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October 27, 2023

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)
Annual Review for 2024 Delivery Rates (Application) ~ Project No. 1599536
Response to Workshop Undertakings

On July 28, 2023, FEI filed the Application referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-241-23 for the review of the Application, FEI respectfully files the attached response to the undertakings from the Workshop held on October 23, 2023.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

UNDERTAKING No. 1

HEARING DATE: Monday, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 24, lines 10 to 14; page 62, lines 4 to 8

REQUESTOR: Ms. Mis, BCOAPO

WITNESS: Ms. Walsh

QUESTION: Provide the historical residential rate increases from 2019 to 2023, and include 2024 based on the proposed 8 percent increase.

RESPONSE:

Please refer to Table 1 below which provides the 2019-2023 Approved and 2024 proposed delivery rate increase, and the effective rate increase of each year in percentage as well as the equivalent bill impact in dollars for the average residential RS 1 customer.[1] FEI notes that for the effective rate increase and the equivalent bill impact from 2019 to 2023, the cost of gas is based on the average commodity rate of each year. For the 2024 effective rate and bill impact, the cost of gas is based on the commodity rate effective October 1, 2023, as reflected in FEI's Q3 Gas Cost Report which was approved by Order G-244-23.

Table 1: Residential Rate Increases from 2019 to 2023 and 2024 Based on Proposed 8 percent Increase

	2019	2020	2021	2022	2023	2024
Delivery Rate Increase (%)	1.10%	2.00%	6.62%	8.07%	7.69%	8.00%
Avg. RS 1 Bill Impact (%)	0.72%	1.33%	3.91%	4.05%	4.48%	5.42%
Avg. RS 1 Bill Impact ($)	5.8	11.1	37.4	48.6	49.9	56.1

[1] Average RS 1 customer with consumption of 90 GJ per year.

UNDERTAKING No. 2

HEARING DATE: Workshop, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 25, lines 11 to 24; page 62, lines 8 to 9

REQUESTOR: Ms. Mis, BCOAPO

WITNESS: Ms. Walsh, Mr. Ho

QUESTION: Provide the total bill impact for residential customers at the proposed 8 percent delivery rate increase (based on the 2023 Q3 Gas Cost Report).

RESPONSE:

Please refer to FEI's response to Undertaking 1 for the total bill impact for residential customers at the proposed 8 percent delivery rate increase and commodity rate based on the 2023 Q3 Gas Cost Report.

UNDERTAKING No. 3

HEARING DATE: Workshop, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 28, lines 23 to 25; page 36, lines 19 to 26; page 62, lines 10 to 14

REQUESTOR: Ms. Mis, BCOAPO and Mr. Weafer, CEC

WITNESS: Ms. Walsh

QUESTION: Provide the annual delivery rate increase if the 16.12 percent was spread equally over 5 years. Also include the impact specifically to residential customers.

RESPONSE:

If the 16.12 percent delivery rate increase, which is equivalent to a revenue deficiency of $170.348 million in 2024, is spread equally over 5 years, the 2024 delivery rate increase will be 3.22 percent (this includes the full 2023 and 2024 GCOC impacts as well as a portion of the 2024 deficiency before the GCOC decision).

This scenario would defer approximately $70.183 million to the 2023 Revenue Deficiency deferral account, which would be amortized into rates from 2025 to 2028, with the first $34.070 million of the total deficiency of $170.348 million included in 2024 rates. This will result in an incremental delivery rate impact of approximately 4.09 percent in 2025 with a similar level of impact from 2026 to 2028[1], before consideration of the delivery rate increases resulting from the revenue requirement each year.

Generally, FEI would only consider deferring such a sizable amount to future years if there was reason to believe that there was an upcoming period where rate changes were expected to be low or minimal. However, FEI has no reason to believe this will be the case for the 2025 to 2028 period. FEI is therefore not supportive of deferring such a large amount to future years (i.e., 2025 to 2028).

Please refer to Table 1 below which provides a comparison of the delivery rate increase in 2024, the equivalent bill impact to the average residential customer in 2024, and the incremental impact to the 2025 delivery rates due to the amortization of the 2023 revenue deficiency deferral account between FEI's proposed 8.00 percent delivery rate increase in 2024 and the scenario suggested by this undertaking (i.e., setting the 2024 delivery rate increase at 3.22 percent but with an incremental delivery rate impact of 4.09 percent in 2025 and similar levels of impact until 2028). Ultimately, deferring more of the deficiency to the future will result in higher carrying costs (i.e.,

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[1] The amortization of the deficiency in each year from 2025 to 2028 would vary slightly due to the different AFUDC rates in each year.

AFUDC) and a higher delivery rate impact over the period from 2025 to 2028, before considering the revenue requirement of each individual year.

Table 1: Comparison of the Incremental Impact in 2025 between 8.00 percent and 3.22 percent Delivery Rate Increase in 2024

	2024 Delivery Rate Increase (%)	2024 Bill Impact - RS 1 ($)	Incremental Delivery Rate Impact in 2025 (%)
Proposed	8.00%	$ 56.1	1.71%
Undertaking 3	3.22%	$ 22.6	4.09%

Ultimately, FEI considers the proposed delivery rate increase of 8.00 percent in 2024 is a reasonable balance between providing some rate smoothing without deferring a significant portion of the 2024 revenue deficiency to future years.

FortisBC Energy Inc. (FEI or the Company)
Annual Review for 2024 Delivery Rates Application

UNDERTAKING No. 4

HEARING DATE:	Workshop, October 23, 2023
TRANSCRIPT REFERENCE:	Volume 1, page 29, lines 1 to 8; page 62, lines 15 to 16
REQUESTOR:	Mr. Weafer, CEC
WITNESS:	Ms. Walsh
QUESTION:	File the long-term rate forecasts from the 2022 LTGRP on the record.

RESPONSE:

Please refer the attached excerpt of Section 9.4 – Rate Impact Implications of the Diversified Energy (Planning) Scenario, from the FEI 2022 Long Term Gas Resource Plan (LTGRP). However, FEI notes the rate impacts shown in the LTGRP are not an indication of a detailed rate forecast; rather, they simply provide a directional, 20-year view of how FEI's rates are influenced by the different scenarios over time, and they are based on assumptions specifically listed in Section 9.4 of the LTGRP. They do not represent or reflect the individual components of FEI's revenue requirement in each year over the 20-year period.

Market Being Influenced	Anticipated Outcome in 2042
DSM Reduces Energy Consumption in Residential, Commercial and Industrial Sectors	
Demand-side Management and high efficiency equipment	Heat pumps (gas and electric), dual-fuel heating systems, deep energy retrofits, building envelope upgrades and HVAC control systems will reduce energy requirements as BC's building stock is transformed to high performance. Waste heat recovery and integrated community energy systems offer some of the emerging innovations that will allow FEI to reach the GHGRS emissions cap for gas utilities.
Decarbonization in Commercial and Industrial Processes	Innovative technologies, process improvements and waste heat recovery will be implemented to help transform commercial and industrial processes toward higher efficiency and low-carbon emissions.
Enabling Activities to Support Market Transformation	
Clean energy workforce capacity	Workforce training and capacity building across the clean energy supply chain ensures decarbonization success.
Utility, government, rightsholder and stakeholder collaboration on climate action	All stakeholders collaborating on an approach to BC's energy system, understanding that there needs to be a multi-faceted approach to decarbonization.
Policy and regulatory environment supportive of decarbonization	Policy and regulatory environment are supportive of a diversified, complementary approach to meeting BC's energy needs.

9.4 RATE IMPACT IMPLICATIONS OF THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

To provide context for FEI's long-term volume forecasts Figures 9-7 through 9-10 provide a 20-year directional view at the potential impact on customer rates under the Reference Case, Diversified Energy (Planning), Deep Electrification, and the Upper Bound Scenarios for Residential (RS 1), Small Commercial (RS 2), Large Commercial (RS 3), and Industrial General Firm Service (RS 5) customers, respectively.

Considering the volume of information presented, FEI has only included the results for these four scenarios since they provide a representative overview of the implications for rates that different futures will have. The figures below do not consider future rate design changes and are not indicative of a detailed rate forecast; rather, they simply provide a directional, 20-year view of how FEI's rates are influenced by these scenarios over time.

The analysis on effective rate impacts compares the changes in rates to the current 2022 approved rates with the following assumptions:

- The 20-year annual demand for each scenario includes DSM and low-carbon transportation;

- The long-term DSM expenditures for each scenario are under the High DSM setting discussed in Section 5.4.1;
- Commodity costs are based on a mix of supply of conventional natural gas and renewable gas, and midstream (i.e., storage and transport charges) costs assumed an escalation of by inflation;
- Carbon tax under the Diversified Energy (Planning) and Deep Electrification scenarios assumes annual escalation until it reaches $170 per tonne in 2030 as discussed in Section 2.2.1.4.2. For the Reference scenario, carbon tax is assumed to remain at $50 per tonne while for the Upper Bound scenario, carbon tax is assumed to be eliminated. For all scenarios, the bill impact analysis includes the avoided carbon tax resulting from the mix of renewable and low carbon gas in the commodity costs. For example, assuming FEI's gas supply includes 5 percent mix of renewable and low carbon gas in 2023, then the carbon tax is applied to the 95 percent of conventional natural gas only with no carbon tax on the remaining 5 percent;
- The 2022 approved delivery margin as the baseline cost of service plus annual escalation by inflation as well as the incremental cost of service for the capital expenditures on FEI's major transmission systems (VITS, CTS, and ITS) related to capacity upgrades, integrity, and resiliency depending on the peak demand forecast in each scenario;
- The incremental cost of service (including any offsetting revenue) related to FEI's major capital projects recently filed (or expected to be filed) or approved by BCUC, including:
    - Inland Gas Upgrades (IGU) CPCN;
    - Pattullo Gas Line Replacement (PGR) CPCN;
    - Tilbury LNG Storage Expansion (TLSE) CPCN;
    - Advanced Metering Infrastructure (AMI) CPCN;
    - CTS and ITS Transmission Integrity Management (TIMC) CPCNs;
    - OIC Tilbury Phase 1B; and
    - Woodfibre Gas Pipeline.
- The effective rate impacts are based on the average use per customer (UPC) between 2022 and 2042 under the Diversified Energy (Planning) Scenario:
    - Residential (RS 1): 60 GJ per year
    - Small Commercial (RS 2): 293 GJ per year
    - Large Commercial (RS 3): 3,253 GJ per year
    - Industrial General Firm Service (RS 5): 18,542 GJ per year

Figure 9-7: Cumulative Effective Rate Impact (2022 – 2042) – Residential RS 1, Avg. UPC 60 GJ

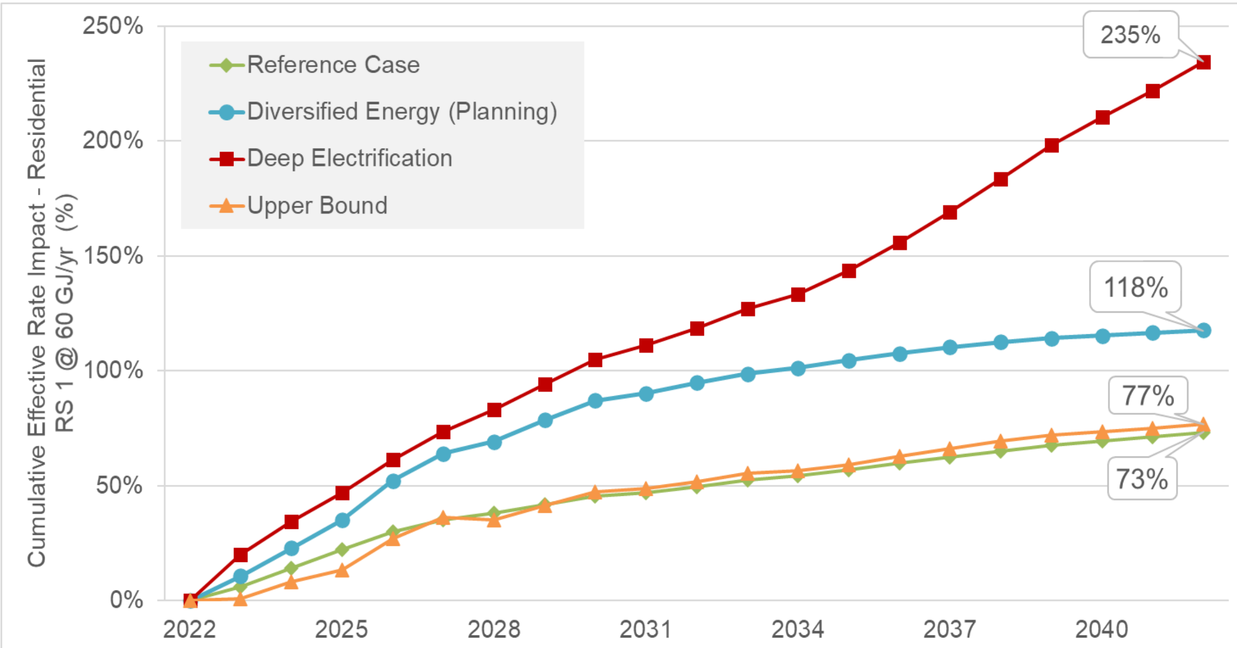


Figure 9-8: Cumulative Effective Rate Impact (2022 – 2042) – Small Commercial RS 2, Avg. UPC 293 GJ

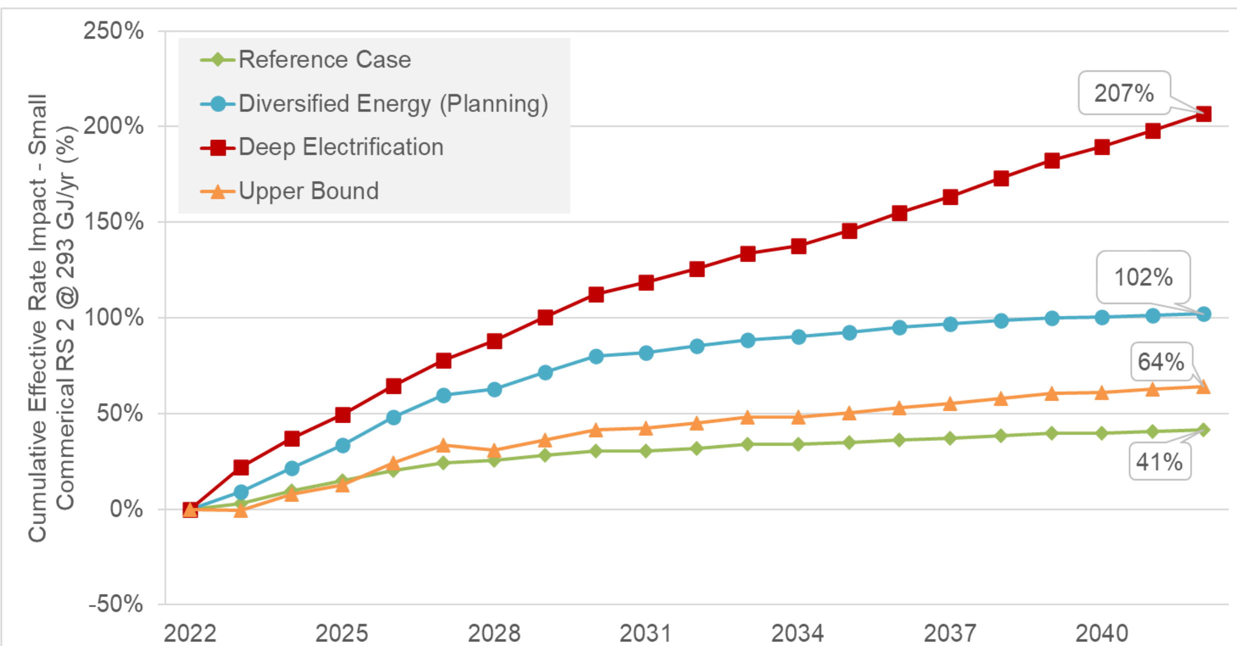


Figure 9-9: Cumulative Effective Rate Impact (2022 – 2042) – Large Commercial RS 3, Avg. UPC 3,253 GJ

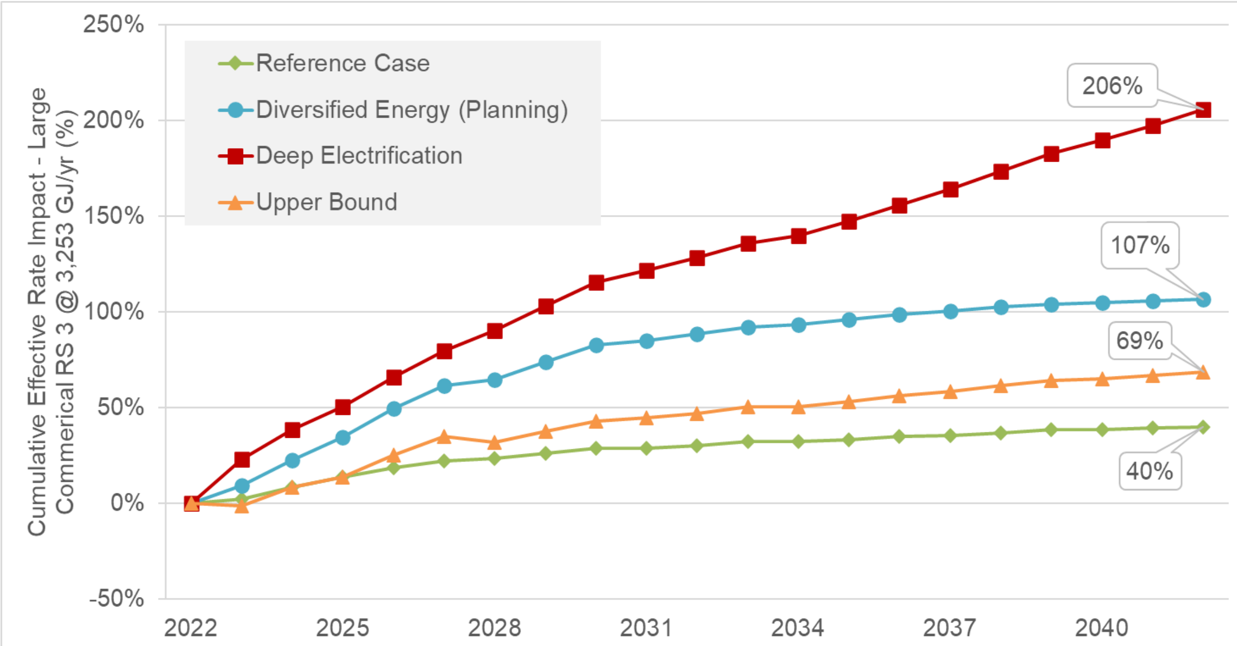


Figure 9-10: Cumulative Effective Rate Impact (2022 – 2042) – General Firm Service RS 5, Avg. UPC 18,542 GJ

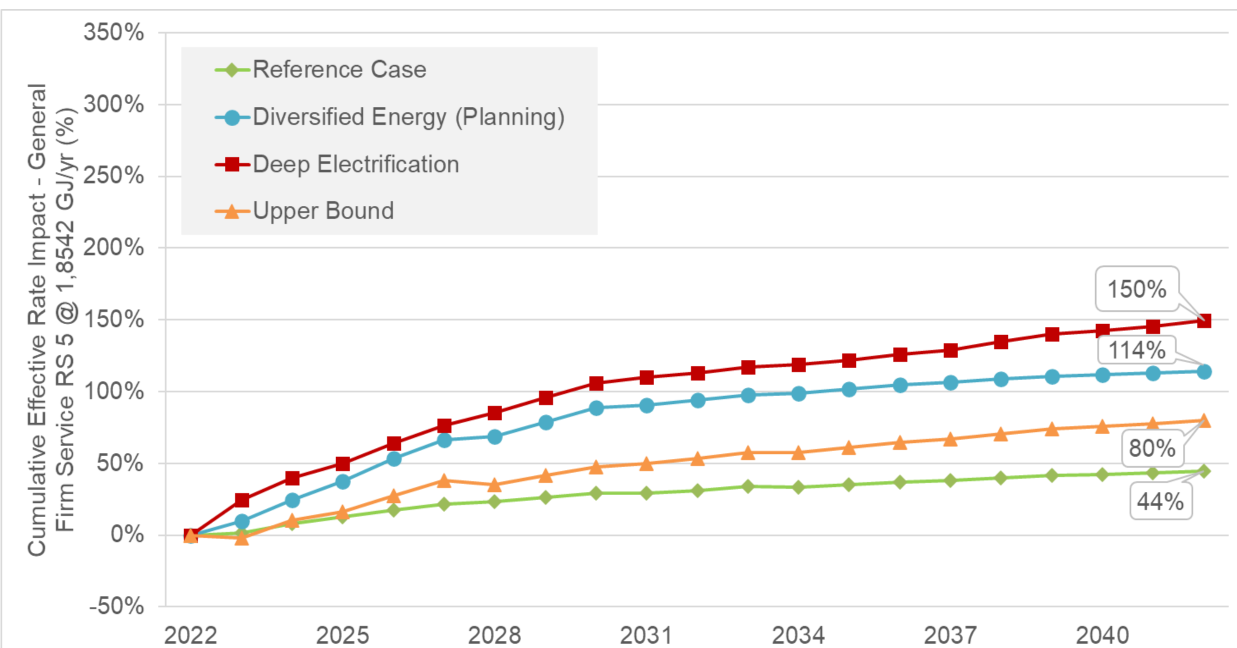


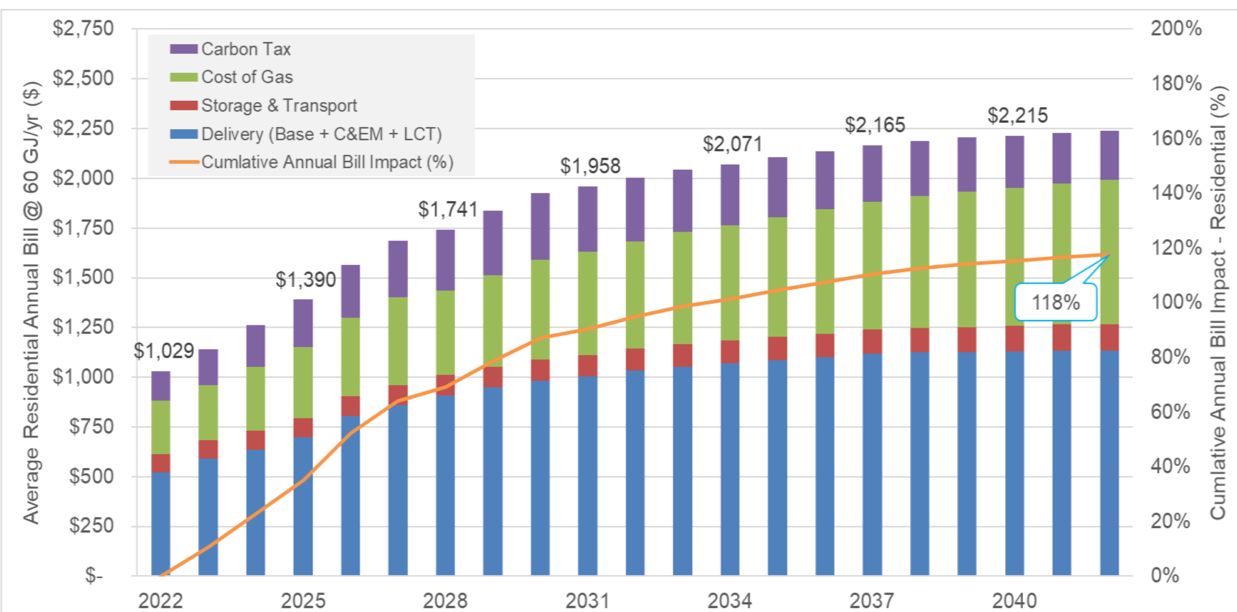
Table 9-2 below summarizes the cumulative effective rate impact projections as well as the equivalent annual rate impact over the 20-year period for each scenario.

Table 9-2: Summary and Comparison of Average Projected Delivery Rate Changes

	Effective Rate Change (2022 - 2042, %)								
	Average UPC (2022 - 2042)	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	73%	2.8%	77%	2.9%	118%	4.0%	235%	6.2%
Small Commercial (RS 2)	293	41%	1.7%	64%	2.5%	102%	3.6%	207%	5.8%
Large Commercial (RS 3)	3,253	40%	1.7%	69%	2.6%	107%	3.7%	206%	5.7%
General Firm Service (RS 5)	18,542	44%	1.9%	80%	3.0%	114%	3.9%	150%	4.7%

The cumulative effective rate impacts shown in the figures above are made up of individual impacts in all components of FEI's rates, including delivery, cost of gas, storage & transport, and carbon tax. Using Residential (RS 1) as an example, Figure 9-11 below provides a breakdown of the annual bill projections for the average residential customer under the Diversified Energy (Planning) Scenario from 2022 to 2024. It can be seen that the total residential bill is estimated to increase from approximately $1,029 in 2022 to $1,958 in 2031, and to approximately $2,215 in 2040 under the Diversified Energy (Planning) Scenario. The cumulative effective rate increase by 2042 under the Diversified Energy (Planning) Scenario is driven by increases in all three components – 50 percent due to the delivery rate impact, 41 percent due to commodity related impacts (cost of gas and storage & transport), and 9 percent due to carbon tax increases.

Figure 9-11: Breakdown of the Cumulative Effective Rate Impact for Residential RS 1 under the Diversified Energy (Planning) Scenario



UNDERTAKING No. 5

HEARING DATE: Workshop, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 52, lines 1 to 26

REQUESTOR: Ms. Mis, BCOAPO

WITNESS: Mr. Ho

QUESTION: Recreate the pie chart from Slide 10 of the presentation based on the original 2024 proposed rate increase and based on the 2023 approved rate increase. Also include carbon taxes.

