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THE FUTURE OF FREIGHT

PART C: IMPLICATIONS FOR ALBERTA OF ALTERNATIVES TO DIESEL

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UNIVERSITY OF CALGARY

CESAR

A project associated with

The Transition Accelerator

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VERSION 1

About CESAR and The Transition Accelerator

CESAR (Canadian Energy Systems Analysis Research) is an initiative started at the University of Calgary in 2013 to understand energy systems in Canada, and develop new analytical, modeling and visualization tools to support the transition to a low-carbon economy.

In 2017, CESAR launched its **Pathways Project** to define and characterize **credible** and **compelling** transition pathways for various sectors of the Canadian economy that would help the nation meet its 2030 and 2050 climate change commitments made in Paris in 2015 (**Figure 1.1**).

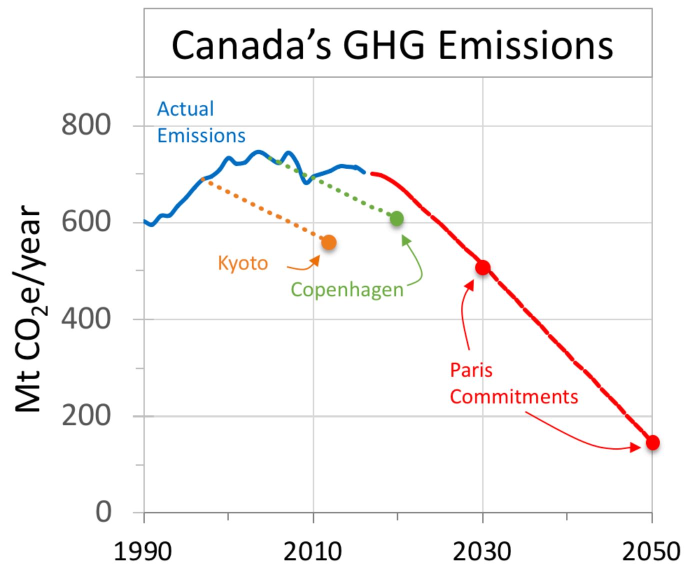

Figure 1.1. Canada's greenhouse gas emissions (solid blue line), showing the future trajectory needed to meet Paris commitments (red line). Past failed commitments are also shown. Data from the 2018 National Inventory Report for Canada for 1990-2016 (http://www.publications.gc.ca/site/eng/9.506002/publication.html)

A CESAR Scenarios publication in early 2018[1], and the support and encouragement from a number of charitable foundations led to discussions among CESAR's Director, **David Layzell**, Carleton University professor **James Meadowcroft** (Canada Research Chair in Governance for Sustainable Development, School of Public Policy and Administration) and Université de Montréal professor **Normand Mousseau** (Dept of Physics and Academic Director, Trottier Energy Institute) regarding the need for a pan-Canadian initiative to accelerate the development and deployment of Transition Pathways.

1 D. B. Layzell and L. Beaumier, "Change Ahead: A Case for Independent Expert Analysis and Advice in Support of Climate Policy Making in Canada," CESAR Scenarios, vol. 3, no. 1, Feb. 2018 [Online]. Available: https://www.cesarnet.ca/publications/cesar-scenarios/change-ahead-case-independent-expert-analysis-and-advice-support

With guidance and financial support from a number of private Canadian foundations, a charitable non-profit was launched in 2019 and called the **Transition Accelerator**. Associated with the launch, a report was published[2] to articulate a philosophy and methodology that is now used by both CESAR and the Accelerator.

In defining and advancing transition pathways, **CESAR** and the **Accelerator** recognize that transformative systems change is needed to achieve climate change targets (see **Figure 1.1**). However, for many, perhaps most Canadians, climate change is not a sufficiently compelling reason for large-scale systems change, especially if it has substantive costs. Nevertheless, we live in a time of disruptive systems change driven by innovations that both promise and deliver highly compelling benefits, such as enhanced convenience, comfort, status, value for money and quality of life. What if it were possible to harness these disruptive forces to also deliver societal objectives for climate change mitigation?

The **Accelerator**'s mandate is to work with key stakeholders and innovators to speed the development and deployment of credible and compelling pathways that are capable of meeting climate change targets using a four-stage methodology:

1. **Understand** the system that is in need of transformative change, 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, the academy, environmental organizations and other societal groups. This engagement process will be 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 researchers then re-engage the stakeholders to revise the vision and pathway(s) so they are more credible, compelling and capable of achieving societal objectives that include GHG reductions (see **Figure 1.2**)
4. **Advance** the most credible, compelling and capable transition pathways by informing innovation strategies, engaging

2 J. Meadowcroft, D. B. Layzell, and N. Mousseau, "The Transition Accelerator: Building Pathways to a Sustainable Future," vol. 1, no. 1, p. 65, Aug. 2019. [Online]. Available: https://www.transitionaccelerator.ca/blueprint-for-change

decision makers in government and industry, participating in public forums, and consolidating coalitions of parties enthusiastic about transition pathway implementation.

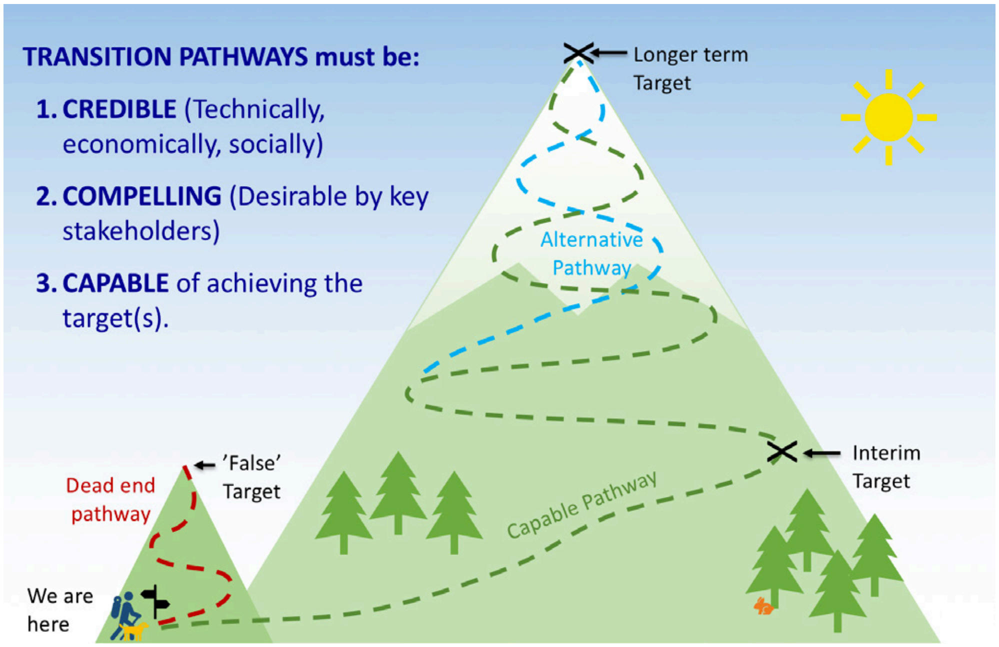

Figure 1.2. Criteria for a useful transition pathway. The two-mountain image is provided to stress the importance of pathways being capable of achieving longer term targets. Some climate change policies encourage dead end pathways to 'false' targets based only on incremental GHG reductions, but which clearly are not on a pathway to a longer-term target.

This study reports Stage 3 results for an assessment of the implications for Alberta of a shift away from diesel fuel for the freight sector and other diesel-using sectors in North America.

About the Authors

David B. Layzell, PhD, FRSC

David Layzell 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, B Comm, MSc (SEDV)

Jessica Lof is a Research Lead for the Canadian Energy Systems Analysis Research (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, a Bachelor of Commerce degree, and a professional designation with the Canadian Institute of Traffic and Transportation.

Kyle McElheran, BSc, EIT

Kyle McElheran completed a Bachelor of Science in Mechanical Engineering at the University of Calgary, specializing in energy and the environment. Kyle's interest lies in nuclear energy. Some of his projects include a life cycle assessment comparison of using small modular nuclear reactors to generate steam in the oil sands, a review of Canada's current nuclear waste management plan, and a review of the DUPIC (Direct Use of Spent Pressurized Water Reactor Fuel in CANDU) nuclear fuel cycle to feed unprocessed spent fuel from pressurized water reactors into CANDU reactors.

Kyle completed a one year internship with Suncor Energy where he worked to optimize construction productivity on the Fort Hills oil sands mine project. In his final academic year, he began studying Canadian energy systems and investigated, as part of an Energy and Environment Specialization capstone course, how autonomous vehicles might impact the future emissions of personal transportation in Alberta.

Madhav Narendran, BSc, BA

Madhav Narendran graduated from the University of Calgary with dual undergraduate degrees in Electrical Engineering (specializing in Energy and the Environment) and Economics. As an undergraduate student he worked with CESAR on a study that considered SAGD cogeneration in the oil sands as a means of greening Alberta's electrical grid. With a variety of interests in the study of energy systems, Madhav has experience working in several fields, including high voltage engineering with ABB, electrical transmission with Altalink LP, and most recently, natural gas trading with BP Canada Energy Group. Madhav is passionate about the use of data to impact real change in policy and decision making. Through his contributions at CESAR he hopes to do just that – provide simple and accessible information to corporate and government entities so they may make meaningful strides toward a more sustainable future.

Nicole Belanger, BSc

Nicole recently graduated with an undergraduate degree in Mechanical Engineering at the University of Calgary, specializing in Energy and the Environment. Passionate about sustainable energy systems, Nicole has worked and studied in several areas of the energy sector. She spent a research term in wind turbine optimization and also studied renewable energy and entrepreneurship abroad in China. For her internship, she worked for one year in Switzerland for GE Power, in gas turbine reconditioning and maintenance. In her Energy and Environment capstone course she developed a pathway with her team to transform Canada's agricultural residues into biochar, a more permanent form of carbon storage.

Nicole is interested in whole system design and the circular economy. She wants to design systems that combine opportunities for economic prosperity with the disruptive changes needed to make society more sustainable. Her interests encompass waste management, biodegradable alternatives to plastic packaging, alternative fuels and emerging technologies in carbon capture and storage.

Bastiaan Straatman, PhD

Bastiaan Straatman has been modeling complex systems throughout his career, but since early 2012, he has been focused on developing and using the Canadian Energy Systems Simulation (CanESS) model to study the past, present and possible future energy systems of Canada. His past work has involved spatial decision support models, models of evolutionary dynamics in economics and models depicting greenhouse gas emissions in municipalities. Bastiaan holds a Master degree in Mathematics and a PhD in Geography. He currently has a fulltime position as a modeller with whatIf? Technologies Inc.

Song Sit, PhD, PEng

Song P. Sit is a Chemical Engineer with 40 years of industrial experience. A veteran of oil sands operations, Song has been involved in many different aspects of the industry over the past 28 years. Most recently, he helped to establish the collaboration agreement for the Canada's Oil Sands Innovation Alliance (COSIA) greenhouse gas (GHG) Environmental Priority Area (EPA). This enabled

COSIA members to work together to develop new GHG reduction technologies. Before that, as a member of the Joint Venture Owner Management Committee of an integrated mining/upgrading Joint Venture, he helped to launch a multi-phase expansion program that trebled its production. As a member of the National Oil Sands Task Force, Dr. Sit helped the Alberta Government implement the Generic Oil Sands Royalty regime in 1997, and as a member of the Canadian Association of Petroleum Producers (CAPP) task group working with Alberta Environment, he helped to establish the rules for the Specified Gas Emitter Regulations, including emission allocations for cogeneration. As an employee of a major oil sands producer for 28 years, he has been engaged in the development of technologies for new oil sands surface facilities, including innovations in GHG reduction and value-added oil sands products. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the principal of GHG Reduction Consultancy, founded in 2015.

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List of Terms

Abbreviation	Definition
1xAB	The diesel energy consumed in Alberta in 2016
9xAB	The diesel energy produced from Alberta oil in 2016
AAC	Annual Allowable Cut
AESO	Alberta Electric System Operator
BD-ICE	Bio-diesel fueled internal combustion engine energy system
Blue Hydrogen	Hydrogen produced from natural gas
CanESS	Canadian Energy Systems Simulator Model from whatIf? Technologies Inc
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CESAR	Canadian Energy Systems Analysis Research Initiative, University of Calgary
CO_2	Carbon dioxide
DC	Direct current
EJ	Exajoule (10^{18} joules)
FD-ICE	Fossil-diesel fueled internal combustion engine energy system
G-BE	Public grid powered battery electric energy system
GHG	Greenhouse gas
GJ	Gigajoule (10^{9} joules)
Green Hydrogen	Hydrogen produced by water electrolysis using intermittent zero-carbon electricity generated from wind and solar facilities
GVWR	Gross Vehicle Weight Rating (the weight of the vehicle plus the payload)
H_2	Hydrogen gas
HDV	Heavy duty vehicle: GVWR of >= 15 tonnes
HFCE	Hydrogen fuel cell electric drivetrain (typically hybrid, with batteries)
HHV	Higher Heating Value
HVO	Hydrotreating vegetable oils

ICE	Internal combustion engine
Mt	Megatonne (10^6 tonnes)
MWh	Megawatt hour
NG	Natural Gas
NGCC	Natural gas combined-cycle power generation
NGSC	Natural gas simple-cycle power generation
NG-HFCE	Natural gas-based hydrogen fuel cell electric energy system
NOx	Nitrogen Oxides
O_2	Oxygen gas
Other Road Freight	Vehicles with a GVWR >= 3.9 < 15 tonnes with a primary purpose of moving freight
PADD	Petroleum Administration for Defense Districts
PJ	Petajoule (10^{15} joules)
$PM_{2.5}$	Particulate Matter ≤2.5μ in diameter
RPP	Refined petroleum products
SCO	Synthetic Crude Oil
SI units	International System of Units
SMR	Steam methane reforming
T&D	Transportation and distribution
WS-HFCE	Wind and solar power-based hydrogen fuel cell electric energy system

Executive Summary

This report extends two previous studies on the 'Future of Freight' in Canada (Part A and Part B) to explore credible and compelling transition pathways that are capable of addressing sectoral challenges, including the need to greatly reduce or eliminate greenhouse gas (GHG) and air pollution emissions associated with diesel fuel use by the sector.

Since Alberta oil provides North America with nine times more diesel than that consumed in the province, this study assesses whether alternative low or zero-emission fuels could make a similar or greater contribution to the provincial and Canadian economies in the future.

Comparison of Low or Zero Emission Alternatives to Fossil Diesel.

While bio-based diesel is a drop-in fuel with low GHG emissions, its use would not address the air pollution problem associated with internal combustion engines. Moreover, Alberta does not have the biomass resources to meet even its own demand for diesel, let alone contribute to the supply of diesel for other jurisdictions. Therefore, as an energy resource, biomass feedstocks may be better suited to smaller markets (e.g. jet fuels), but bio-based diesel is not a credible, compelling or capable diesel alternative.

"Bio-based diesel is not a credible, compelling or capable diesel alternative."

Plug-in, battery electric vehicles may be a viable alternative for moving light or medium duty loads over short distances. However, for heavy duty vehicles, especially those driving long distances, the weight of the batteries will compete with load capacity, and the long recharge time will undermine the economic prospect for the carriers. Consequently, the plug-in, battery electric alternative is not a compelling option for heavy freight transport in Canada. Even if these issues could be addressed, Alberta is already challenged by the need to reduce the carbon intensity of its public grid, and adding the freight sector to the public grid would exacerbate the problem.

The heavy freight sector companies consulted for this project are most interested in hydrogen fuel cell electric (HFCE) vehicles since they promise rapid refueling, longer distances between refueling and the desirable performance of electric drive vehicles. The lack of fuel infrastructure, and the absence of HFCE vehicles are major barriers, as are concerns regarding the cost of the fuel and the vehicles should they become available.

"[The] plug-in, battery electric alternative is not a compelling option for heavy freight transport in Canada"

Two possible sources for the hydrogen are considered. Steam methane reforming of natural gas coupled to carbon capture and geological storage (i.e. 'blue' hydrogen), and electrolysis of water to hydrogen and oxygen using wind or solar generated electricity (i.e. 'green' hydrogen). Alberta has both the natural gas and the wind/solar resource to make sufficient hydrogen to satisfy not only all of the diesel demand in the province, but nine (9) times that amount to be equivalent to what the province currently exports as crude oil for the North American diesel market.

"The heavy freight sector [is] most interested in hydrogen fuel cell electric (HFCE) vehicles"

Compared with other nations, Canada is among the world best places to produce carbon-free hydrogen, primarily due to its low-cost supplies of natural gas and hydropower. This is especially the case for 'blue' hydrogen production in Alberta, the wholesale cost of which is about one third the cost of 'green' hydrogen and one half the pre-tax, wholesale cost of diesel (**Figure 1.3**).

"The wholesale cost of 'blue' hydrogen in Alberta is about one half the pre-tax cost of diesel"

Where hydrogen is likely to have trouble competing with diesel is on the cost of fuel transport and retail. Whereas, transport and retail only adds about $C4 per GJ to the cost of diesel, the lack of infrastructure as well as difficulties in moving and compressing a gas like hydrogen, instead of a liquid fuel, could make the transport and retail cost for hydrogen much higher (**Figure 1.3**).

Minimizing the cost of hydrogen transportation and retail will be essential if there is to be a shift to a hydrogen economy.

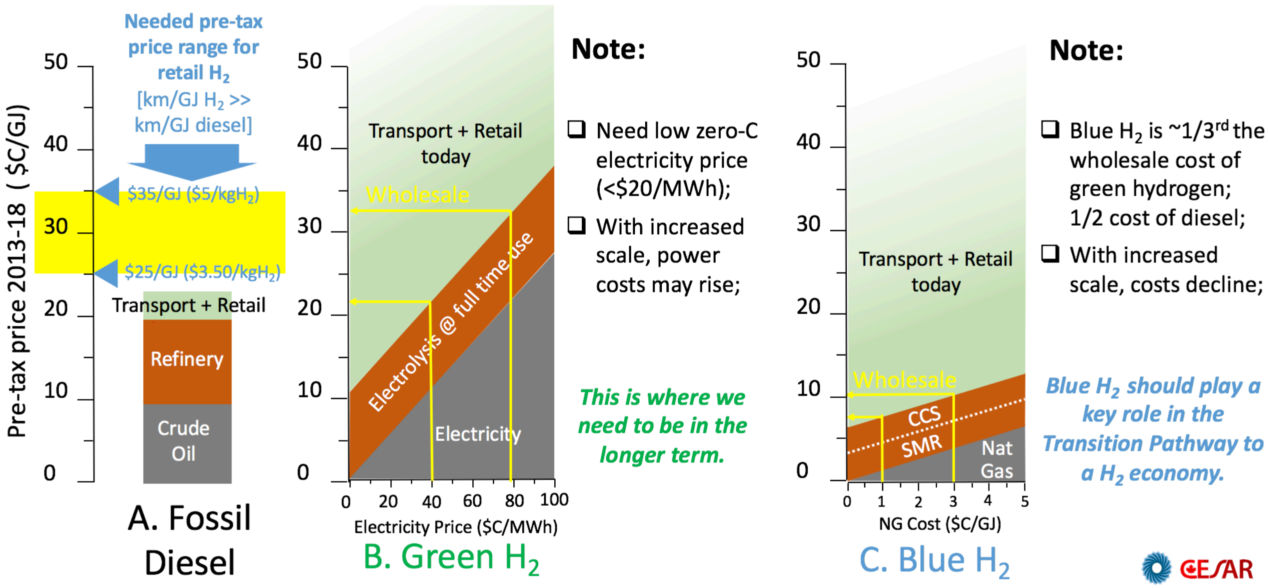

Figure 1.3. A comparison of the average pre-tax cost of diesel fuel (A), green hydrogen (B) and blue hydrogen (C). The diesel numbers (average for 2013-18) are separated into the embedded cost of crude oil (grey), refined to wholesale diesel (red), and transportation and retail (green). The hydrogen costs are presented as charts where the energy input cost (electricity for green H_2, natural gas for blue H_2) impacts the price of hydrogen. The large transport and retail costs for green and blue hydrogen are depicted as a green area, fading to while, since they are highly variable and linked to infrastructure availability and scale of demand. CCS, carbon capture and storage; SMR, steam methane reforming.

