

Biofuels in Canada **2026**

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.

Funding and Authorship

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Executive Summary

Canada has many policies aimed at cutting transportation GHG emissions by boosting renewable and low-carbon fuel use. Yet no single government source provides a detailed, comprehensive picture of these policies and their impacts. To fill this gap, Advanced Biofuels Canada Association has engaged Navius Research to produce the annual *Biofuels in Canada* report, now in its 11th year.

Objectives and Method

This report evaluates and communicates 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 petroleum refinery – are also included. As of this year, the analysis also quantifies the supply of sustainable aviation fuel (SAF) in Canada.
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 the annual supply of Clean Fuel Regulations (CFR) credits and the size of the cumulative credit bank or deficit.
6. Estimating impact of renewable fuel consumption on energy costs, including the role of fuel taxation.
7. Communicating trends in Canadian renewable fuel trade.

The analysis runs from 2010 to 2025 (where the most recent year includes some estimated data, indicated as “2025e” 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 (2025e) includes preliminary national CFR data and uses preliminary or final data for many regions. However, it relies on estimates for renewable fuel consumption and CIs in 2025 for Québec. Data for Québec, as well as revised data for other regions, will be used to revise the 2025e results in next year’s edition of *Biofuels in Canada*. Likewise, this year’s analysis uses final data to update the 2024 estimates from the previous edition. Therefore, the results and trends reported last year for 2024e will differ somewhat from what is now reported for 2024.

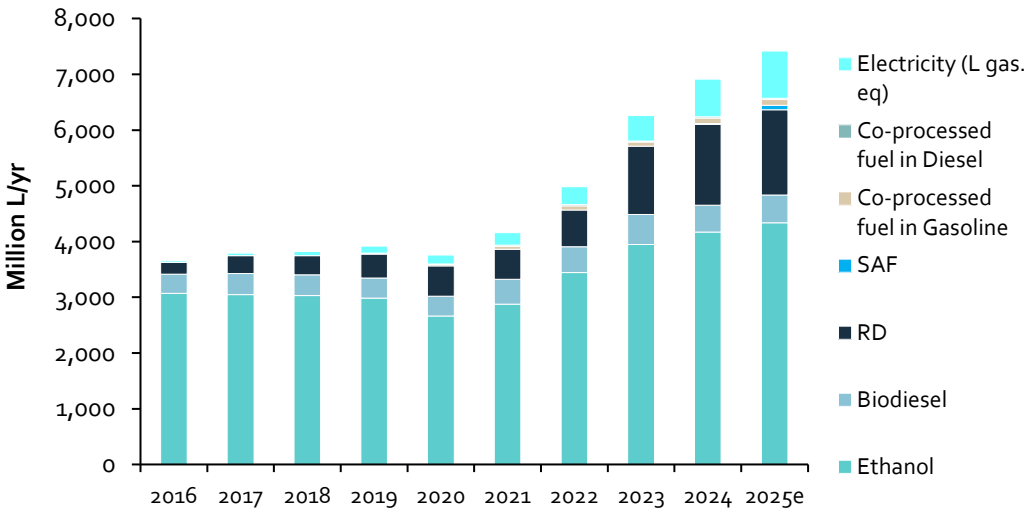
Renewable Fuel Consumption

Renewable fuel consumption in Canada increased by 6% in 2025, on top of the 10% increase in 2024 (Figure 1). This ongoing growth is a function of the overlapping national CFR and provincial policies, many of which become increasingly stringent over time:

- **Biodiesel and renewable diesel (RD) consumption grew modestly in 2025.** The growth comes from both biodiesel and RD, where the volume increased by 5% to almost 2.0 billion (giga, or G) L/yr, on top of 10% growth in 2024.
- **Similarly, ethanol volumes grew by 4% in 2025, on top of 6% growth in 2024.** Ethanol consumption in 2025 was just over 4.3 GL/yr.
- **Electricity consumption by light-duty vehicles grew by an estimated 26% in 2025, on top of 46% growth in 2024.** The volume of fuel displaced by electric vehicles is still less than the volume of renewable fuels (about 0.85 GL of gasoline equivalents in 2025). However, it remains the fastest growing category.
- As of 2025, co-processed fuel was still only being produced and consumed in the British Columbian market. The volume was about 128 ML/yr.

Change in clean fuel consumption, 2024 to 2025:
Ethanol +4%
Biomass-based diesel +5%
Electricity +26%

Figure 1: Total clean fuel consumption in Canada grew by 6% in 2025, on top of 10% growth in 2024



In 2025, the renewable fuel content in gasoline and diesel in Canada was well above the regulated minimum levels because of the fuel CI reductions required by the CFR and the BC LCFS. Ethanol content in the gasoline pool was almost 10%_{vol}, while biomass-based diesel content grew to more than 7.3%_{vol}.

Increasing renewable fuel consumption in Canada has primarily relied on increased renewable fuel imports from the US. In 2025, Canada imported about two thirds of its renewable fuel supply.

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 0.12% from 2010 to 2025 (Figure 2).

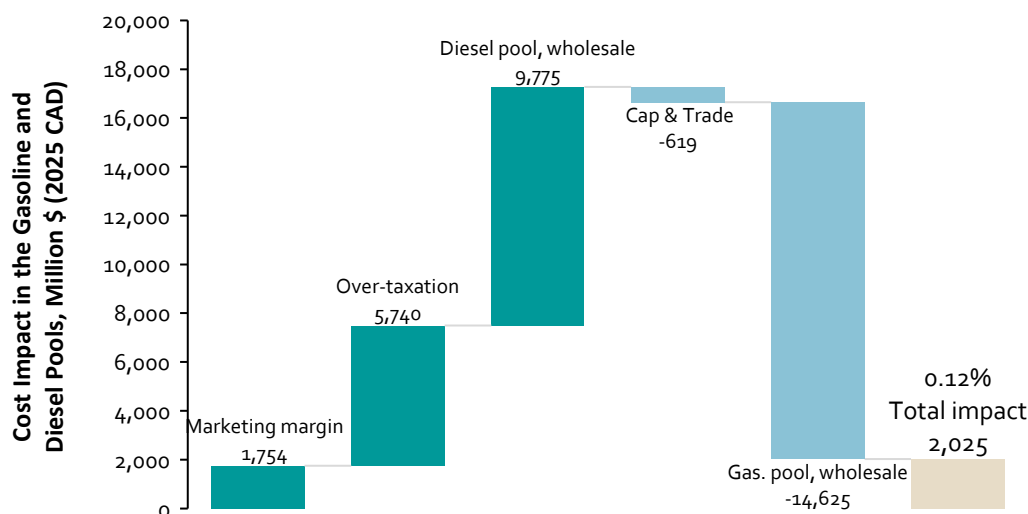
Renewable fuels have added +0.12% to consumer costs since 2010.

In 2025:

- Ethanol reduced wholesale fuels costs by \$1.1 billion
 - Biomass-based diesel increased whole-sale fuel costs by \$1.3 billion
 - Volumetric taxation of renewable fuels increased consumer costs by \$0.5 billion
-

- Renewable fuel blending in gasoline reduced wholesale fuel costs by \$1.1 billion in 2025, for a cumulative savings of \$14.6 billion from 2010 to 2025. The price of ethanol, per litre, 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 \$1.3 billion in 2025, for a cumulative additional cost of \$9.8 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 \$1.8 billion from 2010 to 2025 (the marketing margin impact in Figure 2).
- Over-taxation of renewable fuels, also related to its lower energy density, cost consumers an additional \$450 million in 2025, or \$5.7 billion since 2010.
- Note that these 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 and refined petroleum products will reduce global demand for oil, resulting in a lower oil price.

Figure 2: Renewable fuel consumption has increased consumer fuel costs by 0.12% since 2010



Cumulative cost impact resulting from renewable fuel blending (2010-2025e). Excludes impact of co-processed fuels and light-duty electric vehicles.

To illustrate these costs, we attribute them to archetypal consumers in each fuel pool. Without renewable fuels, a typical heavy-duty vehicle might have spent about \$34,526 on fuel in 2025. Low-carbon fuel consumption increased that cost by about \$1,100 to \$35,600 (+3% in 2025, versus an average of +1.4% over the horizon of the analysis). For a typical light-duty vehicle driver, fuel costs with renewable fuels were about \$14 lower in 2025 than they would have otherwise been (-1% in 2025, with an average of -0.5% over the horizon of the analysis). These examples are based on renewable fuel cost-recovery within the gasoline and diesel pools, though fuels suppliers may recover their costs across fuel pools and regions.

Cost Impacts: Over-Taxation on Renewable Fuels

Legacy volume-based fuel taxation means renewable fuel consumers pay more taxes. In 2025, 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 than 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 volumetric taxation has cost consumers about \$5.7 billion between 2010 and 2025, relative to equal taxation on an energy basis.

Over-taxation on renewable fuels:

\$5.7 Billion since 2010

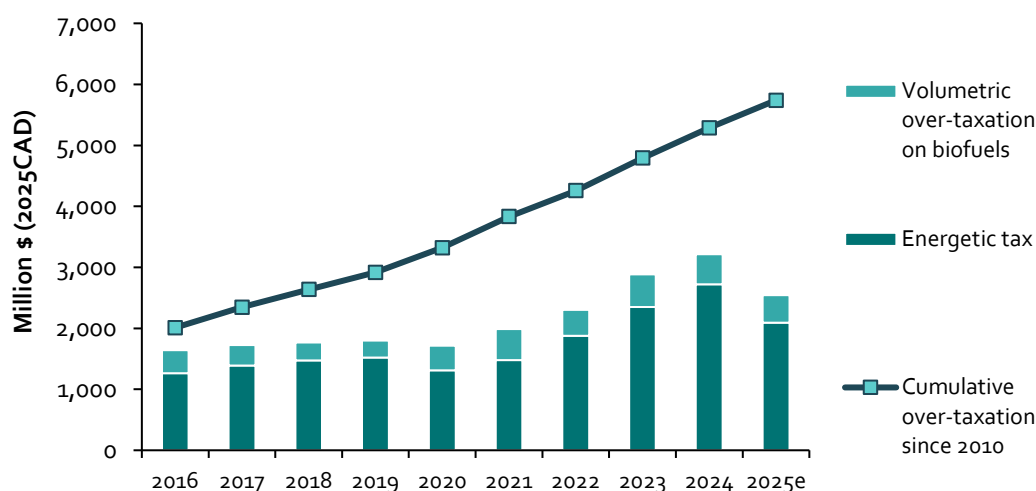
\$0.5 Billion in 2025

First, these fuels have a lower energy density than 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 volumetric taxation has cost consumers about \$5.7 billion between 2010 and 2025, relative to equal taxation on an energy basis.

In 2025, over-taxation of biofuels amounted to an extra 22% in fuel taxes paid on biofuels, or roughly \$450 million (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 \$5.7 billion in 2025 (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 \$3.7 billion rather than costing them \$2.0 billion.**

Figure 3: Volumetric taxation of biofuels means consumers paid an extra \$450 million in taxes in 2025



Fuel tax paid on biofuels in terms of what would be paid for an equivalent amount of energy from fossil gasoline or diesel (the energetic tax) and the additional tax paid as a result of charging tax per volume sold (the over-taxation). The line shows the cumulative over-taxation.

Retail Price Impacts

The average impact of *the Clean Fuel Regulations* on retail fuel prices has been negative:

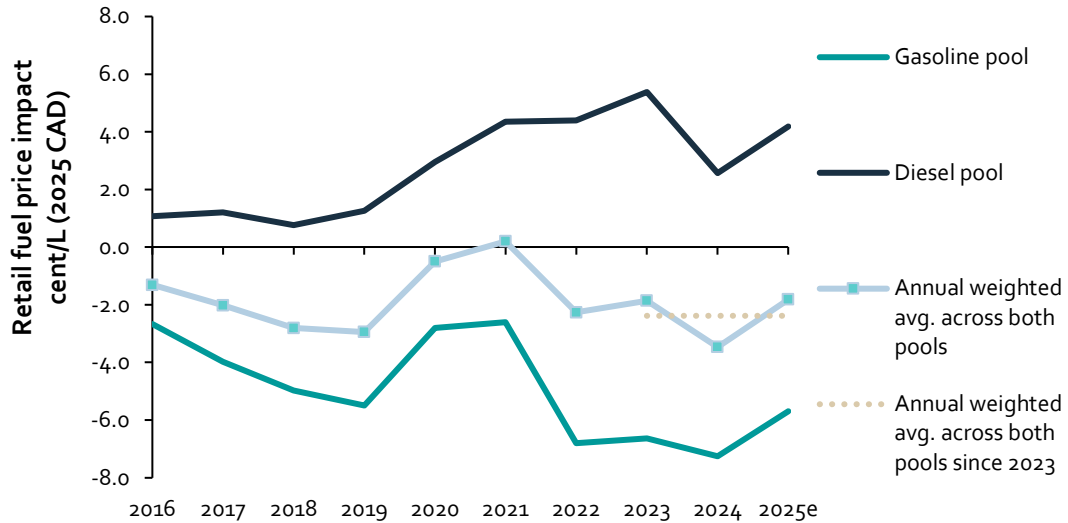
-2.4 /L from 2023 to 2025

This section highlights how renewable fuel supply has affected the price at the pump. This is what consumers experience on a day-to-day basis, in contrast with the costs described in the previous sections, which are a function of changes in prices, changes in fuel energy density (and fuel consumption) and taxation.

Renewable fuel supply has reduced retail fuel prices, on average across the gasoline and diesel pool. For example, since the start of the CFR in 2023 until the end of 2025, the associated renewable fuel supply should have reduced prices by an average of 2.4 ¢/L relative to a scenario without renewable fuel (Figure 23). CFR market data show that fuel suppliers have complied with this policy over that period, while generating a bank of credits. Therefore, this national average price impact includes the impact of the CFR. Much of that price reduction comes from ethanol supply. Ethanol reduces blended fuel prices because:

- Ethanol is generally cheaper than gasoline on a volumetric basis.
- Ethanol blending avoids the need for higher cost octane boosters (e.g., benzene, toluene, and xylene).

Figure 4: Retail fuel price impact of renewable fuel supply in Canada



Fuel CIs and Avoided GHG Emissions

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

- The average CI of ethanol is 60% less than gasoline (around 37 gCO₂e/MJ in 2025e)
- The average CI of biomass-based diesel fuels is 86% less than fossil diesel (around 13 gCO₂e/MJ in 2025e)
- The CI of co-processed fuels has varied over the years from being slightly negative to slightly positive, likely a function of the available feedstocks and specifics of the refining process.
- The average CI for electricity used for transportation in Canada was about 95% less than the CI of gasoline on a gasoline equivalents basis (about 5 gCO₂e/MJ).
- The CI of SAF was 27.5 gCO₂e/MJ in 2025e, about 68% less than fossil jet fuel.

GHG emissions avoided by clean fuels:

13.1 MtCO₂e/yr in 2024

14.2 MtCO₂e/yr in 2025

The CIs of renewable fuels have been declining, yielding greater GHG abatement per unit of fuel consumed. This is a result of fuel regulations that create an incentive to consume lower-CI fuels. For example, in British Columbia from 2010 to 2025, the CI of ethanol decreased by 81%, the CI of RD decreased by 48%, and the CI of biodiesel decreased by 82%.

The GHG benefit of clean fuel consumption in Canada has grown substantially in recent years, reaching a new high of 14.2 MtCO₂/yr in 2025, up from 13.1 MtCO₂/yr in 2024 (Figure 5). This trend is a function of stronger clean fuels regulations. The avoided emissions in 2025 are double what they were in 2021, before the increased stringency of many 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 38%/yr over the past five years.

The renewable fuel consumption and avoided GHG emissions seen in Canada from 2023 to 2025 created a surplus of CFR compliance credits that can be used in future years. We estimate this bank of credits at about 12 million tCO₂ as of the end of 2025. This is somewhat larger than ECCC’s estimate of about 9 million tCO₂ where the difference may be due to the ongoing process of updating fuel CIs within the CFR account as well as the use of different lifecycle GHG models.

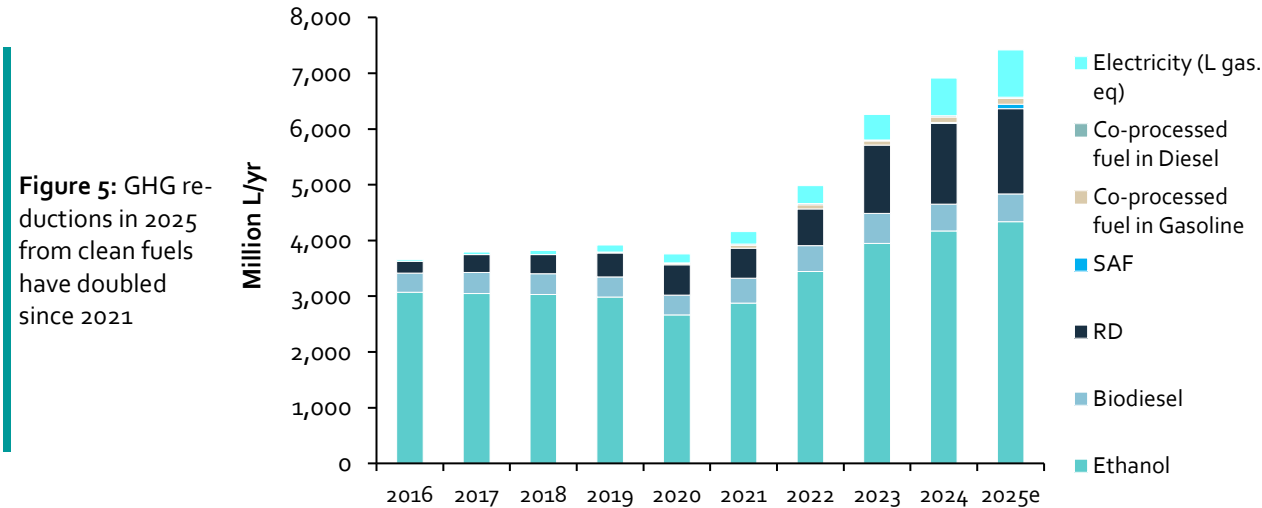


Table of Contents

Executive Summary	i
1. Introduction	1
2. Canadian Policy Summary	2
2.1. Renewable Fuel Blending Requirements	3
2.2. Carbon Pricing.....	4
2.3. Low-Carbon Fuel Standards.....	6
2.4. Low-Carbon Fuel Production Incentives.....	9
2.5. Market Carveouts	10
2.6. Investment Incentives	11
2.7. Support for the Deployment of Sustainable Aviation Fuel.....	11
3. Summary of the Methodology.....	14
4. Results and Discussion	17
4.1. Fuel Consumption.....	17
4.2. Blending Rates.....	18
4.3. Lifecycle GHG Emissions.....	21
4.4. Clean Fuel Regulations Compliance.....	29
4.5. Cumulative Costs.....	30
4.6. GHG Abatement Cost	35
4.7. Consumer Cost Impact.....	36
4.8. Detailed Tax Costs.....	37
4.9. Retail Fuel Price Impacts	39
4.10. Electric Vehicles.....	40
4.11. Renewable Fuel Trade.....	42
Appendix A: Canadian Policy Background	47
Provincial Renewable Fuel Blending Requirements.....	47
Carbon Pricing Across Canada	53
Detailed Description of Low-Carbon Fuel Production Incentives in Canada vs. the US	61
Low-Carbon Fuel Standards	62
Appendix B: Summary and Discussion of Inputs to the Analysis	78
Appendix C: Biofuel Type and Feedstock Assumptions and Data.....	84
Appendix D: Impact of Ethanol on Gasoline Refining and Consumption GHGs	93
Appendix E: Cost Analysis Methodology.....	96
Appendix F: 2021 and 2025 Updates to the Cost Analysis Methodology	101
Appendix G: Plug-in Electric Vehicle Analysis Methodology	104

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, no single government source comprehensively characterizes 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. Advanced Biofuels Canada Association 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 2024, with estimates for 2025. These fuels are further characterized by type (e.g., ethanol, 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.

This year, the analysis also:

- Shows the supply, blend rate, CI and GHG impact of sustainable aviation fuel (SAF) in Canada.
- Summarizes policies relevant to SAF demand in Canada.

The quantitative analyses that support this report are contained in a Microsoft Excel spreadsheet. Contact the Advanced Biofuels Canada Association regarding access to this spreadsheet. 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 summary of the analysis methodology and a discussion of the results. The appendices contain more detail on the methodology and assumptions of this analysis as well as a detailed policy overview.

2. Canadian Policy Summary

This section summarizes the existing federal and provincial renewable fuel policies in Canada, as of Summer 2026, 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. Policies relevant to renewable fuels fall into six categories:

- **Minimum renewable fuel blending requirements (section 2.1)**, that set a floor for the renewable and low-carbon fuel content in a fuel pool, most commonly in gasoline and diesel. As of 2026, these regulations exist in all provinces except for those in Atlantic Canada. Note that Ontario and Québec's blending requirements are a function of fuel CI, so have some features in common with low-carbon fuel standards, described below.
- **Carbon pricing (section 2.2)**, where a fee 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. Since April 1, 2025, consumer carbon pricing (i.e., not including large industry) has effectively ended across Canada, except for Québec. Industrial carbon pricing remains in force, providing an additional incentive to use renewable fuels within industry, but the stringency of this policy is being adjusted.
- **Low-carbon fuel standards (section 2.3)**, 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. The value of compliance credits creates a price signal that incentivizes renewable fuel supply and other low-carbon transportation measures. However, these policies do not create a "carbon tax" and consumers are not charged at the pump for the carbon emissions from their fuel use. 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 Standard* (BC LCFS) applies only in that province.
- **Low-carbon fuel production incentives (section 2.4)**, which incentivize fuel production on a per volume-produced basis (e.g., a tax credit or subsidy paid per litre).
- **Low-carbon fuel production market carveouts (section 2.5)**, notably the recent requirement for renewable fuel volumes required by provincial policies to be made in Canada, or the proposed amendment to the CFR to create a similar requirement within that federal policy.
- **Low-carbon fuel investment incentives (section 2.6)**, which reduce the upfront cost of building a new production facility (e.g. an investment tax credit, grant, or capital cost 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 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. Gasoline and diesel supplied for scientific research, competition, and to remote northern communities, as well as aviation gasoline, are not covered by the CFR volumetric requirement.

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; Atlantic provinces are excluded, as they have no provincial requirements). 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. Therefore, these policies also incentivize the supply of lower-CI fuels, and the actual share of biofuel may vary from what is reported in the table.

As of April 2025, minimum volumetric diesel amounts in British Columbia must be supplied by Canadian producers. This requirement applied to the volumes in gasoline as of January 1st, 2026.³ Similarly, as of August 2025 in Ontario, a minimum of 75% of the renewable content required in diesel fuel and 64% of the renewable content required in gasoline must be made in Canada.⁴ In Ontario the requirement for gasoline decreases to 54% for 2028 and

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

² Ibid.

³ BC OIC 81/2025, BC Ministerial Order No. M41.

⁴ Government of Ontario, 2025, [Cleaner Transportation Fuels: Proposed Domestic Renewable Content Requirement for Diesel Fuel](#)

2029, and 47% in 2030 onwards. In 2024, British Columbia also implemented a minimum blending requirement in jet fuel, starting at 1%_{vol} in 2028 and rising to 3%_{vol} by 2030.⁵

Ontario and Québec have legislated schedules for greater renewable fuel blending in gasoline by 2030 (Table 1). Similarly, Québec has a schedule for increased blending in diesel (Table 2). No other provinces have legislated or announced an increase in regulated minimum blending rates, but Alberta intends to implement an updated regulation by 2028.⁶ The appendix describes the renewable fuel blending policies for each province in more detail (starting on page 47).

Table 1: Minimum required renewable fuel content in gasoline (made-in-Canada requirements for British Columbia and Ontario described above)

Region	2023 & 2024	2025	Trajectory for 2030
BC	5%	5%	No change announced
Alberta	5%	5%	Updated policy to be implemented in 2028
Saskatchewan	7.5%	7.5%	No change announced
Manitoba	10%	10%	No change announced
Ontario	10%	11%	15%, CI adjusted
Québec	10%	12%	15%, CI adjusted
Canada	5%	5%	No change announced

Table 2: Minimum required renewable fuel content in diesel (made-in-Canada requirements for British Columbia and Ontario described above)

Region	2023 & 2024	2025	Trajectory for 2030
BC	4%	8%	No change announced
Alberta	2%	2%	Updated policy to be implemented in 2028
Sask.	2%	2%	No change announced
Manitoba	5%	5%	No change announced
Ontario	4%	4%	No change announced
Québec	3%	5%	10%, CI adjusted
Canada	2%	2%	No change announced

2.2. Carbon Pricing

Carbon pricing on consumer fuel purchases, including gasoline and diesel, has effectively ended in Canada, outside of Québec. Starting April 1st, 2025, the federal government

⁵ Government of British Columbia, 2023, [Low Carbon Fuels \(General\) Regulation](#).

⁶ Government of Alberta, 2026, [Renewable Fuels Standard engagement](#)

amended the *Greenhouse Gas and Pollution Pricing Act* (GGPPA), setting the tax rate to 0, removing the requirement to register or report under the policy, and defining the final carbon tax rebates for consumers.⁷ The BC government created a similar amendment to the BC Carbon tax.⁸ More information on the repealed federal and provincial carbon prices is in the appendices starting on page 53.

Québec's cap-and-trade system, which applies to gasoline and diesel suppliers, remains in force, with a year-to-date carbon price of \$39/tCO₂e in 2026⁹, equivalent to a charge of roughly 8.8 ¢/L for fossil gasoline and 10.7 ¢/L for fossil diesel. This charge creates an additional incentive to supply renewable fuels in Québec that stacks with other policy signals and incentives (e.g., notably, the credit value from the CFR). More information on Québec's cap-and-trade program is available on page 56 in the appendix.

Carbon pricing on large industries across Canada also remains in force. 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. 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 are not required to remit compliance credits for the CO₂ emissions associated with their renewable fuel consumption. Therefore, the industrial carbon price also creates an incentive to consume renewable fuels within industrial sectors that stacks with other policies such as the CFR.

The updated headline carbon price that these industrial policies should achieve is \$95/tCO₂e in 2026, rising to \$115/tCO₂e in 2030 (Table 3).¹⁰ This would create an additional incentive for industry to consume renewable fuels of 31 ¢/L of diesel in 2030. However, the effective carbon price that the Albertan industrial carbon pricing system must aim to achieve is lower, only reaching \$130/tCO₂e by 2040.¹¹ This may become the effective price that other provincial industrial carbon pricing policies must achieve (e.g., in B.C. and Saskatchewan). Furthermore, the implementation agreement between Alberta and Canada that defines the future of Alberta's industrial carbon pricing system also specifies a price floor for carbon credits, starting at \$60/tCO₂e in 2030.¹² If the stringency of GHG intensity reductions required of industry

⁷ Government of Canada, [Greenhouse Gas Pollution Pricing Act](#)

⁸ Government of British Columbia, 2025, [BILL 8 – 2025 CARBON TAX AMENDMENT ACT, 2025](#)

⁹ Government of Québec, The Carbon Market, [Auction Proceeds Allocated to the Electrification and Climate Change Fund](#)

¹⁰ Government of Canada, 2026, [Carbon pricing systems across Canada](#)

¹¹ Prime Minister of Canada, 2026, [Implementation Agreement for the Canada-Alberta Memorandum of Understanding of November 27, 2025](#)

¹² Ibid.

is not high enough, credit prices could remain at the floor, meaning the additional incentive for industry to consume renewable fuels would only be 16 ¢/L of diesel in 2030.

