Biofuels in Canada 2021

Tracking biofuel consumption, feedstocks and avoided greenhouse gas emissions

November 9th, 2021

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About Navius Research

Navius Research is a private consulting firm, specializing in the analysis of policies designed to meet environmental goals, with a focus on energy and greenhouse gas emission policy. We are Canada's leading experts in forecasting the environmental and economic impacts of energy and greenhouse gas emissions policies.

Funding

Navius Research thanks Advanced Biofuels Canada for funding this project. Navius Research maintained full control over the analysis and editorial content of this project.

Acknowledgments

Navius Research would like to thank individuals within the governments of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec and Canada for providing data and input to our analysis. We would also like to thank: Don O'Connor of (S&T)² Consultants for his review of data sources, assumptions and the cost analysis; Kristin Moore of KMoore Consulting for input on the analysis of octane value.

Executive Summary

There are many policies designed to increase the consumption of renewable and low-carbon fuels in Canada, and thus reduce transportation greenhouse gas (GHG) emissions. However, there is no detailed and comprehensive data source characterizing the impact of these policies. As such, Advanced Biofuels Canada has again engaged Navius Research to fill this information gap by updating the "Biofuels in Canada" report that has been released annually since 2016.

Objectives

The objectives of this project are to evaluate and communicate the impact of renewable and low-carbon fuel policies in Canada by:

1. Quantifying the volumes of renewable transportation fuels consumed in each Canadian province (i.e. biofuel), characterized by fuel type, feedstock, and carbon intensity (CI). The biofuels include ethanol, biodiesel and hydrogenation derived renewable diesel (HDRD). The analysis also includes fuels produced from renewable feedstocks that are refined with crude oil (i.e. co-processed fuels) and the impact of light-duty electric vehicles.
2. Estimating their impact on GHG emissions.
3. Estimating how biofuel consumption may impact energy costs, including an analysis on the role of fuel taxation within this cost impact.

New Analysis and Updates to the Methodology

Biofuels in Canada now includes:

- Estimated results for 2020
- An estimate of the impact of light-duty electric vehicles on fuel consumption and GHG emissions
- An estimate of co-processed fuels' impact on fuel consumption and GHG emissions (renewable feedstocks refined with crude oil)

This current edition of the Biofuels in Canada analysis includes some methodological changes that affect the results for 2019 and prior years:

- **Estimated Octane Value from Wholesale Prices:** In past years, this model used the spread in retail prices between regular and premium gasoline to estimate the value of octane provided by ethanol. To better reflect the cost of refining associated with increasing octane (rather than changes to marketing margins on premium gasoline), the model now uses the wholesale value of octane. The impact and reasoning behind this change is discussed in more detail in Appendix C: Change to Cost Analysis Methodology.

- **Change in Statistics Canada Data Source:** Due to discontinuation of provincial-level fuel demand estimates in the Supply and Disposition of Petroleum Products tables, the model is now using Statistics Canada's data on energy consumption. This results in minor changes to demand estimates and removes the need to estimate redacted monthly data.

- **HDRD Price Data:** In previous years, investor materials from Neste were used to estimate the commodity cost of HDRD. This year, the HDRD prices implied in Diamond Green Diesel's financial materials were used in place of the Neste data for pricing from January 2015 onward. Neste data is still used for 2010 to the end of 2014. Imports from the U.S. are eligible for a $1 USD/Gallon blenders' tax credit, which would be passed through to export prices. The U.S. imports are assumed to be the price-setting supply in the Canadian market.

- **Mid-Year Tax Changes:** The gasoline and diesel cost analysis has been adjusted to include a month-by-month representation of fuel taxes to reflect the fact that tax rates typically change with governments' fiscal year (e.g., after March 31st), rather than the calendar year.

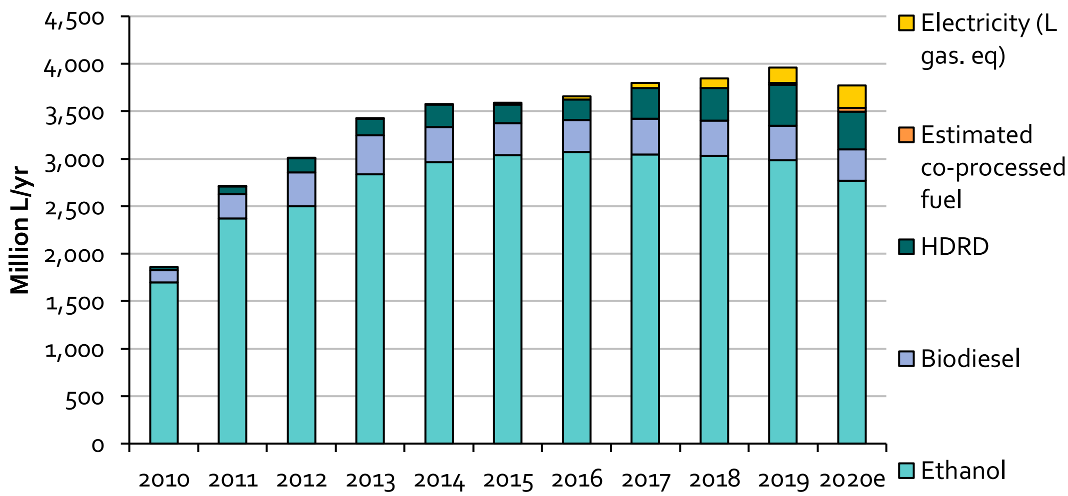
- **Co-Processing and Electric Vehicles:** Estimates for energy consumption and avoided GHG emissions for co-processed volumes and electric vehicles are now included in the analysis to quantify the role of these other low-carbon transportation options alongside blended biofuels. Currently there is no data describing the volume or GHG intensity of co-processed fuels and these quantities have been estimated using the methodology in Appendix D: Co-processed Fuel Methodology. Electric vehicle sales are reported in Statistics Canada data, but the energy and GHG impact must also be estimated, using the methodology described in Appendix E:Electric Vehicle Analysis Methodology.

Fuel Consumption

Using data obtained from provincial and federal government sources and contacts, we estimate that annual ethanol consumption has increased from roughly 1,700 million litres in 2010 to 2,985 million L/yr in 2019 (down by 1.6% since 2018). The estimated ethanol consumption for 2020 is slightly lower at 2,767 million litres, where the reduction is a result of lower overall reported fuel consumption for that year, a result of reduced demand during the COVID-19 pandemic.

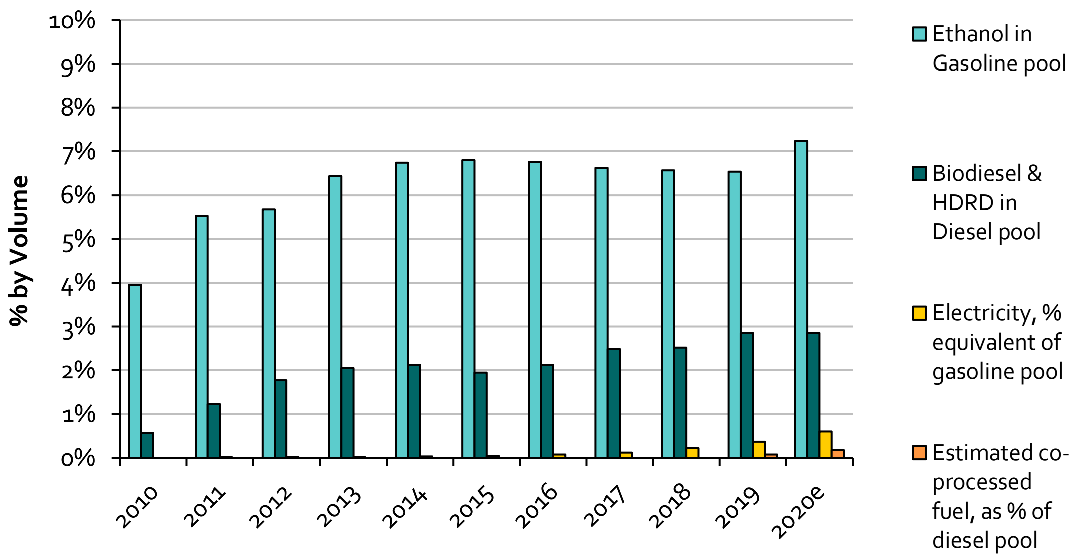
Annual biodiesel consumption has increased from roughly 123 million L/yr in 2010 to 360 million L/yr in 2019. HDRD consumption increased from roughly 37 million L/yr to 432 million L/yr in that same period (Table 11). The total quantity of biomass-based diesel consumption in Canada that we report for 2019 is 792 million litres (11% more than in 2018). Like ethanol, the estimated consumption of biomass-based diesel in 2020 is lower than in 2019, largely due to reduced overall fuel consumption during the pandemic.

Figure 1: Renewable and low-carbon transportation energy consumption in Canada



Since 2013, ethanol has accounted for over 6% of the gasoline pool volume. Biodiesel and HDRD have been close to 2% of the diesel pool volume, rising to almost 3% in 2019 (Figure 2). The blending rates in the gasoline and diesel fuel pools were 6.5% and 2.9% in 2019 respectively. Co-processed fuel accounted for a volume equivalent of about 0.1% of the diesel pool, while light-duty electric vehicles offset a quantity of fuel consumption equivalent to about 0.4% of the gasoline pool. Blending rates are estimated to be greater in 2020, when the pandemic reduced fossil fuel consumption somewhat more than renewable fuel consumption.

Figure 2: Renewable fuel content by fuel pool with estimate for 2020



Lifecycle GHG Emissions

Based on lifecycle carbon intensities reported by government contacts and obtained from GHGenius 4.03a, renewable fuel consumption and light-duty electric vehicles have avoided 47 Mt CO_2e between 2010 and 2019. Annual avoided GHG emissions have grown from 2.1 Mt in 2010 to 6.4 Mt in 2019. The estimated annual reduction for 2020 is just 6.2 MtCO_2e, again due to lower overall fuel consumption in that year due to COVID-19.

Trends in biofuel carbon intensities in British Columbia and California indicate that biofuel production is becoming less emissions intensive. This is consistent with the default CI scores produced with the GHGenius 4.03a model. Therefore, a fixed amount of biofuel consumption avoids more GHG emissions in 2019 than it would have in 2010.

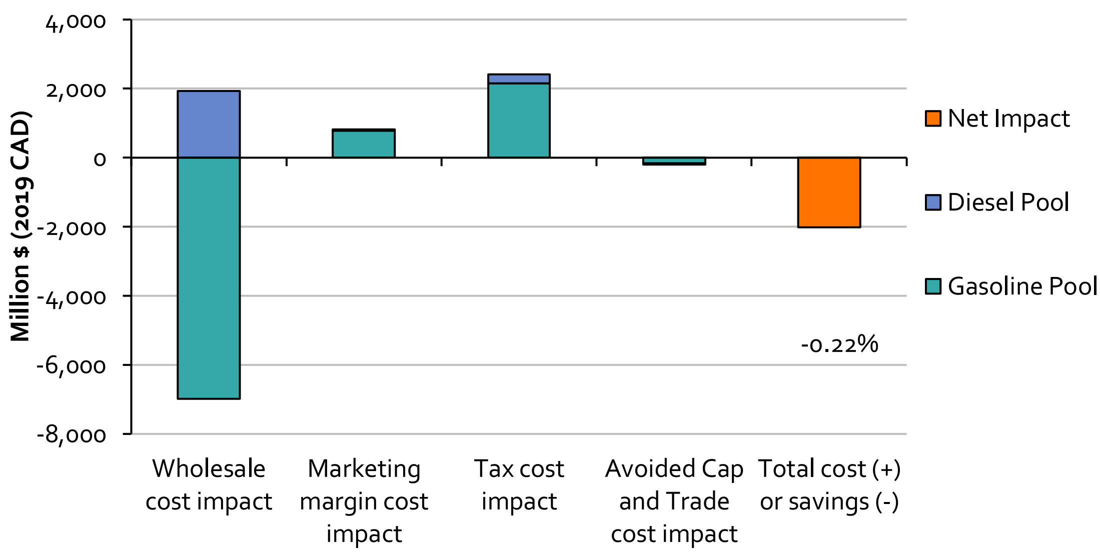
Cost Analysis

Figure 3 shows the cumulative consumer cost impact, by component, resulting from biofuel consumption between 2010 and 2019. The cost components are the wholesale cost, the marketing margin cost (i.e. distribution), the fuel tax cost (including carbon taxes), and avoided costs under emissions cap and trade policies (in Québec, Nova Scotia, and previously Ontario). The wholesale cost impact is based on observed market prices for fuels and accounts for biofuel transportation costs and the octane value of ethanol, which allows a lower-cost gasoline blendstock to be used. While

Canadian refiners may not capture the octane value of ethanol in all cases, this analysis assumes they do; higher octane fuels have a higher market price and we assume that refiners would not provide extra octane with no additional charge.

Biofuel consumption has yielded a cost savings, relative to a scenario where no biofuel was consumed, of roughly $2.0 billion over ten years (2019 CAD), or -0.22% of total gasoline and diesel pool expenditures. Note that the cost analysis methodology has been updated this year, reducing this cumulative cost savings (as compared to previous Biofuels in Canada reports).

Figure 3: Cumulative cost impact resulting from ethanol blending in the gasoline pool and biomass-based diesel blending in the diesel pool (2010-2019), total % change in data label

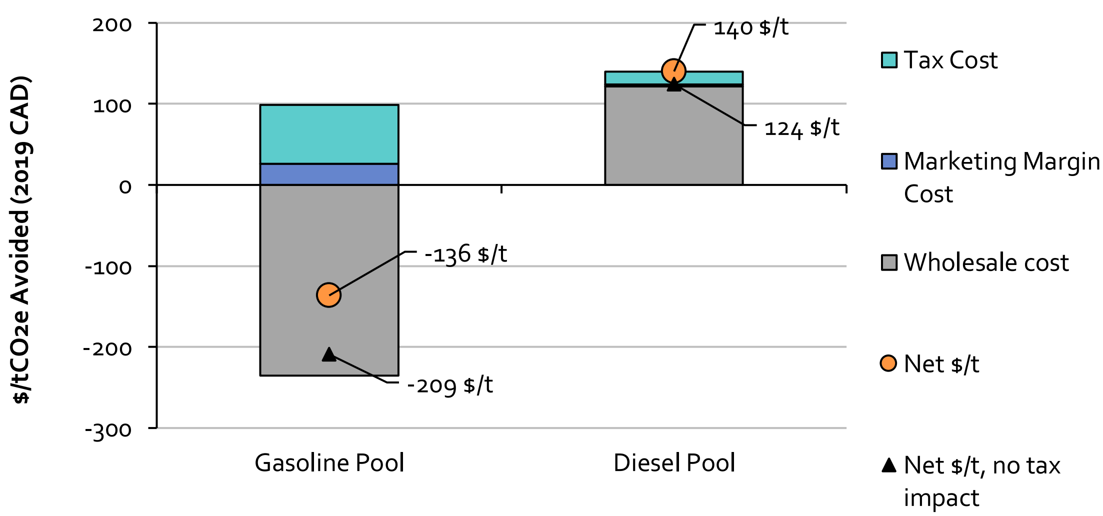


The total cost impact has a component related to wholesale fuel costs, where the octane value of ethanol reduces wholesale fuel costs. The total cost also has components related to tax costs and distribution costs that exist because of the differences in energy density between fossil fuels and biofuels. Notably, because ethanol is roughly 33% less energy dense than gasoline, consumers must purchase more of it to obtain the same amount of energy. That exposes them to greater distribution costs based on our assumption that marketing margins in a $/L basis are not affected by biofuel blending rates.

Lower energy density also increases the tax consumers paid on biofuels since most fuel taxation (e.g. excise and carbon taxes) in Canada is charged per litre, regardless of how much energy is in that litre. Furthermore, percent sales taxes (e.g. PST, GST, HST) may be larger per litre on renewable fuels if these fuels cost more per litre, as often is the case with blends containing biomass-based diesels. Consequently, consumers generally pay more taxes per kilometer driven when using biofuel blends. In 2019, on average in Canada (fuel consumption-weighted), a driver of a light-duty vehicle using gasoline with 10% ethanol (i.e. E10) will have paid an additional 1.5% more taxes per kilometre than when using E0 (i.e. pure gasoline). Similarly, a heavy-duty vehicle driver will pay an additional 0.3% more taxes per kilometre when using diesel with 5% biodiesel (i.e. B5) than when using B0 (pure fossil diesel). Consequently, Canadians have paid an additional $2.4 billion in taxes from 2010 through 2019 as a result of renewable fuel blending (Figure 3).

Figure 4 shows the cumulative consumer cost divided by the cumulative avoided GHG emissions from 2010-2019 for the gasoline and diesel pools in Canada. The costs do not account for any co-benefits or costs other than those shown in Figure 3 (i.e. no accounting for reduced air pollution and reduced health impacts related to biofuel consumption). The abatement cost in the gasoline pool is -$136/t$CO_2$e versus $140/t$CO_2$e in the diesel pool. The negative abatement cost for ethanol is largely a consequence of its value in raising the octane of gasoline blends, though this value is offset partly by the additional distribution cost and tax burden associated with ethanol consumption. On net, renewable fuel consumption in Canada has saved a typical gasoline consumer (based on a typical light-duty vehicle) $9/yr (-0.5%), whereas it has cost a typical diesel consumer (based on a long-distance truck operator) an additional $205/yr (+0.6%).

Figure 4: GHG abatement cost, 2010-2018



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1. Introduction

There are many policies designed to increase the consumption of renewable and low-carbon fuels in Canada, and thus reduce transportation greenhouse gas (GHG) emissions. However, there is no detailed and comprehensive government source characterizing the impact of these policies.

Environment and Climate Change Canada (ECCC) and the US Department of Agriculture both provide reporting and estimates of biofuel consumption in Canada, while several provincial governments publish data describing fuel consumption in their provinces, sometimes with estimates of fuel carbon intensity (CI) and GHG emission impacts. Still, there is no comprehensive data source in Canada that allocates renewable fuel consumption by province using data from provincial regulators and no single source that communicates the impact of renewable consumption on GHG emissions and fuel costs. As such, Advanced Biofuels Canada has again engaged Navius Research to fill this information gap by updating the “Biofuels in Canada” report that has been released annually since 2016.

The goals of this project are to evaluate and communicate the impact of renewable and low-carbon fuel policies in Canada. This is done by quantifying the annual volumes of transportation fuels consumed in individual provinces and nationally from 2010 to 2019, the most recent year for which data is available (with estimates for 2020). These fuels are further characterized by type (i.e. gasoline, ethanol, diesel, biodiesel, co-processed renewable fuel etc.), feedstock, and CI. Using these volumes and CIs, we then estimate the impact of biofuel consumption on GHG emissions and energy costs by province, with additional focus on how fuel taxation affects these costs. New this year is an estimate of how the growing fleet of electric light-duty vehicles in Canada is affecting GHG emissions and fuel consumption.

A further goal of this study is to provide transparent results that are available to a wide range of stakeholders. As such, this report is a companion to a Microsoft Excel spreadsheet that contains the analysis and visual representations of key results for fuel volumes, cost impacts and avoided GHG emissions ("Biofuels in Canada Analysis, 2021-11-09"). Results are shown for Canada and each province.

The remainder of this report provides an overview of the existing and upcoming renewable and low-carbon fuel policies in Canada and a discussion of carbon pricing policies. This is followed by a description of the analysis methodology and discussion of the results. The appendices contain more information on the cost analysis methodology and on our renewable fuel volume and feedstock data and assumptions.

2. Canadian Policy Background

This section of the report summarizes the existing renewable fuel policies in Canada as of autumn 2021 at both the federal and provincial levels to provide an understanding of the regulations driving renewable fuel consumption in the period. The existing and upcoming carbon pricing policies that affect the price of gasoline and diesel blends are also explained, as is the potential impact of the proposed Canadian Clean Fuel Standard (CFS). Throughout this report, fuel carbon intensity (CI) refers to the lifecycle GHG emissions associated with each fuel, from feedstock production (e.g. an oil well or a corn farm) through to final consumption.

2.1. Renewable Fuel Blending Requirements

National Summary

The Canadian federal government enacted the *Renewable Fuels Regulations* on August 23, 2010. This regulation mandates 5% renewable fuel by volume in the gasoline pool, and 2% renewable fuel by volume in diesel pool, which included distillate heating oil until removal in 2013. The purpose of this policy is to reduce the amount of GHGs emitted from the combustion of these fuels.

The gasoline blending requirement started December 15, 2010, whereas the diesel blending requirement began July 1, 2011. The federal regulation only requires compliance on average across Canada. This means that fuel sold across Canada may have very different biofuel blending rates, where over-compliance in one region is offset by undercompliance in another region.

In December 2020, the Government of Canada published the draft regulations for the federal Clean Fuel Standard. The final regulations are expected to be published in late 2021 or early 2022. Upon publication of the final regulations, facilities will become eligible to generate *Clean Fuel Regulations* credits. Sections 5 and 6 of the draft *Clean Fuel Regulations* adopted a similar volumetric requirement for low carbon intensity fuels (5% for gasoline, 2% for diesel).

Alongside the national policy there are a variety of provincial policies, which mandate specific volumes of renewable content in fuel pools. Table 1 summarizes the percentage of ethanol to be blended with gasoline as mandated by various regulations at different levels of government in Canada. It is important to note that some quantities of gasoline and diesel are exempt from blending policies in Canada. For example, gasoline and diesel pools in Newfoundland and Labrador, the Territories, as well as other regions north of 60 degrees latitude are not regulated under the federal policy. As described in the following sub-section, the Ontario *Cleaner Transportation Fuels* regulation prescribes the biofuel content in gasoline based on the average CI of the biofuels relative to fossil diesel or gasoline, so the actual share of biofuel may vary from what is reported in the table.

Table 1: Gasoline biofuel blending policies

Region	2010	2011 to 2019	2020	2021
British Columbia	5.0%	5.0%	5.0%	5.0%
Alberta	-	5.0%	5.0%	5.0%
Saskatchewan	7.5%	7.5%	7.5%	7.5%
Manitoba	8.5%	8.5%	8.5%	9.25%
Ontario	5.0%	5.0%	10%	10%
Canada	-	5.0%	5.0%	5.0%

Some regions in Canada are not yet subject to any provincial or territorial gasoline biofuel blending policies. However, they are still regulated under the federal policy. These regions have been excluded from Table 1: Québec, New Brunswick, Nova Scotia, Newfoundland and Labrador, and Prince Edward Island.

Similarly, Table 2 summarizes the prescribed percentage of biofuels to be blended in regulated diesel pools in Canada. The most common forms of biofuels blended into diesel include biodiesel and hydrogenation-derived renewable diesel (HDRD). As with gasoline, the share of biomass-based diesel required in Ontario is subject to a carbon intensity requirement and it may vary from what is reported in the table.

Table 2: Diesel biofuel blending policies

Region	2010	2011	2012 & 2013	2014 & 2015	2016	2017 to 2020	2021
British Columbia	3.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Alberta	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Saskatchewan	-	-	2.0%	2.0%	2.0%	2.0%	2.0%
Manitoba	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	3.5%
Ontario	-	-	-	2.0%	3.0%	4.0%	4.0%
Canada	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

As with ethanol, some regions in Canada are not subject to any provincial or territorial diesel biofuel blending policies, but they are still regulated under the federal policy. These regions have been excluded from Table 2: Québec, New Brunswick, Nova Scotia, Newfoundland and Labrador, and Prince Edward Island.

Provincial Policy Design

Canada has a variety of renewable fuel policies at the federal and provincial levels of government. However, besides prescribing different renewable fuel volumes (summarized in Table 1 and Table 2), these policies vary in design and application.

Alberta has the *Renewable Fuel Standard* which came into effect April 1, 2011. It mandates fuel producers to blend biofuels with gasoline and diesel. An average of 5% is required in gasoline pools, while an average of 2% is required in diesel pools. However, Alberta's policy also specifies that the CI of the renewable content must be 25% lower than the corresponding gasoline and diesel. In practice, most biofuels meet this criterion. For example, in 2011 the lifecycle CI of gasoline (as estimated by GHGenius 4.03a) was approximately 88.8 gCO_2e/MJ. In contrast, the default CI of ethanol was 59% to 65% lower, depending on the ethanol feedstock. The CI of diesel in Alberta in 2011 was 96 gCO_2e/MJ, while the CI of biodiesel in that province ranged from 8 to 20 gCO_2e/MJ, or 79% to 92% lower than diesel (also based on GHGenius 4.03a). Note that Alberta uses a different version of the GHGenius model, so actual lifecycle CI values used in the policy may differ slightly.

Manitoba has the *Ethanol General Regulation* and the *Biodiesel Mandate for Diesel Fuel Regulation*. These policies mandate the blending of biofuels with gasoline and diesel pools. The first compliance period for the diesel policy began November 1, 2009, but was later revised to delay implementation until April 1, 2010. The ethanol policy mandates 8.5% renewable content by volume in gasoline since January 1, 2008, 9.25% as of 2021, and 10% as of 2022.[1] The biodiesel policy required 2% biodiesel by volume through 2020, rising to 3.5% in 2021 and 5% in 2022.[2]

Ontario previously had the *Greener Gasoline – Bio-Based Content Requirements for Gasoline*[3] regulation mandating 5% ethanol content in gasoline, which was increased to a carbon intensity-adjusted requirement of 10% by volume beginning in the 2020.

