A Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in Newfoundland & Labrador

ZEN and the art of CLEAN ENERGY SOLUTIONS

In partnership with:

Dunsky Energy Consulting, Redrock Power Systems & NEIA

Prepared For:

OERA

March 2021

ACKNOWLEDGEMENTS

The Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in Newfoundland & Labrador was facilitated by the Offshore Energy Research Association (OERA) and conducted by Zen and the Art of Clean Energy Solutions and project partners Dunsky Energy Consulting, Redrock Power Systems, and the Newfoundland & Labrador Environmental Industry Association (NEIA). Work on the study ran from January to March 2021.

The project team would like to thank the many individuals and organizations that provided input to the study through participation in workshops, surveys, and individual interviews. The team would also like to thank Natural Resources Canada for supporting the study and all of the members of the project management committee, including OERA, Heritage Gas Limited, the Atlantic Canada Opportunities Agency, Atlantica Centre for Energy, the Transition Accelerator, Memorial University, Mysa, and OilCo. The Newfoundland & Labrador Department of Industry, Energy, and Technology acted as an observer on the project management committee, and due to the provincial election planned for February 13, 2021 that was subsequently delayed as a result of a COVID-19 outbreak, were unable to provide input to the study. The study therefore represents recommendations from the study authors and stakeholders consulted throughout the project and should therefore not be construed as the position of the Government of Newfoundland and Labrador.

Project Team

ZEN and the art of CLEAN ENERGY SOLUTIONS

dunsky

REDROCK Power Systems

neia.org
Newfoundland and Labrador Environmental Industry Association

EXECUTIVE SUMMARY

NL has the necessary ingredients to become a major producer of hydrogen to serve its own energy needs as well as the neighbouring Maritimes provinces and international markets.

The Newfoundland & Labrador (NL) Hydrogen Feasibility Study is an extension to the Maritimes Hydrogen Study completed in October 2020.[1] The study was commissioned by the Offshore Energy Research Association (OERA) in partnership with Natural Resources Canada (NRCan). It is intended to build on the Maritimes Hydrogen Study by looking specifically at the opportunities and challenges of hydrogen production, storage, distribution, and use in NL and the potential for interaction with the rest of Atlantic Canada. This work supports the region's broad energy policy objectives related to climate change, inclusive economic development, and sustainable development of energy resources. The report has been written as an addendum to the original study, and duplication of information has been avoided where possible.

The objective of the study is to provide a technical and economic assessment of the role that hydrogen *could* play in NL's energy transition. All aspects of this resource were considered from creation to end-use, and economic and technical constraints and opportunities were evaluated as hydrogen use and production scales up over time in NL. The study seeks to identify the role(s) hydrogen could play in NL from 2021 through 2050 and includes recommendations for instruments and policies to enable hydrogen to have an important role in decarbonizing the economy.

Stakeholder Engagement & Analysis Approach

Development of hydrogen production in NL and attraction of new industry could result in new green jobs and a hydrogen sector in NL valued at >$11 billion/year by 2050 while contributing to meeting decarbonization targets across Atlantic Canada.

As part of the expanded NL Hydrogen Feasibility study, the project team engaged key industry stakeholders across the province to understand regional opportunities to deploy hydrogen in the near-, mid-, and long-term.

Almost 40 organizations were engaged through a series of targeted one-hour virtual interviews and one two-hour virtual workshop. While the level of knowledge and experience on hydrogen varied among stakeholders, they all provided important perspectives on how hydrogen can fit within the energy and economic development landscape in NL.

[1] Zen Clean Energy Solutions. (2020). A Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in the Maritimes. Retrieved from https://oera.ca/sites/default/files/2020-10/A%20Feasibility%20Study%20of%20Hydrogen%20Production%20Storage%20Distribution%20and%20Use%20in%20the%20Maritimes.pdf

Key Findings

The Maritimes Hydrogen Study highlighted fifteen key findings related to the potential for hydrogen in New Brunswick, Nova Scotia, and Prince Edward Island. NL bring unique energy resources to the mix that enables greater potential for hydrogen production than the other Atlantic Canada provinces. Key findings related specifically to the NL opportunity are identified here. Many of the previous key findings are still relevant and have not been replicated here for the sake of brevity but they are available in the Maritimes Hydrogen Study. Findings that are significantly different from the previous study have been noted.

1. NL has the potential to be a major producer of hydrogen to serve domestic demand as well as the Maritimes provinces and international markets.

NL's abundant hydroelectric electricity, wind, and oil & gas (O&G) resources position it to become a major producer of hydrogen to serve domestic demand as well as other provinces in Canada and international markets with the most probable markets being the Northeastern United States or Europe.

Green hydrogen production shows compelling promise in the region in the near-term. Once Muskrat Falls is fully operational, the province will have an estimated 3.5 TWh/year surplus electricity is expected to be available. Hydrogen offers a pathway to optimize the value of the surplus electricity that would otherwise be sold at bulk export pricing to the Maritimes. The incremental value that could be realized through in-province production of green hydrogen could ultimately reduce costs for the ratepayers while at the same time enabling a profitable new hydrogen generation industry in the province that can result in new jobs and decarbonization benefits.

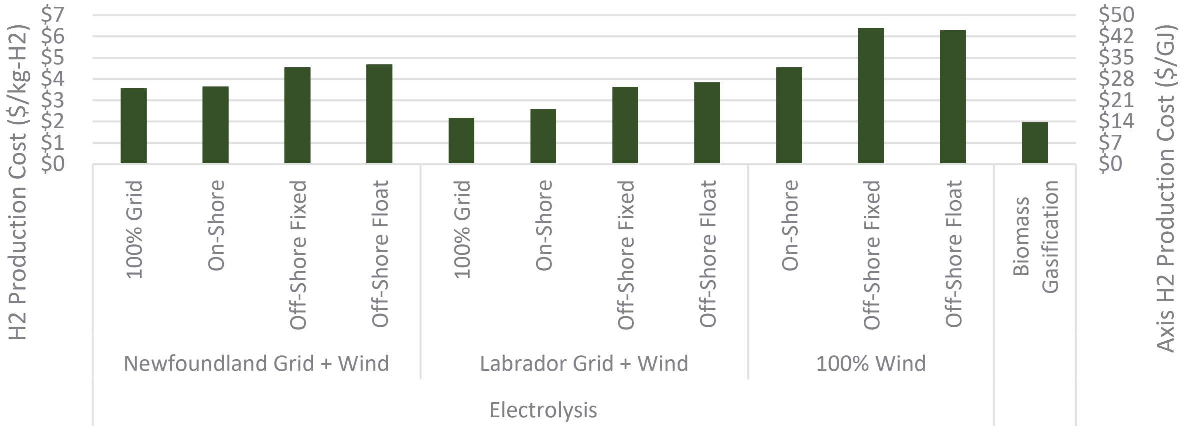
Longer-term, hydrogen represents an opportunity for NL's offshore O&G sector to transition to a net-zero energy future. The region's rich fossil fuel reserves, skilled labour sector, and significant CO2 sequestration potential provide the foundation for a pivot to hydrogen as a new low carbon fuel product.

The cost at which hydrogen can be produced and transported is of critical concern when considering hydrogen's role in the energy sector. The British Columbia Hydrogen Study estimated low carbon production to cost between $1.75-$7.50,[2] and the National Hydrogen Strategy for Canada targets a future price of $1.5-$3.50/kg-H2.[3] The cost of NL-produced hydrogen can be very compelling compared to other regions in Canada and competing international producers.

---

[2] Zen and the Art of 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

[3] Natural Resources Canada. (2020). Hydrogen Strategy for Canada: Seizing the Opportunities for Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

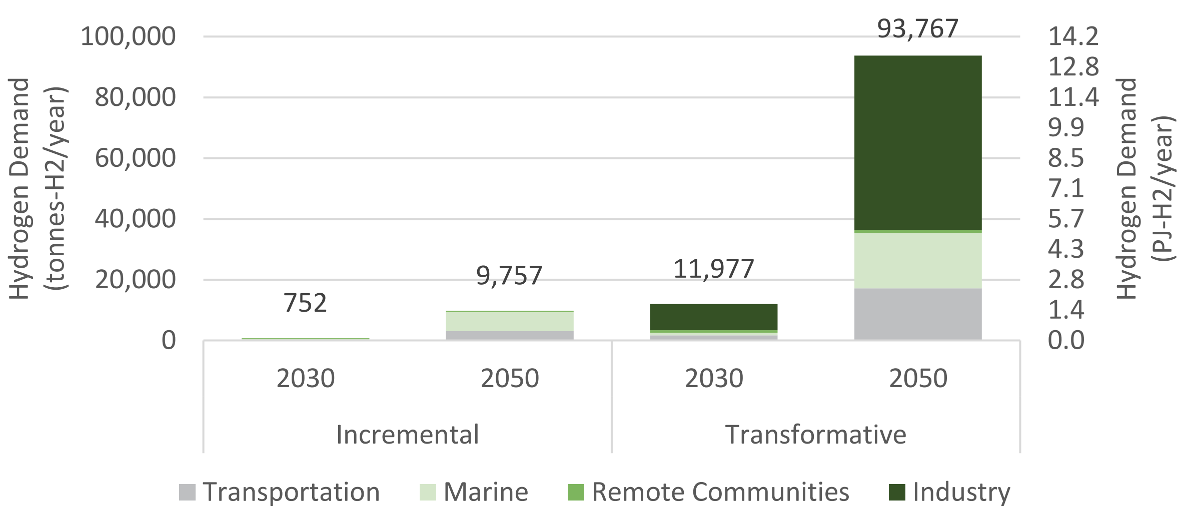


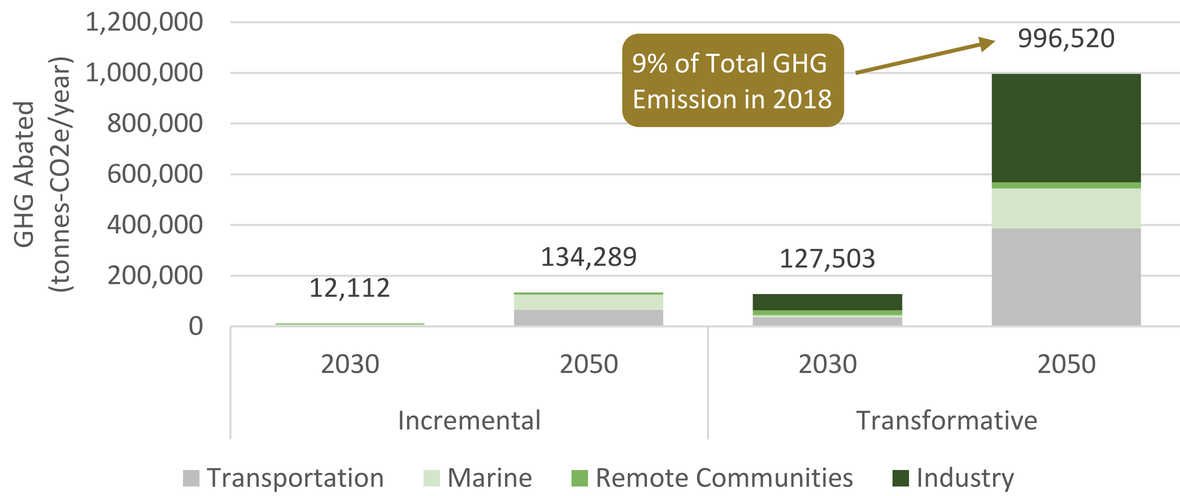
2. Local demand for hydrogen is projected to be lower in NL than in other Atlantic provinces due to the momentum around direct electrification.

The Maritimes Hydrogen Study showed that hydrogen has the potential to deliver up to 22% of end-use energy demand in the Maritimes by 2050, contributing up to 21% towards the region's decarbonization challenge.

The opportunity for local adoption of hydrogen in NL is estimated to be lower than other Atlantic Canada provinces, at just 8% of delivered energy by 2050 in the transformative scenario. This would result in 9% of the province's greenhouse gas (GHG) reduction target in that timeframe. Adoption is anticipated to be primarily in heavy duty transportation applications and in O&G upgrading at the North Atlantic Refinery Limited (NARL). The greater opportunity for hydrogen lies in NL becoming an exporter of hydrogen versus a widespread local adopter.

The relatively conservative estimate of hydrogen adoption is driven in part by an absence of provincial government focus on hydrogen opportunities at the present time, and a significant push toward direct electrification. A number of upside opportunities have been identified beyond those presented in the transformative scenario, but major policy change and increased government support would be required.





3. Supply of NL low-carbon intensity hydrogen to other Atlantic Provinces could support decarbonization of the region.

The projected aggregate hydrogen demand in Maritimes in the transformative 2050 is 1,790 tonnes-H2/day. Hydrogen supplied from NL could be distributed to Maritimes at about $1.75-4.50/kg at this scale. This is based on modeling of the electrolytic pathway at an input electricity price of $10-50/MWh at a scale of 1,000 tonnes-H2/day. This hydrogen pricing provides a compelling opportunity for those provinces to utilize hydrogen in difficult-to-abate sectors to help with decarbonization objectives. Construction of a hydrogen pipeline from NL to the Maritimes could be the lowest cost transportation option at this scale and would be an important regional infrastructure project with potential for demonstrating Canadian leadership and innovation. While the costs of a hydrogen pipeline have been incorporated into the costs shown, the expected price is highly dependent on local factors and must be further validated to confirm the cost effectiveness of the project.

4. NL is strategically positioned to establish a hydrogen export market that could generate significant jobs and economic growth for the region.

The potential hydrogen market is estimated at 57 million tonnes/year by 2050. This is the total projected demand that is expected to be met through a combination of domestic supply and import. Canada has been identified as a potential exporter of hydrogen to Europe. If export from Atlantic Canada was able to address just 5% of the total European demand, it could generate $9 billion / year in revenues, assuming a bulk hydrogen sales price of $3/kg. This is comparable to current revenues from the O&G sector which was approximately $8.2 billion in 2019.[4]

Combining domestic demand with potential for export, the hydrogen and fuel cell sector has the potential to generate over $11 billion annually and support almost 140,000 jobs in the transformative scenario by

[4] Government of Newfoundland & Labrador. (2020). The Economy: Budget 2020 Today. Tomorrow. Together. Retrieved from https://www.gov.nl.ca/budget/2020/wp-content/uploads/sites/3/2020/09/The-Economy-2020.pdf

2050. This represents a compelling economic development opportunity for NL that in turn helps to achieve the regional decarbonization goals.

Recommendations

The Maritimes Hydrogen Study outlined seven recommendation themes and a total of 14 specific recommendations. All previous recommendations are still relevant with the NL scope added. Some minor changes have been made to reflect the Atlantic Hydrogen scope versus previous Maritimes focus.

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 – e.g., utilities, low-carbon fuel producers, emerging transportation, O&G.
Theme 2: Hydrogen Awareness
3. Include hydrogen in provincial and regional integrated Clean Energy Roadmap or consider releasing a government-led Atlantic Canada Hydrogen Roadmap[5].
4. Support hydrogen outreach initiatives.
Theme 3: Infrastructure and De-Risking of Investments
5. Initiate studies to determine options and magnitude of investment for hydrogen infrastructure build out, both in individual provinces and as a regional approach.
6. 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
7. Foster collaborative efforts between industry and academia by supporting consortium-based projects for fundamental research priority areas important to the region.
8. Form Atlantic Canada chapter of Canadian Hydrogen and Fuel Cell Association or like industry association to encourage regional cluster development.
Theme 5: Codes and Standards
9. Adopt Canadian Hydrogen Installation Code and like standards to facilitate new technology and infrastructure adoption in early markets.
10. Develop and adopt common standards and practices across the region to facilitate inter-provincial trade.
Theme 6: Policy and Regulation
11. Ensure regional policy framework developed to meet decarbonization targets does not unintentionally preclude hydrogen as a pathway for compliance through narrow definitions.
12. 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
13. Identify champions and hosts for regional deployment hubs.
14. Provide support for feasibility studies to advance projects from conceptual to implementation phase.

[5] BC, Alberta, Yukon, Ontario and Quebec governments are developing regional hydrogen strategies or roadmaps

Three additional recommendations have been developed with this addendum:

1. Provincial government should consider expanding the mandate of crown corporation Nalcor to consider green hydrogen opportunities as a strategic enabler for greater fuel switching and decarbonization in sectors reliant on high carbon fuels such as RPPs. Green hydrogen can be viewed as indirect electrification pathway for the utility with potential technical and economic advantages in some applications such as heavy-duty transport and remote communities.

   When the Muskrat Falls Facility is fully operational, it is estimated that NL will export approximately 3.5 TWh in electricity through the Maritime Link transmission cable at an anticipated average price of $0.045/kWh. Development of electrolytic hydrogen generation plants in province provide a compelling business case for both project developers and the rate payers of NL. To highlight this point, if a large scale electrolysis plant was built in NL to generate green hydrogen as an alternative to bulk electricity sales, and the electricity to generate hydrogen is sold at a rate of $0.05/kWh to the hydrogen production plant – compared to the bulk electricity sales price of $0.045/kWh – the incremental increase in annual revenue to the utility would be approximately $9 million for a 100 tonnes-H2/day plant or $17.5 million if the full 3.5 TWh was utilized.

2. Identify opportunities for government fleets (light-duty, ferries) and/or infrastructure to adopt hydrogen end use technologies to create certainty in demand for hydrogen project developers.

3. Pursue detailed feasibility studies and further stakeholder engagement related to the three NL lighthouse projects identified in the study:

   - Offshore wind electrolysis project
   - Port of Argentia hydrogen hub with Marine Atlantic ferry conversion
   - North Atlantic Refinery Limited hydrogen hub anchored by green hydrogen production for reducing carbon intensity (CI) of conventional fuels

The opportunities for hydrogen in Atlantic Canada are compelling, particularly when coupling NL's potential to become a bulk hydrogen producer with the other Atlantic Provinces' potential demand for hydrogen in energy-intensive, high-emitting applications. The challenge lies in defining a common vision and roadmap for hydrogen across the four provinces, particularly given current economic challenges, lack of aligned supporting policy and regulation, and limited energy innovation resources. With the global and federal momentum around hydrogen, and with governments identifying green infrastructure projects as a top priority for stimulus funds to spur on economic recovery post-COVID, an aligned path forward supported by the regional governments could successfully position the Atlantic Provinces in the national hydrogen innovation agenda.

GLOSSARY

ACOA	Atlantic Canada Opportunities Agency
ASD	Azimuth Stern Drive
ASHP	Air-source Heat Pumps
BEV	Battery Electric Vehicle
CCUS	Carbon Capture and Utilization/Sequestration
CHP	Combined Heat and Power
CI	Carbon Intensity
C-NLOPB	Newfoundland and Labrador Offshore Petroleum Board
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
CO2-EOR	Carbon Dioxide for Enhanced Oil Recovery
CUTA	Canadian Urban Transportation Association
DAC	Direct Air Capture
EER	Energy Equivalence Ratio
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FPSO	Floating, Production, Storage, and Offloading
GHG	Greenhouse Gas
HD	Heavy-duty
IEA	International Energy Agency
IMO	International Maritime Organization
IPHE	International Partnership for Hydrogen and Fuel Cells
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
LD	Light-duty
LIL	Labrador-Island Link
LNG	Liquid Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LPG	Liquefied Petroleum Gas
M&NP	Maritimes and Northeast Pipeline
MD	Medium-duty
MHD	Medium- and Heavy-duty
NARL	North Atlantic Refinery Limited
NEIA	Newfoundland & Labrador Environmental Industry Association
NG	Natural Gas
NH3	Ammonia
NL	Newfoundland and Labrador
NOIA	Newfoundland & Labrador Oil & Gas Industries Association
NOx	Oxides of Nitrogen
NRCan	Natural Resources Canada
NREL ATB	National Renewable Energy Laboratory Annual Technology Baseline
NS Power	Nova Scotia Power
O&G	Oil and Gas
OERA	Offshore Energy Research Association
OSV	Offshore Support Vessels
PEI	Prince Edward Island

PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
RCV	Recyclage Carbonne Varennes
RPPs	Refined Petroleum Products
SMR	Steam Methane Reforming
SOx	Oxides of Sulphur
SWOT	Strengths, Weaknesses, Opportunities, and Threats
TRL	Technology Readiness Level
US	United States
US DOE	United States Department of Energy
WAG	Water Alternating Gas
ZEB	Zero-emission Bus
ZEV	Zero-emission Vehicle

TABLE OF CONTENTS

Acknowledgements ... ii

Project Team ... ii

Executive Summary ... iii

Glossary ... ix

Table of Contents ... xi

Table of Figures ... xiii

List of Tables ... xv

1. Introduction ... 1

Objectives and Scope ... 1

Project Methodology ... 1

Energy Consumption and GHG Emissions in NL ... 2

Current Uses and Applications of Hydrogen in NL ... 5

2. Hydrogen Production ... 7

Electrolysis using Grid Electricity ... 7

Electrolysis using Wind Power ... 9

Natural Gas Pathways ... 13

Biomass Gasification ... 15

Cost and Carbon Intensity Comparison Summary ... 16

3. Hydrogen Storage ... 17

Salt Caverns ... 17

4. Hydrogen Transport ... 18

5. Potential Hydrogen End Uses ... 22

Heating Buildings ... 22

Transportation ... 23

Marine ... 33

Industrial Applications ... 41

Remote Communities ... 45

Aggregated End-Use Applications ... 49

6. Hydrogen Production for Export ... 52

7. Supply Chain Capability Assessment ... 54

Hydrogen Supply Chain and Value Network Overview 54
Opportunities and Challenges for Local Service Providers in the Hydrogen Supply Chain 54
8. Carbon Capture and Sequestration 58
NL Offshore Oil Resources 58
CCUS with CO2-EOR Pathway 58
CCUS Deployment 59
9. Hydrogen for Utility Scale Energy Storage in Atlantic Canada 60
10. Economic opportunities 68
11. National Potential for Hydrogen 70
12. Regulation and Policy 72
13. Summary Recommendations 74
Appendix A. Summary of Stakeholder Engagement 76
Context 76
Key Findings 76
Stakeholder Table 79
Appendix B. List of Remote Communities 81

TABLE OF FIGURES

Figure 1 – End-use energy demand in NL by sector and fuel 3
Figure 2 – NL interconnected system 4
Figure 3 – GHG emissions in NL in 2018 per sector 5
Figure 4 – Ramea Island Wind-Hydrogen-Diesel Project configuration 6
Figure 5 – Hydrogen production cost – grid electricity electrolysis 8
Figure 6 – Hydrogen carbon intensity – grid electricity electrolysis 8
Figure 7 – Levelized cost of electricity from wind power 10
Figure 8 – Offshore floating wind turbines 12
Figure 9 – AquaVentus infographic 12
Figure 10 – Hydrogen production cost – wind power electrolysis 13
Figure 11 – Hydrogen carbon intensity – wind power electrolysis 13
Figure 12 – Hydrogen production cost – SMR+CCUS and pyrolysis 14
Figure 13 – Hydrogen carbon intensity – SMR + CCCUS and Pyrolysis 15
Figure 14 – Hydrogen production cost – biomass gasification 15
Figure 15 – Hydrogen carbon intensity – biomass gasification 15
Figure 16 – Hydrogen production cost – all pathways 16
Figure 17 – Hydrogen carbon intensity – all pathways 16
Figure 18 – Salt caverns in the Atlantic Canada 17
Figure 19 – Predicted hydrogen transport cost by shipping by storage method and distance 19
Figure 20 – Predicted pipeline hydrogen transport cost by distance overland 20
Figure 21 – Potential hydrogen transport options for export 21
Figure 22 – Space heating energy use by energy currency (2018) 22
Figure 23 – Transportation GHG emissions in NL by subsector (2018) 23
Figure 24 – Percent of transportation GHG emissions in NL by subsector (2018) 23
Figure 25 – LD registrations per year in NL 24
Figure 26 – New LD registrations per year in NL 24
Figure 27 – MHD registrations per year in NL 25
Figure 28 – New MHD registrations per year in NL 25
Figure 29 – Forecasted annual new LD vehicle registrations per year in NL 26
Figure 30 – FCEVs on the road and hydrogen demand - transformative 27
Figure 31 – GHG abated from LD FCEVs – transformative 27
Figure 32 – Forecasted annual new MHD vehicle registrations per year in NL 28
Figure 33 – Projected MHD FCEVs on-the-road and hydrogen demand from 2020 – 2050 29
Figure 34 – Projected GHG abated from MHD FCEVs from 2020 – 2050 29
Figure 35 – Projected FCEBs on-the-road and hydrogen demand 30
Figure 36 – Projected GHG abated from FCEBs 30
Figure 37 – Aggregate transportation H2 demand 31
Figure 38 – Aggregate transportation GHG abatement from H2 31
Figure 39 – Incremental and transformative transportation hydrogen demand by on-road vehicle type 31

Figure 40 – Marine GHG emissions by subsector 33
Figure 41 – Norse Spirit shuttle tanker 34
Figure 42 – Energy density of marine fuels by mass and volume 35
Figure 43 – Port of Argentia aerial view 36
Figure 44 – Marine Atlantic vessel, MV Atlantic Vision 36
Figure 45 – Ammonia engine for marine applications 37
Figure 46 – Marine incremental scenario - H2 demand 38
Figure 47 – Marine incremental scenario - GHG emission abatement 38
Figure 48 – Marine transformative scenario - H2 demand 39
Figure 49 – Marine transformative scenario - GHG emission abatement 39
Figure 50 – Marine transformative and incremental scenarios - H2 demand 39
Figure 51 – Marine transformative and incremental scenarios - GHG emissions abatement 39
Figure 52 – Refinery in Come by Chance, NL 42
Figure 53 – North Atlantic service area 42
Figure 54 – Clean hydrogen demand and GHG abatement for hydrogen at NARL 43
Figure 55 – Remote communities by primary power source in NL 45
Figure 56 – Projected hydrogen demand for remote communities 48
Figure 57 – Projected GHG abated from remote communities 48
Figure 58 – Aggregated hydrogen demand forecast by sector 49
Figure 59 – Aggregated GHG emission reduction forecast by sector 49
Figure 60 – Hydrogen as part of NL's energy mix in 2050 – transformative scenario 50
Figure 61 – Electricity and natural gas requirements to meet 2050 H2 demand - transformative 51
Figure 62 – Forecasted European Union hydrogen demand (TWh) 52
Figure 63 – Current and potential local service providers 55
Figure 64 – Offshore oil production assets in the Jeanne D'Arc and Flemish Pass Basins 58
Figure 65 – Floating production, storage, and offloading (FPSO) unit 59
Figure 66 – Estimated cost of bulk hydrogen production and transportation 61
Figure 67 – Cost of hydrogen production and distribution by electricity cost 62
Figure 68 – Cost of hydrogen compared to transportation fuels 63
Figure 69 – Cost of hydrogen compared to heating sources 64
Figure 70 – Comparison of energy storage technologies 66
Figure 71 – Estimated potential hydrogen related revenue and jobs in NL (2030 & 2050) 68
Figure 72 – Regional hydrogen studies and roadmaps in Canada 71
Figure 73 – Major hydrogen projects in Canada 71
Figure 74 – Toyota Mirai 72

LIST OF TABLES

Table 1 – Hydrogen production pathway key parameters 7
Table 2 – % FCEV purchases of mandated EV purchases per year model assumptions 26
Table 3 – LD FCEV H2 demand and GHG abatement summary - transformative 28
Table 4 – % FCEV sales of total annual MHD vehicle sales model assumptions 28
Table 5 – MHD FCEV demand and GHG abatement summary 29
Table 6 – FCEB H2 demand and GHG abatement summary 30
Table 7 – Marine transportation subcategories 33
Table 8 – Hydrogen marine vessels adoption assumptions 37
Table 9 – Percent clean H2 model assumptions to replace grey hydrogen at NARL 43
Table 10 – Remote communities incremental H2 adoption scenario model assumptions 47
Table 11 – Remote communities transformative H2 adoption scenario model assumptions 47
Table 12 – Remote communities annual H2 demand and GHG abatement adoption scenario summary 48
Table 13 – SWOT analysis 57
Table 14 – IRR of hydrogen as a transportation fuel 64
Table 15– IRR of hydrogen as a substitute for natural gas 65
Table 16 – IRR of hydrogen for dispatchable power (1 day storage) 67
Table 17 – IRR of hydrogen for dispatchable power (10-day storage) 67
Table 18 – IRR of hydrogen for dispatchable power (30-day storage) 67
Table 14 – Stakeholder engagement summary 79
Table 15 – Isolated electricity systems in NL 81

1. INTRODUCTION

Objectives and Scope

The Newfoundland & Labrador (NL) Hydrogen Feasibility Study is an extension to the Maritimes Hydrogen Study completed in October 2020.[6] The study was commissioned by the Offshore Energy Research Association (OERA) in partnership with Natural Resources Canada (NRCan). It is intended to build on the Maritimes Hydrogen Study by looking specifically at the opportunities and challenges of hydrogen production, storage, distribution, and use in NL and the potential for interaction with the rest of Atlantic Canada. This work supports 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 NL's energy transition. All aspects of this resource were considered from creation to end-use, and economic and technical constraints and opportunities were evaluated as hydrogen use and production scales up over time in NL. The study seeks to identify the role(s) hydrogen could play in NL from 2021 through 2050 and includes recommendations for instruments and policies to enable hydrogen to have an important role in decarbonizing the economy.

Project Methodology

The same general methodology was used to carry out this study as the previously completed Maritimes Hydrogen Study. A collaborative approach was used to generate relevant and actionable results using a combination of stakeholder engagement, market and technology reports, internet research, and leveraging of the project team's expertise in the field.

Stakeholders were invited to participate in a workshop to discuss the potential for hydrogen in the region's energy transition. The workshop included breakout sessions targeting four main subject areas:

- Interconnection with the electric grid
- Potential end-users and project developers
- Interconnection with the oil & gas sector
- Potential to deliver economic growth

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

Using the same approach as the Maritimes Hydrogen Study, the cost and carbon intensity (CI) of hydrogen produced by various pathways were evaluated at a scale of 100 tonnes/day, targeting deployment in 2030. The Maritimes Hydrogen Study considered production via wind power electrolysis at a high level,

[6] Zen Clean Energy Solutions. (2020). A Feasibility Study of Hydrogen Production, Storage, Distribution, and Use in the Maritimes. Retrieved from https://oera.ca/sites/default/files/2020-10/A%20Feasibility%20Study%20of%20Hydrogen%20Production%20Storage%20Distribution%20and%20Use%20in%20the%20Maritimes.pdf

but this was identified as a particular area of focus for the expanded scope. New analysis was conducted including in-depth research into the cost and expected capacity factors for onshore, offshore fixed, and offshore floating facilities. The results are applicable to NL as well as the Maritimes provinces.

Hydrogen storage and transportation options were assessed, emphasizing how hydrogen could be exported from NL to the rest of Atlantic Canada and internationally, including bulk transportation via pipelines and shipping.

End-use demand for hydrogen in NL was estimated for two scenarios: transformative and incremental. Both scenarios were developed using input from 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, technological developments, and adoption growth rates leading to net-zero-emissions by 2050, representing 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 export market and local supply chain for hydrogen in NL were also considered at a high level, including a rough estimation of the potential opportunity for hydrogen export from Atlantic Canada to Europe and a description of organizations that are likely to participate in the hydrogen supply chain.

A techno-economic analysis was also conducted to explore the feasibility of a hydrogen production facility concept in NL. The analysis considers a 100 tonne-H2/day production facility using surplus grid electricity and considers the profitability of such a project to produce hydrogen for various end-use applications.

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

Energy Consumption and GHG Emissions in NL

Energy Consumption

NL energy end-use demand in 2017 was 162 PJ, ranking as the 9th largest in Canada and the 4th largest per capita basis.[7] The total end-use energy demand in NL by sector and fuel type in 2019 is displayed in Figure 1.

