GHG emissions from large industrial sources in the Maritimes. Figure 116 below identifies large industrial emission sources relative to the location the Maritimes' geological basins.

Carbon Capture and Storage Research Consortium of Nova Scotia (CCSNS) was a non-profit consisting of Province of Nova Scotia, Nova Scotia Power, and Dalhousie. CCSNS has identified the Sydney Sub-basin as high potential for on-shore geological storage. This basin is a large carboniferous structural basin located in eastern Cape Breton Island. As shown in Figure 117, RPS Energy identified five potential CO2 storage sites (A1-A5).

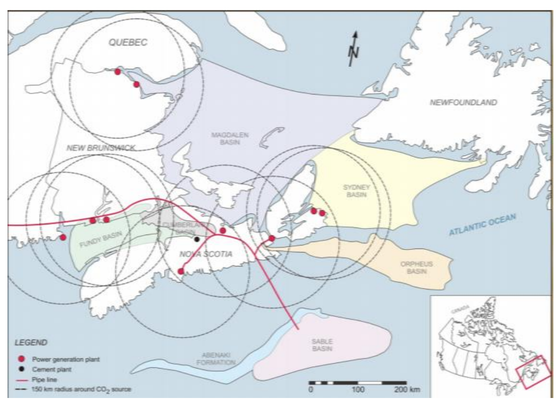

Figure 116 – Map of large industrial emission sources in the Maritimes[127]

As mentioned in the background section, a successful geological sequestration operation requires a combination of porous underground sedimentary formations and caprock seal. The area of interest to the study was the Cranberry Half-Graben (A4) where the Horton Group is at sufficient depth for storage of CO2 (> 800m). The Horton group consists

[126] Keelman, P., Benson, S. M., Pilorgé, H., Psarras, P., Wilcox, J., (2019). An Overview of the Status and Challenges of CO2 Storage in Minerals and Geological Formations. Retrieved from https://www.frontiersin.org/article/10.3389/fclim.2019.00009

[127] Pothier, H., Wach, G. D., Zentili, M. (2011). Reservoir and Seal Pairs: Carbon Sequestration in Atlantic Canada. Retrieved from https://cdn.dal.ca/content/dam/dalhousie/pdf/faculty/science/earth-environmental-sciences/basinReservoirLab/Carbon_Sequestration2011.pdf

of conglomerate, sandstone, and siltstone and potentially contains porous and permeable zones for CO2 injection. The capstone in the proposed injection site is the Windsor Group.

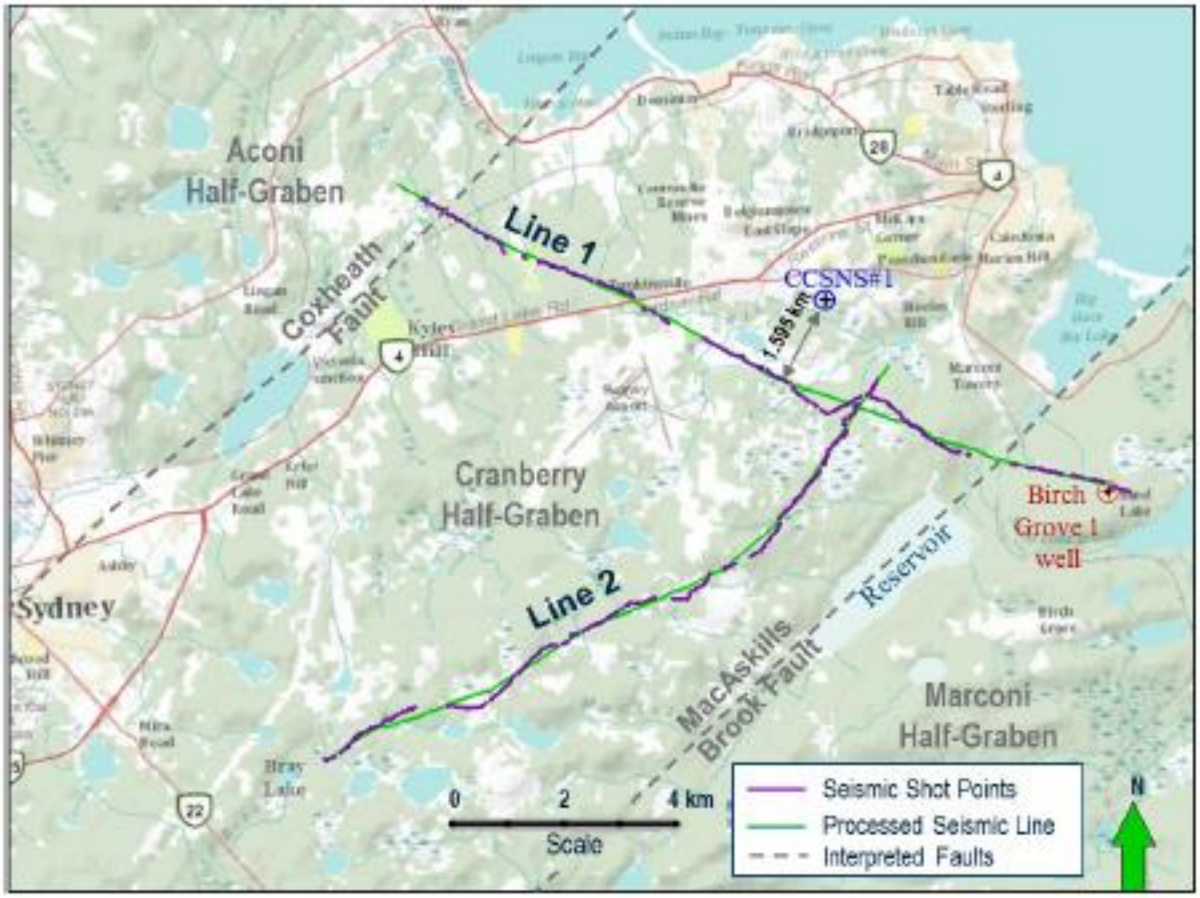

Figure 117 – Potential CCUS sites in the Maritimes[128]

The objectives of the 2015 CCSNS study were to gather further data to update and validate the model developed from the two predecessor studies and 2D seismic survey. A stratigraphic test well was drilled at CCSNS #1 location, as shown in Figure 118, to investigate the composition of the Windsor and Horton Groups at this location.

Figure 118 – Windsor Group test facility[128]

The results confirmed the Windsor Group is composed of a very tight dark grey shale with occasional units of grey-white siltstone. This confirms its compatibility as a caprock for CCUS. It was found to be thinner than modelled in the 2011

[128] CCS Nova Scotia. (2015). CCS Nova Scotia: Stratigraphic Test Well and Implications for CO2 Storage.

study, 311m thick at CCSNS #1. To investigate the Horton Group, a sample was collected at 1424m and 1526.7m depths. The samples showed very tight rhyolite, which is not suitable for CO2 storage. Based on these findings, the report concluded the Horton Group must be present in this area, just not at the CCSNS #1 test well location.

The updated models decreased the estimation of onshore CO2 storage capacity to 35% of the original estimates in 2011 feasibility study from 2.637*10^11 m^{3}3 to 9.610 *10^{10}m^3. The Horton Group was thought to be a homogenous formation, where the drilling results showed it may not be. Using the updated capacity estimate, the formation is capable of storing approximately 44 Gt of CO2.

