Biofuels in Canada 2022

Tracking biofuel consumption, feedstocks and avoided greenhouse gas emissions

October 27th, 2022

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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 plug-in electric vehicles (PEVs).
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

This year the volume and GHG impact of renewable co-processed fuels is based on data from the government of British Columbia. As well, this edition of Biofuels in Canada contains a new analysis indicating the extent to which current renewable fuel consumption would satisfy the requirements of the upcoming *Clean Fuel Regulations*. As well, the analysis includes some key methodological improvements made in the previous editions:

- Renewable fuel volumes, CIs, and avoided GHG emissions are estimated for 2021.
- The value of octane is estimated from wholesale gasoline prices rather the retail prices.
- National gasoline and diesel consumption is based on Statistics Canada Data energy data rather than the Supply and Disposition of Petroleum Products tables.

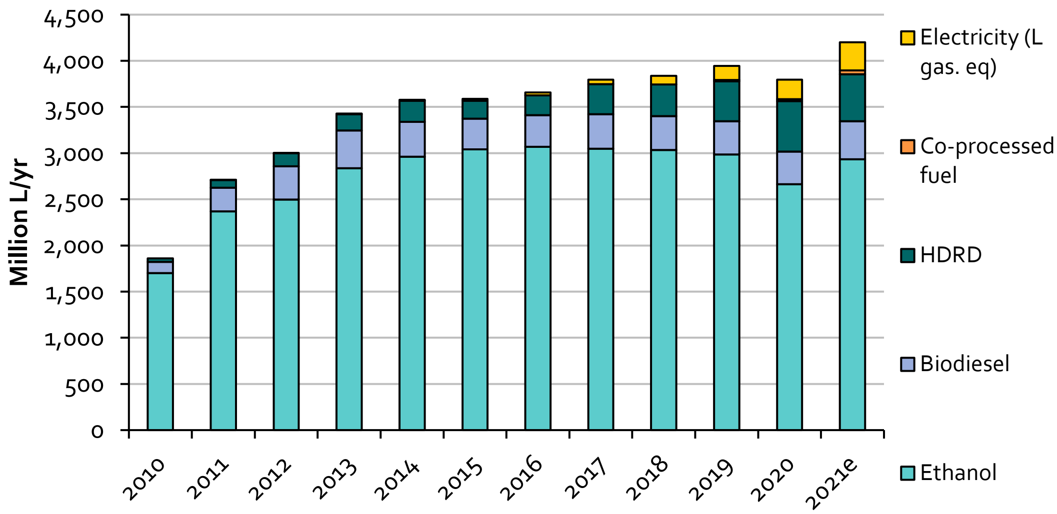
- HDRD prices from 2015 onward are based on data from Diamond Green Diesel's financial reports, rather than from Neste's financial data.
- Tax rates used in the cost impact calculations now change by fiscal year rather than calendar year.

Fuel Consumption

The data obtained from provincial and federal government sources shows that renewable content in gasoline and diesel pools has increased from 2010 to 2020, though volumes declined somewhat in 2020 relative to previous years due to the reduction in overall fuel consumption during the COVID pandemic (-6% in 2020 relative to 2019).

The volume of ethanol consumed in Canada each year has increased from roughly 1,700 million L/yr in 2010 to 2,665 million L/yr in 2020. However, ethanol consumption in 2020 declined by over 300 million L/yr relative to 2019 (-11%), again due to less gasoline consumption during COVID (Figure 1). Biomass-based diesel consumption actually increased during the pandemic, rising by more than 100 million L/yr (13%) relative to 2019, with total consumption reaching almost 900 million L/yr (Figure 1). Growth in HDRD consumption continued to drive the increase in biomass-based diesel while biodiesel consumption remained relatively constant from 2019 to 2020. Consumption of co-processed fuels, where renewable feedstock is refined with fossil crude oil, grew to 20 million L/yr in 2020, with that consumption occurring only in British Columbia. Meanwhile, in 2020, PEVs displaced the equivalent of 212 million L/yr of gasoline (Figure 1).

Figure 1: Renewable and low-carbon transportation energy consumption in Canada, with estimate for 2021

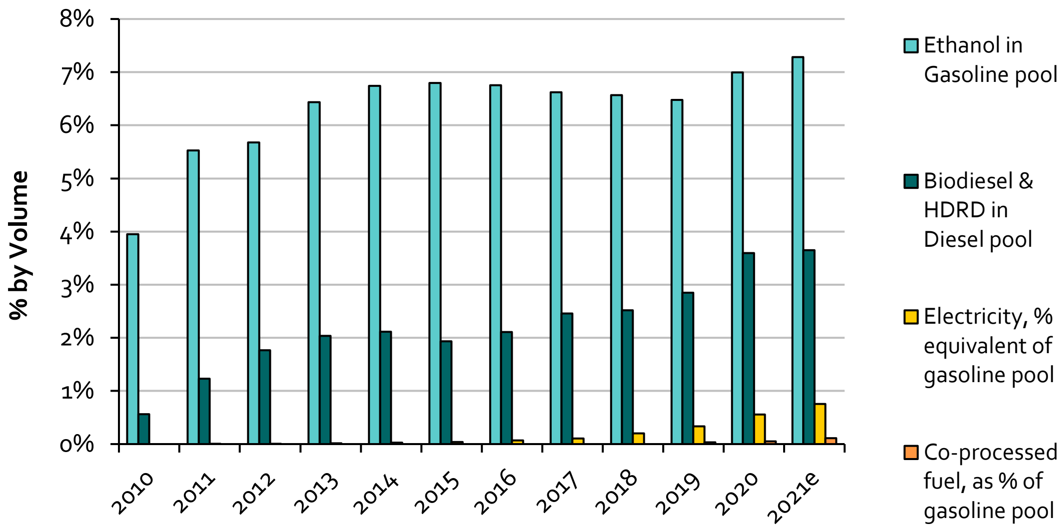


Although ethanol consumption declined in 2020, gasoline consumption declined proportionally more. Consequently, the blend rate of renewable fuels in gasoline increased to 7% by volume in 2020, up from about 6.5% in 2019 (Figure 2). The fraction of Biodiesel and HDRD in diesel increased to 3.6% in 2020, up from 2.9% in 2019 (Figure 2).

Our estimate for 2021 shows a rebound in ethanol consumption to pre-pandemic levels and additional growth in biomass-based diesel consumption. In that year, estimated blend rates reach a new high of 7.3% in gasoline and 3.7% in diesel (Figure 2). These blending rates are in excess of what is required by the *Renewable Fuels Regulations* and indicate that fuel suppliers may not need to take any additional action to comply with the *Clean Fuel Regulations* until the third compliance period in 2025.

Co-processed fuel accounted for a volume equivalent of about 0.1% of the gasoline pool, while light-duty PEVs offset a quantity of fuel consumption equivalent to about 0.5% of the gasoline pool (Figure 2).

Figure 2: Renewable fuel content by fuel pool, with estimate for 2021



Lifecycle GHG Emissions

Based on lifecycle carbon intensities reported by government contacts, government compliance reporting, and GHGenius 4.03a, renewable fuel consumption and light-duty PEVs have avoided 60 Mt CO_2e between 2010 and 2020. Despite lower overall biofuel consumption in 2020 due to the pandemic, annual avoided GHG emissions from increased slightly to about 5.9 $MtCO_2e$/yr from 2019 to 2020, while emissions avoided by light-duty PEVs increased to 0.6 $MtCO_2e$/yr.

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 2020 than it would have in 2010.

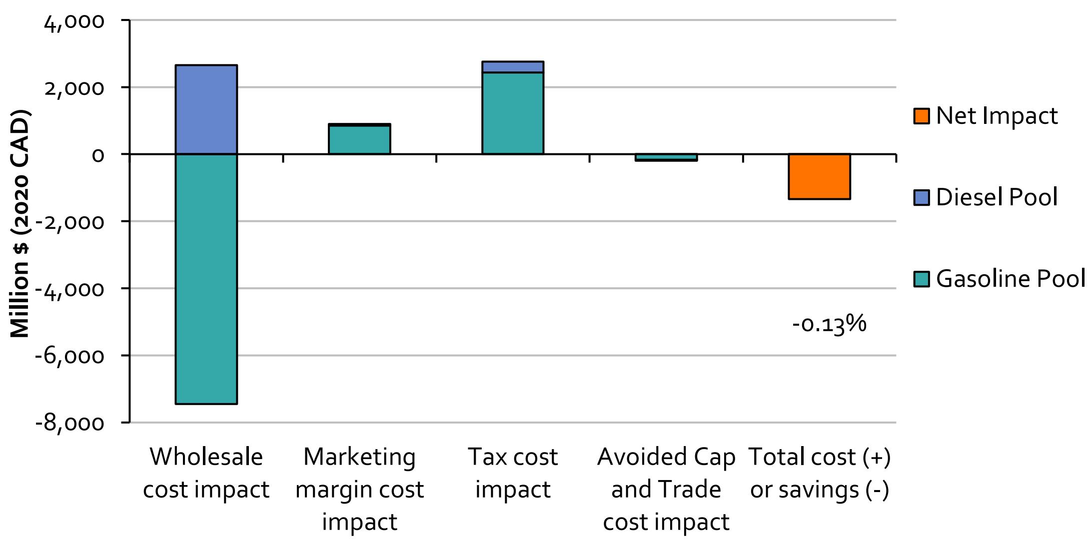
Cost Analysis

Figure 3 shows the cumulative consumer cost impact, by component, resulting from biofuel consumption between 2010 and 2020. 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 meaning refiners normally 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 $1.3 billion over eleven years (2020 CAD), or -0.13% of total gasoline and diesel pool expenditures.

Figure 3: Cumulative cost impact resulting from ethanol blending in the gasoline pool and biomass-based diesel blending in the diesel pool (2010-2020), total % change in data label



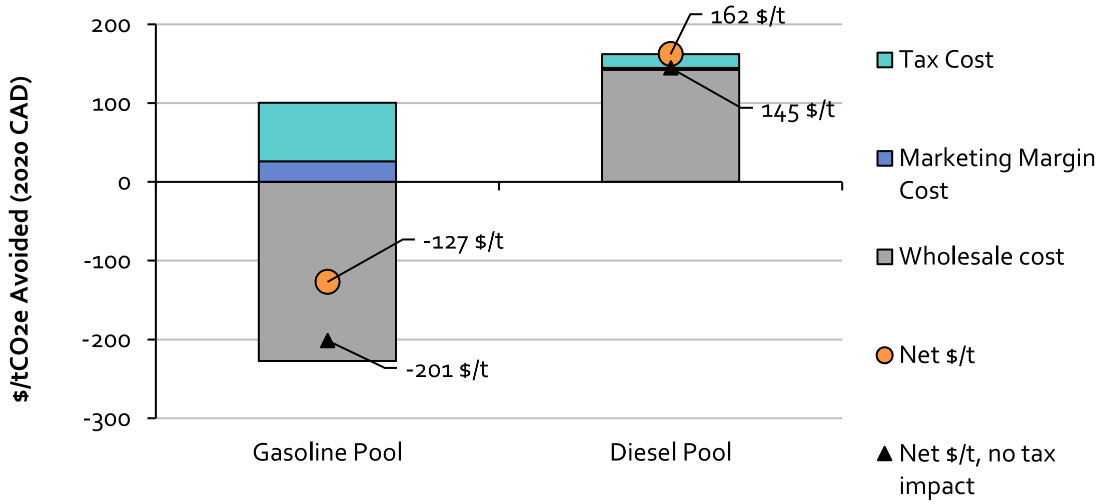
The total cost impact has a component related to wholesale fuel costs, where, in the case of gasoline, the octane value of ethanol reduces wholesale fuel costs. The total cost also has components related to tax costs and distribution costs that exist because of the differences in energy density between 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) exacerbate the additional tax charge on fuels with lower energy density because they are applied on the 'tax in' fuel price. Nonetheless, because blended gasoline can have a lower per litre retail price than unblended gasoline in a "counterfactual" scenario without biofuels, our analysis suggests that the absolute amount of sales tax paid can be lower when gasoline is blended. In jurisdictions like Ontario, where there is a high sales tax tied to actual retail value (i.e. 13% HST), the savings on the sales tax impact may outweigh the increases due to federal and provincial fuel taxes.

Consequently, consumers generally pay more taxes per kilometer driven when using biofuel blends. In 2020, 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 2.3% more taxes per kilometre than when using E0 (i.e. pure gasoline). Similarly, a heavy-duty vehicle driver will pay an additional 0.7% more taxes per kilometre when using diesel with 5% biodiesel (i.e. B5) than when using B0 (pure fossil diesel). Canadians have paid an additional $2.7 billion in taxes from 2010 through 2020 as a result of renewable fuel blending (Figure 3).

Figure 4 shows the cumulative consumer cost divided by the cumulative avoided GHG emissions from 2010-2020 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 -$127/t$CO_2$e versus $162/t$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, based on average kilometers driven per year, renewable fuel consumption in Canada has saved a typical gasoline consumer (based on a typical light-duty vehicle) $9/yr (-0.4%), whereas it has cost a typical diesel consumer (based on a long-distance truck operator) an additional $255/yr (+0.7%).

Figure 4: GHG abatement cost, 2010-2020



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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 these policies and their impact.

Environment and Climate Change Canada 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 low-carbon fuel policies in Canada. These policies drive the supply and consumption of biofuels or renewable fuels, terms that are used interchangeably in this report to describe low-carbon transportation fuels in Canada. The impact of these policies is estimated by quantifying the annual volumes of biofuels consumed in individual provinces and nationally from 2010 to 2020, the most recent year for which data is available (with estimates for 2021). 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. For context, the analysis also includes an estimate of how the growing fleet of light-duty plug-in electric vehicles (PEVs) 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, 2022-10-27"). The results in this spreadsheet are shown for Canada as whole and for 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 2022 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 final Canadian *Clean Fuel Regulations* (CFR). Throughout this report, fuel 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* (RFR) 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 gasoline and diesel 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 July 2022, the Government of Canada published the final *Clean Fuel Regulations* (CFR), based on similar policies already implemented in British Columbia and California.[1] Although this policy is a CI-based standard, it replaces the RFR, which will be repealed as of December 31, 2022, and retains the same minimum required blending rates. Sections 6 and 7 of the CFR adopted the same volumetric requirement for low CI fuels (5% for gasoline, 2% for diesel), while expanding the types of eligible alternative fuels to be any 'low carbon intensity fuel' recognized under the regulation.[2]

[1] Government of Canada, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

[2] Ibid.

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 renewable fuel content (typically 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, are not regulated under the new federal CFR policy (the Territories, as well as other regions north of 60 degrees latitude are exempt from the current RFR). As described in the following sub-section, the Ontario *Cleaner Transportation Fuels* regulation prescribes the biofuel content in diesel or 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	2022
British Columbia	5.0%	5.0%	5.0%	5.0%	5.0%
Alberta	-	5.0%	5.0%	5.0%	5.0%
Saskatchewan	7.5%	7.5%	7.5%	7.5%	7.5%
Manitoba	8.5%	8.5%	8.5%	9.25%	10%
Ontario	5.0%	5.0%	10%	10%	10%
Canada	-	5.0%	5.0%	5.0%	5.0%

Some regions in Canada are not yet subject to any provincial or territorial gasoline biofuel blending policies. However, with the exception of Newfoundland and Labrador, they are still regulated under the federal RFR and CFR policies. 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 CI 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	2022
British Columbia	3.0%	4.0%	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%	2.0%
Sask.	-	-	2.0%	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%	5.0%
Ontario	-	-	-	2.0%	3.0%	4.0%	4.0%	4.0%
Canada	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

As with gasoline regulations, 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.

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

British Columbia

The British Columbia *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.

Alberta

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.[3] However, Alberta's policy also specifies that the CI of the renewable content must be 25% lower than the corresponding CI of gasoline and diesel. In practice, most biofuels

[3] Government of Alberta, Renewable Fuels Standard Regulation

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 and HDRD in that province ranged from about 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.

Saskatchewan

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.[4] Saskatchewan also has *The Renewable Diesel Act* that started on July 1, 2012 mandating 2% renewable fuel by volume in diesel pools.[5]

Manitoba

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 mandated 8.5% renewable content by volume in gasoline since January 1, 2008, 9.25% as of 2021, and 10% as of 2022.[6] The biodiesel policy required 2% biodiesel by volume through 2020, rising to 3.5% in 2021 and 5% in 2022.[7]

Ontario

Ontario previously had the *Greener Gasoline – Bio-Based Content Requirements for Gasoline*[8] regulation mandating 5% ethanol content in gasoline, which was increased to a CI-adjusted requirement of 10% by volume beginning in the 2020. Suppliers must

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[4] Government of Saskatchewan, The Ethanol Fuel Act, The Ethanol Fuel (General) Regulations

[5] Government of Saskatchewan, The Renewable Diesel Act

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

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

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

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*[9], which combines the *Greener Gasoline* and *Greener Diesel* regulations.

Like the previous regulations, the *Cleaner Transportation Fuels* regulation set requirements for a CI-adjusted bio-based fuel (e.g. ethanol) blend rate of 10% in 2020-24, 11% in 2025-27, 13% in 2028-29, and 15% in 2030 (summarized in Table 3). For example, between 2020 and 2024, the regulation requires 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) (Table 4 and Figure 5). 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 fuel is used, a higher blend rate would be required to achieve compliance (Figure 5). Similarly, by 2030, the policy requires a 15% volumetric blend rate if the weighted average CI of the bio-based content is 42 gCO_2e/MJ (45% below a benchmark CI for gasoline). Volumes of renewable fuel may be transferred between the regulated parties, presumably bought and sold, to effectively allow compliance credit trading. 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 rating (AKI) of 89 or greater (i.e. typically mid-grade and premium gasoline).