[7] Canada Energy Regulator. (2020). Provincial and Territorial Energy Profiles – Newfoundland and Labrador. Retrieved from https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-newfoundland-labrador.html#s1

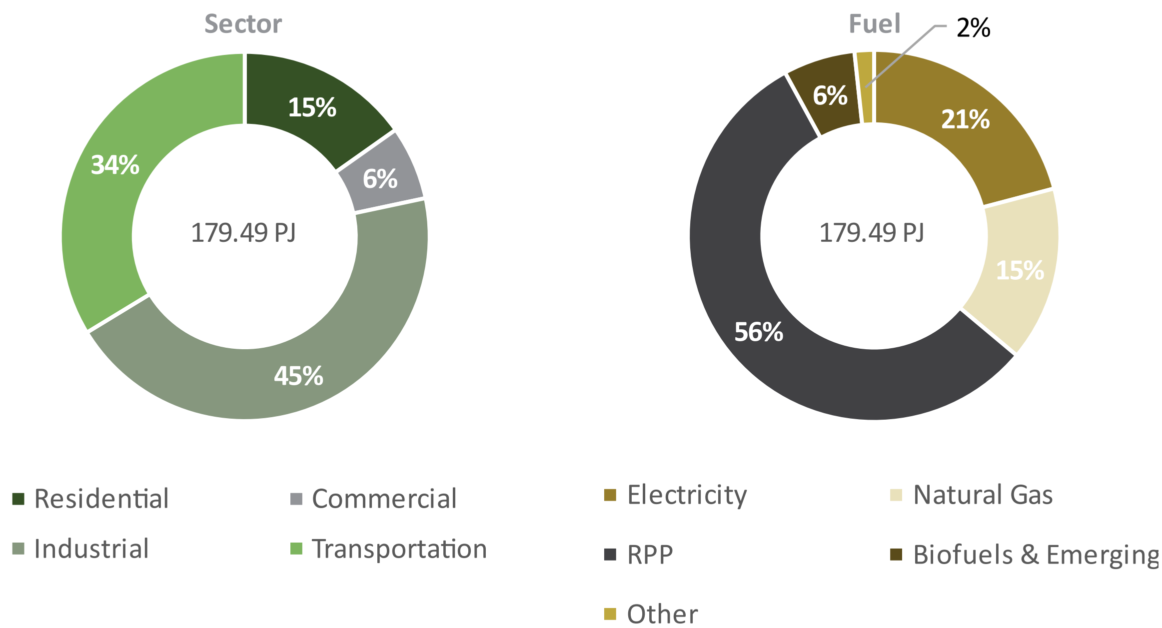


Figure 1 – End-use energy demand in NL by sector and fuel[8]

The energy demand from the industrial sector can largely be attributed to crude oil production. NL is the largest oil producer in Eastern Canada and the 3rd largest oil-producing province in Canada. The majority of oil is extracted from four offshore developments off Newfoundland's coast in the Jeanne d'Arc Basin. NL does not have any oil pipelines or crude-by-rail facilities. All offshore crude oil is transported to refineries by ship from the Newfoundland Transshipment Limited terminal located in Wiffen Head.

Refined petroleum products (RPPs) were the largest fuel type consumed in NL, accounting for 56% of all energy in 2019. In 2018, NL's per capita RPP consumption was 66% above the national average. RPPs in NL have primarily been refined in the province at the North Atlantic Refinery Limited (NARL), however, this facility is currently out of operation while new ownership is being sought. RPPs in NL are also supplied from the Irving Oil Refinery in New Brunswick, from Quebec, and via international imports.

In 2017, NL ranked 3rd in Canada for per capita electricity consumption and consumed 33% more than the national average. This is largely because NL relies heavily on electricity for heating in comparison to many other provinces that use natural gas to a large extent. Electricity was the 2nd largest fuel type consumed in NL, accounting for 21% of all energy-demand in 2019. Most electricity used in NL comes from hydro resources along the Churchill River and Lower Churchill River.

Natural gas (NG) accounted for 15% of NL's energy demand in 2019. Natural gas is entirely consumed in the industrial sector, where it is produced and used for offshore crude oil production facilities and operations.

[8] Canada Energy Regulator. (2017). Canada's Energy Future Data Appendices. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Electricity Generation

Electricity was the 2nd most consumed energy currency in NL in 2020, with a total end-use demand of 35.46 PJ.[10] The residential sector accounted for 48% of electricity end-use consumption in 2020, followed by industrial (31%) and commercial (21%). No electricity for end-use in the transportation sector was recorded separately; rather, this was included under the previous categories.

Newfoundland Power, a subsidiary of Fortis Inc., is the primary electricity distributor serving over 87% of NL's customers. Newfoundland and Labrador Hydro (NL Hydro), a subsidiary of the provincial energy corporation Nalcor Energy, is NL's primary energy generator and distributes electricity to the remaining 38,000 rural customers in NL. NL Hydro has a generating capacity of 1,763 MW from 9 hydroelectric generating stations, 1 oil-fired plant, 4 gas turbines, and 25 diesel generating stations.[11] NL Hydro's electricity generation network is displayed in Figure 2.

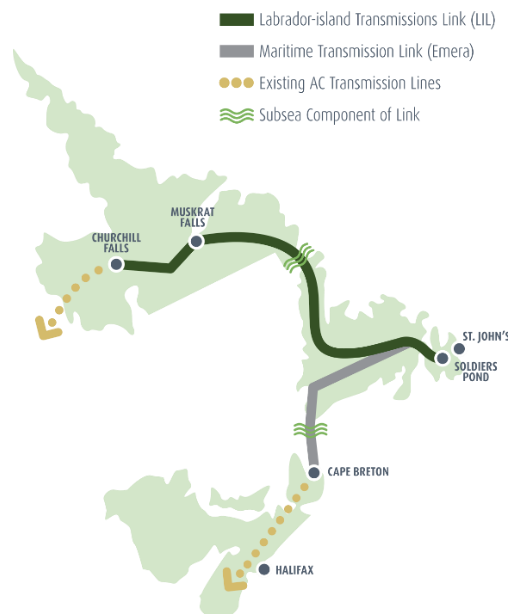


Figure 2 – NL interconnected system[9]

Approximately 80% of the energy generated by NL Hydro is from hydroelectric resources, most notably at the Churchill Falls generating station and generating stations along the Lower Churchill River. The Churchill Falls generating station is one of Canada's largest power plants, accounting for ~80% of NL's hydroelectric generation capacity in 2018. The Muskrat Falls Project successfully produced its first power in September 2020 and will soon be fully online, resulting in NL's electricity grid being generated from 98% clean resources. The project involved constructing an 824 MW hydroelectric generating facility at Muskrat Falls on the lower Churchill River, making it the second-largest hydroelectric facility in NL.[12]

The Maritimes Link and Labrador-Island Link (LIL) electric transmission lines (Figure 2) were constructed in conjunction with the Muskrat Falls project to transmit the electricity from Muskrat Falls in Labrador to the Island of Newfoundland, and from the Island of Newfoundland to Nova Scotia and the North American electricity grid. These links allow electricity from Muskrat Falls to be transmitted across the province and the North American grid.

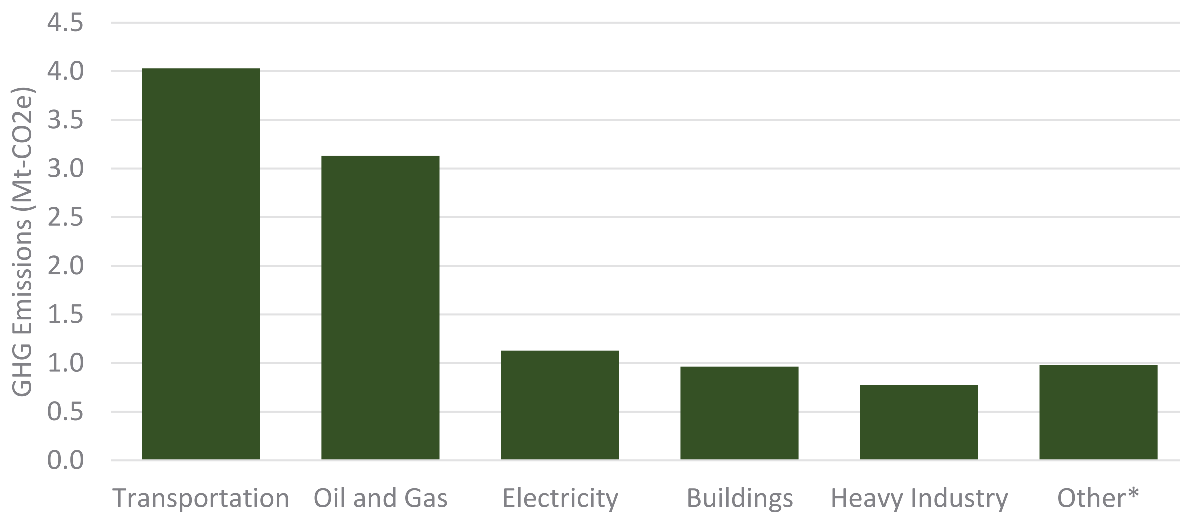
Holyrood Thermal Generating Station is NL's 2nd largest electricity generation station, accounting for 32% of NL Hydro's production in 2019. Nalcor is planning on decommissioning Holyrood in 2021 to be used as

[9] Newfoundland and Labrador Hydro (2018). Planning for Today, Tomorrow, and the Future. Retrieved from https://nlhydro.com/wp-content/uploads/2018/11/NL-Hydro-Report-Nov-15-FINAL.pdf
[10] Canada Energy Regulator (2021). End – Use Demand. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA
[11] Newfoundland and Labrador Hydro (2021). About Hydro. Retrieved from https://nlhydro.com/about-hydro/
[12] Nalcor Energy. Muskrat Falls Generating Project. Retrieved from https://muskratfalls.nalcorenergy.com/project-overview/muskrat-falls-hydroelectric-generation-facility/

a back-up generation and replaced by hydroelectricity generated from Muskrat falls and transmitted through the LIL. Diesel generation stations service the remaining communities in NL that are not connected to the main electrical grid.

GHG Emissions

In 2018, NL produced 11 Mt-CO2e, 20.9 tonnes-CO2e per capita, which is 7% higher than the national average. Greenhouse gas (GHG) emissions per sector in 2018 in NL are displayed in Figure 3.



**Other includes: waste, light manufacturing, construction, forest resources, and agriculture*

Figure 3 – GHG emissions in NL in 2018 per sector[13]

On a per-capita basis, NL's transportation sector ranked 6th largest on emissions in Canada, with a value 43% higher than the Canadian average. NL's high transportation emissions can be attributed to the province's prominent marine sector and the small and spread-out population that limits public transit and increases the average distance between locations. The oil and gas (O&G) sector emitted 3.13 Mt-CO2e, of which 2.1 Mt-CO2e and 1.03 Mt-CO2e were from offshore oil production and petroleum refining, respectively.

Current Uses and Applications of Hydrogen in NL

There is currently minimal hydrogen usage in NL. The NARL, was a major producer of hydrogen for its own uses as a feedstock for crude oil refining. NARL used hydrogen produced from carbon-emitting pathways, including steam methane reforming (SMR) and naphtha reformation.

Ramea Wind-Hydrogen Diesel Project

The Ramea Wind-Hydrogen Diesel project was commissioned in 2009 in the remote community of Ramea to reduce the community's dependence on diesel generators by implementing a hydrogen and wind energy system. The project was led by NL Hydro, with support from the Atlantic Canada Opportunities

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

Agency, the Government of NL, and NRCan. The project utilized included installation of wind turbines and a hydrogen production and storage system. In times of excess wind, hydrogen would be produced from the installed hydrogen electrolyzer and stored until power output from the wind turbines was insufficient to meet the community load, where the hydrogen would be converted back into electricity through a power generator. The proposed project configuration is displayed in Figure 4.

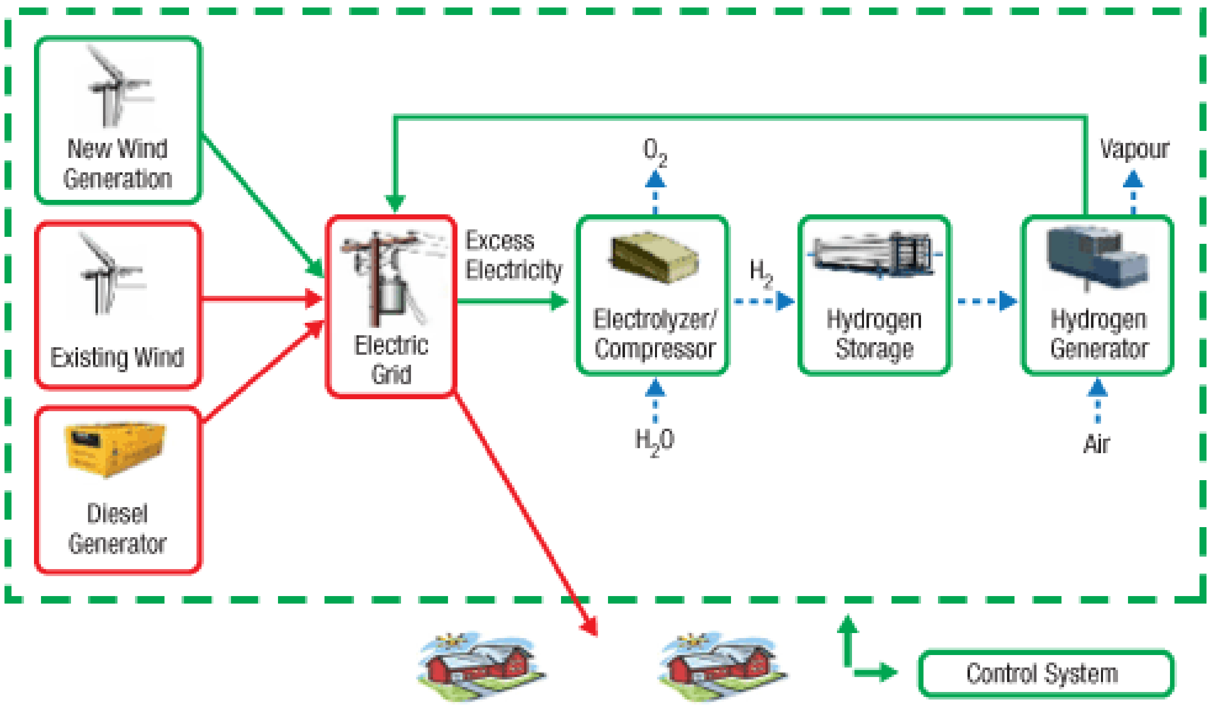


Figure 4 – Ramea Island Wind-Hydrogen-Diesel Project configuration[14]

The system did not operate as planned due to technical issues primarily with the internal combustion engine used to generate electricity from the hydrogen. Given that hydrogen technology reliability and cost has improved since the implementation of this project in 2009, hydrogen and wind electricity systems should be re-evaluated in the region incorporating fuel cells instead of internal combustion engines.

[14] NRCan (2015). Wind-Hydrogen-Diesel on Ramea Island. Retrieved from https://www.nrcan.gc.ca/energy/energy-sources-distribution/renewables/wind-energy/ramea-island/7319

2. HYDROGEN PRODUCTION

Using the same methodology as the Maritimes Hydrogen Study, the cost and CI of hydrogen production was evaluated for NL taking into account local feedstock costs and related emissions.

Several key variables remain consistent across the various pathways that 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	Region	
	Newfoundland	*Labrador*
Electricity Demand Charge ($/kW)[15]	$10.73	$1.49
Electricity Energy Charge ($/kWh)[16]	$0.0443	$0.0287
Electricity Carbon Intensity (g-CO2e/kWh)[17,]	32	
Natural Gas Carbon Intensity (g-CO2e/MJ)[18]	62	
Equipment Amortization Period (years)[19]	25	
Cost of Capital[19]	8%	

A study from the Asia Pacific Energy Research Centre estimated the cost of producing low carbon hydrogen from various pathways in different parts of the world.[20] The report found that production potential in Canada were among the most cost effective in the world, ranging from approximately $1.50/kg-H2 to $3.25/kg-H2 (CAD). Costs in the majority of countries exceed $4.25/kg-H2 with prices ranging to as high as $8.00/kg-H2 (CAD). The National Strategy for Hydrogen in Canada targets a future delivered price of $1.50-$3.50/kg-H2.[21]

Electrolysis using Grid Electricity

NL's abundant hydroelectricity enables low-carbon hydrogen production using interconnected the electrical grid throughout the province. Electric rates differ between the Island of Newfoundland and Labrador, so the resulting cost of hydrogen will differ in each region. Since the bulk of electricity is generated in Labrador, the rates are lower, as shown in Table 1. The analysis was based on current

[15] Newfoundland and Labrador Hydro. (2021). Schedule of Rates, Rules and Regulations. Retrieved from https://nlhydro.com/wp-content/uploads/2021/02/Schedule-of-Rates-Rules-and-Regulations-February-1-2021.pdf
[16] Ibid.
[17] Canada Energy Regulator. (2020). Provincial and Territorial Energy Profiles. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/index-eng.html
[18] 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
[19] 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
[20] Asia Pacific Energy Research Centre. (2018). Perspectives on Hydrogen in the APEC Region. Retrieved from https://aperc.or.jp/file/2018/9/12/Perspectives+on+Hydrogen+in+the+APEC+Region.pdf
[21] Natural Resources Canada. (2020). Hydrogen Strategy for Canada: Seizing the Opportunities for Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

electrical rates for a large industrial customer. It is expected that these prices will increase as the Muskrat Falls hydroelectric facility is fully operational, but the magnitude of the change is unknown. Even with increased rates, it may be possible for a special rate to be permitted by the Board of Commissioners of Public Utilities as a way to incentivize hydrogen generation, particularly when it can be linked to decarbonization benefits. Special rates would be beneficial to the ratepayer since it would be a way to utilize surplus electricity without increasing the required peak capacity of the system, assuming the electrolyzer plant is turned off or ramped down during periods of seasonal and daily peak demand.

Figure 5 shows the estimated cost to produce hydrogen via proton exchange membrane (PEM) electrolysis in NL using grid electricity for a 200 MW, 100 tonnes-H2/day facility. As in the Maritimes Hydrogen Study, the electrolyzer equipment costs were estimated to be $910/kW and annual plant operation and maintenance were assumed to be 1.5% of capital expenditure (CapEx).[19] A conversion efficiency of 81% was used based on the higher heating value of hydrogen.[19] Costs range from $2.17/kg ($15.28/GJ) in Labrador to $3.56/kg ($25.07/GJ) in Newfoundland, which is considered very competitive to other production potential throughout Canada and in comparison to other low carbon fuels.

The resulting CI of the hydrogen is driven by the CI of the electricity. Figure 6 shows the resulting hydrogen CI, which is not assumed to vary between Newfoundland and Labrador. The electric grid in NL is among the lowest emitting in Canada, resulting in relatively low CI hydrogen. Using an electricity CI of 32 g-CO2e/kWh,[22] the resulting hydrogen CI is 10.9 g-CO2e/MJ, which is well below the threshold for low carbon hydrogen of 36.4 g-CO2e/MJ recommended for consideration in Canada in the Hydrogen Strategy for Canada.[23]

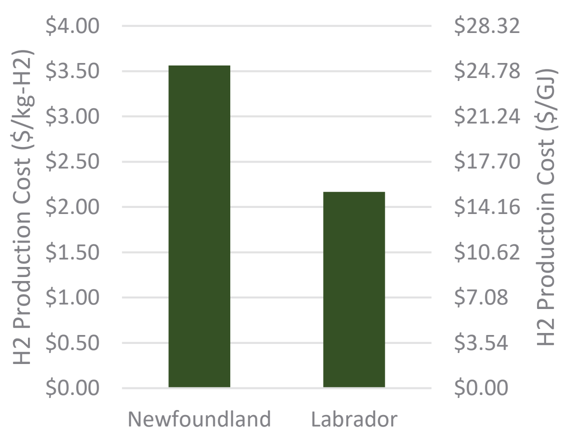


Figure 5 – Hydrogen production cost – grid electricity electrolysis

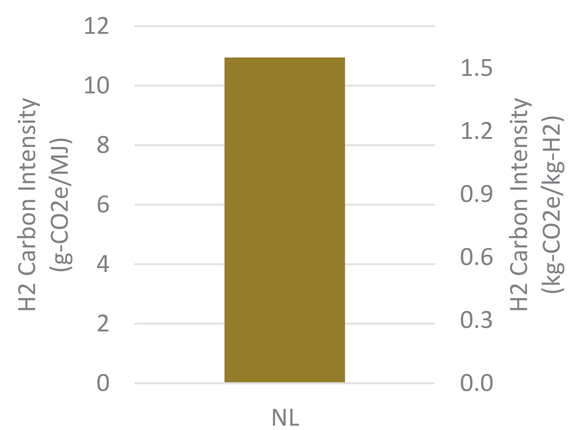


Figure 6 – Hydrogen carbon intensity – grid electricity electrolysis

Quebec, which is similar to NL with about 95% of electricity generation coming from hydro sources, has several large projects under development that couple grid electricity with electrolysis to produce green

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

[23] Natural Resources Canada. (2020). Hydrogen Strategy for Canada: Seizing the Opportunities for Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

hydrogen.[24] Air Liquide completed the construction of a 20 MW PEM electrolyzer plant in Bécancour in January 2021, and the plant will produce up to 8.2 tonnes per day of low CI hydrogen for industrial use and mobility.[25] Hydro Quebec is also planning an 88 MW electrolyzer deployment in Varennes, Quebec. The project will provide green hydrogen and oxygen to the planned Recyclage Carbonne Varennes (RCV) biofuels plant. One use of the resulting biofuels will be to replace fossil fuels in gasoline-powered vehicles, which will help reduce Quebec's transportation GHG emissions. This aligns with Hydro Quebec's overall vision to develop green hydrogen as a strategic solution where indirect electrification is advantageous to direct electrification for technical and/or economic reasons, such as industrial processes, heavy transportation and chemical processes.[26] Evolugen, the Canadian operating business of Brookfield Renewable, and Gazifère Inc., an Enbridge company, recently announced a 20 MW electrolyzer project in Gatineau, Quebec next to Evolugen's hydroelectric facilities to produce green hydrogen for injection into the natural gas network, to contribute to the decarbonization of heating in the region.[27] Together, these projects demonstrate the technical viability and economic growth potential of developing green hydrogen production pathways in NL leveraging the existing, clean, hydro-dominant grid. The projects in Quebec do also signal that there could be competition between provinces to establish a foothold as a hydrogen production center in Canada. However, given the size of the projected Canadian domestic market and the export market for hydrogen, there is likely more room for collaboration to grow the market together rather than viewing this as a competitive threat.

Electrolysis using Wind Power

The Maritimes Hydrogen Study found that there is significant potential for hydrogen production tied to wind power. The electric grid in the Maritimes is relatively high emitting and, as a coastal region, there is significant potential for wind power. Wind generation already makes up a significant portion of electricity generation in the Maritimes, particularly in Prince Edward Island. Further expansion will be necessary to continue to decarbonize the electric grid and enable low carbon hydrogen production. As part of this expanded scope to assess opportunities in NL, electrolysis using wind generated electricity was identified as a topic of particular focus. The results presented are relevant for NL as well as the Maritimes.

Currently, the deployment of wind turbines in NL is relatively limited compared to the Maritimes. Two 27 MW wind projects have been in operation in St. Lawrence and Fermeuse since 2008 and 2009, respectively, but no large-scale projects have been undertaken since then. As a coastal province, there is a great deal of potential for both onshore and offshore wind development. Still, the primary factors limiting the deployment of wind turbines has been the lack of need for extra energy electricity generation capacity from non-hydro energy sources, and regulatory challenges. With the passing of Bill 61 in 2012, Nalcor became the sole Crown Corporation responsible for generating and distributing the province's

[24] Canada Energy Regulator. (2020). Provincial and Territorial Energy Profiles – Quebec. Retrieved from https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-quebec.html

[25] Air Liquide website. (2021). Retrieved from https://energies.airliquide.com/air-liquide-inaugurates-worlds-largest-low-carbon-hydrogen-membrane-based-production-unit-canada

[26] Hydro Quebec. (2020). Website. Retrieved from http://news.hydroquebec.com/en/news/229/developing-green-hydrogen-in-quebec-an-important-step-toward-a-carbon-free-economy/

[27] Evolugen. (2021), Website. Retrieved from https://evolugen.com/news-releases/

power. Although an independent entity is technically permitted to develop an energy source, they must have a Power Purchase Agreement (PPA) with Nalcor to either sell power directly to Nalcor or enter into a partnership with Nalcor to use the province's distribution and transmission system. Local developers have indicated that acquiring a PPA as a key barrier to wind development in the province.[28]

Production of hydrogen could be a way to unlock the potential for wind power in the region by offering an alternative end-use to electricity grid sales. Pairing wind generation directly with hydrogen production allows for behind-the-meter use of the power. The turbines could transmit power to the grid during periods of peak demand when the price of electricity is high, and power an electrolyzer the majority of the time. The resulting hydrogen is a versatile, higher value energy source that can serve multiple markets operating independently of the electric grid.

Figure 7 shows the levelized cost of electricity from wind power from several reference sources: National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB),[29] International Renewable Energy Agency (IRENA),[30] International Energy Agency (IEA) Wind,[31] United States Department of Energy (US DOE),[32] and Nova Scotia Power (NS Power).[33, 34] The costs are shown for 2019, which was the most recent data available, and forecasted to 2030 and 2050. Costs are separated into onshore, offshore fixed and offshore floating wind turbines – all of which could be deployed in Atlantic Canada, although the data is not generally specific to Atlantic Canada.

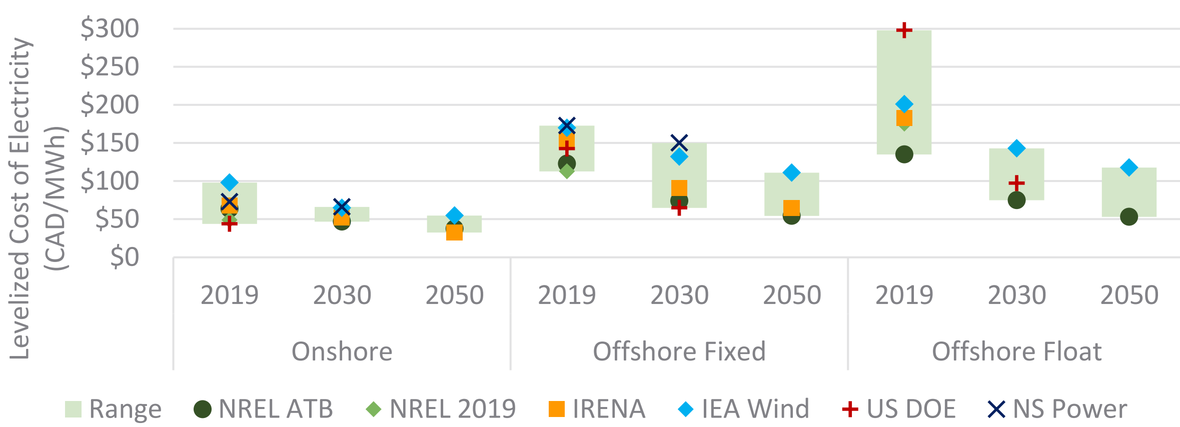


Figure 7 – Levelized cost of electricity from wind power

28 Newfoundland and Labrador Environmental Industry Association. (2017). Retrieved from https://neia.org/wp-content/uploads/2019/08/NEIA_Offshore_Wind_Challenges.pdf
29 NREL. (2020). Annual Technology Baseline. Retrieved from https://atb.nrel.gov/
30 IRENA. (2020). Renewable Power Generation Costs in 2019. Retrieved from https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jun/IRENA_Power_Generation_Costs_2019.pdf
31 Wiser R, et al. (2016). IEA Wind Task 26. Forecasting Wind Energy Costs & Cost Drivers. Retrieved from https://ieawind.connectedcommunity.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=11b4405c-29f3-54c9-e9df-2b716fb2cb22&forceDialog=0
32 US DOE. (2019). 2018 Offshore Wind Technologies Market Report. Retrieved from https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Offshore%20Wind%20Market%20Report%20Presentation.pdf
33 NS 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
34 The levelized cost of energy from the NS Power report was calculated based on the report data for capital and operating expenses.

In all cases, the cost of generation is expected to decrease in the coming years. Lower costs will be driven by improved operation and efficiency as well as reductions in equipment and installation costs. This downward trend will be a continuation of falling prices over the past decade – the average global levelized cost of energy has dropped by 39% and 29% for onshore and offshore wind, respectively, between 2010 and 2019.[35]

Today, the cost of electricity from offshore floating wind turbines is much greater than onshore or offshore fixed operations. Most deployments to date of offshore floating wind turbines are pre-commercial projects. Further development is expected to bring down these costs significantly, as shown in Figure 7. Projects of this type will enable the potential for wind farther offshore and offer advantages such as limited seabed disturbance, which reduces installation time, and potentially lower overall operating costs as major maintenance activities could be carried out in a port.

Projects involving onshore and offshore wind generation should both be considered given the significant potential for both across Atlantic Canada. The region could leverage its skilled workforce with experience in the O&G sector to develop projects incorporating wind generation and create clean energy jobs.

Stakeholder interviews indicated that wind to hydrogen developments could benefit the electricity grid by providing the electricity capacity needed during winter peaking driven by electric heating demand. However, given that Nalcor doesn't currently need the electricity from the wind developments, projects with the primary goal to produce hydrogen, and secondary goal to provide electrical capacity for peaking, could have strong potential in NL.

Figure 10 shows the estimated cost to produce hydrogen using wind power from onshore, offshore fixed, and offshore floating facilities in isolation as well as tied to the electric grid. The costs were calculated using the average levelized cost of energy for each wind technology in 2030 from Figure 7. The capacities were varied between the three technology types since offshore operations can take advantage of greater wind potential. Capacity factors of 36%, 44%, and 48% for onshore, offshore fixed, and offshore floating, respectively, are based on average 2019 values from the IRENA report.[36] Indication from stakeholders is that even greater capacity factors may be possible given the quality of the wind resource in the region, which would result in lower cost of hydrogen generation. Compelling hydrogen costs can be achieved via the wind electrolysis pathway in NL, with onshore wind in Labrador that is grid-connected demonstrating the lowest cost potential.

---

[35] IRENA. (2020). Renewable Power Generation Costs in 2019. Retrieved from https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jun/IRENA_Power_Generation_Costs_2019.pdf
[36] Ibid.

Lighthouse Project Concept: Offshore Wind with Hydrogen Production

Figure 8 – Offshore floating wind turbines

As the cost of offshore wind reduces, largescale projects are becoming increasingly attractive. NL's skilled workforce with experience in offshore operations could be leveraged to lead an offshore wind project paired with hydrogen generation. A project could employ floating turbines relatively close to the offshore oil facilities, which could also generate clean electricity for consumption on the platforms.

Hydrogen could be used as energy storage for electricity generation offshore, and as a transportation fuel in marine applications such as those serving the offshore platforms or in government operated ferries. Depending on scale, hydrogen could be piped to shore for consumption within the province. If all electrical demand can be located offshore, transmission to the mainland would not be necessary, which could have significant cost savings.

A similar project is currently underway in Europe. The AquaVentus initiative is developing a project to pair 10 GW of offshore wind capacity in the North Sea with electrolyzers for hydrogen production by 2030. The hydrogen will be generated offshore and transported to the Island of Heligoland via pipeline for use on the island and in shipping.

Figure 9 – AquaVentus infographic

At full capacity, the facility is expected to generate 1 million tonnes of green hydrogen per year. The first phase will include two 14 MW electrolyzers. Generating the hydrogen offshore eliminates the need for electrical transmission cables to shore, which would reduce the cost of energy and therefore hydrogen. It also avoids intermittency issues associated with wind and interfacing with the onshore transmission network. Wind developers are motivated to explore behind-the-meter use of renewable power to produce high value hydrogen as a replacement transportation fuel. This can be a solution to the economic challenges being experienced as supportive policies such as feed-in-tariff programs are ending, leading to curtailment and negative pricing in some cases. Twenty-seven organizations are part of the project, including RWE Renewables, Shell, and Northland Power.

A sister project in Atlantic Canada would provide an opportunity to further develop domestic capabilities and help develop and demonstrate the regulatory and financial environment as well as routes to market needed for these projects to succeed in Canada. Canada's innovation leadership in wind turbine design for cold climates developed by the Wind Energy Institute of Canada in Prince Edward Island (PEI) through government and industry collaboration, as well as offshore wind platform design for cold climates, could be expanded through the project. To be viable, this type of project would need to be at a scale of hundreds of megawatts, which will require major investment. There is significant private capital available for this type of project, but government support would also be needed particularly to provide certainty in the demand of the hydrogen. This could be for example through committing incorporate zero-emission hydrogen technology onboard the government operated ferry fleet.

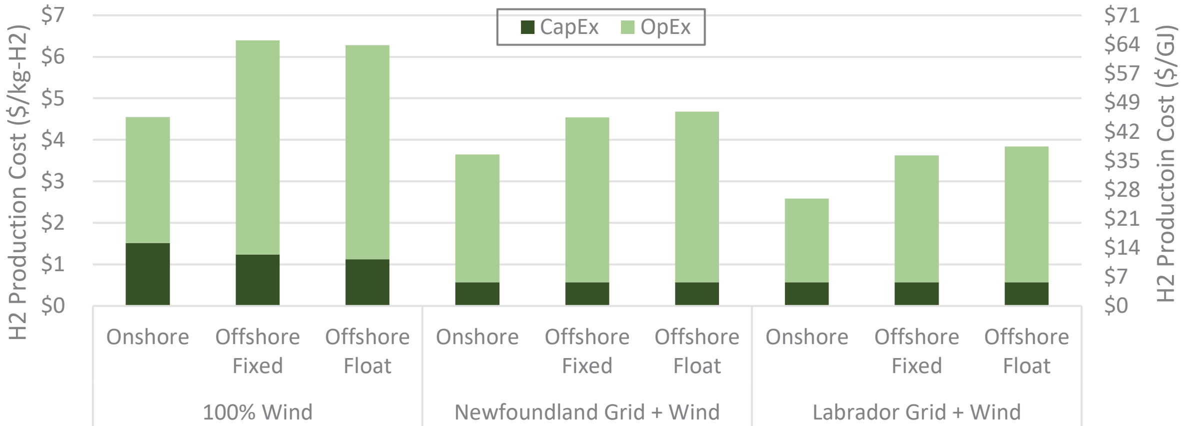


Figure 10 – Hydrogen production cost – wind power electrolysis

There are no emissions from wind power generation, so the CI of the hydrogen produced is zero when wind energy is used without supplemental grid electricity. Figure 11 shows the resulting CI of the hydrogen when produced using wind and grid power based on current grid emissions. As the penetration of renewables increases, the expected CI will decrease further. The results do not differ between Newfoundland and Labrador.