Table 3: Industrial carbon pricing schedule in Canada in 2026, 2030, 2035, and 2040

	2026	2030	2035	2040
Headline price, \$/tCO ₂ e	95	115	130	140
Diesel price impact, ¢/L, at headline credit price	26	31	35	38
Floor price, proposed for Alberta, \$/tCO ₂ e		60	80	110
Diesel price impact, ¢/L, at headline credit price		16	22	30

Prices for years in between what is shown in the table are available at [Carbon pricing systems across Canada](#) and [Implementation Agreement for the Canada-Alberta Memorandum of Understanding of November 27, 2025](#)

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 (i.e., reduced lifecycle GHG intensity per unit of transportation energy supplied). These fuels include gasoline, diesel and, as of the end of 2023, jet fuel in British Columbia. The obligated parties need only to comply ‘on average’ (i.e., throughout the year) 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 are market-based, and 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 4 summarizes each policy and more detail is available in Appendix A: Canadian Policy Background.

British Columbia made several noteworthy amendments to the BC LCFS in 2025. The Low Carbon Fuels (General) and Low Carbon Fuels (Technical) regulations were amended to increase the required volume of renewable fuel in diesel from 4% to 8%. Furthermore, the regulations now require that the minimum volumetric standards for renewable content in gasoline and diesel come from Canadian producers.¹³ The requirement for renewable fuels in diesel took effect April 1st, 2025, while the requirement for renewable fuels in gasoline took effect on January 1st, 2026.

¹³ BC OIC 81/2025, BC Ministerial Order No. M41.

The federal government is considering amendments to the CFR that would support Canadian low-carbon fuel producers. These include a CFR credit multiplier for Canadian-made fuels or a minimum requirement for Canadian-made fuels.¹⁴

Table 4: 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 ₂ e/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 (Canadian-made) 8% _{vol} in diesel (Canadian-made) 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 ₂ e (i.e. per credit), plus inflation. Early compliance in 2022. A rollover of surplus RFR credit.	Compliance credit trading. Credit banking. \$600/tCO ₂ e (i.e., per credit) penalty for non-compliance.
Recent credit prices	\$177/tCO ₂ e, average in 2025, rising to \$300 to \$328 in July/August 2026 ¹⁵	\$260/tCO ₂ e, average in 2025, declining to \$136 to \$172 in July/August 2026 ¹⁶

¹⁴ Environment and Climate Change Canada, 2025, [Clean Fuel Regulations: Discussion Paper to Inform the Draft Targeted Amendments](#).

¹⁵ Environment and Climate Change Canada. [CFR Compliance Credit Market Dataset \(Monthly and Quarterly\)](#).

¹⁶ Government of British Columbia, [LCFS Credit Market Data](#).

	CFR	BC LCFS
Legislation	Clean Fuel Regulations (SOR/2022-140)	Low Carbon Fuels Act , and Low Carbon Fuels (General) Regulation , and Low Carbon Fuels (Technical) Regulation

Both the BC LCFS and the CFR were targeted by opposition political parties in the lead-up to the provincial and federal elections in 2024 and 2025. The Conservative Party of British Columbia pledged to eliminate the BC LCFS.¹⁷ Likewise, the Conservative Party of Canada (CPC) also pledged to eliminate the CFR if they were elected, characterizing it as a second carbon tax.¹⁸ Repealing this policy remains a priority for the CPC.¹⁹

Low-carbon fuel standards have a much lower impact on fuel prices at the pump than carbon taxes. A low carbon fuel standard and a carbon price with the same \$/tCO₂e 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 each 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 tax or levies, for a given carbon/credit price. For example, at \$177/tCO₂e (average credit price in 2025) with the CFR's 2025 CI limit, the retail price of E10 (90% gasoline, 10% ethanol) would increase by:

- 45.5 ¢/L with a carbon tax (40.3 ¢/L plus another 5.2 ¢/L in additional HST or GST).
- 1.3 ¢/L with a low-carbon fuel standard (of which about half could be avoided with a change from volumetric to energy-based fuel taxation).

The example behind these results is elaborated on page 68 in the appendices. Note that these cost impacts are based on an idealized market where no party can exert market power

¹⁷ 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.

¹⁸ Conservative Party of Canada, [Stop Trudeau's Carbon Tax 2](#), Accessed October 2024

¹⁹ Huras, Adam. [Poilievre pledges fight of 'carbon tax 2.0' in Parliament's return](#). National Post, August 27th, 2025

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 creates a different policy signal than a carbon tax. 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 shelters consumers from the policy's compliance credit price.

2.4. Low-Carbon Fuel Production Incentives

In September 2025, the Canadian federal government announced that it will provide \$370 million over two years to support biodiesel and renewable diesel production in Canada. The incentive will be available from January 2026 through December 2027. It will be paid per litre of renewable diesel and biodiesel, incentivizing a maximum of 300 ML from any given facility.²⁰ The incentive has a tiered structure, set at 16¢/L for the first 170 ML and 10 ¢/L for the next 130 ML.²¹

Until this announcement, there have been no federal production credits available in Canada since the ecoEnergy for Biofuels program expired in 2017. However, Québec revised and extended its biofuels production tax credits in 2023 for fuels produced and consumed in the 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 for producers in Québec (if the CI is from 15 to 40 gCO₂e/MJ).²²

Until 2029, Québec's tax credit is additional to the value of CFR credits fuels may earn, consistent with the scheduled expiration of the US tax credit described below. After 2029, Québec's tax credit will not stack with the CFR.²³ For example, if a fuel earns even \$100/tCO₂e per CFR credit it generates, the net tax credit would be zero unless the fuel's CI is extremely

²⁰ Government of Canada, 2025, [Prime Minister Carney launches new measures to protect, build, and transform Canadian strategic industries](#)

²¹ Natural Resources Canada, 2026, Biofuels Production Incentive Program

²² 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

Revenu Québec, 2023, [Tax Credit for Biofuel Production in Québec](#)

²³ Finances Québec, 2026, [Information Bulletin 2026-5, Adjustments to certain fiscal measures](#).

low. This provincial tax credit does not stack with other government assistance, so a producer can not receive both it and the Biofuel Production Incentive.

In contrast, the US Clean Fuels Production Credit (CFPC, also known as 45Z):

- 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 2029, but its duration could be extended, like the biomass-based diesel blenders tax credit, the previous tax credit it replaces.
- Has no claw-back related to other policy support.²⁴

2.5. Market Carveouts

British Columbia and Ontario now both require that some of the fuels supplied for their renewable fuel blending requirements be made in Canada.²⁵ These made-in-Canada requirements for minimum renewable fuel blends could also be characterized as a production incentive. By creating a carve-out for Canadian producers, it gives them some market power to set the price for a portion of the supply. However, this market power is mitigated by the number of qualified suppliers, where no single producer is required to meet the domestic content requirement. As well, cost-control features of the relevant policies put a price ceiling on market power. In the case of British Columbia, the BC LCFS administrative penalty for the volumetric requirement puts a ceiling on the price-setting power. The penalty is currently 45¢/L for a renewable content deficit in diesel fuel.²⁶ Theoretically, if the premium for Canadian-made fuel relative to imported fuel is greater than this penalty, a fuel supplier might choose to buy imported fuel and pay the penalty. In practice, this is a very large margin ceiling for Canadian suppliers (e.g., it is about twice as much as a US producer might get from the CFPC), so we expect the policy change to draw Canadian-made fuel to BC.

Nonetheless, while these provincial-level made-in-Canada requirements may stabilize Canadian biofuel production, they will not be enough to support growth. For example, with the Edmonton Imperial Oil renewable diesel facility online as of August 2025, the 8% volumetric minimum for British Columbian diesel and the approximately 3% requirement for diesel in Ontario (75% of 4%), are equal to 16% of Canadian biomass-based diesel production capacity, including Braya Renewables. The combined domestic ethanol requirement for Ontario

²⁴H.R.1 – 119th Congress (2025-2026): [One Big Beautiful Bill Act](#)

²⁵ Recall these are the minimum required volumes in British Columbia, 75% of the renewable content required in diesel fuel and 64% of the renewable content required in gasoline in Ontario

²⁶ BC Ministry of Energy and Climate Solutions (November 2024). [Information Bulletin RLCF-021, Administrative Monetary Penalties.](#)

and British Columbia is equal to 70-80% of Canadian ethanol production capacity (i.e. about 1,370 ML of roughly 1,800 ML/yr).

The federal government is considering targeted amendments to the CFR, among which is a national domestic sourcing requirement. The details of the potential amendment were not finalized at the time of writing.

2.6. Investment Incentives

There are several policies that could incentivize low-carbon fuel production in Canada by reducing the capital cost of the production facility. In 2021, the federal government established the Clean Fuels Fund, which offered an incentive of up to \$50 million or 30% of the upfront cost for liquid or gaseous low-carbon fuel production facilities built in Canada; the call for applications has now closed.²⁷ The funding was relatively modest compared to the cost of a commercial-scale facility, which could be in the range of \$500 million to \$1 billion.

The BC LCFS includes “Initiative Agreements”, which offer compliance credits for various projects (see the detailed BC LCFS description starting on page 62). Depending on the project, these may be viewed as an investment incentive, though the timing and value of the resulting credit sale or utilization is uncertain.

Finally, CFR credit purchases from the Emissions Reduction Funding Program (i.e., a CFR compliance fund) could be used by fund managers to establish investment incentives for projects that will achieve emissions reductions within five years. These will be administered via registered compliance funds, such as Emissions Reduction Alberta (ERA). CFR market data to date (end of 2025), show no contributions to the fund. However, ERA and other technology accelerators have funded pre-commercial low-carbon fuel startups.²⁸

2.7. Support for the Deployment of Sustainable Aviation Fuel

The government of Canada has an aspirational target of 10% SAF use within jet fuel by 2030, and a vision to have a net-zero aviation sector by 2050.²⁹ Canada recently released its SAF Blueprint, outlining actions to consider for reaching these goals.³⁰ However, there are no legislated federal policies that directly support or require SAF demand in Canada. That said,

²⁷ Government of Canada, 2025, [Clean Fuels Fund: Building new domestic production capacity](#)

²⁸ For example, see [Emissions Reductions Albert - Projects](#) and [NorthX Climate Tech - Portfolio](#)

²⁹ Transport Canada, 2022, Canada’s Aviation Climate Action Plan 2022-2030

³⁰ Transport Canada, 2026, [Sustainable Aviation Fuels Blueprint for Canada](#)

there are a subset of policies in Canada that are driving demand for SAF and SAF supply, with BC the current locus of SAF policy support:

The BC LCFS SAF blending requirement creates a minimum demand for physical SAF supply in BC. As noted in Table 4, the BC LCFS has a physical SAF blending requirement starting in 2028 that rises to 3% by volume by 2030. SAF supply prior to 2028 counts towards future compliance.

Fuel CI regulations (BC LCFS and CFR) create a financial incentive for SAF supply in BC and across Canada. The BC LCFS CI reduction requirement for jet fuel does not specifically require SAF supply for compliance and the CFR has no CI reduction associated with jet fuel. However, SAF supply will generate compliance credits within both policies.

The British Columbia Low-Carbon Jet-Fuel Incentive Program (BC-LCJFIP) incentivizes early SAF supply in BC. The program is a partnership between Vancouver International Airport (YVR) and the Province of BC that funds the purchase of SAF at BC airports. It runs for five years, from the start of 2024 to the end of 2028, dovetailing with the start of the provincial SAF blending requirement. The funding is available to all commercial passenger and freight transportation using SAF at YVR. The level of support varies depending on the CI of the SAF and may be provided as cash to the airline (\$/L purchased) or as BC LCFS credits (credit/L purchased). BC LCFS credits are supplied via the policy's Initiative Agreements (see the detailed BC LCFS section starting on page 62 for more details on this program) where credits are transferred to a registered fuel supplier, which presumably reduce the SAF price negotiated between the supplier and the purchasing airline. **Current LCJFIP incentive rates are:**

- \$0.75 CAD/litre or 0.05 credits/L for SAF with a CI greater than 10 gCO₂e/MJ (the value is equivalent if the BC LCFS credit price is \$150/tCO₂e, where the average price was in that vicinity in summer 2026).
- \$1.12 CAD/litre or 0.075 credits/L for SAF with a CI equal-to or less-than 10 gCO₂e/MJ.

The International Civil Aviation Organization Carbon Offsetting and Reduction Scheme for International Aviation (ICAO CORSIA) creates a GHG offset obligation for flights operating between Canada and other countries, which can be met using SAF. CORSIA requires airlines from participating nations to offset or avoid the GHG emissions from international flights that are greater than 85% of their 2019 baseline. The first phase was voluntary, running from 2024 to 2026. The next phase, running from 2027-2035 is mandatory for ICAO member states. The extent to which this policy will drive SAF demand in Canada is uncertain. First, it is primarily a GHG offsetting program, where SAF consumption is one among many compliance actions. Furthermore, given the policy is international in scope, airlines operating in Canada might procure their SAF outside of the country. Second, CORSIA requires individual nations to enforce compliance. As of 2026, only a subset of ICAO member states, including

Canada, have implemented legal enforcement of the policy.³¹ A lack of enforcement could result in weak demand and low prices for CORSIA compliance credits, providing little incentive to use SAF.

³¹ Carbon Direct, 2026, [CORSIA phase 1: Credits, compliance, and what comes next](#)

E.g. in Canada via the [Canadian Aviation Regulations \(SOR/96-433\)](#) Part X

3. Summary of the Methodology

Table 5 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 5: 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 include January 1, 2010, to December 31, 2024, for all reporting regions. Data for 2025 were available from British Columbia, Alberta, Saskatchewan as well as from the federal government (Q1 through Q3 in the CFR Credit Market Report; preliminary full year data provided in a figure within a public conference presentation). Biofuel products were defined as: ethanol, biodiesel, renewable diesel (RD), SAF 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 to 2023, v5.02c for 2024 and later) with a review by government contacts and industry experts. Energy efficiency impacts (i.e., change in energy per km, 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 BC LCFS. This province is used as a case study because it is one of the few jurisdictions where CI is documented by fuel.
3. Estimate the <i>Clean Fuel Regulations</i> (CFR) compliance position	This analysis also produces an estimate of the size of the CFR credit bank or deficit to the end of the analysis horizon (2025) using fuel volumes collected in this analysis and CFR credit generation data.

Task	Approach
4. Estimate the impact of bio-fuel blending in gasoline and diesel on energy costs	Wholesale ethanol and biodiesel prices from the Chicago Mercantile Exchange (CME) were used to estimate the landed price of these fuels in major Canadian cities, based on typical rail shipping rates. RD prices were estimated using Diamond Green Diesel's financial materials for investors. Regular gasoline and diesel prices were used to estimate the unblended wholesale price of the petroleum fuels. 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.
5. Estimate fuel displaced by PEVs	PEV sales data from Statistics Canada were 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 <i>Clean Fuel Regulations</i>, with the average energy intensity of PEVs based on a weighted average of vehicles sold in 2021.
6. Produce estimated results for 2025	For provinces where no 2025 data were yet available (Québec), volumes and GHG impacts were estimated for 2025 consistent with reported national and provincial renewable fuel consumption as well as the requirements of provincial renewable fuel policies. Statistics Canada data are used to define the size of the gasoline and diesel pools in provinces without 2025 data. Carbon intensities for 2025 are taken from GHGenius or assumed based on provincial data for 2024.
7. Display and discuss renewable fuel trade data	Data from the Canadian International Merchandise Trade Database are presented to describe imports and exports of ethanol, biodiesel and RD, contrasting these with domestic consumption of the fuels. Jet fuel trade data are also presented.

The time horizon of this analysis is from 2010 to 2025, running from when most 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 estimated year (2025e) includes preliminary national CFR data and uses preliminary or final data for many regions. However, it relies on estimates for renewable fuel consumption and CIs in 2025 for Québec. Data for Québec, as well as revised data for other regions, will be used to revise the 2025e results in next year's edition of Biofuels in Canada. Likewise, this year's analysis uses final data to update the 2024 estimates from the previous edition. Therefore, the results and trends reported last year for 2024e will differ somewhat from what is now reported for 2024.

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 2025, the combined co-processing capacity in British Columbia (Parkland and Tidewater) is in the range of 120 million litres of co-processed feedstock per year. For reference, total biodiesel and non-co-processed RD consumption in BC was about 1,100 million litres in 2024.

4. Results and Discussion

The results section summarizes data on:

- The biofuel content of transportation fuels sold in Canada, and an estimate of the quantity of electricity consumed and a gasoline displaced by light-duty PEVs.
- Avoided GHG emissions resulting from the consumption of renewable fuels and electricity for transportation.
- CFR compliance credit generation, relative to the CFR debits indicated by this analysis, to show the net supply of credits each year and the cumulative bank or deficit of credits.
- 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.
- Imports and exports of renewable fuels from Canada, with detail on trade with the US versus the rest of the world.

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 more than 6% in 2025, on top of the 10% increase in 2024. Figure 6 and Table 6 summarize the fuel consumption data as well as the light-duty PEV electricity consumption data (expressed in terms of litres of gasoline equivalent displaced):

- RD consumption has continued to grow, increasing by 5% from 2024 to 2025, on top of the 18% growth in consumption from 2023 to 2024. About two thirds of the RD consumption is concentrated in British Columbia.
- Biodiesel consumption has remained relatively stable over the past five years. Consumption was about 500 ML/yr in 2025.
- Ethanol consumption continued to grow steadily, increasing by 4% from 2024 to 2025, on top of 6% growth from 2023 to 2024.
- The volume of fuel displaced by electric vehicles is still less than the volume of renewable fuels but remains the fastest growing category. Electricity consumption by light-duty vehicles grew by an estimated 26% from 2024 to 2025, on top of 46% growth in the previous year. This result is sensitive to the assumption that PEVs are driven the same annual

distances as conventional vehicles. The merit of this assumption is discussed in the appendix starting on page 105.

Figure 6: Total clean fuel consumption in Canada grew by 6% in 2025, on top of 10% growth in 2024

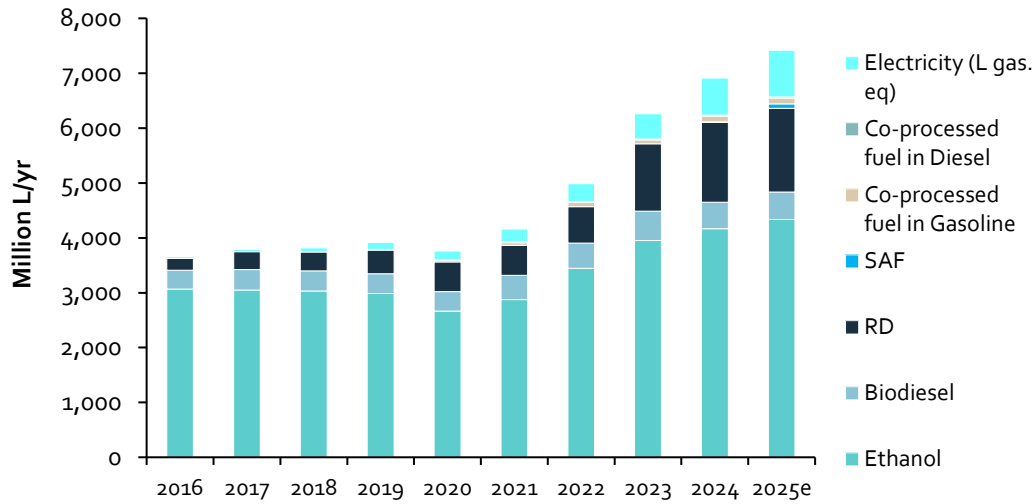


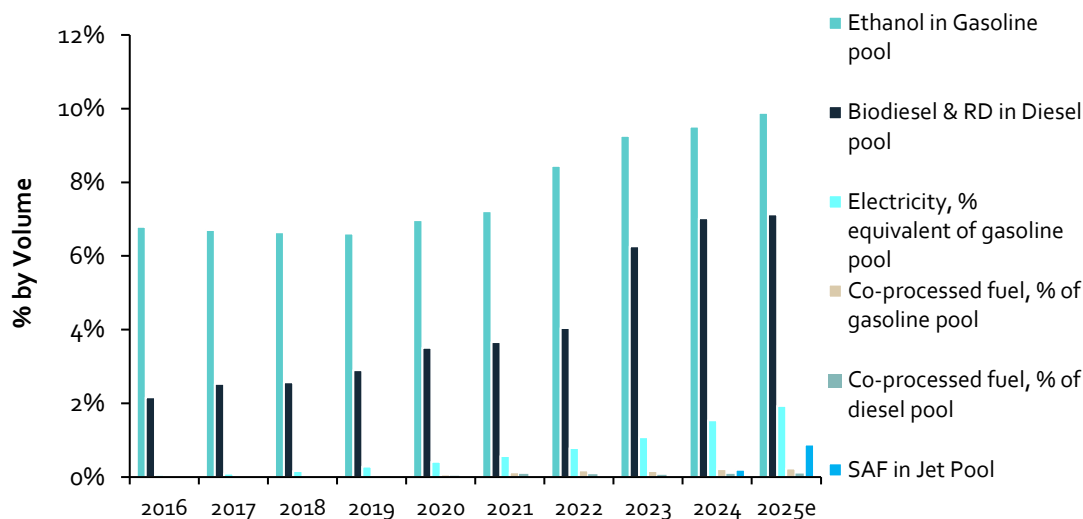
Table 6: Canadian fuel consumption in million litres per year (*or L equivalent for electricity)

Fuel type	2021	2022	2023	2024	2025e
RD	542	661	1,229	1,452	1,525
Biodiesel	444	465	536	481	500
Ethanol	2,876	3,444	3,949	4,169	4,338
Co-proc. gasoline	50	74	70	95	103
Co-proc. diesel	22	22	17	23	25
Electricity*	227	322	462	674	847
Gasoline (Pure)	36,971	37,335	38,705	39,647	38,785
Diesel (Pure)	25,931	26,658	26,394	25,553	25,872

4.2. Blending Rates

We estimate that the ethanol content of gasoline was roughly 10% in 2025, up from about 9.5%_{vol} in 2024. Biomass-based diesel content was more than 7.1%_{vol} in 2025, up from 7.0% in 2023 (Figure 7). 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 2025, accounted for almost 0.2%_{vol} of the gasoline pool and 0.1%_{vol} of the diesel pool in that year. Electric vehicles displaced about 1.5%_{vol} of the gasoline pool in 2024, rising to 2.0%_{vol} in 2025.

Figure 7: Renewable fuel content hit new highs in 2025 – About 10% in Ethanol and 7% in diesel



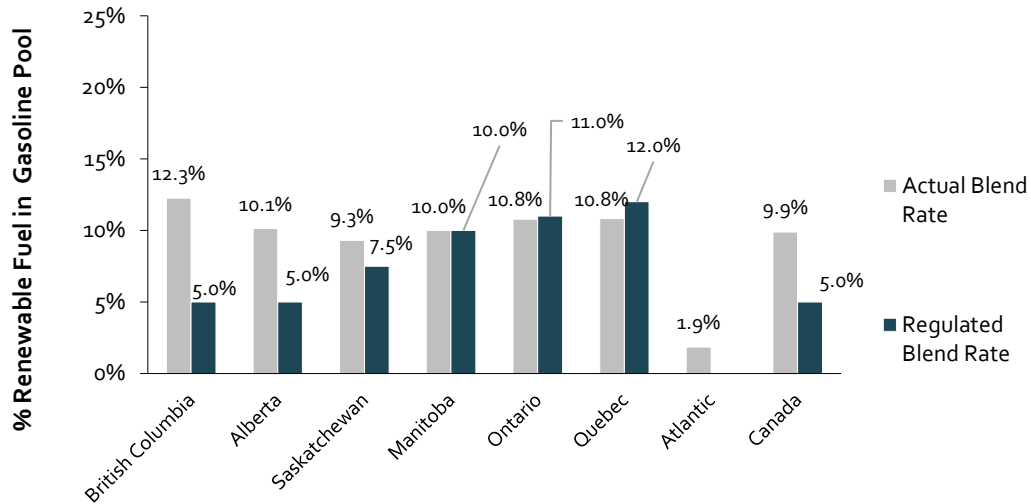
Due to the uncertainty in the volume of RD consumed in Canada prior to 2022, biodiesel and RD are grouped together to avoid misrepresenting the precision of the data. The blend rates do not include any policy-based adjustments to the renewable fuel share (e.g., a volume-equivalency bonus awarded for using for low-CI feedstocks or fuels, as is the case in Ontario's *Cleaner Transportation Fuels* regulation).

Renewable fuel blend rates are higher than the regulated minimums because the CI requirements of federal and provincial fuel policies reinforce the market signal for this fuel supply. This is especially true of biomass-based diesel, where the CI reduction required by the BC LCFS maintained a biomass-based diesel content of more than 26%_{vol} in 2025 (Figure 9). That quantity of renewable fuel also counts for compliance under the CFR's CI standard, showing how provincial policies shape the national fuel market, pulling blend rates well above the regulated minimums. The blend rate in BC is five percentage points lower than in 2024. The outcome in that year may have been shaped by uncertainty in the future of the CFR. In other words, given the risk of the CFR ending following a Conservative victory in the 2025 federal election, it may have been preferable to concentrate CFR compliance in BC, where the provincial fuel regulation was less likely to be repealed.

The ethanol blend surpassed 10% in several provinces in 2025 (Figure 8). The data indicate that ethanol accounted for just over 10% of the gasoline pool in BC, Alberta, and Ontario (Note that renewables in gasoline in BC were around 12% in 2025 because of additional co-processed volumes). Our estimate for Québec shows a similar level of ethanol blending. This outcome is plausible given that fuel suppliers are allowed to sell E15. Gas stations in Ontario already indicate that the fuel may contain up to 15% ethanol and several fuel providers explicitly list E15 within their fuel terminal pricing.³²

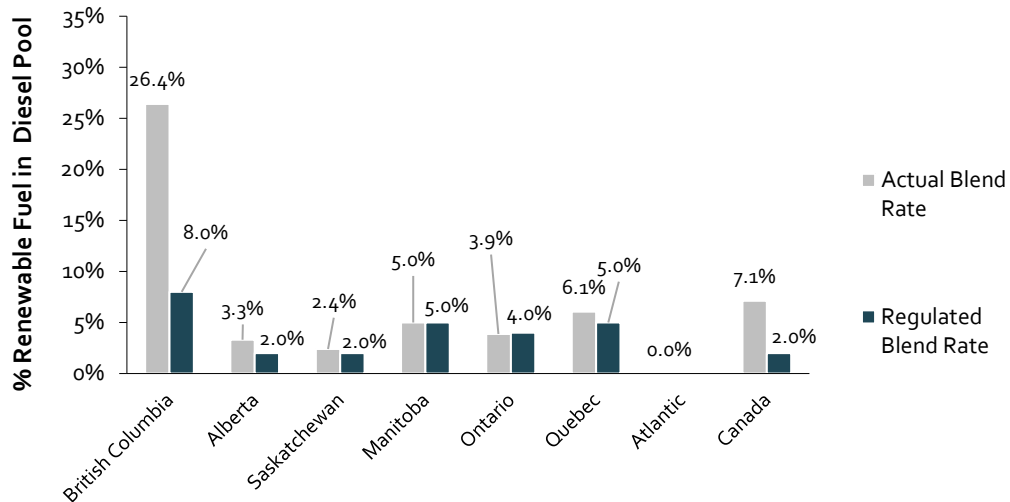
³² E.g. [Valero](#) and [Petro-Canada](#)

Figure 8: 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.