Building Transition Pathways to a Hydrogen Economy Anchored by Heavy Freight

Rather than waiting for new technologies to be developed and deployed, we argue that Canada needs to start the journey towards a hydrogen economy using existing, off-the-shelf technologies. This will create a 'pull' for new technologies that could help to speed advances along the pathway, or even open-up new transition pathways.

One or more pathways need to be envisaged and analyzed while working with industry and government proponents to start the journey. Like chains, the strength of an energy system is only as good as its weakest link, so building a new energy system requires a focus on all components of the energy system, linking demand to supply within a supportive policy and regulatory framework.

Given Alberta's ability to produce low-cost, blue hydrogen, we propose that Alberta create corridors of cost-effective hydrogen supply (retail at $C3.50-5.00/kg H_2) where there is also high-demand for both HFCE powertrains and other uses for the energy carrier. Such a corridor should be self-sustaining and attract companies developing and deploying technologies in support of the transition to a hydrogen economy. Once established, these corridors can grow along major roadways, rail and pipeline right of ways to other parts of the provinces, other provinces, the USA and overseas markets.

"We propose that Alberta works to co-create corridors of cost-effective hydrogen supply where there is also high demand for both HFCE drivetrains and other uses for the energy carrier."

Also, once hydrogen pipeline infrastructure is in place, there should be an opportunity to bring more green hydrogen into the new energy system, since – as discussed in Section 7 of this report- if water electrolysis provides an alternative use for low-cost wind power, it would make sense to build more wind generation and simultaneously lower the carbon intensity of the Alberta grid, while providing a valuable zero-emission transportation fuel.

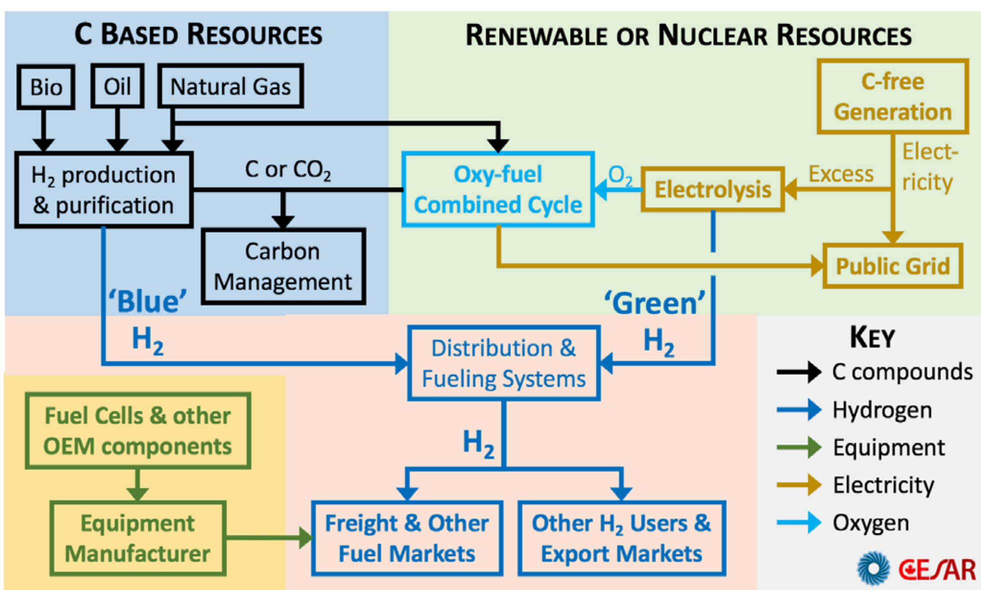

Figure 1.4. A hydrogen energy system supporting zero emission fuels. It incorporates both 'blue' hydrogen production (Section 6 in this report) and 'green' hydrogen production (Section 7 in this report) where green hydrogen production is also linked to the decarbonization of the public electrical grid.

Figure 1.4 offers an overview of how a new energy system based on 'blue' and 'green' hydrogen production could work together to not only decarbonize transportation, but also the electrical grid.

To build out credible and compelling transition pathways that are capable of achieving Canada's emission reduction commitments will require answers to a number of questions (See **Section 8.5**), with an understanding that the answers may differ among regions in Canada.

Building transition pathways is also a team sport, requiring a shared vision on the nature of the objective, a shared appreciation of the resources available for the journey, and a shared conviction that the trip is worth taking. The transition to a zero-emission hydrogen economy will take a number of decades, and many details of the pathway will not be known until the journey is well underway. The current focus must be on the best way to get started and ensure that a broad range of sectors will participate in the journey.

1. Introduction

The freight sector in Alberta, across Canada and around the world is a significant source of greenhouse gas (GHG) and other air emissions, with adverse impacts on the world's climate systems as well as human health. Addressing this problem will require a transition away from the fossil diesel-internal combustion engine (FD-ICE) energy system that currently dominates the sector.

Accelerating the transition to low or zero-emission alternatives to fossil diesel will require the engagement and support of the key stakeholders in this sector: the companies that buy and use the vehicles for goods movement.

In the Future of Freight series, we have used methodology of the Transition Accelerator [1] to gain a deeper understanding of the trends and disruptive forces impacting goods movement in Alberta and Canada [2]. This work showed that the transportation sector is poised for transformative, potentially disruptive changes as a result of technology, business model, policy and social innovations.

The second report in the Future of Freight series [3] compared four alternative energy systems (bio-based diesel, plug in electric, hydrogen fuel cell electric with hydrogen from either fossil fuels with carbon management, or water electrolysis with renewable power). The comparison focused on the 'fit for service' of the alternative energy systems from the perspective of the freight carriers, as well as the ability of these systems to meet societal needs for reductions in GHG and air emissions.

The future of freight is also important to the sectors and regions that provide diesel fuel, as they could work to either facilitate or hinder the transition to low or zero-emission alternatives. As a major source of the oil and natural gas used to create diesel fuel, Alberta is clearly in the transportation fuel business. Not surprisingly, it would be in the best interest of the province to stay in the transportation fuel business if there is to be a transition away from using diesel in internal combustion engines.

This report is the third study in the Future of Freight series. It explores the same four alternative energy systems that were assessed in Future of Freight Part B [3]. However, this report focuses on the potential contribution that Alberta could make to a diesel fuel equivalent demand under each of the alternative energy systems. Four demand scenarios for 2016 are considered:

- Heavy duty road transport demand for diesel in Alberta,
- All diesel demand in Alberta,
- Heavy duty road transport demand for diesel originating from Alberta oil in North America,
- All demand for diesel originating from Alberta oil in North America.

The study begins with an analysis of how much diesel is produced from the crude oil recovered in Alberta, and how that fuel is used. It then explores whether Alberta has the resources and is competitively positioned to produce, use and export a similar quantity of a low or zero carbon transportation fuel into the North American market.

The report concludes with recommendations regarding a possible vision for the Future of Freight Transportation in North America, identifying initial steps in a transition pathway to a credible and compelling low carbon future.

2. Setting the Bar: Alberta and the Supply of North American Diesel

2.1. Production and Use of Diesel Made from Alberta Crude Oil

Oil recovered and produced from geological deposits in Alberta and Canada is categorized into the categories of (1) conventional light oil that has a density <900 kg/m^3, (2) conventional heavy oil that has a density of > 900 kg/m^3, (3) synthetic crude oil (SCO) that is upgraded from raw bitumen, (4) diluted bitumen (dilbit) that is a blend of raw bitumen and condensate products, and (5) synthetic bitumen (synbit) that is a blend of SCO and raw bitumen.

In 2016, oil production in Alberta accounted for approximately 81% of Canada's total oil production [4], [5] and from the years 2000 to 2016, Alberta production of crude oil more than doubled to 3.1 Mbbl/day [5] due in part to expanding oil sands operations (**Figure 2.1.A**).

These oil resources were then transported to refineries across Canada and the United States and made into refined petroleum products (RPP). Using volumetric data compiled from National Energy Board [6] and Statistics Canada [7]–[9]with data for years 2016 - 2017 (not all combinations necessarily have data for all years, it was determined that in 2016, 2.4 Mbbl/day (76%) of Alberta's crude oil was delivered to refineries in the United States, while 0.5 Mbbl/day (17%) was sent to refineries in western Canada, and 0.2 Mbbl/day (7%) was sent to central Canada (**Figure 2.1.B**).

When converted into energy units, refineries across North America were supplied with a total of 7.9 EJ_{HHV}/year of Alberta crude oil in 2016. Based on data from Energy Information Administration [10]–[14], Statistics Canada[7], [9], [15], [16], National Energy Board [6] and GHGenius [17], the refineries also used 0.08 EJ_{HHV}/yr of other feedstock inputs and 0.22 EJ_{HHV}/yr of electrical and heat energy to produce 7.0 EJ_{HHV}/yr of RPP (**Figure 2.2.A**).

In total, 77% of the RPPs produced from Alberta crude oil resources are transportation fuels (i.e. diesel, gasoline, and jet fuel. Heavy fuel oil is not included as a transportation fuel although it can be used as such (e.g. ships). Of course, diesel and gasoline are also used as fuels for services that are not considered transportation (power generation, etc.). Note that diesel fuel accounts for 33% (2.3 EJ_{HHV}) of the RPP that is produced from Alberta oil (**Figure 2.2.A.**).

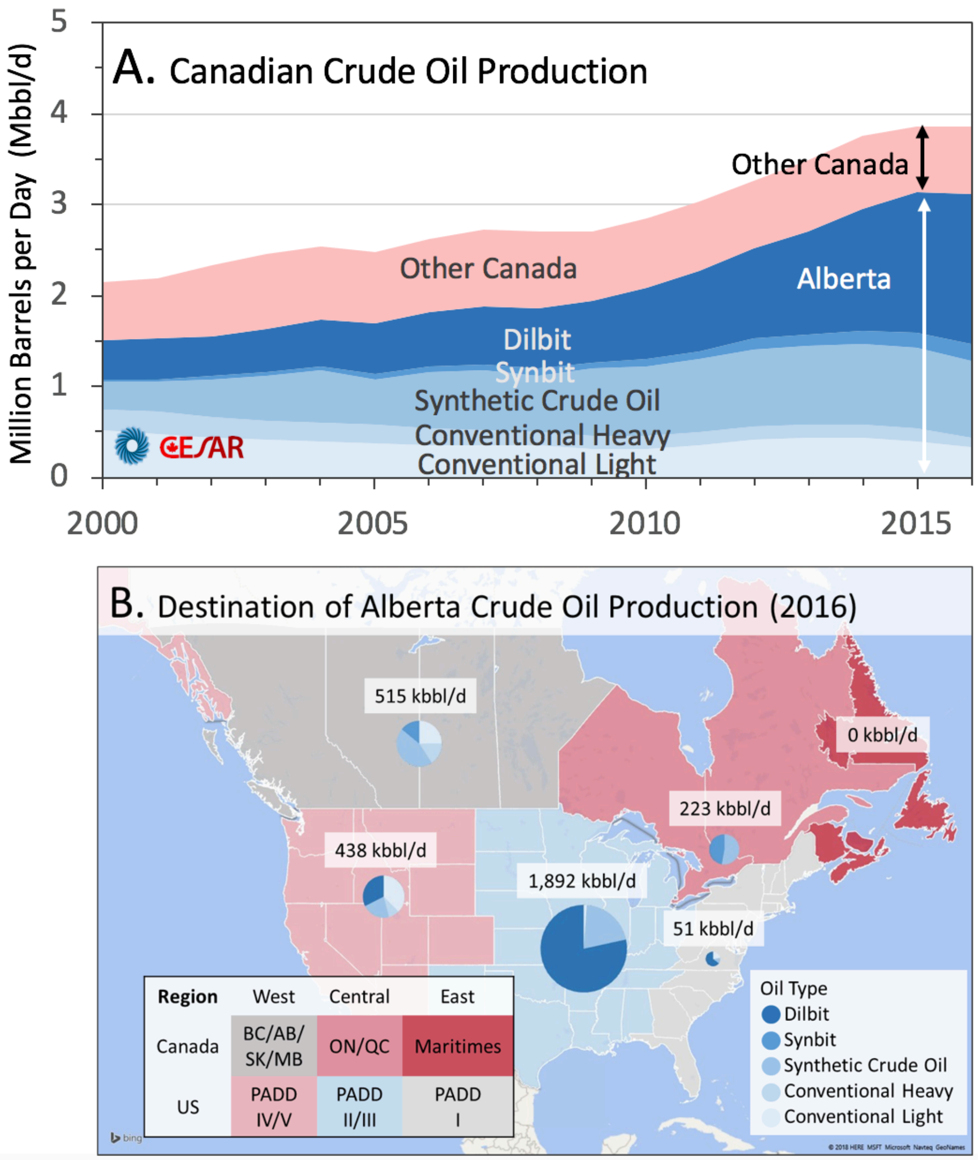

Figure 2.1. Crude Oil Production in Canada from 2000 to 2016 (A), and the refinery destination of the Alberta produced oil in 2016 (B). Refer to text and supplemental information for details. Panel B map from Microsoft Corporation.

In 2016, Alberta consumed about 258 PJ_{HHV}/year [21] or 11% of the diesel that was produced from its oil (**Figure 2.2.B**); the remaining 89% of diesel fuel was consumed in other jurisdictions. Therefore, Alberta supplies oil to make diesel at a scale that is 8.9-times larger than its own domestic market (**Figure 2.2.D**).

Similarly, Alberta's oil supplies a gasoline market that is 12.4-times its domestic size and jet fuel market that is 6.6-times its own domestic needs. On average, Alberta crude oil is used to produce 10.2 times more transportation fuel than that consumed in the province,

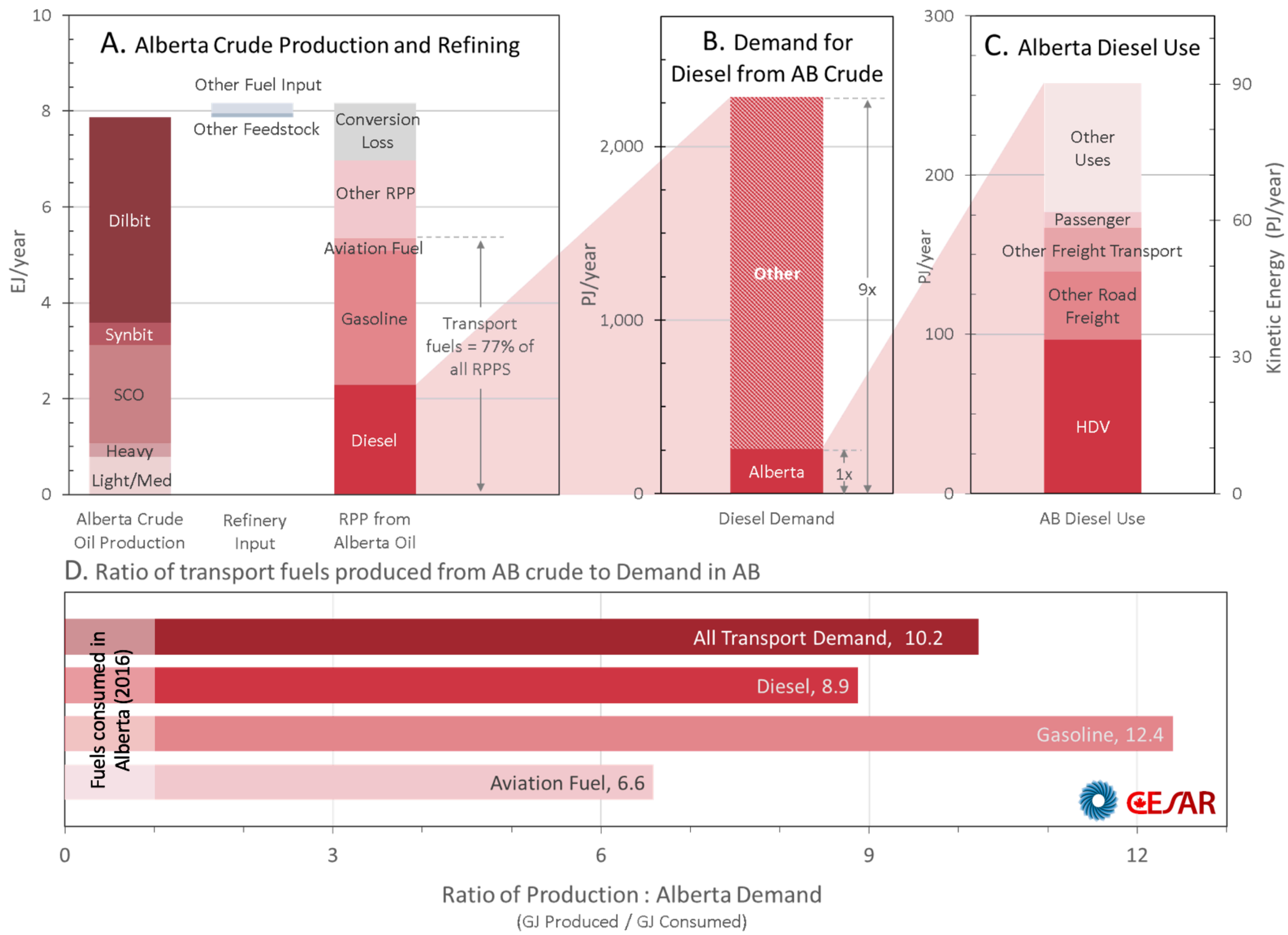

Figure 2.2. The 2016 production of crude oil in Alberta **(A)**, its conversion to refined petroleum products (RPP), the allocation of the diesel production between Alberta's needs and other jurisdictions **(B)**, the use of diesel in Alberta **(C)**, and the ratio of transport fuels produced from AB crude to that which is consumed in Alberta **(D)**. The right scale on panel C shows the kinetic energy demand assuming a 35% diesel internal combustion engine powertrain. See Supplemental Materials Table S1, S2 and S3 for details.

highlighting the importance of the North American transportation sector to the economy of Alberta (**Figure 2.2.D**).

Figure 2.2.C provides a breakdown of how the 258 PJ/year of diesel fuel is used within the province of Alberta. Heavy duty vehicle (HDV) freight transportation[1] accounted for the largest fraction (97 PJ_{HHV}/year or 38%) of Alberta's diesel consumption in 2016 [18], [19]. Other road freight and other freight transportation such as railways accounted for an additional 70 PJ_{HHV}/year (27%) of domestic diesel demand **(Figure 2.2.C).**

Whether the diesel fuel is used to support transportation, farming operations or power generation, the fuel is typically converted into kinetic energy using an internal combustion engine (ICE) powertrain

1 Vehicles that have a gross vehicle weight ratings (GVWR) greater than or equal to 15 tonnes,

with an efficiency of about 35% [20], [21]. Using this conversion factor, the right axis in **Figure 2.2.C** shows that in Alberta, the fossil diesel internal combustion engine (FD-ICE) system delivered about 90 PJ/yr of kinetic energy.

Applying the 35% ICE conversion factor to all diesel fuel made from Alberta oil results in the calculation of 800 PJ /yr for the kinetic energy provided by diesel originating in Alberta (**Figure 2.3**).

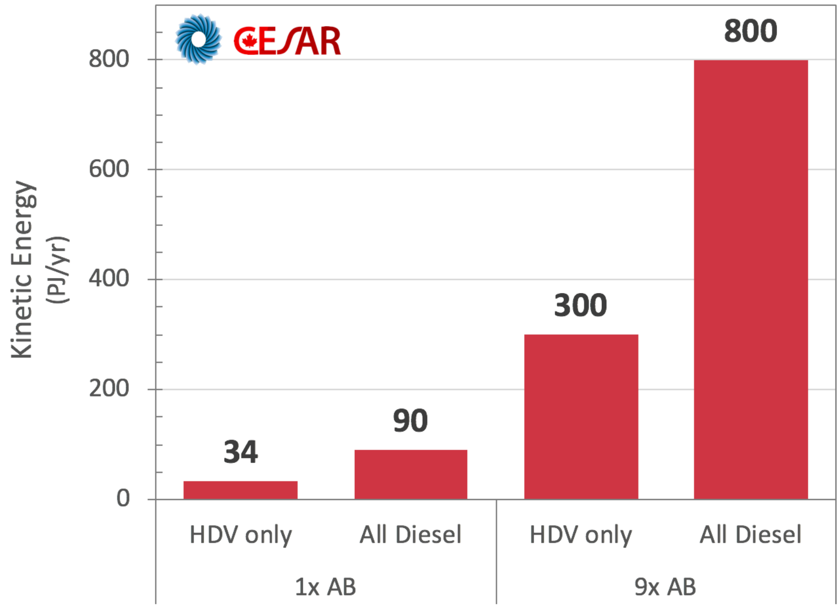

Figure 2.3. The demand for kinetic energy that is currently supplied by diesel that is produced from Alberta oil and consumed domestically in the province (1xAB) and across North America (9xAB). Assumes a 35% efficient internal combustion engine. See Supplemental Materials **Table S3** for details.