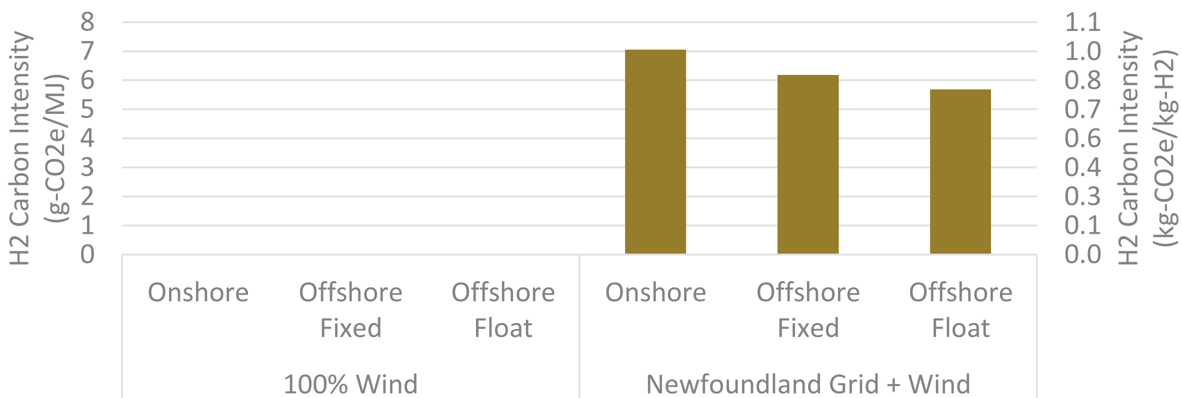


Figure 11 – Hydrogen carbon intensity – wind power electrolysis

Natural Gas Pathways

Currently, there is no natural gas network in NL. Natural gas is extracted offshore at the oil platforms, but it is either used to generate electricity for offshore operations, reinjected back underground, or flared. This natural gas could generate low carbon hydrogen via SMR with carbon capture and utilization/sequestration (CCUS) or through pyrolysis. Due to space constraints at the existing offshore facilities, either pathway would require a large infrastructure project to bring the natural gas or hydrogen to shore. In the case of SMR, the carbon dioxide (CO_2) would need to be transported back to the extraction site to be sequestered underground. Development of a new discovery, such as the Equinor/BP Canada site in the Flemish Pass Basin, could be designed to incorporate hydrogen production offshore, which would limit the required pipeline infrastructure.

Developing the offshore natural gas resources in NL is technically feasible, but the economic viability is uncertain. The potential to produce hydrogen could improve the economic incentive to develop the supply chain because of the increased hydrogen value as a transportation fuel compared to natural gas as heating fuel. As the international market for hydrogen continues to grow, the export opportunity could further drive development of natural gas resources in the region.

Of principal concern to developing the natural gas resource and a potential hydrogen supply pathway is the resulting cost of natural gas brought to shore. This expense represents the major cost of producing hydrogen. Using the same methodology as the Maritimes Hydrogen Study, the price to produce hydrogen via SMR+CCUS and pyrolysis at a scale of 100 tonnes-H2/day was estimated incorporating electricity cost in Newfoundland. The capital cost requirements were estimated to be $1,502/kW, and the operations and maintenance were assumed to be 3% of the CapEx.[37] Based on the higher heating value of hydrogen, it requires 1.37 GJ-NG to produce 1 GJ-H2.[37]

Figure 12 shows the estimated cost of hydrogen relative to the feedstock cost of natural gas. As a reference, the average Alberta NIT and Henry Hub spot prices are shown and the delivered cost of NG in the Maritimes.[38, 39, 40] Based on this analysis, the price of natural gas would need to be below $9/GJ or $13/GJ for SMR + CCUS and pyrolysis, respectively, to remain cost-competitive with hydrogen produced via electrolysis using grid electricity in Newfoundland ($3.50/kg-H2). These costs would need to be the resulting natural gas feedstock costs, including all transmission and distribution charges.

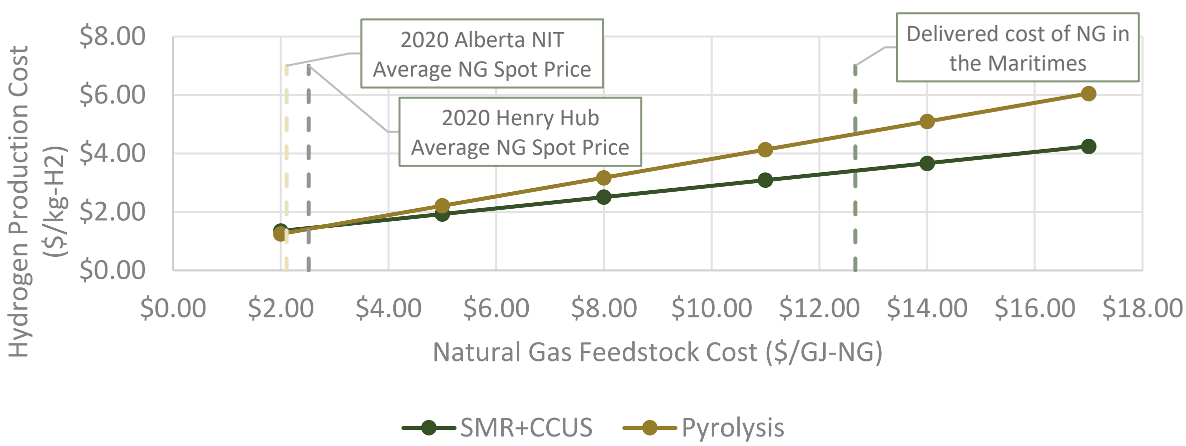


Figure 12 – Hydrogen production cost – SMR+CCUS and pyrolysis

Figure 13 shows the CI of the resulting hydrogen, which was calculated using the same methodology as the Maritimes Hydrogen Study but incorporating the electricity CI of the Province's electrical grid. Both pathways can result in low CI hydrogen, with the SMR+CCUS pathway in a similar range to the current grid

---

[37] 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

[38] Canada Energy Regulator. (2021). Commodity Prices and Trade Update. Retrieved from https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/commodity-prices-trade-updates/

[39] 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

[40] 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

electrolysis pathway. For lack of better information, this analysis assumed the same upstream emissions from natural gas as the Maritimes Hydrogen Study. In reality, natural gas from NL's offshore facilities will have a different emissions profile which should be evaluated as part of a project feasibility study.

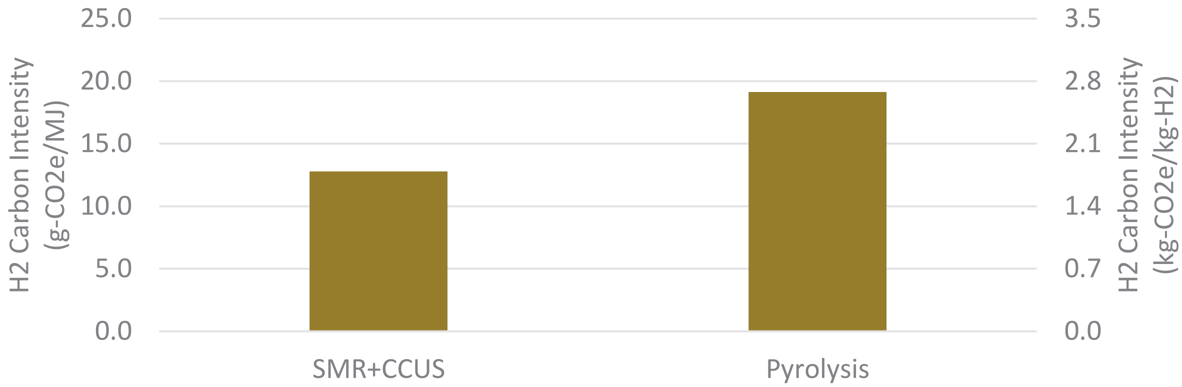


Figure 13 – Hydrogen carbon intensity – SMR + CCCUS and Pyrolysis

Biomass Gasification

Hydrogen production via biomass gasification at a scale of 100 tonnes-H2/day was evaluated in NL using the same methodology as the Maritimes Hydrogen Study. It was assumed that the CapEx would be $1,070/kg-H2/day, and operations and maintenance would be 8.7% of the CapEx.[41] 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.[41]

Figure 14 and Figure 15 show the resulting estimated cost and CI for hydrogen produced via biomass gasification in NL.

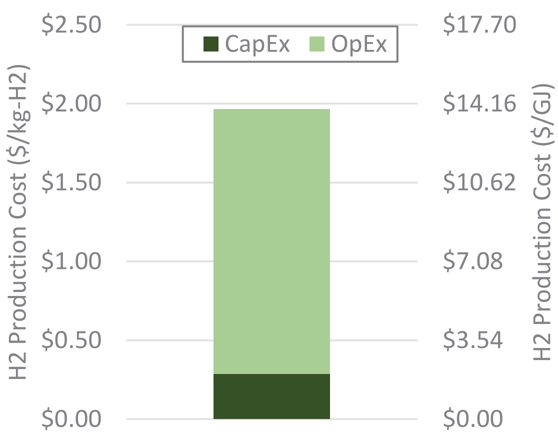


Figure 14 – Hydrogen production cost – biomass gasification

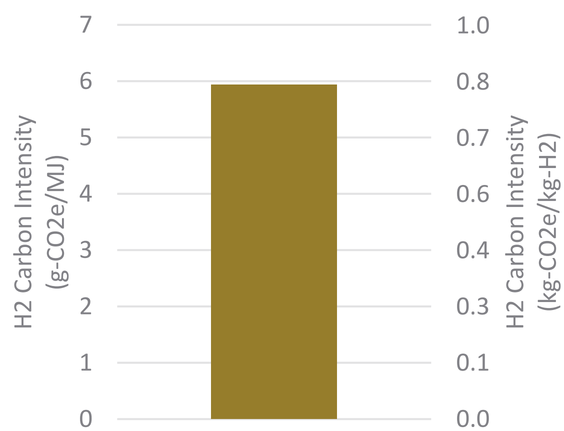


Figure 15 – Hydrogen carbon intensity – biomass gasification

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

Cost and Carbon Intensity Comparison Summary

Figure 16 shows the estimated cost of electrolysis using the grid and wind-generated electricity and biomass gasification. The fossil fuel pathways are not shown here because of the uncertainty of the price of natural gas. The analysis suggests hydrogen produced using wind power alone will be relatively expensive, but it could be combined with grid electricity to keep the price competitive. Hydrogen can be produced very cheaply in Labrador using grid electricity, but end-use demand in that region will be limited and the hydrogen would have to be transported to market. Production at a large scale could be linked to export to the Maritimes, the United States (US), or Europe. Although production via biomass gasification is cost effective, the scale of production will be limited by supply, limiting the potential of the pathway.

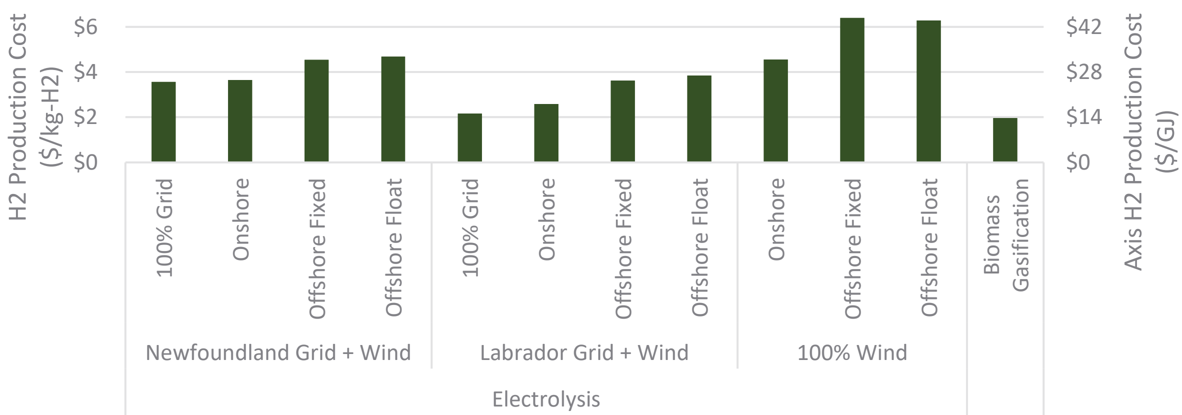


Figure 16 – Hydrogen production cost – all pathways

Figure 17 shows the CI of hydrogen produced by each pathway. All pathways result in hydrogen with CI much lower than the threshold for low carbon hydrogen of 36.4 g-CO2e/MJ recommended in the federal government's Hydrogen Strategy for Canada.[42] Low CI hydrogen will be critical for achieving decarbonization targets and ensuring hydrogen is attractive for export markets.

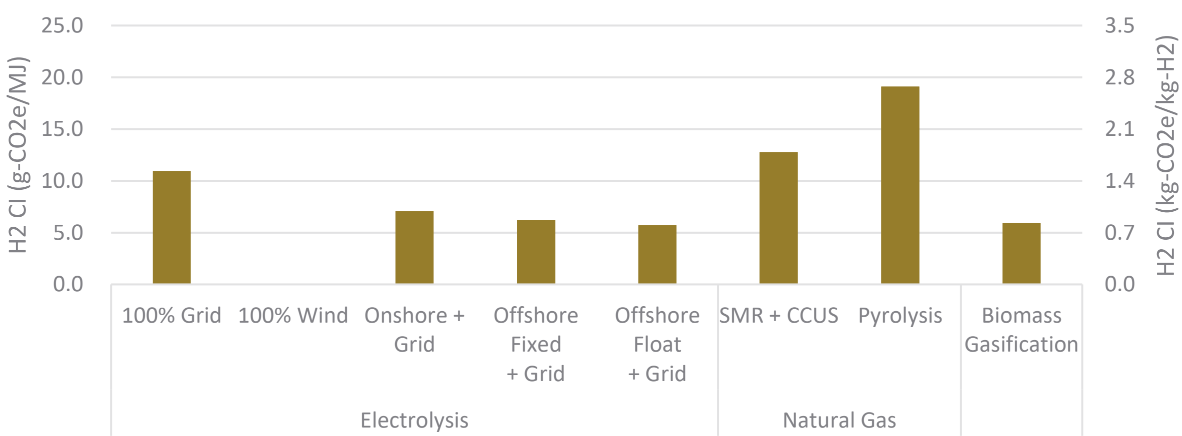


Figure 17 – Hydrogen carbon intensity – all pathways

[42] Natural Resources Canada. (2020). Hydrogen Strategy for Canada: Seizing the Opportunities for Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

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. As such, hydrogen must be stored as a compressed gas, cryogenic liquid, or as part of or attached to another molecule. For more information on common hydrogen storage methods, refer to the *Hydrogen Storage* Section of the Maritimes Hydrogen Study.

Salt Caverns

NL does not have any legislation allowing for storage and recovery of industrial wastes in geological media. This presents a regulatory barrier to the use of salt caverns for hydrogen storage. While the technical and economic feasibility of hydrogen storage in salt caverns in NL requires more study, a small portion of the regional Maritimes Basin discussed in the Maritimes report is in NL at the Fischells Brooke Salt Deposit, located 30 km northeast of the Port of Aux Basques in the southwest corner of Newfoundland. All salt deposits within Atlantic region lie in the Maritimes Basin as displayed in Figure 18.

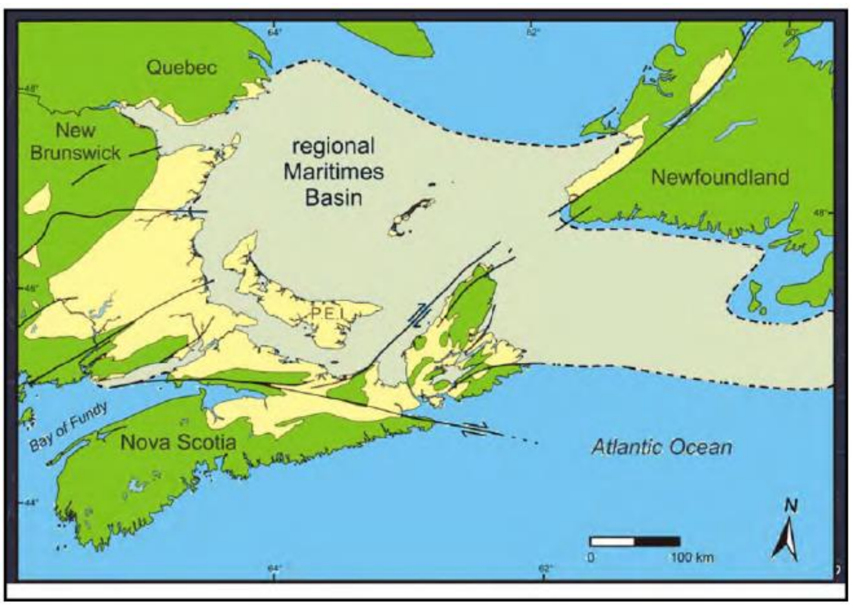


Figure 18 – Salt caverns in the Atlantic Canada[43]

The Fischells Brook Salt Deposit was acknowledged in 2012 as a potential salt cavern site in Atlantic Canada by Newalta Corporation. The Fischells Brook Salt Deposit is the most explored in the province but has only been subject to few drill holes from earlier exploration. The deposit has up to 7 billion tonnes of salt with a length of 4 km and a width of 2 km.[44]

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

4. HYDROGEN TRANSPORT

The transportation of hydrogen is one of the most critical steps of the supply chain that can significantly impact the delivered cost and GHG lifecycle emissions. Hydrogen has a low volumetric energy density which makes cost-effective distribution a challenge. The Maritimes Hydrogen Study provided an overview of transportation options and specific modelling of transportation costs by road. The emphasis of the report was on the local distribution of hydrogen. Those results are equally applicable to NL, but this report expands on the Maritimes Hydrogen Study results by looking more closely at long-distance transportation by ship and pipeline.

Transporting energy over long distances is easier and more cost-effective in a molecular state or as a chemical fuel than transporting electricity. Transportation of chemical fuels is beneficial due to their higher energy density, reduced number of losses during transport, and ability to provide direct transmission throughout wide-scale networks. Hydrogen has the highest gravimetric energy density of all fuels, making it a suitable energy carrier. Similar to natural gas, hydrogen can be transported in large-scale ships and pipelines to provide long-distance transmission.

Shipping

Hydrogen can be transported by ship in liquid form by vessels similar to liquid natural gas (LNG) transport ships, stored in the form of ammonia, or using a liquid organic hydrogen carrier (LOHC).

Several studies and projects focused on the development of capable ships have occurred globally, including the world's first liquified hydrogen carrier, the Suiso Frontier, which was commissioned in 2019 by Kawaski Heavy Industries. The vessel is equipped with a hybrid electric-diesel engine with a transport capacity of 1,250 m^3 of liquid hydrogen.

The liquefaction process increases the costs and GHG emissions associated with transportation. Liquid hydrogen must be stored in highly insulated, cryogenic storage tanks. The potential boil-off that occurs during the liquid hydrogen transport can be used to fuel ships that have hydrogen drivetrain capabilities. Approximately 0.2% of the hydrogen on board the vessel would be consumed daily, similar to LNG carriers' natural gas consumption.[45]

Hydrogen transport via ammonia is the most developed long-distance hydrogen transmission pathway, with numerous trade routes currently in operation. Ammonia (NH3) is composed of nitrogen and hydrogen and can be used as a hydrogen carrier to help mitigate the challenges associated with hydrogen storage and transport. In contrast to hydrogen transport ship requirements, ammonia can be shipped in chemical and semi-refrigerated liquefied petroleum gas (LPG) tankers which are more readily available on the market. Ammonia is relatively cheap and efficient to produce and can be dehydrogenated after transmission to yield 0.176 tonnes-H2/tonne-NH3.

[45] IEA (2019). The Future of Hydrogen. Retrieved from https://www.iea.org/reports/the-future-of-hydrogen

Shipping supply chains for long-distance hydrogen transmission requires additional infrastructure such as storage tanks, liquefaction and regasification plants, conversion and reconversion plants at both the loading and receiving terminals that add to the cost and complexity of the pathway.

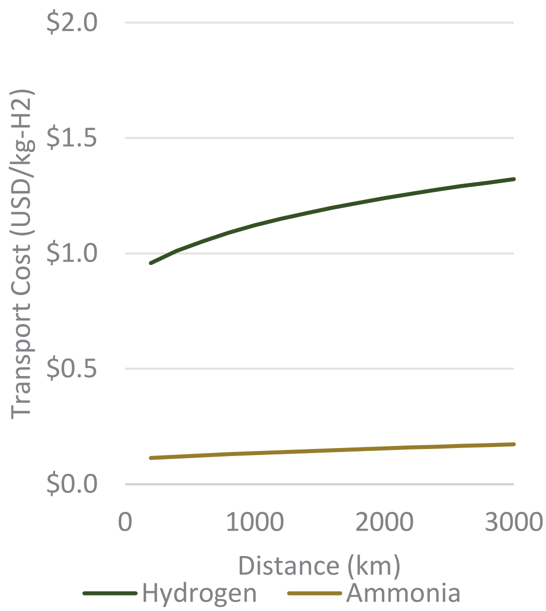


Figure 19 – Predicted hydrogen transport cost by shipping by storage method and distance[45]

The cost of hydrogen liquefaction is roughly equivalent to conversion to ammonia, both costing around USD 1/kg-H2.[45] Figure 19 displays the predicted cost of hydrogen transport by ship, including transportation and required storage costs. The cost associated with distribution and reconversion is not considered.

The cost of transmission by ship increases with distance as additional storage and vessels may be required. However, the cost of hydrogen conversion to liquid or ammonia is the dominant factor. When including hydrogen conversion, the cost to ship pure liquid hydrogen and ammonia 1,500 km is approximately USD 2/kg-H2 and USD 1.2/kg-H2, respectively. These costs do not account for local distribution and reconversion of hydrogen and should be analyzed further for the specific region of interest.

Pipeline

Bulk gaseous hydrogen can be transported via pipeline as pure hydrogen or mixed with natural gas. For more information on natural gas and hydrogen blending, refer to the *Decarbonizing the Natural Gas System* section of the Maritimes report.

Pure hydrogen pipelines currently in operation exist in the industrial sector for industrial hydrogen producers and chemical refinery sites. Pipelines have a long lifespan and relatively low operational costs compared to current conventional hydrogen transportation by road. The main drawbacks of hydrogen transport through pipelines are the high capital cost, regulations, and required support from the public and government needed to construct the pipeline. Hydrogen can be blended with natural gas and transported in existing pipeline infrastructure to mitigate barriers when building a new pipeline. Transportation by pipeline is the lowest CI pathway for hydrogen transportation as no liquefaction or high-emitting fuel such as diesel used in on-road transportation is required.

The construction process and costs of Hydrogen pipelines are comparable to natural gas pipelines. However, the cost of labour for a hydrogen pipeline is estimated to be 25% more than natural gas pipelines as hydrogen-specific welds are required at seals to minimize leaking.[46] Additionally, pipe materials that

[46]Parker. N (2004). Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs. Retrieved from

are not susceptible to hydrogen embrittlement must be used and are estimated to be 50% more than ordinary steel pipes commonly used in natural gas grids.[46]

The cost of pipeline construction will also vary significantly based on its location. There are many potential barriers that could add additional costs, such as geographic constraints (water and terrain), population density, existing right of ways, and existing structures.

A study performed by UC Davis on hydrogen production estimated that transporting 100 tonnes-H2/day a distance of 300 km would cost CAD 1.09/kg-H2 (adjusted for inflation).[47] The levelized cost of transporting hydrogen on a per mass basis reduces as the throughput increases. Hence, transporting large masses of hydrogen via pipeline can be very cost-effective and can offset the construction of a pipeline. The cost sensitivity to design throughput is demonstrated by the IEA's cost estimates that predicted the price for transporting 930 tonnes-H2/day via pipeline for 300 km to be CAD 0.16/kg-H2 (adjusted for inflation).[45]

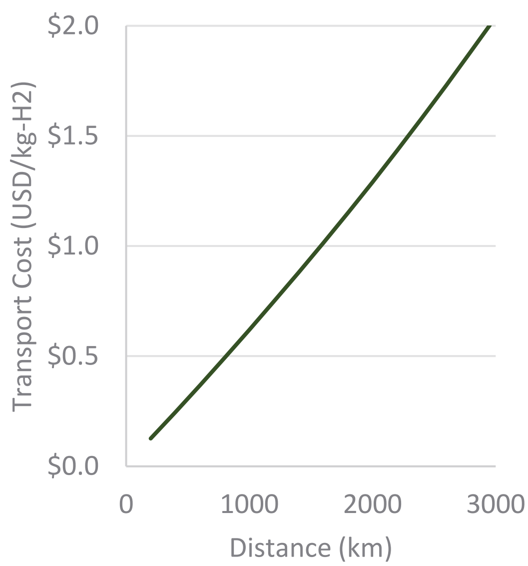


Figure 20 – Predicted pipeline hydrogen transport cost by distance overland[45]

Pipeline transport costs are also sensitive to distance as the capital expenditure increases as the pipeline is longer. Figure 20 shows the predicted cost of hydrogen transport by pipeline as a function of distance for 930 tonnes-H2/day transportation.

As the length of the pipeline increases, additional compressor stations are required to maintain the hydrogen pressure. However, pipeline transmission is the most cost-effective on-land method for the transport of bulk gaseous hydrogen.

Offshore pipelines require additional costs due to the complexity of building underwater. For natural gas pipelines, it is estimated that underwater construction is 1.96 times more expensive than onshore pipelines.[48]

NL Hydrogen Export Transport Pathways

There is a large opportunity for low-carbon hydrogen production in NL due to its extensive hydro and wind energy resources. Further production capacity could be added if natural gas resources in the province are developed, or if the offshore O&G sector considers production of hydrogen as a future low carbon energy product. As much of the province's energy demand can be satisfied by clean electricity generated in

https://www.researchgate.net/publication/254396811_Using_Natural_Gas_Transmission_Pipeline_Costs_to_Estimate_Hydrogen_Pipeline_Costs
[47]Yang. C, Ogden. J, (2007). Determining the Lowest-Cost of Hydrogen Delivery Mode.
[48] SARI/Energy. Natural Gas Value Chain: Pipeline Transportation. Retrieved from https://sari-energy.org/oldsite/PageFiles/What_We_Do/activities/GEMTP/CEE_NATURAL_GAS_VALUE_CHAIN.pdf

province, there is the opportunity for hydrogen export to other regions like the Maritimes, the US, and Europe.

Figure 21 displays potential long-distance hydrogen transmission pathways in NL based on existing power systems and energy distribution in the province and surrounding regions. The potential pathways shown in the figure are for conceptual purposes and do not consider the terrain and constraints of the area.

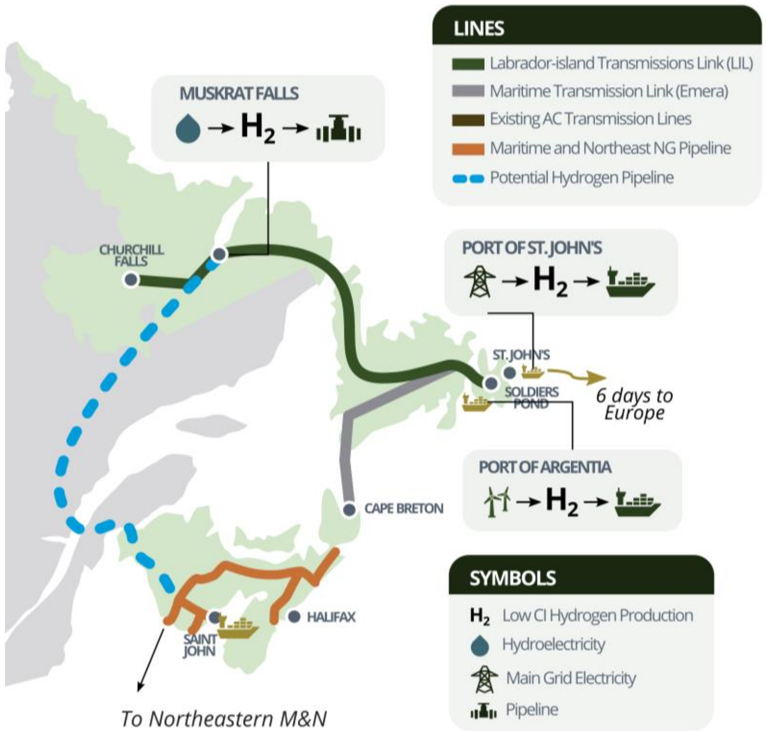


Figure 21 – Potential hydrogen transport options for export

The Port of St. John's and Port of Argentia provide the opportunity for localized hydrogen production that can be transported to other regions such as the Maritimes and Europe via ship. The Port of Rotterdam, which is positioning itself to be a major import hub of hydrogen to Europe, is approximately 4,000 km from the coast of NL. Based on projected shipping costs of hydrogen displayed in Figure 19, it would cost approximately CAD 1.86/kg- H2 to ship hydrogen from NL to the Port of Rotterdam. While this cost will make up a significant portion of the delivered price (>50%), it is a cost that must be borne by any overseas export project. NL's relatively close proximity to Europe will create a competitive advantage compared to other potential exporters.

Hydrogen produced from renewable electricity at Muskrat falls could also be transported to neighbouring regions like the Maritimes and the US via pipeline. A pure hydrogen pipeline could be constructed from Muskrat Falls, where it could be blended with natural gas into the Maritime and Northeast Pipeline (M&NP) and distributed throughout the Maritimes and the Northeastern US. The pipeline could be constructed through Quebec to avoid increased costs associated with offshore pipelines, where it could cross a less dense area of the St. Lawrence River. Figure 21 illustrates a potential hydrogen pipeline concept connecting Muskrat Falls and the Maritimes, with an approximate length of 1,250 km.

Alternatively, electricity could be transmitted through the LIL and Maritime Link for production of hydrogen in the Maritimes. Further analysis is required to determine the costs and benefits of transporting energy as electrons or via pipeline for this specific region.

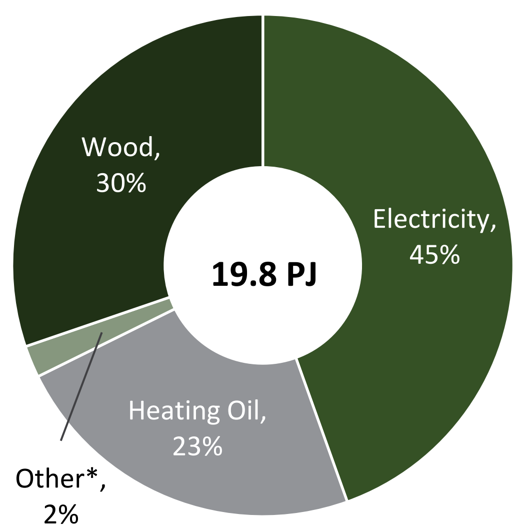
5. POTENTIAL HYDROGEN END USES

The potential for hydrogen was evaluated for several end-use applications: heating buildings, transportation, marine, industrial applications, and remote communities. For each application, incremental and transformative scenarios were created to estimate hydrogen demand and associated emissions reduction out to the 2050 timeframe. The transformative scenario is intended to represent a path to net-zero emissions by 2050, whereas the incremental scenario is based on more moderate adoption of clean energy projects and emissions reduction activities. Both scenarios focus on hydrogen but assume that it will play a role in a larger decarbonization strategy, including other emissions reduction strategies such as direct electrification, biofuels, energy conservation, and emissions offsetting technologies. Neither scenario should be considered a forecast of what will happen in the future but represent possible bookend outcomes based on policy actions, regulations, and assumptions about technology progress and adoption.

Heating Buildings

Space heating in NL is dominated by electricity, heating oil, and wood. While hydrogen is an effective clean energy vector for heating fuel, it is most cost-effective when an existing natural gas network can be leveraged. Incorporating hydrogen into the heating energy mix in NL would require entirely new infrastructure, including all transmission and distribution pipelines and all end-use appliances.

While it would be technically feasible to build up a hydrogen network for heating buildings, it is unlikely to be cost-effective given the low population density of the province. The emissions reduction benefit would be minimal given the abundance of clean electricity as a substitute. For example, it may be possible for hydrogen to play a role for heat generation for large industrial operations in a closed system tied to intermittent renewable energy generation. However, no clear opportunities for this emerged as part of this study.