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[1] Government of Manitoba, The Biofuels Act, Ethanol General Regulation

[2] Government of Manitoba, The Biofuel Act, Biodiesel Mandate For Diesel Fuel Regulation

[3] Government of Ontario, O. Reg. 535/05: GREENER GASOLINE - BIO-BASED CONTENT REQUIREMENTS FOR GASOLINE

Suppliers must meet the compliance target at all their facilities combined. In November 2020, the *Greener Gasoline* regulations were repealed and replaced with a new regulation, *O. Reg. 663/20: Cleaner Transportation Fuels: Renewable Content Requirements For Gasoline And Diesel Fuels*[4], which combines the *Greener Gasoline* and *Greener Diesel* regulations.

Like the previous regulations, the *Cleaner Transportation Fuels* regulation set requirements for a carbon intensity-adjusted ethanol blend rate of 10% in 2020-24, 11% in 2025-27, 13% in 2028-29, and 15% in 2030. Compliance with the regulation between 2020 and 2024 will result in 10% bio-based fuel content if the weighted average CI of the biofuel is approximately 46 gCO_2e/MJ (45% below a benchmark CI for gasoline). If the CI of the biofuel is lower than 46 gCO_2e/MJ, then the blend rate may also be lower; if a higher CI ethanol is used, a higher blend rate would be required to achieve compliance. Gasoline sold for marine, aviation or off-road use is exempt from the regulations, along with gasoline sold in northern Ontario or any gasoline with an octane of 89 or greater.

Along with the ethanol regulation, the *Greener Diesel Regulation* was also repealed and replaced with the *Cleaner Transportation Fuels* regulation. The new regulation maintains the standard from the *Greener Diesel Regulation:* a 4% average blend rate with an average CI reduction of 70% relative to diesel fuel (i.e. biofuels with CI levels below the CI average target mean less renewable fuel must be used). For context, the average reported CI of biodiesel sold in Ontario in 2020 was 6.14 gCO_2e/MJ. This is 93% below the default CI of diesel, 93 gCO_2e/MJ, meaning bio-based diesel of this CI only needed to achieve a blend rate of 3% to comply with the standard.

To allow some compliance flexibility during the COVID-19 pandemic, the Ontario Ministry of Environment merged the 2020 and 2021 compliance periods, meaning fuel suppliers could achieve compliance by blending at a rate above the standard in 2021 if they were to fall below the standard in 2020 (or vice versa).

Saskatchewan has *The Ethanol Fuel Act* and *Ethanol Fuel (General) Regulations* that regulate the volume of ethanol to be blended with gasoline (7.5% by volume) and establishes quality standards for the ethanol to be blended. Saskatchewan also has *The Renewable Diesel Act* that started on July 1, 2012 mandating 2% renewable fuel by volume in diesel pools.

[4] Government of Ontario, O. Reg. 663/20: CLEANER TRANSPORTATION FUELS: RENEWABLE CONTENT REQUIREMENTS FOR GASOLINE AND DIESEL FUELS

The **British Columbia** (BC) *Renewable and Low Carbon Fuel Requirements Regulation* (RLCFRR) has two components. The first component defines the minimum renewable fuel content of gasoline and diesel at 5% and 4% by volume respectively. This component came into effect January 1, 2010, with an initial 3% blending requirement for diesel which increased to 4% in 2011. The second component of the policy regulates the average CI of the fuels, as described in section 2.3.

Québec has no renewable fuel blending policy in force as of 2021, though the government released a draft regulation on May 12, 2021 which, when finalized, is proposed to take effect in January 2023. The draft regulation would require 10% ethanol by volume and 3% biomass-based diesel by volume beginning in 2023, with additional credit given for cellulosic ethanol. Those blending rates would rise to 15% ethanol and 10% biomass-based diesel by 2030.[5]

The **Yukon** has announced they intend to introduce bio-based diesel and ethanol blending mandates by 2025 that "align with the percentage [...] by volume in leading Canadian jurisdictions", aiming for 20% renewable content in the diesel pool and 10% in the gasoline pool. This would be the highest volumetric blend mandate in Canada[6]. Draft regulations have not yet been published.

2.2. Carbon Pricing

British Columbia Carbon Tax

The BC carbon tax was \$30/tCO_2e from 2012 until 2018. In April 2018, the tax rate increased to \$35/tCO_2e, and to \$40/tCO_2e in April 2019. The tax rate will generally increase by \$5/tCO_2e each year until it reaches \$50/tCO_2e. However, the increase in 2020 was delayed in light of the COVID-19 pandemic, the tax was raised to \$45/tCO_2e in April 2021 and will reach \$50/tCO_2e in 2022.[7] Each \$5/tCO_2e increment increased the tax on gasoline by 1.11 ¢/L and the tax on diesel by 1.28 ¢/L (Table 3).[8]

The application of the tax to gasoline and diesel is based on emissions factors that approximate a 5% volumetric biofuel blending rate in the province, resulting in a tax of

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[5] Government of Québec, 2019, Regulation respecting the minimum volume of renewable fuel in gasoline and diesel fuel

[6] Government of Yukon, 2020, *Our Clean Future: A Yukon strategy for climate change, energy and a green economy*

[7] Government of British Columbia, British Columbia's Carbon Tax

[8] Ibid.

10.0 ¢/L on gasoline and 11.7 ¢/L on diesel as of autumn, 2021. The tax is applied equally to each litre of fuel, fossil and renewable, and is not adjusted for tailpipe or lifecycle GHG emissions of alternative fuels.

In light of the December 2020 announcement that the federal backstop carbon price will rise to $170/tCO_2e$ in 2030, the BC carbon tax will either need to be further increased or will be supplemented by the federal fuel charge post-2022. The CleanBC Roadmap to 2030 policy updated released October 25, 2021, proposes to 'align with or exceed federal requirements.'[9]

Table 3: British Columbia carbon tax rates (nominal CAD)

	2012-2017	2018	2019 and 2020	2021-2022	2022 - onwards
Tax rate, $/tCO_2e$	30	35	40	45	50
Gasoline, ¢/L	6.7	7.8	8.9	10.0	11.1
Diesel, ¢/L	7.7	9.0	10.2	11.7	12.7

Alberta Carbon Levy

Alberta implemented a $20/tCO_2e$ carbon levy, essentially a carbon tax, in 2017, which rose to $30/tCO_2e$ in 2018.[10] Similar to BC, the application of the levy to gasoline and diesel used fuel emissions factors that reduce the rate by the prescribed biofuel blend level (i.e. 5% ethanol by volume in gasoline 2% by volume biodiesel in diesel) (Table 4). However, unlike BC, Alberta's carbon levy exempted 100% of the biofuel component of blends that exceeded 10% in gasoline and 5% in diesel.

The Alberta carbon levy was repealed by the newly elected provincial government in 2019.[11] Consequently, as of 2020, gasoline and diesel purchases were subject to the federal carbon pricing backstop discussed below (also shown in Table 4).

Table 4: Alberta carbon levy rates on gasoline and diesel (nominal CAD)

	Rate in 2017	Rate in 2018 and early 2019	Rate in 2020 (federal backstop)	Rate in 2021 (federal backstop)
Gasoline, ¢/L	4.5	6.7	6.6	8.8
Diesel, ¢/L	5.4	8.0	8.1	10.7

[9] Government of British Columbia, 2021, CleanBC Roadmap to 2030

[10] Government of Alberta, Carbon Levy Rates

[11] Government of Alberta, Carbon Tax Repeal

Québec Cap and Trade

The Québec GHG emissions cap and trade system began in 2014 and suppliers of transportation fuels were included as of 2015. It applies to fuel suppliers who must hold credits for the emissions resulting from the fossil fuels they distribute; emissions from biofuels are exempt from the cap and trade system. The emissions credit price affects the wholesale price of fuels; however, wholesale gasoline and diesel pricing does not show a price differentiation between fossil-biofuel blends and fuels without biofuels.

The system has a price floor, which is a minimum price for credit trades. That price began in 2013 at \$10.75/tCO_2e (nominal CAD) and rises by 5% plus inflation each year to 2020.[12] The Québec system is linked with the California cap and trade program, so the minimum credit price in the joint program must also account for the exchange rate. In practice, the average annual credit price has remained slightly above the price floor[13] (Table 5).

Table 5: Québec cap and trade average annual credit price and estimated price impact on gasoline and diesel (nominal CAD)

	2014	2015	2016	2017	2018	2019	2020
Credit price, \$/tCO_2e	13.4	22.71	22.59	22.31	22.67	22.71	22.26
Gasoline, ¢/L	3.3	5.5	5.6	5.5	5.5	5.6	5.5
Diesel, ¢/L	3.7	6.2	6.2	6.2	6.1	6.2	6.1

Nova Scotia Cap and Trade

Nova Scotia's cap and trade system took effect on January 1, 2019, with the first compliance period lasting from 2019 to 2022. A floor price of \$20/tCO2e was in place for the first auction in 2020. The floor price is scheduled to increase at 5% per year plus inflation. Fuel suppliers must purchase allowances for only 20% of the emissions on fuels (including gasoline and diesel) that they import into the province for combustion. The Nova Scotia cap and trade quantification, reporting, and verification

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12 www.environnement.gouv.qc.ca/changements/carbone/Systeme-plafonnement-droits-GES-en.htm

13 Government of Québec, The Carbon Market, Cap-and-Trade Auction Notices and Results

And

California Air Resources Board, Summary of Transfers Registered in CITSS By California and Québec Entities in 2019, April 15 2020 regulations specify that fuel suppliers do not have to purchase allowances for CO_2 emissions from biofuels.[14]

Nova Scotia's provincial government regulates the price of motor gasoline and diesel, including the allowable pass-through of costs associated with the cap-and-trade system. The petroleum product pricing regulation specifies that fuel suppliers may recover 20% of the auction price floor at a fixed CI of 2.36 $kgCO_2e/L$ gasoline from retail sales.[15] If an auction settles above the floor price, a price adder is applied to the pricing formula to support cost recovery. In 2020, the carbon price on motor gasoline ranged from 1.01 ¢/L to 1.23 ¢/L.

New Brunswick Carbon Tax

New Brunswick introduced a provincial carbon tax in April 2020 to replace the federal fuel charge associated with the carbon pricing backstop. The New Brunswick tax follows the rate schedule of the federal Greenhouse Gas and Pollution Pricing Act and applies the same tax rate to bio-based and petroleum fuels. The carbon tax exemptions align with New Brunswick's Motor Fuel Tax exemptions, extending further than most other provinces to exempt almost all off-road fuel consumption from the carbon tax, including manufacturing, mining, and home heating[16].

In tandem with the introduction of the carbon tax, New Brunswick amended its fuel tax regulations to reduce the motor fuel tax on gasoline and diesel. Gasoline and Diesel excise taxes were reduced by 4.63 and 6.05 cents per litre respectively in 2019, resulting in a net carbon price of only 2 cents per litre.

Table 6: New Brunswick Carbon Tax

	2020-2021	2021-2022
Gasoline Carbon Price (¢/L)	6.63	8.84
Gasoline, Change to Fuel Tax from 2019, ¢/L	-4.63	-4.63
Gasoline, Net Carbon Price, ¢/L	**2**	**4.21**
Diesel Carbon Price (¢/L)	8.05	10.73
Diesel, Change to Fuel Tax from 2019, ¢/L	-6.05	-6.05
Diesel, Net Carbon Price, ¢/L	**2**	**4.68**

[14] Government of Nova Scotia, s. 17 (2) Quantification, Reporting and Verification Regulations

[15] Government of Nova Scotia, Petroleum Product Pricing Regulations

[16] Government of New Brunswick (accessed via CanLII), Gasoline and Motive Fuel Tax Act

Ontario Cap and Trade

The Ontario cap and trade program was in effect between January 1st, 2017 and July 2018. The first credit auction was held in January 2018 and the system linked with the cap-and-trade program in California and Québec. However, the program was cancelled later that year by the newly elected provincial government, and all trading was stopped on July 3rd, 2018.[17] As of 2019, gasoline and diesel sales in Ontario are subject to the federal carbon pricing backstop described below.

Like the Québec cap and trade system, fuel suppliers had to hold credits for the emissions resulting from the fuels they distributed when the cap was in effect. The credit price affected the wholesale gasoline and diesel prices at the time indicated that the carbon cost was spread evenly across all fuel blends, regardless of their renewable fuel content.

The average credit price in 2017 was \$18.2/tCO_2e, roughly 4.3 ¢/L on gasoline and 4.8 ¢/L on diesel. The average credit price in 2018 was \$18.6/tCO_2e up until the program was cancelled.[18]

Federal Carbon Pricing Backstop

The carbon pricing backstop applies to provinces that chose to not to implement an equivalent carbon pricing system of their own; these include Saskatchewan, Manitoba, Ontario, and Alberta following the repeal of the carbon levy. Newfoundland and Labrador, PEI, New Brunswick, Nova Scotia, and British Columbia have developed their own provincial carbon pricing systems rather than using the federal system. However, the impact of carbon pricing on fuel prices in Newfoundland and Labrador and PEI in 2019 was the same as the federal system, described below.

The federal carbon price backstop applied to fossil fuels sold in Ontario, Saskatchewan and Manitoba provinces starting April 1st, 2019 (and in Alberta starting in 2020). The price began at \$20/tonne in 2019 and is scheduled to rise by \$10 annually to \$50/tonne by 2022.[19] The fuel charge rates shown in Table 7 account for the regulated volumetric renewable fuel content required in Canada: 5% in gasoline and

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[17] Government of Ontario, Archived – Cap and Trade

[18] Government of Ontario, 2018, *Past auction information and results*

[19] Government of Canada, 2019, *Fuel Charge Rates*

2% in diesel. Biofuel volumes used in blends greater than 10% (E10) in gasoline or 5% (B5) in diesel are exempt from the carbon price.[20]

Table 7: Federal backstop carbon levy rates on gasoline and diesel blends up to E10 and B5 (nominal CAD)[21]

	2019	2020	2021	2022
Carbon price, $/tCO2e	$20	$30	$40	$50
Gasoline, ¢/L	4.42	6.63	8.84	11.05
Diesel, ¢/L	5.37	8.05	10.73	13.41

Because this carbon price does not differentiate by blend rates up to E10 and B5, it creates a foregone price incentive for lower-carbon fuels and a foregone cost savings related to biofuel blending when a carbon price is in effect. This impact will increase substantially as the carbon price increases. For example, once the carbon price reaches $170/t$CO_2$ in 2030, the current design of the federal carbon pricing backstop overtaxes E10 by about ¢2.6/L and it overtaxes B5 by about ¢1.5/L. Based on 2019 fuel consumption (about 46 billion L of blended gasoline and 28 billion L of blended diesel) and assuming widespread E10 and B5 consumption, this policy design would have consumers pay an additional $1.6 billion per year in 2030.

Table 8: The surtax/foregone price incentive on E10 and B5 in relation to the announced federal carbon pricing schedule

	2023	2024	2025	2026	2027	2028	2029	2030
Carbon Price, $/tCO2e	65	80	95	110	125	140	155	170
Surtax/foregone price incentive on E10, ¢/L	1.0	1.2	1.5	1.7	1.9	2.2	2.4	2.6
Surtax/foregone price incentive on B5, ¢/L	0.6	0.7	0.8	1.0	1.1	1.2	1.4	1.5

[20] McKenna, C., Morneau, W.F., 2018, Explanatory Notes Relating to the Greenhouse Gas Pollution Pricing Act and Related Regulations

[21] Government of Canada, 2019, *Fuel Charge Rates*. www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html

2.3. Low-Carbon Fuel Standards

British Columbia Low-Carbon Fuel Requirement

The CI component of the BC *Renewable and Low-Carbon Fuel Requirements Regulation* (RLCFRR, often called a low-carbon fuel standard, or LCFS), came into effect July 1, 2013 with a schedule that required a 10% reduction in average fuel CI by 2020 relative to a 2010 baseline. The 2020 target was reduced to -9.1% in light of the COVID-19 pandemic and a new target of -20% has been legislated for 2030 and beyond.[22,23]

The CI component of the policy has resulted in blending renewable fuels at volumes greater than the minimum 5% in gasoline and 4% in diesel. However, renewable fuel blending is not the only action that can satisfy the low-carbon fuel requirement of the RLCFRR. If the minimum renewable fuel standard is met, the CI requirement of the LCFS can also be met by switching to lower carbon transportation energy sources such as natural gas, electricity, or hydrogen. In other words, while this LCFS policy is likely to encourage more renewable fuel consumption, it does not prescribe this consumption.

The RLCFRR in BC need only be met on average by suppliers of gasoline and diesel in the provincial market. Compliance credits can be traded amongst suppliers, and parties that do not comply will pay a penalty rate of 200 \$/tCO_2e for a compliance shortfall. As of October 2021, credits were trading well above the compliance penalty rate at \$470/tCO_2e. The most compelling reason we have heard is that some fuel suppliers have internal policies that their regional operations must comply with local statutes, requiring that they buy credits to achieve compliance rather than paying the 200 \$/tCO_2e non-compliance rate.

Additionally, a minority of credits each year can be generated through special projects pursuant to Part 3 Agreements. These projects may reduce the CI of the regulated fuels or permit greater availability of low-carbon fuels (e.g. installation of re-fuelling infrastructure capable of dispensing mid-to-high blend biofuels, such as diesel with 20% biodiesel in it). These credits may account for up to 25% of compliance in a given year.

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22 Government of British Columbia, BC-LCFS Requirements

23 Government of British Columbia, BC Reg. 394/2008, RENEWABLE AND LOW CARBON FUEL REQUIREMENTS REGULATION

The CleanBC Roadmap to 2030 proposes to modernize the increase the CI reduction requirement, starting with analysis and consultations on a 30% reduction by 2030.[24]

The Clean Fuel Standard

The Canadian federal government is developing a LCFS-style regulation called the *Clean Fuel Regulations* (CFR), previously referred to as the Clean Fuel Standard (CFS) during regulatory development. Like the BC RLCFRR and the similar California *Low Carbon Fuel Standard*, the CFR will require a reduction in the life-cycle CI of gasoline and diesel fuels. Unlike these policies, the CFR extends to jet fuel and gasoline and diesel fuel use outside of the transportation sector. The CFR currently proposes no reduction requirement for aviation jet fuels.

The final CFR is expected to be published in late 2021, with the policy coming into force in 2022. Similar regulations for gaseous and solid fuels were previously expected be published 12 months following the regulation for liquid fuels but were cancelled in December 2020.[25,26] The proposed CFR for liquid fuels does allow for voluntary credit generation by gaseous and solid fuel suppliers to account for 10% of a liquid fuel supplier's compliance obligation and also provides credits for EV home-charging until 2035, providing the charging equipment is installed before the end of 2030.[27]

The draft regulations propose a CI target for gasoline and diesel fuels in 2030 that is 12 gCO_2e/MJ lower than a 2016 benchmark for fuels, which includes gasoline, diesel, and biofuels used in the baseline year.[28] The draft regulations also reduced the initial reduction requirement from 3.6 to 2.4 gCO_2e/MJ and increased the annual change in the carbon intensity reduction target from 0.8 to 1.2 gCO_2e/MJ per year. The federal *Renewable Fuels Regulation* (RFR) will end when the CFR comes into force for the liquids pool, though the CFR will maintain the same minimum blending rates for low carbon intensity fuels in both the gasoline and diesel pool (5% and 2% by volume,

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[24] Government of British Columbia, 2021, CleanBC Roadmap to 2030

[25] Environment and Climate Change Canada, Clean Fuel Standard – Revised Publication Timeline

[26] Government of Canada, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations

[27] Ibid.

[28] Ibid.

respectively). Early CFR credit generation will be allowed from date of publication of the final regulation and any surplus credits from the RFR will roll over into the CFR.

Like the BC and Californian LCFS policies, the CI of liquid fuels can be reduced by blending lower CI fuels into petroleum fuels, or by switching transportation energy consumption to natural gas, electricity, and hydrogen. While fuel producers and importers (i.e. the fuel suppliers) are required by the policy to reduce the CI of gasoline and diesel fuels, low carbon intensity fuel suppliers and alternative transportation energy suppliers can generate and trade compliance credits. Compliance credits can also be generated by parties that reduce GHG emissions in upstream oil production, upgrading, and refining stages (for example, from the use of lower-carbon fuels, integration of renewable energy, or the use of carbon capture and storage).

Other options will be available to increase the flexibility of compliance: for example, there will be limited use of credits by obligated fuel suppliers of gaseous and solid fuel credit generators (e.g. compliance credits from blending renewable natural gas into natural gas distribution system), unlimited use of credits for early action and surplus compliance with the Renewable Fuels Regulation, and limited use of a compliance fund that allows obligated parties to purchase a limited proportion of the required compliance credits at a maximum ceiling price of $350/credit.

Impact of Low-Carbon Fuel Standards on Retail Fuel Prices

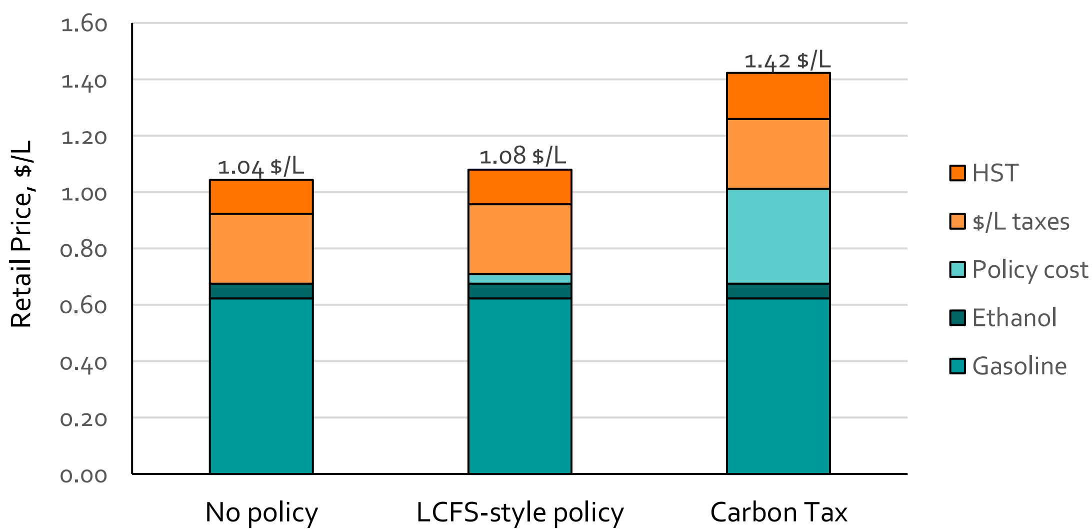
LCFS-style policies create a market-based incentive to supply low-carbon fuels because this action generates compliance credits which can be traded in their associated market. The price of credits will rise until it is high enough to incentivize fuel suppliers to comply with the policy. In a properly functioning market, the credit price will be equal to the GHG abatement cost of the costliest marginal action required for compliance, including ancillary costs like fuel distribution and blending or even foregone revenues from fuel refining and sales. All other actions taken to comply with the policy will be less costly. Therefore, the average cost of compliance and the average carbon abatement cost associated with the policy is less than the credit price.

LCFS credit prices and carbon tax rates are often improperly compared when assessing the impact on retail fuel prices. A LCFS credit price and a carbon price with the same $/tCO_2e$ value have a very different impact on retail fuel prices. The difference exists for two reasons. First, a carbon tax applies to 100% of the direct GHG emissions (i.e. tailpipe) associated with a fuel while on-net, a LCFS credit price only applies to the portion of a fuel's lifecycle GHG emissions above a given threshold (i.e. the required CI reduction in a given year). Second, the LCFS policies in Canada do not produce any financial transfer to the government like a carbon tax does (unless it has a ceiling price for credits that is reached meaning a subset of compliance credits might be purchased from the government).

Using the example of retail fuel prices that were typical in Ontario in 2019 and gasoline containing 10% ethanol by volume (E10), a LCFS policy with a credit price of 150 \$/ tCO_2e would result in an E10 price of 1.08 \$/L versus 1.04 \$/L without an LCFS. The net retail-price impact is just 4 ¢/L. In contrast, a carbon tax of 150 \$/tCO_2e would result in an E10 price of 1.42 \$/L (Figure 5), with a net price impact of 38 ¢/L (34 ¢/L and 4 ¢/L in additional sales tax) However, carbon tax revenue recycling, which is not considered here, could mitigate the cost impact for consumers if, for example, that revenue were used to lower income tax or returned to households as a lump sum payment. Nonetheless, the price impact at the pump with a carbon tax would remain significantly higher than with a LCFS policy.

LCFS policies have a different impact on retail prices because they act like a "feebate" on fuels that have CI's above and below the average life-cycle CI target: the policy applies a "fee" to fuels with CI's above the target, but all the revenue earned from the "fee" ultimately becomes a "rebate" to fuels with CI's that are below the target.