Table 3: Volumetric low-carbon renewable fuel blending requirements in Ontario

	2020	2020-2024	2025-2027	2028-2029	2030
In gasoline	5%	10%, CI adjusted	11%, CI adjusted	13 %, CI adjusted	15%, CI adjusted
In diesel	4%, CI adjusted (no change to 2030)				

Table 4: Threshold CI values where required blending rate = actual blending rate in Ontario, gCO_2e/MJ (based on GHGenius 4.03 a or b)

	2020	2020-2024	2025-2027	2028-2029	2030
In gasoline	Any	45.9	45.9	45.9	41.7
In diesel	27.6				

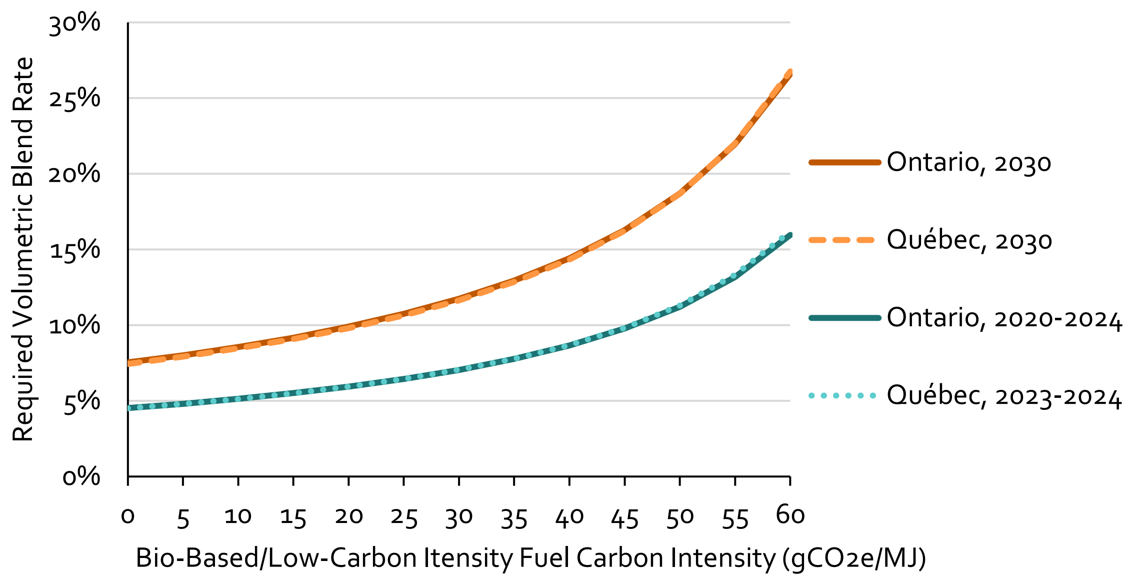
Along with the ethanol regulation, the *Greener Diesel Regulation* was also repealed and replaced with the *Cleaner Transportation Fuels* regulation. The new regulation maintains the standard from the *Greener Diesel Regulation* which requires 4% biofuel

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

blend subject to the weighted average CI of the biofuel, which must be at least 70% below the reference CI for diesel fuel. For context, the average reported CI of biodiesel sold in Ontario in 2020 was 6.14 gCO_2e/MJ (about 93% lower than diesel), which would require a 3% blend rate (Figure 6).

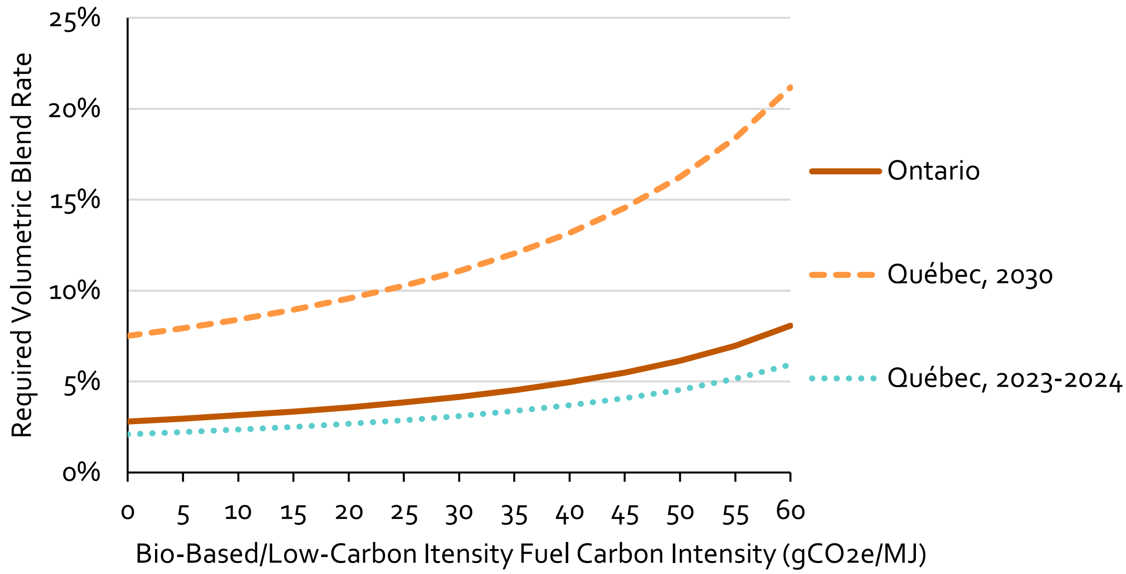
To allow some compliance flexibility during the COVID-19 pandemic, the Ontario Ministry of Environment merged the 2020 and 2021 compliance periods, meaning fuel suppliers could achieve compliance by blending at a rate above the standard in 2021 if they were to fall below the standard in 2020 (or vice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

Figure 5: Volumetric blend rates of renewable fuel **in gasoline** required to comply with the Ontario and Québec regulations prior to 2025 and in 2030



Note: Similar curves exist for 2025-2027 and 2028-2029 in both provinces. The volumetric blend rates **in gasoline** apply to the regulated fuel pool (i.e. net of exclusions for fuel consumed in some geographic areas, premium gasoline in Québec and mid-grade and premium gasoline in Ontario etc.)

Figure 6: Volumetric blend rates of renewable fuel **in diesel** required to comply with the Ontario regulation and the Québec regulation prior to 2025 and in 2030



Note: A similar curve exists for Québec for 2025-2027 and 2028-2029. The volumetric blend rates **in diesel** apply to the regulated fuel pool (i.e. net of exclusions for fuel consumed in some geographic areas)

Québec

Québec finalized a provincial fuel blending policy in December 2021. As of January 1st 2023, this policy requires 10% low-carbon fuel content in gasoline, rising to 12% in 2025, 14% in 2028 and 15% in 2030 (Table 5). The diesel blending requirement begins at 3% low-carbon fuel content in 2023, rising to 5% in 2025 and 10% by 2030 (Table 5).[10] The policy excludes premium gasoline, heating oil, and fuel used for air, marine and rail transport. It also excludes fuel consumption in northern and far-eastern Québec (other areas are also excluded for 2023, the first year that the policy will be in force). It permits buying and selling compliance credits between the regulated parties as well as banking up to 20% of any overcompliance for use in the following year. Overcompliance in the diesel pool can be used for compliance in the gasoline pool on a one-to-one volume basis. Overcompliance in the gasoline pool may be used for compliance in the diesel pool, but that volume is discounted by two-thirds (i.e. one litre beyond what is required in the gasoline pool only counts for 1/3 of a litre of in the diesel pool).

[10] Gouvernement du Québec, 2021, Regulation respecting the integration of low-carbon-intensity fuel content into gasoline and diesel fuel.

Table 5: Volumetric low-carbon renewable fuel blending requirements in Québec

	2023-2024	2025-2027	2028-2029	2030
In gasoline	10%, CI adjusted	12%, CI adjusted	14 %, CI adjusted	15%, CI adjusted
In diesel	3%, CI adjusted	5%, CI adjusted (2025 through 2029)		10%, CI adjusted

Table 6: Threshold CI values where required blending rate = actual blending rate in Québec, gCO_2e/MJ (based on GHGenius 4.0c)

	2023-2024	2025-2027	2028-2029	2030
In gasoline	45.7	45.7	41.9	41.9
In diesel	27.9	27.9	23.2	23.2

As in Ontario, the actual volumetric blend rate of renewable fuels will be a function of the CI of those fuels. The actual blend rate in gasoline in 2030 will be equal to the regulated value, 15%, only if the average weighted CI of the renewable fuel is about 42 gCO_2e/MJ (50 % lower than reference gasoline CI) (Table 6, Figure 5). The blend rate in gasoline could be less than 10% by volume in 2030 if the average weighted CI of the renewable fuel is less than 21 gCO_2e/MJ (Figure 5). Similarly, the required blend rate in diesel in 2030 will be equal to the regulated value, 10%, if the average CI of the blended fuels is about 23 gCO_2e/MJ (75% lower than reference diesel CI) (Table 6). More typical average CI scores for biomass-based diesel around 10 gCO_2e/MJ would require a blend rate closer to 8.4% (Figure 6).

Because Québec is a large fuel market, this regulation will substantially affect renewable fuel consumption in Canada. By 2024, when most fuel consumption in Québec is covered by the policy, the 10% blending rate in gasoline might require roughly 670 million L of ethanol consumption in Québec (or other bio-based gasoline), equivalent to about 23% of current national ethanol consumption. The 3% biomass-based diesel blending requirement might require about 180 million L of renewable fuel, equivalent to about 20% of current Canadian consumption of these fuels.[11] This fuel consumption may not be completely incremental to what would have happened without the new regulation as it will overlap with the CFR. However, this policy will nonetheless produce a step-change in Canadian renewable fuel consumption.

Meanwhile, Québec is also aiming to support biofuel production in the province with a producer tax credit for biofuels and pyrolysis oil, both to start in 2023. Budget 2022-2023 proposes harmonizing all existing producer tax credits into a single program and extending the policy to 2033. The level of government financial assistance would be a

[11] Approximated based on estimated gasoline and diesel consumption in Québec in 2021, assuming 10% of each fuel pool is exempt with an ethanol CI of 40 gCO_2e/MJ and a biomass-based diesel CI of 10 gCO_2/MJ.

function of the fuel and its CI, ranging from 5-15 ¢/L for typical biofuels and 20-40 ¢/L for very low CI fuels provided the biofuels are consumed in-province.[12]

The Yukon

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.[13] Draft regulations have not yet been published.

2.2. Carbon Pricing

British Columbia Carbon Tax

The British Columbia (BC) carbon tax was introduced at \$10/tCO_2e in 2008 and increased to \$30/tCO_2e by 2012 and has since risen in multiple steps to \$50/tCO_2e as of April 1, 2022 (Table 7).[14] Each \$5/tCO_2e increment increased the tax on gasoline by 1.11 ¢/L and the tax on diesel by 1.28 ¢/L (Table 7).[15]

The tax rate on gasoline and diesel is based on emissions factors that approximate a 5% volumetric biofuel blending rate in the province (i.e. the tax is reduced by 5% to recognize biofuel blend components under the RLCFRR), resulting in a tax of 11.05 ¢/L on gasoline and 13.01 ¢/L on diesel as of autumn, 2022. 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

12 Finances Québec, 2022, Budget 2022-2023: Your Government Budget Plan.

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

14 Government of British Columbia, British Columbia's Carbon Tax

15 Ibid.

Roadmap to 2030 policy updated released October 25, 2021, proposes to 'align with or exceed federal requirements.[16]

Table 7: British Columbia carbon tax rates (nominal CAD)

	2012-2017	2018-2019	2019-2021	2021-2022	2022-2023
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	13.0

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.[17] Similar to British Columbia, 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 and 2% by volume biodiesel in diesel) (Table 8). However, unlike British Columbia, 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.[18] Consequently, as of 2020, gasoline and diesel purchases were subject to the federal carbon pricing backstop discussed below (also shown in Table 8, to 2021-2022).

Table 8: Alberta carbon levy rates on gasoline and diesel (nominal CAD)

	2017	2018 and early 2019	2020-2021 (federal backstop)	2021-2022 (federal backstop)
Gasoline, ¢/L	4.5	6.7	6.6	8.8
Diesel, ¢/L	5.4	8.0	8.1	10.7

Ontario Cap and Trade

The Ontario GHG emissions 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

16 Government of British Columbia, 2021, CleanBC Roadmap to 2030

17 Government of Alberta, Carbon Levy Rates

18 Government of Alberta, Carbon Tax Repeal

was cancelled later that year by the newly elected provincial government, and all trading was stopped on July 3rd, 2018.[19] 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 refined petroleum products (gasoline, diesel) they distributed when the cap was in effect; biofuels were not subject to the system. The credit price imbedded in 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.[20]

Québec Cap and Trade

The Québec GHG emissions cap and trade system began in 2013 and suppliers of transportation fossil fuels (gasoline, diesel) 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. The price floor began in 2013 at $10.75/tCO_2e$ (nominal CAD) and rises by 5% plus inflation each year to 2020.[21] The price floor is expected to continue growing at this rate.[22] The Québec system is linked with the California cap and trade program, so the minimum

[19] Financial Accountability Office of Ontario, 2018, Cap and Trade: A Financial Review of the Decision to Cancel the Cap and Trade Program

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

[21] Government of Québec, 2018, Québec cap-and-trade system for greenhouse gas emissions allowances (C&T): Technical Overview

[22] Government of Québec, 2022, The Carbon Market: Auctions

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[23] (Table 9).

Table 9: Québec cap and trade average annual credit settlement price and estimated price impact on gasoline and diesel (nominal CAD)

	2014	2015	2016	2017	2018	2019	2020	2021
Credit price, $/tCO_2e$	13.4	16.07	17.29	18.85	19.3	22.0	22.8	27.7
Gasoline, ¢/L	3.3	3.9	4.2	4.6	4.7	5.3	5.5	6.7
Diesel, ¢/L	3.6	4.4	4.7	5.1	5.2	6.0	6.2	7.5

Nova Scotia Cap and Trade

Nova Scotia's GHG emissions 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.[24] The Nova Scotia cap and trade quantification, reporting, and verification regulations specify that fuel suppliers do not have to purchase allowances for CO_2 emissions from biofuels.[25]

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.[26] If an auction settles above the floor price, a price adder is applied to the pricing formula to support cost recovery. This cap and trade credit price impact on

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[23]Government of Québec, The Carbon Market, Auction Proceeds Allocated to the Electrification and Climate Change Fund

And

California Air Resources Board, Summary of Transfers Registered in CITSS By California and Québec Entities in 2019, April 15 2020

[24] Government of Nova Scotia, 2020, Cap-and-Trade Program Regulations

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

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

ranged from 1.0 ¢/L to 1.2 ¢/L on gasoline and between 1.1 ¢/L and 1.3 ¢/L on diesel in 2020 and 2021.

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* (GGPPA) 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.[27]

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 ¢/L respectively in 2019, resulting in a net carbon price of only 2 ¢/L from April 2020 to April 2021. The net price impact has since risen to approximately 7 ¢/L with subsequent increases to the carbon tax rate.[28]

Table 10: New Brunswick carbon tax

	2020-2021	2021-2022	2022-2023
Carbon Tax rate, \$/tCO_2e	\$30	\$40	\$50
Gasoline Carbon Price (¢/L)	6.63	8.84	11.05
Gasoline, Change to Fuel Tax from 2019, ¢/L	-4.63	-4.63	-4.63
Gasoline, Net Carbon Price, ¢/L	**2.00**	**4.21**	**6.42**
Diesel Carbon Price (¢/L)	8.05	10.73	13.41
Diesel, Change to Fuel Tax from 2019, ¢/L	-6.05	-6.05	-6.05
Diesel, Net Carbon Price, ¢/L	**2.00**	**4.68**	**7.36**

Newfoundland and Labrador

In 2019, Newfoundland and Labrador also implemented a carbon tax that satisfied the fuel charge requirements of the federal backstop under the GGPPA. As in New Brunswick, the tax does not apply to heating oil and its implementation occurred in conjunction with a reduction in other fuel taxes. However, these were a removal of the temporary taxes that had been implemented to stabilize provincial finances. A 4 ¢/L

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

28 Ibid.

gasoline tax and a 5 ¢/L diesel tax were removed,[29] bringing these provincial fuel taxes back to their 2015 values. As of fall 2022, the carbon price on gasoline and diesel is consistent with a $50/t$CO_2$e carbon price, about 11 ¢/L on gasoline and 13 ¢/L on diesel (Table 11).[30]

Table 11: Newfoundland and Labrador carbon tax

	2019-2021	2021-2022	2022-2023
Carbon Tax rate, $/t$CO_2$e	$20	$40	$50
Gasoline Carbon Price (¢/L)	4.42	8.84	11.05
Diesel Carbon Price (¢/L)	5.37	10.73	13.41

Prince Edward Island

Prince Edward Island's (PEI's) carbon tax came also into force in April 2019. Like other provinces, it excludes some off-road uses, for farming, fishing and aquaculture, as well as heating oil (and propane).[31] Current rates are consistent with a $50/t$CO_2$e carbon price, as per federal requirements (Table 12).[32] While reductions in other fuel tax rates do not exactly coincide with changes to the carbon pricing on gasoline and diesel, the provincial fuel tax on gasoline has been reduced by 4.6 ¢/L since 2019, while the provincial fuel tax on diesel has been reduced by 6.0 ¢/L since 2019.[33]

Table 12: PEI carbon tax

	2019-2020	2020-2022	2022-2023
Carbon Tax rate, $/t$CO_2$e	$20	$30	$50
Gasoline Carbon Price (¢/L)	4.42	6.63	11.05
Diesel Carbon Price (¢/L)	5.37	8.05	13.41

[29] Government of Newfoundland and Labrador, 2018, Provincial Government Releases Federally-Approved Made-in-Newfoundland and Labrador Approach to Carbon Pricing

[30] Government of Newfoundland and Labrador, 2022, Provincial Carbon Tax Rates

[31] Government of Prince Edward Island, Carbon Levy Exemptions and Carbon Levy Rates

[32] Ibid.

[33] NRCAN, Fuel Consumption Taxes in Canada

Federal Carbon Pricing Backstop

The GGPPA carbon pricing backstop applies directly 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 in 2019). 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. In this case, the backstop indirectly defines the minimum carbon prices used in these provincial policies.

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 has increased $10 annually to $50/tonne in 2022.[34] Starting in 2023, the price is scheduled to continue increasing by $15 annual until it reaches $170/tCO_2e$ in 2030.[35] The fuel charge rates shown in Table 13 account for the regulated volumetric renewable fuel content required in Canada: 5% in gasoline and 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.[36] As of 2022, the carbon levy rates are about 11 ¢/L on gasoline and 13 ¢/L on diesel. If the price follows the announced schedule, the rate will more than triple, increasing to about 38 ¢/L on gasoline and 46¢/L on diesel in 2030.

Table 13: Federal backstop carbon levy rates on gasoline and diesel blends up to E10 and B5 (nominal CAD)[37]

	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

34 Government of Canada, 2019, *Fuel Charge Rates*

35 Government of Canada, 2021, Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030

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

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

substantially as the carbon price increases. For example, once the carbon price reaches \$170/tCO_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. Note that the surtax in this example does not account for additional taxation that already accrues on biofuels due to their lower energy densities and the federal and provincial taxes that are applied by volume rather than per unit of energy. Based on estimated fuel consumption in 2021 (about 37 billion L of blended gasoline and 24 billion L of blended diesel) and assuming widespread E10 and B5 consumption, this policy design would have consumers pay an additional \$1.4 billion per year in 2030.