Other includes coal and propane*

Figure 22 – Space heating energy use by energy currency (2018)

It was assumed in both the incremental and transformative scenarios that hydrogen does not play a role as a heating fuel in NL except potentially in remote communities, which is discussed in the *Remote Communities* Section of this report.

Transportation

Baseline

The transportation sector is the largest contributor to GHG emissions in NL, accounting for 37% of all emissions in 2018.[49] Total emissions in 2018 from the transportation sector were 4.39 Mt-CO2e and shown by category in Figure 23.

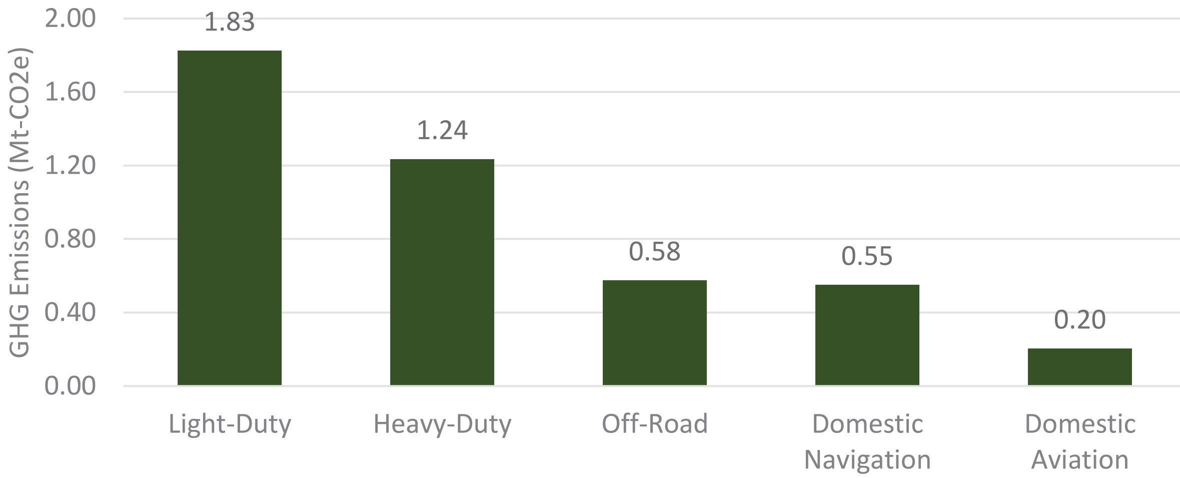


Figure 23 – Transportation GHG emissions in NL by subsector (2018)[49]

Figure 24 represents the percent of total transportation GHG emissions attributable to each transport category in 2019 in NL, indicating that on-road transportation was responsible for 70% of transportation emissions and 28% of total provincial emissions in 2018.

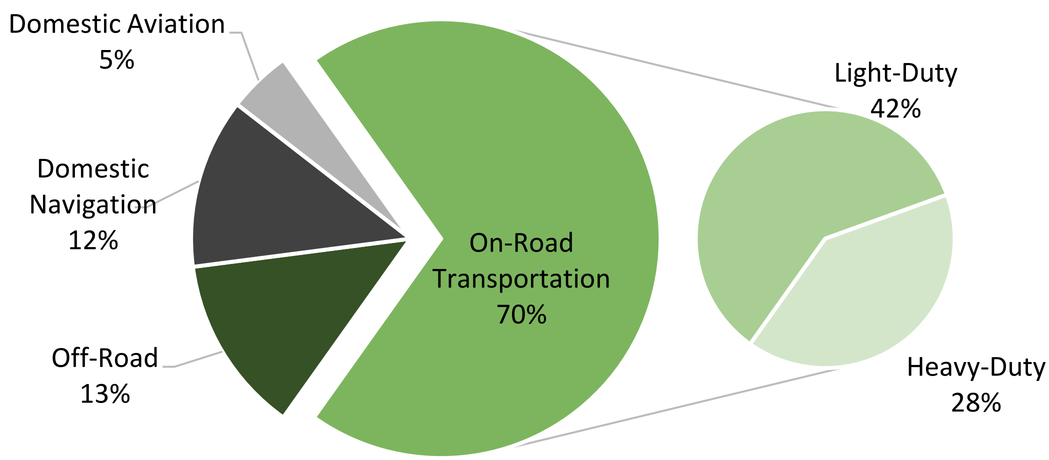


Figure 24 – Percent of transportation GHG emissions in NL by subsector (2018)[49]

[49] 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

Light and Heavy-Duty Vehicle Baseline

This study focuses on light-duty (LD) vehicles and heavy-duty (HD) vehicles within the transportation sector, as they represent the majority of GHG emissions in NL. Marine applications are discussed in the *Marine* Section of this report.

Light-Duty Vehicles

LD vehicles were the largest contributor to transportation emissions in NL in 2018, accounting for 42% of transport and 17% of total 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, which includes both the number of vehicles on-the-road and new LD vehicle registrations per year, i.e., new vehicle sales, in NL, are displayed in Figure 25 and Figure 26, respectively.

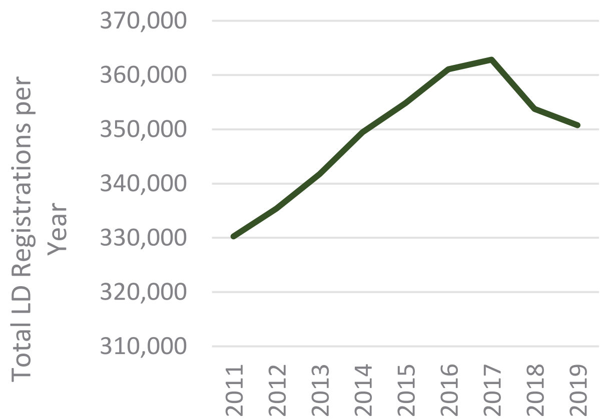


Figure 25 – LD registrations per year in NL[50]

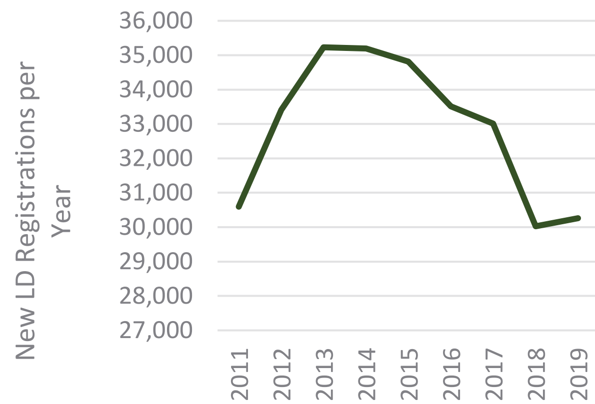


Figure 26 – New LD registrations per year in NL[51]

The majority of new LD vehicle registrations in NL are light trucks, accounting for approximately 79% of all LD vehicles in the sector in 2019. While light-duty passenger vehicles showed a decrease in new registrations per year, the number of new light truck registrations slowly increased.

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

Medium- and heavy-duty (MHD) vehicles include trucks in NL weighing over 4,500 kg. Medium-duty (MD) and HD vehicles are classified as vehicles weighing more than 4,500 kg but less than 15,000 kg and vehicles greater than 15,000 kg, respectively. Buses for public transportation are not included in the MHD vehicle analysis of transportation and are looked at separately in the *Public Transport* Subsection.

The number of new and total MHD vehicle registrations per year in NL is displayed in Figure 27 and Figure 28, respectively.

[50] Statistics Canada (2021). Vehicle registrations, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310006701
[51] Statistics Canada (2021). New motor vehicle sales, by type of vehicle. Retrieved from https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201

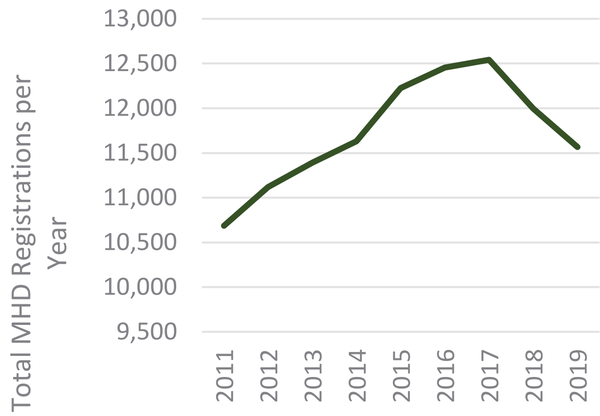


Figure 27 – MHD registrations per year in NL[50]

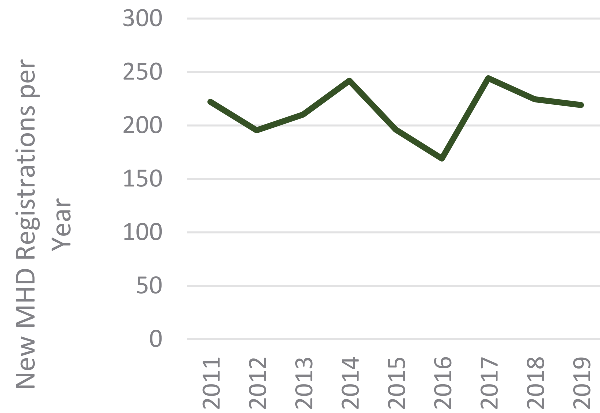


Figure 28 – New MHD registrations per year in NL[51]

Public Transport

NL has a relatively small number of public transit buses in comparison to provinces with larger cities in Canada, and the only major transit agency in NL is in St. John's. Based on data collected by the Canadian Urban Transit Association (CUTA), NL has a total of 65 transit buses.[52]

Opportunities and Challenges for Hydrogen

Due to the relatively small number of vehicles in NL compared to other provinces in Canada, it will be challenging to invest in building out both a retail charging network and hydrogen fueling network. However, the networks can be developed to address different target markets which would avoid duplication of infrastructure. Since NL has substantial hydroelectric resources, electric vehicles will likely account for a significant share of the zero-emission vehicle market. However, to fully decarbonize the transportation sector, battery electric vehicles (BEV) and fuel cell electric vehicles (FCEV) will need to be deployed in parallel. BEVs are likely to dominate the LD vehicle market but may struggle in the MD and HD market due to performance limitations of BEVs, particularly over long distances and in cold climates. The greater energy density of hydrogen makes FCEVs better suited for longer duration operations with more difficult duty cycles typical of the MD and HD markets. FCEVs are also likely to be attractive for applications with high utilization where fast fueling is a priority such as taxis and other fleet vehicles. The Maritimes Hydrogen Study provides additional details about the relative benefits and challenges of BEVs and FCEVs for each vehicle class.

Adoption Scenarios

As NL's transportation sector is relatively small compared to other major Canadian provinces, adoption scenarios for this study were based on reducing the amount of different zero-emission vehicle (ZEV) technologies in the region while considering technology constraints, regulations, and existing infrastructure and natural resources.

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

Light-Duty Vehicles

Hydrogen demand was estimated for the incremental and transformative adoption scenarios of LD FCEVs based on the assumption that NL will instate a ZEV mandate similar to those developed in BC and Quebec and consistent with the federal government's ZEV adoption targets. For more information on these mandates, please refer to the *Transportation* Section of the Maritimes Hydrogen Study. The percent of FCEVs of mandated electric vehicles (EVs), and estimated EV purchases for each scenario from 2025-2050 is displayed in Table 2.

Table 2 – % FCEV purchases of mandated EV purchases per year model assumptions

Year	%FCEV of EV Sales		%EV of New LD Vehicle Sales
	Incremental	Transformative	
2025	0%	0.4%	8%
2030	0%	1.7%	22%
2040	0%	3.6%	86%
2050	0%	4.9%	100%

The adoption scenarios were based on the assumption that BEVs would be the primary focus for the LD market resulting in no FCEVs adoption in the incremental scenario and limited FCEVs in the transformative scenario. LD FCEVs are most likely to be deployed as fleet vehicles where runtime and fast fueling are particularly important.

Forecasted New LD Vehicles per Year

Based on historical data of the number of new LD vehicle registrations per year in NL from 2011 – 2019, forecasted registrations of LD vehicles from 2020 – 2050 were estimated and shown in Figure 29.

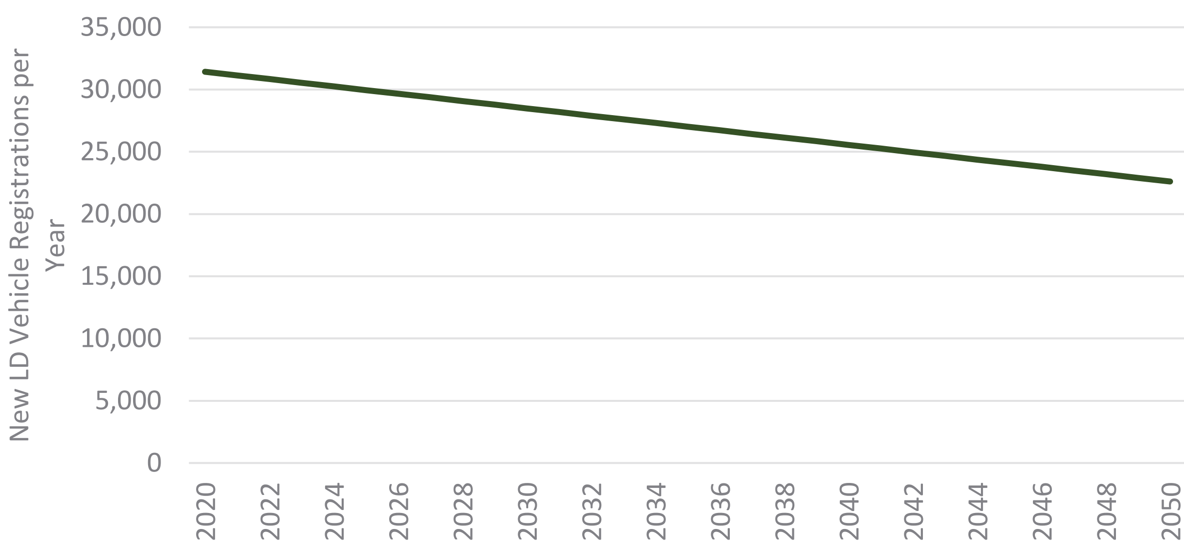


Figure 29 – Forecasted annual new LD vehicle registrations per year in NL

Incremental Scenario

The incremental scenario assumes no FCEV adoption in the LD sector of NL, resulting in zero hydrogen demand and zero GHG abatement from hydrogen adoption. This is an unlikely scenario that would occur if the government made no investment in LD hydrogen infrastructure. The downside of this lack of policy action and infrastructure investment is that retail consumers would have little technology choice when it comes to passenger vehicles, and under a ZEV mandate would have to select a BEV. While these are the preferred choice for many drivers, car owners tending towards minivans and pickup trucks would be particularly range limited, and residents of multi-unit dwellings could find charging to be more challenging compared to having access to public hydrogen fueling stations.

Transformative Scenario

The transformative scenario assumes that the first pilot of 10 FCEVs and a first fueling station are deployed in 2025, with demand gradually growing each year. The assumption in this scenario is that FCEV LD deployments are limited to fleets that can access shared and less widespread infrastructure, including taxi fleets, government fleets, ride-sharing services, and industrial fleets co-located with sources of hydrogen. This transformative scenario could be understated if the NL provincial government takes more progressive action in supporting the build-out of a hydrogen fueling network.

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 transformative scenario is displayed in Figure 30 and Figure 31, respectively.

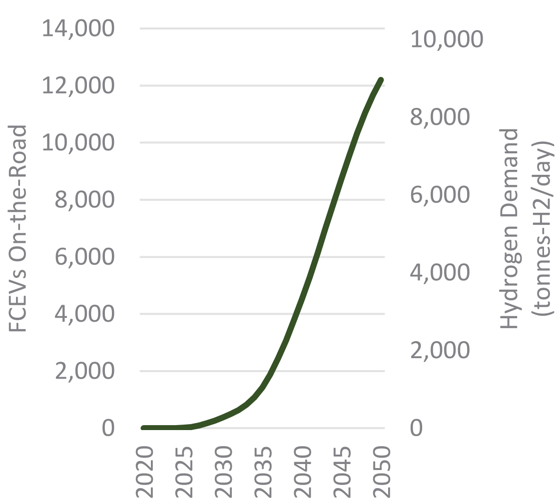


Figure 30 – FCEVs on the road and hydrogen demand - transformative

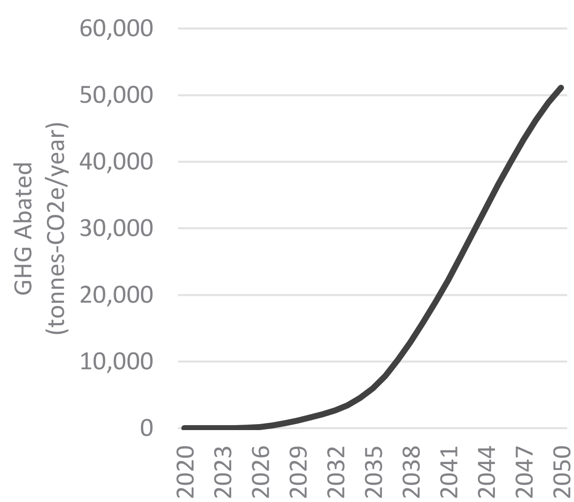


Figure 31 – GHG abated from LD FCEVs – transformative

Table 3 summarizes the number of FCEVs on-the-road, hydrogen demand, and GHG abatement per year associated with the transformative incremental adoption scenario.

Table 3 – LD FCEV H2 demand and GHG abatement summary - transformative

Year	FCEVs On-the-Road	H2 Demand (tonnes-H2/year)	GHG Abatement (tonnes-CO2e/year)
2030	377	55	1,579
2040	4,501	661	18,856
2050	12,199	1,792	51,106

Medium-Heavy-duty Vehicles

Similarly, to the LD market, it was assumed that one vehicle type would dominate the MHD market. Due to the advantages of FCEVs in these applications, the transformative case assumes an FCEV dominant scenario while the incremental case assumes a BEV dominant scenario. The resulting percent of FCEV sales for the incremental and transformative adoption scenarios is displayed in Table 4.

Table 4 – % FCEV sales of total annual MHD vehicle sales model assumptions

Year	%FCEV Sales of MHD Vehicle Sales	
	Incremental	Transformative
2030	4%	25%
2050	25%	75%

Forecasted New MHD Vehicle Registrations

The number of new MHD vehicle registrations per year in NL from 2020 – 2050 was forecasted based on historical data of new MHD vehicle registrations, as shown in Figure 32.

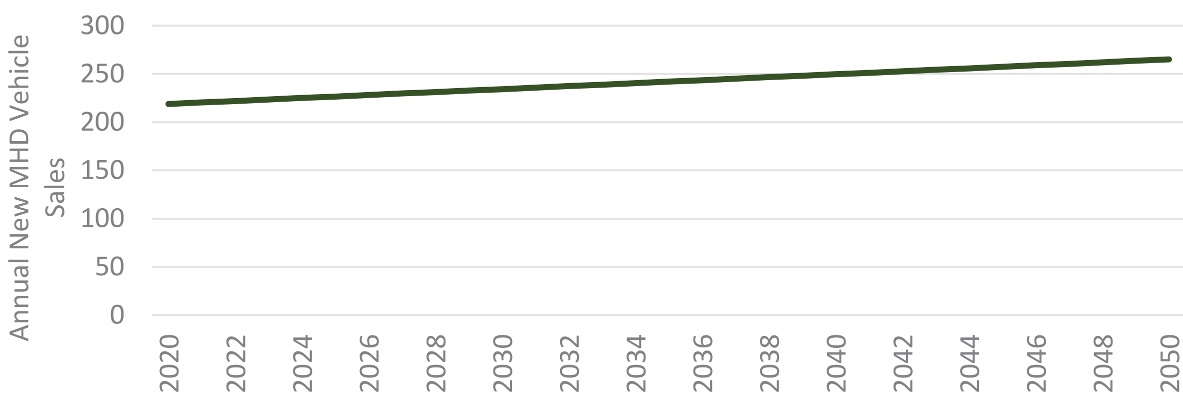


Figure 32 – Forecasted annual new MHD vehicle registrations per year in NL

Model Results

Hydrogen demand per vehicle was determined using the average values for annual distance travelled by a MHD vehicle, 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 33 and Figure 34, respectively.

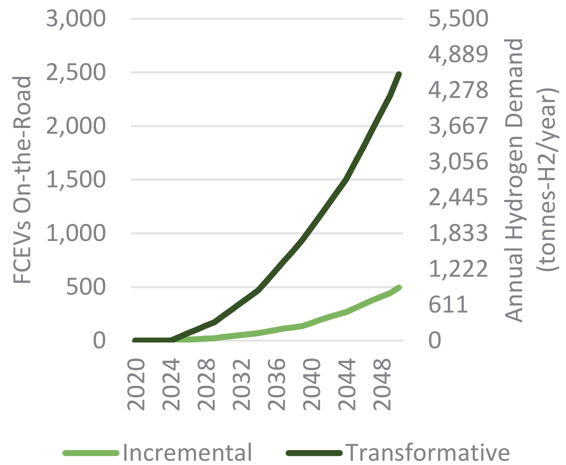


Figure 33 – Projected MHD FCEVs on-the-road and hydrogen demand from 2020 – 2050

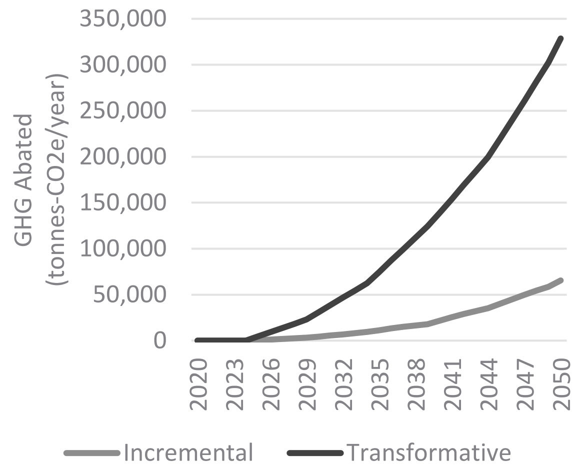


Figure 34 – Projected GHG abated from MHD FCEVs from 2020 – 2050

Table 5 summarizes the number of MHD FCEVs on-the-road, hydrogen demand, and GHG abatement for the incremental and transformative adoption scenarios in NL.

Table 5 – 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	5	34	28	209	607	4,553
2030	32	231	198	1,413	4,319	30,824
2040	163	1,047	991	6,377	21,619	139,088
2050	495	2,483	3,001	15,065	65,452	328,596

Transit Buses

Hydrogen adoption for transit buses in NL assumed one transit agency would use all BEVs or all FCEVs as it transitions to zero-emission. The incremental scenario assumes that by 2050 the agency would be 100% BEV, whereas the transformative assumes 100% FCEVs. It was assumed that the first zero-emission buses (ZEB) would be on the road in 2026, and adoption would follow a similar trajectory as prescribed by the ZEB Mandate in California. This trajectory results in all new bus purchasing being zero-emission by 2032.

Forecasted Bus Purchases per Year

Based on historical bus purchase data provided by CUTA, the average number of buses purchased per year has been 5.[53] It was assumed that this trend continues through 2050.

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

Model Results

The hydrogen demand per FCEB on-the-road was determined using the average annual distance travelled, fuel economy, and EER. The GHGs abated was calculated based on the difference of CI for the low CI hydrogen and diesel gas. Figure 35 and Figure 36 shows the projected number of FCEBs on-the-road and corresponding hydrogen demand and GHG abated for the incremental and transformative scenarios.

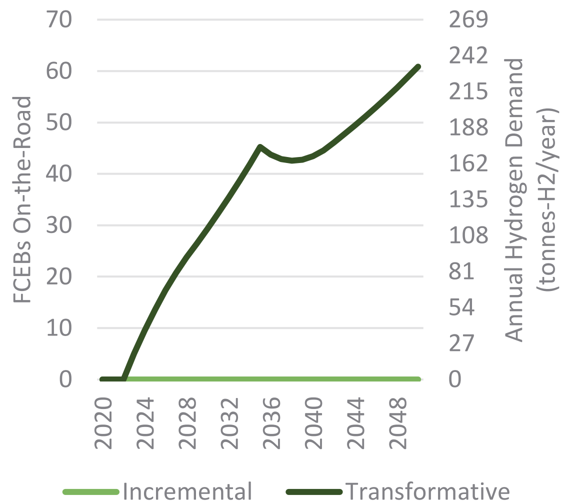


Figure 35 – Projected FCEBs on-the-road and hydrogen demand

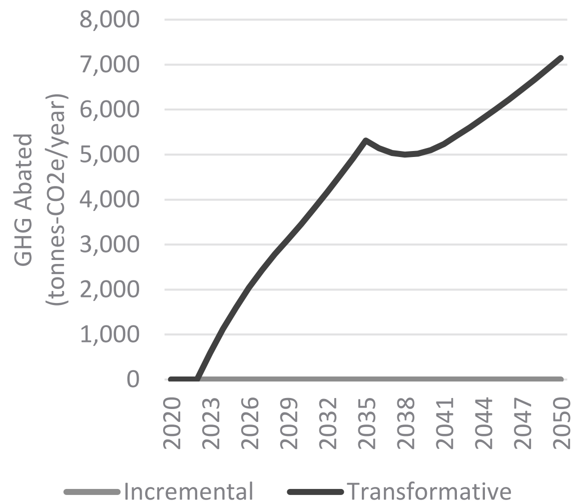


Figure 36 – Projected GHG abated from FCEBs

Table 6 summarizes the number of FCEBs on-the-road, hydrogen demand, and GHG abatement for the incremental and transformative adoption scenarios.

Table 6 – 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	0	14	0	73	0	1,601
2030	0	29	0	158	0	3,450
2040	0	43	0	234	0	5,099
2050	0	61	0	328	0	7,147

Adoption Summary

The aggregate hydrogen demand and GHG abated for on-road transportation in the incremental and transformative scenario is displayed in Figure 37 and Figure 38, respectively. The transformative scenario results in a total GHG abatement of 368,850 tonnes-CO2e in 2050, representing 12% of on-road transportation GHG emissions in NL in 2018.

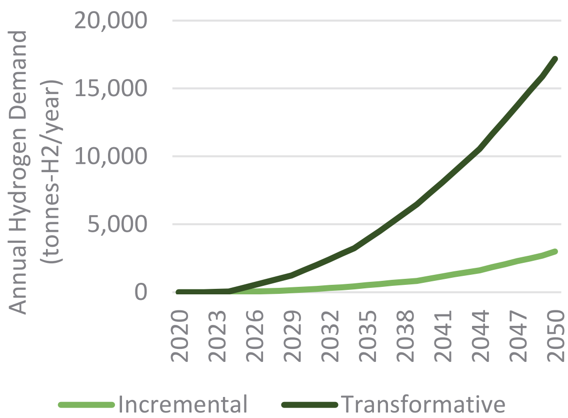


Figure 37 – Aggregate transportation H2 demand

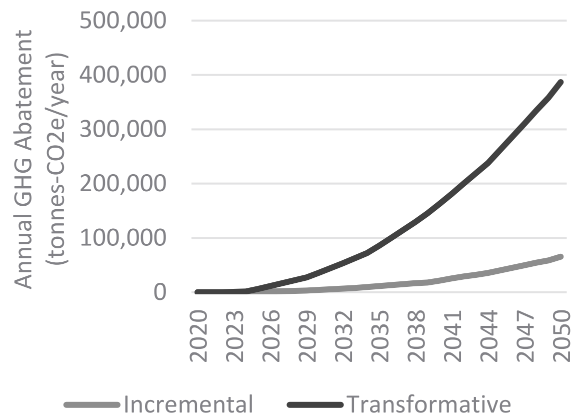


Figure 38 – Aggregate transportation GHG abatement from H2

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 39.

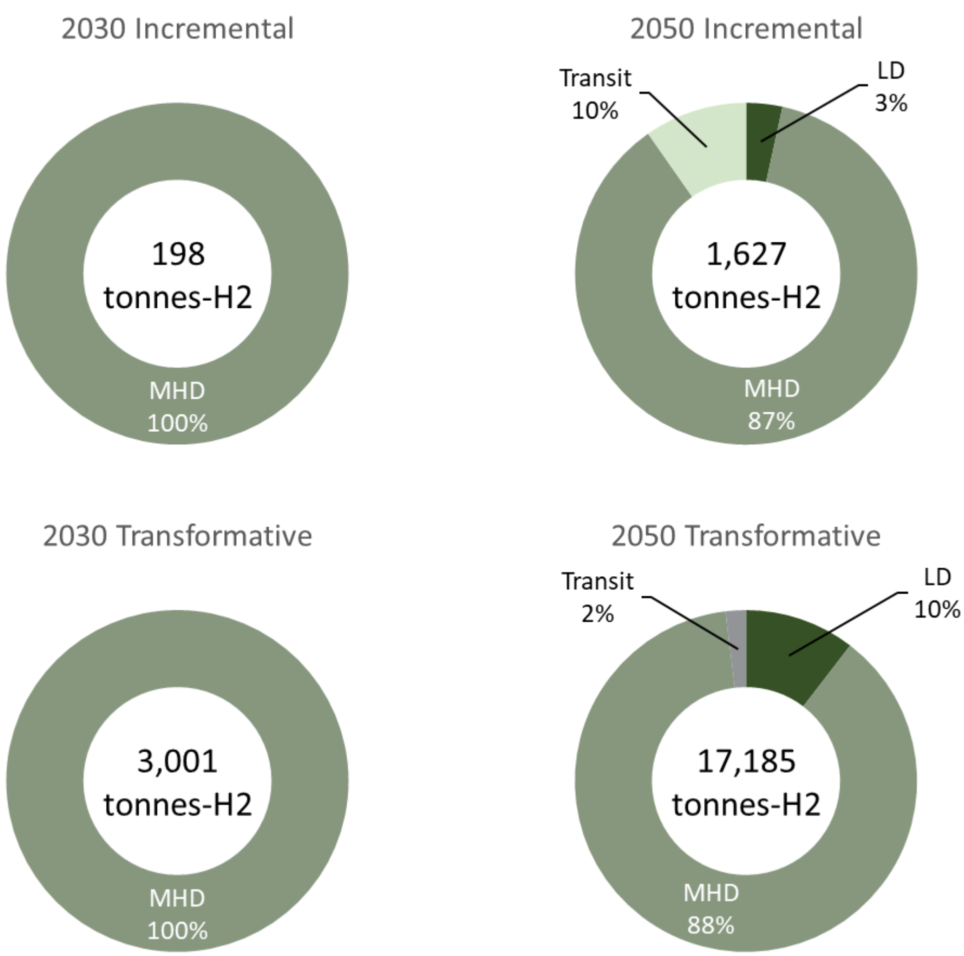


Figure 39 – Incremental and transformative transportation hydrogen demand by on-road vehicle type

Recommendations

Key Transportation Sector Recommendations

- Focus hydrogen activities primarily on MHD applications in NL given the likely high adoption rate of BEVs in LD applications
- Support near-term projects to deploy fuel cell vehicles and supporting infrastructure, particularly relating to MHD vehicles with a targeted focus on government fleets
- Enact strong policies to drive adoption of ZEVs, for example ZEV mandates and funding for ZEV infrastructure, which will motivate manufacturers to make vehicles available in the region
- Provide financial and non-financial incentives for the adoption of ZEVs

Marine

NL's marine transportation sector was evaluated for four categories: fisheries, ferries, tugs and workboats, and shuttle tankers. A breakdown of these categories is shown in Table 7. Marine transportation accounts for 5.7% of GHG emissions in NL's transportation sector and presents a challenge for decarbonization due to the long lifecycle for each vessel. Marine vessels can have an expected service life of 40 or 50 years, if not longer. There are several smaller ferries and tugs currently in service in the NL fleet between 50 and 75 years old. Hydrogen can play an important role in decarbonizing the marine transportation sector, but adoption will be contingent on successful early demonstrations and pilot projects.

Table 7 – Marine transportation subcategories

Subcategory	# of Vessels Considered	Notes
Fishery	4,148	Primarily <45 ft vessels operating the inshore fishery (crab, shrimp, mixed fisheries, etc.)
Ferries	16	Various sizes of vessels operating partially or completely within NL. Only 50% of ferry emissions are considered for routes to locations outside of NL.
Tugs/Workboats	43	Emissions profile is driven by high-power Offshore Support Vessels (OSV), although the largest portion of the fleet is smaller conventional or Azimuth Stern Drive (ASD) Tugs.
Shuttle Tankers	3	These vessels are used to transport crude oil in the offshore oil & gas sector. The emissions profile is split between diesel-powered engines and the use of bunker oil for heat.

Current GHG emissions by subsector are shown in Figure 40. Individual emissions profiles per subsector were modelled based on publicly available data on vessel power, speed, and capacity. The aggregate fuel consumption per sector was estimated based on assumptions for per vessel performance and fleet composition. Total baseline emissions for the marine subsector are 0.586 Mt CO_2e/year.