Figure 5: Impact of an LCFS-style policy and a carbon tax on E10 retail prices, where an LCFS credit price is equal to the carbon tax \$/tonne CO_2e value (\$150 t/CO_2e)

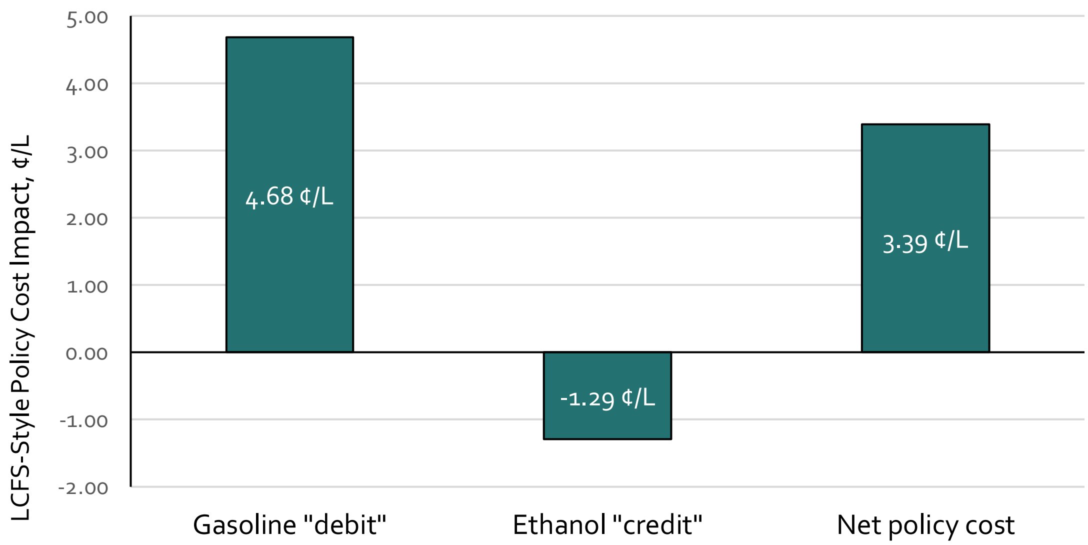


Note: wholesale fuel costs and fuel taxes are based on Ontario in 2019. LCFS credit price and carbon tax are 150 \$/tonne. In the example, the gasoline CI is 87 gCO_2e/MJ, the ethanol CI is 40 gCO_2e/MJ, and the CFS target CI is 77 gCO_2e/MJ.

This "feebate" is illustrated with the example of E10 in Ontario again. If petroleum-derived gasoline has a life-cycle CI of 87 gCO_2e/MJ and the target for 2030 is 10 gCO_2e/MJ lower, the "fee" on the gasoline component in that year would be 4.7 ¢/L of

E10 when the compliance credit price is 150 $/t$CO_2$e. The ethanol component of the E10 would earn a "rebate" of 1.3 ¢/L of E10, when the CI of ethanol is 40 gCO_2e/MJ. Assuming a functioning and somewhat competitive fuel market where the LCFS costs and benefits are mostly passed to the consumer, that policy would increase the price of E10 by 3.8 ¢/L (Figure 6, 3.4 ¢/L from the LCFS policy, 0.4 ¢/L from increased sales tax).

Figure 6: Breakdown of an LCFS-style policy's cost impact on E10 retail price with a hypothetical $150/t$CO_2$e credit price



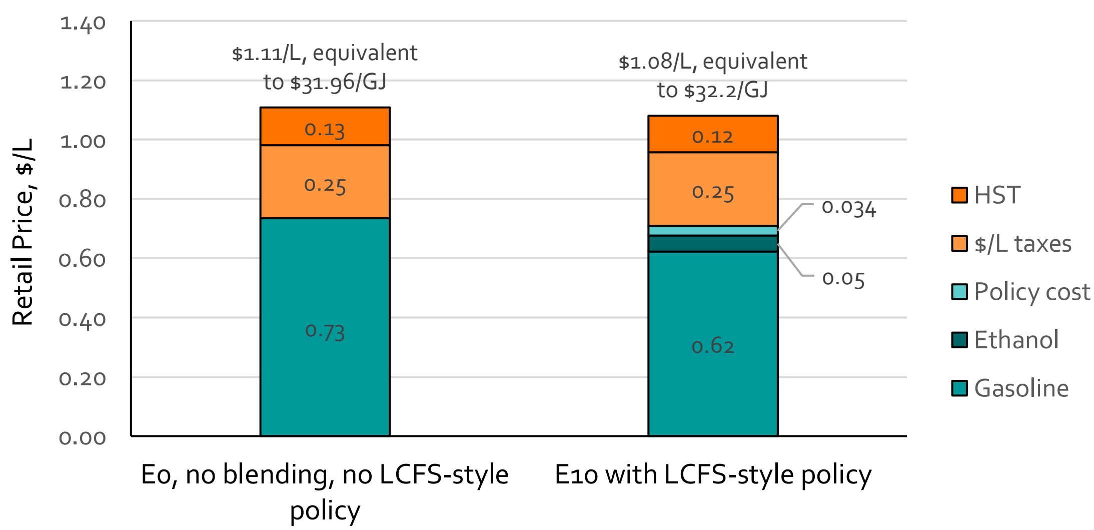
Note: LCFS credit price and carbon tax are 150 $/tonne. In the example, the gasoline CI is 87 gCO_2e/MJ, the ethanol CI is 40 gCO_2e/MJ, and the CFS target CI is 77 gCO_2e/MJ.

The GHG abatement cost broadly perceived by consumers under a LCFS-style policy is defined by the average abatement costs of the actions used to make that consumer's fuel compliant with the policy. This abatement cost is not solely defined by the policy credit price, which represents the abatement cost of the costliest action needed for overall policy compliance (i.e. the marginal cost). In reality, most compliance in response to LCFS-style policies is generated internally by fuel providers when blending low-carbon fuels. Only a small subset of compliance is purchased as credits at the marginal abatement price of the policy, so the credit price does not represent the average abatement cost. For example, since 2013, the start of BC's low-carbon fuel requirement, to 2019 (most recent year with complete data), 12% of compliance credits were obtained by trading while the rest were generated by fuel providers when blending lower-carbon fuels.[29]

[29] Government of British Columbia, RLCF-17: Low Carbon Fuel Credit Market Report

Using the example of E10 above, the average abatement cost perceived by a consumer is just \$24/tCO_2e even though the marginal compliance cost in this example came from the purchase of credits at \$150/tCO_2e. This average cost is based on a comparison with a counterfactual scenario where E0 is used without any policy requirement to blend biofuel or reduce the average fuel CI. The abatement cost comes from energy costs of \$31.96/GJ (\$1.11/L) for E0 versus \$32.20/GJ (\$1.08/L) for E10, including the credits require to comply with the policy (Figure 7). Recall that ethanol is roughly 33% less energy dense than gasoline; thus, in this example, a litre of E0 can be more expensive than E10 per liter, but can still cost less per GJ. Consistent with the cost-impact methodology used later in this analysis, the gasoline in the E0 fuel is more expensive than the gasoline used with E10 since it must be produced with a higher octane rating rather than having its octane raised with the addition of ethanol. This octane value brings down the abatement cost of using ethanol to comply with the LCFS-style policy. While there is some uncertainty in the magnitude of the octane value of ethanol, that uncertainty does not change the fact that the average abatement cost experienced by a consumer is not the same as the policy credit price.

Figure 7: Inputs to calculating the average GHG abatement cost when using E10 and compliance credits to comply with a hypothetical LCFS-style policy



Note: LCFS credit price is \$150/tCO_{2e}. The gasoline CI is 87 gCO2e/MJ, the ethanol CI is 40 gCO2e/MJ, and the LCFS target CI is 77 gCO2e/MJ. Gasoline without ethanol must be produced with a higher octane and is more expensive than the gasoline blendstock used with ethanol (i.e. \$0.73/L vs. \$0.69/L, or a gasoline cost of \$0.62/L of E10)

Abatement Costs with Foregone Refining Margins

The abatement actions that a fuel provider might use in response to a LCFS-style policy are significantly influenced by their costs. However, to understand which actions are used, it is important to include all costs, or perceived potential costs, that a fuel provider might experience when thinking about how to comply with the policy. In addition to the direct cost of an abatement action, a fuel provider might also consider the indirect cost of that action, such as how it might change their revenues. For example, a refinery earns a margin on the product it refines (i.e. the refining margin) and refining and selling less product would reduce its revenues (i.e. there would be foregone refining margins on sales of a refined petroleum product).

Notably, when selling blended biofuels purchased from another producer, there is the potential that this action will reduce the quantity of gasoline or diesel that the refinery may sell. If this outcome is expected, the value of the foregone refining margin will be included in the abatement cost.

The following example illustrates that the foregone refining margin could change the relative abatement costs of two actions available to a fuel provider. In this case, a fuel provider can reduce emissions by blending additional biodiesel into their diesel fuel, or adding carbon capture and storage (CCS) at their refinery hydrogen (H_2) unit. The calculations use the following assumptions:

- Abatement from CCS with H_2 costs \$100/tCO_2e reduction.
- The fuel provider does not need additional investments in blending infrastructure.
- The fuel provider assumes the prices, CI values and fuel densities recorded for 2017[30] in the Biofuels in Canada analysis are representative of future conditions (using Canada fuel-weighted averages): biodiesel costs \$0.75/L with a \$0.05/L transportation cost, has a CI of 7.9 gCO_2e/MJ and a density of 35.4 MJ/L; wholesale diesel (B0) sells for \$0.68/L with a CI of 93.8 gCO_2e/MJ, and a density of 38.7 MJ/L. The refining margin (net revenue) is \$0.25/L.[31]
- The fuel provider cannot pass the additional costs on the consumers.
- Both actions would count towards compliance under a LCFS-style policy and would generate credits worth \$150/tCO_2e.

[30] 2017 provides a convenient data year for this example because there was a positive abatement cost associated with using biodiesel. In 2018 and 2019, that abatement cost is negative, i.e. it theoretically saves money to use biodiesel. This does not change the fact that foregone revenues can change the abatement cost experienced by a fuel provider, but it complicates the example. 2020 data is not yet complete.

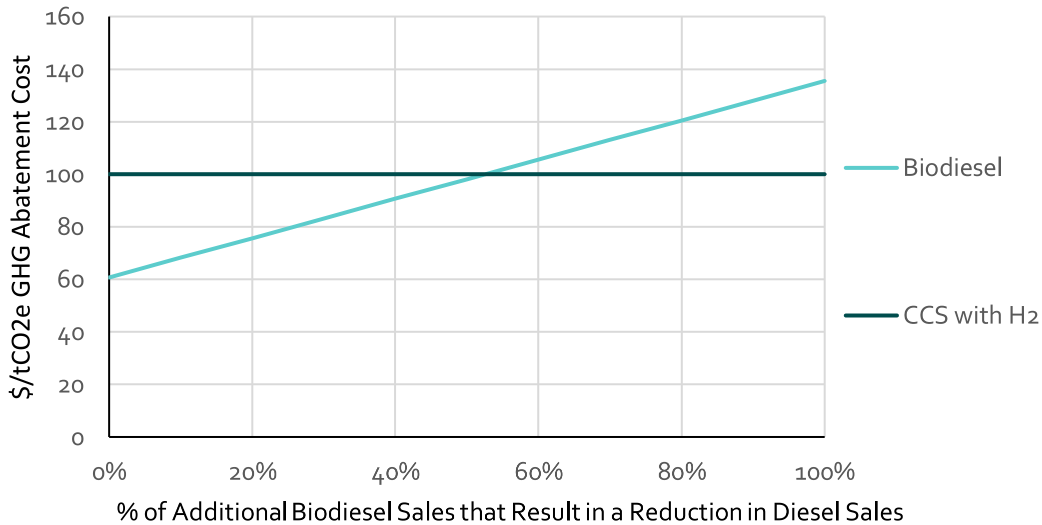
[31] Kent Group, https://charting.kentgroupltd.com/

Based on fuel costs and properties alone, the abatement cost of blending additional biodiesel is \$61/tCO_2e. This is the abatement cost if the fuel provider can find an alternative market for all of its prior diesel production (e.g. in a region without an LCFS-style policy) and blending additional biodiesel has no impact on overall diesel sales. Therefore, the fuel provider would first choose to reduce emissions by blending biodiesel and might also invest in CCS since both abatement actions are less than the credit price.

However, if selling more biodiesel does reduce diesel sales and result in a foregone refining margin, then the fuel provider loses \$0.25 for each litre of diesel not sold. To reduce GHG emissions by one tonne, the fuel provider would have to sell 11.6 GJ of biodiesel, equivalent to 301 L of diesel. If the biodiesel sales completely displace an energetically equivalent amount of diesel, then there is \$101 in foregone refining margin per tonne of GHG reduction and the net abatement cost is \$162/tonne. In this case, the fuel provider would only choose to reduce emission with CCS and would not blend more biodiesel since its abatement cost is greater than the credit price.

It is likely that the impact of additional biodiesel blending on diesel sales is somewhere between the maximum and minimum cases explained above. Still, the abatement cost of biodiesel in this example is sensitive to its impact on diesel sales. If just over 50% of the additional biodiesel sales offset an energetically equivalent amount of diesel sales, CCS is the lower cost abatement action (Figure 8). In reality, this would be further complicated by changes in corporate income tax, lost crude oil production and/or retail revenues for integrated refiners, potential changes in wholesale or retail prices, and economies of scale (i.e. it costs less per litre to refine greater volumes). Nonetheless, this example indicates why a fuel provider might prefer to reduce the emissions intensity of their fuels rather than sell biofuels, even when that latter action appears to have a lower abatement cost.

Figure 8: Relative abatement cost of blending biodiesel versus capturing and storage of CO_2e as a function of how biodiesel sales affect diesel sales.



3. Methodology

3.1. Process

Table 9 outlines the tasks we undertook in this study as well as our approach for each of these tasks.

Table 9: Study method by task

Task	Approach
1. Tabulate renewable fuel use and requirements	Provincial and federal renewable and low carbon fuel regulation compliance data (published, direct communication) were collected. An updated summary of regulations in each jurisdiction was also generated. The data in this report includes January 1, 2010 to December 31, 2019 (with 2020 data from Ontario, Alberta, and Saskatchewan), the most recent data period available for most jurisdictions.
2. Characterize biofuel product use	Biofuel products were defined as: ethanol, biodiesel, hydrogenation-derived renewable diesel (HDRD), as well as co-processed renewable fuels. These products were further disaggregated by biomass feedstocks as identified and estimated from personal correspondences with government contacts and biofuel market experts, publications, or based on region of origin.
3. Characterize biofuel CI and impact on energy efficiency to estimate GHG reductions	Carbon intensities (CI) were defined with GHGenius (v.4.03a), data from 1 & 2 above and with a review by government contacts and industry experts. Energy efficiency (i.e. change in energy per km) impacts (or lack thereof) are defined by literature review. These assumptions were used to estimate the GHG impact of biofuel. Furthermore, this report illustrates how average CI of fuel types (e.g. ethanol, biodiesel) can change through time using the fuels registered under the BC fuels policy. BC is used as a case study because it is one of the few jurisdictions where CI is documented by fuel.
4. Estimate fuel displaced by co-processing and electric vehicles	Co-processed fuel volumes in BC were estimated from public communications from Parkland corporation, which operates the refinery in Burnaby. For electric vehicles, sales data from Statistics Canada was used to estimate the stock of EVs by province. The fuel displaced by EVs is estimated assuming EVs are driven the same annual distance as gas vehicles and the energy effectiveness ratio is from the draft *Clean Fuel Regulations*.
5. Estimate the impact of biofuel on energy costs	Wholesale ethanol and biodiesel prices from the Chicago Mercantile Exchange (CME) were used to estimate the landed price (based on typical rail shipping rates) of these fuels in major Canadian cities. Regular gasoline and diesel prices were used in these cities (Kent Group data) to estimate the unblended

Task	Approach
	wholesale price of the petroleum fuels. HDRD prices were estimated using Neste Oyj's and Diamond Green Diesel's financial materials for investors. These prices, along with marketing margins and taxes were then used to quantify how biofuels may have affected the fuel costs for consumers, accounting for the volumetric energy content of biofuels and the impact of ethanol on the octane rating of gasoline/ethanol fuel blends.
6. Produce estimated results for 2020	For provinces where no 2020 data was yet available, all results (volumes, GHG and cost impacts) were estimated for 2020, assuming constant biofuel blending rates from 2019 (or a continuation of a trend for BC) and using Statistics Canada data to define the size of the gasoline and diesel pools. Carbon intensities for 2020 are taken from GHGenius or assumed based on provincial data for 2019.

3.2. Summary of Inputs

Table 10 summarizes the data and assumptions used in this analysis to complete tasks 1 through 4. The data used in the analysis was either obtained through direct communication with government contacts or from published data (represented in green). Some data required assumptions (represented in yellow). For example, for regions that do not collect data on biofuel carbon intensity as part of their regulations, the default CI from GHGenius was assumed to be representative of the average biofuel consumed in that region.

Table 10 also flags the greatest uncertainties in orange, representing data gaps. For example, neither Québec nor the Atlantic provinces have reporting mandates for biofuels blended into transportation fuels. To infer the volume of ethanol, biodiesel, and HDRD consumed in these provinces, we used the difference between national consumption totals, reported by Environment and Climate Change Canada (ECCC) for 2011-2019[32,33] and the data we collected. Therefore, the resulting biofuel consumption reported for Québec and the Atlantic provinces is particularly uncertain since it is the difference between federal data and the sum of provincial data, all of which is collected using different methodologies.

Note that for 2019, we increased the national total consumption of biomass-based diesel relative to what was reported by ECCC, from 786 to 792 million L/yr, because

[32] Environment and Climate Change Canada, 2016, Renewable Fuels Regulation Report: December 15, 2010 to December 31, 2012.

[33] Environment and Climate Change Canada, 2020, Open Data: Renewable Fuels Regulations 2013, 2014, 2015, 2016, 2017,2018 and 2019

the sum of fuel used for compliance with provincial regulations was more than the reported national volume used for compliance with the federal renewable fuel regulations. This decision is based on information from industry contacts indicating that some renewable fuel imports from the U.S. were not included in ECCC reporting for the RFR. This situation highlights some of the uncertainty in the data and the difficulty with data collection and analysis. Provincial data is not collected in the same way as federal data and these sources are not reconciled with each other. Furthermore, it is difficult to calculate biomass-based diesel consumption using production and trade data because HDRD does not have its own harmonized system (HS) code. The lack of an HS code makes the quantity of this fuel imported into Canada uncertain.

Because ECCC does not report renewable fuel consumption in 2010, consumption in that year is based on the US Department of Agriculture Global Agricultural Information Network (USDA GAIN).

The relative split between biodiesel and HDRD remains an uncertainty for all regions other than BC and Alberta. The Ontario government reported that more HDRD was used for compliance than biodiesel; and 80:20 ratio is assumed in Ontario and Québec (for years where our analysis shows consumption), and no HDRD consumption is assumed in Saskatchewan, Manitoba, and the Atlantic region. Specific assumptions for biodiesel and HDRD and the associated carbon intensities are listed in "Appendix B: Biofuel Type and Feedstock Assumptions and Data".

CI values are mostly still taken from GHGenius 4.03a, except in Ontario and BC where provincial governments provided data on CIs used for compliance. However, the CI for gasoline in all years and regions has been increased by 7 gCO_2e/MJ, such that the combustion (i.e. tailpipe) GHG intensity is approximately 70 gCO_2e/MJ, based on input from (S&T)[2] Consultants. The updated gasoline CI's closely align with what is in the latest GHGenius version 5.0 and the gasoline combustion GHG coefficient used by ECCC in the National Inventory Report. These sources account for emissions of carbon monoxide and volatile organic compounds that oxidize to CO_2 in the atmosphere. For example, ECCC uses a combustion GHG coefficient of 67 to 71 gCO_2e/MJ for light-duty vehicles operating under tier 1 and tier 2 emissions standards,[34] whereas GHGenius 4.03a uses 63 gCO_2e/MJ. The Canada fuel-consumption weighted average CI for gasoline (upstream and downstream) is approximately 92 gCO_2e/MJ.

[34] Environment and Climate Change Canada, 2019, National Inventory Report 2019, Emissions Factors Table A6-12

As noted in Table 9, results for 2020 in some regions are preliminary estimates that are based on several inputs and assumptions. This year, provincial governments in Alberta, Saskatchewan, and Ontario provided their statistics for 2020 as well as 2019. For all other provinces, excluding BC, we assume that the stable year-to-year blend rates persist and remained constant from 2019 to 2020. For BC, where there has been a noticeable annual trend of increasing blend rates, we linearly extrapolated from to 2020 based on the 2017-2019 data.

We derive the size of the gasoline and diesel pools in each province using Statistics Canada data (Table: 25-10-0030-01, Supply and demand of primary and secondary energy in natural units). For 2020, gasoline and diesel consumption data are available from Statistic Canada only at a Canada-wide level, rather than disaggregated by province, as it was in 2019 and earlier. Therefore, consumption by province for 2020 in the analysis is a function of national consumption in that year, pro-rated to each province proportional to provincial consumption in 2019. For example, nationally there was a 14% drop in gasoline demand from 2019 to 2020, so we assume that gasoline demand in BC dropped 14% below the figure provided by the BC Ministry of Energy for 2019.

Finally, the 2020 estimates also require CI assumptions. For most provinces, CI values come from GHGenius 4.03a. For Ontario, the provincial government provided data on the CI of biofuels for 2020. For BC, where there have been year-over-year reductions in the CIs of biofuels supplied to the province, the assumed CIs for ethanol, biodiesel and HDRD in 2020 are linear extrapolations of the CI values in 2017 through 2019.

Table 10: Summary of Inputs (data in green, assumptions in yellow, major uncertainties in orange)

<table>
<tr><th></th><th>BC</th><th>Alberta</th><th>Saskatchewan</th><th>Manitoba</th><th>Ontario</th><th>Québec</th><th>Atlantic</th></tr>
<tr><td>Gasoline volume</td><td rowspan="4">RLCFRR Summary: 2010-2019. Gasoline and diesel volumes are the total, not the non-exempt volume</td><td>2011-2018: From govt. contact.

For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td rowspan="4">Data from govt. contact</td><td rowspan="2">Data from govt. contact</td><td>Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td></tr>
<tr><td>Ethanol fuel volume</td><td>Data from govt. contact</td><td>Average % blending rate provided by govt. contact</td><td>Difference between national total reported under the RFS by ECCC[1] and sum from other provinces, pro-rated to QC and AT</td><td>Difference between national total reported under the RFS by ECCC[1] and sum from other provinces, pro-rated to QC and AT</td></tr>
<tr><td>Diesel volume</td><td>2011-2018: From govt. contact.

For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>2018-2020: data from govt. contact. 2010 to 2017 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy.</td><td>Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy, diesel fuel oil</td></tr>
<tr><td>Biodiesel and HDRD volume</td><td>Data from govt. contact</td><td>Data from govt. contact</td><td>Data for 2018-2020 from Gov't. Provisional data from govt. contact for 2015. Estimates for 2016 and 2017.</td><td>Same method as for ethanol</td><td>Same method as for ethanol</td></tr>
</table>

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Québec	Atlantic
Biofuel feedstock	RLCFRR Summary: 2010-2019. Gasoline and diesel volumes are the total, not the non-exempt volume	Assumptions reviewed by govt. contact and (S&T)[2] Consultants					
Fuel Carbon Intensity	RLCFRR Summary: 2010-2019. Gasoline and diesel volumes are the total, not the non-exempt volume	GHGenius 4.03a by year for Alberta	GHGenius 4.03a by year for Saskatchewan	GHGenius 4.03a by year for Manitoba	Ethanol: GHGenius 4.03a by year for Ontario for 2010-2019, data from govt. contact for 2020. Biodiesel/HDRD: avg. from govt. contact for 2015 and 2018-2020, estimated for 2010-2013, 2016 and 2017	GHGenius 4.03a by year for Québec	GHGenius 4.03a by year for Canada East
Wholesale gasoline and diesel price	Kent marketing,[2] for Vancouver	Kent marketing,[2] for Calgary	Kent marketing,[2] for Regina	Kent marketing,[2] for Winnipeg	Kent marketing,[2] for Toronto	Kent marketing,[2] for Montreal	Kent marketing,[2] for Halifax, Saint John, Charlottetown, and St Johns
Wholesale ethanol price	Chicago Mercantile Exchange futures price[3]						
Wholesale biodiesel price	Chicago Mercantile Exchange spot price[3]						
Wholesale HDRD price	Diamond Green Diesel Investor Financials from January 2015 onward, Neste Oyj for 2010 to 2014[6]						
Marketing margin	Kalibrate,[2] for Vancouver	Kalibrate,[2] for Calgary	Kalibrate,[2] for Regina	Kalibrate,[2] for Winnipeg	Kalibrate,[2] for Toronto	Kalibrate,[2] for Montreal	Kalibrate,[2] for Halifax, Saint John, Charlottetown, and St Johns
Fuel Taxes	NRCAN, Fuel Consumption Taxes in Canada[7]						

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Québec	Atlantic
Carbon costs	Government of BC, BC's Carbon Tax[8]	Government of Alberta, Alberta's Carbon Levy[9] and Government of Canada[10]	Government of Canada, Greenhouse Gas and Pollution Pricing Act[10]	Government of Canada, Greenhouse Gas and Pollution Pricing Act[10]	Government of Ontario, Past auction information and results[11] and Government of Canada[10]	Government of Québec, The Carbon Market[12]	Government of Canada, Greenhouse Gas and Pollution Pricing Act[10] and Government of Nova Scotia, Petroleum Products Pricing Regulations[13]
Biofuel transportation cost	5-13 $/bbl (2018), applied to biofuels based on distance between Chicago and representative city[4]						
Ethanol octane	Used a value of 113, corresponding to ethanol used in low concentration blends						
Value of octane	Value in $/octane point/L based on difference in the wholesale price of regular and premium gasoline in the United States[5]						
Energy efficiency	Assume vehicle energy efficiency (e.g. km/GJ fuel consumed) is constant regardless of the blend.[14]						
Refinery and gasoline GHG intensity	Assume that petroleum refining and gasoline blendstock GHG intensity is independent of the biofuel blend.						
Impact of biofuels on refining and marketing margins	Assume the refining margins for petroleum fuels would be same in a counterfactual scenario without biofuel blending. The refining margin is the $/L net revenue of refiners, embedded in gasoline and diesel wholesale prices from Kalibrate. Also assume the marketing margin would be the same if there were no biofuel. The marketing margin is the $/L net revenue of the fuel retailers.						
Electric vehicle sales, activity, and GHG intensity	Electric vehicle (EV) sales are provided by Statistics Canada for 2011-2020 (Table: 20-10-0021-01). EV stocks are assumed to be equal to cumulative sales from 2011 with no net interprovincial trade of used vehicles. Average annual mileage assumed to be equal to the average for conventional light-duty vehicles since 2010 in the NRCan comprehensive energy use database. EV assumed to use 0.2 kWh/km, and plug-in hybrids assumed to travel 69% of annual km using electricity. Electricity direct GHG intensity by province is from the National inventory report, with upstream emissions inferred from the lifecycle electricity GHG intensities listed in Schedule 5, Canada Gazette, Part I, Volume 154, Number 51: *Clean Fuel Regulations*.						

