SUPPLEMENTAL MATERIALS

FOR

THE FUTURE OF FREIGHT

PART B: ASSESSING ZERO EMISSION DIESEL FUEL ALTERNATIVES FOR FREIGHT TRANSPORTATION IN ALBERTA

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A project associated with

1. Introduction

This document provides additional details and references behind the results and conclusions contained in the following **CESAR Scenario** report:

Lof J, McElheran K, Narendran M, Belanger N, Straatman B, Sit S, Layzell DB. 2019. **The Future of Freight Part B:** Assessing Zero Emission Diesel Fuel Alternatives for Freight Transport in Alberta. **CESAR Scenarios** Vol 4, Issue 2: 1-63 (https://www.cesarnet.ca/publications/cesar-scenarios)

2. Methodology

Details on the Typical HDV trip in Canada are provided in **Table S1**, while **Table S2** provides the energy conversion values (as higher heat values) used for energy feedstocks and fuels.

Table S3 provides details on our calculation of the greenhouse gas intensities (kg CO_2e/MWh) for the public electrical grid of Alberta in 2016, and in 2030 assuming that the 2030 grid will have no coal-fired generation and 30% renewables. Note that these calculations only consider the public grid that would be used for electrical vehicle charging, H_2 compression, etc. We do not include the large 'behind the fence' industrial generation that is dominated by natural gas cogeneration.

Table S1. Calculations for a Typical HDV Trip in Canada

Item	Parameter	Units	Value	Note
1	Distance	km	750	{1}
2	Truck weight (loaded)	tonnes	27	{2}
3	Fuel efficiency of loaded heavy duty FD-ICE freight trucks	L/tonne· 100km	1.4	{3}
4	Diesel required per trip	L	283	{4}
5	Kinetic energy required for a trip	GJ	3.8	{5}

Notes:

{1} Average long distance shipment by freight in Canada [1].

{2} *Item 2 = 17t payload + 10t tractor*, where 17t = average payload for Canadian Class 8B (heavy) trucks in 2013 [2], and 10t = assumed weight of tractor unit.

{3} *Item 3 = 2.22 L/*t_{load}*·100km x 17* t_{load} */ Item 2*, where 2.22 L/t_{load}·100km is the average fuel efficiency of for-hire truck carriers in Canada [3].

{4} *Item 4 = Item 1 x Item 2 x Item 3 / 100km.*

{5} *Item 5 = Item 4 x 0.35 x 38.4 GJ/*m^3 *x 1* m^3 */ 1000 L*, where 35% = the efficiency of a FD-ICE power train (Table S4) and 38.4 GJ/m^3 = the energy content of fossil diesel (Table S2).

Table S2. Energy Content of Feedstock and Fuels

Item	Parameter	Units	Value	Note
1	AB Crude Oil	GJ_{HHV}/bbl	6.2	{1}
2	Diesel	GJ_{HHV}/m^3	38.4	{2}
3	Biomass Residue			
	Straw Bales	$MJ_{HHV}/kg_{(dry)}$	17.8	{3}
	Wood Chips		20.1	
4	FT Bio-Based Diesel	GJ_{HHV}/m^3	38.4	{4}
5	Hydrogen	MJ_{HHV}/kg	141.2	{5}

Notes:

{1} Weighted average of the energy content of crude oil produced in Alberta - adapted from energy content and crude oil production numbers reported by the NEB [4].

{2} From Environment and Climate Change Canada's National GHG Inventory [5].

{3} Adapted from a literature review of the energy content of biomass from various sources on a dry basis [6], [7].

{4} Same as fossil diesel (Item 3).

{5} Adapted from GHGenius [8], a life cycle assessment tool developed by (S&T) Squared Consultants Inc. ("Fuel Char" worksheet).

Table S3: Alberta Electrical Grid GHG Intensity in 2016 and 2030 (Projection)