The **90 PJ_{HHV}/year** and **800 PJ_{HHV}/year** values are important because they establish the size of the energy market that diesel fuel produced from Alberta fossil resources currently supplies. For Alberta to maintain a similar market share and participate and prosper to the same extent it does now, in a new alternative energy system, any new systems would need to be capable of reaching these targets.

2.2. Well to Wheels Greenhouse Gas Emissions from FD-ICE Energy System

As discussed in a previous Future of Freight report [3], the combustion of diesel fuel generates about 71 kg of greenhouse gas (GHG, CO_2e) emissions for every GJ of fuel consumed, and the recovery and processing of the fuel adds another 25 kg CO_2e/GJ for a well to wheels emissions of about 96 kg CO_2e/GJ diesel.

Therefore, the 258 PJ/yr of diesel use in Alberta in 2016 contributed about 25 Mt CO_2e to the province's GHG emissions (i.e. about 6.1 tonnes per capita), and the well to wheels emissions from all diesel fuel made from Alberta oil in 2016 was about 220 Mt CO_2e/yr (**Figure 2.4**). Of course, most of the latter emissions are distributed across the North American jurisdictions that refine and consume the diesel derived from Alberta oil.

To address Canada's climate change commitments, fossil diesel fuel production and consumption with CO_2 release to the atmosphere must be virtually eliminated within the next 30 years. Capturing the CO_2 emissions from the tailpipe of a vehicle is not a feasible option since the CO_2 product of combustion is at least three times the weight of the fuel.

Clearly, an alternative energy system is required that produces very low or zero GHG emissions. From an Alberta perspective – it would be ideal if the province had the resource potential to not only make enough of that fuel to meet its own needs, but sufficient to meet the needs of other jurisdictions, a role the province currently plays with its North American diesel supply.

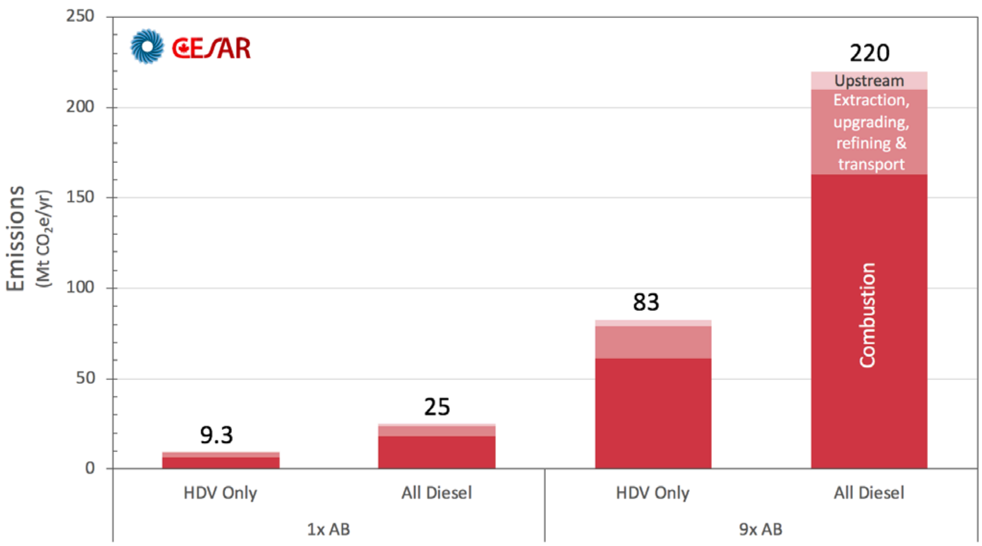

Figure 2.4. Well to wheels greenhouse gas (GHG) emissions in 2016 associated with the diesel produced from Alberta oil and consumed domestically in the province (1xAB) and across North America (9xAB). See Supplemental Materials **Table S4** for details.

3. The Alternative Energy Systems and Assessment Criteria

In addition to the FD-ICE energy system, there are four other low carbon or zero-emission energy systems that have potential to support the heavy freight and other sectors currently reliant on diesel. These are shown in **Figure 3.1** and include:

- **Bio-based Diesel Fueled ICE (BD-ICE) Energy System:** This low carbon energy system involves the use of drop-in replacement diesel fuel made by transesterification of plant and animal lipids (oils and fats) or from bio-based lignocellulosic (wood and straw) feedstock using Fisher-Tropsch synthesis.
- **Grid to Battery Electric (G-BE) Energy System:** Power from the public grid is used to charge battery-electric vehicles that use electric motors in the vehicle drivetrain. The emissions from this energy system comes from power generation.

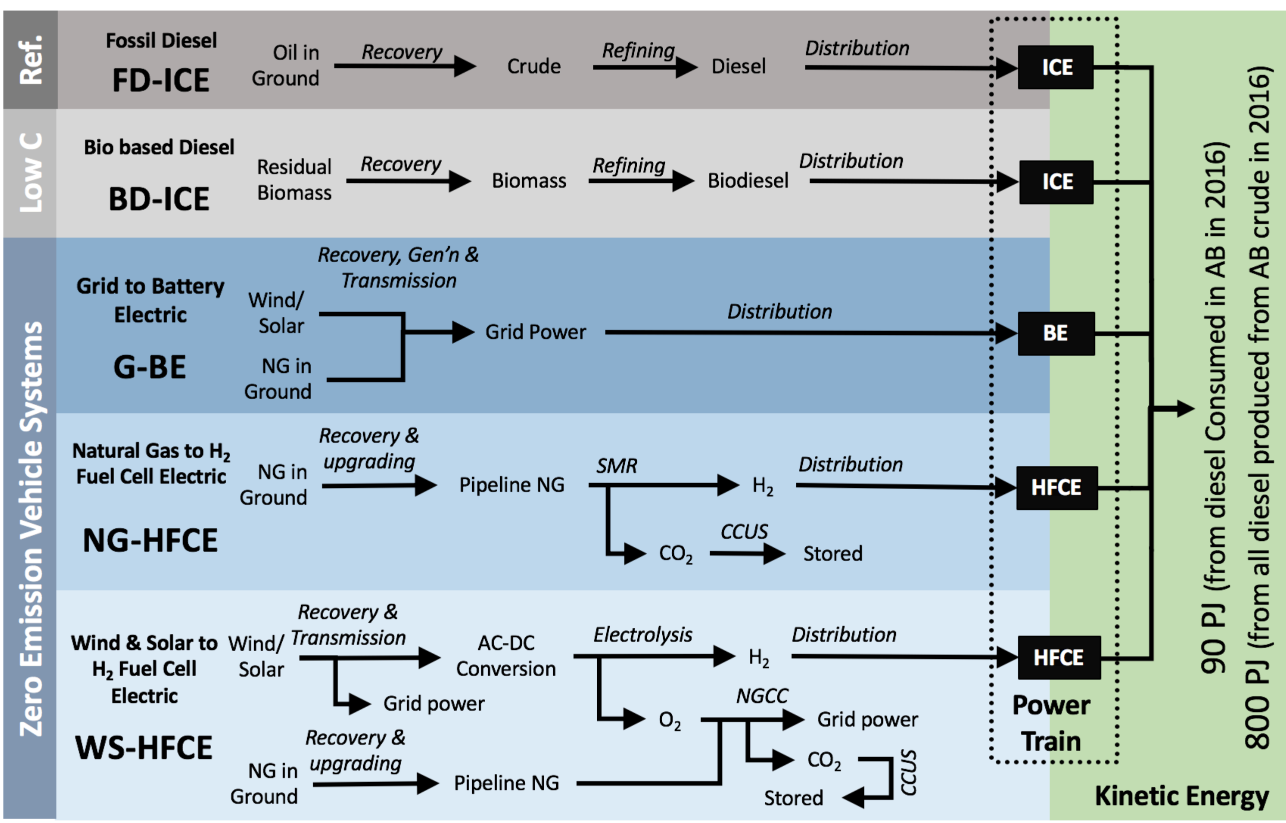

Figure 3.1. Summary of the Five Energy Systems Studied and Compared in this Report. See text for details. CCUS, carbon capture, utilization and/or storage; NGCC, natural gas combined cycle.

Two public grid mixes2 were considered for Alberta: a 2016 grid mix consisting of 61% coal, 27% natural gas (17% co-generation, 1% simple cycle, 9% combined cycle), and 11% renewable power generation [22]. A 2030 public grid mix that assumes post-coal phase out [23], and consisting of a grid mix with 0% coal, 70% natural gas (20% cogeneration, 4% simple cycle, 46% combined cycle) and 31% renewable power generation [22].

- **Natural Gas to Hydrogen Fuel Cell Electric (NG-HFCE) Energy System:** Onboard hydrogen fuel cells are used to convert hydrogen (H_2) fuel to electricity to power an electric motor. In this energy system, the H_2 is generated from natural gas with steam-methane reforming (SMR) technology and part of the waste CO_2 is captured and stored (CCS) in the subsurface or otherwise utilized (CCUS). Such low carbon H_2 from fossil fuel sources is known a 'blue hydrogen'3. Although 'blue hydrogen' can be produced from other fossil fuel sources with other technologies, SMR with CCS has been selected because of its maturity and industrial prevalence.
- **Wind/Solar to Hydrogen Fuel Cell Electric (WS-HFCE) Energy System:** This system is similar to the NG-HFCE system, but the H_2 is generated from large wind and solar facilities that supply the grid when needed and generate H_2 and oxygen (O_2) from water electrolysis when generation is in excess of grid demand. Such zero-carbon hydrogen is known as 'green hydrogen'.

Assessment Criteria

Each alternative energy system was assessed according to the following three criteria:

1. **Ability to supply the kinetic energy equivalent to Alberta's domestic diesel demand (1xAB).** In the FD-ICE energy system, diesel produced from Alberta oil resources easily supplies the province's domestic demand from heavy freight transportation, mining, forestry, construction, residential, agriculture, and other uses for the fuel. Assuming 35% conversion efficiency the 258 PJ diesel use/yr is equivalent to 90 PJ of kinetic

2 In addition to a public grid of about 62.5 TWhr (2016) [22], Alberta has about 20 TWhr of 'behind-the-fence' generation that is dominated by natural gas fired cogeneration. We assume that all HDV vehicle recharging occurs using the public grid.

3 Most of the H_2 produced in Alberta today is from natural gas but the CO_2 byproduct is released to the atmosphere, creating a greenhouse gas emission. Such 'grey' hydrogen is less expensive than the 'blue' hydrogen where the majority of the CO_2 is capture and prevented from entering the atmosphere.

energy **(Figure 2.3)**. Therefore, each of the alternative energy systems were evaluated on their ability to meet the 90 PJ/yr of kinetic energy using energy inputs that derive from provincial resources. This assessment takes into account existing demand for the resource, and the energy system efficiencies described in the preceding Future of Freight report [3].

2. **Ability to supply the kinetic energy equivalent to Alberta's contribution to North American Diesel Demand (9xAB).** Alberta's oil resource also supplies a North American market for 2,286 PJ diesel/yr, equivalent to 800 PJ/year of kinetic energy **(Figure 3.2.)** or about 9 times the domestic (within Alberta) demand for diesel. The concept behind this criterion is that it would be more attractive to the province if an alternative to diesel would make it possible for Alberta to continue to serve a similar proportion of the future North American transportation fuel market.

3. **Ability to reduce by 84%, Alberta's well-to-wheels level of diesel emissions in 2016.** As shown in Figure 2.4, diesel fuel use in Alberta in 2016 was associated with well-to-wheels GHG emissions of about 25 Mt CO_2e/year. To meet Canada's commitments in the Paris climate change agreement, an 80% reduction in 2005 level of emissions is required by 2050. Given growth in diesel fuel demand between 2005 and 2016, an 84% reduction in 2016 level of emissions is required [3], setting a target for the diesel-fueled sector in Alberta of 4 Mt CO_2e/yr. When a similar calculation is applied to the well-to-wheel emissions from all diesel produced from Alberta oil in 2016 (220 Mt CO_2e/yr, Figure 2.4), a target for that proportion of the North American diesel market was set at 35 Mt CO_2e/yr.

4. Bio-based Diesel to Internal Combustion Engine (BD-ICE) Energy System

4.1. An Overview of Bio-based Diesel Alternatives

Bio-based diesel fuels are a renewable substitute for conventional diesel, and are a component of fuel standards that are planned or in place for the nation [24] and province [25]. Since these fuels are made from bio-based feedstocks, the carbon in the molecules were recently (within one year for most agricultural products, within 100 years for most forestry products) in the atmosphere so their combustion and CO_2 release to the atmosphere is not considered a GHG emission.

There are many different methods and technologies that can convert biological resources into a bio-based diesel fuel that act as a drop-in substitute to conventional fossil-based diesel.

Transesterification of plant and animal lipids (oils and fats) is the dominant method of producing bio-based diesel. In recent years, renewable diesel produced from hydrotreating vegetable oils (HVO) has also contributed to the production mix [26] **(Figure 4.1)**.

Supply limitations and food-versus-fuel concerns associated with these ‘1st Generation’ biofuels have increased interest in the production of renewable diesel from lignocellulosic feedstocks. Such ‘2nd Generation’ biofuels are not currently used at scale **(Figure 4.1)**.

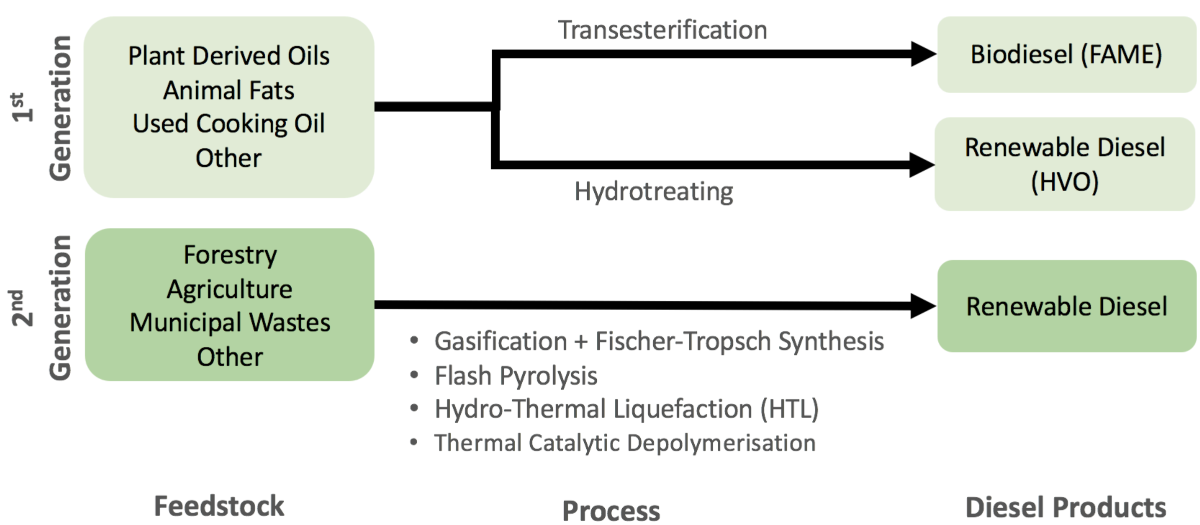

Figure 4.1. Summary of bio-based diesel production methods and corresponding feedstock and products; HVO, hydrotreated Vegetable Oil.

The following sections of this report evaluate the feedstock resource potential of 1st and 2nd generation bio-based diesel in Alberta.

4.2. Resource Potential for First Generation Bio-based Diesel

In 2016, Alberta produced 4.4 PJ_{HHV}/yr (126 ML/yr) of bio-based diesel (biodiesel and renewable diesel) [26] and accounted for only 2% of Alberta's total domestic diesel demand in 2016. This share is consistent with minimum biofuel blend levels that are mandated by the Alberta Renewable Fuel Standard [25].

Canola, a popular crop in Alberta, is assumed to be the sole feedstock for current bio-based diesel production. Canola oil, however, is primarily a food product and there is moral resistance to sacrificing agricultural land or food resources for the production of transportation fuels [27].

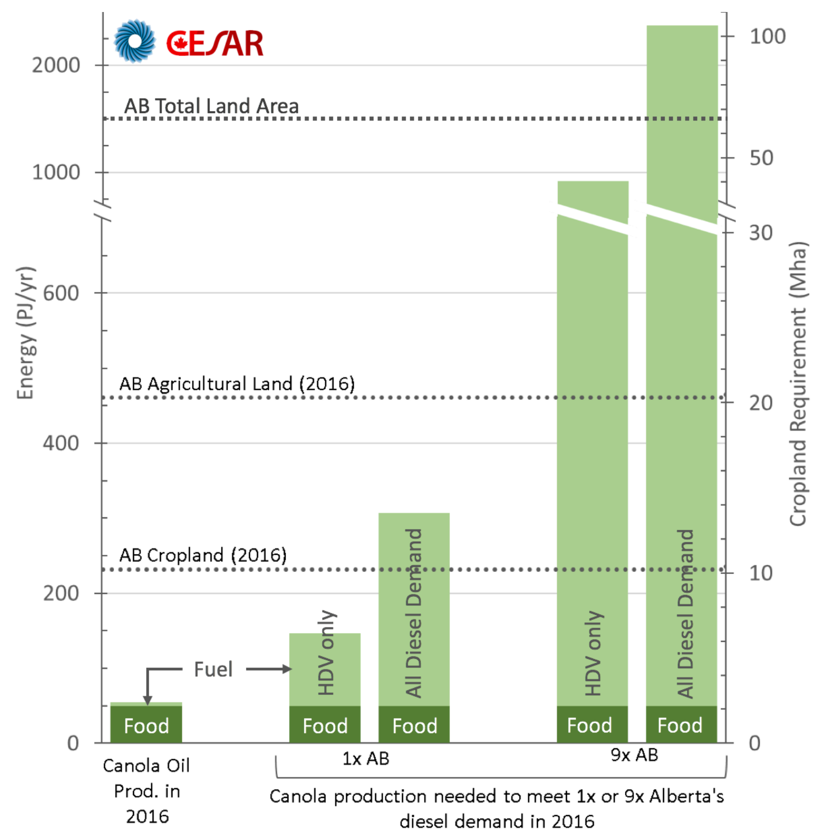

Figure 4.2. Demand for canola oil production (left axis) and cropland required (right axis) in Alberta to replace 1×, or 9× Alberta's 2016 fossil diesel demand (1xAB and 9xAB) for heavy duty vehicle (HDV) freight transportation and all diesel uses. See **Table S5** in Supplemental Materials [30] for details.

We estimated, based on land use data from Statistics Canada [28] and biofuel production data from Navius Research [26], that 2.2 Mha/yr of the province's agriculture land is used to grow canola to support the food industry and 0.2 Mha/yr is used for biofuel production. Combined, canola crops accounted for 24% of Alberta's total cropland and 12% of the total agriculture land that includes pastureland in 2016 (**Figure 4.2.**).

To evaluate the resource potential for oil seeds to supply energy to the diesel fuel market, it was calculated that every hectare of canola can yield 0.6t of biodiesel based on yield ratios reported by Smith et al. [29] (Table S5 in [30]).

Therefore, for Alberta to fulfil its current domestic diesel demand (258 PJ_{HHV}/year) using canola bio-based diesel plus the existing demands for canola-based food production (~50 PJ_{HHV}/year), there would be insufficient cropland available in the province (**Figure 4.2.**). Indeed, about 30% of other agricultural land in the province (e.g. pastureland) would need to be converted to canola production.

