# Submission on the Clean Hydrogen Investment Tax Credit

**Date:** January 6, 2023 | **Prepared by:** Felix Whitton and Ollie Sheldrick, Clean Energy Canada

## Introduction

Clean Energy Canada is a climate and clean energy program within the Morris J. Wosk Centre for Dialogue at Simon Fraser University. We are pleased to submit these comments as part of the Department of Finance consultations on the "Clean Hydrogen Investment Tax Credit".[1]

Global hydrogen demand is expected to more than double by 2030 and reach more than 500 million tonnes by 2050—six times current production—under the IEA's Net Zero scenario. To meet net-zero goals, the share of low-carbon hydrogen must reach 70% by 2030 and 98% by 2050, up from just 9% today.[2]

Thanks to its clean, low-cost electricity, ample freshwater supplies, renewable energy potential, and CO2 storage potential, Canada can play a key role in meeting the growing demand for low-carbon hydrogen at home and abroad.

For this to happen, the proposed Investment Tax Credit and other federal policy supports must prioritize production of the lowest carbon intensity hydrogen on a life cycle basis, regardless of production pathway, aligning with thresholds in the U.S., EU, and other jurisdictions. In addition, the federal government should support enabling infrastructure (including clean electricity supply and transmission and CO2 storage infrastructure), and prioritize hydrogen supply chains in hard-to-abate sectors with few mitigation alternatives.

### Clean Energy Canada's key recommendations for the design of the Clean Hydrogen Investment Tax Credit:

1. Align with the U.S. carbon intensity tiers and thresholds, with a predictable tightening rate going forward to ensure that hydrogen life cycle emissions decrease in line with a net-zero trajectory.
2. Base the level of support on life cycle carbon intensity, determined through robust, credible, and independently verified life cycle assessments that take into account the full value chain of hydrogen production to ensure only the lowest carbon intensity hydrogen is eligible for ITC support.

[1] Consultation on the Investment Tax Credit for Clean Hydrogen - Canada.ca
[2] Net Zero by 2050 - A Roadmap for the Global Energy Sector

3. The ITC should cover critical technologies for green, blue, and turquoise hydrogen production:
    a. Electrolyzers, investment in on-site clean power generation and storage, and water purification technology.
    b. Carbon capture and storage equipment utilized in SMR/ATR facilities and biomass gasification.
    c. Equipment and machinery for thermal and plasma pyrolysis.
    d. The ITC should also extend to off-site transportation and storage for both the carbon captured in blue and turquoise pathways, as well as the transport and storage of the hydrogen itself.
4. Work with other major hydrogen producers and consumers to develop and adopt consistent international standards for the measurement and definition of low-carbon hydrogen.
5. Ensure the federal government's Fuel LCA Model takes into account the most up to date, credible estimates of methane leakage in Canada, and provides options for calculations to use a 20-year global warming potential in addition to the conventional 100-year value.
6. Consider how the ITC design can advance Indigenous participation and reconciliation to ensure sustainable employment and opportunities for impacted communities.

# Discussion Questions

1. **What clean hydrogen production pathways can be expected going forward? What are expectations for future hydrogen demand (e.g., by 2030)? What are potential hydrogen opportunities in Canada?**

## Production Pathways

The table below provides details on the clean hydrogen production pathways open to Canada, with notes on the specific Canadian advantages in each pathway. It is important to note that 'clean' hydrogen does not have a single clear definition in terms of carbon intensity, and within each pathway the technical execution (e.g., carbon capture efficiency) and externalities (e.g., carbon intensity of regional electricity production) will have an impact on the production.

Currently, the best-in-class clean production pathway is hydrogen produced by water electrolysis and powered by zero-emissions electricity; this can in theory be produced at 0 kgCO2eq/kg $H_2$.[3] Beyond this, among blue hydrogen pathways AutoThermal Reforming (ATR) with CCS has the lowest intensity with an average of 3.91 kgCO2eq/kg $H_2$, but this is reliant on high carbon capture rates and limitations on fugitive methane emissions in the supply chain.[4]

[3] Pembina Institute, 2020, Hydrogen on the path to net-zero emissions - Costs and climate benefits

[4] Oni et al, 2022, Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions; Howarth and Jacobson, 2021, How green is blue hydrogen?