Item	Source	2016 Grid {1}			2030 Grid (Projection) {2}		
		Gen. Share	**Conversion Eff.**	**Carbon Intensity**	**Gen. Share**	**Conversion Eff.**	**Carbon Intensity**
		%	%	$kgCO_2e/MWh$	%	%	$kgCO_2e/MWh$
1	Coal	61%	33%	1008	0%	33%	1008
2	**NG Subtotal**	**27%**	**55%** {3}	**372**{4}	**70%**	**52%** {3}	**387** {4}
3	*NG Cogeneration*	*17%*	*60%*	*350*	*20%*	*60%*	*350*
4	*NG Combined Cycle*	*9%*	*51%*	*390*	*46%*	*51%*	*390*
5	*NG Single Cycle*	*1%*	*35%*	*525*	*4%*	*35%*	*525*
6	**Renewable Subtotal**	**11%**	**100%** {3}	**0**{4}	**30%**	**100%** {3}	**0** {4}
7	*Hydro*	*3%*	*100%*	*0*	*3%*	*100%*	*0*
8	*Wind*	*7%*	*100%*	*0*	*24%*	*100%*	*0*
9	*PV*	*0%*	*100%*	*0*	*1%*	*100%*	*0*
10	*Biomass / Other*	*1%*	*100%*	*0*	*2%*	*100%*	*0*
11	Imports	0.7%	100%	0	0%	100%	0
12	**Grid Total / Wtd. Avg**	**100%**	**41%** {3}	**719**{4}	**100%**	**61%** {3}	**270**{4}

Notes:

{1} Based on AESO Annual Market Statistics 2017 [9].

{2} Future grid comprised of 70% natural gas and 30% renewable generation.

{3} *Wtd. Avg Conversion Eff. = Sum (Gen. Share) ÷ Sum (Gen. Share ÷ Conversion Eff.)*, harmonic weighted average of conversion efficiency with respect to generation share.

{4} *Wtd. Avg Carbon Intensity = Sum (Conversion Eff. x Carbon Intensity)*, arithmetic weighted average of carbon intensity with respect to generation share.

3. Fossil Diesel-Internal Combustion Engine (FD-ICE) Energy System

Table S4 provides details and references on the values we used for feedstock retention percentages and energy conversion efficiency for each stage in the FD-ICE energy system. The embedded feedstock price and the fuel cost estimates for the energy system are provided in **Table S5**, and the calculated GHG emissions associated with the trip are provided in **Table S6**.

Table S4. FD-ICE Efficiency and Feedstock Retention

Item	Parameter	Units	Value	Note
1	Crude oil recovery Feedstock Retention (FR)	%	98%	{1}
2	Crude oil recovery efficiency	%	87%	{2}
3	Diesel refining FR	%	92%	{3}
4	Diesel refining efficiency	%	89%	{4}
5	Diesel dist. and dispensing efficiency	%	96%	{5}
6	Diesel power train efficiency	%	35%	{6}

Notes:

{1} Adapted from GHGenius [8], a life cycle assessment tool developed by (S&T) Squared Consultants Inc. Loss of 2% of feedstock attributable to crude products consumed during recovery.

{2} Based on data from [8]; includes all energy feedstock consumed in crude recovery as well as losses incurred during recovery, upgrading, and transportation of crude.

{3} From analysis of refinery input/output model built using data from EIA [10]–[14] and Statistics Canada [15]–[17]; the ratio of crude oil to refined diesel was estimated to be 1.08 : 1 for a FR of 92.4%.

{4} Based on the same refinery model as in {3}; ratio of all input feedstock (NG, electricity, RPPs, etc.) to output diesel was estimated to be 1.12 GJ_{in}/GJ_{out} in energy terms.

{5} Assumes 4% losses via spills, evaporation, etc. during transportation and distribution.

{6} As found on pg. 54 of McKinsey & Co's analysis of transportation power-trains in Europe [18].

Table S5. Energy Costs and Prices for FD-ICE System

Item	Parameter	Units	Range			Note
			Low	Mid	High	
1	Cost of recovered crude oil	2016 U$/bbl	32	47	64	{1}
		2016 C$/GJ	6.23	9.18	12.52	
	Embedded feedstock cost at:					
2	Diesel production	2016 C$/L	0.26	0.38	0.52	{2}
		2016 C$/GJ	6.74	9.93	13.55	
3	Diesel distribution and dispensing	2016 C$/L	0.27	0.40	0.54	{3}
		2016 C$/GJ	7.02	10.34	14.11	
4	Kinetic energy	2016 C$/GJ	20	30	40	{4}
	Estimated price of energy:					
5	Wholesale price of diesel	2016 C$/L	0.58	0.75	0.92	{5}
		2016 C$/GJ	15.07	19.62	23.96	
6	Retail price of diesel	2016 C$/L	0.69	0.86	1.04	{6}
		2016 C$/GJ	17.86	22.36	27.22	
7	Kinetic energy	2016 C$/GJ	51	64	78	{7}

Notes:

{1} Calculated weighted average prices of Canadian Light Sweet and Western Canadian Select for 2013-2017 as reported by the AER [19], [20].