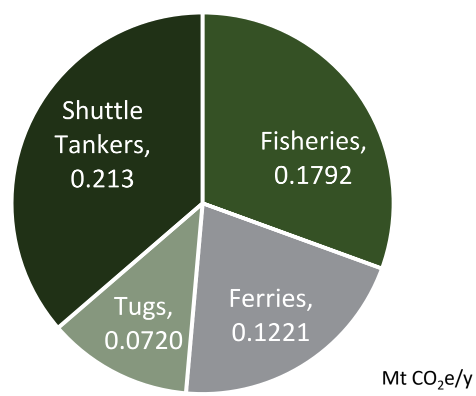


Figure 40 – Marine GHG emissions by subsector

Baseline

Fishing

The NL fishing model is largely similar to that of the Maritimes, where crab, lobster, shrimp, and a variety of other fish are fished on various vessels ranging from less than 35' to over 100'. These fishing vessels are currently fueled with diesel. The International Maritime Organization (IMO) sets emissions standards for marine fuel. The IMO's 2020 MARPOL Annex VI[54], adopted by Transport Canada, reduces allowable NO_X and SO_X emissions for engines over 130kW, effectively regulating the engine category used on fishing vessels (Tier I, Tier II, or Tier III).

Ferries

There are four major ferries to Nova Scotia operated by Marine Atlantic and several coastal ferries operated by the province in NL. Half of the ferries' carbon footprint running between NL and the Maritimes were accounted for in the Maritimes Hydrogen Study, so only the remaining half were considered here. All the ferries are operated on diesel, and no hydrogen projects are currently underway.

Tugs

Tug operations in NL are primarily in ports and offshore oil operations. In total, approximately 43 tugs are operating in NL. Of these tugs, 14 are Offshore Support Vessels (OSVs) meant to service the offshore O&G industry and other offshore operations. These are the largest tugs in the province, all with a power rating of over 4,000 kW. Smaller vessels serving port operations make up the rest of the fleet but do not significantly impact the overall emissions profile when compared to OSVs. These vessels are split among a number of independent operators.

Shuttle Tankers

Currently, three shuttle tankers are being used to service the four offshore oilfields in NL:

- Beothuk Spirit
- Norse Spirit[55]
- Dorset Spirit

Figure 41 – Norse Spirit shuttle tanker

These are large vessels built between 2017 and 2018, each with a 14,600 kW diesel engine. They represent a significant opportunity for decarbonization because, in addition to the diesel consumption for propulsion, they burn bunker fuel to heat the crude oil as it is being transported.

Opportunities and Challenges for Hydrogen

The introduction of hydrogen power plants to marine vessels requires comparable performance to that of the legacy technology (diesel) with comparable short- and long-term costs. In the short-term, one of the main barriers to hydrogen adoption is the lack of local hydrogen supply and the high cost of shipping hydrogen from outside the province. Another key barrier is the lack of strong policy and regulation related to marine sector emissions at both the provincial and federal level, which means that hydrogen and other low carbon fuel alternatives are having to compete with conventional fuels without putting a value on the emissions reductions benefits in the case of low carbon fuels, or alternatively a penalty in the case of

[54] International Maritime Organization. Prevention of Air Pollution from Ships. Retrieved from http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx
[55]Vessel Finder. Norse Spirit. Retrieved from https://www.vesselfinder.com/vessels/NORSE-SPIRIT-IMO-9780770-MMSI-316035893

conventional high CI fuels. Introduction of the anticipated federal Clean Fuel Standard will be an important step forward for incentivizing adoption of lower carbon fuels in marine applications.

To be successful, deployment of hydrogen technology in the marine sector will require reliable fuel production, storage, and distribution, combined with effective power plant design and manufacturing, and supported by a network of maintenance facilities.

Ammonia

For vessels with higher energy demands and prolonged periods between docking, ammonia presents a potential non-carbon-emitting fuel that can replace current solutions. The benefits of ammonia are that it can be used as a standalone fuel for ammonia-adapted combustion engines, as a hydrogen carrier for fuel cell systems, and as an energy delivery and storage vector. Ammonia has greater gravimetric and volumetric energy densities relative to compressed hydrogen, significantly improving its ability to satisfy the requirements for longer voyages, given limited available storage space onboard. Liquid ammonia, being somewhat less cold, does not suffer from boil-off to the same extent as liquid hydrogen.

Figure 42 shows the energy density of different marine fuels by weight and volume. The optimal weight/space ratio is in the top right corner of the graph. The graph shows that ammonia has a higher volumetric energy density than both gaseous and liquid hydrogen. For long distance transportation of hydrogen and/or ability to store significant energy onboard long distance marine vessels, this improved volumetric density is a significant advantage. Coupled with the lower energy required to produce ammonia and the ability to burn ammonia without carbon emissions, this makes ammonia a potentially compelling hydrogen-based fuel for marine applications.

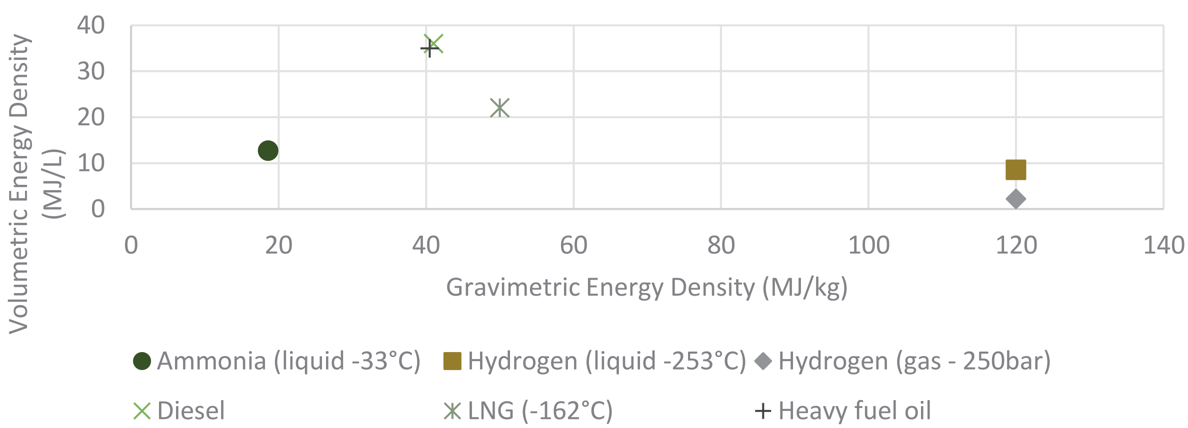


Figure 42 – Energy density of marine fuels by mass and volume

There are now projects underway that seek to further the use of ammonia in the marine sector. Wärtsilä is developing a four-stroke engine that will combust ammonia and plans to collaborate with marine vessel owners in 2022. MAN Energy Solutions is also working on an adaptation of their ME-LGIP propane engine for use with ammonia. The development of this technology opens the doors for new vessel designs that accommodate ammonia as fuel and supports efforts towards meeting a 50% GHG reduction target by 2050.

Lighthouse Project Concept: Port of Argentia Hub

Port of Argentia hosts many businesses at their large industrial property. The port provides services to cargo vessels as well as car and passenger ferries. The variety of potential end use applications for hydrogen as well as the developed road and sea infrastructure make the Port an ideal spot for a hydrogen hub. Producing hydrogen within the port facility would negate the costs associated with the transport of hydrogen, improving the cost effectiveness of the fuel. Investment in the local production of hydrogen will allow the port and its stakeholders, the government and the people of NL, to reap the benefits of reduced costs and increased employment. The port's proximity to St. John's creates more potential use cases, as the port hydrogen production and storage facility can easily become the metro distribution hub for hydrogen fuel to light, medium, and heavy-duty land vehicles among other uses.

Figure 43 – Port of Argentia aerial view

Once hydrogen production, storage, and maintenance are established at the port, there are many opportunities to sustain them. One such case would be for Marine Atlantic to use hydrogen as an auxiliary power source on their ferries that run from Port Argentia. The power required is in the 500-1,000kW range and could be provided by a modular fuel cell system. While providing auxiliary power alone rather than in conjuncture with propulsion power is only an intermediary step, this makes for a good lighthouse project because it prequalifies the hydrogen supply chain and refuelling facilities as well as the onboard installation of hydrogen power plants. However, auxiliary power alone will not provide the emissions reductions that will be needed to meet the overall targets. Hence, adoption scenarios presented in this report are based on hydrogen power plants replacing diesel for both propulsion and "hotel" (auxiliary) power on board the Marine Atlantic ferry fleet.

Figure 44 – Marine Atlantic vessel, MV Atlantic Vision

The port's hydrogen facilities will become attractive for companies that develop such systems, further establishing it as a regional, if not global, center for hydrogen innovation and creating positive ripple effects through the entire local technological innovation and entrepreneurship ecosystem, including Memorial University. The modular hydrogen fuel cell system will be compatible with the current vessel fleet and will not require any major retrofitting, making it feasible to implement it on board the vessels within their current service life.

Small-scale projects introducing hydrogen to marine applications will have multiple immediate benefits. In the short-term, they will justify production of hydrogen at the Port of Argentia, as it will be sold to end users such as Marine Atlantic vessels equipped with hydrogen fuel cells. This limited-scope application will deliver immediate reductions in GHG emissions. The location of the production at the port facility allows for growth to support increased demand as hydrogen becomes more commonly used as a power source. If the production were to grow to the point of being a potential export, the infrastructure is already in place to facilitate this development.

Another favourable aspect of ammonia is that it already has widespread availability. Ammonia is commonly used in fertilizers and refrigerants; thus, the infrastructure required to produce, store, and deliver it is already in place. Although most ammonia is produced through steam reforming of natural gas and coal gasification, renewable energy sources could replace this production to produce green ammonia fuel locally in NL.

Ammonia spills into the marine environment can have deleterious effects on fish and plankton. Concentrations of 1.25 parts per million are sufficient to produce fish kills. A major spill of, for example, seven tons of ammonia has the potential to kill fish and disrupt the marine ecosystem along two kilometer stretch of a 1,000 m^2 cross-section channel.[56] A ferry such as the ones operated by Marine Atlantic would carry at least 70 tons of ammonia, so ten times the amount that can cause severe damage. Thus, precautions must be taken against spills, both at sea and at port during refueling operations.

Figure 45 – Ammonia engine for marine applications

Adoption Scenarios

Table 8 shows the projected number of hydrogen-powered vessels deployed per year for each subsector in the incremental and transformative scenarios.

Table 8 – Hydrogen marine vessels adoption assumptions

Year	H2 Vessels, Incremental Scenario				H2 Vessels, Transformative Scenario			
	Fishing	Ferry	Tug	Shuttle Tanker	Fishing	Ferry	Tug	Shuttle Tanker
2025	0	0	0	0	2	1	3	0
2030	1	1	1	0	9	3	7	0
2035	7	1	2	0	21	4	11	0
2040	22	1	3	0	51	4	15	0
2045	65	2	5	0	130	5	19	1
2050	131	5	6	0	250	10	25	1

For each of the four sectors considered, two scenarios were created to estimate hydrogen demand and GHG emissions reduction potential. The transformative scenario represents an 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 driven by regulations, with lower buy-in from operators.

[56] Pitt R. M8: Fates and Effects of Ammonia Spills. Robert Pitt, Department of Civil, Construction, and Environmental Engineering, University of Alabama. Retrieved from http://unix.eng.ua.edu/~rpitt/Class/EffectsandFates/Module8/M8%20Ammonia%20fate%20and%20effects.pdf

In both scenarios, hydrogen demand and the resulting potential for GHG abatement is highly contingent on the replacement of high-power ferries and OSV tugs with fuel cell or other low carbon technologies that rely on low CI hydrogen, such as ammonia or biofuels. Most of these large vessels have an estimated end of life between 2040 and 2060, making early pilot projects critically important to demonstrate the feasibility and drive adoption for key operators such as Marine Atlantic and Atlantic Towing.

Incremental Scenario

Figure 46 and Figure 47 show the forecasted hydrogen demand and emissions reduction from the marine sector by year and subsector. In this incremental scenario, hydrogen demand and emissions reduction spike sharply between 2045 and 2050, driven by looming IMO regulations as many of the larger vessels reach their expected end of life.

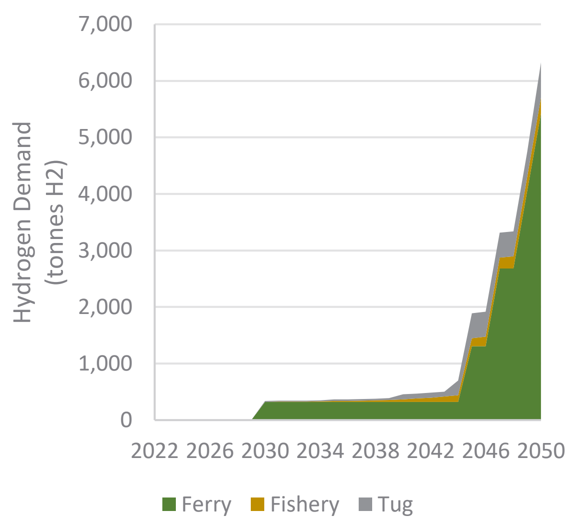


Figure 46 – Marine incremental scenario - H2 demand

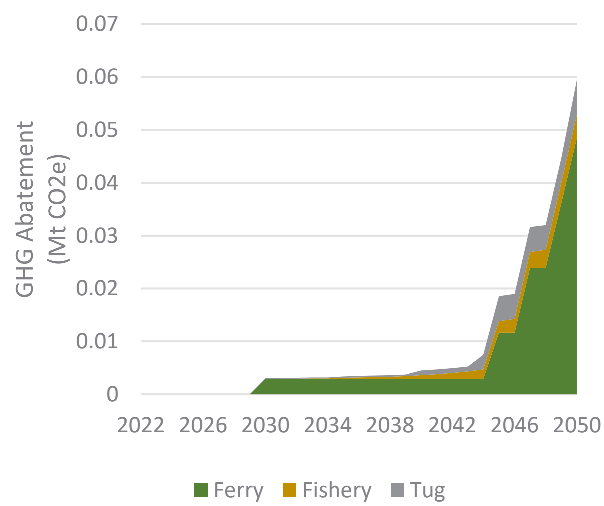


Figure 47 – Marine incremental scenario - GHG emission abatement

Transformative Scenario

In the transformative scenario, early pilot projects boost fuel cell technology confidence and result in almost double the hydrogen demand and GHG emissions abatement by 2050. The largest increase occurs between 2040 and 2050 as the larger vessels are replaced with fuel cell vessels or other hydrogen-based technologies. In this scenario, a larger portion of these vessels are converted to hydrogen than the conservative scenario. In addition, one of the three shuttle tankers currently in use is replaced by a hydrogen-powered vessel in 2046. Figure 48 and Figure 49 show the projected hydrogen demand and GHG abatement for this scenario.

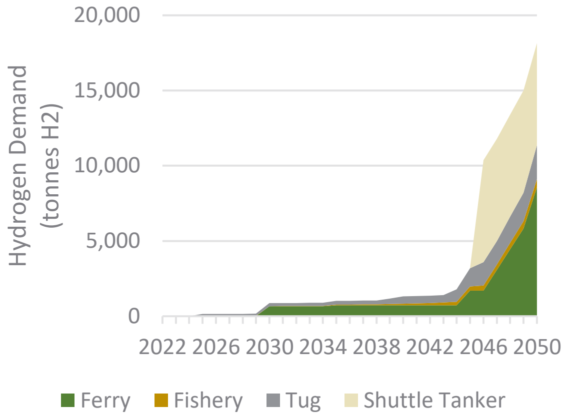


Figure 48 – Marine transformative scenario - H2 demand

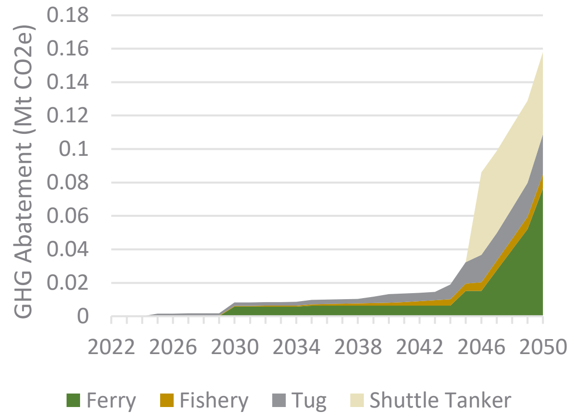


Figure 49 – Marine transformative scenario - GHG emission abatement

Figure 50 and Figure 51 show the annual hydrogen demand and potential GHG emissions reduction for both the incremental and transformative scenarios for the four marine subsectors combined. These figures clearly show that successful pilots leading to adoption as modelled in the transformative scenario can almost triple the annual GHG reductions by 2050.

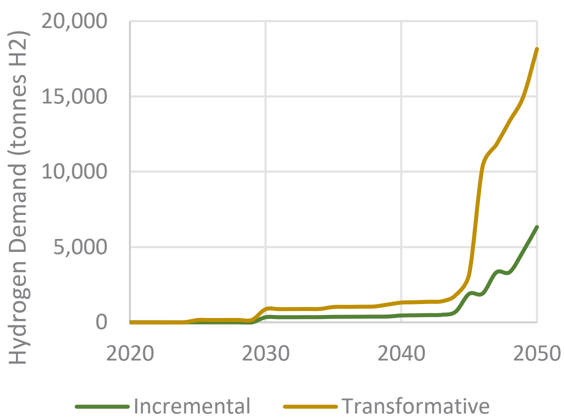


Figure 50 – Marine transformative and incremental scenarios - H2 demand

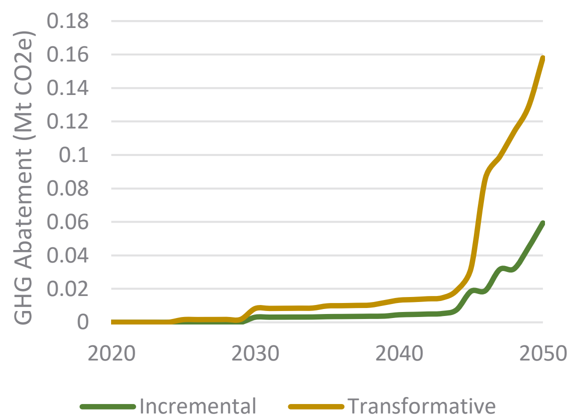


Figure 51 – Marine transformative and incremental scenarios - GHG emissions abatement

Adoption Summary

In the incremental scenario, hydrogen adoption is based on tightening emissions regulations. In this case, adoption accelerates only when forced to do so by imminent deadlines to implement new regulations such as IMO 2050. In the transformative scenario, stakeholders such as operators, large businesses, and the public sector act proactively and initiate pilot projects earlier in the cycle. This leads to earlier buy-in by small-scale operators leading to fleet replacements as they reach their end-of-life between 2030 and 2050.

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 local marine industry about benefits of transitioning to zero-emission technologies
- Adopt policies that align with wider decarbonization goals and regulations (e.g., IMO for fisheries)

Industrial Applications

Baseline

NL's industrial sector contains a variety of organizations that focus on various businesses and services. The industrial sector has the largest end-use energy demand in NL, accounting for 45% of energy consumption in 2020.[57]

The most significant opportunity for hydrogen as a large industrial load based on the current industrial sector is at NARL in Come by Chance, NL. It is the sole refinery in the province and is the only significant hydrogen user in the region. NARL has a processing capacity of 130,000 barrels per day, with 90% of products being exported to foreign markets.[58] The refinery is currently closed and for sale.

The refinery can produce hydrogen using fossil fuel feedstocks without CCUS. The resulting hydrogen was used as a feedstock for multiple refining processes and hydro processing units at NARL. NARL consumed approximately 90% of the hydrogen produced from their 175 tonnes-H2/day production unit.

GHG Emissions

The O&G sector in NL accounts for a large portion of energy demand and GHG emissions, including oil refining and offshore oil production. The sector was the second-largest contributor to GHG emissions in 2018, representing 28% of emissions.[59] Upstream O&G operations alone accounted for 19% of NL's total GHG emissions.[59]

Opportunities and Challenges for Hydrogen

NARL presents the greatest opportunity for industrial use of hydrogen in NL based on industrial users present in the province today. Low carbon hydrogen could replace high-emitting hydrogen used as a feedstock in the refining process, reducing the CI of the produced fuel.

The future uncertainty of the facility is the first major challenge facing the transition to clean hydrogen. A second challenge to incorporating low-CI hydrogen into the refining process is the higher cost. However, the additional cost may be reduced through policies like the Carbon Tax and the proposed Canadian Clean Fuel Standard, raising the price of emissions and incentivizing low-carbon technologies.

With NL's potential to produce large quantities of competitively priced, low-CI hydrogen in the province, the greatest opportunity in the industrial sector lies in developing and attracting new industry to the province. As seen in the Quebec examples, the ability to produce hydrogen in the province can stimulate new biofuels or liquid synthetic fuel industrial projects and other industries such as the production of ammonia for fertilizer or as a low carbon fuel or energy carrier. While this opportunity has not been quantified here, it has been addressed under economic growth potential.

---

[57] Canada Energy Regulator. (2017). Canada's Energy Future Data Appendices. Retrieved from https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA
[58] NARL (2021). Fueling our province and the world. Retrieved from https://northatlantic.ca/refining/
[59] Government of Canada (2018). Canada's Official Greenhouse Gas Inventory. Retrieved from https://open.canada.ca/data/en/dataset/779c7bcf-4982-47eb-af1b-a33618a05e5b#wb-auto-6

Lighthouse Project Concept: NARL

Figure 52 – Refinery in Come by Chance, NL

The NARL refinery in Come by Chance, NL has the only significant hydrogen production unit currently in the province. The facility has emphasized emissions reduction in the past, reducing emissions by 21% since 2008.[60] NARL has the experience and institutional knowledge to produce and use hydrogen, making them it a strong candidate for early hydrogen adoption and potential public demonstrations.

As a large producer and consumer of hydrogen, the refinery could participate in the market throughout the hydrogen value chain. In addition to incorporating low carbon hydrogen into their own operations, NARL could leverage their position as a fuel provider and experience with hydrogen to stimulate deployment of hydrogen technology in other end use applications such as fuel cell electric vehicles.

A public proof-of-concept project with hydrogen produced from NARL's current production facility could help demonstrate hydrogen's capabilities to help enable the growth of clean hydrogen production in the province. The fuel could be used as a transportation fuel in vehicles within the facility property or to supply a demonstration project in another location. This would help build up hydrogen demand in the province to justify installation of further low carbon hydrogen production projects.

Figure 53 – North Atlantic service area

Fuel from NARL is distributed all over the island of Newfoundland including to commercial gas stations and residential heating oil systems. A similar distribution network could be set up to transport hydrogen throughout the island for use in vehicles.

While there is strong potential for NARL to participate in an early demonstration project in the hydrogen sector, the future of the facility is uncertain. A potential lighthouse project should be explored by new ownership whenever the facility begins operation again. A similar project could also be undertaken at the Irving Oil Refinery in Saint John New Brunswick.

[60] North Atlantic Refining Limited Partnership (2019). Retrieved from https://northatlanticrefining.ca/

Several remote mines in NL have limited or no connection to the electrical grid and rely on diesel generators. Hydrogen could be used to decarbonize these locations, using stationary fuel cell stacks to generate electricity and power.

Adoption Scenarios

The industrial demand considered in this report is solely for hydrogen consumed at NARL located in Come by Chance. It was assumed that low-carbon hydrogen could replace the current high-emitting supply through delivered or on-site hydrogen production from electrolysis and low-carbon renewable electricity like hydro or wind.

The incremental scenario assumes no low-carbon hydrogen adoption, which could occur if the hydrogen plant is relocated or if new ownership continues using the existing infrastructure. The transformative scenario assumes that low-carbon hydrogen will eventually represent all hydrogen at NARL. Table 9 shows the percent of hydrogen replaced with low-carbon hydrogen in the two scenarios.

Table 9 – Percent clean H2 model assumptions to replace grey hydrogen at NARL

Year	Percent Clean H2 (%)	
	Incremental	Transformative
2025	0%	5%
2030	0%	15%
2040	0%	50%
2050	0%	100%

The refinery's hydrogen demand was assumed to remain at 57,385 tonnes-H2/year throughout the model. In 2050, the transformative scenario assumes that 100% of hydrogen is low-carbon, resulting in a GHG abatement of 428,618 tonnes-CO2e. Clean hydrogen demand and corresponding GHG reduction from 2020 – 2050 for the two scenarios are displayed in Figure 54.

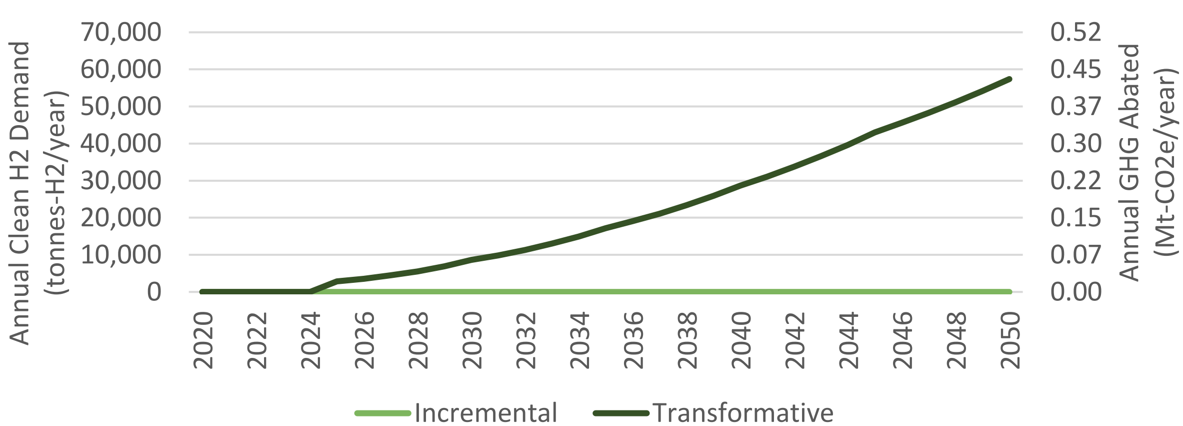


Figure 54 – Clean hydrogen demand and GHG abatement for hydrogen at NARL

Key Industry Sector Recommendations

- Promote a pilot project to incorporate low-carbon hydrogen into the existing refining processes at NARL
- Foster partnerships that can match end-use demand from multiple applications to a single supply point to grow scale
- Seek to leverage existing infrastructure to stimulate early demonstration projects
- Encourage new industrial development that can leverage NL's potential as an economic producer of low-CI hydrogen

Remote Communities

Due to the abundance of hydroelectricity in the province, hydrogen use for heating and electricity will likely not be prominent in NL's future in grid-connection regions of the province. However, many of the remote communities in NL currently rely on diesel, and hydrogen could be a clean alternative to providing energy to these locations.

Baseline

Diesel power generation stations serve most remote communities that are not connected to NL's primary electrical grid. There are 28 remote communities in NL that receive their power from one of 21 isolated electricity systems in NL. Remote communities in NL and their primary power source are displayed in Figure 55.

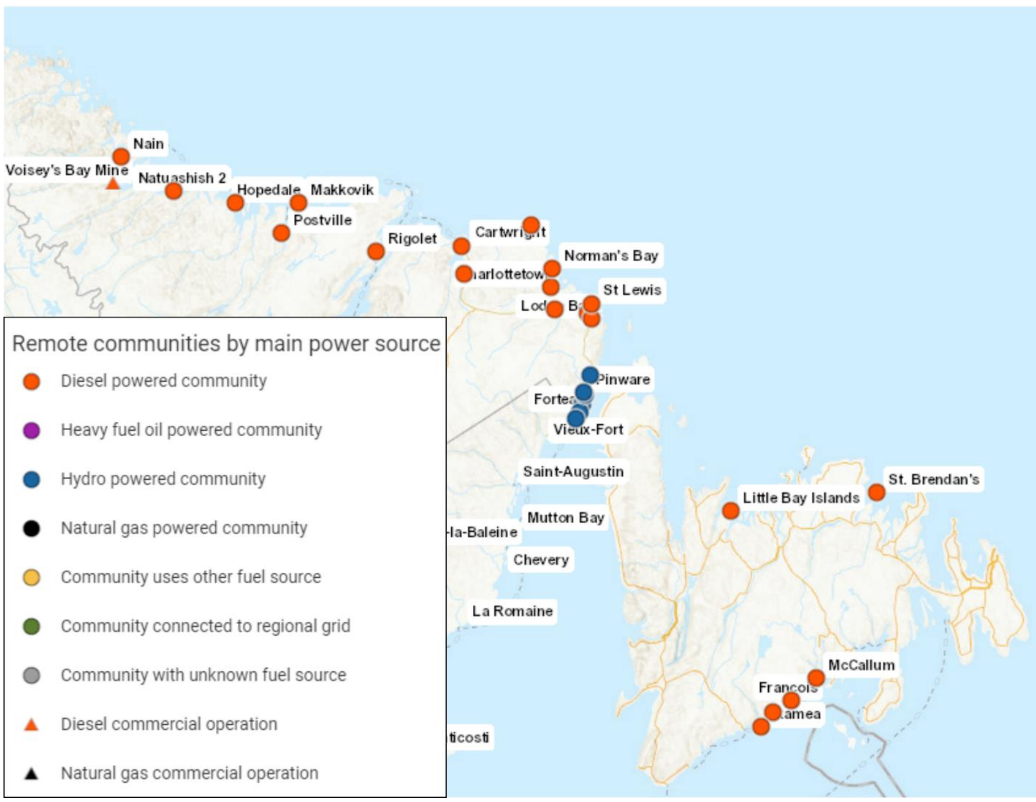


Figure 55 – Remote communities by primary power source in NL[61, 62]

The majority of isolated systems operate on diesel fuel, with a total capacity of 40,091 kW in 2019. Diesel is delivered to the power systems by truck or ship depending on the isolated system's proximity to roads. Of the 21 diesel systems, 14 are located along the province's coast and require shipped fuel. A list of the isolated electricity systems, including their power sources, fossil fuel demand, generating capacity, and fuel transportation method, is available in Appendix B.

[61] NRCan (2021). The Atlas of Canada – Remote Communities Energy Database. Retrieved from https://atlas.gc.ca/rced-bdece/en/index.html

[62] The diesel plant in Little Bay Islands is no longer operating as residents were approved for community relocation.

Opportunities and Challenges for Hydrogen

Hydrogen can significantly reduce remote communities' dependence on diesel-generated electricity and provide reliable and clean electricity and power. Hydrogen could be delivered to remote communities for energy electricity generation or generated in the community using local renewables generation to improve the self-sufficiency of each community. As most remote communities in NL are along the province's coast with high wind potential, hydrogen could be most easily paired with wind energy. Turbines would provide electricity to the community directly and create hydrogen through electrolysis as a form of energy storage. The Ramea Project was intended to demonstrate the effectiveness of this type of installation. The program suffered from maintenance and cost issues, largely related to the hydrogen internal combustion engine used to generate power. If the project were repeated, fuel cells would be used in the place of the combustion engine, which would improve reliability and fuel conversion efficiency.

Hydrogen produced in remote communities could be used to generate electricity during periods when the wind turbines are not generating power and provide heating and transportation fuel for FCEVs. Electricity generation would most likely be produced at a centralized facility, but it would also be possible to develop a distributed system in which hydrogen is delivered via pipeline to buildings where smaller fuel cells generate electricity for local consumption as well as heat. These types of systems are called combined heat and power (CHP) units and offer efficiency gains compared to a centralized system because of the ability to harness waste heat. CHP units have been deployed at a large scale in Japan.

There are many challenges related to transitioning remote communities to clean energy. By nature of them being remote, servicing equipment can be challenging given the specific expertise required by the complex technology. Regular service that must be completed by a technician, which may be simple in an urban environment, will require additional time and cost. For this reason, equipment reliability and serviceability are of principal concern.

It will often be difficult for projects to benefit from economies of scale given the relatively limited energy requirements of the communities. While hydrogen generation from electrolysis is modular and can be effective at small scales, equipment and installation costs are likely to be more expensive on an energy output basis.

Adoption Scenarios

The opportunity for hydrogen in remote communities is limited compared to other sectors in terms of overall hydrogen demand but can significantly improve local air quality and overall quality of life for these populations. Due to the difficulty in delivering diesel to these communities, the incumbent fuel is also relatively high, improving the cost effectiveness of a renewable energy project. The lowest hanging fruit for remote communities is improvements to energy efficiency and conservation to limit consumption, and it was assumed these activities would occur before installation of any hydrogen systems. The first deployment was assumed to be in 2025.

The analysis assumes hydrogen microgrids will be adopted with centralized hydrogen fuel cell generation systems or distributed small-scale cogeneration systems. Central hydrogen turbines for electricity generation could also be considered but are less efficient than fuel cells.

Communities with an annual diesel-demand greater than 2,000 MWh/year were considered separately from the remaining smaller communities as a hydrogen system is more likely and feasible for larger remote communities. Incremental and transformative scenarios were developed by estimating the diesel reduction percentage and the reduction attributed to hydrogen. Table 10 and Table 11 display the adoption parameters used for the incremental and transformative scenario, respectively.