Table 14: 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
Gasoline, ¢/L	14.37	17.68	21.00	24.31	27.63	30.94	34.26	37.57
Diesel, ¢/L	17.43	21.46	25.48	29.50	33.53	37.55	41.57	45.59
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

2.3. Low-Carbon Fuel Standards

British Columbia Low-Carbon Fuel Requirement

The CI component of the British Columbia *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.[38,39]

[38] Government of British Columbia, BC-LCFS Requirements

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

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.

Nonetheless, electricity will likely be an important source of compliance credits, in addition to renewable fuels. The ministry responsible for the policy recently clarified which parties own the compliance credits produced from electricity supply. As of January 1st 2022, the credit generator is the party that supplied the electricity to vehicles through the final supply equipment (i.e. the charging station), so long as it can measure or accurately estimate the electricity consumption. Therefore, that party will either be an electric utility or a charging network operator. However, transit operators will continue to own and report credits from pre-existing electric transit vehicles (routes operating prior to January 1st 2021).[40]

The RLCFRR in British Columbia 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 covered by a "Part 3 Agreement". 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). The quantity of credit generation and the criteria to be met are determined in agreement between the ministry and the credit generator. Part 3 Agreement credits may be issued by the province for up to 25% of prior year compliance credit obligation in a given year. This additional source of compliance credits is a significant departure from the California LCFS regulatory design.

[40] British Columbia Ministry of Energy, Mines and Low Carbon Innovation, 2022, Information Bulletin RLCF-020, Part 3 Fuel Supplier and reporting requirements for electricity

The CleanBC Roadmap to 2030 proposes to modernize the RLCFRR including an increase in the CI reduction requirement, starting with analysis and consultations on a 30% reduction by 2030.[41] Communications from the ministry responsible for the policy indicate that this new CI reduction schedule will be communicated in fall 2022 and will take effect in January 2023. The ministry may also recommend increasing the 200 $/tCO_2e$ penalty for non-compliance to better align with the estimated cost of complying with the new CI schedule.

The Clean Fuel Regulations

The Canadian federal government has finalized a LCFS-style regulation called the *Clean Fuel Regulations* (CFR), previously referred to as the Clean Fuel Standard during regulatory development. Like the British Columbia RLCFRR and the similar California *Low Carbon Fuel Standard*, the CFR requires a reduction in the life-cycle CI of gasoline and diesel fuels. Similar regulations for gaseous and solid fuels were previously expected to be created along with the regulation on liquid fuels but were cancelled in December 2020.

The final version of the CFR was published in July 2022, and the following details are based on the final regulation.[42] The first compliance period with CI limits for gasoline and diesel is July 1st 2023 to December 31st 2023. The regulated CI target for gasoline and diesel fuels in 2030 is 81 gCO_2e/MJ for gasoline and 79 gCO_2e/MJ for diesel, 14 gCO_2e/MJ lower than a 2016 benchmark for the respective fossil fuels and equivalent to roughly a 15% reduction in CI. The initial 2023 compliance period requires a CI reduction of 3.5 gCO_2e/MJ. The emissions intensity limit is lowered by 1.5 gCO_2e/MJ annually until the limit is target is reached in 2030.

On December 31st 2022, the CFR will supersede the earlier *Renewable Fuel Regulations* though the CFR will maintain the same minimum blending rates for low CI fuels in both the gasoline and diesel pools (5% and 2% by volume, respectively). Any surplus RFR credits owned by obligated parties at the end of 2022 will automatically roll over into CFR credits for use in 2024. Credit generation from the RFR is based on a default CI and energy density for renewable fuels in gasoline and diesel (i.e. as if the fuels blended under the RFR were ethanol and biodiesel with CI scores of 59 gCO_2e/MJ and 35 gCO_2e/MJ).

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

[42] Government of Canada, 2022, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

Notably, the same volume of biofuels can simultaneously earn RFR and CFR credits, if the supplier is registered under the CFR credit and tracking system. The CFR has an 'early credit' generation period from June 21st 2022 (date of final regulation) to June 30th 2023. Therefore, in the second half of 2022, the 'RFR rollover' credits and 'CFR early generation' creates may be double counted: The same physical volume of biofuel can produce early CFR credits and surplus RFR credits that roll over as CFR credits, creating an additional incentive to blend biofuel in the second half of 2022.

Table 15 summarizes credit and debit generation during 2022 and 2023 related to fuel supply (credits may be generated in other ways, described below). In 2023, suppliers of gasoline and diesel will only generate debits (i.e. a compliance obligation) during the first compliance period, from July 1st 2023 to December 31st 2023 (row 1 in the table). In contrast, fuel suppliers may generate early credits from the date of the final regulation publication to the start of the first compliance period (June 21st 2022 to June 30th 2023) and regular credits during the first compliance period (rows 2 and 3 in the table). Finally, fuel suppliers may generate additional CFR compliance credits from any surplus RFR credits they hold at the end of 2022 (row 4 in the table).

Table 15: Fuel-based CFR credit and debit generation, 2022 and 2023, in the first and second half of each year (H1 and H2)

Credit/Debit type	2022		2023	
	2022, H1	2022, H2	2023, H1	2023, H2
1) Debits generated from gasoline and diesel supply				
2) Early credits generated from low-carbon fuel supply*				
3) Regular credits generated from low-carbon fuel supply				
4) Credits generated from overcompliance with RFR				

* for participants registered in the CFR credit and tracking system

Like the British Columbian and Californian LCFS policies, credits can be generated by blending renewable and low-carbon fuels into petroleum fuels (i.e., "compliance category 2" credits). The quantity of credit generation is a function of the reduction in fuel CI resulting from this blending. The CI of fuels is defined using a lifecycle approach similar to what is used in California and British Columbia, but calculated using a new lifecycle assessment modelling tool built for the CFR.[43]

[43] See The Fuel Life Cycle Assessment Model

Credits can also be generated by switching transportation energy consumption to other low-carbon alternatives including natural gas, electricity, and hydrogen (i.e., "compliance category 3"). While fuel producers and importers (i.e., the fuel suppliers) are required by the policy to reduce the CI of gasoline and diesel fuels, suppliers of the low-carbon alternatives (i.e., compliance category 2 and 3) can also generate and trade compliance credits. The credits generated by compliance categories 2 and 3 can also be sold to suppliers who supply liquid fuels to compliance category 1 or to any other party that generates credits.

There are some important constraints on the generation of credits from electric light-duty vehicles, primarily to reduce the long-term overlap of the CFR with other policies that will drive the adoption of these vehicles. First, charging network operators can only generate credits from residential charging stations if they were built prior to 2030. Second, there will be no credit generation from residential charging stations after 2035. Finally, charging network operators must reinvest the credit revenue they earned from residential and public chargers by reducing the cost of PEV ownership, or by investing in more public and residential chargers. Charging site hosts that generate credits from commercial vehicle charging are not constrained in this way.

Compliance credits can also be generated by parties that reduce GHG emissions related to petroleum fuel production, namely during oil extraction, upgrading, and refining (i.e., "compliance category 1"). For example, these actions include the integration of lower-carbon hydrogen inputs, integration of renewable energy, or the use of carbon capture and storage. These provisions significantly expand the pool of available credits compared to other LCFS-type programs in British Columbia and California.

Other options are available to increase the flexibility of compliance. In addition to credit trading and banking for future use, obligated parties may obtain up to 10% of their credits from CI reductions in gaseous fuels (i.e., by blending low-carbon gaseous fuels, with credits calculated in a similar lifecycle manner). Likewise, up to 10% of a supplier's deficit of compliance credits may be purchased for \$350/tCO_2e (plus an inflation factor) by contributing to an abatement or technology fund. Additionally, the previously mentioned credits for early actions from all compliance categories and overcompliance with the RFR may be generated in 2022 - 2023 and used at a later date. Finally, compliance credit shortfalls of up to 10% of the total value of debits (i.e., equivalent to 10% of the excess tonnes emitted) can be deferred into the subsequent five compliance periods, the quantity of deferred credits to "repaid" with future compliance growing at 5% annually.

Impact of Low-Carbon Fuel Standards on Retail Fuel Prices

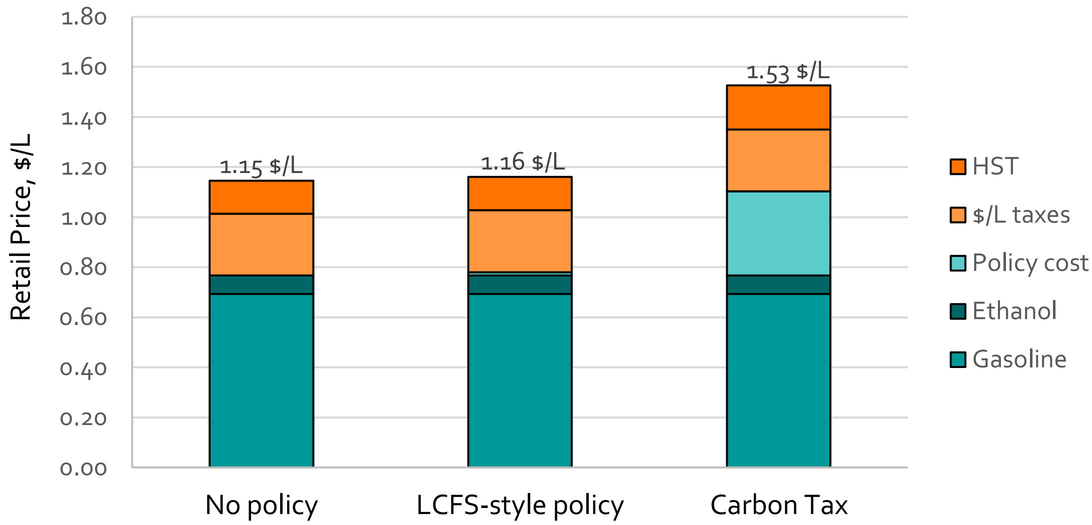
LCFS-style policies create a market-based incentive to supply low-carbon fuels because this action generates compliance credits which can be sold in their associated market. The price of credits will rise until it is high enough to incentivize fuel suppliers to comply with the policy. In a properly functioning 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 $/t$CO_2$e 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 where a subset of compliance credits might be purchased from the government).

Using the example of retail fuel prices that were typical in Ontario in 2021 and gasoline containing 10% ethanol by volume (E10), a LCFS policy with a credit price of 150 $/ t$CO_2$e and the same CI limit as the CFR in 2025 (88.5 gCO_2e/MJ) would result in an E10 price of 1.16 $/L versus 1.15 $/L without an LCFS. The net retail-price impact is about 1 ¢/L. In contrast, a carbon tax of 150 $/tCO2e would result in an E10 price of 1.53 $/L (Figure 7), with a net price impact of 38 ¢/L (34 ¢/L and 4 ¢/L in additional sales tax). Note that carbon tax revenue recycling is not considered here, though it could mitigate the cost impact for consumers if 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. In a competitive fuel market, 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.

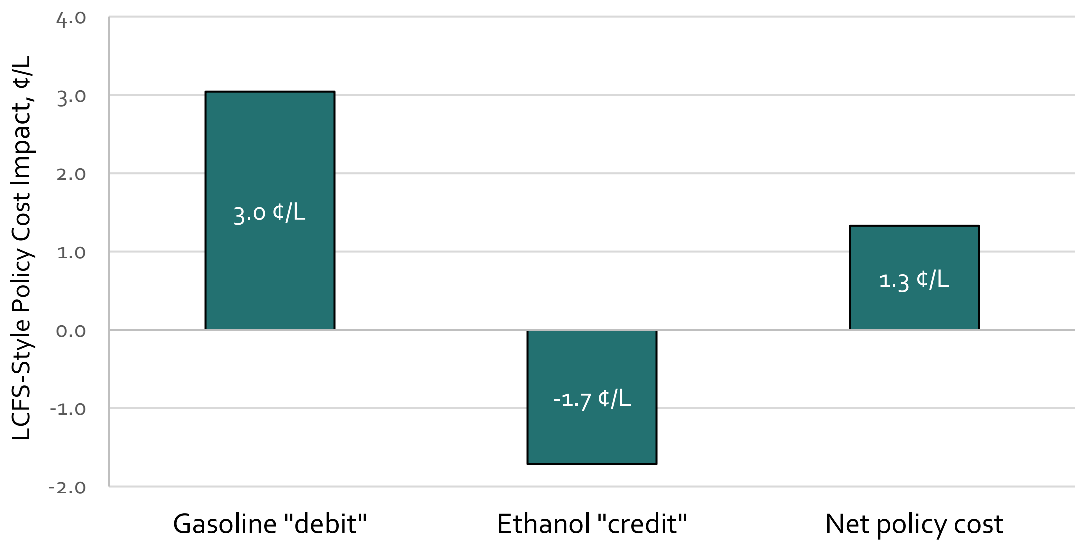
Figure 7: Impact of an LCFS-style policy vs. carbon tax on E10 retail prices in Ontario in 2021, LCFS credit price is equal to the carbon tax $/tonne CO_2e value ($150 t/CO_2e)



Note: wholesale fuel costs and fuel taxes are based on Ontario in 2021. LCFS credit price and carbon tax are 150 $/tonne. In the example, the gasoline CI is 95 gCO_2e/MJ (baseline value in the CFR), the ethanol CI is 40 gCO_2e/MJ, and the LCFS-style policy target CI is 88.5 gCO_2e/MJ (2025 gasoline pool target for the CFR).

This “feebate” is illustrated with the example of E10 in Ontario again. If petroleum-derived gasoline has a life-cycle CI of 95 gCO_2e/MJ and the target for 2030 is 14 gCO_2e/MJ lower, the “fee” on the gasoline component in that year would be 3 ¢/L on E10 when the compliance credit price is 150 $/t$CO_2$e. The ethanol component of the E10 would earn a “rebate” of 1.7 ¢/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 1.3 ¢/L (Figure 8) plus another 0.2 ¢/L from increased sales tax.

Figure 8: Breakdown of an LCFS-style policy's cost impact on E10 retail price with a hypothetical $150/tCO_2e$ credit price



Note: LCFS credit price and carbon tax are 150 $/tonne. In the example, the gasoline CI is 95 gCO_2e/MJ (baseline value in the CFR), the ethanol CI is 40 gCO_2e/MJ, and the LCFS-style policy target CI is 88.5 gCO_2e/MJ (2025 gasoline pool target for the CFR).

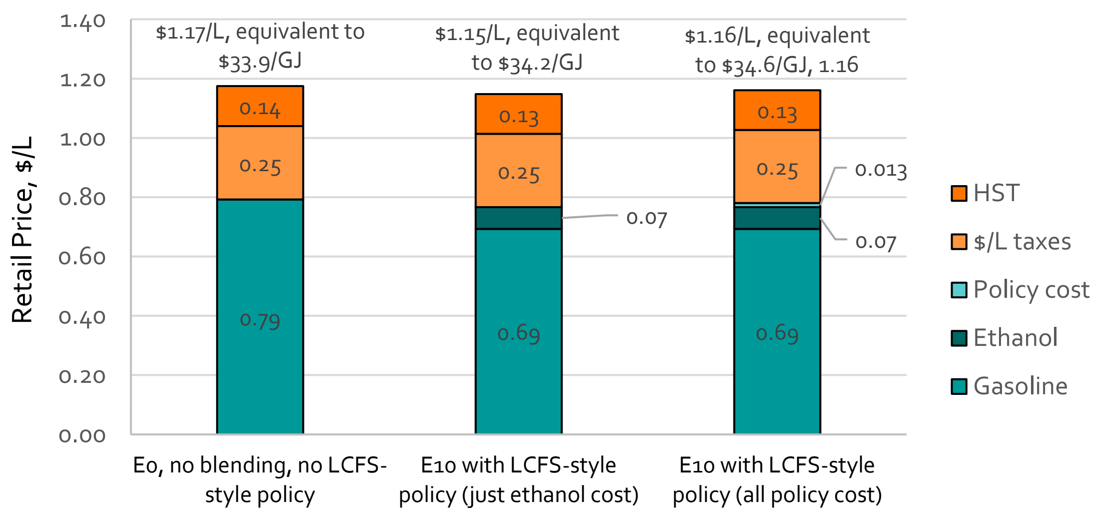
The GHG abatement cost broadly perceived by consumers under a LCFS-style policy is defined by the average abatement costs of the actions used to make that consumer's fuel compliant with the policy. This abatement cost is not solely defined by the policy credit price, which represents the abatement cost of the next 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 British Columbia's low-carbon fuel requirement, to 2020 (most recent year with complete data), 10% of compliance credits were obtained by trading credits through the credit market, while 90% of the credits were self-generated by fuel providers when blending lower-carbon fuels.[44]

The previous Ontario example shows that the average abatement cost perceived by consumers, the abatement cost of renewable fuel blending and the credit price are not the same. For E10 sold in Ontario in 2021, but with the CFR CI limit for 2025, the abatement cost perceived by a consumer resulting from ethanol blending is $55/tCO_2e$ (based on the "E0, no policy" vs. "E10, just ethanol" costs in Figure 9), well

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

below the credit price of $150/tCO$_2$e (where this credit price creates the policy cost of about 1 ¢/L seen in the "E10, all policy" cost in Figure 9). The resulting average abatement cost is $108/tCO$_2$e, between the abatement cost of ethanol blending and the abatement cost related to additional credit purchases at the marginal credit price.

Figure 9: 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 95 gCO2e/MJ, the ethanol CI is 40 gCO2e/MJ, and the LCFS target CI is 81 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. $0.79/L vs. $0.77/L, or a gasoline cost of $0.69/L of E10).

When calculating these abatement costs, 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 (this energy density difference is accounted for in the abatement costs). 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 because 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 within an LCFS-style policy is not the same as the credit price.
- The credit price does not create a carbon cost on the full CI of the fuel, just the difference from the targeted CI limit in a given year.

- Consequently, equivalent LCFS credit prices and carbon tax have a very different retail price impact: For example, a carbon tax of \$150/tCO_2e has a much higher retail price impact than a LCFS credit price of \$150/CO_2e.