{2} Calculated as Item 1 ÷ implied feed stock retention in diesel refining (0.92). See Table S4 for detail.

{3} Calculated as Item 2 ÷ implied feed stock retention in diesel dist. and dispensing (0.96). See Table S4 for detail.

{4} Calculated as Item 3 ÷ efficiency of a diesel internal combustion engine (0.35). See Table S4 for detail.

{5} Wholesale diesel prices from 2013-2017 as reported by Kent Group Ltd [21].

{6} Retail diesel prices without taxes from 2013-2017 as reported by Kent Group Ltd [21].

{7} Calculated as Item 6 ÷ efficiency of a diesel internal combustion engine (0.35). See Table S4 for detail.

Table S6. FD-ICE Emissions per Trip (kg CO_2e/trip)

Item	Source	Primary	Upstream	Total	Note
1	Crude Production, Upgrading, and Transport	137	21	158	{1}
2	Refining	92	29	120	
3	RPP Transport	4	0	4	
4	Combustion	803	0	803	{2}
5	Total	1036	49	1085	

Notes:

{1} Adapted from IHS Markit report on Well-to-Wheel emissions of oil sands and conventional crude production, transport and refining [22].

{2} Based on Environment Canada's National Inventory Report (NIR) 2018 [23].

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

Table S7 provides details and references on the values we used for feedstock retention percentages and energy conversion efficiency for each stage in the BD-ICE energy system. The embedded feedstock price and the fuel cost estimates for the energy system are provided in **Table S8**, and the calculated GHG emissions associated with the trip are provided in **Table S9**.

Table S7. BD-ICE Efficiency and Feedstock Retention

Item	Parameter	Units	Value	Note
1	Biomass drying and processing efficiency	%	96%	{1}
2	Biomass drying and processing FR	%	98%	{2}
3	Fischer-Tropsch biorefining efficiency	%	51%	{3}
4	Biodiesel dist. and dispensing efficiency	%	96%	{4}
5	FT BD-ICE power train efficiency	%	35%	{5}

Notes:

{1} Includes diesel consumed in harvesting and transporting biomass residue.

{2} Assumed 2% losses in drying and pre-processing.

{3} Adapted from van Vleit et al [24]; 51% was the feed to fuel (biomass to diesel) conversion efficiency of a FT refinery that used biomass as its primary feedstock.

{4} Assumed same FR as fossil diesel since the same distribution and dispensing infrastructure should be used for bio-based FT diesel.

{5} Assumed same efficiency as FD-ICE powertrain.

Table S8. Energy Costs and Prices for BD-ICE System

Item	Parameter	Units	Range Low	Range Mid	Range High	Note
1	Cost of delivered biomass	2016 C$/GJ	4.42	5.94	7.31	{1}
	Embedded feedstock cost at:					
2	Bio-based (Fischer-Tropsch) diesel production	2016 C$/L	0.34	0.46	0.56	{2}
		2016 C$/GJ	8.85	11.89	14.63	
3	Diesel distribution and dispensing	2016 C$/L	0.35	0.48	0.58	{3}
		2016 C$/GJ	9.22	12.39	15.24	
4	Kinetic energy	2016 C$/GJ	26.34	35.40	43.55	{4}
	Estimated price of energy:					
5	Wholesale cost of bio-based diesel	2016 C$/L	0.99	1.14	1.26	{5}
		2016 C$/GJ	25.94	29.71	32.94	
6	Retail cost of bio-based diesel	2016 C$/L	1.13	1.29	1.43	{6}
		2016 C$/GJ	29.38	33.65	37.31	
7	Kinetic energy	2016 C$/GJ	84	96	107	{7}

Notes:

{1} Range based on literature review of cost of delivered biomass from sources such as straw, switchgrass and forest residue [6], [7], [25].

{2} Calculated as Item 1 ÷ (feedstock efficiency of processing biomass x feed to fuel efficiency of Fischer-Tropsch diesel plants) = Item 1 ÷ (0.98 x 0.51) [24]. See Table S7 for more detail.

{3} Calculated as Item 2 ÷ implied feed stock retention in diesel dist. and dispensing (0.96). See Table S7 for more detail.

{6} Calculated as Item 3 ÷ efficiency of a diesel internal combustion engine (0.35). See Table S7 for more detail.