RESPONSE:

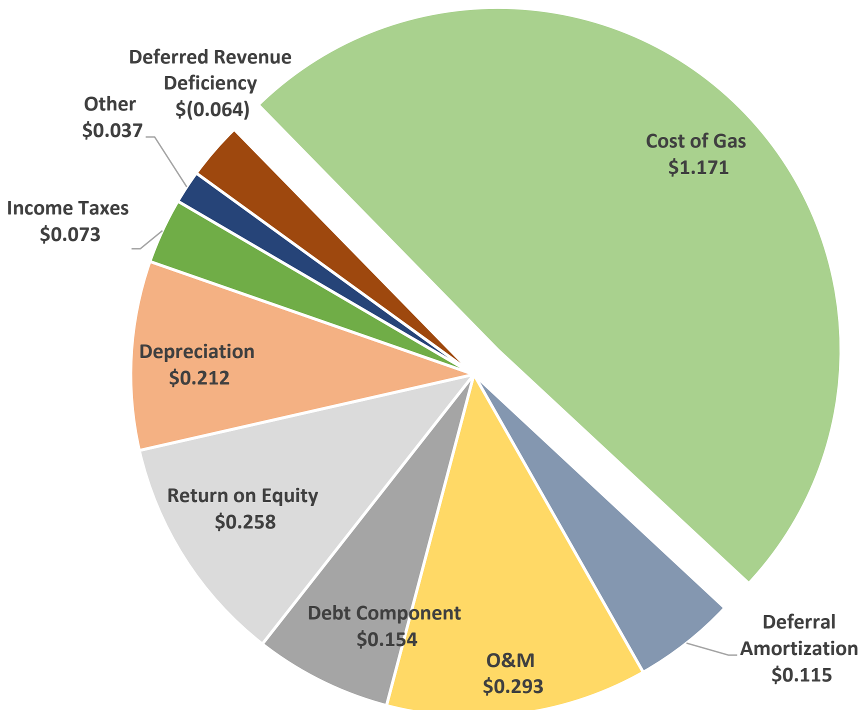
Please refer to the following figures for:

- Figure 1: 2023 Approved revenue requirement based on approved permanent rate increase of 7.69[1] (includes the deferred impact of the GCOC Decision);
- Figure 2: 2024 Forecast revenue requirement as filed on July 28, 2023 (prior to the GCOC Decision) at 4.50 percent delivery rate increase; and
- Figure 3: 2024 Forecast revenue requirement as filed on October 10, 2023 (Evidentiary Update) at 8.00 percent delivery rate increase.

[1] Approved by Order G-275-23.

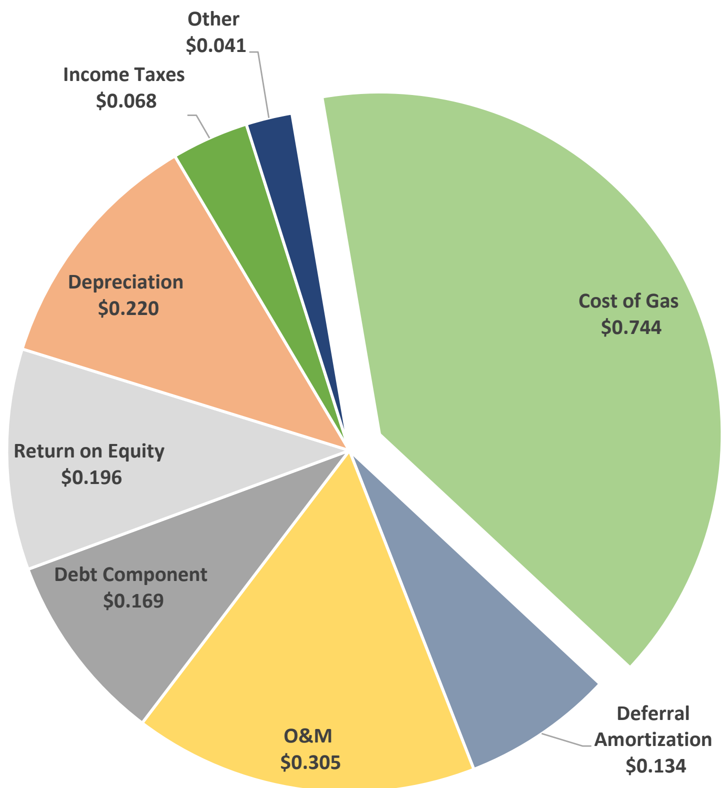
UNDERTAKING No. 5

Figure 1: 2023 Approved Revenue Requirement and Delivery Rate Increase of 7.69%
($ billions)



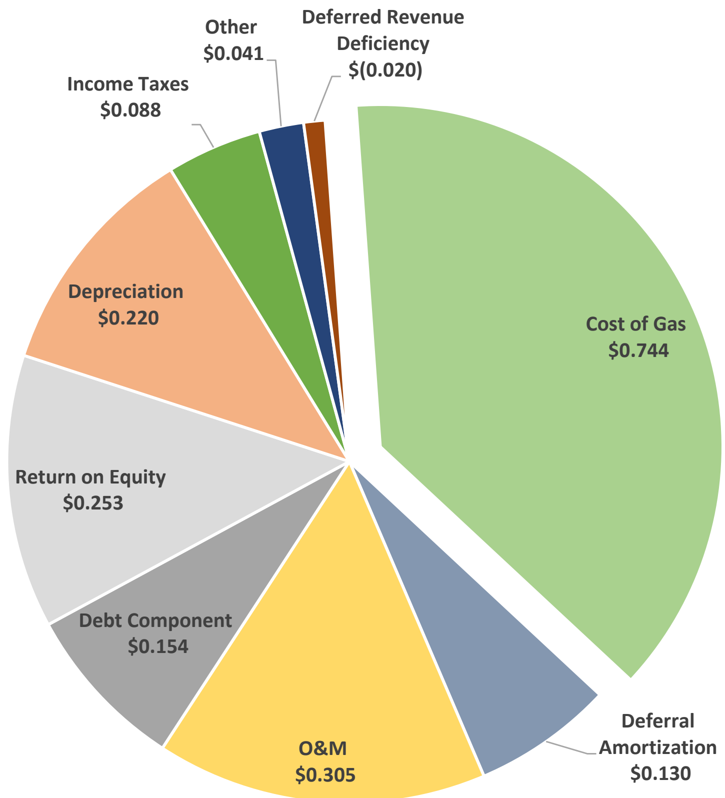
UNDERTAKING No. 5

Figure 2: 2024 Forecast Revenue Requirement as filed on July 28, 2023 (prior to GCOC Decision) at 4.50% Delivery Rate Increase ($ billions)



UNDERTAKING No. 5

Figure 3: 2024 Forecast Revenue Requirement as filed on October 10, 2023 (Evidentiary Update) at 8.00% Delivery Rate Increase ($ billions)



Please also refer to the following figures for FEI's revenue requirement plus carbon tax payable by customers:

- Figure 4: 2023 Approved revenue requirement based on approved permanent rate increase of 7.69[2] (includes the deferred impact of the GCOC Decision), *plus* Carbon Tax payable by FEI's customers to the Province of BC (based on 2023 Forecast demand of 221.773 PJ, less 2.023 PJ of RNG);

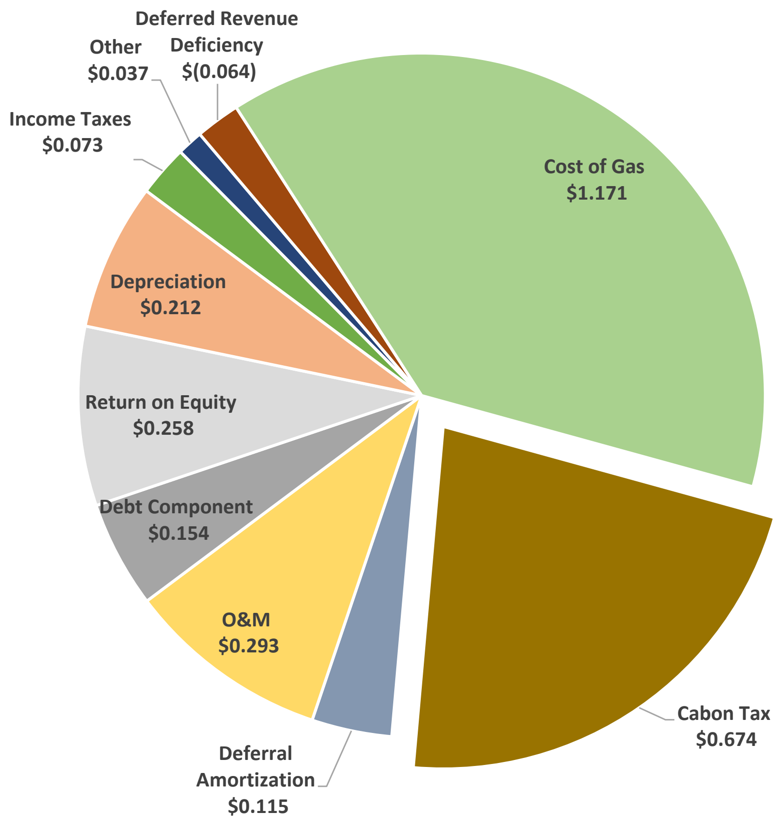
- Figure 5: 2024 Forecast revenue requirement as filed on July 28, 2023 (prior to the GCOC Decision) at 4.50 percent delivery rate increase, *plus* Carbon Tax payable by FEI's customers to the Province of BC (based on 2024 Forecast demand of 220.165 PJ, less 2.023 PJ of RNG); and

[2] Approved by Order G-275-23.

- Figure 6: 2024 Forecast revenue requirement as filed on October 10, 2023 (Evidentiary Update) at 8.00 percent delivery rate increase, ***plus*** Carbon Tax payable by FEI's customers to the Province of BC (based on 2024 Forecast demand of 220.165 PJ, less 2.023 PJ of RNG).

FEI notes that the carbon tax payable by customers shown in Figures 4 to 6 below are not part of FEI's revenue requirement. They are estimated using the carbon tax rates at $2.5588 per GJ from April 2022 to March 2023, at $3.2384 per GJ from April 2023 to March 2024, and at $3.9859 per GJ from April 2024 to March 2025, as set out by the Province of BC[3]. For comparison purposes, the cost of gas effective on July 1, 2023 (used as part of the 2024 Forecast as filed on July 28, 2023 and the Evidentiary Update on October 10, 2023) is $3.159 per GJ.

Figure 4: 2023 Approved Revenue Requirement and Delivery Rate Increase of 7.69% *plus* Carbon Tax payable by Customers ($ billions)



[3] https://www2.gov.bc.ca/gov/content/taxes/sales-taxes/motor-fuel-carbon-tax/publications/carbon-tax-rates-by-fuel-type

UNDERTAKING No. 5

Figure 5: 2024 Forecast Revenue Requirement as filed on July 28, 2023 (prior to GCOC Decision) at 4.50% Delivery Rate Increase *plus* Carbon Tax payable by Customers ($ billions)

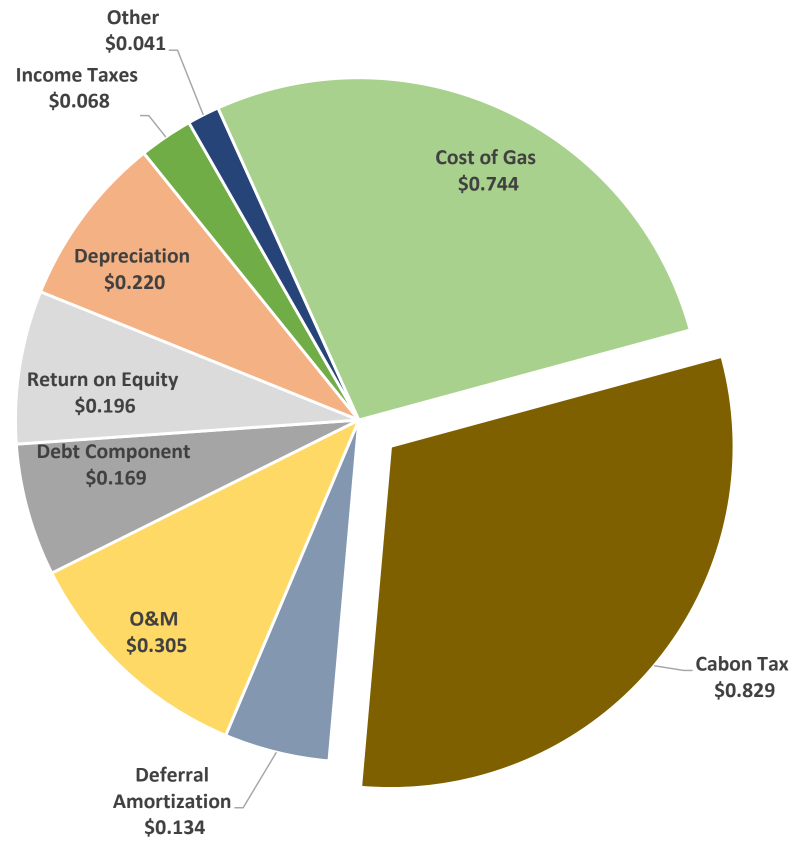
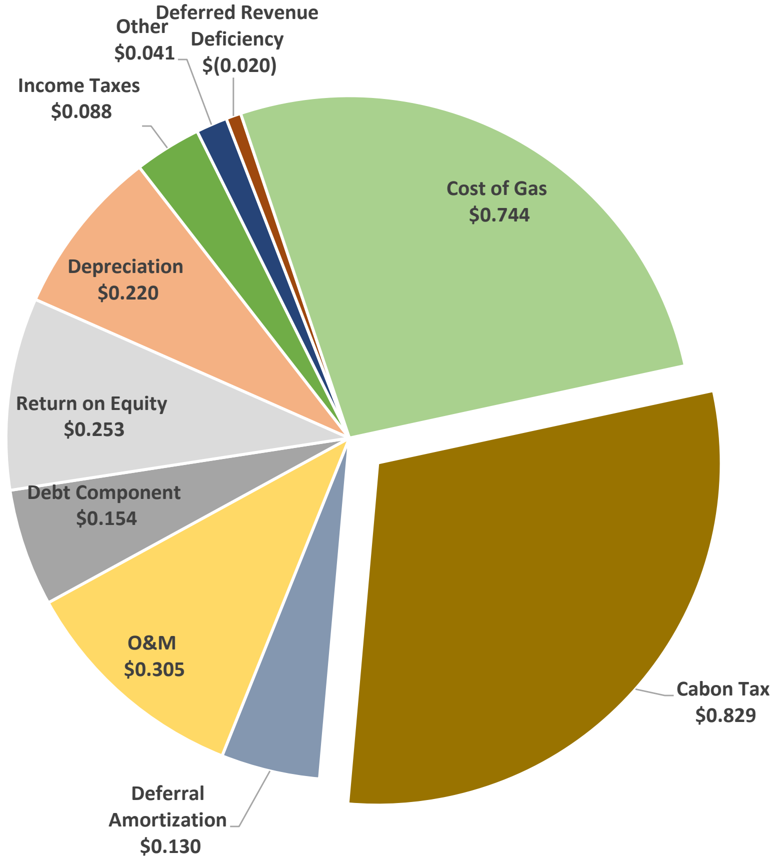


Figure 6: 2024 Forecast Revenue Requirement as filed on October 10, 2023 (Evidentiary Update) at 8.00% Delivery Rate Increase *plus* Carbon Tax payable by Customers ($ billions)



UNDERTAKING No. 6

HEARING DATE: Workshop, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 60, lines 5 to 26; page 61, lines 1 to 15; page 62, lines 21 to 26; page 63, lines 1 to 4

REQUESTOR: BCUC Staff

WITNESS: Mr. Slater, Mr. Ho, Ms. Walsh

QUESTION: Provide the impact on the Weighted Average Cost of Capital (WACC), Allowance for Funds Used During Construction (AFUDC), revenue requirement and rate for 2024 of the following scenarios:

a. Long-term debt is set at 55% and Short-term debt is set at 0%;
b. Unwind/redeem long-term debt to reduce the level to 55%; and
c. Forecast the interest income to be earned on the cash balance resulting from “negative” short-term debt and provide the revised short-term debt percentage.

RESPONSE:

FEI provides a discussion and an updated Schedule 26 for FEI’s return on capital for each scenario as requested. FEI also includes a discussion and comparison to the proposed approach as provided in the Evidentiary Update. However, FEI notes that there is no requirement that stipulates a specific mix between long-term debt (LTD) and short-term debt (STD). The utility is responsible for managing its debt, including LTD, STD, or carrying a cash balance with earned interest, to fund its capital investments with 55 percent debt and 45 percent common equity. Regardless of this mix of LTD, STD and cash balance, FEI will ultimately only recover the costs of an approved deemed equity and debt component of 45% and 55%, respectively, from customers. Further, to clarify, FEI considers that Scenario 3 presented below is representative of FEI’s approach in the Evidentiary Update. The only difference is that in Scenario 3, FEI has included a forecast of interest income on the cash balance whereas in the Evidentiary Update FEI forecast a “0” amount of interest income. Ultimately, the actual amount of interest income earned on the cash balance will be captured in the Flow-through deferral account and will provide a benefit to customers.

<u>Scenario 1 – Fix LTD at 55 percent and STD at 0 percent</u>

For this scenario, FEI would not actually redeem any LTD to reduce the LTD component to 55 percent. Instead, FEI would, on a forecast basis, include in its 2024 revenue requirement a reduced LTD interest expense from $153.587 million to $149.746 million based on reducing the LTD funding amount from 56.37 percent to 55 percent at the average LTD rate of 4.68 percent and applying it to FEI’s 2024 forecast rate base of approximately $5.817 billion. Please refer to Table 1 below which provides an updated Schedule 26 for FEI’s return on capital under this scenario.

Table 1: FEI's Return on Capital under Scenario 1 – Fix LTD to 55 percent

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	2024 Amount	2024 Ratio	2024 Average Embedded Cost	2024 Cost Component	2024 Earned Return	Earned Return Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Long Term Debt	$ 156,163	$ 3,199,693	55.00%	4.68%	2.57%	$ 149,746	$ (6,417)
2	Short Term Debt	(2,271)	0	0.00%	0.00%	0.00%	-	2,271
3	Common Equity	258,172	2,617,930	45.00%	9.65%	4.34%	252,630	(5,542)
4								
5	Total	$ 412,064	$ 5,817,623	100.00%		6.92%	$ 402,376	$ (9,688)

This scenario would, on a forecast basis, reduce the 2024 earned return as well as the deferred 2024 deficiency the most (as FEI is proposing to set the 2024 delivery rate increase to 8.00 percent, the effect of this scenario would be changing the amount of the 2024 deferred deficiency). However, this scenario would not reflect what is likely to actually occur. First, the scenario does not include a forecast of FEI's fixed financing fees related to the short-term debt for maintaining the credit facility, the actual costs of which would be captured in the Flow-through deferral account and recovered from customers in a subsequent year. Second, while FEI has removed 1.37 percent of LTD using an average rate of all the total debt issuances of 4.68 percent for forecasting purposes, in practice, the utility could not adjust its actual debt in the same manner (i.e., partial retirement).

Scenario 2 – Redeem LTD plus Issue New STD

For this scenario, FEI would redeem some LTD such that the LTD component would be reduced on average below 55 percent, and FEI would forecast an amount of issued STD to fill the gap, so that the total debt component equaled 55 percent. For the purposes of modeling this scenario, FEI assumed the following:

1) Redeeming $150 million from the 2016 Medium Term Debt Issue – Series 27 as shown in Schedule 27 of Appendix A of the Evidentiary Update, which will reduce FEI's LTD component to approximately 53.80 percent. FEI selected Series 27 as this debt issue has the earliest maturity date on April 8, 2026, which will likely have the least implications on early redemption fees, make-whole payments, and other tax implications than other debt issues that have later maturity dates; and
2) Funding the remaining 1.20 percent of FEI's rate base through STD at an interest rate of 5.56 percent (i.e., the 2024 forecast STD rate as shown in Table 8-1 of the Application filed on July 28, 2023).

Please refer to Table 2 below which provides an updated Schedule 26 for FEI's return on capital under this scenario.

UNDERTAKING No. 6

Table 2: FEI's Return on Capital under Scenario 2 – Redeeming LTD

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	Amount	Ratio	2024 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Long Term Debt	$ 156,163	$ 3,129,652	53.80%	4.93%	2.65%	$ 154,211	$ (1,952)
2	Short Term Debt	(2,271)	70,041	1.20%	5.56%	0.07%	3,894	6,165
3	Common Equity	258,172	2,617,931	45.00%	9.65%	4.34%	252,630	(5,542)
4								
5	Total	$ 412,064	$ 5,817,624	100.00%		7.06%	$ 410,735	$ (1,329)

As shown in Table 2 above, this scenario would increase FEI's forecast of earned return from $407.007 million (as filed in the Evidentiary Update) to $410.735 million, which will result in a higher 2024 deferred deficiency out of all the scenarios. This is because FEI is replacing LTD at a rate of 2.58 percent with STD that has a higher forecast average interest rate at 5.56 percent. Further, there are early redemption fees, make-whole payments, early amortization of debt issuance costs, and other tax implications of early redemption of debt that FEI is unable to forecast at this time under this scenario, which would result in additional future impacts than what is being shown in Table 2 above.

Scenario 3 – Include Forecast of Interest Income

As discussed during the FEI Workshop on October 23, 2023[1], the $79.758 million of "negative average STD" shown in Schedule 26 of Appendix A of the Evidentiary Update is cash which will attract interest income for the benefit of customers. Under this Scenario 3, FEI would forecast an interest return of approximately $3.350 million at 4.20 percent for the $79.758 million of "negative average STD". This interest return will then be reduced by the fixed financing fees at 0.99 percent (i.e., the 2024 forecast STD fixed financing fee rate as shown in Table 8-1 of the Application filed on July 28, 2023) applied to the $79.758 million for expenses of approximately $0.790 million. The resulting net STD return is approximately $2.560 million. Any variance related to the interest rates between actual and forecast will be captured in the Flow-through deferral account, to be either recovered from or returned to customers in a subsequent year.

FEI notes that this Scenario 3 is essentially the approach proposed by FEI as part of the Evidentiary Update, except Scenario 3 includes a forecast of interest income. In the Evidentiary Update, FEI did not include a forecast of the interest income and instead assumed that the actual interest income would be captured in the Flow-through deferral account, with the variance between the forecast of $0 and the actual interest income being returned to customers in 2025 through amortization.

[1] FEI Workshop Transcript, page 60, lines 5 to 26, and page 61, lines 1 to 15.

Please refer to Table 3 below which provides an updated Schedule 26 for FEI's return on capital under this scenario.

Table 3: FEI's Return on Capital under Scenario 3 – Include Forecast of Interest Income

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	2024 Amount	2024 Ratio	2024 Average Embedded Cost	2024 Cost Component	2024 Earned Return	Earned Return Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Long Term Debt	$ 156,163	$ 3,279,451	56.37%	4.68%	2.64%	$ 153,587	$ (2,576)
2	Short Term Debt	(2,271)	(79,758)	-1.37%	3.21%	-0.04%	(2,560)	(289)
3	Common Equity	258,172	2,617,931	45.00%	9.65%	4.34%	252,630	(5,542)
4								
5	Total	$ 412,064	$ 5,817,624	100.00%		6.94%	$ 403,657	$ (8,407)

This scenario will reduce the 2024 deferred deficiency from the Evidentiary Update (no change to FEI's proposed 8.00 delivery rate increase), but the reduction is slightly less than Scenario 1 above. This scenario, when compared to Scenario 1, is more reflective of what could actually occur to finance 55 percent of the rate base with debt. This is because carrying a cash balance and earning short-term interest on the cash balance is a realistic option to implement, while Scenario 1 would only be shown for forecasting purposes to demonstrate all 55 percent of debt is funded by LTD at the average embedded rate of 4.68 percent. Scenario 1 is not a realistic scenario in actuality and FEI would not be managing its debt as forecast under this scenario.

Summary

Please refer to Table 4 below which provides the pre-tax WACC, AFUDC, and the 2024 deferred revenue deficiency for each scenario as requested. FEI notes that given its proposal to set the delivery rate increase at 8.00 percent, the change due to each scenario will only change the amount of the 2024 deferred deficiency that would be captured in the existing 2023 Revenue Deficiency deferral account. The delivery rate increase for 2024 will remain at 8.00 percent in all scenarios. FEI has also included the approach proposed in the Evidentiary Update (i.e., the same approach as Scenario 3 but without a forecast of interest income) for comparison purposes.

Table 4: Comparison of FEI's 2024 WACC, AFUDC, Revenue Deficiency, and Delivery Rate Increase between Different Scenarios of Debt Treatment

		Pre-Tax WACC(1)	AFUDC	2024 Deferred Deficiency ($millions)	2024 Delivery Rate Increase (%)
Scenario 1	Fix LTD at 55% and STD at 0%	8.52%	6.22%	15.077	8.00%
Scenario 2	Redeem LTD (Series 27) plus Issue new STD	8.67%	6.33%	23.436	8.00%
Scenario 3	Include Forecast of Interest Income	8.54%	6.24%	16.358	8.00%
As-Filed (Evid Update)	No Forecast of Interest Income	8.60%	6.28%	19.708	8.00%

Note (1): After-Tax WACC is equivalent to AFUDC

Ultimately, as explained above, FEI will only recover its cost of capital from customers at the approved deemed equity of 45 percent and deemed debt of 55 percent. Therefore, it is not necessary for the BCUC to direct FEI to take a specific approach in this annual review. Further, while FEI has provided Scenario 2 in response to BCUC Staff's request at the Workshop, it would not be appropriate for the BCUC Panel to direct FEI to unwind/redeem long-term debt, nor would it be beneficial for customers.

With regard to Scenario 1, this approach does not reflect the reality of how FEI would manage its debt with a mix of LTD, STD, and cash with earned interest. Therefore, while FEI could theoretically revise its revenue requirement forecast in accordance with this scenario, the actual 2024 results will be different. For instance, FEI would not be able to avoid the fixed financing fees associated with maintaining access to short term financing, nor would FEI be able to partially redeem its long-term debt issuances to achieve 55 percent LTD.