Of course, dedicating more than 50% of Alberta's agricultural land to canola production would have a serious adverse impact on the production of other food crops (e.g. wheat), not to mention animal production systems. Therefore, the use of fats and oils to displace diesel demand in Alberta is not a credible energy system.

The concept of using such feedstocks to provide bio-based diesel fuel for export markets is even less credible (**Figure 4.2**). For example, to provide feedstock for 9xAB domestic demand for diesel would require more land than is available in the province.

4.3. Resource Potential for Second Generation Bio-based Diesel

Resource Availability

Compared with lipids, lignocellulosic biomass (e.g. wood and straw) is a more prolific and lower cost feedstock option for bio-based diesel fuel production. In part, this is because lignocellulosic biomass is often generated as a byproduct associated with the production of food and fibre.

In 2016, the annual yield of field crops and forest roundwood in Alberta was 445 PJ_{HHV}/year, while the Canadian total was 3,4 PJ_{HHV}/yr (**Figure 4.3,** Table S6 in [30]). The production of the roundwood and field crop harvest generates a large amount of residual lignocellulosic biomass that is in excess of that which is needed to maintain soil carbon stocks. This biomass has the potential to be converted into a bio-based diesel fuel.

The main sources of lignocellulosic biomass waste are from forest and crop residues and unused annual allowable cut (AAC), which includes the whole tree in addition to the residual leaves and branches typically leftover from logging practices. In addition, there are

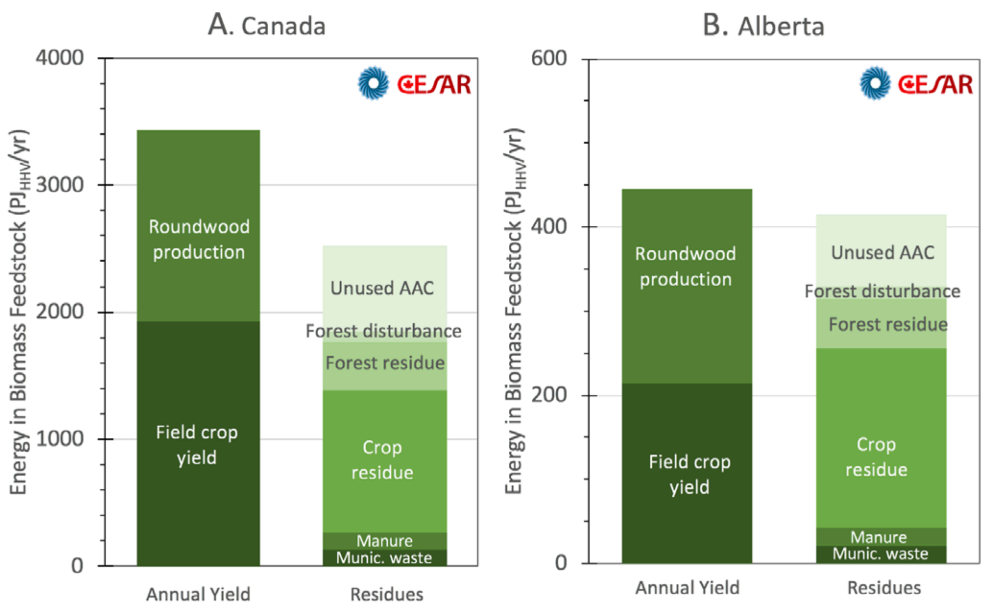

Figure 4.3. Estimated energy content in the annual yield and the available residues from agricultural and forestry production in Canada (A) and Alberta (B). See **Table S6** in Supplemental Materials [30] for more details.

other waste biomass streams coming from urban, agriculture and industrial activities (e.g. municipal solid waste, construction waste, manure).

Taking into consideration that some of the agricultural and forest biomass residues are needed to maintain soil carbon pools and biodiversity[31], we estimate that Canada has about 133 $Mt_{(dry)}$/ yr of total biomass residues available [32]–[40], with an energy content of 2,520 PJ_{HHV}/yr (**Figure 4.3.A**, Table S6 in [30]). Higher heating values [29], [32], [33], [41], [42] and moisture contents [43]–[49] for the various biomass streams were sourced from literature to determine these amounts.

Using the same approach, Alberta should have access to residues with an energy content of 415 PJ_{HHV}/yr (Figure 4.3.B, Table S6 in [30]).

Potential for Bio-based Diesel Production

The relationship between the energy content of feedstock biomass and the amount of diesel that can be generated depends on the efficiency that can be achieved in converting lignocellulosic biomass to renewable diesel. Following an earlier [3] assessment of energy and material flows for biomass gasification and Fischer-Tropsch synthesis of diesel [50], the 415 PJ_{HHV}/yr of available biomass in Alberta in 2016 could be converted into 161 PJ_{HHV}/yr of renewable diesel in the province of Alberta (**Figure 4.4** Table S7 in [30]), thereby meeting 62% of the 258 PJ/yr (**Figure 2.2.C**) of diesel demand in the province.

It is possible that in addition to using residual biomass from forestry and agriculture, biomass crops could be purpose-grown as an energy resource in order to meet the province's demand for diesel fuel. However, this biomass would be even more expensive than residual biomass that we previously showed to be considerably more expensive than fossil diesel [3]. Moreover, such biomass crops would increase demand for land area, and have adverse impacts on biodiversity.

While 2nd generation bio-based diesel production from residual biomass has the advantage of not competing for land with food and fibre production, it is similar to the 1st generation biofuels in being insufficient to satisfy the province's own demand for diesel fuel (**Figure 4.4.**).

Clearly, Alberta's lignocellulosic feedstock are not capable of matching the role played by Alberta's oil industry in providing feedstocks capable of supplying up to 9×AB diesel demand.

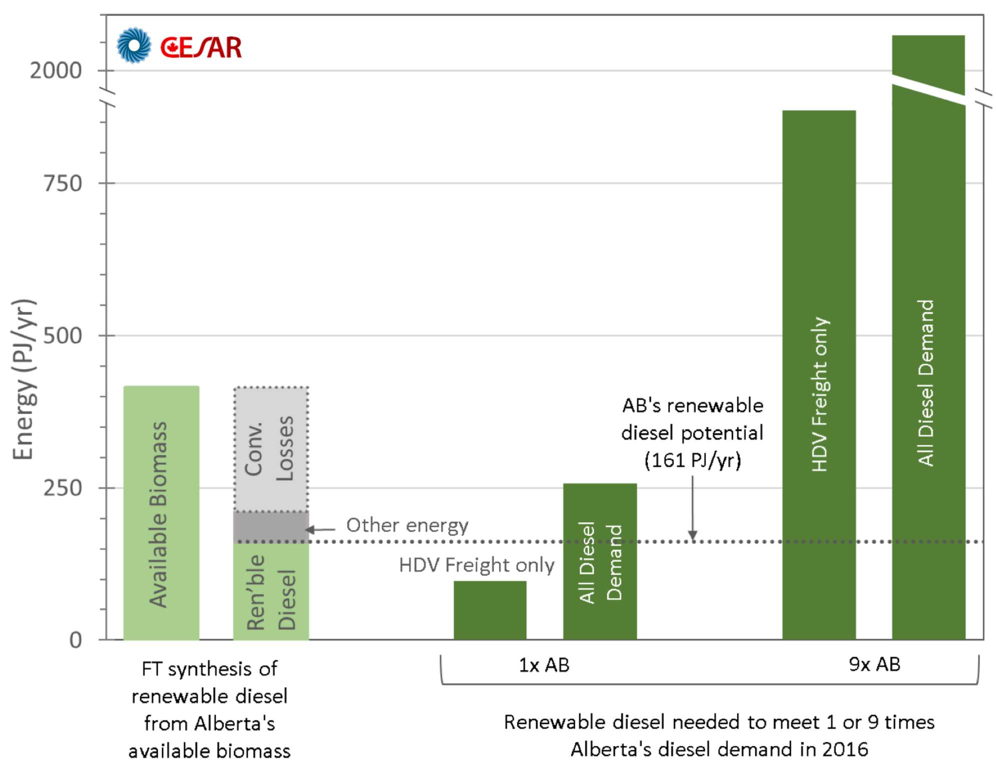

Figure 4.4. Energy content of available lignocellulosic biomass and bio-based diesel potential in Alberta to replace 1 or 9 times Alberta's 2016 fossil diesel demand (1xAB and 9xAB) for heavy duty vehicle (HDV) freight transportation and all diesel uses. See **Table S7** in Supplemental Materials [30] for more details.

While the current diesel demand in Alberta, Canada and North America is beyond the reach of bio-based diesel, smaller markets such as those currently occupied by jet fuel may be attainable.

4.4. BD-ICE Greenhouse Gas Emissions

It is commonly accepted that bio-based fuels are carbon neutral because the carbon in the biomass was recently removed from the atmosphere by plant photosynthesis and the CO_2 losses to the atmosphere during fuel production or ultimate combustion are only completing the cycle and not making a net contribution to the atmospheric carbon pool.

However, this neutrality assumption has been questioned by many researchers [51]–[55] who argue that use of biomass for energy is likely to reduce biomass carbon stocks, since the carbon is released to the atmosphere more rapidly than either the natural decay rate of residual biomass, or the growth rate of purposely-grown biomass crops. Under such cases, the global warming potential of bio-carbon (GWP_{bio}) would be greater than zero, but not as high as the 1.0 that is assigned to fossil fuel CO_2.

As in our earlier Future of Freight study [3], we reported on GHG emissions for the BD-ICE system assuming 100 year GWP_{bio} values ranging from 0 to 1.0. However, assuming residual forest biomass is

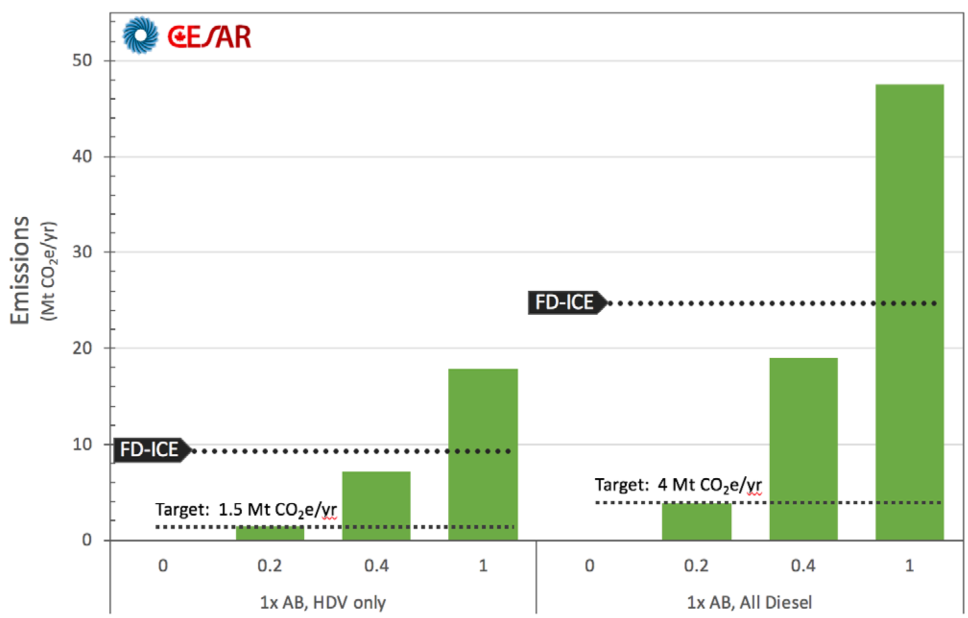

Figure 4.5. Annual greenhouse gas emissions of BD-ICE system for possible GWP_{bio} levels. See **Table S8** in Supplemental Materials [30] for more details.

the primary feedstock, recent literature reports [51]–[55] suggests that the 100 year GWP_{bio} would be less than 0.4, and most likely between 0 and 0.2.

The GWP_{bio} values were applied to all of the bio-based CO_2 emissions to the atmosphere associated with the diversion of residual biomass to bio-based diesel. This includes the emissions associated with the production of the bio-based diesel fuel, and that associated with the fuel combustion in a vehicle or other end use.

The GHG emissions from a BD-ICE system that is equivalent in size to Alberta's fossil diesel consumption in 2016 was calculated to be between 0 and 19 Mt CO_2e/yr for a GWP_{bio} between 0 and 0.4 (**Figure 4.5.,** Table S8 in [30]). At GWP_{bio} values of 0.2 or lower, the BD-ICE energy system was able to achieve the target of 4 Mt CO_2e/yr, an 84% reduction below the FD-ICE emissions of 25 Mt CO_2e/yr.

5. The Grid to Battery Electric (G-BE) Energy System

5.1. The Alberta Public Grid in 2016 and in an 'off coal' Future

In the G-BE energy system, grid power is used to charge the batteries on heavy duty vehicles, so the batteries provide the energy to the motors that drive the wheels. Therefore, the public grid plays a major role in the G-BE energy system.

In 2016, the public grid delivered about 62 TWhr/yr, and was about three times larger than industrial or "behind-the-fence" generation which is usually natural gas fired and involves the production of both heat and power (i.e. cogeneration). Such generation is not considered here.

In 2016, Alberta's public grid mix included 61% from coal, 27% from natural gas (including cogeneration, combined cycle, and simple cycle) and 12% from renewables (wind, hydro, and biomass) or imports [56].

Given provincial and federal off-coal policies, this grid mix is expected to shift to ~70% natural gas and 30% renewables, with a concomitant reduction in GHG intensity from 719 to 270 kg CO_2e/MWh 2030 [3], [23]. In this report, such a future grid is denoted as the 2030 grid.

Of course, in this energy system, the size of the public grid will also need to increase to provide the electricity needed to support the systems that now rely on diesel.

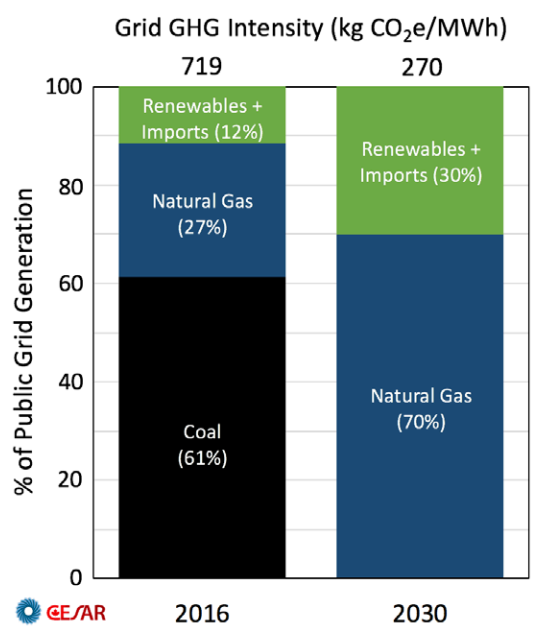

Figure 5.1. Alberta's current grid mix (2016) by power generation method and a projected future grid mix (2030) that includes 30% renewables and a phase out of coal power generation.

5.2. Grid Power Energy Potential

The Alberta public electric power grid generated 62.5 TWh/yr of electricity in 2016 [22]. The additional electricity demands of a G-BE system for diesel replacement were calculated from the energy flows through this energy system as reported in the previous Future of Freight report [3].

Electrifying only HDV transportation would require a grid expansion of 25% to 77.9 TWh/yr, while electrifying all diesel-powered systems would require a 65% grid expansion to 103 TWh/yr (**Figure 5.2.**, Table S9 in [30]).

To put this increased demand for electricity into perspective, the Alberta Electric System Operator (AESO) has projected Alberta's business as usual (reference case) grid load to grow 0.9%/yr, so would reach ~103TWh/yr in about 50 years (2068) [22].

The additional 40.9 TWh/yr of electricity to displace the province's current diesel demand would effectively require a doubling in normal grid load growth, which could be achieved with an annual growth rate of 1.6%/yr starting in 2023 (calculations not shown). While such a growth rate would not be unreasonable, it is less clear how to grow this new generation capacity using non carbon emitting sources for new electricity supply.

However, for Alberta to supply electricity to match the existing diesel markets it currently serves across North America (equivalent

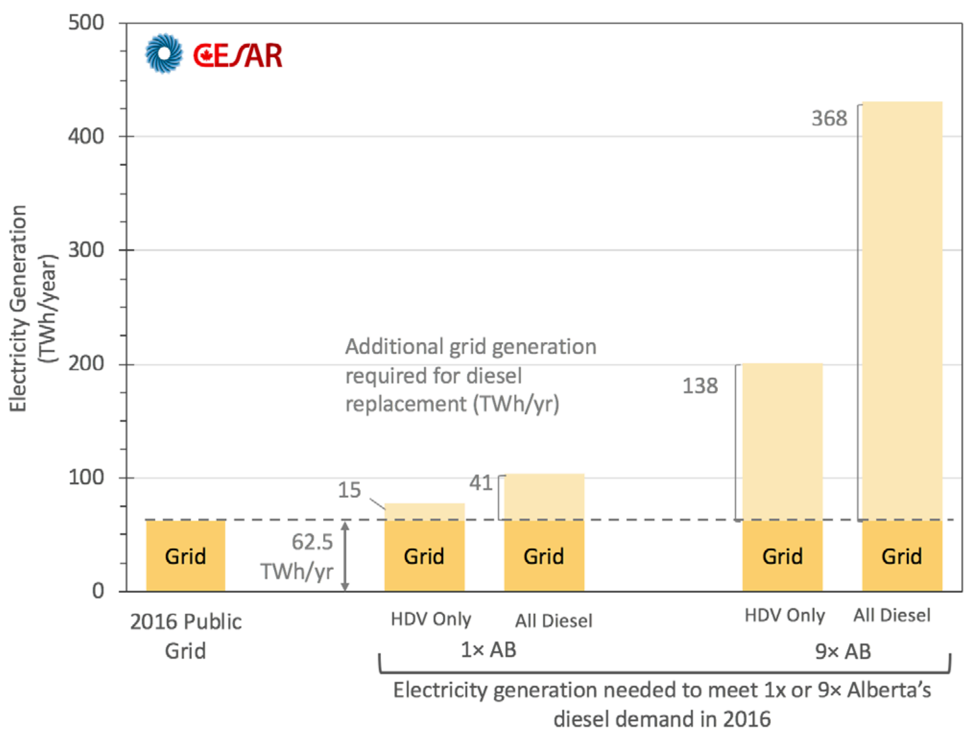

Figure 5.2. Demand for power generation to replace with electricity 1 times and 9 times the 2016 demand for diesel fuel in Alberta (1xAB and 9xAB), without reducing normal grid requirements. See **Table S9** of Supplemental Materials [30] for more details.

to 9xAB demand), an additional 368 TWh/yr of electricity would be required (**Figure 5.2., Table S9 in** [30]). Therefore, Alberta's public grid would need to be 6.9 times the size of the 2016 production level. Of course, scaling up power generation to meet high export demand is a not a credible option, given that Alberta is unlikely to have strong competitive advantage over its neighboring jurisdictions as a low cost, low carbon electricity producer. Also, significant transmission infrastructure and regulatory intertie challenges would need to be resolved [57].

5.3. G-BE Greenhouse Gas Emissions

Battery electric vehicles produce no emissions, so all emissions are associated with how the electricity is generated.

The GHG intensity of the public grid in Alberta is estimated to be 719 kg CO_2e/MWh in 2016, but by 2030 there is hope that it will be reduced to about 270 kg CO_2e/MWh due to an elimination of coal fired generation and an increase in renewable generation (**Figure 5.3.**).