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 considered, 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 lower 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 2020 in the Biofuels in Canada analysis are representative of future conditions (using Canada fuel-weighted averages): biodiesel costs \$0.72/L with a \$0.05/L transportation cost, has a CI of 4.5 gCO_2e/MJ and a density of 35.4 MJ/L; wholesale diesel (B0) sells for \$0.68/L with a CI of 93.9 gCO_2e/MJ, and a density of 38.7 MJ/L. The refining margin (net revenue) is \$0.23/L.[45]

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

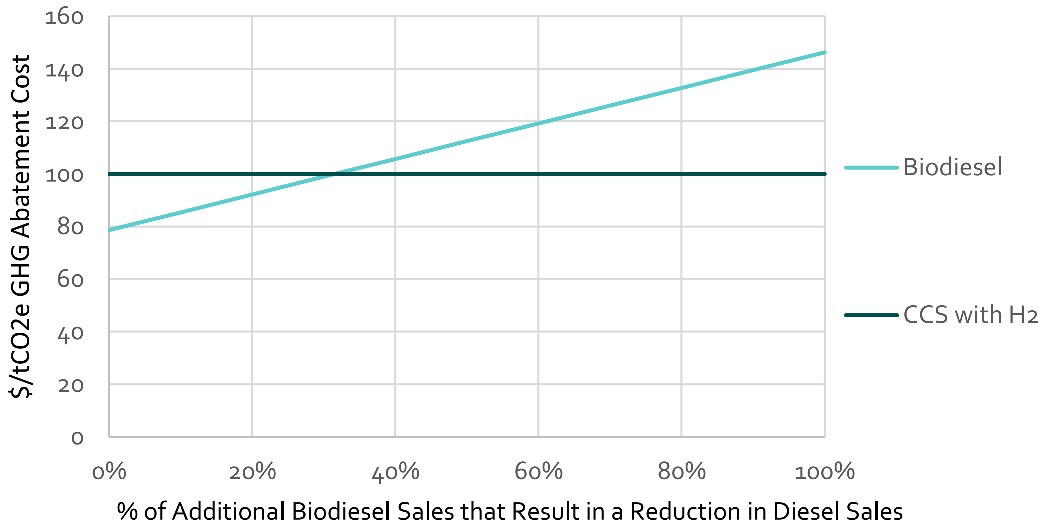
- The fuel provider cannot pass the additional costs on the consumers.
- Both actions would count towards compliance under a LCFS-style policy and would generate credits worth \$125/tCO_2e.

Based on fuel costs and properties alone, the abatement cost of blending additional biodiesel is \$79/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 results in a foregone refining margin, then the fuel provider loses \$0.23 for each litre of diesel not sold. To reduce GHG emissions by one tonne, the fuel provider would have to sell 11.2 GJ of biodiesel, equivalent to 289 L of diesel. If the biodiesel sales completely displace an energetically equivalent amount of diesel, then there is \$68 in foregone refining margin per tonne of GHG reduction and the net abatement cost is \$146/tonne, greater than the assumed credit price in this example. In this case, the fuel provider would only choose to abate emissions 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 30% of the additional biodiesel sales offset an energetically equivalent amount of diesel sales, CCS is the lower cost abatement action (Figure 10). 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 blend biofuels, even when that latter action appears to have a lower abatement cost.

Figure 10: 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 16 outlines summarizes the tasks we undertook in this study as well as our approach for each of these tasks.

Table 16: Study method by task

Task	Approach
1. Tabulate renewable fuel and fossil fuel use	Provincial and federal renewable and low carbon fuel regulation compliance data (published, direct communication) were collected. The data in this report includes January 1, 2010 to December 31, 2020, the most recent data period available for most jurisdictions (but also includes 2021 data from Alberta and Saskatchewan). 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. Fossil fuel consumption is taken from government regulator data where available and otherwise from Statistics Canada data.
2. Characterize biofuel CI and GHG reductions	Carbon intensities (CI) were taken from government regulator data where available and otherwise defined with GHGenius (v.4.03a) 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 British Columbia's fuels policy. This province is used as a case study because it is one of the few jurisdictions where CI is documented by fuel.
3. 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 (Kalibrate data) to estimate the unblended 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.

Task	Approach
4. Estimate fuel displaced by PEVs	PEV sales data from Statistics Canada was used to estimate the stock of these vehicles by province. The fuel displaced by PEVs is estimated assuming EVs are driven the same annual distance as gas vehicles and the energy effectiveness ratio is from the final *Clean Fuel Regulations*, with the average energy intensity of PEVs based on a weighted average of vehicles sold in 2021.
5. Produce estimated results for 2021	For provinces where no 2021 data was yet available, all results (volumes, GHG and cost impacts) were estimated for 2021, assuming constant biofuel blending rates from 2020 (or a continuation of a trend for British Columbia) and using Statistics Canada data to define the size of the gasoline and diesel pools. Carbon intensities for 2021 are taken from GHGenius or assumed based on provincial data for 2020.

3.2. Summary of Inputs

Table 17 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 CI as part of their regulations, the default CI from GHGenius was assumed to be representative of the average biofuel consumed in that region. The assumptions used to complete task 5 (estimate results for 2021) are described following the discussion of Table 17 below.

Discussion of Inputs

Table 17 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 2011-2020[46,47] and the data we collected. Therefore, the resulting biofuel consumption reported for Québec and the Atlantic provinces is particularly uncertain

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

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

since it is the difference between federal data and the sum of provincial data, all of which is collected using different methodologies.

While ECCC data defines total renewable fuel consumption in most years, there are some exceptions. For example, 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 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, prior to 2022, it was difficult to calculate biomass-based diesel consumption using production and trade data because HDRD did not have its own harmonized system (HS) code. The lack of an HS code over much of the period covered by this analysis 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 British Columbia and Alberta. The Ontario government reported that more HDRD was used for compliance than biodiesel. For 2020 and earlier, an 80:20 ratio of HDRD to biodiesel is assumed in Ontario and Québec (for years where our analysis shows consumption). No HDRD consumption is assumed in Saskatchewan, and the Atlantic region, or for Manitoba prior to 2021. Specific assumptions for biodiesel and HDRD and the associated carbon intensities are listed in “Appendix A: Biofuel Type and Feedstock Assumptions and Data”.

CI values are mostly still taken from GHGenius 4.03a, except in Ontario and British Columbia 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 relative to the value from GHGenius, 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,[48] whereas GHGenius 4.03a uses 63 gCO_2e/MJ.

2021 Estimate

As noted above in Table 16, results for 2021 in most regions are preliminary estimates that are based on several inputs and assumptions for fuel volumes, blend rates and fuel CI. This year, the Alberta and Saskatchewan governments provided their volume and blend rate data for 2021 as well as 2020. We used a variety of methods to estimate 2021 fuel volumes for other provinces. For Manitoba, we assumed compliance with the new blending rates (9.25% in gasoline and 3.5% in diesel). In Ontario, Québec and the Atlantic provinces we assumed a constant blending rate from 2020 through to 2021. CI scores for all of these provinces are based on GHGenius 4.03a, except in Ontario where CI scores in 2021 are assumed to be the same in 2020. For British Columbia, we used preliminary data from a public presentation of policy impacts to define fuel volumes and CI scores.

We estimated the size of the gasoline and diesel pools in 2021 for most provinces, excluding Alberta where this information was included in the 2021 data. The estimate is based on using Statistics Canada data (Table 25-10-0081-01 Petroleum products by supply and disposition, monthly). For 2021, 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 2021 in the analysis is a function of consumption in 2020 multiplied by the change in national consumption from 2020 to 2021. For example, nationally there was a 6% increase in gasoline demand from 2020 to 2021 (a partial rebound after the height of the COVID pandemic). Therefore, we assume that gasoline consumption in 2020 was 6% larger than it was in each province in 2020 (where 2020 consumption is provided from fuel blending regulation data or taken from Statistics Canada energy data (Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy in natural units).

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

Table 17: Summary of Inputs (data in green, assumptions in yellow, major uncertainties in orange)

<table>
<tr><th></th><th>British Columbia</th><th>Alberta</th><th>Saskatchewan</th><th>Manitoba</th><th>Ontario</th><th>Quebec</th><th>Atlantic</th></tr>
<tr><td>Gasoline volume</td><td rowspan="4">RLCFRR Summary: 2010-2020. Gasoline and diesel volumes are the total, not the non-exempt volume</td><td>2011-2020: 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 Atlantic CDA</td><td>Difference between national total reported under the RFS by ECCC[1] and sum from other provinces, pro-rated to QC and Atlantic CDA</td></tr>
<tr><td>Diesel volume</td><td>2011-2020: From govt. contact.
For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>Data from govt. contact</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>

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	Atlantic
Biofuel feedstock	RLCFRR Summary: 2010-2020. Gasoline and diesel volumes are the total, not the non-exempt volume	Assumptions reviewed by govt. contacts and (S&T)[2] Consultants					
Fuel CI	RLCFRR Summary: 2010-2020. 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	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
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 marketing,[2] for Vancouver	Kalibrate marketing,[2] for Calgary	Kalibrate marketing,[2] for Regina	Kalibrate marketing,[2] for Winnipeg	Kalibrate marketing,[2] for Toronto	Kalibrate marketing,[2] for Montreal	Kalibrate marketing,[2] for Halifax, Saint John, Charlottetown, and St Johns
Fuel Taxes, including carbon tax cost	NRCAN, Fuel Consumption Taxes in Canada[7]						

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	Atlantic
Carbon prices	Government of BC, British Columbia's Carbon Tax[8]	Government of Alberta, Alberta's Carbon Levy[9] and Government of Canada[10]	Government of Canada, Greenhouse Gas Pollution Pricing Act[10]	Government of Canada, Greenhouse Gas 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 Pollution Pricing Act[10] and Nova Scotia Cap-and-Trade Program Auction of Emission Allowances[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[14]						
Value of octane	Value in $/octane point/L based on difference in the bulk 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.[15]						
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 Marketing. 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.						
Plug-in electric vehicle sales, activity, and GHG intensity	PEV sales are provided by Statistics Canada for 2011-2020 (Table: 20-10-0021-01). PEV 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. PEV are 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 through 2020. 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. 2021. Petroleum & Other Liquids: Refiner Gasoline Price by Grade and Sales Type. Accessed from: www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm

6) Darling Ingredients. 2022. 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/clean-economy/carbon-tax

9) Government of Alberta. 2019. About tax and levy rates and prescribed interest rates. Note that the current source includes no mention of past carbon levy rates

10) Government of Canada, Greenhouse Gas 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: https://www.environnement.gouv.qc.ca/changements/carbone/revenus-en.htm

13) Nova Scotia Cap-and-Trade Program Auction of Emission Allowances https://climatechange.novascotia.ca/sites/default/files/June_2021_Auction_Summary_Results_Report.pdf

14) 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

15) 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 2020 and prior years:

- **Co-processed fuels:** The volumes and CI of co-processed fuels produced and consumed in British Columbia are now based on government data for 2019 and 2020. The estimate for 2021 is based on Parkland Fuel's estimate of the % change in their co-processing input at its Burnaby refinery from 2020 to 2021, roughly a 99% increase.[49] This change corresponds is a volume of about 86 million L of co-processed feedstock, where the co-processing capacity in 2021 was about 100 million L of feedstock annually.[50] Added to the estimated production is what the Tidewater facility in Prince George, British Columbia, may have produced during the final quarter of 2021, about an additional 4.3 million L.[51]
- **Change in use of Statistics Canada data:** The model was updated to account for how Statistics Canada's Report on Energy Supply and Demand (RESD) includes ethanol in volumes of motor gasoline, but does not include volumes of biodiesel in the diesel volumes. Adjusting the diesel blend rates in the regions that use this data (Quebec, Atlantic Canada, Ontario up to 2017) resulted in a minor downwards revision to volumetric blend rates.

As a reminder, the 2021 edition of this analysis included some important methodological changes that have been continued into this update:

- **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. Starting with the 2021 Biofuels in Canada analysis, the model now uses the wholesale value of octane to better reflect the cost of refining associated with increasing octane (rather than changes to marketing margins on premium gasoline). This results in a nearly $300/tCO2e increase to the abatement cost of using ethanol, though the average estimated abatement cost since 2010 remains below zero (i.e., it reduces emissions and prices). The impact

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[49] Parkland, 2022, 2022 Annual General Meeting of Shareholders, Management Information Circular & Proxy Statement

[50] Robert Brelsford, 2021, Parkland Fuel's Burnaby refinery to expand renewables coprocessing, The Oil & Gas Journal

[51] Based on the Tidewater canola co-processor, with an annual capacity of 300 bbl/day, in service since Q4 2021: http://www.tidewater-renewables.com/our-operations/core-projects/

and reasoning behind this change is discussed in more detail in Appendix C: Explanation of Changes to Cost Analysis Methodology Made in 2021.

- **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. Starting in the 2021 analysis, the HDRD prices implied in Diamond Green Diesel's financial materials were used in place of the Neste data for 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 was 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.

- **Light-duty PEVs** Estimates for energy consumption and avoided GHG emissions for PEVs have been included, starting in the 2021 update, to quantify the role of these other low-carbon transportation options alongside blended biofuels. PEV sales are reported in Statistics Canada data, but the energy and GHG impact must also be estimated, using the methodology described in Appendix D: Plug-in Electric Vehicle Analysis Methodology.

Background: What is Co-Processing?

Co-processing is to the process of refining vegetable/animal oils with 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.

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 gasoline and diesel.

As of the end of 2021, the combined co-processing capacity in British Columbia (Parkland and Tidewater) is about 118 million litres per year of co-processed feedstock. For reference, total biodiesel and HDRD consumption in BC was 450 million litres in 2020.

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 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 PEVs 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, 2022-10-27".

4.1. Fuel Consumption

Figure 11 and Table 18 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, which include ethanol, biodiesel, HDRD and co-processed fuels, has been steadily increasing in the years between 2015 and 2021. The trend has been driven in large part by an increase in the use of HDRD and, to a lesser extent, biodiesel, with ethanol consumption being generally stable.

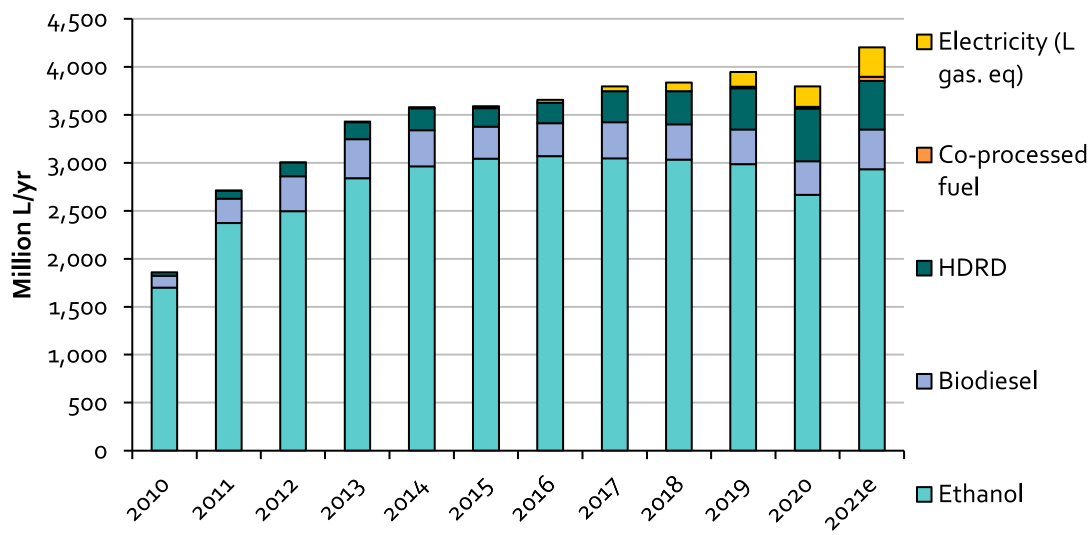
Renewable fuel consumption declined somewhat in 2020 relative to previous years due to the reduction in overall fuel consumption during the COVID pandemic (-6% renewable fuels in 2020 relative to 2019). This change is a function of lower total gasoline consumption leading to less ethanol consumption. The volume of ethanol consumed in 2020 declined by over 300 million L/yr relative to 2019 (-11%). In contrast, the quantity of diesel consumption was less impacted by the pandemic and biomass-based diesel consumption actually increased from 2019 to 2020, rising by more than 100 million L/yr (13%). Total biomass-based diesel consumption was almost 900 million L/yr. Growth in HDRD consumption continued to drive the increase in biomass-based diesel, while biodiesel consumption remained relatively constant from 2019 to 2020 (Table 18, Figure 11).

Table 18: Canadian fuel consumption in million litres per year (2015 to 2020, with an estimate for 2021)

Fuel type	2015	2016	2017	2018	2019	2020	2021e
HDRD	194	215	323	344	432	547	507
Biodiesel	334	341	376	367	360	351	413
Ethanol	3,041	3,069	3,047	3,034	2,985	2,665	2,933
Co-processed					15	20	44
Electricity*	19	31	49	93	153	212	305
Diesel (Pure)	26,752	25,831	27,732	27,550	27,039	24,106	24,284
Gasoline (Pure)	41,697	42,367	42,955	43,148	43,081	35,432	37,331

*Electricity consumption is measured in terms of volume of gasoline equivalent (i.e. what would have been consumed if PEVs 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*.[52]

Figure 11: Renewable and low-carbon transportation energy consumption in Canada



The 2021 estimate shows renewable fuel consumption returning to pre-pandemic levels in the gasoline pool, at about 2,900 million L/yr. Consumption of biomass-based diesel is estimated to be above 2019 levels at about 920 million L/yr. Recall, these estimates are largely based on Statistics Canada gasoline and diesel consumption data for 2021 and the assumption that renewable fuel blending rates remain constant in most provinces from 2020 to 2021. The exception to this assumption is where there

[52] Government of Canada, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

is data (e.g., Alberta) or where regulatory schedules dictate a different trend (e.g., British Columbia and Manitoba).

The volume of HDRD consumed in total and by province is more uncertain compared to other biofuels. HDRD was only recently given a Harmonized System (HS) code within trade data, making it difficult to quantify biomass-based diesel consumption in Canada using import, export, and production data. That being said, all reasonable assumptions regarding HDRD trade indicate that the total volume consumed in Canada is in the vicinity of what is reported in this analysis and by Environment and Climate Change Canada. Regarding the breakdown of HDRD consumption by province, only British Columbia and Alberta report HDRD consumption separately from biodiesel. For other provinces, we use advice from industry experts to allocate the remaining HDRD consumption.