Table 10 – Remote communities incremental H2 adoption scenario model assumptions

Incremental Scenario				
Year	Large Communities		Remaining Communities	
	Diesel Demand Reduction	Diesel Demand Reduction from H2	Diesel Demand Reduction	Energy Use Reduction from H2
2025	20%	25%	5%	0%
2030	40%	25%	10%	0%
2040	60%	25%	20%	0%
2050	80%	25%	30%	0%

Table 11 – Remote communities transformative H2 adoption scenario model assumptions

Transformative Scenario				
Year	Large Communities		Remaining Communities	
	Diesel Demand Reduction	Diesel Demand Reduction from H2	Diesel Demand Reduction	Energy Use Reduction from H2
2025	40%	50%	10%	10%
2030	80%	50%	20%	10%
2040	90%	50%	40%	10%
2050	95%	50%	60%	10%

In the incremental scenario, diesel reduction in the large communities is assumed to gradually increase from 20% in 2025 to 80% in 2050, with hydrogen accounting for 25% of the reduction. The remaining 75% diesel reduction would likely be from non-hydrogen sources such as wind paired with battery storage. It was assumed that none of the smaller communities would use hydrogen.

The transformative scenario assumes that diesel reduction within the large communities will aggressively increase from 40% in 2025 to 95% in 2050, with hydrogen accounting for 50% of replaced diesel. The remaining remote communities experience a diesel reduction of 10% in 2025 to 60% in 2050, with 10% of replaced energy from hydrogen.

Predicted hydrogen demand and GHG abated from the incremental and transformative remote community scenarios are displayed in Figure 56 and Figure 57, respectively.

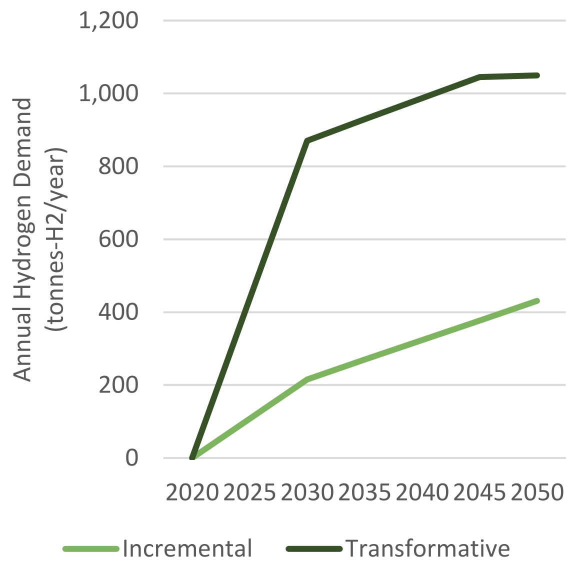


Figure 56 – Projected hydrogen demand for remote communities

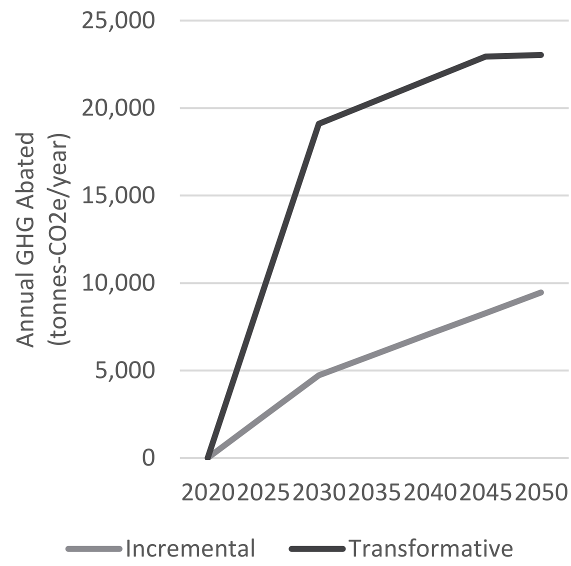


Figure 57 – Projected GHG abated from remote communities

Table 12 summarizes the annual hydrogen demand and GHG abatement for the incremental and transformative remote communities' hydrogen adoption scenarios.

Table 12 – Remote communities annual H2 demand and GHG abatement adoption scenario summary

Year	H2 Demand (tonnes H2/year)		GHG Abatement (tonnes-CO2e/year)	
	Incremental	Transformative	Incremental	Transformative
2025	108	435	2,365	9,554
2030	216	871	4,730	19,108
2040	323	987	7,094	21,663
2050	431	1,050	9,459	23,035

Recommendations

Key Electricity Sector Recommendations

- Encourage development of community plans to implement hydrogen and other low carbon technologies
- Work with educational institutions, labour organizations, and others to develop training programs suited for people living in and/or working with remote communities to develop skills required to maintain and service hydrogen equipment
- Provide access to funding to develop renewable energy projects in remote communities

Aggregated End-Use Applications

Figure 58 and Figure 59 show the aggregated hydrogen demand and GHG emissions reduction potential from all end-use sectors considered in this report. The aggregate hydrogen demand in the transformative case is 94,000 tonnes-H2/year in 2050, which would reduce GHG emissions by ~1.0 Mt-CO2e/year, representing 9% of the emissions reduction required to reach net-zero from the current baseline. The transformative case represents a scenario in which hydrogen adoption is driven by technological advancement, regulations, and government and industry support.

Hydrogen adoption in the industrial sector represented the most significant portion of hydrogen demand and emissions reduction in the transformative scenario. The industrial sector will rely heavily on the future of NARL. The upside to the transformative scenario could be achieved by attracting new industries to the region that leverage the hydrogen production potential. The transformative scenario represents the total opportunity for hydrogen; however, as NL contains strong renewable electricity generation resources, hydrogen adoption for end-use will rely heavily on the split between hydrogen and electricity technologies.

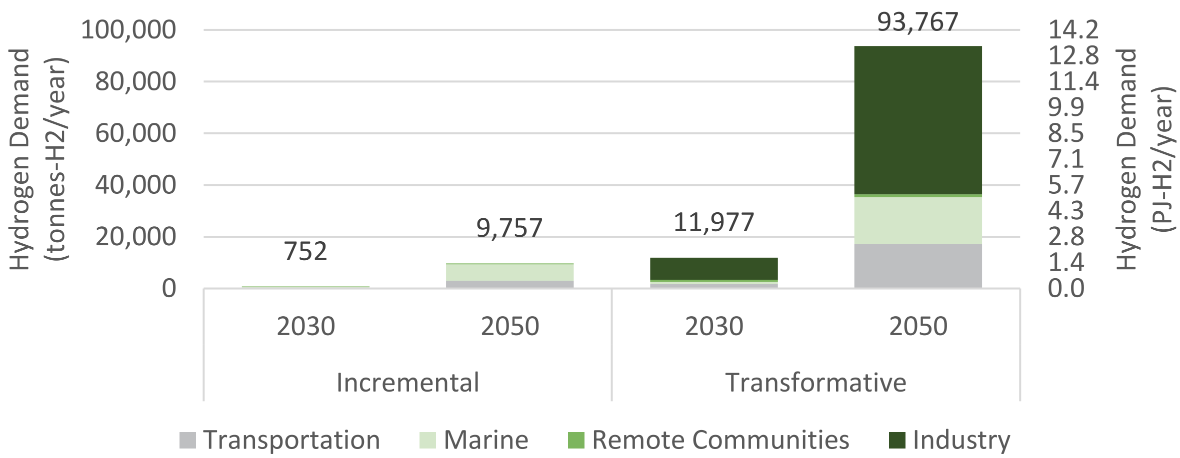


Figure 58 – Aggregated hydrogen demand forecast by sector

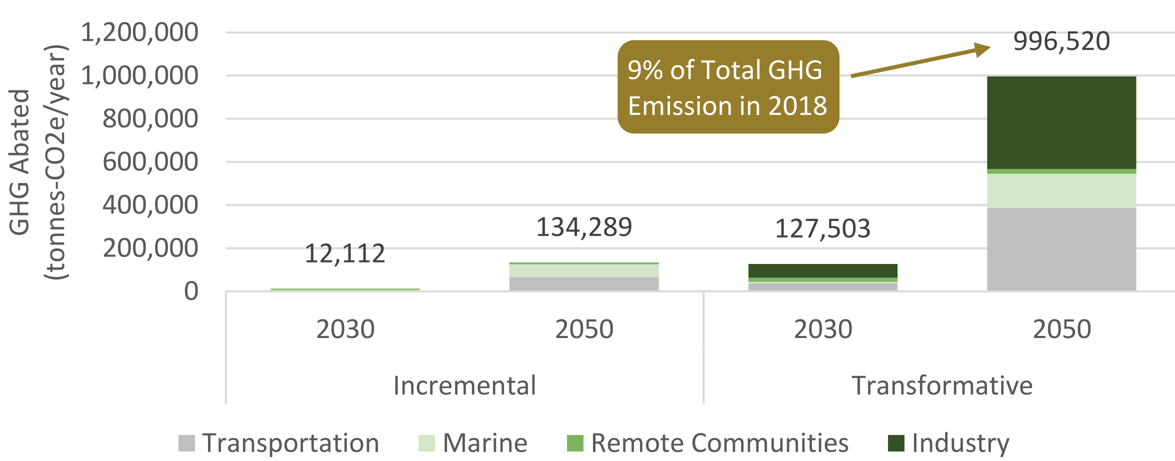


Figure 59 – Aggregated GHG emission reduction forecast by sector

In the transformative scenario, hydrogen accounts for 8% of total delivered (secondary) energy demand in NL in 2050, as shown in Figure 60. The remaining 92% of delivered energy is expected to come from other low-carbon energy sources such as renewable electricity and biofuels. Note that some biofuel production pathways could rely on hydrogen and further increase regional demand. It may also include the use of conventional fossil fuels that have been offset by CCUS or through other negative emission activities such as tree planting or direct air capture.

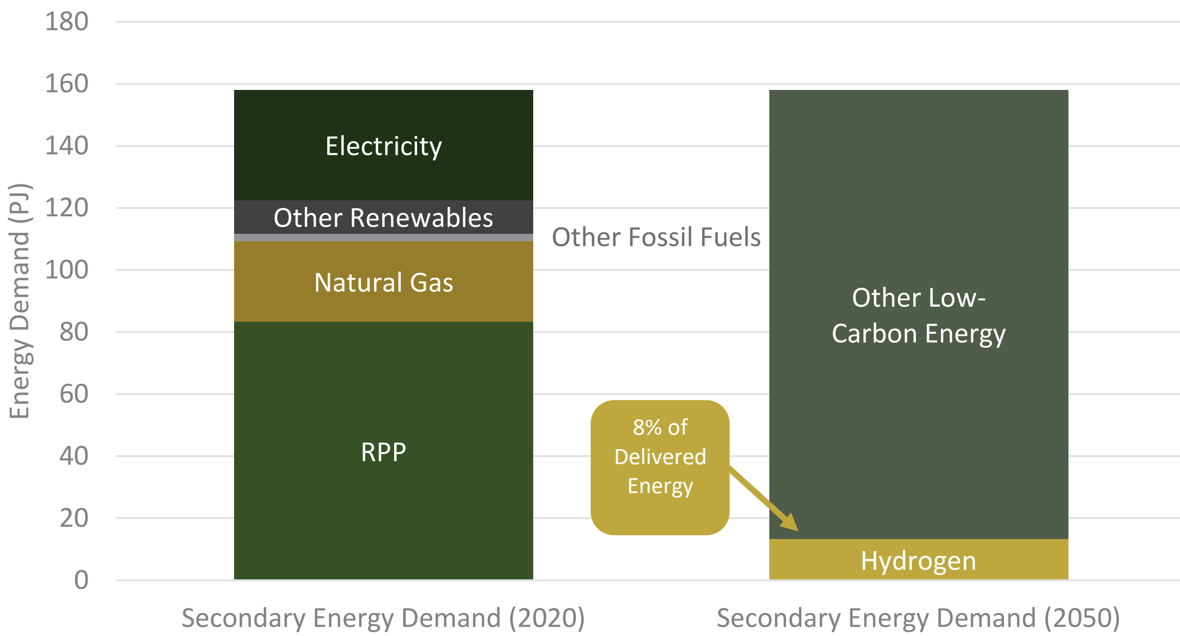


Figure 60 – Hydrogen as part of NL's energy mix in 2050 – transformative scenario[63]

The production of hydrogen for the transformative scenario will require a significant amount of electricity and/or natural gas feedstock. Figure 61 displays the inputs required if 100% of hydrogen was generated via electrolysis or SMR + CCUS.

[63] Source of primary and secondary energy demand (2020): Canada Energy Regulator. (2021). Canada's Energy Future 2020. Retrieved from https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2019/index-eng.html

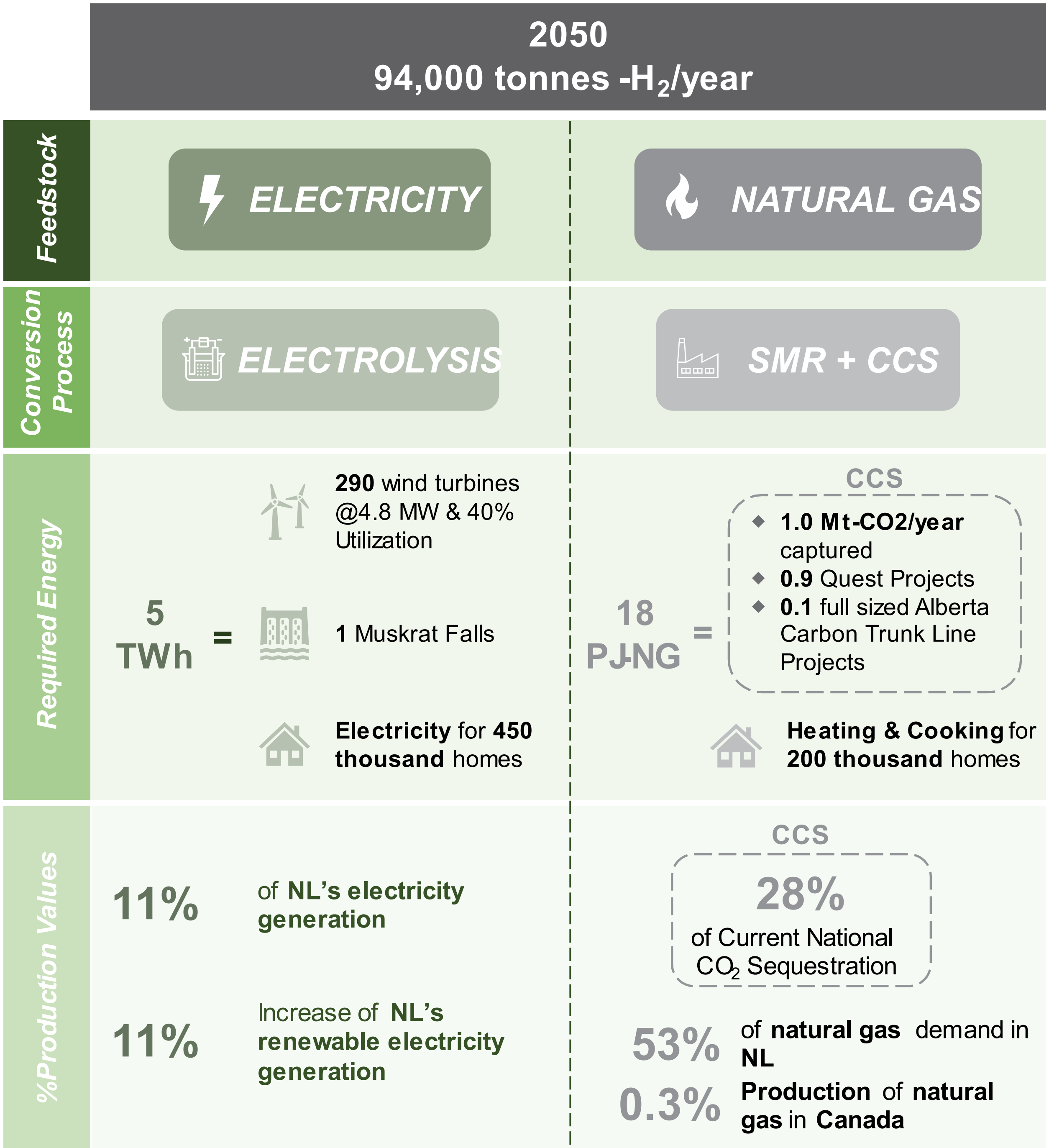


Figure 61 – Electricity and natural gas requirements to meet 2050 H2 demand - transformative

6. HYDROGEN PRODUCTION FOR EXPORT

The Maritimes Hydrogen Study outlines the expected demand for hydrogen in key regions with the export opportunity from Atlantic Canada, including the northeastern United States and European countries such as Germany, France, and the Netherlands. NL is particularly well-positioned to serve the European market given the relatively close proximity and shipping lanes.

The Hydrogen Roadmap for Europe completed by the Fuel Cells and Hydrogen Joint Undertaking in 2019 forecasts that demand for hydrogen in 2050 could be 2,251 TWh/year (57 million tonnes/year) in an ambitious scenario designed to meet the European Union's target of limiting the global temperature increase to 2 degrees.[64] While much of this hydrogen can be produced locally, imports will be needed to meet demand. The European Commission has identified Canada as a potential trade partner in the new hydrogen economy.[65]

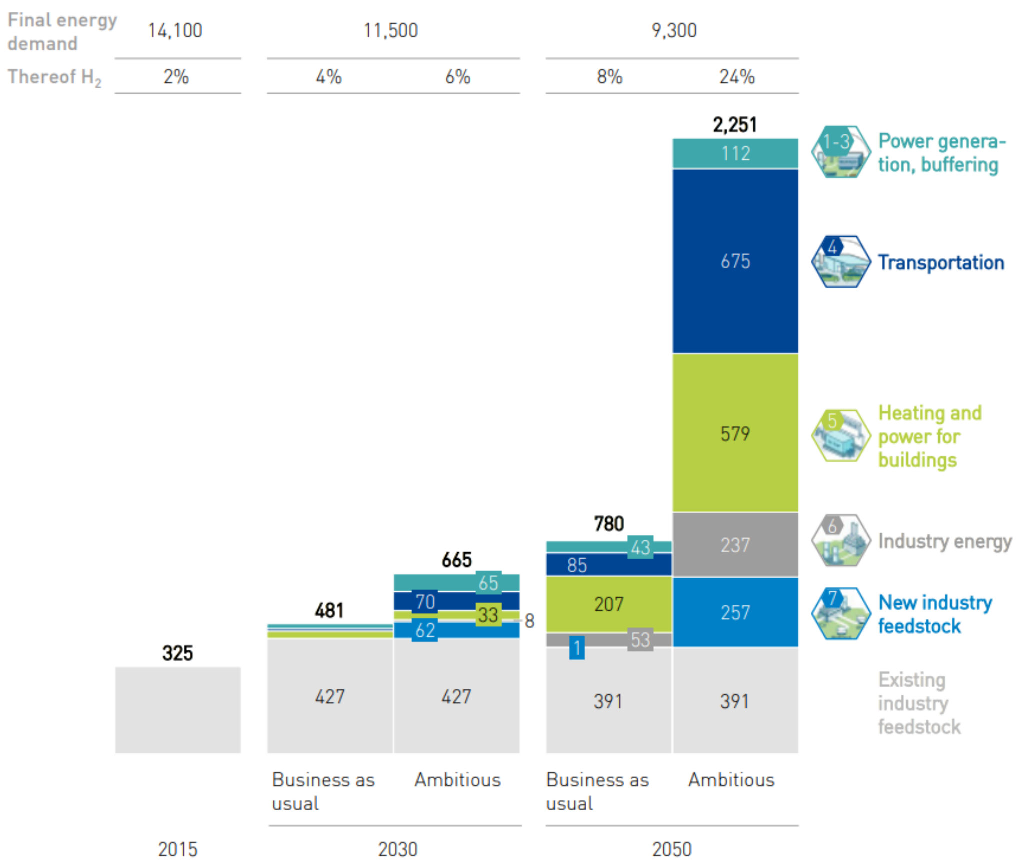


Figure 62 – Forecasted European Union hydrogen demand (TWh)[66]

[64] 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

[65] 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

[66] 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

NL could leverage the available natural resources in the province to become a major producer and exporter of hydrogen to serve the European market. Existing surplus electricity could generate more than 70,000 tonnes of hydrogen annually. This amount could be massively increased through the development of renewable wind energy and offshore natural gas resources. If Atlantic Canada captured 5% of the European market for hydrogen in this ambitious scenario (nearly 8,000 tonnnes-H2/day), the export opportunity could be $9 billion annually at a price of $3/kg-H2.

*Hydrogen export to Europe from Atlantic Canada could generate **$9 billion** annually by 2050.*

Hydrogen could be shipped directly to Europe from NL or travel by pipeline to the Maritimes for shipment from a central hub. A significant advantage of going directly from NL is the proximity. The Port of Rotterdam, which is positioning itself to be a major import hub of hydrogen to Europe, is approximately 4,000 km from the coast of NL. The Port of St. John's, the largest port in the province, is the most easterly port in North America and the closest to Europe. In 2018 it processed 1.66 million tonnes of cargo, and the nearby Port of Argentia moves approximately 200,000 tonnes of cargo annually. [67] Either of these locations could become an export hub for hydrogen.

A major advantage of shipping from the Maritimes is the potential to combine hydrogen produced in NL with hydrogen from other neighbouring regions such as Quebec, increasing the scale of an export facility and minimizing costs. However, the construction of a pipeline to bring the hydrogen to a hub such as Port Saint John or the Port of Halifax would be a major infrastructure project. A more detailed study is required to assess the feasibility of such an undertaking, including geographical, technical, economic, and political factors. As shown in the *Hydrogen Transport* Section, transportation of large quantities of hydrogen via pipeline can be highly cost-effective.

Hydrogen export could also be carried out in several different ways. At this time, it is unclear whether it would be most cost-effective to ship hydrogen internationally as a cryogenic liquid after conversion to ammonia or through a liquid organic hydrogen carrier. Further study is required to determine which approach is most suitable for Atlantic Canada.

[67] Port St. John's. (2021). About The Port of St. John's. Retrieved from https://sjpa.com/about-the-port/

7. SUPPLY CHAIN CAPABILITY ASSESSMENT

Hydrogen Supply Chain and Value Network Overview

The hydrogen supply chain includes the entire process from primary energy/feedstock supply to end-use conversion into electricity, heat, or feedstock into another process. An overview of the hydrogen supply chain and value network and stages of cluster-based industrial development has been given in the Maritimes Hydrogen Study.

The hydrogen supply chain is likely to include many entities. Broadly, it can be broken down into:

- **Primary energy supply** of the feedstocks for hydrogen production such as electricity, water, and natural gas.
- **Production/converion** of hydrogen via reformation, electrolysis, pyrolysis or another pathway. This step may include CCUS, which requires 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.
- **Transportation/distribution/storage** in which is hydrogen is sent through pipeline or compressed/liquefied for transport via truck, rail or ship.
- **End-use demand** of hydrogen as a transportation fuel, to generate heat, or as a feedstock for industrial processes.
- **Other secondary services** such as ancillary benefits like electric grid services.

Opportunities and Challenges for Local Service Providers in the Hydrogen Supply Chain

NL is the third largest crude oil-producing province in Canada after Alberta and Saskatchewan, making it the largest in eastern Canada.[68] The provinces' Churchill Falls Generating Station is the world's largest underground hydroelectric powerhouse. The province also has a knowledgebase of harnessing wind energy with demonstrated projects since 2009. Natural gas reserves exist but are not developed for use or transported; therefore, the supply chain for capturing natural gas and blending with hydrogen for heating purposes or a pipeline currently does not exist. The renewable sources encompassed by the policy include wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy. A consolidated effort on renewable energy sources can position the province as a supplier of green hydrogen.

Examples of companies with relevant operations to possibly be part of the hydrogen supply chain are shown in Figure 63. This is not an exhaustive list, nor does the inclusion of any company represent an endorsement.

[68] Canada Energy Regulator. (2021). Provincial and Territorial Energy Profiles. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-newfoundland-labrador.html

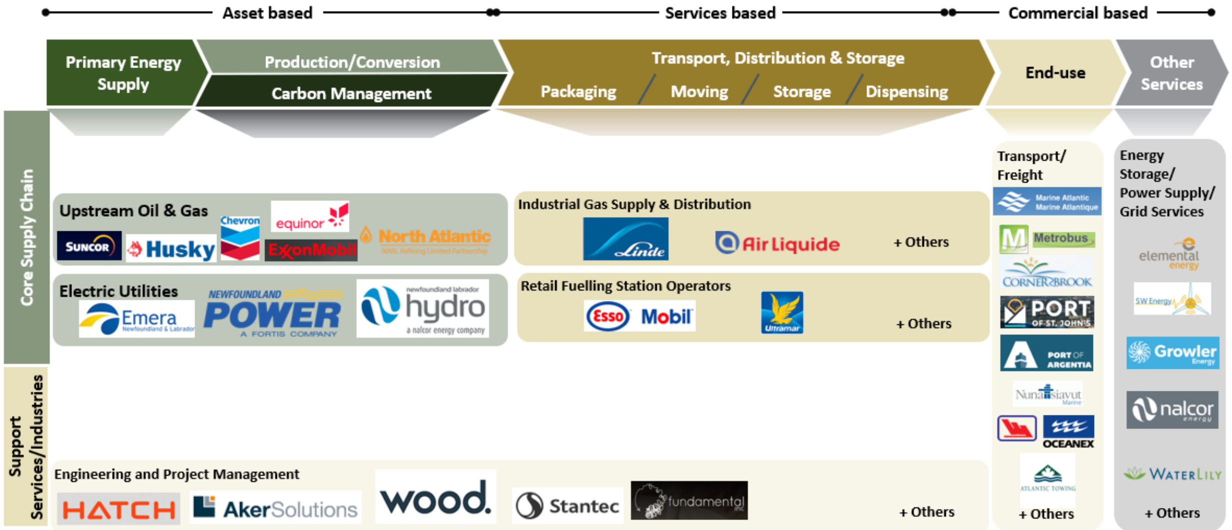


Figure 63 – Current and potential local service providers

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 can be filled by local product and service providers, given they find innovative ways to operate and stay competitive. Offshore wind or hydroelectricity can be used for bulk hydrogen production to be distributed to other eastern provinces. There will also be demand of both skilled workforce and support for on-going development required to meet new needs associated with hydrogen production and transport. There are doctoral thesis published from Memorial University on sustainability and hydrogen, which could be built upon to conduct research in potential regional applications such as marine fuel cell technology. Research and development projects at the educational institutions will also train and position new skilled workforce in the sector.

Several local companies and players would be able to provide equipment and services:

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

NL Hydro is the primary electricity provider in NL and is a subsidiary of government owned **Nalcor Energy**. **Emera** operates in NL and is responsible for the Maritime Link cable connecting NL to Nova Scotia. There are also several independent power producers from hydroelectricity, wind and biogas that are regulated with power purchase agreements with NL Hydro. NL Hydro owns and operates most generation and the transmission grid; **Newfoundland Power**, a subsidiary of **Fortis Inc**., is the principal retailer of electricity on the Island of Newfoundland. These providers could serve electrolyzer loads from their transmission or distribution grids to produce green hydrogen.

Although there is currently no natural gas infrastructure on land in NL, gas from offshore facilities operated by **ExxonMobil, Chevron, Husky, Suncor and Equino**r could be used to generate low carbon hydrogen if paired with CCUS. Although it is not currently operating, the **North Atlantic Refinery** produces and consumes hydrogen as part of its refining process. It could be both a large consumer of low carbon hydrogen and a potential production hub to serve other end use markets like transportation.

Despite the large potential, there are significant gaps in hydrogen production expertise and a limited number of companies that could fill this role at the scale required.

- **Transport, Distribution & Storage:**

The leading Industrial Gas Suppliers, **Linde** and **Air Liquide**, have operations or could serve the region. As these firms are already well-established and experienced with gaseous and liquid hydrogen, they could relatively easily serve the hydrogen supply chain by collaborating with crude oil shipping players or the refined oil export points already in place. The firms operating in the downstream fuels distribution and retail/commercial fuel sales sector include **Irving Oil, North Atlantic, Mobil/Esso**, **Ultramar, Shell** and others. These players could enter the hydrogen supply chain as fuel distributors and retailers, leveraging their existing infrastructure and real estate assets should hydrogen be used as a transportation fuel in NL.

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

- **End-use:**

There are many potential end-users of hydrogen, but the primary sources of demand are likely to come from transport/freight, transit, export opportunities, and industrial users. The transport/freight sector, including road and marine, are a critical part of the region's economy. A large trucking fleet is not necessary in NL, but several independent truck transport services exist. The largest transit operators are **Metrobus** (Saint John's Transit) and a municipally managed service provided by **Corner Brook Transit**. A local source of hydrogen could make them ideal sites to operate FCEBs. The marine industry includes many potential hydrogen opportunities, especially for passenger ferry services (**Marine Atlantic**, **Newfoundland & Labrador Marine Services, Labrador Marine Inc., and Nunatsiavut Marine Inc.**) and transport/towing (**Oceanex, Atlantic Towing**).

Development of an export terminal to provide hydrogen through **Port of St. John's** or **Port of Argentia** to Europe or the US would require hydrogen expertise on-site, which currently does not exist.

The clear challenge in this sector is that the volume would be low given the size and population of the province. Lighthouse projects would be necessary to deploy to move from a nascent understanding of hydrogen to export and develop the supply chain.

- **Other Services:**

There is a myriad of expertise using wind and tidal energy sources to generate electricity that could be used to develop the hydrogen value chain in NL. These include but are not limited to **Elemental Energy, SW Energy, Growler Energy, Nalcor Energy, Water Lily, and others**.

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

The engineering, project management, and construction industry are well-established in NL with a range of global firms that have local presence. The expertise can be easily drawn towards projects related to hydrogen production.

SWOT Analysis

The competitiveness of NL'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 13 – SWOT analysis

Strengths	Weaknesses
◆ Strong integrated road, and marine transportation networks and established freight, and shipping companies ◆ Abundant surplus clean low carbon hydroelectricity ◆ Abundant wind resources that could be harnessed ◆ Established oil sector with existing natural gas resources ◆ Atlantic Canada is ranked among the lowest business-cost locations within G8 countries[69]	◆ Relatively nascent hydrogen industry with limited activity and history ◆ Small, diverse regional demand making aggregation more difficult ◆ No natural gas infrastructure and pipelines that can accept hydrogen blending ◆ Geographically isolated preventing inter-provincial trade
Opportunities	**Threats**
◆ a Large regional and international marine sector including port infrastructure and ship building ◆ Interconnected electrical grid with surplus supply to other provinces- could use for H2 production ◆ Offshore oil skilled workforce available ◆ Natural gas resources are available to be harnessed for blue H2 production ◆ Green H2 production by electrolysis using hydroelectricity to increase annual electricity consumption without increasing seasonal peak demand	◆ Competition from other regions in Canada, the US, and globally for access to key markets in North-East US and Europe

[69] 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

8. CARBON CAPTURE AND SEQUESTRATION

NL Offshore Oil Resources

The best opportunity for CCUS in NL is at the offshore developments: Hibernia, Terra Nova, White Rose, and Hebron, which are located in the Jeanne d 'Arc Basin, approximately 340 km of St. John's. Five additional discoveries have been made in the Deepwater Flemish Pass Basin in recent years, approximately 500 km offshore.