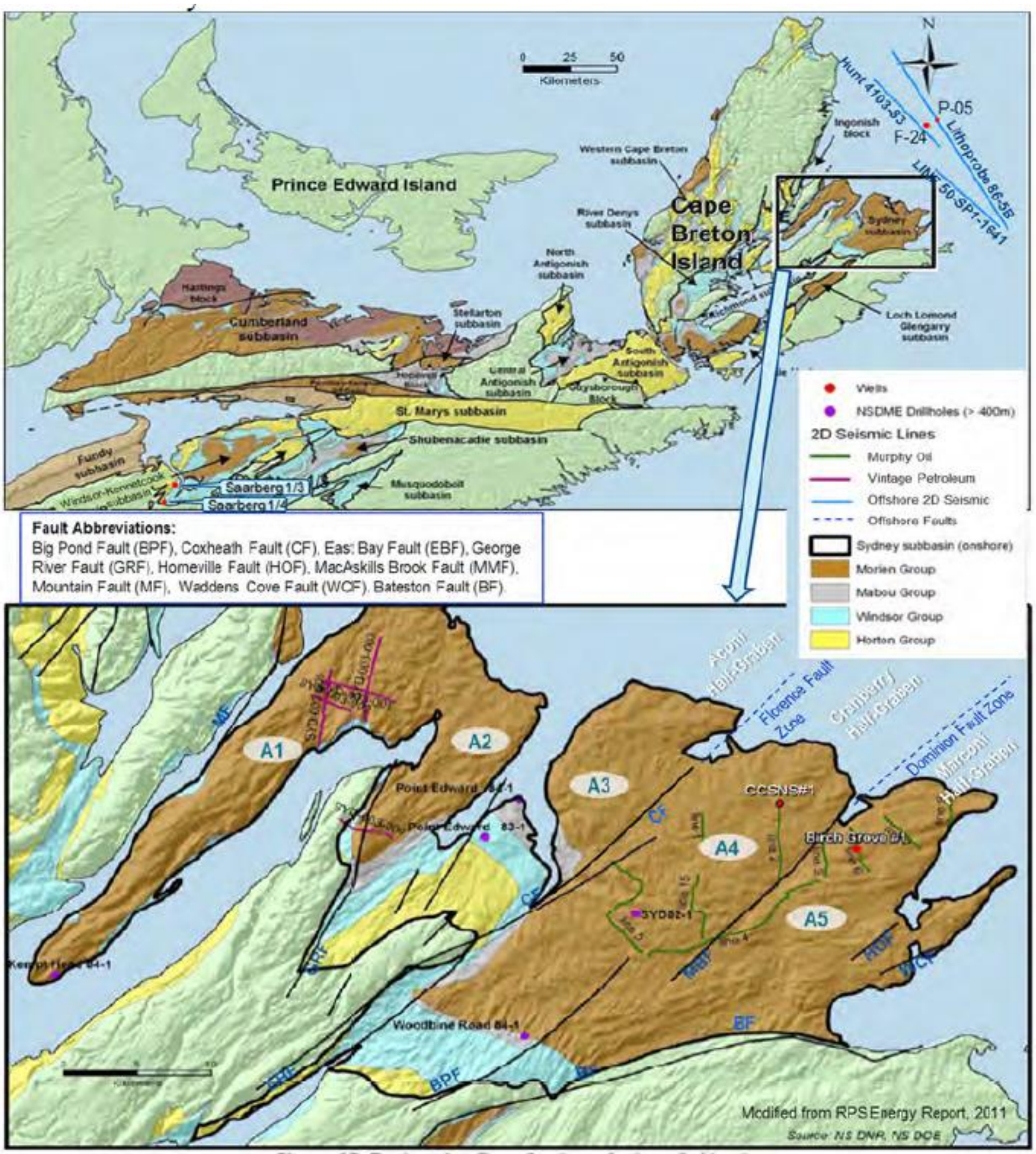

Figure 119 – Map of five potential CCUS sites identified by RPS Energy and the CCSNS#1 test well site[128]

Recommendations for Further Study

Further investigative work is required to further evaluate and refine model for the Sydney Sub-basin. The study wasn't able to draw any new conclusions or update the current model on the aspects relating to porosity, permeability, and lithology. The CCSNS report recommended and performed cost estimations on several follow up actions in order to fully characterize the Sydney Sub Basin, including acquiring a new seismic line extending through CCSNS#1 to reveal the nature of the basement topography and potentially drilling a new well on the existing 2D seismic lines in storage area A4.

After the site qualification and modelling characterization work is complete, follow up work is required to develop the project after prospecting.

- Economic Analysis to determine the project's capital and operational costs and identifying funding sources
- Locating carbon sources and organizing logistics of transportation, such as the construction of a dedicated pipeline from large emitters or integration into an existing network.
- Risk assessment and safeguard implementation to mitigate environmental and health hazards such as setting up surface and groundwater monitoring programs and deploying pressure buildup sensors

There are other basins which were identified by Dalhousie's research into Atlantic Canada's CCUS Opportunities. These locations will be more costly to fully characterize and develop since the sites are offshore. These include the Magdalen. Fundy, Sable, Abenaki, Cumberland and Orpheus Basins shown in the figure below.

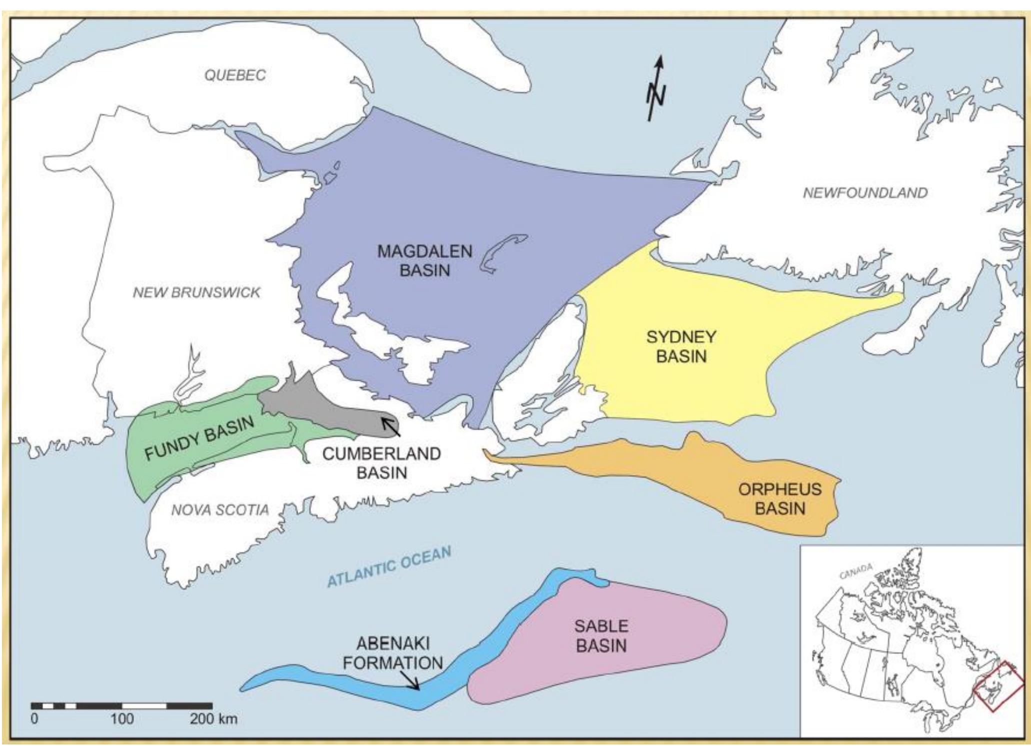

Figure 120 – Map of basins in the Maritimes[127]

9. NATIONAL POTENTIAL FOR HYDROGEN

Current Hydrogen Related Activity Across Canada

Hydrogen Strategy for Canada

For the past three years, NRCan has been working with private sector stakeholders and governments at all levels to inform the development of a *Hydrogen Strategy for Canada*. The *Strategy* is expected to be released in the fall of 2020 and will include a high-level overview of the state of hydrogen in the country, the production pathways and end-uses, the economic and export opportunities, and the remaining challenges and next steps. To ensure regionally specific opportunities are fully realized, the strategy is intended to be complemented with regional blueprints, such as this study for the Maritimes.