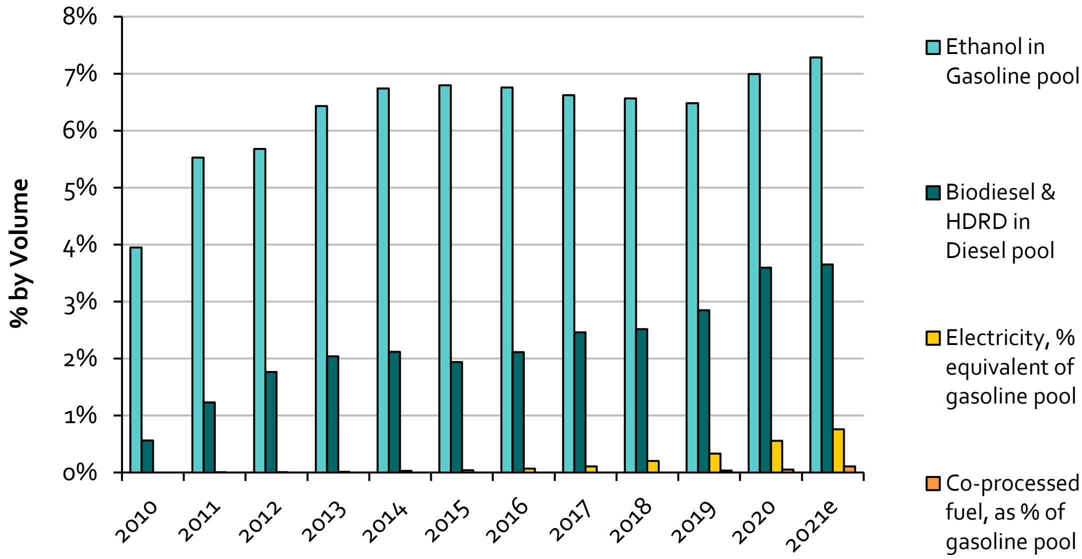
Our analysis also includes estimates of co-processed fuels and fuel consumption avoided by PEVs. An estimated 15 million L/yr of co-processed renewable fuel was produced at Parkland's Burnaby refinery in 2019, rising to 20 million L/yr in 2020 and an estimated 44 million L/yr in 2021 (equivalent to 1% of the estimated Canadian renewable fuel supply).

Electricity as a transportation fuel has also been growing rapidly over the past few years, with a compound annual growth rate averaging roughly 64% between 2015 and 2021. Measured in units of volume of fuel equivalents (i.e., as fuel displaced), the electric energy consumed by light-duty on-road vehicles will soon be comparable to biodiesel, trending towards 400 million L/yr equivalents (Table 18, Figure 11).

4.2. Blending Rates

Figure 12 shows the percentage of renewable fuel in the gasoline pool (ethanol) and in the diesel pool (biodiesel plus HDRD). Due to the uncertainty in the volume of HDRD consumed in Canada, biodiesel and HDRD are grouped together to avoid misrepresenting the data. 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). Co-processed fuel volume and gasoline consumption displaced by light-duty PEVs are shown as a percent of the gasoline pool.

Figure 12: Renewable fuel content by fuel pool, 2010 to 2020, estimate for 2021.



Although ethanol consumption declined in 2020, gasoline consumption declined proportionally more. Consequently, the volumetric blend rate of renewable fuels in gasoline increased to 7% in 2020, up from about 6.5% in 2019. The blend rate of biomass-based diesel also increased from 2019 to 2020, rising from 2.9% to 3.5%. In 2020, co-processed fuels were equivalent to 0.05% of the gasoline pool, while the gasoline consumption avoided by light-duty PEVs was equivalent to 0.6% of the gasoline (Figure 12).

Our estimate for 2021 shows a rebound in ethanol consumption to pre-pandemic levels and additional growth in biomass-based diesel consumption. In that year, estimated blend rates reach a new high of 7.3% in gasoline and 3.7% in diesel. (Figure 12).

The national average blend rates are above what is required by the federal *Renewable Fuels Regulation* (RFR), 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. In the gasoline pool, the blend rate required by the RFR is 5% but the volumetric blend rate of renewable fuels in gasoline was 7% in 2020 (Figure 13). In the diesel pool, the British Columbian and Ontario policies stack with the federal regulation to increase the quantity of biomass-based diesel by about 80% beyond what is required for simple volumetric compliance with the RFR (3.6% vs. 2% in 2020, Figure 14).

Figure 13: Renewable fuel in the gasoline pool in 2020 versus the regulated blend rate

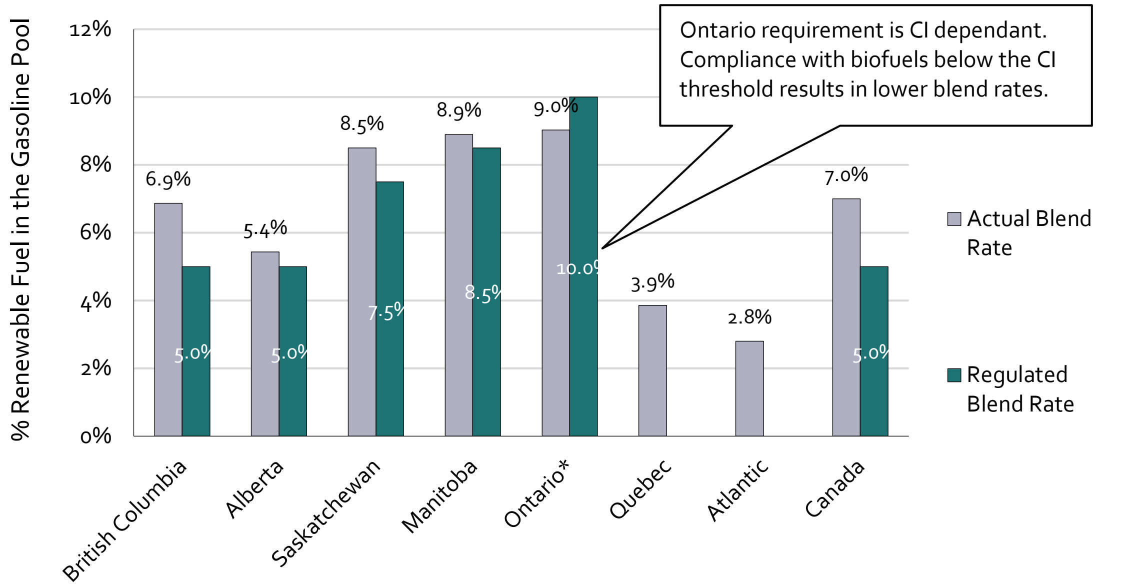
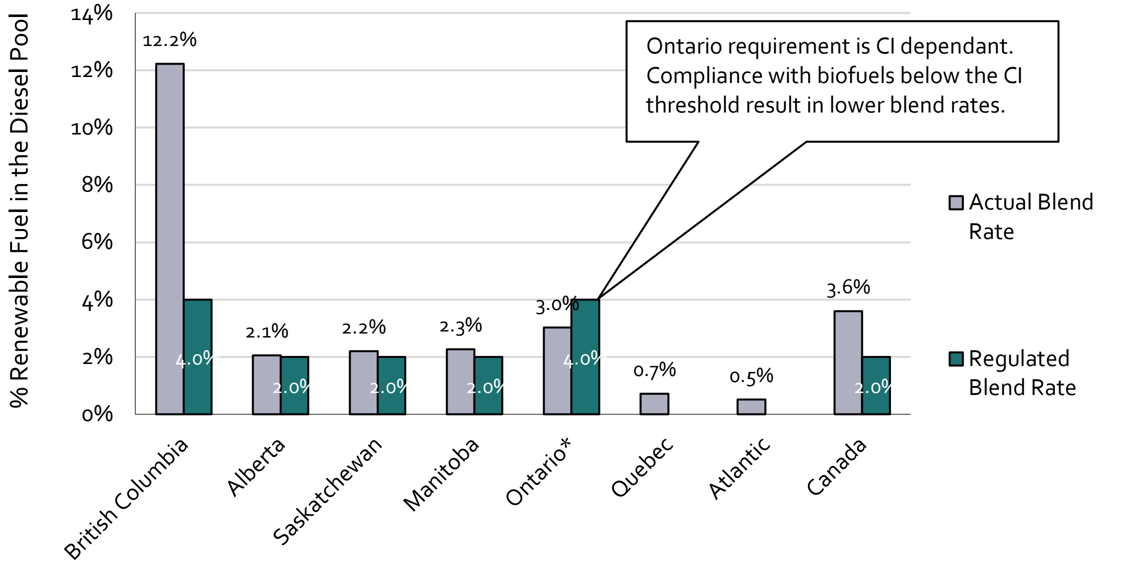


Figure 14: Renewable fuel in the diesel pool in 2020 versus the regulated blend rate

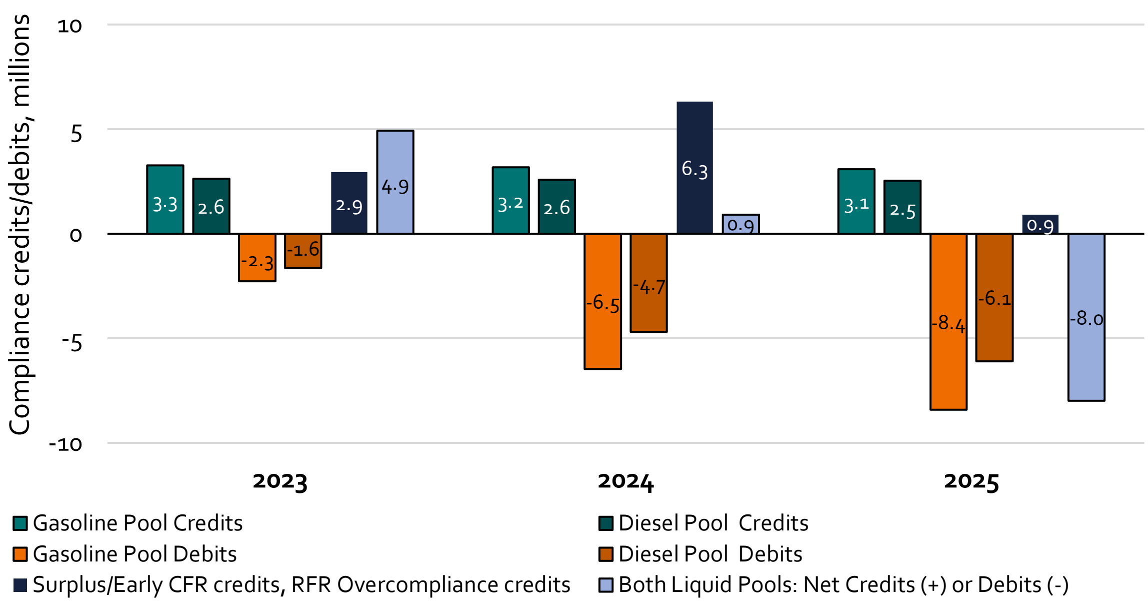


This current rate of renewable fuel blending means that, on average, fuel supplier are already in compliance with the *Clean Fuel Regulations* (CFR) and will not need to take additional compliance actions until at least 2025. Figure 15 illustrates this outcome by showing the hypothetical generation of CFR credits and debits during the first three compliance periods (i.e., to the end of 2025). In the following figure, we assume fuel consumption, blending rates and CIs remain constant at the 2021 values estimated in this edition of Biofuels in Canada. As described in section 2.3 of this report:

- CFR debits are not produced until the second half of 2023.
- Early CFR compliance credits can be obtained starting in the second half of 2022.
- Overcompliance with the RFR, which ends at the end of 2022, produces CFR credits that can be used as of 2024 (as described in section 2.3 of this report or in section 169(1) and 170(1) of the CFR).[53]

Based on these inputs, there is a surplus of almost five million CFR credits at the end of 2023, declining to a surplus of just under one million credits by the end of 2024. By 2025, current blending rates result in a net debit, meaning fuel suppliers would need to take additional actions to comply with the CFR (Figure 15). This is a conservative conclusion, since it does not account for additional credit generation under compliance categories 1 and 3 (i.e., GHG reductions in upstream fuel production and for fuel switching), debit reductions from the increased use of PEVs, or the additional credit generation from increased renewable fuel consumption driven by the rising stringency of some provincial regulations (i.e., British Columbia, Ontario, Québec). Therefore, this analysis shows that the CFR policy may drive greater renewable and low-carbon fuel blending by 2025 *at the earliest.*

Figure 15: Hypothetical credits and debits created under the CFR in its first three compliance periods (for fuels only, i.e. just compliance category 2)

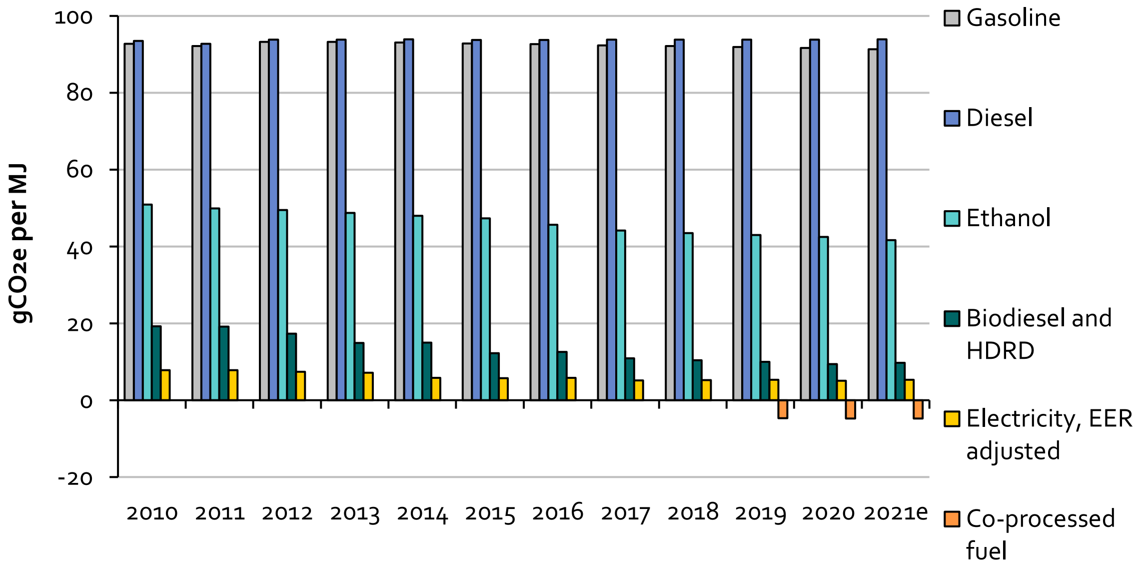


53 www.gazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

4.3. Lifecycle GHG Emissions

Figure 16 shows the estimated lifecycle CI (i.e. well to wheels or farm to wheels) of transportation fuels in Canada between 2010 and 2020, with an estimate for 2021. Due to uncertainties in volume, feedstock and CI, biodiesel and HDRD are grouped together.

Figure 16: Lifecycle CI by fuel type within Canada, from 2010 to 2020 with an estimate for 2021.



The national average CI for ethanol in 2020 is 43 gCO_2e/MJ, 17% below the value in 2010. The weighted average for the biomass-based diesel CI in 2019 is 9 gCO_2e/MJ, 52% below the value in 2010 (Figure 16). As discussed below, the causes of this change are a decline in fuel CI from the British Columbia Renewable and Low-Carbon Fuel Regulation (RLCFR) 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 reported RLCFR compliance data is about -5 gCO_2e/MJ (likely negative due to the production of low-carbon co-products like bio-naphtha and bio-propane). The average CI for electricity is about 5 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 PEVs uses 4.1 times less energy than a conventional vehicle). Furthermore, it is weighted by electricity consumption by province, where most PEVs are in British Columbia, Ontario and Québec, which have low-CI electricity.

GHG emissions resulting from direct land use changes are included in the lifecycle CI of biofuels. DLUC include the GHG emissions resulting from the conversion of pasture or forest to crop land, with the former often being a larger carbon sink than crop land. When reporting carbon intensities, some policies, 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 (liquid fossil and renewable fuels, electricity, hydrogen) are the subject of on-going research and policy debate. At present, Canadian policy-makers do not include ILUC, but there has been speculation that they may include them in the future.[54] The lifecycle model developed for the *Clean Fuel Regulations* does not incorporate ILUC emissions for any fuel. Therefore, compliance credit generation is not affected by ILUC, except for cases where the biofuel would adversely impact land-use biodiversity.[55]

For most provinces, these CI estimates were based on average fuel CI from GHGenius 4.03a. For British Columbia, the CIs are reported in provincial RLCFR compliance reports to 2020 (note that CI values prior to December 31st, 2014, come from GHGenius 4.01b. The province does not retroactively revise these values). For 2021, the CIs are preliminary values taken from policy consultation materials. 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 and 2021. For the rest of Canada, CIs are taken from GHGenius 4.03a.

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[56] (NIR), adjusted to include upstream and indirect GHG emissions (e.g., related to fuel production as well as consumption for electricity generation). The upstream and indirect GHG emissions intensity added to the NIR value is based on the difference between NIR emissions intensity by province and the default electricity CI by province reported in the *Clean Fuel Regulation*.[57] This CI value is divided by an energy efficiency ratio of 4.1 (i.e. EER, the ratio of energy used

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

[55] Government of Canada, 2022, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

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

[57] Government of Canada, 2022, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

by conventional vehicle to a PEV). This provides a consistent comparison with liquid fuel on the basis of energy used per km travelled.

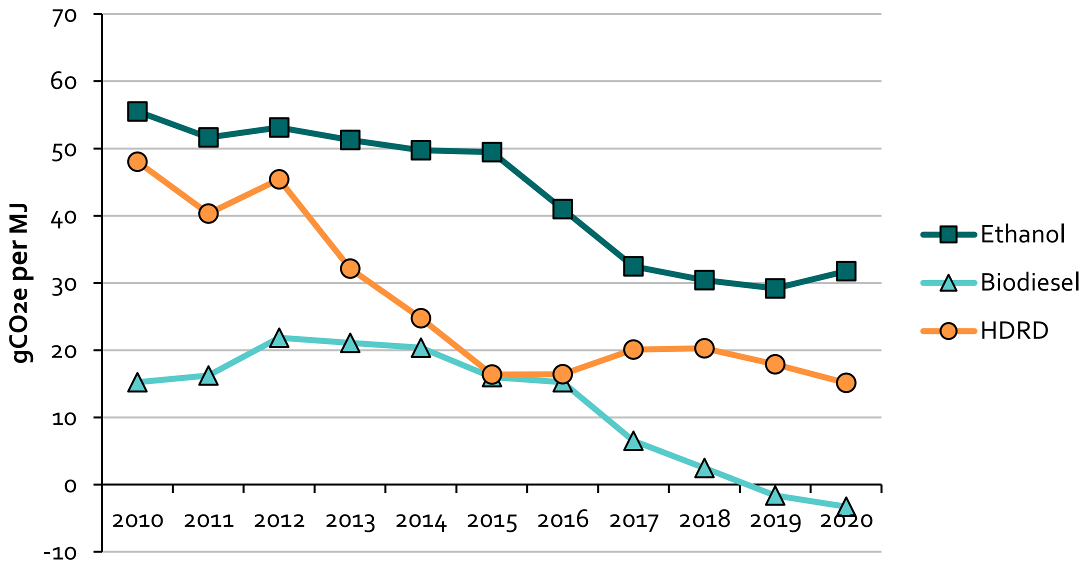
The results in Figure 16 show that the biofuels consumed in Canada offer significant lifecycle CI reductions relative to gasoline and diesel. The data implies that, on average in 2020, ethanol sold in Canada was 54% less carbon intensive than gasoline, while biodiesel and HDRD were about 90% less carbon intensive than diesel. As of 2020, the EER adjusted CI of electricity was about 95% 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 overall; and the fact that most PEV adoption to date has been concentrated in provinces where electricity generation has a particularly low CI, namely British Columbia, Ontario and Québec.