1) ECCC, Open Data reported under the Renewable Fuels Regulations, 2010-2012, 2013-2014, 2015, 2016, 2017, 2019 and 2019. National total for biomass-based diesel in 2018 and 2019 was increased slightly based on information and data from industry and government contacts.

2) Kalibrate, https://charting.kalibrate.com/

3) Chicago Mercantile Exchange ethanol futures: www.investing.com/commodities/ethanol-futures-historical-data. Biodiesel prices are from an OPIS subscription.

4) Gallagher, Paul and Denicoff, Marina. 2015. Ethanol Distribution, Trade Flows, and Shipping Costs, Iowa State University Economics Technical Reports and White Papers Accessed from https://lib.dr.iastate.edu/econ_reportspapers/45

5) EIA. 2020. Petroleum & Other Liquids: Weekly Retail Gasoline and Diesel Prices. Accessed from: https://www.eia.gov/dnav/pet/PET_PRI_GND_DCUS_NUS_M.htm

6) Darling Ingredients. 2021. Investor Relations, Accessed from: https://ir.darlingii.com/. Neste data accessed from Accessed from: https://www.neste.com/corporate-info/investors/materials-0

7) Natural Resources Canada. Fuel Consumption Taxes in Canada. Accessed from: https://www.nrcan.gc.ca/energy/fuel-prices/18885

8) Government of British Columbia. British Columbia Carbon Tax. Accessed from: https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/carbon-tax

9) Government of Alberta. 2019. About tax and levy rates and prescribed interest rates. Accessed from: https://www.alberta.ca/about-tax-levy-rates-prescribed-interest-rates.aspx#carbon-levy

10) Government of Canada, Greenhouse Gas and Pollution Pricing Act. Accessed from: https://laws-lois.justice.gc.ca/eng/acts/G-11.55/FullText.html

11) Government of Ontario. Past auction information and results. Accessed from: https://www.ontario.ca/page/past-auction-information-and-results

12) Government of Quebec. The Carbon Market: Cap-and-Trade Auction Notices and Results. Accessed from: http://www.environnement.gouv.qc.ca/changements/carbone/ventes-encheres/avis-resultats-en.htm

13) Government of Nova Scotia, Petroleum Products Pricing Regulations. Accessed from: https://www.novascotia.ca/just/regulations/regs/ppprice.htm#TOC2_1

14) Most evidence indicates that there is no change in energy efficiency (see literature review in 2019 Biofuels in Canada report):

Niven, R.K., 2005, Ethanol in gasoline: environmental impacts and sustainability review article. Renewable and Sustainable Energy Reviews 9, 535-555. doi.org/10.1016/j.rser.2004.06.003

Yan, X. et al., 2013, Effects of Ethanol on Vehicle Energy Efficiency and Implications on Ethanol Life-Cycle Greenhouse Gas Analysis. Environmental Science & Technology 47, 5535-5544. DOI: 10.1021/es305209a

US Environmental Protection Agency, 2016, Draft Technical Assessment Report: Midterm Evaluation of Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards for Model Years 2022-2025.

Coordinating Research Council, 2018, Renewable Hydrocarbon Diesel Fuel Properties and Performance Review (CRC Report No. DP-08-18).

3.3. Updates to the Methodology

This current edition of the Biofuels in Canada analysis includes some methodological changes that affect the results for 2019 and prior years:

- **Estimated Octane Value from Wholesale Prices:** In past years, this model used the spread in retail prices between regular and premium gasoline to estimate the value of octane provided by ethanol. To better reflect the cost of refining associated with increasing octane (rather than changes to marketing margins on premium gasoline), the model now uses the wholesale value of octane. This results in a nearly $300/tCO2e increase to the abatement cost of using ethanol, though the estimate remains below zero (i.e., it reduces emissions and prices). The impact and reasoning behind this change is discussed in more detail in Appendix C: Change to Cost Analysis Methodology.

- **Change in Statistics Canada Data Source:** Due to discontinuation of provincial-level fuel demand estimates in the Supply and Disposition of Petroleum Products tables, the model is now using Statistics Canada's data on energy consumption. This results in minor changes to demand estimates and removes the need to estimate redacted monthly data.

- **HDRD Price Data:** In previous years, investor materials from Neste were used to estimate the commodity cost of HDRD. This year, the HDRD prices implied in Diamond Green Diesel's financial materials were used in place of the Neste data fro prices starting in January 2015. Imports from the U.S. are eligible for a $1 USD/Gallon blenders' tax credit, which would be passed through to export prices. The U.S. imports are assumed to be the price-setting supply in the Canadian market.

- **Mid-Year Tax Changes:** The gasoline and diesel cost analysis has been adjusted to include a month-by-month representation of fuel taxes to reflect the fact that tax rates typically change with governments' fiscal year (e.g., after March 31st), rather than the calendar year.

- **Co-Processing (see box below) and Electric Vehicles:** Estimates for energy consumption and avoided GHG emissions for co-processed volumes and electric vehicles are now included in the analysis to quantify the role of these other low-carbon transportation options alongside blended biofuels. Currently there is no data describing the volume or GHG intensity of co-processed fuels and these quantities have been estimated using the methodology in Appendix D: Co-processed Fuel Methodology. Electric vehicle sales are reported in Statistics Canada data, but the energy and GHG impact must also be estimated, using the methodology described in Appendix E:Electric Vehicle Analysis Methodology.

Background: What is Co-Processing?

Co-processing refers to the process of refining vegetable/animal oils alongside crude oil at a petroleum refinery to create one blended output. For example, vegetable oil or tallow is added directly to intermediate petroleum distillates; they then are further refined together. Processes to credit the bio-based content of co-processed fuels under federal and provincial regulations are still being developed.

In contrast, ethanol, biodiesel, and HDRD are manufactured by stand-alone plants or dedicated production lines within a refinery. Finished biofuels are then mixed with conventional gasoline and diesel.

Parkland Fuels has made improvements to their Burnaby refinery to allow for up to 100 million litres per year of co-processed feedstock in 2021. For reference, total (non-co-processed) bio-based diesel consumption in BC was 329 million litres.

4. Results and Discussion

The results section summarizes data on the biofuel content of transportation fuels sold in Canada, including an estimate of co-processed fuel volume and the quantity of electricity consumed by light-duty plug-in electric vehicles (PEVs). Also included in the results is an analysis of the avoided GHG emissions, and cost impacts resulting from blending ethanol, biodiesel and HDRD with gasoline and diesel (co-processed fuels and electric vehicles are not part of the cost analysis). This analysis also presents data on light-duty PEV sales and an estimate of the total number of light-duty PEVs on the road. The results in this section are reported at a national level, though these national results are an aggregation of provincial level analysis. The analysis and corresponding data on individual provinces are in the associated excel spreadsheet, named "Biofuels in Canada Analysis, 2020-11-09".

4.1. Fuel Consumption

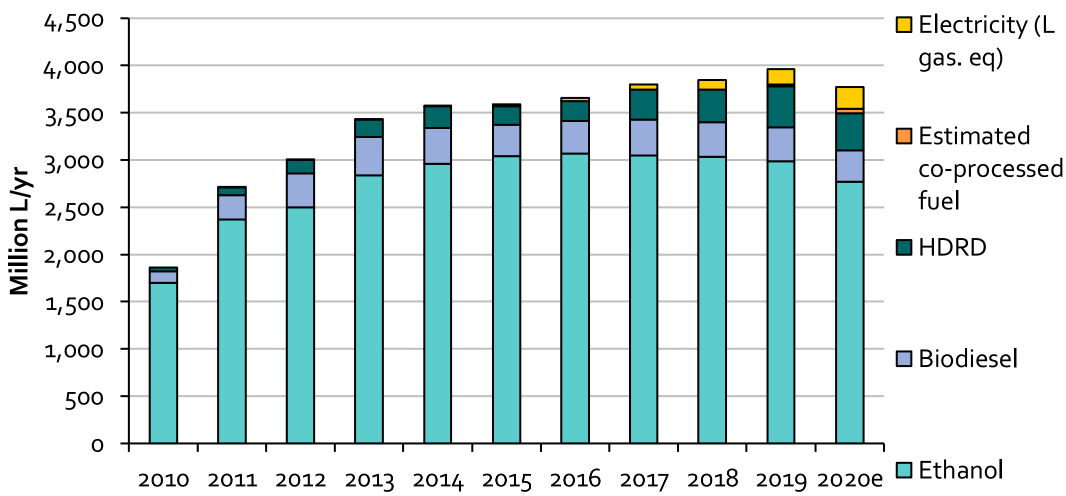
Figure 9 and Table 11 summarize the fuel consumption data and the estimated volume of co-processed fuel and light-duty PEV electricity consumption (expressed in terms of litres of gasoline equivalent). Consumption of biofuels has been gradually increasing since 2015 to 2019, with almost all the growth coming from HDRD. Electricity as a transportation fuel has also been growing rapidly over the past few years, averaging 64% annual growth from 2015 to 2020. It's share amongst renewable and low-carbon transportation energy consumption in Canada, is measured in terms of volume of gasoline equivalents (i.e. as fuel displaced), will soon be similar to that of biodiesel (Table 11, Figure 9).

Table 11: Canadian fuel consumption in million litres per year (2015 to 2019, with an estimate for 2020)

Fuel type	2015	2016	2017	2018	2019	2020e
HDRD	193	215	322	344	432	392
Biodiesel	334	342	378	367	360	334
Ethanol	3,041	3,069	3,047	3,034	2,985	2,767
Co-processed fuel					19	46
Electricity*	20	32	53	102	166	231
Diesel (Pure)	26,674	25,658	27,479	27,528	26,975	24,679
Gasoline (Pure)	41,697	42,367	42,955	43,148	42,685	35,422

*Electricity consumption is measured in terms of volume of gasoline equivalent (i.e. what would have been consumed if electric vehicles were conventional vehicles). This calculation assumes that PEVs are 4.1 times more energy efficient than conventional vehicles, as per the assumption used in the *Clean Fuel Regulations*.[35]

Figure 9: Renewable and low-carbon transportation energy consumption in Canada



The data show that the volume of ethanol and biodiesel consumed has remained relatively constant from 2015 to 2019, potentially decreasing by about 7% during the COVID-19 pandemic in 2020. Note that 2020 results are an estimate – not all data is available for that year. Renewable fuel blending rates in 2020, used to estimate fuel volumes, were assumed to remain constant from 2019 to 2020 for Saskatchewan and the provinces informed by ECCC's national totals (Atlantic Provinces and Québec).

[35] Government of Canada, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations

Blending rates in BC in 2020 are assumed to be a continuation of trends in previous years, while the rates (and hence volumes) in Alberta, Manitoba and Ontario are based on data. Contributing to the increase in average blend rates was the transition from E5 to E10 under Ontario's Greener Gasoline Regulations.

The 2020 estimate shows that while total biofuel consumption declined, the blending rate increased. Total fuel consumption fell by about 14% in 2020 relative to 2019, but fossil fuel consumption fell proportionally more than did biofuel consumption, resulting in the estimated increase in the blending rate.

Biodiesel consumption has been relatively constant between 330 and 405 ML since 2012. HDRD is now blended into diesel in higher volumes than biodiesel, with consumption calculated at 423 million L in 2019 (Table 11). The total quantity of biomass-based diesel consumption assumed across Canada in 2019 is at least 792 million litres per year (11% larger than in 2018). Note that this value is based on the sum of volumes reported by provincial regulators and is 6 ML higher than what ECCC reports within the *Renewable Fuels Regulation* data, implying either that some of the fuel used for compliance with provincial policy was not reported under the federal regulations or that there is some error in data collection.

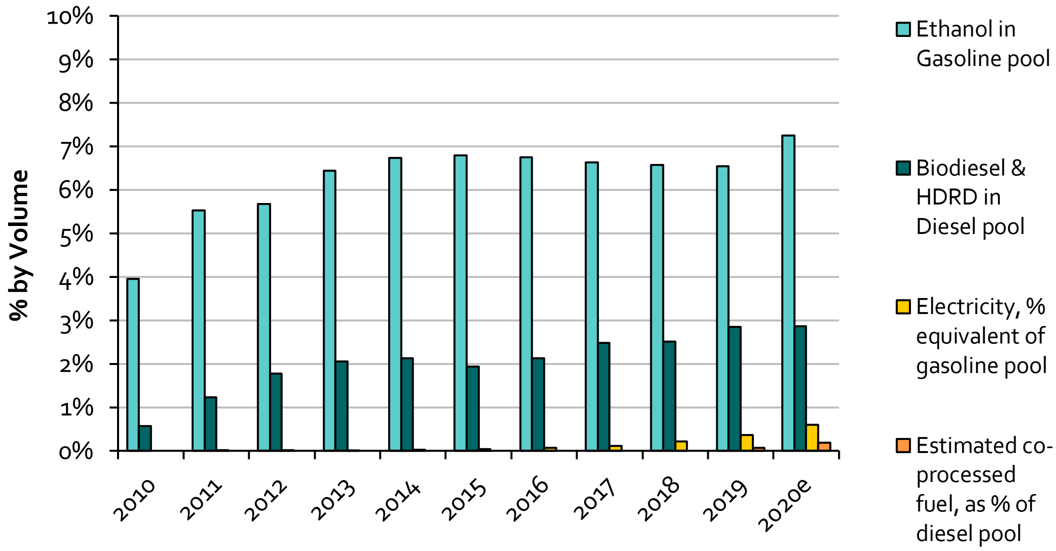
Because HDRD does not have its own Harmonized System (HS) code within trade data, it is it difficult to quantify biomass-based diesel consumption in Canada based on import, export, and production data. That being said, all reasonable assumptions regarding HDRD trade indicate that the total biomass-based diesel consumption in Canada is in the vicinity of the quantities reported in this analysis and by ECCC.

Note that, the volume of HDRD in the Canadian fuel pool is more uncertain compared to other biofuels. Only BC and Alberta report HDRD consumption in those respective provinces; 80% of bio-based diesel in Ontario is assumed to be HDRD based on advice from industry contacts.

This years' analysis also includes estimates of co-processed fuels and fuel consumption avoided by electric vehicles. An estimated 19 ML of biofuel was co-processed at Parkland's Burnaby refinery in 2019, rising to 45 ML in 2020, equivalent to 6% of the Canadian supply of bio-based diesel. Electric vehicles are estimated to have displaced 166 ML of gasoline consumption in 2019, rising to 231 ML in 2020 (Table 11).

Figure 10 shows the percentage of renewable fuel in the gasoline pool (ethanol) and in the diesel pool (biodiesel plus HDRD). Because of the uncertainty in the volume of HDRD consumed in Canada, biodiesel and HDRD are grouped together to avoid giving false precision. The percentages are based on total fuel consumption, including gasoline and diesel volumes exempted from biofuel blending policies. As well, the content does not include any policy-based adjustments to the renewable fuel share (e.g. a volume-equivalency bonus awarded for using for low-CI feedstocks or fuels, as is the case in Ontario's *Cleaner Transportation Fuels* regulation).

Figure 10: Renewable fuel content by fuel pool, 2010 to 2019, estimate for 2020



The ethanol content in Canadian gasoline was 6.5% by volume in 2019, almost exactly equal to the 2018 blend rate. The biomass-based diesel content in 2019 was 2.9%, up from 2.5% in 2018. As noted earlier, there are several assumptions driving the national blending rate in 2020 which appears to have increased for ethanol, up to 7.3% of the gasoline pool.

The national average blend rates are above what is required by the federal *Renewable Fuels Regulation*, in part a result of stacking provincial policies with the federal regulation. For example, once a regulation drives investment in blending infrastructure, it generally results in over-compliance in most provinces, possibly due to the low-cost octane provided by ethanol (Figure 11). In the diesel pool, it seems the CI reduction required by the BC policy is stacking with the federal regulation to increase the quantity of biomass-based diesel by about 33% beyond what it would need to be for simple volumetric compliance (Figure 12).

Figure 11: Renewable fuel in the gasoline pool in 2019 versus the regulated blend rate

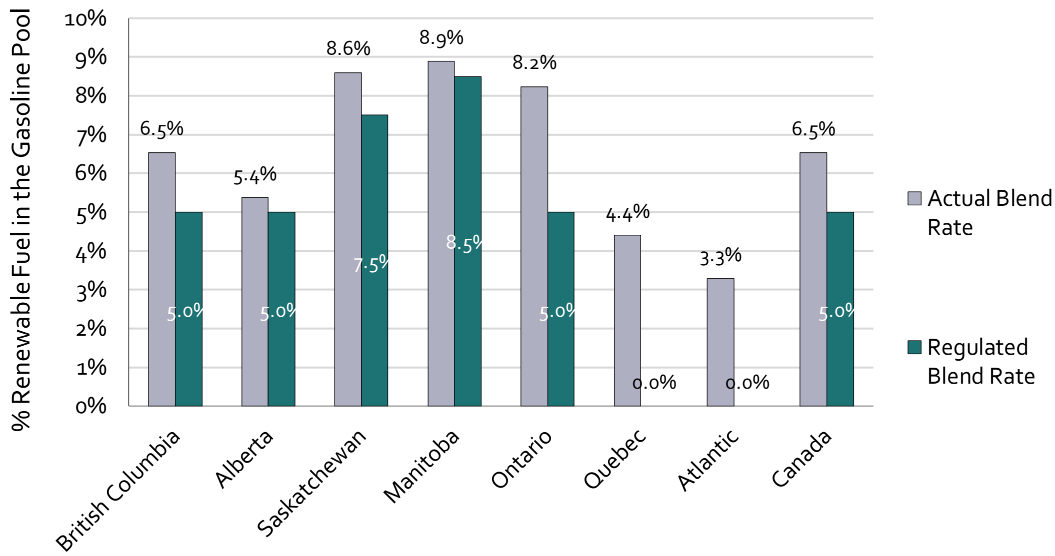
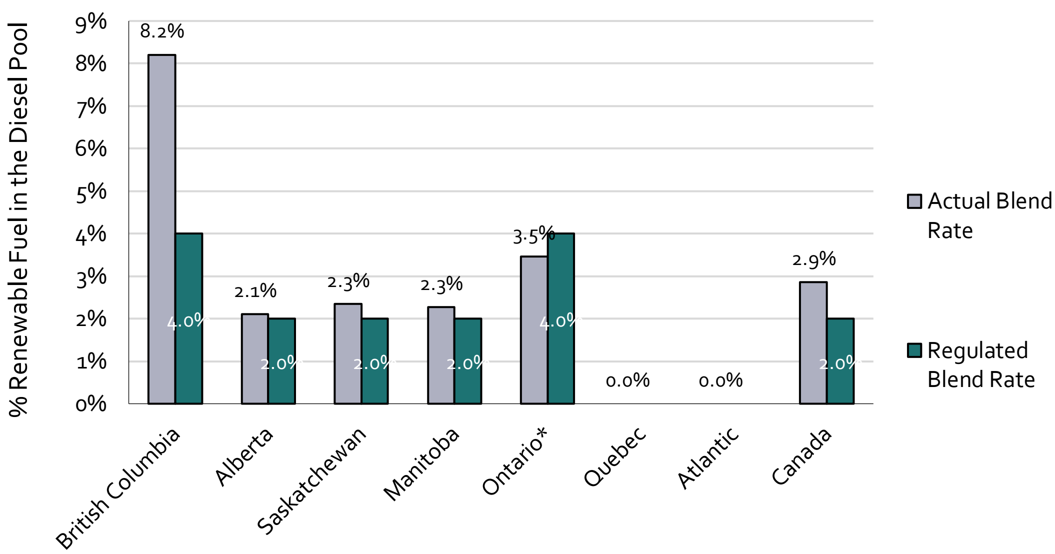


Figure 12: Renewable fuel in the diesel pool in 2019 versus the regulated blend rate



* The actual Ontario blending rate is a function of the CI of the renewable fuels. When very low CI fuels are used, the blend rate may be less than 4%.

4.2. Lifecycle GHG Emissions

Figure 13 shows the estimated lifecycle CI (i.e. well to wheels or farm to wheels) of transportation fuels in Canada between 2010 and 2019, with an estimate for 2020. Because of the uncertainty in volume, feedstock, and CI, biodiesel and HDRD are grouped together to avoid giving false precision.

For most provinces, these CI estimates were based on average fuel CI from GHGenius 4.03a. However, for BC, the CIs are reported in provincial compliance reports which publish carbon intensities for ethanol, biodiesel, and HDRD (CI values prior to December 31st, 2014, come from GHGenius 4.01b). The province does not retroactively revise these values. For Ontario, data for the average biodiesel and HDRD CI was obtained from a government contact for 2015 and 2018 through 2020, while we estimated the CI for 2016 and 2017. For 2020, the estimated CIs in BC are a linear extrapolation of CI's from the previous three years. For the rest of Canada, CIs in 2020 are taken from GHGenius 4.03a. The CI of co-processed fuel is assumed to be roughly 1/8 that of fossil fuels, based on public announcements.[36] Meanwhile, the national CI of electricity is based on a transportation-consumption weighted average of direct emissions intensity by province from 2010 to 2020, reported in Canada's National Inventory Report[37] (NIR), adjusted to include indirect GHG emissions, based on the difference between NIR emissions intensity by province and the electricity CI by province for 2019 reported in the draft *Clean Fuel Regulation*.[38] This CI value is divided by an energy efficiency ratio of 4.1 (i.e. EER, the ratio of energy used by conventional vehicle to a PEV). This provides a consistent comparison with liquid fuel on the basis of energy used per km travelled.

The national average CI for ethanol in 2019 is 43 gCO_2e/MJ, 17% below the value in 2010. The weighted average for the biomass-based diesel CI in 2019 is 10.2 gCO_2e/MJ, 66% below the value in 2010 (Figure 10). As discussed below, the causes of this change are: a decline in fuel CI from the BC RLCFRR and the Ontario Greener Diesel Regulation, as well as the year over year CI reduction estimated with the GHGenius model. The CI of co-processed fuels is 11.6 gCO_2e/MJ, though this is not yet reported in policy compliance data. The average CI for electricity is about 5.3 gCO_2e/MJ. This CI is low because it is adjusted by an energy effectiveness ratio (EER) of 4.1 (i.e. per km, an electric vehicle uses 4.1 times less energy than a conventional vehicle). Furthermore, it is weighted by electricity consumption by province, where most electric vehicles are in BC, Ontario and Québec, which have low-CI electricity.