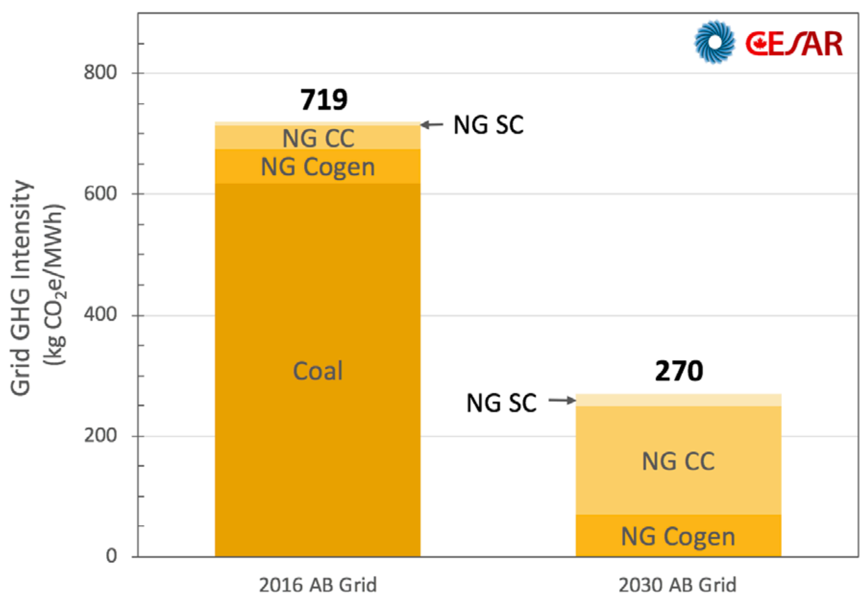

Figure 5.3. Alberta's current grid mix (2016) greenhouse gas (GHG) intensity by power generation method and a projected GHG intensity for future grid mix (2030) [23][56]. NG, Natural Gas; SC, Simple Cycle; CC, Combined Cycle; Cogen, Cogeneration. See **Table S10** of Supplemental Materials [30] for more details.

In addition to these GHG emissions, there are also the 'upstream' emissions associated with extracting, upgrading and distributing the coal or natural gas to the power plants.

Given the 2016 GHG intensity for the Alberta public grid, the G-BE system would have 18% higher well-to-wheels GHG emissions than the FD-ICE system (**Figure 5.4., Table S11 in** [30]).

However, with a 2030 grid mix, the well-to-wheels emissions would be 50% of that for a FD-ICE energy system (**Figure 5.4**). To achieve the mid-century GHG target of 16% (an 84% reduction) using the G-BE energy system, the well-to-wheels carbon intensity of the Alberta grid would have to be less than 100 kg CO_2e/MWh.

Assuming the 2030 grid, the shift from a FD-ICE to a G-BE energy system for all of Alberta's diesel demand would reduce GHG emissions from 25 Mt CO_2e/yr to 12 Mt CO_2e/yr, a savings of 13 Mt CO_2e/yr (**Table S11 in** [30]).

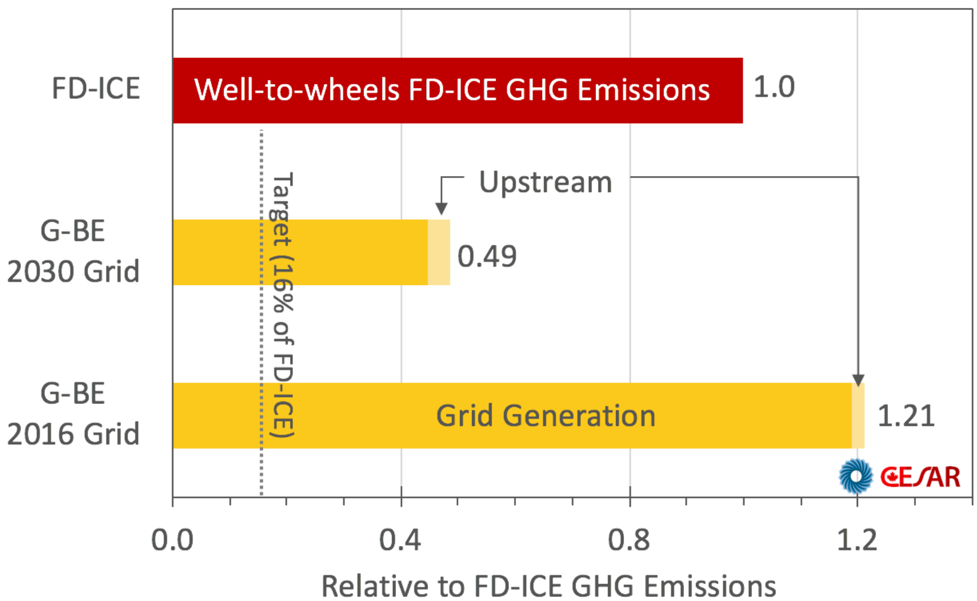

Figure 5.3. Well to wheels GHG emissions for a G-BE energy system in Alberta, having either a 2016 or a 2030 grid mix compared to that of a FD-ICE energy system. See **Table S11** of Supplemental Materials [30] for more details.

6. Natural Gas to Hydrogen Fuel Cell Electric (NG-HFCE) Energy System

6.1. Hydrogen Supply Needed to Serve Diesel Market

Hydrogen fuel cell electric (HFCE) powertrains are an attractive zero-emission alternative to diesel combustion, since they have the power and torque advantages of an electric powertrain, the convenience of rapid refueling, and the flexibility and range that comes with onboard fuel storage / power generation. Other benefits include the absence of emissions (other than water), and a powertrain that is more efficient than a comparable FD-ICE vehicle [3].

To deliver the same amount of work as that provided by Alberta's 2016 demand for diesel (258 PJ_{HHV}/yr, **Figure 2.2.C.**), 192 PJ H_2 /yr would be required for a NG-HFCE energy system (due to the more efficient powertrain), but since leakage/losses of H_2 associated with distribution is expected to be higher than diesel, the estimated H_2 demand was increased by 5% to 202 PJ H_2/yr (**Figure 6.1.**, Table S12 in [30]). This is equivalent to 1.43 Mt H_2/yr, or about 55% of the H_2 that was being produced in Western Canada in 2004 for use in heavy oil upgrading, oil refining and the chemical industry [58]. While industrial H_2 production in Western Canada has certainly increased over the past 15 years, these calculations show that the H_2 required to be equivalent to 2016 demand for diesel in Alberta is on a scale that is similar to current industrial levels of H_2 production in Western Canada.

Assuming fuel cell grade H_2 has a retail price of $5/kg [3], the 1.43 Mt H_2/yr needed to displace diesel demand in Alberta would have a value of about $7.1B/year.

To match Alberta's 2016 contribution on an energy-demand basis to the North America diesel market (2,286 PJ diesel/yr, **Figure 2.2.B.**), the province would need to produce and sell 1,817 PJ H_2/yr (**Figure 6.1., Table S12 in**) or 12.9 Mt H_2/yr.

In the following section, we explore Alberta's capacity to provide sufficient H_2 to displace diesel demand in the province, or to displace the fraction of North American diesel demand that is currently produced from Alberta oil. In our analysis, 'blue hydrogen' is generated from natural gas using Steam Methane Reforming (SMR) coupled to carbon capture and sequestration (CCS). Details on the SMR / CCS process is described in greater detail in the preceding Future of Freight report under **Box 3.2.** [3].

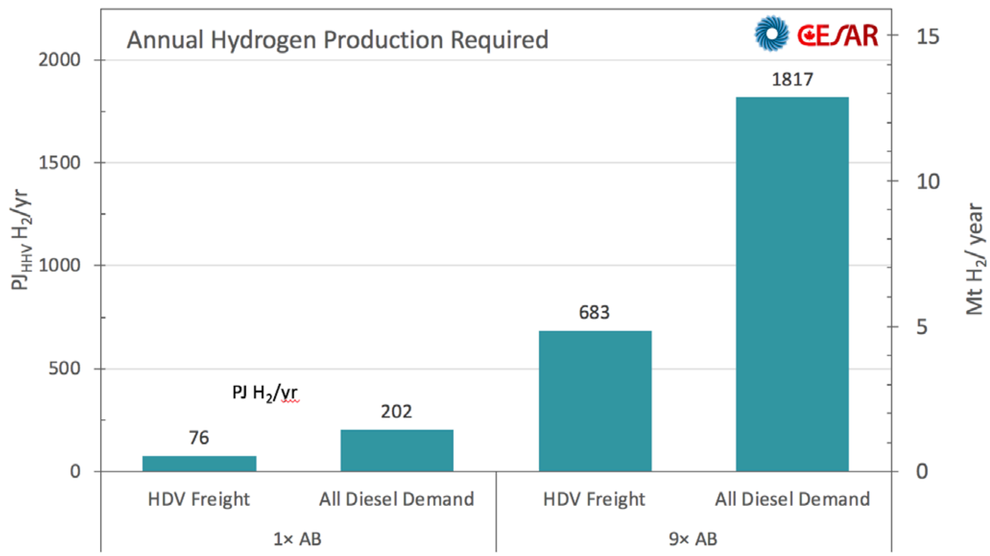

Figure 6.1. Demand for hydrogen to replace 1 or 9 times the 2016 demand for diesel fuel in Alberta (1xAB and 9xAB). The right axis depicts hydrogen production required in megatonnes per year. See **Table S12** in Supplemental Materials [30] for details.

It is important to note that there are technologies other than SMR that could be used to make H_2 from carbon-based feedstocks, such as coal gasification [59], barrier discharge non-thermal plasma [60], methane cracking [61], and *in situ* heavy oil gasification with proton membrane technology [63]. The SMR technology was chosen for this report since it is among the most mature and widely deployed, and it has been deployed with CCS [64].

6.2. Natural Gas to Hydrogen Resource Potential

Alberta is rich in natural gas (NG) resources, producing 4,390 PJ_{HHV} NG/yr based on 2016 data from the Alberta Energy Regulator ([65], **Figure 6.2.**). Of that production, Albertans use around 2,200 PJ_{HHV} NG/yr for applications that include power generation, oil sands recovery/upgrading, and space heating. The balance of the annual natural gas production is exported to other jurisdictions, typically at discount prices compared to the broader North American market.

As described previously [3], the SMR / CCS process requires 1.29 GJ_{HHV} NG to generate every GJ_{HHV} H_2. Therefore, to provide the 202 PJ_{HHV} H_2 to displace 2016 diesel demand in the province (**Figure 6.1**), 260 PJ_{HHV} of NG is required (**Figure 6.2.**).

To generate sufficient H_2 to meet the energy demand equivalent to Alberta oil's 2016 contribution to North American diesel (1,817 PJ

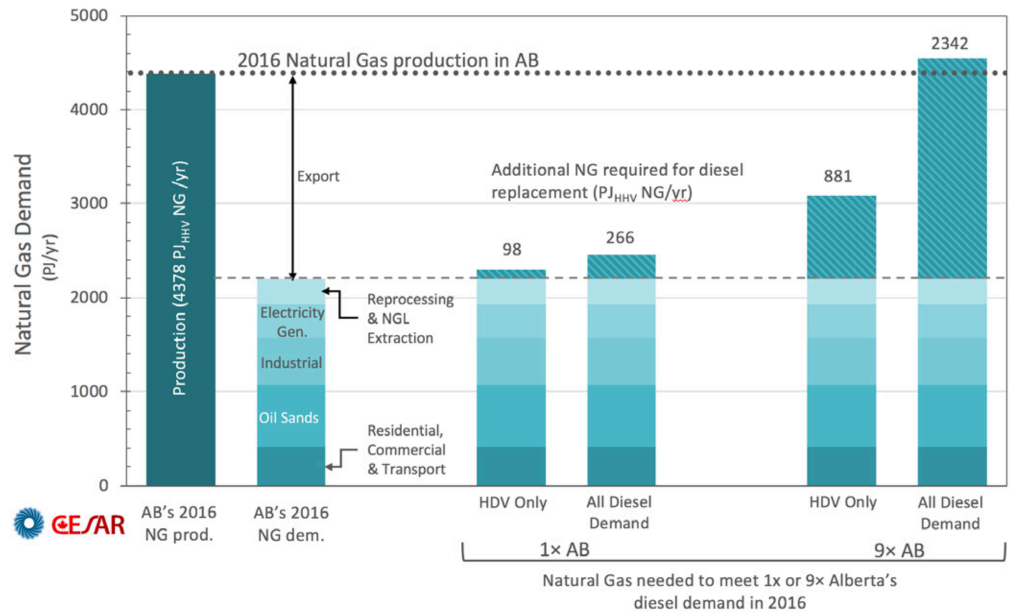

Figure 6.2. Alberta natural gas production, existing demand and incremental demand needed to support a natural gas to hydrogen fuel cell electric (NG-HFCE) energy system that is equivalent to 1 or 9 times (1xAB or 9xAB) Alberta's domestic diesel demand. See Table S12 in [30] for details.

H_2/yr, **Figure 6.1**.), 2,342 PJ_{HHV} of NG is required, creating a total demand for natural gas that is marginally higher than supply in 2016 (**Figure 6.2.**) but easily achievable given the size of Alberta's natural gas resource [66].

These numbers demonstrate that AB has ample natural resources to produce H_2 from NG as an alternative to diesel fuel, while maintaining its existing NG domestic supply obligations. (**Figure 6.2.**). As mentioned previously, some of this H_2 could be made from oil or even coal.

6.3. NG-HFCE Greenhouse Gas Emissions

While the HFCE powertrain has zero emissions (other than water vapour), the production of H_2 from a hydrocarbon could lead to substantial GHG emissions unless the carbon is captured and prevented from entering the atmosphere.

As reported in the previous Future of Freight report [3], the SMR / CCS process generates 65.5 kg CO_2e / $GJ_{HHV}H_2$ [67], upstream NG production generates 9.4 CO_2e/GJ_{HHV} NG [68] and grid electricity demand (assuming 2030 grid intensity, **Box 5.1**) contributes 270 kg CO_2e / MWh. Combining these emission intensities with the data from **Figures 6.1.** and **6.2.** (see also Table S13 in [30]) allows a calculation of the well-to-wheels CO_2e emissions associated with the NG-HFCE energy system as shown in **Figure 6.3**. and **6.4**.

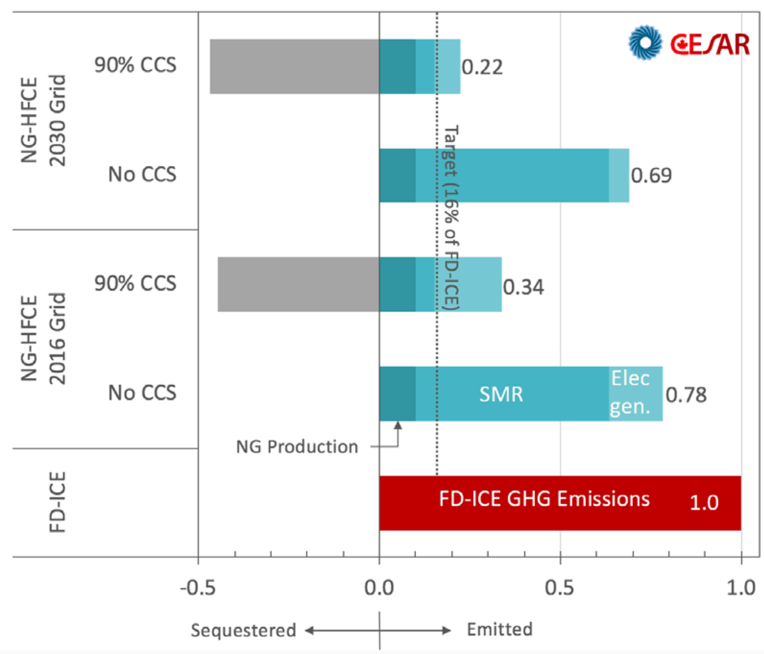

Figure 6.3. Relative well to wheels GHG emission of a NG-HFCE energy system compared to a FD-ICE energy system (FD-ICE=1.0), assuming different C intensities of the electrical grid (**Figure 5.2**), with or without carbon capture and storage of 90% of the CO_2 emissions from carbon capture and storage (CCS). See **Table S13** in [30] for details.

If the carbon produced from the SMR process is simply released to the atmosphere and not captured or sequestered, the well-to-wheels emissions will be 69% to 78% of that for the FD-ICE energy system (Figure 6.3), equivalent to a reduction in well to wheels emissions for diesel use in Alberta from 25 Mt CO_2e/yr to as little as 17 Mt CO_2e/yr (Figure 6.4) depending on the carbon intensity of the electrical grid. Grid power is important to this energy system since it is needed to compress the H_2 for storage, to be available for mobile or distributed use in a way that is similar to the role that diesel fuel now plays.

If 90% of the SMR carbon is captured and prepared for storage, there is an additional demand on the public grid since the CO_2 must be compressed. Hence, with implementation of 90% CCS, the well-to-wheels GHG emissions associated with the NG-HFCE energy system are between 22% and 34% (depending on grid carbon intensity) of the well-to-wheels emissions of the FD-ICE energy system (Figure 6.3.). The well to wheels emissions for the diesel using sector in the province would decline from 25 Mt CO_2e/yr to as little as 5.5 MT CO_2e/yr (Figure 6.4)

While none of the scenarios plotted in Figure 6.3 are capable of meeting the target for an 84% reduction in emissions compared to the FD-ICE energy system, the scenarios including CCS are close. Indeed, with improvements in the carbon intensity of the electrical grid, or fewer emissions associated with the recovery and processing of the natural gas, the target could be achieved or exceeded.

If Alberta were to produce 'blue hydrogen' at a scale equivalent to ~9 times domestic demand for diesel, the well-to-wheels, systems level GHG emissions would be reduced from the FD-ICE level of 220 Mt CO_2e/yr (Figure 2.4) to 50 Mt CO_2e/yr (Figure 6.4), assuming a 2030 electrical grid. It is important to note that in such a hydrogen economy, all of the 50 Mt CO_2e/yr emissions would occur in Alberta, but a major portion of the emission reductions would occur outside the province in jurisdictions that now refine Alberta crude oil to diesel and consume the diesel fuel that is produced.

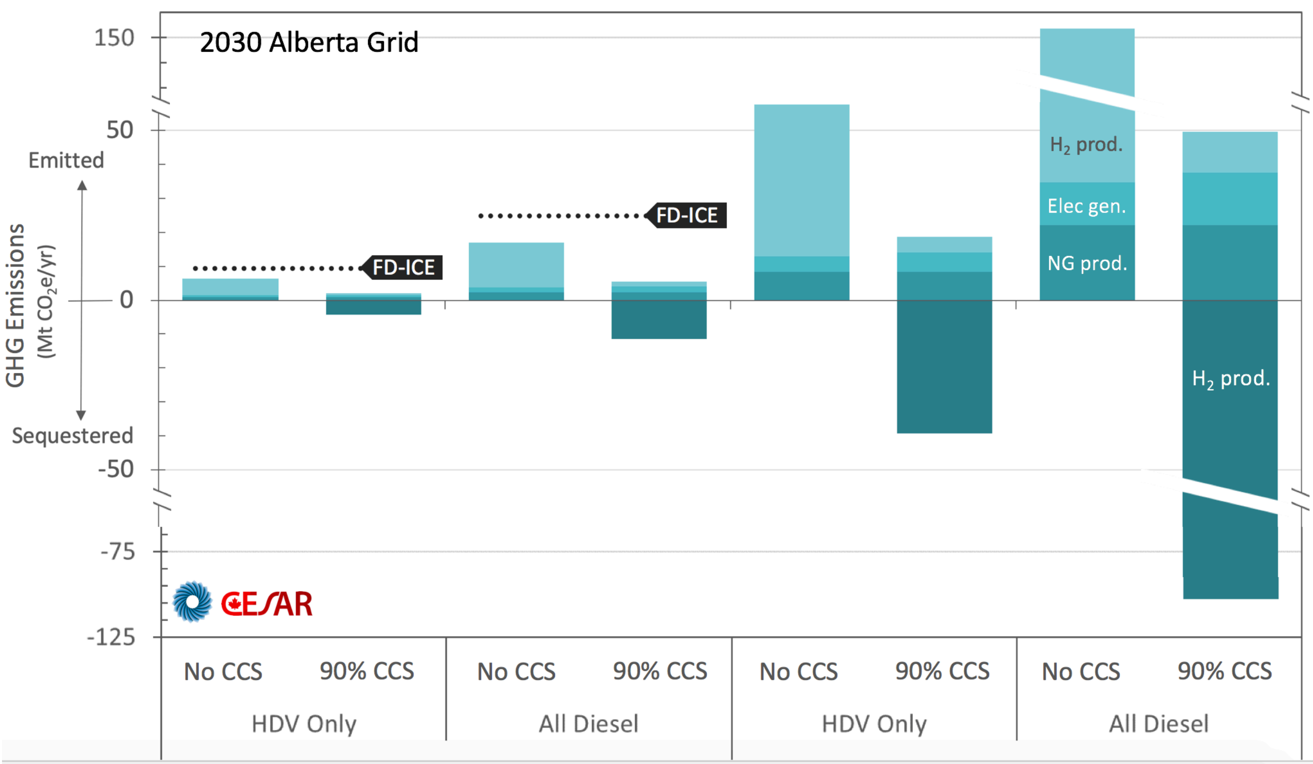

Figure 6.4. Total annual well-to-wheels GHG emissions associated with a NG-HFCE energy system with or without 90% capture utilization and storage (CCS) of the carbon associated with H_2 production for the heavy duty vehicle (HDV) or all diesel demand in Alberta (1xAB), and a HDV or all diesel demand equivalent that is 9 times Alberta's domestic demand (9xAB). The equivalent fossil diesel - internal combustion engine (FD-ICE) number for 2016 are also shown. See Table S14 in [30] for details.