Figure 16 also suggests that the CIs of ethanol, biodiesel, and HDRD are decreasing over time. In part, this is because the regional CIs used to produce Figure 16 are based on default data from GHGenius 4.03a. That dataset extrapolates from historical trends 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.).

Nonetheless, the CI values for biofuels consumed in Ontario and in British Columbia, which are based on collected data rather than modelling results, indicate a similar trend of an overall decline in the CI of biofuels. Likewise, reporting from the California and Oregon low-carbon fuel standards (LCFS) also show a similar decline in CI values. Taken together, these empirical data sources give greater confidence in the results we present here.

Focusing on British Columbia, the CI of ethanol decreased by 47%, the CI of biodiesel decreased by 111%, and the CI of HDRD decreased by 61% from 2010 to 2020 (Figure 17). Continuing the trend started in 2019, the emissions associated with biodiesel in British Columbia are negative, meaning that the cultivation and production of biodiesel leads to an overall decrease of global GHG emissions. In Ontario, the average reported CI for bio-based diesel decreased from 12 to 6 gCO2e/MJ between 2015 and 2020.

Figure 17: 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. Between 2011 and the first quarter of 2022, the CI of ethanol and biodiesel have decreased by 34% and 38% respectively.[58]

A spatial analysis of corn and soy production indicates that some of these CI reductions 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 CI of ethanol and biodiesel relative to a typical corn/soy crop rotation (by 30-50 gCO_2e/MJ).[59]

California's LCFS also supports 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 CI of ethanol (40%-45%). Ethanol with CCS

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[58] California Air Resources Board, LCFS Quarterly Data Spreadsheet, accessed September, 2022.

[59] 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

was recently recognized as a fuel pathway within the California LCFS,[60] coinciding with additional funding being directed towards the deployment of this abatement practice at a facility that supplied fuel to California, the Red Trail Energy ethanol plant in North Dakota.[61]

The trends in measured biofuel CI improvements 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. The broader monitoring of CIs that will occur with the *Clean Fuel Regulations* will provide another opportunity to test this hypothesis.

Figure 18 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 2020. Avoided emissions from PEVs are small but growing rapidly, adding another 0.6 $MtCO_2e$/yr, bringing total avoided emissions in 2020 to 6.5 $MtCO_2e$/yr. Cumulative national avoided GHG emissions from 2010 to 2020 are 60 $MtCO_2e$. Further growth in biofuel consumption and PEV adoption will likely push the annual GHG abatement to more than 7 $MtCO_2e$/yr in 2021.

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

[61] 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 18: Avoided lifecycle GHG emissions 2010-2020, with an estimate for 2021.

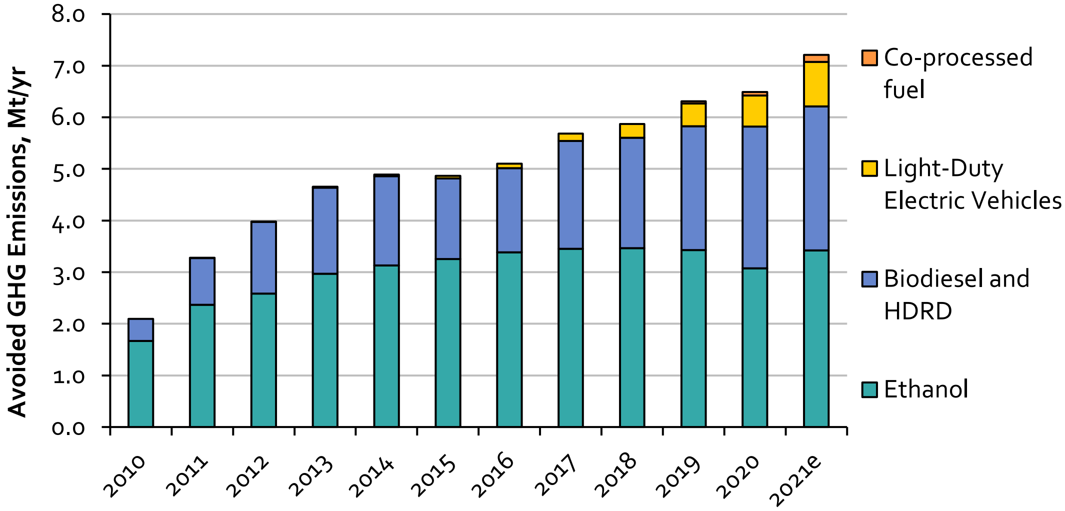
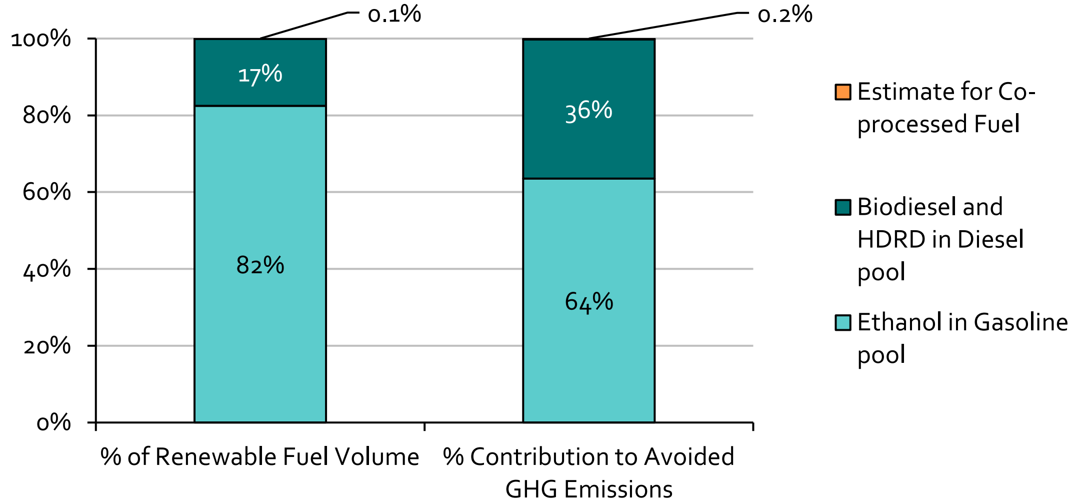


Figure 19 shows the percentage of renewable fuel volume in the gasoline and diesel pools compared with the percentage of avoided GHG emissions resulting from renewable fuel consumption in either pool. Co-processed fuels are shown as a separate category. Ethanol accounted for 82% of the renewable fuel volume consumed during the 2010-2020 period, but only produced 64% 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 36% 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. Note that the inclusion of co-processed fuel does create a rounding error which impacts the graph below.

Figure 19: % of total renewable fuel volume vs. % contribution to avoided GHG Emissions from 2010 to 2020.



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%.[62] Scaling this impact to the ethanol blend rates in our analysis, this increase in efficiency would increase the cumulative GHG impact by 28%, or 17 $MtCO_2e$ from 2010 through 2020 (an additional 3 $MtCO_2e$ avoided per year).

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 increases the octane rating of the overall fuel blend, meaning the gasoline blendstock can have a lower octane rating than if no ethanol were used. Consequently, ethanol blending may cause refinery emissions to decrease if the production of lower octane gasoline is less carbon intensive. 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. Aromatic compounds have a higher combustion (i.e., tailpipe)

[62] 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

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 uncertain. Estimates from our literature review suggest the change to refinery emissions in 2020 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 0.3 to 1.0 $MtCO_2e$/yr (see section 5.2).

4.4. 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 B: 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 PEVs. Appendix C: Explanation of Changes to Cost Analysis Methodology Made in 2021 presents a detailed description of the updates to the cost methodology that were implemented as of the 2021 edition of this report.

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.[63] When used in a gasoline blend, ethanol has an octane rating of 113.[64] 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 20 shows the cumulative change in consumer fuel costs resulting from renewable fuel blending in Canada from the start of 2010 to the end of 2020. 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 consumers, their fuel expenditures from 2010 to 2020 would be 0.13% lower, equivalent to a savings of $1.3 billion over 11 years. Note that all costs in the analysis are expressed in 2020 CAD.

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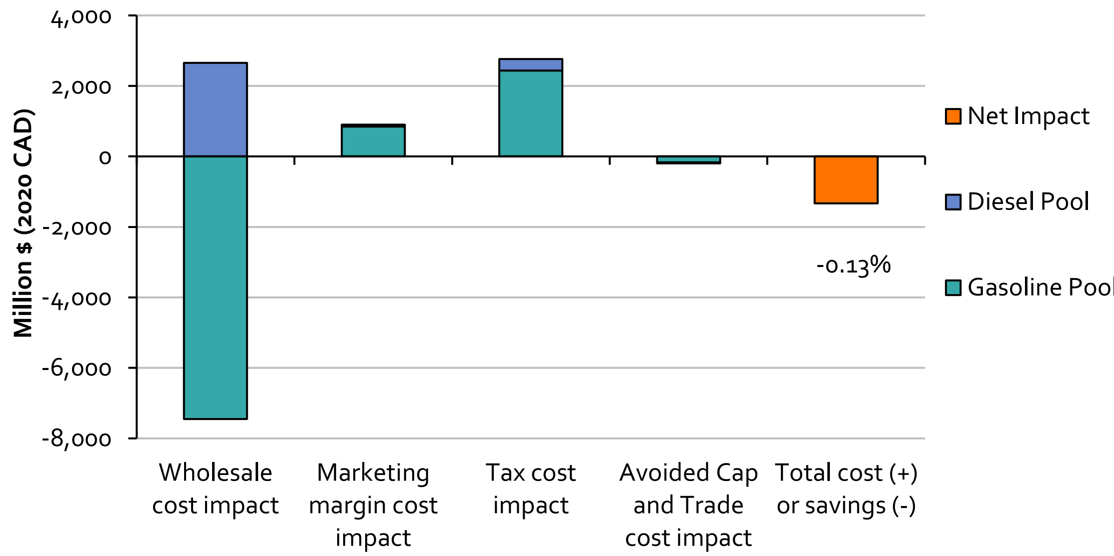
63 U.S. Energy Information Administration, 2013, Price spread between regular and premium gasoline has changed over time. https://www.eia.gov/todayinenergy/detail.php?id=11131

64 113 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.

Figure 20: Cumulative cost impact resulting from ethanol blending in the gasoline pool and biomass-based diesel blending in the diesel pool (2010-2020), total % change in category.



The net impact on consumer cost comes from both the gasoline and diesel pool, and is composed of, a wholesale cost, a marketing margin cost, a tax cost and an avoided GHG cap and trade cost.

The wholesale cost, including the commodity cost and the refining margin, 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, generally between ¢2/L and ¢3/L over the course of this analysis depending on the value of octane in a given year. For the gasoline pool, we find that the wholesale cost impact presents a savings of $7.4 billion in 2020. In contrast, in the diesel pool, the impact of wholesale prices results in an increase of $2.7 billion in the same year. This reflects the fact that biomass-based diesel is generally more expensive than conventional diesel. This is particularly the case with the premium-priced HDRD. Fuel suppliers could mitigate biomass-based diesel costs by substituting biodiesel for HDRD.

Note that these wholesale costs do not include the price-moderating impact of additional biofuel supplied to a tight market. All else being equal, greater supply of alternatives to crude oil will reduce global demand for oil, resulting in a lower oil price. For example, a recent US study estimated that in the current diesel market, the additional supply of biomass-based diesel dampened diesel prices between 8 percent and 19 percent.[65]

The marketing margin cost 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 within the gasoline pool because it is roughly 33% less energy dense than gasoline. Therefore, ethanol consumption increased the marketing cost paid by consumers by $850 million between 2010 and 2020. Because diesel and HDRD are only slightly less energy dense than petroleum diesel, the cumulative marketing cost change in the diesel pool is only $47 million for the same period.

The tax cost results from the application of taxes based on the volume of fuel sold (this includes excise taxes paid "at the pump" as well the carbon taxes and levies where biofuels are not exempt) 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. When taxes a charged per litre, consumers who purchase blended gasoline pay more tax. Furthermore, percent sales taxes (e.g. PST, GST, HST) exacerbate the additional tax charge on fuels with lower energy density because they are applied on the 'tax in' fuel price.

Between 2010 and 2020, our analysis shows that consumers in Canada have paid an additional $2.4 billion in taxes for gasoline as a direct consequence of fuel blending, while the comparable figure for diesel purchases is $325 million. The difference in scale is again due to the fact that biomass-based diesel is relatively closer in energy density to conventional diesel than ethanol is to conventional gasoline.

These Canada-wide tax cost results contain some important variation across jurisdictions. Since blended gasoline can have a lower per litre retail price than the unblended gasoline in the "counterfactual" scenario, our analysis suggests that the

[65] World Agricultural Economics and Environmental Services, 2022, The Offsetting Impact of Expanded Biomass Based Diesel Production on Diesel Prices.

absolute amount of sales tax paid can be lower when gasoline is blended. In jurisdictions like Ontario, where there is a high sales tax tied to actual retail value (i.e. 13% HST), the savings on the sales tax impact may outweigh the increases due to federal and provincial fuel taxes.

The avoided cap-and-trade costs arise 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 (i.e., in a counterfactual scenario). The cost impact calculated here is a savings of $168 million in the gasoline pool and $30 million in the diesel pool, for the period from 2010 to 2020.

There are several important caveats with regards to the cost analysis and how it will be felt by retail consumers. First, the wholesale prices of the fuels are by far the largest determinants of the cost impact. As noted above, we assume that differences in wholesale prices are reflected in retail prices, but given the dynamics of price setting, this may not be the case in all Canadian fuel markets at all times. 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. Anecdotally, bulk purchasers of renewable fuels will exert their market power to negotiate contracts where the Chicago price is an upper limit. Therefore, our method is conservative and may overestimate the wholesale price of renewable fuels.

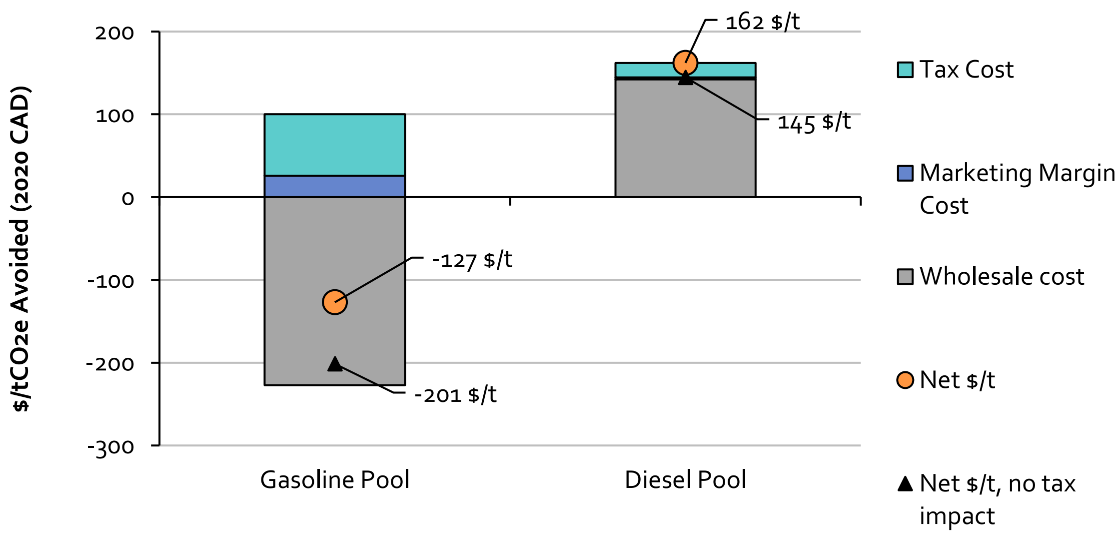
A further uncertainty in the cost analysis is the impact of renewable fuel blends on energy efficiency (defined here as unit of energy required per unit of distance traveled). The weight of evidence suggests that energy efficiency has not been impacted by current blending rates and there is no efficiency change included in the cost analysis. Yet the results would be dramatically changed if this were revised. 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 $8.2 billion from 2010 through 2020, equivalent to about a six-fold increase in the cumulative cost savings resulting from renewable fuel consumption.

4.5. GHG Abatement Cost

Figure 21 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 (including the wholesale cost, marketing cost and tax cost), divided by the cumulative avoided GHG emissions between 2010-2020 for the gasoline and diesel pools. Avoided cap-and-trade costs are not included in this calculation, nor are any additional costs savings, co-benefits (e.g., reduced health costs resulting from 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 (specifically: the impact of ethanol blending on vehicle energy efficiency and refinery GHG intensity is not included).

For interest, net abatement costs without the tax cost impact are shown. In other words, Figure 21 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 21: GHG abatement cost, with and without volumetric tax penalty 2010-2020



The cost of abatement from ethanol blending is -\$127/tCO_2e (Figure 21). 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 -\$201/tCO_2e if the excise taxes on ethanol and gasoline were equivalent on an energy basis. The abatement cost in the diesel pool is \$162/tCO_2e, or \$145/tCO_2e if fuel taxes were based on energy rather than volume.

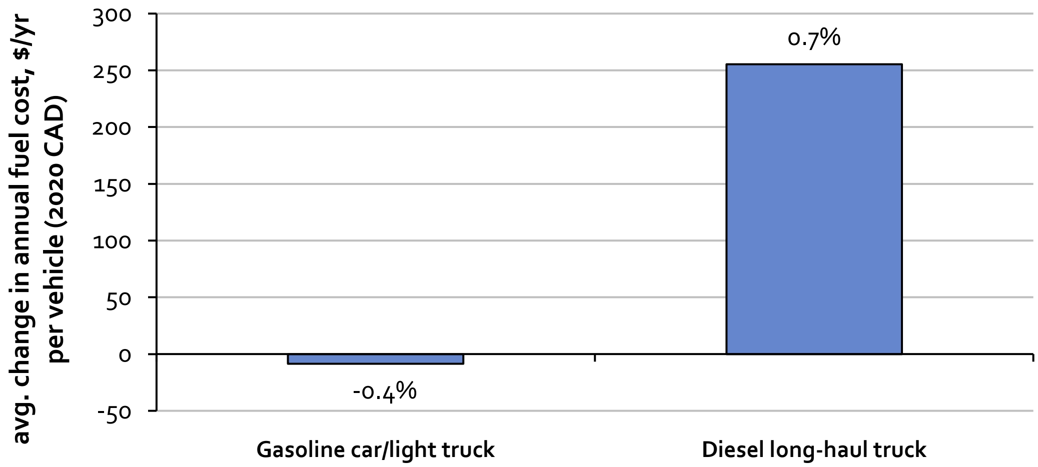
4.6. Consumer Cost Impact

Figure 22 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 15,900 km per year with an average fuel economy of 9.6 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 87,700 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 2010-2019 as reported by Natural Resource Canada in the Comprehensive Energy Use Database.