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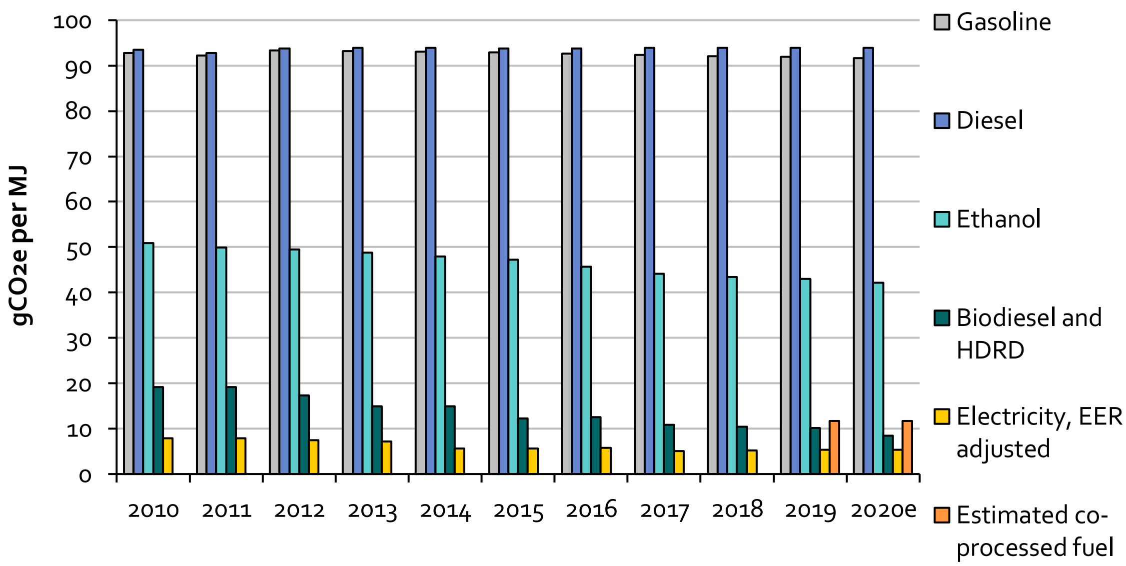
[36] Parkland, 2020, Safety, Integrity, Community, Respect. Inaugural Sustainability Report

[37] Government of Canada, 2021, National Inventory Report 1990-2019: Greenhouse Gas Sources and Sinks, Part 3

[38] Government of Canada, 2020, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations

Figure 13: Lifecycle CI by fuel type, for Canada, with estimate for 2019



GHG emissions resulting from direct land use changes are included in the lifecycle CI of biofuels. For example, this includes the GHG emissions resulting from the conversion of pasture or forest to crop land. These intensities are based only on direct land use changes, and do not include any potential indirect changes from increased biofuel demand. Some fuel regulations, such as the California Low-Carbon Fuel Standard include "indirect land-use change" (ILUC) emissions in the carbon intensities of biofuels. ILUC emissions are one type of "indirect effect" emissions that are applied to biofuels under the assumption that biofuel production increases agricultural commodity prices which indirectly result in more pasture and forest being converted to crop production. The data systems and lifecycle modelling to support accurate measurement of indirect-effect emissions for all fuels (fossil and renewable) are the subject of on-going research and policy debate. Regulators in Canada are stating that they will not include a quantitative factor for these emissions in current policy but will monitor the science and may include them in the future.[39] Currently the *Clean Fuel Regulations* propose developing land-use and biodiversity criteria that would potentially make fuels that have a high risk of producing indirect-land use emissions ineligible for credit generation.[40]

The results in Figure 13 show that the biofuels consumed in Canada offer significant lifecycle CI reductions relative to gasoline and diesel. The data implies that, on average

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[39] Meyer, C., *Canada's Math May Overlook Carbon Pollution from Biofuels,* Canada's National Observer, April 18th, 2018

[40] Government of Canada, 2020, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations

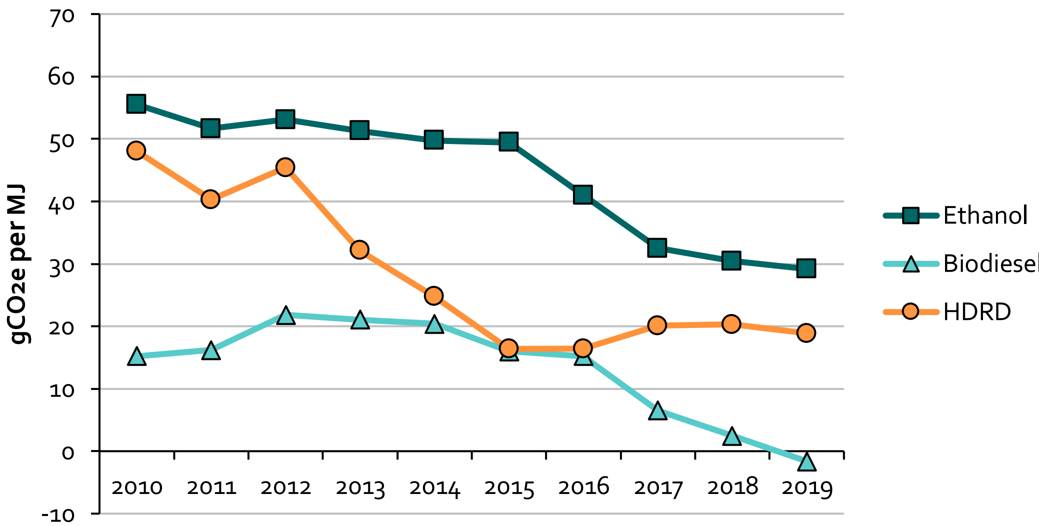
in 2019, ethanol sold in Canada was 53% less carbon intensive than gasoline, while biodiesel and HDRD were about 89% less carbon intensive than diesel. As of 2019, the EER adjusted CI of electricity was about 94% less than gasoline. This difference is a function of the energy efficiency of PEVs (i.e. the EER), the low average CI of electricity generation in Canada and the fact that most PEV energy consumption to date has been concentrated in provinces with lower-than average electricity generation carbon intensity, namely BC, Ontario, and Québec.

Figure 10 also suggests that the CIs of ethanol, biodiesel, and HDRD are decreasing over time. However, some of regional carbon intensities used to produce Figure 13 are based on default data from GHGenius 4.03a. This data extrapolates historical results and assumes that the GHG intensity of inputs to biofuel production continue to decline over time, hence the fuel CI declines as well (e.g. reduced GHG emissions associated with cleaner electricity consumption for biofuel refining, process improvements, increased agricultural yields and reduced fertilizer inputs per area farmed, etc.).

In contrast, CI's for biofuels consumed in BC and Ontario are based on collected data, reported by fuel and feedstock to the government. While these values are observed rather than modelled, they tell the same story of declining biofuel CI. Additional data from the California and Oregon low-carbon fuel standards (LCFS) show a similar trend.

The data in BC suggest that from 2010 to 2019, the CI of ethanol decreased by 47%, the CI of biodiesel decreased by 111%, and the CI of HDRD decreased by 61% (Figure 14). As of 2019, the average reported CI for biodiesel was negative, meaning emissions would be higher than if the fuel had not been produced and consumed. In Ontario, the average reported CI for bio-based diesel decreased from 12 to 6 gCO2e/MJ between 2015 and 2020.

Figure 14: Lifecycle CI by fuel type for British Columbia



Similarly, the California LCFS) has had a substantial impact on the CIs of biofuels used in that state and has supported investments that will lead to step-changes in ethanol CI. With the LCFS in force, California has recorded substantial declines in the carbon intensities of conventional biofuels. From 2011 to 2019, the carbon intensity of ethanol used in California declined by 32% and the carbon intensity of biodiesel fell by 34%.[41] A spatial analysis of corn and soy production indicates that these changes are likely the result of improved farming practices which may have been the response to a market signal for lower-carbon biofuels. Specifically, conservation tilling, use of cover crops, and more efficient use of fertilizer can substantially reduce the carbon intensity of ethanol and biodiesel relative to a typical corn/soy crop rotation (by 30-50 gCO_2e/MJ).[42]

As well, the LCFS is supporting investment in ethanol production with carbon capture and storage (CCS). When ethanol is produced from grains via fermentation, it emits a large and relatively pure stream of carbon dioxide. Capturing and storing this carbon dioxide creates a stepwise reduction in the carbon intensity of ethanol (40%-45%). Ethanol with CCS was recently recognized as a fuel pathway within the LCFS,[43]

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[41] California Air Resources Board, 2021, Low Carbon Fuel Standard Reporting Tool Quarterly Summaries.

[42] Liu, X., Kwon, H., Northrup, D. & Wang, 2020, M. Shifting agricultural practices to produce sustainable, low carbon intensity feedstocks for biofuel production. Environmental Research Letters 15, 084014, doi:10.1088/1748-9326/ab794e

[43] California Air Resources Board, 2020, Low Carbon Fuel Standard, Design Based Pathway Application No. D000.

coinciding with additional funding being directed towards the deployment of this abatement practice at the Red Trail Energy ethanol plant in North Dakota.[44]

These trends in measured biofuel CIs are consistent with the year-over-year improvements assumed in the GHGenius model. Given that they occur across multiple jurisdictions and are associated with changes in production practices, it is likely that they represent true reductions in CI rather than "fuel shuffling", where renewable fuels with low CIs are sold in regulated jurisdictions, while fuels with higher CIs are sold in jurisdictions without policies that regulate this metric. Broader monitoring of CIs, as will happen with the *Clean Fuel Regulations*, will provide another opportunity to test this hypothesis.

Figure 15 shows the avoided lifecycle GHG emissions in Canada resulting from biofuel consumption and electricity consumption by light-duty vehicles. Again, the avoided emissions are based on the quantities and CIs of the fuels described above, assuming biofuels displace an equal amount of fuel energy from their fuel pool (i.e. ethanol displaces gasoline, biodiesel and HDRD displace diesel) and electricity displaces gasoline by a factor of 4.1. This analysis shows that the avoided GHG emissions in Canada resulting from biofuel consumption, including co-processed fuels, has risen to 5.9 $MtCO_2e$/yr in 2019. Avoided emissions from PEVs are small but growing rapidly, adding another 0.5 $MtCO_2e$/yr, bringing total avoided emissions in 2019 to 6.4 $MtCO_2e$/yr. Cumulative national avoided GHG emissions from 2010 to 2019 are 46.8 $MtCO_2e$. The estimated annual reduction for 2020 is 6.2 $MtCO_2e$/yr, slightly lower than the 2019 number due to overall drop in fuel consumption caused by the COVID-19 pandemic.

[44] North Dakota Industrial Commission, 2020, North Dakota Industrial Commission Awards $500,000 for Development of a Blueprint for a Carbon Capture and Storage Facility

And

Ethanol Producer Magazine, 2021, USDA awards $25M loan to Red Trail Energy for CCS project

Figure 15: Avoided lifecycle GHG emissions 2010-2019, with estimate for 2020

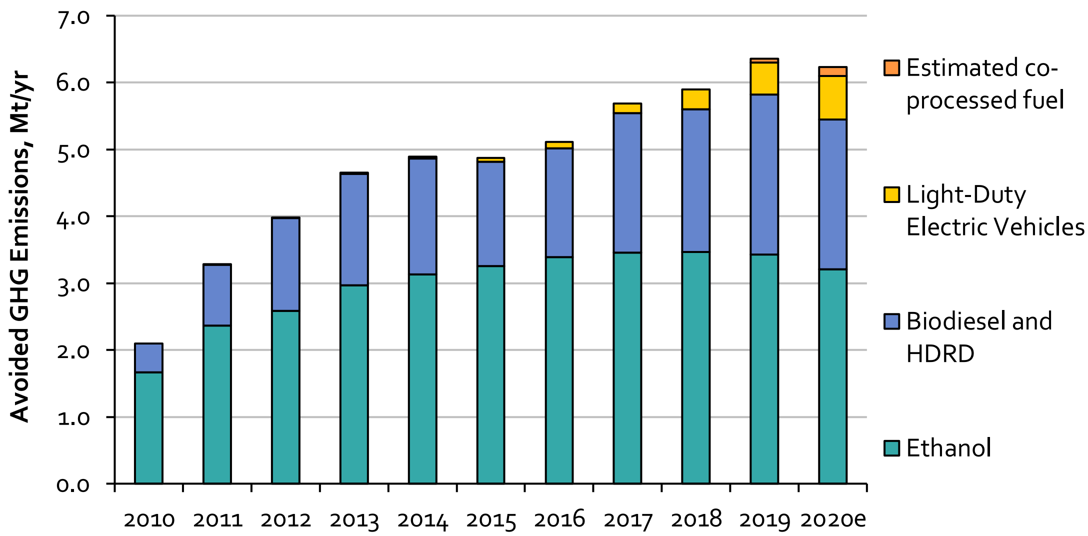
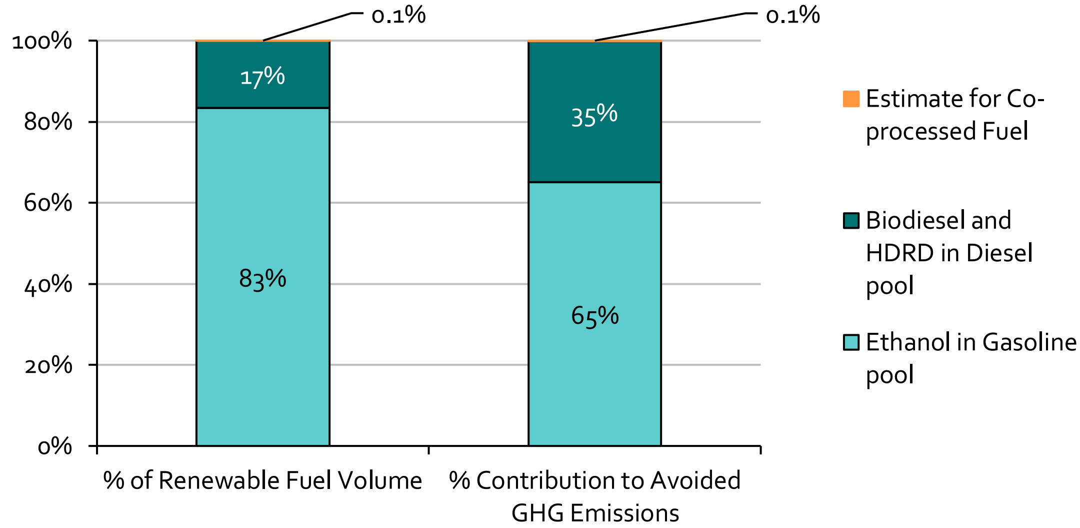


Figure 16 shows the percentage of renewable fuel volume in the gasoline and diesel pool compared with the percentage of avoided GHG emissions resulting from renewable fuel consumption in those fuel pools. Co-processed fuels are shown as a separate category. Ethanol accounted for 83% of the renewable fuel volume consumed during the 2010-2019 period, but only produced 65% of the avoided GHG emissions. Biodiesel and HDRD, which generally have lower CIs than ethanol, yielded a proportionally larger GHG impact; these fuels accounted for 17% of renewable fuel consumption, but 35% of the avoided GHG emissions. Because co-processed fuel only entered the market in 2019, it accounts for a negligible share of volume and avoided GHG emissions.

Figure 16: % of total renewable fuel volume vs. % contribution to avoided GHG Emissions from 2010 to 2019



The GHG impacts in these results are calculated assuming that biofuel blending does not change vehicle energy efficiency. While the weight of evidence supports our assumption that biofuel blending does not affect the energy efficiency of vehicles (i.e. energy per km), it is possible that biofuel blends have increased energy efficiency and the GHG impact is very sensitive to this assumption. A meta-analysis by Geringer et al. (2014) found that at the 50th percentile, E10 increased engine energy efficiency by 1.8%.[45] Scaling this impact to the ethanol blend rates in our analysis, this increase in efficiency would increase the cumulative GHG impact by 34%, or 15 MtCO_2e from 2010 through 2019.

Furthermore, the GHG impacts are calculated under the assumption that biofuel blending does not affect the combustion GHG emissions of the fossil fuels blended with the biofuel (just the emissions of the blend itself) nor the GHG intensity of petroleum refining. However, ethanol raises the octane rating of the fuel blend, meaning the gasoline blendstock can have a lower octane rating than if no ethanol were used. Consequently, refinery emissions may change in response to lower octane requirements. Similarly, using ethanol to raise the octane of gasoline blends can change the chemical composition of the gasoline blendstock, for example it may have fewer octane raising ‘aromatic’ compounds. These compounds have a higher

[45] Geringer, B., Spreitzer, J., Mayer, M., Martin, C, 2014, *Meta-analysis for an E20/25 technical development study - Task 2: Meta-analysis of E20/25 trial reports and associated data*, Institute for Powertrains and Automotive Technology, Vienna University of Technology

combustion (i.e., tailpipe) emissions intensity than gasoline on average. Consequently, raising octane with ethanol could reduce the combustion emissions intensity of the gasoline blendstock. Section 5 of this report contains a "deep dive" on this subject.

These additional emission reductions from foregone refinery emissions and lower aromatic content in gasoline blendstocks are quite uncertain. Estimates from our literature review suggest the change to refinery emissions in 2019 could range from a 1.4 $MtCO_2e$/yr decrease to a 0.2 $MtCO_2e$/yr increase (see section 5.1). Estimates for emission reduction from changing chemical composition of the fossil portion of gasoline are more consistent in direction, ranging from an additional reduction of 0.27 to 1.1 $MtCO_2e$/yr (see section 5.2).

4.3. Cumulative Costs

Below, we report our cost impact analysis resulting from the renewable fuel consumption described above, focusing on the impact of renewable fuel blending on consumer fuel expenditures. Refer to "Appendix A: Cost Analysis Methodology" for a detailed explanation of the methodology used for this cost analysis. Note that this cost analysis does not include the impact of co-processed fuels or electric vehicles.

This year's report contains a revised methodology which reduced our estimate of the cost benefit of biofuels. Three changes were made: (1) wholesale prices, instead of retail prices, were used to estimate the value of octane, (2) premium gas was assumed to have an average octane of 92 instead of 93, and (3) new sources were used to estimate the cost of HDRD. "Appendix C:Change to Cost Analysis Methodology" presents a detailed description of the reasoning behind the changes and a comparison of this year's and last year's assumptions.

Renewable fuel consumption may change overall fuel costs for three reasons:

- First, the commodity price per volume of renewable fuels may be different from the price of the petroleum fuels they replace.
- Second, the energy content per volume of fuel may differ; for example, the energy contained in one litre of ethanol is approximately 33% lower than it is for gasoline. The energy content of biodiesel is approximately 9% lower than it is for diesel fuel. We have assumed no change in energy efficiency (i.e. distance per unit of energy) resulting from renewable fuel use. In other words, if a renewable fuel has less energy content per volume, we assume the volume of fuel consumed rises proportionally, so a consumer is buying more litres of fuel to drive the same distance.

- Finally, cost reductions may arise due to different biofuel properties, such as: changes in fuel octane value (i.e. the anti-knock index of a gasoline blend); combustibility (i.e. the extent to which more complete combustion occurs with biofuel use, minimizing air pollution and associated health impacts); and, lubricity (i.e. the extent to which biodiesel fuel reduces friction and wear in the engine). Of these biofuel properties, this cost analysis only accounts for the octane value of ethanol.

Gasoline in North America must meet a standard octane value before it can be sold to the consumer. Refiners have various methods to raise the octane value of gasoline blendstock, one of which is the addition of ethanol to gasoline. The U.S. Energy Information Administration (EIA) estimates that American refiners produce gasoline blendstock with octane 84, which is raised to 87 (regular gasoline) with the addition of ethanol.[46] When used in a gasoline blend, ethanol has an octane rating of 113.[47] Consequently, the ethanol can be blended with a lower-octane gasoline blendstock. Based on the price spread between regular gasoline (octane 87) and premium gasoline (octane 91 or more), one can infer that raising octane imposes a cost. Therefore, using lower-octane gasoline blendstock with ethanol is a potential cost-saving opportunity that may offset any additional cost related to using ethanol.

Note that we do not know if Canadian refiners are capturing the octane value of ethanol. In this analysis, we assume they do. Therefore, the cost analysis presents a reasonable scenario of what the cost of using renewable fuel could be, though the octane costs savings may not be realized in all cases.

This value of octane is only included insofar as it reduces the cost of gasoline blendstock used with ethanol; any energy or GHG reduction that may occur at the refinery due to producing a lower octane blendstock is not included.

Figure 17 shows the cumulative change in consumer fuel costs resulting from renewable fuel blending in Canada from the start of 2010 to the end of 2019. We estimate that the net-costs have diverged by less than 1% relative to what they would have been without biofuel consumption. If all costs and savings are passed onto

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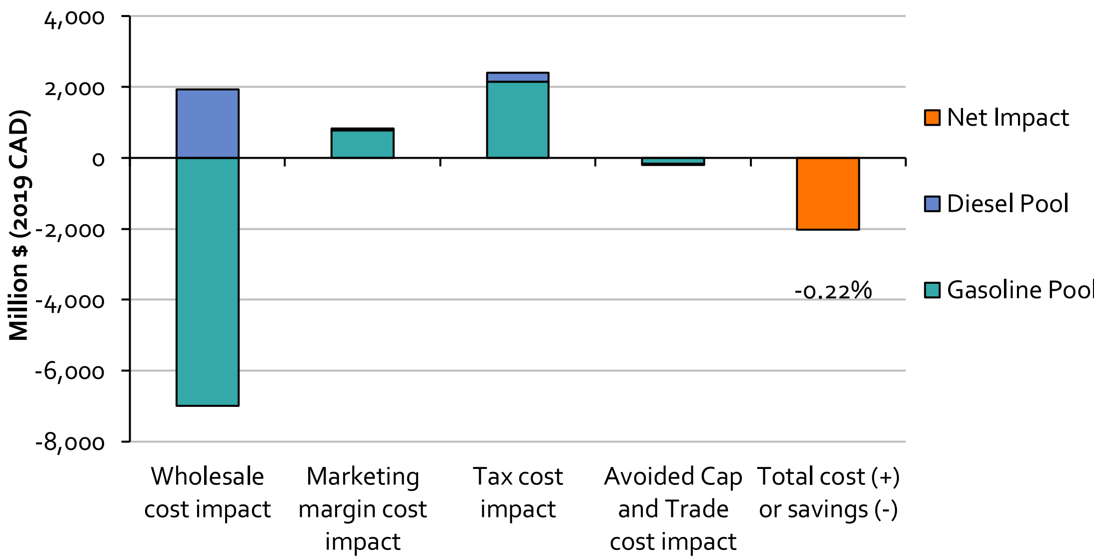
[46] U.S. Energy Information Administration, 2013, Price spread between regular and premium gasoline has changed over time. https://www.eia.gov/todayinenergy/detail.php?id=11131

[47] 113 to 115 is a typical value for blends cited by EIA https://www.eia.gov/todayinenergy/detail.php?id=11131. This value corresponds to ethanol used in low concentration blends. The octane rating of pure ethanol is 100.

consumers, their fuel expenditures were 0.22% lower, equivalent to a savings of $2 billion over 10 years. Note that all costs in the analysis are expressed in 2019 CAD.

Figure 17: Cumulative cost impact resulting from ethanol blending in the gasoline pool and biomass-based diesel blending in the diesel pool (2010-2019), total % change in data label



The net impact on consumer cost comes from both the gasoline and diesel pool, and is composed of:

- **The wholesale cost** including the commodity cost and the refining margin, which is the net cost and revenue for fuel refining, where we assume that differences in wholesale prices are reflected in retail prices. This cost component includes the octane value of ethanol but does not include other cost benefits like reduced air pollution and health impacts. The wholesale cost of using ethanol in the gasoline pool is negative due, in part, to the octane value of ethanol which reduces the cost of the gasoline blendstock. Without ethanol, the cost of the gasoline would have otherwise been higher, ranging between zero and ¢3/L over the course of this analysis depending on the value of octane in a given year. These savings more than offset any increase in the unit energy cost of the fuel blend due to the lower energy density of ethanol, with a wholesale fuel cost savings from ethanol use of $7.0 billion from 2010-2019. In the diesel pool, the wholesale fuel cost is positive because biodiesel and HDRD are on average more expensive than diesel, resulting in a wholesale cost of $1.9 billion from 2010 to 2019.
- **The marketing margin**, which is the net cost and revenue for retail fuel marketers (e.g. includes terminal costs, transport, and distribution from terminals to retail

fueling stations). Marketing margins are based on historic data and we have assumed they would have been the same even if no renewable fuel had been used. Margins generally range from 6 to 12 cent/L depending on the region and fuel in question. Because biofuels are less energy dense than petroleum fuels, using biofuels involves consuming a greater volume of fuel. Therefore, we have assumed the marketing cost is higher (e.g. more fuel delivery trucks are needed to carry the same amount of energy to fuelling stations). This is most noticeable with ethanol because it is roughly 33% less energy dense than gasoline. Therefore, ethanol consumption increased the marketing cost paid by consumers by $780 million between 2010 and 2019. Because diesel and HDRD are only slightly less energy dense than petroleum diesel, the cumulative marketing cost change in the diesel pool is only $41 million.

- **The tax cost**, which results from the application of taxes based on the volume of fuel sold (i.e. excise taxes and the carbon tax in BC, where biofuels are subject to the full carbon tax) and sales taxes (e.g. GST and HST). The federal excise tax is $0.10/L for gasoline and $0.04/L for diesel. Provincial excise taxes range from $0.13 to $0.22/L. As mentioned earlier, because biofuels are less energy dense than petroleum fuels, a consumer must purchase a greater volume of fuel to obtain the same amount of energy. Consequently, consumers pay additional excise taxes. Due to ethanol's lower energy density, the tax cost resulting from ethanol blending is large, roughly an additional $2.2 billion over ten years relative to a scenario with no biofuel consumption. At $250 million, the tax cost related to lower energy densities is much smaller in the diesel pool.

  Because biofuel blending can change the retail price of fuel, sales taxes that are charged as a percent of the retail price also result in different taxation on biofuel blends versus gasoline and diesel with no biofuel. For example, ethanol is typically cheaper per volume than gasoline. Combined with the assumption that the octane boost from ethanol further reduces the cost of gasoline blendstock, ethanol blends have a lower per litre retail price than the counterfactual gasoline without ethanol. Consequently, the sales tax per litre would be higher in the counterfactual scenario. Where sales tax rates are high, such as with the 13% HST in Ontario, this difference in sales taxes can substantially offset the tax cost impact from the federal excise tax and provincial fuel taxes. On the other hand, the volumetric retail prices of biomass-based diesels are generally higher than petroleum diesel so sales taxes per litre are also higher, increasing the overall tax cost impact.

- **The avoided cap-and-trade costs** stem from the GHG emissions cap and trade systems operating in Québec, since 2015, and in Ontario, for 2017 to mid-2018, and Nova Scotia since 2019. The cap-and-trade systems add a carbon cost to gasoline and diesel that will affect the wholesale price of these fuels. Biofuels are exempt from the cap-and-trade systems, but there is generally no price distinction between biofuel blends and fuels without biofuels at the wholesale 'rack' for fuel distribution, indicating that the cap-and-trade cost is being spread evenly across all fuels. The avoided cap and trade costs represent the additional carbon costs that would have been incurred without biofuel consumption. The cost impact calculated here is a savings of $170 million in the gasoline pool and $29 million in the diesel pool.