{5} Range based on literature review of the economics of Fischer-Tropsch diesel production [24], [26].

{6} Calculated as Item 5 x 1.13, the average wholesale to retail markup on fossil diesel in Alberta for 2013-2017 (13%, derived from prices reported by Kent Group [21]). Assumed same wholesale to retail markup as fossil diesel since the same distribution and dispensing infrastructure should be used for bio-based FT diesel.

{7} Calculated as Item 6 ÷ efficiency of a diesel internal combustion engine (0.35). See Table S7 for more detail.

Table S9. BD-ICE Emissions per Trip

Item	Parameter	Unit	Value			Note
1	Biomass Required	GJ/trip		22.7		{1}
2	Biomass Required	kg(dry)/trip		1127.6		{2}
3	Bio-Based Diesel Used in Harvest	GJ diesel/trip		0.47		{3}
4	Bio-Based Diesel Used in Harvest	kg Diesel/trip		10.2		{4}
5	Carbon in Biomass	kg C /trip		558.2		{5}
6	Carbon in Bio-Based Diesel	kg C/trip		8.9		{6}
7	Total Carbon Emissions	kg CO_2bio/trip		2078		{7}
8	Reference FD-ICE Emissions	kg CO_2bio/trip		1085		{8}
10	GWP	CO_2eq/CO_2bio	0.1	0.2	0.4	{9}
11	CO_2e/trip	kg CO_2eq/trip	207.8	415.6	831.2	{10}

Notes:

{1} Based on van Vliet et al.'s analysis of biomass based Fischer-Tropsch synthesis plants [24].

{2} *Item 2 = (Item 1 x 1000kg / t) / (20.1 GJ_{HHV} / t_{dry})*, where 20.1 GJ_{HHV} / t_{dry} = the assumed energy content of woody biomass residue based on literature review [6], [7].

{3} Adapted from [27], includes diesel used in gathering, processing and transportation of woody biomass residue.

{4} *Item 4 = Item 3 x 45.6 GJ_{HHV} / t x 0.001 t/ kg*, where 45.6 GJHHV / t is the energy density of diesel [28].

{5} *Item 5 = Item 2 x 50%*, where 50% = the carbon content by weight of woody biomass [29].

{6} *Item 6 = Item 3 x 87%*, where 50% = the carbon content by weight of diesel [30].

{7} *Item 7 = (Item 5 + Item 6) x 3.66* where 3.66 = molar mass ratio of carbon to carbon dioxide.

{8} Calculated for FD-ICE system, see Table S5 Item 5.

{9} Range of Global Warming Potential multipliers deemed reasonable based on literature [31]–[35].

{10} *Item 11 = Item 7 x Item 10.*

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

Table S10 provides details and references on the values we used for feedstock retention percentages and energy conversion efficiency for each stage in the G-BE energy system. The embedded feedstock price and the fuel cost estimates for the energy system are provided in **Table S11**, and the calculated GHG emissions associated with the trip are provided in **Table S12**.

Table S10. G-BE Efficiency and Feedstock Retention

Item	Parameter	Units	Value	Note
1	Natural gas production efficiency and FR	%	90%	{1}
2	Power generation (2030 AB grid) efficiency	%	61%	{2}
3	Electricity transmission and distribution efficiency	%	90%	{3}
4	Charging and on-board electronics efficiency	%	76%	{4}
5	*Charging and Power Electronics Unit (PEU) efficiency*	*%*	*80%*	{5}
6	*On-board electronics efficiency*	*%*	*95%*	{6}
7	Electric motor efficiency	%	90%	{7}

Notes:

{1} Adapted from GHGenius [8], 10% loss attributable to recovery, transmission and processing of NG.

{2} See Table S3.

{3} Historically, line losses during electrical transmission have been in the range of 4-6% in Alberta [36], while losses attributable to electricity distribution are around 5% [37]. So, total losses due to transmission and generation can be estimated as 95% x 95% = 90%.

{4} *Item 3 = Item 4 x Item 5.* The energy available to the motor is the energy at the outlet, minus charging losses, minus energy consumed by the vehicle's on-board electronics.

{5} The net efficiency of charging the vehicle - while this number is heavily dependant on factors such as the state of charge of the battery, method of power delivery (single phase vs. 3-phase, 110V vs 240V) and ambient temperature [38], 80% is a reasonable estimate accounting for Alberta's harsh winter conditions (modern BEVs advertise charging efficiencies of around 90% under optimal conditions).

