Biofuels in Canada 2024

Annual REPORT

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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.

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Executive Summary

There are many policies designed to reduce transportation greenhouse gas (GHG) emissions by increasing the consumption of renewable and low-carbon fuels in Canada. However, there is no detailed and comprehensive government source characterizing these policies and their impact. To address this, Advanced Biofuels Canada has engaged Navius Research to fill this information gap with the annual Biofuels in Canada report.

Objectives and Method

This report evaluates 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.
2. Reporting on fuel type, feedstock, and carbon intensity (CI) of these fuels: ethanol, biodiesel and renewable diesel. Co-processed fuels - produced from renewable feedstocks co-refined in a conventional refinery – are also included.
3. Presenting the sales and stock of light-duty electric vehicles
4. Quantifying the GHG emissions impact of these low-carbon energy types.
5. Estimating impact of renewable fuel consumption on energy costs, including the role of fuel taxation.

The analysis runs from 2010 to 2023 (where the most recent year includes some estimated data, indicated as “2023e” in figures in tables). The start of the analysis coincides with when renewable fuel policies first came into force across Canada and the end of the analysis is defined by data availability. The estimated year (2023) is relatively complete since it includes data, or preliminary data, from most reporting regions and national-level fuel consumption data from the *Clean Fuel Regulations* (CFR) Credit Market Data Report.

Renewable Fuel Consumption

Renewable fuel consumption in Canada increased by 20% from 2021 to 2022 and by another 25% from 2022 to 2023 (Figure 1). This rapid growth coincides with the CFR coming into force, the start of Québec’s renewable fuel policy, and increased stringency of other pre-existing provincial policies:

- Biodiesel and renewable diesel (RD) consumption was steady from 2021 to 2022. However, **RD consumption surged in 2023**. In that year, RD volume more than doubled relative to previous years. In 2023, RD consumption was almost 1.2 billion (giga, or G) L/yr while biodiesel consumption was 0.5 GL/yr.

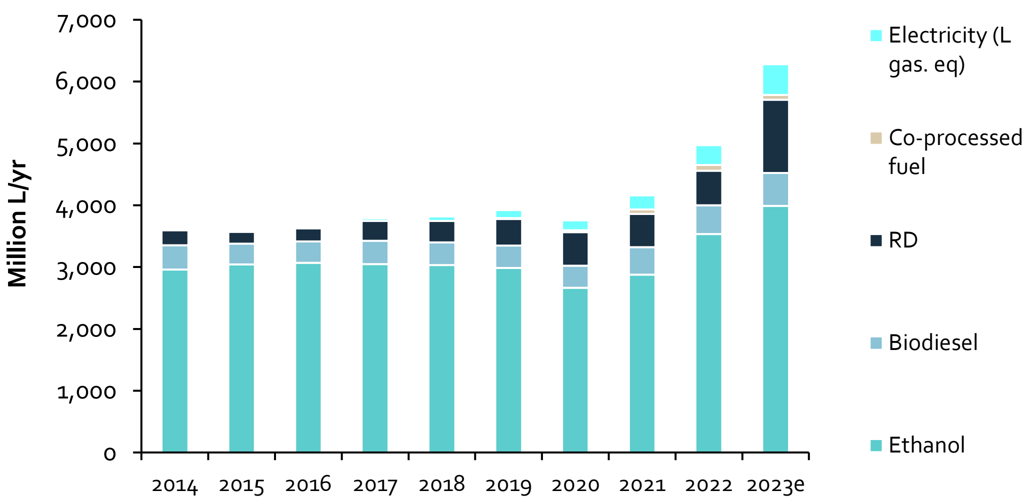
Change in clean fuel consumption, 2022 to 2023:
Ethanol +13%
Biomass-based diesel +68%
Electricity +55%

- **Similarly, ethanol volumes grew by 13% from in 2023, on top of 23% growth in 2022**. Ethanol consumption in 2023 was close to 4.0 GL/yr

- The volume of fuel displaced by electric vehicles is still substantially less than the volume of renewable fuels (about 0.5 GL of gasoline equivalents). However, the rate of growth is accelerating. **Electricity consumption by light-duty vehicles grew by 56% in 2023, on top of 41% growth in 2022**. In 2023, one of every ten light-duty vehicles sold in Canada was electric.

- As of 2023, co-processed fuel was still only being produced and consumed in the British Columbian market. The volume has been between 75 and 95 ML/yr for the past few years.

Figure 1: Total clean fuel consumption in Canada grew by 26% in 2023, on top of the 20% growth in 2022



As of 2023, the renewable fuel content in gasoline and diesel is well above the regulated minimum levels because of the fuel CI reductions required by the CFR and the BC LCFS. Ethanol makes up more than $9\%_{vol}$ of the gasoline pool, while biomass-based diesel content has grown from $3\%_{vol}$ to more than $6\%_{vol}$.

Cost Impacts: Renewable Fuels

Renewable fuel consumption may change overall fuel costs because of differences in commodity prices, differences in fuel energy density and differences in fuel properties (e.g., octane).

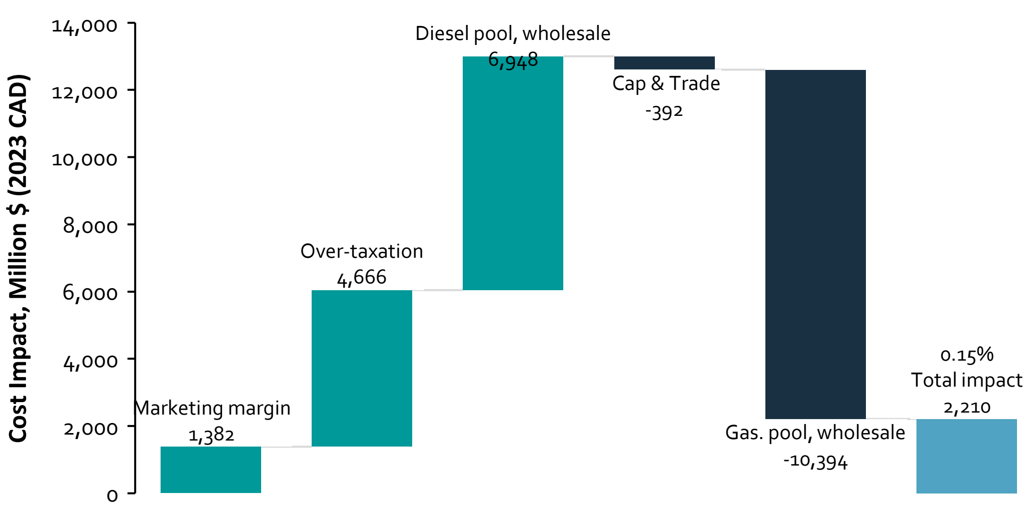
Renewable fuel consumption in Canada has increased cumulative consumer fuel costs by 0.15% from 2010 to 2023 (Figure 2).

Renewable fuels have added +0.15% to costs since 2010. In 2023:

- Ethanol reduced wholesale fuels costs by $1 billion
- Biomass-based diesel increased wholesale fuel costs by $1.5 billion

- In 2023, renewable fuel blending in gasoline reduced wholesale fuel costs by about $1 billion, or a cumulative savings of $10.4 billion since 2010. The price of ethanol, per liter, was less than gasoline and its high-octane rating means it can be blended with less expensive, lower-octane, gasoline.
- In contrast, renewable fuel blending in diesel increased the wholesale cost of fuels by $1.5 billion in 2023, or a cumulative additional cost of $6.9 billion since 2010
- Because renewable fuels are less energy dense than fossil fuels, we estimate that distributing and dispensing them has cost consumers an additional $1.4 billion from 2010 to 2023.
- Over-taxation of renewable fuels, also related to its lower energy density, cost consumers an additional $0.6 billion in 2023, or $4.7 billion since 2010.

Figure 2: Renewable fuel consumption has increased consumer fuel costs by 0.15% since 2010



Cumulative cost impact resulting from renewable fuel blending (2010-2023). Excludes impact of co-processed fuels and light-duty electric vehicles.

Renewable fuel consumption has reduced costs for gasoline consumers, while higher prices for biodiesel and RD in 2023 have resulted in a larger impact on diesel prices (assuming no cross subsidization of renewable fuels between the gasoline and diesel pool). Without renewable fuels, a typical heavy-duty vehicle might have spent about $37,150 on fuel in 2023. Low-carbon fuel consumption increased that cost to $38,400 (+3.4% in 2023, versus an average of +1.2% over the horizon of the analysis).

Cost Impacts: Over-Taxation on Renewable Fuels

Over-taxation on renewable fuels:

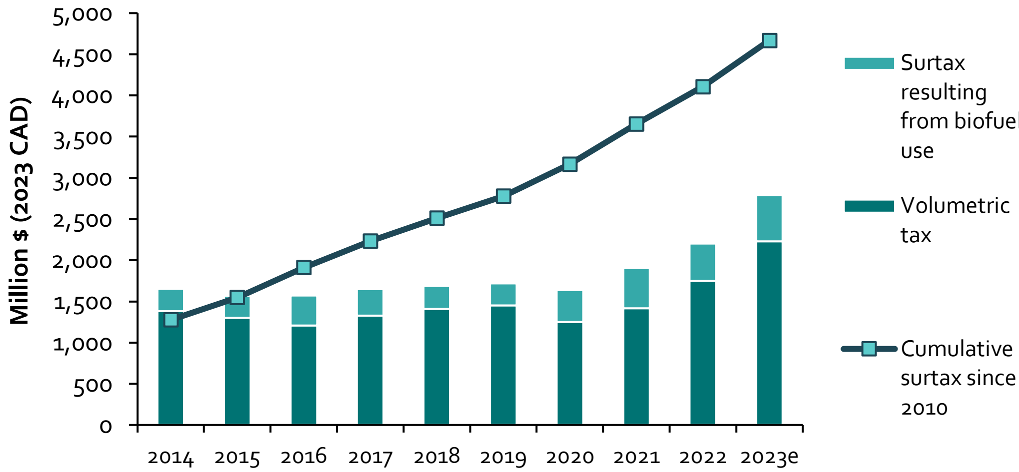
$4.7 Billion since 2010

$0.6 Billion in 2023

In 2023, a Canadian using E10 paid 2% more fuel taxes than someone using fossil gasoline. A B5 consumer paid 1% more fuel tax than someone using only fossil diesel. Over-taxation of renewable fuels exists for two reasons. First these fuels have a lower energy density that fossil fuels. Second, the federal and provincial governments have continued to tax all fuels equally on a per litre basis, regardless of energy content. This cost is the result of legacy tax policies. It has cost consumers about $4.7 billion between 2010 and 2023. Additional taxes are also paid because carbon taxes and levies are charged on low-level renewable fuel blends in most provinces (less than 10% in gasoline or 5% in diesel); In BC carbon taxes apply to renewable fuels regardless of the blend rate.

In 2023, over-taxation of biofuels amounted to an extra 26% in fuel taxes paid on biofuels, or roughly $0.6 billion (Figure 3). This amount is in addition 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 3). The cumulative over-taxation cost impact since 2010 rose to about $4.7 billion in 2023 (note, this is the same as the total tax cost impact shown in Figure 2). **If taxes were charged per unit of energy, renewable fuel consumption since 2010 could have saved consumers a total of $2.5 billion rather than costing them $2.2 billion.** Eliminating carbon taxes and levies on renewable fuels would have increased the savings while creating an additional incentive to consume these low-carbon fuels.

Figure 3: Volumetric taxation of biofuels means consumers paid an extra $0.6 billion in taxes in 2023



Cost Impacts: Fuel Standards vs. Carbon Pricing

The fuel price impact of the *Clean Fuel Regulations* is more than 10x smaller than the impact of a carbon tax with an equivalent $ per tonne CO_2 price

2023 marked the first compliance period for Canada's national low-carbon fuel standard, the *Clean Fuel Regulations* (CFR). Some have described the CFR as a second carbon tax, even though its price impact and purpose are very different.

Low-carbon fuel standards, like the CFR, have a much lower impact on fuel prices at the pump than carbon taxes, with equivalent credit and carbon prices. Characterizing them as a second carbon tax is incorrect. A low carbon fuel standard credit price and a carbon price with the same $/t$CO_2$e value have a very different impact on retail fuel prices because:

- A carbon tax applies to 100% of the direct GHG emissions (i.e., tailpipe emissions)
- A low-carbon fuel standard 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)
- Low carbon fuel standards in Canada will not create financial transfer to the government like a carbon tax does (except when paying into a technology fund or paying a penalty for non-compliance).

The fuel price impact at the pump created by a low carbon fuel standard is an order of magnitude smaller than the impact of a carbon taxes or levies, for a given carbon/credit price. For example, at \$150/tCO_2e with the CFR's 2025 CI limit, the retail price of E10 (90% gasoline, 10% ethanol) would increase by:

- 39 ¢/L with a carbon tax (34.5 ¢/L plus another 4.5 ¢/L in additional HST or GST).
- Less than 2 ¢/L with a low-carbon fuel standard.

Finally, a low-carbon fuel standard is not a carbon second tax because it creates a completely different policy signal. Carbon taxes and levies primarily create an incentive for consumers to use less fuel. In contrast, low-carbon fuel standards create an incentive for fuel suppliers to provide lower-carbon fuels, in a way that largely shelters consumers from the policy's compliance credit price.

Fuel CIs and Avoided GHG Emissions

The life cycle CI scores of clean fuels are well below those of fossil fuels. In other words, clean fuels produce many fewer GHG emissions per unit of energy consumed, across the whole supply chain (i.e., from well/farm to wheels):

GHG emissions avoided by clean fuels:
8.4 MtCO_2e/yr in 2022
11.4 MtCO_2e/yr in 2023

- The CI of ethanol is 55% less than gasoline (around 40 gCO_2e/MJ in 2023)
- The average CI of biomass-based diesel fuels is 87% less than fossil diesel (in the range of 9-12 gCO_2e/MJ over the last ten years)
- The CI of co-processed fuels has been about 92 to 95% below the CI of gasoline over the past few years (about 4-7 gCO_2e/MJ)
- The average CI for electricity used for transportation in Canada is about 95% less than the CI of gasoline on a gasoline equivalents basis (4 gCO_2e/MJ)

The CI of renewable fuels have been declining, yielding greater GHG abatement per unit of fuel consumed. This is a result of policies, such as the BC LCFS that create an incentive to consume lower-CI fuels. For example:

- In British Columbia from 2010 to 2023, the CI of ethanol decreased by 57%, the CI of RD decreased by 55%, and the CI of biodiesel decreased by 118%.
- In Ontario, the average reported CI for biomass-based diesel declined from 12 to 16 gCO2e/MJ in 2015 and 2016 to between 5 and 8 gCO2e/MJ over the past few years.

The GHG benefit of clean fuel consumption in Canada has grown substantially in the past few years. Avoided emissions were 8.4 $MtCO_2$/yr in 2022 and 11.4 $MtCO_2$/yr in 2023 (Figure 4). This trend is a function of stronger clean fuels policies. The avoided emissions in 2023 are roughly double what they were five years ago, before the start of the CFR, Québec's fuel regulation, and the increased stringency of many of the other existing provincial fuel policies and standards. Although electric vehicles are not directly affected by these policies, their share of avoided emissions has been increasing at the greatest rate, with an average growth of 45%/yr over the past five years.

Figure 4: GHG reductions from clean fuels have been growing exponentially since 2020

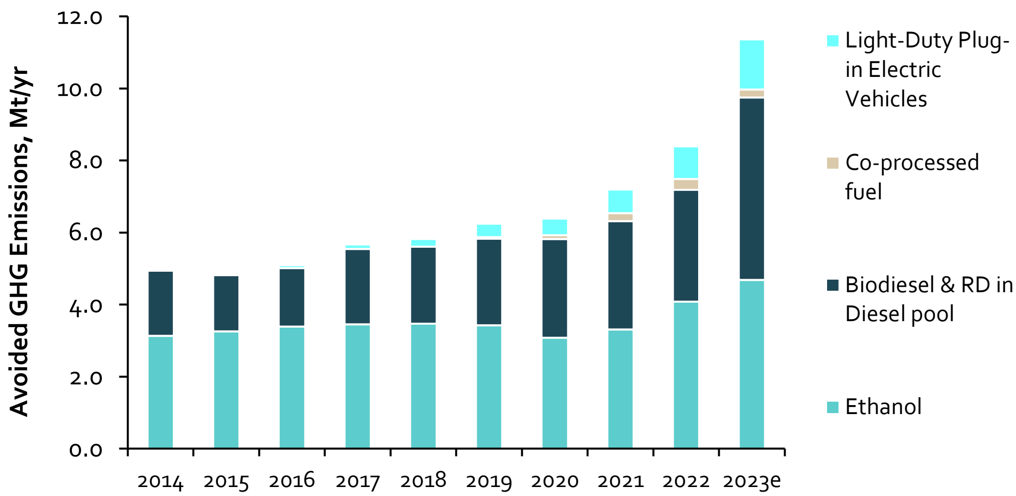


Table of Contents

Executive Summary i

1. Introduction 1

2. Canadian Policy Summary 2

2.1. Renewable Fuel Blending Requirements 2
2.2. Carbon Pricing 4
2.3. Low-Carbon Fuel Standards 6
2.4. Low-Carbon Fuel Production Incentives 9

3. Summary of the Methodology 11

4. Results and Discussion 14

4.1. Fuel Consumption 14
4.2. Blending Rates 16
4.3. Lifecycle GHG Emissions 18
4.4. Cumulative Costs 27
4.5. GHG Abatement Cost 31
4.6. Consumer Cost Impact 33
4.7. Detailed Tax Costs 34
4.8. Electric Vehicles 36

Appendix A: Canadian Policy Background 38

Provincial Renewable Fuel Blending Requirements 38
Carbon Pricing by Province 43
Detailed Description of Low-Carbon Fuel Production Incentives in Canada vs. the US 49
Low-Carbon Fuel Standards 51

Appendix B: Summary and Discussion of Inputs to the Analysis 66

Appendix C: Biofuel Type and Feedstock Assumptions and Data 72

Appendix D: Impact of Ethanol on Gasoline Refining and Consumption GHGs 79

Appendix E: Cost Analysis Methodology 82

Appendix F: 2021 Updates to the Cost Analysis Methodology 87

Appendix G: Plug-in Electric Vehicle Analysis Methodology 90

1. Introduction

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

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

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 2022 (with estimates for 2023). 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 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 affects GHG emissions and fuel consumption.

The quantitative analyses that support this report are contained in a Microsoft Excel spreadsheet. For more information, contact the Advanced Biofuels Canada Association. The remainder of this report provides a summary of the existing and upcoming policies that affect renewable fuel consumption in Canada. This is followed by a description of the analysis methodology and discussion of the results. The appendices contain more detail on the methodology and assumptions of this analysis.

2. Canadian Policy Summary

This section summarizes the existing federal and provincial renewable fuel policies in Canada, as of autumn 2024, to provide an understanding of the regulations driving renewable fuel consumption and supply. More detail and discussion of these policies is available in Appendix A: Canadian Policy Background. These policies fall into four categories:

- **Minimum renewable fuel blending requirements**, that set a floor for the renewable and low-carbon fuel content in a fuel pool, most commonly in gasoline and diesel. As of 2024, these regulations exist in all provinces except for those in Atlantic Canada.
- **Carbon pricing**, where a tax is levied per volume of fuel purchased based on the combustion GHG emissions resulting from that fuel consumption multiplied by a carbon price. Renewable fuel volumes may or may not be exempt from carbon pricing. At the pump, consumers are charged for all GHG emissions resulting from their fuel consumption. However, these revenues may be returned to households via rebates and tax cuts. Carbon pricing exists across Canada
- **Low-carbon fuel standards**, which require fuel suppliers to reduce the average lifecycle CI of transportation fuels by blending renewable and low-carbon fuels, undertaking other allowed GHG abatement actions, or purchasing compliance credits from entities that have carried out these abatement actions. These policies create a carbon price signal that incentivize renewable fuel supply. However, these policies do not create a second carbon tax and consumers are not charged for the carbon emissions from their fuel at the pump. Instead, the cost impact is a function of differences in the supply cost of conventional and low-carbon fuels. The *Clean Fuel Regulations* (CFR) apply across Canada, while the British Columbia *Low Carbon Fuel Standards* (LCFS) also applies in that province.
- **Low-carbon fuel production incentives**, which may incentivize fuel production (e.g., a tax credit or subsidy paid per volume of fuel) or may incentivize investment in fuel production (e.g. an investment tax credit, an upfront subsidy).

2.1. Renewable Fuel Blending Requirements

National minimum renewable fuel blending requirements are currently defined in the CFR at 5% in gasoline and 2% in diesel.[1] Although this policy is primarily a CI-based performance standard, it retains the same minimum blending rates of the previous *Renewable Fuels Regulations* (RFR), which had existed since 2010 for gasoline and 2011 for diesel. The CFR superseded the RFR at the end of 2022, while expanding the types of eligible alternative fuels

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

to be any 'low-carbon-intensity fuel' recognized under the regulation.[2] These federal regulations require 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.

Alongside the national policy, there are several provincial policies which mandate specific volumes of renewable content in fuel pools (see Table 1 for requirements in gasoline and. Table 2 for diesel). Some quantities of gasoline and diesel are exempt from these blending policies. For example, the gasoline and diesel pools in Newfoundland and Labrador are not covered by the minimum blending rates prescribed by the CFR, though they are still subject to its CI requirement. Likewise, Newfoundland and Labrador, the Territories, as well as other regions north of 60 degrees latitude were exempt from the RFR. As well, fuel blending regulations in both Ontario and Québec prescribe 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. The appendix describes the renewable fuel blending policies for each province in more detail.

