TRANSITION ACCELERATOR REPORTS
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BUILDING A TRANSITION PATHWAY TO A VIBRANT HYDROGEN ECONOMY IN THE ALBERTA INDUSTRIAL HEARTLAND

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Jessica Lof, MSc
Cameron Young, MSc, PEng
Jonathan Leary

The Transition Accelerator · L'Accélérateur de transition · CESAR · University of Calgary

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David B. Layzell, PhD, FRSC
Research Director, The Transition Accelerator
Director, CESAR and Professor, University of Calgary

Jessica Lof, MSc
Research Lead on Freight Transportation, CESAR
University of Calgary

Cameron Young, MSc, PEng
Energy Systems Analyst, CESAR, University of Calgary

Jonathan Leary
Research Assistant, CESAR, University of Calgary

CONTACT:
Dr. David B. Layzell, Tel: 403 220-5161
Email: dlayzell@ucalgary.ca Web: www.transitionaccelerator.ca

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- Reeve David Diduck, Lamont County

Project Management

- Dan Wicklum, President and CEO, The Transition Accelerator

Analytical Team and Report Authors

- David Layzell, Research Director, The Transition Accelerator
- Cameron Young, Energy Systems Analyst, CESAR
- Jessica Lof, Research Lead Freight, CESAR
- Jonathan Leary, Research Assistant, CESAR
- Song Sit, Senior Associate, CESAR

Special Advisors to the Analytical Team

- Hilary Faulkner, Director, Strategic Policy and Energy Diversification, Alberta Energy
- Oleg Podporin, Senior Policy Analyst, Natural Gas Strategy and Engagement, Alberta Energy
- Wes Lu, Senior Analyst, Alberta Energy

Task Force Advisors

- Mark Summers, Exec. Director, Technology & Innovation, Emissions Reduction Alberta (ERA)
- Justin Riemer, Assistant Deputy Minister, Western Economic Diversification Canada, Alberta Region, Government of Canada
- Mark Kirby, President and CEO, Canadian Hydrogen and Fuel Cell Association
- Barbra Korol, Executive Director, Strategic Policy Branch, Alberta Department of Energy
- Chris Nash, President, Alberta Motor Transport Association
- Sean McCoy, Assistant Professor, Dept of Chemical and Petroleum Engineering, Univ of Calgary
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MEDIA INQUIRIES AND INFORMATION: For media inquiries, contact dlayzell@transitionaccelerator.ca
MAILING ADDRESS: The Transition Accelerator, 2603 7th Ave NW, Calgary AB T2N 1A6
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About the Transition Accelerator and this report

The Transition Accelerator is a pan-Canadian, non-profit organization that works with groups across the country to solve business and social challenges while building major emissions reductions into solutions. The Accelerator philosophy starts with understanding that we live in a time of disruptive change which is shaping the future. The Accelerator harnesses disruptions, shaping the future by helping to develop credible and compelling transition pathways and actively taking steps down these pathways to achieve futures that include the need to achieve net-zero greenhouse gas (GHG) emissions by 2050.

The Accelerator uses a four-stage methodology described in a document [1] that was used to define the philosophical approach of the organization when it was launched in 2019:

1. **Understand** the system that is being transformed, including its strengths and weaknesses, and the technology, business model, and social innovations that are poised to disrupt the existing system by addressing one or more of its shortcomings;
2. **Codevelop** transformative visions and pathways in concert with key stakeholders and innovators drawn from industry, government, indigenous communities, academia, and other groups. This engagement process is informed by the insights gained in Stage 1;
3. **Analyze** and model the candidate pathways from Stage 2 to assess costs, benefits, trade-offs, public acceptability, barriers and bottlenecks. With these insights, the process then re-engages key players to revise the vision and pathway(s) so they are more credible, compelling and capable of achieving societal objectives that include major GHG emission reductions;
4. **Advance** the most credible, compelling and capable transition pathways by informing innovation strategies, engaging partners and helping to launch consortia to take tangible steps along defined transition pathways.

This study is the 5th in a series of reports that began with a focus on understanding the needs, challenges and disruptive forces facing the freight transportation sector [2], went on to identify hydrogen as a zero-emission fuel that could be competitive with diesel in that sector [3], [4] and then explored the opportunity to develop a vibrant hydrogen economy in Canada with net-zero GHG emissions [5]. This report focuses on a possible transition pathway for Alberta, and its Industrial Heartland to take a leadership role in the transition to a vibrant hydrogen economy in Canada.

For this nodal approach to develop a hydrogen economy to work, it will need to complement and extend both a provincial and a federal strategy for a hydrogen economy, thereby aligning resources from all levels of government with those from industry. We see this report as supporting Alberta's recently released 'Natural gas vision and strategy' [6] and we hope that it will be of value to the Canadian hydrogen strategy that is due to be released soon [7].

About the authors

David B. Layzell, PhD, FRSC is a Professor at the University of Calgary and Director of the Canadian Energy Systems Analysis Research CESAR initiative, as well as co-founder and Research Director of the Transition Accelerator. Between 2008 and 2012, he was Executive Director of the Institute for Sustainable Energy, Environment and Economy (ISEEE), a cross-faculty, graduate research and training institute at the University of Calgary.

Before moving to Calgary, Dr. Layzell was a Professor of Biology at Queen's University, Kingston (cross appointments in Environmental Studies and the School of Public Policy), and Executive Director of BIOCAP Canada, a research foundation focused on biological solutions to climate change. While at Queen's, he founded a scientific instrumentation company called Qubit Systems Inc. and was elected 'Fellow of the Royal Society of Canada' (FRSC) for his research contributions.

Jessica Lof, BComm, MSc (SEDV) is a Research Lead for the CESAR Initiative at the University of Calgary with a special interest in low carbon transition pathways for Canada's transportation systems. Jessica is also actively exploring hydrogen economy ecosystems and evaluating system-level opportunities and trade-offs while connecting with stakeholders.

Jessica joined CESAR with more than a decade of business experience in the railway and trucking sectors. Throughout her career, she has designed transportation and logistics solutions that enable economic potential and drive operational efficiency in a vast array of industries, including wind energy, oil and gas, automotive and global trade. Jessica has a Master of Science degree in Sustainable Energy Development (SEDV), a Bachelor of Commerce degree, and a professional designation with the Canadian Institute of Traffic and Transportation.

Cameron Young, PEng, MSc (SEDV) is an Energy Systems Analyst at CESAR. He joined CESAR to help create a hydrogen economy in Canada. His work will include research on different pathways for hydrogen production, transmission and distribution to provide pragmatic information for industry and policy makers. He hopes his work will help develop projects that convert Alberta's resources into a sustainable source of hydrogen fuel.

Cameron has a Chemical Engineering & Management double-major bachelor's degree from McMaster University, a Masters in Sustainable Energy Development from the University of Calgary and is registered as a Professional Engineer with APEGA. He has 10 years of process engineering and project development experience in Alberta's energy sector.

Jonathan Leary, BSc (Eng) Student joined CESAR through the CREATE-IISC (Integrated Infrastructure for Sustainable Cities) highly qualified personnel training program at the University of Calgary. At CESAR, Jonathan is engaged in projects focused on the future of autonomous vehicles in Alberta and initiatives to establish a hydrogen economy in Alberta.

Driven by a desire to solve real-world issues, Jonathan recently transferred from the Faculty of Science (Honours in Chemistry) to the Schulich School of Engineering, where he plans to obtain a Bachelor of Science in Engineering.

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Abbreviation	Definition
AIH	Alberta Industrial Heartland, a region in Alberta which includes Edmonton, Strathcona, Fort Saskatchewan, Sturgeon, and Lamont counties
AMTA	Alberta Motor Transport Association
ATR	Autothermal Reforming
AZETEC	Alberta Zero-Emission Truck Electrification Collaboration Project
BEB	Battery Electric Bus
Blue Hydrogen	Hydrogen produced from natural gas and carbon capture and storage
C	Carbon
CESAR	Canadian Energy Systems Analysis Research
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilization or Storage
CO2	Carbon Dioxide
DTE Ratio	Drivetrain Efficiency Ratio (GJ H2/GJ diesel or gasoline for same distance)
EOR	Enhanced Oil Recovery
EWMC	Edmonton Waste Management Centre
FCEB	Fuel Cell Electric Bus
FF	Fossil Fuel
GHG	Greenhouse Gas
GJ	Gigajoule (109 joules)
Green Hydrogen	Hydrogen produced by water electrolysis using intermittent zero-carbon electricity generated from wind and solar facilities
H2	Hydrogen gas
HDV	Heavy-Duty Vehicle: Vehicles with a gross vehicle weight rating > 15 tonne

HFCE	Hydrogen Fuel Cell Electric
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine
kJ	Kilojoule (103 Joules)
LDV	Light-Duty Vehicle
LH2	Liquid Hydrogen
LHV	Lower Heating Value
MDV	Medium-Duty Vehicle
MJ	Megajoule (106 joules)
Mt	Megatonne (106 metric tonnes)
NG	Natural Gas
NWR	Northwest Redwater Partnership
PJ	Petajoule (1015 joules)
PSA	Pressure Swing Adsorption
SMR	Steam Methane Reforming
SUT	Single Unit Truck
TJ	Terajoule (1012 joules)
TTC	Tractor Trailer Combination
WGS	Water-Gas Shift Reactor

Executive Summary

The global shift to net-zero emission energy systems will require replacement of fossil carbon energy carriers (i.e. gasoline, diesel, jet fuel, natural gas), the combustion of which generates the majority of the world's energy-based greenhouse gas (GHG) emissions. Electricity made from zero/low emission sources is likely to become the dominant energy carrier. However, electricity is not a viable solution for all sectors (heavy transport, heavy industry, space heating in cold climates); zero emission chemical fuels will also be required.

The potential of biobased fuels is limited by resource availability and concerns about adverse impacts on biodiversity and food production. Hydrogen (H_2) is rapidly becoming the global, zero-emission fuel of choice.

As one of the world's lowest cost producers of low-carbon 'green' (from water electrolysis) or 'blue' (from fossil fuels coupled to carbon capture and storage) H_2, Canada is strategically positioned to benefit from taking a leadership role in the transition to a net-zero H_2 economy. This advantage is clear in the Alberta Industrial Heartland, northeast of Edmonton, Alberta. The region already produces about 2250 tH_2 per day for use as an industrial feedstock (for fertilizer production, bitumen upgrading, oil refining, etc), with ~42% of the H_2 being 'blue' since the byproduct carbon dioxide (CO_2, a greenhouse gas) is captured and sequestered underground.

Canada is strategically positioned to benefit from taking a leadership role in the transition to a net-zero H_2 economy. This advantage is clear in the Alberta Industrial Heartland.

The region's low cost for natural gas, technical expertise and ability to rapidly scale-up the production of blue H_2 makes it possible to not only decarbonize industrial processes that use H_2, but also create new fuel markets with up to 90% lower life cycle GHG emissions. Given a wholesale blue H_2 price of C$1.50/kg H_2 (C$10.62/GJ_{hhv} H_2) before carbon/tax credits, the H_2 cost will be about half the wholesale and one third the retail cost of diesel.

This report explores potential nearby markets for fuel hydrogen and proposes a deployment strategy based on the principal that if public investments end, an economically viable new energy system must remain.

The findings shows that significant potential fuel markets (hundreds to thousands of tonnes H_2/day) exist along two corridors that transect the City of Edmonton (**Figure A**).

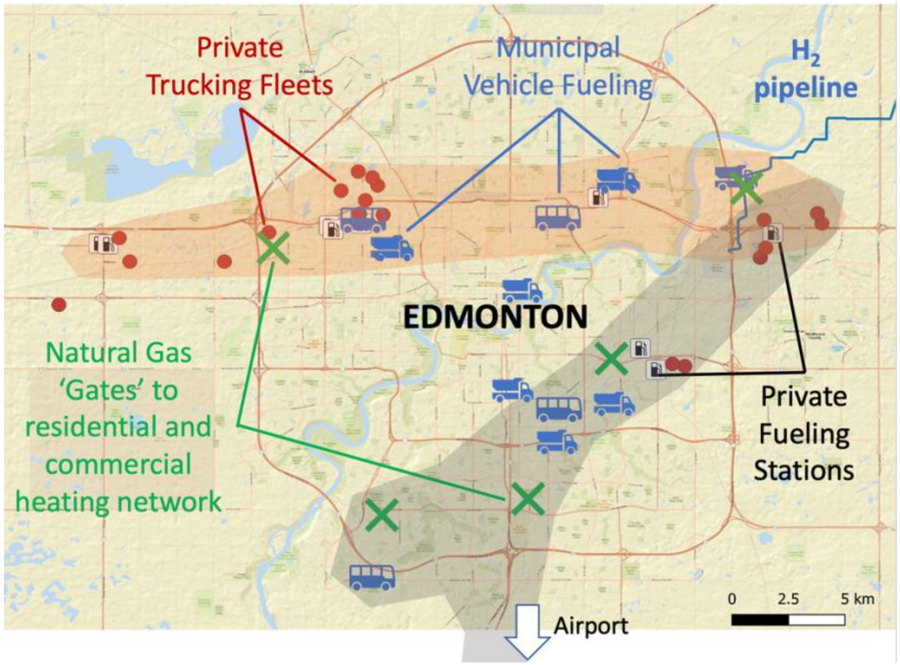


Figure A. The two corridors in Edmonton, Alberta where most of the potential future markets for hydrogen are located. Both corridors are anchored in the northeast, near locations capable of producing blue hydrogen.

Techno-economic analyses shows that strategically located pipelines carrying H_2 along these corridors could make it possible to provide fuel cell grade, compressed H_2 to sites of existing diesel markets at a price (about C\$3.50/kg H_2) that is competitive with the current retail price for diesel as long as the H_2 fueling stations are operating at a sufficient scale (2 to 10+ t H_2/d). The same pipelines could be used to bring hydrogen to gates in the natural gas distribution system serving residential and commercial buildings at a price of about C\$2/kg H_2. At that price, policy instruments such as fuel standards would be needed to achieve economic viability compared to the current energy system.

The report provides a number of recommendations for building out a new hydrogen-for-fuel energy system around nodes of low-cost production, such as that found in the Alberta Industrial Heartland. Recommendations with particular relevance to the Edmonton region include:

1. **A Roadmap is needed** that clearly embraces the scale and nature of the ambition for a hydrogen future in Alberta and Canada. It should engage all levels of government as well as industry and other stakeholders.
2. **Standards and Regulations** related to H_2 and CO_2 must be put in place soon, including what defines low carbon H_2, safety, monitoring and regulatory issues around fueling stations, H_2 use for heating and carbon capture and storage,

3. **First Nations Engagement**. Explore interest and opportunities for First Nations to get involved, and lead, in the production, transportation and use of H_2, as well as the management of CO_2, etc.
4. **Blue hydrogen Production**. Engage companies producing H_2 for use as an industrial feedstock to capture and store the carbon, thereby making 'blue' H_2 that could be used as both an industrial feedstock and a fuel.
5. **Past work on the Carbon Capture Utilization and Storage (CCUS)** potential and security in Alberta must be reviewed, updated (including new studies) and used to inform other recommendations including the roadmap and First Nations engagement.
6. **Fueling Stations for Buses, Trucks and Trains.** To provide H_2 as a transportation fuel at a competitive price (C\$3-5/kg H_2, but ideally <C\$3.50/kg H_2), strategically located fueling stations must deliver 2 to 10 tH_2/d, and be able to serve both hydrogen fuel cell electric (HFCE) vehicles and H_2-diesel dual-fuel vehicles. Smaller, temporary stations will be needed to support pilots and demonstration projects.
7. **Hydrogen Vehicle Deployments** must use pilots or demonstration projects to explore 'fit for service' potential of H_2-using vehicles under real world conditions in Alberta and across Canada. Insights must be made public, including a transparent discussion of pros and cons, to assess the viability of H_2 vehicles for specific end-uses. When evidence of 'fit for service' has been achieved, public support will be needed to deploy dozens to hundreds of HFCE and/or H_2-diesel vehicles (including buses, trucks, trains) in partnership with municipalities or companies, all relying on one or two fueling stations.
8. **Decarbonizing Natural Gas for Heat and Power.** In Alberta, natural gas is a low-cost fuel (\$1 to \$5/GJ_{hhv}) that has widespread use in industry (cement, fertilizer, oil sands, power generation, etc.) and space/water heating for residential and commercial buildings. In a net-zero energy system, hydrogen is a credible alternative, but is significantly more expensive (\$10-\$14/GJ_{hhv} H_2 or \$1.40 to \$2/kg H_2). The successful transition to hydrogen as a zero-emission heating fuel will require society to accept either a higher cost for heating fuels (offset, in part, by thermal efficiency improvements) or for new technology innovation to decrease the cost of H_2 production.

   H_2 can be mixed with natural gas at up to 15% by volume in pipelines serving residential and commercial buildings with minimal impact on infrastructure or fuel cost. An ATCO pilot will soon add 5% H_2 into natural gas pipelines serving residential and commercial buildings in Fort Saskatchewan. If all goes well, the pilot could be extended to the City of Edmonton and involve higher proportional volumes (**Figure A**). Research is also needed to explore the use of 100% H_2 to support the heat requirements of building and industry as well as power generation. Partnerships with makers of furnaces, water heaters, cook stoves, reciprocal engines and gas turbines as well as international collaborations (e.g. Hy4Heat.info initiative in the UK) will be essential.

9. **Moving Hydrogen from Supply to Demand.** Connecting H_2 supply to demand is one of the greatest challenges associated with building-out a new hydrogen energy system. The major benefit of the Edmonton / Industrial Heartland node is the pre-existing ability to produce a large amount of low-cost, blue hydrogen adjacent to corridors having the potential for substantial demand for the gas as a transportation or heating fuel. With sufficient demand in the corridor, pipeline infrastructure can be justified, and the new energy system will become economically viable in the absence of ongoing public investment.

   Alternatives to H_2 pipelines include the trucking of compressed H_2 (<0.8 t H_2/vehicle) or cryogenic liquid hydrogen (LH_2, <4 t H_2/vehicle) from the site of supply to sites of demand. The preparation and transport costs add C$2-4 per kg H_2, making it impossible to meet the target prices for H_2 as either a transportation or heating fuel without ongoing public investment. In the case of cryogenic H_2, the electricity used to liquify hydrogen would require low emission power that could drive the H_2 cost even higher.

   For the Edmonton/Industrial heartland region, we recommend a focus on rapidly building supply-demand value chains to justify investments in pipelines that connect multiple demand centres along strategically planned corridors. Specific recommendations include:

   - The potential to repurpose abandoned/decommissioned pipelines to minimize costs until demand increases enough to justify a new and larger pipeline;
   - Strategically placed pipelines in industrial corridors to serve multiple sectors (transport, natural gas decarbonization, new thermal industries or power generation);
   - Consider whether the cost for new hydrogen pipelines should be shared by ratepayers covering the cost of the natural gas pipeline infrastructure in the province;
   - Explore the potential for pipeline-connected salt caverns for H_2 storage

10. **International Engagement.** Alberta and Canada should explore new markets for hydrogen exports, and engage companies from around the world that are designing, building, testing and selling hydrogen sensors, fuel cells, vehicles, gas-turbines, compressors, furnaces, etc. A vibrant hydrogen node in the Edmonton/Industrial Heartland region has the potential to attract the international investment and jobs that the region needs in the transition to a net zero emission energy future.