{6} Estimated energy consumed by on-board electronic systems (includes HVAC) is around 5%. In harsh conditions where there is a significant difference between ambient and desired cabin temperature, this number can be as high as 35% [39].

{7} Efficiency of a 3-phase induction motor [40].

Table S11. Energy Costs and Prices for G-BE System

Item	Parameter	Units	Range			Note
			Low	Mid	High	
1	Cost of delivered natural gas	2016 C$/GJ	2.02	2.83	4.35	{1}
2	Cost of electricity generation	2016 C$/MWh	18	42	84	{2}
		2016 C$/GJ	5.08	11.58	23.28	
	Embedded feedstock cost at:					
3	Distributed (i.e. delivered) electricity	2016 C$/MWh	20	46	93	{3}
		2016 C$/GJ	5.64	12.87	25.87	
4	Electricity on board	2016 C$/GJ	7.42	16.93	34.04	{4}
5	Kinetic energy	2016 C$/GJ	8.25	18.81	37.82	{5}
	Estimated price of energy:					
6	Transmission cost	2016 C$/MWh		43		{6}
		2016 C$/GJ		12		
7	New infrastructure markup	multiplier	1.20	1.40	1.60	{7}
8	Distributed electricity	2016 C$/MWh	96	147	216	{8}
		2016 C$/GJ	27	41	60	
9	Electricity on board	2016 C$/GJ	35	54	79	{9}
		2016 C$/MWh	126	193	284	
10	Kinetic energy	2016 C$/GJ	39	60	88	{10}

Notes:

{1} From AESO daily prices averaged per year for 2012-2017 as reported by the AESO in their Annual Market Statistics 2017 [9].

{2} Annual average of the hourly pool price for 2012-2017 as reported by the AESO in their Annual Market Statistics 2017 [9].

{3} Calculated as Item 2 ÷ efficiency of transmission and distribution in Alberta as in Table S10, Item 3 (0.90).

{4} Calculated as Item 3 ÷ efficiency of charging the battery electric vehicle from delivered grid power as in Table S10, Item 4 (0.76); includes losses in power electronics. See Table S10 for more detail.

{5} Calculated as Item 4 ÷ energy conversion efficiency for motor as in Table S10, Item 10 (0.90).

{6} From AESO's Transmission Rate Projection [41] which projects transmission prices to increase from $33/MWh in 2018 to $43/MWh by 2022.

{7} This system would require significant additions to the grid infrastructure, be it electrification of roads, or adding transmission and distribution capacity, and substations to support a network of charging stations. To account for this, we have assumed a range of multipliers which mark-up the cost of delivered electricity.

{8} Calculated as (Electricity rate + Item 6) x Item 7, where the electricity rate is the average annual electricity rates paid by commercial consumers in 2013-2017 as reported by the AUC [42].

{9} Calculated as Item 8 ÷ efficiency of charging the battery electric vehicle from delivered grid power as in Table S10, Item 3 (0.76); includes losses in power electronics. See Table S10 for more detail

{10} Calculated as Item 9 ÷ energy conversion efficiency for an electric motor as in Table S10, Item 10 (0.90). See Table S10 for more detail.

Table S12. G-BE Emissions per Trip

Item	Parameter	Units	Grid Scenario		Note
			2016 Grid 719 kg CO_2 eq./MWh	2030 Grid 270 kg CO_2 eq./MWh	
1	Electricity Generation	kgCO_2eq /trip	1239	465	{1}
2	Upstream Total	kgCO_2eq /trip	45	79	{2}
3	*Upstream NG*	kgCO_2eq /trip	*29*	*79*	{3}
4	*Upstream Coal*	kgCO_2eq /trip	*16*	*0*	{4}
5	Total	kgCO_2eq /trip	1284	544	{5}

Notes:

{1} *Item 1 = 6.2 GJ/trip x 0.277 MWh/GJ x Grid Emission Intensity*, where 6.2 GJ = the amount of electrical generation required per trip, and Grid Emission Intensity = 719 kg/CO_2e and 270 kg/CO_2e for the 2016 and 2030 grids.

{2} *Item 2 = Item 3+ Item 4.*

{3} *Item 3 = NG used in power gen. x 9.4 kg CO_2e/GJ_{HHV}*, where NG used in power gen = 3.1 GJ and 8.4 GJ for the 2016 and 2030 grids respectively, and 9.4 kg CO2e/GJ_{HHV}NG = upstream emissions associated with the production of NG in Alberta (adapted from [43]).

{4} *Item 4 = Coal used in power gen. x 1.7 kg CO_2e/GJ_{HHV}*, where Coal used in power gen = 9.5 GJ and 0 GJ for the 2016 and 2030 grids respectively, and 1.7 kg CO2e/GJ_{HHV}NG = upstream emissions associated with the production of coal in Alberta [23].

{5} *Item 5 = Item 1 + Item 2.*

6. Natural Gas to H_2 Fuel Cell Electric (NG-HFCE) Energy System

Table S13 provides details and references on the values we used for feedstock retention percentages and energy conversion efficiency for each stage in the NG-HFCE energy system. The embedded feedstock price and the fuel cost estimates for the energy system are provided in **Table S14**, and the calculated GHG emissions associated with the trip are provided in **Table S15**.

Table S13. NG-HFCE Efficiency and Feedstock Retention

Item	Parameter	Units	Value	Note
1	Natural gas production efficiency and FR	%	90%	{1}
2	Hydrogen production via Steam Methane Reforming (SMR) FR	%	78%	{2}
3	Hydrogen production via Steam Methane Reforming (SMR) efficiency	%	77%	{3}
4	Hydrogen distribution and dispensing FR	%	95%	{4}
5	Hydrogen distribution and dispensing efficiency	%	88%	{5}
6	PEMFC efficiency	%	55%	{6}
7	Inverter and power electronics efficiency	%	95%	{7}
8	Electric motor efficiency	%	90%	{8}

Notes:

{1} Adapted from GHGenius [8], 10% loss attributable to recovery, transmission and processing of NG.

{2} Based on ratio of 1.29 GJ_{HHV} NG / GJ_{HHV} H_2 from a NREL model for centralized hydrogen production from Steam-Methane Reforming with CO_2 Capture [44].

{3} From the same model used for Item 2, with the addition of electricity used throughout the SMR process.

{4} Losses of 5% attributed to energy used and leaks during hydrogen transportation and dispensing [45] – assumes a 500km round trip distance from H_2 production facility to distribution and dispensing site.

{5} Includes losses in Item 4 as well as energy consumed to compress the produced hydrogen both for transportation and for dispensing [45].

{6} Based on consultation with PEMFC manufacturer, Ballard.

{7} Based on consultation with hydrogen systems manufacturer, Hydrogenics.

{8} Efficiency of a 3-phase induction motor [40].

Table S14. Energy Costs and Prices for the NG-HFCE System

Item	Parameter	Units	Range			Note
			Low	Mid	High	
1	Cost of delivered natural gas feedstock	2016 C$/GJ	2.02	2.83	4.35	{1}
	Embedded feedstock cost at:					
2	H_2 production via SMR with 90% CCS	2016 C$/GJ	2.60	3.65	5.60	{2}
3	Compressed and delivered (retail) H_2	2016 C$/GJ	2.74	3.85	5.91	{3}
4	Electricity on board	2017 C$/GJ	5.25	7.37	11.31	{4}
5	Kinetic energy	2016 C$/GJ	5.83	8.19	12.57	{5}
	Estimated price of energy:					
6	Wholesale price of H_2 at SMR plant with 90% CCS	2016 C$/kg	1.34	1.53	1.85	{6}
		2016 C$/GJ	9.47	10.80	13.10	
7	Cost of distributing H_2 via tube trucks	2016 C$/kg	1.50	2.42	3.71	{7}
		2016 C$/GJ	10.63	17.11	26.29	
8	Cost of compressing and dispensing H_2	2016 C$/kg	0.98	1.20	1.59	{8}
		2016 C$/GJ	6.90	8.50	11.23	
9	Retail price of H_2	2016 C$/kg	4.19	5.66	7.86	{9}
		2016 C$/GJ	30	40	56	
10	Electricity on board	2016 C$/GJ	57	77	107	{10}
		2016 C$/MWh	205	276	384	
11	Kinetic energy	2016 C$/GJ	63	85	118	{11}

Notes:

{1} From AESO daily prices averaged per year for 2012-2017 as reported by the AESO in their Annual Market Statistics 2017 [9].

{2} Calculated as Item 1 ÷ feedstock retention for SMR with 90% CCS as in Table S13, Item 2 (0.78) [44].