7. Wind and Solar to Hydrogen Fuel Cell Electric (WS-HFCE) Energy System

7.1. Grid Generation Profile with increasing Wind and Solar

The WS-HFCE energy system is similar in many respects to the NG-HFCE energy system, but rather than 'blue hydrogen' being produced from natural gas, 'green hydrogen' is produced by water electrolysis using a portion of the intermittent zero-carbon electricity generated from wind and solar facilities as summarized in **Figure 7.1**.

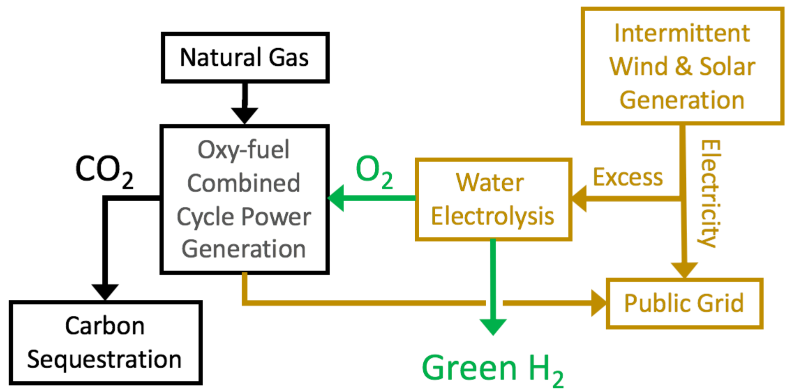

Figure 7.1. Green hydrogen production in the WS-HFCE energy system. Note that this system is integrated with the production of zero or low carbon electricity for the public grid.

Electricity generation from wind and utility-scale solar projects now have the lowest levelized cost of electricity production for new generation facilities [69]. In Alberta, this ranges from \$30 to \$50 per MWh.

Since electricity generates better economic returns when fed into an electrical grid, and since 'green hydrogen' production is only competitive with 'blue hydrogen' when the electricity price is less than \$30 /MWh [3], we envisage that the WS-HFCE energy system serves both the public grid and the fuel-hydrogen market, with the following features:

- When public grid electricity demand is high, and the prices are high, the wind and solar generation will be sent to the public grid;
- When public grid demand is low, the generation sites will divert direct current (DC) electricity to electrolysis units that convert water to green hydrogen to be pipelined away for use as a transportation fuel, and O_2 gas to be stored, perhaps in sub-surface caverns;
- When the wind is not blowing and the sun not shining, but grid demand exists, the O_2 is recovered for use in oxy-fired,

natural gas fueled, combined cycle power generation facilities [70]. These facilities will produce both near-zero-carbon grid power and a pure CO_2 stream that can be sequestered in the sub-surface.

This system provides both an alternative use for wind and solar electricity, and a way to backup renewable generation, so there should be fewer constraints on the magnitude of the contribution that wind and solar generation could make to the public grid.

Using a dispatch model for Alberta [71], we estimate the proportion of intermittent wind and solar generation, that could be used by the Alberta grid as the renewable generation, increases from 0% to 200% or more of the public grid demand (i.e. 62.5 TWh/yr in 2016).

The model projects that wind and solar generation up to 30% of public grid demand would all be available to the grid, but if wind and solar generated electricity is equivalent to 80% of public grid demand, renewable generation can only contribute 60% of grid demand (**Figure 7.2A**; equivalent to 75% of the total wind and solar generated). The remainder of the grid demand (40%) needs to be met by other generation sources, and the excess wind and solar generation (25%) could be used for H_2 generation.

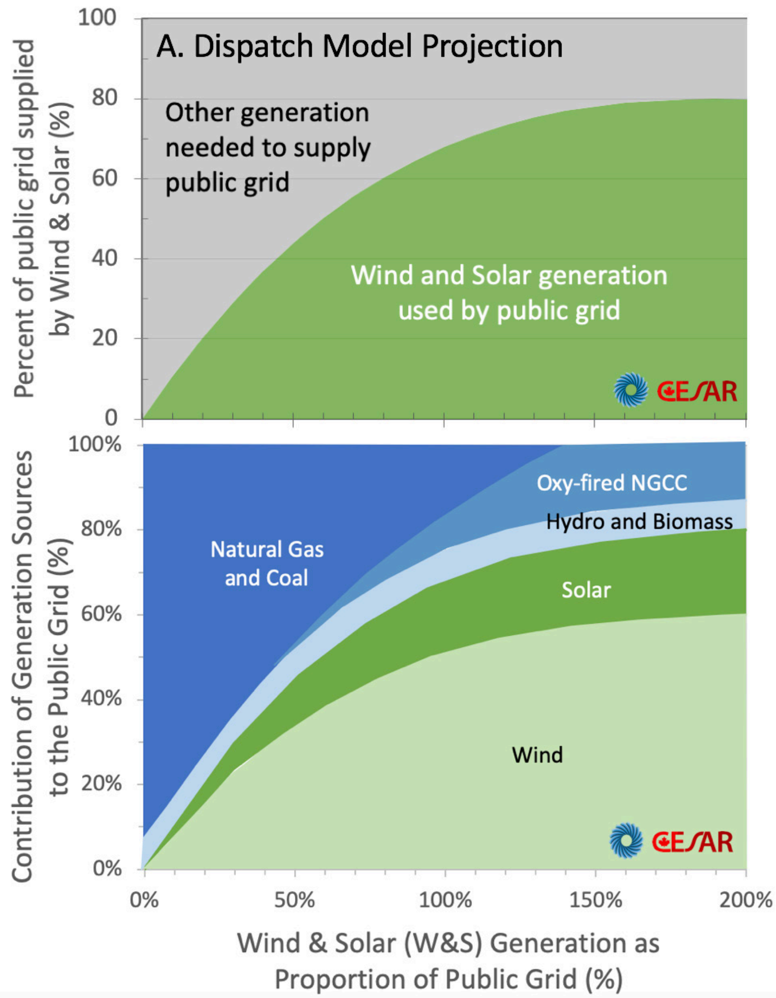

Figure 7.2. A. The projections of an Alberta grid dispatch model [71] on the contribution of wind and solar to the public grid (green shaded area) when the total generation of wind and solar is increased to 200% of the total public grid demand. **B.** The supplementation of this dispatch model with other conditions described in the text and consistent with **Figure 7.1** to show how increasing wind and solar generation impacts grid composition in the WS-HFCE energy system.

In our analysis, we assume that future renewable generation is 75% wind and 25% solar. When this condition is applied to the dispatch model projection (**Figure 7.2A**), and allowances are made for both existing hydro/biomass generation, and for oxy-fired natural gas combined cycle (NGCC, limited by availability of O_2 as a byproduct of H_2 production, **Figure 7.1**), it is possible to calculate the power generation requirements from fossil carbon sources (**Figure 7.2B**).

Note that the model projections showed (**Figure 7.2B**) that if annual wind and solar generation in Alberta were to be 140% larger than the electricity requirements of the public grid, and if the generation that cannot be used by the grid is to be used for water electrolysis, all fossil-fuel based generation needs could be met with oxy-fueled NGCC, coupled to CCS.

Of course, the cost of the electricity when renewable generation is not available would be more expensive since the grid must be supplied by oxyfired NGCC coupled to CCS. These costs were not modelled here. Another possibility is to pipeline the oxygen to other uses in the province and make up public grid demand by converting stored or pipeline hydrogen to electricity using either fuel cells or gas turbines.

Figure 7.3A shows how the annual wind and solar generation is allocated to the public grid and H_2 production as their contribution to power generation in Alberta rises to be equal to, and then greater than, the grid demand. As the annual production of wind and solar power generation rises above 30% of the needs of the public grid, increasingly more of the generation must be allocated to the electrolytic production of H_2. When annual wind and solar generation is the same magnitude as the public grid demand, 68% of the wind and solar power flows to the grid (light green shading, **Figure 7.3A**) and 32% flows to H_2 and O_2 production (dark green shading, **Figure 7.3A**). The subsequent use of the O_2 in oxy-fired, NGCC generation provides another 9% of public grid demand.

The model predicts that first coal, and then natural gas generation is displaced from the public grid, resulting in a decline in GHG intensity of the grid from over 700 kg CO_2e per MWh to 270 kg CO_2e/MWh when wind, solar, biomass and hydro provide 30% of the public grid demand (**Figure 7.3B**). When annual wind and solar generation is the same magnitude as the public grid demand, the emission intensity of the grid is about 67 kg CO_2e/MWh.

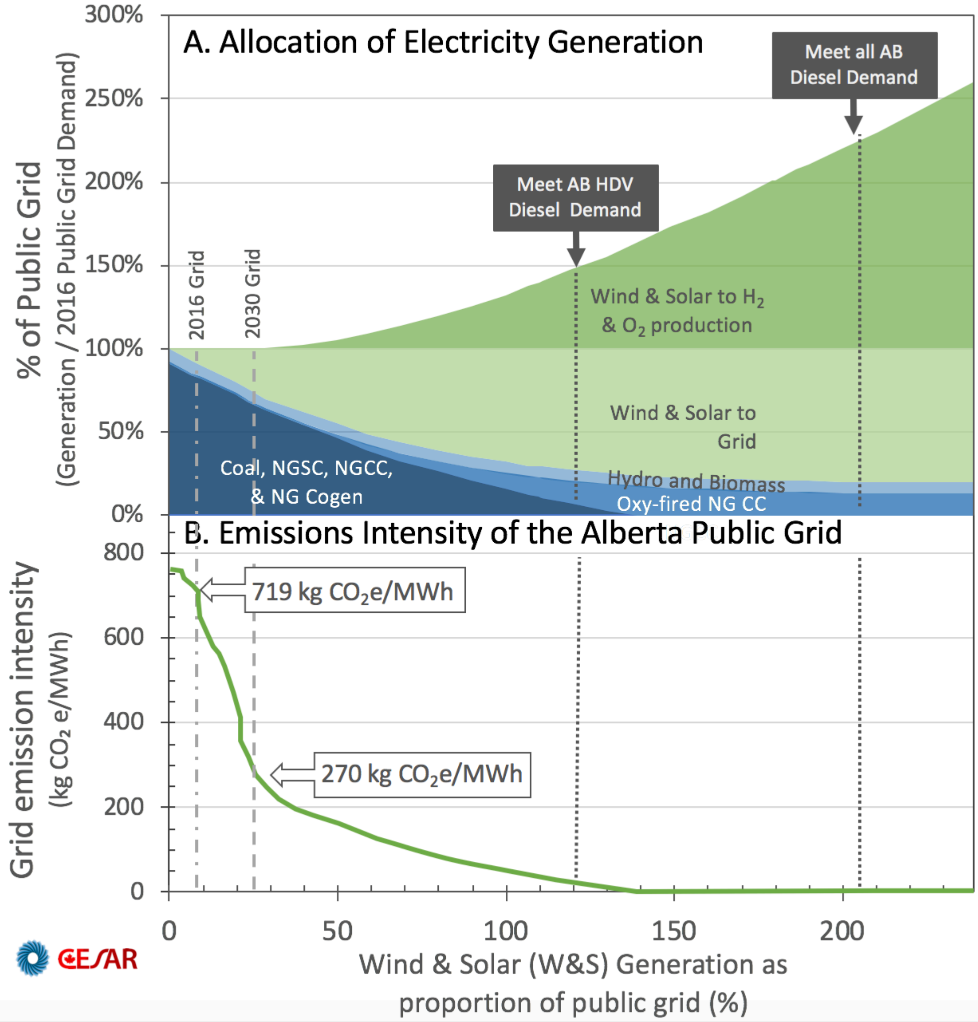

Figure 7.3. The effect of increased wind and solar generation on the source and allocation electricity generation between the public grid and hydrogen generation (A) and the resulting implications for the greenhouse gas emissions intensity of the public grid (B). The vertical lines denote four different scenarios that are discussed in the text.

7.2. Wind/Solar Scenarios to Meet Grid and Hydrogen Demands

To supply the 202 PJ_{HHV} H_2/yr required to match the kinetic energy equivalent of Alberta's 2016 market for diesel (**Figure 6.1.**, Table S12 in [30]), the WS-HFCE energy system would need 78 TWh/yr of electricity (**Figure 7.4.**, All Diesel, 1xAB, Table S15 in [30]), an increase in electricity generation equivalent to 125% of the public grid in Alberta in 2016. These calculations were based on an electricity to H_2 production ratio of 1.39 PJ^e/PJ_{HHV} H_2 [72], [3] and 0.278 $TWhr/PJ^e$ (See Table S15 in [30]).

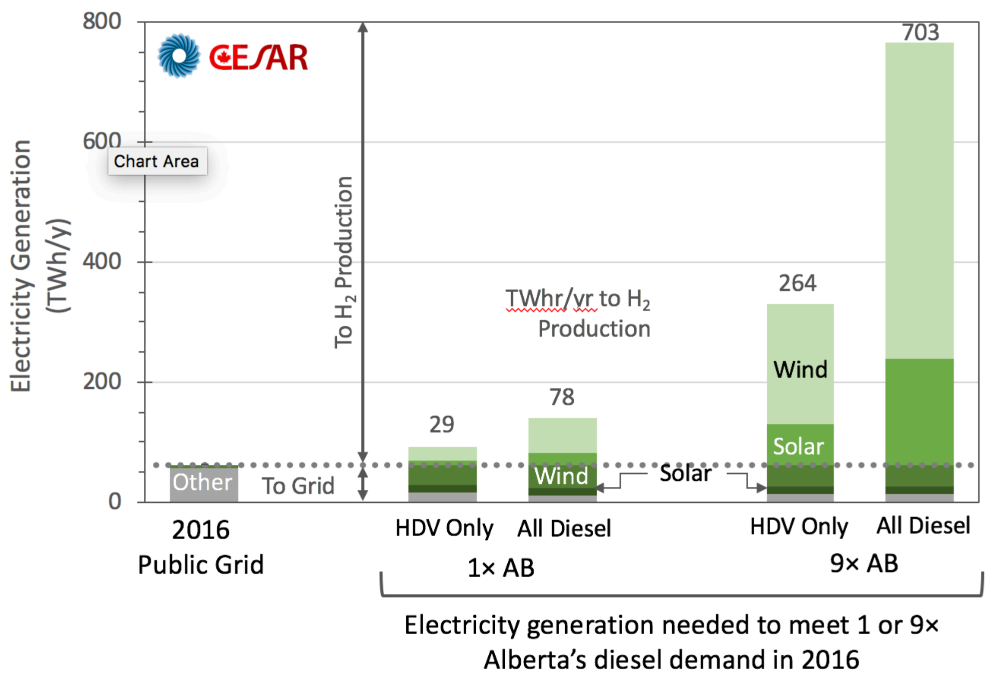

Figure 7.4. Electricity generation required to produce enough H_2 via electrolysis of water to meet 1 and 9 times (1xAB and 9xAB) the kinetic energy equivalent of Alberta's 2016 demand for diesel fuel.

To supply H_2 equivalent to 9 times Alberta's diesel demand in 2016, 703 TWh/yr is required (**Figure 7.4**, Table S15 in [30]), equivalent to 11 times the output of the Alberta public grid in 2016. Of course, this electricity demand is in addition to the generation required to support the public grid (62.5 TWh/yr in 2016, where wind and solar generation constitutes 7% of the grid mix [56]).

The production of the H_2 to meet HDV diesel demand for 1xAB is also shown in more detail in **Figure 7.3** (vertical line labelled 'Meet AB HDV Diesel Demand'). This would require 75 TWh/yr of wind and solar generation, 61% of which would be used by the public grid. The grid intensity in this scenario would be about 50 kg CO_2e/MWh, in part because the O_2 byproduct from electrolysis is being used to provide 13% of the grid power through oxyfuel NGCC when wind or solar is not available, with 90% of the resulting CO_2 being sequestered.

Using the WS-HFCE energy system to produce sufficient green hydrogen to displace all diesel demand in Alberta would require 128 TWh/yr, equivalent to 205% of Alberta's public grid in 2016 (**Figure 7.3**, vertical line labelled 'Meet all AB Diesel Demand'). Of the wind and solar generation, 50 TWh/year would be used by the grid and 78 TWh/yr used for H_2 production. The grid intensity for this scenario would be reduced to 5 kg CO_2e/MWh.

Using Alberta wind and solar generation to provide H_2 equivalent to 9xAB diesel demand in 2016 would require 327 and 752 TWh/yr for the HDV only and All Diesel markets, respectively. Of this generation, 84% (264 TWhr/yr) or 93% (703 TWhr/yr), respectively, would be used for H_2 production (**Figure 7.4** and **Table S15** in [30]).

7.3. Scale and Land Use Requirements for Wind and Solar Deployment

The results of **Figures 7.2B, 7.3 and 7.4** can be used to calculate the number of wind turbines needed, and the land area required to support both the wind turbines and utility scale solar. As noted previously (**Figure 7.2B**), this WS-HFCE energy system assumes that wind contributes 75% of the generation and solar the other 25%.

Wind

For the wind turbine calculations, we assume the deployment of 4.8 MW General Electric onshore turbine with a rotor diameter of 158m [73]. Assuming a capacity factor of 36% [74], each turbine would generate 15.1 GWh each year. Therefore, for wind in the WS-HFCE energy system to do its 75% share of renewable power, support the public grid and provide H_2 to displace diesel demand in the province (1xAB, all diesel scenario), 6,340 turbines would be required to deliver the 96 TWh/yr of electricity. (See **Table S15 and S16** in [30] for details).

Assuming a power density of 1.12 km^2 per 4.8 MW turbine [73], wind turbines would have to be spread over 7,123 km^2 of land, equivalent to 1.1 % of the province. To assess whether such a number of wind turbines is feasible, we referred to a report by Solas written for CanWEA [75]. They estimated that 36.6% of Alberta land area is suitable for building wind turbines in that this land has a net capacity factor equal to or greater than 25%. They also suggested that only one in four possible build sites would be viable for development, so a maximum of 9.2% of Alberta (or 58,590 km^2 of land) could be available for locating wind turbines.

So, there is sufficient land in the province to support the public grid and sufficient H_2 to provide fuel equivalent to all diesel demand in the province in 2016.

It is also important to note that the presence of a wind farm does not preclude the land around each turbine from being used for other purposes such as agriculture or oil and gas operations. The direct land use of a wind farm, i.e. the amount of land occupied by the towers themselves and any other infrastructure (access roads, substations, etc.) was estimated to be 0.003 km² per MW [76], so direct land use to meet the 1xAB all diesel target would consume 91 km², or less than 0.014% of the land in the province (**Figure 7.5**).

To supply H_2 for 9xAB - all diesel scenario demand (while also supporting the Alberta public grid), 37,374 turbines would be distributed over 41,985 km² of land (See **Table S16** in [30]). This would engage 6.6% of provincial land, equivalent to 71% of the Solas' [75] estimate of wind energy potential in the province. Whether such large-scale wind deployment would be socially acceptable in the province has not been explored.

Note that direct land use for this scale of wind turbine deployment would require 538 km² of land, less than 0.084% of the land in the province (**Figure 7.5A**).