The approaches in Scenario 3 and in the Evidentiary Update are essentially the same, with the only difference being that in Scenario 3 FEI would include a forecast of interest income. FEI is amenable to including a forecast of interest income in the 2024 revenue requirement if so directed. Regardless of whether a forecast amount of interest income is included in the 2024 revenue requirement, the proposed delivery rate increase will remain at 8.00 percent, as explained above, and any variances between forecast and actual interest income will be captured in the Flow-through deferral account and returned to/recovered from customers in 2025.

UNDERTAKING No. 7

HEARING DATE: Workshop, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 63, lines 25 to 26; page 64, lines 1 to 12

REQUESTOR: Ms. Mis, BCOAPO and Mr. Weafer, CEC

WITNESS: Mr. Slater

QUESTION: File IR Responses on Price Elasticity.

RESPONSE:

Please refer to the attached responses to RCIA IR1 2.3 and 21.1 on price elasticity from FEI's Stage 2 - Revised Renewable Gas Program Application.

Response:

Please refer to the response to RCIA IR1 2.1.

2.3 Please indicate what FEI believes to be the price elasticity of demand for natural gas? Please present the information in a table showing the expected volume of demand relative to specific prices.

Response:

FEI relies on third party studies for its elasticity assumptions. In 2019, FEI retained the services of the Posterity Group to advise FEI on the values to use for price elasticity for natural gas demand for its load forecasting. The Posterity Group conducted an extensive literature search of fuel and sector specific price elasticity of demand values and recommended the following values:

Table 1: Natural Gas Short Run and Long Run Elasticity Values

	Short Run (SR) Values			Long Run (LR) Values		
	SR Min	SR Reference Case	SR Max	LR Min	LR Reference Case	LR Max
Residential	-0.030	-0.278	-0.670	-0.100	-0.380	-0.880
Commercial	-0.055	-0.205	-0.530	-0.125	-0.350	-0.990
Industrial	-0.067	-0.709	-3.680	-0.142	-0.700	-0.700

The reference values in the above table are from the elasticity values for natural gas by sector provided by the State of Washington's Department of Commerce while the minimum and maximum values are based on an extensive literature review of various elasticity studies. The reference case indicates an increase in price elasticity of natural gas compared to previous assumptions.[1]

Price elasticity is represented numerically and calculated as the percent change in quantity demand divided by the percent change in price. A value of >1 is considered "elastic", as the change in quantity demanded is greater than the change in price. A value of <1 is considered "inelastic", as the change in quantity demanded is less than the change in price.

For instance, a long-term residential price elasticity of -0.38 in the reference case means that for every one percent increase in natural gas price, the demand may fall by 0.38 percent.

[1] In the 2016 LTGRP the residential price elasticity was assumed to be at -0.2.

21.0 Reference: Exhibit B-11, Stage 2 Application, Page 69

Section 5.8 – Customer Sensitivity to Price of Renewable Gas

At the above noted location FEI states:

"Price elasticity studies require demand and price data that reflect market forces with consumer demand being driven by the pricing of competitive options. Price elasticity measures the response of consumers to changes in market prices. This kind of market data is not available for voluntarily purchased Renewable Gas. Due to the nature of the various BERC rate setting mechanisms the price has never been based on market forces and has not been allowed to rise and fall with demand."

21.1 Please confirm if price elasticity studies have been performed with regard to conventional natural gas.

<u>Response:</u>

Confirmed. FEI has relied on price elasticity studies conducted by reputable independent research entities for its elasticity estimates. FEI provides the following third-party elasticity studies for reference.

Table 1: Independent Research Entities Price Elasticity Results

Research Institution	Publication date	Natural Gas Price Elasticity of Demand (Residential)		Description
		Short-term	Long-term	
National Renewable Energy Lab[5]	Feb 2006	-0.12	-0.36	This study estimated elasticity values at state and national levels. The numbers presented here are at national level.[6]
Energy Information Administration[7]	Oct 2014	-0.07 to -0.15	-0.21	This study was referenced in FEI's 2014 Long-Term Resource Plan application.
UC Berkley, Energy Institute at HAAS[8]	Jan 2018	-0.23 to -0.17		This study does not separate the long-term and short-term elasticity and provides an average range of estimates.

As illustrated in the table above, natural gas residential customers are largely inelastic to price variations, and elasticity estimates ordinarily range from -0.07 to -0.36 depending on the study's

5 www.nrel.gov/docs/fy06osti/39512.pdf.

6 For comparison purposes, Washington State's short-term and long-term elasticities were estimated at -0.16 and -0.21 respectively.

7 www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf.

8 https://haas.berkeley.edu/wp-content/uploads/2019/05/WP287.pdf.

timeframe. Furthermore, the table above also indicates that elasticity numbers do not change materially over time (the elasticity estimates from NREL's 2006 report and UC Berkley's 2018 report are similar).

The review of published elasticity studies indicates that although price elasticity estimates may change slightly by jurisdiction and over time, these variances do not change the overall conclusion that the majority of natural gas customers are price inelastic.

21.2 Please explain in detail how FEI consumption forecasts are adjusted to account for higher and lower future natural gas prices.

Response:

The impact of gas prices on demand is captured intrinsically in the historical data used for forecasting.

FEI demand forecasts are not adjusted based on future forecasts of natural gas prices. Future gas prices are not an input into the use per customer forecast methods.

21.3 Does FEI have any reason to believe that the price elasticity of demand is materially different for conventional natural gas when compared to Renewable Gas? Please discuss.

Response:

FEI has not undertaken an analysis comparing the price elasticity of demand for conventional natural gas and Renewable Gas. Please refer to Section 5.8 of the Application with respect to the 2015 BERC Rate Application,[9] which describes that prior to the updated BERC Rate mechanism FEI witnessed a notable decline in demand for Renewable Gas when the price premium for Renewable Gas increased relative to conventional natural gas.

21.4 What is the price elasticity of demand for any the various gas products FEI sells?

[9] Application for Approval of Biomethane Energy Recovery Charge (BERC) Rate Methodology, August 28, 2015.

UNDERTAKING No. 8

HEARING DATE: Workshop, October 23, 2023

TRANSCRIPT REFERENCE: Volume 1, page 91, lines 2 to 18

REQUESTOR: Mr. Craig, CEC

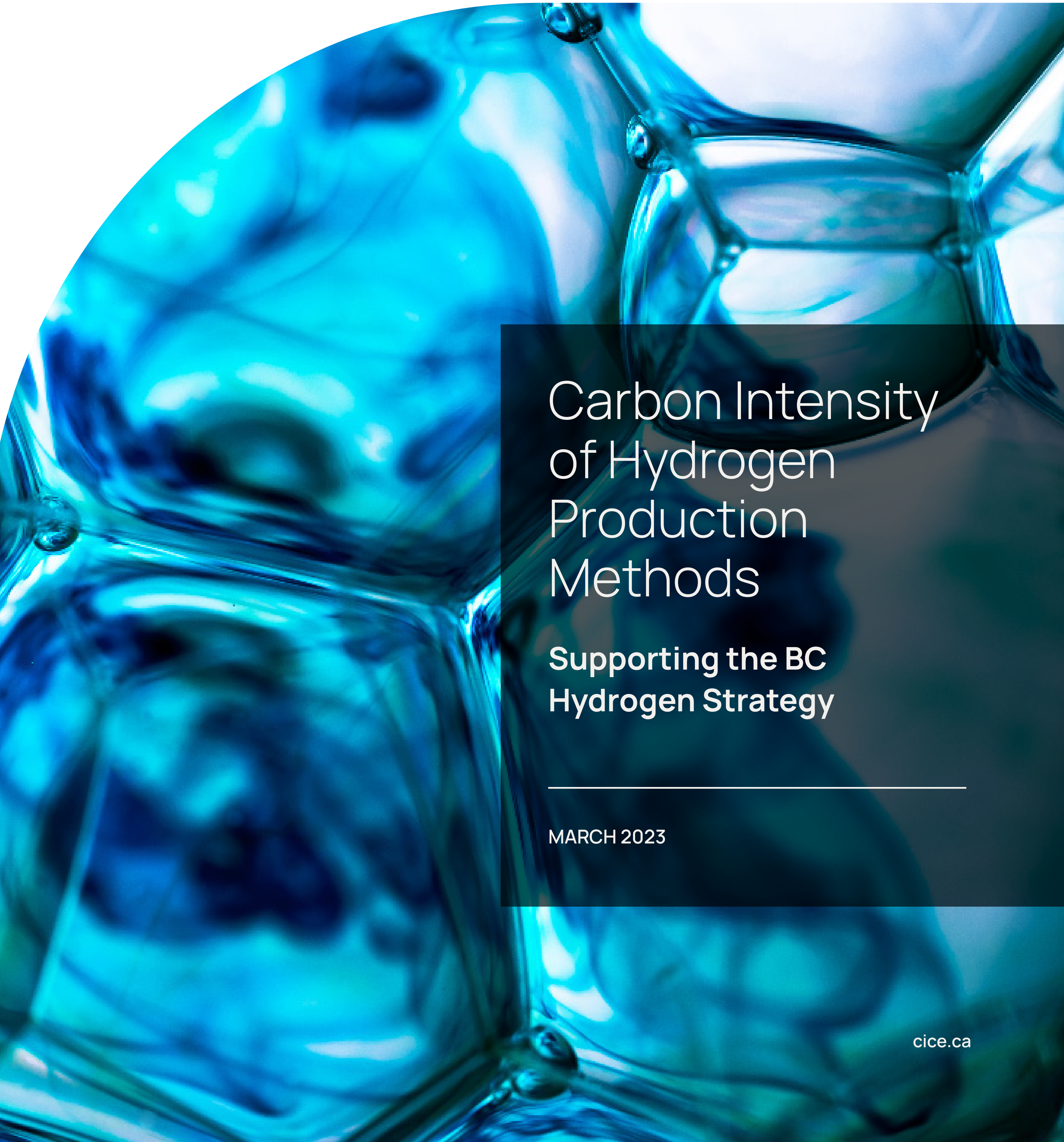
WITNESS: Mr. Slater, Ms. Walsh, and Mr. Quinn

QUESTION: File the Carbon Intensity of Hydrogen Production Methods Report.

RESPONSE:

Please refer to the attached report, *Carbon Intensity of Hydrogen Production Methods Supporting the BC Hydrogen Strategy,* by the BC Centre for Innovation & Clean Energy, in collaboration with Deloitte, (S&T)^2 Consultants, and the BC Ministry of Energy, Mines and Low Carbon Innovation.

CICE Deloitte. British Columbia (S&T)²



Carbon Intensity of Hydrogen Production Methods

Supporting the BC Hydrogen Strategy

MARCH 2023

cice.ca

Acknowledgement

This report is the result of collaboration between the B.C. Centre for Innovation & Clean Energy, Deloitte, (S&T)[2] Consultants, and the B.C. Ministry of Energy, Mines and Low Carbon Innovation. Our teams have worked closely to obtain and validate data inputs and assumptions required to model carbon intensities of hydrogen production pathways that are realistic and representative for British Columbia.

We would like to thank all of the stakeholders that have contributed to the development of this report through data acquisition, result validation and verification, and stress testing of the final report. These stakeholders, across the hydrogen production value chain, include technology developers, early-stage production companies, natural gas utilities, clean energy think tanks and accelerators, research organizations, safety and standard developers, and end-users.

We acknowledge that our offices reside on traditional, treaty, and unceded territories as part of Turtle Island (North America), which are still home to many First Nations, Metis, and Inuit peoples. We acknowledge the First Nations' long history of land stewardship and knowledge of the land—including the shared territories of 10 local First Nations: Katzie, Kwantlen, Kwikwetlem, Matsqui, Musqueam, Qayqayt, Semiahmoo, Squamish, Tsawwassen, and Tsleil-Waututh on whose lands Metro Vancouver is situated.

Notice to Reader

This study has been prepared by the B.C. Centre for Innovation and Clean Energy (CICE) in collaboration with Deloitte LLP ("Deloitte"), (S&T)² Consultants, and the B.C. Ministry of Energy, Mines and Low Carbon Innovation (EMLI) for the determination of carbon intensities for hydrogen production and the potential GHG reduction from hydrogen blending into the gas grid within the context of the broader strategic and climate objectives of British Columbia. The authors recognize that further studies and consideration of other factors such as economic and environmental opportunity costs are required to achieve a more holistic understanding of hydrogen development potential in the province.

This report should not be used for any other purpose or in any other context, and CICE, Deloitte, (S&T)², and EMLI accept no responsibility for its use. CICE, Deloitte, (S&T)², and EMLI do not assume any responsibility or liability for losses incurred by any party as a result of the circulation, publication, reproduction, or use of this analysis contrary to its intended purpose.

The analysis is provided as of January 16, 2023, and we disclaim any undertaking or obligation to advise any person of any change in any fact or matter affecting this analysis, which may come or be brought to our attention after that date. In the analyses, we may have made assumptions with respect to the industry performance and other matters, many of which are beyond our control, including government and industry regulation.

No opinion, counsel, or interpretation is intended in matters that require legal or other appropriate professional advice. It is assumed that such opinion, counsel, or interpretations have been, or will be, obtained from the appropriate professional sources. To the extent that there are legal issues relating to compliance with applicable laws, regulations, and policies, we assume no responsibility.

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Table of Contents

1. Executive summary

Hydrogen plays a critical role in helping British Columbia achieve its commitment to net-zero emissions by 2050, by enabling the province to decarbonize energy systems and facilitate transition to a low-carbon economy. In 2021, the BC government released the BC Hydrogen Strategy, which outlined support for low-carbon hydrogen production and how it can help meet provincial climate targets and economic goals. Understanding the carbon intensity of different hydrogen production pathways is key to fostering the right decisions regarding hydrogen's role in decarbonization. Exploring potential carbon intensity thresholds and reduction schedules will ensure BC's hydrogen economy is clean and continually reducing the province's emissions.

Carbon intensity (CI) is a measure of the greenhouse gas (GHG) emissions per unit of energy produced, and is typically expressed in grams of carbon dioxide equivalent (CO_2e) per megajoule (MJ). Determining the CI of hydrogen production pathways helps inform decision-making and investments towards pathways based on their GHG emissions. In the context of BC's Hydrogen Strategy, incorporating CI into hydrogen production and use implementation can help build BC's hydrogen economy to meet provincial net-zero goals.

This report has been produced by Deloitte and (S&T)[2] on behalf of the BC Centre for Innovation and Clean Energy (CICE) and the BC Ministry of Energy, Mines and Low Carbon Innovation (EMLI). The report is intended to provide data and insights that support the determination of the lifecycle CI for selected hydrogen pathways, and to explore the highest potential for CI reductions.

We recognize that the hydrogen landscape is quickly changing. The jurisdictional data and incentives presented in this report are current as of October 2022 and may not reflect the most recent updates.

Carbon intensity: Global themes for hydrogen production pathways

A review of the hydrogen strategies of several Canadian and global jurisdictions provided insights into emerging themes or potential trends that may be of interest to decision-makers in BC.

» **Leveraging CI thresholds to incentivize low-carbon hydrogen production.** By attaching increasingly stringent CI thresholds to increasing amounts of hydrogen production credits, jurisdictions such as the United States and United Kingdom plan to make low-carbon hydrogen production more economically competitive.

» **Defining lifecycle boundaries to provide a uniform basis for determining low-carbon hydrogen.** Accurately determining CI requires a consistent set of criteria and specifications that can be applied uniformly across hydrogen producers. In the UK, for example, emissions must be accounted for up to the point of production and meet stringent processing and product specifications.

» **Enabling low-carbon hydrogen production through supportive regulatory policies.** A number of jurisdictions, including BC, are using regulatory policies to support and encourage low-carbon hydrogen production, particularly around three areas: carbon capture utilization and storage (CCUS) hubs, zero-emission vehicle (ZEV) policies, and electricity cost incentives.

BC hydrogen production carbon intensity: Modelling approach

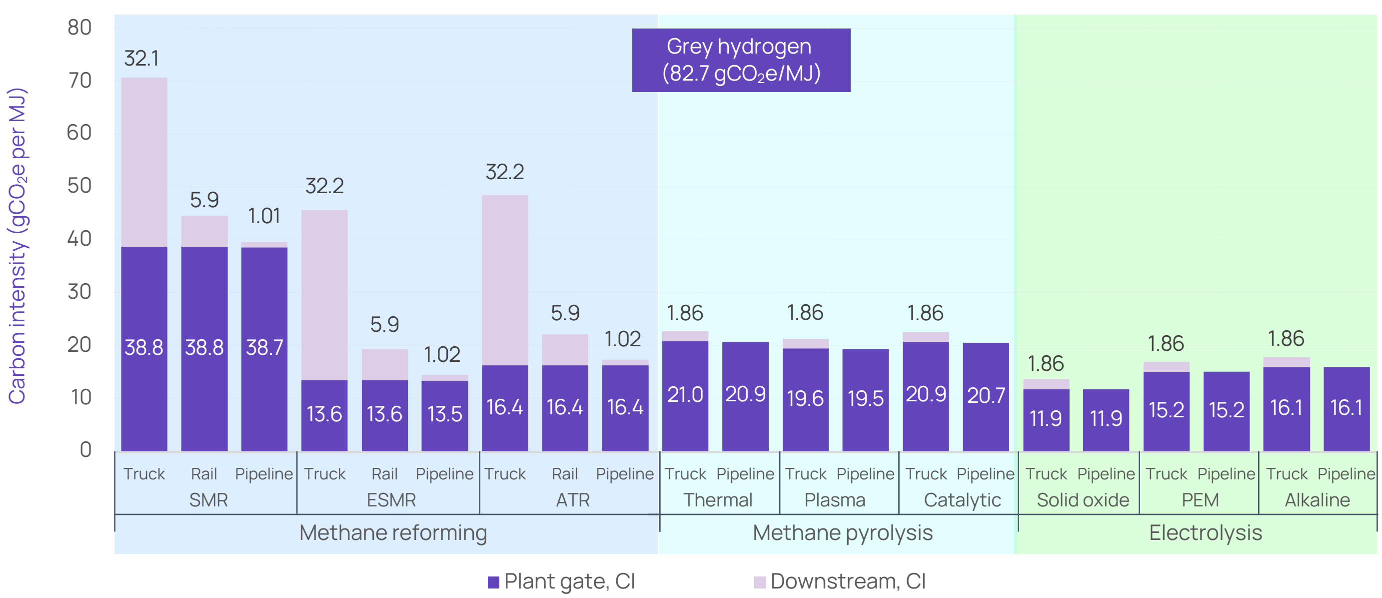
There are many existing and evolving pathways to produce hydrogen. This report focuses on three families of hydrogen production technologies that have the potential for application in British Columbia: methane reforming with carbon capture and storage (CCS), methane pyrolysis, and electrolysis. Three variations of each technology were considered, resulting in nine hydrogen pathways.

The CI for each of these nine pathways was modelled using GHGenius and a consistent set of assumptions and parameters (Section 5.1, page 34). GHGenius is a lifecycle analysis model developed by (S&T)² Consultants Inc. that analyzes contaminant emissions related to the production and use of traditional and alternative fuels. GHGenius is also the basis for low-carbon fuel standard reporting in BC and other LCA models within Canada.

Modelling results

The modelling shows differences in the lifecycle CI of the three main hydrogen production technologies. The modelling shows that downstream emissions, such as transportation, significantly contribute to the lifecycle CI for pathways that involve longer distances between the point of production and the point of use. The modelling also finds that newer technology variants offer improved lifecycle CIs. Autothermal reforming (ATR) and electric steam methane reforming (ESMR), for example, generate half the CI of the more mature steam methane reforming (SMR). The differences are less stark when considering methane pyrolysis and electrolysis variants.

Carbon intensity for compressed hydrogen by technology family, pathway and transport mode



The assessment in this report reflects data available as of October 2022 for existing and emerging hydrogen technology. As the market and technology matures, policy, market, and technology drivers could potentially result in lower CIs in the future (Section 5.6, page 48). However, the assessment in this report does not consider economic feasibility or other potential trade-offs among the production technologies and pathways.

Hydrogen blending and its impact on emissions

The report also analyzed the GHG emissions reductions that would be possible by blending hydrogen into BC's natural gas network. Four scenarios were developed: a high efficiency scenario, an electrolysis-only scenario, a mixed reduction scenario, and a scenario using proven technology alone.

Using these scenarios, analysis shows that blending hydrogen at approximately 20% by volume (21.5 million GJ of hydrogen) into the province's natural gas network for utility heating can achieve emission reductions of 350,000 to 815,000 tonnes/year CO_2e. This results in a 0.5% to 1.3% reduction in overall BC GHG emissions, and a 1.7% to 4% reduction in emissions from BC's utility natural gas system.

For the purposes of this report, blending hydrogen with natural gas is only considered in the context of the impact on GHG emissions reductions.

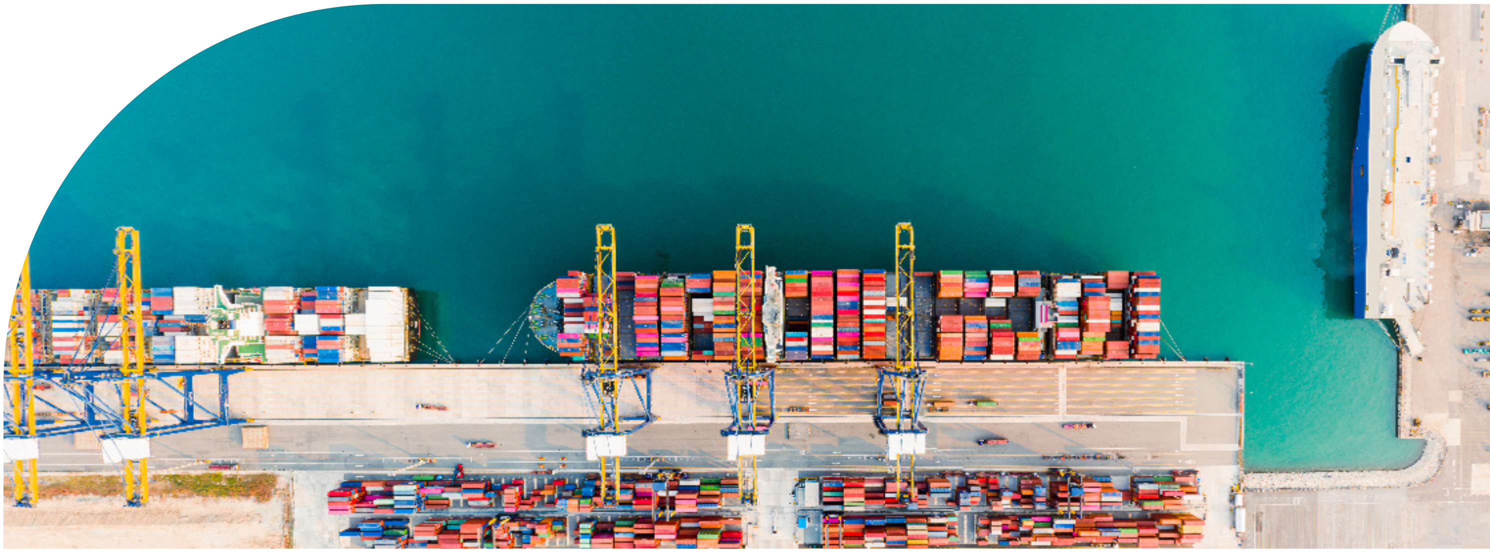
Conclusions

Based on the modelling completed for this study, hydrogen produced in BC today can achieve cradle-to-plant-gate CIs that range from 11.9 to 40.1 gCO_2e/MJ.

By 2030, it is anticipated that plant-gate CIs for hydrogen from solid oxide electrolysis and SMR with CCS would be 11.9 to 39.1 gCO_2e/MJ, respectively.

By 2040, and beyond to 2050, CI thresholds for hydrogen in BC could be reduced to 12.2, 8.2 and 11.9 gCO_2e/MJ for pathways in methane reforming, methane pyrolysis, and electrolysis technologies, respectively, driven primarily by increased carbon capture rates, and for pyrolysis, market availability for solid carbon.

The work undertaken as part of this study can be leveraged to develop policy options, identify and select technologies, and invest in specific hydrogen pathways to produce low-CI hydrogen in BC.



2. Glossary

ATR	Auto-thermal reforming
CCS/CCUS	Carbon capture and storage / Carbon capture utilization and storage
CI	Carbon intensity (using CO_2e)
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
ESMR	Electric steam methane reforming
FCEV	Fuel cell electric vehicle
GHG	Greenhouse gas
GJ	Gigajoule
GWP	Global warming potential
H_2	Hydrogen
HHV	High heating value
LCA	Lifecycle analysis
LHV	Low heating value
MJ	Megajoule
MPa	Megapascal
NMHC	Non-methane hydrocarbons
PEM	Proton exchange membrane
PSI/psi	Pounds per square inch
SMR	Steam methane reforming
SOEC	Solid oxide electrolyzer cells
ZEV	Zero-emissions vehicle

3. Introduction

British Columbia is committed to achieving net-zero emissions by 2050. Hydrogen can play a key role in decarbonizing energy systems and the transition to a low-carbon economy, especially in sectors where direct electrification is not practical, such as heavy-duty transportation and high-grade industrial heating. Hydrogen can be used to produce low-carbon synthetic fuels or used in fuel cells to produce energy for transportation and stationary power systems. Hydrogen also has the potential to provide heat to homes and buildings in place of fossil fuels when blended into the natural gas grid. However, the thinking around using hydrogen for heat is evolving, and this study aims to better understand the benefits and constraints of doing so.

As part of the BC Hydrogen Strategy, carbon intensity (CI) thresholds for hydrogen production pathways will be established to support a low-carbon hydrogen industry within British Columbia. This will be of importance as BC moves towards achieving its emission reduction targets as established under the Climate Change Accountability Act, including 40% emission reductions by 2030, 50% by 2040, and 80% by 2050 from 2007 levels.

To reduce emissions and decarbonize the economy, the BC Hydrogen Strategy focuses on advancing and providing support only for renewable and low-carbon pathways, with long-term targets for declining CI consistent with net-zero emissions by 2050.[1] CI is expressed in terms of grams of CO_2 equivalent (CO_2e) per megajoule (MJ) of energy.