Box A. The Intended Audience for this Report

This is a technical report. Its objective is to inform and motivate a broad suite of actors that have key roles in accelerating the implementation of the hydrogen-as-fuel economy in Canada. They include:

- Policy Makers: This report, and earlier reports in this series published by the Transition Accelerator are intended to inform and encourage policy makers, but not usurp their role in developing and implementing economic and environmental policy that is critical to the attainment of a self-sustaining hydrogen economy in Canada.
- Academics and Students: This report and those preceding it, present technoeconomic analyses and a detailed approach to speed the implementation of a hydrogen economy. The Transition Accelerator feels academia can play a much larger role in making practical, tangible progress to help society attain societal objectives, in addition to the traditional roles of analyses, research and technology development. Society has invested massively in technology innovation, yet comparatively, there has been extremely limited societal investment and focus on innovating commercial deployment of existing technologies so society can benefit from R&D. To this end, the Accelerator has launched a Fellow Program to attract like-minded professionals, including academics, to grow capacity and focus combined efforts on innovating new energy systems and commercial deployment of existing technologies.
- Environmental Groups: This report presents very practical steps to help realize the environmental and economic benefits of hydrogen, especially as a step in a transition pathway to a net-zero emissions society. The Transition Accelerator is convinced that the production and use of both blue and green hydrogen are critical in a transition pathway to net-zero and would like to engage environmental groups in this discussion.
- Industry: Attaining an economically self-sustaining hydrogen economy is a complicated endeavour, requiring new public and private sector roles and outcomes along a full, new hydrogen value chain. Industry is essential in this venture. The Transition Accelerator is eager to work with a ‘coalition of the willing’, typically led by industries who wish to start on the journey along a transition pathway to a net-zero energy future fueled, in part by hydrogen.

1. Introduction

Canada and 72 other nations have committed to achieve net-zero greenhouse gas (GHG) emissions by 2050 [8]. The end use combustion of carbon-based energy carriers (gasoline, diesel, jet fuel, natural gas) is the largest source of GHGs followed closely by the emissions associated with making those fuels (**Figure 1.1**A [9]). Clearly, the transition to net-zero emission energy systems needs to involve changing the energy carriers that are used to meet societal needs. Electricity, made from very low, or zero-emission sources is seen by most as a key part of the solution.

However, there is widespread consensus that a net-zero emission energy future cannot be met by (zero-emission) electricity alone [10]–[12]. Chemical-based fuels are required for sectors such as heavy transport, many thermo-chemical industries, space heating in cold climates and for the long-term storage of electricity. Biofuels can help but their capacity is limited, especially if biological systems are to provide negative emission technologies (i.e. increase the carbon stocks in forests and agricultural soils), while providing even more food and fibre to support the world's growing population and expanding economies.

As a result, nations around the world (e.g. Australia [13], Germany [14], UK [15], USA [16], S Korea [17], and China [18]) are developing strategies and starting to build out a new energy system based on hydrogen and electricity made from very low or zero-emission sources. Hydrogen (H2) is a carbon-free gas that releases energy when combined with oxygen from the atmosphere. If hydrogen and oxygen are combined through combustion, heat is generated, but if combined in a fuel cell, half or more of the energy is delivered as electricity and the balance as heat.

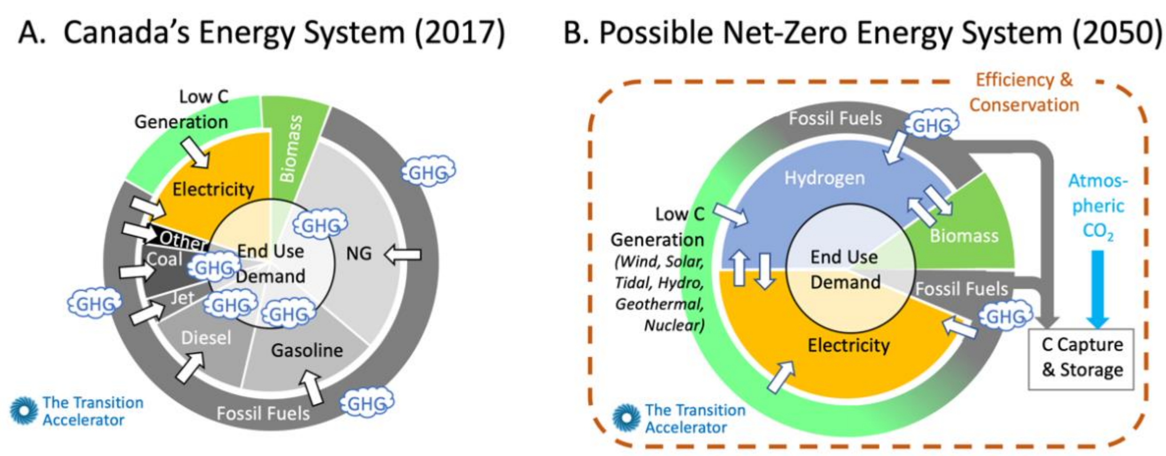


Figure 1.1. Comparison of Canada's Energy System and Possible Net-Zero Energy System.
Comparison of Canada's energy system in 2017 (A), and a possible net-zero emission energy system in the future (B). Note that the net-zero energy system replaces the fossil fuel-based energy carriers (gasoline, diesel, jet fuel, natural gas) with electricity, hydrogen or biomass-based energy carriers. GHG, greenhouse gas. Panel A from NRCan Comprehensive Energy Database [9].

Figure 1.1-B provides an example of a possible net-zero energy system for Canada in 2050. It envisages an expanded role for electricity and biomass as energy carriers in the future, as well as a major role for hydrogen that is produced with zero or very low GHG emissions.

In September 2020, we published a report called "Towards Net-Zero Energy Systems In Canada: A Key Role For Hydrogen" [5]. It took a pan-Canadian perspective to assess the potential for hydrogen to be part of Canada's transition to a net-zero emission energy system needed to limit global climate change this century to 1.5 or 2 degrees Celsius. Insights from the report include:

- ❑ Canada is internationally recognized as a low-cost producer of hydrogen [19] from either electrolysis with low carbon electricity (green hydrogen) or from fossil fuels (especially natural gas) where the byproduct CO_2 is released to the atmosphere (grey hydrogen, 9 kg CO_2/kg H_2) or coupled to carbon capture and storage (blue hydrogen, 1 kg CO_2/kg H_2);
- ❑ In Canada today, grey hydrogen production dominates, and the gas is used as an industrial feedstock for the production of fertilizer, synthetic crude oil, refined petroleum products and other chemicals;
- ❑ If blue or green hydrogen is used to support transportation, life cycle GHG emissions are reduced by 80% to 95% relative to the incumbent gasoline or diesel fuels;
- ❑ The estimated cost of blue hydrogen produced in Alberta is one half to one third the cost of green hydrogen produced in provinces that have low cost surplus hydro, wind or nuclear power, and about one half the wholesale cost of diesel fuel based on higher heat value energy content;
- ❑ Compressing, distributing and retailing hydrogen is currently more costly than for gasoline or diesel. However, if done at scale, and especially with carbon credits, zero-emission H_2 could be cost competitive with the incumbent transportation and heating fuels in Canada;
- ❑ The USA, and nations in Europe and Asia are interested in importing green or blue hydrogen, creating a potential export market for Canada that is equal in size to the domestic market. Domestic and export markets combined offer a market potential for hydrogen of $100 billion per year or more.

To realize this opportunity, it is imperative that the supply, distribution and demand systems are deployed at an appropriate scale, and in a synchronized way. While public funding may be required to establish a new energy system, once established, it is important that the system is economically viable and not dependent on continuous government subsidies.

We recommend that the transition pathway begins with "hydrogen nodes" that are built around regions with:

- The ability to make low cost byproduct, blue or green hydrogen;
- Substantial nearby markets for the hydrogen;
- The ability to connect supply to demand (ideally pipelines);
- A scale of supply/demand where the economics works without sustained public investment;
- Engaged industry, governments and academics.

The sub-regional scale of this approach (i.e. municipalities, transportation corridors, etc.) and its deployment across Canada can focus public and private investment towards the creation of small, but viable zero-emission energy systems that will coalesce over time to create the transformative change that is needed for the energy systems of Canada.

This report assesses the market potential for hydrogen in Alberta (Sections 2 and 3) and then focuses on one region of Alberta, the Industrial Heartland near Edmonton, to explore how a vibrant hydrogen economy could be built there (Sections 4 and 5). The hope is that this work will lead to an industry and government led deployment of a hydrogen node in the Alberta Industrial Heartland.

2. Domestic Market Potential for Hydrogen in Alberta

2.1 Combustion Emissions and Target Markets

In 2018, GHG emissions in Alberta were 273 Mt CO2e/yr, 75% of which (204 Mt CO2e/year) were associated with the combustion of fuels. As a result, Alberta, with 12% of the nation's population, accounted for 40% of Canada's total combustion emissions of 541 Mt CO_2e/yr [5], [20].

The largest proportion of the province's combustion emissions were associated with the production of crude oil and natural gas, most of which is exported to other jurisdictions in North America (**Figure 2.1** [20]). However, more than half of the combustion emissions are associated with the generation of electricity and the end use of transportation and heating fuels (**Figure 2.1**).

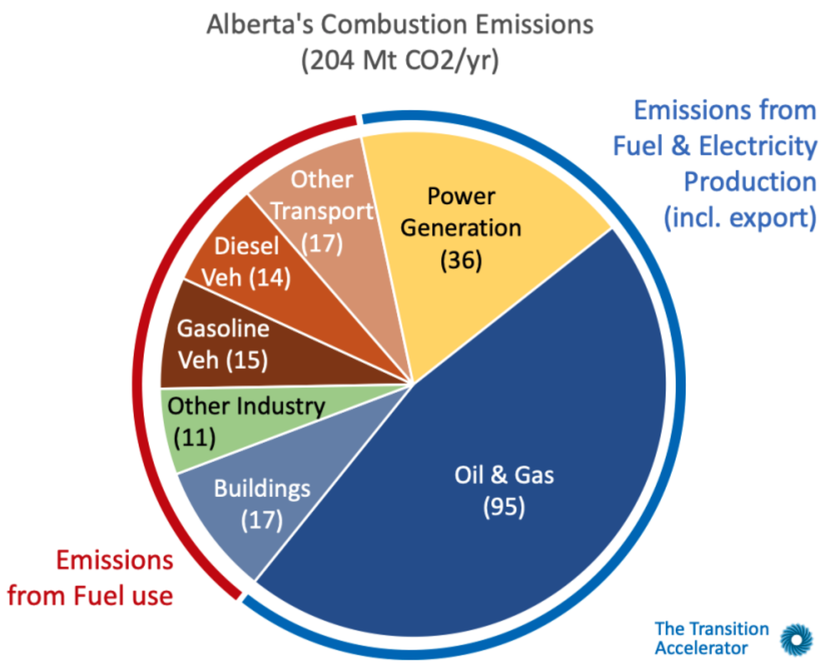


Figure 2.1. Greenhouse Gas Emissions in Alberta by IPPC Sector (2018).
Data from ECCC National Inventory Report 2020 [20].

Certainly, achieving net-zero energy systems will require the elimination of these emissions. Options under consideration include bio-fuels, small modular nuclear reactors, electrification with renewable power and blue or green hydrogen production and use. It is worth noting that at least three Alberta oil companies (CNRL [21], MEG Energy [22], and Cenovus [23]) have committed to net-zero emissions.

For reasons discussed in our previous report [5], hydrogen (especially blue, but also green and some by-product) production, use and export is likely to play a major role in Alberta's energy transition. In the following sub-sections, current markets for diesel, gasoline and natural gas are used to estimate the future market potential for hydrogen in Alberta. We have not considered growth (or shrinkage) in these markets over the next 30 years, since the purpose of this analysis is only to provide an assessment of the magnitude of the challenge and opportunity.

2.2 The Alberta Diesel Market

In 2017, the demand for diesel fuel in Alberta was 284 PJ/yr (Figure 2.2A, [5], [9], [24]). Of that total, 171 PJ/yr was sold as transportation fuels with the road freight sector being the dominant consumer in addition to the lesser amounts of diesel sold for rail and passenger transportation. Examples of non-transportation uses of diesel include agriculture, oil and gas extraction, construction, and stationary heat/power generation.

In a net-zero future that is also motivated to restrict the use of diesel internal combustion engines for air pollution and air quality concerns, the freight sector is exploring zero emission drivetrain options. This trend is supported in places like California where heavy-duty zero-emission standards are being introduced to mandate that 30% of heavy-duty vehicle sales are zero-emission by 2030 [25].

The heavy-duty road freight segment is a target market for hydrogen because of its fit for a variety of operating conditions including long distances, heavy payloads, and cold weather. While hydrogen fuel cell electric (HFCE) drivetrains are suitable for a range of duty-cycles, they may not be the preferred technology for short haul, urban, and lighter loads [3]. These market segments are likely to be plug-in battery electric. Other diesel markets (e.g. off-road vehicles) in a net-zero future are expected to be split between plug-in electric, hydrogen and some bio-based diesel alternatives.

If the shift to hydrogen were to account for 80% of the 2017 diesel market,[1] and the drivetrain efficiency ratio (Report A, Figure 2.6, [5]) is 0.86 GJ_{hhv} H_2/GJ_{hhv} diesel,[2] the hydrogen demand would be 3.8 kt H_2/day (Figure 2.2B).

[1] In a net zero future, some of the Alberta diesel market could shift to plug-in battery electric, or to biodiesel, but with the build out of a hydrogen economy, we have projected a 80% market share of 2017 level of demand. Overall growth in demand has not been included in these projections.

[2] Calculated as the ratio of diesel ICE drivetrain efficiency of 0.405 GJ kinetic energy/GJ_{hhv} diesel divided by HFCE drivetrain efficiency of 0.47 GJ kinetic energy/ GJ_{hhv} hydrogen. See reference [5] for details.

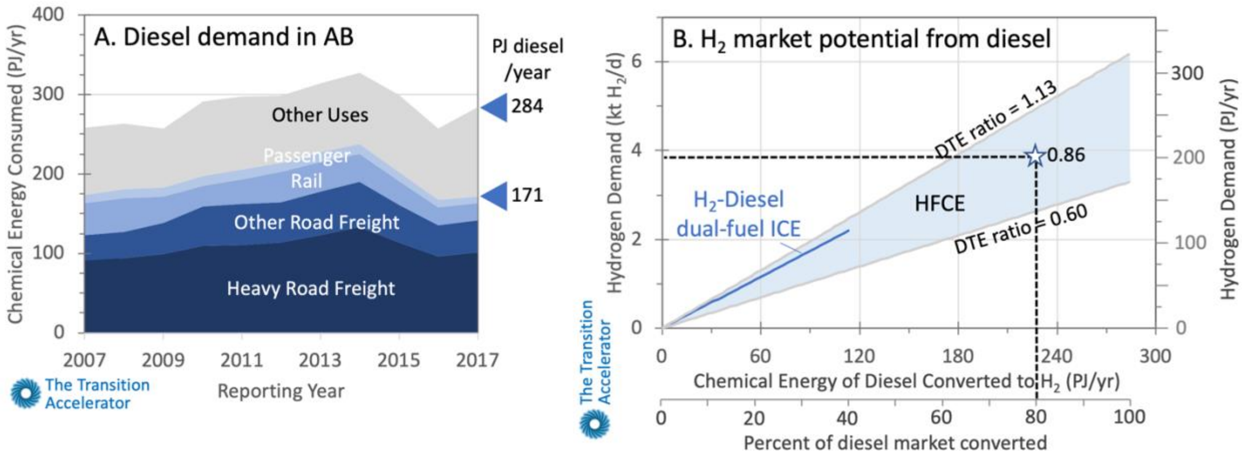


Figure 2.2. Annual Demand for Diesel in Alberta and Estimated Demand for Hydrogen
Annual demand for diesel in Alberta by end-use (A) and estimated demand for hydrogen by proportion of the diesel market converted to hydrogen (B). Figure A data sources: Statistics Canada [24] and NRCAN's Comprehensive Energy Use Database [9]. HFCE: Hydrogen fuel cell electric; ICE: Internal combustion engine; DTE ratio: Drivetrain efficiency ratio from diesel ICE to HFCE (Report, A [5] Figure 2.6).

In **Figure 2.2 B**, the blue line labelled H_2-diesel dual-fuel ICE (Internal combustion engine) accounts for the adoption of an onboard fuel blending technology at a ratio of 40% H_2 : 60% diesel. It assumes that 1 GJ H_2 in an ICE engine will take a vehicle the same distance as 1 GJ diesel [26]. If 40% of the diesel demand is converted to H_2-diesel dual-fuel ICE, the corresponding hydrogen demand is about 2 kt H_2/day in Alberta (**Figure 2.2 B**).

Because of its relatively low cost and its flexibility to operate with or without an assured hydrogen supply, these dual-fuel vehicles could be an important bridge technology to build demand at hydrogen fueling stations and for manufacture of on-board hydrogen tanks [27]. The combination of H_2-diesel and HFCE vehicles could help break the vicious cycle[3] that is a barrier to the deployment of hydrogen infrastructure which, in turn, undermines demand for HFCE vehicles and keeps prices high for both the vehicles and the hydrogen fuel [28].

As noted previously [5], to meet the retail price targets for fuel cell grade hydrogen (~C$3 to 5/kg H_2), the fueling stations must be strategically located and attract sufficient vehicles to deliver 2 to 10 tH_2/day, or more. Given that large trucks and buses typically use only 20 to 80 kg H_2/vehicle per day, up to one hundred hydrogen using vehicles or more must be on the road to support each fueling station.

[3] The 'vicious cycle' is based on the concept that there are no H_2-using vehicles because the fueling infrastructure is lacking and the infrastructure is lacking because there are no H_2 using vehicles.

2.3 The Alberta Gasoline Market

In 2017, the demand for gasoline fuel in Alberta was 234 PJ/yr (Figure 2.3A, [5], [9], [24]) with the vast majority being consumed as a transportation fuel for light and medium duty vehicles. For the majority of personally owned vehicles, direct electrification would be the most likely technology of choice in the transition to a net-zero energy future.

For intensively driven fleet vehicles such as taxis (or future shared, autonomous vehicles) hydrogen is likely to be a more suitable option, given range requirements and the need for a shorter refueling/recharge time. The home base for these fleet vehicles are also likely to be in the industrial regions of cities near where the heavy trucks and buses are fueled. Therefore, this relatively small number of vehicles with large fuel use per vehicle is the target market envisaged for hydrogen.

If the shift to hydrogen were to account for 30% of the 2017 gasoline market[4] (234 PJ/yr in 2017, **Figure 2.3A**), and the drivetrain efficiency ratio (**Report A, Figure 2.6,** [5]) is 0.56 PJ H_2/PJ diesel,[5] the hydrogen demand is 0.76 kt H_2/day (**Figure 2.3B**).

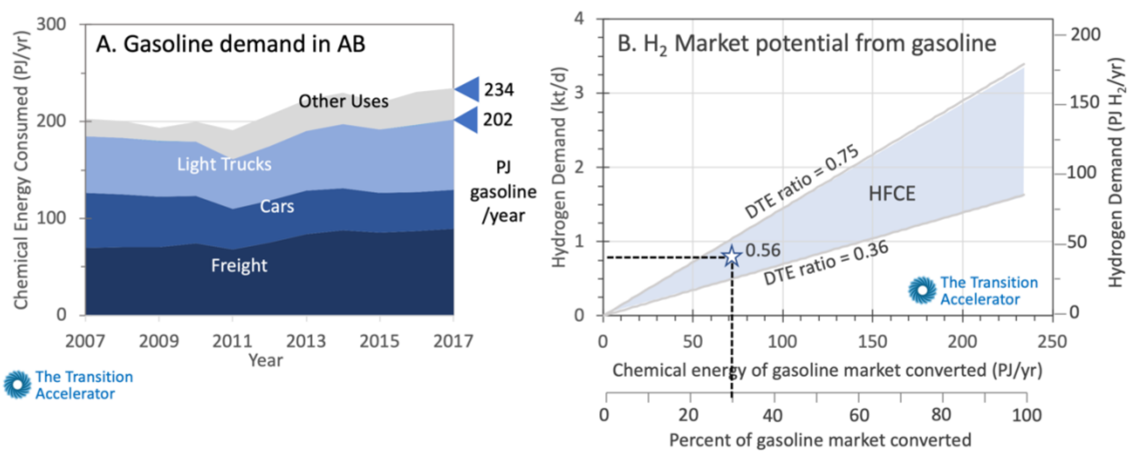


Figure 2.3. Annual Demand for Gasoline in Alberta and Estimated Demand for Hydrogen.
Annual demand for gasoline in Alberta by end-use (A) and estimated demand for hydrogen by proportion of the gasoline market converted to hydrogen(B). Figure A data sources: Statistics Canada [24] and NRCAN's Comprehensive Energy Use Database [9]. HFCE: Hydrogen fuel cell electric; ICE: Internal combustion engine; DTE ratio: Drivetrain efficiency ratio from diesel ICE to HFCE (Report A [5], Figure 2.6).