The average consumer of gasoline saved \$9/yr (-0.4%) because of ethanol blending in Canada. A typical heavy-duty diesel consumer spent an additional \$255/yr (+0.7%) because of biodiesel and HDRD blending (Figure 22). 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 between 1 to 1.5% of the diesel pool volume during the eleven-year study period, while a 2% average annual blend is considered feasible by even the most conservative fuel supplier. In contrast, biodiesel has generally accounted for 3% to 4.5% of the US diesel pool over the same period.[66] 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); based on recent and active capital investment activity, the latter case is actively underway in the US and Canada.

[66] US Energy Information Agency, 2022, September 2022 Monthly Energy Review, Tables 3.7, 10.4a 10.4b

Figure 22: Archetypal fuel consumer cost impact, annual average 2010-2020



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 British Columbia, 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 RLCFRR constrains the 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.

4.7. 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 22 (a light-duty gasoline vehicle and a long-haul diesel tractor-trailer).

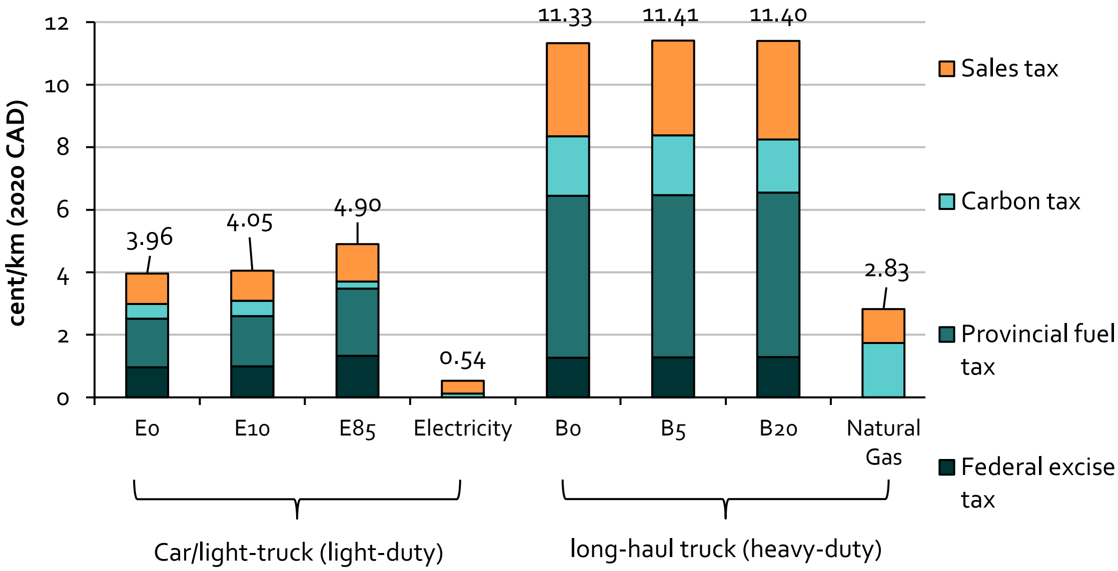
On average in Canada in 2020, the archetypal gasoline user paid 2.3% more tax per km when using E10 rather than E0. A similar trend exists for the diesel fuel, where an archetypal vehicle user consuming B5 pays 0.7% more tax per km travelled (Figure 23).

Again, this additional taxation (i.e., a "surtax") 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, such as 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 23 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). Furthermore, Québec and Nova Scotia had cap and trade systems in 2020 rather than carbon taxes (i.e. the carbon tax value in the figure would be zero). As well, the British Columbian carbon tax does not exempt renewable fuel blends above 10% in gasoline or 5% in diesel. However, in provinces where the federal carbon price is in force (i.e. the GGPPA) or whose policy closely emulates the GGPPA, the renewable portion of the B20 and E85 are exempt from the carbon price. As a final note, the carbon price tax impact in Figure 23 is calculated assuming fuel suppliers will apply for the GGPPA and pass that carbon tax savings on to consumers, but this may not happen in all cases.

In 2020, the octane value of the ethanol was higher than average resulting in the same sales tax per km for E10 and 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 and 2020. 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 when carbon prices, which do not distinguish between unblended fossil fuels and typical biofuel blends (e.g. E5 to E10, B2 to B5), are included.

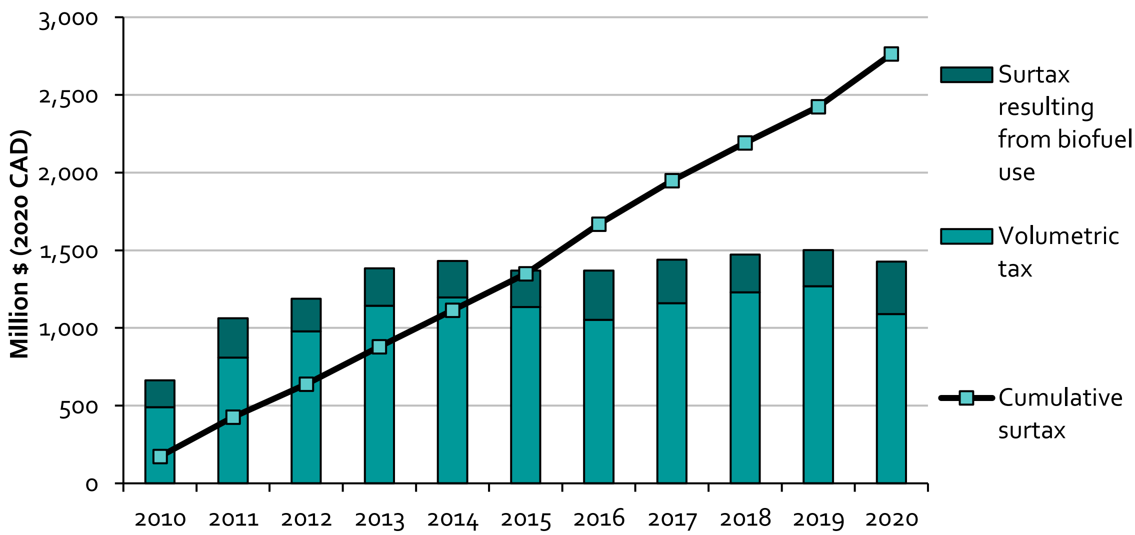
Figure 23: Fuel taxes and carbon costs for archetypal fuels and consumers, illustrative fuel consumption weighted average for Canada in 2020 (total shown in data label)



In 2020, these "surtaxes" taxes paid on biofuels amounted to an extra 31%/yr, or roughly $339 million (2020 CAD), relative to the tax that would have been paid if taxes were assessed equally on a "per unit of energy" basis instead of a "volumetric" basis within the gasoline and diesel pools (Figure 24).

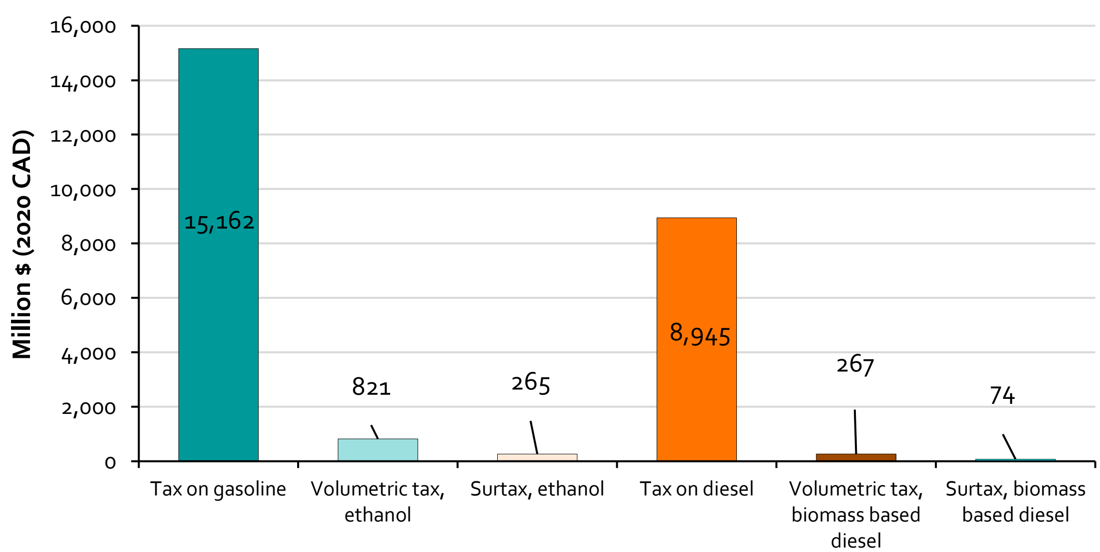
From 2010 to 2020, this surtax was equivalent to an additional 20%-35% tax paid on biofuels each year, or roughly $170 to $340 million/yr (2020 CAD), where the annual variation comes from variations in fuel prices, marketing margins and the value of octane from ethanol. The cumulative surtax cost impact since 2010 rose to about $2.8 billion (2020 CAD) in 2020 (note, this is the same as the total tax cost impact shown in Figure 20). Our estimate for 2021 shows that the tax cost impact will be even larger than in 2020, roughly $430 million, with the cumulative surtaxes paid on biofuels rising to just over $3.2 billion (2020 CAD).

Figure 24: Breakdown of fuel taxes paid on biofuels in Canada, with cumulative “Surtax” paid



Taxes paid on ethanol in Canada in 2020 account for 6.7% of the total taxes paid on fuel from the gasoline pool, where the “surtax” on ethanol is 1.6% of that total (i.e., the surtax is about a quarter of the total tax paid on ethanol). Taxes paid on biomass-based diesel represent 3.7% of the total taxes paid on the diesel pool in Canada in 2020. The “surtax” on biomass-based diesel is about 0.8% of that total (i.e., the surtax is about one fifth of that total) (Figure 25).

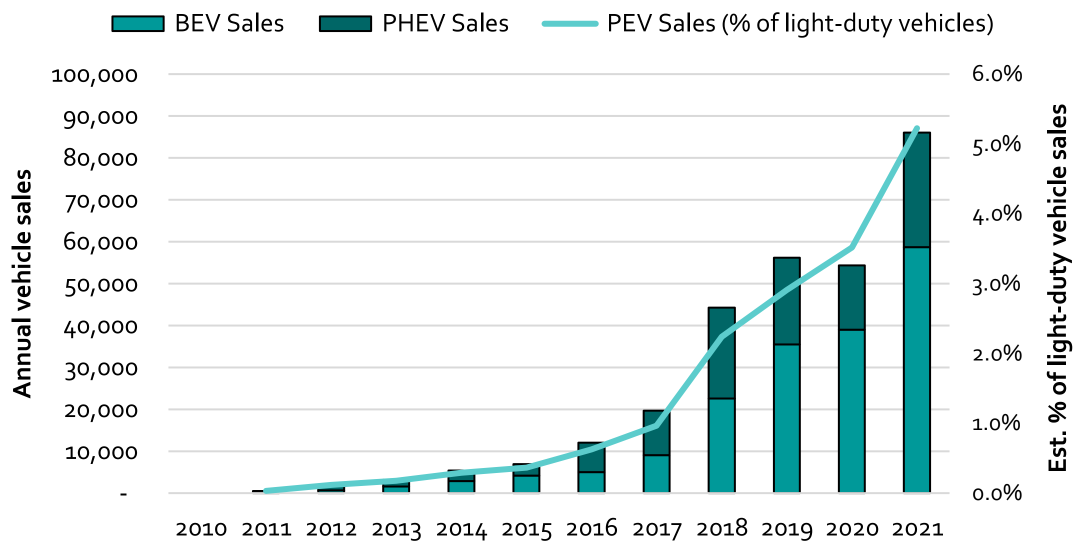
Figure 25: Breakdown of taxes paid on the gasoline and diesel fuel pools in 2020



4.8. Electric Vehicles

This analysis estimates how light-duty PEVs have affected gasoline consumption and GHG emissions. This broader classification can be broken down into “Battery Electric Vehicles” (BEVs) and “Plug-in Hybrid Electric Vehicles” (PHEVs), which are disaggregated in Figure 26 below. The former category is composed of cars which consume only electricity, while the second, PHEVs, also have on-board auxiliary engines which consume liquid fuel and can be used to extend their range.

Figure 26: Sales of light-duty PEVs in Canada, 2010-2021



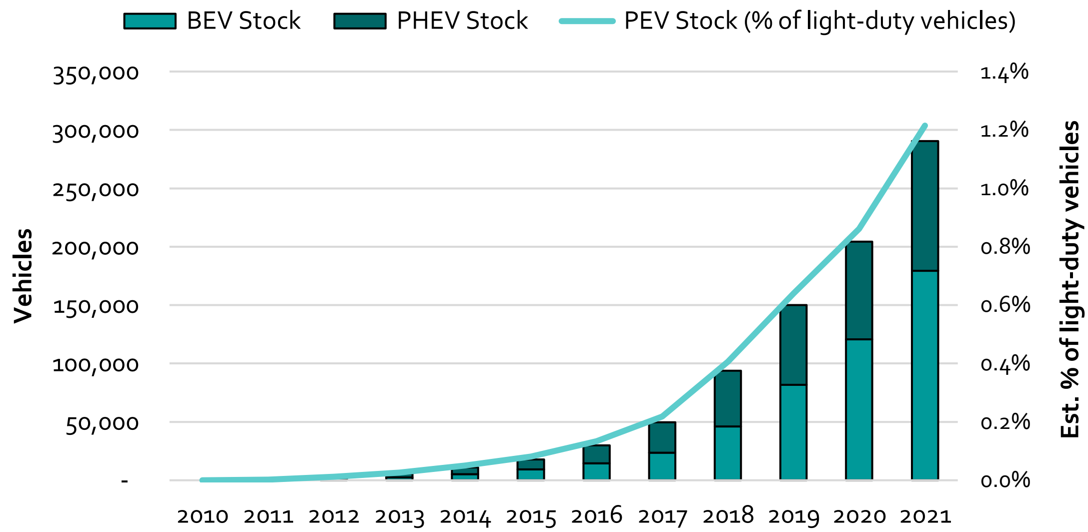
Source: Statistics Canada, New Motor Vehicle Registrations, Table: 20-10-0021-01

In 2020, PEVs accounted for 3.5% of light-duty vehicle sales in Canada, rising to 5.2% in 2021, equivalent to nearly 39,000 PEV sales in 2020, rising to 59,000 in 2021 (Figure 26). These relatively high sales rates for PEVs are heavily weighted by sales in specific provinces. In British Columbia, for example, we estimate that more than 11% of car sales were PEVs in 2021. Comparably, an estimated 9% of vehicle sales in Quebec were PEVs. In other provinces and regions, such as in Atlantic Canada, and in the prairies (Alberta, Saskatchewan, and Manitoba), PEVs accounted for between 1% and 2% of total light-duty vehicle sales.

These results are based on Statistics Canada data describing light-duty PEV sales, which feed into our calculation of PEVs on the road in Canada. Our intention is to track these statistics going forward as an indicator of how policy and consumer preferences impact PEV sales and use in Canada.

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 PEVs account for 1.2% of the light-duty vehicles on the road in Canada in 2021, up from 0.8% in 2020 (Figure 27). This estimate assumes all PEVs sold over the past nine (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. The stock of PEVs on the road is concentrated in the same provinces that have had higher PEV sales.

Figure 27: Light-Duty PEVs on the Road, 2010-2021



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 *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 beyond the levels estimated in this analysis.

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.[67] 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.[68] Another US paper found a 6% and 12% reduction in refining GHG emissions compared to E10 for E20 and E30 blends respectively.[69] 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 for E5 fuel. 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 CI of ethanol and MTBE production, resulting in a net impact of 1.2 gCO_2/MJ.[70] 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.[71] Catalytic reformers also produce hydrogen, and the emissions from producing the foregone hydrogen via steam methane reforming would undo the emissions benefit of less severe operation of the catalytic reforming.

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

[68] 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

[69] 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

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

[71] 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. However, given that current policies (e.g. the compliance category 1 of the *Clean Fuel Regulations*, federal tax credits for carbon capture and storage (CCS)) incentivizing the use of CCS with hydrogen production at refineries, this insight might not apply in Canada in the future.

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 28 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 19: CI of Gasoline versus Aromatics/Olefins in GHGenius 4.03a

Fuel	Exhaust Emissions (gCO_2e/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.[72]

An EPA study found a 1.8% reduction in CI 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.[73] This change in CI is for the blended fuel itself, seemingly including biogenic carbon, indicating a change in the CI of the pure gasoline component. 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.[74]

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).[75] 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.[76] 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.[77]

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

[73] 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

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

[75] 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

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

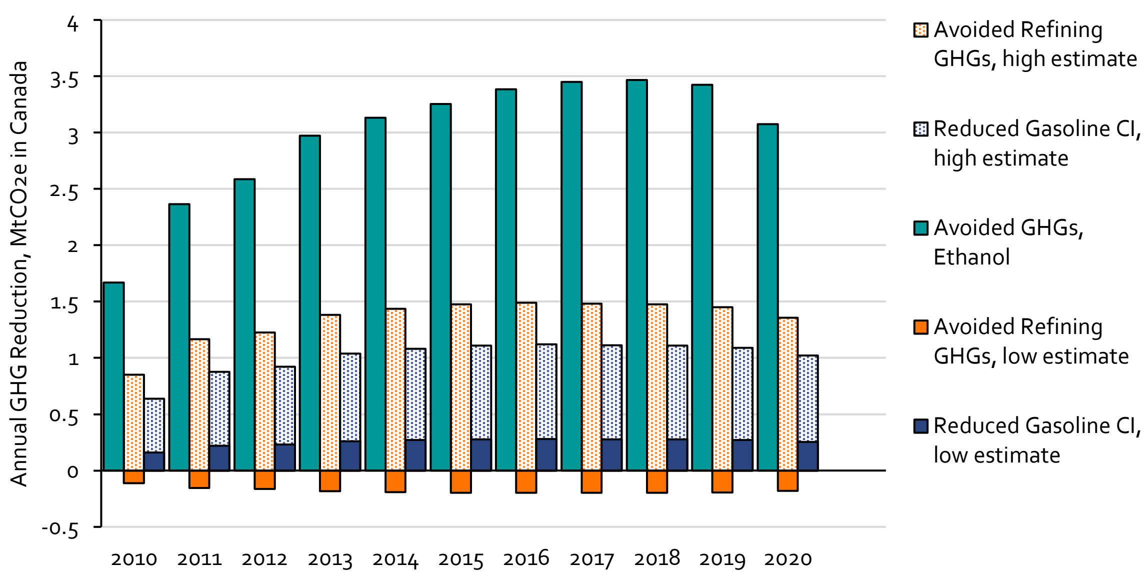
[77] Splash blending refers to mixing gasoline by splashing ethanol into an otherwise finished but suboctane fuel. Match blending refers to creating an ethanol fuel blend that matches certain characteristics of a non-ethanol blend, such as 50% distillation temperature or aromatic content.