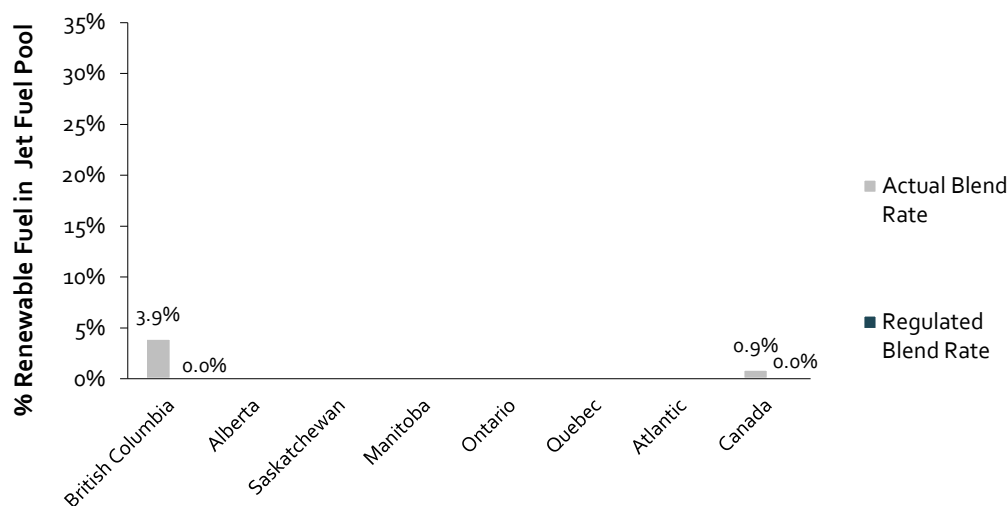
Figure 9: The renewable fuel content in diesel is higher than the regulated minimum because of policies that require reductions in fuel CIs



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.

The SAF blending rate in BC was almost 4% in 2025, three years ahead of when provincial policy will first require a 1% blending rate (Figure 10). The policy credits early action for later compliance, so it is possible that this level of SAF blending will not be sustained over the next few years. Nationally, SAF blending in BC means that about 1% of Canada's jet fuel was renewable.

Figure 10: SAF content in BC has surpassed the 1% requirement scheduled for 2028, three years early

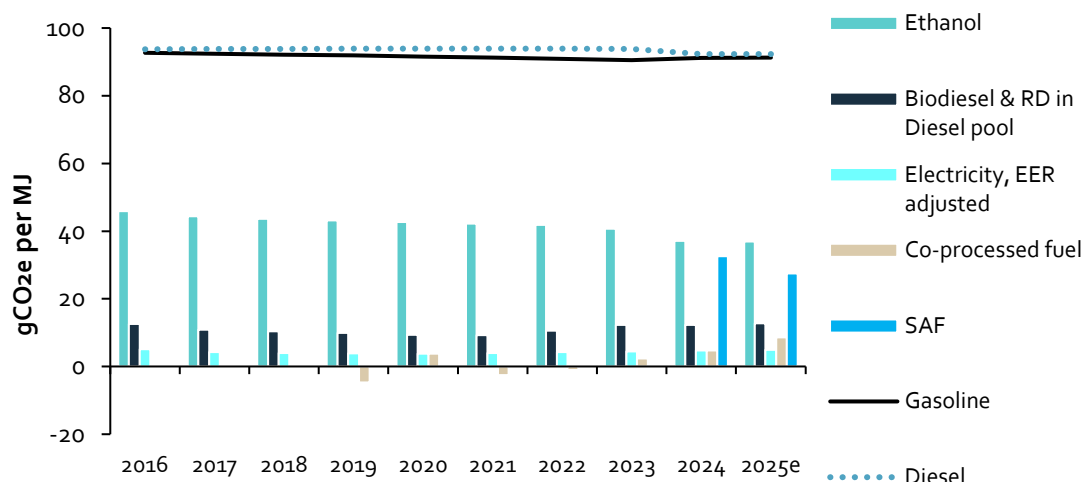


4.3. Lifecycle GHG Emissions

Renewable fuels produce many fewer GHG emissions per unit of energy consumed, across the whole supply chain (i.e., from well/farm to wheels) (Figure 11). Therefore, the lifecycle CI scores of these fuels are well below those of fossil fuels:

- The average CI of ethanol is 60% less than gasoline (around 37 gCO₂e/MJ in 2025e).
- The average CI of biomass-based diesel fuels is 86% less than fossil diesel (around 13 gCO₂e/MJ in 2025e).
- The CI of SAF was 27.5 gCO₂e/MJ in 2025e, about 68% less than fossil jet fuel.
- The CI of co-processed fuels reported in the British Columbian LCFS compliance data have 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 28 for more information about the CI of co-processed fuels).
- The average CI for electricity is about 5 gCO₂e/MJ. This CI is low because it is adjusted by an energy effectiveness ratio (EER) of 4.1 (i.e., if 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 where most PEVs are used (British Columbia, Ontario and Québec).

Figure 11: 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 v4.03a (to 2023) and v5.02c (2024 onward). The CI of electricity is based on a transportation-consumption weighted average of direct emissions intensity by province from 2010 to 2024, 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 and 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.³³

Ethanol CIs have declined since 2015, 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). This trend is a function of lower fuel CIs reported by provincial regulators. It is also a function of declining default fuel CIs from the GHGenius model, which are associated with reduced GHG emissions associated with cleaner electricity consumption for biofuel refining, process improvements, increased agricultural yields, and reduced fertilizer inputs per area of feedstock farmed.

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

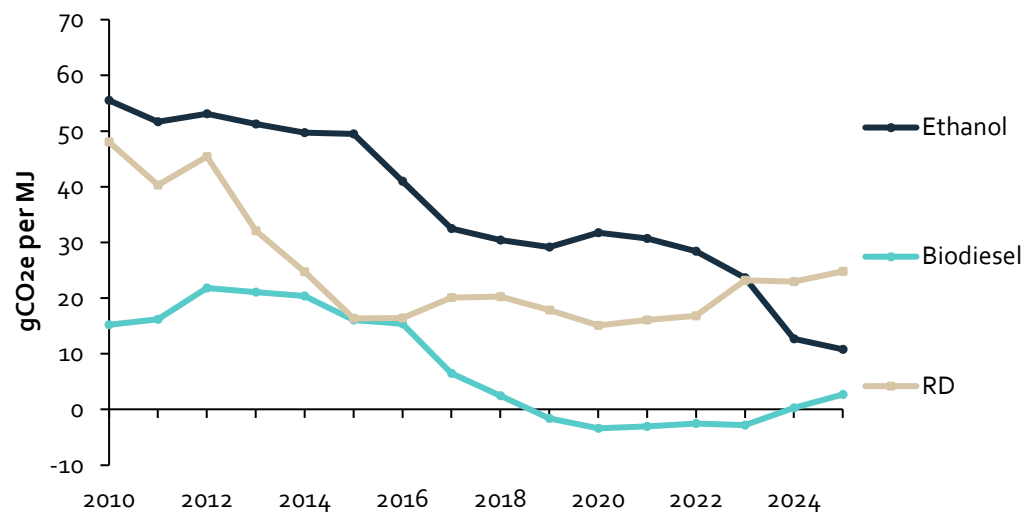
³³ Government of Canada, 2022, [Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations](#)

on data rather than modelling results, indicate a similar trend of an overall decline in the CI of biofuels. Likewise, reporting from the California LCFS also shows 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 generally 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 2025:

- The CI of ethanol decreased by 81%. Notably, there was a step change in the CI from 2023 to 2024, falling from 24 to 12 gCO₂e/MJ, that may be the result of additional ethanol supplied from facilities that capture and store the CO₂ emission produced during grain and starch fermentation.
- The CI of RD decreased by 48% though has been trending upwards since 2020, potentially due to the variability of feedstocks used and changes to the LCA model used to calculate the CI scores.
- The CI of biodiesel decreased by 82% (Figure 12). From 2019 to 2023, the emissions associated with biodiesel in British Columbia were negative, meaning that the farm-to-tank supply of biodiesel leads to an overall decrease of global GHG emissions.

Figure 12: The CI of renewable fuels used in British Columbia are substantially lower than they were in 2010



Average CI by fuel type in British Columbia reported in the BC LCFS compliance data.³⁴

³⁴ British Columbia Ministry of Energy, Mines and Low Carbon Innovation, 2026, Information Bulletin RLCF-007, Renewable and Low Carbon Fuel Requirements Summary: 2010-2025

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 last quarter of 2025, the CI of ethanol declined by 35% and the CI of biodiesel decreased by about 7% (the CI of RD has not declined due to changes in the CI calculation methodology without revisions to previous CI scores).³⁵

A spatial analysis of corn and soy production indicates that some of these CI reductions are likely the result of improved farming practices in 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 gCO₂e/MJ).³⁶ Additionally, the version of the GREET lifecycle GHG model has incorporated data on these practices, dubbed “Regenerative Agriculture”, to allow fuel suppliers to claim these benefits when applying for the Clean Fuel Production Tax Credit.³⁷ This change would broaden the price signal that incentivizes these practices to all US low-carbon fuel production, beyond what is destined for regions with low-carbon fuel standard policies.

Creating markets that value low CIs, as is done by low-carbon fuel standards, 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 fuel pathway within the California LCFS,³⁸ 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.³⁹ Along with the ADM plant in Decatur, Illinois, this plant has since become among the first ethanol plants using CCS, capturing 180 ktCO₂/yr, reducing the CI of the resulting ethanol by about 40 gCO₂e/MJ.⁴⁰ The US EPA indicates that

³⁵ California Air Resources Board, [LCFS Quarterly Data Spreadsheet](#), accessed September, 2026.

³⁶ 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

³⁷ US Department of the Treasury, 2025, [Press Releases - U.S. Department of the Treasury Releases Guidance on Clean Fuels Production Credit](#)

³⁸ California Air Resources Board, 2020, *Low Carbon Fuel Standard*, Design Based Pathway Application No. D000.

³⁹ North Dakota Industrial Commission, 2020, North Dakota Industrial Commission Awards \$500,000 for Development of a Blueprint for a Carbon Capture and Storage Facility

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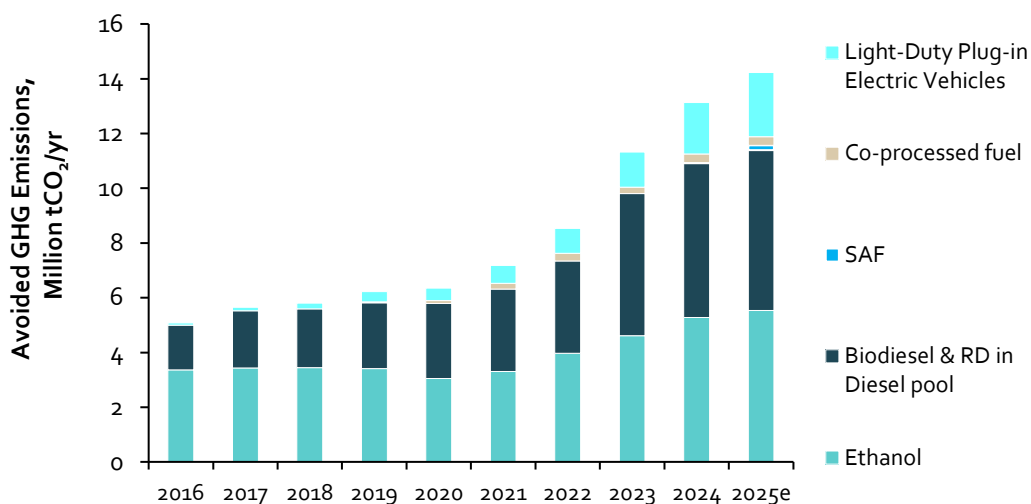
Ethanol Producer Magazine, 2021, [USDA awards \\$25M loan to Red Trail Energy for CCS project](#)

⁴⁰ Ethanol Producer Magazine, 2022, [Red Trail Energy Begins Carbon Capture And Storage](#)

over 40 ethanol facilities are capturing CO₂, with a subset of them sequestering it.⁴¹ As noted above, there was a step change in the CI of ethanol consumed in British Columbia from 2023 to 2024, which may be a function of the combined BC LCFS and federal CFR compliance credit values drawing ethanol with CCS into the province.

The GHG impact of clean fuel consumption in Canada reached a new high of 14.2 MtCO₂/yr in 2025, double the impact in 2021 (Figure 13). This trend is a function of stronger clean fuels policies across Canada, both federally and provincially. Notably, the CFR incentivizes GHG reductions from gasoline and diesel supplied across Canada. Since 2020, new or stronger policies have been in-force in British Columbia, Manitoba, Ontario, and Québec. 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 38%/yr over the past five years. Subsidies, cost reduction, increased supply, and improved performance have all contributed to the rapid growth of electric vehicle sales. The lack of federal and provincial subsidies in 2025 slowed growth in that year.

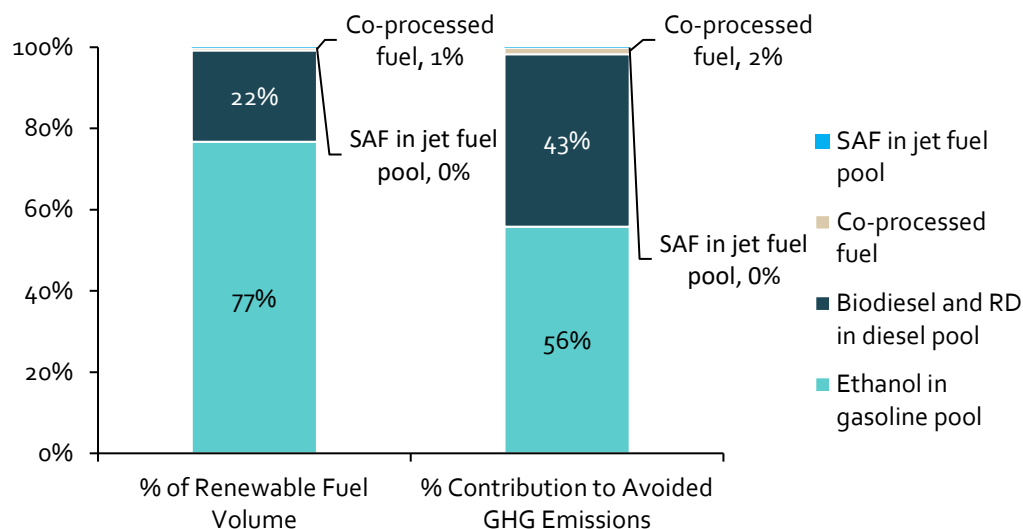
Figure 13: GHG reductions from clean fuels have doubled since 2021



Biomass-based diesel and co-processed fuels provide proportionally more GHG abatement than ethanol (Figure 14). Biomass-based diesel accounted for 22% of the renewable fuel consumed over the time-horizon of this analysis (2010-2025e). Due to their low CI scores, these fuels were responsible for 43% of the cumulative avoided GHG emissions. Likewise, co-processed fuel has accounted for about 1% of the cumulative volume of renewable fuel, but closer to 2% of the avoided GHG emissions.

⁴¹ US Environmental Protection Agency, 2024, [2023 Greenhouse Gas Reporting Program](#)

Figure 14: 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 2025e).

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%.⁴² A study from 2020 found that E10 could increase the energy efficiency by 1.2%,⁴³ 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.⁴⁴ 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.

⁴² 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

⁴³ 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.

⁴⁴ Yadav J., Deppenkemper, K., Pischinger, S. 2023, Impact of renewable fuels on heavy-duty engine performance and emissions. *Energy Reports*, 9, 1977-1989.

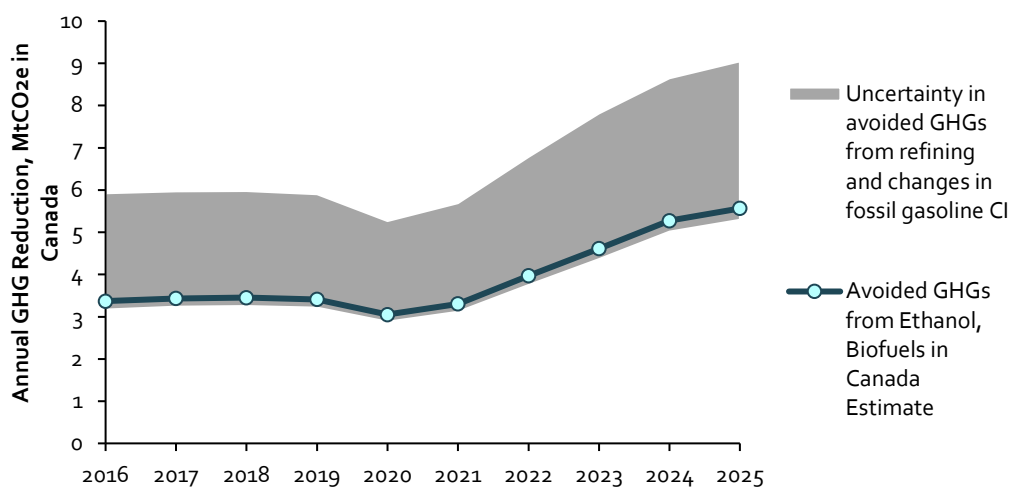
Furthermore, the GHG impacts are calculated under the assumption that renewable fuel blending does not affect the combustion GHG emissions of the fossil fuels blended with the biofuel (just the emissions of the blend itself), nor the GHG intensity of petroleum refining. However, ethanol increases the 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 2025 could range from a 2.0 MtCO₂e/yr decrease to a 0.3 MtCO₂e/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 1.5 MtCO₂e/yr.

Figure 15 illustrates this uncertainty in the ethanol GHG impact related to refinery GHG emissions and gasoline combustion emissions. The high end of that range (i.e., more GHG abatement) is almost 63% greater than what is reported in Biofuels in Canada, consistent with:

- A 1.5 gCO₂e/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 15: The avoided GHG emissions related to ethanol consumption could be much larger than shown in this analysis.



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

Box 2: How do Regulators Determine the Volume and CI of Co-Processed Fuels?

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 data from year-long “baseline” period using only petroleum feedstocks with a seven-day “benchmark” run 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 to the base fossil fuels and co-processed fuels 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

There are two key differences between the federal co-processing quantification methodology and the methodology prescribed for the BC LCFS:

- First, the baseline test period, using only petroleum feedstock, must only last for seven days (rather than a year).
- Second, the determination of co-processed fuels volumes must be done by regular radiocarbon testing rather than using the incremental allocation approach.

Like the federal protocol, the CI of the co-processed fuels in the BC LCFS are defined by a comparison of the petroleum-only baseline data with the benchmark data using low-carbon feedstocks. However, the CI of the input hydrogen is based on actual production input rather than a baseline value that reflects steam methane reformation of methane.

Sources:

Environment and Climate Change Canada (2022). [Clean Fuel Regulations: Quantification Method for Co-processing in Refineries Version 1.0](#).

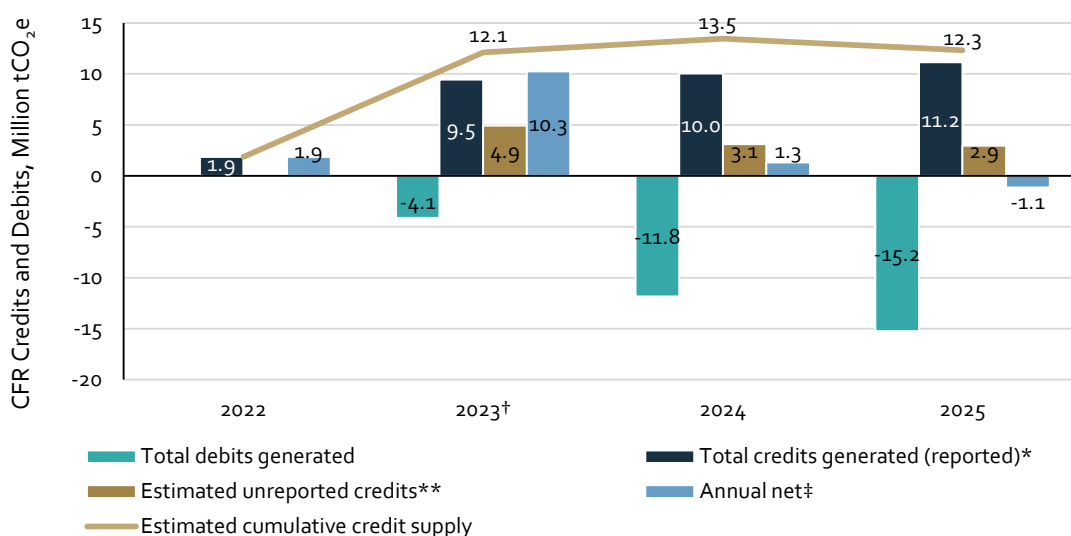
British Columbia Ministry of Energy and Climate Solutions (2026). [Co-processing Methodology, Information Bulletin RLCF-019](#).

4.4. Clean Fuel Regulations Compliance

Preliminary data from ECCC indicate that there was still a surplus of CFR credits at the end of the 2025 compliance period. Active credit supply was listed at 23 MtCO₂e, or up to 24.5 million pending a credit adjustment. Estimated credit demand for 2025 was 15.6 MtCO₂e, indicating a surplus of almost 9 million credits.⁴⁵

Using the Biofuels in Canada analysis, combined with CFR credit market data, we estimate that the surplus at end of 2025 may have been closer to 12 million credits (Figure 16). This is based on the volume of fossil gasoline and diesel reported in this analysis, combined with the regulated CI reduction required by the CFR each year, and the credit generation reported in the CFR market reports and a public presentation of CFR compliance data.⁴⁶

Figure 16: We estimate that there was a bank of around 12 million CFR credits at the end of 2025, somewhat larger than ECCC's estimate of 9 million credits



* 2022 credit generation is early action in the latter half of 2022; RFR rollover credits are included in 2023; Some credit generation is based on default fuel CIs and could be revised as pathway specific CIs are defined.

** See the explanation in the text above for unreported credits.

† Debits in 2023 are based on 50% of the fossil fuel consumption in that year since compliance began in the latter half of the year.

‡ The annual net includes the estimate of unreported credits.

This credit bank includes our estimate of CFR credits that have not yet been realized or reported in the data. Our hypothesis is that this is due to the use of default fuel CIs rather than project-specific CIs. The adoption of final CIs will result in an upward revision of the credit supply. We have approximated this impact as the difference in reported credit generation, and lifecycle GHG impact estimated in Biofuels in Canada from liquid renewable fuel

⁴⁵ Environment and Climate Change Canada, May 2026, Clean Fuel Regulations Program Update

⁴⁶ Ibid. ; ECCC, 2024, [June 2024 CFR credit market report](#).

consumption (data labels in Figure 16 show the quantity is in the range of 5 million credits in 2023, declining to 3 million in 2025).

Some of the difference between ECCC's and our estimate of the credit supply is a result of using different lifecycle GHG models. Credit supply in the CFR is based on the fuel LCA model, whereas credit supply in this calculation is based on various versions of the GHGenius model. Using different models will result in some variation in the resulting calculated credit supply.

4.5. 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, PEVs, or SAF blending. It covers the cost of renewable fuel blending in the gasoline and diesel pool. However, it does not show how biofuel supplies can moderate overall fuel prices during energy-supply shocks by expanding the total liquid fuel supply.

The cost impacts in this analysis are based on publicly available benchmark fuel prices, while actual contracted fuel prices are unknown. Furthermore, low-carbon fuel standards are market-based mechanisms and the power of buyers and sellers in the market will vary over time, over geographies, and over fuel classes and types. Additionally, compliance credit market values may be indicative of the price of renewable fuels, but they are not clear 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 will change fuel costs in this analysis 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 84 octane, which is raised to 87 (regular gasoline) with the addition of ethanol.⁴⁷ When used in a gasoline blend, ethanol has an octane rating of 113.⁴⁸ Consequently, the ethanol can be blended with a lower-octane gasoline blendstock. The price spread between regular gasoline (87 octane) and premium gasoline (91 octane or more) implies that raising octane imposes a cost. Ethanol remains the lowest cost octane booster,⁴⁹ so using lower-octane gasoline blendstock with ethanol is a potential cost-saving opportunity that contributes to the business case of using ethanol.

It is reasonable to assume Canadian refiners are capturing the octane value of ethanol. By analogy with the production of winter and summer gasoline, where refiners adjust the surrounding gasoline blend to meet octane requirements,⁵⁰ refiners would also adjust the gasoline blend with ethanol to meet those requirements.

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 and additional GHG impacts in Figure 15 on page 27).

Renewable fuel consumption in Canada has increased cumulative consumer fuel costs by 0.12% since 2010 (Figure 17). 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 in Québec. The cumulative net cost from 2010 to 2025e is about \$2.0 billion.

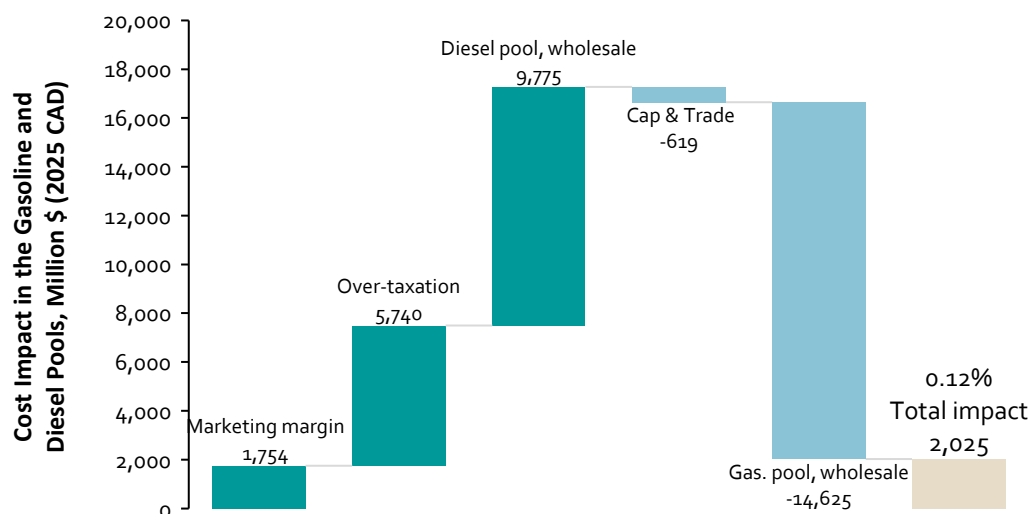
⁴⁷ U.S. Energy Information Administration, 2013, Price spread between regular and premium gasoline has changed over time. <https://www.eia.gov/todayinenergy/detail.php?id=11131>

⁴⁸ 113 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.

⁴⁹ For example, see US Grains & Bioproducts Council, 2025. [Ethanol Market and Data Report, 2025-06-11](#)

⁵⁰ Canadian Fuels Association, [Why Does Gasoline Change Between Summer and Winter?](#)

Figure 17: Renewable fuel consumption has increased consumer fuel costs by 0.12% since 2010



Cumulative cost impact resulting from renewable fuel blending (2010-2025e). Excludes impact of co-processed fuels and light-duty electric vehicles.

The wholesale cost of biodiesel and RD has increased consumer costs by about \$9.8 billion from 2010 to 2025e, while the octane value of ethanol has decreased the wholesale costs borne by consumers by about \$14.6 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 \$5/L over the course of this analysis depending on the cost of boosting octane *without* ethanol each year. Consequently, for the gasoline pool, there is a net savings in the wholesale cost. In contrast, there is a net cost in the diesel pool. 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.

Again, 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 and refined petroleum products will reduce global demand for oil, resulting in a lower oil price. For example, a 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.⁵¹

Because renewable fuels are less energy dense than fossil fuels, we estimate that distributing and dispensing them has cost consumers an additional \$1.8 billion from 2010 to

⁵¹ World Agricultural Economics and Environmental Services, 2022, [The Offsetting Impact of Expanded Biomass Based Diesel Production on Diesel Prices](#).

2025e. 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 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 (i.e., 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 than fossil fuels and the federal and provincial governments have continued to tax all fuels equally on a per litre basis. This impact is the result of legacy tax policies, costing consumers about \$5.7 billion between 2010 and 2025e. 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 2025e, our analysis shows that consumers in Canada have paid an additional \$4.6 billion in taxes for gasoline as a direct consequence of blending lower-density biofuel, while the comparable figure for diesel purchases is \$1.1 billion. The difference in scale is again because biomass-based diesels are closer in energy density to conventional diesel than ethanol is to 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 the 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 consumer costs by about \$620 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 CO₂ emissions are exempt

from the cap-and-trade systems, but minor emissions from CH₄ and N₂O are accounted for.⁵² 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.
- Cost by province and fuel pool is not indicative of where costs are recovered (i.e. where cost impacts result in impacts in what consumers pay). Fuel suppliers may recover costs across fuel pools and provinces. This becomes more likely with the trade in CFR credits. Surplus credits may be generated in one region and purchased in another. Credit trading can easily decouple the location of blending from cost recovery. Consequentially, the total cost incurred across Canada is more certain, while the recovery of these costs from a specific province or fuel pool becomes increasingly uncertain.

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. 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 \$14 billion from 2010 through 2025e. In other words, the wholesale cost savings in the gasoline pool would more than double and the tax cost impact would decline substantially. On net, the cumulative cost savings across

⁵² See Table 30-1 in Government of Québec, [Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere](#)

both fuel pools would be about 0.7% of total gasoline and diesel fuel costs over that period (rather than a cost of about 0.1%).

4.6. GHG Abatement Cost

The GHG abatement costs presented in this section are based on the costs explained above. Therefore, they account for the cost and GHG impact of renewable fuel blending in the gasoline and diesel pools, excluding co-processed fuels, PEV adoption, and SAF consumption.

Ethanol has a negative average GHG abatement cost over the time horizon of this analysis (2010 to 2025e). The cost of GHG abatement from ethanol blending is $-\$151/\text{tCO}_2\text{e}$ (Figure 18). 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 dollar value per tonne CO_2e abated, which would be $-\$235/\text{tCO}_2\text{e}$ if the taxes on ethanol and gasoline were equivalent on an energy basis.

Biodiesel and RD have a positive abatement cost, at $\$261/\text{tCO}_2\text{e}$. 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 closer to the energy density of fossil diesel, the additional tax cost has a minimal impact on the abatement cost.

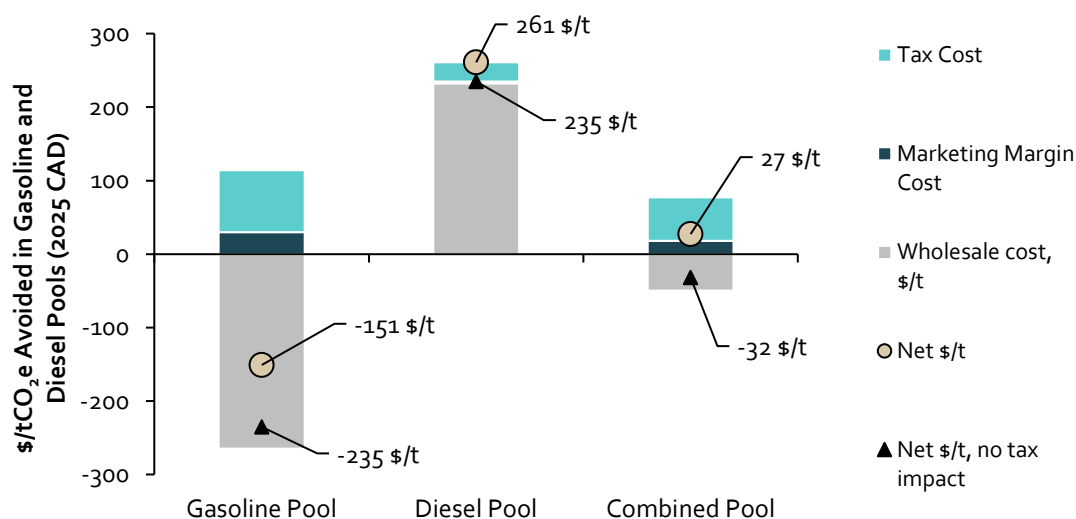
The average abatement cost across all fuel pools and all of Canada over the time horizon of this analysis is $\$27/\text{tCO}_2\text{e}$. The attribution of abatement costs to a given fuel pool or region illustrates where renewable fuel costs are incurred and the extent to which they reduce GHG emissions. However, this attribution does not mean that fuel suppliers are recovering these costs in that way.

The abatement cost in the diesel pool is strongly influenced by the price of RD. The average price of RD in this analysis in 2025 was $\$1.68/\text{L}$ when sold with its environmental attributes (i.e., compliance credit). This price is about 34% lower than the peak prices observed in 2022, which has reduced the average abatement cost attributed to the diesel pool. However, US Renewable Fuel Standard D4 credits and California LCFS credit prices, which are also sensitive to the price of RD, indicate that RD prices have been rising in 2026. The price of D4 credits has risen to about 2.00 USD per credit as of September 2026, up from about 1.00 USD per credit in 2025.⁵³ Likewise, the California LCFS credit price has risen to about 80 USD per credit as of August 2026, up from 50-60 USD per credit in 2025.⁵⁴

⁵³ United States Environmental Protection Agency, [RIN Trades and Price Information](#), accessed September, 2026.

⁵⁴ California Air Resources Board, [Monthly LCFS Credit Transfer Activity Reports](#), accessed September, 2026.

Figure 18: 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 2010-2025e.

Avoided cap-and-trade costs are not included in the abatement cost calculation, nor are any additional cost 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 blending on vehicle energy efficiency, refinery GHG intensity, and fossil gasoline GHG intensity are not included).

4.7. Consumer Cost Impact

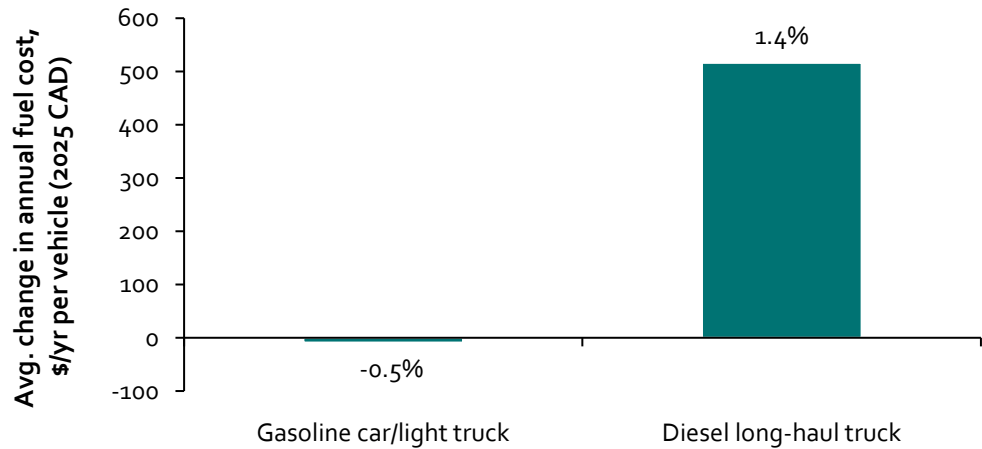
The cost of renewable fuel blending in Canada can be illustrated in terms of how it affects annual fuel costs: It has saved gasoline consumers an average of 0.5% of their fuel costs over the time horizon of this analysis (2010-2025e). In contrast, it has cost diesel consumers an additional 1.4% in fuel costs. For a typical gasoline consumer, driving a car or light truck, this is equivalent to a savings of \$10/vehicle/yr (Figure 19). For a typical diesel consumer (e.g., a class 8 tractor trailer), the cost has been in range of an additional \$513/vehicle/yr.

These consumer cost impacts are illustrative and do not indicate how fuel suppliers have passed on fuel savings (ethanol) to consumers or recovered costs (biomass-based diesel). Again, fuel suppliers may recover costs across fuel pools and regions, so what consumers experience may differ from these results.

Over the past few years, higher biomass-based diesel blend rates, as well as the higher prices for biodiesel and RD in 2022 and 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 \$34,526 on fuel in 2025; low-carbon fuel consumption increased that cost to \$35,600.

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 often accounted for about 1.6% of the diesel pool volume since 2020. A 2% average annual blend is considered feasible by even the most conservative fuel supplier and biodiesel has generally accounted for 3.5% to 4.5% of the US diesel pool over the same period.⁵⁵

Figure 19: Renewable fuel consumption in Canada has saved money for gasoline users, while costing an additional 1.4% for diesel users



Average consumer cost impact as a percent and \$/vehicle/yr, averaged from 2010 to 2025e. The gasoline consumer is based on a light-duty vehicle travelling 14,221 km/yr using 8.9 L/100km. The diesel consumer is based on a class 8 truck travelling 78,856 km/yr using 28.6 L/km. Values taken from NRCan Comprehensive Energy Use Database.

4.8. Detailed Tax Costs

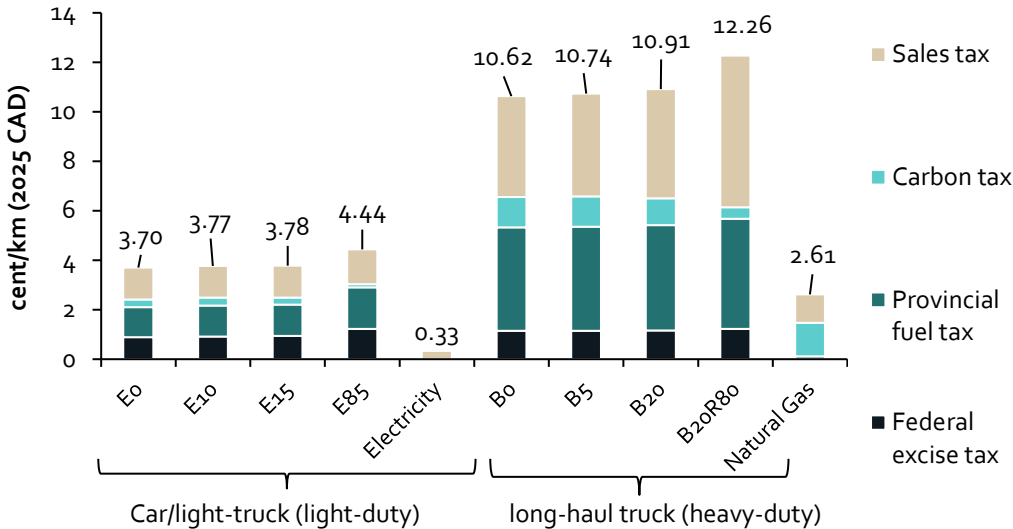
In 2025e, a Canadian using E10 paid 2% more fuel taxes than someone using fossil gasoline. A B5 consumer paid 1% more fuel tax than someone using only fossil diesel (Figure 20). Again, much of this over-taxation results from the lower energy density of biofuels and the fact that most fuel taxes are applied 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 much less tax per km.

The tax impacts in Figure 20 are fuel-consumption-weighted averages for Canada and are not specific to any province. However, there are important regional differences hidden within that average. For example, biofuel users will pay less sales tax per km (charged as a % of the fuel price) when there is a sufficiently large volumetric price discount between the biofuel blend and the unblended fossil fuel (i.e., the \$/L price of the biofuel is lower). Furthermore,

⁵⁵ US Energy Information Agency, 2025, [August 2025 Monthly Energy Review](#), Tables 3.7, 10.4a

Québec has a cap-and-trade system rather than a carbon tax (i.e., the carbon tax value in the figure would be zero).

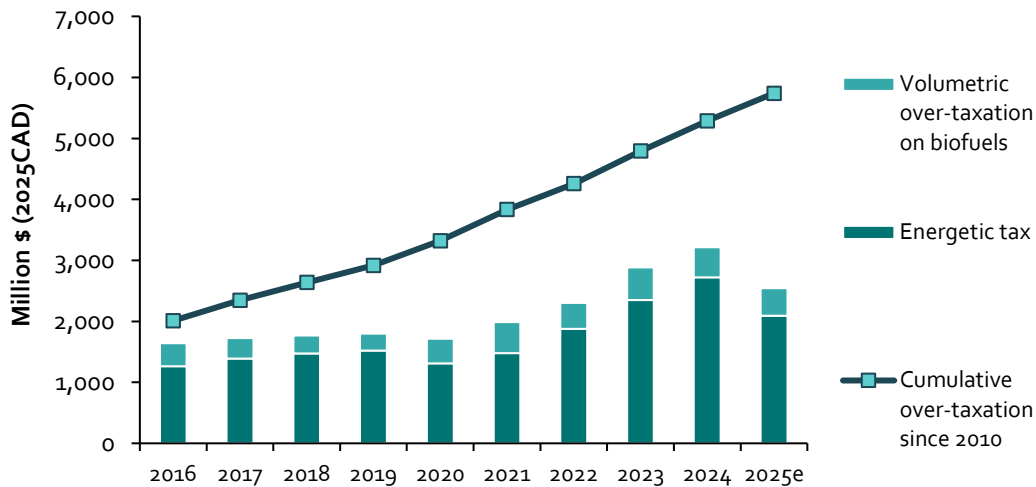
Figure 20: People pay more tax for each km travelled when they consume renewable fuels



Consumption weighted average taxes per distance travelled in 2025e 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 19 (a light-duty gasoline vehicle and a diesel tractor-trailer).

In 2025e, the over-taxation of biofuels amounted to an extra 22% in fuel taxes paid on biofuels, or roughly \$450 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 21). The cumulative over-taxation of biofuels since 2010 rose to about \$5.7 billion in 2025e (note, this is the same as the over-taxation cost impact shown in Figure 17).

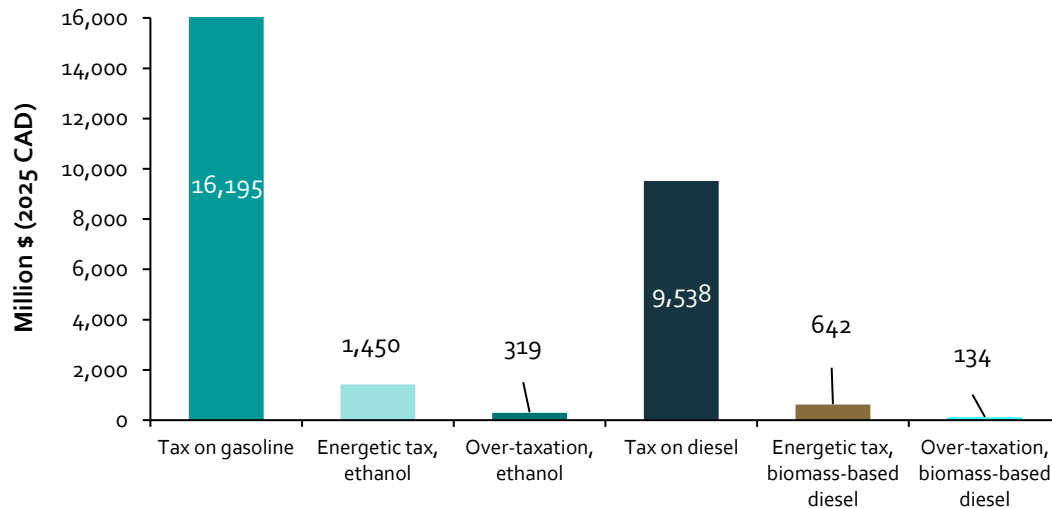
Figure 21: Volumetric taxation of biofuels means consumers paid an extra \$450 million in taxes in 2025e



Fuel tax paid on biofuels in terms of what would be paid for an equivalent amount of energy from fossil gasoline or diesel (the energetic tax) and the additional tax paid as a result of charging tax per volume sold (the over-taxation). The line shows the cumulative over-taxation.

The over-taxation represents more than a sixth of the total tax paid on ethanol and biomass-based diesel. Taxes paid on ethanol in Canada in 2025e account for 9.8% of the total taxes paid on blended gasoline, where the over-tax paid on ethanol is about 1.8 percentage points or 18% of that total. Taxes paid on biomass-based diesel represent 7.5% of the total taxes paid on blended-diesel in Canada in 2025e. The over-tax paid on biomass-based diesel is about 1.3 percentage points, or 17% of that total (Figure 22).

Figure 22: Break-down of taxes paid on gasoline and diesel in 2025e



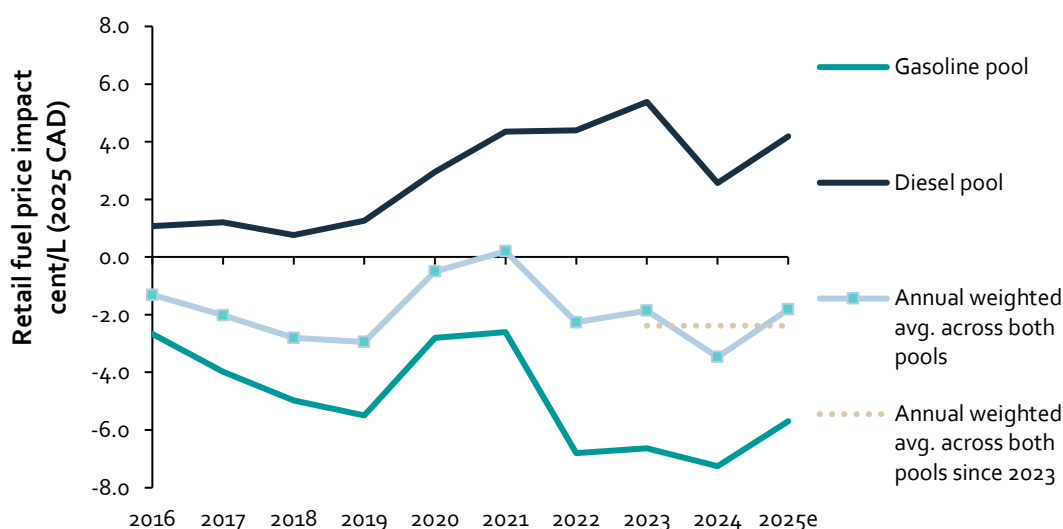
4.9. Retail Fuel Price Impacts

This section highlights how renewable fuel supply has affected the price at the pump. This is what consumers experience on a day-to-day basis, in contrast with the costs described in the previous sections, which are a function of changes in prices, changes in fuel energy density (and fuel consumption) and taxation.

Renewable fuel supply has reduced retail fuel prices, on average across the gasoline and diesel pool. For example, since the start of the CFR in 2023 to the end of 2025, the associated renewable fuel supply should have reduced prices by an average of 2.4 ¢/L relative to a scenario without renewable fuels (Figure 23). CFR market data show that fuel suppliers have complied with this policy over that period, while generating a bank of credits. Therefore, this national average price impact includes the impact of the CFR. Much of that price reduction comes from ethanol supply. Ethanol reduces blended fuel prices because:

- Ethanol has historically been cheaper than gasoline on a volumetric basis.
- Ethanol blending avoids the need for higher cost octane boosters (e.g., benzene, toluene, and xylene).

Figure 23: Retail fuel price impact of renewable fuel supply in Canada



The retail price impacts shown here are indicative, in that they are based on market fuel prices, rather than specific contract prices. As well, these results assume full cost recovery via prices in the province or region where renewable fuel supply occurs. Therefore, the national results shown here are more reliable than a provincial view of these results, which may be affected by CFR credit transfers between fuel suppliers operating in different provinces and regions.

4.10. Electric Vehicles

This analysis estimates how light-duty plug-in electric vehicles (PEVs) have affected gasoline consumption and GHG emissions. These impacts are a function of PEV sales and PEV stock. PEVs can be broken down into “Battery Electric Vehicles” (BEVs) and “Plug-in Hybrid Electric Vehicles” (PHEVs), which are disaggregated in Figure 24 below. BEVs consume only electricity, while PHEVs also have auxiliary engines which consume liquid fuel to extend their range.

In 2025, PEVs accounted for 9.5% of light-duty vehicle sales in Canada, down from 14% in 2024, a function of fewer purchase rebates for PEV sales. 178,000 PEVs were sold in Canada in 2025 (Figure 24). PEV sales declined in 2025 relative to 2024 primarily due to the end of the federal rebate,⁵⁶ a pause on rebates in BC,⁵⁷ and a reduction in the rebate in Québec (part of a planned phase-out by 2027).⁵⁸ PEVs sales in 2025 remained concentrated

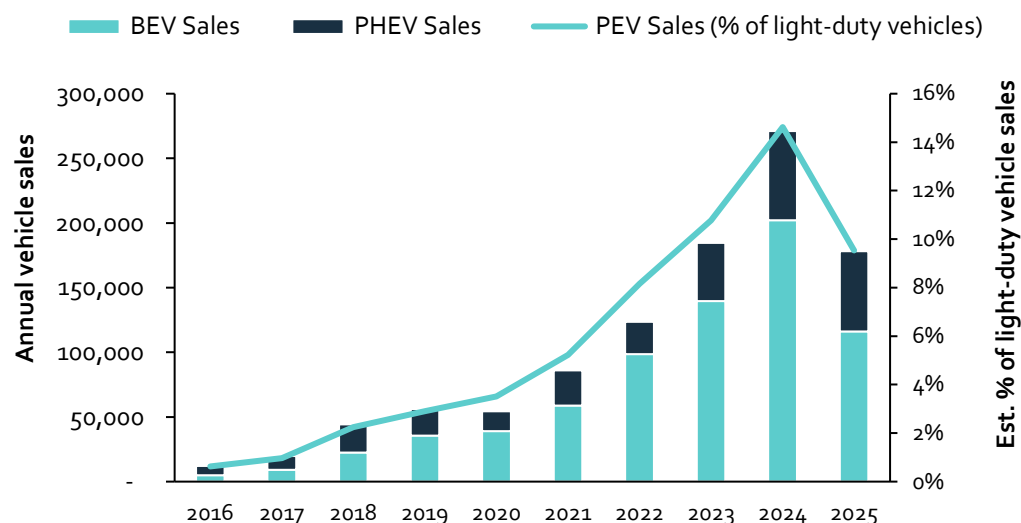
⁵⁶ Government of Canada, 2025, [Closed: Incentives for Zero-Emission Vehicles \(iZEV\)](#)

⁵⁷ New Car Dealers Association of BC, 2025, [Electric Passenger Vehicle Rebate Program](#)

⁵⁸ Government of Québec, 2026, [About the Roulez vert Program](#)

in specific provinces. In Québec and BC, almost 17% of car sales were PEVs in 2025. Sales were about 7% in Ontario and 4 to 5% in the rest of Canada.

Figure 24: Electric cars accounted for almost one in ten light-duty vehicles sold in Canada in 2025



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

Electric vehicles now account for about 3.5% of all light-duty vehicles on the road in Canada (Figure 25). Because a relatively small fraction of vehicles on the road is purchased new every year, PEVs represent a smaller fraction of Canada's vehicle stock than vehicle sales. The stock of PEVs is split about 70:30 between BEVs and PHEVs and is concentrated in the provinces that have historically had higher PEV sales (British Columbia, Québec and Ontario).

PEV sales may rebound somewhat in 2026 and continue growing thereafter, as a function of existing and new provincial and federal policies. In September 2025, the federal government removed its 2026 zero-emissions vehicle (ZEV) sales requirement and launched a 60-day review of the policy, with the goal of supporting the Canadian automotive sector in the face of US tariffs.⁵⁹ In August 2026, the government began the process of repealing this policy.⁶⁰ Nonetheless both Québec and BC have retained their ZEV sales requirements, albeit with reduced policy stringency (Rather than 100% ZEV sales in 2035, BC now requires 75% and Québec requires 80%).⁶¹ As well, the federal government implemented the Electric

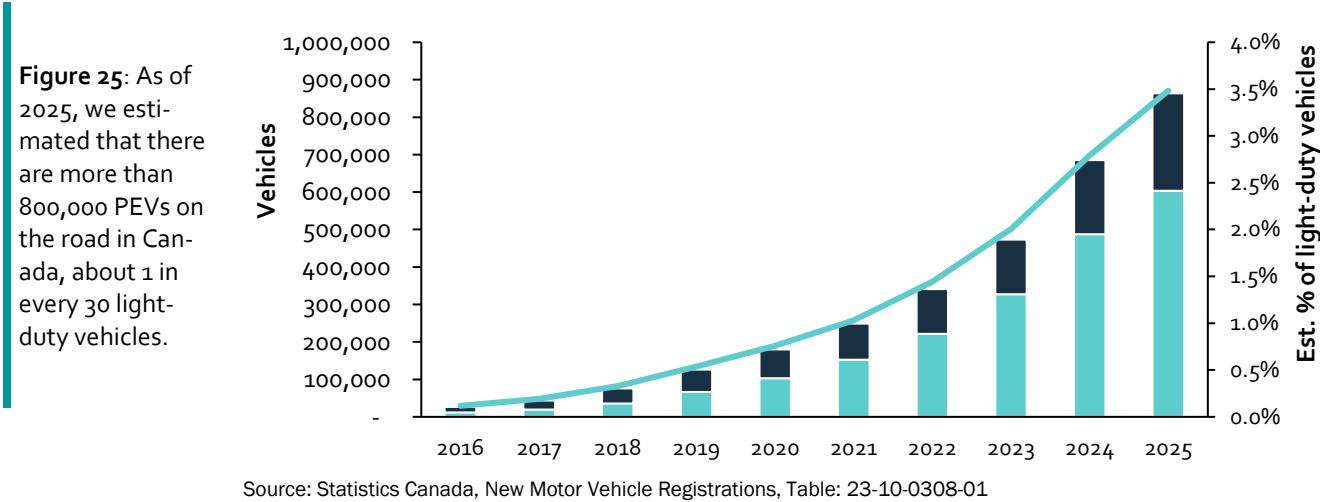
⁵⁹ Government of Canada, 2025, [Prime Minister Carney launches new measures to protect, build, and transform Canadian strategic industries](#)

⁶⁰ Government of Canada, 2026, [Canada Gazette, Part I, Volume 160, Number 33: Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations](#)

⁶¹ British Columbia Ministry of Energy and Climate Solutions, 2026, [Updating zero-emission vehicle targets, expanding charging network](#) and

Cabinet de la ministre de l'Environnement, de la Lutte contre les changements climatiques, de la Faune et des Parcs, 2026, [Norme sur les véhicules électriques : Québec adopte une approche équilibrée et pragmatique](#)

Vehicle Affordability Program in 2026, a new point-of-sale incentive for PEV sales.⁶² Finally, the federal government also announced its intention to strengthen the vehicle tailpipe GHG intensity standard to drive 75% ZEV sales by 2030.⁶³



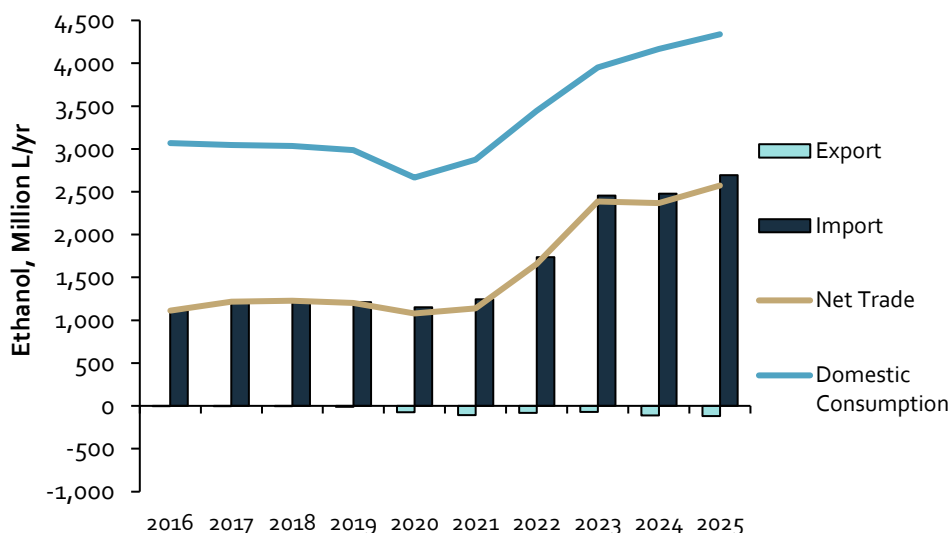
4.11. Renewable Fuel Trade

Canada is both a significant ethanol producer and importer (Figure 26). Prior to 2022, domestic production supplied about 60% of Canadian ethanol demand (the difference between net-imports and domestic consumption in the figure). The other 40% was satisfied mostly with US imports. As of 2025, domestic demand increased by 21% relative to 2022, without any increase in domestic production capacity. Consequently, Canada now imports about 60% of its ethanol supply from the US.

⁶² Government of Canada, 2026, [Electric Vehicle Affordability Program](#)

⁶³ Government of Canada, 2026, [Prime Minister Carney unveils Canada's new automotive strategy to protect jobs and position our country as a global leader in next-generation vehicle manufacturing](#)

Figure 26: Canada is a major ethanol producer and importer

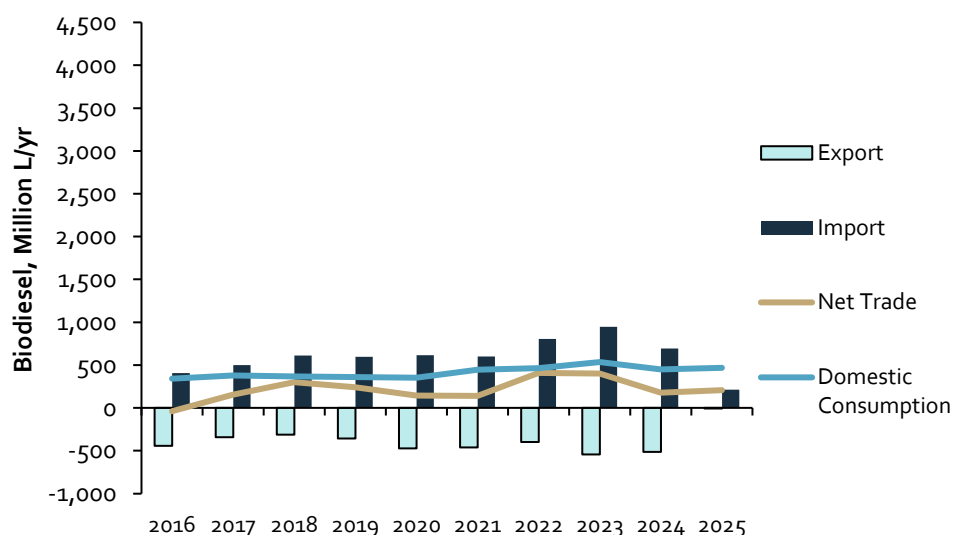


Source: [Canadian International Merchandise Trade Database](#)

In 2024 and earlier, Canada exported and imported a similar amount of biodiesel from the US, but changes in US tax incentives have reduced trade in 2025 (Figure 27). Through December 2024, Canadian biodiesel exported to the US qualified for the biomass-based diesel blender's tax credit.⁶⁴ Canadian fuel was exported to the US where it was blended with diesel to become eligible for the tax credit. Blended biodiesel was then imported to meet Canadian demand. The difference between domestic consumption and net trade indicates the quantity of domestically produced biodiesel that was not exported. As of January 1st, 2025, Canadian-made biodiesel no longer generated a US tax credit, resulting in a significant reduction in biodiesel trade.

⁶⁴ Alternative Fuels Data Center, [Biodiesel Mixture Excise Tax Credit](#)

Figure 27: Because of changes in US tax incentives, Canadian biodiesel trade declined substantially in 2025



Source: [Canadian International Merchandise Trade Database](#)

Canada has imported almost all its RD supply to date, and the trade data underestimate the volume (Figure 28). Canada had no standalone RD production capacity prior to 2023, and it was only about 170 ML at the start of 2024.⁶⁵ Consequently, almost all RD consumed in Canada has been imported. Braya Renewables and Imperial Oil, each capable of producing about 1,000 ML/yr, came on-line in 2024 and 2025 respectively.⁶⁶

However, there is a large gap between domestic consumption of RD and the RD imports, owing to an earlier lack of a “harmonized system” (HS) code to define RD in the trade data as well as a misclassification of the fuel as fossil diesel or biodiesel. This situation may change as the RD HS becomes more widely used, and as Canadian RD production begins to penetrate the Canadian markets due to market conditions and made-in-Canada requirements.

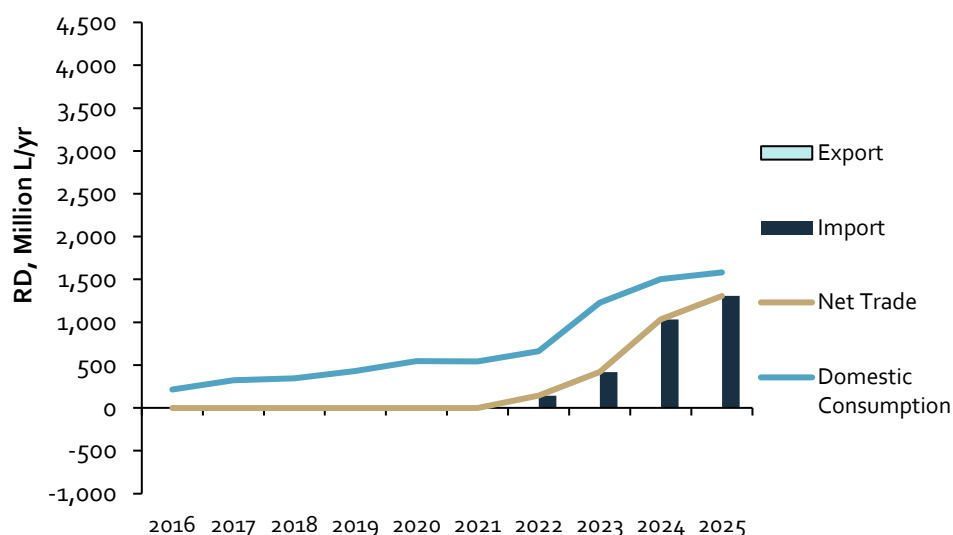
⁶⁵ British Columbian co-processed RD capacity plus an approximation of Tidewater RD production capacity also in BC. See Tidewater Renewables, [Core Projects](#)

⁶⁶ Braya Renewable Fuels, 2024, [Braya Renewable Fuels Celebrates the Come by Chance Refinery’s Commercial Operations Start as a Renewable Diesel Facility and its 50-year Legacy in the Community](#)

and

Imperial, 2025, [Imperial now producing renewable diesel at Strathcona refinery](#)

Figure 28:
Canada has imported almost all its RD supply to date. Trade data underestimate the volume

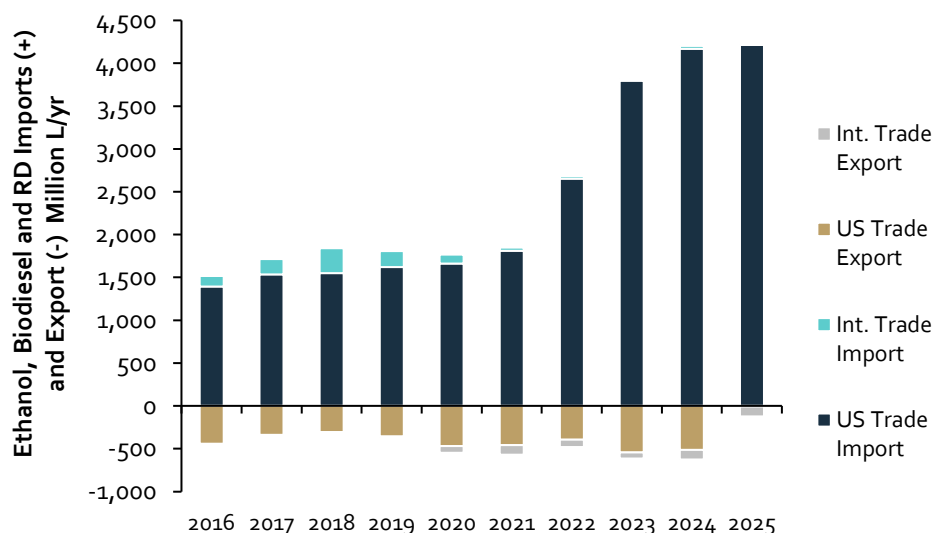


Source: [Canadian International Merchandise Trade Database](#)

Canada imports about two thirds of its renewable fuel supply. Imports from the US are the largest component of Canada's renewable fuel trade (Figure 29). Imported renewable fuel volumes into Canada are historically six to seven times larger than export volumes. Most renewable fuel trade is with the US, which generally accounts for more than 95% of imports. As of 2025, Canada exports very little renewable fuel, largely due to the decline in biodiesel exports described above. The performance of Canada's two largest RD production facilities could significantly change the scale of both imports and exports. If the Imperial Oil facility in Alberta produces at capacity in 2026, it could reduce fuel imports by 1,000 ML/yr relative to what they would have been without that domestic production. Likewise, if Braya Renewable fuels in Newfoundland and Labrador operates at capacity and sells into the Canadian market, it could shift the trade balance by another 1,000 ML/yr. Both outcomes will be a function of emerging federal and provincial policy responses (fiscal, regulatory) to US tariffs, fuel regulations, international demand (i.e., non-US), and tax incentives on renewable fuel production, as well as restrictions on vessels that may carry product from Braya in Newfoundland to Canadian markets.⁶⁷

⁶⁷ The Coasting Trade Act requires marine trade between Canadian provinces must be on Canadian-registered vessels.

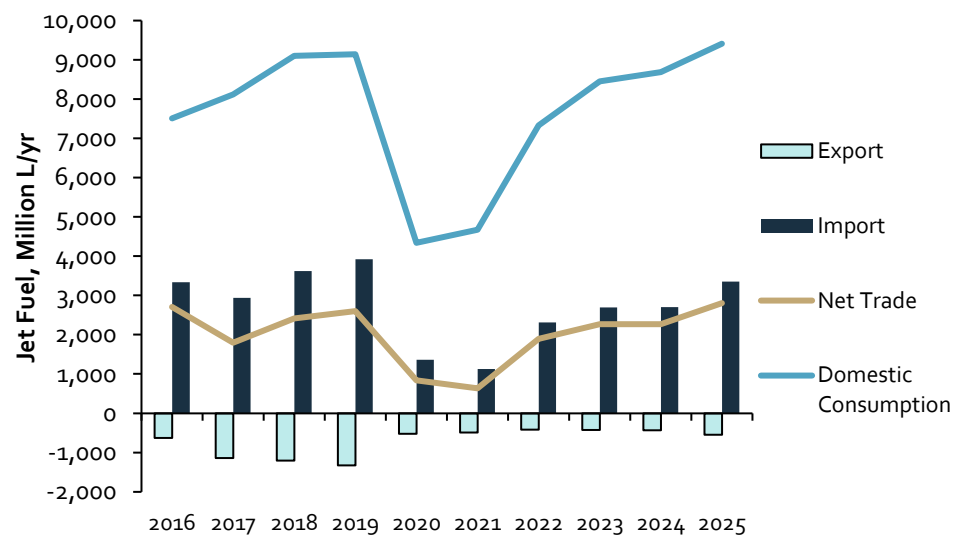
Figure 29:
Imports from the
US dominate Can-
ada's trade in re-
newable fuels



Source: [Canadian International Merchandise Trade Database](#)

Canada is a net importer of jet fuel, where imports account for about one third of domestic supply (Figure 30). Net imports are around 2.5 billion L/yr. If Canada were to achieve its 2030 target of 10% SAF consumption, with that fuel supplied domestically, it would cut net imports of jet fuel by half.

Figure 30:
Canada imports
about a third of its
domestic jet fuel
supply



Source: [Canadian International Merchandise Trade Database](#)

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. The federal blending requirements are described in full in section 2.1, along with a summary of the provincial requirements.

British Columbia

The British Columbia low-carbon fuel standard (BC LCFS)⁶⁸ 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 and 8% in 2025. As of April 2025, the minimum volumetric amount in diesel must be supplied by Canadian producers and that requirement applies to the minimum amount in gasoline as of January 1st, 2026.⁶⁹

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 62. 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.⁷⁰ However, Alberta's

⁶⁸ 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](#).

⁶⁹ BC OIC 81/2025, BC Ministerial Order No. M41.

⁷⁰ Government of Alberta, [Renewable Fuels Standard Regulation](#)

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 in North America meet this criterion. For example, in 2011 the lifecycle CI of gasoline (as estimated by GHGenius 4.03a) was approximately 88.8 gCO₂e/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 gCO₂e/MJ, while the CI of biodiesel and RD in that province ranged from about 8 to 20 gCO₂e/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.⁷¹ Saskatchewan also has *The Renewable Diesel Act* that started on July 1, 2012, mandating 2% renewable fuel by volume in diesel pools.⁷²

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 2022.⁷³ The biodiesel policy required 2% biodiesel by volume through 2020, rising to 3.5% in 2021 and 5% in 2022.⁷⁴

Diesel sold for use in areas north of latitude 55° N and in communities serviced by winter roads is not subject to the blending mandate. Gasoline sold for use in Churchill or surrounding areas and communities serviced by winter roads is not subject to the blending mandate.

⁷¹ Government of Saskatchewan, *The Ethanol Fuel Act*, [The Ethanol Fuel \(General\) Regulations](#)

⁷² Government of Saskatchewan, [The Renewable Diesel Act](#)

⁷³ Government of Manitoba, *The Biofuels Act*, [Ethanol General Regulation](#)

⁷⁴ Government of Manitoba, *The Biofuel Act*, [Biodiesel Mandate For Diesel Fuel Regulation](#)

Ontario

Ontario previously had the *Greener Gasoline – Bio-Based Content Requirements for Gasoline*⁷⁵ 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 Transportation Fuels: Renewable Content Requirements For Gasoline And Diesel Fuels*,⁷⁶ 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 7). 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 gCO₂e/MJ (45% below a benchmark CI for gasoline) (Table 8 and Figure 31). If the CI of the biofuel is lower than 46 gCO₂e/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 31). Similarly, by 2030, the policy requires a 15% volumetric blend rate if the weighted average CI of the bio-based content is 42 gCO₂e/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 7: Volumetric low-carbon renewable fuel blending requirements in Ontario

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

Table 8: Threshold CI values where required blending rate = actual blending rate in Ontario, gCO₂e/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

⁷⁵ Government of Ontario, O. Reg. 535/05: [GREENER GASOLINE - BIO-BASED CONTENT REQUIREMENTS FOR GASOLINE](#)

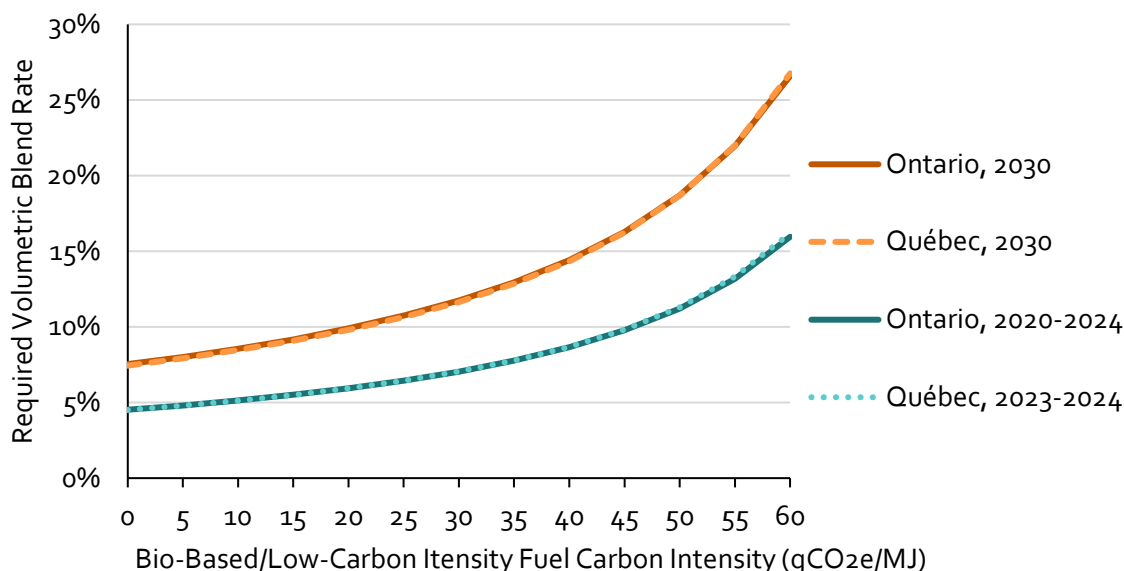
⁷⁶ Government of Ontario, O. Reg. 663/20: [CLEANER TRANSPORTATION FUELS: RENEWABLE CONTENT REQUIREMENTS FOR GASOLINE AND DIESEL FUELS](#)

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 32).

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

As of August 2025, Ontario created a minimum domestic renewable fuel requirement for its policy. A minimum of 75% of the renewable content required in diesel fuel and 64% of the renewable content required in gasoline must be made in Canada (with those volumes pro-rated to 25% and 24% for 2025). The domestic requirement for renewable content in gasoline falls to 54% of the required amount in 2028, then to 47% of the required amount from 2030 onward.⁷⁷

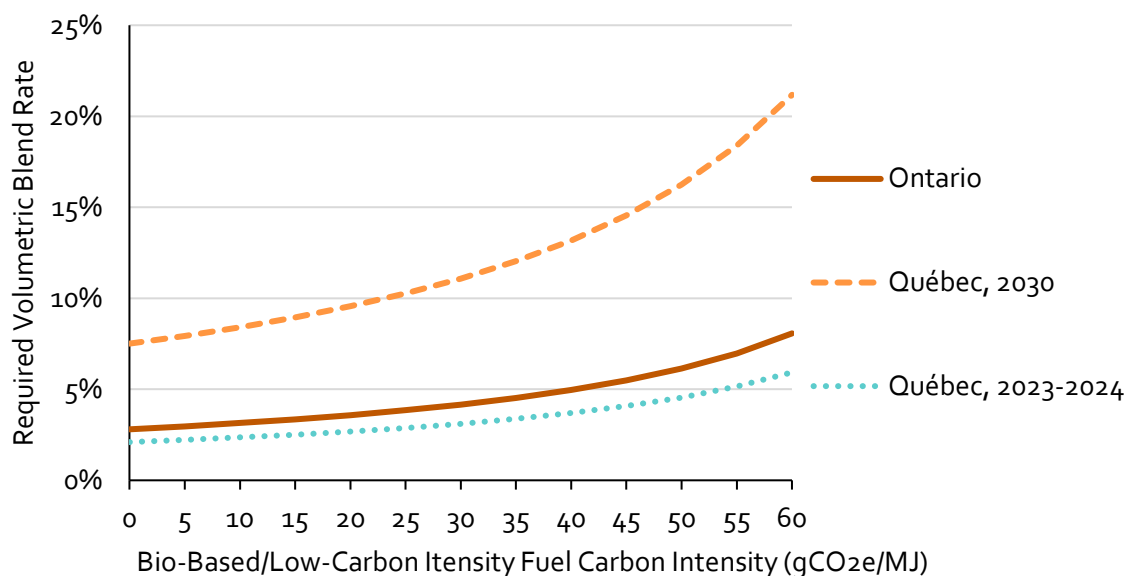
Figure 31: Volumetric blend rates of renewable fuel in gasoline required to comply with the Ontario and Québec regulations prior to 2025 and in 2030



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.)

⁷⁷Government of Ontario, 2025, [Cleaner Transportation Fuels: Proposed Domestic Renewable Content Requirement for Diesel Fuel](#)

Figure 32: 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 9). The diesel blending requirement begins at 3% low-carbon fuel content in 2023, rising to 5% in 2025 and 10% by 2030 (Table 9).⁷⁸ As discussed below, there is a CI threshold used to determine an adjusted volume for the fuels used to comply with these requirements and the threshold declines over time (Table 10). The policy excludes premium gasoline, heating oil, and fuel used for air, marine and rail transport. It also excludes fuel consumption in northern and far-eastern Québec (other areas were also excluded for 2023, the first year that the policy was 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 in the diesel pool).

⁷⁸ Gouvernement du Québec, 2021, [Regulation respecting the integration of low-carbon-intensity fuel content into gasoline and diesel fuel](#).

Table 9: 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 10: Threshold CI values where required blending rate = actual blending rate in Québec, gCO₂e/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 gCO₂e/MJ (50 % lower than reference gasoline CI) (Table 10, Figure 31). 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 gCO₂e/MJ (Figure 31). 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 gCO₂e/MJ (75% lower than reference diesel CI) (Table 10). More typical average CI scores for biomass-based diesel around 10 gCO₂e/MJ would require a blend rate closer to 8.4% (Figure 32).

Because Québec is a large fuel market, this regulation significantly affected renewable fuel consumption in Canada. A 10% blending rate in gasoline might require roughly 800 million L of ethanol consumption in Québec (or other bio-based gasoline), equivalent to about 24% of national ethanol consumption prior to the implementation of this policy. A 3% biomass-based diesel blending rate might require about 125 million L of renewable fuel, equivalent to about 12% of Canadian consumption of these fuels prior to the implementation of the policy.⁷⁹

The Yukon

The Yukon announced that they intended 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.⁸⁰ Draft regulations have not yet been published as of August 2026 and there is no timeline to do so.

⁷⁹ 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 gCO₂e/MJ and a biomass-based diesel CI of 10 gCO₂/MJ.

⁸⁰ Government of Yukon, 2020, [Our Clean Future: A Yukon strategy for climate change, energy and a green economy](#)

Carbon Pricing Across Canada

As of April 1st, 2025, consumer carbon pricing has ended in all provinces except Québec. Before April 2025, consumer carbon pricing in Canada was defined by the federal GGPPA. The GGPPA, also referred to as the federal fuel charge, applied to provinces that chose not to implement an equivalent carbon pricing system of their own. As of fall 2023, these included all provinces except British Columbia and Québec.

The GGPPA also defined the stringency of carbon pricing required in provinces with their own systems. British Columbia and Québec continued to use their provincial carbon pricing systems, which were deemed to be of equal or greater stringency to the federal backstop price. The British Columbia Carbon Tax followed the same schedule as the federal carbon tax and had a very similar impact on fuel prices at the pump. Québec still uses a GHG cap-and-trade system that is linked with a similar program in California. Therefore, the impact of carbon pricing on fuel prices in Québec will vary as a function of the market price for cap-and-trade 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 2022.⁸¹ In 2023, the price began to increase by \$15/yr and was scheduled to reach \$170/tCO₂e in 2030.⁸² The fuel charge rates shown in Table 11 accounted 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 paid 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 >R5⁸³) in diesel were fully exempt from the carbon price.⁸⁴ Revenues collected from the GGPPA were returned as rebates to households and small businesses.⁸⁵

⁸¹ Government of Canada, 2019, [Fuel Charge Rates](#)

⁸² Government of Canada, 2021, [Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030](#)

⁸³ 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.

⁸⁴ 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.

⁸⁵ Government of Canada, [Canada Carbon Rebate \(CCR\) for individuals](#), Accessed October 2024

Table 11: Federal fuel charge rates on gasoline and diesel blends up to E10 and B5/R5 (nominal CAD)⁸⁶

	2021-2022	2022-2023	2023-2024	2024-2025	Apr 1, 2025-
Carbon price, \$/tCO ₂ e	\$40	\$50	\$65	\$80	\$0
Gasoline, ¢/L	8.84	11.05	14.31	17.68	-
Diesel, ¢/L	10.73	13.41	17.28	21.46	-

Because this carbon price did not differentiate by blend rates up to E10 and B5/R5, there was a foregone price incentive to use lower-carbon fuels and a foregone cost savings for consumers of these fuels. Prior to the end of carbon pricing, the federal carbon pricing backstop overtaxed E10 by about ¢1.2/L and B5/R5 by about ¢0.7/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 2024 (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 made consumers pay an additional \$750 million in 2024.

Table 12: The over-taxation/foregone price incentive on E10 and B5/R5 in relation to the announced federal carbon pricing schedule

	2023	2024
Carbon Price, \$/tCO ₂ e	65	80
Gasoline, carbon price ¢/L	14.37	17.68
Diesel, carbon price ¢/L	17.43	21.46
Over-taxation /foregone price incentive on E10, ¢/L	1.0	1.2
Over-taxation /foregone price incentive on B5/R5, ¢/L	0.6	0.7

British Columbia Carbon Tax

The British Columbia (BC) carbon tax was introduced at \$10/tCO₂e in 2008 and increased to \$30/tCO₂e by 2012 and rose in multiple steps to \$80/tCO₂e as of April 1, 2024 (Table 13).⁸⁷ The BC carbon tax was scheduled to rise to \$170/tCO₂e by 2030, consistent with the federal backstop carbon price.⁸⁸ Each \$5/tCO₂e increment increased the tax on gasoline by 1.11 ¢/L and the tax on diesel by 1.28 ¢/L, while the \$15/tCO₂e increments increased those

⁸⁶ Government of Canada, 2019, *Fuel Charge Rates*. www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html

⁸⁷ Government of British Columbia, British Columbia's Carbon Tax. Formerly available at <https://www2.gov.bc.ca/gov/content/environment/climate-change/clean-economy/carbon-tax>

⁸⁸ Greenhouse Gas Pollution Pricing Act, [Schedule 4](#)

prices by about 3 and 4 ¢/L respectively (Table 13).⁸⁹ The carbon tax was eliminated on April 1st, 2025.

The tax rate on gasoline and diesel was based on emissions factors that approximated a 5% volumetric biofuel blending rate in the province (i.e., the tax was reduced by 5% to recognize biofuel blend components under the BC LCFS), resulting in a tax of 17.6 ¢/L on gasoline and 20.7 ¢/L on diesel as of fiscal 2024-2025. The tax was applied equally to each litre of fuel, fossil and renewable, and was not adjusted for tailpipe or lifecycle GHG emissions of the biofuels.

Table 13: British Columbia carbon tax rates (nominal CAD)

	2018- 2019	2019- 2021	2021- 2022	2022- 2023	2023- 2024	2024- 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 was unique in that renewable fuels were covered by the carbon tax regardless of blend rate.⁹⁰ However, in BC's output-based pricing system, which maintains a carbon price for large industries, biodiesel, ethanol, and renewable diesel are listed as eligible "Schedule C" biomass,⁹¹ meaning the biogenic CO₂ 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 transport fuel consumption outside of industry would only include the value of the LCFS and CFR credits.

Alberta Carbon Levy

Alberta implemented a \$20/tCO₂e carbon levy in 2017, which rose to \$30/tCO₂e in 2018.⁹² 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 14). However, unlike British

⁸⁹ Ibid.

⁹⁰ Schedule 1, BC Carbon Tax Act. Available at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/00_08040_01#Schedule1

⁹¹ 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

⁹² Government of Alberta, Carbon Levy Rates. Formerly available at <http://www.alberta.ca/about-tax-levy-rates-prescribed-interest-rates.aspx#carbon-levy>

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 2019.⁹³ Consequently, as of 2020, gasoline and diesel purchases were subject to the federal carbon pricing fuel charge which ended on April 1st, 2025.

Table 14: 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, 2018.⁹⁴ As of 2019, gasoline and diesel sales in Ontario were subject to the federal carbon pricing backstop which ended on April 1st, 2025.

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; CO₂ emissions from 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/tCO₂e, roughly 4.3 ¢/L on gasoline and 4.8 ¢/L on diesel. The average credit price in 2018 was \$18.6/tCO₂e up until the program was cancelled.⁹⁵

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 CO₂

⁹³ Government of Alberta, Carbon Tax Repeal. Formerly available at <https://www.alberta.ca/carbon-tax-repeal.aspx>

⁹⁴ Financial Accountability Office of Ontario, 2018, [Cap and Trade: A Financial Review of the Decision to Cancel the Cap and Trade Program](#)

⁹⁵ Government of Ontario, 2018, *Past auction information and results*. Formerly available at <http://www.ontario.ca/page/past-auction-information-and-results>

emissions from biofuels are exempt from the cap-and-trade system (CH₄ and N₂O emissions are covered). 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.

The system has a price floor, which is a minimum price for credit trades. The price floor began in 2013 at \$10.75/tCO₂e (nominal CAD) and rises by 5% plus inflation each year.^{96,97} 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 has generally remained 30% to 50% above the price floor, though it rose well above the floor from 2022 through 2025⁹⁸ (Table 15).

Table 15: Québec cap-and-trade average annual credit settlement price and estimated price impact on gasoline and diesel (nominal CAD)

	2017	2018	2019	2020	2021	2022	2023	2024	2025 ytd	2026 ytd
Credit price, \$/tCO ₂ e	18.9	19.3	22.0	22.8	27.7	36.9	44.7	48.3	39.4	38.8
Gasoline, ¢/L	4.6	4.7	5.3	5.5	6.7	9.0	10.8	11.7	9.6	9.4
Diesel, ¢/L	5.1	5.2	6.0	6.2	7.5	10.0	12.1	13.1	10.7	10.5

Nova Scotia Cap-and-trade

Nova Scotia's GHG emissions cap-and-trade system took effect on January 1, 2019, with the first compliance period lasting from 2019 to 2022. A floor price of \$20/tCO₂e was in place for the first auction in 2020. The floor price 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.⁹⁹ The Nova

⁹⁶ Government of Québec, 2018, [Québec cap-and-trade system for greenhouse gas emissions allowances \(C&T\): Technical Overview](#)

⁹⁷ Government of Québec, 2026, [The Carbon Market: Auctions](#)

⁹⁸ 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

⁹⁹ Government of Nova Scotia, 2020, Cap-and-Trade Program Regulations. Formerly available at <https://www.novascotia.ca/just/regulations/regs/envcapandtrade.htm>

Scotia cap-and-trade quantification, reporting, and verification regulations specified that fuel suppliers did not have to purchase allowances for CO₂ emissions from biofuels.¹⁰⁰

As of July 1st, 2023, the cap-and-trade program was replaced with the now defunct federal carbon price on retail fuels, paired with a provincial Output-Based Pricing System for large industrial GHG emitters.¹⁰¹

Nova Scotia's provincial government regulates the price of motor gasoline and diesel. Therefore, while the cap-and-trade program was in force, the petroleum product pricing regulation specified that fuel suppliers could recover 20% of the auction price floor at a fixed CI of 2.36 kgCO₂e/L gasoline from retail sales.¹⁰² 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.¹⁰³ As of July 1st, 2023, the New Brunswick tax was replaced with the federal carbon tax¹⁰⁴ which subsequently ended on April 1st, 2025.

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 2025, even with the re-introduction and elimination of the federal carbon tax.

¹⁰⁰ Government of Nova Scotia, s. 17 (2) Quantification, Reporting and Verification Regulations. Formerly available at https://www.novascotia.ca/just/regulations/regs/envqrv.htm#TOC3_17

¹⁰¹ Government of Nova Scotia, 2020, Cap-and-Trade Program Regulations. Formerly available at <https://www.novascotia.ca/just/regulations/regs/envcapandtrade.htm>

¹⁰² Government of Nova Scotia, [Petroleum Product Pricing Regulations](#)

¹⁰³ Government of New Brunswick (accessed via CanLII), [Gasoline and Motive Fuel Tax Act](#)

¹⁰⁴ Government of New Brunswick, 2023, Province opts for federal backstop on carbon pricing. Formerly available at [https://www2.gnb.ca/content/gnb/en/departments/elg/news/news_release.2023.02.0065.html.html#:~:text=News%20Release&text=FREDERICTON%20\(GNB\)%20%E2%80%93%20The%20provincial,for%20redistributing%20the%20collected%20revenues](https://www2.gnb.ca/content/gnb/en/departments/elg/news/news_release.2023.02.0065.html.html#:~:text=News%20Release&text=FREDERICTON%20(GNB)%20%E2%80%93%20The%20provincial,for%20redistributing%20the%20collected%20revenues).

Consequently, the net carbon price impact was about 5 to 6¢/L lower for gasoline and diesel with subsequent increases to the carbon price rate (Table 16).¹⁰⁵

New Brunswick was not alone in adjusting fuel tax rates to mitigate the 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 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 2022.¹⁰⁶

Table 16: New Brunswick carbon tax

	2020-2021	2021-2022	2022-2023
Carbon Tax rate, \$/tCO 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,¹⁰⁷ bringing these provincial fuel taxes back to their 2015 values. As of fiscal 2022-2023, the carbon price on gasoline and diesel was consistent with a \$50/tCO₂e carbon price, about 11 ¢/L on gasoline and 13 ¢/L on diesel (Table 17).¹⁰⁸

¹⁰⁵ Government of New Brunswick (accessed via CanLII), [Gasoline and Motive Fuel Tax Act](#)

¹⁰⁶ NRCAN, [Fuel Consumption Levies in Canada](#)

¹⁰⁷ Government of Newfoundland and Labrador, 2018, [Provincial Government Releases Federally-Approved Made-in-Newfoundland and Labrador Approach to Carbon Pricing](#)

¹⁰⁸ Government of Newfoundland and Labrador, 2022, [Provincial Carbon Tax Rates](#)

As of July 1st, 2023, Newfoundland and Labrador also replaced the provincial tax with the now defunct federal carbon price.¹⁰⁹

Table 17: Newfoundland and Labrador carbon tax

	2019-2021	2021-2022	2022-2023
Carbon Tax rate, \$/tCO 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.¹¹⁰ As of fiscal 2022-2023, the tax was consistent with a \$50/tCO₂e carbon price, as per federal requirements (Table 18).¹¹¹ Like the rest of the Atlantic provinces, PEI adopted the now defunct federal carbon price as of July 1st, 2023, thus increasing the carbon price to \$65/tCO₂e in that year and following the federal schedule thereafter.¹¹²

Also, in keeping with other provinces, PEI reduced provincial fuel taxes around the same time that carbon pricing was implemented. The provincial fuel taxes on gasoline and diesel were reduced by 4.6 ¢/L and 6.0 ¢/L since 2019 and these reductions remain in place, even with the elimination of the carbon price.¹¹³

Table 18: PEI carbon tax

	2019-2020	2020-2022	2022-2023
Carbon Tax rate, \$/tCO 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

¹⁰⁹ Government of Newfoundland and Labrador, 2023, [Public Advisory: Information for Wholesalers and Retailers of Carbon Products on the Repeal of Provincial Carbon Tax](#)

¹¹⁰ Government of Prince Edward Island, [Carbon Levy on Fossil Fuels](#) and [Rates of Carbon Levy on Fossil Fuels for 2020 to 2022](#)

¹¹¹ Ibid.

¹¹² Government of Prince Edward Island, [Carbon Levy on Fossil Fuels](#)

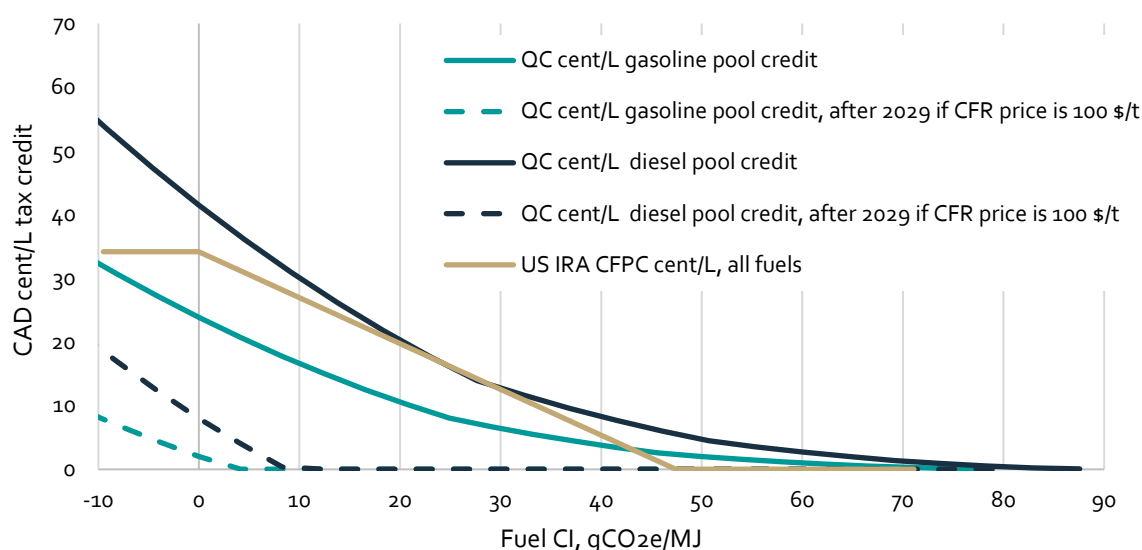
¹¹³ NRCAN, [Fuel Consumption Levies in Canada](#)

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

The Biofuel Production Incentive is available in Canada in the 2026 and 2027 calendar years, with \$372 million in federal support for domestic biodiesel and renewable diesel producers (described in section 2.4). The funding is available on a per-litre basis, for up to 300 ML produced (16¢/L for the first 170 ML and 10 ¢/L for the next 130 ML).

In 2023, Québec introduced a new tax credit design to support biofuel production in that province.¹¹⁴ 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 gCO₂e/MJ, Figure 33). The gross tax credit for ethanol would likely fall between 5-15 ¢/L (CI 15 to 40 gCO₂e/MJ, Figure 33). This tax credit is allowed to stack with the value of CFR credits generated by that fuel until the end of 2029, consistent with the end date of the US tax credit described below.¹¹⁵ After 2029 the actual tax credit is net of other policy support earned by that fuel. If a fuel earns \$100/tCO₂e per CFR credit it generates, the net tax credit is zero unless the fuel's CI is less than about 5 gCO₂e/MJ (Figure 33, post-2029 QC trend lines with a CFR price of \$100/tCO₂e).

Figure 33: Production tax credit for low-carbon fuels produced and consumed in Québec versus the US production tax credit



¹¹⁴ 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](#)

¹¹⁵ Finances Québec (2026). [Information Bulletin 2026-5, Adjustments to certain fiscal measures.](#)

The US Clean Fuels Production Credit (CFPC, also known as 45Z) 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. The CFPC initially provided a bonus incentive rate for low-carbon aviation fuels of about 1.75x the base rate given to gasoline and diesel substitutes.¹¹⁶ The CFPC came into force in January 2025 and replaced the biomass-based diesel blenders tax credit (which provided a \$1/gallon (USD) incentive for biomass-based fuels blended with diesel in the US). The CFPC was initially scheduled to end December 31, 2027, but that has been extended until the end of 2029 under the One Big Beautiful Bill Act 2025 (OBBBA). Furthermore, the OBBBA removed ILUC emissions from the CI calculation, so the production tax credit rates increased towards the higher rather than lower end of the range. It also eliminated the multiplier for aviation fuel.¹¹⁷

Until the federal announcement of the Biofuel Production Incentive in September, 2025, there have been no producer credits available in Canada since the ecoEnergy for Biofuels (ecoEBF) program expired in 2017 and the Alberta Bioenergy Producer Program expired in March 2020. The ecoEBF 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.¹¹⁸ The Alberta 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).¹¹⁹

Low-Carbon Fuel Standards

British Columbia Low-Carbon Fuel Standard

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.^{120,121} At the end of 2023, the original legislation was replaced with the *Low Carbon Fuels Act* and the *Low Carbon Fuels*

¹¹⁶ H.R. 5376 – 117th Congress: [Inflation Reduction Act of 2022](#)

¹¹⁷ H.R.1 – 119th Congress (2025-2026): [One Big Beautiful Bill Act](#)

¹¹⁸ Government of Canada, [ecoEnergy for Biofuels Program](#). Formerly available at <https://natural-resources.canada.ca/energy/alternative-fuels/programs/ecoenergy-biofuels/3591>

¹¹⁹ Government of Alberta, 2017, [Bioenergy Producer Program Outline](#)

¹²⁰ Government of British Columbia, 2023, [Low Carbon Fuels \(General\) Regulation](#).

¹²¹ Government of British Columbia, BC Reg. 394/2008, [RENEWABLE AND LOW CARBON FUEL REQUIREMENTS REGULATION](#)

(General) Regulation and Low Carbon Fuels (Technical) Regulation, which now includes a CI and blend requirement for jet fuel and cover fuels consumed by port and airport equipment as well as forklifts.¹²² The current CI reduction requirement for each fuel pool is in Table 19.

Table 19: 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 8% 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 renewable 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 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. However, an electric utility is considered a supplier for residential charging at buildings with fewer than five dwelling units, and for TransLink train and trolley routes operating before December 31, 2021¹²³.

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 \$/tCO₂e for a compliance shortfall¹²⁴, up from 200 \$/tCO₂e prior to 2023. As of the end of July 2026, the average credit price was

¹²² Referring to the [Low Carbon Fuels Act](#), the [Low Carbon Fuels \(General\) Regulation](#), and the [Low Carbon Fuels \(Technical\) Regulation](#), which replace both the *Greenhouse Gas Reduction (Renewable & Low Carbon Fuel Requirements) Act* and the *Renewable & Low Carbon Fuel Requirements Regulation*.

¹²³ British Columbia Ministry of Energy and Climate Solutions, 2026, Electricity Supply and Reporting Requirements

¹²⁴ Government of British Columbia, 2023, [Low Carbon Fuels \(General\) Regulation](#).

\$136/tCO_{2e}, down from a peak of about \$500/tCO_{2e} in 2024¹²⁵, with the decline owing in large part to the overlap with the CFR credit (i.e. a lower BC LCFS credit price is needed to bridge the price gap between diesel and renewable diesel, the marginal compliance action in that policy).

The legislation governing the BC LCFS allowed 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”.¹²⁶ Under the new *Low Carbon Fuels Act*, these agreements are now referred to as “Initiative Agreements”.¹²⁷ 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 low-carbon fuel). The allowable volume of credits for Initiative Agreements is up to 25% of the sum of all debits in the previous compliance period. Credits granted under an Initiative Agreement are interchangeable with credits produced via blending low-carbon fuels (i.e., credits granted via Initiative Agreements reduce the volume of renewable fuel needed to achieve compliance with the policy).

A description of projects that have been awarded Initiative Agreements and the associated volume of credits is published by the B.C. Government in Information Bulletin RLCF-014.¹²⁸ Currently the most recent projects date from the 2025 program year. From 2014 to 2025, 48 projects have been allocated 4.2 million LCFS credits (equal to about 17% of debits from 2024 and earlier).

About 57% of the total credits have been awarded to projects involved in co-processing and the production of biocrude and renewable diesel. Another 14% 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 development of hydrogen refuelling infrastructure, the production of sustainable aviation fuel, the electrification of other transportation modes (e.g., heavy-duty, marine), and the deployment of refuelling infrastructure capable of supplying higher biofuel blends (e.g., B20) (Figure 34).

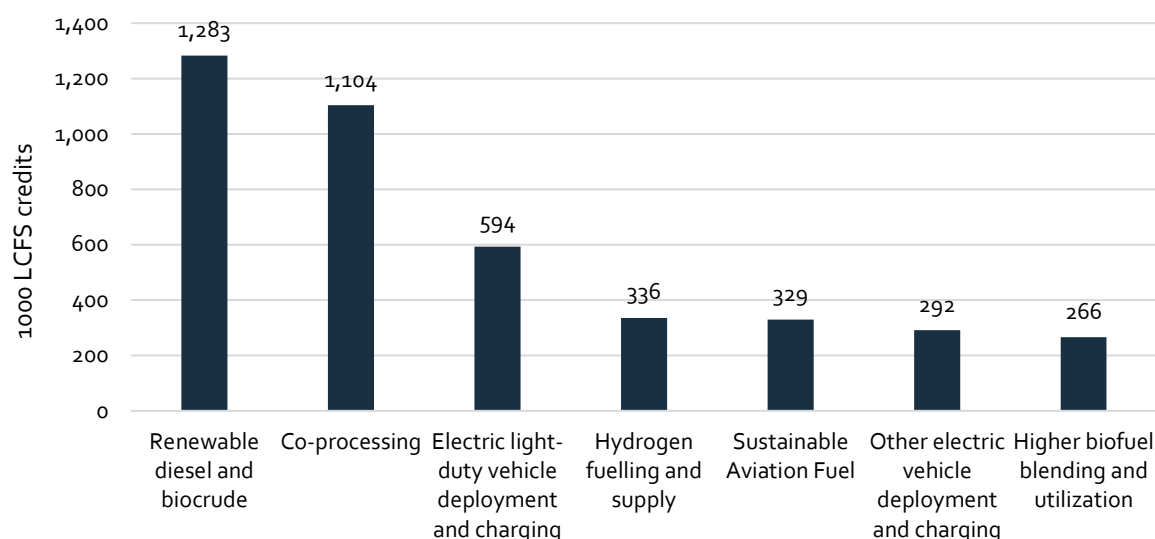
¹²⁵ Government of British Columbia, [LCFS Credit Market Data](#).

¹²⁶ *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*, RSBC 2008, c. 16, s. 8.01

¹²⁷ Bill 15, *Low Carbon Fuels Act*, 3rd Session., 42nd Parliament, British Columbia, 2022

¹²⁸ Government of British Columbia, 2025, [Information Bulletin RLCF-014: Projects supported under Initiative Agreements](#).

Figure 34: LCFS credits issued under Part 3 Agreements, 2014-2025



The Clean Fuel Regulations

The Canadian federal government implemented 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 these were set aside in December 2020.

The final version of the CFR was released in June 2022. The first compliance period with CI limits for gasoline and diesel was July 1st, 2023, to December 31st, 2023. The regulated CI target for gasoline and diesel fuels in 2030 is 81 gCO₂e/MJ for gasoline and 79 gCO₂e/MJ for diesel, 14 gCO₂e/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 gCO₂e/MJ. The emissions intensity limit is lowered by 1.5 gCO₂e/MJ annually until the target is reached in 2030.¹²⁹

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 (i.e., unused RFR credit balances) were automatically rolled over into CFR credits for use starting in 2023. Credit generation from the RFR to the CFR was based on a default CI and energy density for renewable fuels in gasoline and

¹²⁹ Government of Canada, 2022, [Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations](#)

diesel (i.e., as if the fuels blended under the RFR were ethanol and biodiesel with CI scores of 59 gCO₂e/MJ and 35 gCO₂e/MJ, respectively).

Notably, in the period from the date of CFR publication (June 21, 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 had 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’ credits could be double counted, creating an additional incentive to blend biofuels in the second half of 2022.

Table 20 summarizes credit and debit generation during 2022, 2023 and onward related to fuel supply (credits may be generated in other ways, described below). In 2023, suppliers of gasoline and diesel 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 20: 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 onward
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 as of June 21st

Like the British Columbian and other US state-level LCFS policies, credits can be generated by blending renewable and low-carbon fuels into petroleum fuels (i.e., CFR “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 is calculated using a specific lifecycle assessment modelling tool built for the CFR.¹³⁰

¹³⁰ See [The Fuel Life Cycle Assessment Model](#)

Credits can also be generated by switching transportation energy consumption to other low-carbon alternatives including renewable natural gas, electricity, and hydrogen (i.e., CFR “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., CFR “compliance category 2 and 3”) can both generate and trade compliance credits. The credits generated 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, including refining of co-processed low-carbon-intensity fuels (i.e., CFR “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. Category 1 credits are tradeable, just like category 2 and 3 credits.

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} (in 2023, plus an inflation factor thereafter) by contributing to an abatement or technology fund (called ‘Emissions Reduction Funding Programs’).¹³¹ 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.

¹³¹ Environment and Climate Change Canada, 2025, [Compliance with the Clean Fuel Regulations](#)

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

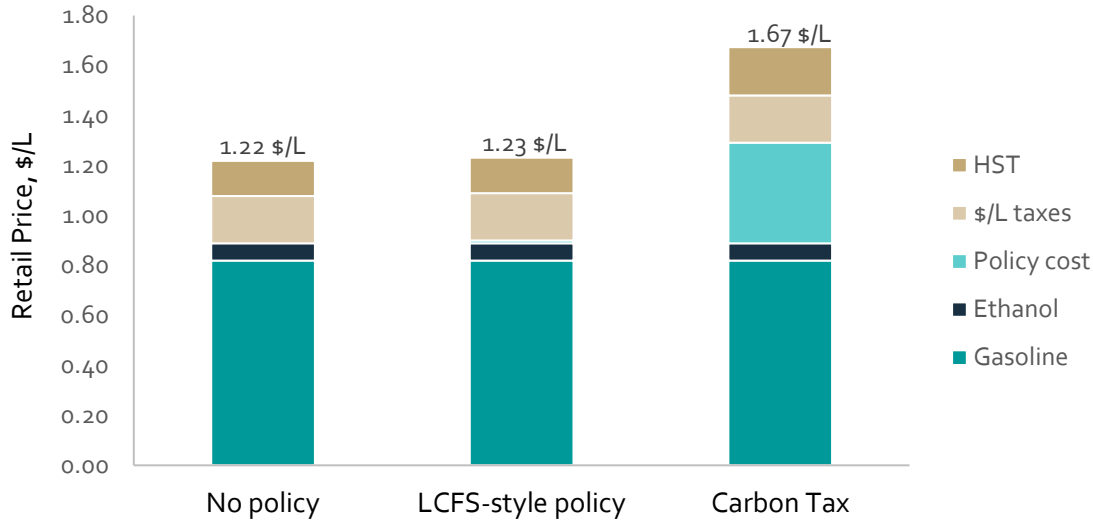
LCFS-style policies create a market-based incentive to supply low-carbon fuels because this action generates compliance credits which can be sold in their associated market or utilized to meet compliance obligations. The price of credits will rise until it is high enough to incentivize fuel suppliers 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 each 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 2025 and gasoline containing 10% ethanol by volume (E10), a hypothetical LCFS policy with a credit price of 177 \$/tCO_{2e} (2025 CFR average) and the same CI limit as the CFR in 2025 (88.5 gCO_{2e}/MJ) would result in an E10 price of 1.23 \$/L versus 1.22 \$/L without an LCFS. The net retail-price impact is less than 2 ¢/L. In contrast, a hypothetical carbon tax of 177 \$/tCO_{2e} would result in an E10 price of 1.67 \$/L (Figure 35), with a net price impact of 45.5 ¢/L (40.3 ¢/L carbon tax and 5.2 ¢/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.

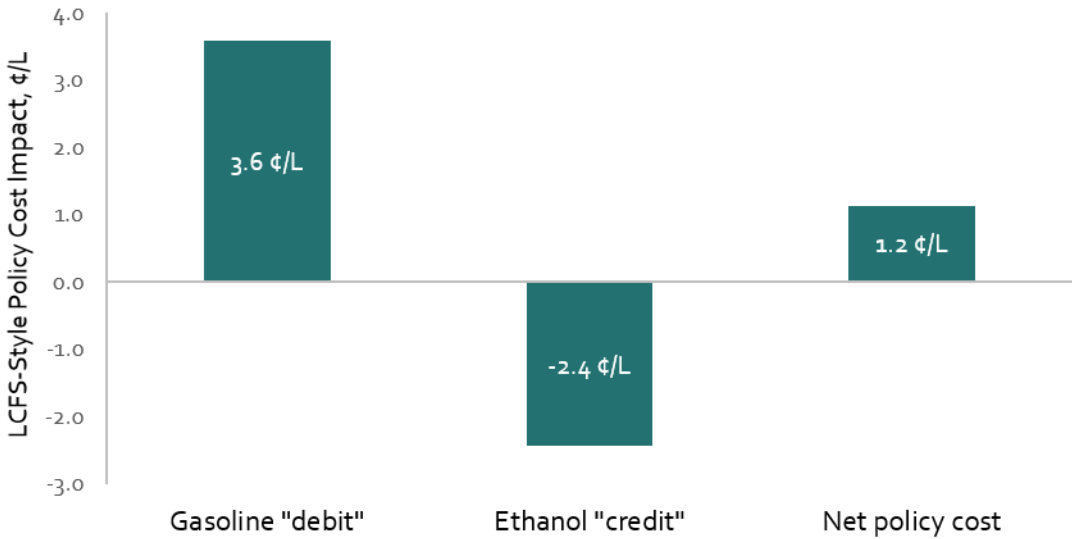
Figure 35: Impact of an LCFS-style policy vs. carbon tax on E10 retail prices in Ontario in 2023, LCFS credit price is equal to the carbon tax \$/tonne CO₂e value (\$150 t/CO₂e)



Note: wholesale fuel costs and fuel taxes are based on Ontario in 2025. LCFS credit price and carbon tax are 177 \$/tonne (2025 average price). In the example, the gasoline CI is 95 gCO₂e/MJ (baseline value in the CFR), the ethanol CI is 30 gCO₂e/MJ, and the LCFS-style policy target CI is 88.5 gCO₂e/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 gCO₂e/MJ and the target for 2025 is 6.5 gCO₂e/MJ lower, the “fee” on the gasoline component in that year would be 3.6 ¢/L on E10 when the compliance credit price is 177 \$/tCO₂e. The ethanol component of the E10 would earn a “rebate” of 2.4 ¢/L of E10, when the CI of ethanol is 30 gCO₂e/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 1.2 ¢/L (Figure 36) plus another 0.2 ¢/L from increased sales tax.

Figure 36: Breakdown of an LCFS-style policy’s cost impact on E10 retail price with a hypothetical \$177/tCO₂e credit price



Note: LCFS credit price and carbon tax are 177 \$/tonne (2025 average price). In the example, the gasoline CI is 95 gCO₂e/MJ (baseline value in the CFR), the ethanol CI is 30 gCO₂e/MJ, and the LCFS-style policy target CI is 88.5 gCO₂e/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, the majority of credits were self-generated by fuel providers when blending lower-carbon fuels. Over the past five complete compliance years (from 2021 through 2025), traded credits have accounted for between 17% and 28% of total credit generation.¹³²

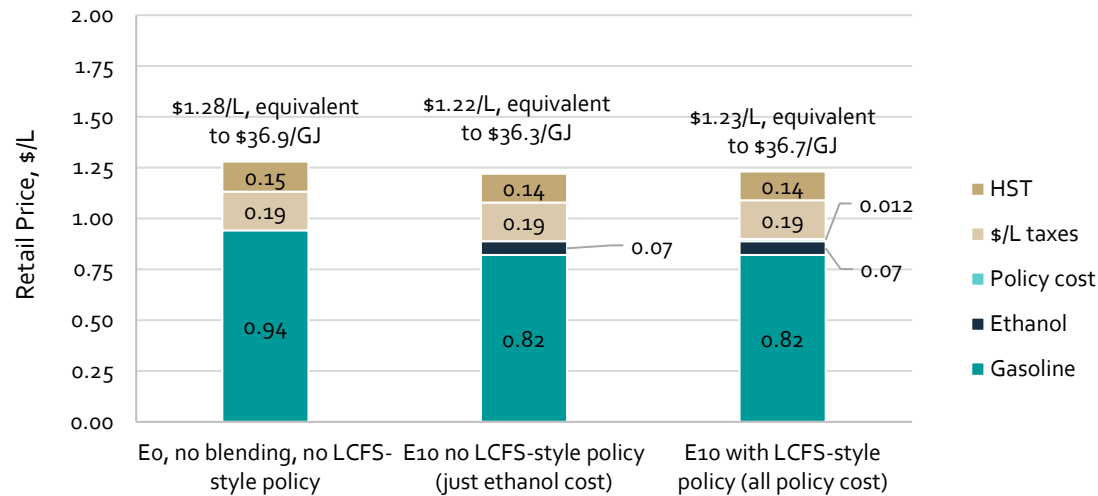
The previous Ontario example shows that the average abatement cost of renewable fuel blending and the credit price are not the same. A comparison of some hypothetical fuel prices reinforces this point. For E10 sold in this example, the abatement cost perceived by a consumer resulting from ethanol blending is negative \$92/tCO₂e (i.e., consumer savings - accounting for both the lower cost per litre and lower energy density of E10). Therefore, blending to E10 resulted in a savings (compare the “E0, no policy” vs. “E10, just ethanol” costs in

¹³² Government of British Columbia, 2026, RLCF-007-2025 Renewable and Low Carbon Fuel Requirements Regulation Summary for 2010 – 2025

Government of British Columbia, 2026, BC-LCFS Credit Market Data (2015 to present)

Figure 37). If that E10 were also subject to the 2025 CFR CI limit, hypothetically resulting in a credit price of \$177/tCO₂e (the average 2025 credit price), the cost of E10 would increase by about 1.2 ¢/L since some credit purchases would be required for compliance (see the “E10, all policy” cost in Figure 37). The resulting average abatement cost of using E10 in this example is still negative and well below the marginal credit price.

Figure 37: 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 \$177/tCO₂e (2025 CFR average). The gasoline CI is 95 gCO₂e/MJ, the ethanol CI is 30 gCO₂e/MJ, and the LCFS target CI is 88.5 gCO₂e/MJ. Gasoline without ethanol must be produced with a higher octane and is more expensive than the gasoline blendstock used with ethanol (i.e., \$0.94/L vs. \$0.91/L, or a gasoline cost of \$0.89/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 1.6% savings on a per GJ basis even though the cost per volume is 5.7% less than E0 (this energy density difference is accounted for in the abatement costs). Consistent with the cost-impact methodology used 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 are 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 \$177/tCO₂e has a much higher retail price impact than a LCFS credit price of \$177/tCO₂e.

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 actual 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 perfect information on CFR compliance costs, energy regulators in Atlantic Canada currently make the following adjustments to the maximum fuel prices (as of August 2026):

- **PEI:** PEI has no adjustment. In December 2023, the PEI Island Regulatory & Appeal Commission ruled that the cost of the CFR was already passed into PEI via its rack prices.¹³³ The regulated retail prices in PEI are based on the competitively determined Charlottetown rack prices. Consequently, the CFR cost is embedded in those wholesale prices, and no further adjustment is allowed.
- **Newfoundland and Labrador:** The maximum price of gasoline and diesel was increased by 10.5 ¢/L for gasoline and 11 ¢/L for diesel, where those values may be changed periodically based on information provided to the Board of Commissioners of Public Utilities by fuel suppliers.¹³⁴
- **Nova Scotia:** As of June 2026, the Nova Scotia Energy Board (NSEB) issued an interim order to increase the CFR adjustors while reviewing its methodology for defining those adjustors, citing a potential emergency situation where fuel supply could be disrupted as a consequence of regulated prices that are too low. During that review, the values are set

¹³³ Prince Edward Island Regulatory & Appeals Commission, 2023, <https://irac.pe.ca/wp-content/uploads/PC23-007.pdf>

¹³⁴ Newfoundland and Labrador Board of Commissioners of Public Utilities, 2026, An Order of the Board [NO. P.P. 80\(2026\)](#) and [NO. P.P. 99\(2026\)](#)

to 11.66 ¢/L for gasoline and 12.99 ¢/L for diesel¹³⁵, up from 9.04 ¢/L and 10.07 ¢/L, respectively.

- **New Brunswick:** The adjustment to the maximum prices is based on the Argus daily estimate of CFR costs, which is reported in CAD ¢/L.¹³⁶ The Argus costs are a function of the required CI reduction and the CFR credit price.¹³⁷ Therefore, the adjustment is based on the assumption that the marginal compliance cost (i.e., most expensive compliance action: purchasing a credit from the market) is equal to the average compliance cost experienced by an obligated party. Using this method, the adjustments in New Brunswick for August would be:
 - 8.3 CAD ¢/L for gasoline and 9.3 CAD ¢/L for diesel, if the Argus method uses a credit price comparable to the average CFR credit price reported by ECCC for August 2026 (\$300/tCO_{2e}).
 - 12.7 CAD ¢/L for gasoline and 14.1 CAD ¢/L for diesel, if the Argus method uses a credit price comparable to the maximum CFR credit price reported by ECCC for August 2026 (\$456/tCO_{2e}).¹³⁸

The regulated fuel price adjustments used by Newfoundland and Labrador and Nova Scotia are similar to those calculated for New Brunswick above, suggesting that all three jurisdictions try to account for the cost of CFR compliance based on the marginal abatement cost, as represented with the compliance credit price.

It is very likely that fuel suppliers to these provinces are being overcompensated for their CFR costs, especially for their compliance obligation resulting from gasoline supply. Much of the CFR compliance in the gasoline pools is generated with ethanol blending. Ethanol blending will reduce blended gasoline supply costs on a per-litre basis because:

- Ethanol is much cheaper than pure gasoline blendstock
- Ethanol avoids the use of higher cost octane boosters
- Ethanol reduces the average CI of the blended fuel, which reduces any additional CFR compliance costs associated with that fuel.

¹³⁵ Nova Scotia Energy Board, 2026, [Schedule A. Prices Prescribed for Petroleum Products under the Petroleum Products Pricing Act and the Petroleum Products Pricing Regulations](#)

¹³⁶ New Brunswick Energy & Utilities Board, 2026, a Review as a Consequence of the Repeal of the Cost of Carbon Adjustor from the Petroleum Products Pricing Act.

¹³⁷ Argus, 2026, [Argus Air Daily: Methodology and Specifications Guide](#)

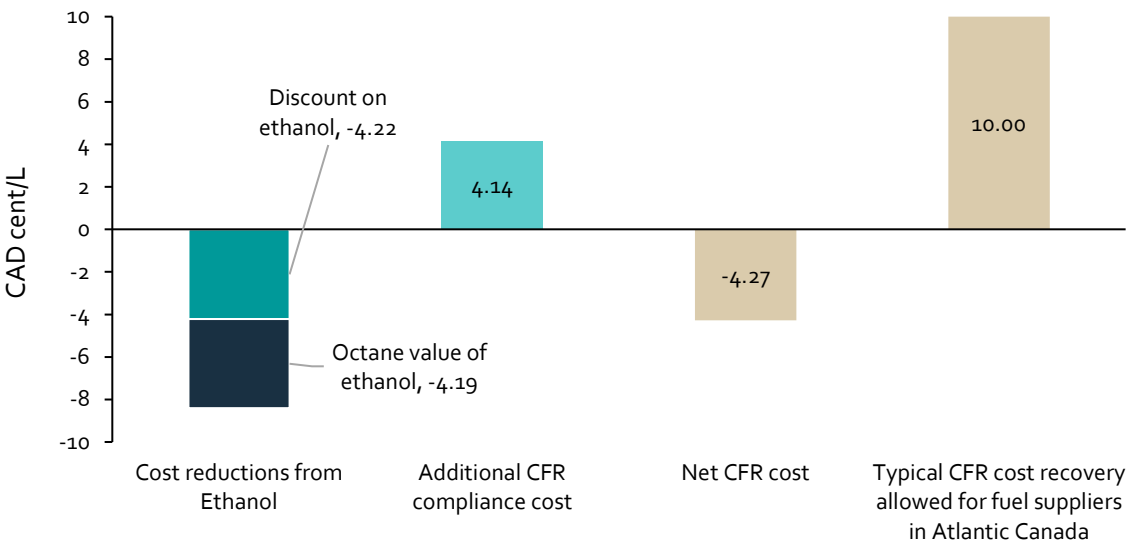
¹³⁸ Environment and Climate Change Canada, 2026, [CFR Compliance Credit Market Dataset \(Monthly and Quarterly](#)

An example for E10 in August 2026 illustrates this reality (Figure 38). A 10% ethanol blend will:

- Reduce the cost of the blended fuel, relative to pure gasoline by 4.2 ¢/L due to the volumetric price discount of ethanol versus gasoline blendstock.
- Avoid an additional 4.2 ¢/L by substituting for more expensive octane boosters (e.g., benzene, toluene, Xylene).
- Have an additional CFR compliance cost of just 4.1 ¢/L, if that additional compliance were achieved by purchasing CFR credits at the average August price (\$300/tCO₂e).

The net CFR compliance cost for E10, relative to using pure gasoline is -4.3 ¢/L. Fuel suppliers in Atlantic Canada are allowed to charge consumers 13 to 16 ¢/L more than this as compensation for the CFR. Granted, ethanol supply requires investment in blending infrastructure. However, this infrastructure exists in Atlantic Canada. Irving Oil states that it can blend up to 10% ethanol in its product from the Saint John Refinery¹³⁹ and up to 15% ethanol at its Halifax terminal.¹⁴⁰

Figure 38: Example of per litre CFR costs for E10 (relative to pure gasoline) in comparison with CFR cost adjustments on regulated fuel prices in Atlantic Canada



This example is based on a 10%_{vol} ethanol blend using the CME price for ethanol and New York Harbor price for gasoline blendstock in August 2026 (average of 0.75 and 1.17 CAD/L respectively). The net CFR cost is based on a CI of 39.6 gCO₂e/MJ for ethanol (the average for Q3 2025 in the CFR market), the 2026 CFR CI reduction requirement (-8 gCO₂e/MJ relative to the constant gasoline CI of 95 gCO₂e/MJ) and a CFR credit price of \$300/tCO₂.

¹³⁹ Irving Oil, 2020, [Report on Sustainability](#)

¹⁴⁰ Irving Oil, 2022, [Report on Sustainability](#)

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 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, supplied by another firm, 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/tCO₂e 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 2025 in the Biofuels in Canada analysis are representative of future conditions (using Canada fuel-weighted averages): biodiesel costs \$1.46/L with a \$0.06/L transportation cost, has a CI of 12.2 gCO₂e/MJ and a density of 35.4 MJ/L; wholesale diesel (B0) sells for \$1.07/L with a CI of 92.4 gCO₂e/MJ, and a density of 38.7 MJ/L. The refining margin (net revenue) is \$0.54/L.¹⁴¹
- 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 \$194/tCO₂e. 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.

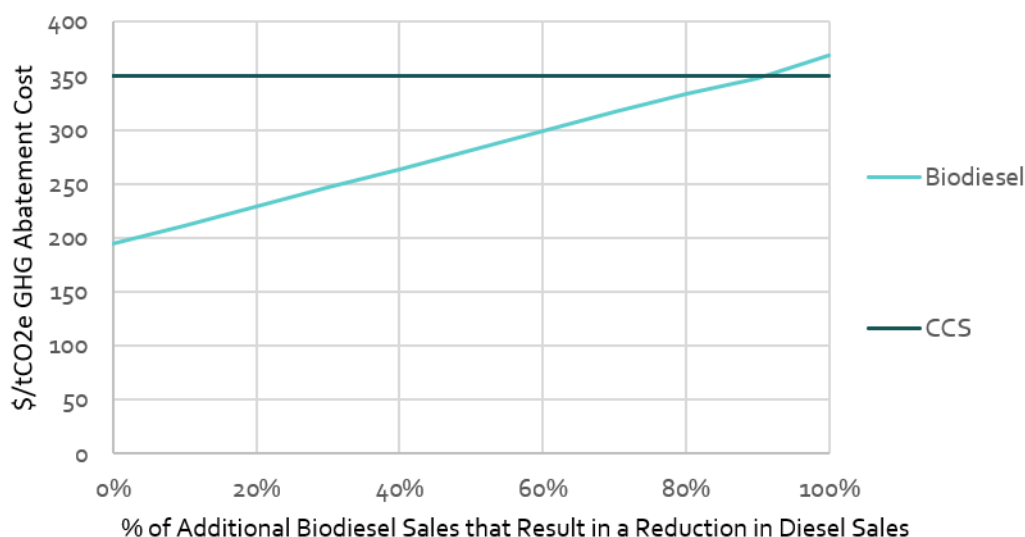
However, if selling more biodiesel reduces diesel sales and results in a foregone refining margin, then the fuel provider loses \$0.54 for each litre of diesel not sold. To reduce GHG emissions by one tonne, the fuel provider would have to blend 12.5 GJ of biodiesel,

¹⁴¹ Kalibrate, <https://charting.kalibrate.com/>

equivalent to 322 L of diesel. If the biodiesel sales completely displace an energetically equivalent amount of diesel, then there is \$174 in foregone refining margin per tonne of GHG reduction and the net abatement cost is \$368/tonne, greater than the assumed credit price in this example. In this case, the fuel provider would only choose to abate emissions with CCS and would not blend more biodiesel since its abatement cost is greater than the credit price.

It is likely that the impact of additional biodiesel blending on diesel sales is somewhere between the maximum and minimum cases explained above. Nonetheless, the abatement cost of biodiesel in this example is sensitive to its impact on diesel sales. If about 90% or more of the additional biodiesel sales offset an energetically equivalent amount of diesel sales, CCS is the lower cost abatement action (Figure 39).

Figure 39: Relative abatement cost of blending biodiesel versus capturing and storing CO₂e as a function of how biodiesel sales affect diesel sales.



The choice of abatement actions 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.
- Economies of scale (i.e., it costs less per litre to refine greater volumes).
- Perceived risk of policy repeal and capital constraints, where the biodiesel is a one-time purchase, but the investment required for CCS would need to be amortized over a long period.
- Policy overlap, where the installation of CCS could also generate compliance credits within industrial carbon pricing policies and could be eligible for investment tax credits.

- Expectations for the spread between renewable and fossil fuel prices as well as refining margins.

Nonetheless, this example illustrates 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.

Appendix B: Summary and Discussion of Inputs to the Analysis

Table 21 summarizes the data and assumptions used in this analysis. The data were 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 (v4.03 for values to 2023, switching to v5.02c for 2024 onward).

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, the Atlantic provinces do not report the volume of biofuels blended into transportation fuels. This was also the case for Québec prior to 2021. In these situations, we use the difference between fuel volumes reported by provincial regulators and national consumption totals, reported by ECCC for 2011-2024^{142,143,144,145} to infer the volume of ethanol, biodiesel, and RD consumed in Atlantic Canada and Québec (prior to data availability). The resulting biofuel consumption estimated 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 are collected using different methodologies.

Although national data provided by ECCC defines total renewable fuel consumption in most years, there are some exceptions, where these data were used as a guideline. 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 are 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

¹⁴²Environment and Climate Change Canada, 2016, Renewable Fuels Regulation Report: December 15, 2010 to December 31, 2012. [Available on Google Drive](#).

¹⁴³Environment and Climate Change Canada, 2022, Open Data: Renewable Fuels Regulations 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021 and 2022. [Available on Google Drive](#).

¹⁴⁴Environment and Climate Change Canada, 2024, [Clean Fuel Regulations credit market report, June 2024](#)

¹⁴⁵Environment and Climate Change Canada, 2025, Clean Fuel Regulations Quarterly Credit Market Report – Q1 to Q4

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 uncertain. Trade data indicate that, as of 2024 and possibly 2025, 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 4% 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 these data are 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, prior to 2024, the government of Ontario indicated approximately how much biodiesel versus RD is consumed in that province (e.g. about 50/50 in some years, or "much more RD than biodiesel" other years). 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, 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 gCO₂e/MJ relative to the value from GHGenius v4.03a, 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 CO₂ in the atmosphere. For example, ECCC uses a combustion GHG coefficient of 67 to 71 gCO₂e/MJ for light-duty vehicles operating under tier 1 and tier 2 emissions standards,¹⁴⁶ whereas GHGenius 4.03a uses 63 gCO₂e/MJ. Our adjusted value falls in the middle of ECCC's emission factors at 70 gCO₂e/MJ. The gasoline CIs taken from GHGenius v5.02c already account for these emissions and are not adjusted.

¹⁴⁶ Environment and Climate Change Canada, 2019, National Inventory Report 2019, Emissions Factors Table A6-12

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

	BC	Alberta	Saskatchewan	Manitoba	Ontario	Québec	Atlantic
Gasoline volume	RLCFRR Summary: 2010-2025. Gasoline and diesel volumes are the total, not the non-exempt volume. Co-processed fuel volumes based on RLCFRR Summary: 2010-2023. Co-processed fuel supply has not been explicitly reported since 2023. For 2024 onward, we assume that all renewable gasoline and naphtha are co-processed and that co-processed renewable diesel was a constant proportion of the total co-processed volume (roughly 20%).	2011-2025: From govt. contact. For 2010 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	To 2020 - Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy. From 2020 - government data.	Data from govt. contact to 2019, estimated for 2020 onward	Data from govt. contact to 2024	Based on GHG data from 2013 to 2022. Based on RCFIC data for 2023 and 2024. Prior to 2013, based on Statistics Canada Table: 25-10-0030-01.	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy
Ethanol fuel volume		Data from govt. contact	Average % blending rate to 2025 provided by govt. contact			Difference between national total reported under the RFS and CFR by ECCC ³ and sum from other provinces, allocated to QC and Atlantic CDA (to 2020). Based on GHG data from 2021 to 2022. Based on RCFIC data for 2023 and 2024.	Difference between national total reported under the RFS and CFR by ECCC ³ and sum from other provinces, allocated to QC and Atlantic CDA
Diesel volume		2011-2025: From govt. contact. For 2010: Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy	Data through to 2025 from govt. contact		2018-2024: data from govt. contact. 2010 to 2017 Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy.	Same method as for gasoline volume	Statistics Canada Table: 25-10-0030-01: Supply and demand of primary and secondary energy, diesel fuel oil
Biodiesel and RD volume		Data to 2025 from govt. contact	Data from govt. contact		Data for 2018-2024 from Gov't. Provisional data from govt. contact for 2015. Estimates for 2016 and 2017.	Same as the method used for ethanol volume	Same method as for ethanol
Jet Fuel Volume		Statistics Canada Table: 25-10-0030-01	Statistics Canada Table: 25-10-0030-01	Statistics Canada Table: 25-10-0030-01	Statistics Canada Table: 25-10-0030-01	Statistics Canada Table: 25-10-0030-01	Statistics Canada Table: 25-10-0030-01
SAF Volume		n/a	n/a	n/a	n/a	n/a	n/a
Co-proc. volumes		n/a	n/a	n/a	n/a	n/a	n/a

Biofuel feedstock		Informed by government data for 2023 and 2024. Other years are informed by the breakdown in those data.	Assumptions reviewed by govt. contacts and (S&T) ² Consultants				
Fuel Carbon Intensity		GHGenius 4.03a by year for Alberta to 2023, v5.02c for 2024 onward.	GHGenius 4.03a by year for Saskatchewan to 2023, v5.02c for 2024 onward.	GHGenius 4.03a by year for Manitoba to 2023, v5.02c for 2024 onward.	Ethanol: GHGenius 4.03a by year for Ontario for 2010-2019, data from govt. contact for 2020 onward. Biodiesel/RD: avg. from govt. contact for 2015 and 2018-onward, estimated for 2010-2013, 2016 and 2017	GHGenius 4.03a by year for Québec to 2023, v5.02c for 2024 onward.	GHGenius 4.03a by year for Canada East to 2023, v5.02c for 2024 onward.
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						

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	8-12\$/bbl (in 2025), 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 inferred from the difference in the bulk price of regular and premium gasoline in the United States to April 2022. After that date, the octane value is inferred from BTX prices. 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 2011-2025 (Table: 20-10-0021-01). PEV stocks are from Statistics Canada for 2011-2024 (Table: 23-10-0308-01), while the 2025 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 0.19 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, 2024 and 2025 Q1 to Q3 (and for all of 2025 in a figure within a public presentation). 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 & US Grains Council Ethanol Market and Data Reports, available at https://grains.org/ethanol_report/,

- 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 Québec. 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, 2025, Rail Trends 2024. <https://www.railcan.ca/resources/annual-rail-trends/>

Appendix C: Biofuel Type and Feedstock Assumptions and Data

Data were collected on the volume of renewable fuels blended into gasoline and diesel — characterized as ethanol, biodiesel, or RD. 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 were obtained from personal correspondences with government contacts or obtained from various publications. However, data for every region and every fuel were 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. The resulting national fuel consumption by fuel-type and feedstock is reported in the figures at the end of this section.

Assumptions for British Columbia

Feedstock data were obtained from the government of British Columbia.¹⁴⁷ The data are generally used “as-is” with little need for assumptions or interpretation:

1. In some years, there are minor summation errors in the data published by the BC government. We used an "Unknown" feedstock category to make the total fuel volume from individual feedstocks equal to the total reported volumes. These values were calculated to fill the gap and are not numbers reported by the BC government.
2. BC reporting does not distinguish between feedstocks used for biodiesel, RD, or SAF; roughly 77 million L of SAF was from Neste in 2025 (assumed 50/50 tallow and yellow grease). We assume the remainder is 50/50 canola/tallow; 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 and 2024, there was a substantial increase in fuel made from canola and we assume some of this is RD.
3. Some minor feedstocks are added to the "other/unknown" categories, e.g. pea starch for ethanol or fatty acid distillates and tall oil for RD.
4. Co-processed fuels are not included in this table. Currently, they are covered in the sheet labelled "Co-processing". Renewable components are included in the blended gasoline and diesel volumes reported on the dashboard. Co-processed fuel supply has not been explicitly

¹⁴⁷ British Columbia Ministry of Energy and Climate Solutions, 2026, [Renewable and Low Carbon Fuel Requirements Regulation Summary: 2010-2025](#)

reported since 2023. For 2024 onward, we assume that all renewable gasoline and naphtha are co-processed and that co-processed renewable diesel was a constant proportion of the total co-processed volume (roughly 20%).

Assumptions for Alberta

1. 2011 to 2025 fuel volumes were collected via personal correspondences with the Alberta government. Gasoline and diesel volumes in these data are unblended volumes.
2. 2010 gasoline and diesel sales by volume were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). We assume no renewable content prior to policy-in force dates in 2011.
3. 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 and 2023-2024 ethanol feedstock data from the government. Ethanol by feedstock in 2025 is based on proportion reported for 2024.
4. 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).
5. 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.
6. RD feedstocks in all years are based on the proportion of fuel by feedstock in BC.
7. Jet fuel sales by volume are from Statistics Canada Table: 25-10-0030-01.

Assumptions for Saskatchewan

1. Ethanol content for 2010-2012 and 2015 to 2025 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 2012-2025 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 were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Note that diesel consumption data from the provincial regulation and Statistics Canada do not align after 2012.
7. Diesel and biodiesel consumption in 2016 is an average of 2015 and 2017 values.
8. Jet fuel sales by volume are from Statistics Canada Table: 25-10-0030-01.

Assumptions for Manitoba

1. All data from 2010-2019, as well as total blended gasoline and diesel volumes from 2020-2025, are 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 Cenovus Energy and from discussion with industry contacts
3. We assume that biodiesel feedstocks are 50/50 canola and soy, based personal correspondence with a government contact
4. We assume there is no 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 2025 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)
7. Jet fuel sales by volume are from Statistics Canada Table: 25-10-0030-01.

Assumptions for Ontario

1. Ethanol volumes to 2024 are based on data provided by the Government of Ontario. The data are 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 since 2022, but volumes are currently assumed to be small and are aggregated with ethanol.
2. Bio-based diesel consumption volumes are based on Government Data for 2014, 2015 and 2019 to 2024. 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 HDRD share interpolated towards the known % in 2015.
4. We assume that ethanol is made from corn.
5. We assume biodiesel is 50% soy-based, while the remaining 50% is sourced equally from tallow and yellow grease, whereas we assume RD 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 and jet fuel volumes in 2024 and 2025 are from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). Gasoline volumes and diesel volumes from 2018 onwards are based on data provided by the Government.
7. Data for 2020 and 2021 are for a two-year compliance period that was created due to complications from COVID-19.
8. For 2021 and 2022, we assume biomass-based diesel is 40% biodiesel and 60% HDRD, based on 100% biodiesel consumption by lake freighters: www.cslships.com/en/media-center/news-events/csl-successfully-completes-worlds-largest-b100-biofuel-tests. For 2023 and thereafter, the blend rate is adjusted to better align total national biodiesel and RD consumption with CFR data.
9. We have assumed that the biomass-based diesel blending rate in Ontario increased somewhat from 2024 to 2025, consistent with national total consumption, with RD accounting for 71% of the resulting volume. We have assumed ethanol blending rates increased somewhat from 2024 to 2025, consistent with national total ethanol consumption.
10. Jet fuel sales by volume are from Statistics Canada Table: 25-10-0030-01.

Assumptions for Québec

1. Gasoline and diesel sales by volume for 2010-2012 and jet fuel sales in 2024 and 2025 were retrieved from Statistics Canada Table: 25-10-0030-01 (formerly CANSIM 128-0017). For 2013 to 2023, volumes are based on GHG emissions and emissions factor reported by the government of Québec from the cap-and-trade data (RSPEDÉ).
2. Ethanol volumes before 2023 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 to 2023. Note that this method results in the sum of provincial ethanol consumption in 2022 being somewhat larger than the total reported by ECCC (4% or about 120 ML). Data for 2023 and 2024 are from RCFIC data

3. Biomass-based diesel volumes before 2023 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. Volumes from 2023 and 2024 are from RCFIC data.
4. We assumed most biodiesel and RD is produced from Tallow, with some soy entering the market towards 2023, based on our understanding of what feedstocks Diamond Green Diesel is using. We assume at least 80% of the biomass-based diesel volume is RD from 2014 onward.
5. 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
6. In 2025e, we assume a slight increase in the ethanol blend rate, consistent with the increase in provincial policy stringency.
7. In 2025e, we assume an increase in the biomass-based diesel blend rate, consistent with the increase in provincial policy stringency and national total renewable diesel and biodiesel consumption.
8. Jet fuel sales by volume are from Statistics Canada Table: 25-10-0030-01.

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 and jet fuel 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. With updated data for Québec, our current estimate is that there is negligible biomass-based diesel blending in Atlantic Canada since 2021.
4. We assume ethanol is from corn and biodiesel is from unknown feedstock to better align with ECCC national feedstock values
5. Jet fuel sales by volume are from Statistics Canada Table: 25-10-0030-01.

Gasoline Pool: Detailed Feedstock Results

Figure 40 shows ethanol feedstocks by year, with their associated avoided GHG emissions. Figure 41 shows the cumulative ethanol feedstocks since 2010 and Figure 42 shows ethanol by feedstock in 2025e. Most ethanol consumed in Canada is produced from corn, with 10-15% produced from wheat.

Figure 40: Ethanol consumption in Canada by fuel type and feedstock

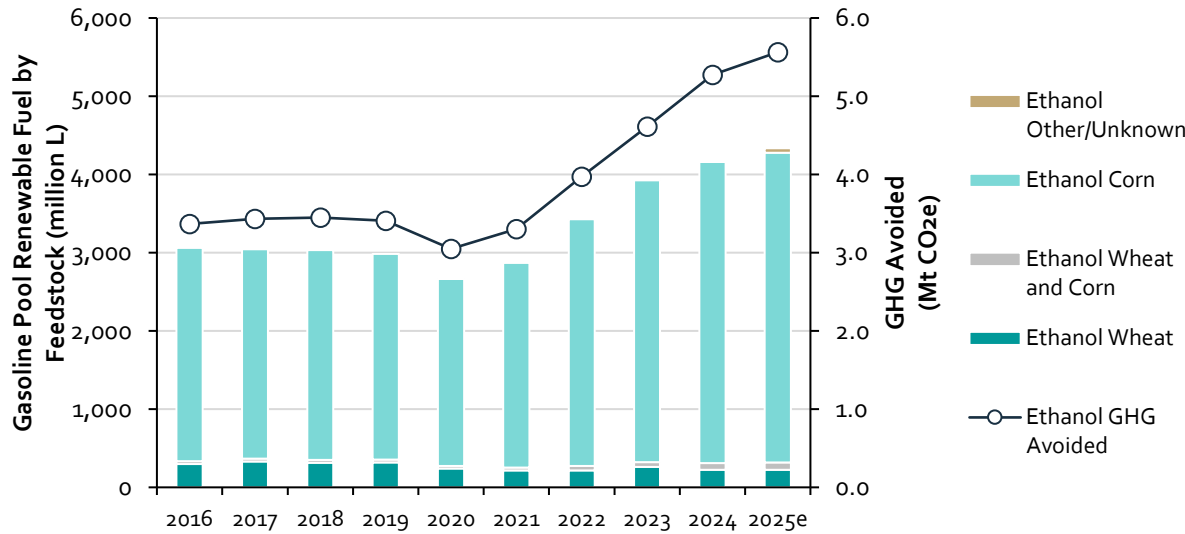


Figure 41: Cumulative ethanol renewable fuel feedstocks

Gasoline pool feedstocks since 2010, million L fuel supplied

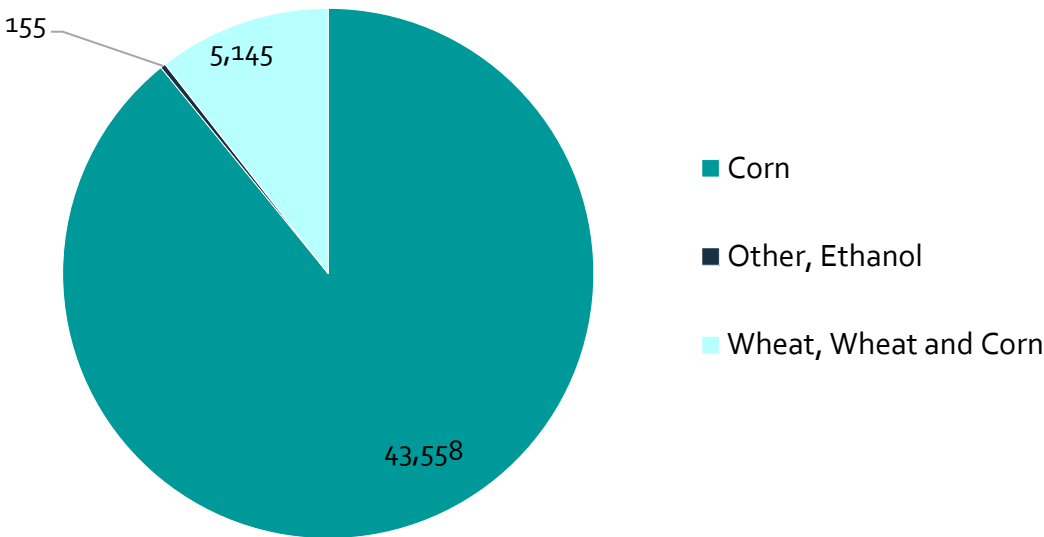
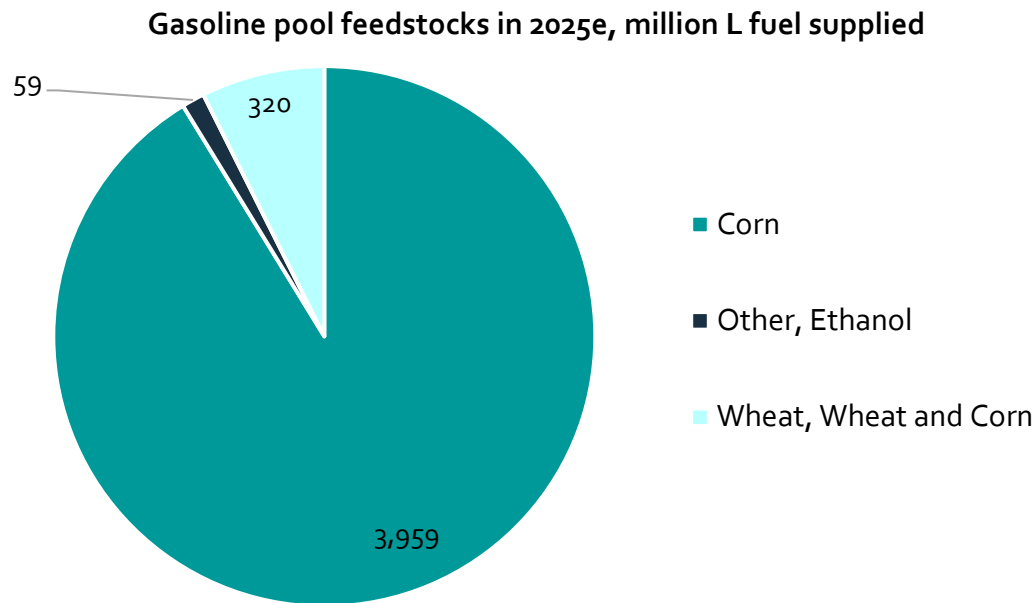


Figure 42: Ethanol fuel feedstocks in 2025



Diesel Pool: Detailed Feedstock Results

Figure 43 shows biomass-based diesel consumption by fuel-type and feedstock by year, with the associated avoided GHG emissions. Figure 44 shows cumulative biomass-based diesel feedstocks since 2010 and Figure 45 shows those feedstocks in 2025. Most biodiesel is produced from canola and soy. Most RD is produced from tallow, yellow grease, and as of 2023, canola.

Figure 43: Biomass-based diesel consumption in Canada by fuel type and feedstock

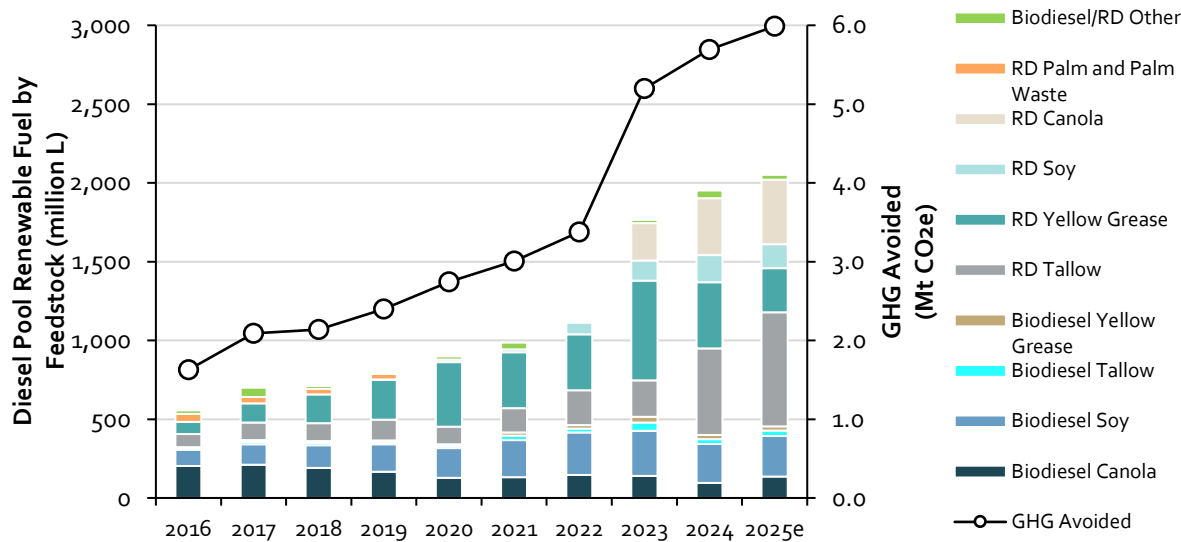


Figure 44: Cumulative biomass-based diesel feedstocks

Diesel pool feedstocks since 2010, million L fuel supplied

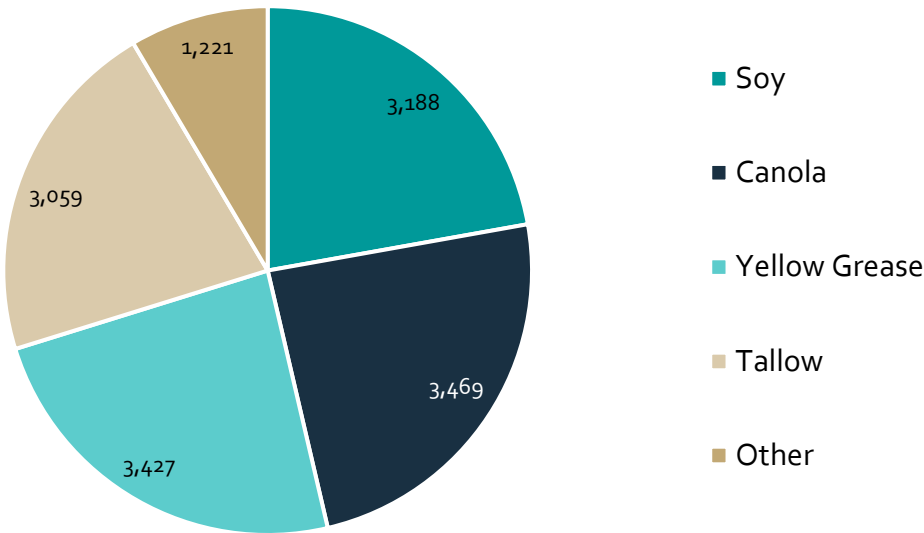
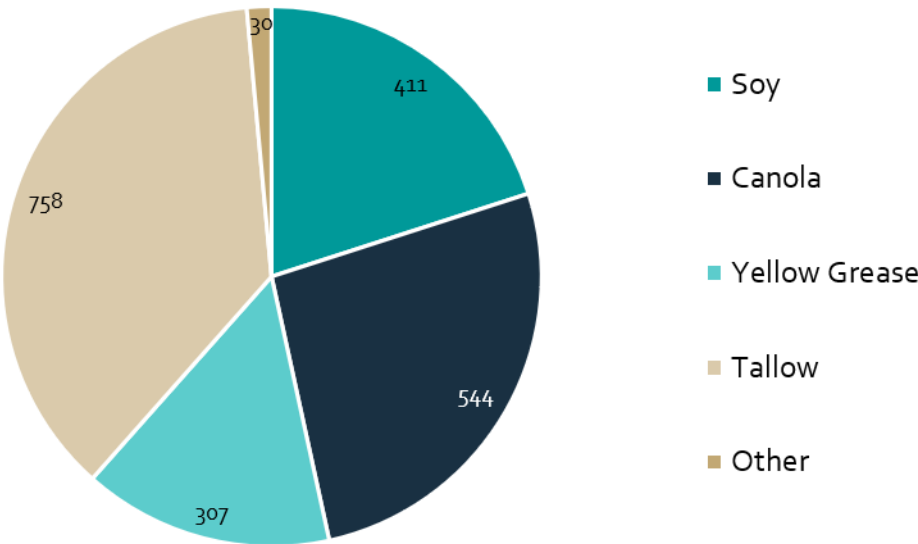


Figure 45: Biomass-based diesel feedstocks in 2025

Diesel pool feedstocks in 2025e, million L fuel supplied



Jet Fuel Pool: Detailed Feedstock Results

Figure 46 shows SAF consumption by fuel-type and feedstock by year, with the associated avoided GHG emissions. Figure 47 shows those feedstocks in 2025. Most SAF consumed in Canada was produced with yellow grease and tallow (from the Neste Singapore refinery), but some of the SAF produced in North America was likely derived from canola.

Figure 46: SAF consumption in Canada by feedstock

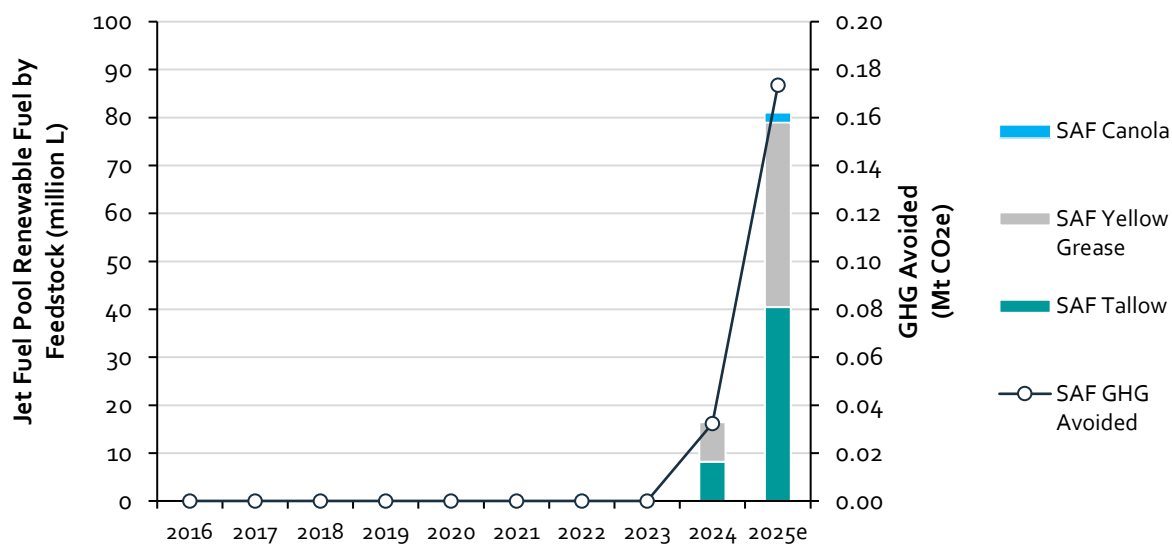
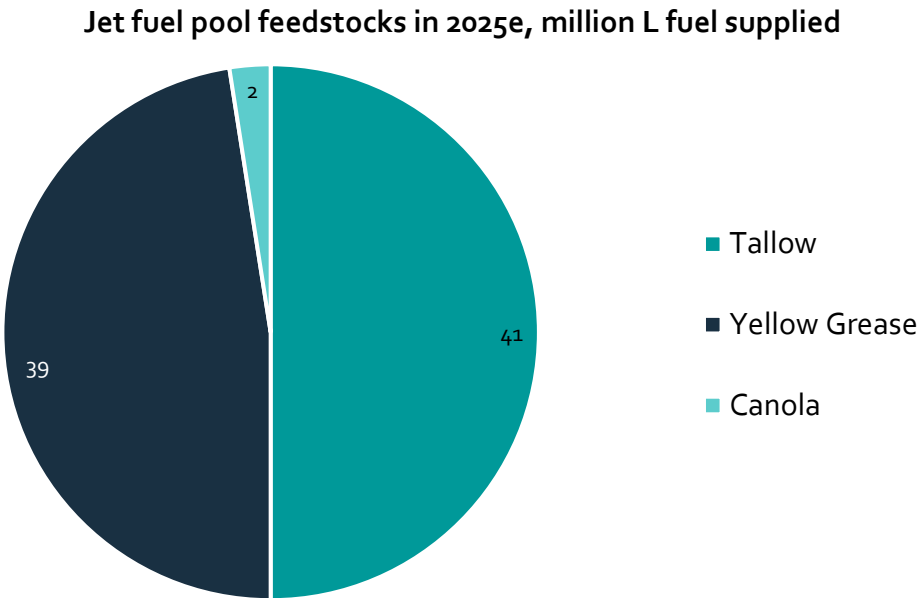


Figure 47: SAF feedstocks in 2025



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 CO₂e/GJ-gasoline for the difference in refinery GHG intensity between E0 and E10.¹⁴⁸

¹⁴⁸ 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 emissions between E10 and E30 cases. In the two 88-octane fuel scenarios, the E30 fuel showed a 0.7-1gCO₂e/MJ reduction in refinery GHG emissions compared to the E10 fuel.¹⁴⁹ Another US paper found a 6% and 12% reduction in refining GHG emissions compared to E10 for E20 and E30 blends, respectively.¹⁵⁰ 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 MTBE as a source of octane for E5 fuel. The authors found a 2.3 gCO₂e/MJ reduction in refinery emissions in the E5 case, partially offset by a 1.1 gCO₂e/MJ difference in the CI of ethanol and MTBE production, resulting in a net impact of 1.2 gCO₂e/MJ.¹⁵¹ 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.¹⁵² 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.

¹⁴⁹ Kwasniewski, V., Blieszner, J., & Nelson, R., 2015, Petroleum refinery greenhouse gas emission variations related to higher ethanol blends at different gasoline octane rating and pool volume levels. *Biofuels, Bioproducts, Biorefining*, 10:36-46

¹⁵⁰ 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

¹⁵¹ Croezen, H., & Kampman, B., 2009, The impact of ethanol and ETBE blending on refinery operations and GHG emissions. *Energy Policy*, 37: 5226–5238

¹⁵² 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 gCO₂e/MJ) to a small increase in emissions when hydrogen production is considered (0.2 gCO₂e/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 5.02c

Fuel	Exhaust Emissions (gCO ₂ e/MJ)
Conventional Canadian Gasoline Blend	70.758
Aromatics in Conventional Canadian Gasoline Blend (i.e., the high-octane portion)	80.515

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 CO₂ 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.¹⁵³

¹⁵³ 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:

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

- 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)¹⁵⁴ 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).¹⁵⁵
- 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 collected by Kalibrate.¹⁵⁶

¹⁵⁴ 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

¹⁵⁵ Railway Association of Canada, 2026, [Rail Trends 2025](#).

¹⁵⁶ Kalibrate, <https://charting.kalibrate.com/>

- All values were converted to 2020 dollars¹⁵⁷ and Canadian currency from US dollars¹⁵⁸ and Euros.¹⁵⁹
- Inputs for Atlantic Canada are constructed from provincial values averaged using population weights from Statistics Canada.¹⁶⁰
- 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.¹⁶¹

¹⁵⁷ CANSIM, 2026, Table 326-0020 Consumer Price Index

¹⁵⁸ Bank of Canada, 2026, Exchange Rates. <http://www.bankofcanada.ca/rates/exchange/monthly-average-lookup/>

¹⁵⁹ www.investing.com/currencies/eur-cad-historical-data

¹⁶⁰ Statistics Canada: Table 17-10-0009-01. Population estimates, quarterly.

¹⁶¹ 113 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 market¹⁶² 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:

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

Where:

- $P_{gasoline,sub-octane}$ is the estimated 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.¹⁶³
- $O_{blend,prem}$ 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).
- $\%vol_{eth}$ 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:

¹⁶² 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

¹⁶³ 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 Kalibrate¹⁶⁴ and are assumed to be independent of biofuel blending rates. Taxes, including carbon taxes and levies, are from NRCAN.¹⁶⁵ Taxes include federal and provincial fuel excise taxes, and sales taxes. Sales taxes were applied as a percent of the actual retail price and the calculated retail price for the counterfactual scenario without biofuels.
- The credit price impact of the cap-and-trade system in Ontario, Québec and Nova Scotia was assumed to already exist in reported wholesale gasoline and diesel blend prices. While biofuels are exempt from the cap-and-trade systems, the credit cost resulting from supplying gasoline and diesel was assumed to be spread evenly across all fuels,

¹⁶⁴Kalibrate, <https://charting.kalibrate.com/>

¹⁶⁵ NRACN, 2026, Fuel Consumption Levies in Canada, <https://natural-resources.canada.ca/domestic-international-markets/fuel-consumption-levies-canada>

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.^{166,167,168}

- 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 2010-2019¹⁶⁹ 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.^{170,171}

¹⁶⁶ Government of Ontario. Past auction information and results.

¹⁶⁷ Government of Ontario, 2018, *Past auction information and results*

¹⁶⁸ Government of Nova Scotia, 2021, Summary Results Report Nova Scotia Cap-and-Trade Program Auction of Emission Allowances

¹⁶⁹ 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.

¹⁷⁰ Natural Resources Canada, 2025, Energy Use Data Handbook Tables, [Passenger Transportation Explanatory Variables](#).

¹⁷¹ Natural Resources Canada, 2025, Energy Use Data Handbook Tables, [Freight Transportation Explanatory Variables](#).

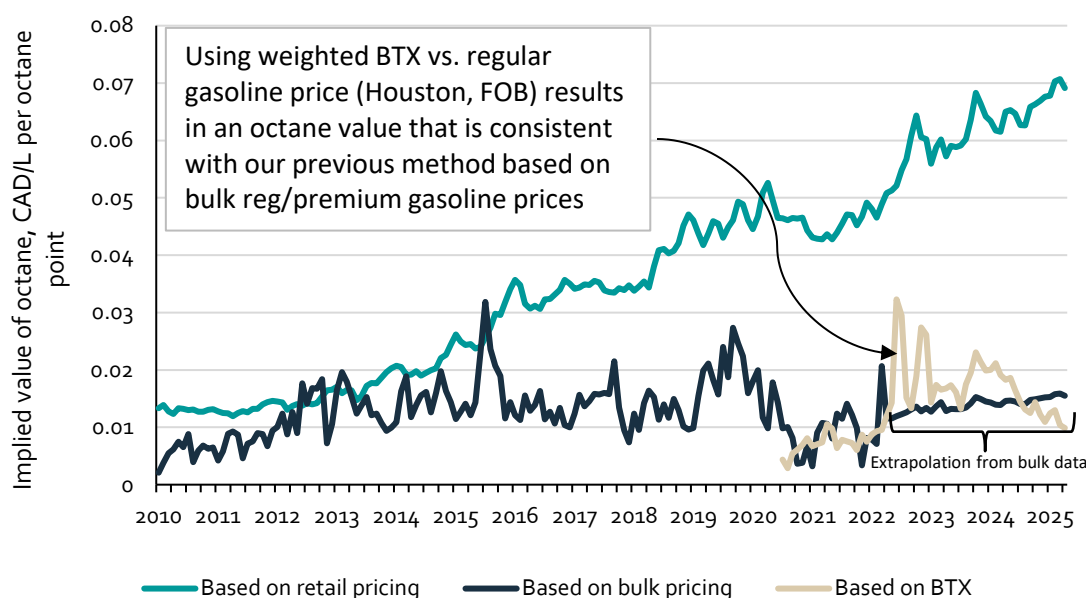
Appendix F: 2021 and 2025 Updates to the Cost Analysis Methodology

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 switched to wholesale, rather than retail, price data to estimate the cost of octane. However, the wholesale gasoline data ceased to be published as of April 2022. Until the 2025 edition of this analysis, we extrapolated the value of octane implied by wholesale gasoline prices prior to that date. In the 2025 edition, we began defining the octane value post-April 2022 using the spread between BTX (a class of octane boosters: benzene, toluene and xylene) and regular gasoline (Figure 48).

Figure 48: Value of octane measured using retail and wholesale prices¹⁷² and BTX prices¹⁷³



The 2021 methodological change resulted in a nearly \$300/tCO₂e increase to the abatement cost of using ethanol, though the estimated average abatement cost since 2010 remained below zero (i.e., it still reduced emissions and prices).

Using wholesale, rather than retail prices, aligned 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.¹⁷⁴ That approach yielded 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 resulted in a value of octane of about 0.9 cents per point per litre, similar to the average value of 1.4 cents per litre used in this report (i.e., both are much lower than the value implied by the retail price spread).¹⁷⁵

¹⁷² EIA. 2022. [Petroleum & Other Liquids: Refiner Gasoline Prices by Grade and Sales Type](#).

¹⁷³ US Grains & Bioproducts Council, 2026. [Ethanol Market and Pricing Data](#)

¹⁷⁴ Baker and O'Brien Inc., 2018, Analysis of Gasoline Octane Costs, prepared for EIA: <https://www.eia.gov/analysis/octanestudy/pdf/phase1.pdf>

¹⁷⁵ Turner, Mason & Company, Mexico Fuel Ethanol Cost Benefit Analysis Study, May 2020

Using the spread between BTX and regular gasoline to define the octane value has had a smaller impact on the results. This approach yields an octane value that is very similar to what comes from the difference between regular and premium wholesale gasoline prices. Nonetheless, the average value of octane is somewhat higher since April 2022 was indicated by our extrapolation. Consequently, the net-cost of blending ethanol is now somewhat lower than we previously estimated.

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 define 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 Biofuels 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.

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 later years (Neste data were used in previous years, where the DGD data are not available).

Appendix G: Plug-in Electric Vehicle Analysis Methodology

Methodology

This 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 are 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 were 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 database¹⁷⁶). 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 GoodCarBadCar¹⁷⁷ and electric travel energy intensity taken from Natural Resources Canada.¹⁷⁸ We assume PHEVs have a utilization factor of 69% (i.e., 69% of annual travel is powered electricity rather than fuel combustion)¹⁷⁹.
 - c. PEVs have an energy efficiency ratio of 4.1, reflecting the difference in efficiency between electric and internal combustion engines, based on the ratio used in the Regulatory Analysis within the *Clean Fuel Regulations*.¹⁸⁰

¹⁷⁶ Natural Resources Canada, [Comprehensive Energy Use Database](#), Accessed September 2024

¹⁷⁷ GoodCarBadCar, [Automotive Sales Data and Statistics](#)

¹⁷⁸ Natural Resources Canada, 2022, [Fuel consumption ratings - Battery-electric vehicles 2012-2022 \(2022-05-16\)](#)

¹⁷⁹ The International Council for Clean Transportation, 2020, [Real-World Usage Of Plug-In Hybrid Electric Vehicles Fuel Consumption, Electric Driving, And CO2 Emissions](#).

¹⁸⁰ Government of Canada, [Canada Gazette, Part II, Volume 156, Number 14: Clean Fuel Regulations](#)

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

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

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.¹⁸¹ These 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 legislation¹⁸² 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)¹⁸³ 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 vkm/yr is heavily dependent 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

¹⁸¹ See [Part 3, Table A13-1 through 11](#)

¹⁸² Government of Canada, [Canada Gazette, Part I, Volume 154, Number 51: Clean Fuel Regulations](#)

¹⁸³ Zhao, L., Ottinger, E., Yip, A., Helveston, J., 2023, Quantifying electric vehicle mileage in the United States. *Joule* 7, 2537-2551.

(2023),¹⁸⁴ 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 PEVs travel in the range of 6,200 to 8,700 miles per year (10,000 to 14,000 km/yr). This distance is 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 Database¹⁸⁵).

Furthermore, a 2024 survey of Canadian PEV drivers indicates that our PEV utilization assumption is conservative. A sample of over 16,000 PEV drivers reported using their vehicles an average of 390 km/week (equivalent to 20,330 km/yr).¹⁸⁶ As well, in about 95% of Canadian households with at least one PEV and one conventional vehicle, the PEV is considered the primary vehicle (n=8,137).

¹⁸⁴ 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.

¹⁸⁵ Natural Resources Canada, [Comprehensive Energy Use Database](#), Accessed September 2024

¹⁸⁶ PlugShare Research, 2024, [The Voice of the Canadian Electric Vehicle Driver](#).