[4] In a net zero future, plug in EVs should dominate this sector. However, shared, autonomous electric vehicles would benefit from the rapid refueling and range benefits of HFCE, so a 30% market share of 2017 demand is projected.

[5] Calculated as the ratio of gasoline ICE drivetrain efficiency of 0.265 GJ kinetic energy/GJ_{hhv} diesel divided by HFCE drivetrain efficiency of 0.47 GJ kinetic energy/ GJ_{hhv} hydrogen. See reference [5] for details.

2.4 The Alberta Natural Gas Market

Alberta has a large domestic market for natural gas (NG) of 2,257 PJ NG/yr in 2018 (Figure 2.4, [29]). This demand accounts for about 35% of the total NG production in Canada (6,335 PJ NG/yr, Report A, Figure 4.2 [5]). Domestic NG consumption is split into the following markets:

- 45% oil and gas industry
- 23% power generation
- 15% for building heat
- 13% industrial applications
- 4% pipeline transportation

Of the 2,257 PJ NG/yr consumed in Alberta, approximately 386 PJ NG/yr is already used to produce hydrogen. This hydrogen is used as a feedstock in oil refining/upgrading and for fertilizer and chemical production (discussed in **Section 3**).

Since hydrogen is made from natural gas in Alberta, it is not surprising that, per GJ, the cost of hydrogen is greater than the wholesale cost of natural gas (typically \$10/GJ_{hhv} H_2 vs. \$2/GJ_{hhv} NG, respectively; **Report A, Figure 2.1** [5]).

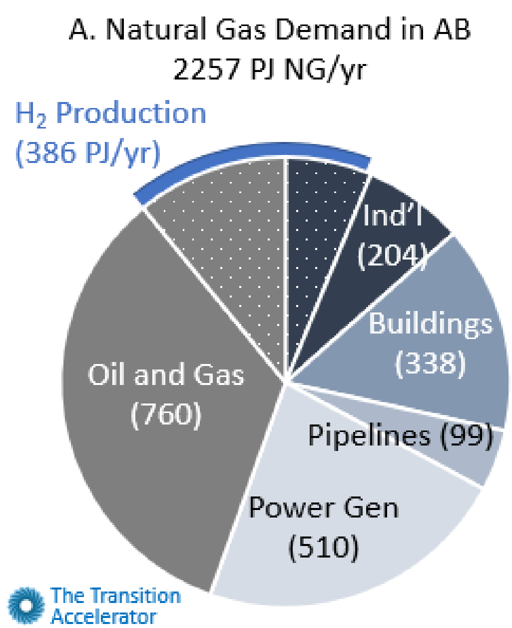


Figure 2.4. Annual Demand for Natural Gas in Alberta
Annual demand (2018) for natural gas in Alberta by end-use demand (A). Source: AER ST 98 Statistical Report [29].

Given a natural gas carbon intensity of 50 kg CO_2/GJ_{hhv} NG [20], the \$8/GJ_{hhv} differential price in the two energy carriers would be equivalent to a carbon price of \$160/tCO_2 (8/50 x 1000) assuming both energy carriers are simply being combusted for heat. While current and projected carbon prices of \$30-\$50/t CO_2 [30] are not sufficient to justify this investment, new clean fuel standards for both liquid, gaseous and solid fuels requiring reductions in the life cycle GHG intensity may provide the necessary economic driver [31]. Also, carbon prices are expected to rise over the next 20-30 years.

Hydrogen is an attractive zero-emission option for a significant portion of current natural gas demand including heavy industries, energy for pipeline transportation, and buildings needing space and water heating. While air source heat pumps hold significant promise for building heating in more temperate regions of Canada, it is difficult to see a major role for them in Alberta because the cold climate is unsuitable for current generation heat pumps. Assuming that 80% of these market segments shift to hydrogen, the potential demand for hydrogen would be 9081 tH_2/day (**Table 2.1, Items 2,3,4**).

Natural gas also plays an important role in power generation for today's electrical grid. While there is limited ability to fuel existing gas turbines with hydrogen, new gas turbines have been designed to use 100% natural gas, 100% hydrogen or anything in between [32], thereby making it possible to produce electricity with a wide range of carbon intensities.

Perhaps the most significant role for hydrogen in power generation is its potential role in working with low cost, intermittent renewables (e.g. wind and solar) to produce both grid power and hydrogen for transportation. This may allow utilities to build out low cost wind and solar farms without concerns about curtailment, since when power production exceeds grid demand, the electricity can be diverted to green hydrogen production and the gas put into the same pipelines carrying blue hydrogen. When the wind is not blowing, or the sun is not shining, blue or green hydrogen from this pipeline infrastructure could be used to supply the grid with low or zero carbon electricity.

Recent studies [12] have identified hydrogen storage in pipeline infrastructure or salt caverns as holding promise for long term or seasonal storage where peak renewable generation does not coincide with the timing for peak electricity demand. In the net-zero emission energy system for Alberta simulated in **Table 2.1 (Line 5)**, hydrogen energy for power generation has been set as equivalent to 50% of the current natural gas demand.

Low carbon hydrogen could also be used for oil sands recovery, including steam generation for *in situ* operations or for fueling heavy haulers in mining operations. For this scenario, we assumed a 50% market share (**Table 2.1, Line 6**), especially considering advances in hydrogen fueled gas turbines discussed above. The existing grey hydrogen production associated with making synthetic crude oil from oil sands bitumen, or with making refined petroleum products (**Table 2.1, Line 7**), or other chemicals and fertilizers (**Table 2.1, Line 1**) is all assumed to be retrofitted to low-carbon blue hydrogen in a net-zero energy future. See **Box 2.1** for additional details on the technologies for blue hydrogen production.

In total, potential domestic markets for low carbon hydrogen production in Alberta include about 5.4 kt H_2/day to meet existing hydrogen demands and an additional 21.4 kt H_2/day to meet additional future fuel hydrogen demands (**Table 2.1 Item 8**).

Table 2.1. Estimate of demand for hydrogen in Alberta by proportion of the natural gas market converted to hydrogen.

		A	B	C	D	E	F	G
	Sector	**Natural Gas Use (2018)**	**Market Share to H2 (a)**	**Conversion Factor (b)**	**New H2 Economy**			
					Gray to Blue H2 (c)	New H2 Market (c)	Gray H2 to Blue H2 (d)	New H2 Market (d)
		PJ NG/yr	%	PJ H2/PJ NG	PJ H2/yr		t H2/day	
1	Industry - SMR	140	100%	0.72	101	-	1,953	-
2	Industry - other	164	80%	1.0	-	131	-	2,532
3	Buildings	338	80%	1.0	-	270	-	5,228
4	Pipeline Transport	99	80%	0.86	-	68	-	1,321
5	Power Gen	510	50%	1.0	-	255	-	4,930
6	Oil&Gas - other	760	50%	1.0	-	380	-	7,347
7	Oil&Gas - SMR	246	100%	0.72	177	-	3,425	-
8	AB Domestic Mkt	2,257	-	6.3	278	1,105	5,378	21,358

Footnotes

(a) Given forces to move to net zero emissions, we assumed a conversion to Hydrogen use as a fuel for all existing natural gas demand except the building sector (20% to electrification), other oil and gas (20% to electrification, 30% to Renewable natural gas), power generation (50% remaining on natural gas), other industry (20% to electrification). For pipeline transport (20% remaining on natural gas).

(b) Amount of hydrogen produced per energy unit of natural gas. Ratios from CESAR's Future of Freight Part D report.

(c) Calculated as NG Gas Use X Market share to Hydrogen X Conversion Factor

(d) Calculated as H_2 Energy divided by a higher heating value of 141.7 PJ/Mt H_2 times 1000 kt/Mt divided by 365 days/yr

Box 2.1. Turning Grey Hydrogen Blue

Steam Methane Reforming (SMR) is the most common industrial process used to make hydrogen in Canada, and it typically leads to greenhouse gas emissions of about 9 kg CO2 per kg 'grey' H2 produced. SMR facilities can be built (or modified) to include carbon capture coupled to utilization or storage (CCUS) focused on either the process stream (Figure 2.5A – block a) or on the flue gas stream (Figure 2.5A – block b), resulting in emission intensities for H2 production of about 4 kg CO2/kg H2 or 1 kg CO2/kg H2, respectively.

In this and a previous Transition Accelerator report [5], blue hydrogen is considered to have an emission intensity of 1 kg CO2/kg H2 or lower, so flue gas capture (Figure 2.5A – block b) is assumed. Therefore, if a 400 t H2/d SMR plant is built to capture process emissions, thereby reducing emissions intensity from 9 to 4 kg CO2/kgH2, such as plant could be considered to be producing 250 t blue H2/d (i.e. 62.5%) and 150 t grey H2/d.

Using IEA data, we previously estimated [5] that the incremental cost for CCUS in a 'greenfield' site adds $0.65/kg H2 or $80/t CO2. Other techno-economic studies [33] focused on the process stream (Figure 2.5A – block a) have estimated a cost of about $50/t CO2. Retro-fitting existing SMRs with carbon capture can also be done (e.g. Shell Quest [34]), and the costs are likely to be higher, but will vary widely depending on the facility. An alternative to SMR-CCUS is autothermal reforming (ATR-CCUS, Figure 2.5B), where most of the reaction heat is supplied inside the process and avoids costly CO2 capture from flue gas. ATR has been studied for several projects (e.g. Acorn [35], H21 North of England [36]) where 90-95% of CO2 can be captured (<1 kg CO2/kg H2). No ATRs currently exist in Canada for hydrogen production, but greenfield ATRs would allow build-out of new hydrogen production with the highest CO2 capture.

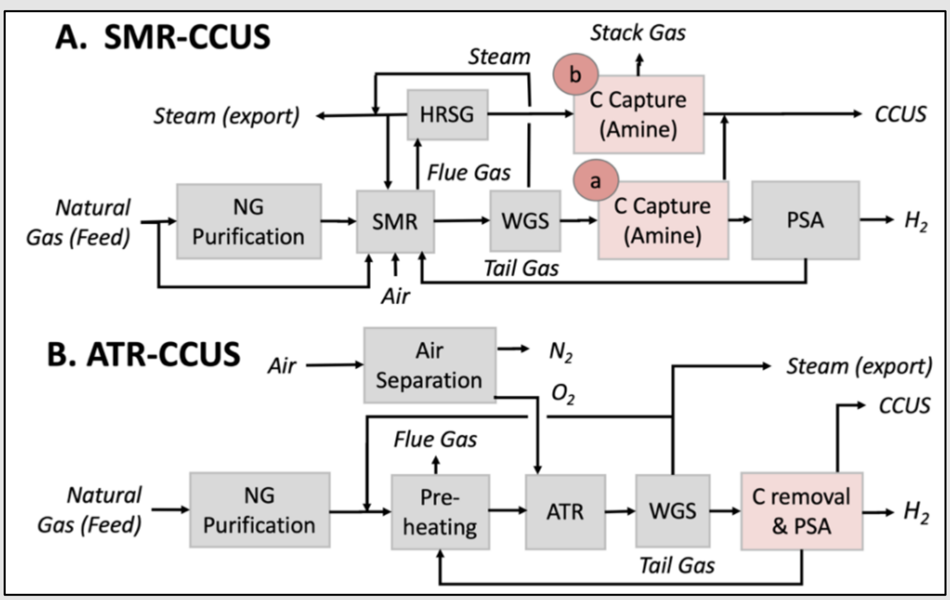


Figure 2.5. H2 Generation by Steam Methane Reforming and H2 Generation via Autothermal Reforming.
A. Hydrogen generation by steam methane reforming (SMR), with CO_2 capture and utilization or storage (CCS) of either the process (a) or flue gas stream (b). B. Hydrogen generation via autothermal reforming (ATR) with CO_2 capture and utilization or storage (CCUS). HRSG, Heat recovery steam generator; PSA, Pressure Swing Adsorption; WGS, Water-gas shift reactor.

2.5 Summary and Implications for the Domestic Market Potential for Hydrogen in Alberta

Summing the hydrogen market estimates generated from diesel (**Figure 2.2 B**) and gasoline **(Figure 2.3 B**) end-uses and existing natural gas markets (**Table 2.1)** led to a hydrogen demand size estimate of 31.3 kt H_2 per day (**Table 2.2**). That is equivalent to almost 50% of the estimated Canada-wide market for the low carbon hydrogen estimate in the previous study (**Report A** [5]**, Figure 4.1C**).

If all hydrogen were produced as blue hydrogen from natural gas coupled to CCUS, the annual CCUS capacity requirement would be about 101 Mt CO_2 /yr. (**Table 2.3, Column A**). This is about 6 times more than the 16.8 Mt CO_2/yr capacity that already exists at Shell Quest and Alberta Carbon Truck Line projects (**Table 3.1**).

Also, the demand for natural gas would not only be maintained but would increase from 2,257 PJ NG/year (**Figure 2.4**) to about 2,782 PJ NG/yr (**Table 2.3, Column D**).

Of course, this simple analysis does not take into consideration that the displacement of diesel and gasoline fuel with H_2-diesel dual fuel, plug in electric or hydrogen fuel cell electric vehicles would reduce demand for conventional transportation fuels, and presumably for the associated production of crude oil. While Alberta's demand for these fuels could be exported to other jurisdictions, it seems likely that a shift to a hydrogen economy in Alberta would be associated with a similar shift to a hydrogen economy in other parts of Canada, the USA and in other economies with which Canada trades.

Also, not all the hydrogen being produced in the province will necessarily come from natural gas. Some could be produced through electrolysis using electricity from wind power, or from the province's oil sands resources coupled to carbon capture and storage (e.g. Northwest Redwater Refinery [37]). A deeper analysis of possible energy futures for the province would be useful, but this would require more time and resources and be done in consultation with input from industry and government.

The previous report [5] did consider the potential for large new export markets for blue or green hydrogen, to the rest of Canada, the USA and to Asia. When these new markets are considered along with market share losses that fuel hydrogen may have on the oil sector's role in providing traditional transportation fuels, the estimates for total market demand laid out in **Tables 2.2** and **2.3** could be considered 'conservative'.

Table 2.2. Summary of potential hydrogen demand in Alberta.

			A	B	C
Potential Markets for Blue H_2 made in Alberta			**Potential Domestic Market Demand for H_2 in Alberta**		
			PJ H2/yr	**kt H2/yr**	**t H2/day**
Converting Existing Gray Hydrogen to Blue Hydrogen					
1	Existing Ind'l Feedstock Mkt (a)		278	1,963	5,378
New Hydrogen Fuel Markets					
2	From Diesel market (b)		195	1,377	3,773
3	From Gasoline market (c)		39	278	760
4	From Natural Gas market (d)				
5		Industry	131	924	2,532
6		Buildings	270	1,908	5,228
7		Pipeline Transport	68	1,321	1,321
8		Power Generation	255	4,930	4,930
9		Oil and Gas	380	7,347	7,347
10	Total New Hydrogen Fuel Mkt		1,339	9,451	25,891
Market Potential for Hydrogen Demand in Alberta					
11	**Total**		**1,617**	**11,414**	**31,269**

Footnotes
(a) From Table 2.1, Item 8, Column D and F (Gray H2 to Blue H2)
(b) From Figure 2.2B, assuming 80% of the Alberta 2017 diesel market converts to Hydrogen
(c) From Figure 2.3B, assuming 30% of the Alberta 2017 gasoline market converts to Hydrogen
(d) From Table 2.1, Item 2 to 6, Column E and G

Table 2.3. Summary of carbon capture & storage (CCS) and natural gas demand in a hydrogen economy

		A	B	C	D
Potential Markets for Blue H_2 made in Alberta		CCS Capacity Needed if Blue H_2 (a)	Natural Gas Demand		
			For H_2 Production (b)	Conventional uses (c)	Total
		Mt CO_2/yr	PJ NG/yr		
Converting Existing Grey Hydrogen to Blue Hydrogen					
1	Existing Ind'l Feedstock Mkt	17.5	386	-	386
New Hydrogen Fuel Markets					
2	From Diesel market	12.2	271	-	271
3	From Gasoline market	2.5	55	-	55
4	From Natural Gas market				
5	Industry	8.2	182	33	215
6	Buildings	17.0	376	0	376
7	Pipeline Transport	4.3	95	20	115
8	Power Generation	16.0	354	255	609
9	Oil and Gas	23.8	528	228	756
10	Total New Hydrogen Fuel Mkt	84	1,860	536	2,396
Market Potential for Hydrogen Demand in Alberta					
11	**Total**	**101**	**2,246**	**536**	**2,782**

Footnotes
(a) Calculated from Table 2.2 Column A X 9.88 t CO2/t H2 X 90% capture
(b) Calculated using same logic as Table 2.1.
(c) Calculated from Table 2.2 Column C ÷ efficiency of Steam methane reforming (0.72)

3. The Current Hydrogen Economy in Alberta & the Heartland

As previously noted, Alberta already produces about 5.4 kt H_2/day (ca. 2 Mt H_2/year), most of which is 'grey' hydrogen (**Figure 3.1A** [38]–[40]), resulting in GHG emissions of about 18 Mt CO_2e/year.

The Alberta Industrial Heartland (AIH) accounts for about 40% of Alberta's total hydrogen production (**Figure 3.1B**). About two thirds of this hydrogen is produced on site as an industrial feedstock for upgrading and refining of bitumen/crude oil, or for fertilizer and chemical production. The last third is produced as merchant hydrogen and sold as an industrial feedstock, typically using a dedicated pipeline for the purpose. Air Products [41] is the region's primary merchant hydrogen producer.

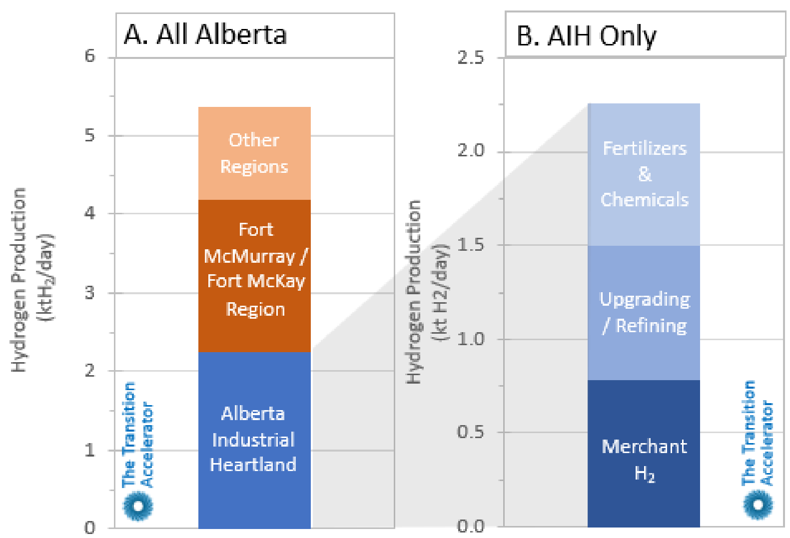


Figure 3.1. Current hydrogen production in Alberta by region (A) and by market (B) for 2017.
Sources include CERI [38], AER [40], NRCAN [39], and industry input.

Given the present hydrogen demand in the AIH, production and distribution infrastructure has been established and some of the relevant companies and infrastructure are shown in **Figure 3.2**. The companies are situated in proximity to each other and close to existing hydrogen and CO_2 pipeline assets (**Figure 3.2**). **Table 3.1** [34] provides summary details about the key pipeline infrastructure, including the hydrogen pipeline and two CO_2 pipelines with a total potential of about 18 Mt CO_2/ per year. The region is underlain by geological formations with large sequestration potential at the right depth for permanent storage. **Table 3.1** shows the total sequestration potential of those geological formations approved for those projects, where more sequestration can be added with new phases of development.