The *Strategy* is expected to demonstrate how hydrogen can play a critical role in the future of Canada's energy system and in achieving GHG emission reduction targets. Some of the high-level findings of the report and modelling work include:

- By 2050, hydrogen could represent as much as 30% of delivered energy in a net-zero energy system in Canada and could be the main component of the natural gas network, a key transportation fuel, and low-carbon feedstock for industry
- Hydrogen could also have significant GHG reduction potential and serve as the main mechanism to decarbonate the top-third of hard to abate sectors such as HD transport, heat, feedstocks, and the natural gas network
- Electrification will also play a key role in a 2050 net-zero energy system and hydrogen can provide a key source of variable demand and large-scale seasonal energy storage
- Significant investment will be needed and well thought out regional policies and shovel ready projects will benefit from release of this strategy

Canada's momentum on hydrogen

Canada is already one of the top 10 hydrogen producers in the world today and is known for its leading hydrogen and fuel cell technology companies and expertise. As of 2017, there were >100 established companies, employing >2100 people, generating revenues >$200 million. Canada's expertise and technologies are exported and used in countries around the world, demonstrating the opportunity for growth and deployment on an international scale

While domestic deployments are limited, the sector is not starting from zero. There are activities related to low CI hydrogen production and use happening across Canada, examples of which are shown in Figure 121. There are strategic hydrogen production and liquefaction assets in Eastern Canada, and end use applications range from deployments of light duty fuel cell cars and hydrogen retail fueling infrastructure, to pilot projects to explore blending of hydrogen into natural gas networks to decarbonize natural gas. There are also many projects in development and regional studies being conducted to explore hydrogen opportunities. This infographic does not include production and use of grey hydrogen in the oil and gas and fertilizer production sectors, which represent an opportunity for conversion to low CI supply, providing important anchor tenants as production capacity of low CI hydrogen in Canada is expanded.

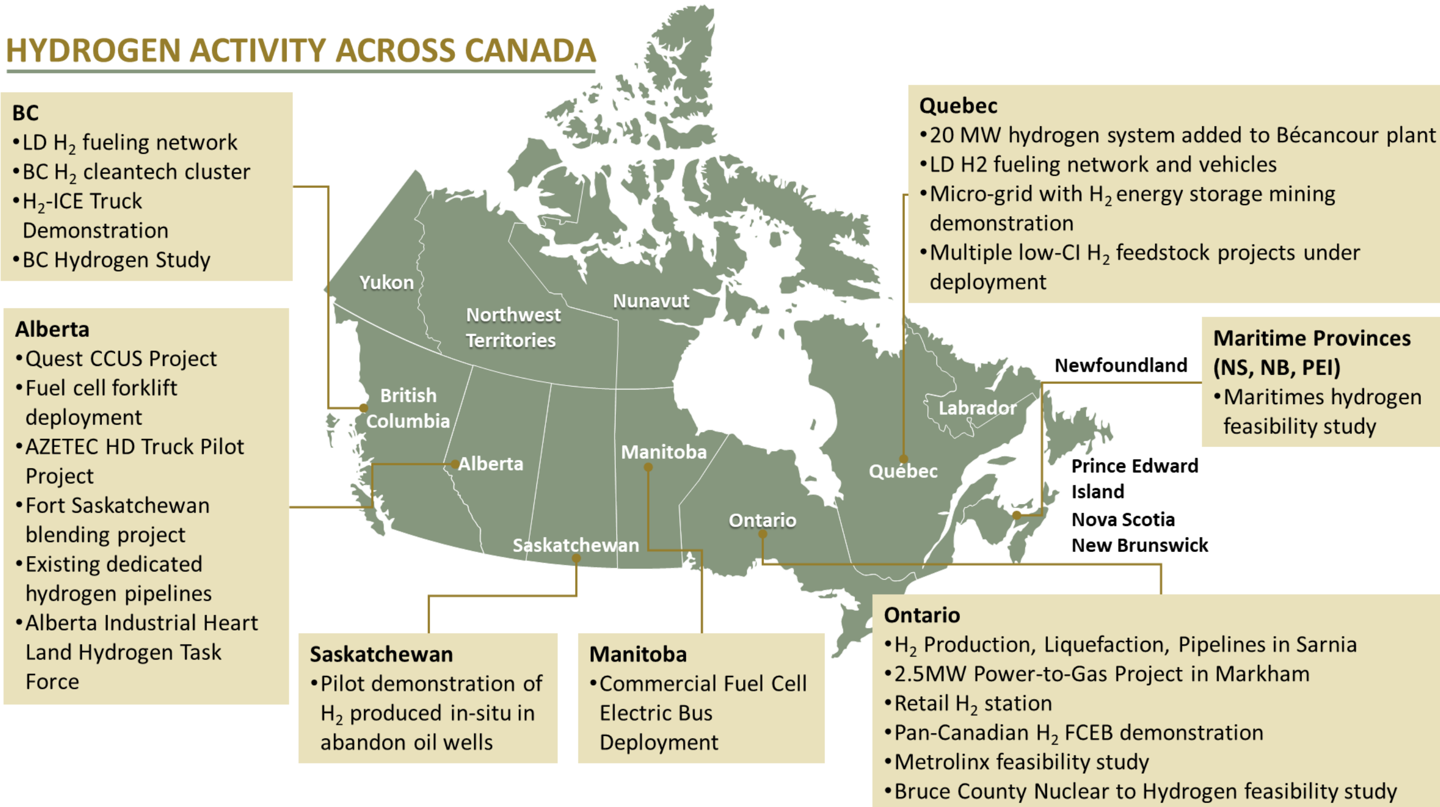

Figure 121 – Hydrogen activity across Canada

Alignment with the National Strategy

The recommended actions and next steps in the *Hydrogen Strategy for Canada* will inform the development of concrete action plans in the implementation phase. The Maritimes hydrogen blueprint will be regionally specific but should aim to align wherever possible with the hydrogen strategy for Canada.

The *Hydrogen Strategy* draft recommendations have been grouped under 8 pillars: 1) Strategic Partnerships, 2) De-Risking of Investments, 3) Innovation, 4) Codes and Standards, 5) Enabling Policies and Regulation, 6) Awareness, 7) Regional Blueprints, and 8) International Markets. The full list of recommendations will be available when the *Strategy* is released but several key themes that are relevant with this study are summarized below.

Table 26 – Recommendation themes from Hydrogen Strategy for Canada

***Hydrogen Strategy* Recommendation Themes**	**Relevance to the Maritimes**
Cross-sector Collaboration	◆ A key to the success of the *Hydrogen Strategy* will be the close collaboration between public and private sectors. In the Maritimes, cross-sector collaboration will be required in order to co-fund pilot projects, to develop codes and standards, and to help develop a deep pool of skilled workers. It is recommended that provincial and municipal governments and private companies participate in the *Strategy* implementation working groups to ensure the Maritime provinces are well represented at the national level.
Domestic Deployment Hubs	◆ Hydrogen developments across Canada will start in clusters of concentrated centres of demand and supply. In the Maritimes, the development of one or more regional deployment hubs and associated supply chains will be crucial for success. To align with the *Hydrogen Strategy*, the Maritimes provinces should propose several potential "shovel-ready" projects that showcase deployments of hydrogen technology at scale.
Inter-provincial Authority Having Jurisdiction (AHJ) Collaboration	◆ The development of codes and standards needs to be supported by inter-provincial collaboration between AHJs. In the Maritimes, cross-provincial collaborations can help with training AHJs on a common implementation approach for new codes and standards related to hydrogen.
Presence in Overall National and Provincial Clean Energy Roadmaps	◆ At the national level, hydrogen will need to factor into the overall strategy for clean energy and climate change. Existing and new provincial strategies will likewise need to incorporate and align hydrogen as opposed to keeping it as a set separate initiatives.
Intergovernmental Collaboration	◆ Collaboration between federal and provincial governments will be a key pillar of the Hydrogen Strategy. Within the Maritimes a common strategy shared by Nova Scotia, New Brunswick and PEI, will be important to building a critical mass of projects and ensuring a critical mass of supply and demand for Hydrogen.

10. REGULATION AND POLICY

Current Hydrogen Related Policies and Regulations in the Maritimes

There are several overlapping sets of policies and regulations that could affect the development of the hydrogen sector in the Maritimes. Depending on where in the supply chain, the geographic location, technologies, and players involved, the regulation and policy impacts will be different. Policies and regulations can be classified across several dimensions including mandate scope (e.g. federal, provincial, municipal), value chain process or element (e.g. production, distribution, end-use), and type (e.g., policies, programs, regulations). This report will briefly cover the relevant federal regulations and policies affecting the hydrogen supply chain followed by a breakdown by province and by sector.