This report has been produced by Deloitte and (S&T)[2] on behalf of the BC Centre for Innovation & Clean Energy (CICE) and the BC Ministry of Energy, Mines and Low Carbon Innovation (EMLI). CICE is an independent non-profit organization that convenes innovators, industry, governments, and academics to accelerate the commercialization and scale-up of BC-based clean energy technologies. It also aims to be a catalyst for new partnerships and world-leading innovation to deliver near-term and long-term GHG reductions. This study is underpinned by CICE's focus on low-carbon hydrogen for clean energy solutions and builds on the objectives of the BC Hydrogen Strategy.

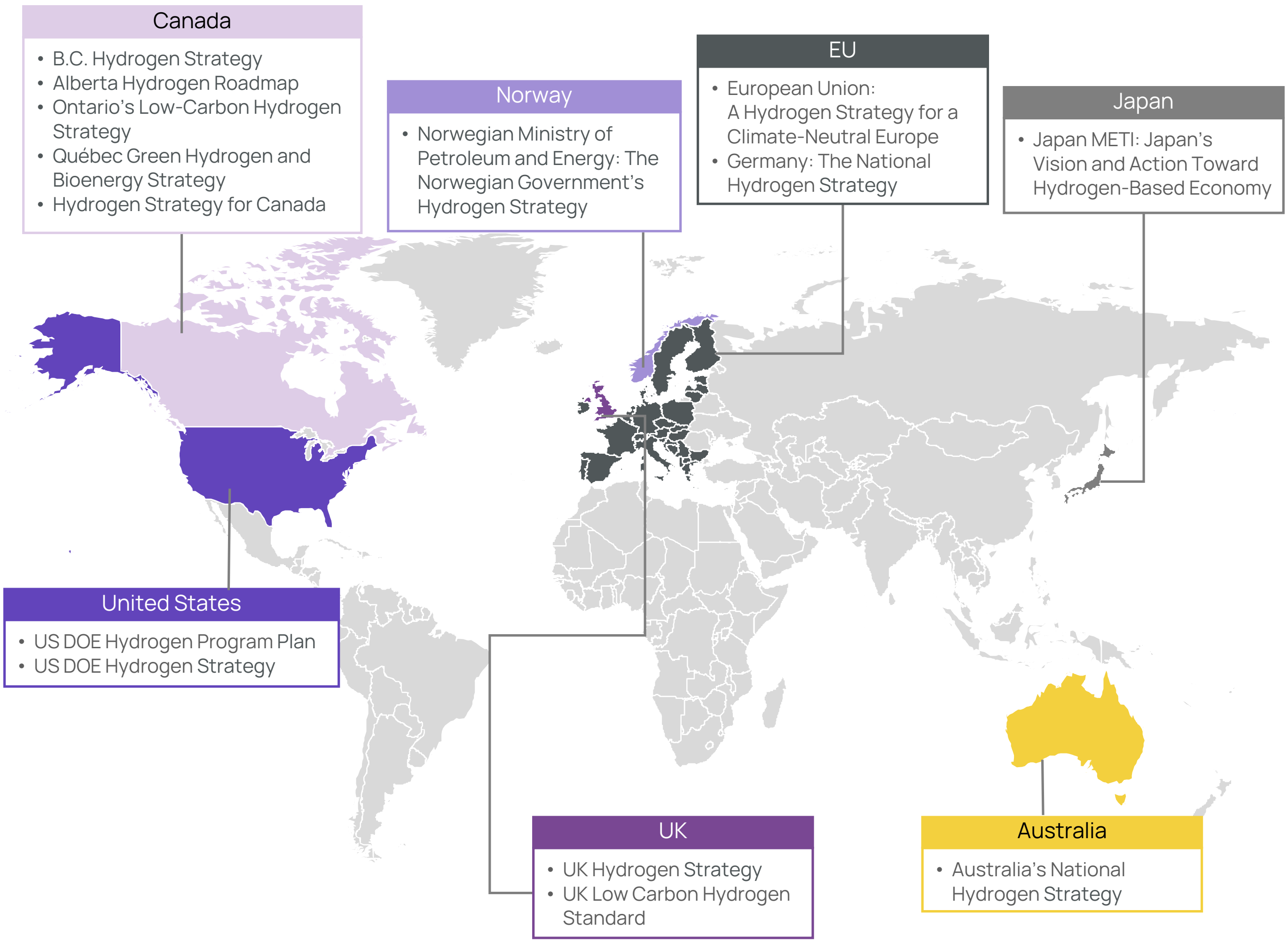
Through the development and analysis of plausible scenarios, and a review of international and national projects, pilots, and policy, this report is intended to provide determinations of lifecycle CIs, using the

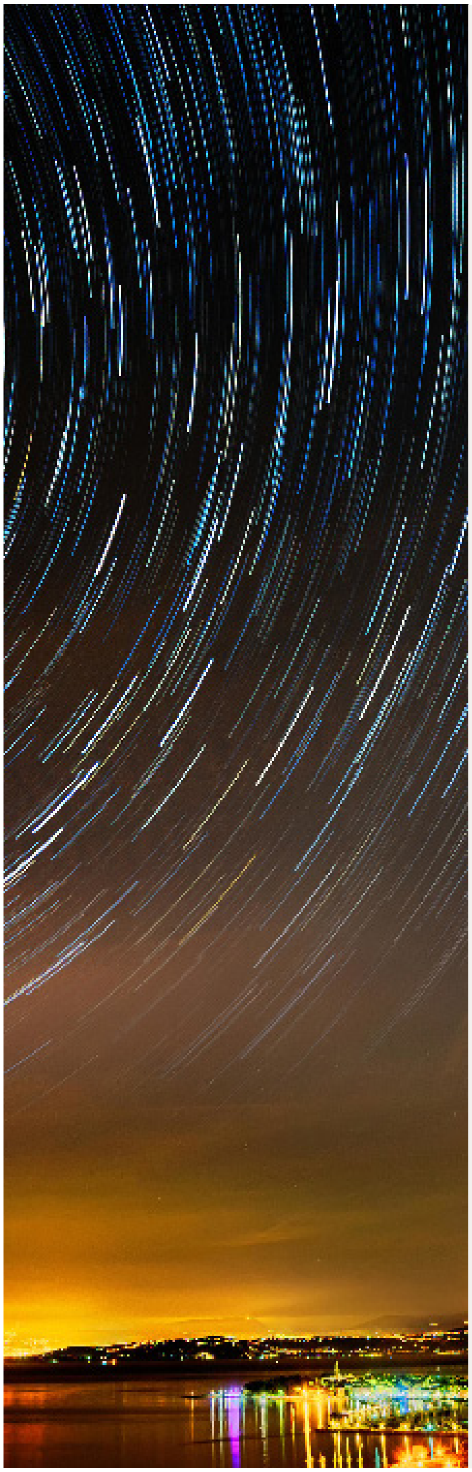
GHGenius LCA modelling tool, for various hydrogen production pathways to support the identification of low-carbon hydrogen opportunities in BC. In addition, this report aims to provide an overview of regional and global hydrogen standards and initiatives. A better understanding of other jurisdictions' activities, including contributions of low-carbon hydrogen pathways from an emissions perspective, can offer insights into recommended CI thresholds and reduction strategies to meet climate goals. This report focuses its modelling on the potential emission reductions achievable by blending hydrogen into BC's natural gas grid. Ultimately, this report intends to provide an objectively determined CI analysis to inform decision-making related to renewable and low-carbon hydrogen production in BC, with particular focus on establishing declining CI thresholds out to 2050 to help meet provincial climate goals.

4. Carbon intensity: Global themes for hydrogen production pathways

Several governments around the world have published hydrogen strategies, setting out their plans for developing a hydrogen industry to address climate change. To gain insights into emerging themes and best practices that could be used to further BC's own hydrogen ambitions, reports from specific jurisdictions were reviewed based on the International Renewable Energy Agency's criteria for "jurisdictions with potential to be policy front-runners and leading markets in hydrogen."[2] The jurisdictions selected, and their relevant hydrogen strategy documents, are illustrated in Figure 1. Information about hydrogen production and demand incentives, existing and proposed CI thresholds, hydrogen blending requirements and policy, and other insights documented in this report are based on the identified documents.

FIGURE 1 - **Jurisdictions and relevant hydrogen strategy documents reviewed**





Jurisdictional scan reference sources

The following sources were used as references for the jurisdictional scan completed for this report:

Canada

» B.C. Hydrogen Strategy
» Alberta Hydrogen Roadmap
» Ontario's Low-Carbon Hydrogen Strategy
» 2030 Québec Green Hydrogen and Bioenergy Strategy
» Hydrogen Strategy for Canada

US

» Department of Energy (DOE) Hydrogen Program Plan
» DOE Hydrogen Strategy

UK

» UK Hydrogen Strategy
» UK Low Carbon Hydrogen Standard

Europe

» A Hydrogen Strategy for a Climate-Neutral Europe (EU)
» The National Hydrogen Strategy (Germany)
» The Norwegian Government's Hydrogen Strategy

Australia

» Australia's National Hydrogen Strategy

Japan

» Japan's Vision and Actions Toward Hydrogen-Based Economy

4.1 Emerging global themes

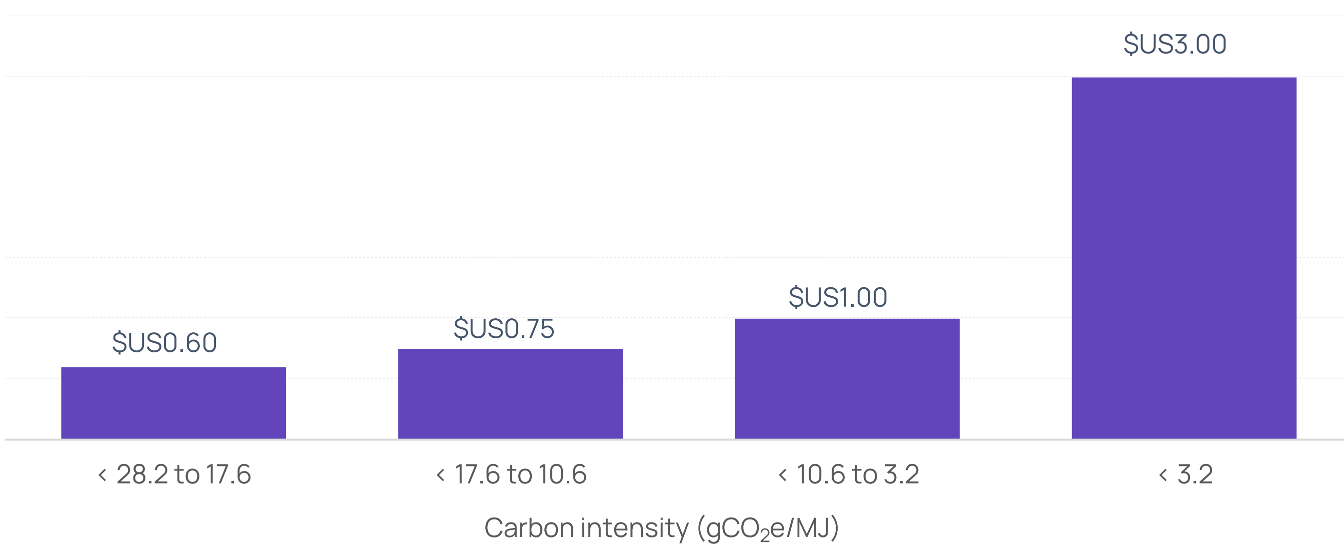
The scan of Canadian and global jurisdictions' hydrogen strategies uncovered the following three primary themes: leveraging CI, defining system boundaries, and enabling low-carbon hydrogen.

4.1.1 Leveraging CI

Some jurisdictions are using CI values to create incentives for hydrogen production. By attaching increasingly stringent CI thresholds to increasing amounts of hydrogen production credits, jurisdictions increase the economic competitiveness of low-CI hydrogen production.

In the US, the Inflation Reduction Act (passed in August 2022) describes qualifying hydrogen production as starting at a base CI of 28.2 gCO_2e/MJ (HHV). The lower the CI of the hydrogen produced, the greater the production credit received (see Figure 2). Projects are required to promote good-paying jobs by following prevailing wage standards and apprenticeship requirements to receive the full credit.

FIGURE 2 - US production credits for low CI hydrogen



The aim of the US approach is to incentivize low-CI hydrogen production by making it profitable in the short term through the use of production credits, which are available for a guaranteed 10-year period from production. Over time, this should spur economies of scale as hydrogen production technologies mature and ensure the sector's long-term, standalone profitability.

The UK's national hydrogen strategy, unveiled in 2021, sets qualifying hydrogen production CI at 17 gCO_2e/MJ (HHV). A £240-million net-zero hydrogen fund was launched in 2022 for co-investments in early hydrogen projects that meet this qualifying threshold. 2022 also saw the launch of a separate £60 million for a low-CI. Projects that meet the qualifying threshold can also apply for production business model support, which provides a subsidy to close the gap between the cost of producing low-CI hydrogen and the price the hydrogen can be sold for.

The UK government, working with industry, is aiming to establish 10GW (~1.2 million tonnes) of low-CI hydrogen production capacity by 2030, for use across the UK economy. The government's intent is to ensure that any new, government-supported low-CI hydrogen production capacity contributes to meeting the national GHG emission reduction targets set out in the UK Climate Change Act.

Key takeaways for BC

- **CI thresholds are being applied as production incentives to low-carbon hydrogen production, rather than as mandates that limit high-carbon hydrogen production. This approach differs from many existing global policy mandates (including those in Canada, such as the zero-emission vehicle (ZEV) mandates and clean fuel programs) as it does not restrict high-CI hydrogen production, but rather creates disincentives to producing it by making low-carbon hydrogen production more economically competitive.**
- **It's important to note, however, that the effectiveness of the UK and US policies has not been tested, as they have only recently been implemented.**

4.1.2 Defining system boundaries

Accurately determining CI requires a consistent set of criteria and specifications that can be applied uniformly across hydrogen producers and technologies, typically defined within a hydrogen standard. Hydrogen standard development is still in the early stages across jurisdictions, and for the purposes of this report, insights were drawn from recent efforts in the United States and United Kingdom.

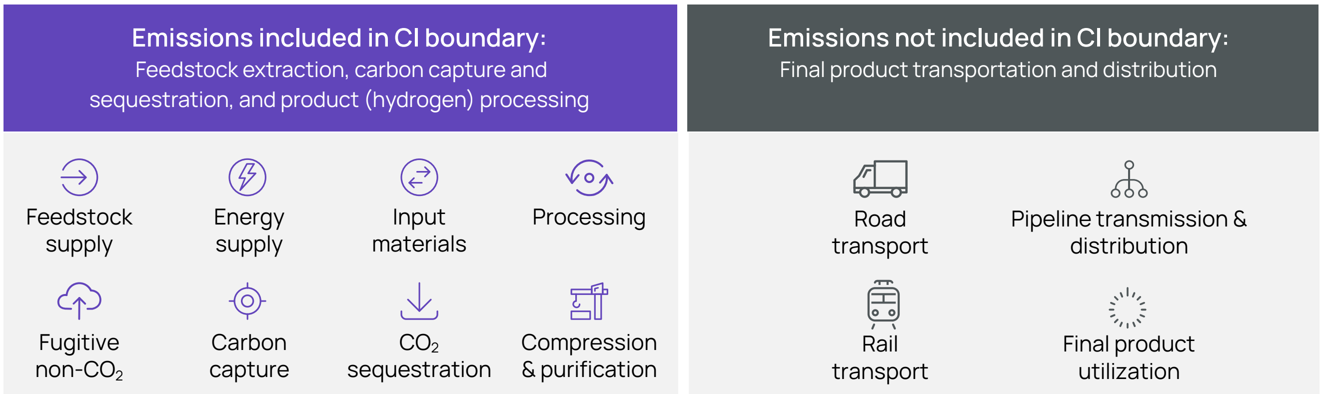
In the UK, lifecycle emission boundaries and emission sources are well-defined, and a hydrogen standard was released in 2022. While the US does not currently have a hydrogen standard or defined lifecycle emission boundaries, these are expected to be developed as they are required by the Inflation Reduction Act.

The UK's approach to defining lifecycle emissions requires emissions to be accounted for up to the point of production, commonly referred to as "cradle-to-gate." Under this approach, emissions are accounted for from feedstock supply and all production processes, and terminate after the point of production. As a result, emissions "downstream" from the hydrogen production facility—e.g., final product transportation, distribution, and use—are not included in the lifecycle boundary (see Figure 3).

Key takeaways for BC

» **Implementing CI thresholds requires the development or adoption of a standard methodology that defines the lifecycle boundary, emission sources, emission factors, and processing and product specifications. The inclusion or exclusion of emission sources and processing and product specifications within the lifecycle boundary has significant implications on CI values.**

FIGURE 3 - UK lifecycle emissions boundary[3]



The UK approach also includes clear specifications for lifecycle processing and product specifications. Produced hydrogen must achieve a theoretical minimum pressure of 3 MPa (435 psi) and a theoretical minimum purity of 99.9% by volume. As for the energy supply, the CI of the natural gas used for hydrogen production is to be assessed daily, while the CI of the power mix used is to be assessed in 30-minute intervals. Energy allocation of emissions is to be used for co-products.

4.1.3 Enabling low-carbon hydrogen

A number of jurisdictions, including BC, are using regulatory policies to support and encourage hydrogen production, particularly around carbon capture utilization and storage (CCUS) hubs, transportation (including ZEV policies), and electricity cost incentives.

» CCUS Hubs: In this area, regulatory policies are designed to promote the co-location of supporting carbon capture and storage infrastructure to leverage economies of scale, creating incentives for market demand and supply. These policies also provide an enabling regulatory framework to facilitate the permitting, measurement, reporting, and verification associated with CCUS.

Alberta, for example, is enhancing its CCUS regulatory framework and evaluating the merits of establishing a hydrogen trading hub to drive price transparency. The province is also launching the Alberta Petrochemicals Incentive Program, which has the potential to support hydrogen production.

» Transportation: The BC Low Carbon Fuel Standard (LCFS) was introduced to reduce the carbon intensity of fuels used in the province and support investment in cleaner transportation fuels and vehicles. The BC LCFS carbon intensity target declines every year and aims to reduce fuel CI by 30% by 2030.[4] Credits are generated in proportion to decreasing fuel CI, thereby providing a financial incentive to decarbonize transportation fuels, such as through the use of low-CI hydrogen.

  » ZEV policies: Policies in this area are typically mandates that stipulate permissible supply of ZEVs and conventional internal combustion engines by vehicle producers. While these policies do not specifically target hydrogen, they can drive a potentially larger market share for hydrogen fuel cell electric vehicles (FCEVs), thereby increasing hydrogen demand. ZEV policies will create demand but not necessarily incentivize low-carbon hydrogen production.

  In BC, the ZEV Act stipulates targets for light-duty ZEV sales and leases: 10% by 2025, 30% by 2030, and 100% by 2050. In Norway, new cars and light vans must be ZEVs, and new urban buses must be ZEVs or use biogas by 2025; new large vans, 75% of new long-distance buses, and 50% of new trucks must be ZEVs by 2030.

» Electricity cost incentives: In this area, policies are designed to provide preferential electricity rates to incentivize the economics associated with hydrogen production by large-scale industrial operators. These incentives have taken the form of tax exemptions and preferential pricing from utility companies.

In BC, for example, the Clean Industry and Innovation Rate discounts electricity costs for hydrogen-producing industrial customers by 20% for the first five years, 13% in the sixth year, and 7% in the seventh year.[5] In Norway, electricity used for hydrogen production is exempt from consumer tax. Ontario filed a Gross Revenue Charge exemption for hydroelectricity to be used in Atura Power's proposed Niagara Falls H_2 pilot project.

Key takeaways for BC

» **BC is already implementing three supportive regulatory policies drawn from the jurisdictional scan. Leveraging regional synergies between jurisdictions may present opportunities to support further hydrogen production in BC.**

4.2 Other highlights from the jurisdictional scan

In addition to the emerging themes described above, the jurisdictional scan also uncovered important findings with respect to GHG modelling and production and demand incentives.

The UK, US, and European Union have proposed values for “low carbon hydrogen,” with other jurisdictions considering values that are primarily aligned with CertifHy™. The UK has a hydrogen standard, and the US will potentially have one in the near term after the recent announcement of draft guidance for a clean hydrogen production standard.[6]

FIGURE 4 - CI and hydrogen standard perspectives from jurisdictional scan

JURISDICTION	CI PERSPECTIVES	HYDROGEN STANDARD PERSPECTIVES
Canada	While not explicitly mentioned, reference is made to the use of CertifHy CI values by the European Union. However, the draft Clean Fuel Regulation Quantification Methodology for Low-CI Hydrogen defines low-CI hydrogen as: » H_2 as fuel: less than 61 gCO_2e/MJ (HHV) (10% lower than reference natural gas CI) » H_2 as feedstock: less than 67 gCO_2e/MJ (HHV) (25% lower than reference SMR hydrogen) » H_2 as fuel or feedstock: at least 50% of production emissions captured and permanently sequestered	This approach defines “low carbon hydrogen” based on its end-use, each with an associated CI threshold

JURISDICTION	CI PERSPECTIVES	HYDROGEN STANDARD PERSPECTIVES
UK	Proposed CI is 17 gCO_2e/MJ » Higher heating value basis (HHV), equivalent to 20 gCO_2e/MJ on LHV basis » Emissions boundaries are well-defined » UK is a net energy importer	Hydrogen Standard was recently released in 2022
EU	Proposed CI is 28.2 gCO_2e/MJ » Lower heating value basis (LHV) » Emission boundaries adopted from CertifHy » The European Union is a significant energy importer	The proposed carbon intensities are a result of consultations under the EU Renewable Energy Directive (RED II)
US	» Under the Infrastructure and Investments Job Act (2021): "Clean hydrogen" is 14.1 gCO_2e/MJ (HHV) » Under the Inflation Reduction Act: "Qualified clean hydrogen" is 28.2 gCO_2e/MJ (HHV) » Proposed lifecycle (including CCS) GHG emissions of 4.0 $kgCO_2e/kg\ H_2$ as part of the US DOE Clean Hydrogen Production Standard (CHPS) Draft Guidance[7]	» Definitions of "clean hydrogen" and "qualified clean hydrogen" between the acts may differ » The IRA requires the development of a hydrogen standard (and regulation) for CI determination, using the GREET LCA model » The draft guidance expands the system boundary beyond the plant gate to include CCS even if not at the site of production but does not include other post-hydrogen production steps such as potential liquefaction, compression, dispensing into vehicles, etc.

JURISDICTION	CI PERSPECTIVES	HYDROGEN STANDARD PERSPECTIVES
CertifHy	Provides certificates that prove the production quality for a given hydrogen quantity: » Green hydrogen label: 31.2 gCO_2e/MJ (HHV): equivalent to 36.4 gCO_2e/MJ on LHV basis » Low carbon hydrogen: 31.2 gCO_2e/MJ (HHV) » Emission boundaries to follow ISO 14044 and 14067	Green hydrogen is that from renewable resources (as defined in EU RED II), while "low-carbon" hydrogen is that from non-renewable energy sources using CCS/CCU

While incentives are largely targeted at funding research, development, and market acceleration of hydrogen technologies, the US provides a production credit based on CI performance in the recent Inflation Reduction Act.