Note also that three hydrogen production facilities in the AIH are already producing 'blue' hydrogen & putting CO_2 into pipelines for sequestration. These facilities are at the Shell refinery in Scotford, the Northwest Refinery and the Nutrien fertilizer plant (**Table 3.1**). The Shell refinery uses a proprietary (ADIP-X) CO_2 capture targeting the process CO_2 stream (see **Box 2.1**) on SMRs to generate ~666 t H_2/day [34], of which 416 t H_2/day is considered by us to be 'blue' since they are only capturing process CO_2 (see **Box 2.1**). In addition, 56 t H_2/day of blue hydrogen is generated at the NWR facility using the Rectisol process from Lurgi, and Nutrien produces about 465 t H_2/day of blue hydrogen by dehydrating process CO_2 [42]. Assuming the GHG intensity of H_2 production at the NWR and Nutrien facilities is about 1 kg CO_2/kg H_2, current blue hydrogen production in the Alberta Industrial Heartland is about 937 t H_2/day.

Not shown on **Figure 3.2** is the fact that the geology of the region contains salt deposits into which caverns could be created for the large-scale storage of hydrogen [43]. This blue hydrogen production, storage and distribution infrastructure is embedded in a community of over 1 million residents, including individuals in the Cities of Edmonton and Fort Saskatchewan, and the three adjacent counties (Strathcona, Lamont and Sturgeon).

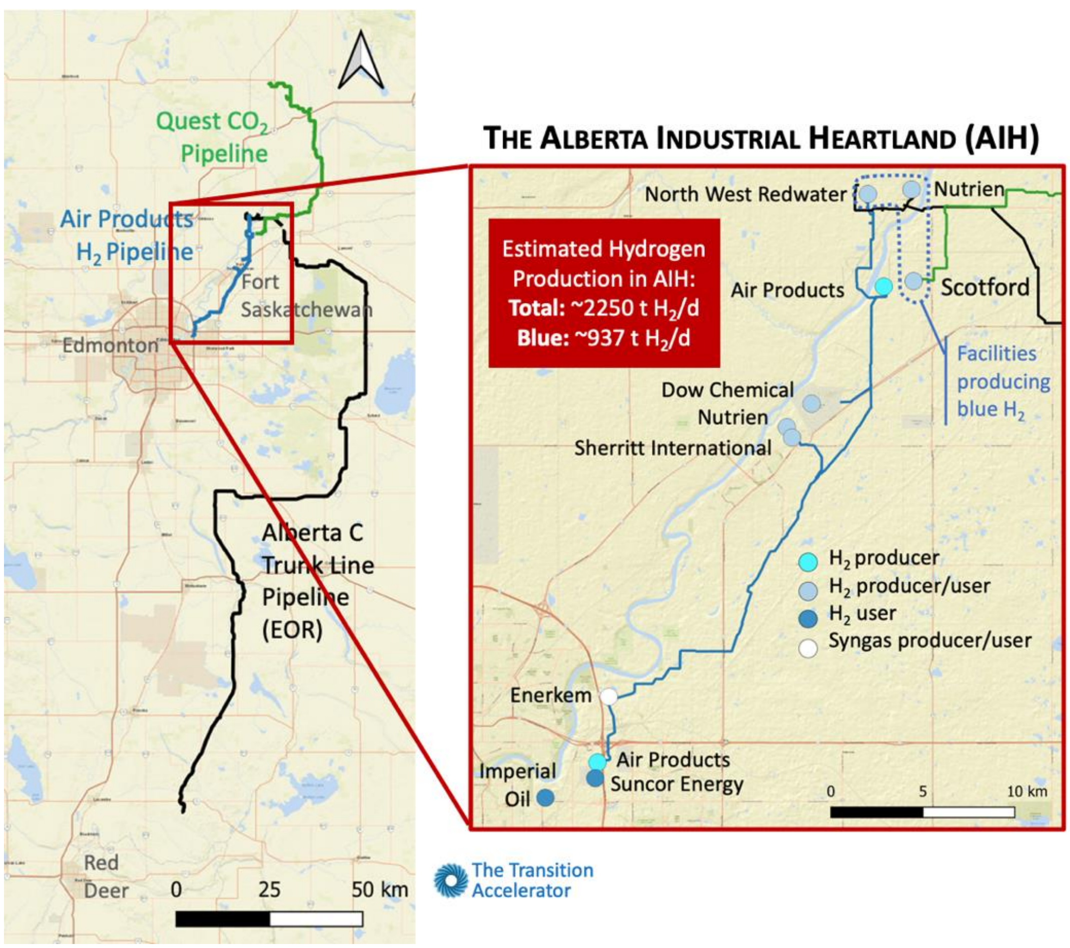


Figure 3.2. Map of Hydrogen and CCS Infrastructure in the Alberta Industrial Heartland.

Table 3.1. Characteristics of existing hydrogen and carbon pipeline infrastructure.

	Hydrogen Pipeline	Quest Pipeline	Alberta Carbon Trunk Line
Pipeline capacity	~2300 t H_2/day (=1 billion scfd)	Current use: 1.2 Mt CO_2/yr; Capacity: 2.2 Mt CO_2/yr	Current use: 1.6 Mt CO_2/yr Capacity: 14.6 Mt CO_2/yr
Pipeline length	48 km	64 km	240 km
Pipeline diameter	12 to 16 inch	12 inch	12 to 16 inch
Operating pressure	68 bar (maximum)	85 to 140 bar	89 to 179 bar
Source	Two Air products SMR	SMR at Scotford Upgrader	NWR Refinery hydrogen plant; Nutrien fertilizer plant
Destination	Scotford Refinery, Sherritt, Williams Energy (Suncor)	Saline aquifer	Clive EOR field
Total Storage Capacity	-	27 Mt CO_2	3.8 Mt CO_2

Note: SMR: Steam Methane Reformer; EOR: Enhanced Oil Recovery; NWR: Northwest Redwater Partnership; Information from Open Alberta Government sources [34] and input from industry. EOR, enhanced oil recovery; scfd, standard cubic feet per day; SMR, steam methane reformer.

Clearly, the Alberta Industrial Heartland (AIH) has most, if not all the features needed to justify creating a hydrogen node noted in the Introduction of this report:

- The ability to make low cost byproduct, blue or green hydrogen;
- Substantial nearby markets for the hydrogen;
- The ability to connect supply to demand (ideally pipelines);
- A scale of supply/demand where the economics works without sustained public investment;
- Engaged industry, governments and academics

The remaining sections of this report focus on defining what a transition pathway to a vibrant hydrogen economy might look like for the Alberta Industrial Heartland.

4. Towards a Hydrogen Economy in the Alberta Industrial Heartland

4.1 Proposed Strategy

A diagrammatic representation of the proposed strategy for developing a hydrogen economy in the Alberta Industrial Heartland is provided in **Figure 4.1.** A summary of the features of a new hydrogen economy that we envisage for the AIH, include:

- Anchored by large (ideally 300+ t H_2/day) blue hydrogen facilities where the wholesale cost of hydrogen production (including 90+% of the carbon captured and sequestered) can be kept below $1.50/kg H_2.
- A network of pipelines strategically located so it can carry both blue, green or biproduct hydrogen to truck or train fueling stations or to 'gates' connecting natural gas high pressure pipelines to pipeline distribution systems supporting residential and commercial buildings, etc. (**Figure 4.1**). This pipeline network could also serve sites for natural gas fired power generation and support decarbonization of the electrical grid. Consideration is needed as to how the costs of this pipeline infrastructure should be paid, including its relationship to the natural gas infrastructure.
- Economically viable fueling stations that deliver at least 2 t H_2/day at a retail price (includes purification, compression and retail) of about $3.50/kg. At this price, the hydrogen should be at a lower cost than diesel per unit of energy content (**Figure 4.1**).
- As an alternative for most natural gas markets, hydrogen would not require purification or high levels of compression. Also, it would be delivered in higher volumes than for a vehicle fueling station. These are important attributes since natural gas markets tend to be more price sensitive than transportation markets. However, even at a price of <$2/kg H_2 ($14/GJ_{hhv} H_2), policy instruments requiring decarbonization of lower-cost natural gas (typically $1-$4/GJ_{hhv} in Alberta) would be required for economic viability.
- Primary efforts to build substantial markets for vehicle fueling and natural gas decarbonization should consider the proximity to, and cost of pipeline connectivity. However, to create transportation corridors over longer distances where immediate investments in pipeline infrastructure cannot be justified, the hydrogen could be converted into a cryogenic liquid (LH_2 at -252C) and moved by truck. The liquefaction process adds about $3+/kg H_2 to the cost of the fuel and therefore needs to be subsidized (**Figure 4.1**). Such investments must be carefully considered and time-limited since without ongoing subsidies, they are not economically viable.

In **Section 3**, we noted that the AIH already has large hydrogen production facilities, has existing H_2 and CO_2 pipeline infrastructure, and has experience with CCUS. In this section, we review the potential demand centers for hydrogen in transportation and natural gas market (building and industrial heat) applications.

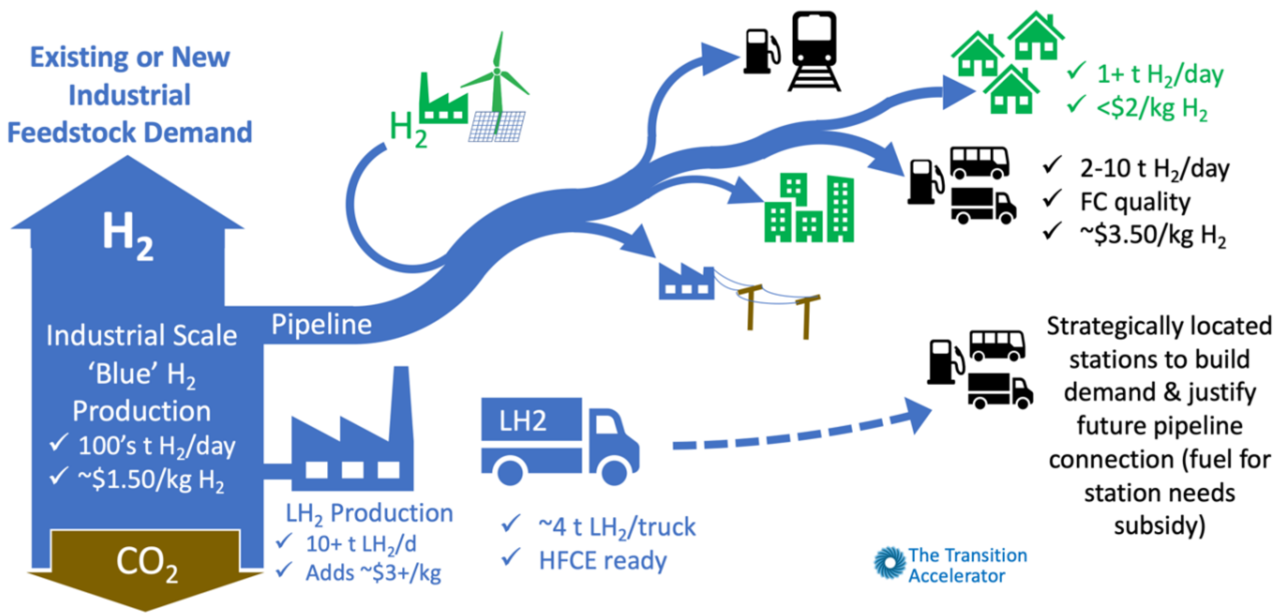


Figure 4.1. Building a Fuel H2 Market as a Branch off Blue H2 Production Used as Industrial Feedstock.
Proposed strategy for building a fuel hydrogen market by branching off from blue hydrogen production used as an industrial feedstock. Note the differences in scale requirements and price targets across the system.

4.2 Estimated Fuel Demand for Transportation in Edmonton

By prorating road and rail consumption of diesel and gasoline for Alberta (**Figures 2.2** and **2.3**) by the population of Edmonton, the current demand for these fuels is estimated to be about 86 PJ/yr (**Figure 4.2**).

Of the 786 thousand vehicles registered in the Edmonton region, a large percentage are light-duty gasoline vehicles. However, for reasons described in **Box 4.1**, heavy-duty diesel-fueled freight vehicles are most likely to adopt hydrogen as the net-zero alternative.

If 80% of the diesel transportation market and 30% of the gasoline market are converted to hydrogen, the potential hydrogen demand in Edmonton would be about 245 kt H_2/yr or 672 tH_2/day (**Table 4.1**).

Heavy-duty hydrogen fuel cell trucks have fuel tanks that hold between 30-100 kg H_2/truck [28] and buses with 30-40 kg H_2/bus [44]. Assuming vehicle H_2 demand of 25-90 kg H_2/day for trucks and 20-30 kg H_2/day for buses, 35 to 80 vehicles refueling every day can provide sufficient demand to draw 2 t H_2/day from a single fueling station. This is approximately the minimum scale of demand needed for a fueling station to be economically viable for blue hydrogen delivery in Alberta at a price that is cost-competitive with diesel, without ongoing public investment.

4.3 Market Assessment for Road Freight Hydrogen Vehicles

Of the approximately 34,000 heavy-duty vehicles (HDV) registered in the Edmonton region for commercial transportation (Box 4.1 [45]), the majority are associated with commercial carriers found either along Highway 16 that cuts across the north side of the city of Edmonton, or in an industrial corridor that bisects the south-east quadrant of the city/Strathcona County (Figure 4.4). Another cluster exists around the Edmonton International Airport, south of the city (not shown in Figure 4.4 [46]).

A number of large refueling stations can be found in the same regions of the city, providing heavy-duty trucks with diesel fuel (**Figure 4.4).** Ideally, hydrogen fueling would be co-located with diesel in existing stations. One advantage of targeting the commercial carrier segment is that only a few, high-capacity stations are needed to supply a large fuel market. This is essential for rapid transition of the fuel supply and delivery systems that can compete with the incumbent diesel market without ongoing public investment.

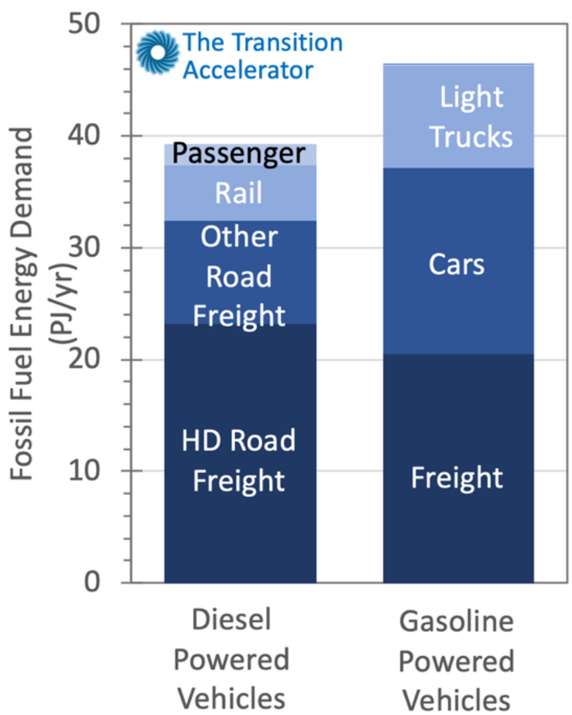


Figure 4.2. Estimated Annual Demand for Diesel & Gasoline Used for Transportation in Edmonton.
Data is prorated from Figures 2.2 and 2.3 for 2017; HD: Heavy duty.

Table 4.1. Calculated potential demand for hydrogen in the Edmonton market for transportation fuels. FF, fossil fuel.

		A	B	C	D	E	F
Transportation Fuel		Current FF Energy Demand	Market Share to H_2 (a)	Energy Content Conversion (b)	H_2 Energy Demand (c)	Annual H_2 Fuel Demand (d)	Daily H_2 Fuel Demand (e)
		PJ/yr	%	J H_2 / J FF	PJ H_2/yr	kt H_2/yr	t H_2/ d
1	Diesel	39	80%	0.86	27.0	190	522
2	Gasoline	46	30%	0.56	7.8	54.9	150
3	**Total**	**86**	**N/A**	**N/A**	**34.8**	**245**	**672**

Footnotes
(a) From Fig. 2.2B & 2.3B
(b) From Report A, Fig 3.2; units of Joules H2/ Joules of fossil fuel for same distance travelled
(c) Calculated as Column A times Column B times Column C.
(d) Calculated as Column D ÷ the higher heating value of hydrogen (141.7 PJhhv/Mt H2)
(e) Column E ÷ 365 days/year

Box 4.1. Estimated vehicle stocks in Edmonton, Alberta

While medium and heavy-duty vehicles represent less than 12% of vehicles on the road in Edmonton (Figure 4.3), these market segments should be a priority for early conversion to hydrogen since:

- Each vehicle consumes significantly more fuel (i.e. more emissions) than light duty vehicles, so the GHG reduction benefits are greater and emission reductions are lower cost considering the incremental cost of HFCE vehicles;
- Buses and freight vehicles are typically driven for long hours every day, and refuel daily at a limited number of locations on major transportation corridors;
- Hydrogen options are likely to be more operationally suitable than other zero emission alternatives due to issues of refueling time, vehicle weight and range requirement.

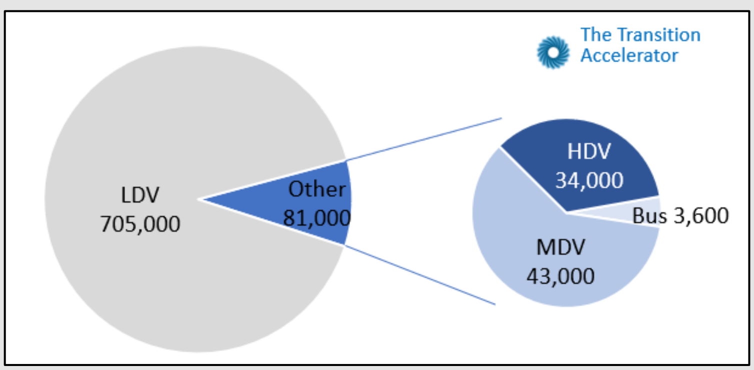


Figure 4.3. Estimate of Vehicle Stock Registered in Edmonton by Vehicle Type (2016).
Pro-rated by population based on Alberta data from Statistics Canada Table: 23-10-0067-01 [45]. LDV: Light Duty Vehicle; HDV: Heavy Duty Vehicle; MDV: Medium Duty Vehicle

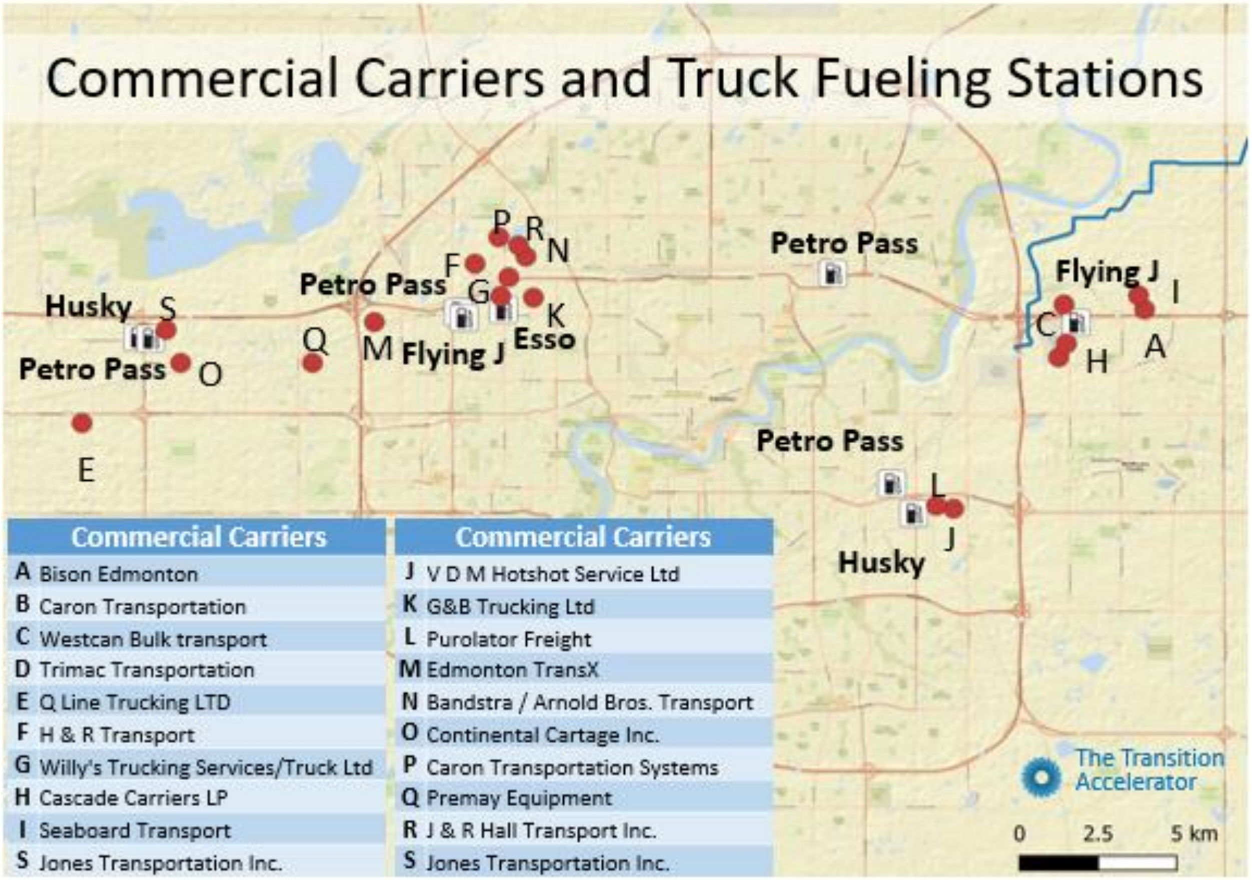


Figure 4.4. Sample of Commercial Carrier Terminals and Common Fueling Locations for Trucks.
Figure created using QGIS V3.10.8 [45].