Table 1: Minimum required renewable fuel content in gasoline

Region	2010	2011 to 2019	2020	2021	2022	2023/2024
BC	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Alberta	-	5.0%	5.0%	5.0%	5.0%	5.0%
Saskatchewan	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Manitoba	8.5%	8.5%	8.5%	9.25%	10%	10%
Ontario	5.0%	5.0%	10%	10%	10%	10%
Québec	-	-	-	-	-	10%
Canada	-	5.0%	5.0%	5.0%	5.0%	5%

2 Ibid.

Table 2: Minimum required renewable fuel content in diesel

Region	2010	2011	2012 & 2013	2014 & 2015	2016	2017 to 2020	2021	2022	2023/ 2024
BC	3.0%	4.0%	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%	2.0%
Sask.	-	-	2.0%	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%	5.0%
Ontario	-	-	-	2.0%	3.0%	4.0%	4.0%	4.0%	4.0%
Québec	-	-	-	-	-	-	-	-	3.0%
Canada	-	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2%

The Atlantic provinces are not subject to provincial fuel blending policies. These regions have been excluded from Table 1 and Table 2.

British Columbia has also implemented a minimum blending requirement in jet fuel, starting at 1%$_{vol}$ in 2028 and rising to 3%$_{vol}$ by 2030.[3]

2.2. Carbon Pricing

Carbon pricing in Canada is defined by the federal *Greenhouse Gas and Pollution Pricing Act* (GGPPA). The GGPPA, also referred to as the federal fuel charge, applies to provinces that chose to not to implement an equivalent carbon pricing system of their own. As of fall 2023, these include all provinces except British Columbia and Québec.

The GGPPA also defines the stringency of carbon pricing required in provinces with their own systems. British Columbia and Québec continue to use their provincial carbon pricing systems, which are deemed to be of equal or greater stringency to the federal backstop price. The British Columbia Carbon Tax follows the same schedule as the federal carbon tax and has a very similar impact on fuel prices at the pump. Québec uses a GHG cap-and-trade system that is linked with a similar program in California's. Therefore, the impact of carbon pricing on fuel price in Québec will vary as a function of the market price for carbon credits. Provincial carbon pricing policies are described in the appendix, including those that preceded the GGPPA.

The federal fuel charge began at $20/tonne in 2019 and increased by $10/yr to $50/tonne in 2022.[4] In 2023, the price began to increase by $15/yr and is scheduled to reach

[3] Government of British Columbia (2023). Low Carbon Fuels (General) Regulation.

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

\$170/tCO_2e in 2030.[5] The fuel charge rates shown in Table 3 account for the minimum volumetric renewable fuel content required in Canada (5% in gasoline and 2% in diesel) by reducing the rates by 5% on gasoline and 2% on diesel. Biofuel volumes pay the same rate as the fossil fuel (i.e., gasoline or diesel) up to 10% in gasoline and 5% in diesel; biofuels used in blends greater than 10% (e.g., >E10) in gasoline or 5% (e.g., >B5 or >R5[6]) in diesel are fully exempt from the carbon price.[7] As of 2024, the carbon levy rates are about 18 ¢/L on gasoline and 22 ¢/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. Revenues collected from the GGPPA are returned as rebates to households and small businesses.[8]

Table 3: Federal fuel charge rates on gasoline and diesel blends up to E10 and B5/R5 (nominal CAD)[9]

	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Carbon price, \$/tCO_2e	\$30	\$40	\$50	\$65	\$80
Gasoline, ¢/L	6.63	8.84	11.05	14.31	17.68
Diesel, ¢/L	8.05	10.73	13.41	17.28	21.46

Because this carbon price does not differentiate by blend rates up to E10 and B5/R5, there is a foregone price incentive to use lower-carbon fuels and a foregone cost savings for consumers of these fuels. This impact will increase 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/R5 by about ¢1.5/L. Note that the over-taxation in this example does not account for additional taxation on biofuels due to their lower energy densities and tax rates that are set per-litre rather than per unit of energy. Based on fuel consumption in 2023 (about 42 billion L of blended gasoline and 28 billion L of blended diesel) and assuming widespread E10 and B5/R5 consumption, the federal carbon tax design will have consumers pay an additional \$1.5 billion per year in 2030.

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

[6] A caution to readers of the GGPPA legislation: Biodiesel within that statute refers to bio-based diesel fuel substitutes, including biodiesel (i.e., FAME) and RD.

[7] McKenna, C., Morneau, W.F., 2018, Explanatory Notes Relating to the Greenhouse Gas Pollution Pricing Act and Related Regulations . See section 8(5) and section 8(6) of GGPPA.

[8] Government of Canada, Canada Carbon Rebate (CCR) for individuals, Accessed October 2024

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

Table 4: The over-taxation/foregone price incentive on E10 and B5/R5 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
Over-taxation /foregone price incentive on E10, ¢/L	1.0	1.2	1.5	1.7	1.9	2.2	2.4	2.6
Over-taxation /foregone price incentive on B5/R5, ¢/L	0.6	0.7	0.8	1.0	1.1	1.2	1.4	1.5

In Canada, renewable fuels used by large industrial firms are generally not covered by carbon pricing. They are exempt from the Québec cap and trade and in all other provinces, industrial operations above a certain threshold of emissions are eligible to opt into, or required to participate in, various output-based pricing systems (OBPS). OBPS-regulated firms receive a fuel charge exemption certificate, meaning fuel distributors delivering fuel to the industrial sites are not required to remit the carbon charge on the fuel, because the industrial firm will manage and remit the necessary compliance. OBPS-regulated firms are not required to remit compliance for the CO_2 emissions associated with quantified renewable fuel consumption.

There is political uncertainty around the future of the GGPPA and the carbon pricing based on this act. The Conservative Party of Canada has promised to eliminate all carbon taxes if they are elected and tend to focus on the fuel charge (e.g., with the "axe the tax" slogan).[10] The government of British Columbia stated that it would suspend its carbon tax if the federal fuel charge were eliminated.[11] The Conservative Party of British Columbia pledged to eliminate all carbon taxes if elected[12], though this could only happen if the federal taxes were removed. Consequently, a Conservative victory in the next federal election, which will be called before fall 2025, could result in the end of carbon pricing on consumer fuels across Canada (potentially with Québec as the exception).

2.3. Low-Carbon Fuel Standards

There are two low-carbon fuel standard policies in Canada: The Canada-wide CFR, and the British Columbia LCFS. Both policies require fuel suppliers to reduce the average CI of the covered fuels supplied in each jurisdiction, which include gasoline, diesel, and as of the end

[10] Conservative Party of Canada, Stop Trudeau's Carbon Tax 2 and Axe the Tax, accessed October 2024

[11] Canadian Press, Sept 12 2024, B.C. will scrap consumer carbon tax if Ottawa drops requirement

[12] Conservative Party of British Columbia, John Rustad Exposes Eby's Carbon Tax Lie: Swapping One Tax for Another to Punish Working British Columbians, accessed October 2024.

of 2023, jet fuel in British Columbia. The obligated parties need only comply on average and may trade compliance credits amongst themselves. Alternatively, they may buy compliance credits from other parties that voluntarily carry out abatement actions to generate compliance credits. The policies do not prescribe how compliance must be achieved. Instead, they allow a range of compliance actions including blending renewable fuels, switching to lower-carbon forms of transportation energy (e.g., electricity or hydrogen), or carrying out other GHG abatement projects (e.g., reducing GHG emissions associated with oil production, using renewable feedstocks in refineries). Table 5 summarizes each policy and more detail is available in Appendix A: Canadian Policy Background.

Table 5: Summary of the CFR and British Columbia (BC) LCFS

	CFR	BC LCFS
Coverage and start date	Covers gasoline and diesel supplied in Canada, including BC. First compliance period was 2023.	Covers gasoline, diesel and jet fuel supplied in BC. First compliance period was 2013.
2030 CI reduction requirement	14 gCO_2e/MJ lower than a 2016 baseline (about a 15% CI reduction).	-30% for gasoline and diesel relative to a 2010 baseline. -10% for jet fuel
Min. renewable fuel blend rates	5%$_{vol}$ in gasoline 2%$_{vol}$ in diesel	5%$_{vol}$ in gasoline 4%$_{vol}$ in diesel 3%$_{vol}$ in jet fuel (by 2030)
Compliance actions and fuels (i.e., what generates compliance credits)	Blending renewable fuels. Low-carbon transportation energy: electricity, hydrogen, natural gas. Reducing upstream oil production GHG emissions. Low-carbon gaseous fuel supply.	Blending renewable fuels. Low-carbon transportation energy: electricity, hydrogen, natural gas. Initiative Agreements (i.e. special projects that reduce GHG emissions).
Flexibility mechanisms and penalties	Compliance credit trading. Compliance Credit banking and borrowing. Contribution to a technology fund for $350/$tCO_2e$ (i.e. per credit), plus inflation. Early compliance in 2022. A rollover of surplus RFR credit.	Compliance credit trading. Credit banking. $600/$tCO_2e$ (i.e., per credit) penalty for non-compliance.

	CFR	BC LCFS
Recent credit prices	\$133/tCO_2e, average in 2023[13]	\$476/tCO_2e, average ytd in 2024[14]
Legislation	Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations	the *Low Carbon Fuels Act* and the *Low Carbon Fuels (General) Regulation*

Both the BC LCFS and the CFR have been targeted by opposition political parties. The Conservative Party of British Columbia pledged to eliminate the BC LCFS, along with the BC carbon tax.[15] Likewise, the conservative party of Canada has also pledged to eliminate the CFR if they are elected, characterizing it as a second carbon tax.[16]

Low-carbon fuel standards have a much lower impact on fuel prices at the pump than carbon taxes and characterizing them as a second carbon tax is incorrect. A low carbon fuel standard and a carbon price with the same \$/tCO_2e value have a very different impact on retail fuel prices because:

- A carbon tax applies to 100% of the direct GHG emissions (i.e., tailpipe) associated with a fuel
- A low-carbon fuel standard 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)
- Low carbon fuel standards in Canada will not create financial transfer to the government like a carbon tax does (except when paying into a technology fund or paying a penalty for non-compliance).

The fuel price impact at the pump created by a low carbon fuel standard is an order of magnitude smaller than the impact of a carbon taxes or levies, for a given carbon/credit price. For example, at \$150/tCO_2e with the CRF's 2025 CI limit, the retail price of E10 (90% gasoline, 10% ethanol) would increase by:

- 39 ¢/L with a carbon tax (34.5 ¢/L plus another 4.5 ¢/L in additional HST or GST).
- Less than 2 ¢/L with a low-carbon fuel standard.

13 Environment and Climate Change Caada, 2024, Clean Fuel Regulations credit market report, June 2024

14 Government of British Columbia, LCFS Credit Market Data.

15 Conservative Party of British Columbia, John Rustad Exposes Eby's Carbon Tax Lie: Swapping One Tax for Another to Punish Working British Columbians, accessed October 2024.

16 Conservative Party of Canada, Stop Trudeau's Carbon Tax 2 , Accessed October 2024

The example behind these results is elaborated on 56 in the appendices. Note that these cost impacts are based on an idealized market where no party can exert market power over contracted fuel prices. Consequently, this analysis indicates what the CFR cost impact could be, but the actual outcome may differ.

Finally, a low-carbon fuel standard is not a carbon second tax because it creates a completely different policy signal. Carbon taxes and levies primarily create an incentive for consumers to use less fuel. In contrast, low-carbon fuel standards create an incentive for fuel suppliers to provide lower-carbon fuels, in a way that largely shelters consumers from the policy's compliance credit price.

2.4. Low-Carbon Fuel Production Incentives

In 2023, Québec introduced a production tax credit to support biofuel production in that province:

- For biomass-based diesel, producers in Québec will receive a tax credit worth 20-40 ¢/L (if the CI is between 0 to 20 gCO2e/MJ).
- For ethanol, the credit is between 5-15 ¢/L (if the CI is from 15 to 40 gCO2e/MJ).

Until 2027, the tax credit is additional to any other policy support a fuel may receive. However, after 2027, the production tax credit is net of other policy support.[17] In practice, if a fuel earns even $100/tCO_2e per CFR credit it generates, the net tax credit is zero unless the fuel's CI extremely low.

In contrast, the US Clean Fuels Production Credit (CFPC):

- Provides a CI-dependent tax credit ranging from 0 to about 34 ¢/L (CAD) for low-carbon gasoline and diesel substitutes produced in the US, regardless of where they are consumed.
- Is scheduled to be in force until the end of 2027, but like the biomass-based diesel blenders tax credit, the previous tax credit it replaces, its duration could be extended.

[17] Assemblée National du Québec, 2022, Projet de loi no 6 (2023, chapitre 2), Loi donnant suite à des mesures fiscales annoncées à l'occasion du discours sur le budget du 22 mars 2022 et à certaines autres mesures

And

Revenue Québec, 2023, Tax Credit for Biofuel Production in Québec

- Has no claw-back related to other policy support. Therefore, a US-based low-carbon fuel producer supplying fuel to Québec would benefit from both the CFPC and the CFR while a Québec-based producer would eventually only earn CFR credits.[18]

There have been no federal producer tax credits available in Canada since the ecoEnergy for Biofuels program expired in 2017.

[18] H.R. 5376 — 117th Congress: Inflation Reduction Act of 2022

3. Summary of the Methodology

Table 6 summarizes the methodology. Appendix B: provides more information on the inputs and assumptions used in Biofuels in Canada, with additional methodological details provided in the rest of the appendices.

Table 6: 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 edition of the analysis includes January 1, 2010, to December 31, 2022, for all reporting regions. Data for 2023 was available from British Columbia, Ontario, Saskatchewan as well as from the federal government in the CFR Credit Market Report. Preliminary data was also available from Alberta. Biofuel products were defined as: ethanol, biodiesel, renewable diesel (RD), as well as co-processed renewable fuels (See Box 1 below for an explanation of co-processing). 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 data on 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.

Task	Approach
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. RD prices were estimated using 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.
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 2023	For provinces where no 2023 data was yet available, volumes and GHG impacts were estimated for 2023, assuming constant biofuel blending rates from 2022, or a trend based on a change in the regulated fuel blending rate. These assumptions were developed to keep total renewable fuel consumption consistent with the national totals reported in the CFR Credit Market Report for 2023. Statistics Canada data is used to define the size of the gasoline and diesel pools. Carbon intensities for 2023 are taken from GHGenius or assumed based on provincial data for 2022.

The time horizon of this analysis is from 2010 to 2023, running from when renewable fuel regulations were first implemented across Canada to the most recently available data. The figures and tables in this report show data for the past decade (or last five years in some cases) to clearly show recent trends. Nonetheless, the full span of the analysis remains available in the excel spreadsheet.

The 2023 data year is relatively complete in the current edition of Biofuels in Canada since it includes data, or preliminary data, from most reporting regions and national-level fuel consumption data from the CFR Credit Market Data Report, published by ECCC. However, it still contains some estimations and is labelled as “2023e” in the figures and tables.

Box 1: What is Co-Processing?

Co-processing is 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 RD are manufactured by stand-alone plants or dedicated production lines within a refinery. Finished biofuels are then mixed with gasoline and diesel.

As of 2023, the combined co-processing capacity in British Columbia (Parkland and Tidewater) is in the range of 100 million litres of co-processed feedstock per year. For reference, total biodiesel and RD consumption in BC was about 830 million litres in 2023.

4. Results and Discussion

The results section summarizes data on:

- The biofuel content of transportation fuels sold in Canada.
- An estimate of the quantity of electricity consumed by light-duty PEVs.
- Avoided GHG emissions resulting from the consumption of renewable fuels and electricity for transportation.
- Cost impacts associated with blending ethanol, biodiesel and RD with gasoline and diesel (co-processed fuels and PEVs are not part of the cost analysis).
- Light-duty PEV sales and the total number of light-duty PEVs on the road.

The results in this section are reported at a national level. They are available at a provincial level along with the full analysis in the associated excel spreadsheet. For more information, contact the Advanced Biofuels Canada Association.

4.1. Fuel Consumption

Renewable fuel consumption in Canada increased by 25% in 2023, on top of the 20% increase in 2022. Figure 5 and Table 7 summarize the fuel consumption data as well as the light-duty PEV electricity consumption data (expressed in terms of litres of gasoline equivalent):

- Biodiesel and RD consumption were steady from 2021 to 2022. However, RD consumption surged in 2023. In that year, the RD volume more than doubled relative to previous years, coinciding with the CFR coming into force in July 2023.
- Similarly, ethanol volumes grew by 13% in 2023, on top of 23% growth in 2022.
- The volume of fuel displaced by electric vehicles is still substantially less than the volume of renewable fuels. However, the rate of growth is accelerating. Electricity consumption by light-duty vehicles grew by 56% in 2023, on top of 41% growth in 2022.

Figure 5: Total clean fuel consumption in Canada grew by 25% in 2023, on top of 20% growth in 2022

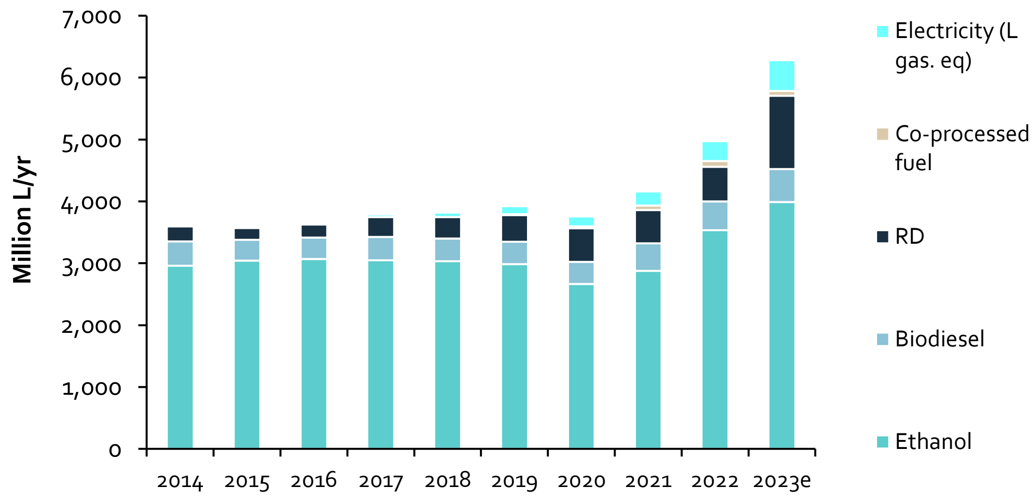


Table 7: Canadian fuel consumption in million litres per year (or L equivalent for electricity)

Fuel type	2017	2018	2019	2020	2021	2022	2023e
RD	321	342	432	543	537	557	1,184
Biodiesel	379	369	360	355	449	466	531
Ethanol	3,047	3,034	2,985	2,665	2,876	3,536	3,992
Co-processed	0	0	15	36	72	94	76
Electricity*	43	74	128	159	227	320	499
Gasoline (Pure)	42,388	42,633	42,161	36,272	36,971	37,405	38,281
Diesel (Pure)	26,951	26,972	26,538	24,654	25,887	26,602	25,797

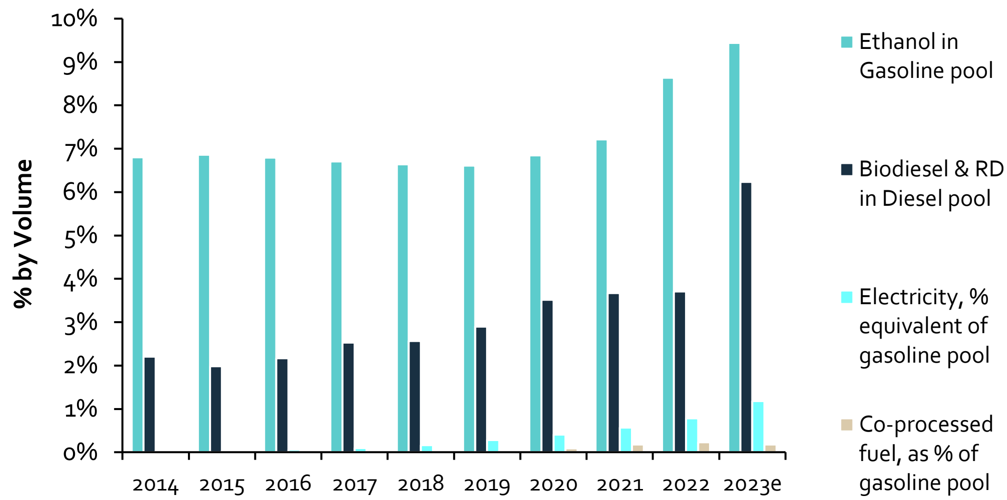
At a provincial level, most of the growth in RD consumption from 2022 to 2023 occurred in British Columbia and Québec (where the volume in Québec is inferred from national CFR data and data from other provinces). Growth in ethanol consumption from 2021 through to 2023 occurred in most provinces.