There are several important caveats with regards to the cost analysis. First, the wholesale prices of the fuels are a major driver of the overall cost impact. As noted above, we assume that differences in wholesale prices are reflected in retails prices, but given the dynamics of price setting, this may not be the case in all fuel markets in Canada. Furthermore, the marketing margin will be affected by this price setting and that margin, on a per litre basis, may not be independent of the renewable fuel content as we have assumed. As well, the wholesale prices are based on commodity prices listed on the Chicago mercantile exchange. While these are indicative of the prices paid for fuels, actual contracts will be settled relative to this price and wholesale costs could be different than calculated in this analysis.

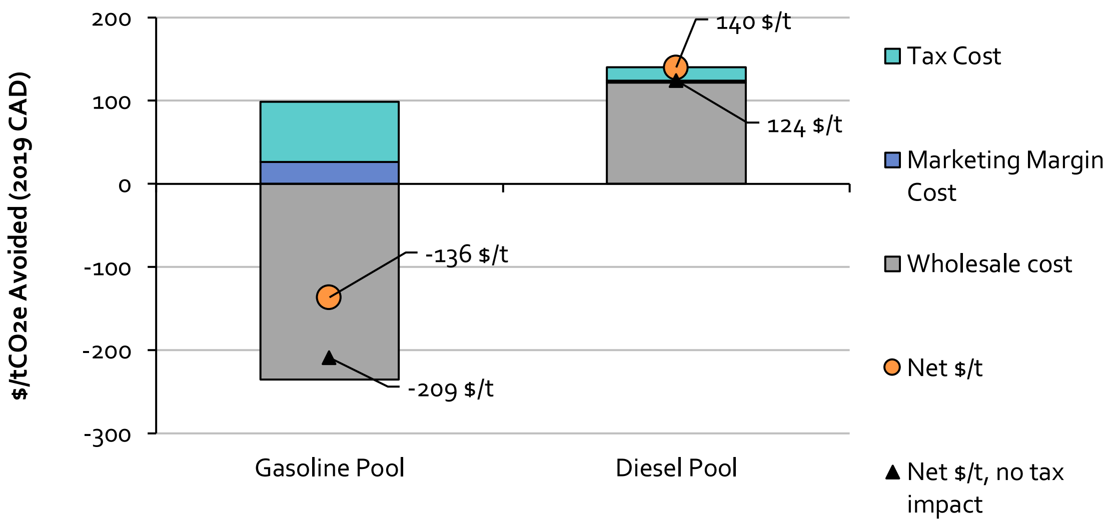
A further uncertainty in the cost analysis is the impact of renewable fuel blends on energy efficiency (i.e. energy per km). The weight of evidence suggests that energy efficiency has not been affected by current blending rates and there is no efficiency change included in the cost analysis. However, the results of the cost analysis are very sensitive to this assumption. Again, using the example based on the analysis of Geringer et al. (2014), if E10 yielded a 1.8% improvement in energy efficiency (scaled to actual blend rates), consumers would have saved another $8.4 billion from 2010 through 2019, equivalent to more than a 400% increase in the cumulative cost impact in the gasoline and diesel pools.

4.4. GHG Abatement Cost

Figure 18 shows the GHG abatement cost of biofuel blending in Canada from the perspective of consumers. The abatement cost is the cumulative cost impact by source (i.e. wholesale cost, marketing cost, tax cost), divided by the cumulative avoided GHG emissions from 2010-2019 for the gasoline and diesel pool. Avoided cap-and-trade costs are not included in this calculation, nor are any additional costs savings, co-benefits (e.g., reduced health costs related to reductions in air pollution), or possible GHG reductions associated with the use of biofuels, besides the differences included in the CIs used in this analysis (e.g. the impact of ethanol blending on vehicle energy efficiency and refinery GHG intensity in not included)

For interest, net abatement costs without the tax cost impact are shown. In other words, Figure 18 shows the net abatement cost if excise taxes, sales taxes, and carbon taxes on fuels had the same $/energy value for gasoline and ethanol, and for diesel, biodiesel and HDRD (i.e. taxes were applied on an energetic basis rather than volumetric).

Figure 18: GHG abatement cost, with and without volumetric tax penalty 2010-2019



The cost of abatement from ethanol blending is -\$136/tCO_2e (Figure 18). Furthermore, the results suggest that excise and carbon taxes on fuels have a significant impact on the net dollar value per tonne CO_2e abated, which would be -\$209/tCO_2e if the excise taxes on ethanol and gasoline were equivalent on an energy basis. The abatement cost in the diesel pool is \$140/tCO_2e, or \$124/tCO_2e if fuel taxes were based on energy rather than volume.

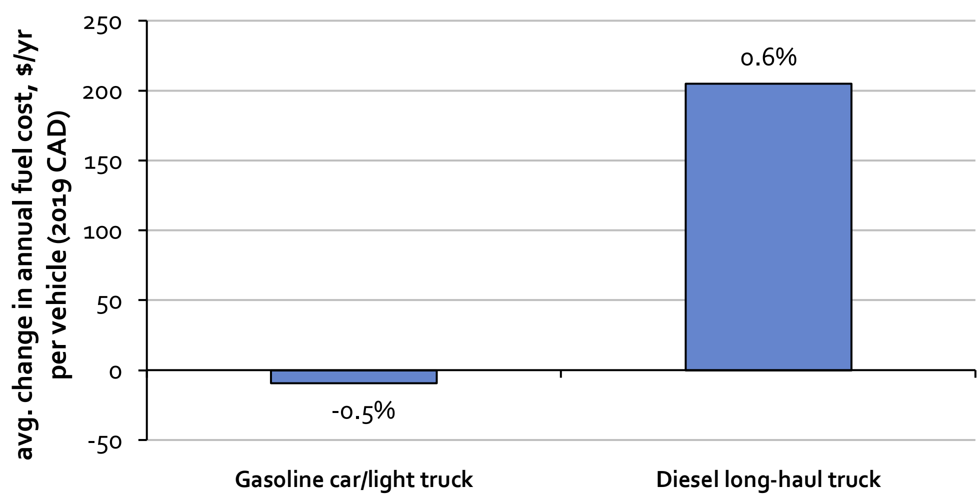
4.5. Consumer Cost Impact

Figure 19 shows the cost impact expressed as a change in average annual fuel expenditures for archetypal consumers. For the gasoline pool, the archetypal consumer uses a light-duty vehicle to travel approximately 15,800 km per year with an average fuel economy of 9.7 litres per 100 km travelled. For the diesel pool, the archetypal consumer is a truck operator who uses a tractor-trailer combination to travel approximately 87,500 km per year with a fuel economy of 32.0 litres per 100 km travelled. These archetypes reflect the average statistics of Canadian consumers from 2010-2018 as reported by Natural Resource Canada in the Comprehensive Energy Use Database.

The average consumer of gasoline saved $9/yr because of ethanol blending in Canada. A typical heavy-duty diesel consumer spent an additional $205/yr (+0.6%) because of biodiesel and HDRD blending (Figure 19). The higher cost for the diesel archetype could have been mitigated if more biodiesel and less HDRD had been used. This outcome was technically feasible given that on average in Canada, biodiesel has only accounted for just over 1% of the diesel pool volume during the eight-year study period, while a 2% average annual blend is considered feasible by even the most conservative fuel supplier. The expectation of ongoing biodiesel and HDRD price spreads could result in increased use of biodiesel (putting upward pressure on biodiesel prices) or increased investment in HDRD supply (putting downward pressure on its price).

This year's analysis used different data sources and assumptions for parts of the cost analysis from previous years' reports, which lower the estimated savings to a typical gasoline consumer. Had last year's methodology been used, the savings and costs would have been $32/year for a typical vehicle owner and $229/year for a long-haul trucker. For a detailed description of the changes made in this year's report, refer to Appendix C: Change to Cost Analysis Methodology.

Figure 19: Archetypal fuel consumer cost impact, annual average 2010-2018



Finally, since the impact of ethanol blending results in savings to consumers, it implies that the ethanol blending mandates in Canada might not be causing substantial changes to fuel use. In other words, since ethanol can be used to boost gasoline's octane value, refiners may be incentivized to blend ethanol regardless of whether the blending mandate is present or not. In BC, Alberta, Saskatchewan, Manitoba, and Ontario, fuel suppliers have historically over-complied with provincial volumetric blending mandates in every year.

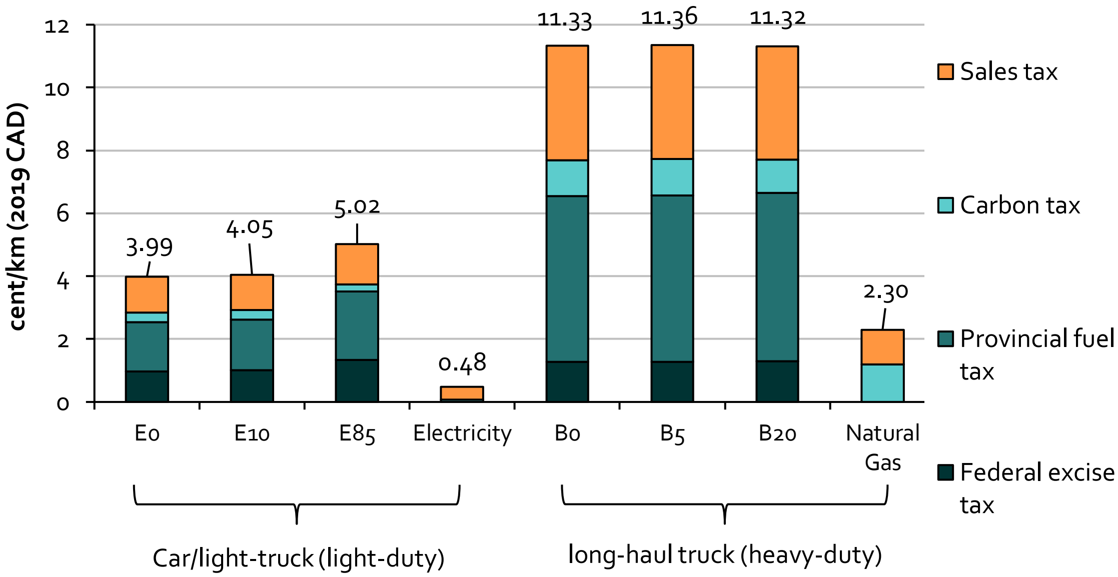
Despite this motivation to over-comply with gasoline blending mandates, policy design can still ensure that these regulations have an additional impact on GHG emissions. For example, the British Columbia *Renewable and Low Carbon Fuel Requirements Regulation*, constrains CI of ethanol to increase the avoided GHG emissions. Furthermore, while the results of this analysis indicate that ethanol use may be 'voluntary', it is possible that the mandates are forcing refiners to use ethanol to boost octane rather than some other method that might result in greater GHG emissions.

4.6. Detailed Tax Costs

A breakdown of fuel taxes per-km-travelled by tax type for different biofuel blends illustrates why there is a tax cost impact associated with biofuel consumption. Taxes per km are calculated using the same archetypal consumers of gasoline and diesel as in Figure 19 (a light-duty gasoline vehicle and a long-haul diesel tractor-trailer). On average in Canada in 2019, the archetypal gasoline user paid 1.5% more tax per km when using E10 rather than E0. Likewise, in 2019 the archetypal diesel user also paid 0.3% more tax per km when using B5 rather than B0 (Figure 20). Again, this "additional" taxation relates to the lower energy density of biofuels and the fact that most fuel taxes are applied per litre. The tax impact would be exacerbated when using fuels with more biofuel content like E85 or B20. In contrast, other alternative fuel vehicles that run on electricity, hydrogen, or renewable natural gas are exempt from provincial fuel taxes and federal excise tax and pay a much lower overall tax per km.

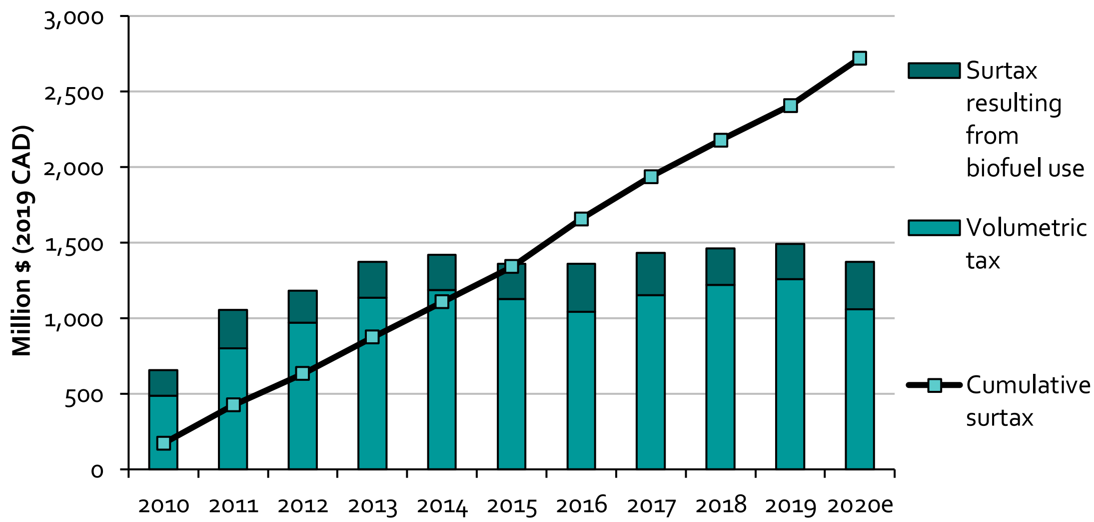
The tax impacts in Figure 20 are fuel-consumption-weighted averages for Canada and are not specific to any province. However, there are important regional differences hidden within that average. For example, biofuel users will pay less sales tax per km (charged as a % of the fuel price) when there is a sufficiently large volumetric price discount between the biofuel blend and the unblended fossil fuel (i.e. the $/L price of the biofuel is lower). In 2019, the volumetric price of ethanol was discounted heavily relative to gasoline and the octane value of the ethanol was higher than average resulting in less sales tax on E10 compared to E0. In provinces with HST (i.e. a higher sales tax rate, as in Ontario), the reduction in sales tax per km on E10 versus E0 can be larger than the increase in other taxes, meaning there was a negative tax cost impact (i.e. using E10 resulted in less tax paid per km). This was the case for Ontario in 2018, though the trend reversed itself in 2019. In contrast, ethanol consumption almost always results in more tax per km in regions with lower sales tax rates (i.e. GST rather than HST), especially in regions with carbon prices that do not distinguish between unblended fossil fuels and typical biofuel blends (e.g. E5 to E10, B2 to B5).

Figure 20: Fuel taxes and carbon costs for archetypal fuels and consumers, illustrative fuel consumption weighted average for Canada in 2018 (total shown in data label)



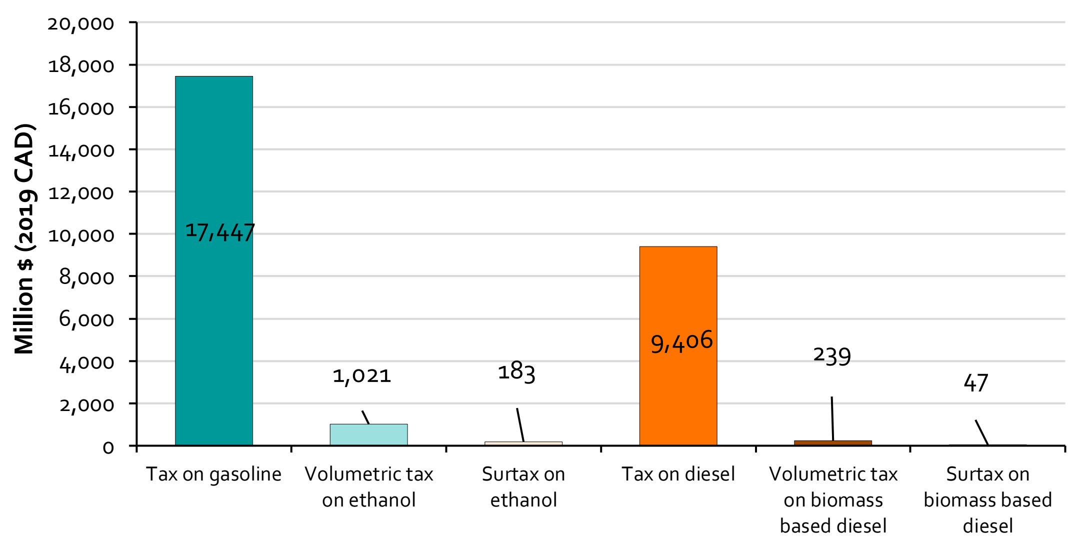
In 2019, these "surtaxes" taxes paid on biofuels amounted to an extra 18%/yr, or roughly $231 million (2019 CAD), relative to the "volumetric" tax that would have been paid if taxes per unit of energy were the same across all fuels used in a given fuel type (i.e. with gasoline or diesel) (Figure 21). From 2010 to 2019, this surtax was equivalent to an additional 5%-30% tax paid on biofuels each year, or roughly $80 to $231 million/yr (2019 CAD), where the annual variation comes from variations in fuel prices, marketing margins and the value of octane from ethanol. The cumulative tax cost impact since 2010 rose to about $2.4 billion (2019 CAD) in 2019 (note, this is the same as the total tax cost impact shown in Figure 17). Our estimate for 2020 shows that the tax cost impact will be even larger than in 2019, roughly $310 million, with the cumulative surtaxes paid on biofuels rising to just over $2.7 billion (2019 CAD).

Figure 21: Breakdown of fuel taxes paid on biofuels in Canada, with cumulative "Surtax" paid



Taxes paid on ethanol in Canada in 2019 account for 6.5% of the total taxes paid on fuel from the gasoline pool, where the "surtax" on ethanol is 1% of that total. Taxes paid on biomass-based diesel represent 3.0% of the total taxes paid on the diesel pool in Canada in 2018. The "surtax" on biomass-based diesel is about 0.5% of that total (Figure 22).

Figure 22: Breakdown of taxes paid on the gasoline and diesel fuel pools in 2019

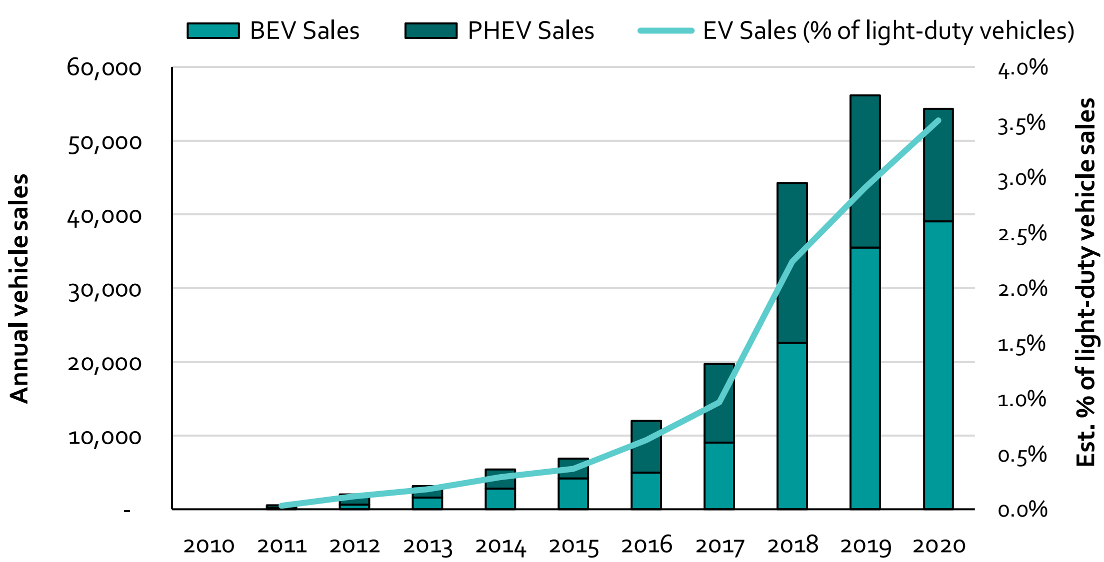


4.7. Electric Vehicles

Biofuels in Canada now includes estimates of how light-duty plug electric vehicles (referred to as LDV PEVs) have affected gasoline consumption and GHG emissions. These results are based on Statistics Canada data describing LDV PEV sales, which feed into our calculation of LDV PEVs on the road in Canada. Our intention is to track these statistics going forward as policy and consumer preferences continue to drive PEV sales in Canada.

In 2019, PEVs accounted for 3% of light-duty vehicle sales in Canada, rising to 3.5% in 2020, equivalent to more than 50,000 PEV sales in that year (Figure 23). Sales rates vary tremendously by province, where in BC and Québec, LDV PEV sales were 7-9% of the total versus other regions where they accounted for only 0.5-1.8% of new vehicle sales. Sales of PEVs include battery electric vehicles (BEVs), which run only on electricity, and plug-in hybrid electric vehicles (PHEVs) which run on electricity but can extend their range using on-board auxiliary engines or generators that consumer fuel.

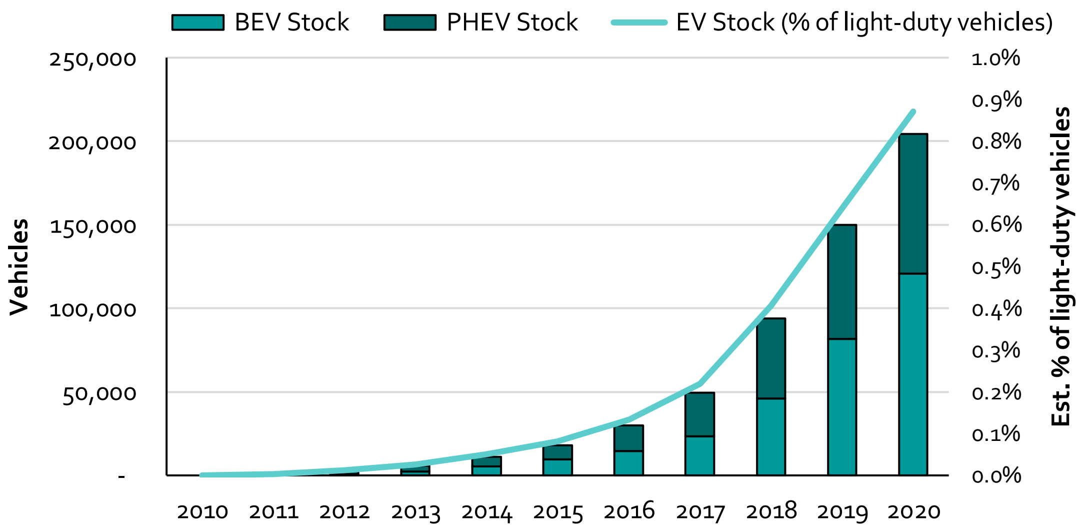
Figure 23: Sales of light-duty plug in electric vehicles in Canada, 2010-2020



Source: Statistics Canada, New Motor Vehicle Registrations, Table: 20-10-0021-01

Because a relatively small fraction of vehicles on the road are purchased new every year, PEVs represent a smaller fraction of Canada's vehicle stock than vehicle sales. We estimate that PEV account for 0.9% of the light-duty vehicles on the road in 2020, up from 0.2% in 2017 (Figure 24). This estimate assumes all PEV sold over the past 9 years are still on the road and does not account for trade in used PEVs between Canada and the US. The stock of PEVs is split about 60:40 between BEVs and PHEVs.

Figure 24: Light-Duty Electric Vehicles On the Road, 2010-2020



5. Biofuel-Caused Reductions in Emissions from Gasoline Refining and Consumption

This section provides descriptions and estimates for two potential GHG benefits of ethanol blending that have not been included in previous versions of *Biofuels in Canada*: first, that the high-octane value of ethanol reduces the emissions intensity of refining gasoline because refineries can produce a lower octane blendstock. Second, that high-octane components of gasoline that are replaced by ethanol, largely aromatics, are more carbon intensive than baseline gasoline. Consequently, ethanol could reduce the combustion (i.e., tailpipe) GHG emissions associated with gasoline blendstock consumption.

Our research shows that the effect of ethanol on refinery emissions and gasoline composition is uncertain but likely not zero. Estimates for how ethanol blending affects refinery emissions range from a modest decrease to small increase. Research more consistently suggests that ethanol blending will reduce emissions by changing the composition of the fossil portion of gasoline, but it remains challenging to evaluate what the composition of gasoline would have been absent ethanol blending. Because of the uncertainty, these impacts are only discussed below and are not currently included in the calculation of GHG emissions or cost impacts.

5.1. Potential Reduction in Refinery Emissions Due to Ethanol's High Octane

Refineries have a selection of feedstocks and processes that they can use to comply with the octane, vapour pressure, and other requirements of the Canadian fuel quality standards for gasoline. In addition to reducing overall demand for crude oil, ethanol blending specifically displaces reformate, alkylate, aromatics, or other high-octane ingredients in gasoline blending which are more energy-intensive to produce than the low-octane outputs from atmospheric or vacuum distillation.

For example, using ethanol as a source of octane would allow a refiner to operate their catalytic reformer, which transforms low-octane naphtha into higher octane reformate, at a lower severity. The octane specifications that were previously being met with reformate can now be achieved with ethanol; a less refined blendstock can be used to achieve the same octane result which means that refinery emissions and costs to produce gasoline blendstock could be lower.

A report prepared by Life Cycle Associates for the Renewable Fuels Association used a figure of 1g CO_2e/GJ-gasoline for the difference in refinery GHG intensity between E0 and E10.[48] The citation for that number, *Kwasniewski 2015*, is unfortunately not included in the works cited in their report.