Data for diesel fuel sales at these stations is not publicly available. Given heavy duty road freight consumption of 23 PJ diesel per year (**Figure 4.2A**), equivalent to 596 million L/year, and assuming a drive train efficiency ratio of 0.86 GJ_{hhv} H_2/GJ_{hhv} diesel, HFCE vehicles serving this market would consume about 382 t H_2/day. This level of demand could support dozens of economically viable truck fueling stations at 10 t H_2/d in the region while maintaining fuel prices at or below the current cost of diesel per kilometer travelled.

Another approach is to assess the fuel demand associated with trucks moving on the major highways in the Edmonton region, which connect Edmonton to other major cities such as Calgary and Fort McMurray. Using Alberta transportation traffic data [47] for trucks, including tractor-trailers and single unit trucks, we explored the three major highways shown in **Figure 4.5**:

- **The Edmonton Ring Road** (**Figure 4.5A** [47]) supports an average of 4,000 to 10,000 trucks per day (both directions) on its 78 kilometers length, with vehicle numbers varying with the section of the highway. Assuming fuel efficiencies of 30 and 21 L/100 km for tractor trailer and single unit trucks, respectively, diesel fuel use was estimated at 45 million L diesel/yr (**Figure 4.6A**) [5], [9].

- **Highway 2, connecting the ring roads of Edmonton and Calgary,** is a 262 km corridor with 4,500 to 8,000 trucks per day, about 80% of which are tractor trailer vehicles (**Figure 4.5A**). The trucks travelling this route consume about 144 million L diesel/yr (**Figure 4.6A**).
- **Highway 63, connecting Edmonton and Fort McMurray,** is a 415 km corridor serving about 1,000 trucks per day (**Figure 4.5B**), 80% of which are tractor trailers. The southern part of this route, near Edmonton is shown to have fewer vehicles, since there are alternative roads into the city. In total, about 43 million L diesel/yr are consumed (**Figure 4.6A**)

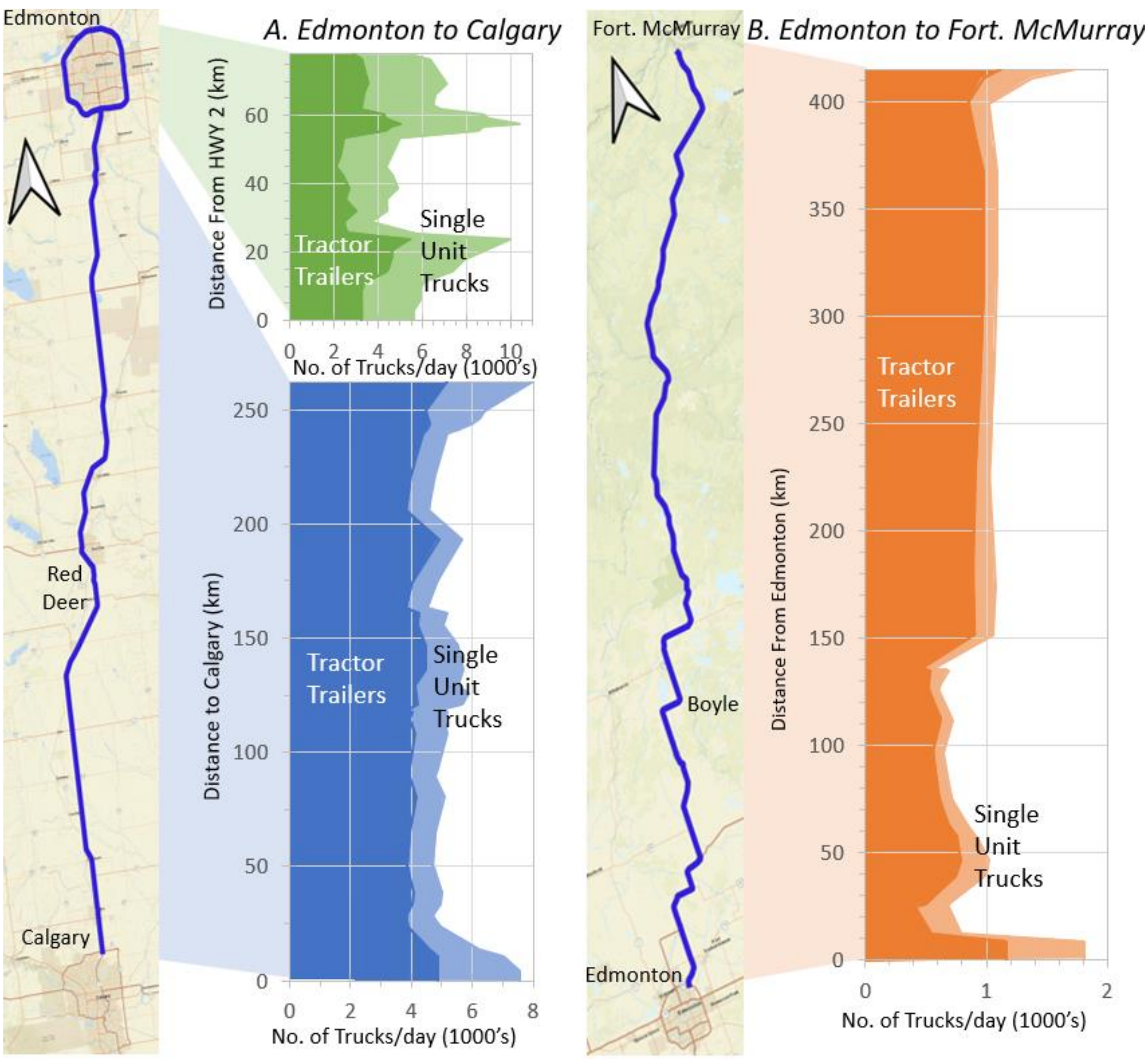
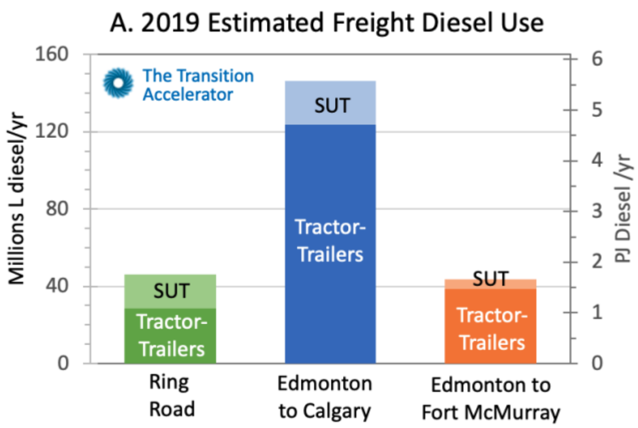


Figure 4.5. Estimated Trucks per Day on the Ring Road, Between Edm/Cgy & Edm/Fort McMurray. Estimated number of trucks per day traveling on the Edmonton ring road and between Edmonton and Calgary (A) and between Edmonton and Fort McMurray (B). Data source: Alberta Transport's Traffic Data Volume Map [47].



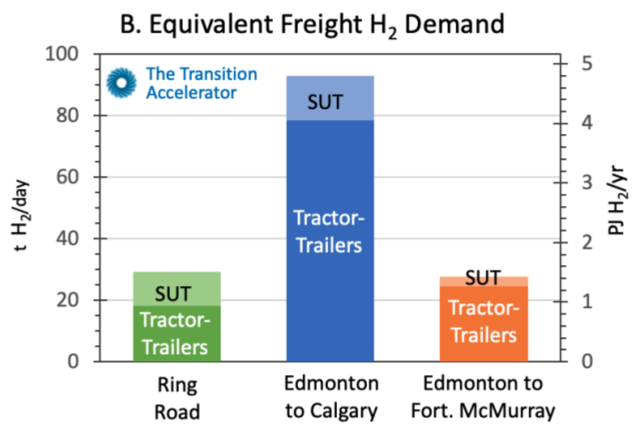


Figure 4.6. Estimated Demand for Diesel for Trucks on AB Major Corridors and Potential H_2 Demand.
Estimated demand for diesel for trucks on Alberta's major corridors (A) and resulting potential demand for hydrogen (B). Data for (A) is calculated from Figure 4.4. assuming an average fuel efficiency of 30 L diesel/100km diesel for tractor-trailer vehicles and 21 L diesel/100km for single unit trucks (SUT) as per NRCAN statistics [9]. Figure (B) takes the data from (A) using higher heating values of 38.6 MJ/L diesel and 141.7 MJ/kg hydrogen and multiplied by a drivetrain efficiency ratio of 0.86 GJ H_2/GJ diesel (Report A [5], Figure 3.6). SUT: Single Unit Truck.

Of course, the 232 million L diesel /year consumed on these highways does not account for fuel consumption before entering, or after leaving the highway, so their actual fuel consumption would be larger. On the other hand, not all of the fuel consumed by these trucks would come from the Edmonton region. This analysis is only to show the importance of corridor traffic on fuel use in the heavy trucking sector.

Replacing the 232 million L diesel /yr with hydrogen in HFCE vehicles (assuming a drive train efficiency ratio of 0.86 MJ H_2/MJ diesel) would require about 150 tonnes H_2/day (**Figure 4.6B**) for the highway traffic shown in **Figure 4.5**. The busiest of the three corridors, Edmonton - Calgary, has a potential market for at least 93 t H_2/day (**Figure 4.6B**), sufficient to support many economically viable fueling stations along the corridor.

Because of the required range between refueling, freight vehicles travelling long distances, (i.e. between Edmonton and Calgary or between Edmonton and Fort McMurray) are well suited for hydrogen. Furthermore, many of the trucks on the highways and within city limits are likely to have heavy payloads that may not be compatible with battery electric drivetrain options. This market segment is a logical early step for hydrogen powered vehicle adoption efforts and the build-up of hydrogen fueling and distribution systems. This is consistent with the hydrogen strategies being developed by many countries around the world [28], [48].

To date, there has yet to be large scale (thousands of vehicles) commercial deployment of hydrogen-fueled trucks worldwide, in large part because of the lack of cost-effective fueling infrastructure. Of course, the infrastructure does not exist because the vehicles are not there to use it. This vicious cycle needs to be broken and reformed into a virtuous cycle [28] if the freight sector is to get on a transition pathway to net zero emissions by 2050. Low cost, abundant blue hydrogen in the Alberta Industrial Heartland, could be the ideal place to begin this transformation and put Alberta and Canada into a global leadership position.

4.4 Breaking the Vicious Cycle

As discussed in previous reports [5], hydrogen fuel cell electric (HFCE) vehicles promise the attributes (zero emission, lower maintenance, improved efficiency, more torque, quiet) that are needed to transform heavy-duty transportation sectors to a more sustainable, low carbon future. The challenge is how to get 'there' from where we are today as fast as possible, at the lowest price and in a way that minimizes stranded assets, maximizes job creation and the quality of life for Canadians.

Box 4.2. The Alberta Zero-Emission Truck Electrification Collaboration (AZETEC) Project.

Led by the Alberta Motor Transport Association (AMTA) and two of its member companies (Trimac and Bison Transport), AZETEC is working with industry leaders Freightliner, Ballard and Dana to design and build two heavy-duty (63.5 tonne) hydrogen fuel cell electric (HFCE) hybrid trucks and put them on the road in Alberta in late 2021. The Trucks will be fueled in Edmonton, carry a full load to Calgary about 325 km to the south, where they will pick up another load and return to Edmonton. This project has been funded by Emission Reduction Alberta and Natural Resources Canada, as well as the Transition Accelerator.

Projects like the Alberta Zero-Emission Truck Electrification Collaboration (AZETEC, Box 4.2) are critically important in demonstrating the technology and showing how it works under real world conditions in Canada. The industry partners that AZETEC has brought together are in a race with other companies and consortia to bring Class 8 HFCE vehicles to the market [28]. At the present time and for a number of years, these vehicles will be significantly more expensive than the incumbent diesel internal combustion engine (ICE) vehicles that they are hoping to replace. Some of these extra costs are associated with the need to scale up the production of fuel cells, electric motors/axles and batteries, but a significant part of the cost premium is associated with the high-pressure tanks for on board storage. They need to be produced in larger volumes to achieve the necessary price reductions [48], [49].

This reality makes it challenging to break the vicious cycle and create sufficient demand for hydrogen at fueling stations that will keep the fuel costs low enough to compete with the incumbent diesel. However, there is an alternative strategy to rapidly build fueling station demand for hydrogen and create an environment where HFCE vehicles can thrive: the early and rapid deployment of H2-diesel, dual fuel vehicles (see Box 4.3).

Box 4.3. Hydrogen-Diesel Dual Fuel Engines

Hydrogen can also be co-combusted with diesel in existing internal combustion engines, where it is known to improve the combustion of diesel fuel and reduce particulate matter emissions, as well as GHG emissions. Numerous reports [50], [51] have shown engine performance equivalent to or better than diesel alone, with up to 98% mixture of H_2:diesel on an energy basis [52]. Companies like Vancouver's Hydra Energy [53], or UK's Ulemco [54] retrofit existing diesel engines so hydrogen can be injected into the cylinders along with diesel fuel. With Transition Accelerator support, Dr. Bob Koch's lab at the University of Alberta [55] is working with an engine OEM to integrate hydrogen injection technology into the software of the engine's electronic control unit. Other companies are building ships [56], [57] or large mining trucks [58] to use H_2-diesel dual fuels.

These vehicles require high pressure hydrogen storage tanks similar to what is used on HFCE vehicles, and therefore their widespread deployment should help to bring down the price of these tanks. In addition, hardware is needed to deliver the hydrogen to each cylinder, and control hardware and software is needed for each engine type.

The hydrogen purity required for H2-diesel vehicles is not as high as that required for HFCE vehicles. However, if H2-diesel vehicles are to assist in development of fueling infrastructure that supports HFCE vehicles, any publicly funded fueling station should require a hydrogen standard to serve both markets.

To explore this concept in more detail, the following sub-sections will compare the performance, fuel use and life cycle GHG emissions of diesel, H2-diesel and HFCE heavy duty vehicles. These values will be combined with estimates for the incremental cost for vehicle retrofits to calculate the effective cost of GHG emission reductions over the prime working life of the vehicle.

Comparing Diesel, H2-Diesel and Fuel Cell Electric Heavy-Duty Vehicles

To compare the performance of heavy duty diesel, H_2-diesel dual fuel and hydrogen fuel cell electric (HFCE) heavy duty vehicles we assumed the trucks would be traveling 650 km/trip (**Table 4.2, Item 1**) with 1 trip per day, 6 days per week and 50 weeks per year (195,000 km/yr, **Table 4.2, Item 2**). For a diesel vehicle using 30 L/100 km, fuel use will be 7.5 GJ/trip. Previous studies [26], [50] have shown that H_2-diesel (40:60 mix) dual fuel vehicles will use a similar amount of energy and have lower particulate and GHG emissions while the more efficient drivetrain on an HFCE vehicle will only use about 6.5 GJ H_2/trip (**Table 4.2, Item 4**).

This calculation assumes a drivetrain efficiency ratio of 0.86 GJ_{hhv} H_2/GJ_{hhv} diesel for a similar distance travelled (**Table 2.2**). HFCE vehicles often have even lower drivetrain efficiency ratios than their internal combustion engine comparators, but we have been conservative since diesel engine efficiencies have improved [59]. These vehicles are assumed to be doing long haul freight so there is little benefit of regenerative braking in HFCE vehicles, and the vehicles are assumed to operate in cold Alberta where heating demand and battery performance work against efficiency in HFCE.

Assuming the hydrogen is produced from natural gas while capturing and sequestering the CO_2 (i.e. blue H_2), as reported previously ([5] Figure 3.3), the per trip life cycle GHG emissions compared to a diesel vehicle will be reduced by 83% in an HFCE vehicle and by 32% in a dual fuel vehicle consuming H_2:diesel in a 40:60 ratio by energy content (**Table 4.2, Item 9**).

Over the operational lifetime of the vehicles for intensive use (assumed to be 6 years for diesel and HFCE, 5 years for H_2-diesel in recognition that retrofits may occur on some vehicles that have been in service for a period of time, **Table 4.2. Item 3**), each HFCE vehicle would reduce emissions by 1,129 t CO_2 and each H_2 diesel dual fuel vehicle by 590 t CO_2 (**Table 4.2, Item 12**) compared to the reference vehicle.

If blue hydrogen can be provided at a retail cost that is 90% the cost of diesel fuel on an energy basis (**Table 4.2, Items 14-15**), there would be fuel cost savings associated with the transition to HFCE (savings of $48.48/trip or 23% of fuel cost for diesel) or H_2-diesel dual fuel vehicles ($8.58/trip or 4% of fuel cost for diesel) (**Table 4.2, Items 16-19**).

Table 4.2. Comparison of fuel use, greenhouse gas emissions and fuel costs associated with diesel Internal Combustion engine (ICE), hydrogen fuel cell electric (HFCE)vehicles and H_2-diesel dual fuel ICE vehicles.

Item			Units	Diesel ICE	HFCE	H2-Diesel (40:60) ICE	Foot-note
1	Trip length between refueling		km/trip	650			-
2		Annual Travel	km/year	195,000			a
3		Vehicle life at this usage rate	years	6	6	5	b
4	Fuel use		GJ/trip	7.5	6.5	7.5	c
5		Diesel	GJ/trip	7.5	-	4.5	d
6			L/trip	195	-	117	e
7		Hydrogen	GJ/trip	-	6.5	3.01	d
8			kg/trip	-	45.7	21.2	e
9	Life cycle GHG emissions		kg CO2e/trip	755	128	513	f
10			t CO2/year	227	38	154	g
11			t CO2/veh life	1359	231	769	h
12	Emission reductions rel. to diesel		t CO2/veh yr	-	188	73	i
13			t CO2/veh life	-	1129	590	j
14	Fuel cost		$/L diesel	$ 1.10	-	$ 1.10	j
15			$/kg H2	-	$ 3.63	$ 3.63	k
16	Trip cost		$/trip	$ 215	$ 166	$ 206	l
17			$/year	$ 64,350	$ 49,807	$ 61,776	m
18			$/veh life	$ 386,100	$ 298,841	$ 308,880	n
19	Fuel cost savings		$/trip	-	$ 48.48	$ 8.58	o

Footnotes

(a) Assumes 1 trip /day (Item 1) X 6 d/week X 50 weeks/year

(b) H2-diesel vehicles are retrofitted in year one so one year shorter working life than for Diesel ICE or HFCE. Vehicles may be used beyond this period, but not at this intensity

(c) Based on energy use of a diesel vehicle with a fuel efficiency of 30L/100km, assuming a drive train efficiency ratio for HFCE vehicle of 0.86 MJ H2/MJ diesel, and for H2-diesel of 1.0.