FIGURE 5 - Production and demand: Funding incentives from jurisdictional scan

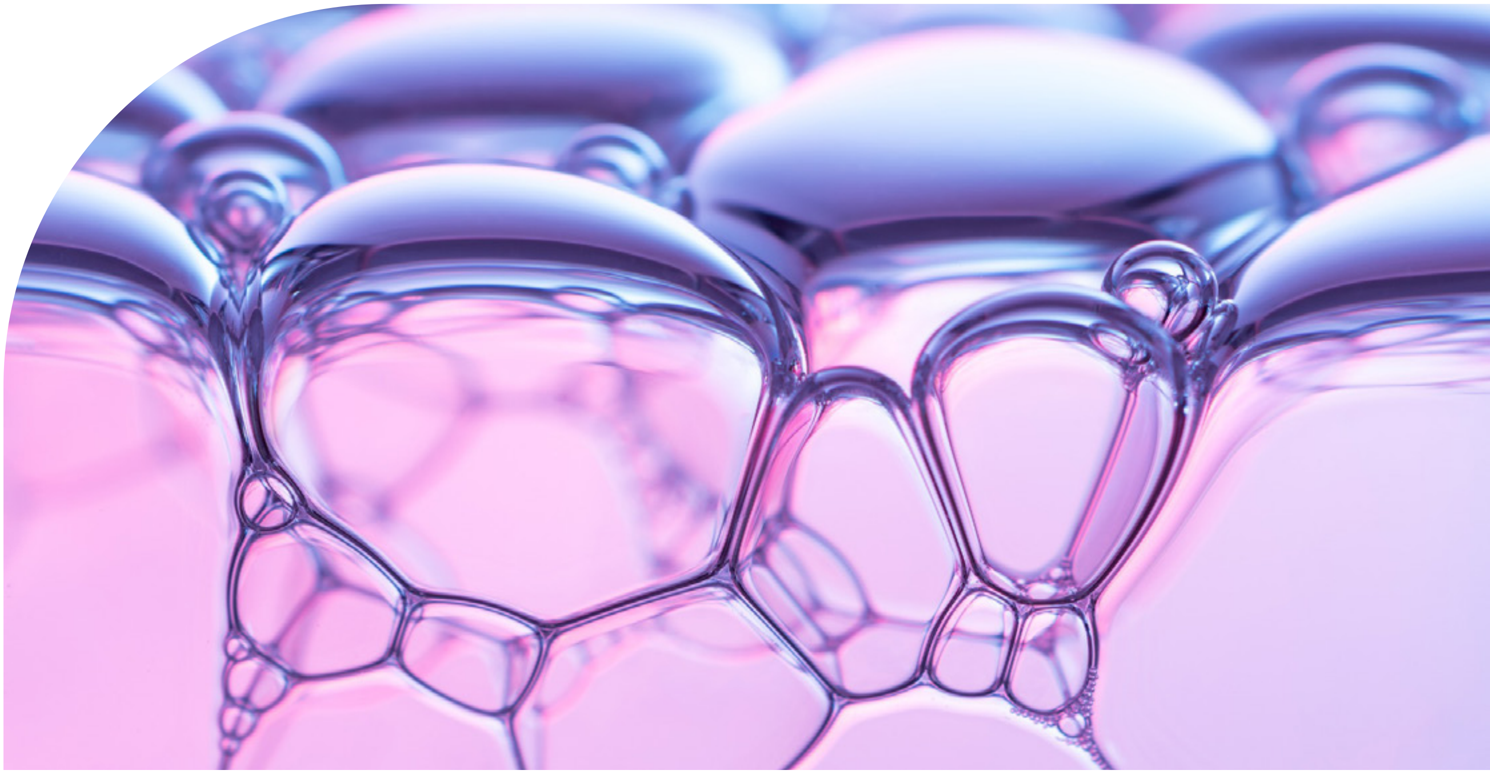
JURISDICTION	FUNDING INCENTIVES
BC	» BC Low Carbon Fuel Standard P3A credits incentivize lower-CI hydrogen for transportation in BC » The CleanBC Industry Fund supports larger emitters to implement GHG emission reduction projects, which can include deployment of proven and potentially pre-commercial clean technologies » The CleanBC Go Electric Vehicle Program is providing funding support for the deployment of both charging and hydrogen fuelling infrastructure across the province » A $40-million partnership between British Columbia's Innovative Clean Energy Fund (ICE) and Sustainable Development Technology Canada (SDTC) supports the development of precommercial clean-energy projects and technologies

JURISDICTION	FUNDING INCENTIVES
Alberta	» Leverage federal funding and incentives to provide Alberta decarbonization funding for carbon capture infrastructure
Quebec	» Has a $1-billion Natural Resources and Energy Capital Fund to support green hydrogen production and consumption projects » The strategy states that the Quebec government will support production projects that first meet local demand
Ontario	» Working towards the development of reduced electricity rates to support low-carbon hydrogen production » Launching feasibility study to explore opportunities to leverage excess energy from the Bruce Power Nuclear Generating Station » Contributing $500 million to support ArcelorMittal Dofasco's $1.8-billion coal-to-hydrogen electric arc furnaces project
US	» The Infrastructure Investment and Jobs Act (2021) provides US$9.5 billion to fund clean hydrogen projects: » US$8 billion to develop at least four regional clean hydrogen hubs » US$1 billion for electrolysis R&D and demonstrations » US$500 million for technology manufacturing and recycling R&D and demonstrations » The Inflation Reduction Act will provide a base credit to qualifying projects, and a further 5x "credit multiplier" to projects that meet wage and job stipulations; the overall credit available for such projects is: » US$0.60/kg H_2 for CI between 28.2 and 17.6 gCO_2e/MJ (equivalent to 4–2.5 kgCO_2e/kg H_2) » US$0.75/kg H_2 for CI between 17.6 and 10.6 gCO_2e/MJ (equivalent to 2.5–1.5 kgCO_2e/kg H_2)

JURISDICTION	FUNDING INCENTIVES
US	» US\$1.0/kg H_2 for CI between 10.6 and 3.2 gCO_2e/MJ (equivalent to 1.5–0.45 $kgCO_2e/kg\ H_2$) » US\$3.0/kg H_2 for CI less than 3.2 gCO_2e/MJ (equivalent to less than 0.45 $kgCO_2e/kg\ H_2$) » The California Energy Commission (CEC) can allocate up to US\$20 million per year for building hydrogen service stations through 2023 » The California Energy Commission is initially investing in 100 public stations to support ZEVs » Specific funding is allocated to hydrogen hub development
UK	» £60-million fund for a low-carbon hydrogen supply competition » £315-million Industrial Energy Transformation Fund » £55-million Industrial Fuel Switching competition » £240-million fund for co-investment in early hydrogen projects (launched in 2022) » Production business model support that provides a subsidy to close the gap between the cost of producing low-CI hydrogen and the price it can be sold for
Germany	» €310 million for basic research of green hydrogen » €200 million for practice-oriented hydrogen technologies » €600 million for speeding up technologies from lab to market » Plans are focused on funding enabling research areas for hydrogen production (between 2020 and 2023) » A 2020 stimulus package contained another €7 billion for market rollout and €2 billion for fostering international partnerships

FIGURE 6 - Production and demand: Tax and investment incentives from jurisdictional scan

JURISDICTION	FUNDING INCENTIVES
Ontario	» Filed a Gross Revenue Charge (GRC) exemption for hydroelectricity for proposed Niagara Falls hydrogen pilot by Atura Power
Norway	» Exempts electricity used for hydrogen production from consumer tax
Germany	» Over €1 billion for investment in technologies and large industries that use hydrogen



4.2.1 Voluntary systems for low-carbon hydrogen certification

There were two voluntary systems identified that could be adopted to measure and certify low-carbon hydrogen and its origin.

CertifHy™

CertifHy™ is a hydrogen certification scheme that was initiated at the request of the European Commission and is financed by the Clean Hydrogen Partnership, a unique public-private partnership supporting hydrogen technology research and innovation activities in Europe. There are over 100 platform members, including government agencies, engine manufacturers, hydrogen producers, oil companies, consultants, and others with an interest in hydrogen certification.

CertifHy has established a system of electronic certificates that provide proof that a given quantity of hydrogen is produced by a registered production device with a specific quality and method of production. The CertifHy certificates are maintained in a CertifHy Registry, a central database that will manage the CertifHy certificates' lifecycle for every account holder (certificates are cancelled upon use to avoid double counting).

The CertifHy certificate includes the following information:

- CertifHy GO (Guarantee of Origin) scheme, including unique ID number, date of issuing, cancellation date
- Information on the plant that produced the hydrogen
- Time of production of the hydrogen
- Energy source of the hydrogen (fuel or heat) and technology
- Whether the hydrogen production has received financial support
- Share of renewable energy
- CI of the hydrogen

There are also two CertifHy labels:

- **Green Hydrogen** originates from renewable resources as defined in the EU Renewable Energy Directive (RED II) and has a GHG emission intensity 60% below the benchmark, which is hydrogen production from SMR—this benchmark is 91 gCO_2e/MJ (LHV). Applying the 60% threshold to the benchmark leads to a determination that green hydrogen would have a GHG emissions intensity of 36.4 gCO_2e/MJ.
- **Low Carbon Hydrogen** originates from non-renewable nuclear or fossil energy resources using carbon capture and storage (and potentially carbon capture and utilization, which is yet to be defined by the European law) and meets the same 60% threshold, or 36.4 gCO_2e/MJ (LHV).

GHG emissions are to be calculated following the ISO 14044 (Environmental management – Life cycle assessment) and 14067 (Greenhouse gases – Carbon footprint of products) standards. The lifecycle system boundary is to include all production stages needed to reach 99.9% hydrogen by volume at a minimum of 3 MPa pressure.

International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE)

The IPHE was established in 2003 by the US Department of Energy (DOE) and Department of Transportation to foster international cooperation on hydrogen and fuel cell R&D, common codes and standards, and information sharing on infrastructure development.

IPHE currently has 22 partners that share information and help facilitate multinational research, development, and deployment initiatives that advance the introduction of hydrogen and fuel cell technologies on a global scale.

In 2021 the IPHE Hydrogen Production Analysis Task Force prepared a working paper detailing a methodology for redeeming the GHG emissions associated with the production of hydrogen, with references to ISO 14040, 14044, and 14067. It provides some specific guidance on how to apply these standards to hydrogen from electrolysis, SMR hydrogen, by-product hydrogen, and hydrogen from coal gasification. However, the document does not present any thresholds.

4.3 The state of hydrogen blending internationally

BC is not the only jurisdiction exploring hydrogen blending as a means of reducing GHG emissions. Projects of various sizes and at various stages of implementation are underway around the world. There is a diversity of perspectives regarding hydrogen blending at this time, on everything from blending volume percentages to safety concerns to whether to pursue blending at all. Figure 7 lists a selection of hydrogen blending perspectives, while Figure 8 describes a range of hydrogen blending projects that have been completed, are in process, or are planned.

FIGURE 7 - Hydrogen blending perspectives

JURISDICTION	HYDROGEN BLENDING PERSPECTIVES	IMPORT/EXPORT PERSPECTIVES
BC	» Establish regulatory framework for H_2 in natural gas and propane distribution systems » Partner with a utility to review infrastructure requirements to accommodate up to 100% hydrogen in distribution systems	» Leverage existing natural gas infrastructure and proximity to top export markets, such as China, Japan, and California, which are expected to account for 50% of global demand
Alberta*	» Amend the Gas Utilities Act and Gas Distribution Act to remove a key roadblock for H_2 blending into natural gas distribution systems » Assess mechanisms to build demand for hydrogen in the utility heat market, including options for cost recovery	» Pursue market access through establishment of a clean energy corridor with connection through British Columbia and other jurisdictions » Pursue hydrogen export memoranda of understanding
US	» Announced goal to cut cost of hydrogen over the next decade and invest in the advancement of clean hydrogen, but is wary of the technical challenges and risks of blending	» Pursue Canadian market for imports and other markets in close proximity

*Alberta blending perspectives are focused on the next 5-10 years

JURISDICTION	HYDROGEN BLENDING PERSPECTIVES	IMPORT/EXPORT PERSPECTIVES
EU	» Notes that the change in the quality of blended gas in Europe may affect the design of gas infrastructure, end-user applications, and cross-border system interoperability. This risks fragmenting the internal market if neighbouring member states accept different levels of blending and cross-border flows are hindered	» Pursue green hydrogen partnerships that promote imports from other countries
Australia	» Agrees not to support the blending of hydrogen in existing gas transmission networks until further evidence emerges that hydrogen embrittlement issues can be safely addressed	» Support exports to Japan through Australian Clean Hydrogen Trade Program » Partner with countries for research to build international partnerships and supply chains

FIGURE 8 - Hydrogen blending perspectives

JURISDICTION	FUNDING INCENTIVES
Canada	» The Cummins Enbridge project in Ontario, which uses electrolysis to produce hydrogen that is blended into the gas grid at 2% by volume, began operations in January 2022. It serves 3,600 residential customers. » In October 2022, ATCO launched a project in Fort Saskatchewan, Alberta to blend hydrogen into the city's gas grid at 5% by volume; the hydrogen-blended natural gas is used by 2,000 gas customers. Appliance and gas piping inspections have also begun for all homes and businesses within the project zone to ensure they are in proper working order. It is expected that the hydrogen being blended for this project will ultimately be produced nearby through electrolysis.
US	» The first phase of the SoCalGas project was originally scheduled to begin in early 2021, but is now planned to begin in 2024 with a focus on the University of California, Irvine, campus. In this phase, the impact of hydrogen blending (1%–20%) on polyethylene (PE) pipe distribution systems will be the focus. The next stage of the project will move to the service area of San Diego Gas and Electric and test blending's impact on mixed PE and steel distribution networks. » The HyBlend project comprises three main elements and an aggressive timeline. Sandia National Laboratories and the Pacific Northwest National Laboratory are leading research on the impact of hydrogen exposure (at blending volumes of 1% to 30%) on the life expectancy of metal and polymer pipeline materials when exposed to hydrogen. These two national labs will also be cooperating with the Hydrogen Materials Compatibility Consortium (H-Mat), which has over 20 partners in industry and academia researching hydrogen compatibility with metals and polymers. Argonne National Laboratory is analyzing the lifecycle emissions of hydrogen-natural gas blends. The last task, a techno-economic analysis of hydrogen blending, will be quantified by the National Renewable Energy Laboratory (NREL). However, the project includes no field trials.

JURISDICTION	FUNDING INCENTIVES
UK	» Four hydrogen blending projects have launched in the UK since 2019: HyDeploy (20% blending by volume, serving 1,500 residential customers); East Neuk Power (20% blending by volume, producing 15 Gwh/year); Aberdeen Vision (2% to 20% blending by volume, serving 300 residential customers); and HyNTS Hydrogen Loop (30% blending by volume). » The UK government is scheduled to decide in 2023 whether to proceed with the use of hydrogen in the country's natural gas distribution networks. In the meantime, industry is focused on hydrogen blending preparedness: the UK's five gas distribution companies have announced that their networks will be compatible with 20% blended hydrogen by volume by that time. However, the UK's gas transmission company is not part of this commitment.
Europe	» France's GRHYD project, which ran from 2014 until 2020, involved delivering blended hydrogen (20% by volume) to 200 residential customers. » Germany has run two demonstration projects—WindGas Falkenburg and WindGas Hamburg. Both involved hydrogen blending at very low levels: 2% by volume. The Falkenburg project began with hydrogen produced by electrolysis, but subsequently added a methanation plant where hydrogen was combined with CO_2 to make synthetic methane. » EU countries launched the THyGA (Testing Hydrogen Admixture for Gas Appliances) project in 2019 to test the impact of blending hydrogen into natural gas on commercial end use applications at concentrations of 10% to 100% by volume. In addition, THyGA was also designed to verify the safety of different hydrogen concentrations in natural gas. While experimental studies were developed to test the impact of hydrogen blending impact on about 100 commercial and residential appliances, and develop standards, safety parameters, and other protocols, no actual blending took place.

JURISDICTION	FUNDING INCENTIVES
Australia	» Australia's HyP Murray Valley project, if completed, will be the largest hydrogen blending project in the world: 40,000 residential and commercial customers will use hydrogen blended with natural gas at 10% by volume. While the project has been funded, hydrogen injection is not scheduled to begin until later in 2023. » Other projects include HyP SA (5% blending by volume, serving 700 residential customers), HyP Gladstone (10% blending by volume, serving 800 residential and commercial customers), and Jemena Western Sydney (2% blending by volume, serving 259 residential customers).

5. Modelling BC hydrogen production CI

The BC Hydrogen Strategy highlights pathways to produce hydrogen that use fossil fuel and renewable feedstocks.[8] These pathways are often represented by colours to depict the production process, using terms such as “green hydrogen,” “blue hydrogen,” and “grey hydrogen.” However, the use of colours does not follow a defined terminology and can often lead to confusion around the environmental benefits of the different hydrogen production pathways, which vary across geographies and technology-specific implementations.

In this section, in-depth modelling is presented for hydrogen production pathways, with an emphasis on parameters and characteristics that are unique to BC. The pathways considered build on three technologies identified in the BC Hydrogen Strategy: methane reforming, methane pyrolysis, and electrolysis. Within each technology, three variations of technology implementations are considered, for a total of nine hydrogen production pathways. These nine pathways can be compared uniformly based on the lifecycle approach used and the resulting carbon intensities (CIs).

The technologies and production pathways considered are not exhaustive of all pathways that have the potential to produce low-carbon hydrogen in BC. Other pathways exist, such as biomass gasification and the use of renewable natural gas (RNG) in reforming or pyrolysis systems. However, pathways that leverage BC’s natural gas (as a feedstock) and renewable electricity were prioritized for this study.

5.1 Goal and scope

The goal of the lifecycle assessment is to quantify the total GHG emissions associated with hydrogen production from the selected pathways, specific to implementation in BC. The resulting CIs provide a basis to assess and support hydrogen production and planning in the province.

Emissions are accounted for primary greenhouse gases and criteria pollutants from combustion sources. These include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), chlorofluorocarbons (CFC-12), and hydrofluorocarbons (HFC-134a). These also include the CO_2-equivalent of carbon monoxide (CO), nitrogen oxides (NO_x), and non-methane organic compounds (NMOCs) weighted by their ozone forming potential (i.e., the total emissions including emissions from chemical reactivity), sulphur dioxide (SO_2), and total particulate matter.

The potential for warming due to hydrogen leakage is not considered. Currently, the United Nations Intergovernmental Panel on Climate Change (IPCC) does not have a global warming potential (GWP) for hydrogen, but emerging research in the UK indicates it might have a GWP of about 11.[9] There is also work on potential leakage rates for hydrogen systems (Frazer Nash, 2022), and initial results indicate rates around 5% for some production activities. However, further investigation is required.

5.1.1 Product and functional unit

The product is defined as gaseous hydrogen, compressed to a pressure of three megapascals (3 MPa) at the production facility gate (plant gate). Therefore, the functional unit is defined as one megajoule (1 MJ) of hydrogen at 3 MPa, with a purity of 99.9%, at the plant gate.

The product is defined based on the HHV of hydrogen, which is taken as 141.2 MJ per kg H_2. It is worth noting that many hydrogen methodology development efforts, such as those by CertifHy,[10] the IPHE[11] and the National Research Council of Canada,[12] use an LHV basis. However, the HHV is chosen for this work for the following reasons:

» Federal and provincial regulations in Canada related to the CI of fuels, such as LCFS, use HHV

» Federal and provincial GHG reporting programs in Canada use HHV

» HHV is used for commerce in Canada

5.1.2 Geographical scope

The production pathways are considered under the context of BC. Therefore, hydrogen production and all associated activities, such as carbon capture and geological storage, are modelled to occur within BC.

5.1.3 Production pathways

Figure 9 describes characteristics of the three hydrogen production technologies explored in this report and their variations, for a total of nine pathways.

FIGURE 9 - Hydrogen production technologies and variants assessed in this report

	METHANE REFORMING WITH CCS "BLUE HYDROGEN"	PYROLYSIS "TURQUOISE HYDROGEN"	ELECTROLYSIS "GREEN HYDROGEN"
Overview	Reacts methane with water, resulting in the primary formation of hydrogen and gaseous CO_2	Decomposition of methane in the absence of air/ oxygen, resulting in the primary formation of hydrogen and solid carbon	Splits water with electricity, resulting in the formation of hydrogen and oxygen
Handling of carbon/CO_2	Requires CO_2 generated by the process to be captured	Produces "carbon black," a form of solid carbon	Does not produce any CO_2 or solid carbon
Variants	» Steam methane reforming (SMR): Methane combustion with air (TRL 9)[13] » Auto-thermal reforming (ATR): Methane combustion with pure oxygen and a catalyst (TRL 8)[14] » Electric steam methane reforming (ESMR): Methane heated with electricity (TRL 6)[15]	» Thermal decomposition: Methane decomposition at over 1000˚C (TRL 5) » Plasma decomposition: Plasma torch decomposition up to 2000˚C (TRL 9) » Catalytic decomposition: Catalyst decomposition under 1000˚C (TRL 5)	» Alkaline electrolysis: Uses alkaline material for electrolysis (TRL 9) » Proton exchange membrane (PEM): Uses polymer material for electrolysis (TRL 9) » Solid oxide electrolyzer cell (SOEC): Uses solid oxide material for electrolysis (TRL 8)

5.2 LCA system boundary

The primary system boundary of interest in this study accounts for the CI impacts associated with all material and energy flows from feedstock extraction through to hydrogen production, commonly referred to as a "cradle to plant gate" lifecycle assessment. This is consistent with the approach proposed by hydrogen certification schemes such as the IPHE and CertifHy, as well as the UK low-carbon hydrogen standard and the draft clean hydrogen production standard in the US.[16]

To provide further insight on the CI impact of the distance between hydrogen production locations and hydrogen end-use, processes downstream of hydrogen production are also presented in this study. These downstream processes typically include all associated material and energy processes required to transport the product to its end use. This insight provides a more holistic basis with which to consider the relationship between hydrogen production siting and overall environmental benefit within BC. An overview of the system boundary is presented in Figure 10, and emissions within each stage of the system boundary are described in Figure 11.

FIGURE 10 - System boundary overview

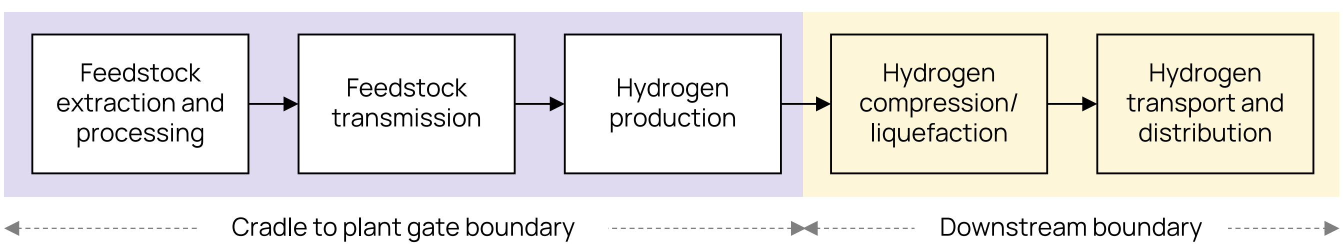


FIGURE 11 - Emission in each system boundary stage

Feedstock extraction & processing	Production & processing	Transportation & distribution
Feedstock recovery Emissions from recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, and upstream processing prior to transmission **Feedstock transmission** Emissions from transporting feedstock, including pumping, compression, leaks, fugitive emissions, and transportation from point of origin to the fuel refining plant	**Hydrogen production (from raw materials)** Emissions associated with conversion of feedstock to a saleable product. Includes process emissions, combustion emissions for process heat/steam, electricity generation, fugitive emissions, and emissions from the lifecycle of chemicals used for fuel production cycles **Carbon capture and sequestration** Emissions associated with CO_2 capture, during hydrogen production, and the subsequent transport and geological storage of the captured CO_2 **Emissions displaced by co-products of alternative fuels** Emissions displaced by co-products generated through the various pathways	**Fuel dispensing at the retail level** Emissions associated with the transfer of the fuel at service stations from storage into the vehicles. Includes electricity for pumping, fugitive emissions, and spills **Fuel storage and distribution at all stages** Emissions associated with storage and handling of fuel products at terminals, bulk plants, and service stations. Includes storage emissions, electricity for pumping, space heating, and lighting

A key energy flow into the system boundary is electricity imported from the BC grid. The electricity grid CI used is 42.1 gCO_2e/kWh, which includes an estimate of methane emissions from hydroelectricity reservoirs as is now required by the IPCC.[17]

The lifecycle impact of water is also considered, especially for electrolysis pathways where demineralized water is required. Studies show that water treatment emissions are primarily due to electricity for operations such as desalination, membrane treatment, and ozone production.[18] It has also been shown that the electricity required for water treatment is in the range of 0.05 to 0.72 kWh per tonne of produced water.[19] The high end of this range translates to an electricity requirement of 0.0063 kWh per kg of hydrogen, which is insignificant to the overall electricity requirements of about 55 kWh per kg of hydrogen. As a result, the water load is excluded from the LCA analysis.

5.2.1 Downstream plant-gate assumptions

As shown in Figure 10, the downstream CI impacts begin after hydrogen production (compressed hydrogen at 3 MPa). The two main assumptions in this section are associated with the distance the hydrogen is transported to the end use, and the mode of transportation of the hydrogen.

For this study, it is assumed that methane reforming pathways occur in northeast BC, given the proximity to natural gas production, while pyrolysis and electrolysis pathways occur in BC's Lower Mainland; hydrogen end-use is also assumed to occur in the Lower Mainland. Therefore, hydrogen produced from methane reforming is assumed to be transported 1200 km from the province's northeast to the Lower Mainland; hydrogen produced from pyrolysis and electrolysis is assumed to be transported 80 km within the Lower Mainland.

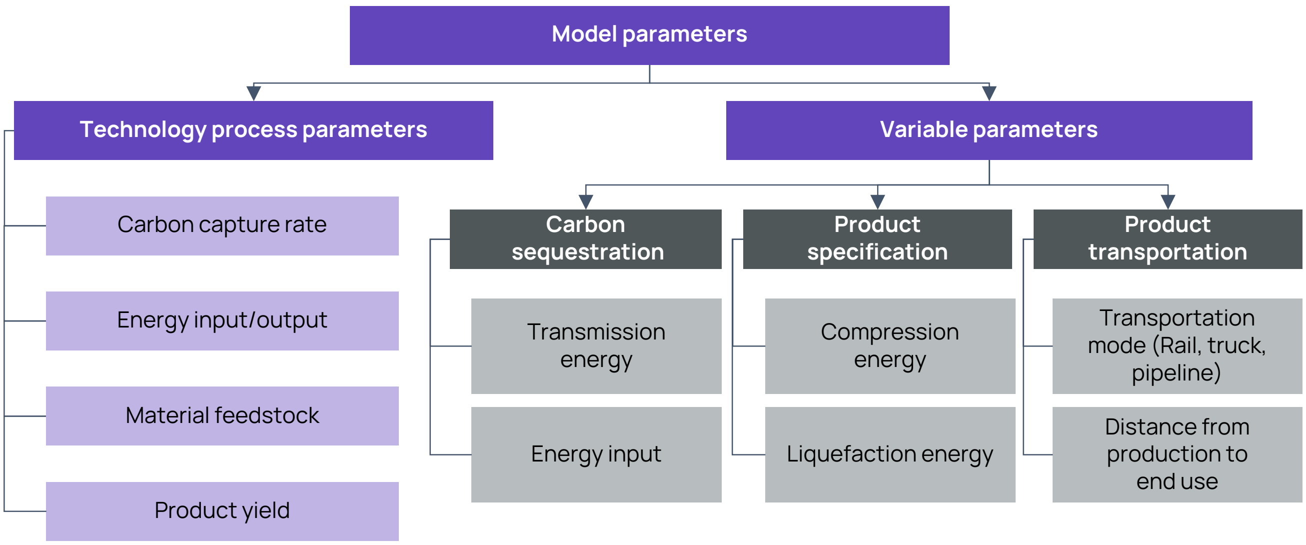
Three transportation modes are considered: pipeline transport, truck transport, and rail transport. Transportation states of gaseous compressed hydrogen and liquefied hydrogen are considered for each transport mode, with the exception of pipeline transport, for which only compressed hydrogen is considered.

As pipeline transportation occurs at 3 MPa, further compression from the plant gate is negligible. For truck and rail transportation, compressed, liquefied hydrogen transport occurs at 35 MPa, and liquefaction requires an additional 0.26 joules of electricity per joule of hydrogen (see further details in Section 7.3.) Additionally, hydrogen losses within downstream transportation are considered, including transfers at the plant, during transportation and storage, and at end use.