Note that the volume of ethanol we report for 2022 is greater than what was reported by ECCC in the *Renewable Fuel Regulations* data. Our total is the sum of ethanol consumption reported by individual provinces, with the volume in Québec calculated from GHG emission data and a prescribed combustion emission factor for ethanol. The total reported in Biofuels in Canada is 6% larger than what ECCC reported. As well, reconciling national and provincial data in 2022 produces an erratic ethanol blending rate in Atlantic Canada since it is inferred from the difference in the national and provincial totals. This outcome highlights the challenges of characterizing renewable fuel consumption by province and nationally using multiple different data sources.

4.2. Blending Rates

The ethanol content of gasoline hit new highs of 8.5%vol in 2022 and more than 9.5%vol in 2023. Likewise, biomass-based diesel content surpassed 6% vol in 2023, more than 1.5 times the blend rate in previous years (Figure 6). Co-processed fuel volumes and the gasoline displaced by light-duty PEVs are shown as a percent of the gasoline pool. Co-processed fuel, which was still only produced in British Columbia as of 2022 and 2023, accounted for the equivalent of about 0.2% vol of the gasoline in pool in those years. Meanwhile, electric vehicles displaced about 0.8% vol of the gasoline pool in 2022 and 1.2%vol in 2023.

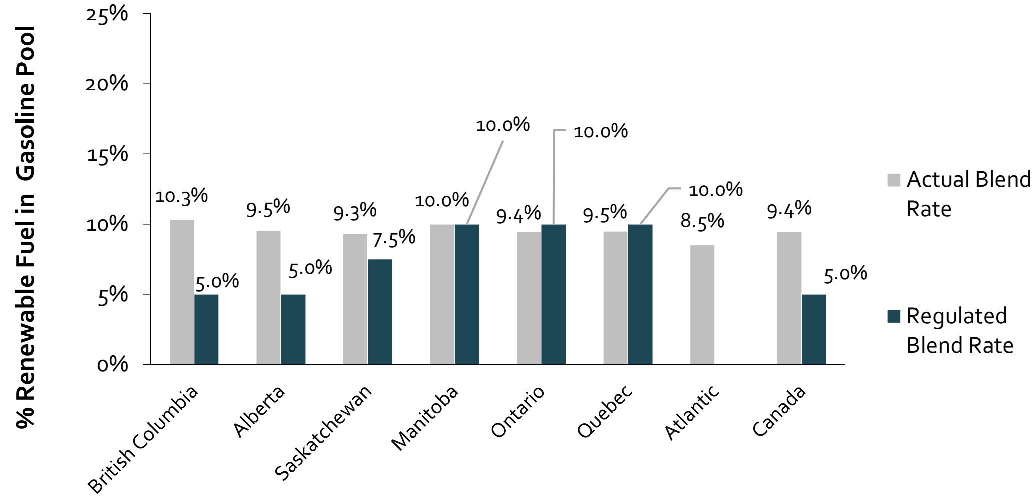
Figure 6: Renewable fuel content hit new highs in 2023 – greater than 9% in gasoline and 6% in diesel



Due to the uncertainty in the volume of RD consumed in Canada prior to 2022, biodiesel and RD are grouped together to avoid misrepresenting the precision of the data. The blend rates do 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).

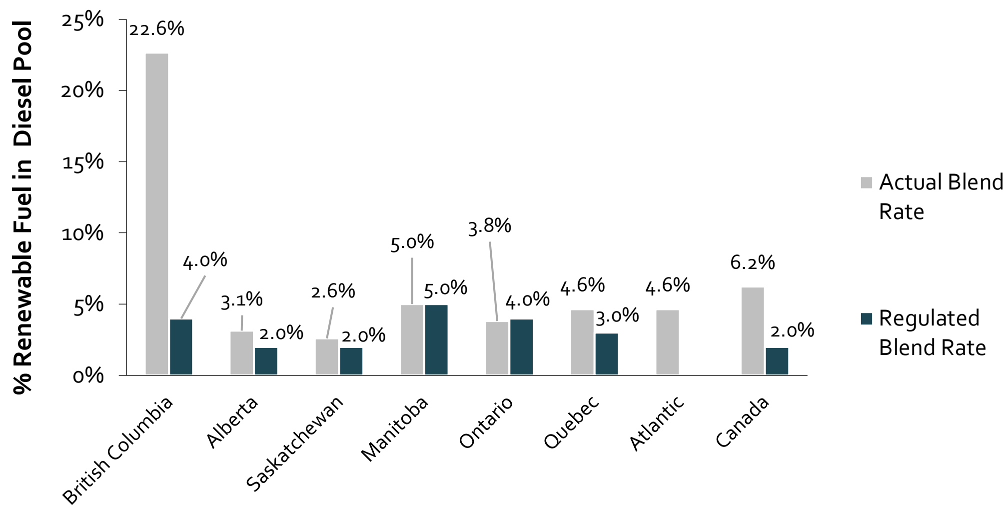
The growth in renewable fuel blending coincides with the CFR coming into force across Canada as well as the implementation of Québec's low-carbon fuel policy. The CFR sets a minimum requirement for renewable fuel blending in gasoline and diesel of 5% and 2% by volume (consistent with what was required by the *Renewable Fuels Regulation* in 2022 and earlier). As of 2023, the CFR stacks with renewable fuel blending requirements across most of Canada, aside from the Atlantic provinces, and many of these sub-national policies have become more stringent, or in the case of Québec, came into force in 2023. However, the fuel CI reductions mandated by the CFR and the opportunity to bank credits for later years are likely why actual blend rates generally exceed the national and provincial minimums required by these policies (Figure 7 and Figure 8). For British Columbia in particular, it is likely the provincial LCFS that is yielding blend rates that are many times higher than the legislated minimum.

Figure 7: The renewable fuel content in gasoline is higher than the regulated minimum because of policies that require reductions in fuel CIs



Ontario and Québec's fuel policies have regional exemptions and CI-based adjustments to the volume of fuels used for compliance. Consequently, the actual blend rate may be smaller than the required blend rate.

Figure 8: The renewable fuel content in diesel is higher than the regulated minimum because of policies that require reductions in fuel CIs



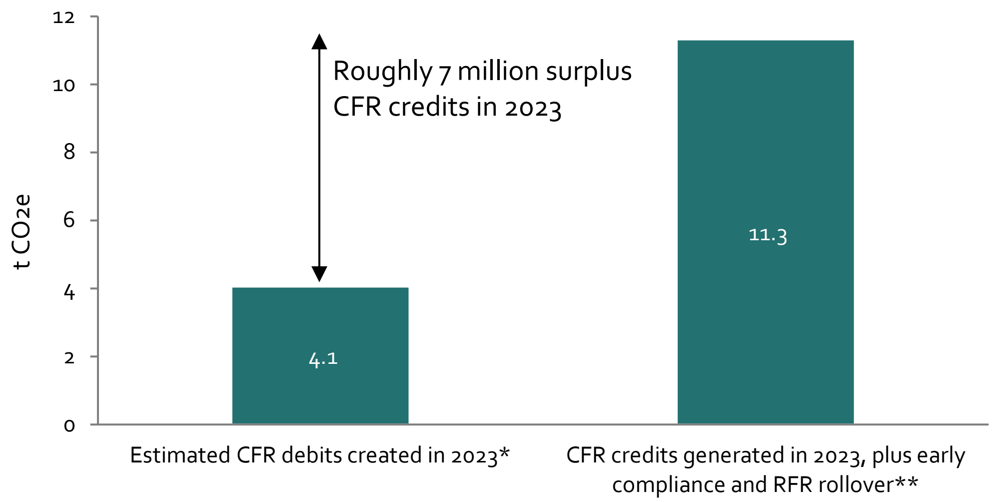
Ontario and Québec's fuel policies have regional exemptions and CI-based adjustments to the volume of fuels used for compliance. Consequently, the actual blend rate may be smaller than the required blend rate.

We estimate that this supply of low-carbon fuels also exceeded the 2023 compliance requirements for the CFR by about 7 MtCO2e (Figure 9), when combined with other credit generation opportunities (e.g., category 1, reducing the CI of fossil fuels, category 3, supply energy to advanced vehicles, and RFR credit rollovers). Credits are taken from the June 2024 credit market report[19] and CFR debits are calculated from the estimated gasoline and diesel consumption reported for 2023 in Biofuels in Canada. The surplus credits will be banked and used for compliance in future years. In previous editions of Biofuels in Canada, we correctly

[19] ECCC (2024). June 2024 CFR credit market report.

predicted that there would be surplus of credits in 2023 (and at least through 2024). However, we underestimated the extent to which market participants would increase renewable fuel blending rates in 2023 to take advantage of credit banking. We expect that credit banking will continue to drive growth in the Canadian renewable fuel supply through 2024, albeit at a slower rate than was observed from 2022 to 2023. However, this outcome is highly uncertain and will depend on the cost of abatement actions in 2024 as well as expectations for future CFR credit prices (e.g., a decline in RD prices in 2024 combined with expectations for a high CFR credit price in the future will support more fuel blending and credit banking).

Figure 9: We estimate a surplus 3 million CFR credits by the end of 2023



* Calculated from the estimate for gasoline and diesel consumption in 2023 from Biofuels in Canada, divided by 2 since the first compliance period was in the second half of that year.

** The sum of all credit types produced in 2022 and 2023 listed in the June 2024 CFR credit market report.

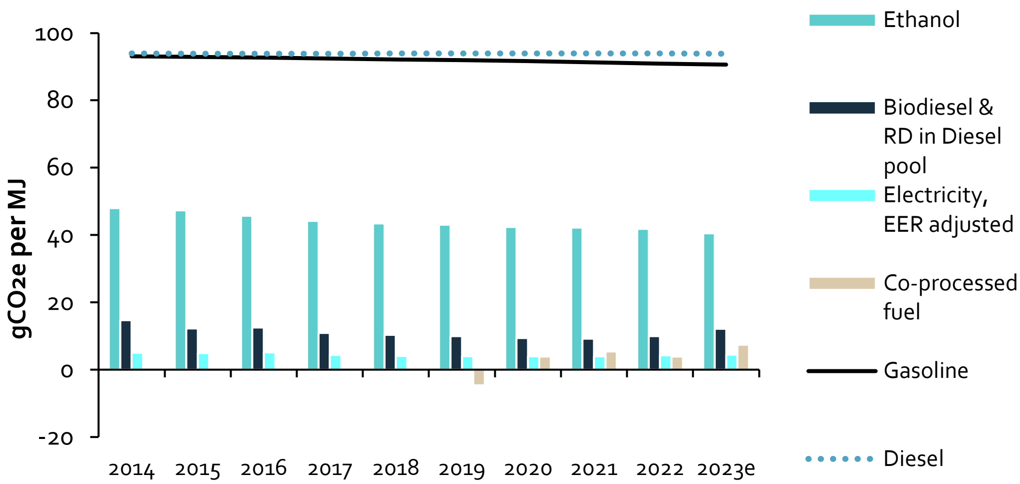
4.3. Lifecycle GHG Emissions

The life cycle CI scores of clean fuels are well below those of fossil fuels (Figure 10). In other words, clean fuels produce many fewer GHG emissions per unit of energy consumed, across the whole supply chain (i.e., from well/farm to wheels):

- The CI of ethanol is 55% less than gasoline (around 40 gCO_2e/MJ in 2023).
- The average of CI biomass-based diesel fuels is 87% less than fossil diesel (in the range of 9-12 gCO_2e/MJ over the last ten years).
- The CI of co-processed fuels reported in the British Columbian LCFS compliance data has varied over the years from being slightly negative to slightly positive, likely a function of the available feedstocks and specifics of the process (see Box 2 on page 26 for more information about the CI of co-processed fuels).
- The average CI for electricity is about 4 gCO_2e/MJ. This CI is low because it is adjusted by an energy effectiveness ratio (EER) of 4.1 (i.e., assuming that per km, PEVs use 4.1 times

less energy than a conventional vehicle) and weighted by the low CI of the electricity in the regions that where most PEVs are used (British Columbia, Ontario and Québec).

Figure 10: Renewable fuels offer large reductions in lifecycle CI relative to fossil fuels



CI scores are from provincial regulators where possible, otherwise they are default values from GHGenius 4.03a. CI of electricity is based on a transportation-consumption weighted average of direct emissions intensity by province from 2010 to 2021, reported in Canada's National Inventory Report, adjusted to include upstream and indirect GHG emissions.

These CI scores include GHG emissions resulting from direct land use changes (DLUC), but not "indirect land-use change" (ILUC) emissions. DLUC GHG emissions result from the conversion of pasture or forest to crop land. When reporting CIs, some policies, such as the California *Low-Carbon Fuel Standard*, include ILUC emissions in the CIs 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 policies do not include ILUC, but there has been speculation that they may include them in the future.[20] 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 biodiversity.[21]

Ethanol CIs have declined since 2014, as have RD and biodiesel CIs in some regions and over the longer term (e.g., since 2010, the first year characterized in previous editions of this analysis). In part, this is because the regional CIs used to produce Figure 10 are based on

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

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

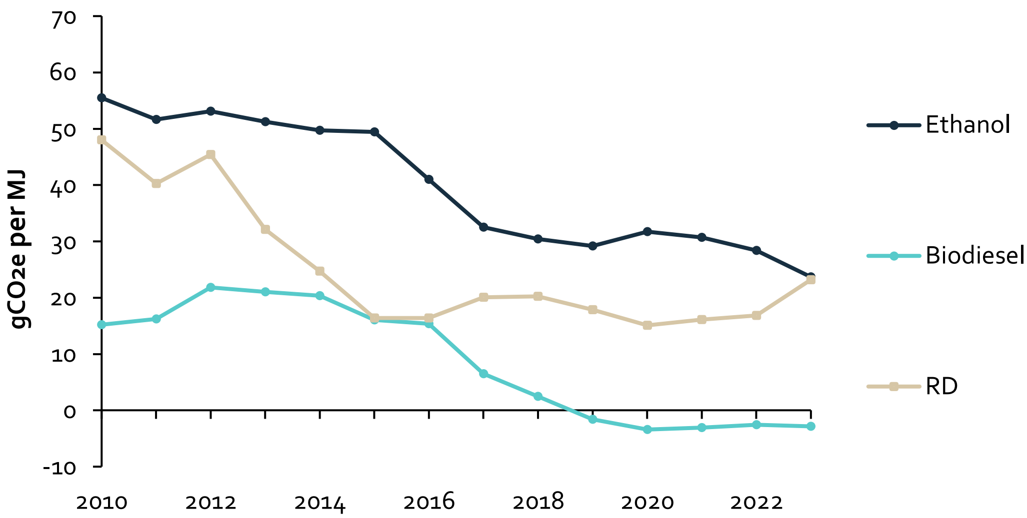
default data from GHGenius 4.03a. That dataset extrapolates from historical trends and assumes that the GHG intensity of inputs to biofuel production continue to decline over time, hence the fuel CI declines as well (e.g., reduced GHG emissions associated with cleaner electricity consumption for biofuel refining, process improvements, increased agricultural yields, and reduced fertilizer inputs per area farmed, etc.).

Data from British Columbia, Ontario and California support the broader trend in declining CIs. The CI values for biofuels consumed in Ontario and in British Columbia, which are based on data rather than modelling results, indicate a similar trend of an overall decline in the CI of biofuels. Likewise, reporting from the California and LCFS also show a similar decline in CI values. These empirical data sources give greater confidence in the modelled CI values used in this analysis. Furthermore, given that the measured CI values occur across multiple jurisdictions, 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 CFR will provide another opportunity to test this hypothesis.

In British Columbia between 2010 and 2023:

- The CI of ethanol decreased by 57%
- The CI of RD decreased by 55%
- The CI of biodiesel decreased by 118% (Figure 11). 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.

Figure 11: The CI of renewable fuels used in British Columbia has declined substantially since 2010



Average CI by fuel type in British Columbia reported in the BC LCFS compliance data.[22]

In Ontario, the average reported CI for biomass-based diesel range from 12 to 16 gCO2e/MJ in 2015 and has decline to between 5 and 8 gCO2e/MJ over the past few years. 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. Between 2011 and the first quarter of 2024, the CI of ethanol and biodiesel both decreased by about 30% (the CI of RD has not declined due to changes in the CI calculation methodology without revisions to previous CI scores).[23]

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).[24]

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 was recognized as a

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[22] British Columbia Ministry of Energy, Mines and Low Carbon Innovation, 2024, Information Bulletin RLCF-007, Renewable and Low Carbon Fuel Requirements Summary: 2010-2023

[23] California Air Resources Board, LCFS Quarterly Data Spreadsheet, accessed October, 2024.

[24] 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

fuel pathway within the California LCFS,[25] coinciding with additional funding being directed towards the deployment of this abatement practice at the Red Trail Energy ethanol plant in North Dakota, a facility that supplies ethanol to the Californian market.[26] Along with the ADM plant in Decatur, Illinois, this plant has since become among the first ethanol plants using CCS, capturing 180 ktCO_2/yr, reducing the CI of the resulting ethanol by about 40 gCO_2e/MJ.[27]

The CI scores in this analysis are sensitive to the method and models used to calculate them. As regulators update their lifecycle analysis models, we may see a step change in the CI scores reported in this analysis. For example, the CFR data may eventually include CI scores from the federal LCA model and as of January 1st, 2024, British Columbia requires CI scores to be calculated with GHGenius v5.

The GHG impact of clean fuel consumption in Canada has grown substantially in the past few years. Avoided emissions in 2022 reached 8.4 MtCO_2/yr, increasing to 11.4 MtCO_2/yr in 2023 (Figure 12). This trend is a function of stronger clean fuels policies. The avoided emissions in 2023 are roughly double what they were five years ago, before the start of the CFR, Québec's fuel regulation, and the increased stringency of many of the other existing provincial fuel policies and standards. Although electric vehicles are not directly affected by these policies, their share of avoided emissions has been increasing at the greatest rate, with an average increase of 45%/yr over the past five years. Subsidies, cost reduction, increased supply, and improved performance are all contributing to the rapid growth of PEV sales.

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

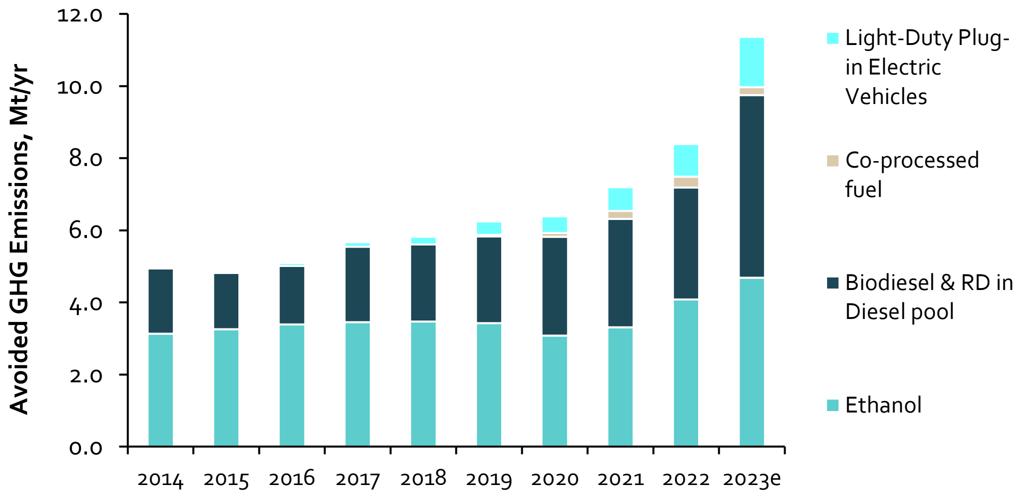
[26] North Dakota Industrial Commission, 2020, North Dakota Industrial Commission Awards $500,000 for Development of a Blueprint for a Carbon Capture and Storage Facility

And

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

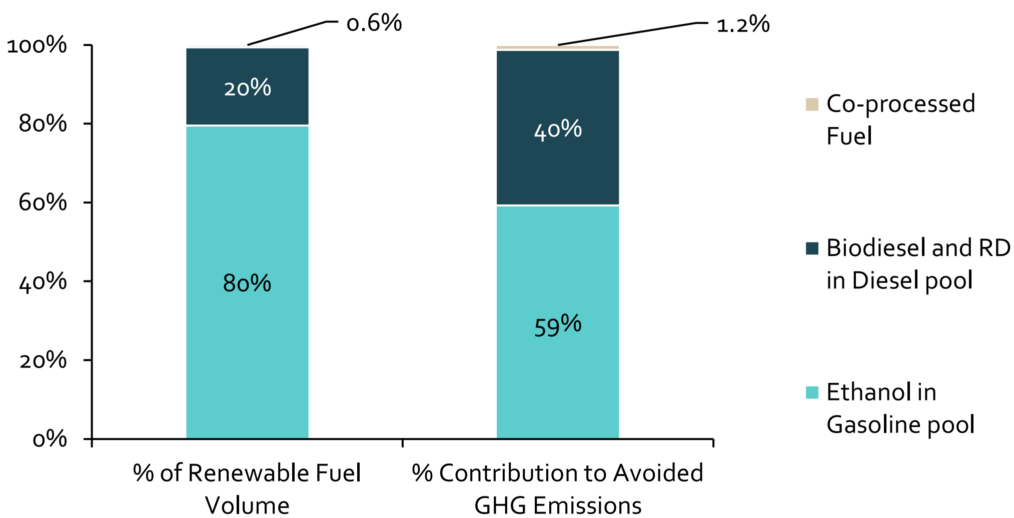
[27] Ethanol Producer Magazine, 2022, Red Trail Energy Begins Carbon Capture And Storage

Figure 12: GHG reductions from clean fuels have been growing exponentially since 2020



Biomass-based diesel and co-processed fuels provide proportionally more GHG abatement than ethanol (Figure 13). Biomass-based diesel accounted for 20% of the renewable fuel consumed over the time-horizon of this analysis (2010-2023e). Due to their low CI scores, these fuels were responsible for 40% of the cumulative avoided GHG emissions. Likewise, co-processed fuel has accounted for about 0.6% of the cumulative volume of renewable fuel, but 1.2% of the avoided GHG emissions.