General Regulations and Policies

Cross-sectorial or industry-wide regulations and policies focused on climate change, economics and the environment will have the largest impact on the hydrogen supply chain. These overarching strategies will dictate the scope and requirements of sector-specific regulations, policies, codes and standard, both at the federal and provincial levels.

Relevant Federal Legislation, Policies and Programs

In 2019, the federal government commissioned an environmental scan and gap analysis of legislation, policies and programs, and codes and standards related to hydrogen in Canada, including related effects on hydrogen deployment and use across the Canadian economy[129]. The study also identified the gaps and areas where additional tools may be needed to further enhance the development of the Canadian hydrogen industry. Currently, Canada has hydrogen-specific instruments in the following policy areas:

- Health and safety
- Environmental
- Infrastructure
- Research and development

Many of the federal hydrogen legislation, policies, and programs in Canada fall under the mandates of Transport Canada, the National Research Council, and Environment and Climate Change Canada. Table 27 provides a full summary of the federal legislation, policies, and programs that apply directly to the hydrogen economy.

[129] Delphi Group. *Federal Regulatory Instruments and Non-Regulatory Programs that Impact Hydrogen Production, Distribution and Use in Canada*. November 2019. Natural Resources Canada.

Table 27 – Relevant federal legislation, policies, and programs

Federal Department/ Agency	Regulatory Instruments	Non-regulatory Instruments
Environment and Climate Change Canada	• Canadian Environmental Protection Act • *Clean Fuel Standard (proposed)*	• Pan-Canadian Framework on Clean Growth and Climate Change
Infrastructure and Communities		• Investing in Canada Plan • Smart Cities Challenge
Innovation, Science and Economic Development Canada	• Electricity and Gas Inspection Act • Weights and Measures Act	
Natural Resources Canada		• National Jet Fuels Combustion Program • Electric Vehicle and Alternative Fuel Infrastructure Deployment Initiative • Fuel Consumption Guide • EnerGuide for Vehicles • Electric Charging and Alternative Fuelling Stations Locator • FleetSmart Fuel-Efficient Fleet Management • Green Freight Assessment Program • Greening Government Services • Green Mining Innovation • SmartWay Transport Partnership • Oil and Gas Clean Tech Program • Clean Growth Program
Public Services and Procurement		• Policy on Green Procurement
Transport Canada	• Canada Transportation Act • Motor Vehicle Fuel Consumption Standards Act • Motor Vehicle Safety Act • Railway Safety Act	• Carbon Offsetting and Reduction Scheme for International Aviation • Memorandum of Understanding (MOU) between Transport Canada and the Railway Association of Canada for Reducing Locomotive Emissions • Transportation 2030: A Strategic Plan for the Future of Transportation in Canada • ecoTECHNOLOGY for Vehicles Program • Clean Transportation Initiatives • Northern Transportation Adaptation Initiative Program • Shore Power Technology for Ports • Clean Rail Academic Grant Program • National Trade Corridors Fund

Federal Department/ Agency	Regulatory Instruments	Non-regulatory Instruments
		• Canada's Action Plan to Reduce Greenhouse Gas Emissions from Aviation • Ports Modernization Review
Transport Canada Collaboratives		• Global Air Navigation Plan (with the International Civil Aviation Organization) • Initial IMO Strategy on Reduction of GHG Emissions from Ships (with the International Maritime Organization) • National ZEV Strategy (proposed with Innovation, Science and Economic Development Canada)
Treasury Board		• Greening Government Strategy

These Federal policies and regulations will have a generally positive effect on the development of hydrogen as an alternative, green energy carrier. Regional and provincial regulations and policies should be designed with these federal strategies in mind to be as effective as possible.

Nova Scotia

The overarching pieces of legislation concerning climate and the environment in Nova Scotia are the *Environmental Goals and Sustainable Prosperity Act* of 2007 and the *Sustainable Development Goals Act (SDGA)* of 2019. In 2020-21, Nova Scotia will be releasing its *Climate Change Plan for Clean Growth* to outline how the province will achieve GHG emission targets of 53% below 2005 levels by 2030 and net-zero by 2050. The existing Climate Action Plan contains a number of potential opportunities for hydrogen; however, these are mostly outdated and will be replaced by the upcoming SDGA regulations and Climate Change Plan for Clean Growth.

New Brunswick

The *Transitioning to a Low-Carbon Economy, New Brunswick's Climate Change Action Plan* was endorsed in 2018 by New Brunswick Premier Blaine Higgs. The Plan lays out GHG reduction targets of 35-45% below 1990 levels by 2030 and 75-85% below 2001 levels by 2050. There are several areas where hydrogen could play a role in achieving these targets including:

- ♦ Reducing emissions from the government's 4,500 fleet vehicles to become carbon neutral by 2030.
- ♦ Phasing out the use of fuel oil for heating publicly funded buildings and replace it with low-carbon fuels such as wood pellets, natural gas, biomass and solar energy.
- ♦ Implementing an electric vehicle strategy that specifies the required incentives, regulations, policies, programs and charging infrastructure to achieve the above-mentioned targets for electric vehicles.

- Working with industry, transport companies and other stakeholders to identify opportunities and partnerships to facilitate multi-modal transportation (road, rail, marine and pipelines) aimed at improving efficiencies (e.g., logistics) and reducing GHG emissions.
- Working with freight trucking partners to improve the fuel efficiency of freight trucks by installing proven fuel-saving devices such as aerodynamic features and new engine technologies while addressing regulatory barriers to implementation; piloting the use of alternative fuels such as natural gas will also be considered
- Set emissions limits on the largest industrial emitters in consultation with relevant stakeholders, the federal government and other provinces to ensure that the measures are effective in reducing GHG emissions and are fair and equitable.

Prince Edward Island

The *Climate Change Action Plan for Prince Edward Island* is the main climate plan of PEI and outlines the 2030 goal of reducing GHG emissions by 40% below 2005 levels, a 1.2 Mt CO2e reduction. An update in 2019 showed PEI's GHG emissions to be 10% below 2005 levels, or 25% of the way towards the 2030 target. The plan contains the following policy and regulatory plans and targets that will influence hydrogen demand:

- Committing to the development of 500 MW of wind generated power on Prince Edward Island
- Considering the introduction of escalating Renewable Fuel Standards for bioethanol and biodiesel
- Endorsing the concept of a Low-Carbon Fuel Standard, to reduce greenhouse gas emissions, through the increased use of environmentally and economically sustainable biofuels

Gas Industry

The most immediate role for hydrogen is as a fuel in the natural gas network. The regulation and policies that will most impact this blending could be Environment and Climate Change Canada's Clean Fuel Standard, and for some applications, the Finance Canada Capital Cost Allowance for clean energy generation and energy efficiency equipment. As it relates to the gas industry, there are three primary types of code documents: gas installation codes (Canadian Standards Association [CSA] B149 series); boiler and pressure vessel codes (CSA B51 series); and oil and gas pipeline codes (CSA Z662 series). Specifically, for hydrogen, there also exists the Canadian Hydrogen Installation Code (CAN/BNQ 1784-000). These codes set the standards for hydrogen blended in the natural gas network, used in boilers and end use equipment, and how infrastructure such as refuelling stations are designed and installed. These codes and the relevant Authorities Having Jurisdiction are summarized in Table 28.