5.3 Modelling parameters and data sources

A range of technical and variable parameters were used in modelling the lifecycle CI of the nine hydrogen production pathways (see Figure 12).

FIGURE 12 - CI modelling parameters



Technology process parameters are based on production technology characteristics, such as carbon capture rate, energy input/output, material feedstock, and product yield. These parameters change due to advances in technology and as technology implementations move from pilot to commercialization.

Variable parameters used include:

» Carbon sequestration parameters associated with the transportation and sequestration of captured CO_2 emissions in methane reforming technologies. While sequestration typically occurs outside the production facility, associated emissions are captured in the calculation of hydrogen CI.

» Product specification parameters associated with the final state of the hydrogen produced, whether compressed or liquefied, and the energy required for compression to a specific pressure or for liquefaction.

» Product transportation parameters associated with the transportation and distribution of the final hydrogen product, downstream from the production facility. The parameters change depending on the transportation mode used and the distance to reach end users.

For each of the nine pathways listed in Figure 9, a literature review was conducted to identify sources of reference data, using publicly available data and prioritizing recent data from credible organizations. After an extensive review, the following reports were identified as the best sources currently available, and their data, assumptions, and inputs have been incorporated into the work:

» Methane reforming: The IEAGHG Technical Report 2022, Low-Carbon Hydrogen from Natural Gas: Global Roadmap.[20]

» Methane pyrolysis: Research papers published by Sebastian Timmerberg et al.[21] and Florian Kerscher et al.[22]

» Electrolysis: The IEA Hydrogen Projects Database,[23] the IEA Hydrogen TCP Report,[24] and a 2022 presentation to the US DOE by Brian D. James.[25]

5.4 Technology-specific assumptions

While technology-agnostic assumptions used in the carbon modelling are described, it is also important to note the technology-specific assumptions that factor into the modelling.

5.4.1 Methane reforming using CCS

Methane reforming is a mature technology. In 2020, 60% of global hydrogen production was generated using steam methane reforming and was almost exclusively produced without the use of carbon capture technology,[26] which is essential to produce low-carbon hydrogen from natural gas.

For methane reforming with CCS, a significant determinant of production CI is the CO_2 capture rate. However, while SMR is a mature (TRL 9) and widely deployed technology, SMR with CCS is much more limited.[27] Two mature hydrogen production systems that use methane reforming with CCS are Shell Quest (Alberta) and Valero Port Arthur (Texas); each of these facilities uses different CCS technologies, but they do not have very high rates of CO_2 capture. Shell Quest, for example, captures approximately 80% of CO_2 from process streams, but it does not capture CO_2 from combustion streams that provide energy to run the process;[28] the portion of overall facility CO_2 emissions targeted for capture has been estimated to be around 60%.[29]

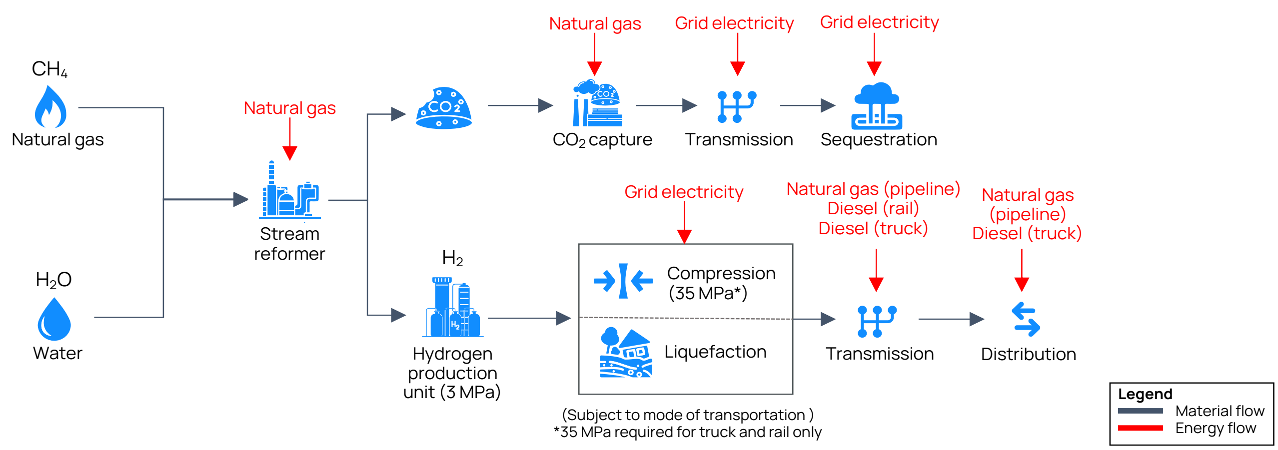
The technologies used in ATR and ESMR should enable hydrogen production facilities to achieve higher CO_2 capture rates. However, neither has been demonstrated at a commercial scale for hydrogen production.

ATR uses the same process material and energy flows as SMR, though the material and energy values differ. ESMR uses the same process material flows, but uses electricity—not natural gas—as the energy source for production, processing, and CCS. The technology-specific parameters used for SMR, ATR, and ESMR are shown in Figure 13. The process involved in SMR with CCS is illustrated in Figure 14.

FIGURE 13 - Methane reforming parameters summary

	STEAM METHANE REFORMING (SMR)	AUTOTRHERMAL REFORMING (ATR)	ELECTRIC STEAM METHANE REFORMING (ESMR)
Hydrogen produced (GJ)	1	1	1
Electrical energy (kWh)	-7.75	19.0	61.2
Natural gas (MJ)	1,235	1,207	1,008
CO_2 capture rate (%)	60	94	98.6
CCS electrical energy (kWh)	5.3	3.2	7.8
CCS natural gas (MJ)	104	0	0

FIGURE 14 - Steam methane reforming process



5.4.2 Methane pyrolysis

Methane pyrolysis technologies are at an earlier stage of development than methane reforming systems. A well-known company using methane pyrolysis at what could be considered a commercial level is the US-based company Monolith. The majority of methane pyrolysis projects are at a lab or pilot scale; FortisBC and Suncor, for example, are planning to use the Hazer process, which involves catalytic decomposition pyrolysis, in a project in BC.[30]

Methane pyrolysis uses 35% more natural gas than methane reforming. It also produces solid carbon—carbon black—as a by-product. The literature review indicates that all methods of methane pyrolysis claim to produce approximately three tonnes of solid carbon black per tonne of hydrogen.[31] Current CI modelling assumes the carbon black is landfilled (a waste product). However, a market for the solid carbon black may be required to reduce production costs; this would also lead to lower hydrogen CI, because pyrolysis emissions would be allocated between the hydrogen product and the useful solid carbon by-product (this allocation does not occur if the solid carbon is a considered a waste).

Figure 15 illustrates the process used for thermal decomposition, a variant of methane pyrolysis. Other variants—plasma decomposition and catalytic decomposition—use the same process material and energy flows, but the materials used and energy values differ. Figure 16 outlines the relevant parameters used.

FIGURE 15 - Thermal decomposition process

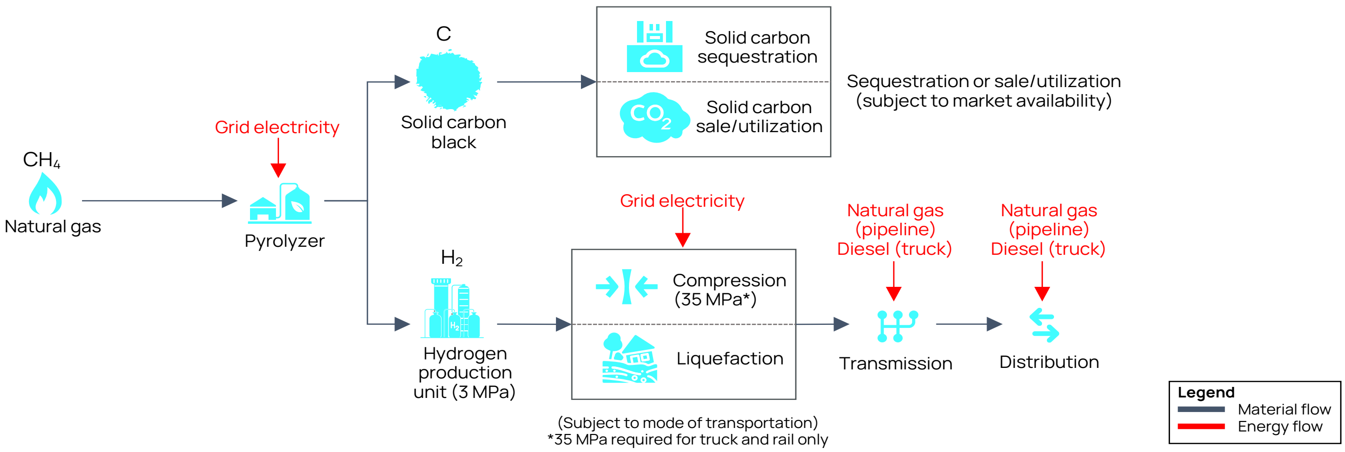


FIGURE 16 - Pyrolysis parmeters summary

	THERMAL DECOMPOSITION	PLASMA DECOMPOSITION	CATALYTIC DECOMPOSITION
Hydrogen produced (GJ)	1	1	1
Electricity (kWh)	141.0	105.8	17.6
Natural gas (MJ)	1,586.3	1,586.3	2,115.0
Solid carbon produced (kg)	21.2	21.2	21.2

5.4.3 Electrolysis

In 2020, the IEA reported that electrolysis technologies produced just 0.03% of the world's hydrogen for energy and chemical feedstock.[32] However, hydrogen production using electrolysis is expected to grow, since the technology can achieve very low CI when powered by low-carbon electricity.

Alkaline electrolysis is a mature technology, but it has demonstrated few efficiency gains over the past 20 years. Proton exchange membrane (PEM) electrolysis typically operates at lower temperatures and is slightly more efficient, but it can incur higher capital costs due to the use of precious metals such as palladium and platinum. Solid oxide electrolyzer cells (SOECs) are at an early stage of development and operate at temperatures much higher than either alkaline electrolysis or PEM; they also have the potential to achieve much higher efficiency that other methods of electrolysis. Indeed, increased market penetration by SOEC systems is likely to be the key driver of efficiency gains and CI reductions from electrolysis-based hydrogen production pathways. Danish company Topsoe recently announced its intention to build a factory to produce 500 MW of SOEC systems annually.[33]

Figure 17 illustrates the process material and energy flows associated with alkaline electrolysis. PEM and SOEC systems use the same process material and energy flows, though actual energy consumption values differ. The technology parameters are shown in Figure 18.

FIGURE 17 - Electrolysis process material and energy flows

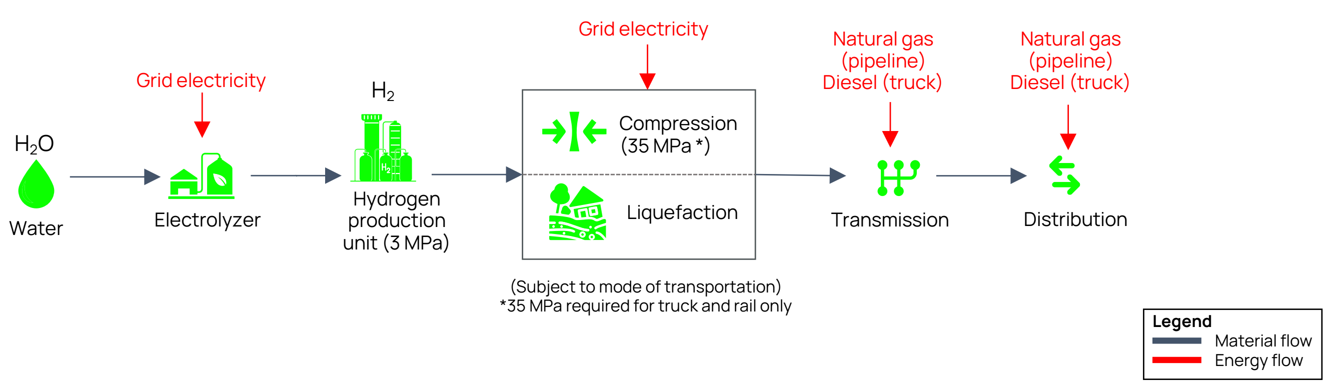


FIGURE 18 - Electrolysis parameters summary

	ALKALINE ELECTROLYSIS	PEM ELECTROLYSIS	SOEC ELECTROLYSIS
Hydrogen produced (GJ)	1	1	1
Electricity (kWh)	381	360	282

With electrolysis systems, lifecycle CI is significantly dependent on the CI of the electricity used to perform electrolysis. The CI of the water supply is excluded, but it is assumed that power requirements from manufacturing generally suffice for any water purification energy requirements.

5.5 Modelling with GHGenius

The lifecycle CI for each hydrogen production technology was modelled using GHGenius (ghgenius.ca), a lifecycle analysis (LCA) model developed by $(S\&T)^2$ Consultants Inc. that can analyze contaminant emissions related to the production and use of traditional and alternative transportation fuels.[34] GHGenius version 5.02 uses the 100-year GWP figures—without feedback—as set out in the IPCC's Fifth Assessment Report, completed in 2014. It has been assumed that carbon monoxide (CO) and non-methane hydrocarbons (NMHC) emissions ultimately oxidize to CO_2.

About GHGenius

» **The GHGenius model has been developed by $(S\&T)^2$ Consultants Inc. over the past 20 years; early versions of the model were supported by Natural Resources Canada. GHGenius uses an attributional LCA approach, which considers process material and energy flows within a defined system boundary, and the associated impacts of production, consumption, and disposal to determine the emissions directly associated with the lifecycle of a specified product.**

» **GHGenius can predict emissions for past, present, and future years (through to 2050), using historical data or correlations for energy and process parameters that change over time. Within each segment of the life cycle analysis, GHGenius determines the impact of co-products on the lifecycle emissions using the energy allocation approach. It is used in low-carbon fuel programs in BC, Alberta, Ontario, and Quebec.[35]**

5.6 CI modelling results

The modelling shows clear differences in the lifecycle CI of the three main hydrogen production technologies—methane reforming with CCS, methane pyrolysis, and electrolysis. The modelling also shows that transportation and newer technologies have a significant impact on lifecycle CIs within each technology pathway.

Transportation is a significant contributor to the lifecycle CI for hydrogen production pathways that involve greater distances between the point of production and the point of use. This is especially clear with respect to the SMR plus CCS pathway, which assumes that hydrogen is produced in northeastern BC and transported 1,200 km to the Lower Mainland. The modelling also shows that truck transportation makes a far larger contribution to lifecycle CI than transport by either rail or pipeline. Pipeline transportation is the least carbon intensive, but building a dedicated hydrogen pipeline from the production source to the demand centre is cost-prohibitive. Another option would be to blend hydrogen into the existing natural gas pipeline from the production source, but this would require significant blending of hydrogen at the transmission pressure. This would introduce several challenges, including the potential for catastrophic failure due to hydrogen embrittlement. See Section 6.1 for additional challenges and issues for blending into the transmission infrastructure.

Regardless of the technology "family," newer technology variants offer improved lifecycle CIs. This is particularly obvious in methane reforming variants: ATR and ESMR have less than half the CI of the more common and mature SMR. The differences are less stark when considering methane pyrolysis and electrolysis variants; however, these technology families are themselves comparatively newer than SMR.

To facilitate comparison of the modelled production pathways against current practices, a baseline was used that represents the currently more widespread method of hydrogen production: hydrogen produced from natural gas without the use of CCUS technologies, commonly referred to as "grey hydrogen." The lifecycle CI for this baseline is determined from GHGenius as 82.7 gCO_2e/MJ (HHV). This is within a similar range to the value used in the 2022 IEAGHG low-CI report,[36] which is 10.13 $kgCO_2e/kg\ H_2$ (equivalent to 71.74 gCO_2e/MJ on HHV basis), and represents grey hydrogen produced in the Netherlands. It should be noted that these CI values are cradle-to-plant gate, and thus do not account for any product transportation/distribution emissions.

Figures 19 and 20 illustrate the comparative lifecycle carbon intensities for each main hydrogen production pathway and their variants for both compressed and liquefied hydrogen. The charts distinguish between plant gate CI and downstream CI, which have differences primarily due to the different transportation modes for compressed and liquefied hydrogen.

FIGURE 19 - CI for compressed hydrogen (plant gate and downstream CI separated)

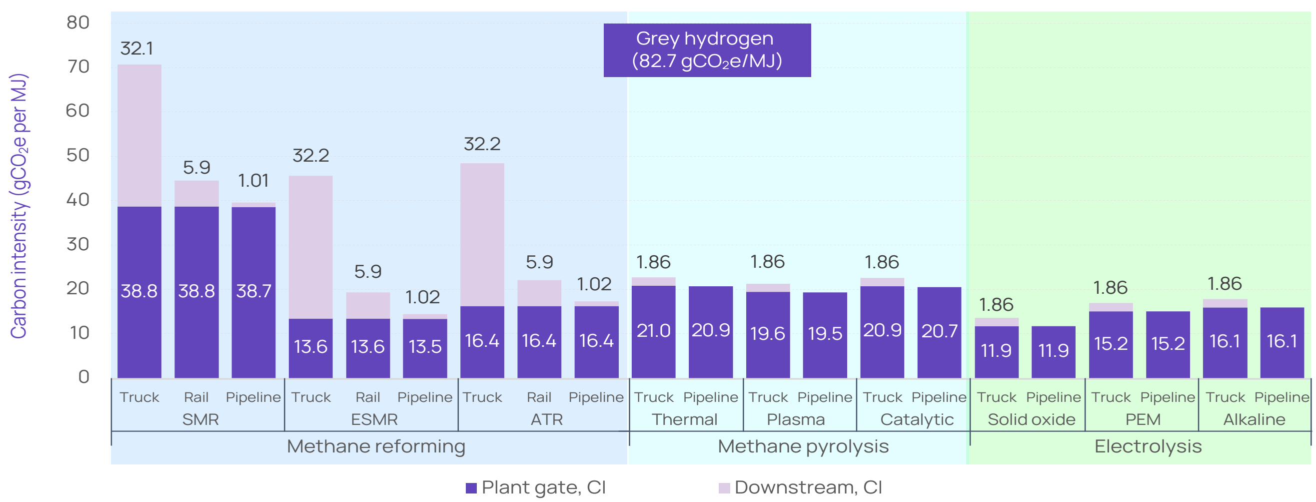
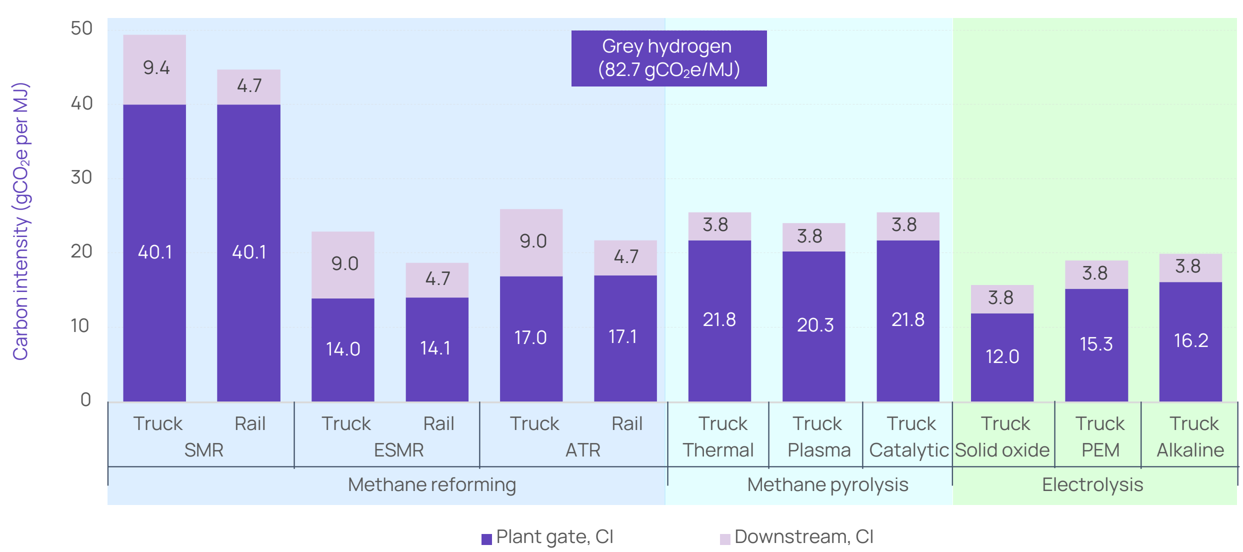


FIGURE 20 - CI for liquefied hydrogen (plant gate and downstream CI separated)



Leakage allocations

Plant-gate CIs for the same pathways differ between compressed and liquefied hydrogen; this is due to accounting for losses associated with all gaseous and cryogenic fuels when they are transferred from one tank to another and includes boil-off losses for cryogenic fuels. This means that to deliver one MJ of hydrogen to the user, more than one MJ of hydrogen must be produced at the plant, which causes higher plant-gate emissions.

For compressed hydrogen, the losses are a function of the number of transfers; for liquefied hydrogen, they are function of the number of transfers as well as the number of days in transport or storage. Figure 21 lists the assumptions considered in this study.

FIGURE 21 - Leakage allocation assumptions

	METHANE REFORMING PATHWAYS								
	SMR			ESMR			ATR		
	Truck	Rail	Pipeline	Truck	Rail	Pipeline	Truck	Rail	Pipeline
CCS rate (%)	60%	60%	60%	98.6%	98.6%	98.6%	94%	94%	94%
Transport fuel, diesel, CI (gCO_2e/MJ)	93	93	-	93	93	-	93	93	-
Transport distance (km)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200

	PYROLYSIS PATHWAYS						ELECTROLYSIS PATHWAYS					
	Thermal pyrolysis		Plasma		Catalytic		SOEC		PEM		Alkaline	
	Truck	Rail	Truck	Rail	Truck	Rail	Truck	Rail	Truck	Rail	Truck	Rail
Market for carbon black	No	No	No	No	No	No	-	-	-	-	-	-
Transport fuel, diesel, CI (gCO_2e/MJ)	93	-	93	-	93	-	93	-	93	-	93	-
Transport distance (km)	80	-	80	-	80	-	80	-	80	-	80	-

6. Hydrogen blending and its impact on emissions

This study explores the reduction in GHG emissions that would be possible by blending hydrogen into BC's natural gas network. BC is a major producer and exporter of natural gas. The province produced an average of 2,264 GJ of natural gas between 2016 and 2021, according to Statistics Canada,[37] only 15% of which was used for domestic, industrial, residential, or commercial consumption. BC's natural gas is produced in the northeast of the province, in the Western Canadian Sedimentary Basin, and transported across the province through a combination of three networks:

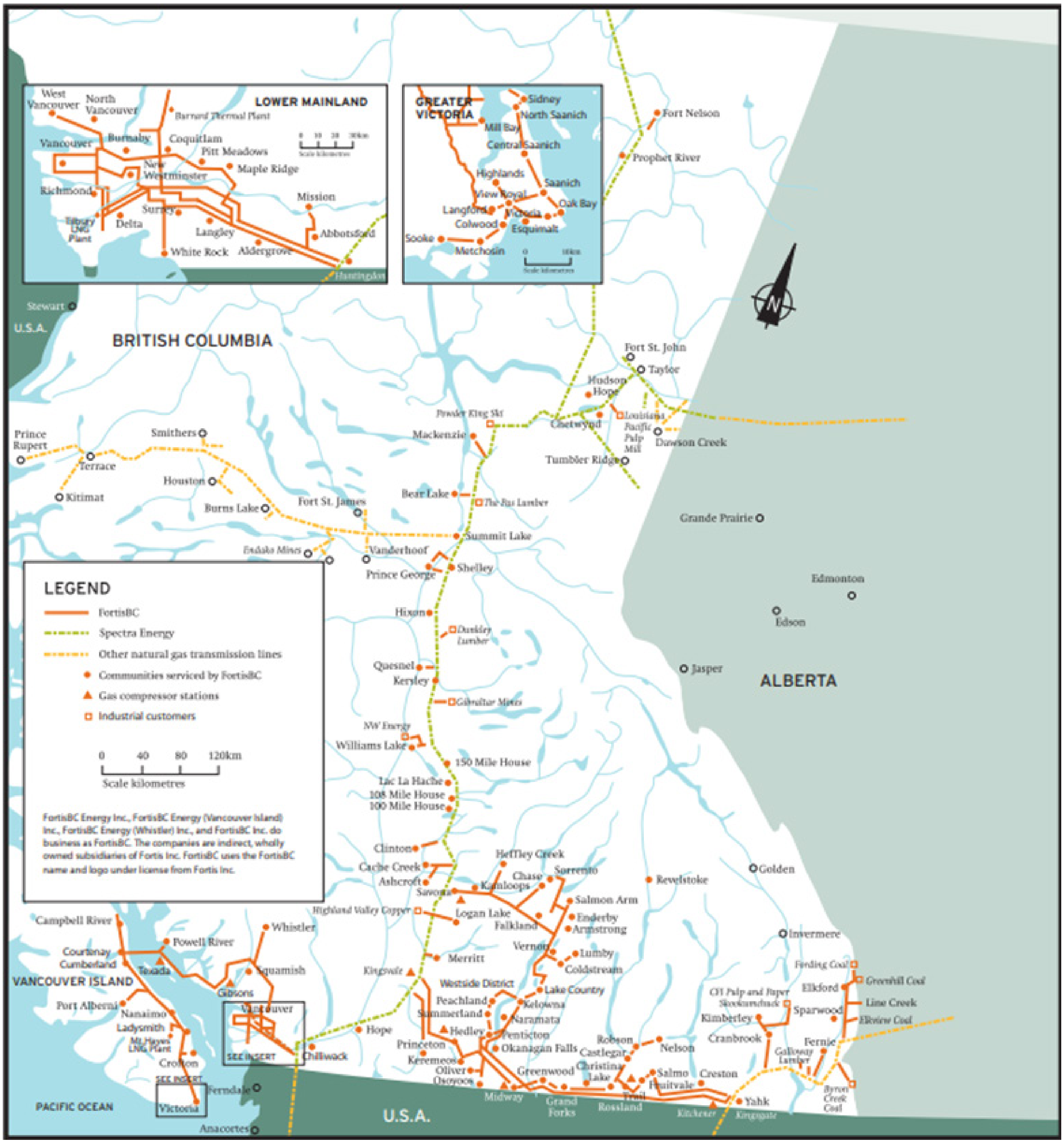
» The Westcoast pipeline, operated by Enbridge, which transports natural gas to consumers in BC, other Canadian provinces and territories, and the Canada-US border for export to the US.