Figure 13: Biomass-based diesel and co-processed fuels provide proportionally more GHG abatement than ethanol



Percentage of cumulative renewable fuel volume compared with the percentage of cumulative avoided GHG emissions resulting from renewable fuel consumption (2010 to 2023e).

Our evaluation of the GHG impact of ethanol is conservative. Avoided GHG emissions from ethanol consumption could be two to three times larger if that fuel improves vehicle energy efficiency, reduces refinery GHG emissions and reduces the CI of fossil gasoline feedstock. The GHG impact in these results is calculated assuming that renewable fuel blending does not change vehicle energy efficiency (i.e., energy per km). The weight of evidence supports this assumption, but it is possible that renewable fuel blends have increased energy efficiency. Ethanol's 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%.[28] A study from 2020 found that E10 could increase the energy efficiency by 1.2%[29], though this result is based on a test engine and is not derived from real-world driving data. While there is significant uncertainty in these results, the impact on GHGs is potentially large. A 1.8% improvement in vehicle energy efficiency increases the GHG impact of ethanol by about 50%. Similarly, diesel test engines may also be more energy efficient when fuelled with custom blends of renewable fuels.[30] This efficiency improvement would also increase the GHG impact of consuming biomass-based diesel, though there is a lack of real-world driving data to quantify the impact of commercially available diesel fuel blends used by existing vehicles.

Furthermore, the GHG impacts are calculated under the assumption that renewable fuel 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 could reduce refinery emissions if the production of lower octane gasoline is less carbon intensive. Similarly, using ethanol to raise the octane of gasoline blends may change the chemical composition of the gasoline blendstock. For example, the blendstock may have fewer octane raising 'aromatic' compounds. Aromatic compounds have a higher combustion (i.e., tailpipe) emissions intensity than gasoline on average. Consequently, raising octane with ethanol could reduce the combustion CI of the gasoline blendstock. The appendix of this report contains a "deep dive" on this subject (see Appendix D: Impact of Ethanol on Gasoline Refining and Consumption).

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 2023 could range from a 1.9 $MtCO_2e$/yr decrease to a 0.3 $MtCO_2e$/yr increase. 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 0.4 to 1.4 $MtCO_2e$/yr.

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[28] 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

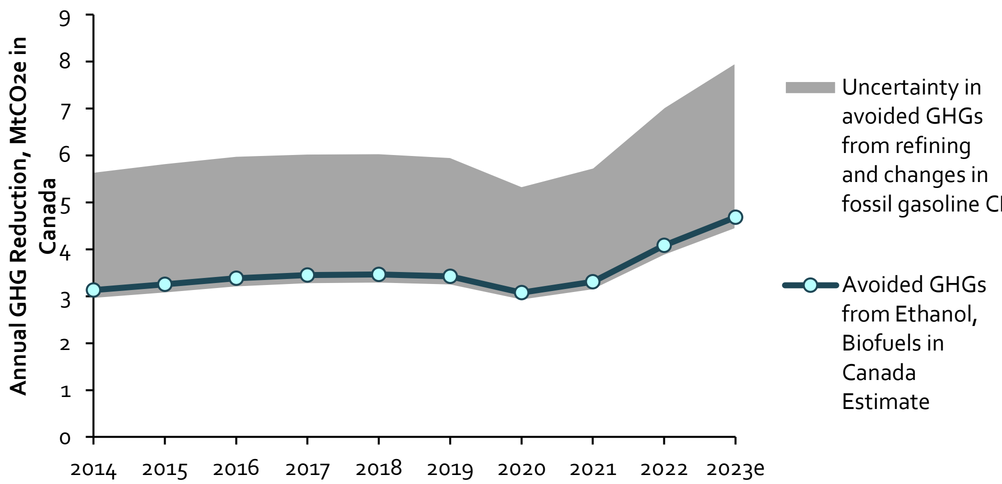
[29] Koten, H., Karagoz, T., & Balci, O. 2020. Effect of different levels of ethanol addition on performance, emissions, and combustion characteristics of a gasoline engine. *Advances in Mechanical Engineering, Vol. 12(7) 1-13.*

[30] Yadav J., Deppenkemper, K., Pischinger, S. (2023) Impact of renewable fuels on heavy-duty engine performance and emissions. *Energy Reports*, 9, 1977-1989.

Figure 14 illustrates this uncertainty in the ethanol GHG impact. The high end of that range (i.e., more GHG abatement) is almost 75% greater than what is reported in Biofuels in Canada, consistent with:

- A 1.5 gCO_2e/MJ reduction in the CI of refining petroleum gasoline for use with E10
- An 8% reduction in the higher CI aromatics within the gasoline blendstock used with E10 relative to the blendstock used with E0

Figure 14: The avoided GHG emissions related to ethanol consumption could be much larger than shows in this analysis.



Range of uncertainty in ethanol GHG reductions related to refineries and gasoline composition

Box 2: How is the Carbon Intensity of Co-Processing Defined?

Clean Fuel Regulations

Under the CFR, the volume of co-processed renewable fuel is limited to the biogenic portion of finished fuels which leave the refinery. Facilities can estimate renewable fuel volumes using “incremental allocation”: The facilities compare a “benchmark” scenario using only petroleum feedstocks with a test scenario using the maximum flow of the low-CI feedstock. Then, the actual amount of low-CI feedstock is used to define the renewable content of the finished fuel based on those maximum/minimum bookends. Refineries must also submit samples for radiocarbon testing once per month to verify the biogenic portion of the finished products.

The CI of the renewable fuel volume is defined with the Fuel LCA Model where the energy and material inputs are estimated via incremental allocation. Any hydrogen input must use the pre-defined CI of hydrogen produced via steam methane reforming (presumably to avoid double counting credits generated from low-CI hydrogen production). Only products that leave the refinery are eligible to create CFR credits; the GHG reduction associated with own-use of biofuels at the refinery should be reflected in the CI of the finished fuels via crediting as co-products in the assessment (e.g., a bio-propane used for on-site heat generation reduces the CI of the renewable gasoline and diesel products).

BC Low Carbon Fuel Standard

The B.C. Ministry of Energy, Mines, and Low-Carbon Innovation currently has a draft *Coprocessing Methodology Protocol* posted for comment on their website[1]. Unlike the federal protocol for the CFR, the draft BC protocol does not allow the use of incremental allocation for determination of renewable fuel volumes, instead proposing radiocarbon testing on daily (or batch) samples, conducted once monthly. The use of radiocarbon testing to determine fuel volumes would also apply to co-products used within the refinery. Estimation of hydrogen use, a key input to the LCA, can be done via “step test” (effectively a much shorter-duration incremental allocation), stoichiometric allocation, or statistical regression. Other material and energy inputs, which tend to be secondary in their importance, could be estimated by incremental allocation or step test.

The draft protocol did not include insight into how existing co-processing projects, which have been operating in BC since 2019, have estimated their CIs.

Sources:

Government of Canada (2022). Clean Fuel Regulations: Quantification Method for Co-processing in Refineries Version 1.0.

Government of British Columbia (2023). B.C. Low Carbon Fuel Standard: Coprocessing Methodology Protocol.

4.4. Cumulative Costs

This section describes the cost impact resulting from the renewable fuel consumption described above, focusing on the impact of renewable fuel blending on consumer fuel expenditures. Refer to Appendix E: 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.

The cost impacts in this analysis are based on publicly available benchmark fuel prices, while actual fuel contracted fuel prices are unknown. Furthermore, clean fuel regulations are 'market-based mechanisms and buyer and seller power in the market will vary over time, over geographies, and over fuel classes and types. Additionally, compliance credit market values may be indicative of, but are not necessarily accurate indicators of the value or price of all fuels bought and sold in the market. Therefore, this analysis provides a reasonable portrayal of cost impacts, but it will not show how market power and the resulting negotiated fuel prices may affect these impacts.

Renewable fuel consumption may change overall fuel costs because of differences in commodity prices, differences in fuel energy density and differences in fuel properties (e.g., octane value):

- 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 (Note that the analyses in the report adjust for energy density in calculating end-user cost.). 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.

Ethanol blending may reduce gasoline costs by raising the octane rating of the blended fuel. 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.[31] When used in a gasoline blend, ethanol has an octane rating of 113.[32] Consequently, the ethanol can be blended with a lower-octane gasoline blendstock. The price spread between regular gasoline (octane 87) and premium gasoline (octane 91 or more) implies that raising octane imposes a cost. Therefore, using lower-octane gasoline blendstock with ethanol is a potential cost-saving opportunity that contributes to the business case of 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.

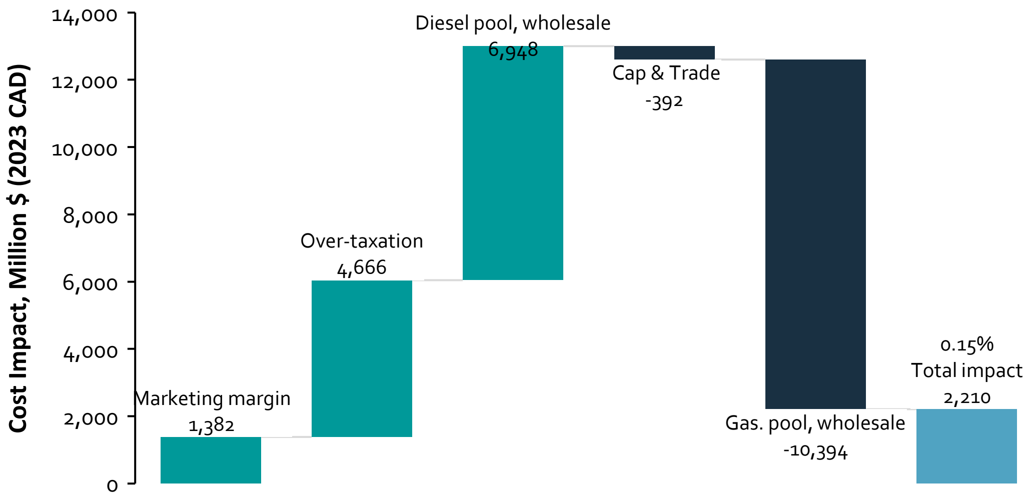
This value of octane is only included insofar as it reduces the cost of gasoline blendstock used with ethanol; any energy or GHG reduction that may occur at the refinery due to producing a lower octane blendstock is not included (see the discussion of energy efficiency on page 24 and the discussion of additional GHG impacts shown in Figure 14 on page 25).

Renewable fuel consumption in Canada has increased cumulative consumer fuel costs by 0.15% since 2010 (Figure 15). The net impact on consumer cost comes from both the gasoline and diesel pools and is composed of a wholesale cost, a marketing margin cost, a tax cost, and an avoided GHG cap and trade cost. The cumulative net cost from 2010 to 2023 is about $2.2 billion.

[31] 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

[32] 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 15: Renewable fuel consumption has increased consumer fuel costs by less than 0.2% since 2010



Cumulative cost impact resulting from renewable fuel blending (2010-2023). Excludes impact of co-processed fuels and light-duty electric vehicles.

The wholesale cost of biodiesel and RD has increased consumer costs by about $6.9 billion from 2010 to 2023, while the octane value of ethanol has decreased the wholesale costs borne by consumer by about $10.4 billion over that period. The wholesale cost of fuels, 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 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 each year. For the gasoline pool, there is a net savings in the wholesale cost. In contrast, in the diesel pool, there is a net cost. This reflects the fact that biomass-based diesel is generally more expensive than conventional diesel. This is particularly the case with the premium-priced RD, where in most years fuel suppliers could have mitigated biomass-based diesel costs by substituting biodiesel for RD.

Note that these wholesale costs do not include the price-moderating impact of additional biofuel supplied to a tight fuel 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.[33]

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

Because renewable fuels are less energy dense than fossil fuels, we estimate that distributing and dispensing them has cost consumer an additional $1.4 billion from 2010 to 2023. This "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 for ethanol within the gasoline pool because it is roughly 33% less energy dense than gasoline.

The over-taxation of biofuels exists because renewable fuels have a lower energy density that fossil fuels and the federal and provincial governments have continued to tax all fuels equally on a per litre basis. This cost is the result of legacy tax policies. It has cost consumers about $4.7 billion between 2010 and 2023. Fuel taxes include excise taxes paid "at the pump", 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 zero to $0.27/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 are 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 2023, our analysis shows that consumers in Canada have paid an additional $3.5 billion in taxes for gasoline as a direct consequence of fuel blending, while the comparable figure for diesel purchases is $600 million. The difference in scale is again because biomass-based diesel is 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 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 can sometimes outweigh the increases due to federal and provincial fuel taxes.

Renewable fuels allow consumers to avoid GHG cap-and trade-costs applied to fossil gasoline and diesel in jurisdictions where GHG caps have existed. In this instance, renewable fuels have reduced consumers costs by almost $400 million since 2010. Québec has had a cap-and-trade system since 2015, and similar policies previously existed in Ontario and Nova Scotia. The cap-and-trade systems add a carbon cost to gasoline and diesel that will affect the wholesale price of these fuels. Low-carbon renewable fuel CO_2 emissions are exempt from the cap-and-trade systems, but minor emissions from CH_4 and N_2O are accounted for.[34] However, historically, there has been no price distinction between fuels with and without renewable fuels 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 renewable fuel consumption (i.e., in a counterfactual scenario).

There are several important caveats for this cost analysis:

- 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 always be the case in all Canadian fuel markets.
- 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.
- 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 those 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 about a 1.8% improvement in energy efficiency (scaled to actual blend rates), consumers would have saved another $11 billion from 2010 through 2023.

4.5. GHG Abatement Cost

Ethanol has a negative average GHG abatement cost over the time horizon of this analysis (2010 to 2023). The cost of GHG abatement from ethanol blending is -$116/t$CO_2$e (Figure 16). Again, the negative abatement cost is a function of the octane value provided by ethanol. The results show that excise and carbon taxes on fuels have a significant impact on the net

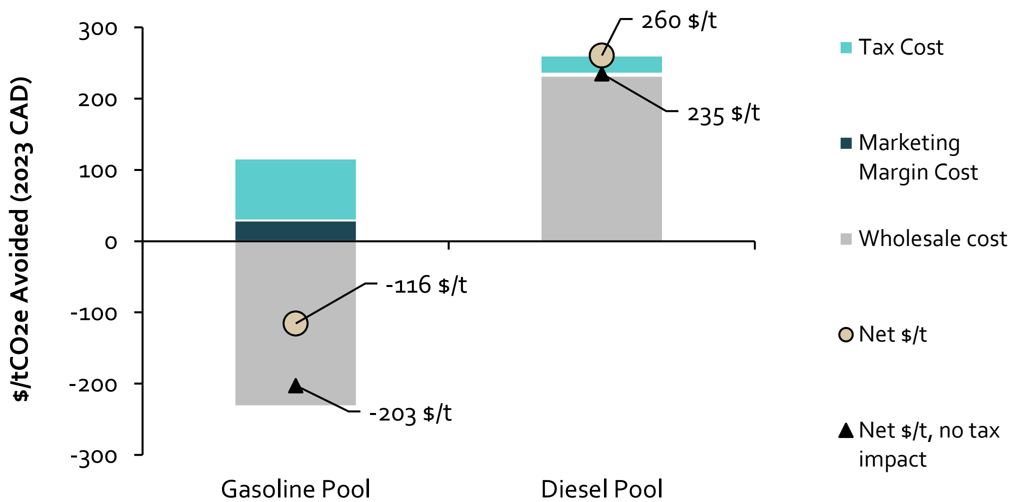
[34] See Table 30-1 in Government of Québec, *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere*

dollar value per tonne CO_2e abated, which would be -$203/t$CO_2e$ if the taxes on ethanol and gasoline were equivalent on an energy basis.

Biodiesel and RD have a positive abatement cost, at $235/tCO2e. The positive abatement cost is a function of the higher wholesale price for these fuels, especially RD. Because the energy density of these diesel alternatives is much closer to the energy density of fossil diesel, the inclusion or exclusion of the additional tax costs has a minimal impact on the abatement cost.

The abatement cost in the diesel pool is strongly influenced by the price of RD. RD prices are to be declining, which may result in lower abatement costs in the future. The price of RD is a key driver in the value of D4 (biomass-based diesel) credits in the US Renewable Fuel Standard and of California LCFS credits. The price of D4 credits has declined from a peak of about 1.75 USD per credit in 2022, to about 0.75 USD per credit in 2024.[35] Likewise, the price of California LCFS credits has declined from a peak of about 200 USD per credit to 50 – 60 USD per credit.[36] This trend suggests that RD prices are declining, which will reduce the abatement cost in the diesel pool once this cost analysis covers 2024.

Figure 16: Ethanol consumption has negative abatement costs while biomass-based diesel has positive costs



GHG abatement cost, with and without volumetric tax penalty, based on cumulative costs divided by cumulative GHG abatement from 2010-2023.

Avoided cap-and-trade costs are not included in the abatement cost 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 renewable fuels besides the differences included in the CIs used in this analysis (specifically: the impact of ethanol

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[35] United States Environmental Protection Agency, RIN Trades and Price Information, accessed September, 2024.

[36] California Air Resources Board, Monthly LCFS Credit Transfer Activity Reports, accessed September, 2024.

blending on vehicle energy efficiency, refinery GHG intensity, and fossil gasoline GHG intensity are not included).

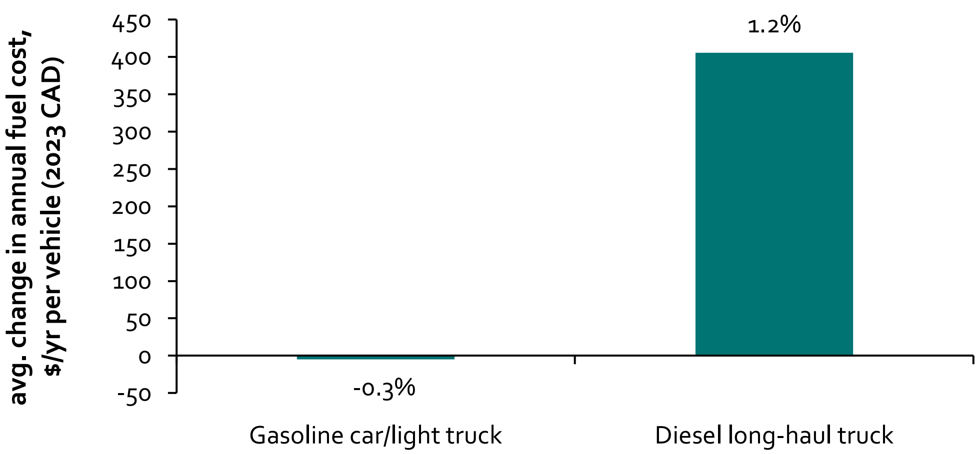
4.6. Consumer Cost Impact

Renewable fuel blending in Canada has saved gasoline consumers an average of 0.3% of their fuel costs over the time horizon of this analysis (2010-2023). In contrast, it has cost diesel consumers an additional 1.2% in fuel costs. For a typical gasoline consumer, driving a car or light truck, this is equivalent to a savings of $6/vehicle/yr (Figure 17). For a typical diesel consumer (e.g., a class 8 tractor trailer), the cost has been in range of an additional $407/vehicle/yr.

Higher prices for biodiesel and RD in 2023 have resulted in a larger impact on diesel prices (assuming no cross subsidization of renewable fuels between the gasoline and diesel pool). Without renewable fuels, a typical heavy-duty vehicle might have spent about $37,150 on fuel in 2023. Low-carbon fuel consumption increased that cost to $38,400.

The higher cost for diesel consumers could have been mitigated if more biodiesel and less RD had been used. This outcome was technically feasible given that on average in Canada, biodiesel has only accounted for between 1.0 to 1.6% of the diesel pool volume prior to 2023. 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.[37]

Figure 17: Renewable fuel consumption in Canada has saved money for gasoline users, while costing an additional 1% for diesel users



Average consumer cost impact as a percent and $/vehicle/yr, averaged from 2010 to 2023. The gasoline consumer is based on a light-duty vehicle travelling 13,440 km/yr using 9.1 L/100km. The diesel consumer is based on a class 8 truck travelling 74,650 km/yr using 29.3 L/km. Values taken from NRCan Comprehensive Energy Use Database.