The one publicly available paper by Kwasniewski in 2015 compares refinery emission between E10 and E30 cases. In the two 88-octane fuel scenarios, the E30 fuel showed a 0.7-1gCO_2e/MJ reduction in refinery GHG emissions compared to the E10 fuel.[49] Another US paper found a 6% and 12% reduction in refining GHG emissions compared to E10 for E20 and E30 blends respectively.[50] In other words, this GHG impact applies when going from typical current ethanol blending rates to mid- to high ethanol blending rates and does not directly inform what the impact would be for a shift from E0 to E10.

A paper from 2009 examining the European gasoline market compared refining GHG intensity of fossil gasoline using MBTE as a source of octane with E5. The authors found a 2.3 gCO_2e/MJ reduction in refinery emissions in the E5 case, partially offset by a 1.1 gCO_2e/MJ difference in the carbon intensity of ethanol and MTBE production, resulting in a net impact of 1.2 gCO_2/MJ.[51] Unfortunately, this paper compares ethanol blending with a scenario that is not fully relevant to present-day Canada that being where a refinery produces sub-octane blendstock and blends with MTBE (rather than using internal processes to achieve the required octane rating).

A 2021 analysis by the consultancy Transport Energy Strategies critiqued existing literature on this subject, finding that ethanol blending would cause a small increase, not decrease in refinery emissions.[52] Catalytic reformers also produce hydrogen, and the emissions from producing the foregone hydrogen via steam methane reforming would undo the emissions benefit of less sever operation of the catalytic reforming.

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48 Unnasch, S., & Parida, D. (2021). *GHG Emissions Reductions due to the RFS2-A 2020 Update.* Life Cycle Associates, LLC

49 Kwasniewski, V., Blieszner, J., & Nelson, R. (2015). Petroleum refinery greenhouse gasemission variations related to higher ethanol blends at different gasoline octane rating and pool volume levels. *Biofuels, Bioproducts, Biorefining*, 10:36-46

50 Hirshfeld, D. S., Kolb, J. A., Anderson, J. E., Studzinski, W., & Frusti, J. (2014). Refining Economics of U.S. Gasoline: Octane Ratings and Ethanol Content. *Env. Science and Technology*, 48: 11064−11071

51 Croezen, H., & Kampman, B. (2009). The impact of ethanol and ETBE blending on refinery operations and GHG emissions. *Energy Policy*, 37: 5226–5238

52 Klein, T., Clark, N., Higgins, T., & McKain, D. (2021). *Well-to-Wheels Carbon Intensity for Ethanol Blended Fuels.* Transport Energy Strategies

They estimate that ethanol would increase refinery emissions by 0.2 gCO2e/MJ gasoline.

In short, estimates in the literature for how ethanol blending affects refinery emissions range from a modest decrease in emissions (2.5 gCO_2e/MJ) to a small increase in emissions when hydrogen production is considered (0.2 gCO_2e/MJ). Estimates for avoided refinery emissions are presented in Figure 25 below. Given this uncertainty, these changes to refining GHG intensity are addressed only in this discussion and are not part of the general analysis and main results.

5.2. Reduction in Emissions Associated with Changing Gasoline Composition

The methodology used to calculate avoided GHG emissions resulting from ethanol blending in this analysis assumes that ethanol displaces conventional fossil gasoline, and that the emissions benefit of this is equal to the difference in lifecycle CI between the gasoline and ethanol. However, because ethanol displaces other octane-enhancing ingredients in gasoline, this methodology has the potential to understate the tailpipe emissions benefit of ethanol. For comparison, the exhaust emissions of conventional gasoline and the high-octane aromatics portion of gasoline are presented below.

Table 12: Carbon Intensity of Gasoline versus Aromatics/Olefins in GHGenius 4.03a

Fuel	Exhaust Emissions (gCO2e/MJ)
Conventional Canadian Gasoline Blend	62,961
Aromatics in Conventional Canadian Gasoline Blend (i.e., the high octane portion)	73,224

The challenge with quantifying the emissions effect of the changing chemical composition of gasoline is twofold: first, accurately developing a counterfactual as to what would be in the gasoline in a no-ethanol case, and second, actually measuring the relatively small change to emissions in experimental settings. Various studies have looked at this, mainly focusing on how ethanol affects emissions of criteria air contaminants, not GHGs. Two studies were identified that summarized estimates for CO_2 in addition to air pollutants.

A literature review by consultancy Transport Energy Strategies found that “a 1% change in ethanol would correspond to a change in aromatic level of about 0.8%”. Using this ratio of substitution between ethanol and aromatics, the authors’ estimate of CI for a blended E10 fuel was 1.4% lower than the baseline estimate that didn't consider changing composition of the fuel.[53]

An EPA study found a 1.8% reduction in carbon intensity between an E10 tier-3 test fuel and an E0 tier-2 test fuel, caused by the 8.5 percentage point reduction in aromatics in the E10 test fuel.[54] This change in carbon intensity is for the blended fuel itself, seemingly including biogenic carbon, suggesting an even larger reduction in inventory emissions. Another study also estimated a 1 to 2% reduction in CO_2 emissions between E0 and E10, but found none of the results for CO_2 emissions between E10 and E0 were statistically different at any reasonable level of significance.[55]

The largest study identified, the EPAct Tier 2 Gasoline Fuel Effects study, did collect the data for CO_2, but didn't publish or summarize the conclusions for CO_2 in the report (the focus was CACs).[56] One meta-analysis of the literature on the effect of ethanol and tailpipe emissions found that "Variability between studies in itself suggests that many studies should not be used to predict real-world emissions effects", in part because the fuel blends used in laboratory testing do not always reflect real world fuel composition.[57] This critique was largely driven by the use of "match" blended fuels in emissions studies, in which fuels are blended to match specific properties such as 50% distillation temperature or aromatic content, leading to fuel blends which may not reflect real-world fuels that are sold, which may be "splash" blended, thereby foregoing the benefits attributed to the "match" blended fuels.[58]

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[53] Klein, T., Clark, N., Higgins, T., & McKain, D. (2021). *Quantifying Ethanol CI Benefits in Gasoline Composition.* Urban Air Institute

[54] Butler, A., Warila, J., Fernandez, A., & Hart, C. (2018). *Effect of Fuel Composition on Fuel Economy and CO2 Emissions in LD Gasoline Vehicles [slide deck].* US EPA Office of Transportation & Air Quality

[55] Yuen et al. (2019). *Comparison of real-world vehicle fuel use and tailpipe emissions for gasoline-ethanol fuel blends,* Fuel, 249: 352-364

[56] United States Environmental Protection Agency. (2013). *Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards: Analysis of Data from EPAct Phase 3 (EPAct/V2/E-89) Final Report.* US EPA

[57] Nigel Clark Et Al. (2018). *Effects of Ethanol Blends on Light-Duty Vehicle Emissions: A Critical Review.* Urban Air Initiative

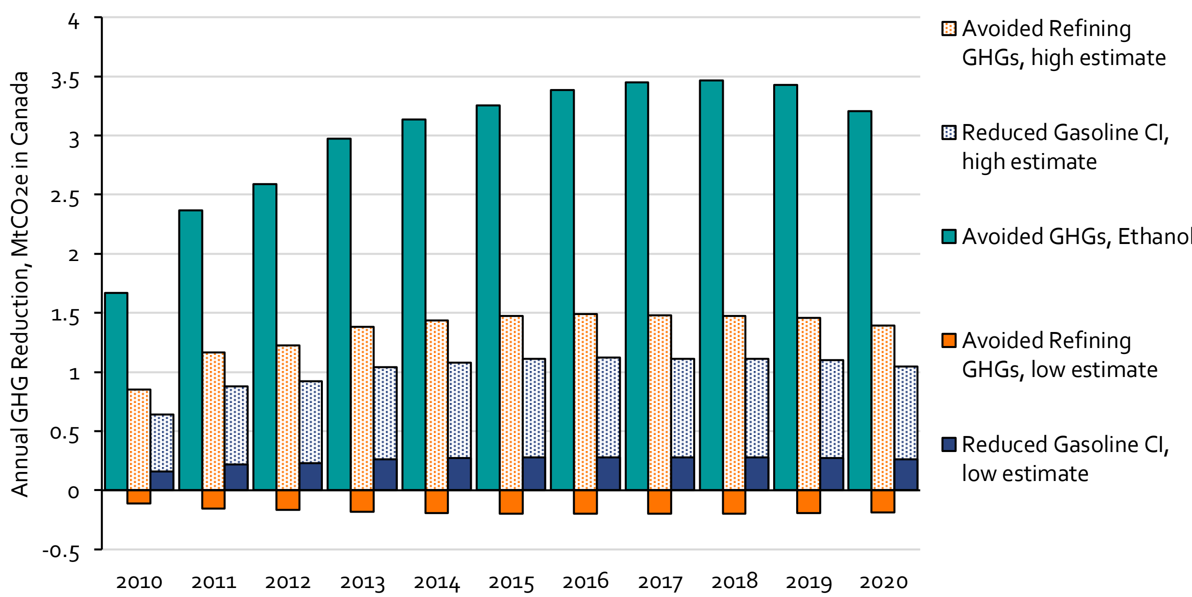
[58] Splash blending refers to mixing gasoline by splashing ethanol into an otherwise finished but suboctane fuel. Match blending refers to creating an ethanol fuel blend that matches certain characteristics of a non-ethanol blend, such as 50% distillation temperature or aromatic content.

There's a compelling argument that ethanol should reduce the carbon intensity of the gasoline due to lower aromatic content, but the effect is small enough that it is hard to quantify in experimental settings and even harder to define in real-world usage. Given the size of gasoline pool, even a 1% change in the CI of the fossil portion of gasoline would yield more than a million tonnes of annual emission reductions. Compared to the emissions effect of ethanol displacing gasoline, the effect of changing fuel composition is secondary but still potentially significant.

5.3. Comparing Abatement from Gasoline Displacement to Reduced Gasoline CI

Figure 25 presents a range of how abatement at refineries and from reduced aromatics in gasoline compared to the avoided GHG estimate in this report that results when ethanol is consumed in place of gasoline.

Figure 25: Emission reductions from refineries and changing gasoline composition not previously quantified



The high estimate for avoided emissions from using lower intensity refining processes is substantial compared to our estimates for avoided GHGs from gasoline displacement alone. Using a 1.5gCO_2e/MJ reduction in the emissions intensity of refining petroleum gasoline in an E10 blend, towards the higher end of what was observed in literature, produces a GHG reduction estimate of 1.5 Mt in addition to the 3.5 Mt of avoided emissions from displacing gasoline. For reference, petroleum refineries in Canada emitted 19 Mt[59] in 2019. Using the lower estimate that ethanol blending causes a slight increase in refinery emissions suggests blending causes a 0.2 Mt increase in refinery emissions. The actual impact is uncertain but is very likely to fall within this range. Given the potential large value of these savings, future years of the Biofuels in Canada report may seek to better quantify how ethanol blending affects refinery emissions.

Literature regarding how ethanol would affect the aromatic content in the petroleum portion of gasoline was more consistent in the direction of the effect. If 80% of the ethanol blended into gasoline displaces aromatics (i.e., a 10% ethanol blend has 8% lower aromatic content), this would imply that the reduced CI of the fossil gasoline blendstock used with ethanol would further reduce emissions 1.1 MtCO2e in 2019; about an additional third of the lifecycle effect of ethanol previously estimated in this report. The low-end of this potential impact would only result in an additional 0.27 $MtCO_2e$ of avoided GHG emissions in 2019.

[59] Environment and Climate Change Canada, 2021 National Inventory Report by Economic Sector (Petroleum Remining)

6. Conclusions

The aim of this study is to provide a comprehensive analysis of the volumes of renewable transportation fuels being consumed in Canada as well as the impact of this fuel consumption on GHG emissions and consumer fuel expenditures. Key conclusions from this study are summarized below.

Renewable fuel consumption

The renewable content in gasoline and diesel pools has increased from 2010 to 2019, though volumes have grown only slightly since 2018 (+1.3%, including the estimated co-processed fuel volume). The data compiled for this study indicates that the volume of ethanol consumed in Canada each year has increased from roughly 1,700 million L/yr in 2010 to 2,985 million L/yr in 2019 (down by 1.6% since 2018). Annual biodiesel consumption has increased from roughly 123 million L/yr in 2010 to 360 million L/yr in 2019. HDRD consumption increased from roughly 37 million L/yr to 432million L/yr in that same period (overall biomass-based diesel is up by 11% since 2018). Our estimate for 2020 shows a reduction in renewable fuel consumption due to an overall reduction in gasoline and diesel consumption within Statistic Canada data, largely a function of reduced travel activity during the COVID-19 pandemic. Despite reduced renewable fuel consumption estimated for 2020, the blend rates appear to have increased in that year.

Avoided GHG emissions

Annual avoided GHG emissions resulting from biofuel blending in Canada have increased from 2.1 $MtCO_2e$/yr in 2010 to 5.9 $MtCO_2e$/yr in 2019 (including the estimated avoided GHG emissions from co-processing). Because of declining biofuel CIs, avoided emissions are greater than in 2018, even though the total volume of renewable fuel was relatively static. As well, this analysis now estimates the GHG emissions avoided from the use of light-duty plug-in electric vehicles (PEVs), which were estimated at 0.5 $MtCO_2e$/yr in 2019. The cumulative GHG emissions avoided between 2010 and 2019 are 47 $MtCO_2e$, including the contribution from PEVs.

Cost Impacts

Between 2010 and 2019, blending ethanol, diesel, and HDRD with conventional transportation fuels reduced consumer fuel costs in Canada by 0.22%, relative to what they would have been without renewable fuels. If all costs and savings were passed on to consumers, they saved $2.0 billion (2019 CAD) over the ten-year study period. The octane value of ethanol creates a substantial savings that offsets other costs associated with renewable fuel consumption. Assuming no other co-benefits related to biofuels other than the octane value of ethanol, the GHG abatement cost resulting from ethanol blending is negative, -\$136/tCO_2e, whereas the abatement cost from biofuel blending with diesel is positive at \$140/tCO_2e. Ethanol blending reduced the annual fuel costs of a typical driver by \$9/yr (-0.5%) over the study period, relative to a scenario without ethanol consumption. Biodiesel and HDRD blending increased the annual fuel costs of an archetypal long-haul trucker by \$205/yr (+0.6%).

Note there were improvements to the cost analysis methodology this year. Notably, the value of octane is now lower given that is based on the wholesale price spread between regular and premium gasoline, rather than the retail price spread. While this has reduced the cost savings related to ethanol consumption, it provides a more realistic portrayal of these impacts on fuel refiners.

Taxation impacts

Biofuel consumption, especially ethanol, has increased the fuel tax burden on consumers while generating additional tax revenue for governments in Canada. This impact comes from fuel taxes that are applied per litre, such as excise taxes as well as carbon taxes and levies; the application of sales taxes (PST, GST) amplifies the volumetric tax impact. Because biofuels are generally less energy dense than petroleum fuels, using biofuels involves consuming a greater volume of fuel and, thus, paying more tax than if taxes were applied on an energetic basis. Consequently, consumers pay more tax per kilometer when using biofuel blends, all else being equal. This impact is most noticeable with ethanol because it is roughly 33% less energy dense than gasoline, though the impact varies from year to year as a function of the variation in spread between ethanol and gasoline prices and the value of octane from ethanol. This tax structure has cost gasoline consumers an additional \$2.2 billion during the ten-year study period (2010 to 2019) and is included within the net savings noted above. The corresponding tax cost on diesel consumers during that period was roughly \$0.2 billion (2010 to 2019 CAD).

Appendix A: Cost Analysis Methodology

This appendix provides more detail on the methodology used for the cost analysis:

- The wholesale price of ethanol and biodiesel were obtained for 2010-2020.
  - Ethanol and biodiesel prices were based on monthly averages from Chicago Mercantile Exchange (CME) from 2010 to the end of 2020. Biodiesel prices are used net of biodiesel blenders tax credit.
- HDRD wholesale prices were estimated using Darling Ingredients', the parent company of Diamond Green Diesel, financial materials for investors. Prices were calculated annually as follows:

$$P_{HDRD} = \frac{Revenue}{Volume}$$

- Landed prices of ethanol and biodiesel were estimated for each province in Canadian dollars. These prices were based on a representative major terminal city in each province, with costs relative to the CME price based on typical fuel transport costs by rail. Distances between Chicago and each representative city are based on results from Google maps (road distances used to approximate rail distance). Transportation costs ranged from $5/bbl to $13/bbl, with a variable cost per kilometer that inversely scales with distance to account for economies of scale when shipping longer distances with rail, based on Gallagher and Denicoff (2015).[60]
- The wholesale price for blended gasoline and diesel for each year was obtained for each of the provinces in the analysis.
  - These prices were based on monthly average wholesale price data for regular gasoline and diesel in representative cities in each province from collected by Kalibrate.[61]

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[60] Gallagher, Paul and Denicoff, Marina. 2015. Ethanol Distribution, Trade Flows, and Shipping Costs, Iowa State University Economics Technical Reports and White Papers Accessed from https://lib.dr.iastate.edu/econ_reportspapers/45

[61] Kalibrate, https://charting.kalibrate.com/

- All values were converted to 2019 dollars[62] and Canadian currency from US dollars[63] and Euros.[64]

- Inputs for Atlantic Canada are constructed from provincial values averaged using population weights from Statistics Canada.[65]

- Inputs and results for Canada as a whole are calculated using fuel-consumption weighted averages, based on the fuel consumption reported in the analysis.

- The price of gasoline blendstock and diesel were estimated based on average reported blends in each year and the price of biofuel and blended fuel. For example, the price of gasoline blendstock ($P_{BOB,}$ Where BOB = blendstock of oxygenate blending) was calculated as:

$$P_{BOB} = \frac{P_{blend,reg} - P_{eth} * \%vol_{eth}}{\%vol_{BOB}}$$

  - Where $P_{blend,reg}$ is the price of the blended regular gasoline and P_{eth} is the price of ethanol in each region.

  - $\%vol_{eth}$ and $\%vol_{BOB}$ are the volume fraction of ethanol and gasoline blendstock in the regular gasoline, respectively.

- The price of pure gasoline was estimated assuming the octane of that fuel would have had to be higher if no ethanol were added. In other words, we estimated the price of pure gasoline assuming the blendstock used with ethanol is sub-octane, and ethanol was used to boost its octane to 87. Without the addition of ethanol, pure gasoline would have had to be refined to a higher octane and its price would be higher than the price of the sub-octane blendstock. To estimate this price, we used the following method:

[62] CANSIM, 2018, Table 326-0020 Consumer Price Index

[63] Bank of Canada, 2020, Exchange Rates. http://www.bankofcanada.ca/rates/exchange/monthly-average-lookup/

[64] www.investing.com/currencies/eur-cad-historical-data

[65] Statistics Canada: Table 17-10-0009-01. Population estimates, quarterly.

- The blended fuel was assumed to have an octane value of 87 (regular) and the ethanol was assumed to have an octane value of 113 when used in a gasoline blend.[66]

- The implied cost per octane point was estimated for each year based on the difference between wholesale regular and premium gasoline prices in the US market[67] where that price spread better reflects the cost of octane than in the Canadian market.

- Our estimated price of pure sub-octane gasoline was decreased based on the implied cost per octane point and the estimated octane of the gasoline blendstock:

$$P_{gasoline,sub-octane} = P_{BOB} - \left(\frac{P_{blend,prem} - P_{blend,reg}}{O_{blend,prem} - O_{blend,reg}}\right) * \left(O_{gasoline,87} - O_{BOB}\right)$$

Where:

- $P_{gasoline,sub\text{-}octane}$ is the estimate price of pure gasoline if the gasoline blendstock is sub-octane.

- $P_{blend,prem}$ and $P_{blend,reg}$ are the price of premium and regular gasoline blends, respectively, based on US data[68]

- $O_{blend,prem}$ and $O_{blend,reg}$ are the octane values of premium and regular gasoline blends, 92 and 87 respectively

- $O_{gasoline,87}$ is the octane of regular gasoline blend (87)

- O_{BOB} is the octane of the gasoline blendstock. If it is refined sub-octane 87, with the intention of adding ethanol to increase the octane rating, then:

$$O_{BOB} = \frac{O_{blend,reg} - O_{eth} * \%vol_{eth}}{\%vol_{BOB}}$$

Where:

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[66] 113 to 115 is a typical value for blends cited by EIA https://www.eia.gov/todayinenergy/detail.php?id=11131. This value corresponds to ethanol used in low concentration blends. The octane rating of pure ethanol is 100.

[67] EIA. 2021. Petroleum & Other Liquids: Refiner Gasoline Prices by Grade and Sales Type. Accessed from: https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm

[68] ibid

- $O_{blend,reg}$ is the octane value of regular gasoline blend (87)
- $\%vol_{ethl}$ and $\%vol_{BOB}$ are the volume fraction of ethanol and gasoline blendstock in the regular gasoline, respectively
- O_{eth} is the octane value of ethanol (113)

- The average price per litre cost/savings of blending ethanol and gasoline was estimated for each province in each year of the analysis based on the estimated price of pure gasoline and ethanol. For example, this price differential (P_{Δ}) in $/L for gasoline was calculated as:

$$P_{\Delta\$/L} = P_{blend,reg} - P_{gasoline,87}$$

- Similarly, the price per litre cost/savings of blending biodiesel and HDRD with pure diesel was estimated.
- The average $/GJ cost or savings that results from blending biofuel was estimated, assuming biofuel consumption does not change energy consumption. The following energy densities from GHGenius 4.03a were used to convert $/L price to $/MJ prices:
  - Ethanol= 23.6 MJ/L
  - Gasoline= 34.7 MJ/L
  - Diesel= 38.7 MJ/L
  - Biodiesel= 35.4 MJ/L
  - HDRD= 36.5 MJ/L
- The equation is:

$$P_{\Delta\$/MJ} = \frac{P_{blend,reg}}{MJ/L_{gasoline} * \%vol_{BOB} + MJ/L_{eth} * \%vol_{eth}} - \frac{P_{gasoline,87}}{MJ/L_{gasoline}}$$

- We then estimated the total fuel expenditures in each region and year with biofuels blended and for a counterfactual without biofuels blended:
  - A counterfactual volume of gasoline and diesel was estimated that would have been consumed if no biofuels were blended into the fuel. This was calculated as the actual volume of fuel consumed multiplied by the ratio of the energy density (i.e. MJ/L) of gasoline to the energy density of the blend.

- Taxes and marketing margins were added to each price to get retail prices. Margins on $/L basis were obtained from Kalibrate[69] and are assumed to be independent of biofuel blending rates. Taxes are from NRCAN.[70] Taxes include federal and provincial fuel excise taxes, and sales taxes. Sales taxes were applied as a percent of the actual retail price and the calculated retail price for the counterfactual scenario without biofuels.

- In BC, the carbon tax was applied equally to each litre sold, regardless of the renewable fuel blend. The same is true for the carbon levy in Alberta for 2017 and 2018, though if there were blends with more than 10% renewable content in gasoline, or 5% in diesel, those biofuels would be exempt.

- The credit price impact of the cap-and-trade system in Ontario and Québec was assumed to already exist in reported wholesale gasoline and diesel blend prices. While biofuels are exempt from the cap-and-trade systems, the credit cost resulting from supplying gasoline and diesel was assumed to be spread evenly across all fuels, regardless of their biofuel content. For the counterfactual scenario with no biofuels, the additional cap and trade cost resulting from the gasoline and diesel that would have been consumed was based on average annual credit prices and added to the observed wholesale fuel price.[71,72]

- Retail prices were multiplied by volumes. For example: retail price of gasoline blend by volume consumed, or counterfactual retail price of gasoline by counterfactual volume. The same was done for diesel.

- The difference in cost in each year was calculated for each province for gasoline and diesel pools.

- The change in fuel expenditures was shown for an archetypal consumer, broken down by component (i.e. change in wholesale fuel cost, additional margin cost, taxes). The consumer archetype was defined to reflect the average statistics of

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[69] Kalibrate, https://charting.kalibrate.com/

[70] NRACN, 2019, Fuel Consumption Taxes in Canada, https://www.nrcan.gc.ca/energy/fuel-prices/18885

[71] Government of Ontario. Past auction information and results. Accessed from: https://www.ontario.ca/page/past-auction-information-and-results

[72] California Air Resources Board, 2020, Summary of market transfers complete in 2019 Government of Quebec. Accessed from: https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program

Canadian consumers from 2010-2018[73] as reported by Natural Resource Canada, for the average L/100 km and annual km travelled. For the archetypal gasoline consumer, these values are 9.7 L/100 km and 15,788 km/yr. For the archetypal diesel consumer, these values are 32.0 L/100 km and 87,539 km/yr.[74,75]

[73] The NRCan National Energy Use Database has not yet been updated with values for 2019; the 2010-2018 averages were assumed to remain unchanged for 2019 and 2020.

[74] Natural Resources Canada, 2021, Energy Use Data Handbook Tables, Passenger Transportation Explanatory Variables.

[75] Natural Resources Canada, 2021, Energy Use Data Handbook Tables, Freight Transportation Explanatory Variables.

Appendix B: Biofuel Type and Feedstock Assumptions and Data

In this analysis, data were collected on the volume of renewable fuels blended into gasoline and diesel — characterized as ethanol, biodiesel, or HDRD. However, to calculate the lifecycle CI of the various biofuels sold in Canada, it was necessary to further disaggregate these data by feedstock, and in some cases separate aggregate biomass-based diesel volumes into biodiesel and HDRD.