» The PNG West pipeline, operated by Pacific Northern Gas, which connects to the Westcoast pipeline north of Prince George and runs west to Prince Rupert.

» The FortisBC natural gas distribution network, which extends across the Lower Mainland, the southern portion of the BC interior, and Vancouver Island.

This extensive transmission and distribution gas infrastructure could facilitate the use of hydrogen blending as a potential pathway to decarbonization of gas utility heating and other end uses. Figure 22 shows BC's grid and gas transmission lines (green and yellow) and distribution lines (orange). The transmission system infrastructure distributes natural gas at high pressure to the regional grid distribution network, which distributes the gas in a safe and reliable manner to residential, commercial, and industrial end users.

FIGURE 22 - BC pipeline system[38]



6.1 Potential challenges with hydrogen blending in transmission infrastructure

Hydrogen blending offers a low-CI method of transporting hydrogen along existing natural gas infrastructure to demand centres in metropolitan areas. This is particularly true for hydrogen produced using methane reforming with CCS in northeast BC, which is home to the province's natural gas resources and potential carbon sequestration locations. However, hydrogen blended into the Westcoast pipeline would have to be extracted from the system before any natural gas was exported to the US market. Furthermore, an analysis of the natural gas infrastructure's technical capability would be required because of the potential technical challenges associated with blending.

One of these challenges is hydrogen embrittlement, a phenomenon that causes catastrophic failures in metal and non-metallic materials that are constantly exposed to hydrogen and is often a limiting factor to the quantity of hydrogen that can be accommodated in natural gas infrastructure. Embrittlement is also specific to the pressures and materials under exposure, which means that its impact on transmission and distribution pipelines varies. Furthermore, embrittlement considerations apply to key infrastructure components, such as compressors, that play an important role in natural gas transportation.

Another challenge involves the separation of blended hydrogen in transmission lines prior to US export—specifically, limitations in the applicability of separation technologies at scale and increased energy requirements. These limitations are typically associated with the levels of selectivity (i.e., how much hydrogen can be separated) and purity (i.e., how pure the separated hydrogen is) achievable from separation technologies. This separation would likely require processing large volumes of natural gas, up to the entire export volume; which would result in significant energy and cost implications due to pressure losses from depressurization during separation, and subsequent post-separation repressurization for export.

In the early 2010s, the National Renewable Energy Laboratory (NREL) estimated the cost of hydrogen extraction using PSA units to be between $3.3 and $8.3 per kg of hydrogen, not including the cost of natural gas recompression for subsequent export. The NREL's estimate was based on extracting hydrogen from a 300-psi pipeline at 10% concentration.

6.2 Analysis approach and considerations

Data available from Statistics Canada and BC's three natural gas utilities differ in terms of the quantity of utility natural gas consumed in BC (see Figure 23); this difference is due to end users of gas that bypass local utilities and take natural gas directly from the gas transmission line.

Using Statistics Canada data, it was estimated that the lifecycle GHG emissions from BC domestic natural gas consumption are 20.76 million tonnes of CO_2e—or roughly 32% of the total 2020 GHG emissions reported in BC's GHG emissions inventory. This is calculated using a CI of 60 gCO_2e/MJ for conventional utility gas heating, which is obtained from modelling in GHGenius.

FIGURE 23 - BC natural gas consumption summary (in million GJ)

	PNG WEST	PNG NE	FORTIS	STATSCAN	DIFFERENCE
Residential	1.27	1.85	81.6	100	15.3
Commercial	1.61	1.69	57.9	66	4.8
Industrial	3.84	1.85	89.5	181	85.1
Transportation fuel	-	-	2.5	-	-2.5
LNG	-	-	0.2	-	-0.2
Total	6.7	5.4	231.7	347	103

It should be noted that given the relatively high energy density of natural gas in BC (40.9 MJ/m^3)[i] and hydrogen's energy density of 12.7 MJ/m^3, a 20% by volume hydrogen blend translates to a 6.2% blend by energy content. This implies that the maximum emissions reduction achievable from utility gas hydrogen blending is 6.2% (assuming the lifecycle CI of the hydrogen is zero). With BC's total gas consumption of 325 million GJ annually,[ii] this would result in a demand of 21.5 million GJ of hydrogen to achieve 20% blending by volume.

The analysis completed for this study assumes that hydrogen blending occurs in the natural gas distribution network due to the potential challenges associated with blending hydrogen into existing natural gas transmission networks described in Section 6.1. This is consistent with the hydrogen blending projects currently being considered internationally, as described in detail in Section 4.3.

Hydrogen produced from methane reforming with CCS is assumed to occur in northeast BC with subsequent liquefaction and rail transport to the Lower Mainland for blending into the existing natural gas distribution infrastructure (to avoid problems identified with hydrogen blending in the natural gas transmission system). Hydrogen produced from pyrolysis and electrolysis is assumed to occur in the Lower Mainland with potential to be blended into the distribution network.

6.3 Blending scenarios and analysis results

Four hydrogen blending scenarios were developed using the most likely scenarios in BC based on the jurisdictional scan and stakeholder discussions held during the development of this report. These scenarios are based on permutations of hydrogen production technologies and their technology assumptions.

Scenario 1: High efficiency

In this scenario, BC's discounted electricity is assumed to be maximized, at the highest electrolysis efficiency, and hydrogen is produced from a mix of electrolysis, methane reforming, and pyrolysis technologies. Hydrogen from electrolysis is produced using the highest efficiency electrolysis pathway, solid oxide fuel cell technology, using 1,500 GWh of electricity, which is the maximum quantity of discounted electricity available in BC.[iii] The balance of the hydrogen is produced from very low-CI SMR and pyrolysis

[i] As measured at Huntingdon, the Lower Mainland delivery point, over the past 12 months.
[ii] The maximum number that could be generated based on incremental power that will be available when Site C is active.
[iii] Introduced under the Clean Industry and Innovation Rate, electricity cost is discounted for industrial customers involved in hydrogen production from electrolysis and synthetic fuel production from hydrogen

technologies, which results in hydrogen blending at 20% by volume. Solid oxide has the highest electrolysis efficiency, but as it is not yet proven in commercial operations, it is not used in subsequent scenarios.

Scenario 2: Electrolysis only

In this scenario, it is assumed that hydrogen is produced exclusively from electrolysis, using the PEM electrolysis pathway. Here, it is assumed that the entire 5,100 GWh of energy from BC Hydro's expansion (Site C) is used to produce hydrogen. This electricity quantity produces 18.1 million GJ of hydrogen, which results in hydrogen blending at 16.9% by volume; this is the maximum that could be generated from the incremental power provided when Site C comes on stream.

Scenario 3: Mixed reduction

In this scenario, it is assumed that hydrogen is produced from a mix of electrolysis, methane reforming, and pyrolysis technologies. Hydrogen from electrolysis is produced using the PEM pathway, using 1,500 GWh, the current maximum quantity of discounted electricity in BC. The balance of the hydrogen is produced from very low CI steam methane reforming; this results in hydrogen blending at 20% by volume.

Scenario 4: Proven technology only

In this scenario, it is assumed that hydrogen is produced using pathways with parameters that are more reflective of current levels of technology. Hydrogen is produced using the PEM and steam methane reforming pathways. Pyrolysis is excluded in this scenario, as it is not considered a proven technology at scale today; this results in hydrogen blending at 20% by volume.

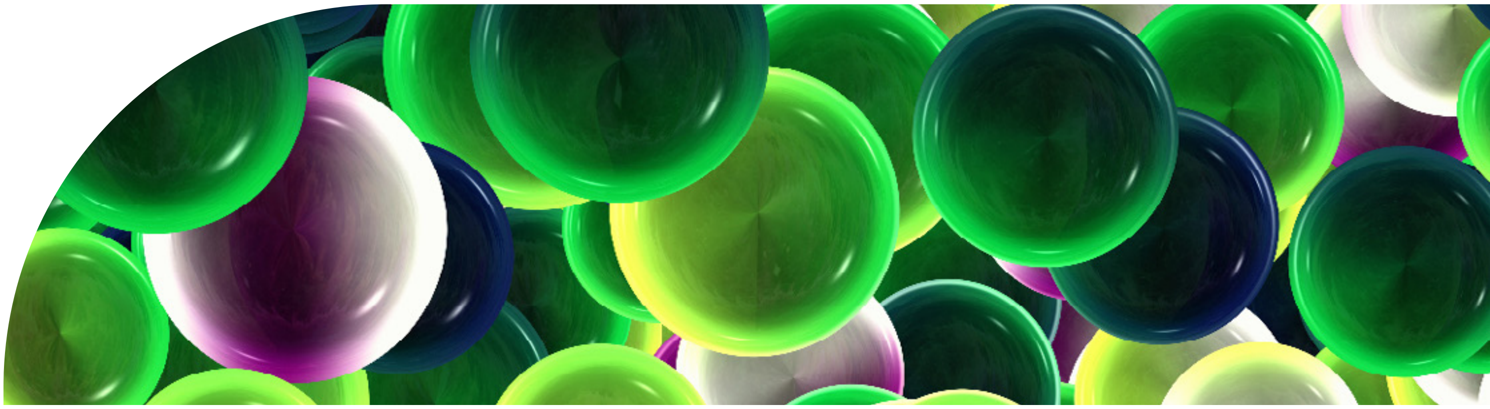


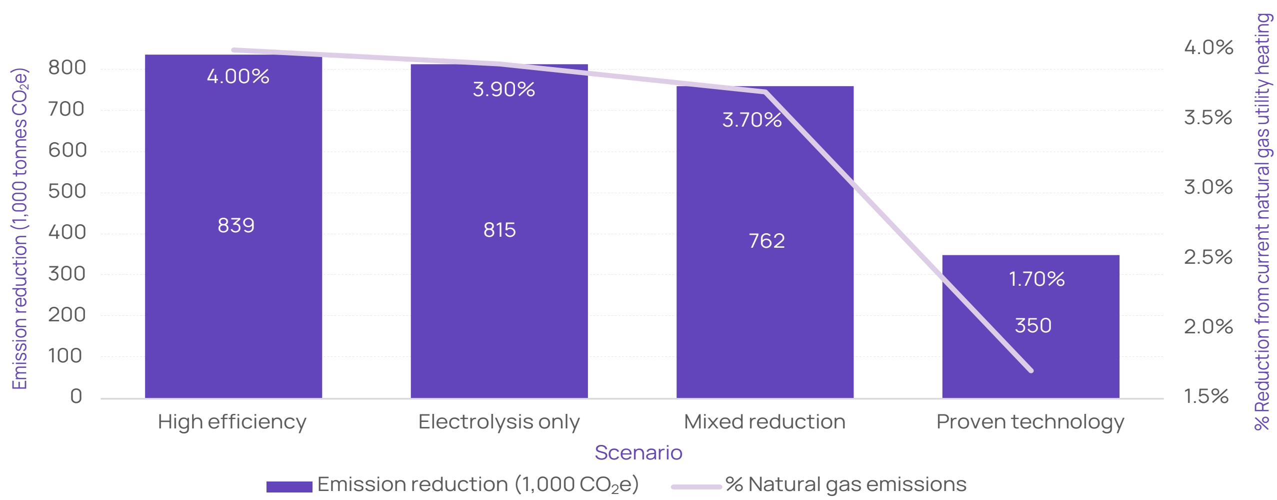
FIGURE 24 - Hydrogen blending analysis production technologies and key parameter assumptions

	SCENARIO 1: HIGH EFFICIENCY	SCENARIO 2: ELECTROLYSIS ONLY	SCENARIO 3: MIXED REDUCTION	SCENARIO 4: PROVEN TECHNOLOGY
Hydrogen production technologies	21.5 million GJ of hydrogen: » Electrolysis: 5.4 million GJ » Reforming: 12.9 million GJ » Pyrolysis: 3.2 million GJ	18.1 million GJ of hydrogen: » Electrolysis: 18.1 million GJ	21.5 million GJ of hydrogen: » Electrolysis: 3.9 million GJ » Reforming: 16.5 million GJ » Pyrolysis: 1.1 million GJ	21.5 million GJ of hydrogen: » Electrolysis: 3.9 million GJ » Reforming: 17.6 million GJ
Key technology parameter assumptions	Electrolysis: solid oxide fuel cell, CI: 12 gCO_2e/MJ Reforming: SMR, 89% CO_2 capture, CI: 27 gCO_2e/MJ Pyrolysis: plasma pyrolysis, market for carbon black, CI: 12 gCO_2e/MJ	Electrolysis: PEM, CI: 15 gCO_2e/MJ	Electrolysis: PEM, CI: 15 gCO_2e/MJ Reforming: SMR, 89% CO_2 capture, CI: 27 gCO_2e/MJ Pyrolysis: plasma pyrolysis, no market for carbon black, CI: 20 gCO_2e/MJ	Electrolysis: PEM, CI: 15gCO_2e/MJ Reforming: SMR, 60% CO_2 capture, CI: 50 gCO_2e/MJ

6.4 Hydrogen blending analysis: results and conclusions

From the scenarios considered, the analysis shows that blending hydrogen into the province's natural gas network for utility heating can achieve emission reductions of 350,000 to 815,000 tonnes of CO_2e per year. This results in a 0.5% to 1.3% reduction in overall BC GHG emissions, and a 1.7% to 4% reduction in emissions from BC's utility natural gas system (see Figure 25).

FIGURE 25 - Emissions reductions from utility heating for blending scenarios considered



6.5 Hydrogen blending considerations

The BC Hydrogen Strategy mentions blending hydrogen with natural gas as a potential means to decarbonize utility heating. The CleanBC Roadmap to 2030 commits to implementing a GHG emissions cap for natural gas utilities, allowing utilities to determine how best to meet the target. Renewable gases, such as hydrogen, can support utilities in meeting this commitment, as described in Section 6.0 of this report. However, maximum emission reductions from hydrogen blending in the most aggressive scenario amounts to a decrease of 839,000 tonnes of CO_2e, or a 4% per year reduction from current utility heating emissions.

The objectives and deployment of hydrogen production require careful consideration for successful implementation. Although low-carbon hydrogen production is possible, as shown in this study, the subsequent use of hydrogen in utility blending does not result in the highest emission reduction benefit. However, hydrogen blending could be considered to serve other objectives, such as creating scaled offtake to incentivize production while demand develops for end-uses that provide more effective emission reductions (e.g., transportation and industrial applications).

As hydrogen is a nascent industry, one of its challenges is in incentivizing demand. The benefits accruing from increased demand include promoting the scaling up of production and decreasing the production cost, which translates to more affordable costs for consumer adoption. The initial demand for hydrogen production could be driven by hydrogen blending.

Challenges to hydrogen blending in utility gas infrastructure have been noted in this report. However, an alternative perspective may be to consider 100% hydrogen conversions or sector or hub approaches where hydrogen blending is targeted at specific applications such as co-location with industrial hubs and large natural gas consumption sites. In this implementation, large customers would drive hydrogen production through their usage.

While blending hydrogen with natural gas is a consideration, alternative uses for hydrogen would have a greater impact on carbon emissions reductions in BC. The following sections describe additional considerations for hydrogen blending.

6.5.1 Safety

Hydrogen blending into existing natural gas infrastructure will require consideration of its impacts on end-use appliances. Safety and regulatory organizations are at varying stages of research and trials/testing that are required to develop safety regulations and codes. However, the vast amount of natural gas appliances in industrial and residential use suggests that it would take some time for safety codes and standards to be harmonized. In addition, hydrogen blending is tested at different percentages, thus adding further complexity to the process. A minimum “safe” blending percentage may be established after preliminary research has been conducted, prior to further work on establishing safety at higher blending percentages.

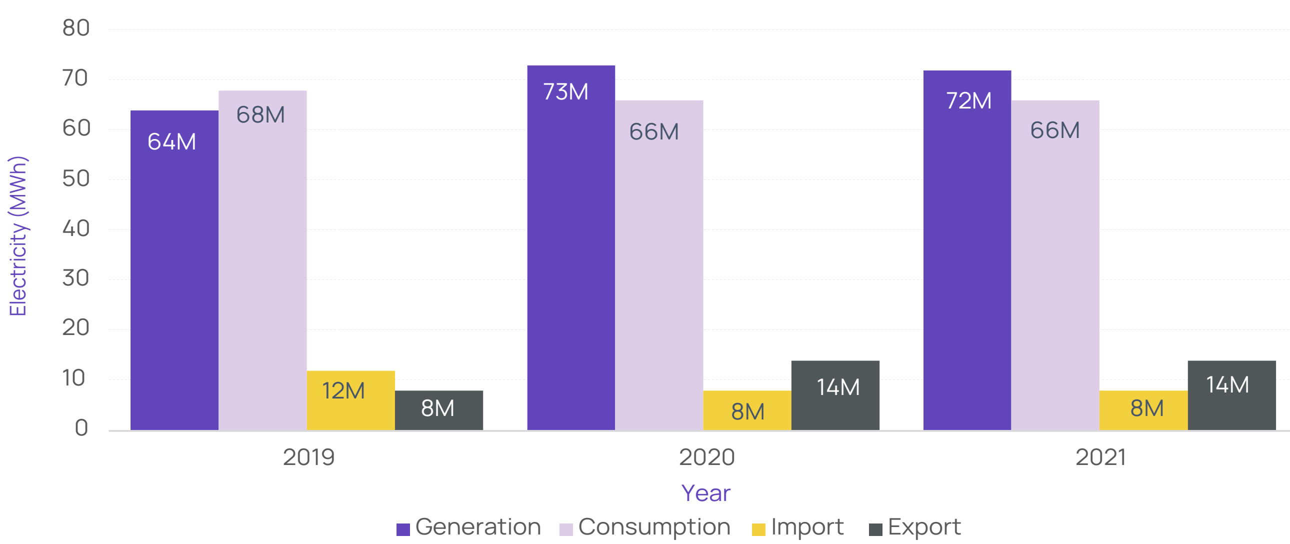
6.5.2 Scaling technology and distribution

There is the potential that in the future, efficiency gains through scaling of existing hydrogen production technologies could ultimately match the CIs that are being observed at pilot and demonstration scales. Improvements may also apply to separation technologies, which would be required for hydrogen blended within the existing natural gas transmission infrastructure.

6.6 Best use of electricity

There are minimal limitations for hydrogen production pathways that use natural gas as a feedstock as BC is a significant producer and exporter of natural gas—the province's natural gas consumption represents only 15% of total production. However, this energy surplus is not necessarily the case with respect to electricity. At different times, BC may be a net exporter or importer of electricity, primarily due to fluctuations in precipitation levels and the varying quantities of hydroelectricity that can be generated as a result (Figure 26).

FIGURE 26 - BC electricity supply and demand, 2019-2021[39]

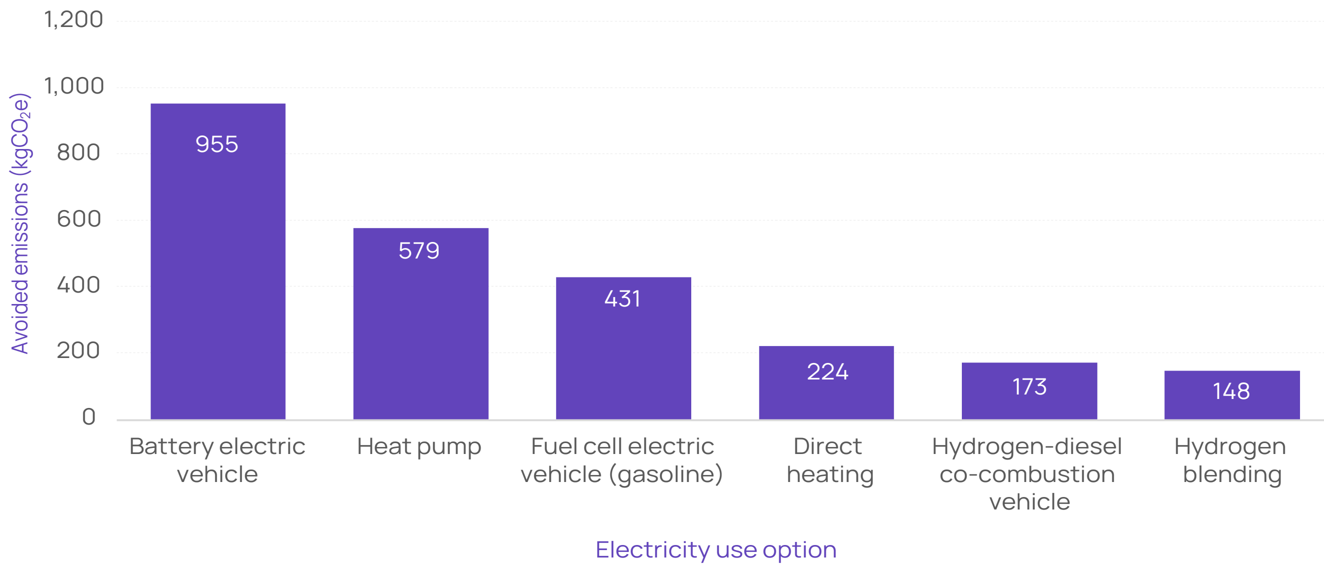


Given that clean electricity in BC is a strategic, valuable, and limited resource, the opportunity cost of using electricity for hydrogen production was compared to other potential alternative uses for electricity and the associated impact on emissions reduction. For illustration purposes, these options are compared on a 1 MWh basis of base load energy, and are compared to hydrogen blending produced via electrolysis technology, the least carbon intensive hydrogen production technology considered in this report. The alternative electricity-use options and the emission sources they displace are illustrated in Figures 27 and 28.

FIGURE 27 - Alternative electricity uses: Emission sources displaced and avoided emissions

ELECTRICITY-USE OPTIONS	FUEL DISPLACED	AVOIDED EMISSION (kg CO_2e)
1 MWh for battery electric vehicle	10.8 GJ gasoline	955
1 MWh for heat pump	10.8 GJ NG	579
1 MWh for fuel cell electric vehicle	5.1 GJ of gasoline	431
1 MWh for direct utility heating	4.5 GJ NG	224
1 MWh for H_2 for diesel co-combustion	2.3 GJ of diesel	173
1 MWh for hydrogen for utility gas blending	3.2 GJ NG	148

FIGURE 28 - Avoided emissions by electricity use option



The results of the analysis show that while hydrogen produced using electrolysis may result in lower CIs in utility heating, it may not be the most effective use of clean electricity resources from an emissions perspective. This is especially apparent when compared to electricity-use options such as battery electric vehicles and heat pumps. However, blending has strategic uses that indirectly support emissions reductions for other hydrogen applications. Using the existing gas infrastructure to blend hydrogen serves as a storage buffer for early-stage hydrogen production when connections to end-use demand applications are not yet developed at scale. Utilities can also use the pooled commodity cost of gas for all customers to include hydrogen, and offer a lower blended rate to kick-start the hydrogen economy in BC.

7. Opportunities to reduce hydrogen CI in BC

BC's Hydrogen Strategy commits to working with other jurisdictions to develop a common methodology for measuring and verifying the CI of hydrogen. Furthermore, BC will consider establishing a CI threshold and reduction schedule out to 2050 to ensure BC's hydrogen economy helps decarbonize energy systems in support of provincial climate goals. The analysis contained in this report shares a regional perspective and understanding of the CI of the identified hydrogen production technologies and the emissions impact from subsequent hydrogen blending in utility gas infrastructure, along with other considerations for CI reductions out to 2050.

7.1 The potential for CI reductions over time

There are many uncertainties that may affect the potential reduction of hydrogen CI over time beyond advances in technology maturation and innovation. Factors associated with current/potential policy, technology maturity, and market availability have been identified as having the potential to reduce the lifecycle CI associated with the hydrogen production technologies considered in this report.

A summary of the factors affecting carbon intensity and the resulting reductions, depending on production pathway and quantified in GHGenius, is provided in Figures 29 and 30. The potential reduction factors are described in further detail in Sections 7.2, 7.3, and 7.4.