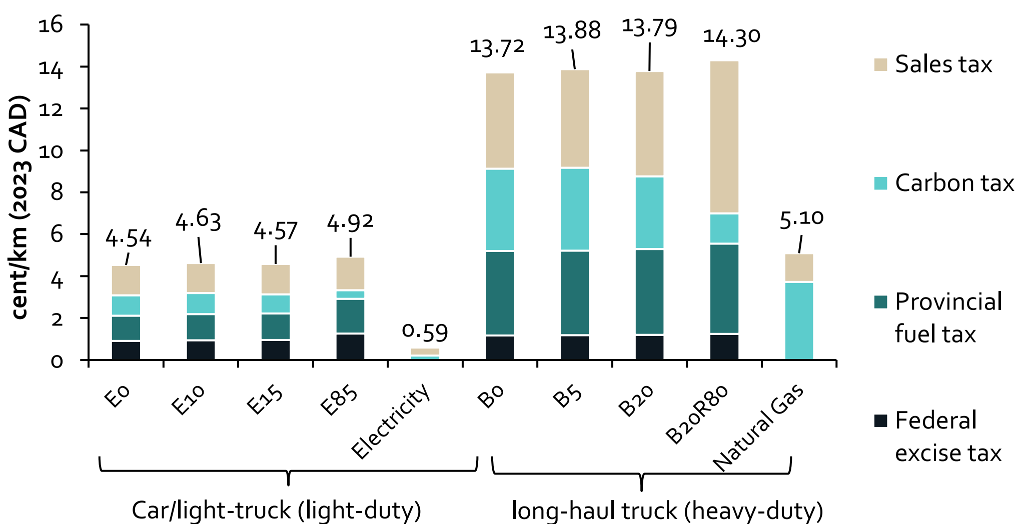
[37] US Energy Information Agency, 2023, September 2023 Monthly Energy Review, Tables 3.7, 10.4a 10.4b

4.7. Detailed Tax Costs

In 2023, a Canadian using E10 paid 2% more fuel taxes than someone using fossil gasoline. A B5 consumer paid 1% more fuel tax than someone using only fossil diesel (Figure 18). Again, much of this over-taxation results from the lower energy density of biofuels and the fact that most fuel taxes are applied per litre. The impact of volumetric taxation is further exacerbated for higher blends of ethanol, such as E15 or E85. In contrast, other alternative fuel vehicles that run on electricity, hydrogen, or renewable natural gas are exempt from provincial fuel taxes and federal excise taxes and pay a much less tax per km.

The tax impacts in Figure 18 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 2021 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, the renewable portion of the E15, E85, B20, and B20R80 are exempt from the carbon price (this is why the national average carbon tax on B20R80 is relatively small).

Figure 18: People pay more tax for each km travelled when they consume renewable fuels



Consumption weighted average taxes per distance travelled in 2022 by tax type with the total in the data label. Taxes per km are calculated using the same typical gasoline and diesel consumers described in Figure 17 (a light-duty gasoline vehicle and a diesel tractor-trailer).

In 2023, on the over-taxation of biofuels amounted to an extra 25% in fuel taxes paid on biofuels, or roughly $560 million. This amount is in addition 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 19). The cumulative over-taxation of biofuels since 2010 rose to about $4.7 billion in 2023 (note, this is the same as the total tax cost impact shown in Figure 15).

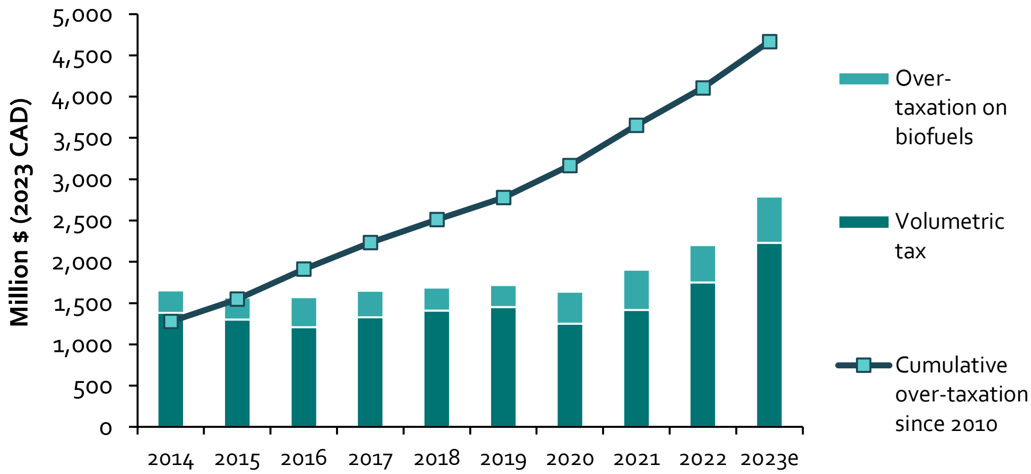


Figure 19: Volumetric taxation of biofuels means consumers paid an extra $560 million in taxes in 2023

The over-taxation represents about a fifth of the total tax paid on ethanol and biomass-based diesel. Taxes paid on ethanol in Canada in 2023 account for 9.4% of the total taxes paid on fuel from the gasoline pool, where the over-tax paid on ethanol is about 1.9 percentage points or 20% of that total. Taxes paid on biomass-based diesel represent 6.6% of the total taxes paid on the diesel pool in Canada in 2023. The over-tax paid on biomass-based diesel is about 1.3 percentage points, or 20%, that total (Figure 20).

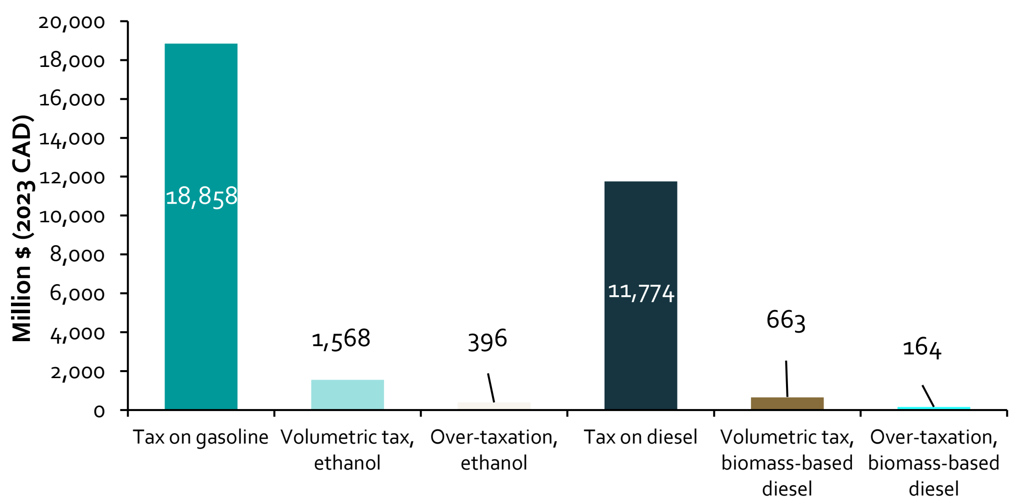


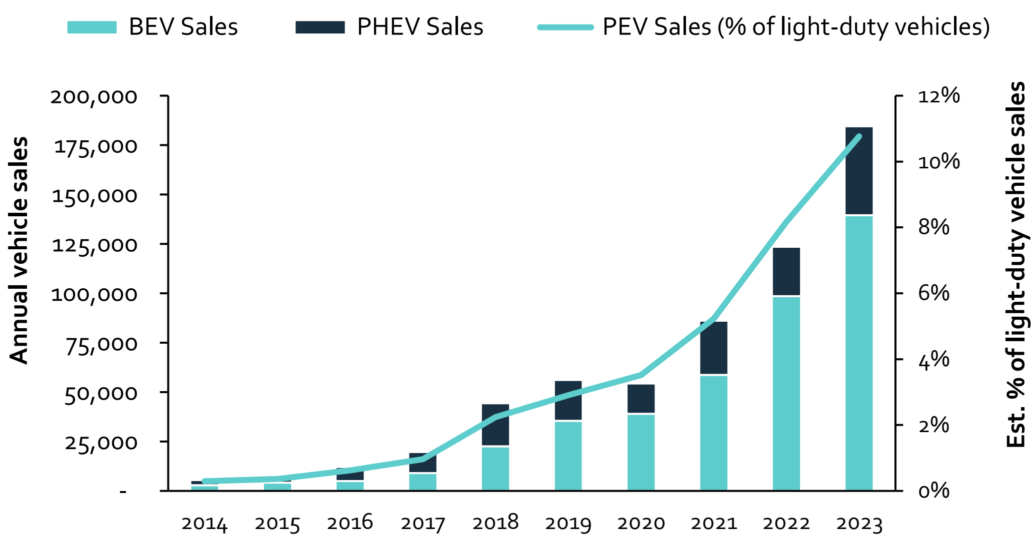
Figure 20: Breakdown of taxes paid on the gasoline and diesel fuel pools in 2023

4.8. Electric Vehicles

This analysis estimates how light-duty PEVs have affected gasoline consumption and GHG emissions. PEVs can be broken down into "Battery Electric Vehicles" (BEVs) and "Plug-in Hybrid Electric Vehicles" (PHEVs), which are disaggregated in Figure 21 below. BEVs consume only electricity, while PHEVs also have auxiliary engines which consume liquid fuel and to extend their range.

In 2022, PEVs accounted for 8% of light-duty vehicle sales in Canada, rising to 11% in 2023, equivalent to nearly 123,000 PEV sales in 2022 and 185,000 in 2022 (Figure 21). These relatively high national sales rates for PEVs are heavily weighted even greater sales specific provinces. In British Columbia, more than 20%% of car sales were PEVs in 2023. Comparably, PEVs accounted for 19% of vehicle sales in Québec and almost 8% in Ontario. In other provinces and regions, such as in Atlantic Canada, and in the prairies (Alberta, Saskatchewan, and Manitoba), PEVs accounted for between 2% and 4% of total light-duty vehicle sales in 2023.

Figure 21: Electric cars accounted for more than one in ten light-duty vehicles sold in Canada in 2023

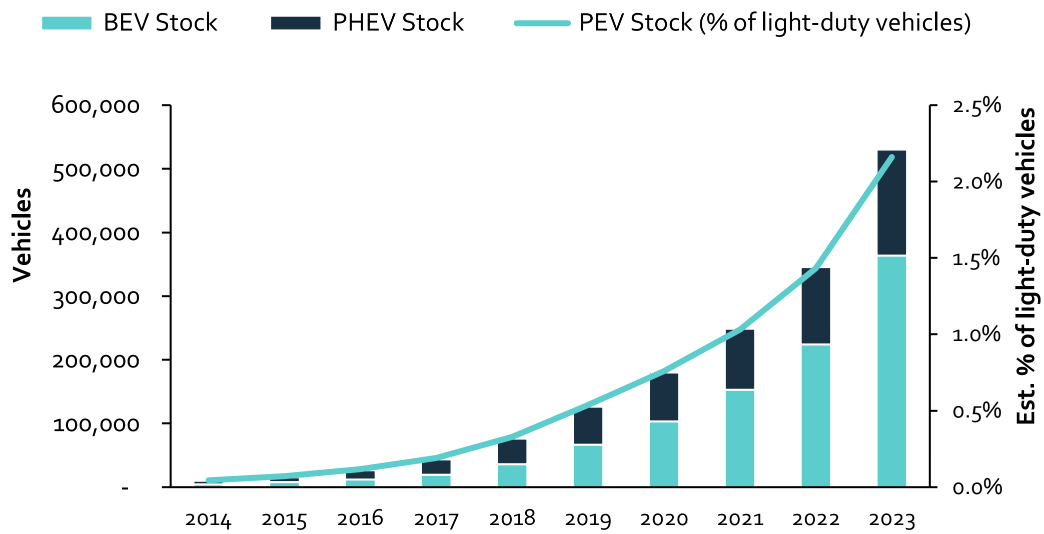


Light-duty electric vehicles sales in Canada. Source: Statistics Canada, New Motor Vehicle Registrations, Table: 20-10-0021-01

Electric vehicles now account for more than 2% of all light-duty vehicles on the road in Canada (Figure 22). 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. The stock of PEVs is split about 75:25 between BEVs and PHEVs and is concentrated in the provinces that have higher PEV sales (British Columbia, Québec and Ontario).

The growth in PEV sales and PEVs on the road is accelerating. We expect this trend in PEV sales and PEVs on the road to continue. The federal government has proposed amending its passenger automobile and light truck GHG emission regulations to establish legally binding zero-emissions vehicle sales targets. The targets are 20% of light-duty vehicle sales by 2026, rising to 60% by 2030, and 100% by 2035.[38] This would result in PEVs being about 5% of vehicles on road in 2026, rising to 16% in 2030 and 40% by 2035.[39]

Figure 22: As of 2023, there are more than half a million light-duty electric vehicles on the road in Canada – 1 in every 50 cars.



Source: Statistics Canada, New Motor Vehicle Registrations, Table: 23-10-0308-01

[38] Government of Canada, Canada Gazette, Part I, Volume 156, Number 53: Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations

[39] Transport Canada, 2022, Canada's Zero-Emission Vehicle (ZEV) sales targets

Appendix A: Canadian Policy Background

Provincial Renewable Fuel Blending Requirements

Canada has a variety of renewable fuel policies at the provincial level of government that, prescribe different renewable fuel volumes and vary in design and application, as described in the following sections.

British Columbia

The British Columbia low-carbon fuel standard (BC LCFS)[40] 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. In 2024, the province added a blending requirement for jet fuel, which must have:

- 1%$_{vol}$ renewable content in 2028
- 2% in 2029
- 3% in 2030

The second component of the policy regulates the average CI of the fuels, as described on page 51. British Columbia adopted a new *Low Carbon Fuel Act* which replaced the existing statute and regulation on January 1, 2024.

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 the gasoline pool, while an average of 2% is required in the diesel pool.[41] 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 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 from that model was 59% to 65% lower, depending on the ethanol feedstock. The CI of diesel in Alberta in 2011 was 96 gCO_2e/MJ,

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40 Referring to the *Low Carbon Fuels Act*, which replaces both the *Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the *Renewable & Low Carbon Fuel Requirements Regulation*, and under that act, the Low Carbon Fuels (General) Regulation.

41 Government of Alberta, *Renewable Fuels Standard Regulation*

while the CI of biodiesel and RD 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.[42] Saskatchewan also has *The Renewable Diesel Act* that started on July 1, 2012, mandating 2% renewable fuel by volume in diesel pools.[43]

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.[44] The biodiesel policy required 2% biodiesel by volume through 2020, rising to 3.5% in 2021 and 5% in 2022.[45]

Ontario

Ontario previously had the *Greener Gasoline – Bio-Based Content Requirements for Gasoline*[46] regulation mandating 5% ethanol content in gasoline, which was increased to a CI-adjusted requirement of 10% by volume beginning in 2020. Suppliers must meet the compliance target at all their facilities combined. In November 2020, the *Greener Gasoline* regulations were repealed and replaced with a new regulation, *O. Reg. 663/20: Cleaner*

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

[43] Government of Saskatchewan, *The Renewable Diesel Act*

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

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

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

Transportation Fuels: Renewable Content Requirements For Gasoline And Diesel Fuels[47], 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 8). 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 9 and Figure 23). 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 23). 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 (50% 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 or any gasoline with an octane rating (AKI) of 89 or greater (i.e., typically mid-grade and premium gasoline).

Table 8: Volumetric low-carbon renewable fuel blending requirements in Ontario

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

Table 9: 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				

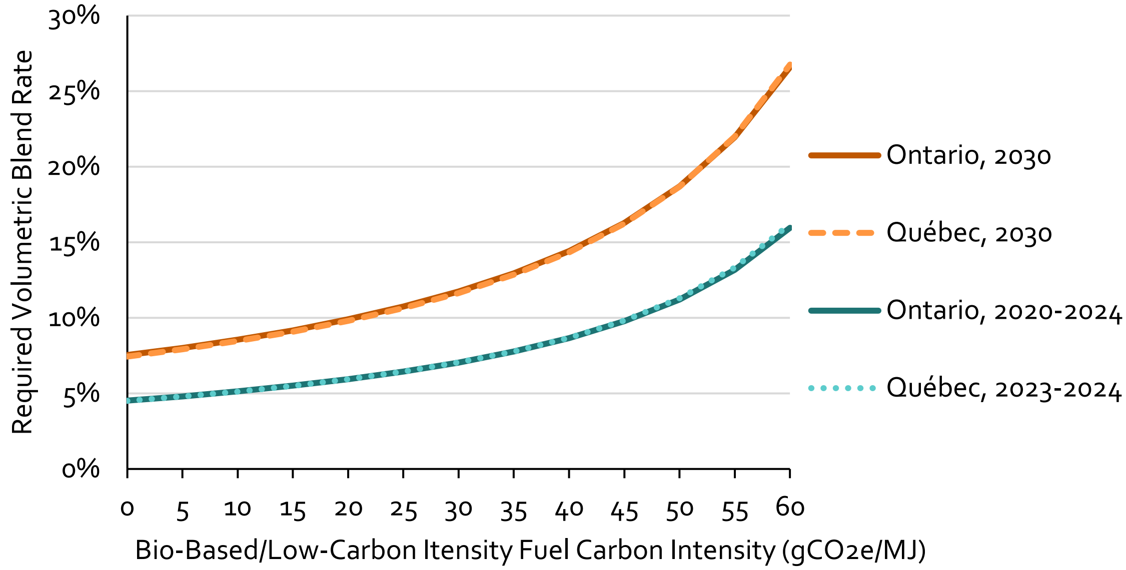
Along with the ethanol regulation, the *Greener Diesel Regulation* was also repealed and replaced with the *Cleaner Transportation Fuels* regulation. The new regulation maintains the standard from the *Greener Diesel Regulation* which requires 4% biofuel blend subject to the weighted average CI of the 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 24).

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

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

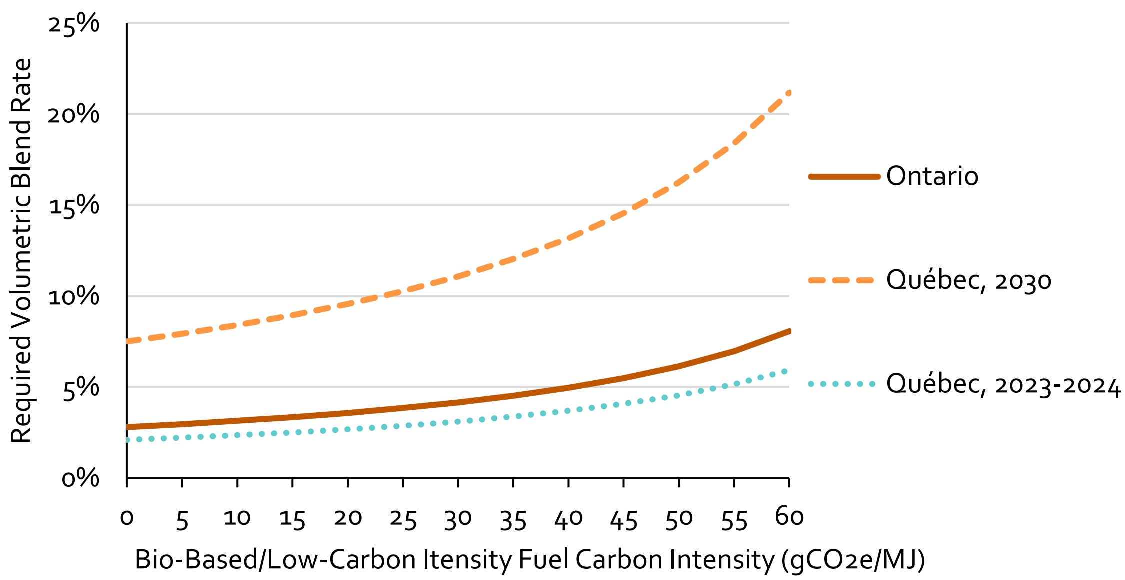
achieve compliance by blending at a rate above the standard in 2021 if they were to fall below the standard in 2020 (or vice versa).

Figure 23: 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 24: 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 10). The diesel blending requirement begins at 3% low-carbon fuel content in 2023, rising to 5% in 2025 and 10% by 2030 (Table 10).[48] 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).

Table 10: 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 11: 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. For example, 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 11, Figure 23). 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 23). Similarly, the required blend rate in diesel in 2030 will be equal to the regulated value, 10%, only if the average CI of the blended fuels is about 23 gCO_2e/MJ (75% lower than reference diesel CI) (Table 11). More typical average CI scores for biomass-based diesel around 10 gCO_2e/MJ would require a blend rate closer to 8.4% (Figure 24).

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

Because Québec is a large fuel market, this regulation will significantly 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.[49] 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.

The Yukon

The Yukon announced that 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.[50] Draft regulations have not yet been published.

Carbon Pricing by Province

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 \$65/tCO_2e as of April 1, 2023 (Table 12).[51] The BC carbon tax will rise to \$170/tCO_2e by 2030, consistent with the federal backstop carbon price.[52] Each \$5/tCO_2e increment increased the tax on gasoline by 1.11 ¢/L and the tax on diesel by 1.28 ¢/L, while the \$15/tCO_2e increments increase those prices by about 3 and 4 ¢/L respectively (Table 12).[53]

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 BC LCFS), resulting in a tax of 14.31 ¢/L on gasoline

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49 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.

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

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

52 Greenhouse Gas Pollution Pricing Act, Schedule 4

53 Ibid.

and 16.85 ¢/L on diesel as of autumn, 2023. 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.