(d) Assumes the H2:diesel vehicles are 40%:60% by energy content of fuel (higher heat value)

(e) Calculated from Items 5 or 7 given an energy content of 38.6 MJ/L for diesel and 141.7 MJ/kg for hydrogen

(f) Calculated from Items 6 and 8 given life cycle GHG emissions of 3.87 kg CO2e/kg Diesel and 2.8 kg CO2e/kg H2 ([5], Figure 3.3)

(g) Calculated as Item 9 X Item 2/Item 1/1000

(h) Calculated as Item 10 X Item 3

(i) Calculated as Item 10 for Diesel vehicle - Item 10 for each H2 fueled vehicle

(j) Calculated as Item 11 for Diesel vehicle - Item 11 for each H2 fueled vehicle

(k) Typical retail price of Diesel fuel in Canada (including taxes etc.). The target price for hydrogen was set at 90% of the energy equivalent price of diesel.

(l) Calculated as Item 6 * Item 13 for diesel, Item 8 * Item 14 for HFCE and (Item 13 * Item 6 + Item 14 * Item 8) for H2-diesel

(m) Calculated as Item 15 X Item 2/Item 1

(n) Calculated as Item 16 X Item 3

(o) Calculated as Item 15 for Diesel vehicle - Item 15 for H2 fueled vehicle

Incremental HFCE and H2-Diesel Vehicle Cost and Vehicle Life Emission Reduction Cost.

One of the major barriers to deployment of HFCE vehicles is the incremental cost of the vehicle compared to the incumbent diesel. Within a few years from now, this incremental cost is expected to come down to around $350,000 per vehicle [60]6, depending on design, and potentially be near parity with diesel vehicles by 2030 and beyond [48], [49], [61] (Table 4.3, Item 1). The challenge in building a transition pathway for hydrogen vehicles, is how to break the vicious cycle over the next 10 years and create an environment where HFCE vehicles can rapidly take market share.

Given the life cycle emissions reductions reported above (Table 4.3, Item 2), in the short term, the emissions reduction cost for HFCE vehicles will be about $310/t CO_2e (Table 4.3, Item 3). In comparison, the incremental cost of retrofitting a diesel engine for dual fuel is $50,000/vehicle, resulting in an emissions reduction cost of about $85/t CO_2e (Table 4.3, Items 1-3).

With the differences in hydrogen fuel requirements of the two vehicle types (**Table 4.2, Item 8**), to create a fleet of heavy trucks sufficiently large for an economically-viable fueling station (estimated to require about 2 t H_2/day) would require the deployment of 44 HFCE vehicles or 94 H_2-diesel dual fuel vehicles (**Table 4.3, Item 4**). The public subsidy needed to incentivize such a facility would be over $15M for the HFCE fleet but under $5M for the H_2-diesel fleet (**Table 4.3, Item 5**).

Given the cost differential, a strong case can be made for coordinated deployment of both HFCE and H_2-diesel dual fuel vehicles over the next decade, with initially more investment into H_2-diesel vehicles to build economically viable fueling stations. To ensure that these stations offer no barrier to the deployment of HFCE vehicles, any new, public-supported fueling station should be HFCE compliant. As noted previously (**Box 4.3**), H_2-diesel vehicles could use a lower quality fuel, but stations providing only this fuel would not be compatible with HFCE vehicles and the vicious cycle would continue.

It is important to note that as H_2 fueled vehicles are deployed in greater numbers, the incremental cost of the vehicles will decline as a result of the efficiencies associated with larger scale production of fuel cells, batteries, electric motors and high-pressure hydrogen tanks [48], [49]. This is especially true for the HFCE vehicle (**Table 4.3, Item 1**). By 2030, the emission reduction cost for HFCE vehicles could decline from $310/t CO_2e to under $12/t CO_2e. In contrast, the decline in the cost of the H_2-diesel vehicles is expected to be much less, being associated primarily with a decline in the cost of the hydrogen storage tanks (**Table 4.3, Items 7-9**). Therefore, our model projects an emissions reduction cost for H_2-diesel vehicles of $42/t CO_2e in the longer term (**Table 4.3, Item 3**). Given these trends and calculations, HFCE vehicles should eventually take market share, but H_2-diesel dual fuel vehicles will play an important role in the transition pathway.

6 Adapted from ICCT study: Moultak et al, (2017) [60], accounting for a larger battery than in the study and CAD funds.

Table 4.3. The comparative economics for the deployment of hydrogen fuel cell electric (HFCE) and H_2-diesel heavy duty trucks in both the short term (next 5-7 years) and the longer term (2030+).

	Item	Units	Short Term (Next 5-7 yrs)		Longer Term (2030+)	
			HFCE	H2-Diesel	HFCE	H2-Diesel
1	Incremental cost of vehicle [a]	$/vehicle	$ 350,000	$ 50,000	$ 13,000	$ 25,000
2	Emission Reductions relative to diesel [b]	t LC CO2e/Veh life	1,129	590	1,129	590
3	Emission Reduction Cost [c]	$/t CO2e	$ 310.07	$ 84.70	$ 11.52	$ 42.35
4	# Veh to support 2t/day Fueling Stn [d]	Vehicle number	44	94	44	94
5	Cost to support a 2t/day fueling station [e]	$million	$ 15.32	$ 4.71	$ 0.57	$ 2.35
6	Emission reductions [f]	t CO2/station-year	8,236	6,848	8,236	6,848
7	Number of 5 kg H_2 Compressed Tanks [g]	# tanks/Veh	10	5	10	5
8	Cost per tank installed [h]	$/tank	$ 6,000	$ 7,000	$ 2,000	$ 2,800
9	Total Tank Cost [i]	$/Veh	$ 60,000	$ 35,000	$ 20,000	$ 14,000

Footnotes
(a) Estimated cost from industry and literature [48-49], [60-61]
(b) From Table 4.2, Item 12
(c) Item 1/Item 2
(d) Calculated as 2000 kg H2/day ÷ Table 4.2, Item 8
(e) Calculated as Item 1 X Item 4
(f) Calculated as Item 4 * [Table 4.2, Item 12]
(g) Calculated from Table 4.2, Item 8 considering that some spare fuel capacity is needed
(h) Estimated from discussions with industry. The extra cost for H2-diesel tanks is associated with the vehicle modifications needed to mount the tanks. In HFCE vehicle those costs are embedded in the base vehicle
(i) Calculated as Item 6 X Item 7

Other Factors Supporting the Rapid Deployment of H2-Diesel Vehicles.

There are other non-economic factors to be considered when building a credible and compelling transition pathway to a hydrogen economy, as summarized in **Table 4.4**. Some relate to the perceptions of risk by the 'key stakeholders' in the transition to hydrogen as a fuel: i.e. the carriers who buy and fuel vehicles. They will see a performance risk, that can only be addressed by piloting and demonstrating HFCE and H_2-diesel vehicles under real world conditions, and report on their performance in an open and transparent way.

The carriers will also see a refueling risk (**Table 4.4**) associated with the lack of hydrogen refueling infrastructure. In this case, the H_2-diesel vehicles have a clear advantage over the next decade since if they run out of hydrogen, they simply revert to a diesel-only vehicle (**Table 4.4**). HFCE vehicle operators will need to pay very close attention to the fuel supply and the location of fueling stations.

A number of reasons position H_2-diesel vehicles as promising technology in the transition pathway to a vibrant hydrogen economy. These include the cost benefits of an H_2-diesel as an emissions reduction technology, along with the large number of incumbent vehicles that could rapidly be converted, and the lack of serious concern about running out of fuel.

Table 4.4. The comparative business case for the deployment of hydrogen fuel cell electric (HFCE) and H_2-diesel heavy duty trucks in both the short term (next 5-7 years) and the longer term (2030+).

Item		Short Term (Next 5-7 years)		Longer Term (2030+)	
		HFCE	H2-Diesel	HFCE	H2-Diesel
1	Performance Risk	Moderate: need to demonstrate under Canadian conditions		Low: Should be proven technologies	
2	Refueling Risk	High: Lack of fueling stations	Low: If H_2 runs out, works as diesel-only vehicle	Low: Should be H_2 fueling stations on major corridors across Canada	
3	Maintenance Risk	High: Few know HFCE vehicles	Moderate: Still diesel engine and can turn off H_2	Low: Should be understood and well supported	
4	Operator/Driver Learning Curve	Moderate, but many would see this learning as positive		Low: should be common-place	
5	Public Support Needed	High: Subsidy needed for early vehicles	Moderate: Subsidy needed	Low: Major price reduction with volume	Moderate: Subsidy may still be needed
6	Ability to Expand Rapidly to Support H_2 Fueling Stations, and Rapidly Reduce GHGs	Poor: Due to cost and limited manufacturing capability	Good: Especially for retrofitting fleets of similar vehicles	Good: Many models of HFCE vehicles should be available	Good: Especially for retrofitting fleets of similar vehicles

4.5 Market Assessment for Municipal Fleets Converting to Hydrogen

Public vehicle fleets can play a major role in the transition to more sustainable transportation systems. Each year (before COVID-19), the five municipalities associated with the Alberta Industrial Heartland consumed about 36 million litres of diesel and 8.7 million litres of gasoline (**Figure 4.7**).

The city of Edmonton municipality itself accounts for the majority of demand so we have focused on the potential of this market. While the municipal diesel demand accounts for only about 3% of the estimated total diesel demand for the entire city (**Table 4.1**), the public ownership and 'return to base' nature of this fleet makes it a potential early market for a hydrogen fueling station near the Industrial Heartland.

As part of Canada's climate change strategy, a federal mandate is now supporting municipalities in their purchase of 5,000 zero-emission buses by 2025 [62]. As described in **Box 4.4** [63]–[65], a case can be made for municipalities to adopt hydrogen over other zero-emission options, based on each agency's unique duty cycle, operational structure, resource availability and grid carbon intensity.

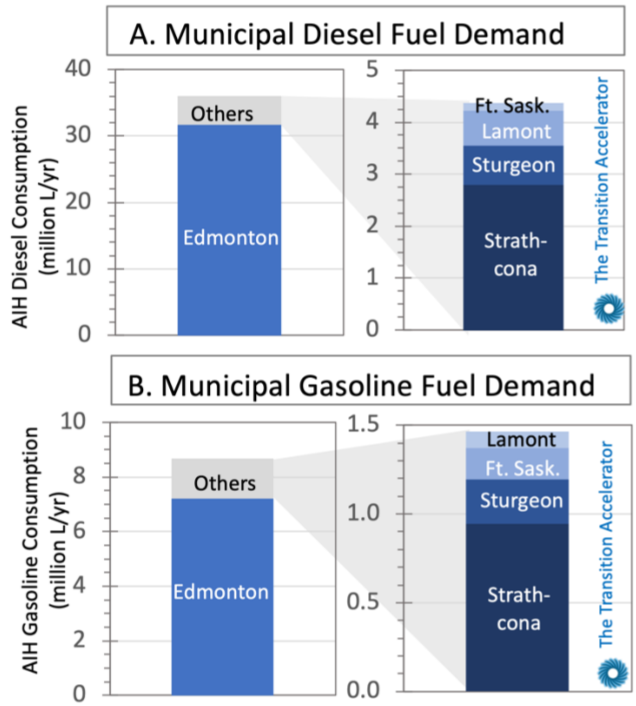


Figure 4.7. Estimated Annual Diesel & Gasoline Fuel Consumption in AIH Municipal Fleets.
Estimated annual diesel (A) and gasoline (B) fuel consumption in municipal fleets of the five Alberta Industrial Heartland counties. Data provided by the individual counties.

Municipal initiatives will send signals to provincial and federal governments, industry, as well as the international stage, that the AIH is invested in and moving forward on hydrogen. Municipalities taking a leadership role is a key element in hydrogen strategies in places like Germany [14], Japan [66], and California [65].

Edmonton and Strathcona County have large municipal fleets (Box 4.5, Figure 4.9 [28]). Transit buses are an obvious target for an early shift to hydrogen vehicles because of their 'return to base' fueling system (Figure 4.10, Locations 1 to 4), large fuel use, and the potential to access federal funding [62]. Based on consultations with the City of Edmonton, and depending on budget, an average of 45 new buses per year are added to Edmonton's fleet of over 1,000 buses (replenishment and growth). Each bus consumes an average of 64 L diesel/day which is the equivalent of 15 kg H_2/day. Larger buses with higher fuel use (20-25 kg H_2/day) on longer routes should be targeted for early adoption.

The annual transit bus purchase is dependent on a set budget. If fuel cell buses are more expensive than diesel options, the City would purchase fewer buses or require funding support from other jurisdictions or partners. According to a report by Ballard Power systems, fuel cell buses are currently more than twice the price of a diesel bus but are projected to reach purchase parity by 2029 [49].

Box 4.4. Making a case for hydrogen fuel cell transit fleets

Edmonton Transit has already made investments in a zero-emission transit fleet with the first 21 of 40 battery electric buses being integrated into their fleet in the summer of 2020 [63]. These buses will have a range of 350 km/charge and will be charged using overhead infrastructure at the Kathleen Edwards bus depot (Figure 4.10, Location 1).

While there are significantly more battery electric buses than fuel cell electric buses in cities around the world [64], and they are currently less expensive than fuel cell options, according to a report by the California Fuel Cell Partnership [65], large battery electric fleets can be challenged to:

- Accommodate charging infrastructure in congested depots;
- Maximize facility utilization;
- Balance power demands in energy constrained districts;
- Justify costly grid integration evaluations and upgrades (substations & feeder systems);
- Provide operational flexibility needed for reliable service;
- Meet life cycle emission reduction targets in regions with high carbon grid power.

The inclusion of hydrogen fuel cell buses into zero-emission fleet strategies will help moderate many of these issues, especially with larger fleets as shown in Figure 4.8.

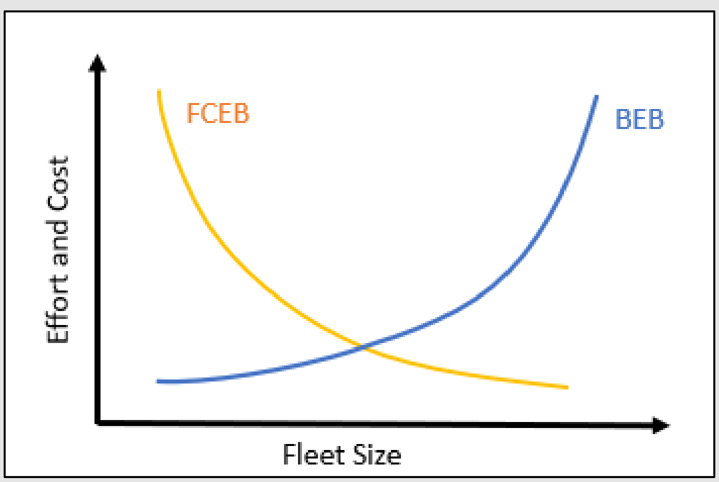
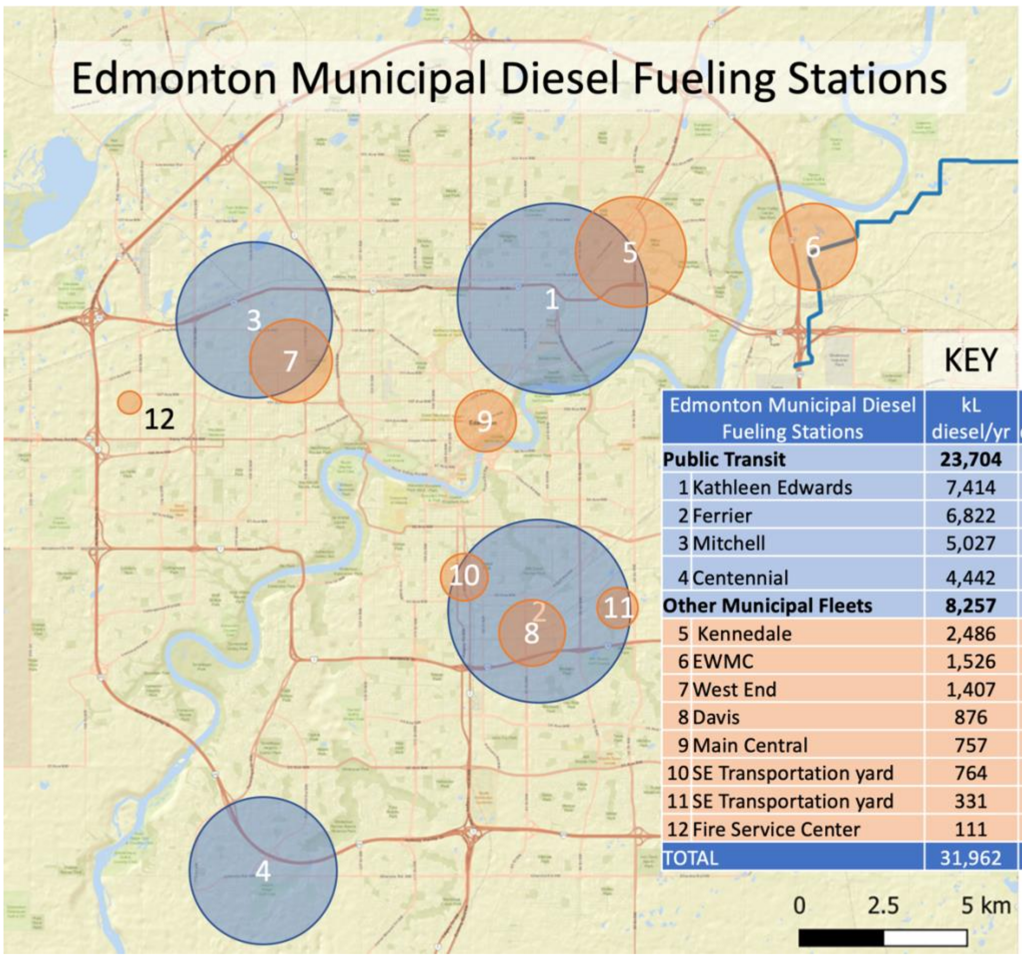


Figure 4.8. Relative Cost and Effort Impact of Bus Deployments with Increasing Scale.
BEB: Battery Electric Bus; FCEB: Fuel Cell Electric Bus.
Figure adapted from the Center for Transportation and the Environment [65].

It is important to note that the fueling stations for the municipal vehicle fleets (**Figure 4.10**) are in the same industrial regions of the city as the private truck fleets and the fueling stations that serve them (**Figure 4.4**): along Highway 16 across the top of the city and in an industrial corridor starting in Sherwood Park on the east side of Edmonton and bisecting the south-east quadrant of the city. This opens up the potential for a coordinated, cost-effective strategy to build infrastructure such as pipelines and fueling stations that will serve both the municipal and private fleets converting to hydrogen.

If Edmonton's entire municipal transit fleet were to be converted to HFCE, the fuel demand would average about 15 t H_2/day, sufficient to support three or four economically viable fueling stations.



	Edmonton Municipal Diesel Fueling Stations	kL diesel/yr	TJ_{hhv} diesel/yr	kt H2/yr	t H2/d
	Public Transit	**23,704**	**915**	**5.55**	**15.21**
1	Kathleen Edwards	7,414	286	1.74	4.76
2	Ferrier	6,822	263	1.60	4.38
3	Mitchell	5,027	194	1.18	3.23
4	Centennial	4,442	171	1.04	2.85
	Other Municipal Fleets	**8,257**	**319**	**1.93**	**5.30**
5	Kennedale	2,486	96	0.58	1.60
6	EWMC	1,526	59	0.36	0.98
7	West End	1,407	54	0.33	0.90
8	Davis	876	34	0.21	0.56
9	Main Central	757	29	0.18	0.49
10	SE Transportation yard	764	30	0.18	0.49
11	SE Transportation yard	331	13	0.08	0.21
12	Fire Service Center	111	4	0.03	0.07
	TOTAL	31,962	1,234	7.5	20.5

Figure 4.9. Edmonton's Municipal Fleet Fueling Locations and Summary of Diesel & H2 Demand.
Locations of Edmonton's municipal fleet fueling locations sized by diesel demand. The key to the stations shows both diesel demand and the equivalent hydrogen demand if the vehicles were hydrogen fuel cell electric.