Table 28 – Gas industry codes[130]

Code		Canadian Hydrogen Installation Code	Boiler and Pressure Vessel Code	Gas Installation Code	Oil and Gas Pipeline Code
Number		CAN/BNQ 1784-000	CSA B51	CSA B149 series	CAN/CSA-Z662
Federal Authorities Having Jurisdiction		Interprovincial Gas Advisory Council (IGAC)	Boiler and Pressure Vessels (ACI)	Interprovincial Gas Advisory Council (IGAC)	National Energy Board
Province	**Gas Regulation(s)**	**CHIC adopted in Regulation?**	**Provincial Authorities Having Jurisdiction**		
New Brunswick	NB Reg. 84-177	Yes	Justice and Public Safety Technical Inspection Services	Justice and Public Safety Technical Inspection Services	New Brunswick Energy and Utilities Board
Newfoundland and Labrador	NLR Reg. 119/96 Public Safety Act O.C. 96-427	Yes	Service NL, Newfoundland & Labrador	Service NL, Newfoundland & Labrador	No crude oil or natural gas pipelines
Nova Scotia	Fuel Safety Reg. (NS Reg. 11/2011) Technical Safety Standards Reg. (NS Reg. 102/2014)	No	Nova Scotia Department of Labour and Advanced Education, Technical Safety Division, Fuel Safety Section	Nova Scotia Department of Labour & Advanced Education, Technical Safety Division, Fuel Safety Section	Nova Scotia Utility and Review Board
Prince Edward Island	Boilers and Pressure Vessels Act Regulations Chapter B-5	Yes	Government of Prince Edward Island	Government of Prince Edward Island – Department of Agriculture and Land	No crude oil or natural gas pipelines Hydrogen pipelines: Department of Agriculture and Land

[130] KauliNG Solutions. (2019). Natural Resources Canada. Environmental scan and gap analysis of codes and standards related to hydrogen in Canada.

Transport Industry

As the largest potential source of demand for pure hydrogen in the Maritimes, policies and regulations affecting hydrogen use in transportation will have a major impact. High vehicle capital cost and the lack of refuelling infrastructure have created a dilemma for early adopters and developers. Economies of scale on both sides of supply and demand are required to bring down costs and increase adoption. Policies and regulations that favour low-carbon fuels and zero-emission vehicles are essential for the success of hydrogen in this sector. There are currently few provincial policies and standards that specifically encourage the use of hydrogen in the Maritimes, but several potential solutions are discussed in the next section. This section will focus on existing federal policies for MDVs and HDVs summarized in Table 29.

Table 29 – Federal programs impacting emissions and clean fuels in transportation

Program Name	Supply Chain Segment	Description
Clean Fuel Standard	Fuel retailers	Controls the acceptable carbon intensity of liquid and gaseous (transportation) fuels sold in Canada
HDV & Engine GHG Emission Regulations	Original Equipment Manufacturers	Establishes an average GHG level for new HD Vehicles and engines sold in Canada
GHG Pollution Pricing Act	Transportation Fleet Owners	Prices carbon emissions to encourage polluters to invest in fuel efficiency, route planning and other ways to reduce fuel use
Smart Driver for Highway Trucking Program		Training and best practices programs to improve driving practices and reduce operating costs
Green Freight Assessment Program		Data sharing, benchmarking tools, and other methods for reducing fuel consumption
SmartWay Program		SmartWay encourages best practices in freight supply chains. It helps carriers and shippers benchmark their operations, track fuel consumption, and improve their overall performance

Marine Industry

The marine industry is uniquely important in the Maritimes. About 75% of Canada's gross domestic product (GDP) from ocean/marine activities comes from Atlantic Canada making it the centre of Canada's ocean industry and an ideal place to develop a marine hydrogen economy[131]. Implementing hydrogen as

[131] Stakeholder engagement session quote. August 2020.

a marine fuel in the Maritimes will require development of standards and regulations and subsequent approval by both Class Societies and Transport Canada. LNG serves as a good example for the Canadian context as it is now in use and has the required approvals in place. The Maritimes has also already adapted to the incoming IMO Sulfur regulations which entered into force in 2020[132].

The rapid adoption of LNG and the IMO sulfur regulations demonstrates that the marine sector can manage change and implement new technologies quickly. However, it also sets up a significant barrier to entry for hydrogen systems as the industry has just invested heavily in LNG. Class societies (non-governmental organization that establish and maintain technical standards for the construction and operation of ships and offshore structure) will need to develop new rules for approving marine hydrogen propulsion systems. In the case of an entirely new fuel type there will need to be a global movement toward hydrogen to incentivize class societies to do the require research and development to design these standards[133].

At the Federal level both ECCC and Transport Canada regulate emissions from marine propulsion engines. The Air Pollution Regulations of the Canada Shipping Act of 2001 regulates the density of black smoke from ships in Canadian waters and within 1 mile of land. Transport Canada has authority to regulate emissions from marine propulsion engines larger than 37 kW. Transport Canada also has contributed to the global IMO Strategy on Reduction of GHG Emissions from Ships. The Transportation 2030 strategic plan sets out the federal vision for Green and Innovative Transportation within the marine sector, including the adoption of cleaner fuel sources.

Electricity/Nuclear Industry

Electric utilities in the Maritimes are regulated by the independent utility and review boards in each province. In Nova Scotia, the Nova Scotia Utility Review Board is the supervisory body that oversees Nova Scotia Power and other public utilities under the Public Utilities Act. In New Brunswick, the New Brunswick Energy and Utilities Board regulates the rates charged by NB Power, the provincially owned electric utility, under the Electricity Act. In PEI, the regulatory role is held by the Island Regulatory and Appeals Commission under the Electric Power Act.

Utilities must obtain approval for capital expenditure over a certain amount and the regulatory bodies must assess how investments will affect rate payers. This could have a significant impact on new technologies such as hydrogen from electrolysis. Without a mandate or approvals to invest in demonstration projects or to trial new tariff structures, these utilities are not able to pursue projects that could negatively affect rate payers. Utilities in the Maritimes also have obligations and trade agreements with other jurisdictions in North America under the North American Bulk Electric System and must follow the reliability criteria as set out by the North American Electric Reliability Corporation.

Nuclear energy has been part of New Brunswick's electricity supply since 1983, when NB Power began commercial operation of a 660 MW CANDU 6 unit at Point Lepreau. The Point Lepreau Nuclear Generating Station is the only nuclear power station in Canada outside of Ontario and was refurbished between 2009

[132] Vard Marine Inc. (2019). Natural Resources Canada. Hydrogen in the Marine Sector.
[133] Ibid.

and 2011. NB Power's nuclear safety regulator is the Canadian Nuclear Safety Commission (CNSC). The CNSC is responsible under the Nuclear Safety and Control Act for regulating all nuclear facilities and nuclear-related activities in Canada. The CNSC grants the stations' operating licenses, which set out the regulations and requirements the station must operate under.

Recommended Regulations and Policies to Promote Hydrogen

Hydrogen Policy and Regulation Approaches from Other Regions

Jurisdictions leading in hydrogen development have integrated the industry into their overall energy systems and climate planning and have set well-defined targets to measure success. The Maritimes can learn from the success of other jurisdictions but will need to adapt its approach to match the unique goals of the region including energy security, local air quality, GHG emissions reductions, economic growth, and job creation.

Some examples of effective policy and regulation approaches from Canada and internationally are listed below to illustrate the range of strategies being adopted.

- Japan and South Korea are investing heavily in hydrogen fuel cell technology and are rapidly scaling up vehicle deployments, particularly in light-duty passenger vehicles and medium-duty trucks through incentives and voucher/grant programs. By 2030, Japan expects to have 621,000 fuel cell cars and 1,300 FCEBs on the road, and South Korea's roadmap calls for 6.2million FCEBs produced in the country annually by 2040.
- Jurisdictions leading in light-duty fuel cell vehicle adoption have focused on building up fueling infrastructure, providing incentives (monetary and non-monetary), and tightening emissions standards. California, which leads adoption, also implemented a ZEV mandate.
- Europe, particularly Germany, has put the greatest emphasis on power-to-gas projects to better utilize intermittent renewable energy sources.
- Switzerland's Lump-sum and Performance-based Heavy Vehicle Charges have greatly improved the competitiveness of zero-emission trucking solutions. The Heavy Vehicle Charges apply to all vehicles with a permissible laden weight of more than 3.5 metric tonnes.[134]
- The United States has used tax credits to great effect in growing several clean energy technologies, including wind energy, solar photovoltaics, and fuel cells. US Federal incentives for the purchase of zero-emission vehicles also take the form of tax credits instead of purchase subsidies. A key lesson from the US experience has been that long-term policy certainty is required for industries to benefit; among other factors, sales cycles can be lengthy.