Table 12: British Columbia carbon tax rates (nominal CAD)

	2018-2019	2019-2021	2021-2022	2022-2023	2023-2024	2026-2025
Tax rate, $/tCO$_2$e	35	40	45	50	65	80
Gasoline, ¢/L	7.8	8.9	10.0	11.1	14.3	17.6
Diesel, ¢/L	9.0	10.2	11.7	13.0	16.9	20.7

BC's carbon pricing regime is unique in that renewable fuels are covered by the carbon tax regardless of blend rate[54]. However, in BC's output-based pricing system, biodiesel, ethanol, and renewable diesel are listed as eligible "Schedule C" biomass[55], meaning the biogenic CO_2 emissions can be deducted from the regulated firms' compliance emissions. Accordingly, renewable fuel used in OBPS-regulated industries in BC can generate three types of compliance credits: An OBPS credit, a BC LCFS credit, and a CFR credit. Consequently, there is an extra incentive for large industries to use low-carbon fuels since other consumption would only yield LCFS and CFR credits (and no carbon tax exemption).

Alberta Carbon Levy

Alberta implemented a \$20/tCO_2e carbon levy in 2017, which rose to \$30/tCO_2e in 2018.[56] 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 13). 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 provincial government elected in 2019.[57] Consequently, as of 2020, gasoline and diesel purchases were subject to the federal carbon pricing fuel charge.

[54] Schedule 1, BC Carbon Tax Act. Available at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/00_08040_01#Schedule1

[55] Schedule C, Biomass Exclusions. B.C. Reg. 249/2015. Available at: https://www.bclaws.gov.bc.ca/civix/document/id/lc/statreg/249_2015#ScheduleC

[56] Government of Alberta, Carbon Levy Rates

[57] Government of Alberta, Carbon Tax Repeal

Table 13: Alberta carbon levy rates on gasoline and diesel (nominal CAD)

	2017	2018 and early 2019	2020 and thereafter
Gasoline, ¢/L	4.5	6.7	Current federal carbon price fuel charge
Diesel, ¢/L	5.4	8.0	

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 was cancelled later that year after a change in government, and all trading was stopped on July 3rd, 2018.[58] As of 2019, gasoline and diesel sales in Ontario are subject to the federal carbon pricing backstop.

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.[59]

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; tailpipe CO_2 emissions from biofuels are exempt from the cap-and-trade system. The emissions credit price affects the wholesale price of fuels. However, until recently, wholesale gasoline and diesel pricing generally has not shown a price differentiation between fossil-biofuel blends and fuels without biofuels.

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

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

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.[60,61] However, because the Québec system is linked with the California cap and trade program, there is a joint minimum price that applies to both jurisdictions (the higher of the two systems). While the California minimum price increases at the same rate, the actual minimum credit price in the joint program will be a function of the CAD/USD exchange rate. In practice, the average annual credit price remained slightly above the price floor until about 2020, though it rose well above the floor as of 2023 [62] (Table 14).

Table 14: Québec cap and trade average annual credit settlement price and estimated price impact on gasoline and diesel (nominal CAD)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Credit price, \$/tCO_2e	16.1	17.3	18.9	19.3	22.0	22.8	27.7	36.9	44.7	46.0
Gasoline, ¢/L	3.9	4.2	4.6	4.7	5.3	5.5	6.7	9.0	10.8	11.2
Diesel, ¢/L	4.4	4.7	5.1	5.2	6.0	6.2	7.5	10.0	12.1	12.5

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/tC02e was in place for the first auction in 2020. The floor price was scheduled to increase at 5% per year plus inflation. Fuel suppliers had to purchase allowances for only 20% of the emissions on fuels (including gasoline and diesel) that they import into the province for combustion.[63] The Nova Scotia cap and trade quantification, reporting, and verification regulations specified that fuel suppliers did not have to purchase allowances for CO_2 emissions from biofuels.[64]

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

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

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

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

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

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

As of July 1st, 2023, the cap-and-trade program was replaced with the federal carbon price on retail fuels paired with a provincial Output-based Pricing System for large industrial GHG emitters.[65]

Nova Scotia's provincial government regulates the price of motor gasoline and diesel, including the allowable pass-through of costs associated with the former cap-and-trade system and the newly implemented *Clean Fuel Regulations*. The petroleum product pricing regulation specifies that fuel suppliers could recover 20% of the auction price floor at a fixed CI of 2.36 $kgCO_2e/L$ gasoline from retail sales.[66] If an auction settled above the floor price, a price adder was applied to the pricing formula to support cost recovery. This cap-and-trade credit price impact on fuel prices ranged from 1.0 ¢/L to 1.9 ¢/L on gasoline and between 1.1 ¢/L and 2.2 ¢/L on diesel from 2020 through 2023.

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 followed the rate schedule of the federal *Greenhouse Gas and Pollution Pricing Act* (GGPPA) and applied the same tax rate to bio-based and petroleum fuels. The carbon tax exemptions aligned 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.[67] As of July 1st, 2023, the New Brunswick tax was replaced with the federal carbon tax.[68]

In tandem with the introduction of the provincial 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 an effective net carbon price of only 2 ¢/L from April 2020 to April 2021. The change in provincial fuel taxes remains as of 2024, even with the re-introduction of the federal carbon tax. Consequently, the net carbon price impact remains about 5 to 6¢/L lower for gasoline and diesel with subsequent increases to the carbon tax rate (Table 15).[69]

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

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

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

[68] Government of New Brunswick, 2023, Province opts for federal backstop on carbon pricing

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

New Brunswick is not alone in adjusting fuel tax rates to mitigate increase in retail fuel prices. Since 2022, other provinces have introduced multi-year fuel tax holidays to address the high cost of fuels resulting from volatile crude oil prices as well as rising carbon costs. For example, Alberta has set its fuel tax rates on gasoline and diesel to zero from April 2022 to April 2023, while Ontario reduced its fuel tax rates by about 40% starting in 2022.[70]

Table 15: New Brunswick carbon tax

	2020-2021	2021-2022	2022-2023
Carbon Tax rate, $/t$CO_2$e	$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 did 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 gasoline tax and a 5 ¢/L diesel tax were removed,[71] bringing these provincial fuel taxes back to their 2015 values. As of fall 2022, the carbon price on gasoline and diesel was consistent with a $50/t$CO_2$e carbon price, about 11 ¢/L on gasoline and 13 ¢/L on diesel (Table 16).[72]

As of July 1st, 2023, Newfoundland and Labrador also replaced the provincial tax with the federal tax.[73]

[70] NRCAN, Fuel Consumption Taxes in Canada

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

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

[73] Government of Newfoundland and Labrador, 2023, Public Advisory: Information for Wholesalers and Retailers of Carbon Products on the Repeal of Provincial Carbon Tax

Table 16: 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 also came into force in April 2019. Like other provinces, it excluded some off-road uses, for farming, fishing and aquaculture, as well as heating oil (and propane).[74] As of 2022, the tax was consistent with a $50/t$CO_2$e carbon price, as per federal requirements (Table 17).[75] Like the rest of the Atlantic provinces, PEI adopted the federal carbon price as of July 1st, 2023, thus increasing the carbon price to $65/t$CO_2$e in that year and following the federal schedule thereafter.[76]

Also, in keeping with other provinces, PEI reduced provincial fuel taxes around the same time that carbon pricing was implemented. The provincial fuel tax on gasoline and diesel were reduced by 4.6 ¢/L and 6.0 ¢/L since 2019.[77]

Table 17: 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

Detailed Description of Low-Carbon Fuel Production Incentives in Canada vs. the US

In 2023, Québec introduced a tax credit to support biofuel production in that province. Until the end of 2027, this policy will be allowed to stack with the CFR. However, after that date, this policy may have no effect because the tax credit will be calculated net of the CFR credit value a fuel receives.

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74 Government of Prince Edward Island, Carbon Levy on Fossil Fuels and Rates of Carbon Levy on Fossil Fuels for 2020 to 2022

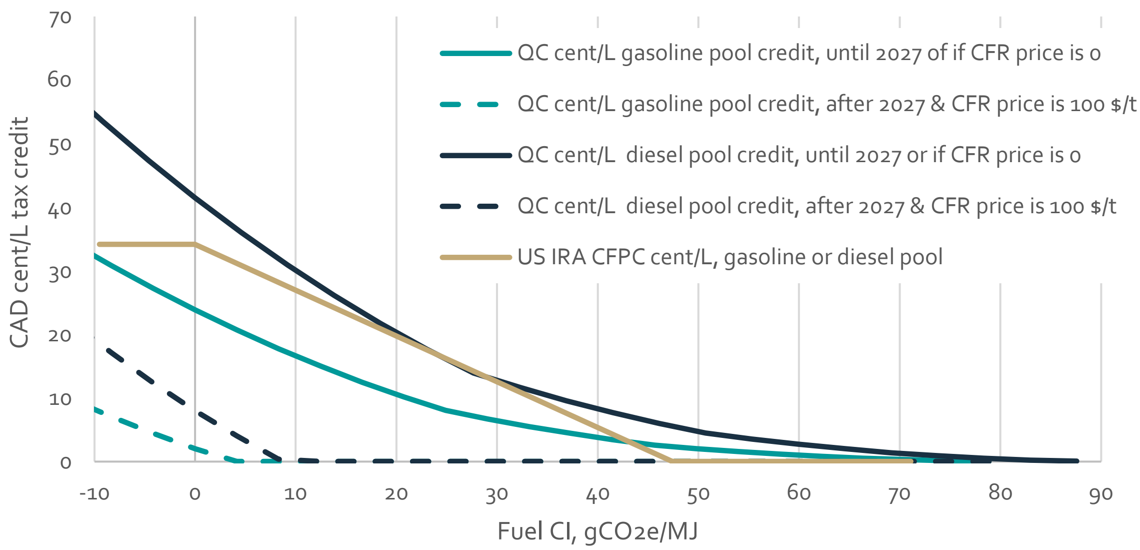
75 Ibid.

76 Government of Prince Edward Island, Carbon Levy on Fossil Fuels

77 NRCAN, Fuel Consumption Taxes in Canada

The policy provides a gross refundable production tax credit for fuels produced and consumed in Québec. The gross credit is in the range of 20-40 ¢/L for a typical biomass-based diesel fuel (CI between 0 to 20 gCO_2e/MJ, until 2027 or when the CFR price is 0, Figure 25). The gross tax credit for ethanol would likely fall between 5-15 ¢/L (CI 15 to 40 gCO_2e/MJ, when CFR price is 0, Figure 25**Error! Reference source not found.**). However, after 2027 the actual tax credit is net of other policy support earned by that fuel. If a fuel earns even $100/$tCO_2e$ per CFR credit it generates, the net tax credit is zero unless the fuel's CI is less than about 5 gCO_2e/MJ (Figure 25, QC trend lines with a CFR price of $100/t).[78]

Figure 25: Production tax credit for low-carbon fuels produced and consumed in Québec (with and without CFR credit value) versus the US production tax credit



In contrast, the US Clean Fuels Production Credit (CFPC) will provide a CI-dependent tax credit ranging from 0 to about 34 ¢/L (CAD) for low-carbon gasoline and diesel substitutes produced in the US, regardless of where they are consumed or what other policy support they have. The CFPC also provides a bonus incentive rate for low-carbon aviation fuels of about 1.75x the base rate given to gasoline and diesel substitutes. The CFPC comes into force in 2025 and replaces the biomass-based diesel blenders tax credit, which currently provides a $1/gallon (USD) incentive for biomass-based fuels blended with diesel in the US. The CFPC is scheduled to be in force until the end of 2027, but like the previous tax credit, its duration could be extended. Because it has no claw-back related to other policy support, a US-based

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[78] Assemblée National du Québec, 2022, Projet de loi no 6 (2023, chapitre 2), Loi donnant suite à des mesures fiscales annoncées à l'occasion du discours sur le budget du 22 mars 2022 et à certaines autres mesures

And

Revenue Québec, 2023, Tax Credit for Biofuel Production in Québec low-carbon fuel producer supplying fuel to Québec would benefit from both the CFPC and the CFR while a Québec-based producer would likely only earn CFR credits.[79]

Nationally, there have been no producer tax credits available in Canada since the ecoEnergy for Biofuels program expired in 2017 and the Alberta Bioenergy Producer Program expired in March 2020. The federal program provided Canadian producers with 10 ¢/L for gasoline substitutes and 26 ¢/L for diesel substitutes when it started in 2008/2009; rates declined annually, falling to between 3 and 4 ¢/L in the program's final year.[80] The Albertan program provided 10 ¢/L for ethanol, 13 ¢/L for renewable diesel, biodiesel and pyrolysis oil and 14 ¢/L for "advanced" fuels (e.g., ligno-cellulosic derived drop-in fuels).[81]

Low-Carbon Fuel Standards

British Columbia Low-Carbon Fuel Requirement

The CI component of the BC LCFS came into effect July 1st, 2013, with a schedule that required a 10% reduction in average fuel CI by 2020 relative to a 2010 baseline. In July 2020, a reduction requirement of -20% by 2030 was established and the requirement scheduled for 2020 was delayed due to the COVID-19 pandemic. Subsequently, in December 2022, a new target of -30% was legislated for 2030 and beyond.[82,83] At the end of 2023, the original legislation was replaced with the *Low Carbon Fuels Act* and *the Low Carbon Fuels (General) Regulation*, which now include a CI target for jet fuel and cover fuels consumed by port and airport equipment as well as forklifts.[84] The current CI reduction requirement for each fuel pools is in Table 18.

[79]H.R. 5376 — 117th Congress: Inflation Reduction Act of 2022

[80] Government of Canada, ecoEnergy for Biofuels Program

[81] Government of Alberta, 2017, Bioenergy Producer Program Outline

[82] Government of British Columbia, 2023, Low Carbon Fuels (General) Regulation.

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

[84] Referring to the *Low Carbon Fuels Act* and the *Low Carbon Fuels (General) Regulation*, which replace both the *Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the *Renewable & Low Carbon Fuel Requirements Regulation*.

Table 18: CI reduction requirements in the BC LCFS

Compliance Period	Gasoline and Diesel Pool	Jet Fuel Pool
2024	16%	0%
2025	18.3%	0%
2026	20.6%	2%
2027	23%	4%
2028	25.3%	6%
2029	27.7%	8%
2030	30%	10%

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 LCFS. If the minimum renewable fuel blending 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.

Consequently, 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 (i.e., routes operating prior to January 1st, 2021).[85]

The LCFS 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 600 $/tCO_2e$ for a compliance shortfall[86], up from 200 $/tCO_2e$ prior to 2023. As of the end of September 2024, the average credit price was $471/tCO2_e$ over the calendar year.[87]

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

[86] Ibid.

[87] Government of British Columbia, LCFS Credit Market Data.

The legislation governing the BC LCFS allows the program director to issue “Part 3 Agreement” credits. These are credits issued to fuel suppliers for projects that the director “is satisfied {…} has a reasonable possibility of reducing the amount of carbon dioxide equivalent emissions resulting from the use of Part 3 fuels”.[88] The director may issue credits for a project which will also generate credits once it is completed (e.g., provide credits to finance the capital investment in a project, which will subsequently generate further credits once it is operating and supplying of low-carbon fuel). The allowable volume of credits for Part 3 Agreements is up to 25% of the sum of all debits in the previous compliance period. Credits granted under a Part 3 agreement are interchangeable with credits produced via blending low-carbon fuels (i.e., credits granted via Part 3 Agreements reduce the volume of renewable fuel needed to achieve compliance with the policy).

Under the new *Low Carbon Fuels Act*, which will replace the existing *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, these agreements will now be referred to as “Initiative Agreements”[89].

A description of projects that have been awarded Part 3 Agreements and the associated volume of credits is published by the B.C. Government in Information Bulletin RLCF-014[90]. Currently the most recent projects date from the 2020 program year. From 2014 to 2020, 51 projects have been allocated 3.5 million LCFS credits (approximately the maximum allowable). About 58% of the total credits have been awarded to projects involved in co-processing and the production of biocrude and renewable diesel. Another 18% were awarded to support the deployment of light-duty electric vehicles and charging infrastructure (primarily to fund the incentive available through the British Columbia Scrap-It program administered by Shell Canada). The remaining credits have been awarded to projects supporting the electrification of other transportation modes (e.g., heavy-duty, marine), the development of hydrogen refuelling infrastructure, and the deployment of refuelling infrastructure capable of supplying higher biofuel blends (e.g., B20) (Figure 26).

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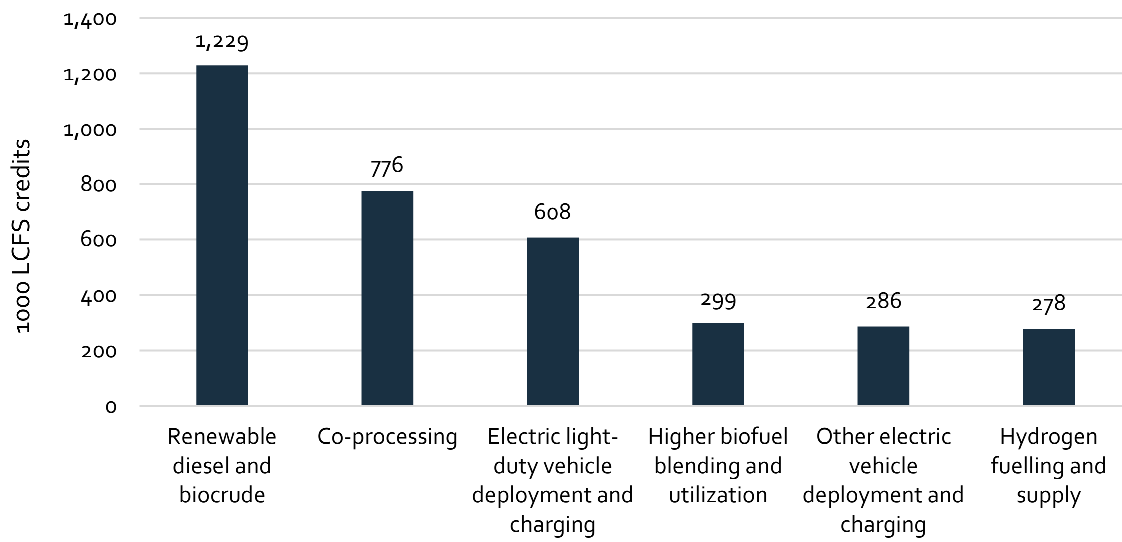
[88] *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, RSBC 2008, c. 16, s. 8.01

[89] Bill 15, Low Carbon Fuels Act, 3rd Session., 42nd Parliament, British Columbia, 2022

[90] Government of British Columbia, 2024, *Information Bulletin RLCF-014: Projects supported under Part 3 Agreements*.

Figure 26: LCFS credits issued under Part 3 Agreements, 2014-2020



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 LCFS 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.[91] 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 target is reached in 2030.

On December 31st, 2022, the CFR superseded 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 were automatically rolled over into CFR credits for use in 2024. Credit generation from the RFR was based on a default CI and energy density

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

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, respectively).

Notably, in the period from date of CFR publication (June 21st, 2022) to December 31st, 2022, the same volume of biofuels could simultaneously earn RFR and CFR credits, if the supplier was registered under the CFR credit and tracking system. The CFR also has an 'early credit' generation period from June 21st, 2022, to June 30th, 2023. Therefore, in the second half of 2022, the 'RFR rollover' credits and 'CFR early generation' creates could be double counted, creating an additional incentive to blend biofuels in the second half of 2022.

Table 19 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 only generated 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 could 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 could generate additional CFR compliance credits from any surplus RFR credits they held at the end of 2022 (row 4 in the table).

Table 19: 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 over-compliance 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 like what is used in California and British Columbia but calculated using a new lifecycle assessment modelling tool built for the CFR.[92]

[92] 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 these low-carbon alternatives (i.e., compliance category 2 and 3) can both generate and trade compliance credits. The credits generated by compliance categories 2 and 3 can be sold to other registered CFR participants.

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 later. 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. In this case, the quantity of deferred credits must be “repaid” with future compliance and grow by 5% annually.