FIGURE 29 - Policy, technology, and market factors that could impact hydrogen CI reduction over time, by pathway

FACTOR	DEPENDENT ACTION FOR IMPLEMENTATION	CATEGORY	LIFECYCLE IMPACT (gCO_2e/MJ	TIMELINE
50% reduction in natural gas fugitive emissions	Fugitive emission limit Electrification of production fields	Policy	1–1.4	2030
Increase in CO_2 capture rate from 60% to 89%	Technological improvement in CO_2 capture rate	Technology	1–18	Long-term (beyond 2040)
Energy reduction from 0.26 to 0.15 joules electricity per joule hydrogen	Technological improvement in hydrogen liquefaction energy	Technology	1.7	Long-term (beyond 2040)
Emission allocation for useful by-product	Market availability for solid carbon by-product	Market	7–10	2050
Diesel CI of 75.81 gCO_2e/MJ by 2030	BC LCFS implementation	Policy	0.2–7*	2030

Values identified are potential reductions beyond the values provided in Figure 19
**Would only be applicable post-plant gate*

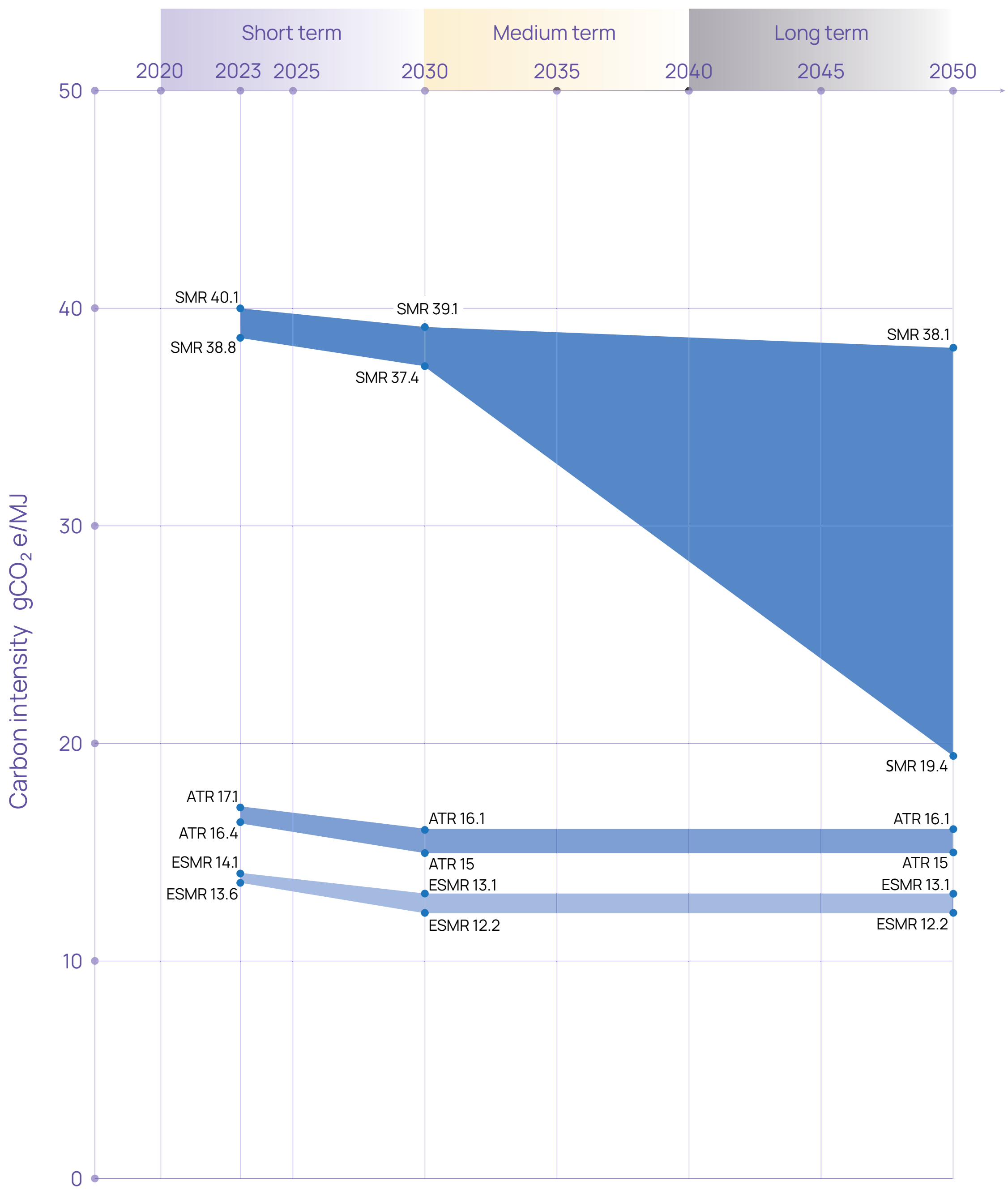
FIGURE 30 - Policy, technology, and market factors mapped to relevant hydrogen production technology

		Lifecycle impact		Methane reforming technologies			Pyrolysis technologies			Electrolysis technologies		
		Cradle-to-gate	Downstream	SMR	ATR	ESMR	Thermal	Plasma	Catalytic	Alkaline	PEM	SOEC
Policy factors	Carbon intensity of natural gas	●		●	●	●	●	●	●			
	Carbon intensity of transportation fuels		●	●	●	●	●	●	●	●	●	●
Market factors	Market availability for solid carbon	●					●	●	●			
Technology factors	CO_2 carbon capture rate	●		●	●	●						
	Hydrogen liquefaction energy		●	●	●	●	●	●	●	●	●	●

Figures 31, 32, and 33 illustrate achievable CIs for hydrogen production pathways over the medium term (2030 to 2040) and long term (2040 to 2050). These CIs result from the application of the potential reduction factors (excluding downstream factors) described in Figures 29 and 30, to the current-day CI modelling results computed in this study (Figures 19 and 20); thereby, projecting a hydrogen reduction schedule over time from a cradle-to-plant gate perspective.

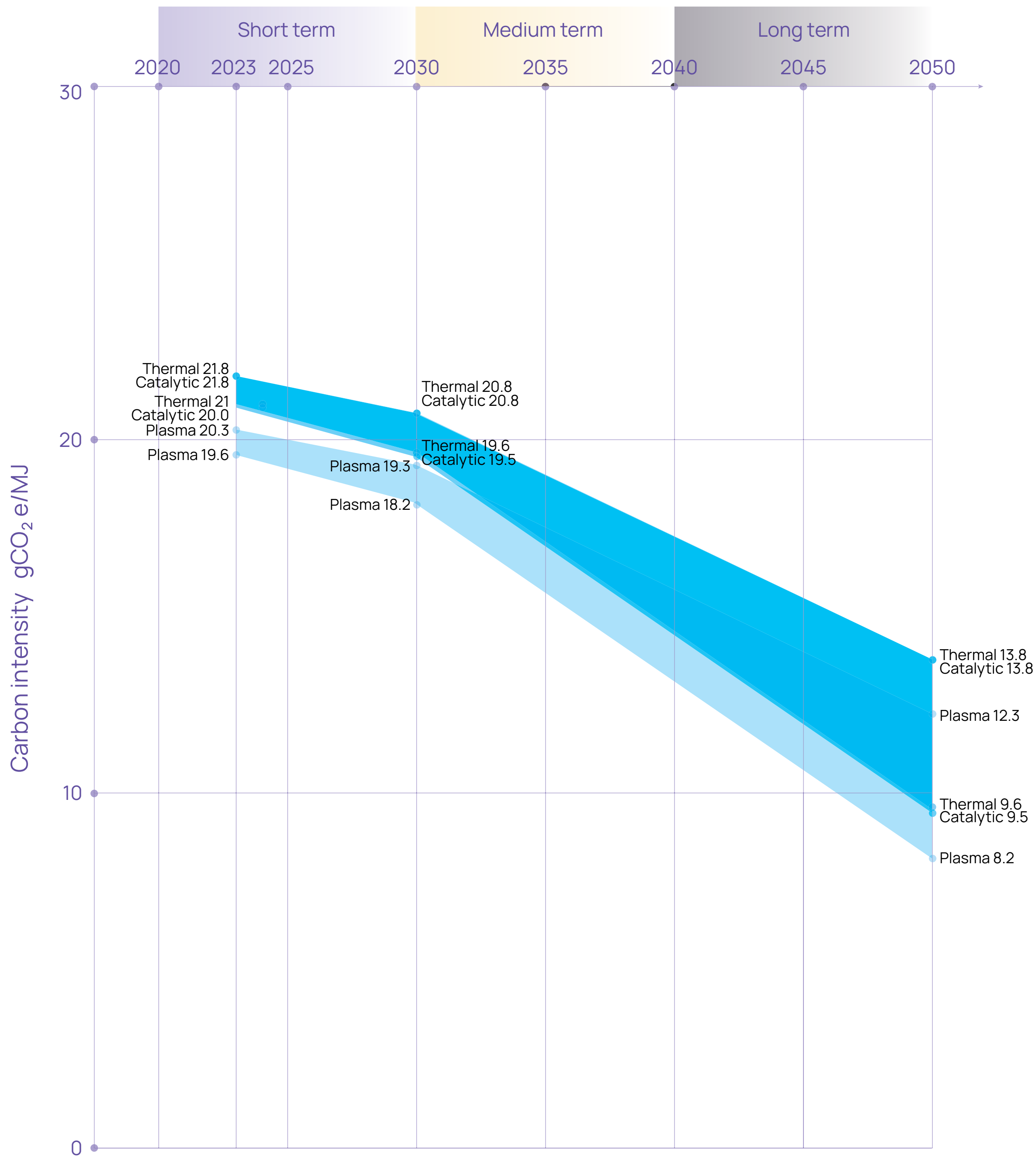
The reduction schedules are directional, as they are subject to assumed timing/implementation of the reduction factors. Factors identified as downstream impacts have not been calculated in the plant gate CI calculations and reductions in this report. Furthermore, the presented schedules are exclusive of hydrogen compression and liquefaction, which are attributed to downstream carbon intensity beyond plate gate. The potential reduction of CI of electricity has not been modelled based on the regulated nature of BC's power market.

FIGURE 31 - Incremental CI reduction schedule summary—methane reforming tech



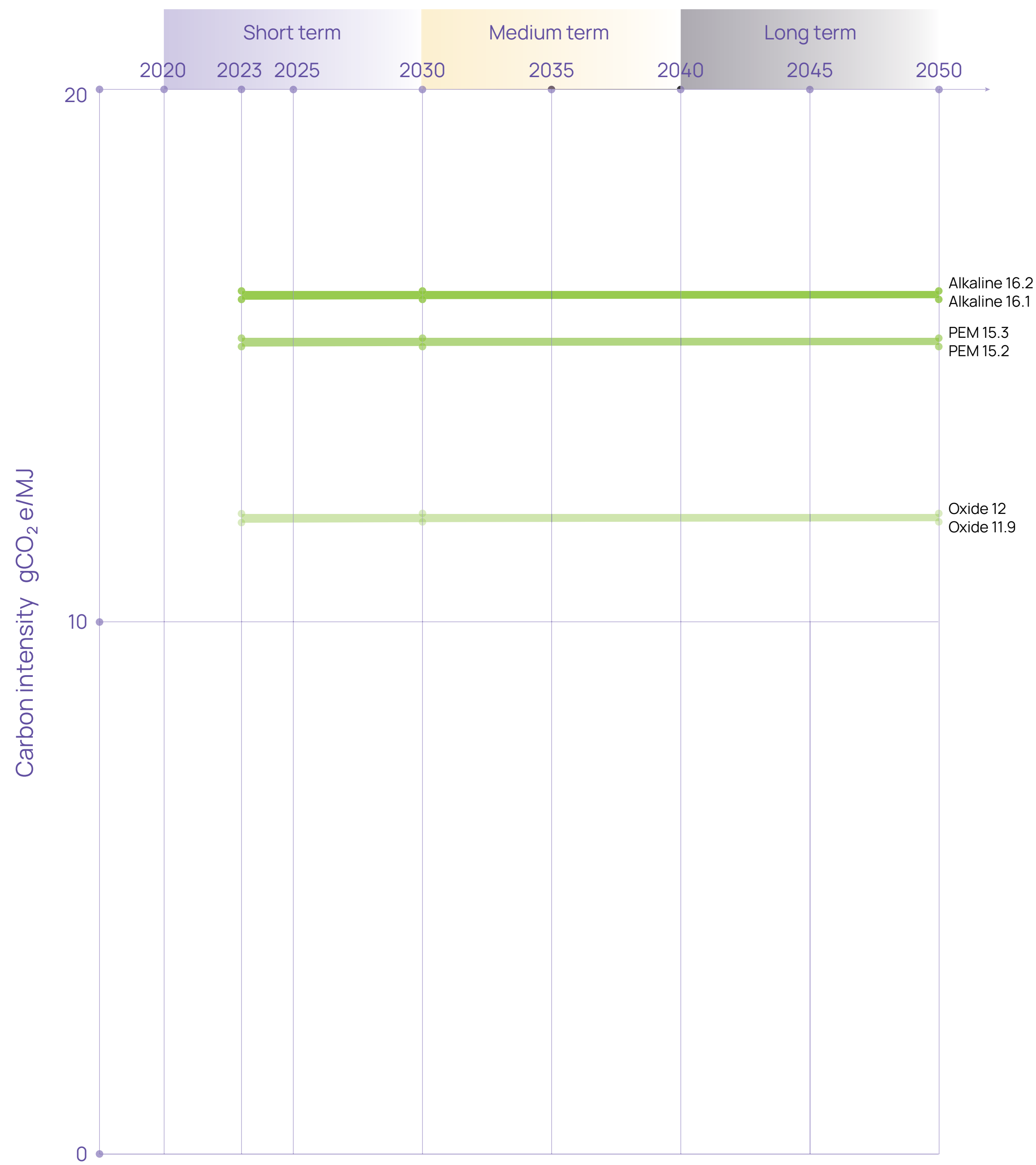
*only reduction factors up to the plant gate (within cradle-to-plant gate boundary) are considered in this reduction schedule

FIGURE 32 - Incremental CI reduction schedule summary—methane pyrolysis



*only reduction factors up to the plant gate (within cradle-to-plant gate boundary) are considered in this reduction schedule

FIGURE 33 - Incremental CI reduction schedule summary—electrolysis



*only reduction factors up to the plant gate (within cradle-to-plant gate boundary) are considered in this reduction schedule

7.2 Policy factors

- **Natural gas fugitive emission reductions:** Reductions in emissions associated with natural gas production would lead to lower CI values for hydrogen production pathways that use methane as a feedstock. Potential policy drivers include the electrification of upstream oil and gas fields or mandated fugitive emissions limits.

  While the nature of fugitive emissions makes accurate quantification challenging, improved monitoring coupled with actions such as fugitive limits and electrification of natural gas fields provide credible reduction pathways. Fugitive emission rates in GHGenius, based on historical data from Statistics Canada and the Alberta Energy Regulator,[40] are shown in Figure 34.

FIGURE 34 - Fugitive emission rates

STAGE	IMPORT/EXPORT PERSPECTIVES
Natural gas production	0.288%
Natural gas processing	0.002%
Natural gas transmission	0.05%
Natural gas distribution	0.06%

A 50% reduction in natural gas production translates to an impact on hydrogen CIs that ranges from 1.0 to 1.4 gCO_2e/MJ, depending on the natural gas quantity used in the hydrogen production process.

- **BC Low Carbon Fuel Standard (LCFS):** Further reductions could be possible beyond the plant gate. The LCFS is a provincial emission reduction policy aimed at decarbonizing the transportation sector by requiring annual reductions in the CI of diesel and gasoline class fuels. The LCFS has a CI target of 75.81 gCO_2e/MJ in 2030.[41]

  The LCFS target, if achieved, could translate to reduced emissions from truck- and rail-based supply of produced hydrogen. GHGenius uses a diesel CI of 93 gCO_2e/MJ; therefore, a reduction of approximately 20% is achievable, resulting in a range of 0.2–7 gCO_2e/MJ by 2030. Since hydrogen is a substitute for either gasoline or diesel, reductions in its CI can help fuel suppliers reach their mandated reductions in each of these categories when supplied for transportation.

7.3 Technology factors

- **CO_2 capture rate:** This is an area that can significantly reduce lifecycle emissions for methane reforming-based hydrogen production technologies. These reductions can be driven by improvements in the reliability of nominal capture rates over a project's lifetime and the scope of total facility emissions targeted; these are anticipated to develop with maturity of carbon capture projects and technologies.[42]

  A 2022 review by the Institute for Energy Economics and Financial Analysis (IEEFA) notes that a 90% CO_2 capture rate, commonly considered the prime target for blue hydrogen, is being projected for future projects, such as Air Products' planned hydrogen facility in Ascension Parish, Louisiana (2025-2026).[43] However, it cautions that current projects, such as Alberta's Quest and Texas's Port Arthur, that have shown CO_2 capture rates of 75% and 80%, respectively, on process streams (but do not capture CO_2 from fuel/combustion sources) target only around 60% of the total facility CO_2 emissions. Furthermore, due to process constraints, Alberta Quest's CO_2 capture rate has fallen well below 60% in some years, with rates reported as low as 30-40%. This has created uncertainty around the reliability of the CO_2 capture rates and potential for decline over time.

  GHGenius modelling has used a CO_2 capture rate of 60% for SMR, 94% for ATR, and 98.6% for ESMR. ATR and ESMR are newer technologies with higher projected CO_2 capture rates, but these high rates have not yet been demonstrated at a commercial scale. For SMR, an improvement in the CO_2 capture rate from 60% to 89% translates to an impact on hydrogen CIs of around 17-18 gCO_2e/MJ.

- **Hydrogen liquefaction energy:** Possible technology reductions beyond the plant gate could include the reduction of hydrogen liquefaction energy requirements. Current practical liquefaction energy requirements are around 0.26 joules electricity/joule of hydrogen, which is the value in GHGenius. Research on liquid hydrogen reports that some recent plants used as much as 0.35 joules electricity/joule of hydrogen.[44] However, the US DOE has set a goal of 0.15 joules electricity/joule of hydrogen.[45] If this is achieved, it would reduce the CI of liquid hydrogen pathways by 1.7 gCO_2e/MJ.

7.4 Market factors

» **Market availability for solid carbon:** Potential use of the solid carbon by-product of the pyrolysis process has significant implications for lifecycle accounting. If an end use is available for the by-product (solid carbon), a portion of the emissions associated with hydrogen production emissions is allocated to this by-product. This does not occur when the by-product is landfilled or otherwise unused. This translates to an impact on hydrogen CIs that ranges from 7 to 10 gCO_2e/MJ, depending on the natural gas quantity used in the hydrogen production process.

8. Conclusion: Supporting BC's greenhouse gas strategy and climate ambitions

The objective of this study has been to identify, model and establish a CI threshold for hydrogen production pathways most relevant to BC today. This study supports the goals of BC's Hydrogen Strategy, which focuses on defining and providing support for low-carbon hydrogen pathways, with an "ultimate objective of identifying long-term targets for declining carbon intensity consistent with net-zero emissions by 2050." This objective is mirrored by Canada-wide objectives to focus on the production of lower-CI hydrogen over time, as the hydrogen market matures.

Based on the modelling completed for this study, hydrogen produced in BC today can achieve cradle-to-plant-gate CIs that range from 11.9 gCO_2e/MJ to 40.1 gCO_2e/MJ, as set out in Figure 35 below.

FIGURE 35 - Achievable cradle-to-plant-gate CI ranges in BC today

	LOW END CI: SOLID OXIDE ELECTROLYSIS	HIGH END CI: SMR + CCS (60% CO_2 Capture)
Compressed hydrogen	11.9 gCO_2e/MJ	38.8 gCO_2e/MJ
Liquefied hydrogen	12.0 gCO_2e/MJ	40.1 gCO_2e/MJ

By 2030, it is anticipated that plant-gate CIs for hydrogen from solid oxide electrolysis and SMR with CCS would be in the range of 11.9 to 39.1 gCO_2e/MJ, respectively, driven primarily by reductions in natural gas fugitive emissions, improved CO_2 capture rate, and solid carbon market availability for reforming and pyrolysis-based pathways. For electrolysis, the potential reduction factors identified are post-plant gate, which means that this study has not predicted the potential to reduce CI up to plant gate for this pathway, largely due to the regulated nature of BC's power market.

By 2040, and beyond to 2050, CI thresholds for hydrogen in BC could be reduced to 12.2, 8.2, and 11.9 gCO_2e/MJ for pathways in methane reforming, methane pyrolysis, and electrolysis technologies, respectively, driven primarily by increased carbon capture rates, and for pyrolysis, market availability for solid carbon.

The work undertaken as part of this study can be leveraged to develop policy options, identify and select technologies, and invest in specific hydrogen pathways to produce low-CI hydrogen in BC.

8.1 Region-specific and consistent determination of hydrogen CI

As documented in this study, there has been a need to create a consistent understanding of potential CIs across different hydrogen production pathways in BC. The data parameters and assumptions used in this study are based on BC-specific material and energy characteristics and reflect current (as of October 2022) technology capabilities from both literature and stakeholders. The data in this report can be used to identify parameters for future low-CI hydrogen quantification and to help quantify current CI as required by the BC LCFS program.[46]

Policy makers can implement policy and other frameworks to regulate and incentivize the lowering of CI in BC's hydrogen supply. The CI of natural gas pathways can be effectively reduced by decreasing fugitive emissions, as well as by increasing CCS rates and solid carbon uses. Identifying and setting CI thresholds for low carbon hydrogen, coupled with realistic yet stringent reduction schedules, can help the province balance its economic and climate goals, and ensure the growth of BC's low carbon hydrogen economy that contributes to net-zero by 2050.

8.2 Focusing on pathways with an ability to result in lower CI

This study identifies parameters that are determining factors in helping to achieve the potential low-carbon performance of hydrogen pathways, including nascent pathways (ATR, ESMR, SOEC, and pyrolysis), and the technology, policy, and market factors described in Section 7. Monitoring these drivers for lower CI can also help guide expected decarbonization plans and inform future decision-making for all stakeholders.

Technology developers can also continuously improve the capture rates of SMR technologies, explore hydrogen and CO_2 liquefaction improvements, and advance pyrolysis, electrolysis, and other emerging technologies to lower the CI of hydrogen production (as described in Section 7).

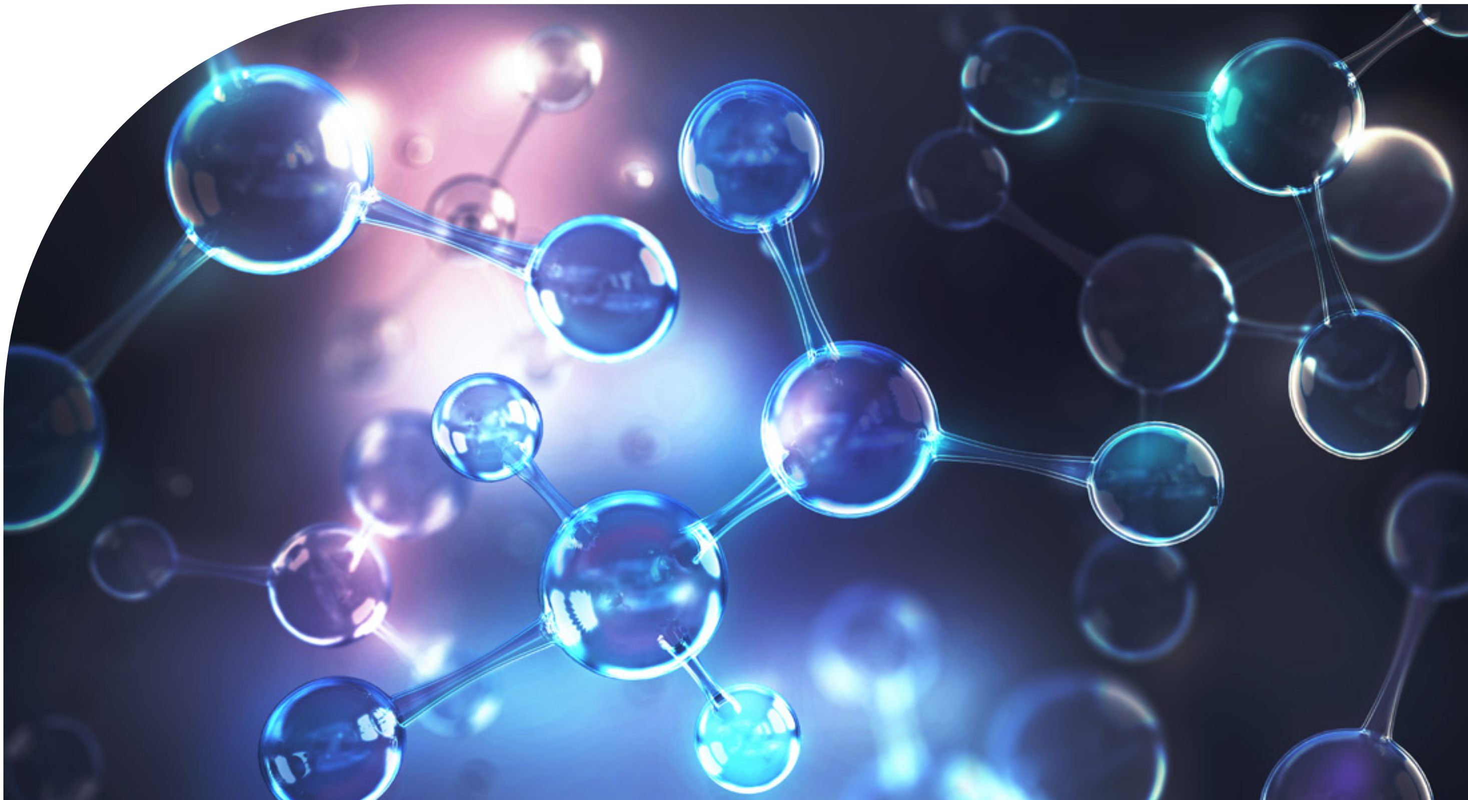
8.3 BC's hydrogen strategy and GHG reduction targets are ambitious—and achievable

The GHGenius modelling undertaken as part of this study can provide inputs to model new options to achieve BC's provincial 2030 GHG reduction target (40% below 2007 levels). Current modelling methodology to achieve this ambition considers reductions from the oil and gas sector,[47] which uses hydrogen in upstream upgrading and refining, and the transportation and building sectors, where there is potential for hydrogen use in vehicles and heating.

This study suggests that there are minimal emissions reduction benefits associated with hydrogen blending into the natural gas system. However, as hydrogen production and demand develop in BC, hydrogen blending could be used as a stepping stone while transportation and industrial applications are maturing.

In setting carbon intensity thresholds for use in BC's hydrogen production in the short, medium, and long term, policymakers and stakeholders will need to balance several considerations: emissions reductions goals, technological feasibility, available funding, electricity supply, available markets for hydrogen exports and hydrogen by-products such as carbon black, and more. Understanding the interplay between these factors—and how they change in the years to come—will be important to keep BC's hydrogen economy growing efficiently and effectively.

BC's hydrogen strategy is ambitious—and achievable. By working together, policymakers, industry participants, investors, and other stakeholders can make BC's vision of a hydrogen economy a reality and make progress towards achieving the emission reduction targets established under the Climate Change Accountability Act.



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We acknowledge with respect and gratitude that this report was produced on many traditional and unceded territories, covering all regions of British Columbia whose deep connections with this land continue to this day.

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