There is a compelling argument that ethanol should reduce the CI 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 in Canada. 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 28 presents a range of how abatement at refineries and from reduced aromatics in gasoline compare to the avoided GHG estimate in this report (i.e. results only based on ethanol consumed in place of gasoline).

Figure 28: 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/yr in most years, in addition to the 3.5 Mt/yr of avoided emissions from simply displacing gasoline with ethanol. For reference, petroleum refineries in Canada emitted between 17 and 21

Mt/yr over the past decade. 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.[78] 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 by about 1.1 MtCO2e/yr in most years; about an additional third of the lifecycle effect of ethanol otherwise estimated in this report. The low-end of this potential impact would only result in an additional 0.3 $MtCO_2e$/yr of avoided GHG emissions in most years.

[78] Environment and Climate Change Canada, 2022, 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 2020, though volumes declined somewhat in 2020 relative to previous years due to the reduction in overall fuel consumption during the COVID pandemic (-6% in 2020 relative to 2019). The data indicates that the volume of ethanol consumed in Canada each year has increased from roughly 1,700 million L/yr in 2010 to 2,665 million L/yr in 2020. However, ethanol consumption in 2020 declined by over 300 million L/yr relative to 2019 (-11%), again due to less gasoline consumption during COVID. Although ethanol consumption declined in 2020, gasoline consumption declined proportionally more. Consequently, the blend rate of renewable fuels in gasoline increased to 7% in 2020, up from about 6.5% in 2019.

Biomass-based diesel consumption actually increased during the pandemic, rising by more than 100 million L/yr (13%) relative to 2019, with total consumption reaching almost 900 million L/yr. Growth in HDRD consumption continued to drive the increase in biomass-based diesel, while biodiesel consumption remained relatively constant from 2019 to 2020.

Our estimate for 2021 shows a rebound in ethanol consumption to pre-pandemic levels and further growth in biomass-based diesel consumption. In that year, estimated blend rates reach a new high of 7.3% in gasoline and 3.7% in diesel. These blending rates are in excess of what is required by the *Renewable Fuels Regulations* and indicate that fuel suppliers may not need to take any additional action to comply with the *Clean Fuel Regulations* until the third compliance period in 2025,

Avoided GHG emissions

The cumulative GHG emissions avoided between 2010 and 2019 are 60 $MtCO_2e$, including the contribution from PEVs and co-processed fuels. Despite a reduction in overall biofuel consumption in 2020 relative to 2019, annual avoided GHG emissions remained increased slightly to about 5.9 $MtCO_2e/yr$. Because of declining biofuel CIs, avoided emissions in 2020 were greater than in 2019, even though the total volume of renewable fuel was lower. As well, this analysis estimates the GHG emissions avoided from the use of light-duty PEVs, which were estimated at 0.6 $MtCO_2e$/yr in 2020, up from 0.5 $MtCO_2e$/yr in 2019.

Cost Impacts

Between 2010 and 2020, blending ethanol, diesel, and HDRD with conventional transportation fuels reduced consumer fuel costs in Canada by 0.13%, relative to what they would have been without renewable fuels. If all costs and savings were passed on to consumers, they saved $1.3 billion (2020 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, -\$127/tCO_2e, whereas the abatement cost from biofuel blending with diesel is positive at \$162/tCO_2e. Ethanol blending reduced the annual fuel costs of a typical driver by $9/yr (-0.54%) over the study period, relative to a scenario without ethanol consumption. Biodiesel and HDRD blending increased the annual fuel costs of a typical long-haul trucker by $255/yr (+0.7%).

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/levies/fuel charges; the application of sales taxes (PST, GST) amplifies the volumetric surtax 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 $2.4 billion (2020 CAD) during the eleven-year study period (2010 to 2020). The corresponding surtax cost on diesel consumers during that period was roughly $0.3 billion (2020 CAD). Without these additional tax costs, the net savings resulting from biofuel use during the 11-year study period would be over $4 billion rather than $1.3 billion (2020 CAD).

Appendix A: 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.[79] 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 British Columbia 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 British Columbia government.
2. British Columbia 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.
3. Estimates for 2021 (including CI's) are based on preliminary data interpolated from graphs found in a slide deck produced by the ministry of energy, mines and low-carbon innovation, "The Low Carbon Fuels Act, June 21, 2022"

[79] Ministry of Energy and Mines, 2022, Renewable and Low Carbon Fuel Requirements Regulation Summary: 2010-2020

Assumptions for Alberta

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

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 on review with Don O'Connor of (S&T)2 Consultants (80% soy as of 2020).

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 2021, which is based on the ratio in 2020.

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

Assumptions for Saskatchewan

1. Ethanol content for 2010-2012 and 2015 to 2021 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 2012-2021 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. However, as of 2020, we are assuming 50/50 canola/soy split based on input from Don O'Connor of (S&T)2 Consultants.

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 ethanol feedstocks are wheat and corn, transitioning primarily to corn based on the feedstocks processed in Manitoba facilities as reported by Husky Energy and from discussion with industry contacts.

3. We assume that biodiesel feedstocks are 50/50 canola and soy based personal correspondence with a government contact.

4. We assume there is no HDRD consumption prior to 2021 based on correspondence with Don O'Connor of (S&T)2 Consultants.

5. 2020 is estimated assuming compliance with the fuel regulation (constant blend rate from 2019).

6. 2021e is estimated assuming compliance with the updated fuel regulation (where the increase in the diesel pool is soy HDRD, assuming imports by rail from the Sinclair facility in Wyoming).

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 and 2018-2020. From 2016 to 2017, 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 British Columbia 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.

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.
8. For 2021, we assume biomass-based diesel is 40% biodiesel and 60% HDRD, based on 100% biodiesel consumption by lake freighters: www.cslships.com/en/media-center/news-events/csl-successfully-completes-worlds-largest-b100-biofuel-tests

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, up until 2020).

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 29 and Figure 30. Figure 29 shows the renewable fuel content in the diesel pool in Canada from 2010 to 2020, 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 30 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 29: National results for renewable fuel consumption of diesel pool by fuel type and feedstock

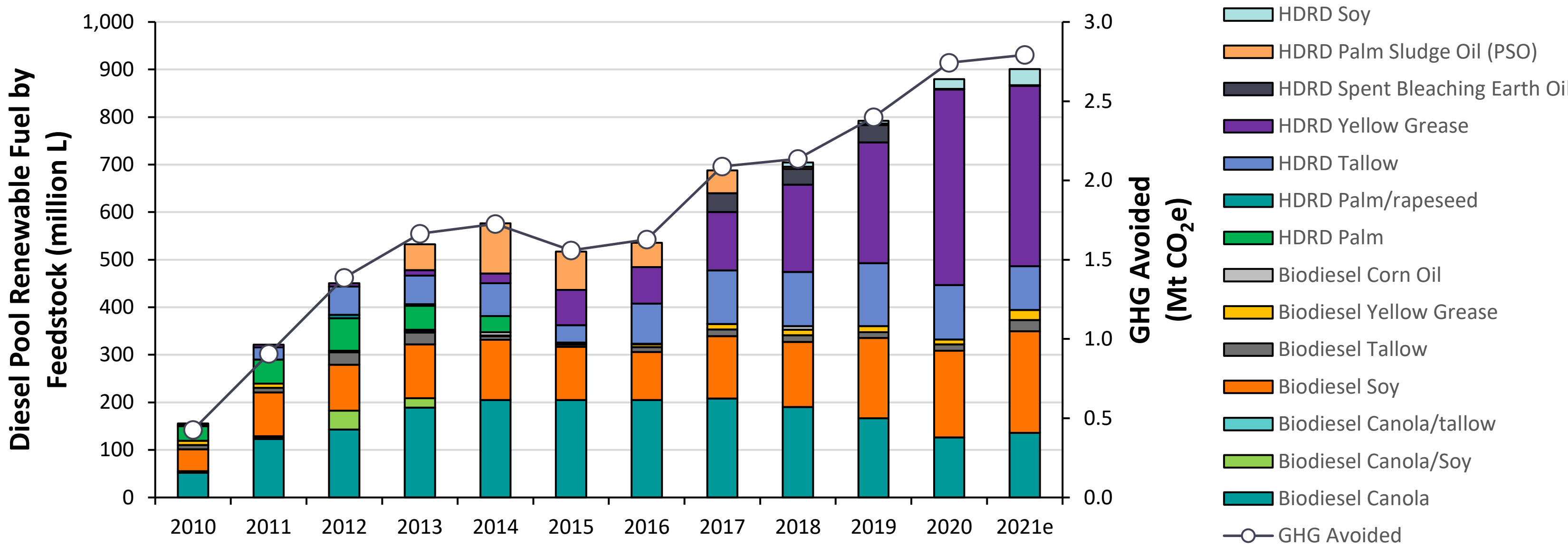
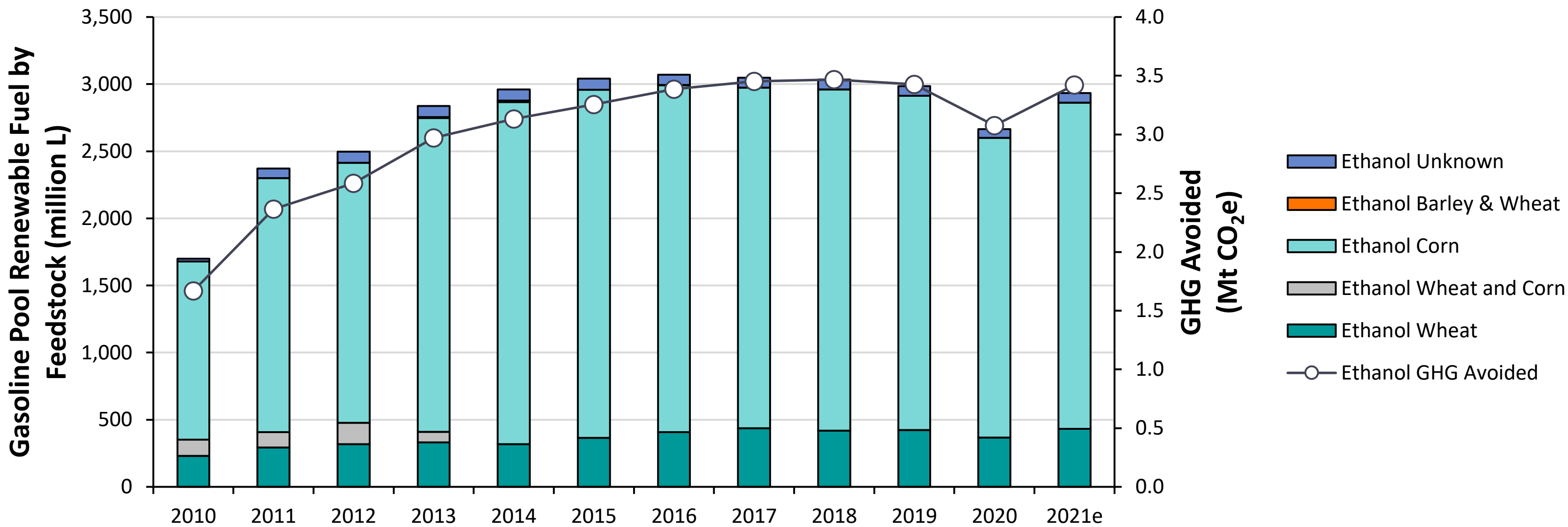


Figure 30: National results for renewable fuel consumption for gasoline pool by fuel type and feedstock



Appendix B: 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).[80]
- 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.[81]

[80] 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

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

- All values were converted to 2020 dollars[82] and Canadian currency from US dollars[83] and Euros.[84]

- Inputs for Atlantic Canada are constructed from provincial values averaged using population weights from Statistics Canada.[85]

- 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:

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

[83] Bank of Canada, 2022, Exchange Rates. http://www.bankofcanada.ca/rates/exchange/monthly-average-lookup/

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

[85] 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.[86]

- 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[87] 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[88]

- $O_{blend,prem}$ 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:

[86] 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.

[87] EIA. 2022. 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

[88] 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[89] and are assumed to be independent of biofuel blending rates. Taxes, including carbon taxes and levies, are from NRCAN.[90] 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.

- The credit price impact of the cap-and-trade system in Ontario, Québec and Nova Scotia 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.[91,92,93]

- 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 Canadian consumers from 2010-2019[94] as reported by Natural Resource Canada, for the

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

[90] NRACN, 2022, Fuel Consumption Taxes in Canada, https://www.nrcan.gc.ca/energy/fuel-prices/18885

[91] Government of Ontario. Past auction information and results. Accessed from: https://www.ontario.ca/page/past-auction-information-and-results (note this data is longer available)

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

[93] Government of Nova Scotia, 2021, Summary Results Report Nova Scotia Cap-and-Trade Program Auction of Emission Allowances

[94] The NRCan National Energy Use Database has not yet been updated with values for 2020; the 2010-2019 averages were assumed to remain unchanged for 2020 and 2021.

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.[95,96]

[95] Natural Resources Canada, 2022, Energy Use Data Handbook Tables, Passenger Transportation Explanatory Variables.

[96] Natural Resources Canada, 2022, Energy Use Data Handbook Tables, Freight Transportation Explanatory Variables.

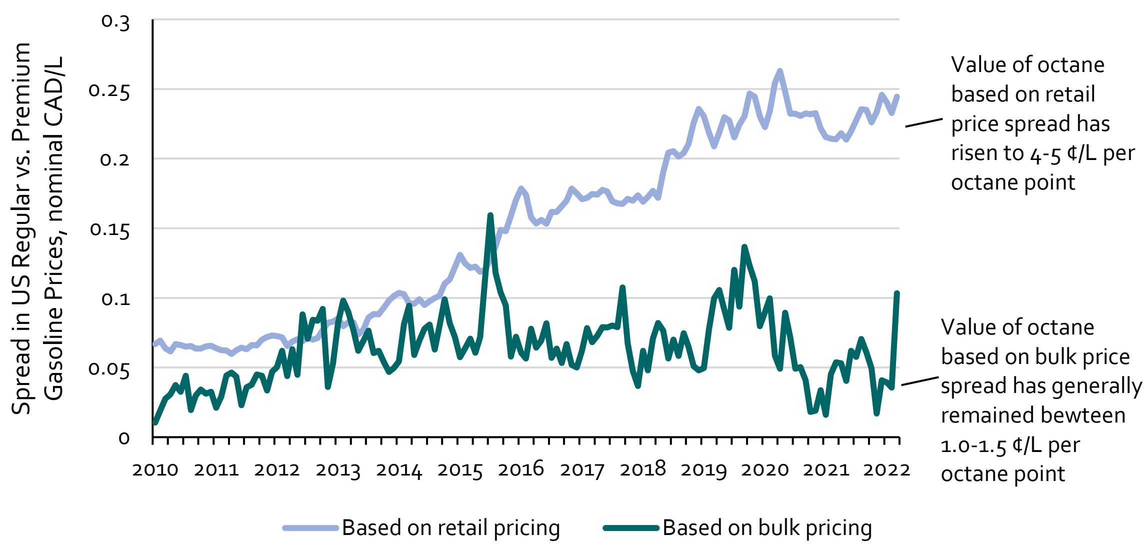
Appendix C: Explanation of Changes to Cost Analysis Methodology Made in 2021

Using Wholesale Instead of Retail Prices to Estimate Octane Value

Prior to the 2021 edition 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. Starting with the 2021 analysis, we used wholesale, rather than retail, price data to estimate the cost of octane. A comparison between the two is presented below.

Figure 31: Value of octane measured using retail and wholesale prices[97]



[97] EIA. 2022. 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

This methodological change resulted in a nearly \$300/tCO_2e increase to the abatement cost of using ethanol, though the estimated average abatement cost since 2010 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.[98] 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.

Likewise, 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).[99]

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. Starting in 2021, the analysis uses

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

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

a value of 92 to 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. Starting in 2021, this analysis uses these numbers to estimate the price of HDRD in Canada for 2016 and onward years (Neste data was used in previous years, where the DGD data is not available).

Appendix D: Plug-in Electric Vehicle Analysis Methodology

This year's report contains estimates for how PEV 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 PEVs was estimated using the following assumptions:
    a. All PEVs 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 stock of PEVs in British Columbia is equal to cumulative sales in that province alone.
    c. PEVs are driven the same amount as gas cars (about 15,000 km/year).
    d. PEVs use 19 kWh per 100km, an estimate of the sales weighted average of PEVs sold in Canada in 2021, with sales taken from GoodCarBadCar[100] and electric travel energy intensity taken from Natural Resources Canada.[101] We assume PHEVs have a utilization factor of 69% (this fraction of the vehicles travel uses the electric drive is from electricity, the rest is from gasoline)[102].

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[100] GoodCarBadCar, Automotive Sales Data and Statistics

[101] Natural Resources Canada, 2022, Fuel consumption ratings - Battery-electric vehicles 2012-2022 (2022-05-16)

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

e. PEVs have an energy efficiency ratio of 4.1, reflecting the difference in efficiency between electric and internal combustion engines, based on the ration used in the Regulatory Analysis within the *Clean Fuel Regulations*.[103]

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 PEVs, the average carbon intensities of electricity by province and year from Canada's National Inventory Report are used.[104] Theses direct carbon intensities are supplemented by "upstream" lifecycle GHG emissions factors that are based on the difference between the direct GHG intensities in the National Inventory Report for 2019 and the CI for electricity noted for each province in the *Clean Fuel Regulation* draft legislation[105] in schedule 5, point 8 (e.g. to account for fuel production emissions, methane emissions from hydro reservoirs etc.)

[103] Government of Canada, Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations

[104] See Part 3, Table A13-1 through 11

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