There is also a possibility for Edmonton's waste collection vehicles to be converted to hydrogen as is being demonstrated in Europe with the H2Revive project [67] or the Ulemco H_2-diesel trucks in the UK [54]. The Edmonton Waste Management Centre (EWMC) is adjacent to the existing hydrogen pipeline (**Figure 4.10, Location 6**) and their vehicles would use about 1 t H_2/day.

The EWMC could make hydrogen for its own fleet of vehicles and serve other private fleets in the region. There are a number of technologies that can be used to make hydrogen from municipal waste streams [68], [69]. If the biproduct CO_2 were to be captured from the process and directed to the nearby CO_2 pipelines (**Figure 3.2, Table 3.1**), negative carbon emissions could be generated.

The city currently purchases around 8-10 new waste collection vehicles per year and each vehicle consumes about 37 L diesel/day (equivalent to about 8 kg H_2/day/vehicle). From discussions with the City, their Waste Management department is pursuing other zero emission alternatives with renewable diesel produced from the waste streams. These options would need to be compared with, and balanced against, the hydrogen vehicle alternatives.

Box 4.5. Estimated Municipal Vehicle Stock

While a large portion of municipal fleets are light duty vehicles, diesel buses and heavy-duty fleets consume more fuel per year and have frequent, concentrated fueling needs. Compared to other heavy-duty drivetrains, hydrogen fuel cell buses have had more trials and deployments globally [28]. Therefore, municipal buses are a good early step in both Edmonton and Strathcona.

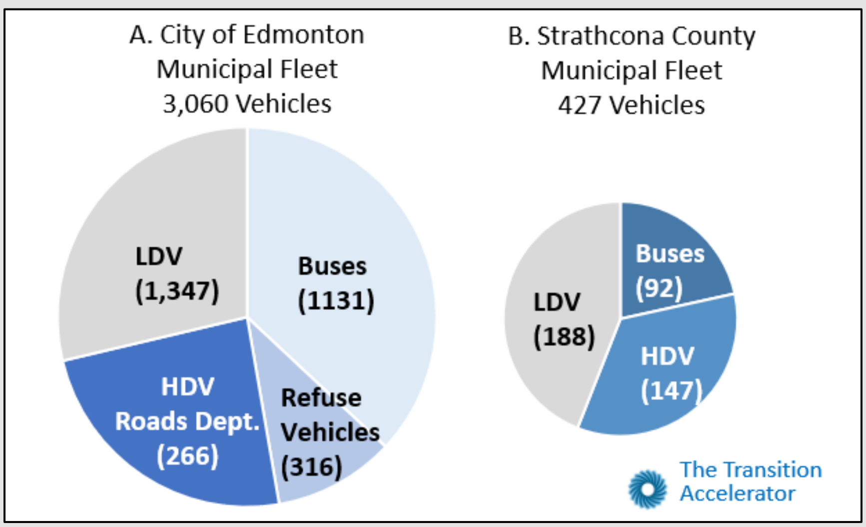


Figure 4.10. Municipal Fleet Composition by Vehicle Type for Edmonton and Strathcona County.
Municipal fleet composition by vehicle type for Edmonton (A) and Strathcona County (B).
Data provided by the jurisdictions; LDV: Light Duty Vehicle; HDV: Heavy Duty Vehicle.

4.6 Natural Gas Market Assessment

The precise chemical composition of natural gas is more important for some applications (e.g. fertilizer production, gas turbine power generation) than for others (e.g. space and water heating), so the concept of using hydrogen to decarbonize natural gas has focused on the building sector where the supply pressures are lower, and the pipes tend to be plastic and therefore more compatible for use with hydrogen than some steel pipes which can be embrittled by hydrogen.

Alberta has a large demand for natural gas to provide heat for homes, institutions and businesses. The current demand for natural gas in Edmonton averages about 6.4 PJ NG/month however there are large seasonal variations, from 1.6 PJ NG/month in August to 12.5 PJ NG/month in January [29], [70] (**Figure 4.11**). Daily variations in energy demand for space heating, especially in winter, can be even greater than the seasonal variation.

This large seasonal and daily variation is one reason why direct electrification of space heating is particularly challenging in cities like Edmonton, especially if low carbon electricity is required. Like natural gas, hydrogen can be stored in sub-surface reservoirs when there is lower demand, and utilized when needed. Assuming 1 GJ H_2 is equivalent to 1 GJ NG for the purposes of space and water heating, the average demand for pure hydrogen to meet the residential and commercial heating needs of Edmonton would be about 2,854 t H_2/day in January, and 361 t H_2/day in August.

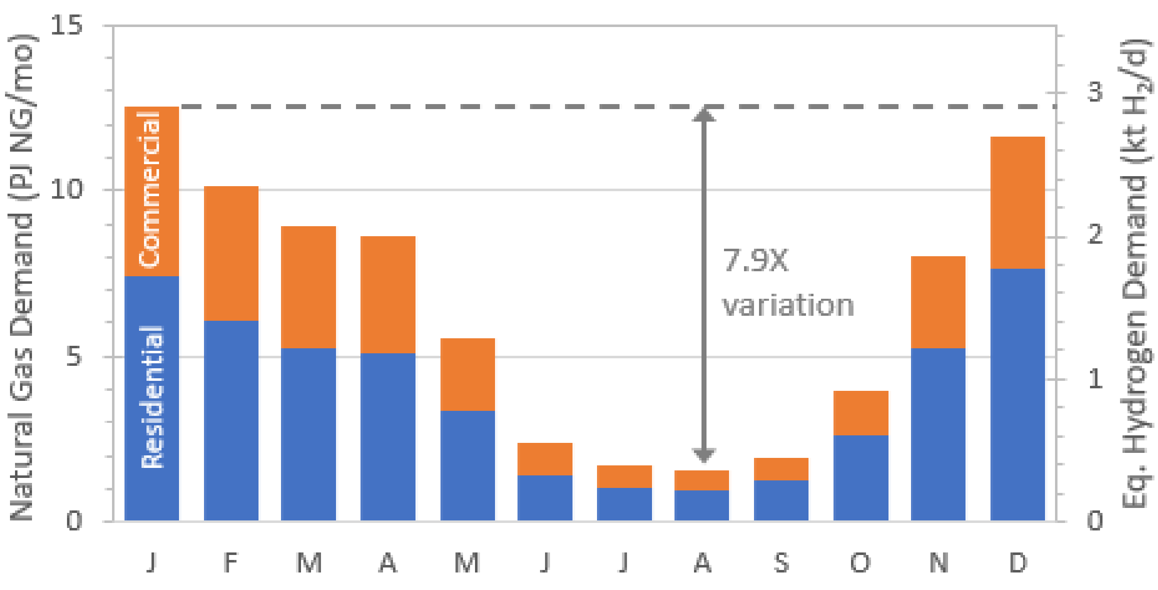


Figure 4.11. Seasonal Variation in NG Demand for Residential & Commercial Buildings in Edmonton.
Approximate seasonal variation in natural gas demand for residential and commercial buildings in Edmonton in 2018. Seasonal variation data obtained for 2013 from the Market Surveillance Administrator [70] but applied to 2018 estimates of total annual natural gas use for residential and commercial buildings in Edmonton data from the Alberta Energy Regulator [29].

Using hydrogen to decarbonize natural gas is likely to be done, at least initially through admixing it with natural gas in a range of blend rates. According to a US government report [71], blends up to 20% hydrogen by volume (7.25% by energy, see **Box 4.6**) can be injected into the natural gas network with minimal or no changes in valves, burner tips or appliances. Above 20% hydrogen by volume will require some changes in valves and fittings so the emerging strategy is to consider admixing to 20% and then, change over the natural gas system to pure hydrogen. The use of 100% hydrogen for space heating is being explored in the UK as part of the H21 project in Leeds [36]. The UK government has also set up a Hy4Heat initiative [72] to develop the technologies, protocols, policies and standards needed for such a transition.

It is important to note that blending hydrogen will have an impact on pipeline capacity because of its low volumetric density compared to natural gas. A 100% hydrogen pipeline will have an energy capacity that is only about one third that of a natural gas pipeline of the same size and pressure (**Box 4.6, Figure 4.12**). The seasonal demand fluctuations could be managed with the help of flexible blending rates.

Box 4.6. Volume impacts of hydrogen blending in natural gas pipelines

Even though hydrogen has a higher energy content than natural gas per unit weight, the density of hydrogen (MJ/m3) is only about one third that of natural gas. Therefore, volumetrically blending hydrogen into natural gas reduces the energy content of the mixed gas as shown in Figure 4.12.

To meet the same energy demand as pure natural gas when combusted, a larger volume of the mixed gas would be required.

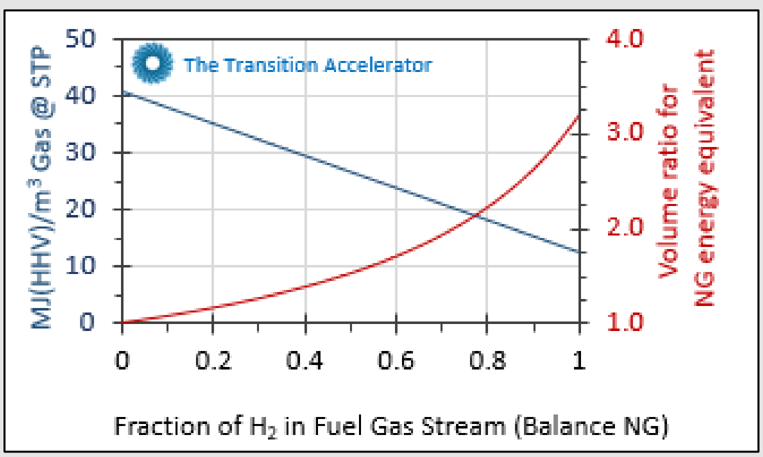


Figure 4.12. Volumetric Energy Density of Mixed Gas & Providing the Same Amount of Heat Energy.
The effect of hydrogen blending into natural gas (NG) on the volumetric energy density of the mixed gas (blue) and the relative volume required to provide the same amount of heat energy as 1 m3 of natural gas (red).
HHV: Higher Heating Value

At a 20% hydrogen fraction, the potential average hydrogen demand from the natural gas market in Edmonton is 108 t H_2/day (**Figure 4.13A**) and 1.1 t H_2/day in Fort Saskatchewan (**Figure 4.13B**).

The Alberta Industrial Heartland has a large existing network of high-pressure, natural gas pipelines (**Figure 4.14**). To serve the residential and commercial building market, there are a number of gates where hydrogen could be admixed with natural gas as shown in **Figure 4.14.** Gate 5 in Fort Saskatchewan is the location where ATCO will be doing a 5% hydrogen trial that was recently announced [73].

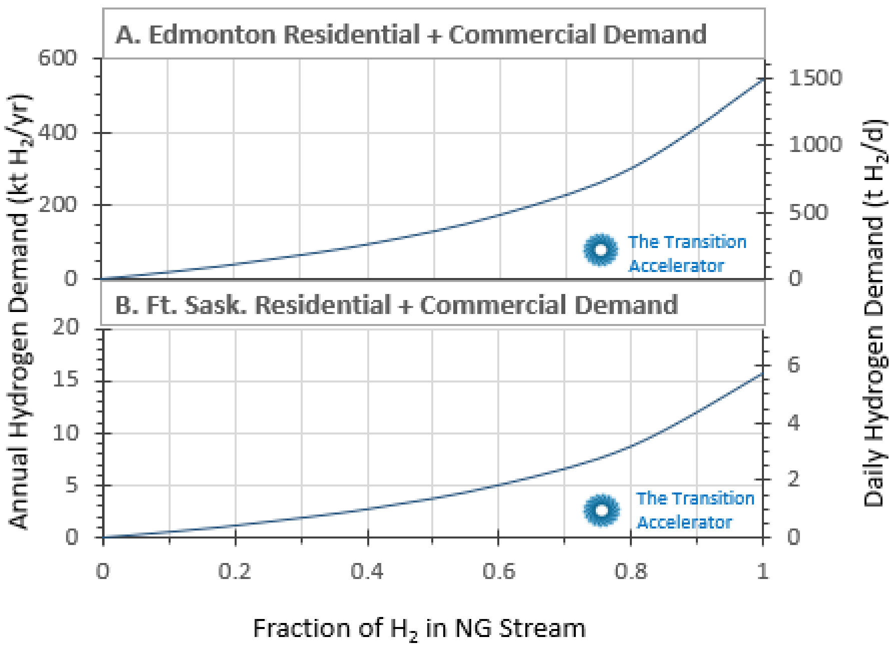


Figure 4.13. Estimated H_2 Demand: Mixing NG with H_2 at Various Ratios in Edm & Ft. Saskatchewan.
Estimated hydrogen demand resulting from the mixing of natural gas with hydrogen at various ratios in Edmonton (A) and Ft. Saskatchewan (B). Assumes that hydrogen is used in both commercial and residential heating applications. Data for Figure (A) based on Industry input.

The Hermitage Gate in Sherwood Park is also of interest because of its close proximity to the Air Products hydrogen pipeline. Gates 1, 4 and 7 are also of interest since they are located in the two corridors that also have many heavy-duty trucking companies, municipal vehicles and truck fueling stations as shown in Figure 4.4 and Figure 4.9. This opens up a potential for a small number of pipelines to bring hydrogen from the Alberta Industrial Heartland to new markets for hydrogen as a fuel, thereby improving the economics for all.

The Alberta Industrial Heartland also has the potential to serve new fuel markets for hydrogen beyond the boundaries of the five municipalities. A major opportunity is the Edmonton International Airport, which anchors the north end of the busy Highway 2 corridor to Calgary (Figure 4.5) and the location of the new Amazon Fulfillment Centre and many trucking companies and truck fueling facilities. Moreover, Red Deer and Calgary could also be served by a hydrogen pipeline from the Industrial Heartland running along Highway 2.

Abandoned and discontinued natural gas pipelines (Figure 4.15A, B, [74]) could provide an opportunity to get started quickly by repurposing some of this infrastructure to reach new hydrogen markets. The discontinued jet fuel pipeline (Figure 4.15C) not only links a region of hydrogen production in Sherwood Park to the Edmonton International Airport but goes all the way to the Calgary International Airport. At airports, hydrogen could not only fuel the ground fleets, but also building heating, and in the future, the planes themselves [75].

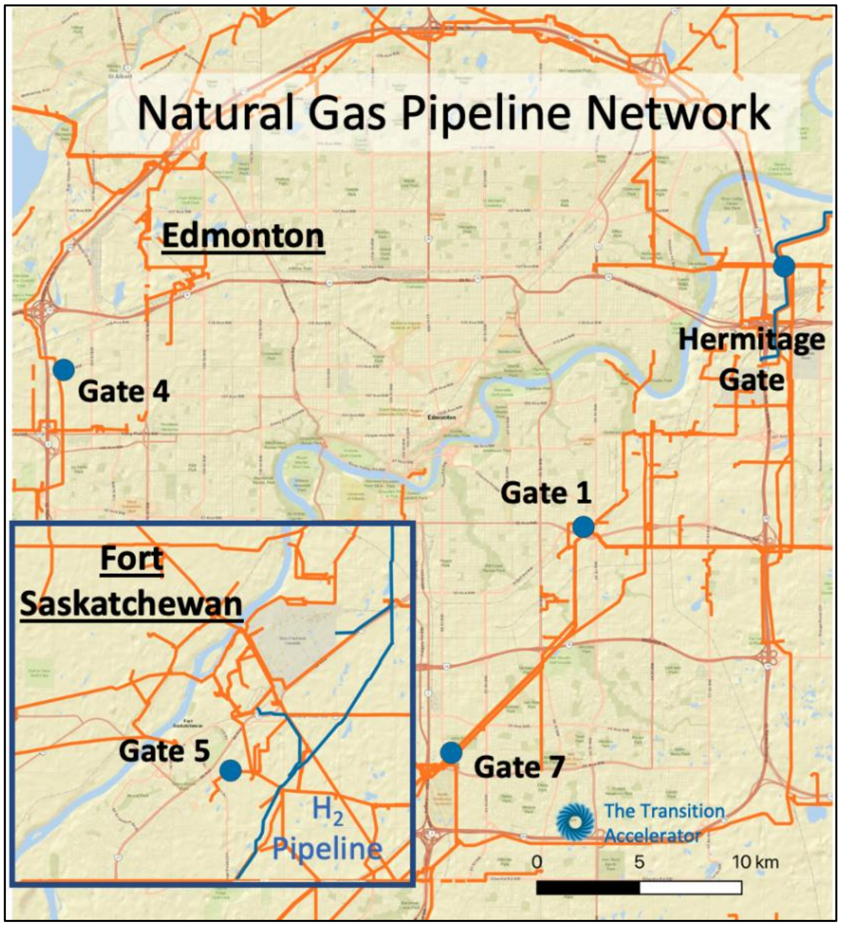


Figure 4.14. Map of Active NG High Pressure Distribution Pipelines in Edm & Ft. Saskatchewan.
Map of active natural gas high pressure distribution pipelines (orange) in Edmonton and Ft. Saskatchewan (insert figure). Pipeline data from Alberta Energy Regulator [74]. Blue markers indicate possible locations for hydrogen injection (gates) into the natural gas system based on industry input. Blue line, Air Products hydrogen pipeline.

Detailed studies are needed to explore the feasibility of using any of these pipelines, and how those investments align with the planned growth of the hydrogen economy in Alberta, across Canada and internationally.

4.7 Summary of Markets for New Blue Hydrogen Production

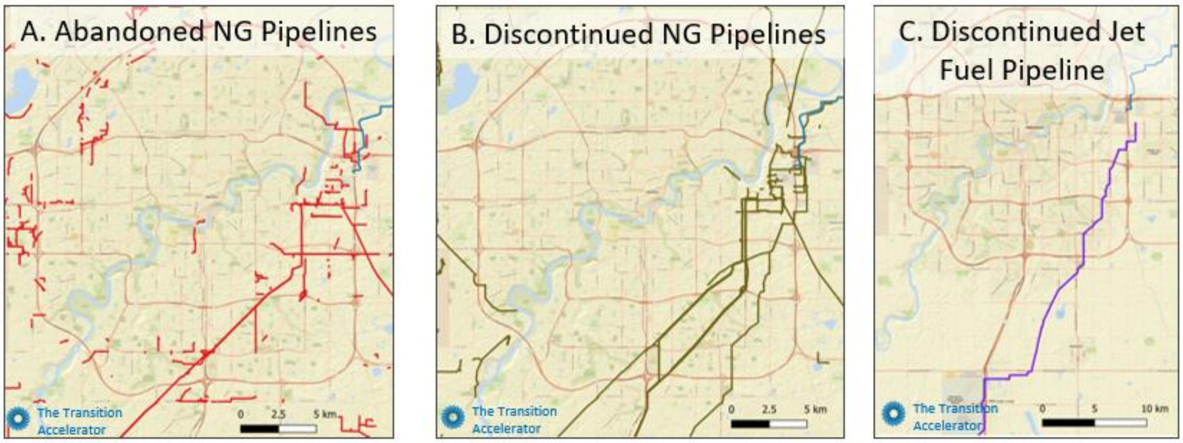


Figure 4.15. Maps of Abandoned/Discontinued Natural Gas and Jet Fuel Pipelines in the AIH Region.
Maps of abandoned (A) and discontinued (B) natural gas pipelines and discontinued jet fuel pipelines (C) in the Alberta Industrial Heartland region. Location data from Alberta Energy Regulator [74].

Of the 2250 t H_2/day produced in the Alberta Industrial Heartland, about 937 t H_2/day is produced with the carbon being managed (**Figure 3.2**). Therefore, there is potential for another 1,313 t H_2/day of blue hydrogen production, plus any new growth in the markets for industrial hydrogen (**Table 4.5, Item 1**).