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[134] Swiss Confederation, Federal Customs Administration. Lump-sum heavy vehicle charge (PSVA) for Swiss vehicles. Retrieved from: https://www.ezv.admin.ch/ezv/en/home/information-companies/transport--travel-documents--road-taxes/heavy-vehiclecharges--performance-related-and-lump-sum-/lump-sum-heavy-vehicle-charge--psva--for-swiss-vehicles.html

- In BC and Quebec, provincial ZEV mandates have spurred the development of networks of hydrogen fuelling stations in Vancouver, Victoria, Montreal and Quebec City. This has given vehicle OEMs the assurance they need to begin selling FCEVs in these provinces.
- In Alberta, Emissions Reductions Alberta, has successfully leverage revenues from the oil and gas industry to fund new technology demonstrations, including the $17m Alberta Zero-Emissions Truck Electrification Collaboration (AZETEC) HD vehicle FCEV Truck project.

Regulations and Policies to Promote Hydrogen

While the detailed strategy and timelines for hydrogen in the region are yet to be determined, there are a number of high-level policies and programs—both federal and provincial—that should be considered for the Maritimes. These policy and regulation suggestions are grouped by sector and their priority to the Maritimes.

General Polices and Regulations (Including Federal)

These policies and regulations which will likely flow from the federal to provincial level, but the Maritime provinces will need to understand how to fit them in with their unique strategies.

- **ECCC Clean Fuel Standard** - The Clean Fuel Standard is a key policy tool currently in development at the federal level. It is aimed at achieving 30 mega-tonnes of annual reductions in GHG emissions by 2030 across the transportation, building, and industry sectors. The standard is performance-based and will require liquid, and in later iterations, solid, and gaseous fossil fuel suppliers to reduce the lifecycle GHG intensity of their fuels. While the CFS does not specify a particular action or require the adoption of hydrogen technology, it does include hydrogen as one of several compliance options. Hydrogen can be used as an end-use fuel or can displace higher CI feedstocks and process fuels in the manufacturing of traditional fuels. The implementation of the CFS will significantly impact traditional fuel production in the Maritimes and will create a large demand for low CI hydrogen from local sources.
- **ECCC GHG Pollution Pricing Act –** The Pollution Pricing Act puts a price on carbon in GHG emissions. Implemented in various forms across Canada, the federal levy ensures that all jurisdictions have a minimum carbon price of $50/t-CO2e by 2022. The provincial governments of New Brunswick and PEI have adopted the federal backstop system in full or in part, while Nova Scotia has its own system. Including hydrogen as an eligible fuel under the Act and considering amending Schedule 2 of the Act to include rates for low-GHG hydrogen and SMR hydrogen fuels could have a significant benefit for hydrogen.
- **Finance Canada Capital Cost Allowance –** The Capital Cost Allowance allows infrastructure developers to defer taxes until their capital expenditures outlays have been recaptured. A separate call for hydrogen infrastructure (refuelling stations, electrolyzers, etc.) combined with provincial tax credits would de-risk these investments and spur new project developments.

- **Passenger Automobile and Light Truck GHG Emission Regulations** - Amendments require new passenger vehicles and light trucks sold in Canada to meet fleet-wide GHG emission standards of 119 g CO_2/km by 2025, about 30% below the current required fleet average.

- **Measurement Canada Weights and Measurements Act** – The Weights and Measurements Act is currently being updated by Measurement Canada. Expanding the flexibility of this regulation to consider the adoptions of new fuels and the rapid development of measuring tools, will be crucial to the success of hydrogen. The Maritimes provinces can support the development of these regulations and ensure AHJs are given the training and information required to implement them.

Hydrogen Production

Cost-effectiveness is more of a limiting factor in hydrogen production than technology. Lowering the bulk and retail price of hydrogen will unlock many additional end-use applications and help production reach the required economies of scale.

- **Standardized Carbon Intensity Measures** - The CI threshold for hydrogen production for all provincially funded projects should be established. There must also be a transition plan to renewable hydrogen supplies through establishing tiered thresholds of required renewable content over time. The CFS will have baseline CI levels for certain hydrogen pathways and the international CertiHy standards will influence hydrogen produced for export.

- **Electricity Rate Incentives and Programs** – Electricity is the largest component of cost in green hydrogen. Developing specific electricity rate schedules to encourage production of green hydrogen through electrolyzers can make early projects more viable. Capital cost support and other programs can also be used in addition to special tariffs to encourage industry to shift from natural gas to hydrogen in their processes.

Hydrogen Transport, Distribution and Storage

Hydrogen can benefit from policies and regulations which allow it to be integrated with existing energy system transport, distribution, and storage infrastructure.

- **Electricity and Gas Utility Sector Coupling** – Policies and regulations that support the integration of the gas and electricity grid will allow these two systems to reinforce each other. Power-to-gas provides an effective means for converting excess renewable energy production into a fuel for later use and electrolyzers provide additional grid regulation benefits. The region should consider amendments to their utility regulators' mandates that would allow these projects to be funded.

- **Renewable natural gas content for pipelines** – A renewable natural gas content target could also be set with the provision that hydrogen is considered a renewable gas. This will encourage development of compatible end-use equipment and start the transition to a 100% hydrogen gas grid. Hydrogen should also be incorporated into existing regulations related to the distribution, storage, and use of natural gas to speed adoption. There is potential for unintended consequences with a renewable pipeline content requirement as increasing the cost of pipeline gas in isolation could exacerbate competitive pressures from propane.

- **Coordination of infrastructure** – A coordinated regional and municipal planning approach that incentivizes co-located hydrogen supply and demand projects would reduce the need for transport and distribution infrastructure in the near-term and would foster the development of industrial clusters, i.e. appropriately locating hydrogen facilities to meet network needs.

Hydrogen in Transportation

Hydrogen in transportation end-uses can be encouraged by lowering the barriers to adoption (e.g. costs, infrastructure availability), incentivizing technology switching (e.g. differential access to parking, ferries, high-occupancy vehicle lanes, border crossings, etc.), and by discouraging polluters (e.g. taxes for traditional fuels).

- **ZEV mandates for LD vehicles** – Battery Electric Vehicles have benefited from a much faster market deployment than FCEVs, but both technologies lag far behind in the Maritimes. In Nova Scotia, EVs represent less than 1% of new vehicle sales, as compared with up to 10% in leading regions Provincial ZEV mandates combined with other incentives would significantly increase EV uptake in the region – exceeding 30% of sales and putting more than 60,000 vehicles on the road by 2030 in Nova Scotia. These policy levers would alleviate the two main barriers that hinder EV adoption, high incremental cost, and limited vehicle supply [135].

- **ZEV mandates for MD/HD vehicles and buses** – Similarly, the provinces would benefit from a ZEV mandate for MD/HD trucks and possibly buses. Canada has set a target for 100% of new vehicle sales to be ZEVs by 2040, and hydrogen fuel cell vehicles could play a key role in achieving this target. The State of California, motivated largely by air pollution concerns has funded many *Advanced Technology Demonstration Projects* and proposed an Advanced Clean Truck regulation that will mandate 50% of all Class 4-8 straight trucks are zero-emission by 2030[136].

- **Regulatory development for marine sector** – Provinces can build on Transport Canada's current marine regulations for other low-flashpoint fuels such as natural gas to ensure that there is reduced uncertainty for hydrogen technology proponents regarding the measures that will be required to ensure safe operations.

- **Government purchasing** – i.e. fleet purchasing of FCEVs. Provincial governments can encourage the development of ZEVs by converting a portion of their regular fleet replacement budget to FCEVs.