{3} Calculated as Item 2 ÷ feedstock retention for distribution / dispensing as in Table S13, Item 4 (0.95).

{4} Calculated as Item 3 ÷ energy conversion efficiency for PEM fuel cell as in Table S13, Item 6 x Item 7 (0.55 x 0.95 = 0.52).

{5} Calculated as Item 4 ÷ energy conversion efficiency for motor as in Table S13, Item 8 (0.90).

{6} Calculated using NREL's model of a SMR plant with 90% CCS [44] as in Figure 3.10 [46] [$/kg H_2 = Item 1* 0.22 + 0.90], assuming the delivered natural gas feedstock price (Item 1). To convert $/kg to $/$GJ_{HHV}$, multiply by 7.08 kg H_2/GJ_{HHV} H_2.

{7} Assumes transportation of hydrogen via tube trucks; based on literature [47]–[49] and consultation with freight carriers.

{8} Includes capital and operating expenditures for compression, storage, and dispensing infrastructure calculated from an NREL study [50].

{9} Calculated as (Item 6 + Item 7 + Item 8) * 1.1 to include an additional retail markup.

{10} Calculated as Item 9 ÷ energy conversion efficiency for PEM fuel cell as in Table S13, Item 6 x Item 7 (0.55 x 0.95 = 0.52). A conversion factor of 3.6 GJ/MWh was used to calculate price per MWh.

{11} Calculated as Item 10 ÷ energy conversion efficiency for motor as in Table S13, Item 8 (0.90).

Table S15. NG-HFCE Emissions per Trip

Item	Process	Units	2016 Grid 270 kg CO_2 eq./MWh		2030 Grid 719 kg CO_2 eq./MWh		Notes
			No CCS	CCS	No CCS	CCS	
1	NG Production and Processing	$kgCO_2eq$ /trip	100	100	100	100	{1}
2	Steam Methane Reforming Process	$kgCO_2eq$ /trip	557	56	557	56	{2}
3	Electricity Generation	$kgCO_2eq$ /trip	156	158	59	59	{3}
4	*Generation for SMR e-*	$kgCO_2eq$ /trip	*25*	*27*	*9*	*10*	{4}
5	*Generation for Distribution e-*	$kgCO_2eq$ /trip	*131*	*131*	*49*	*49*	{5}
6	**TOTAL**	**$kgCO_2eq$ /trip**	**812**	**315**	**716**	**216**	{6}

Notes:

{1} *Item 1 = 10.6 GJ_{HHV}/trip x 9.4 kg CO_2e/GJ_{HHV}*, where 10.6 GJ_{HHV}/trip = NG required for SMR, and 9.4 kg CO_2e/GJ_{HHV} = upstream emissions associated with the production of NG in Alberta (adapted from [43]).

{2} Item 2 = 65.5 kg CO_2e / $GJ_{HHV}H_2$ x 8.5 GJ_{HHV}H2 x (1 - % Carbon Capture), where 65.5 kg CO_2e / $GJ_{HHV}H_2$ = carbon intensity of SMR per NREL model [44], 8.5 $GJ_{HHV}H_2$ = H_2 production required per trip, and % Carbon Capture = 0% and 90% for the No CCS and CCS scenarios, respectively.

{3} *Item 3 = Item 4 + Item 5.*

{4} *Item 4 = Electricity Used in SMR x 0.277 MWh/GJ x Grid Emission Intensity*, where Electricity Used in SMR = 0.13 GJ/trip and 0.14 GJ/trip in the No CCS and 90% CCS cases, respectively, and Grid Emission Intensity = 719 kg/CO_2e and 270 kg/CO_2e for the 2016 and 2030 grids, respectively (See Table S3 for more detail on each grid scenario).

{5} *Item 5 = 0.66 GJ/trip x 0.277 MWh/GJ x Grid Emission Intensity*, where 0.66 GJ/trip = the amount of electrical generation required for compression and distribution of H_2, and Grid Emission Intensity = 719 kg/CO_2e and 270 kg/CO_2e for the 2016 and 2030 grids, respectively (See Table S3 for more detail on each grid scenario).

{6} *Item 6 = Item 1 + Item 2 + Item 3.*

7. Wind and Solar to H_2 Fuel Cell Electric (WS-HFCE) Energy System

Table S16 provides details and references on the values we used for feedstock retention percentages and energy conversion efficiency for each stage in the WS-HFCE energy system. The embedded feedstock price and the fuel cost estimates for the energy system are provided in **Table S17**, and the GHG emissions were effectively zero.