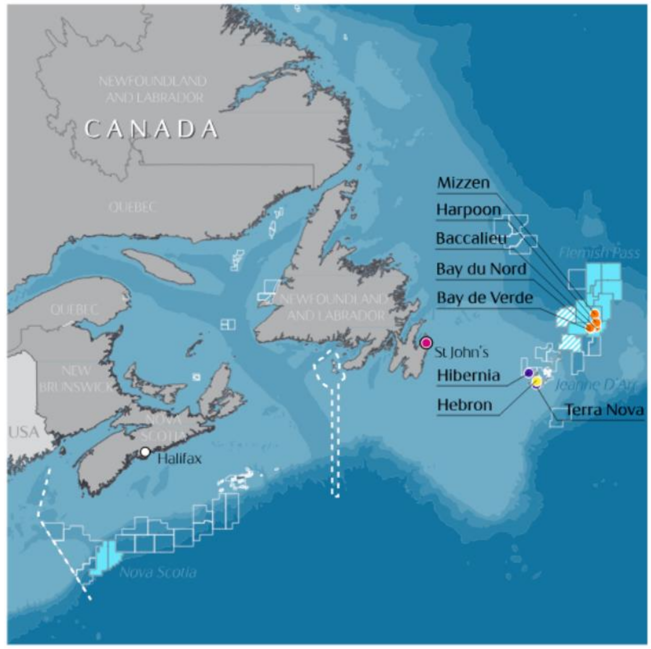


Figure 64 – Offshore oil production assets in the Jeanne D'Arc and Flemish Pass Basins[70]

In addition to heavy and light oil production, the offshore facilities also extract natural gas, which is currently used to power the facilities, re-injected back into the wells to maintain reservoir pressure or flared. In 2018, 549 MMcft/day of natural gas was produced at the offshore crude oil facilities. The NL Offshore Petroleum Board estimates the province's remaining offshore reserves potential includes 12.6 trillion cubic feet of natural gas.[71]

CCUS with CO2-EOR Pathway

As discussed in the *Hydrogen Production* Section, low carbon hydrogen can be generated using SMR with CCUS. The CO2 produced can be compressed and transported to sequestration sites such as the locations identified in the *Carbon Capture and Sequestration* Section of the Maritimes Hydrogen Study or to end-users. Transportation of CO2 via long pipelines to distant storage sites can be expensive. However, the existing offshore assets could be leveraged to sequester the CO2. There are various methods of CCUS, including sequestration in onshore and offshore deep saline formations and utilizing high-pressure CO2 for enhanced oil recovery (CO2-EOR). CO2-EOR is a mature technology and has been deployed in 99 projects in the US alone. All CO2 is retained within the subsurface formation after the project ends. The process has been an effective technique to increase oil recovery by an additional 4-15% over primary and secondary recovery efforts.[72] Offshore CO2-EOR technology is not as mature as onshore, with the first project starting in 2011.[73]

---

70 Quinor. Retrieved from https://www.equinor.com/en/where-we-are/canada.html

71 CAPP (2018). Canada's Offshore Oil and Natural Gas Industry in Newfoundland and Labrador. Retrieved from https://www.capp.ca/wp%2Dcontent/uploads/2019/11/Canada_s_Offshore_Oil_and_Natural_Gas_Industry_in_Newfoundland_and_Labrador-320561.pdf

72 NETL (2010). Carbon Dioxide Enhanced Oil Recovery. Retrieved from https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf

73 Carbon Sequestration Leadership Forum (2017). Enabling Large-scale CCS using Offshore CO2 Utilization and Storage Infrastructure Developments. Retrieved from https://www.cslforum.org/cslf/sites/default/files/documents/7thMinUAE2017/Offshore_CO2-EOR_Final_02_Dec_2017.pdf

CCUS Deployment

NL could leverage its substantial natural gas reserves to produce blue hydrogen through SMR combined with CCUS. Due to the size constraints of offshore platforms, the SMR facility must be constructed onshore. Depending on the scale of deployment and economics, the natural gas can be transported onshore via transmission pipelines or transport vessels. The captured CO2 from the SMR process can be compressed in preparation for transportation at the onshore SMR facility and directly transported to the offshore platforms through high-pressure transmission pipelines.

The Hibernia Enhanced Oil Recovery Laboratory at Memorial University was launched in June 2014 with a $15 million investment from the Hibernia Management and Development Company Ltd, consortium owners of the Hibernia oil field, and the Research and Development Corporation of NL.[78] Research explicitly targets the application of CO2-EOR techniques at NL's offshore fields. Hibernia, Terra Nova, and White Rose are the oldest fields, with production beginning in 1997, 2002, and 2005 respectively and may benefit the most from applying CO2-EOR technologies. The program's research involves testing and validating methods including CO2-EOR to recover "stranded oil" in the offshore reservoirs, which cannot be extracted utilizing the current recovery practices.

LULA OIL FIELD CO2-EOR PROJECT

The Lula Oil Field CO2-EOR project, located approximately 230 km from Brazil's Southeastern coast is an example of a commercial success story. The project utilizes the Water Alternating Gas process, which involves CO2 injection alternative with volumes of water. Piloting began in 2011, with commercial scale operation beginning in 2013.[74] The project utilizes nine floating, production, storage, and offloading (FPSO) vessels that perform CO2 injection and recycling onboard. In NL, the Terra Nova and White Rose production facilities also utilize FPSOs. This approach was chosen to address the challenges of constructing long-length oil pipelines in the ultra-deep offshore environment and other economic considerations.[75] The project has successfully deployed a CO2-EOR process at the site for nearly a decade, and no major operational or reservoir issues have been detected.[75] From 2013-2018, around 9.8 million MT of CO2 was injected at the site, while increasing oil recovery operations.[76]

Figure 65 – Floating production, storage, and offloading (FPSO) unit[77]

[74]Carbon Capture & Sequestration Technologies. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project. Retrieved from https://sequestration.mit.edu/tools/projects/sleipner.html
[75] MDPI (2019). Retrieved from https://www.mdpi.com/1996-1073/12/10/1945/htm
[76] Negrais Seabra, Paulo (2020). Lula Oil Field CO2-EOR Project Update. Retrieved from https://www.beg.utexas.edu/files/gccc/media/4th%20international%20workshop%20on%20offshore%20geologic%20co2%20storage/13-12_1121%20Paulo%20Negrais%20Seabra%20Lula%20v1.pdf
[77] NS Energy. Lula Oil Field Development. Retrieved from https://www.nsenergybusiness.com/projects/lula%2Doil%2Dfield%2Ddevelopment/
[78] Campbell, D. Miracle cure. Retrieved from https://www.naturalresourcesmagazine.net/wp%2Dcontent/uploads/2015/07/v17n2_miraclecure.pdf

9. HYDROGEN FOR UTILITY SCALE ENERGY STORAGE IN ATLANTIC CANADA

Hydrogen can play a major role in transitioning the energy sector in Atlantic Canada to zero-emission. As described in the Maritimes Hydrogen Study, the Maritimes has the potential to be a major consumer of hydrogen as a transportation fuel, as a substitute for natural gas in the pipeline network, and for electricity generation. Currently, the potential to produce low carbon hydrogen in the Maritimes is limited due to the relatively high carbon electric grid and relatively expensive natural gas. In contrast, the demand for H2 is NL is expected to be relatively small compared to the Maritimes, but NL has many of the necessary ingredients to become a major producer of hydrogen. Improved electrical interconnectedness through the Atlantic Loop could enable increased transmission of clean electricity to be used to generate hydrogen throughout Atlantic Canada.

NL can leverage its existing surplus hydroelectricity and all of Atlantic Canada can develop new energy production through wind power or other renewables to generate hydrogen. Offshore natural gas reserves could also produce low carbon hydrogen if the carbon were captured either through injection of CO2 into the underground reservoirs or disposal of carbon black. The fossil fuel pathway for hydrogen production should be considered in future studies looking at the potential for offshore natural gas to be brought to shore from both a technical and economic perspective.

The cost at which hydrogen can be produced and transported is of critical concern when considering hydrogen's role in the energy sector. Figure 66 shows the results of a model to estimate the cost of bulk production and transmission of hydrogen at two scales: 100 and 1,000 tonnes-H2/day. The intention is to show delivered costs of hydrogen for local use, delivery from NL to the Maritimes, or export to international markets such as the Northeastern US or Europe. Local distribution, such as hydrogen transportation from a central location to fueling stations or international shipping, has not been considered. In all cases, hydrogen was assumed to be produced via electrolysis at an average rate of $0.05/kWh. This is a fairly conservative price for NL, as it is greater than the current industrial rate in Labrador, but it exceeds current rates in the Maritimes. At each scale, four possible scenarios were considered:

1. **Liq**: the hydrogen is produced and liquefied with no further transportation costs. This scenario could reflect the production of hydrogen co-located with an export terminal for international shipping in NL or the Maritimes.
2. **Liq. + Deliv**: the hydrogen is liquefied and then transported via truck to a centralized facility. This could represent hydrogen used for domestic purposes within Atlantic Canada or hydrogen transported to an export terminal for international shipping.
3. **Pipe**: the hydrogen is transported via pipeline to a central location. The costs assume the construction of a new hydrogen pipeline, which could be incorporated into a local distribution market or continue in a pipeline into the Northeastern US.

4. **Pipe + Deliv**: the hydrogen is transported via pipeline to a central facility and then liquefied. This could represent transportation of hydrogen from a production facility to an export terminal where it must be liquefied before loading onto ships.

The costs include the capital expenditure for equipment and installation as well as operating expenses such as labour, electricity, and maintenance are consistent with the *Hydrogen Production* Section of the Report. Assumptions were taken from available reference material – including the IEA G20 Hydrogen Report – regional electricity and fuel costs, and industry knowledge.[79]

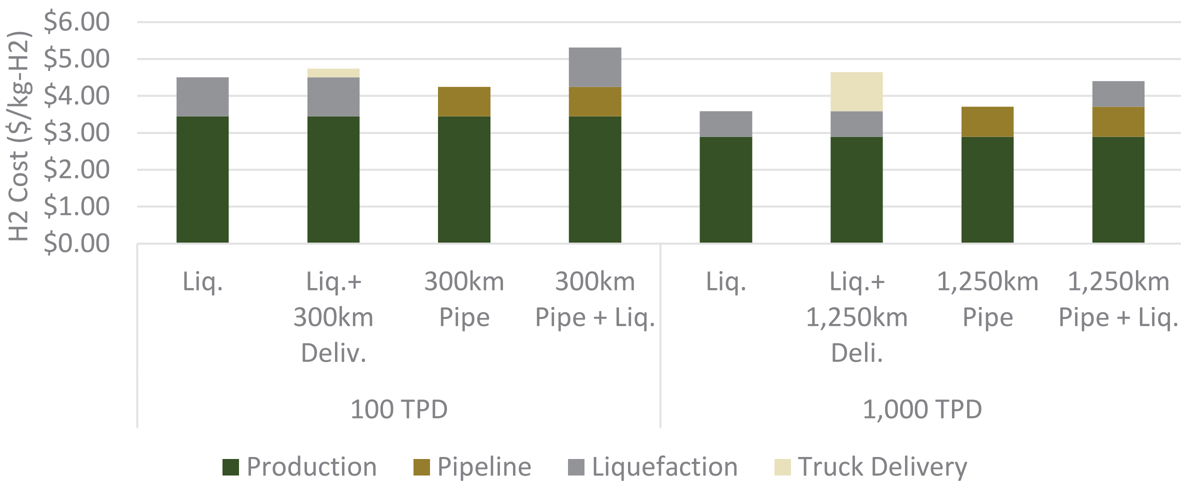


Figure 66 – Estimated cost of bulk hydrogen production and transportation

At the 100 tonnes-H2/day scale, the hydrogen pipeline is the most cost-effective over a 300 km distance, but only if there is no need to liquefy the hydrogen further distribution. Based on the assumptions in this analysis, pipeline distribution becomes cost-prohibitive over distances greater than approximately 500 km. At the 1,000 tonnes-H2/day scale, hydrogen pipelines are the most cost-effective transportation options, even over long distances and when liquefaction is required.

*Hydrogen production using surplus electricity could increase utility revenue by **$17.5 million** annually compared to exporting electricity*

Production and distribution at the 100 or 1,000 tonnes-H2/day scale would require significant energy consumption – approximately 1.8 TWh/year and 16.4 TWh/year, respectively.[80] When the Muskrat Falls Facility is fully online, it is estimated that NL will export approximately 3.5 TWh in electricity through the Maritime Link transmission cable at an anticipated average price of $0.045/kWh. Thus, a 100 tonnes-H2/day facility could operate purely on surplus electricity. However, if the electricity were used to generate hydrogen at a rate of $0.05/kWh as modelled above, the incremental

[79] 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

[80] The conversion efficiency at the 1,000 tonnes-H2/day scale was assumed to be better than the 100 tonnes-H2/day because of economies of scale and because it is more likely to occur further in the future when technology has improved.

increase in annual revenue to the utility would be approximately $9 million for a 100 tonnes-H2/day plant or $17.5 million if the full 3.5 TWh was utilized.

This revenue generation opportunity could grow in the future if hydrogen production is deemed a strategic priority for NL. The Holyrood generating station is currently a source of backup power supply for NL and is set to be decommissioned. This facility and the infrastructure surrounding it presents an incremental opportunity for the generation and export of green hydrogen. The facility has the grid connection infrastructure, large fuel storage tanks, and the marine infrastructure already in place. It is a publicly owned asset (NL Hydro) and its repurposing and/or expansion could be investigated. Power from Churchill Falls presents an additional opportunity for future expansion when output reverts back to NL control.

Alternatively, the production facility could be constructed in the Maritimes and effectively power transmitted through the Maritimes Link cable. Essentially, the energy from NL's hydroelectric facilities could be transported from NL to the Maritimes as hydrogen in a pipeline or truck or as electrons through an electric cable.

Based on the findings of the Maritimes Hydrogen Study, 1,000 tonnes-H2/day would satisfy approximately 56% of anticipated demand in the transformative case in 2050 in the Maritimes. To justify a large export terminal, even greater production would likely be required. Transporting the hydrogen to the Maritimes would enable hydrogen produced in Atlantic Canada to be more easily merged with production from other regions such as Quebec to increase scale.

PEM electrolyzers are capable of rapid turndown and are not impacted by on/off cycling, so the plant electrical load could be limited during peak periods and the required generating capacity of the province would not need to increase. The benefits of this may enable special rate structures for hydrogen generation, which could be below $0.05/kWh. Figure 67 shows the cost of hydrogen production and distribution for electricity priced between $0.01-0.05/kWh for two of the scenarios shown in Figure 66. The figure shows a price range of approximately $1.75-4.50/kg-H2.

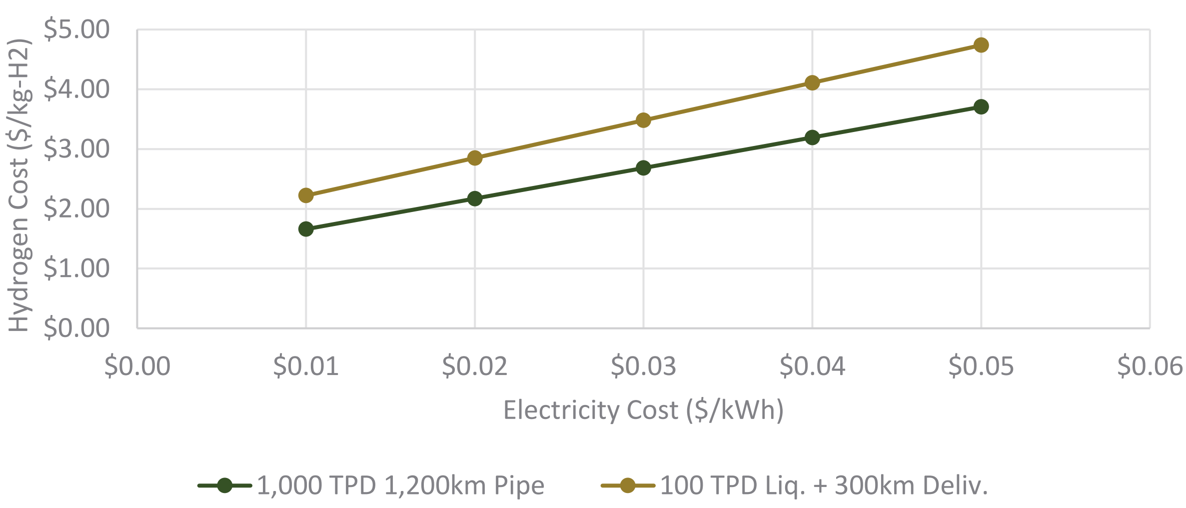


Figure 67 – Cost of hydrogen production and distribution by electricity cost

The expected sale price for hydrogen will be dependent on its end-use application. Below is a technoeconomic analysis of several project concepts. All concepts are based on a plant size of 100 tonnes-H2/day using the same cost assumptions as the analysis above. The results are shown dependent on electricity cost and hydrogen sale price and are equally applicable to operation in any of the provinces in Atlantic Canada.

Hydrogen as a Transportation Fuel

As a transportation fuel, hydrogen is a substitute for gasoline or diesel and benefits from the efficiency gain of a fuel cell compared to an internal combustion engine. Figure 68 compares the cost of bulk distributed hydrogen ranging from $1.75-$4.50 compared to the expected cost of other options such as BEVs, gasoline, diesel, and gasoline/diesel combined with direct air capture (DAC) in which the emissions are offset through CCUS. The relative costs of the alternative fuels were calculated taking into account the efficiency improvement of FCEVs and BEVs compared to gasoline and diesel engines.

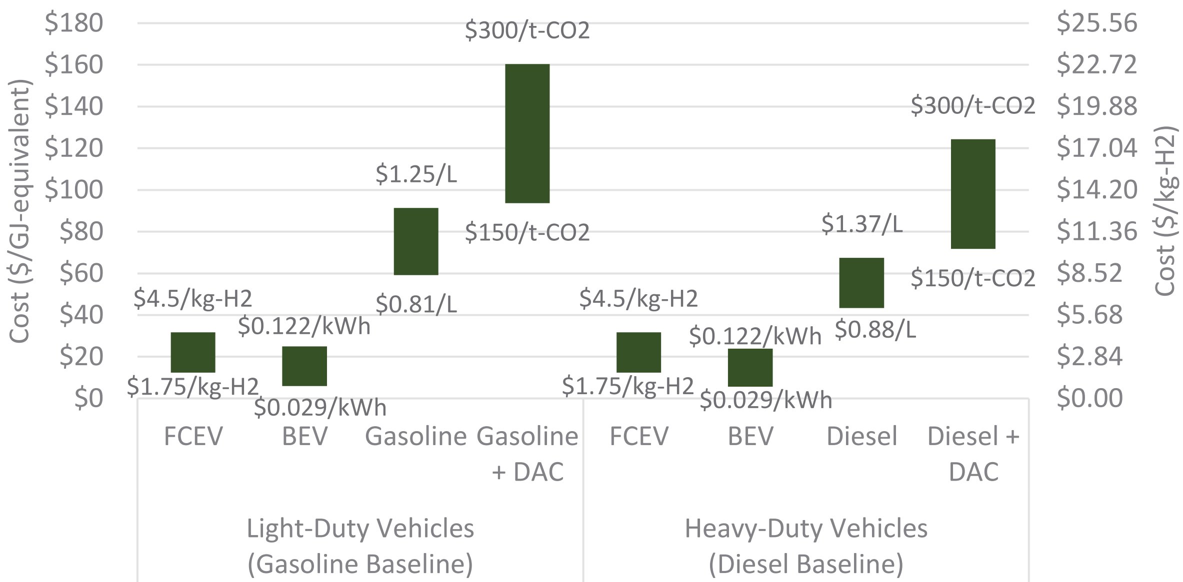


Figure 68 – Cost of hydrogen compared to transportation fuels

The cost of hydrogen is competitive with electric vehicles and significantly less than the fossil fuel sources. When additional factors are added – such as local distribution and compression – the price of hydrogen will be greater than shown. However, there is still sufficient room for profit margins within the supply chain compared to gasoline and diesel vehicles. The cost of electricity for BEVs will likely remain cheaper than hydrogen, even if special rates are given for hydrogen production. Adoption of FCEVs instead of BEVs will be driven by performance factors, including longer range and faster fueling.

The internal rate of return (IRR) was estimated for a 100 tonne-H2/day hydrogen production facility including liquefaction and distribution within a 300 km radius via tanker. Table 14 shows the IRR for a given input cost of electricity and sale price of hydrogen. For example, if the electricity cost is $0.05/kWh and the hydrogen sale price is \$50/GJ (equivalent to \$7.06/kg-H2) the IRR is 35%. Cells highlighted in red indicate a negative IRR, meaning the project would not be profitable.

Table 14 – IRR of hydrogen as a transportation fuel

Expected Range: \$30.00 – \$80.00

Electricity Cost (\$/kWh)	Hydrogen Bulk Sale Price to Dispenser (\$/GJ)								
	\$10.00	\$20.00	\$30.00	\$40.00	\$50.00	\$60.00	\$70.00	\$80.00	\$90.00
\$0.01	1%	17%	29%	42%	54%	66%	78%	90%	102%
\$0.02	<0%	11%	25%	37%	49%	61%	73%	85%	97%
\$0.03	<0%	5%	20%	32%	44%	56%	68%	81%	93%
\$0.04	<0%	<0%	14%	27%	40%	52%	64%	76%	88%
\$0.05	<0%	<0%	9%	22%	35%	47%	59%	71%	83%
\$0.06	<0%	<0%	1%	17%	30%	42%	54%	66%	78%
\$0.07	<0%	<0%	<0%	12%	25%	37%	49%	62%	74%
Hydrogen Bulk Sale Price to Dispenser (\$/kg-H2)	\$1.41	\$2.82	\$4.24	\$5.65	\$7.06	\$8.47	\$9.89	\$11.30	\$12.71

In this scenario, there is a window of operating conditions which would lead to a profitable project. To replace gasoline as a transportation fuel, a bulk sale price of \$50-80/GJ could be expected, which would be profitable with electricity prices up to \$0.07/kWh. An expected bulk sales price for hydrogen replacing diesel would more likely be around \$30-50/GJ, which would be profitable in most circumstances, and will become more profitable over time as the carbon tax increases.

Hydrogen as a Replacement for Natural Gas

Figure 69 shows the cost of hydrogen as a heating fuel compared to electric resistive heaters, air-source heat pumps (ASHP), RNG, natural gas with DAC, and traditional fossil fuel sources. Again, the bulk price of \$1.75-\$4.50/kg-H2 is shown as the bulk price of hydrogen.

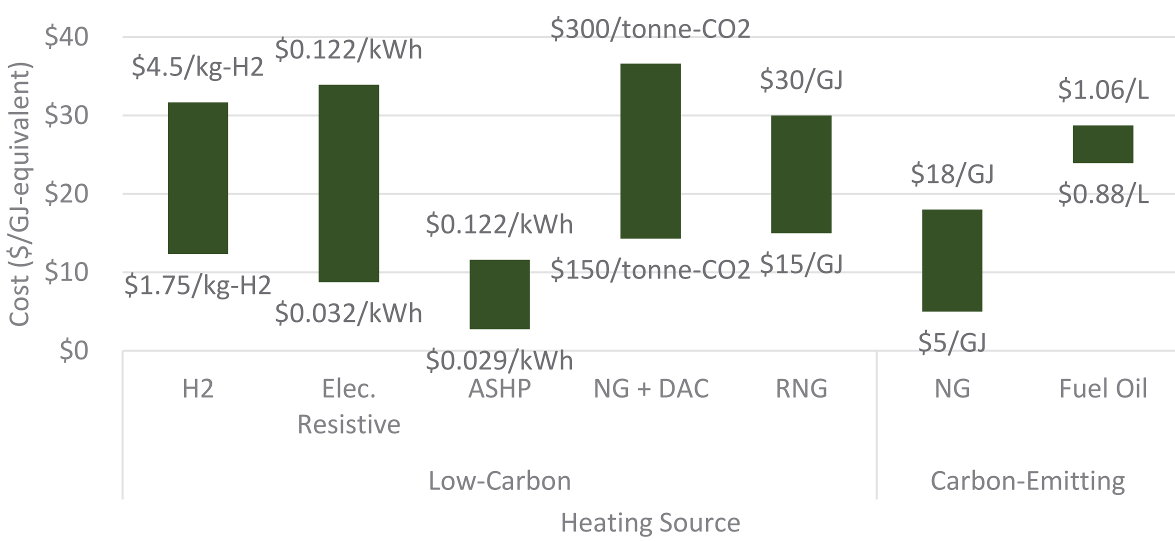


Figure 69 – Cost of hydrogen compared to heating sources

As a heating fuel, hydrogen is cost-competitive with the other low carbon options except ASHPs. There is less room for profit margins compared to sale as a transportation fuel. However, the cost of compression and distribution will be much lower than when sold as a transportation fuel if existing natural gas pipelines are used – which could be the case if the hydrogen is exported to the Maritimes.

The IRR for a hydrogen project concept in which a 100 tonnes-H2/day hydrogen electrolyzer produces hydrogen to be injected into a natural gas pipeline to displace natural gas is shown in Table 15. In this case, it is assumed that there are no transportation charges, meaning the production facility is co-located with an injection point into the natural gas network. This would be possible only if the facility was located in Nova Scotia or New Brunswick or if new pipelines were constructed in PEI or NL. Table 15 shows the IRR for a given input cost of electricity and sale price of hydrogen.

Table 15– IRR of hydrogen as a substitute for natural gas

Expected Range

		Hydrogen Sale Price as Substitute for Natural Gas ($/GJ-H2)								
		$4.00	$5.00	$6.00	$7.00	$8.00	$9.00	$10.00	$11.00	$12.00
Electricity Cost ($/kWh)	$0.01	<0%	15%	32%	47%	63%	78%	94%	110%	125%
	$0.02	<0%	6%	24%	40%	55%	71%	87%	102%	118%
	$0.03	<0%	<0%	16%	32%	48%	63%	79%	95%	110%
	$0.04	<0%	<0%	6%	24%	40%	56%	72%	87%	103%
	$0.05	<0%	<0%	<0%	16%	33%	48%	64%	80%	95%
	$0.06	<0%	<0%	<0%	7%	25%	41%	56%	72%	88%
	$0.07	<0%	<0%	<0%	<0%	17%	33%	49%	65%	80%
		$0.56	$1.56	$2.56	$3.56	$4.56	$5.56	$6.56	$7.56	$8.56
		Hydrogen Sale Price as Substitute for Natural Gas ($/kg-H2)								

Currently, the commodity price of natural gas in the Maritimes is approximately $10/GJ. This enables a positive IRR for production using electricity from $0.01/kWh to $0.07/kWh. The siting of such a project may be difficult as it would require sufficient access to electrical and natural gas infrastructure. The analysis has also not incorporated any cost to upgrade natural gas infrastructure, which may or may not be necessary depending on the expected blending rate of hydrogen in the pipeline and the local pipeline materials and end use appliances or industrial equipment receiving the blend. However, the results suggest there is the potential for a profitable project of this type if the right conditions can be met.

Hydrogen as Dispatchable Power

Hydrogen could also be used as energy storage for the electric grid. Energy storage is critical for the widespread adoption of intermittent renewable generation such as wind and solar power generation. Currently, energy storage is being deployed at a rapid pace with record growth in the energy storage market in 2020 and a forecasted 5x increase in market size by 2025 in the US.[81] However, these energy storage projects are focused on a short duration (<6 hours). As renewable penetrations increase, long

[81] Wood Mackenzie. (2020). Energy Storage Monitor. Retrieved from https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/

duration energy storage will be needed.[82] Long duration storage could also help reduce the cost burden of seasonal peaking. Hydrogen has been shown to be cost competitive with other long duration energy storage options.[83] As shown in Figure 70, storage via chemical fuels such as hydrogen are best suited for long duration, high-capacity energy storage.

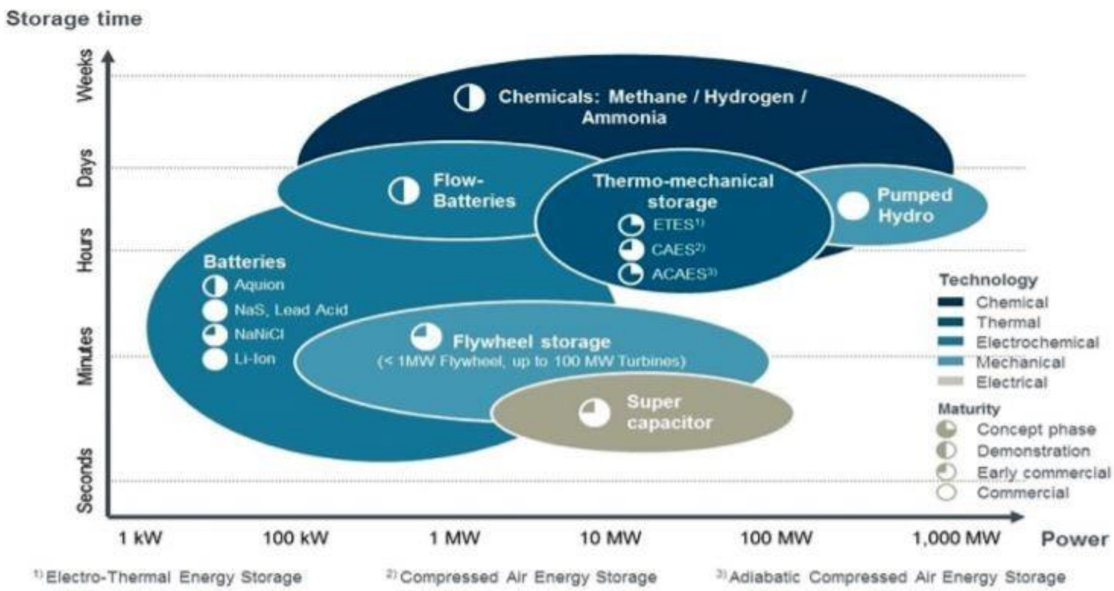


Figure 70 – Comparison of energy storage technologies[84]

The IRR for a hydrogen project concept in which a 100 tonnes-H2/day hydrogen electrolyzer produces hydrogen to function as energy storage and generate electricity during periods of peak demand is shown in Table 16, Table 17, and Table 18 for a range of energy storage durations. In this case, it was assumed that there are no transportation charges, meaning the production facility is co-located with the electrical transmission infrastructure. The analysis was conducted for three systems designed to store 1-, 10-, and 30-days worth of hydrogen for future use. The capital cost to install hydrogen storage was estimated to be $102/kg-H2, which represents bulk storage in a salt cavern.[85] The cost of generating electricity via hydrogen combustion in a turbine was estimated based on a study conducted by the Hydrogen Council.[86] For a hydrogen costs ranging from $1.75-4.50/kg-H2, the resulting cost of electricity was estimated to be $90-200/MWh for hydrogen.

[82] Zhang, J. et al. (2020). Benefit Analysis of Long-Duration Energy Storage in Power Systems with High Renewable Energy Shares. Retrieved from https://www.frontiersin.org/articles/10.3389/fenrg.2020.527910/full
[83] Guerra, O. et al. (2020). The value of seasonal energy storage technologies for the integration of wind and solar power. Retrieved from https://pubs.rsc.org/en/content/articlelanding/2020/ee/d0ee00771d
[84] Cleatech Group. (2019). Green Ammonia – Potential as an Energy Carrier and beyond. Retrieved from https://www.cleantech.com/green-ammonia-potential-as-an-energy-carrier-and-beyond/
[85] Mongird K, et al. (2020). 2020 Grid Energy Storage Technology Cost and Performance Assessment. US DOE Technical Report Publication No. DOE/PA-0204. Retrieved from https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[86] 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

Table 16 – IRR of hydrogen for dispatchable power (1 day storage)

		Electricity from Hydrogen Turbine Sale Price ($/kWh) – 1 Day Storage								
		$0.05	$0.07	$0.09	$0.11	$0.13	$0.15	$0.17	$0.19	$0.21
Electricity Cost ($/kWh)	$0.01	0%	12%	21%	30%	38%	46%	54%	62%	71%
	$0.02	<0%	0%	12%	21%	30%	38%	46%	54%	63%
	$0.03	<0%	<0%	1%	12%	22%	30%	38%	46%	55%
	$0.04	<0%	<0%	<0%	1%	13%	22%	30%	38%	47%
	$0.05	<0%	<0%	<0%	<0%	1%	13%	22%	30%	38%
	$0.06	<0%	<0%	<0%	<0%	<0%	1%	13%	22%	30%
	$0.07	<0%	<0%	<0%	<0%	<0%	<0%	1%	13%	22%

Table 17 – IRR of hydrogen for dispatchable power (10-day storage)

		Electricity from Hydrogen Turbine Sale Price ($/kWh) - 10 Day Storage								
		$0.05	$0.07	$0.09	$0.11	$0.13	$0.15	$0.17	$0.19	$0.21
Electricity Cost ($/kWh)	$0.01	<0%	6%	14%	20%	26%	32%	38%	43%	49%
	$0.02	<0%	<0%	6%	14%	20%	26%	32%	38%	43%
	$0.03	<0%	<0%	<0%	6%	14%	20%	26%	32%	38%
	$0.04	<0%	<0%	<0%	<0%	7%	14%	20%	26%	32%
	$0.05	<0%	<0%	<0%	<0%	<0%	7%	14%	20%	26%
	$0.06	<0%	<0%	<0%	<0%	<0%	<0%	7%	14%	20%
	$0.07	<0%	<0%	<0%	<0%	<0%	<0%	<0%	7%	14%

Table 18 – IRR of hydrogen for dispatchable power (30-day storage)

		Electricity from Hydrogen Turbine Sale Price ($/kWh)- 30 Day Storage								
		$0.05	$0.07	$0.09	$0.11	$0.13	$0.15	$0.17	$0.19	$0.21
Electricity Cost ($/kWh)	$0.01	<0%	<0%	5%	10%	14%	18%	21%	25%	29%
	$0.02	<0%	<0%	<0%	5%	10%	14%	18%	21%	25%
	$0.03	<0%	<0%	<0%	<0%	5%	10%	14%	18%	21%
	$0.04	<0%	<0%	<0%	<0%	<0%	5%	10%	14%	18%
	$0.05	<0%	<0%	<0%	<0%	<0%	<0%	5%	10%	14%
	$0.06	<0%	<0%	<0%	<0%	<0%	<0%	<0%	5%	10%
	$0.07	<0%	<0%	<0%	<0%	<0%	<0%	<0%	<0%	5%

This type of project requires low input cost of electricity to be profitable, but low prices may be available when intermittent generating sources must be curtailed because of low demand. Long duration energy storage enables better utilization of generating assets, decreasing the overall cost of the electric system.