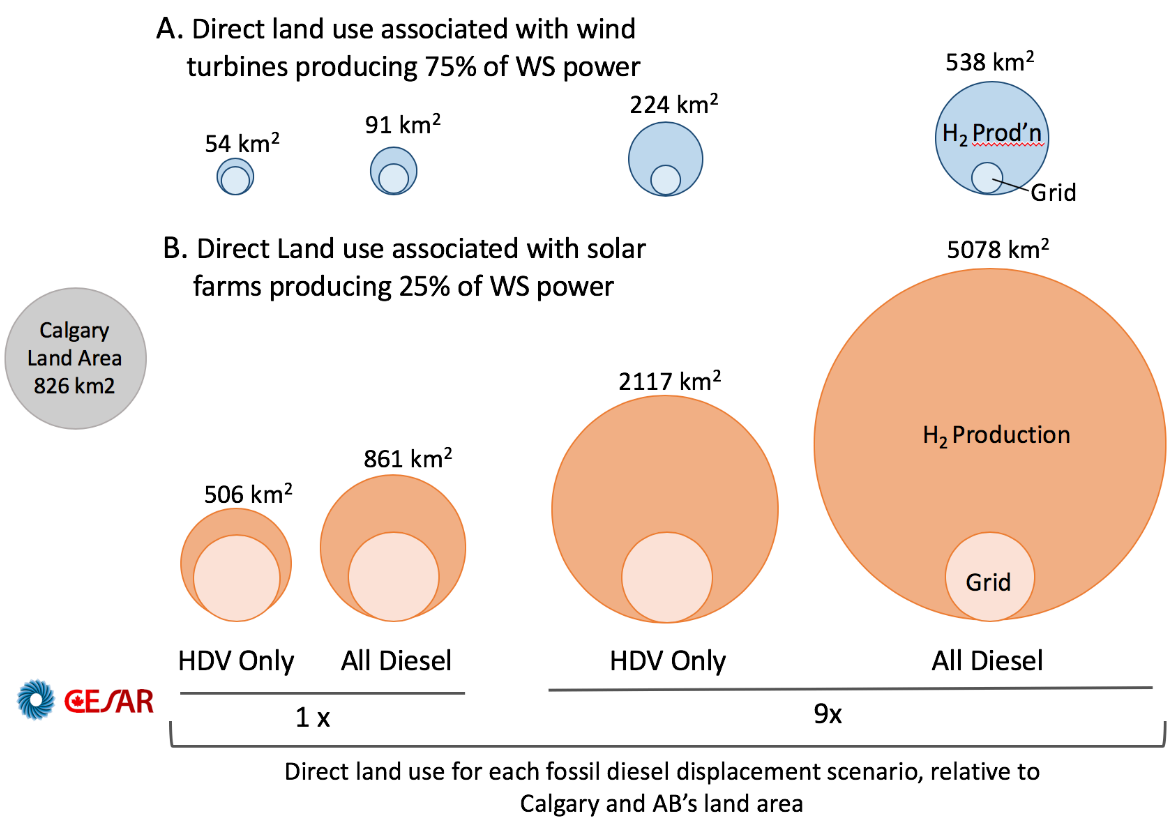

Figure 7.5. Direct land area required for wind turbine (A) and solar farm (B) generation for the four scenarios described in this report. The City of Calgary's land area [77] is provided for scale. The larger circle of each pair shows the total land area allocated to wind (A, blue) or Solar (B, orange) and the smaller, embedded circle shows the fraction needed to meet the demand of Alberta's 2016 public grid. The remaining land area is attributed to meet the needs for hydrogen production. See **Table S16** in [30] for details.

Solar

To assess the requirement for solar photovoltaic (PV) modules, a 17% capacity factor was assumed for Alberta based on Natural Resources Canada's solar resource map [78]. Therefore, 21.5 GW of installed solar capacity could provide the 32 TWhr /yr of power needed to provide solar's 25% share in electricity supply to the public grid, and to support H_2 production capable of meeting 1xAB - all diesel scenario.

Given a solar farm density of 0.04 km^2/MW and 17% capacity factor (**Table S16** in [30]), utility scale solar would need to cover 861 km^2 of land, or about 0.13% of the province (**Figure 7.5B**).

For the 9xAB - all diesel scenario, 126 GW of installed solar capacity would be needed to deliver 188 TWhr/year using 5,078 km^2 of solar farms, equivalent to 0.79% of the province [77] (**Figure 7.5B**).

It is also worth noting that in terms of 'Direct' land use, solar farms that provide only 25% of the required power claim 90% of the land needed for renewable generation, while the wind turbines delivering 75% of the power requirements claim the remaining 10% of the direct land requirements.

Therefore, the WS-HFCE energy system has the potential to produce sufficient H_2 to not only displace all of Alberta's domestic diesel demand, but the demand across North America equivalent to 9 times that in the province.

7.4. Oxygen Production and Use in the WS-HFCE Energy System

As shown in **Figure 7.1**, the WS-HFCE energy system being studied here provides both H_2 as a diesel fuel alternative, and electricity for a low carbon public grid. To provide public grid electricity when there is insufficient wind and solar generation, we propose the use of oxy-fueled, natural gas-powered combine cycle power plants to produce both grid electricity and a pure CO_2 stream that can be sequestered [70], [79]for very high capture rates the heat duty strongly increases. The efficiency penalty of the SCOC-CC is much less affected by the chosen capture rate, because the duty of the air separation unit (ASU.

The high purity O_2 for these power generation systems comes as the by-product of water electrolysis that is used for H_2 production:

$$2H_2O + 4e^- \rightarrow 2H_2 + O_2$$

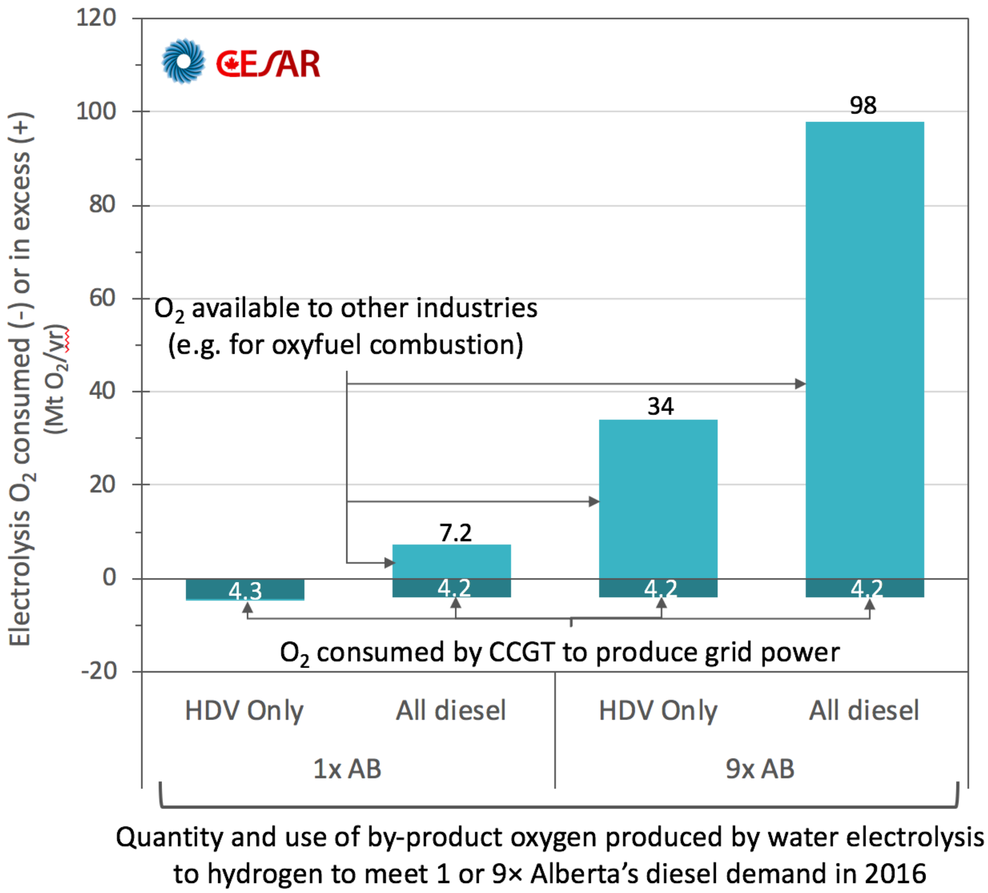

Figure 7.6. The quantity and use of oxygen produced as a byproduct of hydrogen production from electrolysis to deliver 1x or 9x the energy equivalent of 2016 diesel demand in Alberta. The oxygen consumed by natural gas fired, combined cycle gas turbines to balance non-dispatchable renewables are shown as negative numbers, whereas surplus oxygen are shown as positive values. See Table S17 in [30] for calculations and references.

We envisage the electrolysis process being implemented with utility-scale wind and solar operations when the price of grid electricity drops below some minimal value. The produced H_2 would be put into a pipeline and taken to market, while the O_2 would be stored and used with natural gas to produce electricity (and a pure CO_2 stream) when wind and solar production is less than needed for the public grid. This would allow the wind/solar farm operators to provide dispatchable, zero or very low GHG electricity to the grid and potentially get a better price.

Figure 7.6 shows the magnitude of O_2 produced when Alberta is generating H_2 from electrolysis at 1xAB or 9xAB the energy equivalent of 2016 diesel demand in the province. If the WS-HFCE energy system is generating sufficient H_2 to supply an equivalent to one times Alberta's diesel demand, 11.4 Mt O_2/yr is generated, of which 4.2 Mt

O_2/yr is used for electricity production by oxy-fueled combined cycle gas turbines, and the remaining 7.2 Mt O_2/yr is surplus.

To provide H_2 equivalent to 9X all of Alberta's diesel demand in 2016, 102 Mt O_2/yr is generated, 98 Mt O_2/yr of which is in excess of grid demand. While not modeled in this report, the excess O_2 could be used with fossil fuels by other industries such as cement making, or in situ oil sands facilities to produce heat and a pure CO_2 stream that could be geologically sequestered to keep it from the atmosphere.

7.5. Greenhouse Gas Emissions Associated with the WS-HFCE Energy System

Reduction of FD-ICE emissions. The H_2 that is produced and consumed in the WS-HFCE system has zero emissions (other than water vapour), thereby making it possible to eliminate the emissions that are associated with diesel fuel production from Alberta oil, and its consumption across North America.

As noted previously (**Figure 2.4**), displacing the FD-ICE energy system in Alberta would reduce GHG emissions by 25 Mt CO_2 e/yr, while replacing Alberta's 2016 contribution to the North American FD-ICE (i.e. 9X Alberta) would reduce emissions by 220 Mt CO_2 e/yr.

Reduction of Alberta Public Grid emissions. The WS-HFCE system envisioned in this study also has the benefit of reducing GHG emissions of the public grid by increasing wind and solar power generation, and by utilizing the O_2 byproduct from electrolysis for oxy-fired natural gas power generation when wind and solar generation does not meet demand. Electricity produced using oxy-fire technology has efficiency advantages and creates a pure CO_2 stream that is conducive to CCS [70].

As summarized in **Figure 7.3B**, the coal-rich public grid of 2016 has a GHG intensity of 719 kg CO_2e/MWh, but in a '2030 grid' that has no coal and boasts 30% renewables, the GHG intensity would have dropped to 270 kg CO_2/MWh. As wind and solar deployment increases renewable contribution to the grid above 30%, more and more of the wind and solar generation is diverted to hydrogen and oxygen production. The oxygen can then be stored and subsequently combined with natural gas in oxy-fueled, combined cycle gas turbines to produce electricity when wind and solar generation does not meet demand. This generation technology produces a pure CO_2 stream containing 90% of the produced CO_2 that can be geologically sequestered.

When hydrogen production from electrolysis of ‘excess’ wind and solar power is equivalent to diesel demand for heavy duty vehicles in Alberta, sufficient oxygen is produced to generate 8.4 TWh/yr (**Table S17**) and 2.9 MT CO_2/yr, 90% of which is sequestered (**Figure 7.7 1X HDV only).** The remaining 10% of the CO_2 (0.29 MT CO_2e/yr) is a GHG that adds to the emissions from air fueled natural gas combined cycle gas turbines (NG-CCGT) needed to satisfy grid demand (1.56 MT CO_2e / yr; **Figure 7.7**, **1X HDV only**). Also shown in **Figure 7.7** is an estimate of the upstream emissions associated with the recovery and processing of the natural gas.

As hydrogen demand increases in the ‘1x AB, all diesel’ scenario or in the ‘9x AB’ scenarios, the wind and solar contribution to the grid increases (Figure 7.3A) so only oxy-fueled combined cycle generation is needed. System level GHG emissions drop to 0.29 MTCO_2e/yr, plus upstream emissions of 0.55 Mt CO_2e/yr (**Figure 7.7**), less than 2% of the estimated grid only emissions in 2016.

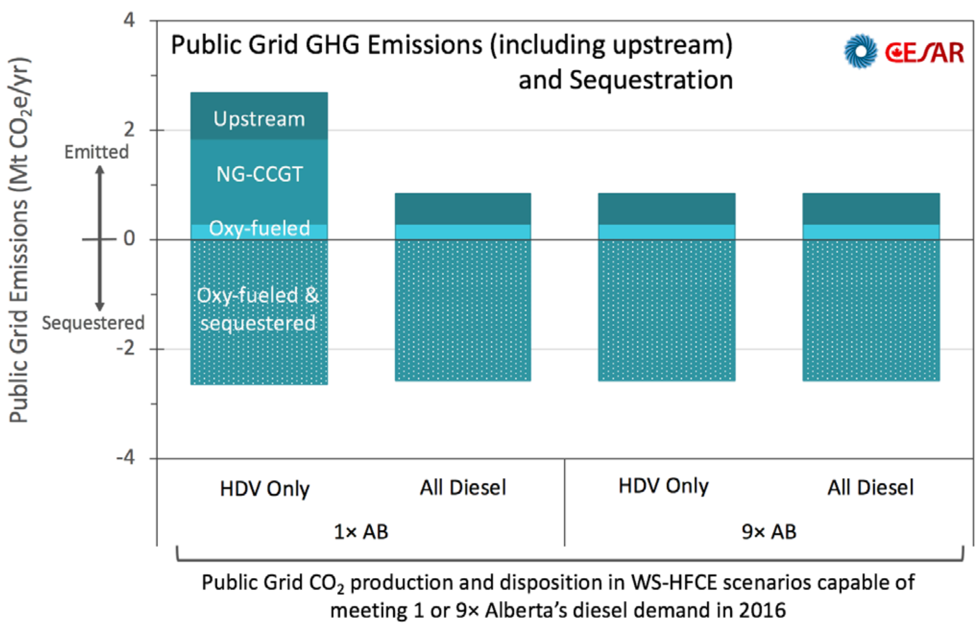

Figure 7.7. Public grid CO_2 production and its disposition in the WS-HFCE scenarios in which wind and solar generation also provide transportation fuel hydrogen equivalent to 1X or 9X Alberta’s diesel demand in 2016. See text and Table S18 for details [30].

8. Discussion and Conclusions

8.1. Alternative Fuel Comparison for Heavy Freight Transport in Alberta

Diesel is important to Alberta as both a fuel source for heavy transport and other sectors, and as a product of Alberta's crude oil resource. The latter supplies a diesel market that is 9 times larger than the province's own demand for the fuel.

While the FD-ICE system has provided lucrative economic opportunities for the province, the combustion of diesel has significant environmental downsides, including GHG emissions forcing climate change and air pollution with serious health implications [2].

A global effort is currently underway to identify very low or zero-emission alternatives to diesel for sectors such as freight transport that are highly dependent on the fuel. The alternatives must meet the needs of the industry, a focus of the previous report in the Future of Freight series [3].

For a province like Alberta, whose economy is highly dependent on recovering, processing and exporting the feedstock for diesel production, it would be ideal if a similar opportunity existed for the production, processing and export of the alternative, low carbon fuel resource. This is the focus of the current report.

The studies, combined with extensive consultations with stakeholders across many sectors in Alberta and across Canada has led to the following insights:

1. **Bio-based diesel is not part of a credible, compelling transition pathway to a low carbon future.** While bio-based diesel has the advantage of being a drop-in fuel and is considered to be net free of greenhouse gas (GHG) emissions, it is likely to be an expensive alternative to fossil diesel. Moreover, its use perpetuates the other problems associated with the 120-year-old diesel engine technology, such as air pollution, noise, and high maintenance cost.

   From the perspective of the provincial economy, Alberta does not have sufficient residual biomass from forestry and agriculture to supply even its own fuel demands for diesel, let alone contribute to the supply of a diesel fuel alternative to other jurisdictions. Similarly, there is simply not enough agricultural land in Alberta to meet the needs for both food and fuel production should we want to grow crops to make sufficient bio-diesel to replace fossil diesel. Bio-based fuels may be better suited to smaller markets, such as low carbon jet fuels. We do not see this alternative as part of a credible, compelling or capable transition pathway towards a low or zero-emission freight transportation system.

2. **Plug-in, battery electric vehicles will be challenged in meeting the needs of the heavy-duty and long-distance freight sector in Canada.** Plug-in electric vehicles have a lower cost source of 'fuel' for the vehicles, and the performance of electric drivetrains are compelling to the freight sector. While they are a viable alternative to diesel for moving light or medium loads over shorter distances, for heavy duty vehicles, especially those driving long distances, the weight of the batteries will compete with load capacity, and the long recharge time will undermine the economic prospect for the carriers.

   As long-distance freight carriers look to platooning, autonomous vehicles, and improved load management over the major transportation corridors, they will want to see their vehicles on the road most of the time and lengthy recharge times will not be acceptable. Battery swapping, or in road electrification may address some of these challenges, but it is difficult to see this as a viable option under Canadian conditions (long distances, low temperatures, heavy loads).

   Moreover, the on-demand requirements for zero emission electricity to rapidly charge the vehicle will strain electrical grids, especially in provinces without large hydropower resources, or without the public support to flood more valleys for new hydro, or to build out nuclear power capacity.

   In the case of Alberta, the province already has a challenge in reducing the carbon intensity of its public grid, and this challenge would be amplified if heavy transport requires even more on-demand grid power. While the province should be able to supply the electricity needs for its own diesel demands, the systems level GHG emissions will be more than 3 times that needed to meet the Paris agreement (Figure 5.3).

   Moreover, Alberta has no strategic advantage in the production of low cost, low carbon electricity, so the prospect of an export market for a diesel fuel alternative does not exist with plug in electric vehicles.

3. **Hydrogen fuel cell electric hybrid vehicles are of interest to the freight sector.** The heavy freight sector was most interested in

hydrogen fuel cell electric (HFCE) hybrid vehicles since they promise rapid refueling, longer distances between refueling and the desirable performance of electric drive vehicles. The lack of fuel infrastructure, and the absence of HFCE vehicles were major barriers, as were concerns regarding the cost of the fuel and the vehicles should they become available.

4. **Alberta has both 'blue' and 'green' hydrogen resources.** We considered two possible sources for the hydrogen: that from steam methane reforming of natural gas coupled to carbon capture and geological storage ('blue' hydrogen), and electrolysis of water to hydrogen and oxygen using wind or solar generated electricity ('green' hydrogen).

   Our analysis showed that Alberta has both the natural gas and the wind/solar resource to make sufficient hydrogen to satisfy not only all of the diesel demand in the province, but 9 times that amount to be equivalent to what the province currently exports as crude oil for the North American diesel market.

Of the four low-carbon or zero-emission alternatives to freight transport examined here, the two HFCE options hold the most promise, especially for a province wanting to stay in the business of producing and exporting transportation fuels.

The rest of this discussion will focus on the challenges and opportunities associated with defining a credible, compelling transition pathway for the diesel-using sectors in the journey to a low carbon future.

8.2. Diesel versus 'Green' and 'Blue' Hydrogen: A Cost Comparison

At Canadian $0.75/L, the average wholesale pre-tax price of diesel in Alberta over the 2013-18 period is about $19/GJ (**Figure 8.1A,** top of the red 'Refinery' bar, [3]). Transport and retail of that fuel adds another $4/GJ to give a pre-tax retail price of about $0.87/L or $23/GJ[3].

To be cost-competitive with diesel, the target price for low carbon, zero-emission hydrogen is about $25-$35/GJ ($3.50-$5/kg H_2). The higher pre-tax price for diesel can be attributed to the fact that the powertrain for HFCE vehicles tend to be more efficient than the powertrain for ICE vehicles. Therefore, a GJ of hydrogen fuel will take a vehicle further than GJ of diesel.