Table S16. WS-HFCE Efficiency and Feedstock Retention

Item	Parameter	Units	Value	Note
1	PEM electrolysis efficiency	%	72%	{1}
2	Hydrogen distribution and dispensing FR	%	95%	{2}
3	Hydrogen distribution and dispensing efficiency	%	88%	{3}
4	PEM-FC efficiency	%	55%	{4}
5	Inverter and power electronics efficiency	%	95%	{5}
6	Electric motor efficiency	%	90%	{6}

Notes:

{1} Assumes a conversion ratio of around 1.4 GJ of electricity per 1 GJ of hydrogen [51].

{2} Losses of 2% attributed to energy used and leaks during hydrogen transportation and dispensing [45].

{3} Includes losses in Item 4 as well as energy consumed to compress the produced hydrogen both for transportation and for dispensing [45].

{4} Based on consultation with PEMFC manufacturer, Ballard.

{5} Based on consultation with hydrogen systems manufacturer, Hydrogenics.

{6} Efficiency of a 3-phase induction motor [52].

Table S17. Energy Costs and Prices for WS-HFCE System

Item	Parameter	Units	Range			Note
			Low	Mid	High	
1	Levelized cost of wind and solar generation	2016 C$/MWh	30	40	67	{1}
		2016 C$/GJ	8.45	11.00	18.53	
	Embedded feedstock cost at:					
2	H_2 production via PEM electrolysis	2016 C$/kg	1.66	2.16	3.64	
		2016 C$/GJ	12	15	26	{2}
3	Compressed and delivered H_2	2016 C$/kg	1.75	2.28	3.84	
		2016 C$/GJ	12.40	16.14	27.19	{3}
4	Electricity on board	2016 C$/GJ	23.72	30.89	52.05	{4}
5	Kinetic energy	2016 C$/GJ	26.36	34.32	57.83	{5}
	Estimated price of energy:					
6	Wholesale price of H_2 at PEM electrolysis plant	2016 C$/kg	3.10	3.87	5.01	
		2016 C$/GJ	21.9	27.4	35.5	{6}
7	Cost of distributing H_2 via tube trucks	2016 C$/kg	1.50	2.42	3.71	
		2016 C$/GJ	10.63	17.11	26.29	{7}
8	Cost of compressing and dispensing H_2	2016 C$/kg	0.98	1.20	1.59	
		2016 C$/GJ	6.90	8.50	11.23	{8}
9	Retail price of H_2 (retail)	2016 C$/kg	6.13	8.23	11.34	
		2016 C$/GJ	43.40	58.29	80.28	{9}
10	Electricity on board	2016 C$/GJ	83	112	154	{10}
		2016 C$/MWh	299	402	553	
11	Kinetic energy	2016 C$/GJ	92	124	171	{11}

Notes:

{1} From results of the AESO's Renewable Electricity Program (REP) [1], Lazard's LCOE Analysis [2], and CERI's Guide to Electricity Generation Options in Canada [3].

{2} Calculated as Item 1 ÷ conversion efficiency of PEM electrolysis (electricity to H_2) as in Table S16, Item 1 (0.72).

{3} Calculated as Item 2 ÷ feedstock retention rate of hydrogen compression and distribution as in Table S16, Item 2 (0.95).

{4} Calculated as Item 3 ÷ energy conversion efficiency for PEM fuel cell as in Table S16, Item 4 x Item 5 (0.55 x 0.95 = 0.52).

{5} Calculated as Item 4 ÷ energy conversion efficiency for motor as in Table S16, Item 6 (0.90).

{6} Adapted from a NREL model for hydrogen production costs via PEM electrolysis [44].

{7} Assumes same range of transport costs as NG-HFCE system (Table S14, Item 7).

{8} Assumes same range of compression, storage, and dispensing costs as NG-HFCE system (Table S14, Item 7).

{9} Calculated as (Item 6 + Item 7 + Item 8) * 1.1 to include an additional 10% retail markup.

{10} Calculated as Item 9 ÷ energy conversion efficiency for PEM fuel cell in as in Table S16, Item 4 x Item 5 (0.55 x 0.95 = 0.52). A conversion factor of 3.6 GJ/MWh was used to calculate price per MWh.

{11} Calculated as Item 10 ÷ energy conversion efficiency for motor as in Table S16, Item 6 (0.90).

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