As the duration of storage increases, so do the capital costs of the project and therefore a higher sale price is required to ensure profitability. This trend will be true for any energy storage technology, and in general the cost competitiveness of hydrogen projects will improve at larger scales compared to alternatives.

10. ECONOMIC OPPORTUNITIES

Combining domestic demand with potential for export, the hydrogen and fuel cell sector has the potential to generate over $11 billion annually and support almost 140,000 jobs in the transformative scenario by 2050. This includes revenue and jobs relating to the production and sale of hydrogen as well as local manufacturing and services. Domestic hydrogen demand in incremental and transformative scenarios outlined in the *Potential Hydrogen End Uses* Section were paired with export potential based on the business-as-usual and ambitious scenarios outlined in the Hydrogen Roadmap Europe. [87] It was assumed that NL captures 2% of the European market in 2030 and 5% in 2050. For both domestic and export markets, the hydrogen sale price was assumed to be $3/kg-H2.

The number of jobs supported was estimated based on the direct sector revenue estimates using job multiplier factors from the National Strategy for Hydrogen.[88] The estimate includes new job growth as well as retrained and reskilled labour. The analysis excludes markets that would indirectly benefit from growth in the hydrogen market such as adjacent industries like CCUS facilities, pipeline development and installation, and end-use applications. While a significant portion of these jobs could be located in NL, some would likely be located elsewhere in Canada where equipment manufacturing may occur.

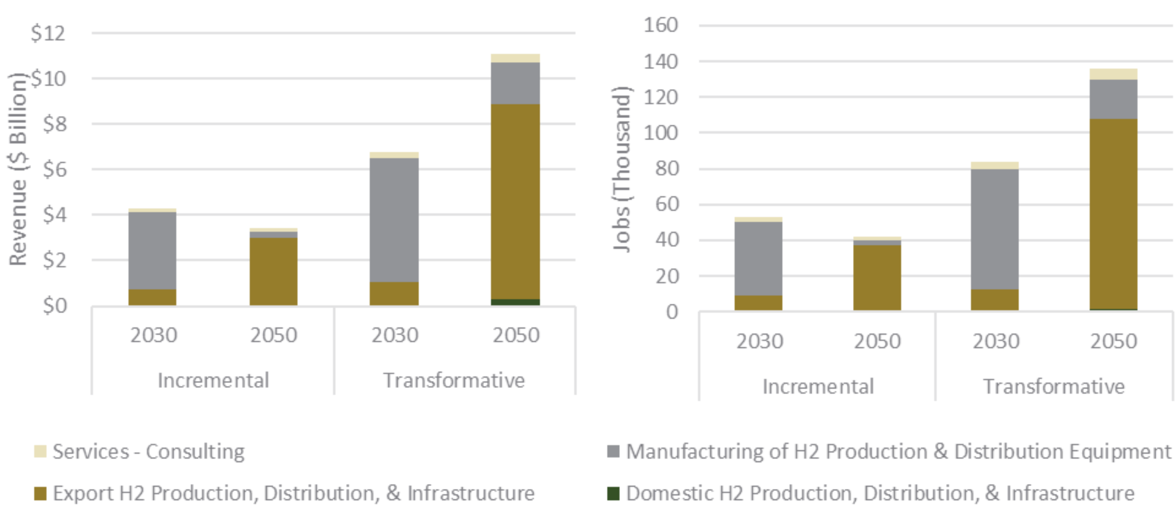


Figure 71 – Estimated potential hydrogen related revenue and jobs in NL (2030 & 2050)

In 2030, the bulk of the revenue is linked to the presumed increase in hydrogen generation potential in the province. It was assumed that production capacity would increase dramatically over this time to meet international demand. By 2050, there is little new construction of hydrogen generation facilities since the infrastructure is already in place, and the bulk of revenue and jobs are related to the ongoing production and distribution of hydrogen, primarily for export.

[87] 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
[88] Natural Resources Canada. (2020). Hydrogen Strategy for Canada: Seizing the Opportunities for Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

NL possesses unique human and physical resources to support full participation in the green economy. To capitalize on this, the province needs to promote international sustainable development goals through the application of clean energy technologies in Academia, Industry, and Municipalities.

Pilot or lighthouse projects can form the basis of partnerships to explore, develop, and commercialize sustainable, innovative, cost-effective, and practical hydrogen production and distribution solutions. These projects can simultaneously act as a demonstration, training, and research facilities, and can link existing expertise within post-secondary institutions and industry.

Through pilot project testing, the gaps that exist in knowledge transfer and training can be addressed and help set the foundation for local hydrogen economy capacity building in NL. This can in turn enable all sectors of the NL economy to grow during the global energy transition.

11. NATIONAL POTENTIAL FOR HYDROGEN

The Maritimes Hydrogen Study summarized the current hydrogen projects across Canada, and also highlighted the anticipated key results of the Hydrogen Strategy for Canada, which had not yet been released by NRCan. This section covers key updates since the previous report release.

Hydrogen Strategy for Canada and Regional Hydrogen Studies

NRCan released the Hydrogen Strategy for Canada in December 2020,[89] and the anticipated key messages highlighted in the previous Maritimes Hydrogen Study were all accurate. The strategy provided additional detail about the strategic importance and opportunity for hydrogen in Canada. Key messages include:

- Hydrogen production
  - By 2050, Canada can be one of the top three global producers of low-CI hydrogen, leveraging its natural resources, innovation leadership, and skilled energy sector
  - Canada must develop all potential low-CI hydrogen production pathways to achieve the scale needed to meet net-zero by 2050
- Opportunity for Hydrogen in Canada
  - Up to 30% of Canada's end-use energy could be delivered via hydrogen by 2050, equivalent to ~ 20 million tonnes of annual hydrogen demand
  - Adoption of hydrogen will be focused on energy-intensive applications where it offers advantages over alternative low-carbon options, including in long-range transportation and power generation, to provide heat for industry and buildings, and as a feedstock for industrial processes
  - With Canada's strong starting position, hydrogen can result in up to 45 Mt-CO_2e of GHG emissions reduction by 2030, achieving 21% of Canada's 2030 decarbonization target
  - By 2050 deployment of hydrogen at-scale could result in up to 190 Mt-CO_2e annual emmissions reduction, achieving 26% of the target GHG reduction vs. today's baseline
- Economic and export potential
  - With worldwide demand for hydrogen increasing, the global market is expected to reach more than $2.5T by 2050, and there is a significant export opportunity for Canada as energy importers are actively looking to Canada as a potential supplier
  - By 2050, there could be ~ 350,000 hydrogen sector jobs In Canada, and >$50 billion in direct hydrogen sector revenue for the domestoc market
  - The development of an export market could double the revenue potential to >$100 million annual sector potential

The strategy outlines 32 recommendations across eight pillars. The recommendations provided in the Maritimes Hydrogen Study were aligned with the pillars and are still valid with this addendum.

[89] Natural Resources Canada. (2020). Hydrogen Strategy for Canada: Seizing the Opportunities for Canada. Retrieved from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

Since the Hydrogen Strategy for Canada was released, there has been significant activity at the regional level in supporting studies and developing provincial roadmaps. Current activities are summarized in Figure 72.

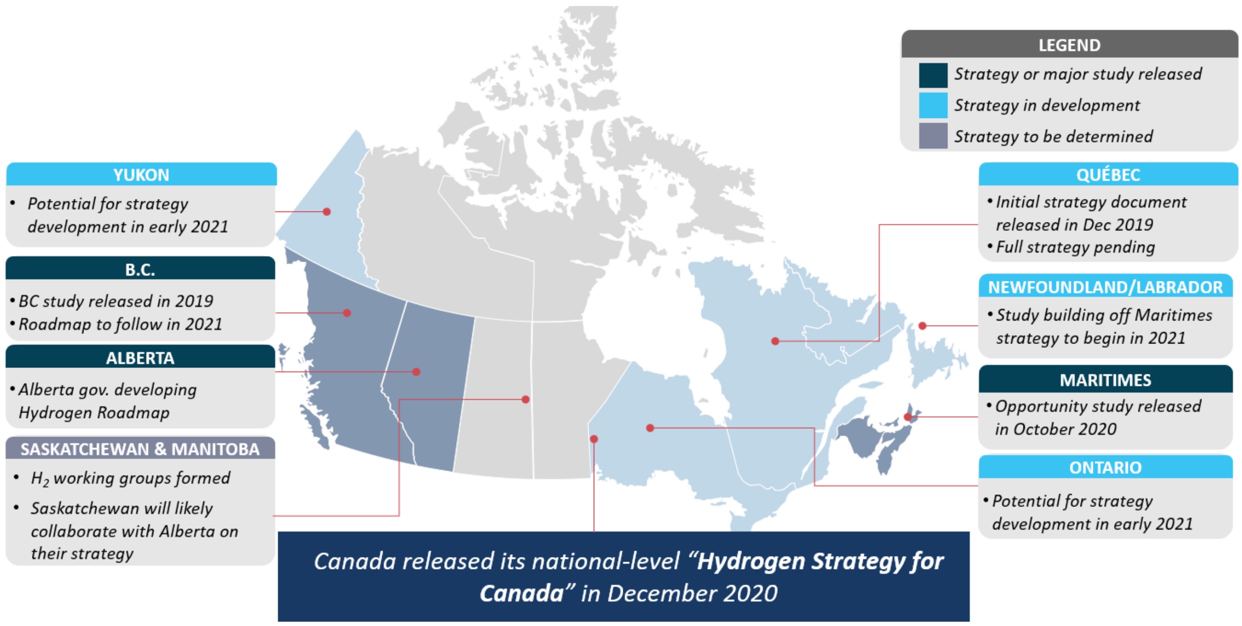


Figure 72 – Regional hydrogen studies and roadmaps in Canada

Hydrogen Projects in Canada and Cluster Development

There has been significant momentum in hydrogen projects in Canada announced since the Maritime Hydrogen Study was published. An updated map of major hydrogen projects in Canada is shown in Figure 73. The map also shows where Canadian clusters have formed. Efforts to develop hydrogen deployment hubs tend to be located in the same regions as the clusters.

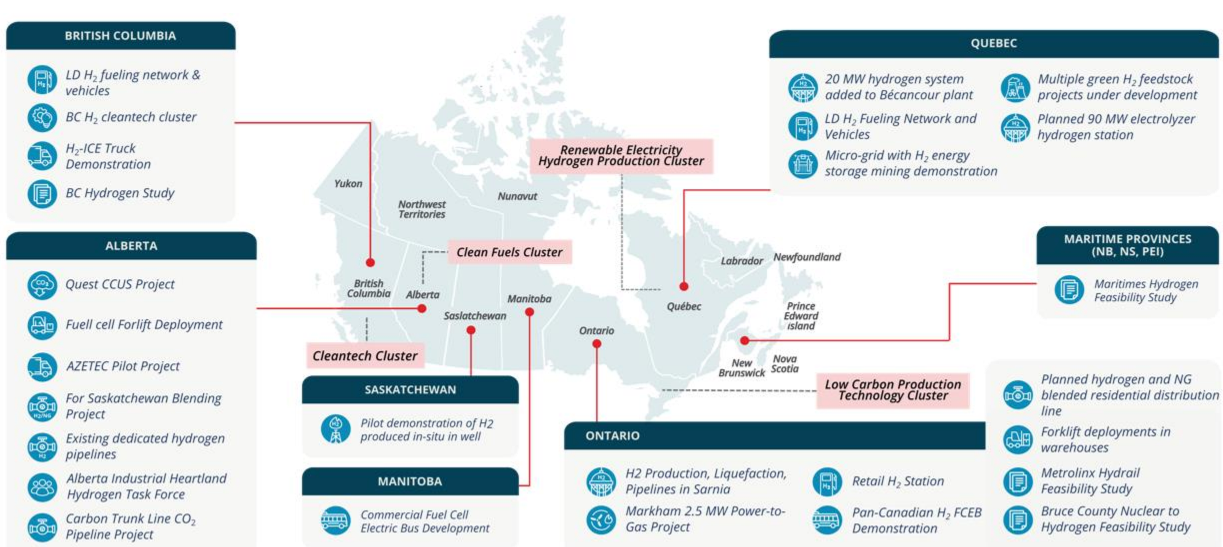


Figure 73 – Major hydrogen projects in Canada

12. REGULATION AND POLICY

Policies and regulations can be classified across several dimensions, including value chain process or element (e.g., production, distribution, end-use), mandate scope (e.g., federal, provincial, municipal), and type (e.g., policies, programs, regulations). This section briefly covers the relevant provincial regulations and policies affecting the hydrogen supply chain. The Maritimes Hydrogen Study details federal government policies, standards, and regulations that also apply to NL. This report highlights existing policies and regulations in NL related to hydrogen, climate change, the environment, industry, and energy.

LEADING BY EXAMPLE

The Government of NL owns or leases over 1,000 buildings and structures, operates over 3,000 vehicles and employs over 45,000 people. Further to this, it procures over $3.5 billion annually in goods and services such as equipment, supplies, travel, and building leases. This is a significant opportunity to demonstrate lighthouse projects where hydrogen hubs can improve energy efficiency and lower GHG emissions, combined with provincial investments and federal funding through the Low Carbon Economic Leadership Fund.

Figure 74 – Toyota Mirai[90]

The Government of Quebec procured the first deployment of Toyota Mirai hydrogen fuel cell electric vehicles to serve as government fleet vehicles in Quebec City. This project stimulated the deployment of hydrogen infrastructure, leading to the country's first public hydrogen fueling station.

- In 2019, the Government of NL released the province's approach to climate change with a five-year action plan, *The Way Forward on Climate Change in Newfoundland and Labrador*.[91] The province aims to reduce its GHG emissions by 30% below its 2005 level by 2030.
- The province has the *Management of Greenhouse Gas Act* targeting large industrial emitters with emission reporting requirements.[92]
- The federally approved *Made in Newfoundland and Labrador Approach to Carbon Pricing* came into effect on January 1, 2019, and highlights the province's role in reducing GHG emissions and encourage efforts to produce green and renewable energy.[93] There is a performance-based system for offshore and onshore industries that will establish GHG reduction targets for extensive industrial facilities. Under the plan, the province addresses climate

---

[90] CBC. (2018). Canada's 1st Fleet of Hydrogen Fuel Cell Vehicles Coming to Quebec this Year. Retrieved from https://www.cbc.ca/news/canada/montreal/75th-annual-montreal-auto-1.4494138

[91] Government of Newfoundland & Labrador. The Way Forward on Climate Change in Newfoundland and Labrador. Retrieved from https://www.gov.nl.ca/eccm/files/publications-the-way-forward-climate-change.pdf

[92] Government of Newfoundland & Labrador. (2016). Management of Greenhouse Gas Act:: Chapter M-1.001. Retrieved from https://www.assembly.nl.ca/legislation/sr/statutes/m01-001.htm

[93] Government of Newfoundland & Labrador. (2018). Provincial Government Releases Federally-Approved Made-in Newfoundland and Labrador Approach to Carbon Pricing. Retrieved from https://www.gov.nl.ca/releases/2018/mae/1023n01/

change by encouraging Muskrat Falls to achieve full power, accounting for 98% of electricity to be renewable in NL. The plan will allow the province to export clean energy to other jurisdictions.

- Canada Energy Regulator has authorized offshore renewable energy activities in Canada, allowing the highest possible operational safety and environmental protection standards.[94]
- The NL Department of Industry, Energy, and Technology has significant incentives to develop projects in the province. The department has robust supports available to assist in innovation at all Technology Readiness Level (TRL) levels and project development. This is complemented by a strong support system within the Atlantic Canada Opportunities Agency (ACOA).

The Maritimes Hydrogen Study also provides an overview of potential policies in place or under consideration in other jurisdictions which could be employed in Atlantic Canada. It outlines considerations for policies at the provincial and federal levels that will impact the development of a hydrogen sector in the region. These considerations are applicable to NL as the Maritimes as they relate to hydrogen production, transport, distribution, storage, and end-use.

[94] Government of Canada. The Offshore Renewable Energy Regulations Initiative. Retrieved from https://www.rncanengagenrcan.ca/en/collections/offshore-renewable-energy-regulations-initiative

13. SUMMARY RECOMMENDATIONS

The Maritimes Hydrogen Study outlined seven recommendation themes and a total of 14 specific recommendations. All previous recommendations are still relevant with the NL scope added. Some minor changes have been made to reflect the Atlantic Hydrogen scope versus the previous Maritimes focus.

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 – e.g., utilities, low-carbon fuel producers, emerging transportation, O&G.
Theme 2: Hydrogen Awareness
3. Include hydrogen in provincial and regional integrated Clean Energy Roadmap or consider releasing a government-led Atlantic Canada Hydrogen Roadmap[95].
4. Support hydrogen outreach initiatives.
Theme 3: Infrastructure and De-Risking of Investments
5. Initiate studies to determine options and magnitude of investment for hydrogen infrastructure build out, both in individual provinces and as a regional approach.
6. 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
7. Foster collaborative efforts between industry and academia by supporting consortium-based projects for fundamental research priority areas important to the region.
8. Form Atlantic Canada chapter of Canadian Hydrogen and Fuel Cell Association or like industry association to encourage regional cluster development.
Theme 5: Codes and Standards
9. Adopt Canadian Hydrogen Installation Code and like standards to facilitate new technology and infrastructure adoption in early markets.
10. Develop and adopt common standards and practices across the region to facilitate inter-provincial trade.
Theme 6: Policy and Regulation
11. Ensure regional policy framework developed to meet decarbonization targets does not unintentionally preclude hydrogen as a pathway for compliance through narrow definitions.
12. 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
13. Identify champions and hosts for regional deployment hubs.
14. Provide support for feasibility studies to advance projects from conceptual to implementation phase.

[95] BC, Alberta, Yukon, Ontario and Quebec governments are developing regional hydrogen strategies or roadmaps

Three additional recommendations have been developed with this addendum:

1. Provincial government should consider expanding the mandate of crown corporation Nalcor to consider green hydrogen opportunities as a strategic enabler for greater fuel switching and decarbonization in sectors reliant on high carbon fuels such as RPPs. Green hydrogen can be viewed as indirect electrification pathway for the utility with potential technical and economic advantages in some applications such as heavy-duty transport and remote communities.

   When the Muskrat Falls Facility is fully operational, it is estimated that NL will export approximately 3.5 TWh in electricity through the Maritime Link transmission cable at an anticipated average price of $0.045/kWh. Development of electrolytic hydrogen generation plants in province provide a compelling business case for both project developers and the rate payers of NL. To highlight this point, if a large scale electrolysis plant was built in NL to generate green hydrogen as an alternative to bulk electricity sales, and the electricity to generate hydrogen is sold at a rate of $0.05/kWh to the hydrogen production plant – compared to the bulk electricity sales price of $0.045/kWh – the incremental increase in annual revenue to the utility would be approximately $9 million for a 100 tonnes-H2/day plant or $17.5 million if the full 3.5 TWh was utilized.

2. Identify opportunities for government fleets (light-duty, ferries) and/or infrastructure to adopt hydrogen end use technologies to create certainty in demand for hydrogen project developers.

3. Pursue detailed feasibility studies and further stakeholder engagement related to the three NL lighthouse projects identified in the study:

   - Offshore wind electrolysis project
   - Port of Argentia hydrogen hub with Marine Atlantic ferry conversion
   - North Atlantic Refinery Limited hydrogen hub anchored by green hydrogen production for reducing carbon intensity (CI) of conventional fuels

The opportunities for hydrogen in Atlantic Canada are compelling, particularly when coupling NL's potential to become a bulk hydrogen producer with the other Atlantic Provinces' potential demand for hydrogen in energy-intensive, high-emitting applications. The challenge lies in defining a common vision and roadmap for hydrogen across the four provinces, particularly given current economic challenges, lack of aligned supporting policy and regulation, and limited energy innovation resources. With the global and federal momentum around hydrogen, and with governments identifying green infrastructure projects as a top priority for stimulus funds to spur on economic recovery post-COVID, an aligned path forward supported by the regional governments could successfully position the Atlantic Provinces in the national hydrogen innovation agenda.

APPENDIX A. SUMMARY OF STAKEHOLDER ENGAGEMENT

Context

As part of the expanded NL Hydrogen Feasibility study, the project team engaged key industry stakeholders across the province to understand regional opportunities to deploy hydrogen in the near-, mid-, and long-term. We discussed how hydrogen can pay a role in managing surplus electricity and potential utility scale applications; explored opportunities to decarbonize the O&G sector, produce blue hydrogen and strengthen the business case to develop existing natural gas reserves; and identified economic development opportunities and potential lighthouse projects for early hydrogen technology demonstrations.

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 40 organizations were engaged through a series of targeted one-hour virtual interviews and one two-hour virtual workshop. While the level of knowledge and experience on hydrogen varied among stakeholders, they all provided important perspectives on how hydrogen can fit within the energy landscape in NL.

Key Findings

Several key themes emerged from the workshops, including:

1. **Education and awareness, and small-scale pilots** – supported by government and major industry players – are necessary to grown competency, familiarity and comfort with hydrogen. Several near-term lighthouse project opportunities exist to demonstrate and test hydrogen.
2. **Surplus electricity to create hydrogen as a new commodity** could offer greater benefits than transmitting electricity out of province and potentially help to unlock new renewable energy resources.
3. **The greatest hydrogen prospects may be in export,** but domestic adoption will be necessary to attract international investment and export opportunities.
4. **Overcoming risk aversion will be challenging** but can be overcome through enabling policies, and standards and an integrated approach.
5. **Blue hydrogen can help enable the transition of the O&G industry** and position it as part of the clean energy future.

Each key finding is discussed in more detail below.

Education and awareness, and small-scale pilots – supported by government and major industry players – are necessary to grow competency, familiarity, and comfort with

hydrogen. Several near-term lighthouse project opportunities exist to demonstrate and test hydrogen.

- **A broad education and awareness campaign may need to precede or accompany any near-term lighthouse projects**. Some stakeholders suggested that there is a wide range of hydrogen understanding across the province, which was supported by a survey of workshop participants (the hydrogen awareness level score was a 6.1 out of 10). Lack of awareness and challenges with past hydrogen projects contribute to risk aversion. The Ramea wind-hydrogen diesel research project commissioned in 2011 has experienced technical challenges and lost community trust. Improving hydrogen literacy and a successful flagship project will help to build support for future projects and investment.
- **Smaller projects or pilots in the near-term are needed to demonstrate proof of concept before scaling up.** Pilots and demonstrations with major industry partners (i.e., those with established technologies and demonstrate best in class) will be needed to start. Government support is also a critical component to test hydrogen and de-risk projects for developers; the costs of electrolyzers and other infrastructure could make it challenging to attract developers for a pilot in the absence of supporting policies and funding.
- **Several near-term lighthouse project opportunities exist specifically with marine applications, refineries, and industrial processes**. The *Port of Argentia* is a marine port with large footprint, suitable for wind production on site and its proximity to shipping lanes is ideal for potential export. The Port is actively exploring partnership opportunities. Ferries may be positioned well for a lighthouse project given they are highly visible and publicly funded. The *Come-by-Chance Refinery* was mentioned as a possible end use for hydrogen and research and development opportunity. Lastly, *energy produced industrially* at micro scale (e.g., sawmills, papermills, agricultural operations, landfills, etc.) is often wasted presenting an opportunity for a lighthouse project that looks at these as a collective system and novel approach to produce hydrogen.
- **Remote communities/sites that are diesel dependent were seen as potential lighthouse opportunities but there are additional factors that must be considered**. There are currently many diesel systems that could benefit from hydrogen combined with renewables for energy storage. However, remote communities specifically are complex, requiring a multi-faceted approach and local engagement and support. Seasonal access can be an issue and service reliability is critical. Some stakeholders cautioned that while diesel communities may benefit from hydrogen, they could be expensive lighthouse projects, difficult to manage and lack visibility – an important element of lighthouse projects.

Using the surplus electricity to create hydrogen as a new commodity could offer greater benefits than transmitting electricity out of province and potentially help to unlock new renewable energy resources.

- **Surplus electricity to create hydrogen could have greater cost benefit than transmission out of province or curtailment**. NL will have a large electricity surplus once Muskrat Falls is online. The challenge will be balancing low electricity costs with the high capital expenditures associated with electrolysis infrastructure and low utilization.
- **Opportunities for utility scale applications may be limited**. While it is possible utilities could produce/distribute hydrogen there would need to be a compelling business case for ratepayers. A

more likely scenario may be to sell power to another hydrogen producer. Energy storage is not a likely end-use demand since hydro already offers storage capabilities.

Hydrogen export development may offer the greatest economic prospects, but domestic adoption will be necessary to attract international investment and export markets.

- **Several potential hydrogen export markets were identified but stakeholders agreed that it will be important to clearly define the target market and develop a roadmap to capitalize these opportunities.** Several export markets were suggested, including using hydrogen to produce ammonia for export as a fuel/fertilizer. Large low-speed combustion engines can be retrofitted with modest tweaks to operate with ammonia and/or a mix of conventional fuel and ammonia. The Norwegian parliament has introduced new requirements stipulating that all cruise ships and ferries in World Heritage fjords must be emission-free from 2026. If this were to become the norm, and NL provided clean fuel, the province may have a competitive advantage with maritime traffic. The energy market will be very different in 2050 thus it will be important to clearly define the target export market, identify who will be responsible (e.g., Crown corporations, private enterprises) and develop a roadmap to get there.
- **Interprovincial trade and other Atlantic Canada initiatives could present new export market opportunities.** Hydrogen produced in NL could be shipped across Atlantic Canada to create synthetic fuels. Partnerships with Marine Atlantic could be developed to ship liquid hydrogen for refueling of ferries. This is a common transportation and delivery mechanism when high-volume transport is needed in the absence of pipelines however this method is energy intensive and expensive. Additional research to improve liquefaction technology and increase economies of scale could help lower costs. The “Atlantic Loop” initiative is intended to increase the sharing of clean electricity to displace coal use in the region. Stakeholders questioned whether the infrastructure (e.g., additional subsea linkages) could include hydrogen transportation networks (e.g., pipelines) to achieve economies of scale and reduce costs to transport hydrogen. Additionally, NL must consider hydrogen in the context of the other Atlantic Canadian provinces and build on the region’s strengths with significant green energy, a young natural gas network, and potential for geological storage.
- **It will be important to drive foreign investment to develop the NL supply chain including new technology, system integrators, and large multinationals**. The supply chain development must happen in parallel across various segments and should consider the role colleges/universities could play in research and development activities.
- **Several domestic hydrogen applications exist across NL, including heavy duty trucking, marine applications and mining**. NL relies heavily on trucking to deliver goods received via maritime transport across the region. And with transportation being one of the largest sources of GHG emissions in NL there is significant opportunity to decarbonize this sector. Marine Atlantic and coastal ferries were identified as another opportunity. Mining in remote areas across NL could use renewables to produce hydrogen and decarbonize operations. Stakeholders pointed to examples like Orkney Islands, Los Angeles Port and Chile. Biomass in Atlantic Canada also offers the opportunity for gasification/pyrolysis for hydrogen storage and purification. Additionally, understanding carbon pricing (expected to increase to $170 per tonne by 2030) and how this will impact the value of hydrogen will be an important consideration.

Overcoming risk aversion will be challenging but can be overcome through enabling policies and standards, and an integrated approach.

> **"Fear of missing out should outweigh risk."**
> - Workshop participant

- **There are many synergies between existing petroleum and gas products** and future hydrogen supply chain. There is the potential to build the supply chain for hydrogen in a modular while ensuring integration with various segments.
- **NL should capitalize on the low carbon fuel standard and available funding.** The goal of the clean fuel standard is to significantly reduce GHG emissions by making fuels used everyday cleaner over time. The standard will require liquid fuel (gasoline, diesel, home heating oil) suppliers to gradually reduce the CI of the fuels produced and sold in Canada over time, leading to a decrease of approximately 13% (below 2016 levels) in the CI of liquid fuels by 2030. The government of Canada has allocated $1.5B towards a low-carbon and zero-emissions fuel fund that could be leveraged to develop domestic hydrogen production.

Blue hydrogen can help enable the transition of the O&G industry and position it as part of the clean energy future.

- Pipelines can be leveraged for hydrogen and will need to be thought of as energy pipeline in the future as opposed to natural gas pipelines.
- There is currently no real incentive to examine natural gas reserves today, **hydrogen can help enable the opportunity for economic expansion.** Specifically, some operators have over-abundance of natural gas production and have to stifle oil production due to excess natural gas. In those cases, natural gas to produce hydrogen could have a negative cost.
- **Hydrogen can be used to help offset emissions associated with logistics** in the offshore O&G industry. Along with electrification at the port level, hydrogen can be looked at for tankers and vessels.
- **There is an opportunity for the offshore O&G industry to remain relevant by producing blue hydrogen** that can be then exported to global markets including western Europe.
- The refinery can be a great location to initiative a hydrogen project with prospects of integration with local fleets.

Stakeholder Table

As part of the study, the Zen team engaged with representatives from government, academia, industry, not for profits, that provided a range of perspectives and insights into electric utility and O&G opportunities, the role of a hydrogen economy & energy storage opportunities, hydrogen development and end use in NL and economic development opportunities. The following stakeholders were engaged.

Table 19 – Stakeholder engagement summary

#	Organization	Workshop	Targeted Interview
1	Aker Solutions	✓	
2	Atlantic Canada Opportunities Agency	✓	
3	Canadian Biogas Association	✓	

#	Organization	Workshop	Targeted Interview
4	Caron Hawco Group	✓	
5	City of St. John's	✓	
6	College of the North Atlantic	✓	
7	Currach Consulting	✓	
8	Department of Environment, Climate Change, and Municipalities	✓	
9	Department of Industry, Energy, and Technology	✓	
10	Emera	✓	
11	Fortis	✓	
12	Fundamental Inc.	✓	
13	Growler Energy	✓	✓
14	Hatch		✓
15	Heritage Gas	✓	
16	Individual	✓	
17	Innovation, Science, and Economic Development	✓	
18	Innovation, Science, Economic Development Canada	✓	
19	International Partnership for Hydrogen and Fuel Cells (IPHE)	✓	
20	Marine Atlantic		✓
21	Marine Renewables Canada	✓	
22	Memorial University	✓	
23	MUN - Harris Centre	✓	
24	Nalcor	✓	✓
25	National Research Council Canada	✓	
26	Newfoundland Power	✓	
27	Newfoundland & Labrador Oil & Gas Industries Association (NOIA)	✓	
28	Northland Power		✓
29	Natural Resources Canada	✓	
30	Ocean Choice International		✓
31	Ocean Supercluster	✓	
32	OceanChoice		✓
34	OERA	✓	
35	Oil and Gas Corporation of Newfoundland and Labrador		✓
36	Port of Argentia	✓	✓
37	Power Environmental Consulting Services	✓	
38	Seaformatics	✓	
39	Wind Project Inc.	✓	

APPENDIX B. LIST OF REMOTE COMMUNITIES

Table 20 – Isolated electricity systems in NL[96]

Isolated System	Service Areas	Power Source(s)	Fossil Fuel Demand (MWh/yr)	Fossil Fuel Generating Capacity (kW)	Fuel Transportation
Francois	1	Fossil-Diesel	616	635	Ship
Grey River	1	Fossil-Diesel	443	522	Ship
Little Bay Islands	1	Fossil-Diesel	459	930	Ship
McCallum	1	Fossil-Diesel	345	446	Ship
Ramea	1	Fossil-Diesel (Primary) Renewable-Wind Renewable-Wind/Hydrogen	3,635	2,775	Ship
St. Brendan's	5	Fossil-Diesel	846	712	Ship
Charlottetown	2	Fossil-Diesel	4,788	2,545	n/a
L'anse au Loup	13	Hydro (Primary) Fossil-Diesel	1,505	8,050	Truck
Norman Bay	1	Fossil-Diesel	209	160	Ship
Mary's Harbour	2	Fossil-Diesel Hydro	4,191	2,615	Truck
Port Hope Simpson	1	Fossil-Diesel	3,089	2,325	Truck
St. Lewis	2	Fossil-Diesel	1,448	1,020	Truck
Back Tickle	2	Fossil-Diesel	1,166	1,005	Ship
Cartwright	1	Fossil-Diesel	4,433	2,220	Truck
Hopedale	1	Fossil-Diesel	5,410	2,629	Ship
Makkovik	1	Fossil-Diesel	4,316	1,765	Ship
Nain	1	Fossil-Diesel	9,554	3,865	Ship
Paradise River	1	Fossil-Diesel	191	148	Truck
Postville	1	Fossil-Diesel	1,847	1,067	Ship
Rigolet	1	Fossil-Diesel	2,980	1,320	Ship
Natuashish	1	Fossil-Diesel	8,895	3,337	Ship

[96] Open Data Newfoundland and Labrador (2020). Isolated Electricity Systems in Newfoundland and Labrador. Retrieved from https://opendata.gov.nl.ca/public/opendata/page/?page-id=datasetdetails&id=681