Impact of Low-Carbon Fuel Standards on Retail Fuel Prices in Markets Without Price Regulation

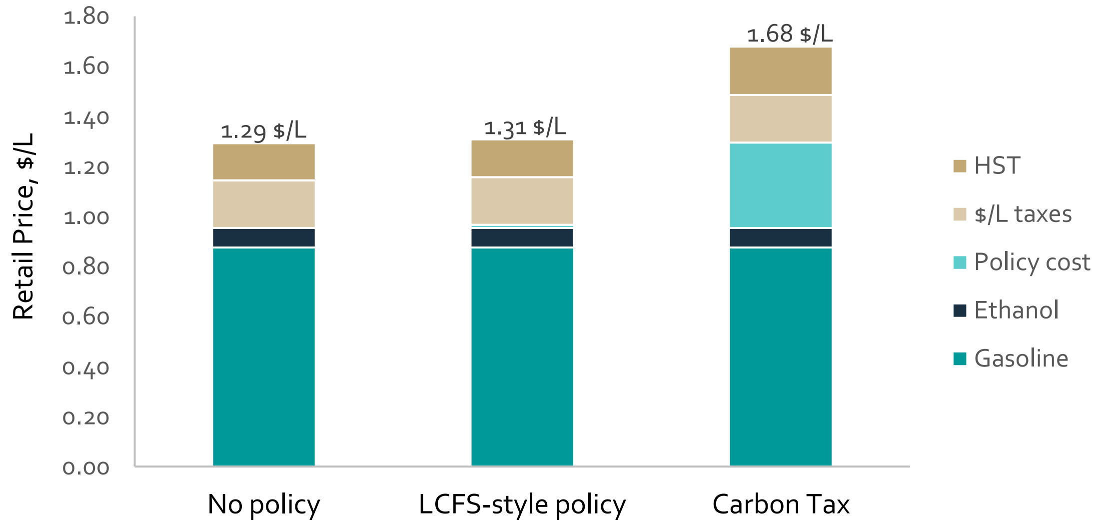
LCFS-style policies create a market-based incentive to supply low-carbon fuels because this action generates compliance credits which can be sold in their associated market or utilized to meet compliance obligations. The price of credits will rise until it is high enough to incentivize fuel suppliers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

LCFS credit prices and carbon tax rates are often improperly compared when assessing the impact on retail fuel prices. A LCFS credit price and a carbon price with the same \$/tCO_2e value have a very different impact on retail fuel prices. The difference exists for two reasons. First, a carbon tax applies to 100% of the direct GHG emissions (i.e., tailpipe) associated with a fuel while, on-net, a LCFS credit price only applies to the portion of a fuel's lifecycle GHG emissions above a given threshold (i.e., the required CI reduction in a given year). Second, the LCFS policies in Canada do not produce any financial transfer to the government like a carbon tax does (unless it has a ceiling price for credits 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 2022 and gasoline containing 10% ethanol by volume (E10), a LCFS policy with a credit price of 150 \$/ tCO_2e and the same CI limit as the CFR in 2025 (88.5 gCO_2e/MJ) would result in an E10 price of 1.31 \$/L versus 1.29 \$/L without an LCFS. The net retail-price impact is less than 2 ¢/L. In contrast, a carbon tax of 150 \$/tCO2e would result in an E10 price of 1.68 \$/L (Figure 27), with a net price impact of 39 ¢/L (34.5 ¢/L and 4.5 ¢/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 CIs 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.

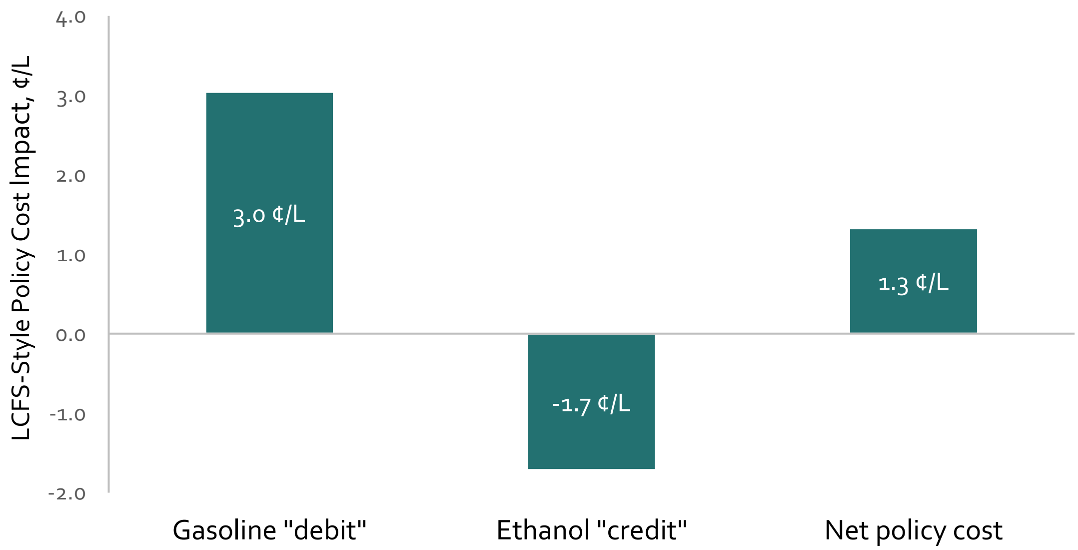
Figure 27: Impact of an LCFS-style policy vs. carbon tax on E10 retail prices in Ontario in 2023, LCFS credit price is equal to the carbon tax $/tonne CO_2e value ($150 t/CO_2e)



Note: wholesale fuel costs and fuel taxes are based on Ontario in 2023. 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. Supplying fuels creates "debits" (i.e., the "fee") that must be offset by "credits" (i.e., the "rebate") generated by the provision of low-carbon fuels (or other compliance actions). 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 $/tCO_2e$. 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 28) plus another 0.2 ¢/L from increased sales tax.

Figure 28: Breakdown of an LCFS-style policy's cost impact on E10 retail price with a hypothetical $150/tCO$_2$e credit price



Note: LCFS credit price and carbon tax are 150 $/tonne. In the example, the gasoline CI is 95 gCO$_2$e/MJ (baseline value in the CFR), the ethanol CI is 40 gCO$_2$e/MJ, and the LCFS-style policy target CI is 88.5 gCO$_2$e/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). Most compliance in response to LCFS-style policies is generated internally by fuel providers when blending low-carbon fuels. Only a 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 the start of British Columbia's low-carbon fuel requirement in 2013 to 2022 (the most recent year with complete data), 14% of compliance credits were obtained by trading through the credit market, while 86% of the credits were self-generated by fuel providers when blending lower-carbon fuels.[93]

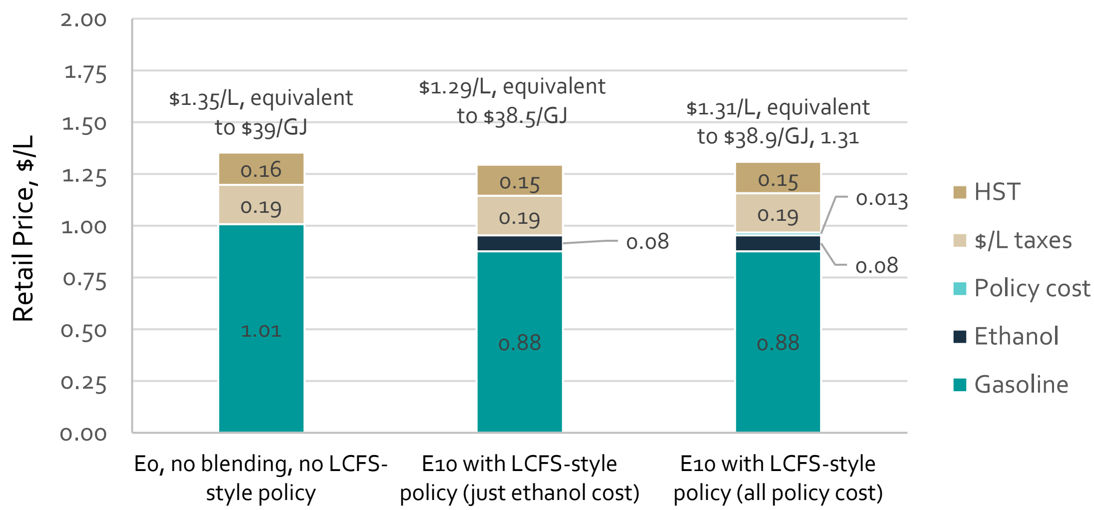
The previous Ontario example shows that the average abatement cost of renewable fuel blending and the credit price are not the same. A comparison of some hypothetical fuel prices reinforces this point. For E10 sold in Ontario in 2023, the abatement cost perceived by a consumer resulting from ethanol blending is negative $50/tCO$_2$e (accounting for both the lower cost per litre and lower energy density of E10). Therefore, at 2023 prices, blending to

[93] Government of British Columbia, 2024, RLCF-007-2023 Renewable and Low Carbon Fuel Requirements Regulation Summary for 2010 – 2023

Government of British Columbia, 2024, BC-LCFS Credit Market Data (2015 to present)

E10 resulted in a savings (compare the "E0, no policy" vs. "E10, just ethanol" costs in Figure 29). If that E10 were also subject to the 2025 CFR CI limit, hypothetically resulting in a credit price of $150/tCO_{2}e$, the cost E10 would increase by about 1.5 ¢/L since some credit purchases would be required for compliance (see the "E10, all policy" cost in Figure 29). The resulting average abatement cost of using E10 in this example is still negative and well below the marginal credit price.

Figure 29: 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., $1.01/L vs. $0.97/L, or a gasoline cost of $0.88/L of E10).

When calculating these abatement costs, recall that ethanol is roughly 33% less energy-dense than gasoline; thus, in this example, E10 results in a slight savings on a per GJ basis even though it cost per volume is 4% less than E0 (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.

As well, like all cost estimates in this analysis, these calculations are based on benchmark fuel prices that are publicly available. Actual cost impacts will be affected by contract prices that a negotiated subject to the market power of the buyers and sellers. Consequently, these CFR cost impacts indicate what could happen in an idealized market.

While there is some uncertainty in the magnitude of the octane value of ethanol and the contracted prices of fuels, those uncertainties do not change the fact that:

- The average cost of abatement 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 on the difference between the fuel CI and the CI limit required by the policy.
- Consequently, equivalent LCFS credit prices and carbon tax have a very different retail price impact: For example, a carbon tax of $150/t$CO_2$e has a much higher retail price impact than a LCFS credit price of $150/t$CO_2$e.

Impact of Low-Carbon Fuel Standards on Retail Fuel Prices in Markets with Price Regulation

The Atlantic provinces have regulated maximum prices for gasoline and diesel. Consequently, the relevant energy regulators need to adjust their rules to account for any additional costs incurred by fuel suppliers to comply with the CFR. Accordingly, they put adders on their maximum regulated fuel prices called "Carbon Cost Adjustors" and "Clean Fuel Adjustors".

Ideally, these adders would be based on the costs incurred by fuel suppliers to comply with the CFR. In other words, the maximum prices would rise and fall as a function of the average cost of compliance. However, in the absence of data from the nascent CFR credit market or information about how fuel suppliers in Atlantic Canada will comply with the CFR, the energy regulators made the following interim adjustments to the maximum fuel prices in July 2023:

- The price of gasoline and diesel in Newfoundland and Labrador and Nova Scotia was increased by about 4 ¢/L, based on the assumption of compliance via credit purchases from the CFR credit clearance mechanism at $300/t$CO_2$.[94,95]
- New Brunswick developed a cost of carbon adjustment, based on the value of imported renewable diesel, inferred from US fuel policy credit prices (the California LCFS credit and

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94 Newfoundland and Labrador Board of Commissioners of Public Utilities, 2023, Media Release, Thursday, July 6, 2023 Weekly Adjustment of Maximum Prices of Regulated Petroleum Products: Gasoline and Diesel Motor Fuels Adjustments Related to the Federal Clean Fuel Regulations

95 Nova Scotia Utility and Review Board, 2023, Application of New Fuel Charges (Carbon Tax) and Clean Fuel Costs to Gasoline and Diesel Oil Prices

Nova Scotia Utility and Review Board, 2023, Order M10853 the US *Renewable Fuel Standard* D4 credit).[96] The cost of carbon adjustment as of October 15th, 2023, was about 5 ¢/L.[97]

- In December 2023, the PEI Island Regulatory & Appeal Commission ruled that the New Brunswick price CFR price adjustment could be passed into PEI via its rack prices.[98]

The cost adders have since increased in New Brunswick, PEI and Newfoundland and labrador, while Nova Scotia is currently reporting a lower adder (summarized in Table 20).

It is likely that these adders are overestimating the cost of complying with the CFR. The regulators are implicitly assuming that compliance can occur only through two of the highest cost actions: blending imported renewable diesel or purchasing credits from the compliance clearance mechanism. However, fuel suppliers in Atlantic Canada have other lower-cost compliance opportunities, such as ethanol blending. Notably, Irving oil states that it can blend up to 10% ethanol in its product from the Saint John Refinery[99] and up to 15% ethanol at its Halifax terminal.[100]

It is impossible to know what it cost fuel suppliers in Atlantic Canada to comply with the CFR in 2023, but we can produce some estimates that indicate they are being overcompensated for their actions. While the volume and prices of renewable fuel consumed in Atlantic Canada are uncertain, Biofuels in Canada provides an estimate of this quantity and its cost impact. In 2023, our analysis indicates that the cost impact of renewable fuel consumption in Atlantic Canada was 1.2 ¢/L, measured very conservatively against a baseline with no renewable fuel consumption. We can also use the CFR credit price and policy requirements to estimate what the compliance cost could have been if the fuel suppliers only bought compliance credits from the market at the average price. The average credit price in 2023 was \$127/tCO_2e[101] and the CI reduction requirement was 3.5 g/MJ. Using only credit purchases for compliance, this yields a compliance cost of about 1.7 ¢/L.[102]

[96] New Brunswick Energy and Utilities Board, 2023, Matter No. 549

[97] New Brunswick Energy and Utilities Board, Price Schedule - New Brunswick Maximum Allowable Prices and Delivery Cost, Accessed October 18th, 2023

[98] Prince Edward Island Regulatory & Appeals Commission, 2023, https://irac.pe.ca/wp-content/uploads/PC23-007.pdf

[99] Irving Oil, 2020, Report on Sustainability

[100] Irving Oil, 2022, Report on Sustainability

[101] Environment and Climate Change Caada, 2024, Clean Fuel Regulations credit market report, June 2024

[102] Environment and Climate Change Caada, 2024, Clean Fuel Regulations credit market report, June 2024

As with all cost estimates in this analysis, these are based on benchmark fuel prices that are publicly available. Actual cost impacts will be affected by contract prices that a negotiated subject to the market power of the buyers and sellers. Consequently, these cost impacts indicate what could have happened in an idealized market while the true cost impact remains uncertain. Nonetheless, these examples show that regulators are putting all the pricing risk and uncertainty onto the consumers while completely sheltering the fuel suppliers and providing little incentive to compete or innovate.

Table 20: CFR price adjustments in Atlantic Canada

Province	Price adjustment, July 2023	Price adjustment, Nov. 2024	Adjustment based only on credit purchases at average CFR price in 2023	Biofuels in Canada estimated cost impact
Newfoundland and Labrador	Gasoline: 3.7 ¢/L Diesel: 4.17 ¢/L	Gasoline: 5.4 ¢/L Diesel: 6.0 ¢/L[103]	1.6 to 1.7 ¢/L*	1.2 ¢/L**
Nova Scotia	Gasoline: 3.7 ¢/L Diesel: 4.17 ¢/L	Gasoline: 1.8 ¢/L Diesel: 2.0 ¢/L[104]		
New Brunswick	Gasoline: 3.7 ¢/L Diesel: 4.17 ¢/L	Gasoline: 4.4 ¢/L Diesel: 4.9 ¢/L[105]		
PEI		Same as New Brunswick		

*Based on an average credit price of $127/tCO2e in 2023 and a CI reduction requirement of 3.5 g/MJ

**based on the fuel volumes and prices estimate for Atlantic Canada in the Biofuels in Canada Analysis, measured very conservatively against a baseline with no renewable fuel consumption.

Abatement Costs with Foregone Refining Margins

The abatement actions that a fuel provider might use in response to a LCFS-style policy are 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

103 http://www.pub.nl.ca/HowPricesAreSet/CarbonPriceAdjustment.php

104 https://nsuarb.novascotia.ca/sites/default/files/Weekly%20Petroleum%20Pricing%20Example%20Nov%208-24.pdf

105 https://nbeub.ca/images/documents/petroleum_pricing/currentmaximumpriceenglish.pdf

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 refined petroleum products).

Notably, when selling biofuels purchased from another producer, this action could 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 by adding carbon capture and storage (CCS) at their refinery process heat unit. The calculations use the following assumptions:

- Abatement from CCS is \$350/tCO_2e reduction as is the credit price in this example.
- The fuel provider does not need additional investments in blending infrastructure.
- The fuel provider assumes the prices, CI values and fuel densities recorded for 2023 in the Biofuels in Canada analysis are representative of future conditions (using Canada fuel-weighted averages): biodiesel costs \$1.78/L with a \$0.06/L transportation cost, has a CI of 5.4 gCO_2e/MJ and a density of 35.4 MJ/L; wholesale diesel (B0) sells for \$1.11/L with a CI of 93.9 gCO_2e/MJ, and a density of 38.7 MJ/L. The refining margin (net revenue) is \$0.52/L.[106]
- The fuel provider cannot pass the additional costs to the consumers.

Based on fuel costs and properties alone, the abatement cost of blending additional biodiesel is \$245/tCO_2e. This is the abatement cost if the fuel provider can find an alternative market for all 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.

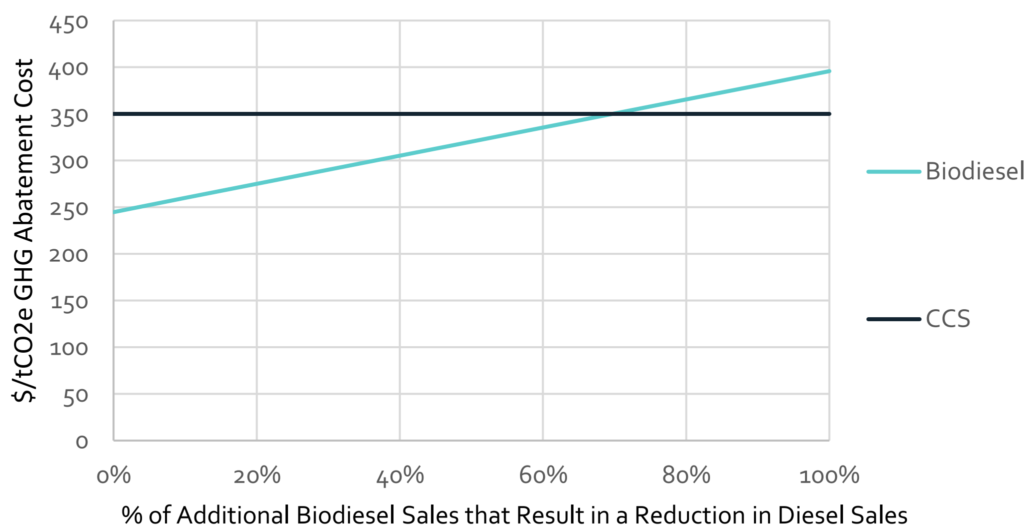
However, if selling more biodiesel reduces diesel sales and results in a foregone refining margin, then the fuel provider loses \$0.52 for each litre of diesel not sold. To reduce GHG emissions by one tonne, the fuel provider would have to sell 11.3 GJ of biodiesel, equivalent to 292 L of diesel. If the biodiesel sales completely displace an energetically equivalent amount of diesel, then there is \$151 in foregone refining margin per tonne of GHG reduction and the net abatement cost is \$396/tonne, greater than the assumed credit price in this

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

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. Nonetheless, the abatement cost of biodiesel in this example is sensitive to its impact on diesel sales. If just about 70% or more of the additional biodiesel sales offset an energetically equivalent amount of diesel sales, CCS is the lower cost abatement action (Figure 30). 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. For integrated crude oil and petroleum product producers, this analysis could be extended to account for margins earned on crude oil.

Figure 30: Relative abatement cost of blending biodiesel versus capturing and storage of CO_2e as a function of how biodiesel sales affect diesel sales.



Appendix B: Summary and Discussion of Inputs to the Analysis

Table 21 summarizes the data and assumptions used in this analysis. The data was either obtained through direct communication with government contacts or from published data (represented in green). Some inputs required assumptions or modelled values (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.

Table 21 also flags the greatest uncertainties in orange, representing data gaps where inputs to the analysis must be inferred from other data. For example, neither Québec nor the Atlantic provinces report the volume of biofuels blended into transportation fuels. To infer the volume of ethanol, biodiesel, and RD consumed in these provinces, we used the difference between national consumption totals, reported by ECCC for 2011-2023[107,108,109] and the data we collected. Therefore, the resulting biofuel consumption reported for Québec and the Atlantic provinces is particularly uncertain since it is the difference between federal data and the sum of provincial data, all of which is collected using different methodologies. As of the 2021 data year, we have been able to calculate the ethanol consumed in Québec based on combustion GHG emissions, which reduces the uncertainty somewhat.

Although national data provided by ECCC 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 RD 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

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[107] Environment and Climate Change Canada, 2016, Renewable Fuels Regulation Report: December 15, 2010 to December 31, 2012. Available on Google Drive.

[108] Environment and Climate Change Caada, 2022, Open Data: Renewable Fuels Regulations 2013, 2014, 2015, 2016, 2017,2018, 2019, 2020, 2021 and 2022. Available on Google Drive.

[109] Environment and Climate Change Caada, 2024, Clean Fuel Regulations credit market report, June 2024

uncertain. Anecdotally, as of 2024, some of the RD imported into Canada is still not reported under the correct HS code.

Likewise, the sum of ethanol consumption reported in the provincial data, including what is calculated from Québec's GHG data, is slightly larger than national ethanol consumption in 2022. In this case, the total reported in this analysis is 6% larger than ECCC's figure.

Furthermore, the relative split between biodiesel and RD remains an uncertainty for all regions other than British Columbia and Alberta, including Canada as a whole. ECCC reports national total consumption for these fuels, but this data is affected by the same problems in reporting the imported amounts of these fuels. In some provinces, we have qualitative information guiding our assumptions. For example, the government of Ontario indicates approximately how much biodiesel versus RD is consumed in that province (e.g. about 50/50, much more RD than biodiesel). Specific assumptions for biodiesel and RD consumption by province are listed in Appendix C: Biofuel Type and Feedstock Assumptions and Data.