Feedstock data and guidance on the split between HDRD and biodiesel was obtained from personal correspondences with government contacts or obtained from various publications. However, data for every region and every fuel was not available. For this reason, various assumptions were made to fill these gaps. The following lists summarize the assumptions and sources we used to define fuel types and feedstocks and volumes by region in Canada.

Assumptions for British Columbia

Feedstock data was obtained from the government of British Columbia.[76] The data is essentially used "as-is" with little need for assumptions or interpretation:

1. In some years, there are minor summation errors in the data published by the BC government. We used an "Unknown" feedstock category to make the total fuel volume from individual feedstocks equal to the total reported volumes. These values were calculated to fill the gap and are not numbers reported by the BC government.

2. BC reporting does not distinguish between feedstocks used for biodiesel or HDRD, we assume that tallow, yellow grease and palm oil by-products are used for HDRD. Some soy feedstock for HDRD is also assumed to ensure total biodiesel and HDRD consumption matches the data.

Assumptions for Alberta

1. 2011 to 2020 fuel volumes were collected via personal correspondences with the Alberta government.

[76] Ministry of Energy and Mines, 2021, Renewable and Low Carbon Fuel Requirements Regulation Summary: 2010-2019

2. Ethanol feedstock volumes are estimated based on the types of feedstocks processed in Alberta's facilities. We estimate a substantial amount of corn-based ethanol, based upon a review with Don O'Connor of (S&T) [2] Consultants.

3. We assume that biodiesel feedstocks are canola and soy, as indicated through personal correspondence with Alberta Government. We assume a greater proportion of soy than canola, based upon a review with Don O'Connor of (S&T) [2] Consultants.

4. 2010 gasoline and diesel sales by volume were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017).

5. Alberta's provincial regulation and the federal regulation didn't become effective until 2011. Since we do not have data for 2010, we are assuming that there was no renewable content in 2010.

6. Gasoline and diesel data received from the Alberta government represents unblended volumes.

7. The proportion of biodiesel vs. HDRD in all years prior to 2017 is based on data reported for 2017. The split is based on data thereafter, except for 2020, which is based on the ratio in 2019.

8. We assume the feedstocks used for HDRD in Alberta are proportionally the same as what is used in BC, given that they are likely sourced from the same imports.

Assumptions for Saskatchewan

1. Ethanol content for 2010-2012 and 2015 to 2020 is based on data provided in correspondence with the Saskatchewan government. We've received indication that in 2013-2014 ethanol content remained between 9.1%-9.2%. Biomass based diesel volumes from 2012-2020 are based on data provided by Saskatchewan.

2. We assume that the proportion of biofuel in diesel is 0% HDRD and 100% biodiesel.

3. We assume that the feedstocks for ethanol are 70% wheat and 30% corn. We base this on correspondence with Don O'Connor of (S&T) [2] Consultants.

4. We assume that the primary feedstock for biodiesel is canola based on correspondence with the government of Saskatchewan.

5. Gasoline volumes were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017).

6. Diesel sales by volume for 2010-2012 and were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Note that diesel consumption provided with regard to the provincial regulation does not align with Statistics Canada data after 2012, possibly due to an increase in diesel consumption for non-transport or other policy exempt uses of the fuel.

7. Diesel and biodiesel consumption in 2016 is an average of 2015 and 2017 values.

Assumptions for Manitoba

1. All volume data from 2010-2019 is from the Government of Manitoba as reported under Manitoba's ethanol and biodiesel mandates.

2. We assume that biodiesel feedstocks are 50/50 canola and soy based personal correspondence with a government contact. Ethanol is assumed to be produced from a mix of corn and wheat, transitioning to a higher fraction of corn over time.

3. We assume there is no HDRD consumption based on correspondence with Don O'Connor of (S&T)^2 Consultants.

Assumptions for Ontario

1. Ethanol volumes are based on data provided by the Government Ontario.
2. Bio-based diesel consumption volumes for are based on government data for 2014, 2015. From 2016 to 2018, volumes are estimated assuming compliance with the Greener Diesel Regulation, 80% of volume is HDRD with CI based on Diamond Green Diesel from 2016 to 2018 (from CI registered under the BC RLCFRR), 20% is biodiesel with net-0 CI, 10% of diesel pool is distributed in Northern Ontario (based on 2015 data) and is exempted from the regulation prior to 2017. For 2019 and 2020, government contacts provided diesel and biodiesel volumes from the Greener Diesel Regulation.
3. Bio-based diesel in 2010-2013 is based on fuel tax exemption data with the HDRD share interpolated towards the known % in 2015.
4. We assume that ethanol is made from corn.
5. We assume biodiesel is 50% soy-based, while the remaining 50% is sourced equally from tallow and yellow grease, whereas we assume HDRD is made from tallow and yellow grease. These assumptions are based on a qualitative discussion with a government contact.

6. Diesel volumes for 2010-2017 are from retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Gasoline volumes and diesel volumes 2018-onwards are based on data provided by the Government.
7. Data for 2020 forms only half of a two-year compliance period that was created due to respond to market constraints due to the COVID-19 pandemic.

Assumptions for Québec

1. Gasoline and diesel sales by volume were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017).

2. Ethanol and biomass-based diesel volumes are uncertain and should be used with caution: They are estimated based on the difference between federal data reported by ECCC (or industry contacts) and total biofuel content collected for the other provinces. That difference is allocated to Québec and the Atlantic Provinces, pro-rating by population. Newfoundland and Labrador is excluded from the calculation since we have good confidence that very little biofuel is consumed there.

3. We assumed most biodiesel and HDRD is produced from tallow and that 80% of the biomass-based diesel volume is HDRD from 2014 onward (same as Ontario assumption).

4. We assume ethanol feedstock is corn since there is a facility in Quebec that processes corn ethanol and imports are assumed to be corn ethanol.

Assumptions for the Atlantic region

1. Gasoline volumes are based on Statistics Canada energy supply and demand data (Table: 25-10-0029-01, energy use, final demand).

2. Diesel volumes are based on Statistics Canada energy supply and demand data (Table: 25-10-0029-01, energy use, final demand).

3. Ethanol and biomass-based diesel volumes are uncertain and should be used with caution: They are estimated based on the difference between federal data reported by ECCC (or industry contacts) and total biofuel content collected for the other provinces. That difference is allocated to Québec and the Atlantic Provinces, pro-rating by population. Newfoundland and Labrador is excluded from the calculation since we have good confidence that very little biofuel is consumed there.

4. We assume ethanol is from corn and biodiesel is from unknown feedstock to better align with ECCC national feedstock values.

Detailed Feedstock Results

Based on the assumptions outlined above, the feedstocks used to produce biofuels sold in Canada were estimated and summarized in Figure 20 and Figure 21. Figure 20 shows the renewable fuel content in the diesel pool in Canada from 2010 to 2019, with an estimate for 2020. The volume of fuel is shown by fuel type and feedstock: most biodiesel is from canola and soy, most HDRD is from palm oil by-products and tallow. Figure 21 shows the renewable fuel content in gasoline pool in Canada from 2010 to 2019 by fuel type and feedstock, with an estimate for 2020: most ethanol consumed in Canada is produced from corn, with 10-15% produced from wheat.

Figure 26: National results for renewable fuel consumption of diesel pool by fuel type and feedstock

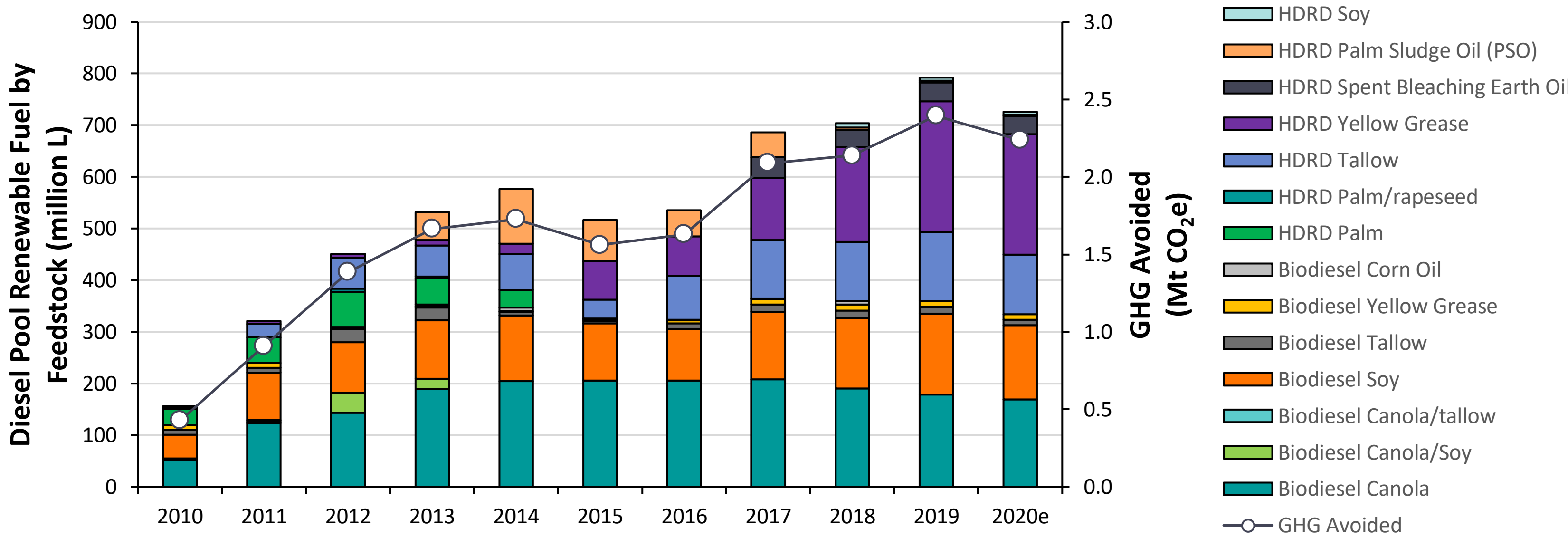
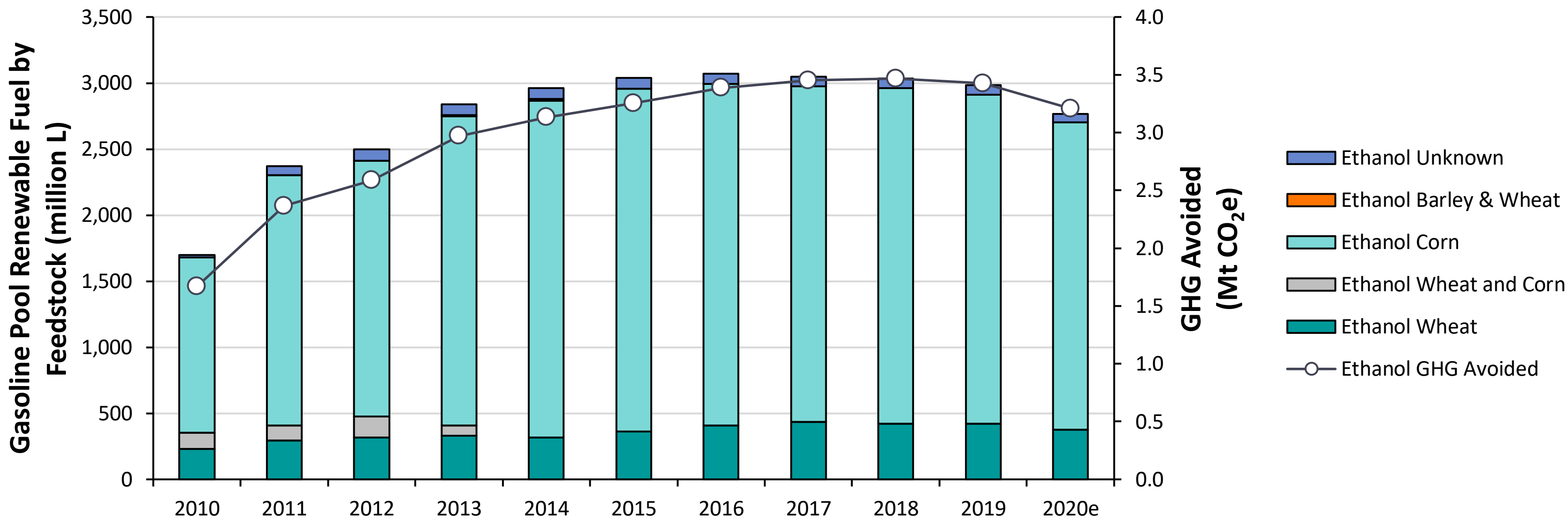


Figure 27: National results for renewable fuel consumption for gasoline pool by fuel type and feedstock



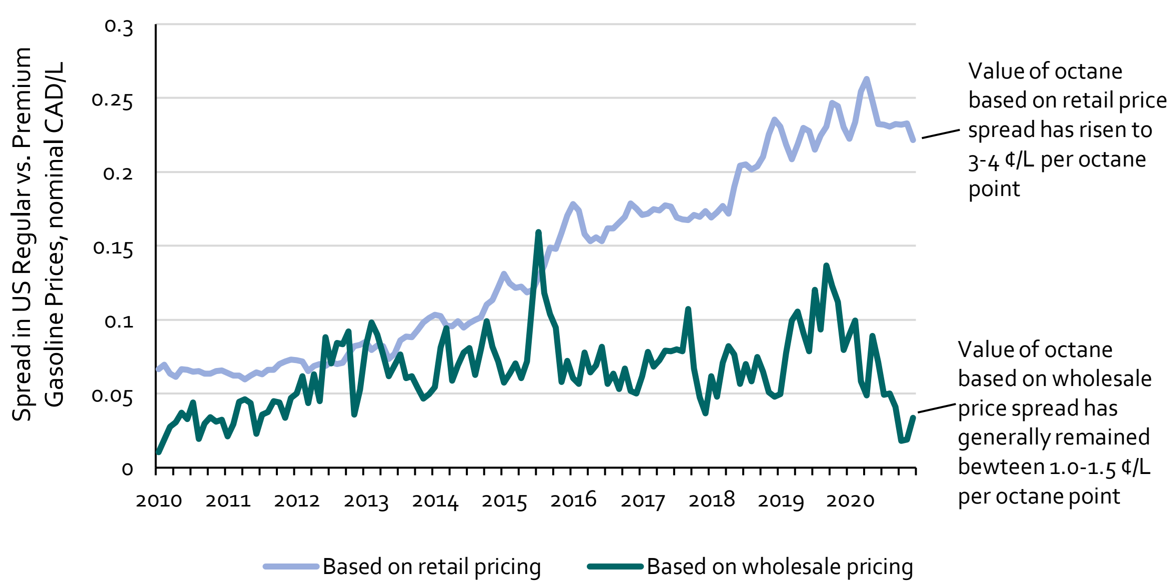
Appendix C: Change to Cost Analysis Methodology

Using Wholesale Instead of Retail Prices to Estimate Octane Value

In previous years of the Biofuels in Canada analysis, the spread in retail prices between regular and premium gasoline was used as a proxy for the cost of increasing octane using a process other than ethanol blending. This assumption is key to the cost analysis – it determines how much additional cost would have been required to meet an octane value of 87 in regular gasoline had ethanol not been available.

Historically, retail and wholesale price spreads between premium and regular gas have been similar. However, since 2016 this spread has been gradually increasing, inflating the estimate for cost savings from the high blending octane of ethanol. For this year's report, we've shifted to using wholesale, rather than retail, price data to estimate the cost of octane. A comparison between the two is presented below.

Figure 28: Value of octane measured using retail and wholesale prices[77]



[77] United States Energy Information Agency, http://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm

This methodological change results in a nearly \$300/tCO_2e increase to the abatement cost of using ethanol, though the estimate remains below zero (i.e., it still reduces emissions and prices).

Using wholesale, rather than retail prices, aligns our assumption for the value of octane in similar analyses that have been done in the U.S. and Mexico. Working for the U.S. EIA, consultants at Baker and O'Brien Inc. presented an engineering approach to the cost of octane by estimating the cost of using a catalytic reformer to increase the octane of gasoline.[78] That approach yields very similar results to our method of using the spread in U.S. wholesale prices, which is a lower cost than the value of octane implied by retail prices.

Similarly, a cost-benefit analysis of moving from MBTE to ethanol in Mexico used a similar approach to ours, taking the spread between regular and premium blendstock prices (as opposed to finished gasoline prices). That method results in a value of octane of about 0.9 cents per point per litre, similar to the average value of 1.3 cents per litre used in this report (also much lower than the value implied by the retail price spread).[79]

Assuming Premium Gasoline has an average Octane of 92, rather than 93

Paired with the difference in octane between regular and premium gasoline, the regular-premium price spread (discussed above) is used to estimate the refining/blending cost of increasing octane by one point. Our approach uses the formula below:

$$\text{Average Octane Cost (\$/L-ptAKI)} = \frac{\text{Price}_{\text{premium}} - \text{Price}_{\text{regular}}}{\text{AKI}_{\text{premium}} - \text{AKI}_{\text{regular}}}$$

"Regular" gasoline is generally agreed in North America to have an AKI rating of 87. Premium gasoline is more ambiguous – the EIA wholesale price data used in this report defines premium as having an AKI of "greater than 90". In some states, 93 is typical; 91 is typical in others. Past versions of this analysis have used 93, which results in a lower cost estimate per point of octane. This year's report used 92 to

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[78] Baker and O'brien Inc. (2018), Analysis of Gasoline Octane Costs, prepared for EIA: https://www.eia.gov/analysis/octanestudy/pdf/phase1.pdf

[79] Turner, Mason & Company, Mexico Fuel Ethanol Cost Benefit Analysis Study, May 2020

reflect a more realistic estimate of the octane of the fuels represented in the premium price data.

Using Renewable Diesel Pricing Estimates from Diamond Green, Rather than Neste

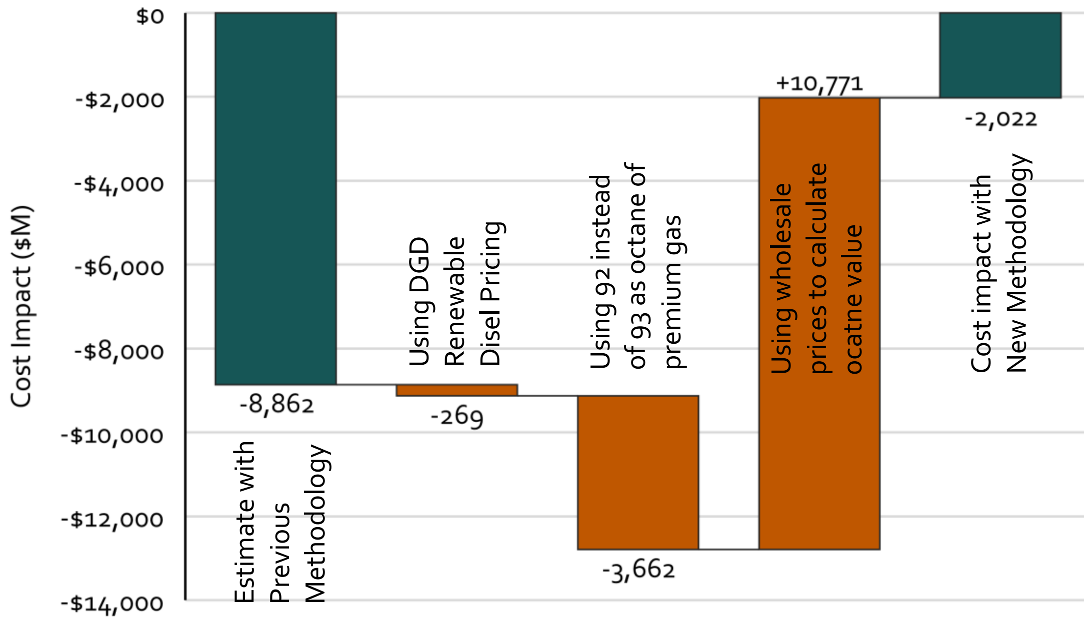
Previous years of the Biofuel in Canada report have estimated the cost of HDRD using investor materials published by Neste, which reflect all their global sales. Industry contacts critiqued this method, saying that it may over-state the average cost of HDRD because a substantial portion of Canadian HDRD is imported from the United States, where it is subject to a $1USD/gallon biomass-based diesel blenders tax credit, even if the fuel is exported.

Darling Ingredients, the parent company of Diamond Green Diesel, publishes equivalent financial materials to Neste, presenting revenue and sales volumes from their renewable diesel business segment, which are inclusive of the tax credit. This year's report used these numbers to estimate the price of HDRD in Canada for the 2016-2020 years (Neste data was used in previous years, where the DGD data is not available).

Net and Gross Impacts of the Methodology Change

The three changes to the methodology of the biofuels in Canada analysis are shown in Figure 29 below.

Figure 29: Changes to the cost analysis methodology in this year's report, shown by their individual impact on the cumulative cost impact (2010-2019)



The changes to this year's methodology present a less favourable, but we think more accurate, depiction of the impact of biofuels on Canadian fuel costs. The cumulative cost savings resulting from biofuel blending in Canada from 2010-2019 are $2 billion rather than $8.9 billion. Using wholesale rather than retail prices to estimate octane value increased costs by $10.8 billion, while using Diamond Green data for HDRD pricing and using 92 as the octane rating for premium gasoline presents smaller offsetting cost benefits ($269 million and $3.7 billion respectively).

Appendix D: Co-processed Fuel Methodology

Starting in 2019, co-processed renewable fuels, produced at the Parkland refinery in Burnaby, were consumed in BC. Currently, there is no data describing the volume or GHG impact of this fuel consumption. However, based on public statements and documents, we have estimated these quantities.

The 2020 Parkland sustainability report[80] states that in 2019, co-processed fuels had a GHG impact equivalent to taking 15,000 "vehicles off the road". That same report indicates that the co-processed fuel has 1/8 the carbon intensity of fossil fuels. Furthermore, a 2021 news article in the Oil and Gas Journal indicates that co-processing increased by 140% from 2019 to 2020 and is forecast[81] to rise by 125% from 2020 to 2021.

The following assumptions allow us to estimate the volume and GHG impact of the co-processed fuel, summarized in Table 13:

- Gasoline CI of 93 g/MJ, co-processed fuel CI of 12 (eight times lower)
- 4.6 tCO_2e avoided per vehicle "off the road", as per the commonly used US Environmental GHG equivalency[82]
- A 50/50 split of resulting renewable fuel between gasoline and diesel fraction, with a resulting average energy density of 36.5 MJ/L

Table 13: Estimate of renewable Co-processed fuel production/consumption in BC

Year	% increase from prev. yr	"Vehicles off the road"	GHG avoided, tCO_2e/yr	Implied energy in co-processed fuel, GJ/yr	Implied volume of co-processed fuel, million L
2019	-	15,000	69,000	850,670	23
2020	140%	36,000	165,600	2,041,609	56
2021	125%	81,000	372,600	4,593,620	126

80 Parkland (2020). Safety, Integrity, Community, Respect. Inaugural Sustainability Report

81 Oil and Gas Journal (2021). Parkland Fuel's Burnaby refinery to expand renewables coprocessing

82 US Environmental Protection Agency (2021). Greenhouse Gas Equivalencies Calculator

Appendix E: Electric Vehicle Analysis Methodology

This year's report contains estimates for how electric vehicle adoption to date has affected fuel consumption and lifecycle GHG emissions from transportation.

1. The primary data for this analysis is from Statistics Canada data for total motor vehicle registrations by province (i.e. cars on the road) and new motor vehicle registrations by province (i.e. cars sold that year) (tables 23-10-0067-01 and 20-10-0021-01). Table 20-10-0021-01, *New Motor Vehicle Registrations*, disaggregates vehicles by whether they were hybrid, plug-in hybrid, or battery electric (collectively called PEVs).
2. Certain provinces were missing PEV sales data (the "Canada" field was greater than the sum of the provinces for which data was available). These data gaps were filled by pro-rating the vehicles of unknown origin to the provinces with no data based on their populations. This adjustment affects only 3% of PEV sales.
3. Energy consumption of electric vehicles was estimated using the following assumptions:
   a. All EVs sold since 2010 are still on the road today. Stock is equal to cumulative sales.
   b. There is no net interprovincial trade of PEVs or imports of used PEVs– for example, the BC stock is equal to cumulative sales in BC alone.
   c. Electric vehicles are driven the same amount as gas cars (about 15,000 km/year).
   d. EVs use 20 kWh per 100km and PHEVs have a utilization factor of 69% (this fraction of the vehicles energy is from electricity, the rest is from gasoline)[83].
   e. EVs have an energy efficiency ratio of 4.1, reflecting the difference in efficiency between electric and internal combustion engines.

[83] The International Council for Clean Transportation, 2020, Real-World Usage Of Plug-In Hybrid Electric Vehicles Fuel Consumption, Electric Driving, And CO2 Emissions.

The following formula is used to estimate displaced gasoline consumption which also defines the avoided GHG abatement:

Displaced Gasoline (GJ/year) = Stock (vehicles)
∗ kilometers/year (km/vehicle-year) * fuel efficiency (kwh/km) * EER (GJ/GJ)*3.6

4. Finally, to estimate forgone emissions due to electric vehicles, the average carbon intensities of electricity by province and year from Canada's 2021 National Inventory Report are used. Theses direct carbon intensities are supplemented by "upstream" lifecycle GHG emissions factors that are based on the difference between the direct carbon intensities in the National Inventory Report for 2019 and the lifecycle carbon intensities for electricity noted for each province in the *Clean Fuel Regulation* draft legislation[84] in schedule 5, point 8 (e.g. to account for fuel production emissions, methane emissions from hydro reservoirs etc.)

[84] Government of Canada, Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations