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Compliance Costs under the Clean Fuel Regulations:

Estimating near-term credit prices, compliance costs, and impacts on fuel prices

Final report

Independent Assessment funded by Environment and Climate Change Canada

ESMIA
Energy Super Modelers and International Analysts

About ESMIA

ESMIA offers a solid expertise in 3E (energy-economy-environment) integrated system modelling for strategic decision-making at city, regional, national and global scales. We specialize in economy-wide energy system optimization models. We have participated in the development of turnkey large-scale energy system models using a large variety of platforms. Many high-profile public and private organizations worldwide have called upon our expertise, in both developed and developing countries. Additionally, we offer advisory services using our proprietary models that focus on analyzing complex and long-term problems such as energy security, electrification, energy transitions, and climate change mitigation.

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List of acronyms

ACRONYM	DEFINITION
3E	Energy-economy-environment
CARB	California Air Resource Board
CC1	Compliance category 1 – one category of credits for CFR compliance
CC2	Compliance category 2 – one category of credits for CFR compliance
CC3	Compliance category 3 – one category of credits for CFR compliance
CFP	Clean Fuel Program (policy name used in Oregon)
CFR	Canada's Clean Fuel Regulations: SOR/2022-140
CFS	Clean Fuel Standard (policy name used in Washington state)
CI	Carbon intensity
CO_2	Carbon dioxide
ECCC	Environment and Climate Change Canada
EOR	Enhanced Oil Recovery
EV	Electric vehicles
E85	Fuel blended with up to 85% ethanol
GGE	Gallon of gasoline equivalent
GHG	Greenhouse gas
IPCC	Intergovernmental Panel on Climate Change
LCA	Lifecycle Analysis
LCFS	Low Carbon Fuel Standard (policy name used in BC and California)
NATEM	The North American TIMES Energy Model
RIAS	Regulatory Impact Analysis Statement
ROI	Return on investment
PV	Photovoltaic panel

Glossary

TERM	DEFINITION
Baseline Carbon Intensity	Canada's Clean Fuel Regulations (CFR) set out the baseline carbon intensity (CI) values for gasoline and diesel produced in and imported for use in Canada. These values are Canadian average lifecycle CI values, calculated from the Department's Fuel Lifecycle Assessment Model. This means that each type of fossil fuel (gasoline and diesel) is assigned the same national average value. GHG emissions from all stages in a fuel's lifecycle are included in the determination of the baseline CI values. The baseline CI of gasoline is 95 g CO2e/MJ and the baseline carbon intensity of diesel is 93 g CO2e/MJ.
Biodiesel	Biodiesel is produced from vegetable oils and/or animal fats, including used cooking oil and grease from restaurants and potentially fat from algae. It must be blended with fossil diesel because its chemical structure is not the same.
Carbon intensity (CI) – for Clean Fuel	Many clean / low carbon fuel programs use carbon intensity of fuel as the metric for required limits and defining credits. Usually the CI is measured in mass of emissions divided by energy, such as grams of CO2e per Megajoule (g CO2e / MJ) and the emissions are measured using lifecycle analysis (see below). The CFR includes specific definitions of low-carbon-intensity fuel and carbon intensity.
Compliance categories, 1-3	The credits created to comply with the CFR using the following three categories: 1. CC1: actions throughout the lifecycle of a liquid fossil fuel that reduce its CI (such as carbon capture and storage) through GHG emission reduction projects; 2. CC2: supplying low-CI fuels (such as ethanol); and 3. CC3: supplying fuel or energy to advanced vehicle technologies (such as electricity in electric vehicles). See section 1.2 for full definition of eligible credits.
Compliance costs, industry	The amount paid by regulated parties for actions that are undertaken to comply with the CFR.

TERM	DEFINITION
Compliance cost, net social	The cost of compliance with CFR including costs for regulated facilities plus costs and benefits for government implementation.
Co-processed low-carbon-intensity fuel	Fuel produced from both petroleum feedstock and a non-petroleum feedstock simultaneously in the same processing unit of a petroleum refinery or upgrader facility and that is a low-carbon-intensity fuel derived from a non-petroleum feedstock.
Hydrogenation-derived renewable diesel (HDRD)	HDRD is a common type of renewable diesel. Large amount of hydrogen is required for production, and the type of hydrogen production will impact the lifecycle analysis for the carbon intensity of this fuel.
Greenhouse gas (GHG)	Gases that trap heat in the Earth's atmosphere and contribute to the greenhouse effect.
Lifecycle analysis (LCA)	LCA is an accounting method that covers total emissions associated with fuels through the lifetime. The CFR LCA is from feedstock extraction, through processing and transportation to combustion by final consumer. There is no single set of accepted rules for LCA for fuels; each program must define the scope and calculation methods.
Renewable diesel	Renewable diesel can be produced from nearly any biomass feedstock, including those used in production of biodiesel. It is a hydrocarbon that can directly replace fossil diesel, without the need to blend.

List of units

ACRONYM	DEFINITION	MEASURE OF
m^3	Cubic metre	Volume
G	Gallon	Volume
l	Litre	Volume
gCO_2e/MJ	Grams of CO_2 equivalent per megajoule of energy	Carbon intensity
t CO_2e credit	Tonnes of CO_2 equivalent as measured for CFR deficits and credits, using lifecycle accounting.	Credits for regulation compliance and lifecycle emissions quantities.
t CO_2e	Tonnes of CO_2 equivalent, based on national inventory accounting	Emissions quantities
Mt CO_2e	Million tonnes of CO_2 equivalent	Emissions quantities
MW	Megawatt	Power
MWh	Megawatt hour	Energy
MJ	Megajoule	Energy
GJ	Gigajoule	Energy
TJ	Terajoule	Energy
PJ	Petajoule	Energy
CAD	Canadian dollars	Currency
USD	United States dollars	Currency

SUMMARY

Executive Summary

The main goal of the study is to estimate costs of compliance for regulated parties under the Clean Fuel Regulations (CFR). To do this, we focus on *incremental* costs, which implies accounting for only the additional costs incurred due to the CFR. Therefore, costs (or revenues) that result from other existing policies are excluded from the compliance costs. The study estimates market prices of credits supplied by voluntary parties – which may differ from incremental cost due to profit seeking or other behaviour in the market. The main analysis was performed per Canadian province, while allowing for CC2 and CC3 credit trading between provinces, whereas CC1 credits are assumed to remain within the province where they are created.

The maximum potential future supply of credits in all three categories was determined based on a combination of data sources, including: planned (announced) projects, projections on (i) carbon capture and sequestration potential (ii) future supply of low-CI fuels and (iii) uptake of advanced vehicle technologies. Achievable or realistic credit supply between 2024 to 2030 was modelled using engagement rates per type of credit creation project. Contributions to a registered emission reduction funding program were limited to 10% per year per province, as dictated by the Regulations.

Credit supply will be dominated by the CC2 category (supply of low-CI fuels) over the study time period, although the share is projected to drop from 78% in 2023 to 45% in 2030. Initially, credit creation in CC1 will be slightly higher than CC3 (supply of fuels to advanced vehicles technologies), but this trend reverses in 2025 after which CC3 sees faster growth. In 2027-2028, it is projected that contributions to a registered emission reduction funding program will begin to be required to meet the obligation amounts due to insufficient credit supply. On average, credits in the CC1 category will be lowest cost (since revenues from the federal carbon pricing policy are accounted for), followed by CC3 credits, with CC2 credits having the highest average cost per tonne CO_{2e}. While individual credit prices may surpass the price of the emission reduction funding program, the latter will remain on average the most expensive credit supply option. The proportion of credits created or purchased by a regulated party in each category will determine the overall average credit cost for a regulated party (represented here at provincial level).

It should be noted that both credit supply in all categories and credit prices from 2025-2030 are highly uncertain. While engagement rates in this analysis tend to be conservative for credit creation project types with higher uncertainty (for example, often below 20% for CC1), it is possible that the projected projects may not materialize and would need to be replaced with other types of projects that would increase compliances costs. Moreover, a constrained credit supply market may lead to higher credit prices.

The annual compliance costs in different jurisdictions, which drive up the revenue requirement for regulated parties, will depend on the compliance categories of created or purchased credits (CC1 generally having lower incremental cost than CC2 and CC3). In Alberta and Saskatchewan, where most of the upstream oil sector is located, a larger share of credits will be from the CC1 category and therefore average credit cost tends to be lower. In Quebec, Ontario, Nova Scotia, and New Brunswick, at minimum ~90% and at maximum all credits will be from CC2 and CC3, increasing average credit cost and consequently, gasoline and diesel retail prices. At the same time, shortage in credit creation will lead to contributions to an emission reduction funding program. Regulated parties in Quebec, Ontario, New Brunswick, Alberta, and Saskatchewan start to extensively contribute to a funding program after 2027 and by 2030 it is expected that their contributions will approach the maximum allowed limit.

The interprovincial trade flows of fuels will partly transfer costs created in one jurisdiction to the gasoline and diesel consumers in another jurisdiction, leading to differing impacts across provinces. On average in Canada, the projected impact on gasoline and diesel prices is respectively, 0.3-0.6 (2022)cent/litre and 0.3-0.7 (2022)cent/litre in 2024, and 4-4.3 (2022)cent/litre and 3.2-3.5 (2022)cent/litre in 2030. The range includes the results of the sensitivity scenario with more limited market trading, leading to higher impacts in 2024.

The impact of interprovincial trade flows is particularly obvious in Atlantic provinces. Regulated parties in New Brunswick will transfer part of their compliance costs associated with diesel production to provinces, such as Newfoundland and Labrador, Nova Scotia, Prince Edward Island, following interprovincial exports. At the same time, in the absence of major interprovincial gasoline exports, CFR compliance cost due to the production of gasoline will remain in the province and will be passed on to provincial consumers. As a consequence, New Brunswick's gasoline price is expected to have highest CFR impact among Canadian provinces, while CFR impact on diesel price will remain under the Canadian average. Nova Scotia, where credit compliance obligation is relatively low, will have additional CFR costs flowing inside the province with gasoline and diesel imported from Ontario, Quebec, and New Brunswick. However, even after transfer of these costs, the CFR cost that will be passed on to Nova Scotia's consumers is expected to remain considerably lower than in New Brunswick, leading to moderate impact on gasoline and diesel prices (under the projected Canadian average).

Other provinces where the CFR impact for gasoline is projected to be higher than the Canadian average are Quebec and Prince Edward Island. Regulated parties in Quebec will have limited opportunities for project creation in lower-cost CC1 categories. Moreover, while some CFR costs will flow out of the province, they will be compensated by CFR costs flowing in with interprovincial imports. As a result, CFR compliance cost will remain relatively high, increasing impact on gasoline consumers. Prince Edward Island is assumed to have no credit obligation but will experience gasoline price increase due to CFR with compliance costs flowing in the province with imports from Ontario and Quebec.

CFR impact on diesel price is expected to be more uniform across all provinces, with a slightly higher impact expected for consumers in the Prairies, Ontario, and British Columbia.

Sensitivity analysis shows that if access to the credit market were limited across Canada, this would drive up annual compliance costs between 2024-2029. The CFR cost component in fuel retail prices may become up to four times higher than in main scenario in 2024. By 2030, the difference in the impact between the main and limited market access scenarios will be minimized. This is due to the fact that under both scenarios, compliance costs are very similar in 2030 because both scenarios require contributions to emission reduction funding programs by all provinces with substantial credit obligations. This shows a robust trend suggesting that by the end of the decade, there is a risk of insufficient credit supply, whether the market is more or less restrained in terms of trade between parties. This trend may also result in a higher risk of spikes in market credit prices.

SECTION 1

1. Background

1.1. Objective

ESMIA Consultants Inc ("ESMIA") was retained by Environment and Climate Change Canada ("ECCC") to estimate compliance costs for regulated parties to the CFR and the Regulations' impact on retail gasoline and diesel prices. The estimates cover different compliance options and flexibility choices, including credit creation, credit purchases, and contribution to an emission reduction funding program. The analysis will provide information at the national and provincial scale, although certain data may be aggregated in order to protect confidential information. The timeline for the analysis is the years 2023 and 2024 with projections provided for the year 2030.

1.2. What are Canada's Clean Fuel Regulations?

The Canadian government's Clean Fuel Regulations (CFR or "the Regulations"), brought into force the regulatory obligation on July 1, 2023 (Government of Canada, 2022). The CFR's primary objective is to combat climate change by reducing the lifecycle carbon intensity of gasoline and diesel fuels used in Canada. The CFR operates as a market-based mechanism. Regulated entities must comply with the Regulations by securing enough credits to match their annual carbon intensity reduction requirement set out in the Regulations. Credits are created through the three compliance categories (see Glossary). Credits can be created by regulated entities and voluntary parties (e.g., low carbon intensity fuel suppliers). Credits can also be bought/sold through private contract or through the credit market. This system encourages the adoption of low-carbon fuels and technologies to cost-effectively meet the specified carbon intensity limit.

1.2.1. Description of policy design

Regulated entities under the CFR are primary suppliers (producers and importers) of gasoline and diesel, of which there are 30 such regulated companies in Canada.[1] The CFR imposes an annual reduction requirement on the lifecycle carbon intensity (CI) for gasoline and diesel supplied in Canada, with the reduction requirement increasing in stringency from 2023 to 2030. The CFR applies to gasoline and diesel supplied for use in Canada, with limited exceptions for certain gasoline and diesel used for aviation, competition vehicles or scientific research, with further precisions indicated under the section "Annual compliance requirements". CFR applies to fuels produced in Canada as well as to net imports (no reduction requirement for exports). A primary supplier who produces or imports into Canada less than 400 m^3 of gasoline or of diesel during a compliance period is exempt.

[1] The list of CFR registrants, including primary suppliers, is found here: https://drive.google.com/drive/folders/1bRQRT4ZRXsp0wMjFd0vKyeyyqlDoLSSi

The CFR requirements are summarized in Table 1, and reflect a reduction in CI of 15% between 2016 and 2030. The baseline CI of gasoline is 95 g CO2e/MJ and the baseline carbon intensity of diesel is 93 g CO2e/MJ.

Table 1. CFR requirements, 2023, 2024 and 2030

	2023	2024	2030
Absolute CI reduction requirement (gCO_2e/MJ)	3.5	5.0	14.0
Fuel CI limit - gasoline (gCO2e/MJ)	91.5	90.0	81.0
Fuel CI limit - diesel (gCO_2e/MJ)	89.5	88.0	79.0

Notes: The changes from 2024 to 2030 are linear.

Emissions accounting

GHG emissions accounting for CFR credits use a lifecycle accounting approach, accounting for emissions associated with fuels from feedstock extraction, through processing and transportation to combustion by final consumer.

Annual compliance requirements

Regulated parties have annual compliance requirements determined by the energy content of fuel supplied multiplied by the absolute CI reduction requirement for that year (Table 1).

The CI reduction requirements do not apply to gasoline or diesel that is

- aviation gasoline;
- exported from Canada;
- used for scientific research, other than research on consumer preferences in respect of various properties of fuels or market research; or
- sold or delivered for the purpose of supplying the engine of a vehicle, including a marine vessel, that is used exclusively for competition.

In addition to the above exclusions and subject to providing complete records, a regulated party may subtract fuel volumes from their pool of gasoline and diesel subject to the CI reduction requirement that is:

- sold or delivered for a use other than combustion;
- sold or delivered for use in a marine vessel that had a non-Canadian port as its destination;

- sold or delivered for use for non-industrial purposes in a geographic area that is served by neither an electrical distribution network that is subject to the standards of the North American Electric Reliability Corporation nor a natural gas distribution system;
- sold or delivered for the purpose of space heating; or
- sold or delivered for use in the generation of electricity in a geographic area that is served by neither an electrical distribution network that is subject to the standards of the North American Electric Reliability Corporation nor a natural gas distribution system.

Credits

Each credit created under the CFR is equivalent to a reduction of one tonne of CO_{2e} (based on lifecycle accounting). Credits can be created by regulated parties or by voluntary participants. For example: suppliers of low-CI fuels, electric vehicle (EV) charging network operators, hydrogen fuelling station owners or operators, and upstream or downstream parties of refinery supply chains. Credits may be created in respect of the liquid class, referring to fossil fuels that are liquid at standard conditions, or in the gaseous class, referring to substitution of natural gas and propane fuels. Table 2 describes options for credit creation by the three compliance categories.

Table 2. Credit creation options

Compliance category	Eligibility
Compliance category 1 (CC1) CC1: Actions throughout the lifecycle of a liquid fossil fuel that reduce its CI through GHG emission reduction projects	This category recognizes actions that reduce a liquid fossil fuel's CI through GHG emission reduction projects to create credits. Projects can include an aggregation of reductions from multiple sources or facilities, and no minimum emissions reduction threshold is set. The number of credits created are determined by a quantification method, which specifies the eligibility criteria for the project as well as the approach for quantification. To be able to create credits under the Regulations, a project must generate emission reductions that are real and incremental (i.e., additional) to a defined base case. Projects create credits for the portion of the fossil fuel and crude oil that is used in Canada (i.e. exported portion of products are not eligible for credit creation). Jurisdictions outside Canada that wish to have projects recognized under the Regulations will be able to enter into an agreement with Canada to ensure their projects are comparable to Canadian projects in effectiveness and meet the Regulations' objectives.
Compliance category 2 (CC2) : Supplying low-CI fuels	This category encompasses credits that are created under the Regulations for low-CI fuels produced or imported in Canada. Low-CI fuels must meet the definition provided in the Regulations. For example, liquid low-CI fuels are fuels, other than the fossil fuels, that have a CI equal to or less than 90% of the credit reference CI value for

Compliance category	Eligibility
	the fuel. All low-CI fuels supplied to the Canadian market, including fuels used to comply with existing federal and provincial renewable fuel regulatory requirements and British Columbia's RLCFRR, are able to create credits under the Regulations. For low-CI fuels produced from biomass feedstock, only low-CI fuels that adhere to the Land Use and Biodiversity criteria are eligible for compliance credit creation. Eligible low-CI fuels do not need to be supplied for transportation. For example, pyrolysis oil that replaces heavy fuel oil can create credits. Renewable natural gas injected in a pipeline can create gaseous class credits.
Compliance category 3 (CC3): CC3: Supplying fuel or energy to advanced vehicle technologies (e.g., electricity or hydrogen for transportation)	This compliance category covers fuel or energy to advanced vehicle technologies. This does not directly reduce the CI of fossil fuels but reduces GHG emissions by displacing gasoline or diesel used in transportation with fuels or energy sources with lower CIs. Credits may be created by the owners or operators of fuelling stations that supply fuels for transportation uses (natural gas, renewable natural gas [RNG], propane, renewable propane), by the producers and importers of low-CI fuels (RNG and renewable propane) used for transportation purposes, by the owners or operators of fuelling stations for dispensing hydrogen to hydrogen fuel cell vehicles or other vehicles, by charging network operators for residential and public charging of EVs, and by charging site hosts for private or commercial charging of EVs. Credits for residential charging of EVs will be phased out by the end of 2035 for charging stations installed by the end of 2030. Any residential charging station installed after the end of 2030 will not be eligible for credits. The Regulations require charging network operators to reinvest 100% of the proceeds from the sale of credits created by residential and public EV charging. The revenue must be reinvested into two available categories of actions: either reducing the cost of EV ownership through financial incentives to purchase or operate an EV, or expanding charging infrastructure in residential or public locations, including EV charging stations and electricity distribution infrastructure that supports EV charging.

Depending on the compliance category, emissions will be tracked using (per compliance category listed above):

1. CC1: A quantification method developed by ECCC consistent with International Standard ISO 14064-2 (Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of Greenhouse Gas Emission Reductions or Removal Enhancements)[2]

[2] Quantification methods are available at https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-regulations/compliance.html

2. CC2: ECCC's Fuel Life Cycle Assessment (LCA) Model[3]
3. CC3: ECCC's Fuel LCA Model

Compliance

A regulated party must retire the required number of credits in each period. The required number is based on the fossil fuel amount supplied by each primary supplier, and the reduction requirement in each period. To comply with the Regulations, a party can:

1. Create credits (see above).
2. Purchase credits from other creators.
3. Contribute to a registered emission reduction funding program for up to 10% of their annual reduction requirement. The credit price is set at (2022)CAD 350 in 2022 (Consumer Price Index adjusted after 2022).
4. Use credits created under the Generic QM under CC1 to satisfy up to 10% of their annual reduction requirement.
5. Use gaseous class credits to comply with up to 10% of their annual reduction requirement.
6. Defer up to 10% of their annual reduction requirement for up to 5 years. The supplier must pay an annual penalty of 5% (the deferred amount is multiplied by 1.05). Before deferring any amount, the regulated party must acquire credits by transfer through the credit clearance mechanism (should registered creators choose to pledge to offer to transfer credits) and must also create enough compliance credits by contributing to a registered emission reduction funding program to satisfy 10% of their total annual reduction requirement for that compliance period. The maximum price of a credit transferred through the credit clearance mechanism is set at (2022)CAD 300 in 2022 (Consumer Price Index adjusted after 2022).

1.2.2. Ex-ante analyses of costs of the CFR

Several studies have estimated the expected compliance costs and fuel price increases of the CFR in advance of its implementation.

Regulatory Impact Analysis Statement for CFR

Together with the Regulations, ECCC published a Regulatory Impact Analysis Statement (RIAS) in June 2022. Certain assumptions in the RIAS are relatively conservative (i.e., leading to a higher cost). For example, the cost assumptions used to calculate fuel price impacts (a single average cost applied to all credits across Canada), zero growth of CCS and EOR projects after 2025, unquantified potential for hydrogen production projects, and

[3] Model is available at https://www.canada.ca/en/environment-climate-change/services/managing-pollution/fuel-life-cycle-assessment-model.html

a significant number of credits coming from contributions to a registered emission reduction funding program or from emerging technologies (costed at $350/tonne) as a result of slower growth in other categories. The RIAS modeling results showed:

- On a national level, in 2023 and 2024, credit creation is estimated to exceed credits required due to credits from low-carbon fuels required to meet federal and provincial fuel blending mandates plus banked credits from previous years, which includes credits rolled over from the federal Renewable Fuels Regulations (surplus compliance units after the 2022 compliance period). The federal Renewable Fuels Regulations will be repealed on September 30, 2024, and the minimum volumetric requirements are incorporated in the CFR.
- In 2025, the bank of credits are anticipated to be used up and credits will be required from additional actions implemented to meet the CFR.
- The most significant costs will be incurred in 2024, for capital investments to comply with future increasingly stringent reduction requirements.

The RIAS' estimates for compliance costs and fuel price increases are shown in Table 3 and Table 4.

Table 3. Estimated net compliance costs or "impacts" from CFR from the Regulatory Impact Analysis Statement (2021 CAD in millions of dollars, present value at 3% discount rate).

	2022-2025	2026-2029	2030
Credit creation costs	4,335	9,077	2,995
Fund payment costs	14	3,055	929
Administrative costs	29	19	4
Fund asset benefits	-14	-3,055	-929
Administrative cost savings	-1	-1	0
Net costs	4,363	9,094	2,999

Source: Government of Canada 2022. Regulatory Impact Analysis Statement, Table 19.

Table 4. Estimated range in incremental fuel price impacts in 2030 (cents per litre. 2021 CAD)

Fuel pool	No credits go to market (All credits are self-created)	Some credits go to market (Some credits are self-created)	All credits go to market (No credits are self-created)
Gasoline pool	6	10	13
Diesel pool	7	12	16

Source: Government of Canada 2022. Regulatory Impact Analysis Statement, Table 23.

Navius Research Biofuels in Canada

The 2023 version of the report, *Biofuels in Canada: Tracking biofuel consumption, feedstocks and avoided greenhouse gas emissions* (Navius Research, 2023), included a section that projects the potential CFR credits created from sales of low carbon fuels (Compliance Category 2) in 2023, 2024 and 2025. The analysis estimated that on a national level, due to current actions, compliance with provincial regulations, and the use of banked credits, credits created will exceed credits needed until 2025, even if no additional CFR credit creating actions occur. This finding aligns with the RIAS findings noted above.

1.3. Policy experience in other jurisdictions

Several jurisdictions have implemented regulations to decrease the carbon intensity of transportation fuels as a policy option for decreasing GHG emissions and spurring innovation. This section summarizes a review of the policies, with an emphasis on research of historic and expected impacts.

The Joint Clean Climate Transport Research Partnership compared Canada's CFR with similar regulations in British Columbia, Oregon and California (Witcover et al., 2022). The comparison found that the instruments have similarities in:

- scope (transportation fuels, excluding maritime, aviation and military fuel);
- credit measurements (carbon intensity based on lifecycle analyses);
- compliance options (credit markets to meet fuel-neutral, flexible and cost-effective objectives); and
- levels of ambition (based on stringency targets and trajectories).

The key differences are:

- base year for credit reduction measurement;

- whether the scope includes indirect land-use change;
- rules for credits from electricity fuelling (which entities and use of revenues)
- credit options from the production of low-CI fossil fuels[4]; and
- price control mechanisms and compliance flexibility.

The differences mean that care is needed when considering the use of impacts from clean fuel instruments in other jurisdictions as potential input to estimating impacts of the CFR.

1.3.1. BC Low Carbon Fuel Standard

BC's LCFS was first implemented in June 2013 and, prior to the federal CFR, was the only clean fuel regulation in Canada that relied on a credit market and on a lifecycle approach. The regulation was most recently amended in January 1, 2023 with increased stringency and higher penalty rates for non-compliance (Government of British Columbia, 2023c).

The BC Utilities Commission inquiry on gas and diesel (British Columbia Utilities Commission, 2019) indicated both fuel price increases and decreases, depending on the option chosen for compliance:

- Ethanol blending with gasoline is a compliance option for the BC LCFS and was cited by third parties as decreasing fuel prices: "Evidence submitted in the Inquiry suggests that the price of ethanol compared with wholesale gasoline prices has been lower for some time, and further the differential between the two has grown in recent years. When adding the cost of transportation, the evidence suggests that the ethanol requirements would have added around 1 cent/litre to wholesale gasoline prices from mid-2015 to the end of 2017, and reduced wholesale prices by approximately 1 cent/litre since 2018."
- Purchasing compliance credits is a compliance option for the BC LCFS and was cited by third parties as increasing fuel prices: "Estimates by Deetken for the cost of compliance credits have ranged from 1 cent/litre to 4 cents/litre for gasoline and 0 cent/litre to 3 cents/litre for diesel."

Historic reporting from BC shows a much tighter market than California, with credits less than debits in 2022. Furthermore, while credits exceeded debits from 2013 to 2016, the bank of credits has steadily declined since 2016. Credit prices (Table 5) increased sharply in 2021 and have remained around 450 (2022)CAD/t CO_2e.

[4] Oregon's Clean Fuel Program does not have the option to generate credits from low carbon fossil fuel production, while Canada, California and British Columbia offer some credit options with specific requirements.

Credits for hydrogen and electricity have decreased as a share of total credits from 2020 to 2022. An update to the regulation meant that as of January 1, 2022, a new procedure was used for reporting credits from electricity and credits for electricity displacing gasoline fell from 117,000 in 2021 to 32,000 in 2022. Part 3 agreements, which are not for low carbon fuel supply but instead for "actions that would have a reasonable possibility of reducing GHG emissions through the use of Part 3 fuels sooner than would occur without the agreed-upon action" (Government of British Columbia, n.d.) contributed to 12% of total credits on average from 2020 – 2022, but with significant annual variation.

Table 5. British Columbia LCFS, select historic reporting

<table>
<tr><th></th><th>Units</th><th>2020</th><th>2021</th><th>2022</th><th>2023 YTD</th></tr>
<tr><td>Credits for hydrogen and electricity</td><td rowspan="2">% of total credits created in each year</td><td>11%</td><td>10%</td><td>7%</td><td>N/A</td></tr>
<tr><td>Credits from ethanol</td><td>16%</td><td>15%</td><td>19%</td><td>N/A</td></tr>
<tr><td>Credit price</td><td>CAD / t CO_2 credit</td><td>250</td><td>447</td><td>450</td><td>466</td></tr>
</table>

Sources: Government of British Columbia (2023a) and Government of British Columbia (2023b)

The *Biofuels in Canada 2022* report (Navius Research, 2023) notes that BC had a non-compliance penalty rate of 200 CAD/t CO2e credit through 2022, which is much lower than the credit price in 2020, 2021 and 2022 (Table 5). The report authors state "The most compelling reason we have heard is that some fuel suppliers have internal policies that their regional operations must comply with local statutes, requiring that they buy credits to achieve compliance rather than paying the 200 CAD/tCO2e non-compliance rate." The compliance penalty rate has been revised to 600 CAD/t CO2e credit as of January 1, 2023 (Government of BC, 2023c). Data from the BC government website show that the fraction of credits purchased for compliance has been increasing from about 13% in the period 2013 – 2020 (Navius Research 2023), when many fuel providers complied with the regulation through blending and selling lower-carbon fuels, to over 30% in 2022 (Government of British Columbia, 2023a) even with the higher credit prices on the market.

1.3.2. California – Low Carbon Fuel Standard (LCFS)

California's Low Carbon Fuel Standard was implemented in January 2011 and its design has been generally replicated in BC, Oregon, Washington, and Canada's federal CFR.

In 2022, the Low Carbon Fuels Coalition engaged Bates White to determine the impact of the California LCFS program on retail gasoline pricing. Bates White (2022) concludes that while California's fuel prices are higher than other states, the study showed no correlation between the LCFS credit prices and consumer fuel prices. The study noted that factors other than the LCFS, in particular world oil prices, have a much larger impact on prices. The study found consumer and public benefits, stating "The LCFS Program has induced substantial growth and diversification in alternative transportation fuels, including electricity" and that the low carbon fuels induced by the LCFS program have lower consumer prices than the fossil fuels being displaced – renewable diesel cost less than fossil diesel from 2017 – 2021, E85[5] was often less than petroleum fuels in California using energy equivalent measurement[6] and compressed biomethane (renewable natural gas) was often significantly less than diesel.

Reporting by the California Air Resources Board (CARB) show that the program has created more credits than required, leading to a growing bank of credits that will help mitigate future compliance costs. Over time, the credit supply has transitioned to a more diverse set of fuels. Initially credits from ethanol dominated the market (almost 40% of credits in 2015) but this share has decreased (14% in 2022, the last full year of data). Credits from electricity and hydrogen (vehicle use and charging infrastructure credits) are also increasing (Table 6). Credits from low carbon fossil fuel production were below 1% in 2020 to 2022. Credit prices have fallen in the last 3 years with average weekly prices decreasing almost 40% from 2020 to 2022 and further reductions expected through 2023.

Table 6. California LCFS, select historic reporting

	Units	2020	2021	2022	2023 q1
Credits for hydrogen and electricity	% of total credits created in each year	19%	22%	25%	26%
Credits from ethanol		24%	19%	14%	12%
Credit price	USD / t CO2 credit	199	186	121	76

Source: CARB (2023a) and CARB (2023c)

CARB's Standardized Regulatory Impact Assessment (CARB 2023b) assesses the impact of potential changes to the LCFS, compared to the impacts of the current program's design.

[5] E85 is fuel with up to 85% ethanol.
[6] Gallon of gasoline equivalent – A GGE is a standardized unit for the energy content of all fuels. This unit quantifies the amount of alternative fuel that has the equivalent energy content of one gallon of conventional gasoline.

That analysis projects credit prices to drop to 0 USD/t by 2030 and remain at zero through 2045, under the current program's design stringency. The report warns that the LCFS credit price trajectories reflect the long-run marginal cost of reducing the carbon intensity of the transportation fuel pool and stating "these prices should be treated as illustrative rather than predictive." (CARB 2023b).

1.3.3. Oregon – Clean Fuels Program

Reporting by the State of Oregon Department of Environmental Quality show that the program generated more credits than required from its start in 2016 until 2020 and has since then produced less credits than required. The credit bank peaked in 2020 and has declined since. As with California, initially credits from ethanol dominated the market (over 60% of credits in 2016) but this share has decreased to 29% in 2022 (Table 7). Credits from electricity and hydrogen (vehicle use and charging infrastructure credits) have increased significantly in the last 3 years (Table 7). Oregon does not have the option to generate credits from low carbon fossil fuel production. Credit prices were below 100 USD/t CO2e credit in the first three years of the program, then increased and have been relatively stable for the last three years.

Table 7. Oregon Clean Fuels Program, select historic reporting

	Units	2020	2021	2022	2023 YTD
Credits for hydrogen and electricity	% of total credits generated in each year	10%	18%	20%	n/a
Credits from ethanol		39%	37%	29%	n/a
Credit price	USD / t CO2 credit	128	125	119	127

Source: Oregon Department of Environmental Quality (2023a) and Oregon Department of Environmental Quality. (2023b).

Oregon's Department of Environmental Quality is required to annually report estimated average cost per gallon from the Clean Fuels Program. The estimates provided are conservative and do not account for benefits such as the value of credits reducing the costs for low carbon fuels and electricity.

Table 8. Oregon Clean Fuels Program, average cost

	Units	2020	2021	2022
For E10	US cents/ gallon *US cents/litre*	3.71 *0.98*	5.09 *1.34*	6.92 *1.83*
For B5	US cents/ gallon *US cents/litre*	4.24 *1.12*	5.80 *1.13*	7.87 *2.08*

Source: Oregon Department of Environmental Quality (2023c) with conversion to litres by ESMIA.

1.3.1. Washington Clean Fuel Standard

Washington's Clean Fuel Standard (CFS) was finalized on January 1, 2023 so historic data on its impacts are not available. The Washington Department of Ecology commissioned a report on expected costs and benefits. The analysis finds that the CFS is expected to have "minimal effects on consumer gasoline and diesel prices at the start of compliance in 2023 but raises consumer gasoline prices over time by up to (2020)USD 0.19/gasoline gallon equivalent (GGE) by 2032 and consumer diesel prices by up to (2020)USD 0.17/GGE by 2032" (BRG Energy and Climate 2022).[7] These cost increases are partially mitigated by the CFS reducing compliance costs for electricity as a transportation fuel and also reducing compliance costs for other climate policies such as the Zero Emissions Vehicles (ZEV) and Advanced Clean Truck Standards. The commissioned report finds that credit prices are expected to collapse in 2035 and beyond due to surplus credits from electric vehicles, as required to meet the ZEV mandate. Prices in 2035 are projected to only cover the transaction costs of the credit market participation, a decrease of 98% from 2032 levels.

[7] Conversion of prices: USD 0.19/GGE is equal to 5.02 US cents/litre and USD 0.17/GGE equals 4.49 US cents/litre.

SECTION 2

2. Estimating costs for credits

To estimate the supply and cost of credits, a common approach was applied with variations for each compliance category. The common approach relies on three steps:

1. Quantifying the actions to be considered – the technical potential for credit creation is estimated based on the Regulations' definition of eligible actions (potential projects) and information on existing or planned projects,
2. Calculating the credit creation of the actions – this calculation is based on the lifecycle emissions of the actions minus the relevant baseline (the reference CI in Schedule 1 of the CFR). Similarly, the incremental cost is based on the levelized cost of creating the credit minus the cost of the relevant baseline, and
3. Applying the engagement rate – the engagement rate is used to scale the total potential to the estimated credits created and accounts for mostly behavioural decisions but also some regulatory limits (for example, electric vehicle charging credits) and physical system challenges (for example, being able to integrate variable electricity generation, such as wind and solar). The engagement rate is provided as a percent of the full credit potential estimated in steps 1 and 2.

The starting point for the credit creation is information provided by ECCC from the Credit and Tracking System for credit creations and credit transactions that occurred in 2022 and the first half of 2023. In addition to supply, the data is used to calibrate the portion of credit cost that is transferred to credit price, for those credits that are assumed to be traded on the market (CC2 & CC3). More specifically, ECCC provided the following information that is referred to as ECCC (2023) Historical Compliance Credit Creation in this report:

- CC1: Information from the annual credit creation reports in regard to the 2022 compliance period (description of the project, location of the project, number of credits created) as well as the list of projects recognized or under review and the estimated number of credits in 2023 and for future years;
- CC2: Information from the quarterly credit creation reports in regard to Q3 and Q4 of 2022 and Q1 and Q2 of 2023 (registered creator, credit class, fuel type, feedstock type, volume, CI, energy density, number of credits, foreign supplier, if any)
- CC3: Information from the annual credit creation reports in regard to 2022 compliance period (registered creator, credit class, fuel or energy type, location of the fuelling station or charging station, volume of fuel or quantity of energy, CI, energy density, number of credits, type of charging station);
- List of CI applications (CI ID, calculated default or Fuel LCA Model, fuel type, feedstock type, approved CI, date of approval);
- Total volume of credit transaction and prices when available.

For future years, the credits and costs are estimated based on incremental cost of production for credits and lifecycle emissions, accounting for technology requirements and feedstock choices. Technology uptake projections are based on announced projects from a range of sources.

This step produced compliance credit supply curves for all categories, which were then compared to the demand for credits, and a calculation tool[8] was used to model least cost compliance choices, as described in section 3.

All monetary results are shown in 2022 Canadian dollars, inflating pre-2022 values (using GDP Deflator data), and converting non-Canadian prices (2022 exchange rates).

2.1. Compliance Category 1

Compliance category 1 credits comprise actions that reduce the lifecycle carbon intensity of liquid fossil fuels in Canada. The lifecycle includes all emissions associated with the extraction of the hydrocarbons used to produce the fuel, with the processing, refining or upgrading of those hydrocarbons to produce the fuel, with the transportation or distribution of those hydrocarbons or the fuel and with the combustion of the fuel. The number of credits created are determined by quantification methods provided by ECCC, which specify the eligibility criteria for the projects as well as the approach for quantification. Projects create credits for the portion of the fossil fuel and crude oil that is used in Canada (i.e. exported portion of products are not eligible for credit creation).

Potential reduction actions include:

- Integrating low-carbon-intensity electricity, for example through on-site solar or wind generation or supplied directly to a fossil fuel facility from an off-site low-CI generator (subject to conditions to ensure reductions are properly accounted);
- Implementing CO_2 capture and permanent storage projects at:
    - a fossil fuel facility not associated with the production of low-CI fuels;
    - a facility that supplies hydrogen, electricity[9] or heat to a fossil fuel facility;
    - a facility that supplies hydrogen to a facility that supplies electricity or heat to a fossil fuel facility;
- Implementing Enhanced Oil Recovery (EOR) with CO_2 Capture and Permanent Storage;
- Co-processing of low carbon- intensity fuel in refineries if the co-processed low-CI fuel is used or sold in Canada; and

[8] The tool was developed in Excel.
[9] Electricity must be supplied directly to the fossil fuel facility, and not supplied through an electrical network and must not be produced by a facility that combusts coal, petroleum coke or synthetic gas that is derived from coal or petroleum coke.

- Other activities eligible to create credits under the generic quantification method: energy efficiency, electrification, methane reductions beyond regulatory requirements, cogeneration but use of these credits will be limited to 10% of a regulated party's annual reduction requirement.

To be eligible reduction actions must have started on or after July 1, 2017.

Credit quantities are based on ECCC (2023) Historical Compliance Credit Creation or on public data.

2.1.1. Methodology

CCS and EOR with CCS

The following existing or planned CCS and EOR projects are considered for CC1 (from public data):

Table 9. Existing and planned CCS and EOR projects for CC1

Project Type	Start Year*	Project Name or Stakeholders	Capture Source
CO_2 capture and EOR	2022	Alberta Carbon Trunk Line (ACTL)	Refinery production
CCS	2028	Suncor and ATCO	Hydrogen production. 65% of the produced clean hydrogen would be used in refining processes and cogeneration of steam and electricity at the Suncor Edmonton Refinery.
CCS	2026	Shell Scotford	Hydrogen production
CO_2 capture and EOR	2026 (second phase)	Federated Coop Limited and Whitecap EOR	Refinery complex

Notes: *Start Year is the year assumed that the project will come online and start creating credits.

The Shell Quest project and the Weyburn SaskPower and Whitecap EOR project are excluded since these projects began operations before 2017 so do not qualify under the CFR. However, the reported project cost for CO_2 avoided from these projects and from the ACTL project are used as a proxy for costs for similar future projects. For CCS, a ~10% cost reduction is assumed compared to historical projects due to economies from learning by doing and cross-check with estimates from literature for CO_2 capture in refineries. For planned projects, credit quantities are based on project announcements (e.g., announced capture rates or hydrogen production rates), while assuming that a maximum of 80% of carbon captured would equate to carbon avoided. Furthermore, only the capture that is eligible under CC1 is considered (therefore excluding capture on chemicals or ethanol plants, for example). A portion of the capture is excluded based on the proportion of projected international exports for gasoline and diesel for each province (2.5% for Alberta, 5% for Saskatchewan) or the projected international exports for crude oil for each province.

For new potential projects, credit supply is estimated via the following formulas.

For EOR, per province and year:

$$\begin{aligned}\boldsymbol{Credit\ supply_{EOR}} &= \boldsymbol{CO_2\ Intensity\ for\ In\ situ\ Production\ and\ Upgrading} \\ &* \boldsymbol{CO_2\ Capture\ Rate} * (\boldsymbol{Crude\ Oil\ Extraction} - \boldsymbol{Exports}) \\ &* \boldsymbol{Engagement\ Rate}\end{aligned}$$

where

$CO_2\ Intensity$ is the intensity of upgrading and in situ production (see Table 12 for sources) (gCO2e/MJ oil);

$Crude\ Oil\ Extraction$ is the amount of crude oil produced in each province (MJ);

$Exports$ refer to international exports (MJ);

$Engagement\ Rate$ accounts for geological potential for sequestration in each province (i.e. total CO_2 capture considering CCS activities is well below total provincial potential) (%).

$CO_2\ Capture\ Rate$ is based on a conservative assumption on capture potential at upgrading facilities and in-situ production (40%).

For CCS, per province and year:

$$\begin{aligned}\boldsymbol{Credit\ supply_{CCS}} &= \boldsymbol{Refining\ Carbon\ Intensity} * \boldsymbol{CO_2\ Capture\ Rate} \\ &* (\boldsymbol{Refining\ Energy} - \boldsymbol{Exports}) * \boldsymbol{Engagement\ Rate}\end{aligned}$$

where

$Refining\ Carbon\ Intensity$ is an average for Canada, based on a bottom-up based engineering approach (see source in Table 12) (gCO2e/MJ gasoline/diesel). It does not include upstream emissions.

$CO_2\ Capture\ Rate$ is based on a conservative assumption on capture potential at refineries (40%);

$Refining\ Energy$ is the amount of gasoline and diesel produced in each province (MJ);

$Exports$ refer to international exports (MJ);

$Engagement\ Rate$ accounts for geological potential for sequestration in each province (i.e. total CO_2 captured in each province is well below total provincial potential) (%).

The engagement rate is described in more detail in Section 2.1.3.

Low-CI Electricity

The only planned project considered for low-CI electricity is that announced by Shell in Alberta, for a solar project at the Scotford Energy Park for the refinery. As described in the Quantification Method for this category, we refer to the data tables in the CFR Specifications for values of emissions intensity for the baseline electricity supply and a new renewable source. For costs, we perform a levelized cost calculation for the type of electricity supplied (utility-scale solar PV and wind) and compare to the cost of electricity from the grid, divided by the difference in emissions intensity. This may result in a cost of zero if the new electricity source has a lower levelized cost than the baseline source, in which case an administrative cost is applied. This approach is applied for both planned projects and new potential projects. For new projects, potential credit supply is estimated via the following formula:

$$\begin{aligned} &Credit\ supply_{lowCIelec} \\ &\qquad = Grid\ Carbon\ Intensity * Electricity\ consumption\ for\ refining \\ &\qquad * (Refining\ Energy - Exports) * Engagement\ Rate \end{aligned}$$

where

$Grid\ Carbon\ Intensity$ is based on the ECCC Specification (see Table 12). We do not consider any future improvement in grid intensity (gCO2e/MJ electricity);

$Electricity\ consumption\ for\ refining$: calculated and cross-checked with external source (Table 12) (MJ electricity/MJ refined product);

$Refining\ Energy$ is the amount of gasoline and diesel produced in each province (MJ);

$Exports$ refer to international exports (MJ);

$Engagement\ Rate$ assumes that only about a portion of refineries total electricity consumption may be directly connected to a solar or wind plant (%).

Table 10. Summary of Parameters Used for CC1 Credit Types

Credit Type	Credit Basis	Engagement Rate	Cost Basis	Other parameters
CCS	Refining energy by province, minus exports (NATEM)	Starting from 2027-2028 and accounting for a maximum of 20% of refining emissions by 2030	Reported costs of past projects, and literature data on capture, transport, and storage costs	Assumption on average CI of refining activities in Canada (used to approximate maximum available supply). Assumption on short-term achievable capture rate (40%).
EOR	Crude oil extraction energy by province, minus exports (NATEM)	Starting from 2028 and accounting for a maximum of 20% of upgrading and in-situ emissions by 2030	Reported costs of past projects	Assumption on average CI of in-situ production and upgrading activities in Canada (used to approximate maximum available supply). Assumption on short-term achievable capture rate (40%).
Low-CI electricity	Refining energy by province, minus exports (NATEM)	Starting in 2025 and accounting for a maximum of 35% of basis in 2030	Levelized cost of utility-scale solar PV and onshore wind, with an allowance for battery storage	Grid emissions intensity from CFR LCA Specifications. Assumption on electricity used per refining product unit.

Co-processing

The following existing co-processing projects are considered. New co-processing projects are not considered in the CC1 credit options. Production of low-CI fuels is considered as part of CC2 credit creation by other parties.

Table 11. Existing co-processing projects for CC1

Project Type	Project Name or Stakeholders	Project Start (for credit creation)
Co-processing	Parkland Burnaby Refinery	2023
Co-processing	Tidewater Renewables	2023

2.1.2. Sources

The main sources for estimating CC1 credits and costs are reported in Table 12.

Table 12. Sources for CC1 calculations

Parameters	Source
For supply calculations: 1) Carbon intensity of refining activities 2) Carbon intensity of upgrading and in-situ production 3) Potential for EOR with CCS (part of engagement rate) 4) Proposed CCS projects in Alberta (used to validate engagement rates) 5) Crude oil, gasoline, and diesel production amounts, export and imports	1) Jing, L., El-Houjeiri, H.M., Monfort, JC. *et al.* Carbon intensity of global crude oil refining and mitigation potential. *Nat. Clim. Chang.* 10, 526–532 (2020). 2) Pembina Institute (2014). CCS Potential in the Oil Sands: Evaluating the Impact of Emerging Carbon Capture Technologies on Oil Sands Emissions. 3) Alberta Economic Development Opportunity (2009). Enhanced Oil Recovery Through Carbon Capture and Storage: An Opportunity for Alberta. 4) Canada Energy Regulator (2022). Market Snapshot: New projects in Alberta could add significant carbon storage capacity by 2030. 5) ESMIA North American TIMES Energy Model (NATEM) (2023).
Reference cost for ACTL and similar projects	Enhance Energy Inc., Wolf Carbon Solutions Inc., and North West Redwater Partnership (2022). Knowledge Sharing Report (2021).
Reference cost for Quest, used for similar projects	Government of Alberta (2023) Quest Carbon Capture and Storage Project: Annual Summary Report 2022.

2023-2025 credit volumes for existing/planned projects	ECCC (2023) Historical Compliance Credit Creation
Low-CI electricity: 1) Electrical grid carbon intensity 2) Levelized cost of solar and wind 3) Industrial grid electricity prices 4) Electricity consumption for refining	1) Specifications for Fuel LCA Model CI Calculations 2) ESMIA Technology Database (2023) 3) Statista (2022). Average industrial electricity prices in Canada as of April 2022, by select city. 4) Calculated by ESMIA and cross-checked with: CONCAWE (2012), EU refinery energy systems and efficiency.

2.1.3. Assumptions

For potential new projects, the engagement rate is intended to approximate the actual potential for project development in the next decade. Due to the complexity of CCS and EOR projects, the significant investments required, and the lead time for construction, it is assumed that these projects could only start to come online in 2027-2028, and would only reach a portion of their full potential by 2030 (up to a maximum of 20%; see Table 13, noting that engagement rate is multiplied by the 40% capture rate). Therefore, the engagement rate is meant to estimate the actions and investments that could be made by regulated parties and their suppliers in the next seven years. Engagement rates vary by province: in Alberta and Saskatchewan, it is assumed that new projects may begin one year earlier due to prior experience and existing regulations. Nevertheless, in 2030, Alberta's engagement rate is 5% lower than Saskatchewan's to account for projects that have already been planned in the province. For New Brunswick and Newfoundland and Labrador, only a low engagement rate of 5% is assumed in 2030, due to the less certain outlook for carbon storage and challenges associated with offshore storage. We ensure that total CO_2 sequestration quantities remain well below sequestration potential limits as well as within the magnitudes of announced projects in Alberta (see Table 12 for sources). The engagement rate for EOR also accounts for the estimated potential of oil that may be recoverable via EOR processes. For example, as a benchmark, production at Weyburn, Saskatchewan using EOR with CO_2 reached over 28,000 barrels per day, and it is estimated that 20 to 30% of the remaining oil could be recovered near the Clive site in Alberta[10]. For low-CI electricity, we assume that a quicker uptake is possible due to lower complexity and

[10] Quan, Holly. Enhancing Canada's sustainability through carbon capture (2020). Context Energy Examined. https://context.capp.ca/articles/2020/feature-enhance-energy-carbon-capture/

greater past experience. These parameters are inherently uncertain and will influence credit supply, and thereby affect total compliance cost.

With regards to costs, since the goal of the study is to calculate incremental cost of the Clean Fuel Regulations, we must subtract the "reference" cost where applicable, or account for any possible revenues (e.g., due to other policies). Furthermore, for existing projects (started prior to 2022, e.g., ACTL, co-processing), it can be assumed that these were created in response to other policies or market conditions and therefore an administrative cost of 2 (2022)CAD/tonne is applied. While we subtract the carbon price for CCS and EOR credits since it is considered as a source of revenue, the minimum cost is limited to 2 (2022)CAD/tonne for two reasons. First, the analysis assumes that the incremental impacts of the CFR cannot be positive (i.e. generate revenues), but rather that costs may be zero at best due to the existence of prior policies and market dynamics within the fossil fuel supply chain (i.e., a crude oil producer, assuming it is a separate entity from a regulated party, would increase its profit margin rather than decreasing sales price of its products). Second, there is a risk that regulated parties may not be able to sell all of their CC1 credits (created via EOR or CCS) in the performance standards policy (via carbon pricing), for example, due to an over-supplied market. The assumptions are summarized in Table 14.

Table 13. Engagement rate for different types of projects, per province (%).[11]

	2025	2026	2027	2028	2029	2030
CCS (%)						
Alberta	0	0	5	10	15	15
Saskatchewan	0	0	5	10	15	20
Ontario	0	0	0	10	15	20
Quebec	0	0	0	10	15	20
New Brunswick	0	0	0	0	0	5
EOR w/ CCS (%)						
Alberta	0	0	0	10	10	15
Saskatchewan	0	0	0	10	15	20
British Columbia	0	0	0	5	10	15
Manitoba	0	0	0	5	10	15
Newfoundland & Labrador	0	0	0	0	0	5
Low-CI electricity (%)						
All provinces	10	10	20	25	30	35

[11] For 2027, engagement rates are above zero for Alberta and Saskatchewan only, due to prior experience with CCS projects that currently exist in these provinces.

Table 14. Incremental Cost Basis.

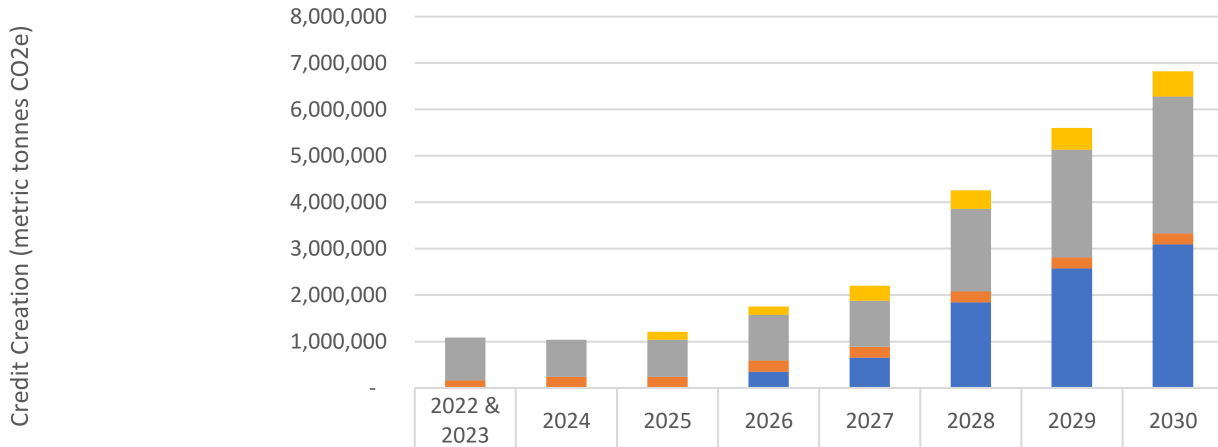
Type of Project	Incremental Cost Basis
CCS	Capital and operating (including energy) costs for CCS projects are included. The CCS Investment Tax Credit is not considered. The avoided carbon price is a benefit and is subtracted from the cost, but costs are limited to $2/tonne at minimum i.e. negative costs are not allowed*
EOR w/ CCS	Same as CCS plus including the benefit of additional oil production from recovery
Low-CI electricity	Difference with grid electricity cost for industrial users (normalized by difference in emissions)
Existing projects (prior to 2022)	Administrative cost is applied

Notes: *Reflecting the assumption that the GHG reductions can also be sold as credits in the industrial carbon pricing policy.

2.1.4. Results

Figure 1The supply of credits in 2022 (grouped with 2023), can be banked for following years but is relatively limited. Credit supply remains relatively stable across 2023-2025, and begins to increase in 2026-2027 as planned projects come online (see Figure 1). Credit supply jumps up in 2028, since it is assumed that further planned and new potential projects for CCS and EOR will start to come online. The credit supply continues to increase in 2029-2030, mainly due to a projected increase in both CCS and EOR activities – this is a result of the assumptions used for the engagement rate. In general, the potential for low-CI electricity credits is a small proportion of total credits due to the small share of input electricity used compared with total refining energy output.

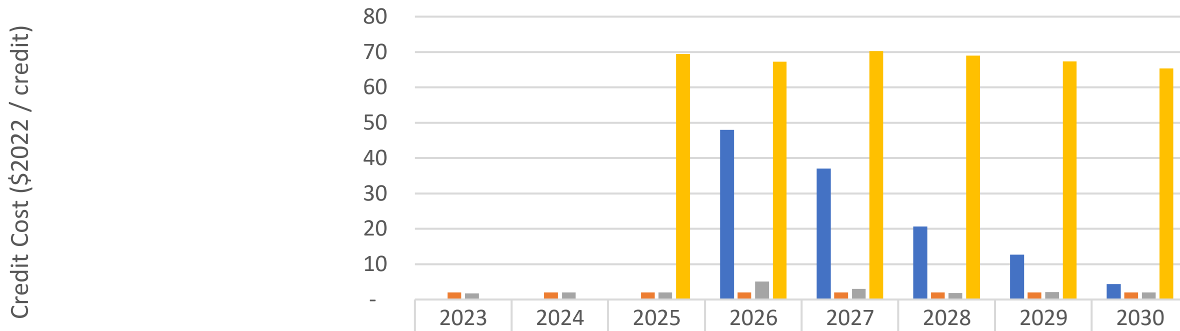
Figure 1. Projected CC1 credit creation potential



	2022 & 2023	2024	2025	2026	2027	2028	2029	2030
Low-CI electricity	-	-	174,535	174,451	322,396	396,200	469,921	543,557
Enhanced oil recovery with CCS	920,411	800,000	800,000	990,000	990,000	1,777,004	2,323,684	2,948,907
Co-processing (existing only)	165,644	238,075	238,075	238,075	238,075	238,075	238,075	238,075
Carbon capture & permanent storage	-	-	-	351,000	651,121	1,843,579	2,573,904	3,090,051

In Figure 2, the weighted average cost of credits is shown (weighted by supply amount). In 2023, credit costs represent only the administrative costs since we assume that the project costs are not related to the CFR policy. Next, we observe that EOR with CCS credits are lowest cost, which is a result of the increasing carbon price that is applied as a revenue for these credits. Similarly, CCS costs also decrease with time due to carbon pricing, but have a higher cost than EOR. This can be explained by the fact that EOR projects generate revenues through the extraction of oil, while at the same time sequestering CO_2 – leading to lower cost of CO_2 avoided. Finally, low-CI electricity projects represent the most expensive credit option in the CC1 category, however their cost can vary widely between provinces since it depends on both the emissions intensity of the grid and the cost of grid electricity.

Figure 2. Weighted average cost of CC1 credit creation



	2023	2024	2025	2026	2027	2028	2029	2030
Carbon capture & permanent storage	-	-	-	48	37	21	13	4
Co-processing (existing only)	2	2	2	2	2	2	2	2
Enhanced oil recovery with CCS	2	2	2	5	3	2	2	2
Low-CI electricity	-	-	69	67	70	69	67	65

2.2. Compliance Category 2

Compliance category 2 (CC2) involves the creation of compliance credits for the production or import of bioenergy consumed in Canada to substitute the use of liquid, gaseous or propane reference fossil energy. It includes production and import of various fuels including:

- First and second-generation biofuels[12] or other liquid low-CI fuels (e.g., produced from direct air capture) to substitute the liquid class;
- Hydrogen, biogas, renewable natural gas to substitute natural gas (gaseous class credits);
- Renewable propane production to substitute propane (gaseous class credits).

The CFR restricts the type of feedstock which can be used to produce bioenergy as well as the carbon intensity (CI) for the energy to be considered as low carbon. Feedstock must meet the Land-use and Biodiversity Criteria. For fuels to be eligible, their CI must be lower than 90% of the reference CI in a given period as set out in Schedule 1 of the Regulations.

[12] Biofuels are diverse but generally classified into two categories, first and second generation biofuels. First generation biofuel refers to ethanol, biodiesel produced from sugar, starch, vegetable oil or animal fat using conventional technology. Second generation biofuel refers to renewable diesel or gasoline produced from non-food biomass through complex synthesis such as FT, DME.

The rollover of surplus credits from the Renewable Fuels Regulations is considered, based on ECCC (2023) Historical Compliance Credit Creation, and is added to total credits created in 2022 (see section 3.3). These credits are assigned the minimum credit price (see section 2.4).

2.2.1. Methodology

CC2 credit creation is calculated at the production plant granularity for Canadian plants (subtracting exported low-CI fuels) and importer origin for imported low-carbon energy. Existing and planned projects are included (from public data).

Table 15. Summary of Parameters Used for CC2 Credit Types

Plant Type	Stakeholders	Assumptions on carbon intensity	Assumptions on production cost
Ethanol, Biodiesel and Renewable diesel production in Canada.	All existing plants and all announced projects.	Production plant specific CI calculated from ECCC (2022) Fuel LCA Model and calibrated with reported CI from ECCC (2023) Historical Compliance Credit Creation. Carbon intensity is assumed constant over time.	Levelized cost of production based on production technology cost, energy cost and feedstock cost. Capital investment is assumed constant over time. Energy cost evolves over time and is derived from historical rates from ESMIA (2023) Tariff Model. Excludes transportation cost.
Ethanol, Biodiesel and Renewable diesel imported to Canada.	Importer from USA and Brazil.	Production plant specific CI calculated from ECCC (2022) Fuel LCA Model and calibrated with reported CI from ECCC (2023) Historical Compliance Credit Creation. Carbon intensity is assumed constant over time.	The cost of import is based on historical market prices then assumed to increase with inflation through 2030.
Hydrogen production in Canada.	All existing plants and all announced projects.	Production plant specific CI calculated from ECCC (2022) Fuel LCA Model and calibrated with reported CI from ECCC (2023) Historical Compliance Credit Creation. No over-time decrease of carbon intensity is assumed.	Levelized cost of production based on production technology cost, energy cost and feedstock cost. Capital investment is assumed constant over time, investment tax credit is not included in the analysis. Energy cost evolves over time and is derived from historical rates from ESMIA (2023) Tariff Model. Includes transmission cost but excludes distribution cost.

Plant Type	Stakeholders	Assumptions on carbon intensity	Assumptions on production cost
Renewable gas production in Canada.	All existing plants and all announced projects.	Production plant specific CI calculated from ECCC (2022) Fuel LCA Model and calibrated with reported CI from ECCC (2023) Historical Compliance Credit Creation. No over-time decrease of carbon intensity is assumed.	Levelized cost of production based on production technology cost, energy cost and feedstock cost. Capital investment is assumed constant over time. Energy cost evolves over time and is derived from historical rates from ESMIA (2023) Tariff Model. Includes transmission cost.

The volume of low-carbon energy produced is derived from available data and projected from 2022 to 2030. The type of biofuels, including imports or domestic production and the feedstock used, is sourced from a detailed review of existing plants. Future projections of the type of fuel and feedstock produced, notably the renewable diesel production is derived from CER (2023). For imports, this analysis assumes that ethanol will be imported to reach at least the province-specific blending mandates target. For biodiesel and renewable diesel, it is assumed to be produced or imported to reach the greater of provincial blending mandates requirements or the assumed real blending rate. The extra-production (i.e., the renewable and bio diesel production exceeding the blending rates) is assumed to be exported as soon as 2023 due to low-cost credits oversupply. Because of legislative recognition granted to US and Canadian agricultural biofuel feedstock providers for meeting the LUB criteria, no limits based on feedstock sources were applied in this analysis.

The maximum amount of compliance credits created is calculated with formulas provided in the Regulations. The initial estimate of supply represents an idealistic amount of compliance credit creation assuming every single unit of energy produced or imported complies with the Regulations' requirements and creates corresponding credits. This maximum number of compliance credits is then refined with a compliance/engagement rate representing both the share of producers compliant with the regulation requirements and their own behavior regarding participation to the compliance credit market. For example, producers may decide to export the low-CI fuels they produce instead of participating to the CFR compliance credit market, which is already the case in 2022 and 2023. This could be due to higher prices in other markets, long-term contracts, or other reasons. For example, assuming that 100% of biofuel producers register to participate in the regulation but only 75% meet the requirements, the compliance/engagement rate value would be 75%.

Similarly, the compliance credit cost is estimated as the incremental cost for the producer/importer to reduce a tonne of carbon by substituting liquid class or gaseous class (natural gas or propane fuels) by low-carbon fuels. The main assumptions to calculate the production cost of low-carbon fuels are provided in Table 15. The compliance credit cost formulas are derived from the compliance credit creation formulas. For example, the compliance credit creation formula uses equation 94 (2) from the Regulations :

$$CC_{creation} = CI_{diff} * (Q * D) * 10^{-6}$$

where

CI_{diff} is the difference between the reference carbon intensity for the liquid class and the carbon intensity of the low-carbon-intensity fuel (g CO_2e/MJ);

Q is, subject to subsection 45(1), the volume of the low-carbon-intensity fuel (m^3); and

D is the energy density of the low-carbon-intensity fuel (MJ/m^3) .

The derived formula to calculate the compliance credit cost (2022 CAD/tonne) is :

$$CC_{cost} = CST_{diff} * (Q * D) * 10^{-3} / CC_{creation}$$

where

CST_{diff} is the difference between the production gate cost of the low-carbon-intensity fuel and the reference production gate cost for the liquid class as per Annex A (2022 CAD/GJ).

2.2.2. Sources

The main sources for estimating CC2 credits and costs are reported in Table 16.

Table 16. Sources for CC2 calculations

Parameters	Source
Fuel volume	- CER (2023) Market Snapshot: Two Decades of Growth in Renewable Natural Gas in Canada; - CER (2023) Market Snapshot: New Renewable Diesel Facilities Will Help Reduce Carbon Intensity of Fuels in Canada; - ESMIA (2023) Hydrogen Project Database; - ESMIA (2023) Existing Biofuel Plants Database; - USDA (2023) Biofuels Annual
Compliance/engagement rate	- ECCC (2023) Historical Compliance Credit Creation;
Carbon intensity	- ECCC (2022) Fuel LCA Model
Reference production gate cost	- CER (2023) Canada's Energy Future; - ESMIA (2023) Tariff model;

- WAEES (2021) Analysis of the Implications of Canada's Proposed Clean Fuel Standard for Canadian Biofuels and Biofuel Feedstock;

2.2.3. Assumptions

The reference production gate cost that has been assumed is indicated in Annex A. It is based on projected commodity production cost in a reference scenario and projected for the time-horizon based on:

- crude oil commodity market price in a reference scenario and refining margin for gasoline and diesel (excluding taxes);
- natural gas commodity market price in a reference scenario;
- propane commodity market price in a reference scenario.

The compliance/engagement rate of low carbon fuel producers is calibrated with ECCC data (ECCC 2023). It is then projected to account for future higher engagement of involved parties accounting for the below factors.

Engagement/compliance rate is based on ECCC (2023) Compliance Credit Creation, with the following case-by-case methodology:

Compliance rate is calculated by estimating the share of low-carbon biofuel produced and consumed within Canada to comply with the assumed real blending rates, which are at least as high as the provincial/federal blending mandates (see

1. Table 18).
2. When credit creation data is provided for a producer/importer, the engagement rate is calibrated in regard to 2022-2023 with credit creation data and assumed constant over the time-horizon;
3. When CI are submitted for a facility, but no credits are created in 2022-2023, the engagement rate is assumed to be 90% in 2024-2030 for a given producer/importer;
4. When no credits are created in 2022-2023, the engagement rate is assumed to gradually increase:
    - from 0% in 2023 to 90% in 2027 for liquid biofuels;
    - from 0% in 2023 to 50% in 2027 for hydrogen;
    - and from 0% in 2023 to 40% in 2027 for renewable natural gas (EnergyRates 2023).

Table 17. CC2 weighted[13] average engagement/compliance rate

Parameters	2022	2023	2024	2025	2030
Ethanol	44%	86%	89%	91%	93%
Biodiesel	9%	20%	34%	51%	72%
Renewable diesel	45%	32%	31%	37%	50%
Hydrogen	0%	0%	25%	50%	50%
Renewable natural gas	1%	1%	11%	20%	35%

Table 18. Assumptions on real blending rate per province[14]

%of energy	Gasoline blend			Diesel blend			Heating oil blend		
	2022	2025	2030	2022	2025	2030	2022	2025	2030
Alberta	5%	6%	10%	2%	6%	10%	2%	3%	5%
Saskatchewan	7.5%	11%	12%	2%	6%	10%	2%	3%	5%
British Columbia	5%	8%	10%	4%	6%	8%	2%	3%	5%
Manitoba	8.5%	10%	10%	5%	5%	5%	2%	3%	5%
Ontario	10%	12%	15%	4%	8%	12%	2%	3%	5%
Québec	5%	12%	15%	2%	6%	12%	2%	3%	5%
New Brunswick	2%	10%	15%	2%	8%	15%	2%	3%	5%
Nova Scotia	2%	6%	10%	2%	6%	10%	2%	3%	5%
PEI	2%	6%	8%	2%	6%	8%	2%	3%	5%
Newfoundland & Labrador	3%	10%	12%	2%	8%	12%	2%	3%	5%
Territories	0%	0%	0%	0%	0%	0%	2%	3%	5%

Carbon intensity is calculated as per ECCC (2022) Fuel LCA Model and calibrated (when data is available) on ECCC (2023) Historical Compliance Credit Cost. This carbon intensity accounts for all life cycle stages from feedstock production/cultivation to the combustion of the fuel. The following table summarizes average carbon intensity for low-carbon energy. Note that carbon intensity is calculated at the facility level. The observed decrease in carbon intensity reported in Table 19 is based on the increased use of an LCA-based CI instead of the default CI from the Regulations. In other words, the analysis assumes the production process and carbon intensities do not change during the time horizon, rather the change in CI reflects more producers using the LCA model.

[13] Weighted by maximum credit creation amount

[14] Note that this table is in percent by energy. Percent by volume rates would be higher, especially for gasoline, due to ~33% lower volumetric energy density of ethanol as compared to gasoline. Biodiesel has ~7% lower energy density than diesel. (Source : US D.O.E. Alternative Fuels Data Center, Fuel Properties Comparison. https://afdc.energy.gov/fuels/properties)

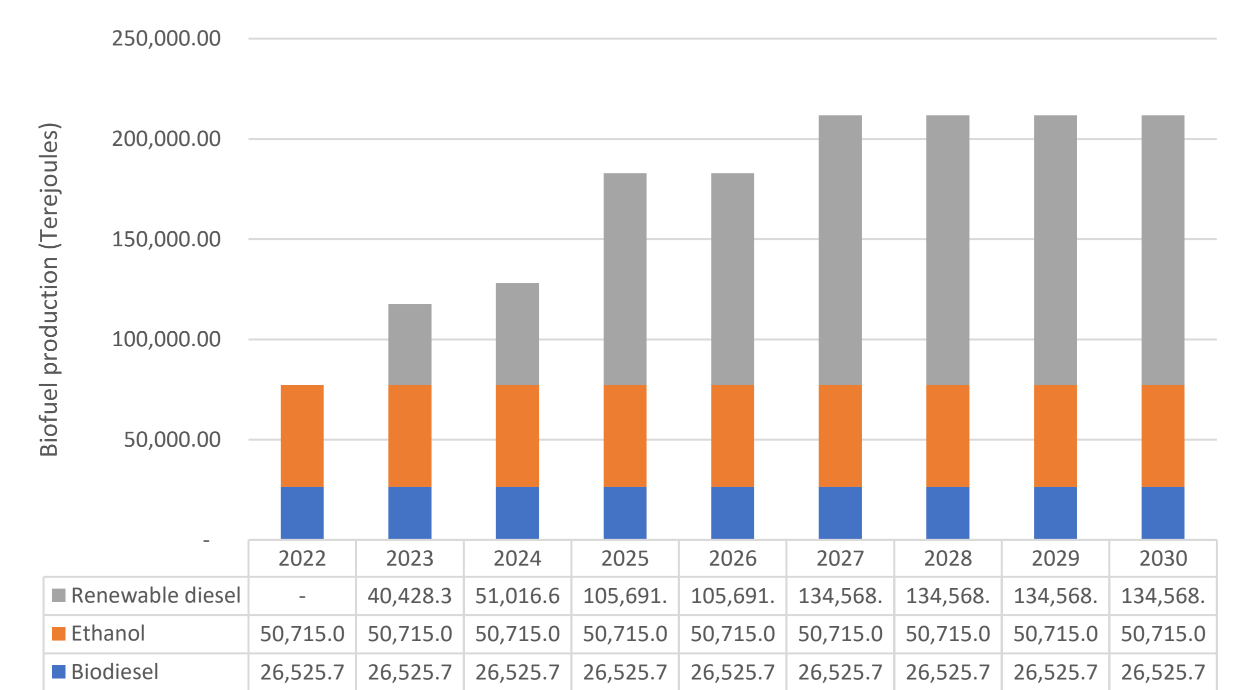
Table 19. CC2 weighted average carbon intensity

Parameters	2022	2023	2024	2025	2030
Ethanol	60.3	56.6	46.0	43.6	43.1
Biodiesel	73.5	71.4	24.8	23.9	23.0
Renewable diesel	76.5	58.0	37.8	25.8	26.0
Hydrogen	n/a	n/a	58.3	51.1	41.6
Renewable natural gas	25.2	25.2	6.6	4.3	4.1

2.2.4. Results

Figure 3 shows the biofuel production trend in Canada, which is expected to almost triple (or increase by 174%) by 2030 compared to 2022 levels with significant deployment of renewable diesel production facilities as soon as 2023. Note that the renewable diesel production will largely over-supply the blending requirements as soon as 2023, which is assumed to lead to increasing exports. On average, the resulting blending rate is expected to rise by 2030 to 5% in heating oil, 8-15% in automotive gasoline and 5-15% in automotive diesel.

Figure 3. Biofuel production in Canada

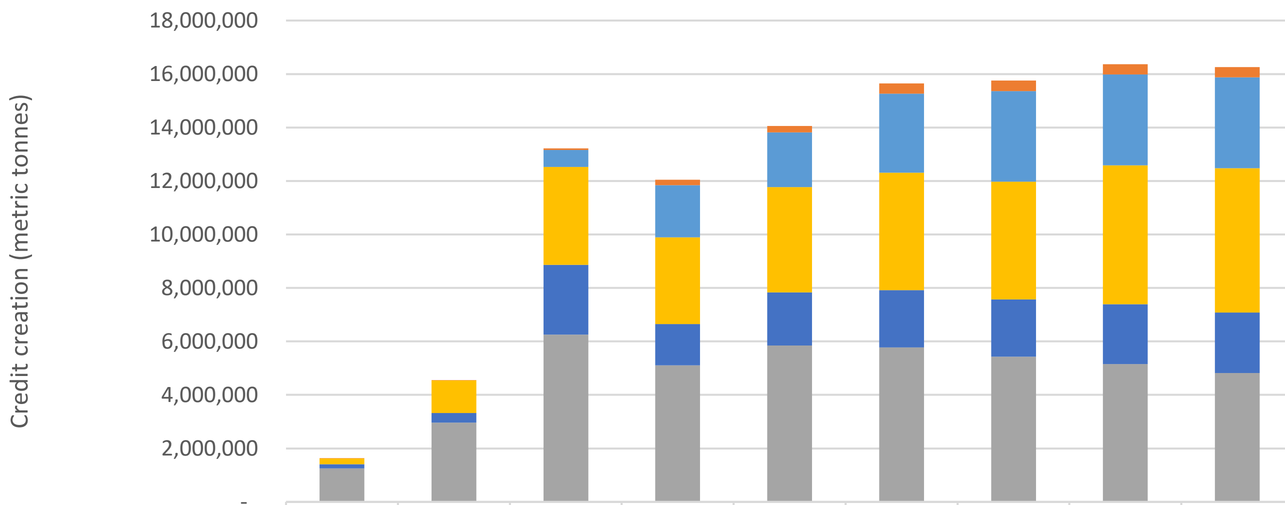


	2022	2023	2024	2025	2026	2027	2028	2029	2030
Renewable diesel	-	40,428.3	51,016.6	105,691.	105,691.	134,568.	134,568.	134,568.	134,568.
Ethanol	50,715.0	50,715.0	50,715.0	50,715.0	50,715.0	50,715.0	50,715.0	50,715.0	50,715.0
Biodiesel	26,525.7	26,525.7	26,525.7	26,525.7	26,525.7	26,525.7	26,525.7	26,525.7	26,525.7

As a general trend, CC2 credit creation is expected to grow eight-fold from 2022 to 2030 (see Figure 4). It is driven by an increasing engagement rate, combined with additional low-carbon fuel production capacities especially for renewable diesel as well as hydrogen.

Biodiesel and renewable diesel credit creation cost is artificially high in 2022-2023 due to the use of default carbon intensities gradually replaced by LCA CI. Year 2024 shows relatively high credit creation due to the retroactive credit creation mechanism which allows 2022-2024 credit creation CI adjustment in regard to 2024. Consequently, year 2024 may exhibit a credit over-supply and lower average credit creation cost. Year 2030 credit creation cost shows real credit creation cost, unaffected by default CI. Renewable natural gas credits are typically modelled to be the least expensive (i.e., around 150 CAD 2022 / tonne CO2e). Biodiesel, HDRD and ethanol credits are modelled to have comparable costs in the 130-350 CAD 2022 / tonne CO2e range. While ethanol is modelled to be relatively less expensive on an energy basis, it has a relatively high CI attributable to its corn feedstock, which results in higher credit creation cost than biodiesel and HDRD. Hydrogen is modelled to have higher credit creation cost of approximately 440 CAD 2022 / tonne CO2e in 2030) on average. Hydrogen credit creation cost varies due to the wide range of CI of the hydrogen production projects deployed in the time-horizon.

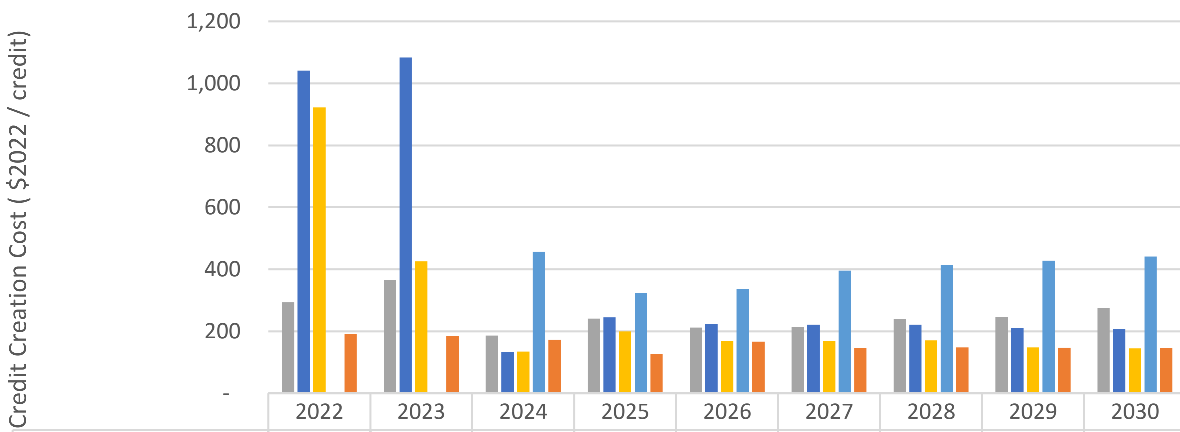
Figure 4. Projected CC2 credit creation[15]



	2022	2023	2024	2025	2026	2027	2028	2029	2030
Renewable natural gas	3,235	5,712	62,573	209,080	233,991	383,027	388,614	388,614	388,614
Hydrogen	-	-	637,078	1,943,630	2,054,028	2,958,866	3,390,028	3,389,447	3,390,214
Renewable diesel	218,697	1,223,662	3,652,579	3,237,922	3,927,183	4,388,501	4,408,564	5,201,323	5,399,052
Biodiesel	155,387	356,846	2,608,493	1,552,915	1,993,183	2,133,679	2,136,143	2,233,485	2,257,764
Ethanol	1,256,400	2,963,915	6,258,462	5,103,018	5,845,635	5,782,379	5,431,051	5,154,694	4,824,811

[15] Note: Figures do not include credits that are rolled over from the Renewable Fuel Regulations (they are shown in overall results in section 3)

Figure 5. Weighted average CC2 credit creation cost



	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ethanol	294	365	186	241	212	214	239	247	275
Biodiesel	1,042	1,084	134	245	224	221	221	210	208
Renewable diesel	922	426	134	199	168	168	171	148	145
Hydrogen	-	-	457	323	337	396	415	428	441
Renewable natural gas	192	185	173	126	166	146	148	147	146

2.3. Compliance Category 3

Compliance category 3 (CC3) involves the creation of compliance credits for the supply in Canada of low-carbon energy sources and fuels to vehicles to substitute the use of liquid fossil energy. It includes the supply of various fuels including:

- Electricity to substitute the liquid class;
- Hydrogen to substitute the liquid class;
- Gas and propane to substitute the liquid class;
- Renewable gas to substitute the liquid class;
- Renewable propane to substitute the liquid class.

2.3.1. Methodology

CC3 credit creation is calculated at the end-use level on the basis of the life-cycle emissions of low-carbon energy supplied to vehicles. Clean energy vehicle uptake is historically calibrated on available data and projected based on ESMIA's North American TIMES Energy Model (NATEM) reference scenario. This study includes all vehicles from electricity to hydrogen, as per the following table:

Table 20. Summary of Parameters Used for CC3 Credit Types

Supply type	Stakeholders	Assumptions on carbon intensity	Assumptions on supply cost
Electricity	Residential, commercial, and public charging stations	Electricity is assumed to be supplied by the electricity grid to the supplier or consumer. The associated carbon intensity is assumed constant as per schedule 6.	The electricity supply cost is assumed to be the commercial electricity supply cost based on ESMIA (2023) Tariff Model. It includes electricity cost, federal carbon price as well as transmission and distribution cost. The capital cost required for charging infrastructure deployment is calculated as a levelized cost and added to the supply cost.
Gas and renewable gas	Gas fuelling stations	Gas supply carbon intensities are calculated based on ECCC (2022) Fuel LCA Model and calibrated with ECCC (2023) Compliance Credit Creation carbon intensity when available.	Gas supply cost is based on commercial rates from ESMIA (2023) Tariff Model. It includes gas cost, transmission, and distribution cost. It excludes the carbon tax.
Hydrogen	Hydrogen fuelling stations	Hydrogen supply carbon intensity is calculated based on ECCC (2022) Fuel LCA and calibrated with ECCC (2023) Compliance Credit Creation carbon intensity.	Hydrogen supply cost is based on hydrogen production cost of CC2 projects. Additionally, transmission and distribution costs are added to the production cost.
Renewable gas production in Canada	All existing plants and announced projects	Production plant specific carbon intensity is calculated from ECCC (2022) Fuel LCA Model and calibrated with reported carbon intensity from existing compliance credit creation.	Levelized cost of production based on production technology cost, energy cost and feedstock cost. Capital investment is assumed constant over time. Energy cost evolves over time and is derived from historical rates from ESMIA (2023) Tariff Model. Includes transmission cost.

The volume of low carbon energy supplied to vehicles is derived from available data and projected from 2022 to 2030 using ESMIA (2023) NATEM Reference Scenario including all Federal and Provincial policies (including ZEV mandates). Historical vehicle uptake is derived from:

- StatsCan until 2021 for Electric Vehicle (EV);
- StatsCan until 2021 for Natural gas and propane vehicles;
- Assumed null until 2021 for Hydrogen vehicles.

The maximum amount of credit creation is calculated at first based on vehicle uptake (i.e., to represent the idealistic amount of credits if every unit of energy supplied to vehicles complies with the regulation and creates the corresponding credits). This maximum number of compliance credits is then refined with a compliance/engagement rate representing both the share of producers compliant with the regulatory requirements and their own behavior regarding participation to the compliance credit market.

Similarly, the compliance credit cost is estimated to be the incremental cost for a supplier to reduce a tonne of carbon by substituting Liquid class fuels by low-carbon fuels. The methodology to calculate the supply cost of low-carbon fuel is described in the previous table. The compliance credit cost formulas are derived from the compliance credit creation formulas. For example, the 102 (1) compliance credit creation formula is:

$$CC_{creation} = \left[\left(R_{ee} * CI_{ref}\right) - CI_e)\right] * (Q * D) * 10^{-6}$$

where

R_{ee} is the energy efficiency ratio;

CI_{ref} is the reference carbon intensity for the liquid class for the compliance period (g CO_{2e}/MJ);

CI_e is the carbon intensity of the electricity supplied to the electric vehicles (g CO_2e/MJ);

Q is the quantity of electricity supplied to the electric vehicles, expressed in kilowatt-hours, as measured by the charging stations; and

D is 3.6 megajoules per kilowatt-hour.

The derived formula for compliance credit cost is :

$$CC_{cost} = \left[CST_e - \left(R_{ee} * CST_{ref}\right))\right] * (Q * D) * 10^{-6}/CC_{creation}$$

where

CST_{ref} is the reference distribution gate cost for the liquid class as per 2.3.3 ((2022)CAD/TJ); and

CST_e is the distribution gate cost of the electricity supplied to the electric vehicles ((2022)CAD / TJ).

Note that negative supply costs are assumed as zero cost credits.

2.3.1. Sources

The main sources for estimating CC3 credit quantity and costs are reported in Table 21.

Table 21. Sources for CC3 calculations

Parameters	Source
Energy volume	- Statistics Canada (2023) New motor vehicle registrations; - ESMIA (2023) NATEM reference scenario.
Compliance/engagement rate	- ECCC (2023) Historical Compliance Credit Creation
Carbon intensity	- ECCC (2022) Fuel LCA Model
Reference distribution gate cost	- Canadian Energy Regulator (2023) Canada Energy Future; - ESMIA (2023) Tariff model.
Energy efficiency	- ESMIA (2023) Technology database

2.3.2. Assumptions

Reference distribution gate cost is assumed as in Annex B. It is based on commodity supply cost at the distribution gate in a reference scenario and projected for the time-horizon based on:

- crude oil commodity market price in a reference scenario, refining operating margin for gasoline and diesel and marketing operating margin for gasoline and diesel as per 3.4.1. (excluding taxes);
- natural gas commodity market price in a reference scenario, natural gas transmission and distribution costs;
- propane commodity market price in a reference scenario, propane distribution cost.

Engagement/compliance rate is calibrated on ECCC (2023) Historical Compliance Credit Creation. It is then projected to account for future higher engagement of involved parties. The following table summarizes average CC3 compliance/engagement rate used in our analysis. Compliance assumptions are similar to those used by ECCC (2022) RIAS: 28% of light-duty EV energy is provided by public stations which are eligible for credit creation. The rest comes from chargers at residential homes. It is assumed that 7.5% of light-duty EV energy in 2021 was from residential charging stations capable of collecting and communicating charging data to a charging network operator, increasing by 2.5% each year. Additionally, a variable engagement rate is required as CC3 credits build over-time. In 2023, we assume that 10% of potential credit creators do engage in credit creation in 2022, reaching 60% by 2030. For other CC3 sub-categories, (i.e., heavy vehicles electricity supply, hydrogen supply, gaseous supply), the compliance rate is assumed to be 100% and the associated engagement rate gradually reaches an upper bound of 90% by 2030. The following table summarizes the resulting CC3 compliance/engagement rate obtained from the methodology.

Table 22. CC3 weighted average compliance/engagement rate

%	2022	2023	2024	2025	2030
Light duty EV & PHEV	4%	4%	5%	7%	30%
Heavy duty EV & PHEV	0%	20%	40%	60%	90%
Hydrogen vehicles	0%	20%	40%	60%	90%
Gaseous vehicles	9%	23%	46%	66%	66%

The energy efficiency ratio (EER) is determined by comparing the efficiency of a vehicle powered by a reference fuel such as gasoline or diesel to that of one powered by an alternative energy source such as electricity or hydrogen. The Regulations use this ratio to determine the amount of fossil fuel energy displaced by electric vehicles, hydrogen fuel cell vehicles, or other vehicles using hydrogen as a fuel in order to determine the quantity of avoided emissions. As required, default EER from the Regulation are used for electric and hydrogen vehicles.

Electricity supplied to vehicles is derived from a NATEM reference scenario as per Table 23. These assumptions are intrinsically uncertain.

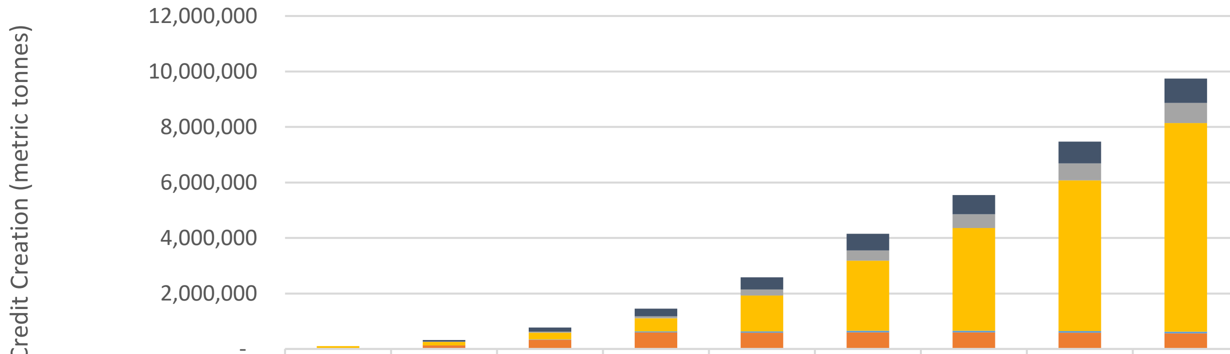
Table 23. Electricity supplied to EV & PHEV in Canada (PJ)

PJ	2022	2023	2024	2025	2030
Light duty EV & PHEV	7	12	17	21	88
Heavy duty EV & PHEV	0	1	1	1	3
Buses EV	0	1	1	1	3

2.3.3. Results

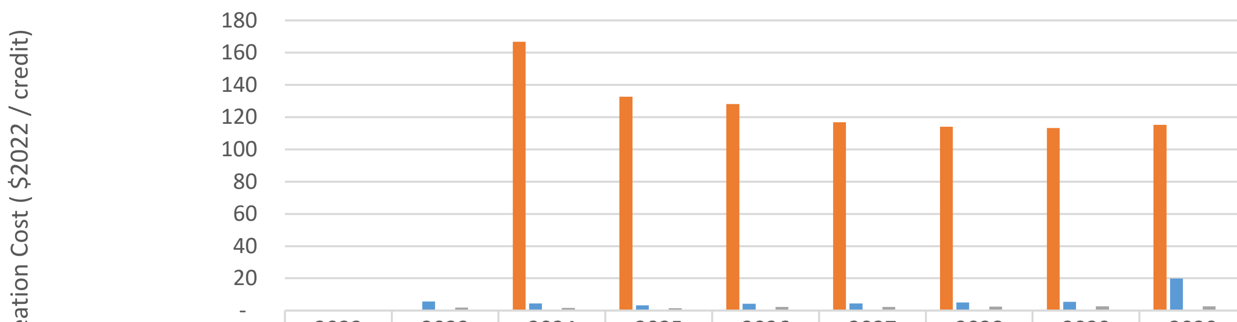
As a general trend, CC3 credit creation is expected to grow significantly from 2022 to 2030 (see Figure 6). It is driven by an increasing engagement rate, combined with rapid uptake of low-carbon vehicles, especially light battery-electric vehicles. Credit creation cost to supply battery-electric and hydrogen vehicles is low or null due to their high efficiency, which compensates for the extra-cost per gigajoule of hydrogen and electricity. Credit creation cost to supply gaseous vehicles (i.e., natural gas, renewable natural gas, and propane) is higher due to multiple drivers including high cost of energy, low efficiency gain, and low carbon intensity gain.

Figure 6. Projected CC3 credit creation



	2022	2023	2024	2025	2026	2027	2028	2029	2030
Buses EV	-	54,370	144,008	268,245	446,751	597,853	692,445	784,796	873,813
Heavy duty EV & PHEV	-	14,854	39,016	72,038	213,345	367,737	491,230	610,491	725,520
Light duty EV & PHEV	77,618	126,053	238,740	477,957	1,298,38	2,528,92	3,703,85	5,426,24	7,518,15
Hydrogen vehicles	-	4,015	15,026	31,486	43,715	50,925	52,467	53,805	54,939
Gaseous vehicles	26,736	125,025	333,177	598,231	585,969	601,795	603,729	591,771	565,920

Figure 7. Weighted average of CC3 credit cost



	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gaseous vehicles	-	-	167	133	128	117	114	113	115
Hydrogen vehicles	-	6	4	3	4	4	5	5	20
Light duty EV & PHEV	-	-	-	-	-	-	-	-	-
Heavy duty EV & PHEV	-	2	2	1	2	2	2	3	3
Buses EV	-	-	-	-	-	-	-	-	-

2.4. From credit cost to credit price

2.4.1. Methodology

Compliance credit costs cover the incremental costs:

- for regulated parties to decrease their own carbon intensity;

- for low-carbon fuel producers to produce low-carbon fuels;
- for low-carbon fuel suppliers to supply a vehicle the required energy to travel a distance with low-carbon fuel instead of conventional fuels.

While the expected compliance credit market price is linked with the compliance credit cost, part of the cost may not be covered in the compliance credit price. This is observed when comparing incremental cost to actual data on market prices, and may be explained by the fact that low-CI fuel suppliers (or other market participants) may recoup part of their costs through the sale of their products. In the short-to-medium term, when regulations are not too stringent, credit prices may remain relatively low. In the long term, as regulations become more stringent, credit prices may rise due to market dynamics and effectively lower the cost of low-CI fuels.

To estimate the compliance credit price, we use the following methodology.

CC1 compliance credits are assumed to be directly used by a regulated party (or transferred through private contract) to comply in a reference period. Therefore, they have no market price.

CC2 and CC3 compliance credits resulting from complying with other regulations such as the provincial blending mandates or the ZEV mandate will be attributed to the minimum price covering an administrative cost of 2 (2022)CAD/tCO2e credit. Those compliance credits are calculated from a baseline scenario that accounts for the impact of existing regulations only. For compliance credits created in response to the Regulations, the associated credit price is calculated as per:

$$CC_{price} = T_{min} + S_{\%} * CC_{cost}$$

where

T_{min} is a fixed minimum price to provide credits to the market, its reference value for 2022 is 38.5 (2022)CAD/t CO2e credit and is based on the analysis of ECCC (2023) Historical Compliance Credit Creation;

$S_{\%}$ is the share of compliance credit cost passed on to credit price. Its value depends on the credit category, and it is calibrated with historical credit prices;

CC_{cost} is the compliance credit cost as defined in previous sections.

2.4.2. Sources

The main sources for estimating credit prices, including estimates of zero price credits are reported in Table 24.

Table 24. Sources for credit price calculation

Parameters	Source
Share of compliance costs passed on to price	- ECCC (2023) Historical Compliance Credit Creation;
Share of zero cost credits	- Government of Canada (2023) Zero Emission Transit Fund; - Government of Canada (2023) Canada's Zero-Emission Vehicle (ZEV) Sales Targets; - United States Department of Agriculture - USDA (2023) for Canadian blending rates; - Government of Quebec (2023) Renewable Natural Gas Mandate; - Government of British Columbia (2023c) Renewable and Low Carbon Fuel Requirements Regulation

2.4.3. Assumptions

Based on the previous methodology, a crucial step in estimating the credit price and therefore the incremental compliance cost for regulated parties is to estimate the share of no cost credits due to current policies. This share (see Table 26) is calculated based on the following federal and provincial policies.

- Biofuel Blending Mandates – The amount of biofuel to blend with conventional fuels to reach the requirements from the provincial and federal blending mandates as per Table 25 is projected using gasoline and diesel consumption by province. As no major gasoline substitute production project is planned, ethanol will continue to be significantly imported to reach the blending requirements. Canadian production of Biodiesel and HDRD will be sufficient to reach the blending mandates requirements as soon as 2023.
- Renewable Natural Gas Mandate – In Quebec, the natural gas supplied will require blending an increasing share of renewable natural gas in the gas network, with a 5% milestone in 2025 and a 10% target in 2030. As such renewable natural gas produced within Quebec that supports the implementation of the gas mandate is associated with no cost.
- Zero Emission Transit Fund – The transit fund supports the deployment of zero emissions transit. As such, all deployment of low-emissions urban buses as well as

school buses in the 2022-2030 period are assumed to be under its jurisdiction and are associated with no cost.

- ZEV Sales Targets – ZEV sales imply ambitious low-emissions sales by 2030 (reaching 100% in 2035), therefore its targets are used as a reference to calculate the share of no cost credits.
- Low Carbon Fuel Requirements – British Columbia regulates its market with its own version of a low carbon fuel standard, with ambitious targets to reduce Gasoline and Diesel classes' carbon intensity by 30% in 2030. As the CFR credits created within BC would be a consequence of its own regulation, ruled by its own market, all credits created within BC will be considered at no cost.

Table 25. Blending mandates rate per province or reference case assumption[16]

%of volume	Gasoline blend			Diesel blend			Heating oil blend		
	2022	2025	2030	2022	2025	2030	2022	2025	2030
Alberta	5%	5%	5%	2%	2%	2%	2%	2%	2%
Saskatchewan	7.5%	7.5%	7.5%	2%	2%	2%	2%	2%	2%
British Columbia	5%	5%	5%	4%	4%	4%	2%	2%	2%
Manitoba	8.5%	10%	10%	5%	5%	5%	2%	2%	2%
Ontario	10%	11%	15%	4%	4%	4%	2%	2%	2%
Québec	5%	12%	15%	2%	5%	10%	2%	2%	2%
New Brunswick, Nova Scotia, PEI	2%	2%	2%	2%	2%	2%	2%	2%	2%
Newfoundland & Labrador	3%	4%	5%	2%	2%	2%	2%	2%	2%
Territories	0%	0%	0%	0%	0%	0%	2%	2%	2%

Table 26. Share of compliance credit cost passed on to credit price[17]

%	2022	2023	2024	2025	2030
Biofuel production	25%	26%	32%	37%	37%
Renewable natural gas production	50%	50%	50%	50%	50%
Hydrogen production	25%	25%	25%	25%	25%
Electric light vehicle	n/a	n/a	n/a	n/a	n/a
Electric medium & heavy vehicles	n/a	n/a	n/a	n/a	n/a
Hydrogen vehicles	n/a	n/a	100%	100%	100%
Gas & propane vehicles	40%	48%	63%	75%	67%

[16] For provinces without blending mandates, we assume a blend rate based on federal blending mandates and/or NATEM reference case scenario

[17] n/a : No cost passed as compliance credit cost is null

Applying this methodology and these assumptions, the credit cost and the credit price in 2030 for hydrogen production are $411 per credit on average (as presented in Figure 5) and in the range of $141 per credit, respectively, as 25% of the credit cost is passed on to the credit price (and adding on the minimum price). Note that actual prices in the model vary per type of project. For ethanol supplied as a result of the CFR (in addition to provincial and federal blending mandates), the credit cost and credit price in 2030 are $275 per credit on average (as presented in Figure 5) and around $140 per credit on average, respectively.

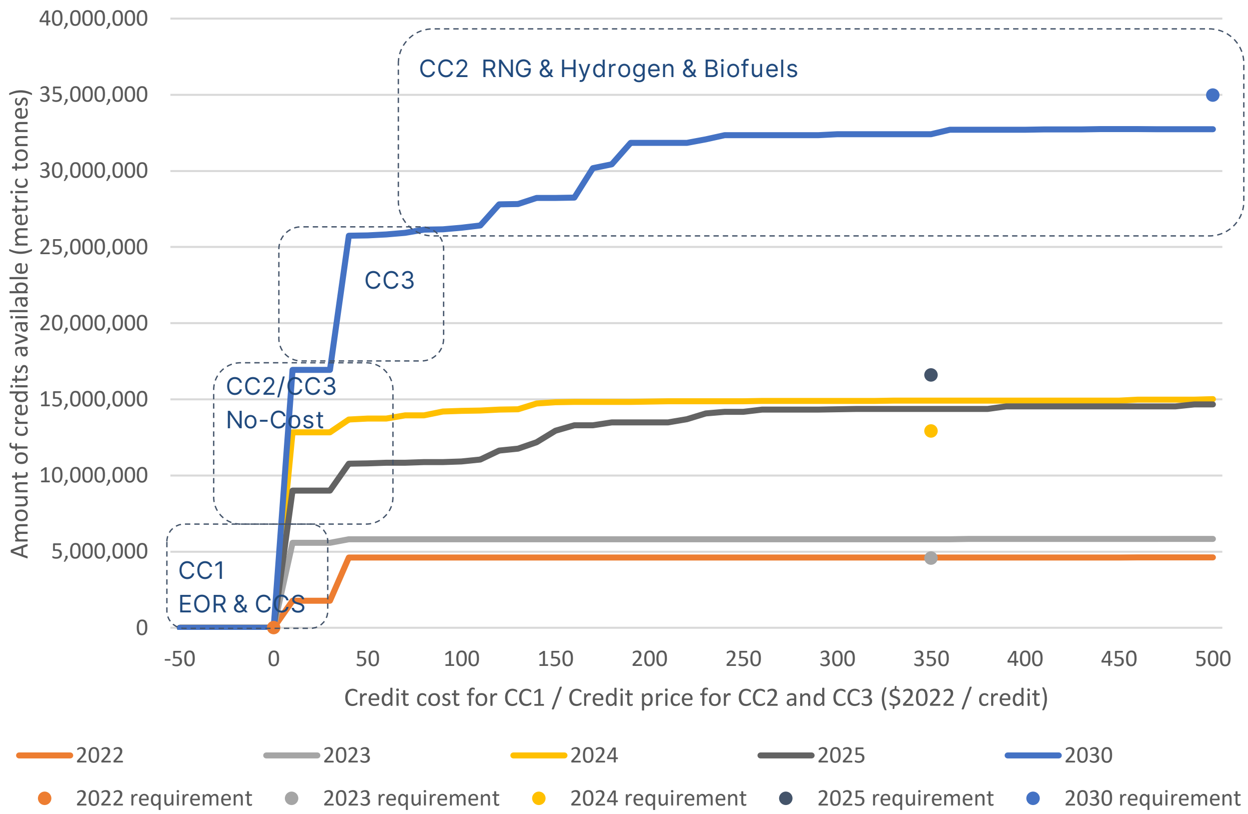
2.4.4. Results

After conversion from credit cost to credit price, a credit supply curve is obtained. Figure 8 presents the amount of credits available each year on the market as a function of the credit price. The figure also presents the amount of credits created under compliance category 1 as a function of their credit cost. Key points on this curve include:

- As expected, the credit supply increases over time, to support higher carbon intensity requirements. The only exception is 2024-2025, due to the retroactive creation of credits in 2024;
- From 2022 to 2025, only a relatively small amount of CC1 credits are created as these credits typically require time intensive investments. Therefore, in this time period, most credits supplied will be from CC2 and CC3;
- As a proxy, the supply curve can virtually be classified in 4 steps (note that in practice, each credit-creating facility or project can have a unique cost and these are general trends):
    - CC1 and especially Enhanced Oil Recovery (EOR) and Carbon Capture & Storage (CCS) are actions with revenue streams (i.e., mainly due to the increasing federal carbon price) which constitutes low supply cost;
    - CC2/CC3 credits which fall under other regulations are associated to no-cost (i.e., administrative cost) resulting in a spike of credit creation around 2 (2022)CAD/ credit;
    - Remaining CC3 credits are often low-cost which result in a second spike around the minimum credit price around 38.5 (2022)CAD/credit;
    - Remaining CC2 credits are typically most expensive resulting in price spread from about 110 (2022)CAD/credit for renewable natural gas production to 350 (2022)CAD/credit for renewable diesel production in 2030.

Figure 8 also shows the credit requirement (Canada-wide obligation amount) for each year, which is placed at the clearing price used in that year (see next section) and thereby determines the amount of supply available on the market. For years 2023-2024, the supply exceeds the requirement, however, in 2025 and 2030 the requirement exceeds supply. Banking of credits from earlier years will thus help meet the requirements later in the decade, and increasing the clearing price in earlier years may also provide greater credit supply for banking.

Figure 8. Compliance Credit Supply Curve



SECTION 3

3. Compliance costs and fuel prices

3.1. CFR compliance obligations

3.2. Obligations

CFR compliance obligations are calculated on the basis of production of gasoline and diesel, international exports and imports to reflect the policy impacts by province. This allocation differs from the fuel price estimates by province which reflect the allocation of cost flow by fuel demand (see section 3.4).

Data was collected from Statistics Canada for historical years (up to 2021) and is used to calibrate ESMIA's North American TIMES Energy Model (NATEM). The model is then resolved for a reference (Business-As-Usual) scenario, which includes modeling of existing energy policies in Canada and its provinces. These policies include:

1. Federal Fuel Charge under Greenhouse Gas Pollution Pricing Act (carbon price)
2. Provincial carbon pricing policies
3. ZEV sales mandate
4. Incentives for LDZEVs and ZEV Infrastructure Program
5. Incentives for MDZEVs and HDZEVs
6. Investment Tax Credit for Clean Hydrogen
7. Investment Tax Credit for CCUS
8. Federal Methane Goals incl. Emissions Reduction Fund for the oil and gas sector

Since NATEM results may differ from actual production and imports for future years (i.e. as of 2022), the results were cross-checked with data from the Renewable Fuel Regulations for the 2021 compliance period provided by ECCC. This data was used to recalibrate NATEM results, while maintaining total amount of obligations per year constant (i.e. by re-allocating obligations between provinces). Nevertheless, differences remain between the two methodologies, while total number of credits for Canada is higher by about 6% for 2023-2024 and by 2% in 2030 in our estimates.

The obligation amounts per year and province are shown in Table 27.

Table 27. Projected CFR credit obligation by province (t CO2e credits)

Obligations	2023	2024	2025	2030
Alberta	1,574,517	4,579,049	6,057,320	13,587,468
Saskatchewan	366,725	1,117,899	1,544,415	3,331,452
British Columbia	266,349	713,651	866,199	1,837,449
Manitoba	1,402	4,374	594	1,024
Ontario	1,056,087	2,994,511	3,863,119	7,836,228
Québec	1,047,083	2,805,576	3,405,333	5,966,870

Obligations	2023	2024	2025	2030
New Brunswick	187,614	502,090	608,583	1,985,741
Nova Scotia	54,693	146,550	186,419	329,214
Newfoundland and Labrador	22,721	53,115	59,280	107,852
Prince Edward Island	0	0	0	0
TOTAL	4,577,190	12,916,815	16,591,262	34,983,299

3.3. Compliance Costs

3.3.1. Definition

Industry compliance costs are defined as the incremental cost to regulated parties to comply with the CFR. They consist of the following:

a. Costs for internal business changes
    i. Implementation of technologies and processes to decrease emissions in the liquid fossil fuel production lifecycle (Compliance Category 1 actions)
    ii. Co-processing (with low-CI fuel and blending)
b. Net cost for purchased credits (purchases – sales of own credits) using estimated market price.
c. Cost of credits created by contributing to a registered emission reduction funding program.
d. Administration costs for businesses to comply.

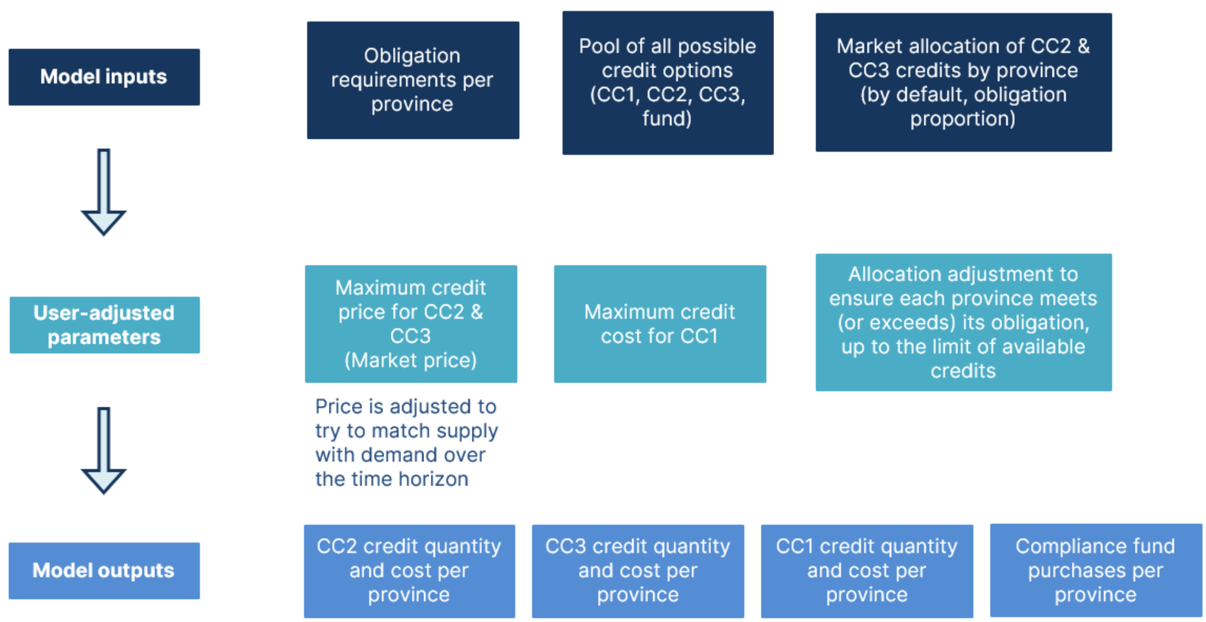
3.3.2. Assumptions and parameters

To calculate the least cost of compliance for regulated parties, we do an analysis at the provincial level.

First, the model takes the obligation requirements per province as an input. Obligations apply to the production of gasoline and diesel within a given province, plus international imports of these fuels, minus international exports. Therefore, the obligations may not be proportional to demand for these fuels within the province since inter-provincial imports or exports are not accounted for.

Next, all possible credit options: CC1, CC2, CC3 are considered and contributions to a registered emission reduction funding program. As described in section 2.1, CC1 credit availability depends on both fuel production in the province (e.g., for CCS, low-CI electricity) and on oil extraction (e.g., for EOR). Therefore, the CC1 compliance category is assumed to be available within provinces and for the purpose of modelling is not traded between provinces. In contrast, CC2 and CC3 credits are assumed to be created by other parties, so called "credit creators" and it is assumed that all of these credits will be traded on the market. Therefore, a credit created in a given province may be purchased in any province. Although these are simplifying assumptions, they may approximate real dynamics since (1) CC1 credits are typically created where the CO_2 is captured and may remain within integrated companies (e.g., a company doing both extracting and refining) and (2) although regulated parties may also create CC2 and CC3 credits (for example, by developing a low-CI fuel business), if a majority of credits are still traded on the market, supply will flow towards remaining demand. Furthermore, accurately estimating incremental cost of low-CI fuel production by a regulated party is complex since it will depend on the difference of profit margin between low-CI and traditional fuels. Therefore, the CC2 market price may make for a reasonable proxy. In section 4, we present a sensitivity case where we limit the amount of credit transfers on the market.

Figure 9. Simplified Diagram of Least-Cost Compliance Methodology



In order to determine the quantity of CC2 and CC3 credits on the market, two factors come into play. First, the "engagement rate" assumptions discussed in section 2 will impact the number of credits (as described in section 2). Second, a maximum credit price is applied per compliance year, which is the highest price at which regulated parties will purchase these credits. For clarity: the maximum price is *not* applied to all credits traded that year; rather the maximum credit price determines the supply of credits and credits can be purchased at or below this price (refer to Figure 8). The maximum credit price is calibrated such that supply meets or exceeds demand, in particular to allow credits to be purchased in earlier years (when the maximum credit price may be lower and supply may exceed demand) in order to bank credits for future years, when obligations increase and supply may become constrained. The maximum credit prices that are applied in 2023-2024 and 2030 are, respectively, $350 and $500.

Similarly, we also define a maximum credit cost for the CC1 category. This cost may differ from the CC2 and CC3 credit price, since companies are effectively investing in their own operations or supply chains, which brings long-term security in meeting credit obligations. In our analysis, CC1 credits are on average lower cost than the marginal credit price on the market. Nevertheless, the supply of these credits is also limited: firstly, by existing projects for years 2022-2025, and then by planned (announced) projects as well as by the engagement rates assumed for potential future (unannounced) projects in later years. Therefore, the credit cost may not be the limiting factor in credit supply.

Initially, it is assumed that the CC1 maximum cost and CC2 and CC3 maximum price must be lower or equal to the price of contributing to a registered emission reduction funding program (350 (2022)CAD/tonne). Once this supply is used up, the next most cost-effective option for a regulated party would be to contribute to a registered emissions reduction funding program, up to the maximum amount of 10% of their obligation. If this does not suffice to meet the obligation, the market clearing price is then further increased to increase credit supply.

To allocate CC2 and CC3 credits per province, initially a baseline proportion is used that is based on the proportion of obligations for each province (versus total obligations at Canadian level). This proportion is calculated per year and may be seen as a representation of market purchasing power. Next, in cases where one province may be in “over-supply” and another in “under-supply”, we rebalance the proportion to distribute credits in a way that allows for the province in “under-supply” to meet its obligation, while considering contributions to an emission reduction funding program. These contributions may be required even for the province initially in “over-supply”, especially later in the decade, when overall credit supply must be increased to achieve total obligations at Canadian level. At the same time, we do allow for “over-creation or over-purchase” of credits since this leads to banking of credits which may be required in future years, and even beyond 2030. For example, with increasing obligations in later years, credit supply may become more constrained, and it is therefore in the interest of a regulated party to bank credits several years earlier when supply is available at a lower price.

- If the regulated parties in a province are in a deficit at the end of year (i.e. credits created or purchased are less than its obligation), these companies would need to purchase the remaining credit difference from contributions to a registered emission reduction funding program, which can be the most expensive compliance option.

This option is limited to 10% of the obligation amount per province and at Canada-wide level.

Exceptions to this methodology are made in two cases:

- For British Columbia, CC2 and CC3 credits created in the province are available within that province only and may not be traded with other provinces, due to the more stringent LCFS. While British Columbia is seen to be in over-supply relative to the CFR, it is likely that it will require all of these credits (or more) to meet the LCFS. Modeling the LCFS requirements is beyond the scope of this study.
- For Manitoba, we allow transfer of CC1 credits to Ontario, since Manitoba's obligation is negligible and crude oil is traded between Manitoba and Ontario.

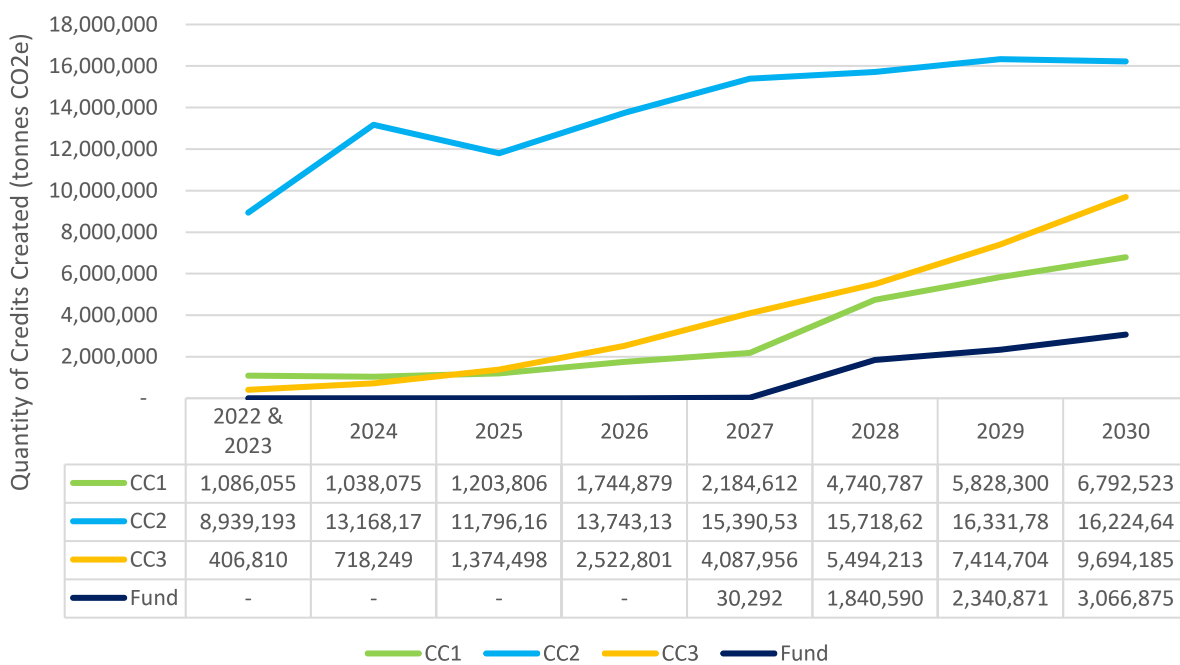
We do not consider the option of deferring credits to later years, since this comes with a penalty and is very complex to forecast due to iterative effects. This option may apply in a limited number of cases: for example, for regulated parties that have invested in large-scale CCS or EOR projects which are certain to come online in 2-3 years, and which will create a surplus of credits once they are online. If these regulated parties find themselves in a deficit during the years where final investment decision is taken or when construction is in progress, they may choose to defer their obligations.

3.3.3. Results

For the 2023 – 2025 period, there may be sufficient supply of credits such that regulated parties would both create CC1 category credits and purchase credits on the market, rather than contribute to a registered emission reduction funding program for up to 10% of their annual reduction requirements (see Figure 11). In 2023 and 2024, the vast of majority of credits is predicted to come from CC2 - between 78-88%, followed by CC1 with 7-17% and CC3 with about 5%. This can be explained by the fact that only projects that came online as from mid 2017 (for CC1) may be taken into account for the CFR. In 2024, credit creation jumps up as a result of the credit adjustment for 2022-2024, as it is expected that lower CIs will be approved and applied retroactively for CC2. Credit banking continues up to 2027 in some provinces, but starts to drop off thereafter as obligations continue to increase and supply increases at a slower rate than demand. After 2027, credit banking continues only in British Columbia, however, in practice, these credits would likely be used under the more stringer LCFS. At the same time, the clearing price for potential market credits (CC2 and CC3) tends to increase during the time horizon: from (2022)CAD 350 in 2023-2024, (2022)CAD 400 in 2028, and (2022)CAD 500 in 2030. Credit banking is modelled to continue past the middle of the decade to ensure sufficient supply to meet obligations by 2030. This implies that for the purpose of the analysis (Figure 9), the maximum credit price in earlier years is set at a higher price than the clearing price such that supply exceeds demand. As such, this analysis involves some foresight of future market dynamics, however, these dynamics are inherently uncertain. By 2030, CC1 credits make up 19% of the compliance credits, while CC2 accounts for 45% and CC3 for 27%. The remaining ~9% consists of contributions to a registered emission reduction funding program.

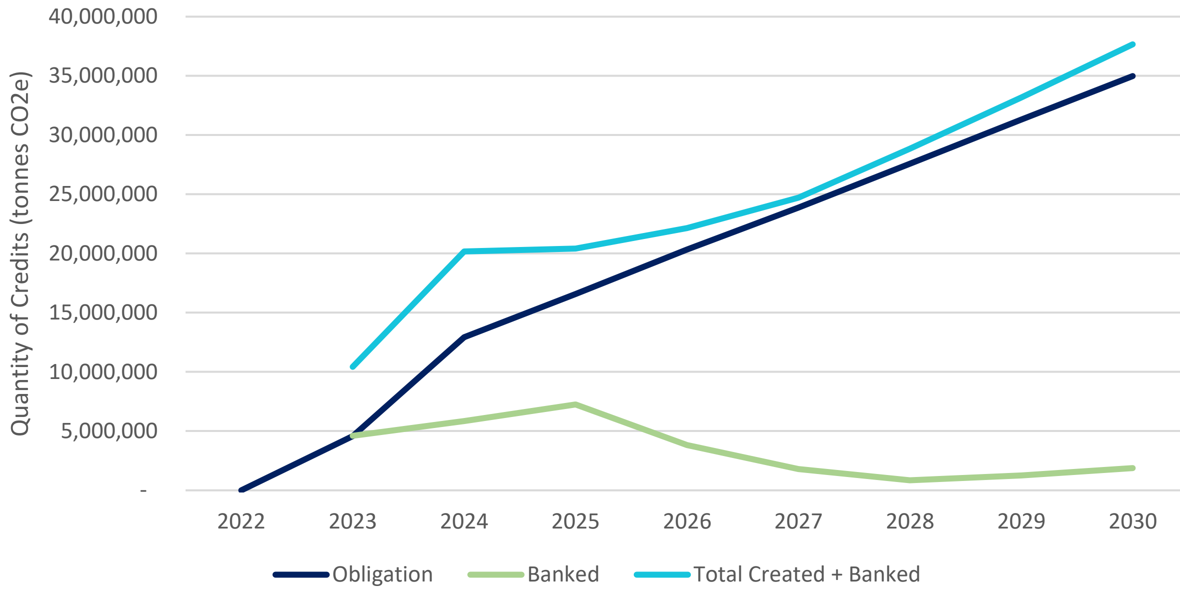
It is important to highlight that these results are highly sensitive to the type and size of projects that will be developed – both by regulated parties, by low-CI fuel suppliers, and by other credit creators. Should the potential CCS and EOR projects not materialize, the market price for CC2 and CC3 credits may increase further, which could further stimulate supply in these categories. Nevertheless, ethanol imports are already required and are projected to increase, in particular for the provinces of Ontario and Quebec, where blending mandates are more ambitious. Blending of diesel at higher rates may be more practically attainable due to development of renewable diesel production facilities in Canada. It should be noted that further contributions to registered emission reduction funding programs could be necessary, for example in 2027-2029, however, these contributions may not increase much further in 2030 as they are approaching the 10% limit for all provinces with major obligations. These factors would substantially increase compliance costs due to the relatively low cost of the CC1 category (see Table 28), stemming from presumed revenues from sales of CO_2 credits due to carbon pricing.

Figure 10. Credits created by compliance category



	2022 & 2023	2024	2025	2026	2027	2028	2029	2030
CC1	1,086,055	1,038,075	1,203,806	1,744,879	2,184,612	4,740,787	5,828,300	6,792,523
CC2	8,939,193	13,168,17	11,796,16	13,743,13	15,390,53	15,718,62	16,331,78	16,224,64
CC3	406,810	718,249	1,374,498	2,522,801	4,087,956	5,494,213	7,414,704	9,694,185
Fund	-	-	-	-	30,292	1,840,590	2,340,871	3,066,875

Figure 11. Total credits created versus obligations

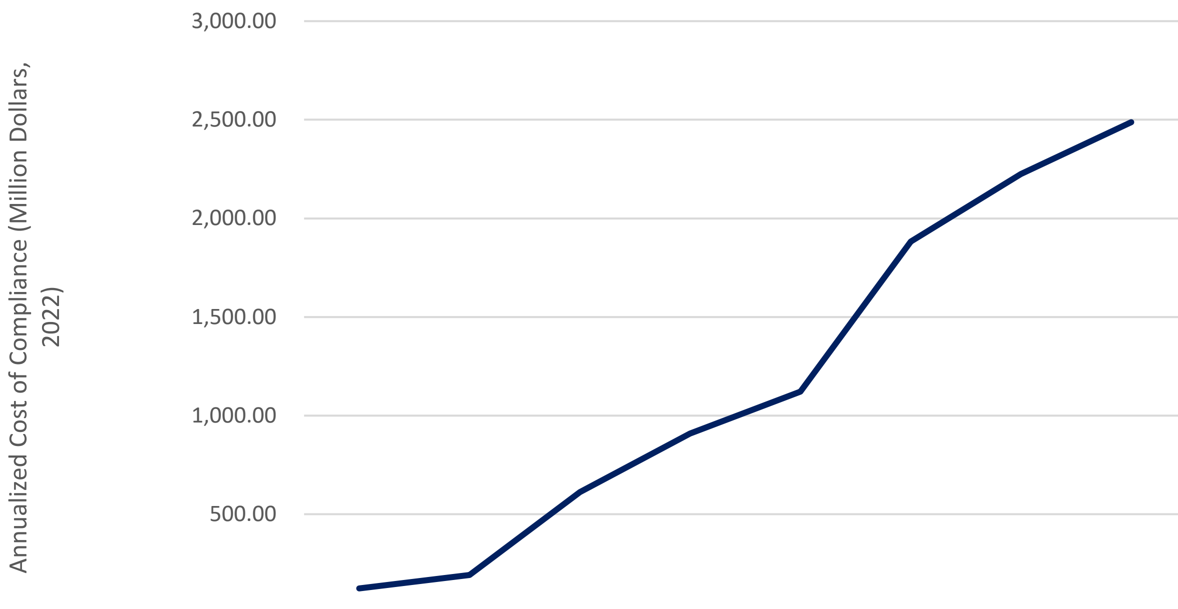


In terms of compliance costs, they are estimated at about (2022)CAD 124 Million for 2022-2023 and (2022)CAD 192 Million for 2024. Note that 2022 costs are aggregated with 2023 since they represent the cost of banking credits for the following year, when obligations begin. Annual costs tend to increase along the time horizon, as the obligation amount increases (see Figure 12). The highest compliance costs are estimated at close to (2022)CAD 2.5 Billion in 2030, which is partially a result of the registered emissions reduction program contributions required and a more rapid increase in demand as compared to supply.

Table 28. Average cost of credit creation/purchase (Canada-wide)

(2022)CAD /tonneCO2e	2022 & 2023	2024	2025	2030
CC1	1.7	1.5	4.8	5.1
CC2	12.3	13.1	48.4	70.2
CC3	28.3	24.8	24.7	24.8

Figure 12. Total annualized cost of compliance

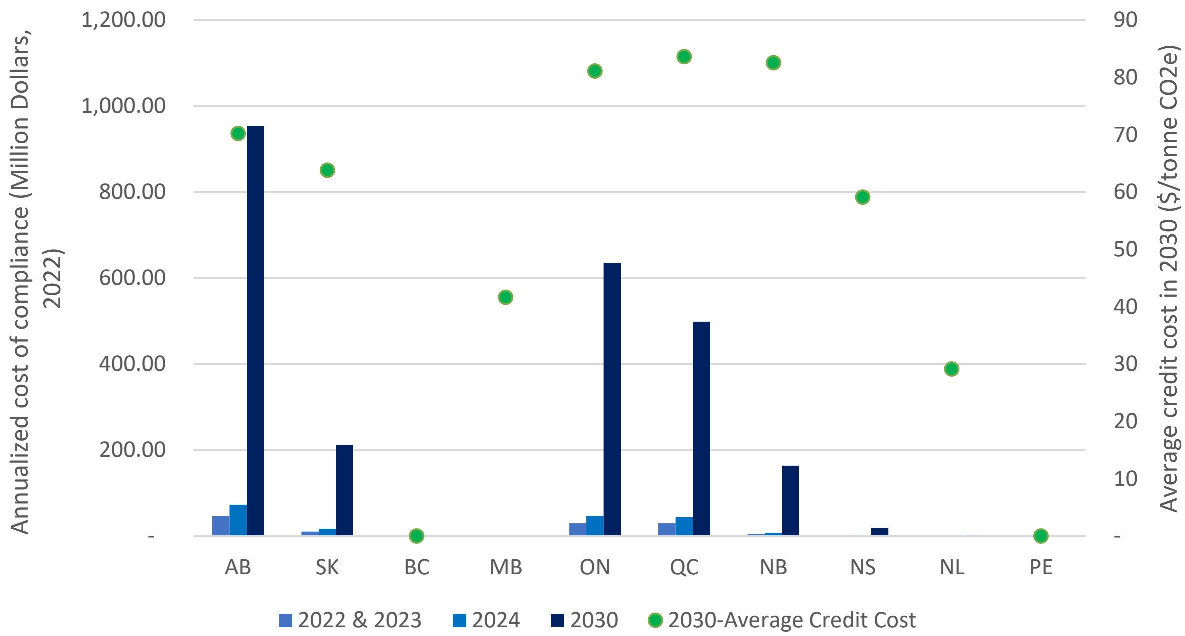


	2022 & 2023	2024	2025	2026	2027	2028	2029	2030
Annual cost (M$/year)	123.64	191.6	611.2	908.6	1,120.8	1,882.2	2,224.8	2,487.7

In 2023, Alberta has the highest compliance cost at (2022)CAD 46 Million (including costs generated in 2022), followed by Ontario and Quebec at around (2022)CAD 30 Million. These numbers are based on the production of gasoline and diesel within the province (plus international imports minus international exports), and do not consider trade between provinces. As such, in the next section, costs are reallocated taking into account inter-provincial transfers to calculate impact at the pump. Although compliance costs by province are to some degree proportional to the obligation amount per province (and this is generally true in early years), costs can be higher or lower depending on the type of compliance credit purchased/created. These differences can arise due to the potential for regulated parties to create credits in their supply chains, and the resulting proportion of market credits that they must purchase. For example, in 2030, Ontario, Quebec, and New Brunswick have compliance costs that are proportionally higher to their obligation amount as compared to Alberta and Saskatchewan, since the latter have greater opportunities to create credits in the CC1 category. This implies that the average cost of a compliance credit will vary by province. After Nova Scotia and Newfoundland and Labrador, Saskatchewan sees the lowest average creation cost, since a large portion of its credits may be created in the CC1 category, generating revenues through carbon pricing in the performance standards policy. Note that for British Columbia, we assume that compliance cost for the CFR will be zero, since the province already has its own clean fuel policies (Renewable &

Low Carbon Fuel Requirements Regulation), which is more stringent than the CFR. However, this does not mean that fuel price impacts will be zero (see next section).

Figure 13. Total annualized cost of compliance by province



3.4. Impacts on Fuel Prices

3.4.1. Methodology

To identify the impact of CFR on fuel (gasoline and diesel) retail prices, compliance costs are reallocated to gasoline and diesel consumers in different provinces and territories. Provincial compliance costs (Figure 13, Section 3.3) are not directly passed on to fuel consumers in each province. Instead, incremental costs for different compliance categories are propagated through the refined oil products supply chain, reallocating costs from provinces where these costs occurred to provinces where fuels will be consumed.

Three main stages of the supply chain are considered: crude oil production and import; refining to produce gasoline and diesel; and oil products distribution. CC1 credits and, as a consequence, costs, may be created at the level of oil production, e.g., with EOR and at the level of a refinery (regulated party), e.g., with the deployment of CCS. It is assumed that CC1 costs that occurred at the production level are embedded in the crude oil price that refineries located in the same province will purchase and are thus passed on to the price of refined products in the same province. CC2 and CC3 credits may be created via various projects in different provinces and territories, and we assume that regulated parties will be able to purchase them in the open market. If there is a lack of credits (if insufficient credits are created through the compliance categories or available purchases in the open market), regulated parties can contribute to registered emission reduction funding programs to satisfy up to 10% of their annual reduction requirement. Costs for CC1, CC2, CC3 and these contributions in different provinces are split based on the shares of gasoline and diesel domestic consumption and interprovincial export. This means that costs due to the CFR follow the flows of gasoline and diesel from refineries to final consumers. Note that fuel imported to the Territories for power generation does not include the CFR cost component. This represents a major part of diesel imported to Nunavut, 20% of diesel imports to the Northwest Territories and 12% of diesel imports to the Yukon territories. It is assumed that the remaining diesel and gasoline imports are used for industry or transportation and will include the CFR cost component.

A simplified formula to calculate an annual reallocation cost $COST_j^{Realloc,gasol,diesel}$ for each province/territory j is:

$$COST_j^{Realloc,gasol,diesel} = \sum_i COST_i^{Compliance} \cdot p_i^{gasol,diesel} \cdot s_{i\to j}^{gasol,diesel}$$

<u>where</u>

i and j are a Canadian province or territory. A province may be at the same time be an oil producer/importer and refined fuel producer i and a consumer j.;

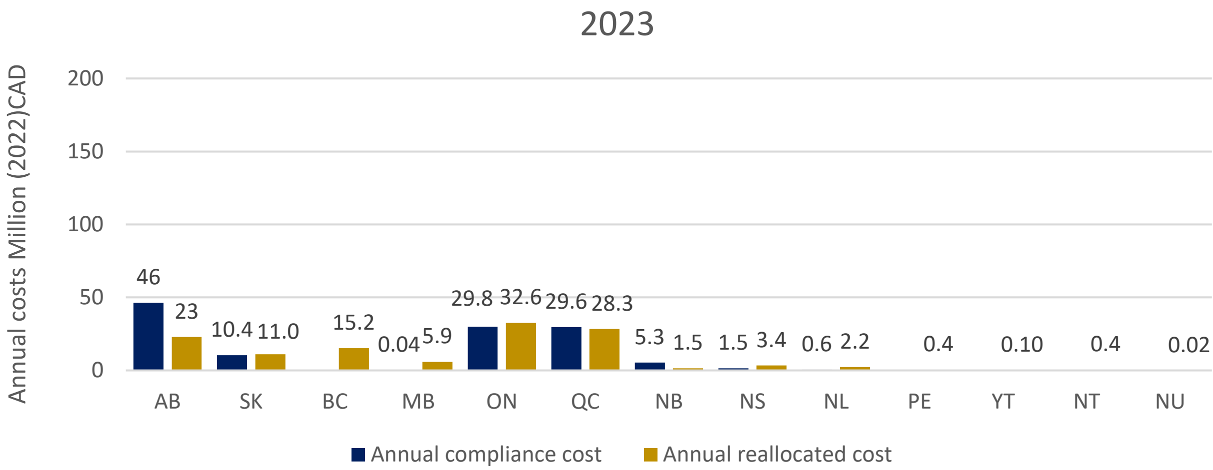
$COST_i^{Compliance}$ is the compliance cost that occurs in province i. It represents a sum of compliance costs of CC1, CC2, CC3 categories and emission reduction funding programs;

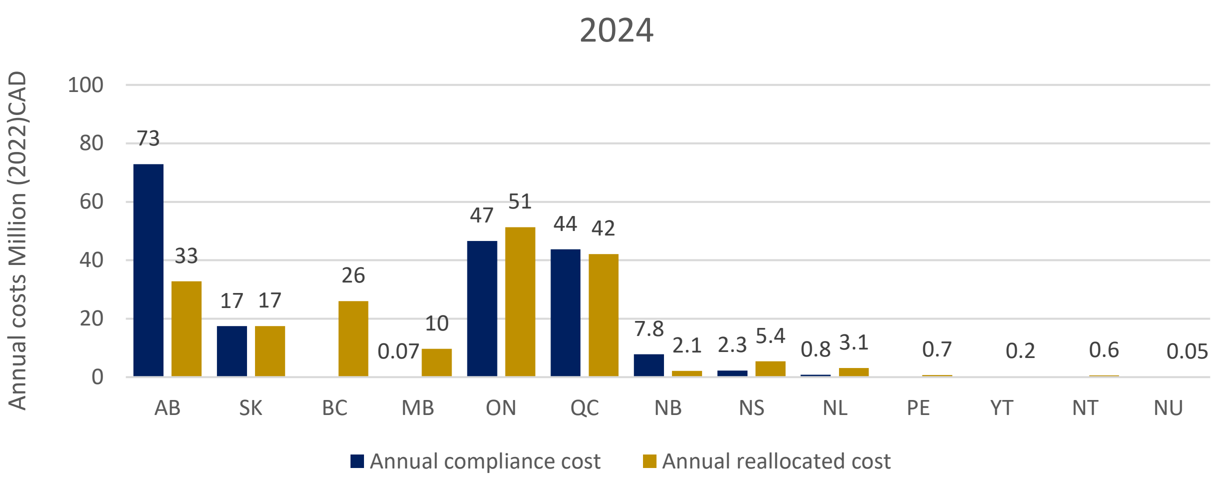
$p_i^{gasol,diesel}$ is the share of gasoline and diesel supply in the province i (identified taking into account production and international imports minus international exports), and that is used to reallocate total compliance cost per flow of gasoline and diesel. p_i^{gasol} and p_i^{diesel} may vary between 0 and 1, so $p_i^{gasol} + p_i^{diesel} = 1$;

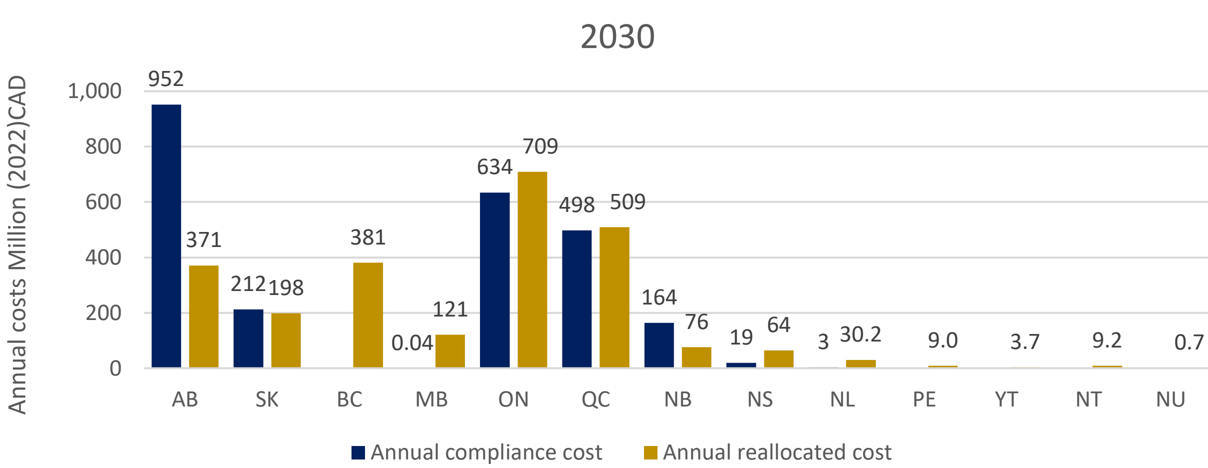
$s_{i\to j}^{gasol,diesel}$ is the factor defined based on the fuel export from province i to province j, $s_{i\to j}^{gasol,diesel}$ may vary between 0 and 1 where 0 means that there is fuel trade between province i and province/territory j and 1 means that all fuel produced in province i is destined to be consumed in province/territory j.

CC1 compliance costs that occur in oil supply provinces i are transferred to the regulated parties in the same province purchasing oil to produce gasoline and diesel. CC2 and CC3 compliance costs and funding program costs in each province$i$ are added to the CC1 costs. This total cost is then reallocated based on gasoline and diesel production in the province with $p_i^{gasol,diesel}$ share. These costs will flow with gasoline and diesel interprovincial export flows defined with factors $s_{i\to j}^{gasol,diesel}$ used to propagate costs to provinces and territories j where gasoline and diesel are consumed. An example of annual compliance and reallocated costs for 2030 is illustrated in Figure 14. A detailed analysis of how reallocated costs are built is presented in results Section 3.4.2, Regional Focus.

Figure 14. Total compliance and reallocated costs[18] for 2023, 2024 and 2030.







[18] Totals of annual compliance and reallocated costs may slightly vary due to rounding.

Reallocated costs are split between diesel and gasoline based on the shares of fuel consumption in different years and different provinces. To estimate the CFR cost component per litre of gasoline and diesel, reallocated costs (by fuel type, province and year) are split between gasoline and diesel and are divided by the gasoline and diesel consumption projected for each province and Territory under a reference scenario. Price increases due to the CFR are shown as a separate category in the retail prices for gasoline and diesel reported below.

Other components that are embedded in the gasoline and diesel retail price are the:

- Crude oil price (based on NATEM results that follows the reference scenario, cf. Annex for more details);
- Refining operating margin that represents the wholesale price of refined products, and embeds revenue requirements for refining operation and profit margin[19]. No major events that could impact the refinery operating margins, such as refinery incidents, extreme weather or major changes in demand, are considered for this analysis;
- Marketing operating margin or retail mark-up[20]; the percentage was assumed to remain the same as in 2022.

In addition, the following taxes are considered, where applicable: Excise Tax (cent/litre), Goods and Services Tax (%), Provincial Sales (%), Provincial Fuel Tax (cent/litre), and carbon price (cent/litre). It is assumed that all these taxes remain the same as today (in %) while the carbon price will increase following the Federal Carbon Pricing schedule. The carbon price will also be affected by the estimated increase of the clean fuels' shares (ethanol and biodiesel) that is blended in gasoline and diesel. It is assumed that the provincial mechanism of the Federal Carbon Pricing application remains the same in each province as now (e.g., levy, cap and trade, carbon price). Municipality charges, such as the one applied in Vancouver and Montreal, are not considered.

The projection starts from the average retail price breakdown for gasoline and diesel for 2022 from Kalibrate Canada Inc. (Kalibrate 2023) and takes into account a more detailed breakdown of fuel consumption levies in Canada (Natural Resources Canada 2023).

[19] Note that refineries typically make a profit (margins are higher) on gasoline and diesel and lose money on other products, such as heavy fuel oil. As a result, the total net refining margin that also accounts for various operational and capital cost may be negative. Theoretically the refining margin on gasoline and diesel may be decreased in case of decrease of not profitable products production (such as heavy oil). However, this possibility is not considered under the reference case scenario.

[20] Retail markup on gasoline and diesel is extremely thin, contrary to refineries, gas stations are not making their profit on gasoline and diesel but on other items (e.g., snacks, beverages, tobacco).

3.4.2. Results

The CFR cost component has a negligeable impact on gasoline and diesel retail prices in 2023 and 2024 (Figure 15 and Table 29). It is expected to represent less than 1% of the retail price of oil products.

In 2030, the CFR cost component is expected to have a moderate impact on gasoline and diesel price increases in comparison with other price components. In 2030, the CFR cost component will represent up to 6.5%.

The impact of the CFR cost will differ by jurisdiction, depending on a combination of the following factors:

- The compliance costs for regulated parties in different jurisdictions (Figure 13) will drive the increase in revenue requirement to be recovered from gasoline and diesel consumers. The total CFR cost depends on the compliance category where credits are created. According to Table 28, the CC1 category is expected to hold credits with the lowest average credit cost, while the average credit costs in CC2 and CC3 categories are expected to be considerably higher. This is followed by contributions to registered emission reduction funding programs (up to 10% of the annual reduction requirement) where credit cost is equal to CAD 350. As a consequence, provinces fulfilling their obligations by creating or purchasing credits in categories with high average credit costs or contributing to funding programs will have higher annual compliance cost;
- The interprovincial trade flows of fuels will partly transfer compliance costs from one jurisdiction to the gasoline and diesel consumers in another jurisdiction. Therefore, provinces with high compliance costs will transfer part of their costs to consumers in other provinces (following interprovincial fuel export flows), increasing their fuel prices.

Table 29 and Figure 16 provide the CFR cost components in gasoline and diesel prices per litre in different provinces, as well as the share of the CFR cost component in the retail price before taxes.

In 2030, it is expected that the CFR cost component will be highest in provinces where the most expensive credits will be used (i.e., CC2 and CC3). In provinces, such as Quebec, Ontario, Nova Scotia, and New Brunswick, at minimum 90% and at maximum 100% of credits will be created in these categories. In addition, these provinces and especially New Brunswick will need more expensive credits from the contributions to registered emission reduction funding programs. This will increase the CFR costs and revenue requirements that must be recovered from sales of gasoline and diesel. In comparison, in provinces where most of the upstream oil sector is located, an important share of credits will be created in the CC1 category, for example, 30% of all credits in Alberta and 43% of all credits in Saskatchewan will be created in CC1. As a consequence, the CFR cost impacts for these provinces will be generally lower. For more detailed regional analysis, please refer to Regional Focus below.

Figure 15. Price breakdown for selected provinces for a) gasoline and b) diesel.

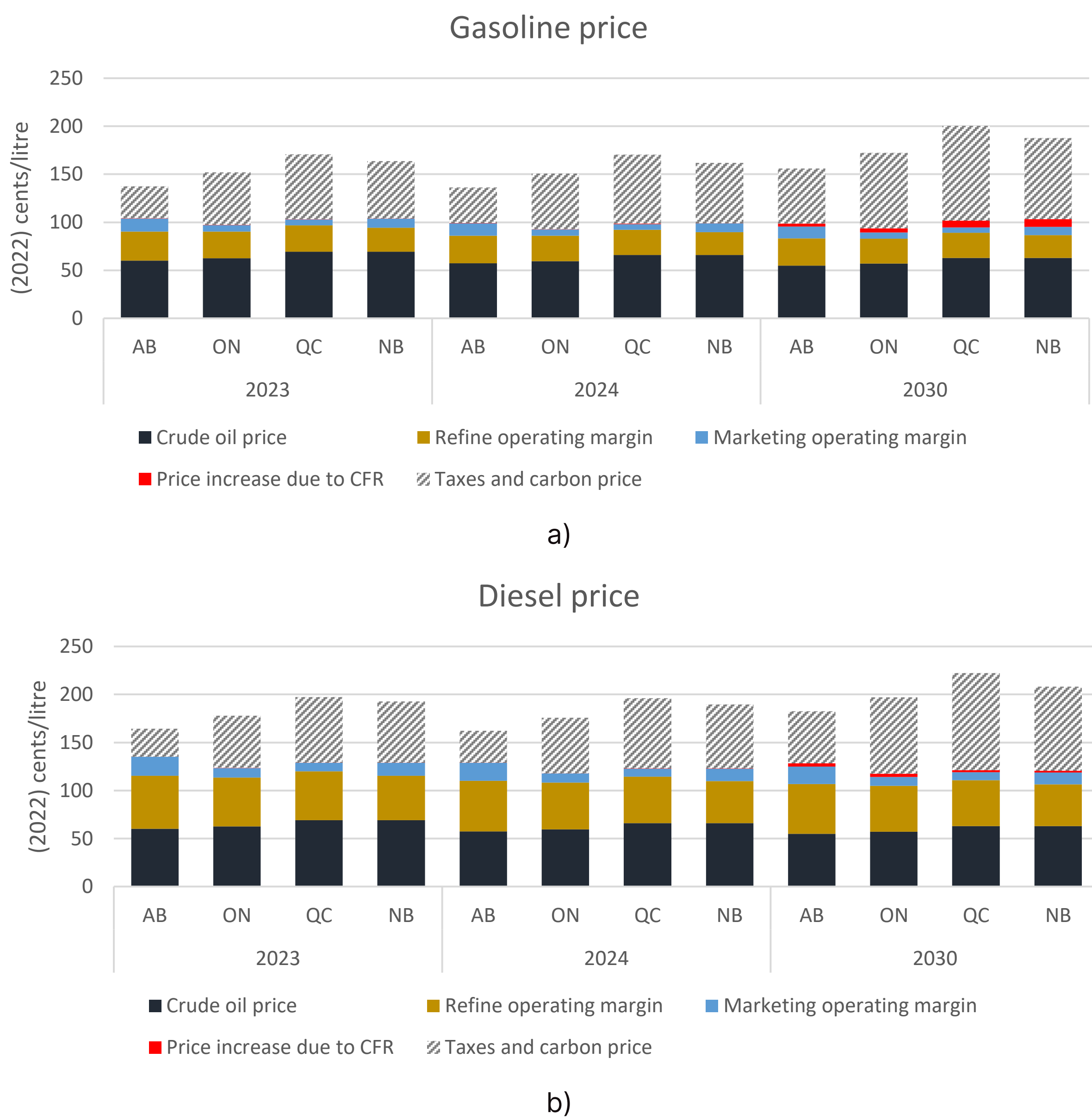
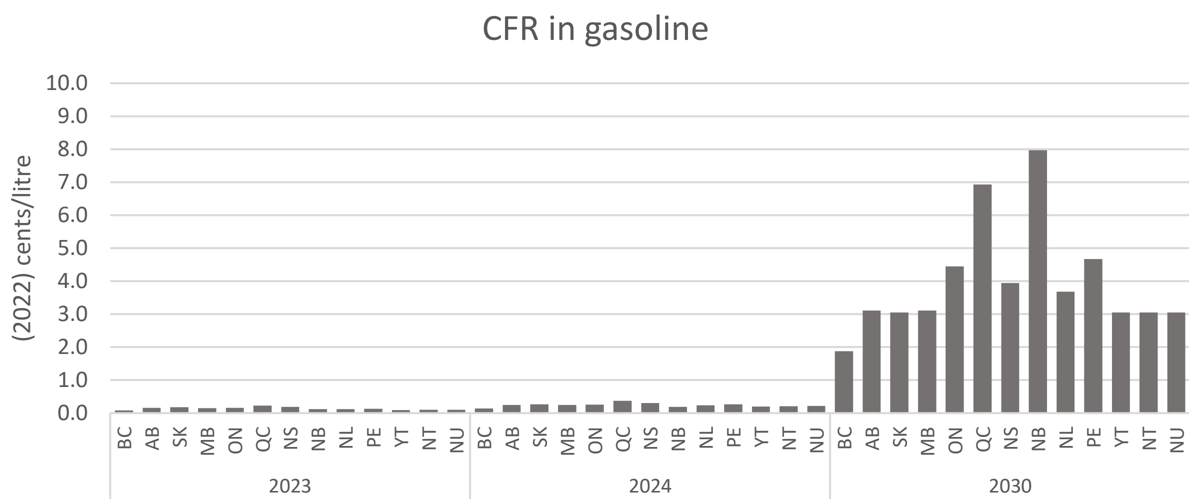


Table 29. CFR cost component in gasoline and diesel retail prices[21]

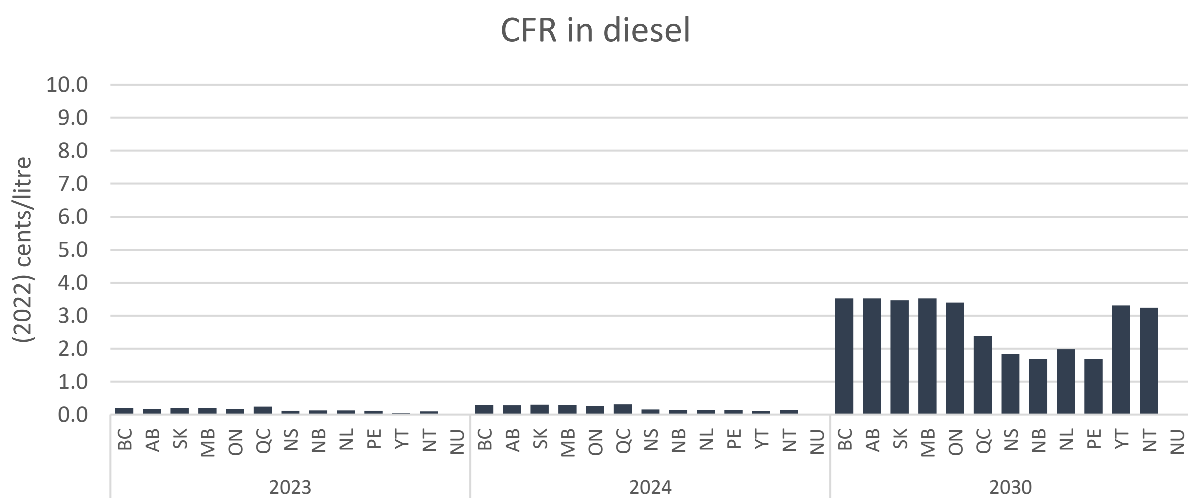
Province	CFR cost component, (2022)cents/litre			CFR cost component share of the retail price before taxes, %			CFR cost component share of retail price after taxes, %		
Year	2023	2024	2030	2023	2024	2030	2023	2024	2030
Gasoline									
BC	0.08	0.1	1.9	0.07%	0.1%	1.7%	0.05%	0.1%	1.0%
AB	0.16	0.2	3.1	0.15%	0.2%	3.1%	0.11%	0.2%	2.0%
SK	0.18	0.3	3.0	0.17%	0.3%	3.0%	0.12%	0.2%	1.8%
MB	0.15	0.2	3.1	0.14%	0.2%	3.1%	0.10%	0.2%	1.8%
ON	0.16	0.3	4.5	0.16%	0.3%	4.7%	0.10%	0.2%	2.6%
QC	0.23	0.4	6.9	0.22%	0.4%	6.8%	0.13%	0.2%	3.4%
NS	0.19	0.3	3.9	0.19%	0.3%	4.1%	0.13%	0.2%	2.7%
NB	0.12	0.2	8.0	0.12%	0.2%	7.7%	0.08%	0.1%	4.2%
NL	0.12	0.2	3.7	0.11%	0.2%	3.6%	0.07%	0.1%	2.1%
PE	0.13	0.3	4.7	0.13%	0.3%	4.7%	0.09%	0.2%	2.7%
YT	0.09	0.2	3.0	0.08%	0.2%	3.0%	0.06%	0.1%	1.8%
NT	0.10	0.2	3.0	0.10%	0.2%	3.0%	0.07%	0.1%	1.8%
NU	0.11	0.2	3.0	0.10%	0.2%	3.0%	0.07%	0.1%	1.8%
Canada average[22]	0.16	0.3	4.3	0.16%	0.27%	4.3%	0.10%	0.17%	2.4%
Diesel									
BC	0.20	0.3	3.5	0.13%	0.2%	2.3%	0.09%	0.1%	1.5%
AB	0.18	0.3	3.5	0.13%	0.2%	2.7%	0.11%	0.2%	1.9%
SK	0.19	0.3	3.5	0.14%	0.2%	2.7%	0.10%	0.2%	1.7%
MB	0.19	0.3	3.5	0.14%	0.2%	2.6%	0.11%	0.2%	1.7%
ON	0.18	0.3	3.4	0.14%	0.2%	2.9%	0.10%	0.1%	1.7%
QC	0.24	0.3	2.4	0.19%	0.3%	2.0%	0.12%	0.2%	1.1%
NS	0.12	0.2	1.8	0.10%	0.1%	1.6%	0.07%	0.1%	1.1%
NB	0.12	0.1	1.7	0.09%	0.1%	1.4%	0.06%	0.1%	0.8%
NL	0.12	0.1	2.0	0.13%	0.2%	1.6%	0.09%	0.1%	1.0%
PE	0.12	0.1	1.7	0.09%	0.1%	1.4%	0.06%	0.1%	0.9%
YT	0.04	0.1	3.3	0.03%	0.1%	2.6%	0.02%	0.1%	1.7%
NT	0.09	0.1	3.2	0.07%	0.1%	2.5%	0.05%	0.1%	1.7%
NU	-	-	-	-	-	-	-	-	-
Canada average[22]	0.19	0.3	3.2	0.14%	0.21%	2.5%	0.10%	0.15%	1.4%

[21] The CFR cost component in Table 29 is based on the compliance costs that account for credit from categories CC1, CC2, CC3 and compliance fund. Credits costs vary per category (refer to Table 28), moreover average credit cost in each category may be different per province due to specific projects and regional context (that may be more or less favorable to some projects).
[22] Canada average is calculated as a provincial average weighted by provincial gasoline and diesel demand.

Figure 16. CFR cost component in the retail price before taxes for a) gasoline and b) diesel.



a)



b)

The impact on gasoline and diesel may be different in a given province due to the different compliance costs in provinces from where gasoline and diesel is coming (i.e., when a province imports gasoline and diesel from two distinct provinces). Provinces exporting fuels within Canada may have different credit obligations and different capabilities in credits creation/purchase leading to different average credit cost per province (e.g., one province may purchase more credits from emission reduction funding programs, and CC1 projects may be more costly in some provinces due to projects like supply of low-CI electricity). This may lead to a situation when, for example, interprovincial import of gasoline from one province may carry higher cost per liter, while the interprovincial import of diesel from another province may carry smaller compliance cost per liter. Theoretically, a fuel retailer may try to balance fuel prices increase by decreasing their margin on fuel prices with higher CFR impact and increasing their margin on fuel prices with lower CFR impact. However, it is estimated that this would have only minor effect – retailer margins on gasoline and diesel are very small.

In 2023 and 2024, the impact of CFR on fuel prices is expected to be small, less than half of a cent per liter of fuel. In 2030, the CFR cost component in gasoline and diesel prices is projected to increase and represent on average 4.3 (2022)cents per litre of gasoline and 3.2 (2022)cents per litre of diesel in Canada (Table 29).

Regional Focus

The impact per province is expected to be different. This section provides in-depth analysis of CFR impact on fuel prices in different provinces and territories. Provinces and territories may be regrouped for analysis based on particular trends for CFR impacts on fuel prices. To better understand credit creation/purchase, this section begins by recalling credit market trends assumed for compliance cost calculation.

Market for CC2 and CC3 credits – Trends and insights

The compliance cost analysis initially assumes that provinces with a higher obligation amount (i.e., typically provinces with large refining capacities) will have market power proportional to their obligation with regards to purchase of CC2 and CC3 credits. Although the methodology subsequently reallocates more market credits to provinces in under-supply, in earlier years provinces with higher market power will be able to bank more credits, giving them an advantage in the long term. Thus, for example, a province such as Alberta, which has the highest obligation amount, and which also has good potential for CC1 creation, will be advantaged as compared to a province like New Brunswick, which will have lower market power and relatively lower potential for CC1.

New Brunswick

New Brunswick consumers are estimated to see the highest CFR impact of the provinces and territories. The total compliance cost for the regulated parties in New Brunswick was (2022)CAD 5.3 Million in 2023 that increases up to (2022)CAD 7.8 Million in 2024 (Figure 13). In 2030, the total compliance cost is expected to reach (2022)CAD 164 Million. It is important to highlight that the estimated compliance cost in this province is relatively high – compliance is expected to be attained through credit creation and purchase from higher cost compliance categories (CC2 and CC3). High compliance cost increases revenue requirements of the regulated parties in the province, affecting the consumers in New Brunswick and, indirectly, in other provinces that import fuel from New Brunswick. A major portion of compliance cost due to diesel production will flow out of New Brunswick following fuel exports to other provinces (New Brunswick exports most of its diesel to provinces, such as Newfoundland and Labrador, Nova Scotia, Prince Edward Island). At the same time, a portion of the compliance cost related to gasoline will remain in the province (in the absence of major interprovincial gasoline exports) and will be passed on to provincial consumers embedded in gasoline prices (of which consumption is projected to decrease between 2023 and 2030). As a consequence, reallocated compliance costs will be divided by a progressively decreasing consumption base. CFR cost component per liter is expected to increase by 2030 in particular for gasoline, reaching 8 (2022)cent/litre, and remaining moderate for diesel with 1.7 (2022)cent/litre (Figure 16 and Table 29).

TAKEWAYS FOR NEW BRUNSWICK

The CFR cost component in fuel prices in New Brunswick may be impacted by a combination of factors. The province has a relatively high credit obligation that is expected to increase by 2030, driven by the increase in gasoline and diesel production (projected to increase by 56% and 37%, respectively). At the same time, credit creation opportunities for CC1 are limited. Although a small amount of CCS projects are considered, they become available only in 2030 and low-CI electricity projects are higher cost. These CC1 projects may also be more expensive due to provincial context, e.g., low-CI electricity may be more expensive due to baseline grid emissions intensity and cost. Relatively low credit creation in CC1 pushes regulated parties in the province to purchase more credits in the market from categories with higher average credit cost (mainly CC2) and to contribute to emissions reduction funding programs. Interprovincial fuel exports reallocate a major part of NB compliance costs associated to diesel to consumers in other provinces, while compliance cost associated to gasoline production will more likely remain in the province. As a consequence, the average CFR cost per liter of gasoline for New Brunswick consumers is expected to be highest in Canada, while the CFR cost component in diesel is expected to be lower than the Canadian average.

Retailer companies may try to balance fuel price increase by decreasing their margin on fuel price with higher CFR impact and increasing their margin on fuel price with lower CFR impact. However, it is estimated that this would have only a minor effect – retailer margins on gasoline and diesel are very small. CFR cost components in gasoline prices for New Brunswick consumers is expected to still be among the highest in Canada.

Nova Scotia

The total compliance cost for the province was (2022)CAD 1.5 Million in 2023, (2022)CAD 2.3 Million in 2024 and (2022)CAD 19.4 Million in 2030 (Figure 13). Unlike New Brunswick, these compliance costs will remain in the province due to the absence of major exports to other provinces. Moreover, additional costs will flow with the interprovincial trade flows. While in 2022, the majority of gasoline is supplied with international imports, by 2030 interprovincial imports to Nova Scotia is projected to increase. In 2030, 33% and 25% of Nova Scotia's gasoline demand is expected to be met by imports from Ontario and Quebec, respectively. As a consequence, total CFR costs that are passed on to Nova Scotia consumers are expected to be higher than the original total compliance cost in this province (shown on Figure 13). The reallocated CFR cost for Nova Scotia consumers reaches (2022)CAD 3.4 Million in 2023 and (2022)CAD 5.4 Million in 2024 and (2022)CAD 64.2 Million in 2030. However, these costs remain much lower that the annual reallocated costs for New Brunswick for the same years. At the same time, gasoline and diesel consumptions are respectively 30% and 38% higher in Nova Scotia than in New Brunswick. Moreover, according to the reference scenario, gasoline and diesel consumption in the province are projected to increase. This means that in Nova Scotia reallocated CFR costs will be divided by a larger annual consumption base leading to a smaller CFR cost component per litre. The CFR cost component is expected to reach 3.9 (2022)cents/litre of gasoline and 1.8 (2022)cents/litre of diesel in 2030 (Figure 16 and Table 29).

TAKEWAYS FOR NOVA SCOTIA

Regulated parties in Nova Scotia do not have opportunities to create credits in CC1, but create/purchase credits from more expensive credit categories (i.e., CC2 and CC3). However, credit obligation in the province is low as compared to New Brunswick. Regulated parties in Nova Scotia need between three and five times less credits per year (depending on the year) to meet policy requirements. This leads to the low annual compliance cost in the province, which increases with fuel imports from other provinces that will carry portions of compliance costs from Ontario, Quebec, and New Brunswick. Nevertheless, this increase does not impact fuel prices in the province up to the same extent as fuel prices in New Brunswick.

Quebec and Ontario

Quebec and Ontario are provinces with the highest credit obligations after Alberta. Regulated parties here have multiple opportunities to create and purchase credits in all categories (although, the opportunity for credits creation in CC1 remains more limited and arises mainly after 2027). Both provinces also contribute to registered emission reduction funding programs as of 2028, as credits available on the market are no longer sufficient. Quebec and Ontario are expected to have reallocated costs that are similar to its CFR compliance costs. Some compliance costs will flow to Quebec and Ontario with gasoline imports from Alberta and Saskatchewan, and diesel imports from New Brunswick. At the same time, a portion of the CFR compliance costs will flow out of Quebec following gasoline and diesel exports to other provinces and territories. The remaining reallocated cost for Quebec is sufficient to add 6.9 (2022)cents and 2.4 (2022)cents per liter of gasoline and diesel, respectively, in 2030. Quebec may show the highest impact of CFR on gasoline price after New Brunswick. In Ontario, the CFR cost components are estimated to reach 4.5 and 3.4 (2022)cents/litre for gasoline and diesel, respectively (Figure 16 and Table 29).

TAKEWAYS FOR QUEBEC AND ONTARIO

Quebec and Ontario are the provinces with highest credits obligations after Alberta. Regulated parties in these provinces have opportunities for credit creation in all three categories. However, the opportunities for credit creation in CC1 remain limited and together with a constrained credit market, may push regulated parties to contribute extensively (up to the allowed limit) to the compliance fund after 2027. Compliance costs flowing inside provinces with interprovincial fuel imports and costs flowing outside provinces with interprovincial fuel exports will keep CFR reallocated costs similar to CFR compliance costs. CFR cost components in fuel prices are expected to be higher than the Canadian average with the highest impact for gasoline prices in Quebec.

Alberta and Saskatchewan

Alberta and Saskatchewan's large upstream oil sector will allow for an important share of credits to be created in the CC1 category. Between 30% and 43% of all credits in these provinces will be created in the CC1 category. As a consequence, the CFR cost impacts for these provinces will be lower than in provinces where most credits are created/purchased in more expensive categories. Average credit cost in Saskatchewan is expected to be the lowest of all provinces with major obligations, and it has relatively low total compliance cost. In the case of Alberta that has the highest credit obligation, a considerable part of its compliance costs will flow out with gasoline and diesel exports to other provinces and territories (cutting the original compliance costs in half, shown on Figure 13). For both provinces, the CFR cost component in gasoline prices is lower than the Canadian average: 3 (2022)cents per liter in 2030. The CFR cost component in diesel is expected to be slightly higher than the Canadian average with 3.5 (2022)cents per liter in 2030.

TAKEWAYS FOR ALBERTA AND SASKATCHEWAN

Alberta and Saskatchewan have more extensive opportunities of credit creation in the lower (incremental) cost CC1 category than other provinces. Regulated parties in Saskatchewan will benefit from this the most, leading to the lowest average credit cost among provinces with major obligations, and as a consequence, lowest relative compliance cost even in the case of credit purchase via emission reduction funding programs. Alberta will also benefit from credit creation in the CC1 category. However, its highest credit obligation in Canada will require credit purchase in the market at higher prices in CC2 and CC3 categories (as well as contributions to funding programs later in the decade). At the same time, an important portion of compliance costs will flow out of Alberta with interprovincial exports of gasoline and diesel. It is expected that CFR cost components will be similar for both provinces.

Territories, British Columbia, Prince Edward Island, Newfoundland and Labrador, and Manitoba

These section reviews the impact of CFR on consumers in regions with low or no credits obligations.

Based on this analysis, Consumers in the Territories are projected to experience price increases due to CFR costs from regulated parties in exporting provinces. However, primary suppliers may subtract volumes of gasoline or diesel from the annual obligation, if they are sold or delivered for use in non-industrial purposes or for use in the generation of electricity to remote communities. This could factor into negotiations on pricing of fuel intended for the Territories as much of it would incur no CFR obligation. Yukon, Northwest Territories and Nunavut have fuel imports coming from Saskatchewan and indirectly from Alberta. These imports may carry some compliance costs that occurred in exporting provinces, i.e., (2022)CAD 0.5 Million in 2023, (2022)CAD 0.8 Million in 2024 and (2022)CAD 13.6 Million in 2030 of CFR costs may flow to the Territories in total. The reference scenario projects a decrease in diesel consumption in Northwest Territories and Yukon by 2030. In 2030, the CFR cost component may reach 3 and 3.3 (2022)cents per litre of gasoline and diesel, respectively, (Nunavut has international import of diesel and is considered to not be affected by the CFR because most of their diesel is used in remote communities for non-industrial purposes or electricity generation) (Figure 16 and Table 29).

A similar situation may occur in British Columbia, where gasoline and diesel are regulated with an alternative provincial policy (that is excluded from the incremental CFR compliance cost estimates in this study). The effect of the CFR on the local gasoline and diesel prices is due to gasoline and diesel imports from Alberta. CFR reallocated cost that may flow to

British Columbia with fuel imports may represent around (2022)CAD 15 Million in 2023; (2022)CAD 26 Million 2024, and (2022)CAD 381 Million in 2030. Demand is expected to drop by around 20% between 2023 and 2030 for both fuels. In 2030, the CFR cost components are estimated to reach 1.9 and 3.5 (2022)cents/litre for gasoline and diesel, respectively (Figure 16 and Table 29).

Prince Edward Island is projected to have no credit obligations in this analysis. Compliance costs will flow inside the province with fuel imports: gasoline from Ontario and Quebec, and diesel from New Brunswick. Fuel demands are expected to remain relatively constant between 2023 and 2030. In 2030, the CFR cost components are estimated to reach 4.7 and 1.7 (2022)cents/litre for gasoline and diesel, respectively (Figure 16 and Table 29).

The total compliance cost for Newfoundland and Labrador is moderate, it was (2022)CAD 0.6 Million in 2023, (2022)CAD 0.8 Million in 2024 and (2022)CAD 3.1 Million in 2030 (Figure 13). Additional compliance costs will flow into the province with gasoline imports from Quebec and Ontario, and diesel imports from New Brunswick. Similarly to Nova Scotia, total CFR costs that are passed to provincial consumers are expected to be higher than the original total compliance cost in this province (shown on Figure 13). CFR cost component is expected to reach 3.7 (2022)cents/litre of gasoline and 2 (2022)cents/litre of diesel in 2030 (Figure 16 and Table 29).

Manitoba is expected to have very low credit obligations. However, the compliance costs flowing inside the province with gasoline and diesel exports from Alberta are substantial. For comparison, the annual compliance cost for Manitoba in 2030 is projected to be (2022)CAD 0.04 Million and the final reallocated cost may reach (2022)CAD 121 Million (Figure 14). As a consequence, it is expected that CFR cost components in fuel prices will be similar to Alberta levels reaching 3.1 (2022)cents/liter for gasoline and 3.5 (2022)cents/liter of diesel.

TAKEWAYS FOR TERRITORIES, BRITISH COLUMBIA, PRINCE EDWARD ISLAND, NEWFOUNDLAND AND LABRADOR, AND MANITOBA

Regions without or with very modest credit obligations may still experience fuel price increases due to the CFR. This results from interprovincial imports that may carry compliance costs that occurred in exporting provinces. In general, this increase remains close to the Canadian average.

SECTION 4

4. Sensitivity Analysis

4.1. Limited access to the credit market

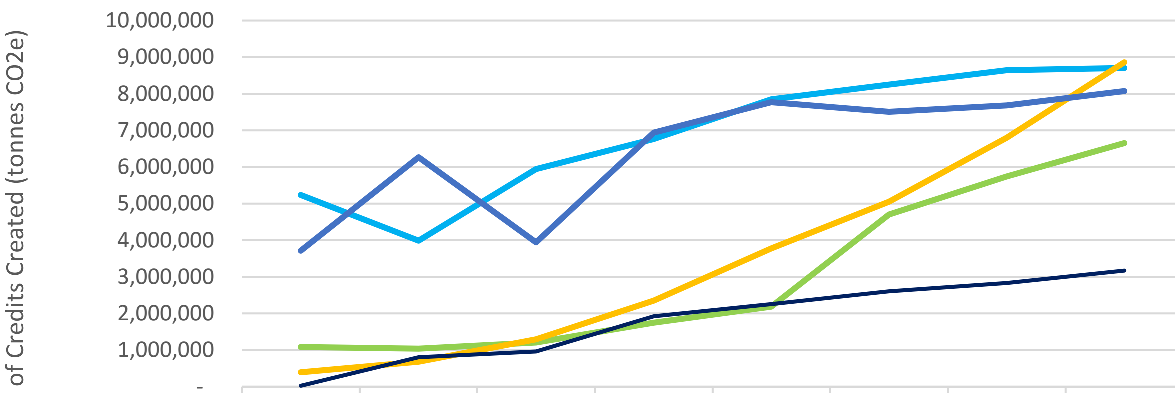
In this sensitivity analysis, we model a more constrained market, where access to the credit market is more limited. This assumption is implemented in the methodology as initially allowing CC2 and CC3 credits to be purchased only in the provinces where they are created – in part representing the fact that regulated parties may also create CC2 and CC3 credits. As the next step, if a regulated party (represented at aggregated provincial level) is found to be in a credit deficit, the party must then purchase 10% of its credits by contributing to a registered emission reduction funding program. As the last step, trade of credits created in provinces without obligations or with a relatively small amount of obligations (Prince Edward Island, Manitoba, Newfoundland and Labrador, the Territories, and credits created from import of US fuel) are then made available to trade on the credit market. Credits will only be purchased if the province is in deficit that year, but credit banking (i.e. over-purchasing relative to obligation in a given year) is still allowed. Due to large potential for credit creation in Newfoundland and Labrador, due in part to the production of renewable diesel, it is ensured that the province is provided with enough market credits to meet its obligation (without contribution to an emissions reduction fund). Due to the use of the fund throughout the study period, there is sufficient supply to meet demand and the maximum credit clearing price may effectively be slightly lower than in the main scenario at the end of the decade.

Compliance costs in this scenario are higher between 2024-2029 than in the main analysis, due to continued use of the registered emission reduction funding programs (which is close to or above 9% Canada-wide for 2026-2030). In 2024, when credit creation is still relatively limited, costs are equivalent to 2.5x of the main scenario, while between 2025-2029, costs are between ~1.1-1.7x. In 2030, annualized costs are very similar since both scenarios require use of the fund in all provinces with major obligations (Alberta, Saskatchewan, Ontario, Quebec, New Brunswick).

Comparing compliance costs by province shows a similar trend: impacts tend to be greater in 2024 than in 2030, and some provinces experience greater impacts than others. For example, in 2030, costs in Saskatchewan are about 10% higher even though Saskatchewan is able to meet about 43% of its obligation with CC1 credits, since credit creation shifts from the CC3 to CC2 category which is generally higher cost. Costs also increase in Alberta, especially in 2024 where they are ~3.5x of the main scenario. Although Alberta is able to create a significant amount of CC1 credits in absolute terms by 2030, they represent only 30% of its obligation amount in 2030 and only 17% in 2024. This means that for most years, Alberta must contribute to a registered emission reduction funding program at 350 (2022)CAD/tonne, in the amount of 10% of its obligation. In New Brunswick, costs are 2.7x of the main scenario costs in 2024 due to limited credit creation within the province, while they are at similar levels in 2030. In Ontario, costs are lower by about 15% in 2024 in 2030, since Ontario only requires contributions to an emission reduction funding program as from 2025 due to sufficient CC2 and CC3 credit creation within the province, and by 2030 lower cost CC3 credits overtake CC2. In Quebec, costs are significantly higher in 2024 (2.9x) since contributions to funding programs are already required, but they fall to lower levels than in the main scenario by 2030 as CC3 credit creation overtakes CC2.

4.1.1. Compliance Costs

Figure 17. Compliance credits by category and year for sensitivity scenario[23]

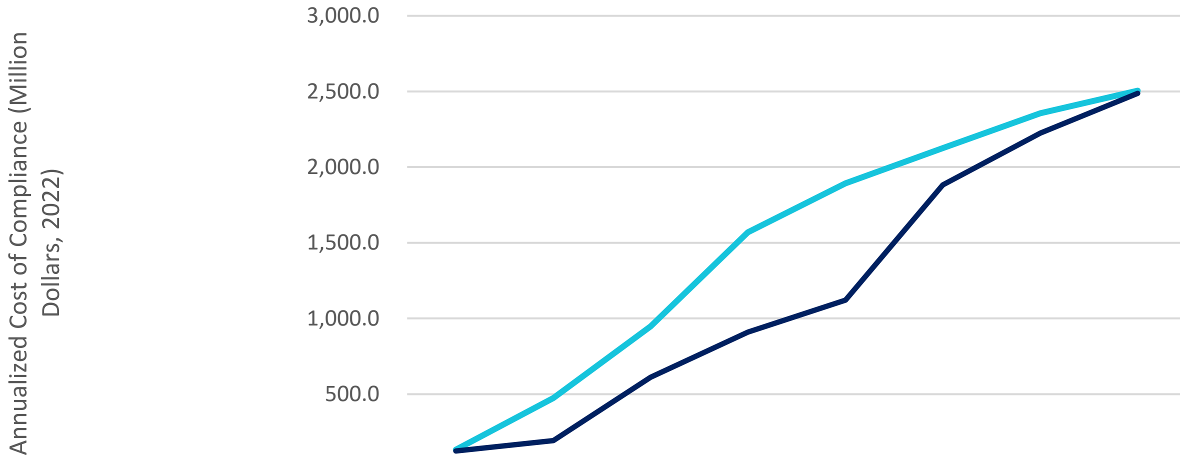


	2022 & 2023	2024	2025	2026	2027	2028	2029	2030
CC1	1,086,055	1,038,075	1,203,806	1,744,879	2,184,612	4,697,532	5,738,401	6,652,591
CC2	5,238,727	3,987,387	5,938,854	6,763,321	7,851,745	8,246,373	8,643,994	8,703,883
CC3	393,155	678,941	1,295,943	2,347,997	3,778,762	5,055,753	6,796,901	8,859,605
CC2-CC3-market	3,713,747	6,268,645	3,941,723	6,935,915	7,765,543	7,503,349	7,678,491	8,073,031
Fund	24,231	803,326	960,787	1,919,984	2,252,959	2,604,380	2,835,682	3,170,439

CC1 CC2 CC3 CC2-CC3-market Fund

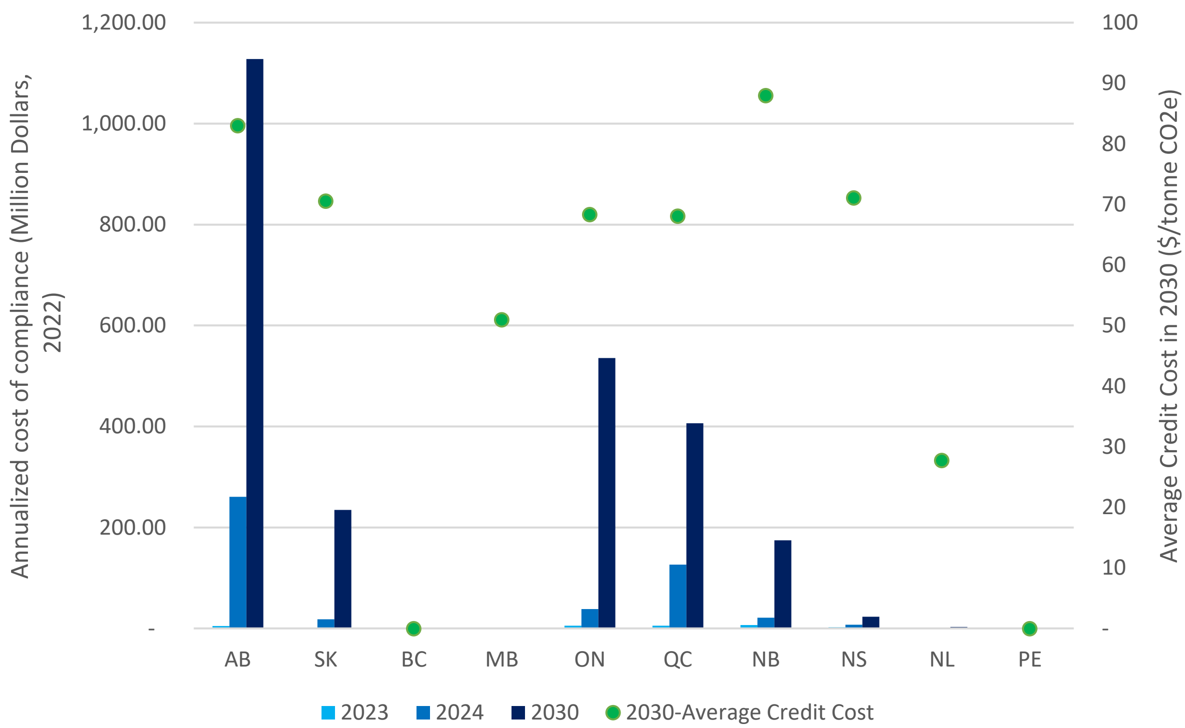
[23] Note that CC2-CC3 market purchases drop in 2025 since Alberta has sufficient banked credits in this year to avoid purchases on the market.

Figure 18. Annualized compliance costs for sensitivity scenario



	2022 & 2023	2024	2025	2026	2027	2028	2029	2030
Annual cost sensitivity ($M/year)	132.1	472.6	947.3	1,569.4	1,893.8	2,124.6	2,356.6	2,505.3
Main scenario	123.6	191.6	611.2	908.6	1,120.8	1,882.2	2,224.8	2,487.7

Figure 19. Annualized compliance costs by province for sensitivity scenario

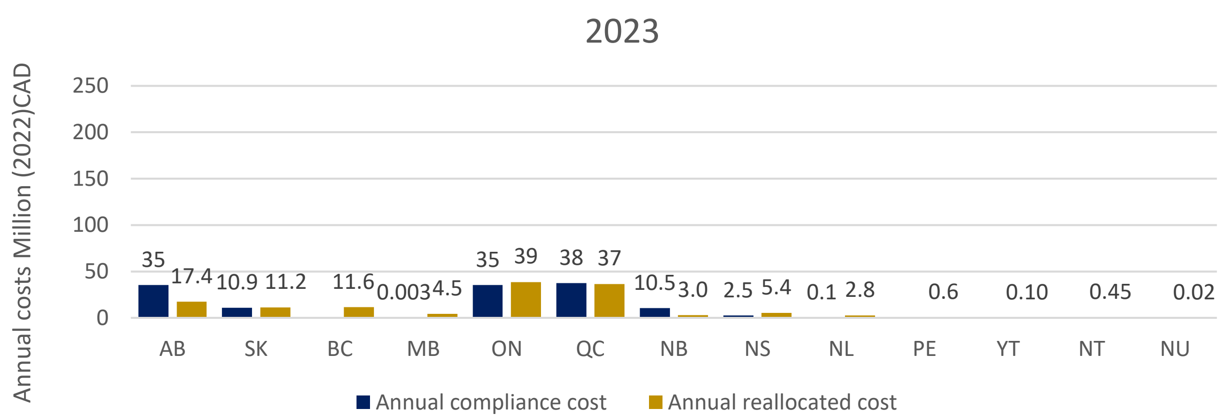


4.1.2. Impact on Fuel Prices

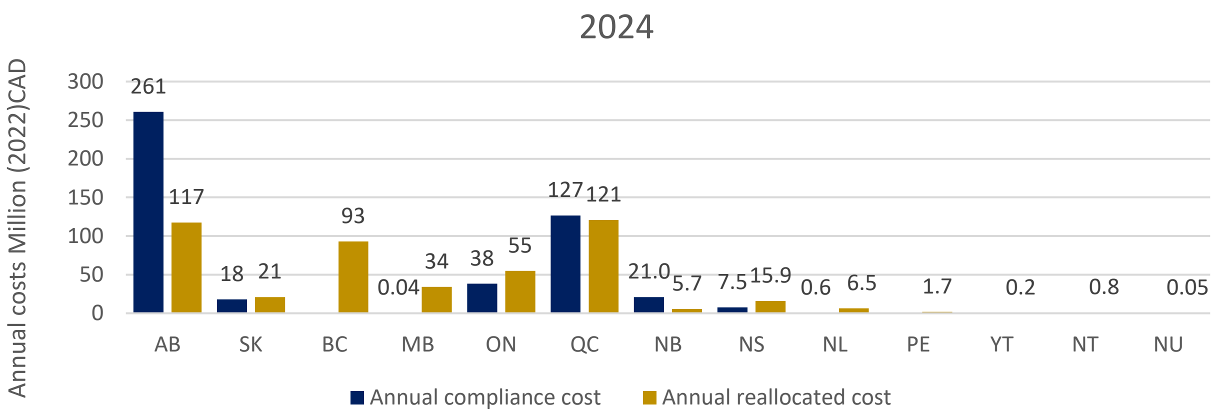
Limited access to the credit market will influence the annual compliance costs and as a consequence, the annual reallocated costs in most provinces (Figure 20). If compared to compliance and reallocated costs of the main scenario (Figure 14), it is clear that limited market access pushes up provincial compliance costs that now have no other option than to contribute to emission reduction funding programs earlier. As a consequence, average credit cost per province and reallocated cost generally increases early in the decade.

Under the limited market access scenario, CFR impact on fuel prices becomes clearly noticeable already in 2024. On average, the CFR impact becomes over two times higher than under the main scenario. In 2024, the impact in Atlantic provinces and Quebec is expected to be three times higher, while in Alberta the impact of a limited market may be four times higher. The increase of costs in Alberta will drive the increasing impact seen in Manitoba and British Columbia, where consumers purchase gasoline and diesel exported from Alberta (Figure 21). Impacts in Ontario and Saskatchewan remain comparable. By 2030, the difference between the main scenario and limited market access scenario becomes small – both scenarios lead to similar compliance costs.

Figure 20. Total compliance and reallocated costs under restraint access to credit market[24].



[24] Total of annual compliance and reallocated costs may slightly vary due to decimals rounding.


2024
Annual costs Million (2022)CAD
300
250
200
150
100
50
0
261
117
18
21
93
0.04
34
38
55
127
121
21.0
5.7
7.5
15.9
0.6
6.5
1.7
0.2
0.8
0.05
AB
SK
BC
MB
ON
QC
NB
NS
NL
PE
YT
NT
NU
Annual compliance cost
Annual reallocated cost

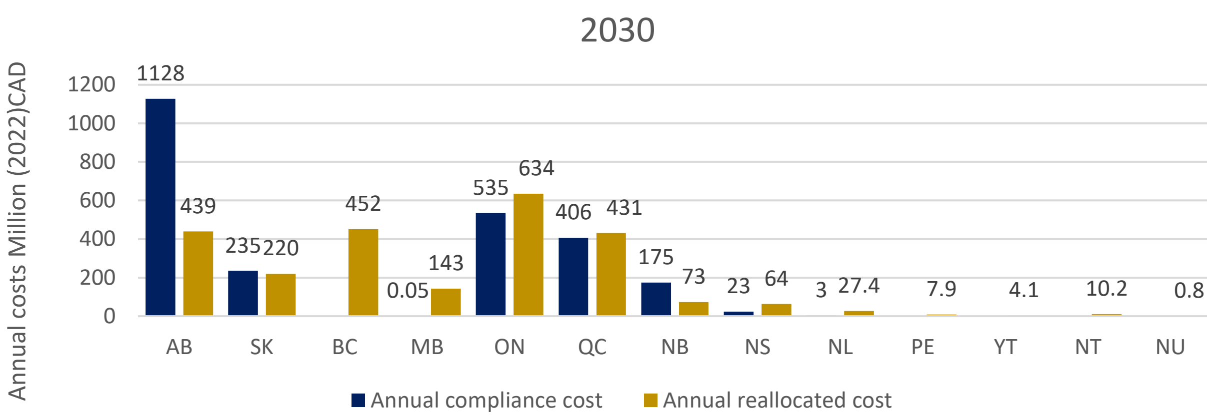
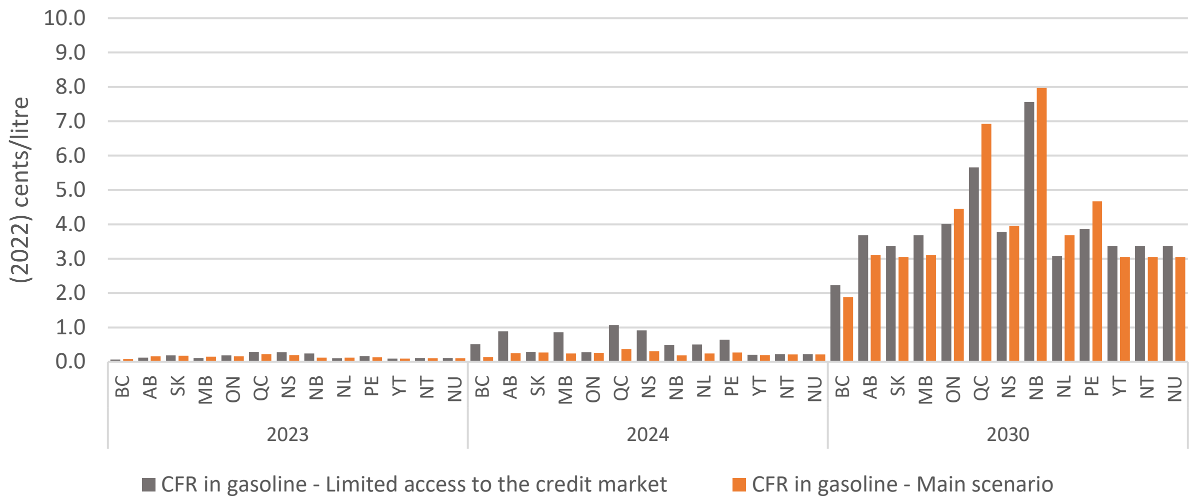
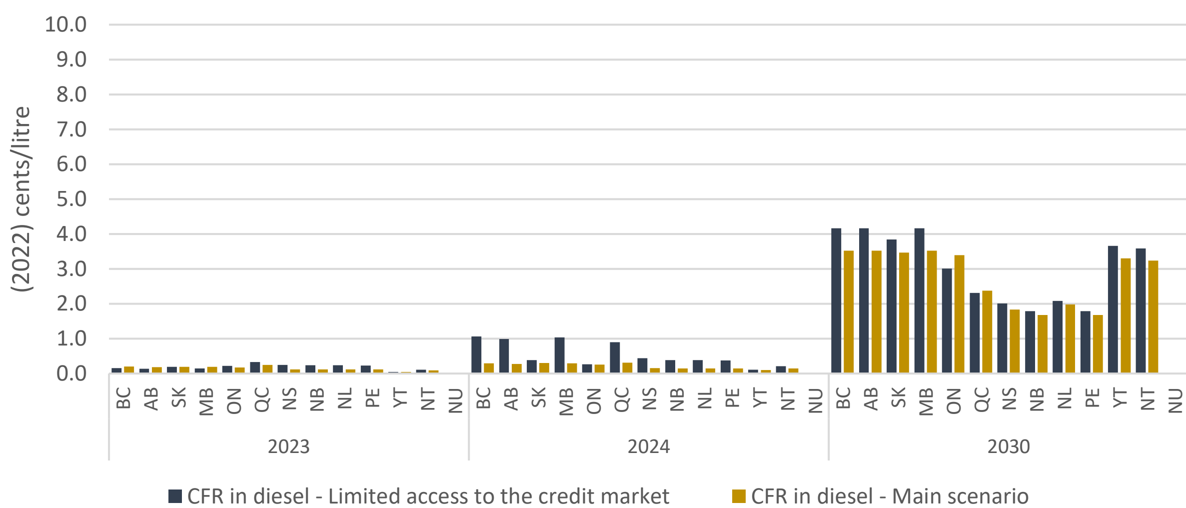

2030
Annual costs Million (2022)CAD
1200
1000
800
600
400
200
0
1128
439
235
220
452
0.05
143
535
634
406
431
175
73
23
64
3
27.4
7.9
4.1
10.2
0.8
AB
SK
BC
MB
ON
QC
NB
NS
NL
PE
YT
NT
NU
Annual compliance cost
Annual reallocated cost

Figure 21. Comparison of CFR cost components in the retail price before taxes for a) gasoline and b) diesel.



a)



b)

SECTION 5

5. Conclusions

The Clean Fuel Regulations increase in stringency between 2023 and 2030, requiring the creation of approximately 170 Million credits, where a credit is equivalent to a tonne of CO_{2e} measured on a lifecycle basis, cumulative over this period. Since credit creation may begin in 2022, credits can be banked due to eligible GHG reduction projects already in operation, existing low-CI fuels demand, as well as surplus compliance units that were created under the Renewable Fuels Regulations that will be converted into credits under the Clean Fuel Regulations. It is estimated that the number of credits created in 2022-2023 will exceed the total obligation amount, by about 5.8 Million credits. In 2024, in which credit adjustment for the 2022-2024 period will be allowed accounting for newly approved CI, the quantity of banked credits remains high, and total credits may exceed obligations by about 7.8 Million credits. As planned projects and new (unannounced projects) are projected to come online in the following years, the credit supply continues to be sufficient to meet obligations until 2026. After 2027, credit supply becomes more constrained, and contribution to registered emission reduction funding programs will be required: reaching 3.1 Million credits Canada-wide in 2030, equivalent to 8.6% of total obligations. It is projected that these contributions would be required across all provinces with substantial obligation requirements: Alberta, Saskatchewan, Ontario, Quebec, and New Brunswick.

The main goal of the study was to estimate costs of compliance for regulated parties. To do this, we focus on *incremental* costs, which implies accounting for only the additional costs incurred due to the CFR. Therefore, costs (or revenues) that result from other existing policies are excluded from the compliance costs. The study estimates the market prices of credits supplied by voluntary parties – which may differ from incremental cost due to profit seeking or other behaviour in the market. The analysis was performed per Canadian province, while allowing for CC2 and CC3 credit trading between provinces.

Over the time horizon, the credit clearing price tends to increase along with increasing obligation amount. It is important to note that our main analysis assumes that credits will continue to be banked, implying that regulated parties will purchase (or create) credits in earlier years (at a lower price) in order to limit contributions to registered emission reduction funding programs or higher cost credit purchases in later years. Our analysis also supposes that new CC1 category projects (CCS and EOR) will start to come online in 2027-2028, which reduces average credit cost due to the low incremental cost of these credits. If the estimated CC1 projects and subsequent credits do not fully materialize, credit clearing prices would be higher and greater contributions to registered emission reduction funding programs would likely be required. Nevertheless, higher credit prices may also stimulate greater supply in the CC2 and CC3 categories. For example, real blending rates may be increased further, beyond provincial mandates, via biodiesel or renewable diesel production, or increased imports of ethanol.

Between 2022-2024, the projected compliance costs in the main analysis for Alberta are (2022)CAD 166 Million, for Ontario: (2022)CAD 106 Million, for Quebec: (2022)CAD 103 Million, and Saskatchewan: (2022)CAD 38 Million. Costs in the Atlantic provinces are lower: (2022)CAD 18 Million for New Brunswick, (2022)CAD 5 Million for Nova Scotia, (2022)CAD and 2 Million for Newfoundland & Labrador. These costs do not account for trade between provinces to meet local demand, which will affect consumer prices at the pump – these are considered in the analysis of fuel prices. Over the study period, Alberta is projected to bear the highest costs of compliance – rising to (2022)CAD 952 Million of annual costs in 2030, as a result of having the highest obligation amount. Its obligation proportion (% of total country-wide obligations) also increases between 2022 and 2030. While compliance costs are the highest in Alberta due to the large production of gasoline and diesel in the province, the reallocated costs considered in the analysis of fuel prices are not. In Alberta, (2022)CAD 371 Million of reallocated costs are considered in the analysis of fuel prices in 2030, as gasoline and diesel are sold to other provinces and the costs are passed on. The next highest compliance costs are in the provinces of Ontario and Quebec, where annual costs rise to about (2022)CAD 634 and (2022)CAD 498 Million respectively in 2030. The reallocated costs considered in the analysis of fuel prices in the provinces of Ontario and Quebec are (2022)CAD 709 and (2022)CAD 509 Million respectively in 2030. Average compliance cost will vary by province due to the differing potential for CC1 credit creation. Provinces with higher potential for CC1 credit creation (in particular, for CCS and EOR projects), tend to see lower average credit costs, since we consider revenues from carbon credit sales in the emissions performance standards policies.

In order to evaluate the effects of a more constrained credit market, a sensitivity analysis was performed where CC2 and CC3 credits may initially only be purchased in the province in which they are created, and a resulting deficit implies that the province must contribute to a registered emission reduction funding program at 350 (2022)CAD/tonne in the amount of 10% of its annual obligation. Finally, the remainder of the credits would be purchased on the credit market, where credit supply is provided by provinces that have little or no obligation (or international imports of low-CI fuels). This sensitivity has significantly higher costs than the main analysis between 2024-2028, since fund purchases are required in earlier years. The proportion of fund purchases is highest in 2026, driving up costs significantly compared to the main analysis. Canada-wide compliance costs are estimated at (2022)CAD 473 Million in 2024, rising to similar levels as the main scenario in 2030 at about (2022)CAD 2.5 Billion. In 2030, the average cost of a credit is highest in New Brunswick. Compared to the main analysis, average cost increases in Alberta and Saskatchewan, while it decreases in Ontario and Quebec due to shifting of credits between compliance categories (CC2 being higher cost than CC3). These costs will have further repercussions on fuel prices seen by consumers, when inter-provincial trade flows of gasoline and diesel are considered.

The projected impact of CFR costs differs by jurisdiction and depends mainly on the combination of two factors:

- Annual compliance cost for regulated parties that will be subject to the project opportunities in different provinces, provincial context and contribution to the compliance fund and;
- Interprovincial trade flows of refined oil products that will transfer portions of compliance cost from the province where these costs occurred to the provinces where fuels will be consumed.

The annual compliance costs in different jurisdictions, which drive up the revenue requirement for regulated parties, will depend on the compliance categories of created or purchased credits (CC1 generally having lower incremental cost than CC2 and CC3). In Alberta and Saskatchewan, where most of the upstream oil sector is located, a larger share of credits will be from the CC1 category. In Quebec, Ontario, Nova Scotia, and New Brunswick, at minimum ~90% and at maximum all credits will be from CC2 and CC3 increasing gasoline and diesel retail prices. At the same time, shortage in credit creation will lead to contributions to emission reduction funding programs (credit cost here is higher than the average credit cost in compliance categories). Regulated parties in Quebec, Ontario, New Brunswick, Alberta, and Saskatchewan start to extensively contribute to these programs after 2027 and by 2030 it is expected that their contributions will approach the maximum allowed limit.

The interprovincial trade flows of fuels will partly transfer costs created in one jurisdiction to the gasoline and diesel consumers in another jurisdiction. The impact of interprovincial trade flows is particularly obvious in Atlantic provinces. A major portion of compliance costs due to diesel production will flow out of New Brunswick following fuel exports to other provinces such as Newfoundland and Labrador, Nova Scotia, and Prince Edward Island. At the same time, a portion of the compliance cost related to gasoline will remain in the province (in the absence of major interprovincial gasoline exports) and will be passed on to provincial consumers. This will lead to the highest impact of the CFR on gasoline prices among Canadian provinces, while the impact on diesel price remains under the projected Canadian average. Regulated parties may choose to reallocate CFR cost from gasoline to diesel prices to decrease burden on gasoline consumers. However, even by doing this, it is expected that CFR cost components in gasoline and diesel prices will be among the highest in Canada.

Nova Scotia has a lower credit obligation than New Brunswick. However, additional CFR costs flow inside the province with gasoline and diesel imported from Ontario, Quebec, and New Brunswick. Even after transfer of these costs, the CFR cost that will be passed on local consumers remains considerably lower than in New Brunswick, leading to moderate impact on gasoline and diesel prices (under the projected Canadian average).

Other provinces where the CFR impact for gasoline is projected to be higher than the Canadian average are Quebec and Prince Edward Island. Regulated parties in Quebec will have limited opportunities for project creation in lower-cost CC1 categories. Moreover, while some compliance costs will flow out of the province, they will be compensated by costs flowing in with interprovincial imports. As a result, the CFR compliance cost will remain relatively high, increasing impact on gasoline consumers. Prince Edward Island is assumed to have no credit obligation, but will experience gasoline price increases due to the CFR with compliance costs flowing in the province via imports from Ontario and Quebec.

CFR impact on diesel price is expected to be more uniform than gasoline, with provincial results showing small deviations from the projected Canadian average. A slightly higher impact is expected for consumers in the Prairies, Ontario, and British Columbia.

Sensitivities show that if access to the credit market were limited across Canada, this would drive up annual compliance costs between 2024-2029 and, as a consequence, annual reallocated costs. The CFR cost component in fuel retail prices may become up to five times higher in 2024 than in the main scenario. By 2030, the difference in the impact between the main and limited market access scenarios will be minimized. This is due to the fact that under both scenarios, compliance costs are very similar in 2030 because they require contribution to emission reduction funding programs by all provinces with substantial credit obligations (Alberta, Saskatchewan, Ontario, Quebec, New Brunswick). This shows a robust trend that by the end of the decade, there is a risk of insufficient credit supply, whether the market is more or less restrained in terms of trade between parties. One possibility to overcome this insufficiency is for regulated parties to begin contributions to the fund earlier (e.g., in 2025-2026) and bank their credits in order to mitigate the risk of credit shortage or credit price spikes in the future.

Uncertainties

There are several sources of uncertainty in this study, which have a high influence on results, in particular the following parameters:

1. Engagement rate assumptions for all credit categories
2. Assumptions on credit market prices (conversion from credit cost to price)

The engagement rate has a very strong influence on the credit supply per category, which in turn influences the compliance costs – for example, whether contributions to emission reduction funding programs are required. Similarly, a lower engagement rate in one category and a higher engagement rate in another category may shift costs. Assumptions on credit prices will inherently affect compliance costs as well. Difficulty in predicting market dynamics and the behavior of potential credit creators with regards to placing credits on the market drive this uncertainty. Market supply will be also affected by the quantity of credits transferred privately. In the case where the market is very constrained by 2030, credit prices may increase as demand will be greater than supply.

Finally, the behavior of each regulated party is uncertain with regards to the strategy taken to comply with the Regulations. In the main analysis, we assumed that CC2 and CC3 credits created by any province may be purchased by any other province, however, private transfers may in reality limit this supply. Furthermore, large market players may have a larger ability to control prices or purchase credits due to their scale and market power. Meanwhile, provinces with no oil extraction industry, with lower levels of refining activity, or with limited capacity for carbon sequestration may find it more difficult to invest in projects to reduce carbon intensity in the supply chain (CC1). This means that they will further depend on the credit market, and that in the worst-case scenario, they may need to make higher contributions to the registered emission reduction funding programs.

Although it is difficult to quantify the impacts of these uncertainties, the sensitivity scenario on limited access to the credit market provides insights into how more limited credit supply (or credit transferability) as well as higher average credit costs/prices may affect the market and the resulting compliance costs for regulated parties.

Uncertainties in future oil and gas prices were not considered in the analysis. A higher future oil and gas price (assuming higher profit margins for suppliers) could reduce incentives to invest in low-CI fuels. Such dynamics are not accounted for in the analysis. However, in this analysis, credit supply is not based on financial cost-benefit analysis from any individual agents' point of view, but rather least cost behavior from a system perspective in response to energy system policies (including the CFR). Nevertheless, changing profit margins would affect the incremental credit cost, for example by increasing or decreasing the gap between traditional and low-CI fuels, however, such uncertainties can be considered as part of the uncertainty in future credit prices (and the portion of credit cost transferred to credit price).

Limitations

This study has a few modeling limitations that may affect overall results. We expect that the following limitations would have relatively low impact on the main trends and conclusions:

- Potential credit creation from new co-processing facilities and for credit creation under the generic emission-reduction quantification method (CC1, up to 10% of total requirement) was not modelled.
- Under the CFR, a primary supplier may defer up to 10% of their annual reduction requirement for up to 5 years. Deferral of annual reduction requirements was not modelled.
- Profit changes for any fuel suppliers (fossil or biofuels) was not considered.

The limitations of the study with greatest impact on results include the following assumptions made:

- The full CC2 and CC3 credit supply (after application of the engagement rate) were assumed to be traded on the credit market, without consideration for private transfers.
- Parties creating credits would be willing to sell their credits (if the estimated credit price is at or below the market clearing price), rather than holding their credits over many years (for example, in anticipation of higher prices).

The first limitation was partly addressed in the sensitivity case on limited access to the credit market, where only credits generated in provinces with little or no obligations are made available for trading to other provinces.

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ANNEX

Annex

Annex A

Item	Fuel	Province	Reference Production Gate Cost (2022 CAD / GJ)								
			2022	2023	2024	2025	2026	2027	2028	2029	2030 and after
1	Liquid class	AB	28.1	24.9	24.2	24.4	24.2	24.0	23.9	23.7	23.5
2	Liquid class	BC	30.3	27.1	26.3	26.6	26.4	26.2	26.0	25.9	25.7
3	Liquid class	MB	28.8	25.6	24.8	25.0	24.9	24.7	24.5	24.3	24.2
4	Liquid class	SK	28.0	24.8	24.1	24.3	24.1	23.9	23.8	23.6	23.4
5	Liquid class	ON	26.7	23.6	22.8	23.0	22.9	22.7	22.5	22.3	22.2
6	Liquid class	QC	25.0	21.9	21.1	21.3	21.1	21.0	20.8	20.6	20.4
7	Liquid class	NB	23.2	20.0	19.2	19.4	19.3	19.1	18.9	18.7	18.6
8	Liquid class	NL	24.3	21.2	20.4	20.6	20.4	20.3	20.1	19.9	19.7
9	Liquid class	NS	23.2	20.0	19.2	19.4	19.3	19.1	18.9	18.7	18.6
10	Liquid class	PE	23.6	20.4	19.7	19.9	19.7	19.5	19.4	19.2	19.0
14	Natural gas	AB	3.5	3.9	4.3	4.8	4.8	4.9	4.9	5.0	5.0
15	Natural gas	BC	3.4	3.9	4.4	4.9	4.9	5.0	5.0	5.1	5.2
16	Natural gas	MB	3.6	3.9	4.3	4.7	4.8	4.8	4.9	4.9	5.0
17	Natural gas	SK	3.7	4.0	4.4	4.7	4.8	4.8	4.9	4.9	5.0
18	Natural gas	ON	3.5	3.9	4.3	4.7	4.7	4.8	4.9	4.9	5.0
19	Natural gas	QC	3.8	4.2	4.5	4.8	4.9	4.9	5.0	5.0	5.1
20	Natural gas	NB	3.9	4.3	4.6	5.0	5.1	5.1	5.2	5.2	5.3

21	Natural gas	NL	3.9	4.3	4.6	5.0	5.1	5.1	5.2	5.2	5.3
22	Natural gas	NS	3.9	4.2	4.6	5.0	5.0	5.1	5.1	5.2	5.2
23	Natural gas	PE	3.9	4.3	4.6	5.0	5.1	5.1	5.2	5.2	5.3
24	Propane	AB	17.1	15.3	14.9	15.0	14.9	14.8	14.7	14.6	14.5
25	Propane	BC	19.1	17.3	16.8	17.0	16.9	16.8	16.7	16.6	16.5
26	Propane	MB	17.3	15.5	15.0	15.2	15.1	15.0	14.9	14.8	14.7
27	Propane	SK	17.2	15.5	15.0	15.1	15.0	14.9	14.9	14.8	14.7
28	Propane	ON	16.1	14.3	13.9	14.0	13.9	13.8	13.7	13.6	13.6
29	Propane	QC	14.8	13.0	12.6	12.7	12.6	12.5	12.4	12.3	12.3
30	Propane	NB	14.3	12.5	12.1	12.2	12.1	12.0	11.9	11.8	11.7
31	Propane	NL	16.0	14.2	13.8	13.9	13.8	13.7	13.6	13.5	13.4
32	Propane	NS	14.3	12.5	12.1	12.2	12.1	12.0	11.9	11.8	11.7
33	Propane	PE	15.1	13.3	12.9	13.0	12.9	12.8	12.7	12.6	12.5

Annex B

Item	Fuel	Province	Reference Production Gate Cost (2022 CAD /GJ)								
			2022	2023	2024	2025	2026	2027	2028	2029	2030 and after
1	Liquid class	AB	22.5	24.0	25.6	27.2	27.0	26.8	26.6	26.5	26.3
2	Liquid class	BC	24.5	26.1	27.7	29.2	29.0	28.9	28.7	28.5	28.4
3	Liquid class	MB	23.3	24.8	26.4	28.0	27.8	27.6	27.5	27.3	27.1
4	Liquid class	SK	22.7	24.2	25.7	27.2	27.1	26.9	26.7	26.5	26.4
5	Liquid class	ON	20.1	21.8	23.5	25.3	25.1	24.9	24.7	24.6	24.4
6	Liquid class	QC	20.6	21.6	22.6	23.6	23.4	23.2	23.0	22.9	22.7
7	Liquid class	NB	17.7	19.2	20.7	22.2	22.1	21.9	21.7	21.5	21.4
8	Liquid class	NL	22.4	23.5	24.6	25.7	25.5	25.4	25.2	25.0	24.8
9	Liquid class	NS	17.1	18.8	20.4	22.1	21.9	21.7	21.6	21.4	21.2
10	Liquid class	PE	18.4	20.0	21.6	23.2	23.0	22.8	22.7	22.5	22.3
14	Natural gas	AB	7.4	7.9	8.3	8.7	10.6	12.5	14.4	16.3	18.1
15	Natural gas	BC	10.0	10.4	10.9	11.4	13.2	14.9	16.6	18.3	20.1
16	Natural gas	MB	7.2	7.6	8.0	8.4	9.9	11.4	12.9	14.4	15.9
17	Natural gas	SK	6.1	6.5	6.8	7.2	9.0	10.9	12.8	14.7	16.5
18	Natural gas	ON	7.3	7.7	8.1	8.5	10.1	11.6	13.2	14.8	16.4
19	Natural gas	QC	10.8	11.1	11.4	11.8	13.3	14.8	16.3	17.9	19.4
20	Natural gas	NB	23.9	24.3	24.6	25.0	26.4	27.8	29.1	30.5	31.9
21	Natural gas	NL	23.9	24.3	24.6	25.0	26.4	27.8	29.1	30.5	31.9
22	Natural gas	NS	26.0	27.0	28.0	29.1	30.4	31.8	33.1	34.5	35.8
23	Natural gas	PE	23.9	24.3	24.6	25.0	26.4	27.8	29.1	30.5	31.9
24	Propane	AB	34.5	35.4	36.2	37.0	36.8	36.5	36.3	36.1	35.8
25	Propane	BC	32.4	33.2	34.0	34.8	34.6	34.4	34.2	34.0	33.8
26	Propane	MB	45.0	46.2	47.4	48.5	48.2	47.9	47.6	47.3	47.0
27	Propane	SK	39.8	41.1	42.5	43.9	43.6	43.3	43.1	42.8	42.5
28	Propane	ON	27.1	28.1	29.2	30.2	30.0	29.8	29.6	29.3	29.1
29	Propane	QC	33.5	33.8	34.1	34.3	34.1	33.8	33.5	33.3	33.0
30	Propane	NB	30.8	30.1	29.4	28.7	28.4	28.2	28.0	27.7	27.5
31	Propane	NL	31.3	32.6	34.0	35.3	35.1	34.9	34.6	34.4	34.1
32	Propane	NS	26.0	27.7	29.3	31.0	30.7	30.5	30.3	30.0	29.8
33	Propane	PE	28.7	30.2	31.6	33.0	32.8	32.5	32.3	32.1	31.8

Annex C. ESMIA's analytical tools and Reference case

ESMIA Consultants offers solid expertise in 3E (energy-economy-environment) integrated system modelling for strategic decision-making at city, regional, national and global scales. We specialize in economy-wide energy system optimization models (both proprietary and open-source models). The goal behind our work is to offer solutions that achieve energy and climate goals without compromising economic growth.

We used several analytical tools to support this project, including our proprietary optimization model, NATEM, to develop a reference case for projections of future fossil fuel use, the techno-economic database used by NATEM as a source for biofuel production costs, and our Tariff tool for estimating impacts on fuel prices by province (as described in the main report).

North American TIMES Energy Model (NATEM)

Some assumptions for this project use the Canadian module of the North American TIMES Energy optimization Model (NATEM). NATEM-Canada describes the entire integrated energy system, as well as non-energy emitting sectors of the 13 Canadian jurisdictions and provides a rigorous analytical basis for identifying least-cost solutions to achieve energy and climate objectives.

NATEM's core strengths are its:

- rigorous representation of the entire integrated energy system,
- detailed database of technologies (including existing and emerging technologies), and
- robust identification of lowest cost solutions over multiple regions and years.

NATEM-Canada is part of a framework covering the North American continent, but the US and Mexico components were not used for this analysis so for the rest of the report, NATEM will refer to the Canadian portion only.

NATEM follows a techno-economic modelling approach of defining all the goods and services required by an economy and the choices for producing these goods and services. The basic unit of production is a technology that consumes energy and produces an intermediate or final end-use. A final good or service generally requires the combination of end-uses, provided by technologies. The energy system describes all the connections between resources, technologies and end-uses to final goods and services.

The main result of a NATEM run is the quantity by type of technologies that were used to provide the final goods and services. Each technology is defined by its costs, energy consumption and GHG emissions. Knowing the type, quantity and operation of technologies allows NATEM to then calculate the total costs, energy use and GHG emissions.

NATEM represents the energy system from resource supply (extraction or imports) through conversion and production to final goods and services for domestic use and exports, including the transportation needed at any step. Figure 1 is a simplified representation of NATEM.

For energy supply, NATEM captures extensive details for all sectors, including electricity and heat generation, fossil fuel extraction, upgrading and transport, uranium extraction and transport, petroleum refining, bioenergy production, natural gas liquefaction and exports, hydrogen, renewable natural gas production with ESMIA capturing new products and processes through on-gong model development.

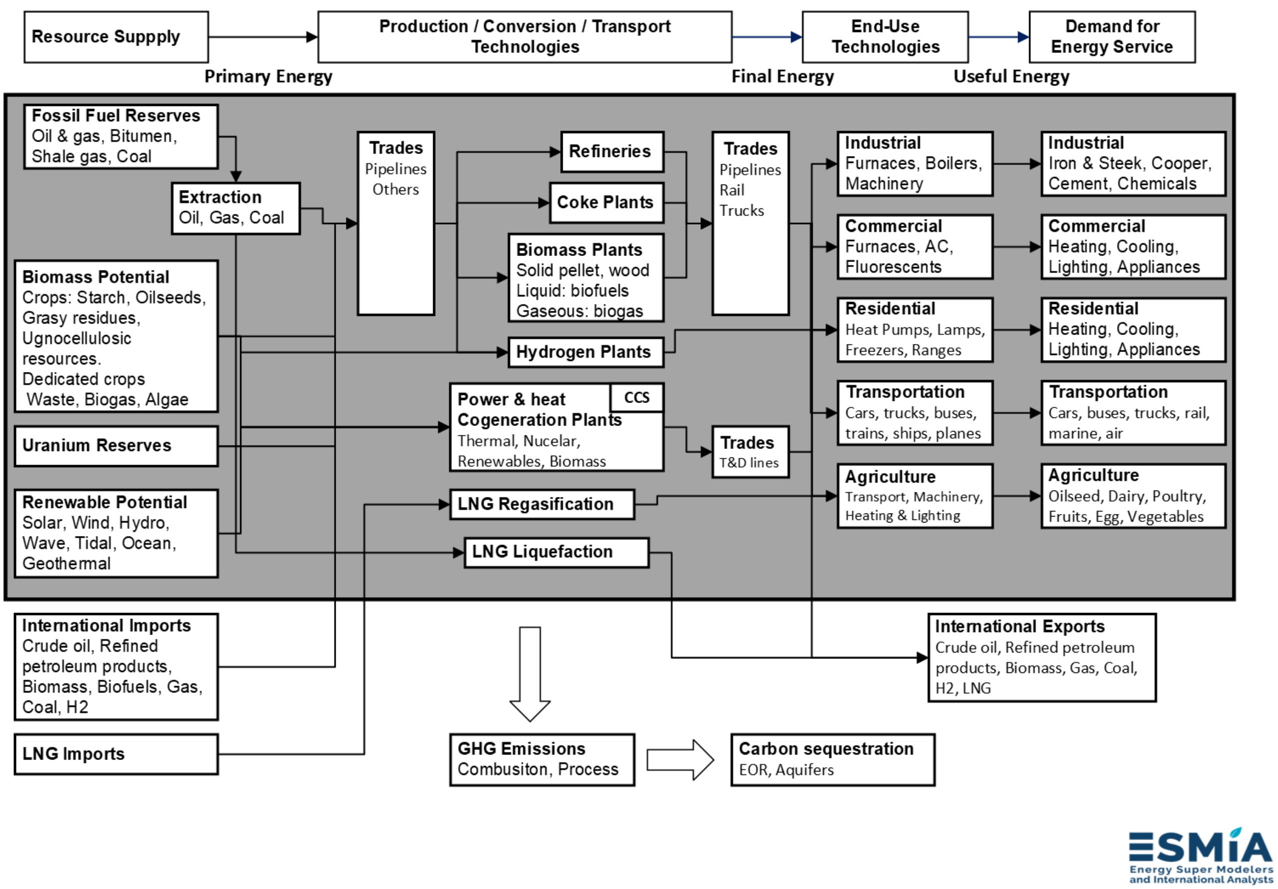
Primary energy resources are reflected from the best available Canadian data, including conventional and unconventional fossil fuels reserves (oil, gas, and coal), renewable potential (hydro, geothermal, wind, solar, tidal and wave), uranium reserves and biomass (various solid, liquid, and gaseous sources).

The energy system in NATEM has been carefully developed, based on engineering studies, to represent each step required for production of goods and supply of services. Steps requiring input from other parts of the energy system are explicit in the model design, which solves to find the least cost across all the inter-connected steps. For example, using a dual fuel (hybrid) heat pump for heating and cooling in a commercial building requires natural gas extraction and processing, electricity generation, and distribution of gas and electricity to the building. The energy or materials that flow from one part of the energy system to another are referred to as commodities. Representing the complete energy system ensures that NATEM solutions are rational, comprehensive, and readily capture unexpected impacts.

As a model, NATEM must apply some simplifications. It represents the steps that are common over the majority of production facilities, buildings, or transportation options with a focus on the steps that consume the most energy. Even with this simplification, NATEM's energy system retains extensive detail with each jurisdiction's representation including over 65 final end-uses, 475 commodities, and 7,000 explicit technologies.

End-use demands are the drivers of the energy system evolution in NATEM. These are an exogenous input to the model, projected through 2050 in physical units (e.g., passengersand tonnes- kilometres for transport segments) using a coherent set of socio-economic projections (GDP, population, etc.) from the Canadian Energy Regulator and other factors such as future announced projects.

Illustrative excerpt of energy system in NATEM

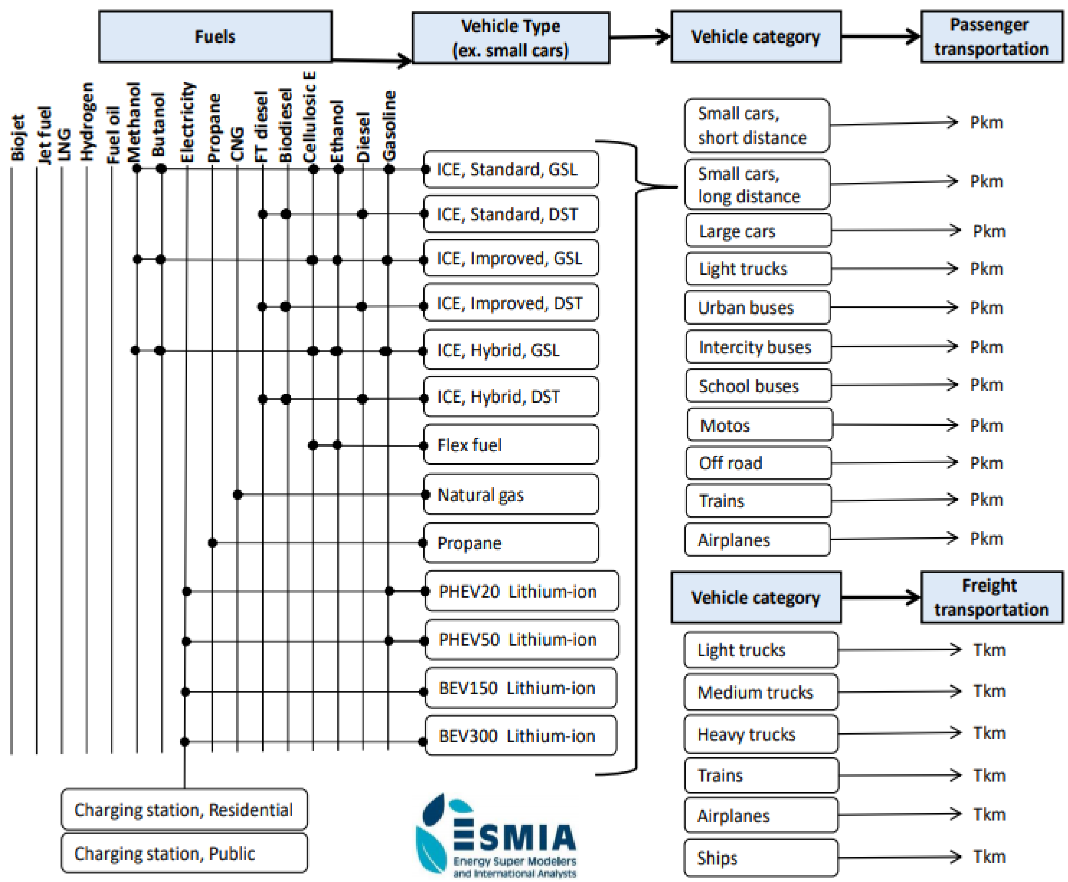


A detailed representation of North American energy systems

NATEM follows a techno-economic modelling approach to describe the energy systems of North American jurisdictions through a large variety of specific energy technologies characterized with their technical and economic attributes as well as pollutant coefficients. It thus offers a detailed representation of an energy sector, which includes extraction, transformation, distribution, end uses, and trade of various energy forms and materials.

NATEM distinguishes between generation technologies that convert primary energy into secondary energy (e.g., refineries, power plants, etc.) and end-use devices that transform final energy into energy services (e.g., cars that serve a demand for mobility, light bulbs that serve a demand for lighting). In particular, they include existing technologies, improved versions of the same technologies and emerging technologies, all characterized by their technical and economic attributes. Consequently, it allows for detailed accounting of all energy flows within the energy sector from primary energy extraction to final energy consumption, accounting for potential technology and system evolution.

Example from the road passenger transport by small cars travelling long distance (not necessarily an exhaustive list of options)



Identifying optimal solutions

A NATEM solution is the optimal technology mix in all supply and demand sectors to meet end-use demands at the least-cost across the entire time-period.

NATEM's optimal solution must meet user-defined specifications. The robust solution space in the model allows for a wide range of such specifications. It can be used to derive minimum cost solutions for meeting prescribed GHG reduction targets in selected jurisdictions or for several and/ or all jurisdictions. Alternatively, it can be used to derive projected GHG reductions in response to defined policies. Policies include GHG prices (carbon tax), subsidies, taxes on specific technologies, renewable portfolio standards, minimum renewable content in conventional fuels, phase out programs and moratoria on energy types (e.g., nuclear or coal), investment growth rate projections, etc.

NATEM's basic specification comprises three components:

- The first component (objective and exogenous service demand) corresponds to the overall goal. By default, NATEM's objective is to provide the exogenous service demand for the energy system, at the minimum net total discounted cost, over the entire time period and all jurisdictions.
- The second component (endogenous decision variables) corresponds to determining the future technology mix, which includes decisions on investments, retirements, and operations of technologies at each time period. The amount of energy produced or consumed by technologies, energy trade, and emissions are determined by the technology mix and operations.
- The third component (constraints) corresponds to various limits and obligations to be respected. Some constraints are policy-based (such as GHG emission caps), others are due to physical resource availability (e.g., biomass) or technology specifications (e.g., hydrogen blend allowed in pipelines or technologies). Many constraints are a function of the energy system connections where one part of the system will demand production from a different part (e.g. energy balances throughout the system, useful energy demand satisfaction). NATEM can also use constraints to represent supply chain or investment growth limitations.

In summary: NATEM solves by mathematically determining (decision variables) the mix of technologies (from the techno-economic database) that meet the energy service demands (inputs), subject to constraints such as government policies and resource availability, *at the least cost* over the full planning horizon.

NATEM Reference case

The reference case for this project includes expected population and economic growth and current policies. A simplified representation of the CFR is included in the reference case.

Calibration

Historic information in NATEM includes energy consumption and production and GHG emissions by fuel and economic sector for the 13 provinces and territories.

Examples of the sources for this information include but are not limited to:

- Environment and Climate Change Canada. 2023. *National Inventory Report*. (ECCC, 2023)
- Natural Resources Canada. n.d. *Comprehensive Energy Use Database*. (NRCan, n.d.)
- Statistics Canada. *Annual Industrial Consumption of Energy Survey, 2022*.(Statistics Canada, 2022)
- Statistics Canada (2023). *Energy Supply and Demand in Canada – Interactive database.* (Statistics Canada, 2023)

Discount rate

For this project ESMIA used a global discount rate of 3%. This choice follows the direction from *Canada's Cost-Benefit Analysis Guide for Regulatory Proposals* (Treasury Board of Canada Secretariat, 2022), which notes that projects considering environmental goods and services can use the social discount rate of 3%. The 2020 regulatory impact assessment statement of the *Clean Fuel Regulation* used the same approach of 3% for the main analysis (Government of Canada, 2020).

Note that the global discount rate is used for setting the objective function where total cost is minimized. Decisions for individual technologies use technology-based discount rates that account for elements such as limits to capital, short-term decision by types of consumers (for example, higher hurdle rates for residential purchases of equipment with low capital costs and relatively lower hurdle rates for industrial customers for larger purchases using credit but still high enough to cover a return on investment).

Projections for population, economic growth and export oil and gas prices

NATEM requires exogenous projections for end-use demand, the units of goods and services that a model solution must meet. These inputs are derived from official sources to describe a set of coherent future conditions. The sources of the future conditions are shown below.

Select sources of forecasts used to derive final end-use projections.

Variable	Purpose	Source
Population	To project future demand for residential housing, personal transportation, and services	*Population Projections for Canada (2021 to 2068), Provinces and Territories (2021 to 2043).* (Statistics Canada, 2022)
Gross domestic product	To project future demand for goods and services	(CER, 2023) *Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050.* Reference scenario (Canadian Climate Institute, 2022). *Damage Control: Reducing the costs of climate impacts in Canada*
Oil and gas export prices	To develop costs for consumption and demand for exports.	(CER, 2023) *Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050.* Reference scenario

NATEM has over 65 end-uses; examples of some key end-uses and physical units are shown below. The end-use demands change over time to represent the evolving economic, infrastructure and social conditions. The model also uses price elasticities for endogenous demand reductions under GHG mitigation scenarios, such as lower demand for floorspace (smaller homes and buildings) when energy costs increase.

Impacts of climate change are expected to change some end-use demands (for example, increasing cooling demand) and areas for economic growth. Such changes are applied exogenously to NATEM. For heating and cooling demand changes, ESMIA adjusted the energy intensity of service demands by building types (e.g., TJ/m2 of useful energy for space cooling in detached houses) using information for one major city in each province and territory, derived from (Pacific Climate Impacts Consortium, n.d.) based on the worst-case scenario (RCP8.5). For changes to economic structure from climate impacts the agriculture and industrial output were adjusted based on information from Canadian Climate Institute (2022).

Examples of end-use demands, exogenous to NATEM.

Transportation	
Passenger	
Aviation	Billion person-km per year
Bicycling and Walking	
Road	
Railways	
Other	
Freight	
Aviation	Billion tonne-km per year
Other	
Railways	
Road	
Buildings (floorspace)	
Commercial	Million m2
Residential	
Industrial Production	
Cement	Million tonnes of final product per year
Chemicals	
Non-ferrous Metals	
Pulp and Paper	
Steel	

Prices for fossil energy imports and exports

In NATEM, most energy prices are endogenous to the model; only prices of energy commodities imported/exported from/to outside Canada are exogenous inputs. For the reference case, the international energy prices are from the reference case of Canada's Energy Future 2023 (CER, 2023).

Policies

NATEM allows a thorough representation of energy and climate policies. Only legislated policies are included in the model, developing or announced policies are excluded. The table below gives an overview of modelled policies in the NATEM reference case.

Energy and climate policies modelled

Level	Policy item
Federal	Federal Fuel Charge under Greenhouse Gas Pollution Pricing Act
Federal	Federal Output-based Performance Standard
Federal	Clean Fuel Regulation, simplified representation
Federal	Incentives for LDZEVs and Zero-emission vehicle infrastructure program
Federal	Incentives for MDZEVs and HDZEVs
Federal	Clean Technology Investment Tax Credit
Federal	Investment Tax Credit for Clean Hydrogen
Federal	Investment Tax Credit for CCUS
Federal	Investment Tax Credit for Clean Electricity
Federal	HFC Regulation (Kigali amendment)
Federal	Heat pump grants / funding
Federal	Greener Homes Grant
Federal	GHG emissions standards for vehicles through 2027 (CAFE)
Ontario	Emissions Performance Standard
Ontario	Cleaner Transportation Fuels Regulation
Ontario	Landfill Gas Regulation
Ontario	Strategy for a Waste-Free Ontario
Ontario	Nuclear Refurbishment
Ontario	Conservation and Demand Management program
Ontario	Industry conservative initiative
Ontario	Framework for regulating geologic carbon storage (CCS)
British Columbia	Zero-emissions vehicle mandate and incentives
British Columbia	CleanBC Better Homes and Better Buildings programs

Level	Policy item
British Columbia	CleanBC Industrial Electrification
British Columbia	CleanBC Industry Fund
British Columbia	Renewable Fuel Regulation
British Columbia	Low Carbon Fuel Standard
British Columbia	Renewable Natural Gas Regulation
Quebec	Quebec cap and trade
Quebec	Roulez vert program
Quebec	Zero-emissions vehicle standard
Quebec	Renewable Natural Gas Mandate
Quebec	Chauffez vert program

NATEM techno-economic database

The NATEM techno-economic database has extensive detail for over 7,000 technologies. Each technology is characterized by their technical and economic attributes as well as pollutant coefficients. The following table shows the type of information used for describing technology options. For proprietary reasons, this level of detail is not shared for technologies in this study.

NATEM includes technologies for all end-uses in the energy system from generation technologies that convert primary energy into secondary energy (e.g., refineries, power plants, etc.) to end-use devices that transform final energy into energy services (e.g., cars that serve a demand for mobility, light bulbs that serve a demand for lighting). Existing technologies, improved versions of the same technologies and emerging technologies are included, each characterized by technical and economic attributes.

Technology characteristics input to NATEM

Attribute	Description
Investment cost	Capital/purchase cost of a technology
Fix operation cost	Fix operation cost
Variable operation costs	Variable operation cost, excluding energy cost
Taxes or tax credits	Relevant taxes or tax credits to include on technologies and/or fuels
Subsidies	Relevant subsidies for technologies and/or fuels
Efficiency	Output/Input
Transmission and distribution losses	Energy lost during electricity transport
Construction time	Time needed for physical construction (excludes permitting and delays that could be shortened by policy)
Technical life	Expected technical life of the technology
Economic life	Economic life used for interest accounting
First year of availability	expected year of commercial availability for emerging technologies
Annual capacity factor	Maximum availability for production (account for shutdowns or resource intermittency)
Seasonal and daily capacity factor	Maximum availability for production
Guaranteed contribution to peak by class of generation plants	For long-term electricity planning in capacity expansion
Average contribution to winter and summer peak	For each hour peak in summer and winter
Achievable supply	Any constraints that may limit the availability of the technology / fuel (if quantitative information is available)

Explicitly tracking technology stock turnover is an additional advantage of NATEM. The database includes estimated quantities for existing stock and the remaining lifespan plus all new stock is tracked with the year of installation and typical lifetime. Technologies can be retired early, if required for the optimal solution, which accounts for decommissioning costs, and the information on forced retirement allows analysis of future stranded assets.

The model tracks all GHGs, including carbon dioxide (CO2), methane (CH4), nitrous oxide (N20), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF6) and nitrogen trifluoride (NF3) from all sectors of the national inventories. NATEM excludes changes in emissions from land use, land-use change and forestry (LULUCF).

Energy costs (part of variable operation costs) are endogenous to NATEM based on the technology and process choices for production and provided as output for each run.

References for Annex C

(select references only, technology database references are excluded due to excess detail)

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