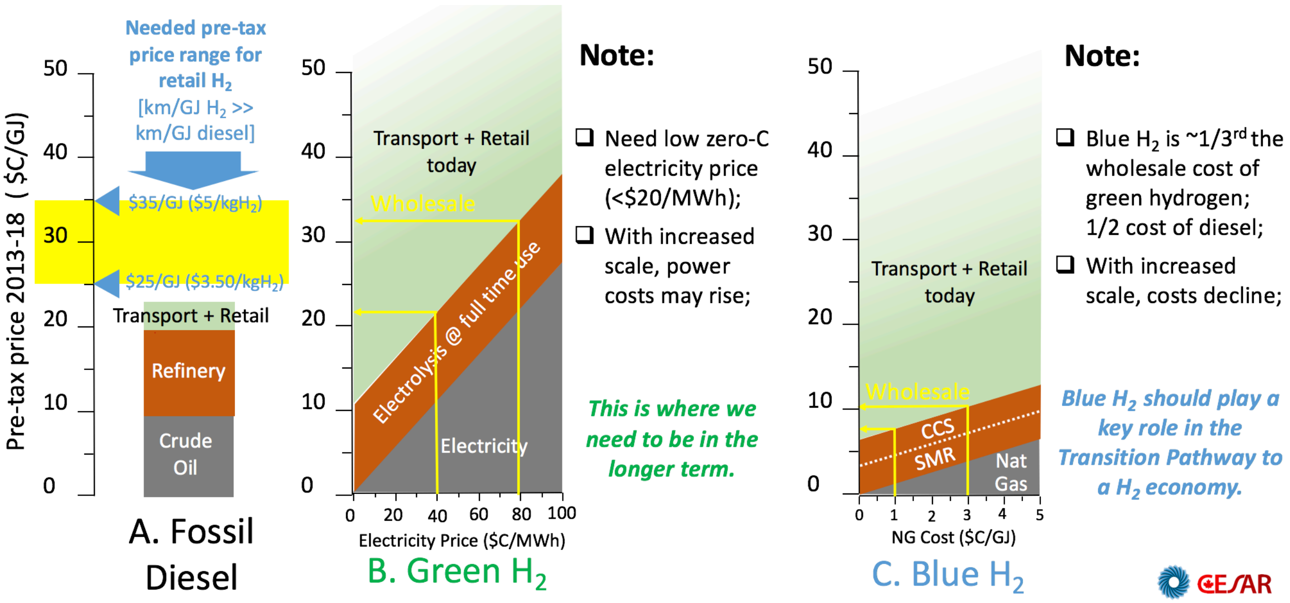

Figure 8.1. A comparison of the average pre-tax cost of diesel fuel (A), green hydrogen (B) and blue hydrogen (C). The diesel numbers (average for 2013-18) are separated into the embedded cost of crude oil (grey), refined to wholesale diesel (red), and transportation and retail (green). The hydrogen cost are presented as charts where the energy input cost (electricity for green H_2, natural gas for blue H_2) impacts the price of hydrogen. The large transport and retail costs for green and blue hydrogen are depicted as a green area, fading to while, since they are highly variable and linked to infrastructure availability and scale of demand. See text for more details. CCS, carbon capture and storage; SMR, steam methane reforming.

As discussed in the previous Future of Freight report (Part B [3]), the wholesale cost of ‘green’ hydrogen production is highly dependent on the price of the feedstock electricity. In some Canadian provinces with large hydropower resources that exceed their electricity demand, green hydrogen can be made at wholesale prices that are cost competitive with diesel (**Figure 8.1B**).

In Alberta, this is more difficult. The levelized cost of wind power is about $40/MWh, but the cost to distribute that electricity through the grid can double that price, making it very challenging to meet the target price for retail hydrogen (**Figure 8.1B**).

Certainly, the costs of wind and solar generation are declining, and there are promising new, more cost-effective electrolysis technologies, but the current economics for green hydrogen production would not justify Alberta taking a leadership role in the transition to a hydrogen economy.

A different conclusion could be reached when assessing the economics of blue hydrogen production in Alberta (**Figure 8.1C**). Like green hydrogen, blue hydrogen price is impacted by feedstock cost, however the magnitude of the impact from natural gas is much lower over its 'normal range' than the impact of grid electricity on green hydrogen production.

In Alberta, the blue hydrogen production with large scale steam methane reforming (SMR) coupled to carbon capture and storage (CCS) is about one half to one third the cost of green hydrogen production, and one half the wholesale cost of diesel (**Figure 8.1C,** [3]). This differential could identify an attractive business opportunity for hydrogen production as a low carbon alternative to diesel in many applications.

A recent study from the Asia-Pacific Energy Research Institute [80] estimates the cost for blue and green hydrogen production in the countries bordering the Pacific Ocean in 2030. As shown in **Figure 8.2**, Canada is among the lowest cost producers of carbon-free hydrogen in the world. Assuming a natural gas price of \$C4.27/ GJ_{HHV} (high compared to the price in recent years in Alberta), blue hydrogen (including CCS) from natural gas can be produced for about \$C10/GJ (\$C1.44/kg H_2).

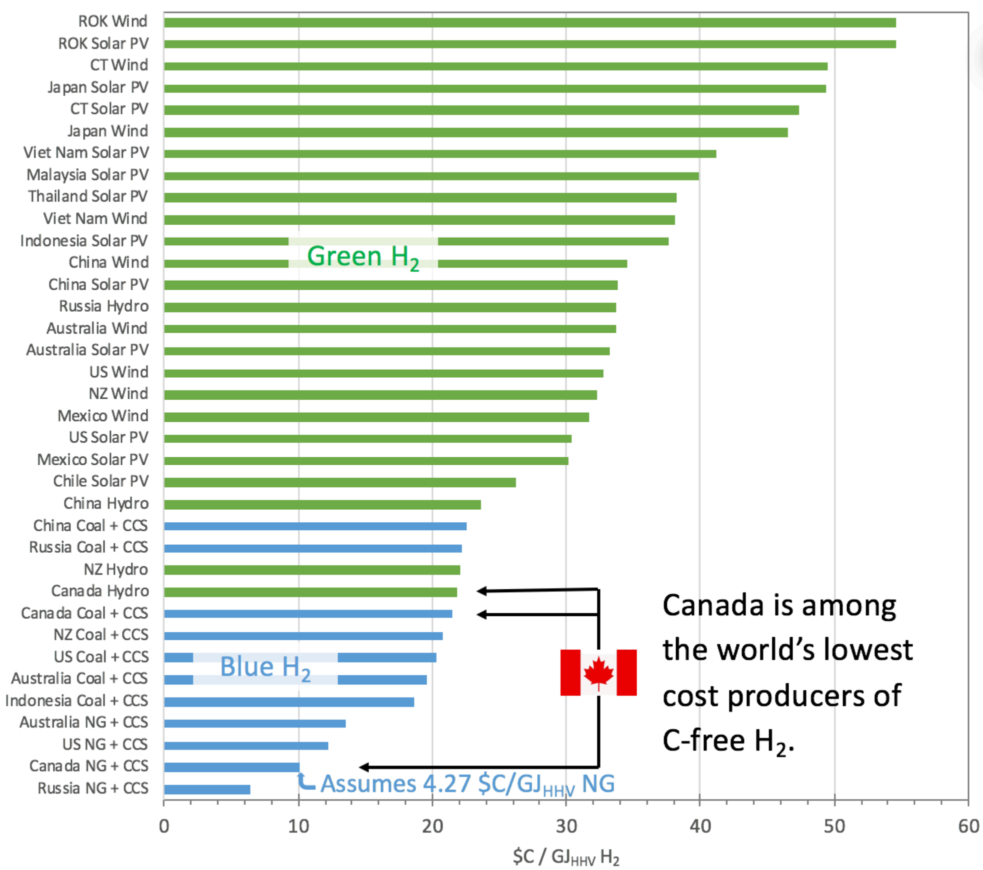

Figure 8.2. Production cost estimates of carbon free hydrogen in the APEC region in 2030. (Canadian dollars/GJ_{HHV}). Adapted from [80] assuming \$C0.80/\$US. ROK, Republic of Korea; NG, natural gas; CCS, carbon capture and storage.

Japan is interested in importing 300,000 tonnes of liquid blue or green hydrogen (LH_2, created by cooling hydrogen gas to -252C) in 2030 to support transportation, combined heat and power and power generation [81]–[83]. This creates an export opportunity for Alberta and other jurisdictions that have the resource potential.

To use hydrogen in support of fuel cell vehicle transport, the gas needs to be free of impurities that would adversely impact the fuel cell [84], delivered to the retail fueling station, compressed, and stored to facilitate rapid vehicle refueling. The cost of these components can be more than the wholesale cost of hydrogen production, as discussed in the next section.

8.3. The Transport and Retail Challenge for Hydrogen

The transport and retail costs for diesel are very low (about $4/GJ), especially when compared to today's cost for transporting and retailing green or blue hydrogen, which dominates the retail price (**Figure 8.1**, green shading on middle and right bars)[3].

This is due, in part, to the nature of hydrogen as a fuel. As a gas with a low volumetric energy density compared to diesel, hydrogen is expensive to compress and move by truck or train. A hydrogen pipeline could keep the price reasonable if the quantity of hydrogen moving through the pipeline is high. Alternatively, if low carbon hydrogen could be generated at the fueling stations in smaller volumes (e.g. 1 to 10 tH_2/day), the higher cost of that hydrogen could be offset by savings from not needing to move the gas.

However, centres of hydrogen demand for transportation in the tonne per day range are rare or non-existent. In part, this is because the focus for HFCE vehicles has been on small vehicles that use relatively little fuel and drive many routes requiring distributed fueling stations. We contend the focus should shift to return-to-base bus fleets and trucks and trains that tend to travel the same routes and consume a lot of fuel.

Anchoring an emerging hydrogen economy around trucks, buses and trains will make it possible to create centres of demand that can achieve reasonable economics of scale, in the early phases of investment. If the vehicle performance and economics align, a demand-pull would then lead to the expansion of the hydrogen economy along major corridors.

8.4. Alberta's Role in Transition Pathways to a Hydrogen Economy

Given concerns about climate change and air pollution, many jurisdictions around the world have announced bans on diesel vehicles or on all vehicles with internal combustion engines [85]–[87]. Even Canada has recently committed to be net zero by 2050 [88], and it is difficult or impossible to imagine how that goal could be achieved if diesel and gasoline remain as the dominant fuels supporting transportation systems.

Vehicle electrification is seen as the answer, where the electricity could either come from the electrical grid or from on-board fuel-cells that are powered by hydrogen. Of course, it is important that both the electricity and the hydrogen are produced with very low or no greenhouse gas emissions, and Canada (potentially led by Alberta) has the potential to deliver both.

For many applications, plug-in, battery electric vehicles will be the technology of choice, but for certain heavy-duty, long-distance or return-to-base operations, hydrogen fuel cell electric hybrid vehicles hold more promise [3]. While this is important for Canada, it is especially important for Alberta.

Canada is positioned globally as a low-cost source of zero or low-emission hydrogen (**Figure 8.2**). Moreover, within Canada, Alberta has a clear strategic advantage in being able to greatly expand its already prodigious production of hydrogen, while eliminating CO_2 emissions, in order to serve a large, new, environmentally-friendly, and lucrative transportation fuel market.

Rather than waiting for new technologies to be developed and deployed, we argue that Canada needs to start the journey towards a hydrogen economy using existing, off-the-shelf technologies. This will create a 'pull' for new technologies that could help to speed advances along the pathway, or even open-up new transition pathways.

One or more pathways need to be envisaged and analyzed while working with industry and government proponents to start the journey. Like chains, the strength of an energy system is only as good as its weakest link, so building a new energy system requires a focus on all components of the energy system, linking demand to supply within a supportive policy and regulatory framework.

Given Alberta's potential for low-cost, blue hydrogen production, we propose that Alberta works to co-create corridors of cost-effective hydrogen supply (retail at $C3.50-5.00/kg H_2) where there is a high-demand for hydrogen to support not only HFCE powertrains, but other uses for the energy carrier.

Such a corridor would be self-sustaining and will have the additional advantage of attracting companies developing and deploying technologies in support of the transition to a hydrogen economy. Once established, these corridors can grow along major roadways, rail and pipeline right of ways to other parts of the provinces, other provinces, the USA and overseas markets.

Also, once hydrogen pipeline infrastructure is in place, there should be an opportunity to bring more green hydrogen into the new energy system. As discussed in Section 7, water electrolysis provides an alternative use for low-cost wind power. Thus, building more Alberta wind generation will simultaneously lower the carbon intensity of the Alberta grid and provide a valuable zero-emission transportation fuel.

Figure 8.3 offers an overview of how a new energy system based on 'blue' and 'green' hydrogen production could work together to not only decarbonize transportation, but also the electrical grid.

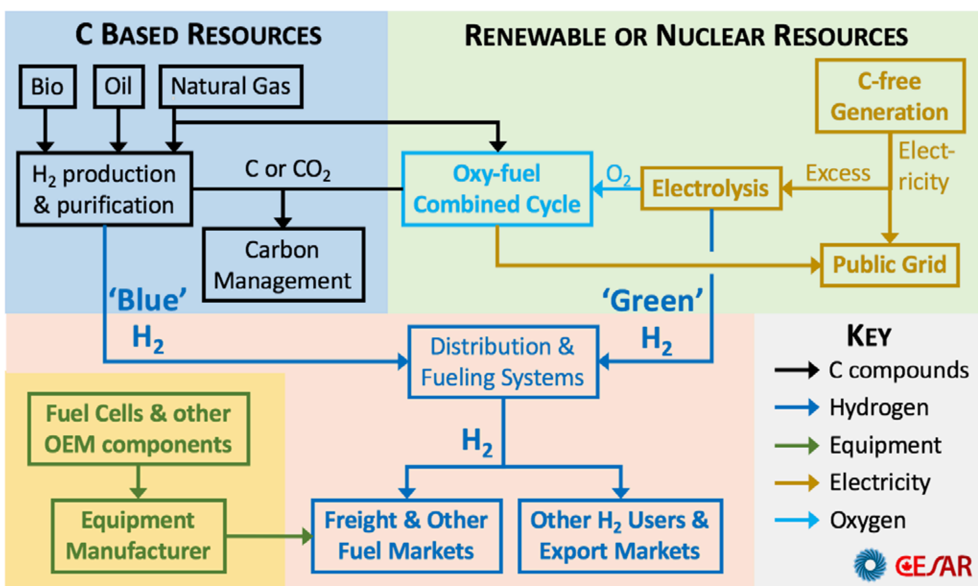

Figure 8.3. A hydrogen energy system supporting zero emission fuels. It incorporates both 'blue' hydrogen production (Section 6 in this report) and 'green' hydrogen production (Section 7 in this report) where green hydrogen production is also linked to the decarbonization of the public electrical grid.

8.5. Questions to Consider in Building Transition Pathways

As discussed at the start this report (About CESAR and the Transition Accelerator section) transition pathways must be **Credible** (technically, economically, socially), **Compelling** to the key stakeholder, and **Capable** of achieving societal objectives that includes meeting emission reduction commitments.

This report, and its two companion studies [2], [3] have identified hydrogen as a zero-emission fuel that could play a major role in the decarbonization of the heavy transport and other diesel-using sectors, while simultaneously keeping Alberta in the business of making and selling transportation fuels. Indeed, Alberta has the opportunity to take a leadership role in this energy system transition. For it to be successful, the transition pathway must be credible, compelling and capable.

Some of the questions that need to be considered in developing such a transition pathway include:

1. **Fit for Service (see Box 8.1).** Will hydrogen fuel cell electric (HFCE) vehicles meet the needs of the key stakeholders: the current users of diesel-internal combustion engine vehicles? Can the new technology cope with real world conditions in Alberta (distances? temperatures? operating conditions?) In what sectors is the fit best? What problems remain? What new business model innovations are needed? How could HFCE vehicles best complement

Box 8.1. The Alberta Zero Emissions Truck Electrification Collaboration (AZETEC) Project

AZETEC
ALBERTA ZERO-EMISSION TRUCK ELECTRIFICATION COLLABORATION

- An industry-led, $15M consortia supported in 2019 by Emissions Reduction Alberta ($7.3M), the Transition Accelerator ($150K) and industry partners ($7.7M);
- Led by the Alberta Motor Transport Association (AMTA), there are eight industry & one academic partners;
- AZETEC has designed and is building two hydrogen fuel cell electric hybrid tractors capable of moving 64t gross weight 700 km between refueling;
- Vehicle testing with H_2 from natural gas between Jun 2021 and Dec 2022, moving freight between Edmonton and Calgary.

other innovations impacting the key stakeholders (e.g. autonomous vehicles)? What public technology development investments would best position Alberta and Canada to win in a new global hydrogen economy?

2. **Low cost, fuel-cell grade hydrogen production with carbon management.** What technologies are available, and what is the optimal scale? Where should this be done first? What approaches are best used to ensure fair, transparent decision making to determine what companies invest in hydrogen production facilities? What is the required standard for 'blue' hydrogen or 'green' hydrogen? Do the policies and regulations around carbon capture utilization and storage in Alberta enable a pathway to a hydrogen economy? Are de-risking incentives needed by the hydrogen producers, or those companies managing the carbon produced when making blue hydrogen?

3. **Cost effective storage and transportation of the hydrogen to fueling stations.** What technologies exist and what are the costs, benefits and tradeoffs of each? What are the regulatory and safety issues, and how are they best managed? How are other countries addressing hydrogen regulatory issues? Can existing pipelines or pipeline corridors be used? Should salt caverns be built for storage? What are the costs, benefits and tradeoffs?

4. **Locating fueling stations to ensure substantial demand.** What quantities of hydrogen must be sold to keep the fuel price low while paying costs and generating a profit for others in the energy system chain? Do fueling station operators need de-risking incentives? What are the regulatory, training and safety issues? Is it possible to create cost effective sources of fuel cell grade hydrogen, and manage carbon emissions at the fueling stations? What are the technology options?

5. **Building HFCE vehicle fleets to ensure station demand.** Where is there a critical mass of willing participants interested in HFCE vehicles and willing to create the hydrogen demand? How can these vehicles be provided? Can they be manufactured or assembled in Alberta, or at least in Canada? What are the regulatory requirements for the vehicles? Are de-risking incentives are needed to overcome the higher costs associated with smaller scale production rates? At what scale of vehicle production would incentives no longer be needed? Do the operators need de-risking incentives?

6. **Alternative value-added uses for hydrogen while demand builds.** Since it will probably be necessary to produce more hydrogen supply than that needed by the vehicles to ensure there are no shortages (and to achieve the efficiency of scale), what alternative uses are there for this produced hydrogen? What are the standards and regulations around these alternative uses? Will proponents need de-risking incentives?

7. **Integration into a national, continental and global strategy.** What are other jurisdictions doing to develop and deploy transition pathways to a hydrogen economy? How can Alberta work as part of a national, continental or global strategy to accelerate the movement to zero-emission fuels?

8. **Hydrogen demand in other jurisdictions.** How can Alberta export hydrogen, and in what form (pipeline, liquid hydrogen, ammonia, etc.) to supply markets such as the other provinces, USA, Japan or Belgium? Ultimately, what is the appropriate scale of the vision for Alberta as a producer, user, and exporter of 'blue' and 'green' hydrogen, and what is the appropriate role for private and public investment?

9. **Interjurisdictional Cooperation.** What role could the Government of Canada play in supporting AB leading in developing a pathway to a hydrogen economy in AB? How can we ensure that learnings and progress in AB can be applied and leveraged in other parts of Canada? Could a pathway to an AB hydrogen economy be among the first steps towards a pan-Canadian hydrogen economy? Could a pathway be used as a tool to focus technology development investments by Alberta, other provinces, and the Government of Canada?

Building transition pathways is a team sport, requiring a shared vision on the nature of the objective, a shared appreciation of the resources available for the journey, and a shared conviction that the trip is worth taking. The transition to a zero-emission hydrogen economy will take a number of decades, and many details of the pathway will not be known until the journey is well underway. The current focus must be on the best way to get started and ensure that a broad range of sectors will participate in the journey.

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