Table 4.1 provided an estimate of the current, on road diesel and gasoline markets in the Edmonton region. It assumed that in a net-zero transition, hydrogen would take 80% of the diesel market and 30% of the gasoline market (balance: electrification). This would create a market for an additional 672 t H_2/day (**Table 4.5, Item 2**).

Residential and commercial buildings in Edmonton and Fort Saskatchewan are estimated to consume natural gas with the energy equivalence of 1,495 t H_2/day, averaged over the year (**Figure 4.13**). Assuming the natural gas system is replaced with 100% hydrogen for space and water heating, this would be an additional market for blue hydrogen.

Not counting export from the region, there is a blue hydrogen market potential in the Industrial Heartland of about 3,480 t H_2/day (**Table 4.5**).

Table 4.5. Summary of markets for additional blue hydrogen production in AIH

	Market Segment	t H_2/day
1	Existing industrial gray H_2 needing to be blue H_2 (a)	1313
2	Hydrogen displacement of existing diesel (80%) & gasoline (30%) market (b)	672
3	Residential and commercial buildings at 100% H_2 (c)	1495
4	Export from region (d)	???
	Total	**3480+**

Footnotes (a) From Fig. 3.2; (b) From Table 4.1; (c) From Fig. 4.13; (d) California, Japan, S Korea & Germany have given notice of wanting to import tens of thousands of tonnes of blue or green H_2 per day

5. Conclusions and Recommendations

5.1 Why Hydrogen Nodes and why the Alberta Industrial Heartland?

Canada, Alberta and Alberta's Industrial Heartland (AIH) are ideally positioned to produce, use and export hydrogen gas, the zero-emission fuel that the world is relying on to address the challenges of climate change while supporting economic growth and a high quality of life.

Successfully transitioning from carbon-based energy carriers (gasoline, diesel, natural gas) to hydrogen that is produced with little or no emissions requires the regional deployment of the entire value chain at a scale that can quickly become economically viable without ongoing public investment.

This is the why we have argued for the deployment of hydrogen nodes [5] across Canada, built around areas where there is a reliable supply of by-product, blue or green hydrogen at low cost, substantial nearby markets for the use of this hydrogen, and a cost-effective way to connect supply to demand.

The Alberta Industrial Heartland is a potential hydrogen node. It is already a centre for low cost grey (GHG emissions of about 9 kg CO_2/kg H_2) and blue (GHG emissions of about 1 kg CO_2/kg H_2) hydrogen production in Alberta. The hydrogen is primarily used as an industrial feedstock for making nitrogen fertilizer, cracking bitumen to synthetic crude oil and making refined petroleum products. There is capacity and interest among industry and all levels of government to make more blue hydrogen and use it as both an industrial feedstock and as a fuel to support heavy transport, space heating and other applications.

5.2 The Demand Sectors in a New Fuel-Hydrogen Economy

In building a credible and compelling transition pathway to a new, more sustainable energy system it is important to understand that energy systems are driven by demand. We must first understand <u>demand</u> and then design the supply side to meet that demand. From the demand perspective, the new energy systems must offer valuable attributes that make it possible to compete with the incumbent carbon-based system that is currently in place.

Sectors that hold the most promise in a fuel hydrogen economy include:

Heavy Transport

In the past, efforts to launch a hydrogen economy have been focused on hydrogen fuel cell electric (HFCE) light duty vehicles. These vehicles use little fuel (typically less than 1 kg H_2/day), require numerous, distributed fueling stations that are, by necessity, small (typically under 200 kg H_2/day) and a major cost centre. The fuel is expensive ($15+/kg H_2) and needs to be subsidized by vehicle leases (which are also expensive) and government grants. These initiatives do not survive in the absence of large government subsidies, and it is unlikely they ever will, especially now that battery electric vehicle technologies have advanced so quickly.

The focus for a hydrogen economy in the transportation sector is now on heavy-duty commercial or municipal vehicles, including fleets of buses and trucks, trains, ships and off-road vehicles. Moreover, the business models being developed for this sector are very different from the incumbent diesel and vehicle markets that they are working to disrupt [76]–[79].

Key characteristics of the target markets for transition to HFCE vehicles include:

- Vehicles that use a lot of fuel (fuel efficiencies of 30-50+ L diesel/100km for road vehicles) and travel long distances per day. HFCE versions of these vehicles will typically consume 20 to 80+ kg H_2/day for road vehicles and hundreds of kg H_2/day for trains, mining trucks, ships etc.;
- Fleets of vehicles that are return to base, or that typically travel the same routes every day so fueling can be carried out at a limited number of large and highly efficient fueling stations, where each fueling station supplies 2 to 10 t H_2/day or more;
- Fleets of vehicles and travel corridors that are likely to support autonomous, driverless vehicles (finding drivers for long haul trucking is a major problem) so the vehicles can be in continuous service, using even more fuel. Plug in electric vehicles are not an attractive solution for such vehicles;
- Many of the HFCE vehicles will be leased, not sold to carriers [76];
- Fueling stations that are strategically located and tied through contractual agreements to fleets of trucks that must refuel there. These stations can also be a site for multi-modal logistics parks and/or an interchange for transferring loads from long haul autonomous vehicles to last mile 'human-driven' vehicles;
- Many of the fueling stations will be owned and operated by the hydrogen vehicle manufacturers or the station owners will have negotiated long-term contracts with the vehicle manufacturers to provide a given volume of low-cost fuel. Another possibility is that the station may be the primary owner of the hydrogen vehicle fleet with subsequent end-use lease agreements with carriers (as being seen in New Zealand with Hiringa Energy and Hyzon Motors [80]). For this market sector, the cost of fuel is one of the largest expenses (also the cost of drivers) and a

consolidation of the value chain from fuel supply to service delivery is a key feature of this disruptive business model.

These kinds of business model changes create the environment in which transition pathways open up for rapid transformation, creating new relationships among fuel suppliers, vehicle manufacturers and vehicle owners and users. This creates an opportunity and challenge for Alberta and Canada in taking a leadership role in this transition. As one of the world's lowest cost producers of blue and green hydrogen, we are ideally positioned to put the infrastructure in place, that will not only attract manufacturers of vehicles and their component parts, but generate economic/business opportunities for the vehicle users (carriers, municipal fleets, etc.), clean up the environment and create new markets for Canada's energy production.

Residential and Commercial Buildings

Decarbonizing energy use by residential and commercial buildings is a major challenge. Electrification with air source heat pumps is a solution that is being proposed for some of the more temperate regions of Canada. In the prairie provinces, winter temperature extremes and shortages of low carbon electricity make electrification of residential and commercial buildings much less feasible: a low carbon chemical fuel is needed. Renewable natural gas (RNG, typically made from landfill gas or anaerobic digestion) is only available in limited quantities. Hydrogen promises to be a lower cost solution, but it is still considerably more expensive than natural gas.

The federal clean fuel standard [31], should it be enacted, could provide an economic incentive to admix hydrogen into natural gas systems up to about 20% by volume (~7% by energy), a concentration that should be compatible with existing infrastructure. Averaged over a year, admixing 20% hydrogen into the natural gas network serving residential and commercial buildings would consume 108 t H_2/day with minimal impact on fuel prices. This is a reasonable deployment target for the next decade.

In the UK, there are efforts to explore the use of 100% hydrogen for space heating [36], [72], but this magnitude of change would require some new infrastructure and a significant increase in fuel costs unless the shift coincided with major improvements in building efficiency.

In the transition to net zero energy systems by 2050, space heating of residential and commercial buildings in cold climates is one of the more challenging sectors to decarbonize. However, hydrogen remains the most promising alternative.

Industrial Heat and Power

In today's economy, coal/coke and natural gas are the predominant fuel sources for industrial heat and power generation. In a future net-zero energy system, hydrogen could take a significant role in sectors that include:

- **Steel Making.** Compared to the use of coke for steel making, hydrogen could reduce GHGs by 80-95% [72], and the companies around the world are exploring opportunities for this transition [81]. While steel making from iron ore is not an active industry in Alberta, it could be a market opportunity for future hydrogen production.
- **Cement Industry.** While hydrogen is being explored as a zero-carbon fuel for cement making [82], it is important to recognize that most of the GHG emissions from cement making comes from the limestone feedstock, not the energy carrier. To address both sources of CO_2, Spinelli and coworkers [83] have proposed the use of molten carbonate fuel cells. The fuel cells use internally produced hydrogen to concentrate flue gas CO_2 into a pure CO_2 stream that can be sequestered, and also produce low carbon electricity.
- **Gas Turbine Power Generation.** While most conventional gas turbines are not designed for fuels containing high hydrogen concentrations, the equipment providers are rapidly developing these [32], [84] , and at least one large power generation facility [85] will be coming on line in the next year that is capable of using pure hydrogen. Such a technology could be very important for Alberta as it shifts from coal to lower carbon generation sources in the next decade.
- **Firming Wind.** Southern Alberta is noted for its excellent wind resource [86], and its low cost of production makes it attractive as a source of energy for either the electrical grid or for green hydrogen production, especially if pipelines were in place to take that hydrogen to market. The variable nature of the wind resource is more easily managed if the end product is hydrogen. However even in wind-to-grid applications, hydrogen could play an important role in firming wind's contribution. If the wind is not blowing, blue or green hydrogen could be used to generate low carbon electricity for the grid until the wind returns.
- **Long Term / Seasonal Energy Storage.** Recent reports [12], [87] have highlighted the potential to use hydrogen for long term or seasonal storage of gas (e.g. in salt caverns [43]) that could then be used as a fuel for heating or transportation, or as a fuel for power generation.

5.3 Recommendations

With these insights in mind, the following recommendations are offered, not only for the Alberta Industrial Heartland, but for other potential nodes in Alberta and across Canada interested in developing a hydrogen economy.

1. Roadmap

A roadmap is needed that clearly embraces the scale and nature of the ambition for a hydrogen future in Alberta and Canada. It should engage all levels of government as well as industry and other stakeholders. The Roadmap must be evidenced based and ideally the ambition will be large and include milestones for deployment every 5 years or so over the next 30 years. Notably the Government of Alberta has already started developing a Hydrogen Roadmap for Alberta.

2. Standards and Regulations

Standards and regulations related to hydrogen and CO_2 must be put in place soon, including:

- What defines various grades of low GHG hydrogen, ideally the maximum life cycle GHG emissions per kg H2, rather than 'blue' vs. 'green'
- Safety regulations for hydrogen fueling stations, monitoring etc.
- Regulations around CCUS, especially that associated with hydrogen production.

3. First Nations Engagement

Explore interest and opportunities for First Nations to get involved in, and lead in, the production, transportation (including pipelines) and use of hydrogen, capturing and storing CO_2, etc. Identify and address concerns. Engage First Nations in being part of hydrogen node development.

4. Strategy for 'Blue' H2 Production

Large scale (100's t H_2/d) production is needed to achieve the best economics for SMR-CCUS or ATR-CCUS, so for the next few years, the primary use of the hydrogen will be as an 'industrial feedstock'. Public investments in these projects should be tied to an ability to divert some H_2 to new fuel markets at a price that is similar to what is being charged for its use as an industrial feedstock. The fuel H_2 will ideally be pipelined along strategic corridors to meet (nearby) demand for heavy transport or space heating, etc. Rapidly build demand to a scale that will pay for the production and distribution of the H_2 fuel without ongoing public subsidies.

5. Strategy for Green H2 Production

If available, convert surplus low C grid power to fuel H_2 and O_2 through water electrolysis. Explore potential markets for the O_2 as well as the H_2. Explore the feasibility of building

12-60 MW_e wind/solar and use an electrolyzer to produce ~2t H_2/d for a single HDV fueling station. 'Piggy-back' on pipelines built for blue hydrogen to take gas to market.

6. Strategy for Byproduct H2 Production

Identify locations where H_2 is made as a byproduct of another process but not used in an optimal way. Assess the GHG footprint associated with diverting that hydrogen to fuel use using published criteria [88], [89] and explore opportunities to find nearby markets for the fuel.

7. Carbon Capture Utilization and Storage (CCUS)

A net-zero energy future relying on hydrogen made from fossil fuels requires a large amount (up to 100-300 t CO_2/year for decades) of secure, permanent storage sites for by-product CO_2. Alberta government policies beginning in 2007 and extending to at least 2014 identified a 2050 CCS target of 139 Mt CO_2/yr, and there seemed to be widespread acceptance that the physical capability existed [90], [91] , even if the costs were high.

It is imperative a critical review of past work on this topic be conducted, to bring it up to date with learnings from Alberta and around the world. With evidence on the magnitude of the opportunity and risks, and detail regarding how they will be managed, it is then essential to engage stakeholder communities and explore the potential to build support for CCUS and a hydrogen economy across Alberta and Canada.

8. Fueling Stations for Buses, trucks and trains

To provide hydrogen as a transportation fuel at a competitive price (C$3-5/kg H2, but ideally <C$3.50/kg H2) without ongoing public subsidies, strategically located fueling stations must deliver 2 to 10 tH2 /d, and be able to serve both hydrogen fuel cell electric (HFCE) vehicle and H2-diesel dual-fuel vehicles. Note that smaller temporary stations will initially be needed to support pilot and small demonstration projects. To meet these criteria, there may be a need for policy instruments, at least in the early stages. Note that smaller temporary stations will initially be needed to support pilots and small demonstration projects.

9. Hydrogen Vehicle Deployment

Hydrogen Vehicle Deployment in pilots or small demonstration projects are needed to explore 'fit for service' potential of these new vehicles under real world conditions in Alberta and across Canada. Insights from these trials must be made public (including a transparent discussion of pros and cons) to assess – and if justified - build confidence in the viability of these vehicles for particular sub-sectors. When evidence of 'fit for service' has been achieved, public support will be needed to deploy a sufficient number of these vehicles at a scale and in concentrated locations to ensure the economic viability of the fueling station. We recommend:

- Public support for the deployment of both HFCE vehicles and H2-diesel dual fuel heavy duty vehicles that (a) have large fuel demand (ideally 20-100+ kg H2/vehicle/day), and (b) can refuel daily at the fueling station in the hydrogen node. Dozens to hundreds of HFCE and/or H2-diesel vehicles (including buses, trucks, trains) will need to be deployed in partnership with municipalities or companies that can operate with only one or perhaps two fueling stations.
- Since the retrofit cost for deployment of H2-diesel vehicles is lower than the incremental cost of HFCE vehicles, and the barriers to deployment are lower, more H2-diesel dual fuel vehicles are likely to be deployed in early years.

10. Decarbonizing Natural Gas for Heat and Power

In Alberta, natural gas is a low-cost fuel ($1 to $5/$GJ_{hhv}$) that has widespread use in industry (cement, fertilizer, oil sands, power generation, etc.) and space/water heating for residential and commercial buildings. In a net-zero energy system, hydrogen is a credible alternative to natural gas, but is significantly more expensive ($10-$14/GJ_{hhv} H_2 or $1.40 to $2/kg H_2). The successful transition to hydrogen as a zero-emission heating fuel will require society to accept either a higher cost for heating fuels (offset, in part, by thermal efficiency improvements) or a decline in hydrogen price with scale of deployment and technology innovation. We recommend:

- Based on work to date, hydrogen can be mixed with natural gas at up to 15% by volume in pipelines serving residential and commercial buildings with minimal impact on infrastructure or fuel cost. A noteworthy ATCO pilot will add 5% H_2 into natural gas pipelines serving residential and commercial buildings in Fort Saskatchewan. If all goes well with this project, the hydrogen additions could be extended to the City of Edmonton using the 'gates' that are located in the same corridors where there should be fueling station demand (**Figure A**).
- Work should also be done to explore the use of up to 100% hydrogen for residential and commercial buildings and for heat and/or power generation. It would be useful to engage with the Hy4Heat.info initiative in the UK, and partner with makers of furnaces, water heaters, cook stoves, reciprocal engines or gas turbines to test the performance of their devices.

11. Moving Hydrogen from Supply to Demand

Connecting hydrogen supply to demand is one of the greatest challenges associated with building a new hydrogen energy system. The major benefit of the Edmonton / Industrial Heartland region is the ability to produce a large amount of low-cost, blue hydrogen adjacent to corridors with substantial demand for the gas as a transportation or heating fuel. With sufficient demand for hydrogen in the corridor, pipeline infrastructure can be justified, and the new energy system will become economically viable in the absence of ongoing public investment.

The alternative to hydrogen pipelines is the trucking of compressed H_2 (<0.8 t H_2/vehicle) or cryogenic liquid hydrogen (LH_2, <4 t H_2/vehicle) from sites of supply to sites of demand. The ongoing preparation and transport costs adds $2-4 per kg H_2, making it impossible to meet the target prices identified in Recommendations #8 and #10 without ongoing public investment. In the case of cryogenic H_2, the electricity used to liquify hydrogen will also undermine the GHG benefits if the Alberta high GHG intensity grid is used. Relying on renewable power in Alberta to liquify H_2 will drive the H_2 price even higher. That being said, the trucking of compressed or liquified hydrogen can play an important role in supporting pilots and small demonstration projects, or in supporting fueling stations awaiting the arrival of a pipeline.

For the Edmonton/Industrial heartland region, we recommend a focus on rapidly building supply-demand value chains to justify investments in pipelines that connect multiple demand centres along strategically planned corridors. Specific recommendations include:

- Explore the potential to repurpose abandoned/decommissioned pipelines to minimize costs until demand increases enough to justify a new and larger pipeline;
- Strategically place pipelines in industrial corridors to serve transport, natural gas decarbonization, new thermal industries or power generation;
- Seriously consider whether the cost for new hydrogen pipelines should be shared by ratepayers covering the cost of the natural gas pipeline infrastructure in the province;
- Explore the potential for pipeline-connected salt caverns for H_2 storage.

12. International Engagement

Despite having among the lowest cost blue and green hydrogen in the world, Canada is behind other nations in the transition to a low carbon economy. Opportunities for international engagement on this file come from multiple forms that should be explored, including:

- Explore new markets for blue/green H2 exports (USA [California], Japan, S Korea, Germany)
- Engage companies from around the world (e.g. Toyota, Hyundai, VW, Nikola/GM, Freightliner/Dana, GE, Siemens, etc.) that are making HFCE HDV, components for H2-diesel dual fuel vehicles, H2-fueled gas turbines, H2 furnaces, etc. Interest them in the low-cost supply of low GHG hydrogen in the hydrogen nodes as a place to test, sell, build their technologies.

13. Build the Entire Value Chain

Public-private investments should be allocated according to need along the entire value chain (hydrogen supply, distribution, retail, demand, system support) with a goal of creating a new energy system around specific nodes and eventually in corridors linking multiple nodes. A key criterion for investment should include evidence that if the flow of public money stops, the energy system will have the self-sufficiency to carry on.

14. Research and Development Investment

Canada has the proven technologies to get started on the transition pathway to a net zero hydrogen economy, and it is imperative that we begin to deploy these technologies now. Research needs to be focused on techno-economic and life cycle assessments and the development of new business models. There should be significant increases in effort on market innovation, innovating the commercial deployment of existing technologies to solve business, social and environmental problems. There are also new and emerging technologies that could be brought to commercialization more quickly with a strong technology ‘pull’, and these should also be encouraged. As the hydrogen nodes start to take shape, problems will be identified and the technology pull will speed innovation and reduce costs. Public and private investment is needed, but it is imperative that the deployment of vibrant hydrogen nodes is not delayed by waiting for new technologies that may never materialize.

15. Engage Colleges and Universities

Universities and colleges in Canada tend to train students and explore R&D questions that are focused on developing new technologies in existing energy systems. They are not well versed in thinking about the characteristics and challenges of how to use existing technologies in new ways to deliver the economic and environmental benefits of net-zero energy systems of the future. This is especially true if future energy systems will be fundamentally different from the systems that exist today. Research, teaching and student training needs to include a better understanding of energy systems, the net-zero transition, and how Alberta and Canada can win economically and environmentally in a quickly changing world. There needs to be more interdisciplinary effort to find solutions to problems that do not respect disciplinary boundaries.

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