Hydrogen for Industry

Industry, such as forestry, pulp and paper, cement and fertilizer, can be transitioned to low-carbon fuels including hydrogen, but this process will take significant time and investment. The equipment and

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[135] Dunsky. *Electric Vehicle Adoption in Nova Scotia 2020-2030.* June 20202. Ecology Action Centre.

[136] California Energy Commission. (2015). Joint Agency Staff Report on Assembly Bill 8: Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. Retrieved from https://ww2.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf

processes used by these industries is large and expensive, so fuel and feedstock conversion will need careful technical assessment and long-term planning.

- **Capital Cost Allowance program** – Provinces can use programs similar to the existing capital cost allowance program to encourage clean energy generation and energy efficiency equipment covering combined heat and gas (CHP) systems for building and process heat using clean hydrogen.
- **Incorporate hydrogen into the Clean Fuel Standard –** Ensure that hydrogen is included as an option to reduce the carbon intensity of natural gas and that fuel switching to hydrogen in all applicable applications is included as an option to generate compliance credits in ECCC's Clean Fuel Standard, Gaseous Stream.

11. SUMMARY RECOMMENDATIONS

Theme 1: Strategic Partnerships
1. Develop regional working group to align provincial approaches to developing hydrogen sector.
2. Encourage leading industry players to participate in national strategy working groups in relevant sector – e.g. utilities, low-carbon fuel producers, emerging transportation.
Theme 2: Hydrogen Awareness
1. Include hydrogen in provincial and regional integrated Clean Energy Roadmap.
2. Support hydrogen outreach initiatives.
Theme 3: Infrastructure and De-Risking of Investments
1. Initiate studies to determine options and magnitude of investment for hydrogen infrastructure build out, both in individual provinces and as a regional approach.
2. Implement policies that support demand for zero emission and low carbon alternatives, as a mechanism to de-risk private sector investments.
Theme 4: Innovation and Hydrogen Cluster Development
1. Foster collaborative efforts between industry and academia by supporting consortium-based projects for fundamental research priority areas important to the region.
2. Form Maritimes chapter of Canadian Hydrogen and Fuel Cell Association or like industry association to encourage regional cluster development.
Theme 5: Codes and Standards
1. Adopt Canadian Hydrogen Installation Code and like standards to facilitate new technology and infrastructure adoption in early markets.
2. Develop and adopt common standards and practices across the region to facilitate inter-provincial trade.
Theme 6: Policy and Regulation
1. Ensure regional policy framework developed to meet decarbonization targets does not unintentionally preclude hydrogen as a pathway for compliance through narrow definitions.
2. Establish policy frameworks that provide long-term certainty for the sector and that are technology-neutral, performance-based, and non-prescriptive.
Theme 7: Regional Deployment Hubs
1. Identify champions and hosts for regional deployment hubs.
2. Provide support for feasibility studies to advance projects from conceptual to implementation phase.

APPENDIX A. SUMMARY OF STAKEHOLDER ENGAGEMENTS

Context

As part of the Maritimes Hydrogen Feasibility study, we engaged key industry stakeholders to understand regional opportunities to deploy hydrogen in the near-, mid-, and long-term; discuss the opportunities and challenges to incorporate hydrogen into the existing energy system; consider the impact hydrogen could have in reducing emissions and achieving climate targets, and identify potential lighthouse projects for early demonstration of hydrogen technology in the region.

Stakeholder engagement is a critical component of the study to support the region's broad energy policy objectives related to climate change, inclusive economic development, and sustainable development of energy resources.

Almost 60 stakeholders representing over 40 organizations were engaged through a series of targeted one-hour virtual interviews, three two-hour virtual workshops, and an online survey. While the level of knowledge and experience on hydrogen varied among stakeholders, they all provided important perspectives on how hydrogen can fit within the Maritimes energy landscape. A list of organizations that were engaged is identified after the summary of key findings presented below.

Key Findings

Several key themes emerged from the workshops, interviews, and online survey, including:

1. **Hydrogen is expected to be an essential part of the mix to reach the Maritimes net-zero energy goal by 2050**. This includes opportunities such as hydrogen blending in the natural gas grid, energy storage for peak demand management, and applications within the transportation sector.
2. **Pilots will be necessary for specific emerging applications (e.g., marine); however, lessons from other jurisdictions can be leveraged for more mature applications.** The Maritimes could fill a potential niche for hydrogen research and deployment, specifically in the marine sector. Pilots are essential to help investors de-risk technology specifically as there is less awareness of hydrogen in the region.
3. **New industrial and regulatory frameworks are needed to enable hydrogen deployment in the Maritimes.** Utilities will need supporting regulations to invest in hydrogen technologies. Regulations will also signal to the industry and technology providers to bring projects into the Maritimes.
4. **Several potential lighthouse projects and key partners offer opportunities to demonstrate and test hydrogen across the Maritimes**. The Maritimes market size can be an advantage and is well positioned to implement high impact hydrogen projects. The economic viability of projects is dependent on successful partnerships from across the supply chain.

Each theme is discussed in more detail below.

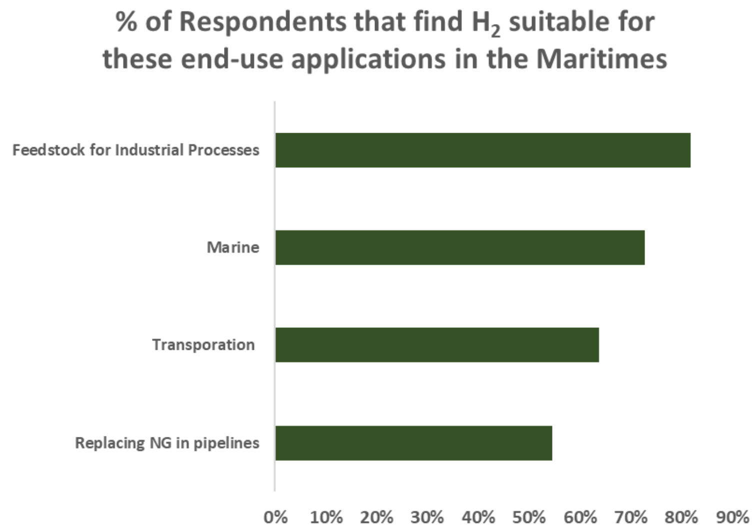
Hydrogen is expected to be an essential part of the mix to reach net-zero by 2050

- **Hydrogen has a role to play in a decarbonized future and could potentially be a Canadian strength**. Canada has many leading companies in the hydrogen sector and is one of the largest producers of green and blue hydrogen in the world. Irving Oil in Saint John, NB already produces large quantities of grey hydrogen and some blue hydrogen for use in their industrial processes. Like other jurisdictions who are investing significantly in hydrogen to hit their ambitious targets, the Maritimes must position itself to produce and access low-cost hydrogen. Moreover, the combination of high prices of natural gas and excess electricity from wind can make hydrogen cost-competitive in the Maritimes.

- **Hydrogen can play a role in energy storage for utilities that are looking for long-duration solutions to reach carbon neutrality by 2050**. Intermittency is a significant problem with renewable energy sources, and hydrogen can provide utility-scale storage solutions. For example, PEI has been adding wind generation capacity; however, the amount produced exceeds demand in the summer, requiring the province to export electricity during these months and import electricity during the winter (when production doesn't meet demand). Energy storage technologies could be used to produce hydrogen during off-peak times and convert it back to electricity at peak-times. Batteries are a mature alternative technology that is being used globally but can't provide economically viable long-duration storage solutions.

- **Hydrogen is the most practical pathway to decarbonize the natural gas grid.** Hydrogen and renewable natural gas can be used as a substitute for natural gas in the grid. However, the supply of renewable natural gas is limited by feedstock availability, thus limiting the potential to incorporate renewable natural gas into the grid. The Maritimes are a particularly attractive region for hydrogen blending in the natural gas grid because the infrastructure is relatively new, so implementation would be easier. Moreover, the gas distribution system is relatively small compared to other provinces; incorporating even a small amount of hydrogen will move the needle toward climate action targets.