Finally, CI values are mostly from GHGenius 4.03a, except in Ontario and British Columbia where provincial governments provide data on CIs used for compliance. Note that the CI for gasoline in all years and regions has been increased by 7 gCO_2e/MJ relative to the value from GHGenius, based on input from (S&T)² Consultants. The updated gasoline CIs closely align with what is in the latest GHGenius version 5.02 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 such as acetone or toluene 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,[110] whereas GHGenius 4.03a uses 63 gCO_2e/MJ. Our adjusted value falls in the middle of ECCC's emission factors at 70 gCO_2e/MJ.

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

Table 21: Summary of Key Inputs (Data in green, assumptions in yellow, major uncertainties in orange, notes below)

<table>
<tr><th></th><th>BC</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: 2010-2023. Gasoline and diesel volumes are the total, not the non-exempt volume</td><td>2011-2023: 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 to 2019, estimated for 2020 onward</td><td rowspan="2">Data from govt. contact to 2023</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 to 2022 provided by govt. contact</td><td>Difference between national total reported under the RFS and CFR by ECCC[1] and sum from other provinces, allocated to QC and Atlantic CDA (to 2020). Based on GHG data from 2021.</td><td>Difference between national total reported under the RFS and CFR by ECCC[1] and sum from other provinces, allocated to QC and Atlantic CDA</td></tr>
<tr><td>Diesel volume</td><td>2011-2023: From govt. contact.
For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy</td><td>Data through to 2023 from govt. contact</td><td>2018-2023: 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 to 2023 from govt. contact</td><td>Data from govt. contact</td><td>Data for 2018-2023 from Gov't. Provisional data from govt. contact for 2015. Estimates for 2016 and 2017.</td><td>Same method as for ethanol, prior to 2021</td><td>Same method as for ethanol</td></tr>
<tr><td>Biofuel feedstock</td><td>RLCFRR Summary: 2010-2023. Gasoline and diesel volumes are the total, not the non-exempt volume</td><td colspan="6">Assumptions reviewed by govt. contacts and (S&T)[2] Consultants</td></tr>
</table>

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	Atlantic
Fuel Carbon Intensity	RLCFRR Summary: 2010-2023. 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 onward. Biodiesel/HDRD: avg. from govt. contact for 2015 and 2018-onward, 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]						

	BC	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	8-15 $/bbl (in 2022/2023), applied to biofuels based on distance between Chicago and representative city[4]. Compared with rail freight rates listed by the Canadian Railway Association and inflated by their rail freight cost index[16].						
Ethanol octane	Used a value of 113, corresponding to ethanol used in low concentration blends						
Value of octane	Value in $/octane point/L based on difference in the 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.[14]						
Refinery and gasoline GHG intensity	Assume that petroleum refining and gasoline blendstock GHG intensity is independent of the biofuel blend.						
Impact of biofuels on refining and marketing margins	Assume the refining margins for petroleum fuels would be same in a counterfactual scenario without biofuel blending. The refining margin is the $/L net revenue of refiners, embedded in gasoline and diesel wholesale prices from Kalibrate 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.						
Electric vehicle sales, activity, and GHG intensity	Plug-in electric vehicle (PEV) sales are provided by Statistics Canada for 2011-2023 (Table: 20-10-0021-01). PEV stocks are from Statistics Canada for 2011-2022 (Table: 23-10-0308-01), while the 2023 stock is inferred from sales. 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 6, Canada Gazette, Part II, Volume 154, Number 51: Clean Fuel Regulations						

1) ECCC, Open Data reported under the Renewable Fuels Regulations, 2010 through 2022 and reported in the CFR Credit Market Report in 2023. 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. 2024. 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 https://climatechange.novascotia.ca/cap-trade-regulations

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).

16) Railway Association of Canada, 2023, Rail Trends 2023. https://www.railcan.ca/resources/annual-rail-trends/

Appendix C: 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 RD. 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 disaggregate biomass-based diesel volumes into biodiesel and RD.

Feedstock data and guidance on the split between RD 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.[111] The data is 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. BC reporting does not distinguish between feedstocks used for biodiesel or RD. We assume that tallow, yellow grease, biodiesel bottoms, fatty acid distillates and palm oil byproducts are used for RD. Some soy feedstock for RD is also assumed to ensure total biodiesel and RD consumption matches the data. In 2023, there was a substantial increase in canola feedstock fuel, and we assume some of this is RD.

3. 2019-2022: Biodiesel bottoms and fatty acid distillates are grouped into Other/unknown.

Assumptions for Alberta

1. 2011 to 2023 fuel volumes were collected via personal correspondences with the Alberta government

[111] British Columbia Ministry of Energy and Mines and Low Carbon Innovation, 2024, Renewable and Low Carbon Fuel Requirements Regulation Summary: 2010-2023

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 on 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. RD in all years prior to 2017 is based on data reported for 2017. The split is based on data thereafter, except for 2023, where RD vs. biodiesel volumes are set to better align with national total consumption reported by ECCC in the Clean Fuel Regulation Credit Market Data Report.

8. We assume the feedstocks used for RD 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 2023 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 blend rates from 2012-2023 are based on data provided by Saskatchewan.

2. We assume that the biofuel in diesel is biodiesel, with no RD.

3. We assume that the feedstocks for ethanol are 70% wheat and 30% corn, based 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 to 2019 were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Volumes from 2020 onward are provided by the Saskatchewan government and are lower than the trend in the Statistics Canada Data.

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 data from 2010-2019, as well as total blended gasoline and diesel volumes from 2020-2023, is from the Government of Manitoba as reported under Manitoba's Fuel Mandate.

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 on personal correspondence with a government contact.

4. We assume there is no RD 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. 2021 to 2023 are estimated assuming compliance with the updated fuel regulation (where the increase in the diesel pool is soy RD, 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. The data is rounded to the nearest 100 ML and in 2021 and 2022 we have adjusted the volumes downward within that level of precision to better align with national consumption (40 ML less in 2021, 49 ML less in 2022). Renewable gasoline is present in Ontario in 2022 and 2023, but volumes are currently assumed to be small and are aggregated with ethanol.

2. Bio-based diesel consumption volumes for are based on Government Data for 2014, 2015 and 2019 to 2023. From 2016 to 2018, volumes are estimated assuming compliance with the Greener Diesel Regulation, 80% of volume is HDRD with CI based on Diamond Green Diesel from 2016 to 2018 (from CI registered under the BC RLCFRR), 20% is biodiesel with net-0 CI, 10% of diesel pool is distributed in Northern Ontario (based on 2015 data) and is exempted from the regulation prior to 2017.

3. Bio-based diesel in 2010-2013 is based on fuel tax exemption data with the RD 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 to respond to market constraints due to the COVID-19 pandemic.
8. For 2021 and 2022, we assume biomass-based diesel is 40% biodiesel and 60% HDRD, based on 100% biodiesel consumption by some lake freighters.[112] For 2023, we assume 51% biodiesel based on communication with a government contact.

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 volumes are uncertain and should be used with caution: To 2020, 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. Volumes are inferred from provincial GHG inventory data for 2021 and 2022. Note that this method results in the sum of provincial ethanol consumption in 2022 being somewhat larger than the total reported by ECCC (+6% or about 210 ML).

3. In 2023, we assume some growth in the ethanol blend rate from 2022, making the blend rate in 2023 consistent with the provincial policy requirement and national CRR data.

4. 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.

5. We assumed most biodiesel and HDRD is produced from Tallow and that 80% of the biomass-based diesel volume is HDRD from 2014 to 2022 (same as Ontario assumption used

[112] Canadian Steamship Lines (2021). CSL Successfully Completes World's Largest B100 Biofuel Tests

to 2020). We assume HDRD feedstock in 2023 is a mix of tallow, yellow grease and soy, based on our understanding of what Diamond Green Diesel is using.

6. We assume ethanol feedstock is corn since there is a facility in Québec 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. In 2023, we assume volumetric compliance with Québec's gasoline regulation and an equal biomass-based diesel blend rate in Atlantic Canada and Québec.

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

5. We assume HDRD feedstock is a mix of tallow, yellow grease and soy, based on our understanding of what Diamond Green Diesel is using.

Detailed Feedstock Results

Figure 31 and Figure 32 show renewable fuel consumption in Canada by fuel type and feedstock, based on the data and assumptions outlined above. Most biodiesel is produced from canola and soy. Most RD is produced from tallow, yellow grease, and as of 2023, canola. Most ethanol consumed in Canada is produced from corn, with 10-15% produced from wheat.

Figure 31: Biomass-based diesel consumption in Canada by fuel type and feedstock

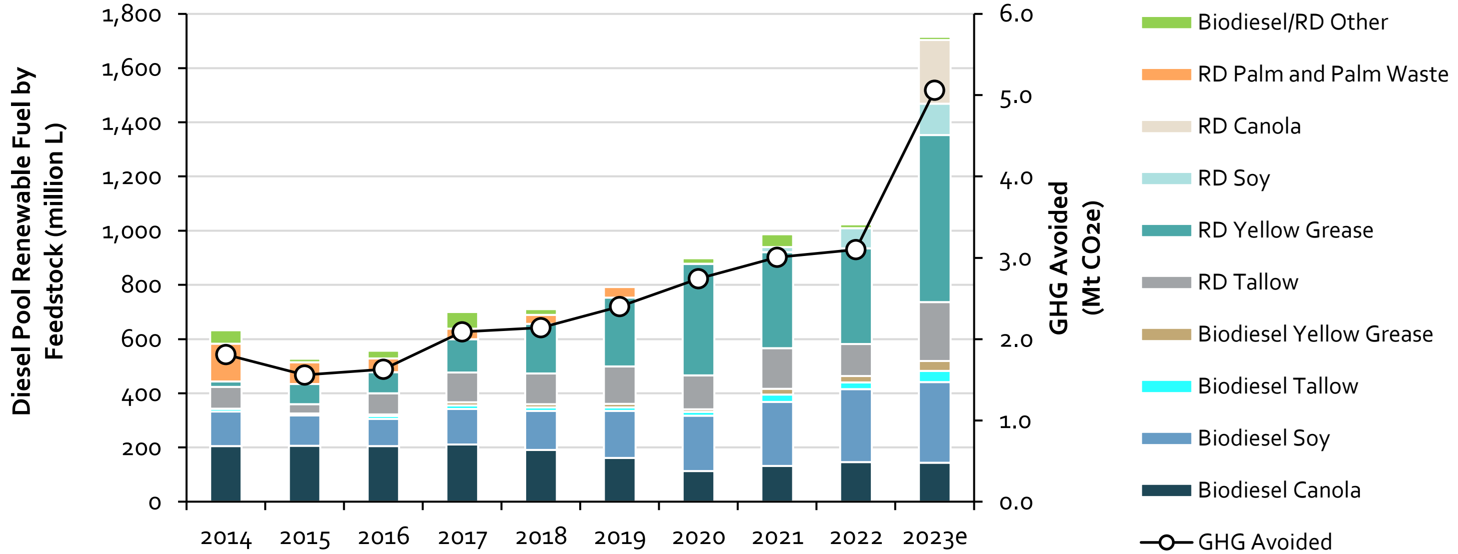
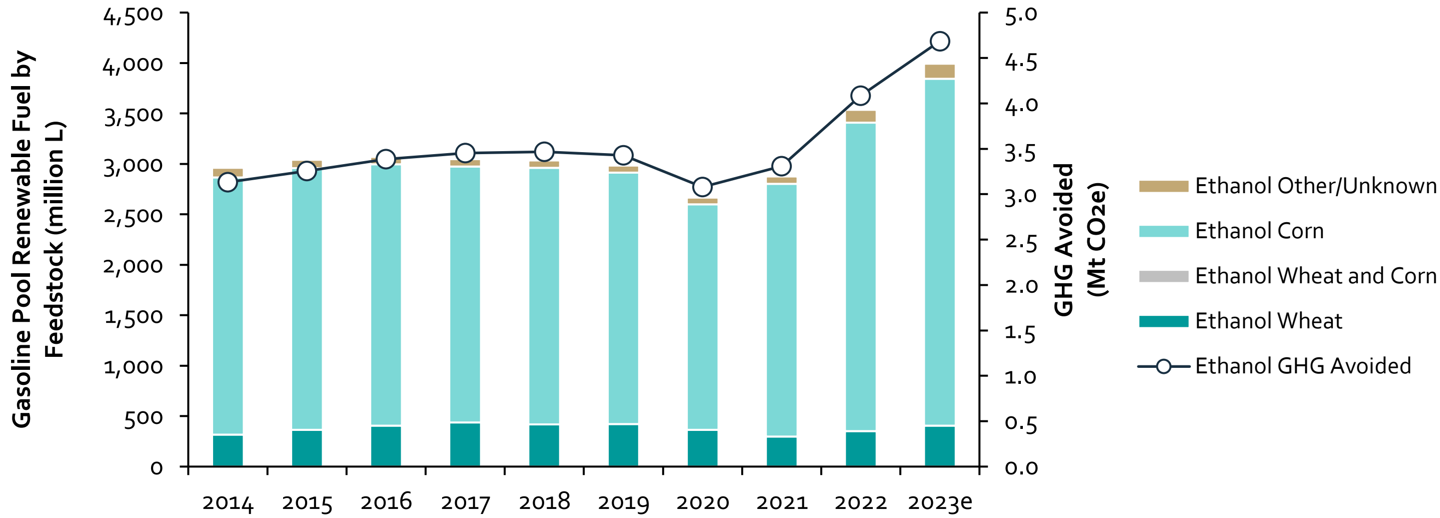


Figure 32: Ethanol consumption in Canada by fuel type and feedstock



Appendix D: Impact of Ethanol on Gasoline Refining and Consumption GHGs

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.

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.[113]

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

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.[114] Another US paper found a 6% and 12% reduction in refining GHG emissions compared to E10 for E20 and E30 blends, respectively.[115] 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.[116] 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.[117] 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. 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)) incentivize the use of CCS with hydrogen production at refineries, this insight might not apply in Canada in the future.

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[114] 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

[115] 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

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

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

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).

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 22: 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, 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.[118]

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

Appendix E: 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 2010-2022.

➢ Ethanol and biodiesel prices were based on monthly averages from Chicago Mercantile Exchange (CME) from 2010 to the end of 2022. Biodiesel prices are used net of the US biodiesel blenders tax credit.

- RD 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)[119] for 2013 and inflated using the Railway Association of Canada's rail cost index available in the annual Rail Trends reports (i.e. index of freight revenue per revenue tonne mile).[120]

- 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.[121]

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[119] 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

[120] Railway Association of Canada, 2023, Rail Trends 2022.

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

- All values were converted to 2020 dollars[122] and Canadian currency from US dollars[123] and Euros.[124]

- Inputs for Atlantic Canada are constructed from provincial values averaged using population weights from Statistics Canada.[125]

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

- The price of gasoline and diesel blendstock 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 (i.e. renewable or fossil component divided by total volume).

- 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:

- 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.[126]

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122 CANSIM, 2018, Table 326-0020 Consumer Price Index

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

124 www.investing.com/currencies/eur-cad-historical-data

125 Statistics Canada: Table 17-10-0009-01. Population estimates, quarterly.

126 113 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.

- 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[127] 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.[128]

- $O_{blend,prem}$ 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 (i.e., below 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:

- $O_{blend,reg}$ 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:

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127 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

128 ibid

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

- Similarly, the price per litre cost/savings of blending biodiesel and RD 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
  - RD= 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[129] and are assumed to be independent of biofuel blending rates. Taxes, including carbon taxes and levies, are from NRCAN.[130] 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

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

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

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.[131,132,133]

- 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[134] as reported by Natural Resource Canada, for the average L/100 km and annual km travelled. For the archetypal gasoline consumer, these values are 9.7 L/100 km and 15,788 km/yr. For the archetypal diesel consumer, these values are 32.0 L/100 km and 87,539 km/yr.[135,136]

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[131] 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)

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

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

[134] 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.

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

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

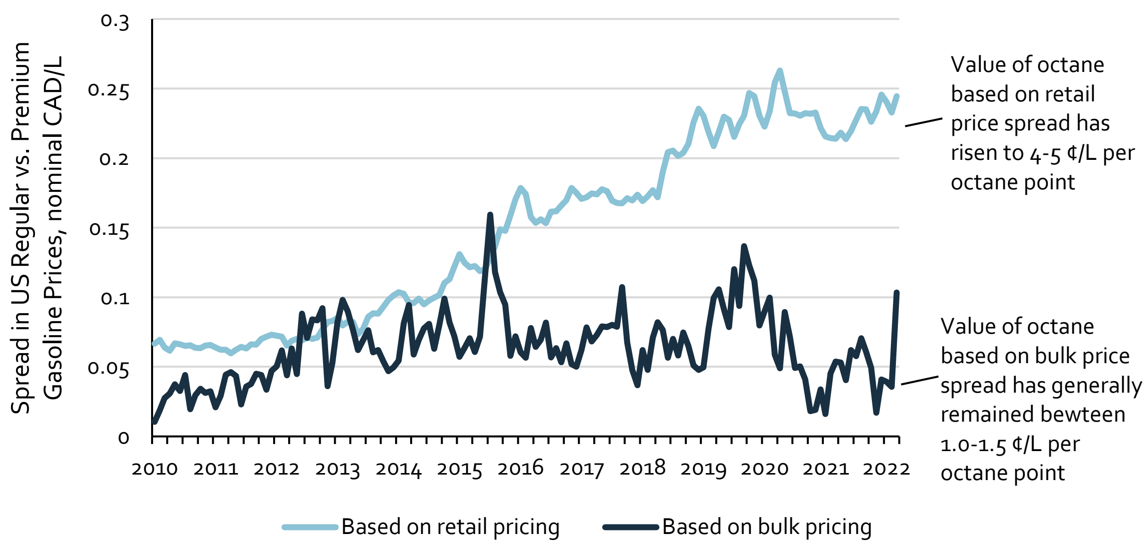
Appendix F: 2021 Updates to the Cost Analysis Methodology

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 33: Value of octane measured using retail and wholesale prices[137]



This methodological change resulted in a nearly \$300/tCO₂e 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).

137 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

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.[138] 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).[139]

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 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 RD 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 RD because a substantial portion of Canadian RD 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.

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

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

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 RD in Canada for 2016 and onward years (Neste data was used in previous years, where the DGD data is not available).

Appendix G: Plug-in Electric Vehicle Analysis Methodology

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. PEVs are driven the same amount as conventional vehicles (about 12,800 km/year as of 2021, based on results/assumption in NRCan's comprehensive energy use database[140]). See the next section for more details on this assumption.
    b. 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[141] and electric travel energy intensity taken from Natural Resources Canada.[142] We assume PHEVs have a utilization factor of 69% (this fraction of the vehicle's travel uses the electric drive is from electricity, the rest is from gasoline)[143].

[140] Natural Resources Canada, Comprehensive Energy Use Database, Accessed September 2024

[141] GoodCarBadCar, Automotive Sales Data and Statistics

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

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

c. 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*.[144]

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

$$\text{Displaced Gasoline (GJ/year)} = \text{Stock (vehicles)} * \text{kilometers/year (km/vehicle-year)} * \text{fuel efficiency (kwh/km)} * \text{EER (GJ/GJ)} * 3.6$$

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.[145] 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[146] in schedule 5, point 8 (e.g. to account for fuel production emissions, methane emissions from hydro reservoirs etc.)

Additional detail on PEV utilization assumption

Zhao et al. (2023)[147] conducted a study of annual vehicle travel based on a large sample of used light-duty vehicles in the US, covering model years 2016 through 2021. It found no material difference between annual vehicle km travelled (vkm/yr) of plug-in hybrid electric vehicles and conventional vehicles. In contrast, it found that battery electric vehicles (BEVs) are driven 39% less than conventional vehicles.

Despite this conclusion, we continue to assume that PEVs have the same annual utilization as conventional vehicles. This choice is based on the age of vehicles included in the Zhao et al. (2023) study and the fact that we already assume relatively low travel for vehicles in this study.

Because older cars are more likely to be sold, Zhao et al. (2023) note that "the number of observations (and the majority of the variability in vehicle age) is concentrated in older rather than newer model year vehicles." Therefore, the conclusions are heavily weighted by older model years, e.g. 2018 and older. We estimate that these vehicles currently represent less than 20% of the Canadian electric vehicle fleet. Furthermore, Zhao et al. (2023) found that

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

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

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

[147] Zhao, L., Ottinger, E., Yip, A., Helveston, J. (2023). Quantifying electric vehicle mileage in the United States. *Joule 7, 2537-2551.*

vkm/yr is heavily dependant on vehicle range. Therefore, the findings of this study likely do not apply to the majority of the BEVs in the Canadian vehicle fleet, where newer BEVs tend to have greater range. This is consistent with other studies, for example by Doshi and Metcalf (2023)[148], which find that there is no difference in annual distance travelled between conventional vehicles and BEVs if they examine long-range cars only.

Finally, Zhao et al. (2023) estimated that electric vehicles travel in the range of 6,200 to 8,700 miles per year (10,000 to 14,000 km/yr). This distance already consistent with the assumption used in our calculation (roughly 12,800 km/yr, based on NRCan's estimate for "car" utilization, which is somewhat lower than their estimate for "light truck" utilization, about 14,100 km/yr, in the Comprehensive Energy use Database[149]).

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[148] Doshi, S., & Metcalf G. (2023). How Much Are Electric Vehicles Driven? Depends on the EV. *MIT Center for Energy and Environmental Policy Research, WP-2023-001 Research Brief.*

[149] Natural Resources Canada, Comprehensive Energy Use Database, Accessed September 2024