- **There are several end-use applications that are highly suitable for hydrogen in the Maritimes**. One of the biggest demands for hydrogen is in the transportation sector (heavy trucks, rail, marine, etc.) and as industrial feedstock where direct electrification may not be feasible or large equipment conversions are required. The figure below highlights the percentage of respondents that found hydrogen to be suitable for specific end-use applications.



Pilots will be necessary for specific emerging applications (e.g., marine); however, lessons from other jurisdictions can be leveraged for more mature applications. The Maritimes could fill a potential niche for hydrogen study and deployment.

- **Smaller-scale projects or pilots might be necessary in the near-term due to the lack of financial resources (no resources to invest heavily by governments) and the need to de-risk technology.** While the technology may be proven in some cases, the financing may not be available. Pilots and demonstrations are necessary to draw government funding and support. This is particularly relevant in the COVID and post-COVID period, where small governments are struggling with growing debt. There's interest at the federal level for green recovery stimulus for shovel ready projects that could be leveraged. Moreover, pilots should be designed to allow for better integration into existing processes, which can be less daunting and ensures effective investment at the implementation stage.

- **Pilots should be designed to build scale and lead toward wider commercialization and deployment.** Pilot projects should be part of wider adoption strategies that will enable shared resources. It will be advantageous to build geographical clusters where hydrogen can be produced at scale and leveraged for multiple end-use applications.

- **Pilot projects are essential for marine projects that have yet to be tested and should include potential export opportunities.** Pilot projects are needed to validate the technology d obtain approval by Transport Canada. A pilot project with Transport Canada that owns and operates a large fleet could serve as a testbed to develop the technology in Canada for export opportunities as there is a growing industry in Northern Europe. The marine sector also provides a significant opportunity to be impactful; a single pilot project could displace a lot of carbon.

- **From the industry's point of view, pilots are needed for some applications, but there have been a lot of pilots around the world that could allow the Maritimes to leapfrog to**

commercialization. Production (blending hydrogen with natural gas) and transportation applications (e.g., buses) have been demonstrated many times over the years. The Maritimes could look to other similar Canadian jurisdictions (e.g., Montreal and Vancouver) and participate at the national level to tie commercial deployment with demonstrations to reduce risk and enable scale. However, even where technology is proven, those operating fleets indicate low cost, reliable, and local hydrogen sources are needed before they will invest.

- **The Maritimes could be a prime location to test, deploy, and export hydrogen**. The Maritimes is highly dependent on refined petroleum products, has a high carbon grid, is at the end of the pipeline, and has a relatively new natural gas pipeline infrastructure favourable to the transportation and distribution of hydrogen. There is access to marine works for storage, and the Maritimes have the only liquid natural gas terminal - Canada's only operational LNG terminal. There are also technology providers that are ideally suited to the Maritimes that are ocean focused. The Maritimes also offer a welcoming environment with robust interprovincial cooperation, integrated natural gas suppliers, applied research groups, willing industry participants, and strong public support to pursue green initiatives.

New industrial and regulatory frameworks must be created to enable hydrogen in the Maritimes.

- **Regulatory change and support will be needed to enable and accelerate the use of hydrogen by utilities.** Stakeholders highlighted the need for regulatory change and support for the energy transition. Energy companies could be champions, but they need regulatory support to make investments. Regulators need to see a demonstrated benefit to Maritimers. Utilities across the region must collaborate to build up the sector, manage costs, and consider the whole energy sector in long-term planning processes.

- **The clean fuel standard will send a signal to industry, and the government can lead by example to spur private investment.** Green procurement and using hydrogen in corporate fleets and buildings will demonstrate leadership to increase demand and lead to larger private investments. In some cases, provincial and Federal regulations barriers need to be addressed. For example, Halifax Charter is not allowed to mandate energy performance standards that go beyond code for new buildings under the Halifax Charter.

> "It all comes down to economics. If you can leverage multiple end-uses and develop a cost share model – with other utilities – for infrastructure investments, it will be more economical for the customer. It makes sense to invest in one system"
>
> **Utility stakeholder**

- **Hydrogen can be a bridge between energy providers to potentially enable consolidated services that will achieve climate-related goals and improve customer experience**. Utility companies could merge to become an energy utility as the market evolves. The Netherlands and Germany serve as models. Rather than utilities competing for a smaller slice of the pie, companies could coexist through partnerships to cost-share infrastructure investments, offer more services, and allow customers to customize solutions.

Several potential lighthouse projects and key partners offer opportunities to demonstrate and test hydrogen across the Maritimes.

- **Lighthouse projects should focus on the areas where hydrogen demand is expected to be greatest**. Lighthouse projects could include commercial fleet operators, long-haul trucking, and industrial processes. Given the geography of the Maritimes, hydrogen vehicle deployment can begin with a relatively small number of stations and focusing on heavy-duty vehicles, which have greater per-vehicle fuel requirements, could accelerate things. Stakeholders pointed out that battery electric vehicles are more cost effective for certain applications. Therefore, a low-cost hydrogen source will be necessary to provide confidence in reliability and spur infrastructure investment.

- **The most successful projects involve partnerships. They should include big players and bring together groups that can offer different perspectives, identify unique interests, and create win-win situations.** Oil and gas companies are starting to look at hydrogen as an opportunity. Big players in the Maritimes could offer opportunities for large lighthouse projects, for example bringing green hydrogen to Irving Oil (or increasing blue hydrogen capacity). Targeted working groups, including a broad range of relevant stakeholders, could be organized to facilitate lighthouse projects.

- **Connectivity can help build scale**. Provincial interconnectivity offers the opportunity to develop hydrogen nodes or clusters within the Maritimes to link hydrogen production to end-use.

- **Visible projects can help build awareness and support in the region**. It will be important to obtain buy-in from all stakeholders, including the pubic, to drive demand. An important aspect of any lighthouse project is to build awareness and support through visible projects. Transportation applications, such as deployment of FCEVs or buses and accompanying fueling infrastructure, offer a high level of visibility.

Stakeholder Table

As part of the study, the Zen team engaged with representatives from government, academia, industry, and not for profits that provided a range of perspectives and insights into the utilities' role in a hydrogen economy & energy storage opportunities, hydrogen supply chains and end uses in the Maritimes. Stakeholders from the following organizations were engaged.

Organization	Workshops			Targeted Interview
	End-use	Utilities & Storage	Supply Chain	
Atlantic Canada Opportunities Agency (ACOA)	✓	✓	✓	
Altagas		✓		
ARC Nuclear			✓	
Atlantic Canada Aerospace and Defence Association	✓			✓
Atlantica Centre for Energy		✓	✓	
Atlantic Towing				✓
Canadian Gas Association		✓	✓	
Canadian Hydrogen and Fuel Cell Association	✓	✓	✓	
Centre for Ocean Ventures & Entrepreneurship	✓			
City of Halifax	✓			
City of Saint John	✓			
Clean Foundation	✓			
Canadian Urban Transit Research & Innovation Consortium (CUTRIC)		✓		
Dalhousie University	✓	✓		
Ecology Action Centre			✓	
Fisheries and Oceans Canada				✓
Government of New Brunswick		✓		
Government of Nova Scotia		✓	✓	✓
Government of PEI		✓		
Halifax Transit				✓
Heritage Gas	✓	✓	✓	✓
IDOM Consulting			✓	
Innovacorp			✓	
International Partnership for Hydrogen and Fuel Cells in the Economy			✓	
Irving Oil				✓
Mitsui Canada	✓		✓	
Moltex Energy			✓	
Natural Forces	✓			
Northumberland Ferries				✓

Organization	Workshops			Targeted Interview
	End-use	Utilities & Storage	Supply Chain	
Nova Scotia Community College	✓	✓		
NS Power		✓	✓	✓
Nu:Ionic	✓	✓	✓	
Planetary Hydrogen		✓	✓	
QUEST Canada	✓			
Repsol	✓	✓		
PEI Fishermen's Association				✓
Saint John Energy		✓		
Saint John Port Authority				✓
StormFisher	✓	✓		
Trecan Combustion				✓
The Maritimes Energy Association		✓		
Toyota Canada			✓	