**Table 1: Hydrogen Production Pathways**

| $H_2$ Colour | Production Pathway | Description | Current Technology Readiness Level | Opportunities for Canada |
|---|---|---|---|---|
| Green | Water Electrolysis with zero-emission electricity. | Water electrolysis utilizes electrolyzers, which use electricity to split water into hydrogen and oxygen. | Alkaline and Proton Exchange Membrane (PEM) electrolyzers are currently TRL 8-9, meaning they are fully commercialized. Solid Oxide Electrolyzers are at TRL 5-6, and Anion Exchange Membrane (AEM) 2-3. | Canada is home to over 20% of the world's surface freshwater, and has an electricity grid that is over 82% non-emitting. Canada also has significant untapped renewable energy resources compared to many jurisdictions with moving water, wind, biomass, solar, geothermal, and ocean energy.<br><br>Canada also has over 14M tonnes of rare earth oxides, which are key to the production of electrolyzers. |
| Blue | Steam Methane Reforming (SMR) with CCS. | Using natural gas as a feedstock, SMR converts the natural gas into a syngas from which hydrogen is yielded in a secondary process. $CO_2$ is produced from the SMR process and fuel for heating. Up to 99% carbon capture has been shown to be possible. | Technology has a high TRL, with commercial facilities already in existence. However, facilities with high capture rates (e.g., 85%+) are less proven, and have higher associated costs. | Canada has significant proven natural gas reserves, and existing SMR production infrastructure. Canada is also developing expertise in deploying CCS for SMR, and has made investments in carbon transportation and storage infrastructure with the Carbon Trunk Line. However there must be a focus on ensuring capture levels are best-in-class. |
| Blue | Autothermal Reforming (ATR) with CCS | Similar to the SMR process, using natural gas feedstock. However, use of a single reactor to create syngas and yield hydrogen creates a single $CO_2$ stream for more efficient capture. | ATR is not yet at a commercial stage compared to SMR, however facilities have been planned with a 95% capture rate, including in Alberta. | Canada has significant proven natural gas reserves, and existing ATR production infrastructure. Canada is also developing expertise in deploying CCS for ATR, however there must be a focus on ensuring capture levels are best-in-class. |
| Blue | Partial oxidation (POx) | Converts liquid fuel (waste products from refineries, and potentially other | POx itself is a mature, already commercialized technology. However its | Canada's existing oil and gas sector can provide significant hydrocarbon |

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|---|---|---|---|---|
| | gasification with CCS. | sources including municipal waste) into hydrogen, with potentially higher energy and $CO_2$ efficiency compared to SMR and ATR. | partial oxidation with CCS is only in the early deployment phase. | feedstock, and an estimated 398 Gt of permanent geological $CO_2$ storage. |
| Blue | Biomass Gasification with CCS. | Converts biomass (e.g., wood, crops) into syngas in a high pressure steam reactor and yields hydrogen and waste carbon through a gas-shift reaction. | Biomass gasification is a mature technology, and biomass is generally cheap. However land use factors must also be considered. | Canada has substantial biomass in forests and land that could be turned to agricultural biomass production. However, there must be a focus on ensuring sustainability of biomass production, that undue pressure is not put on land, and that the carbon capture levels are best-in-class. |
| Turquoise | Methane Pyrolysis with CCS. | Converts methane into hydrogen and solid carbon through the application of high temperatures to 'thermally decompose' the methane. Less efficient than SMR in terms of hydrogen production. | Current analysis finds the various approaches for methane pyrolysis between TRL 3 (proof of concept) and 5 (validated in a simulated environment). | Canada has significant proven natural gas reserves, and multiple, mature sectors that can utilize the solid carbon by-product including the steel, aluminum and construction industries. |
| Red | Thermochemical water splitting. | Waste heat from advanced nuclear reactors can provide very high temperatures (up to 2000°C). This heat can then be used to drive chemical reactions that can split water into hydrogen and oxygen. | Challenges with the durability of reactive materials required, and the limited reactor designs compatible with the technology means this is still in early research and development phases. | Canada has an advanced civilian nuclear sector, with significant research expertise. Canada has 18 nuclear facilities, producing approximately 15% of the national electricity output. |

## Future Hydrogen Demand

The Government of Canada estimates, in a transformative scenario, the annual domestic hydrogen demand could be up to 4 Mt by 2030, and up to 20 Mt of hydrogen per year by 2050.[5] The bulk of this potential demand is allocated to replacing natural gas followed by low-carbon liquid fuel, transportation fuel, grey crude production (hydrogen produced using fossil fuels without any CCS), and other industrial uses.

Estimates on future market size for hydrogen vary significantly—analysis by Goldman Sachs show a market of US$12 trillion by 2050, however the Hydrogen Council suggests a significantly smaller US$2.5 trillion market for both hydrogen and related technology (e.g., electrolyzer manufacturing).[6] For green hydrogen, Boston Consulting Group estimates the market could be

[5] Natural Resources Canada, 2020, Hydrogen Strategy for Canada
[6] Farooq et al 2022, CHALLENGES AND OPPORTUNITIES IN SCALING CANADA'S CLEAN HYDROGEN ECONOMY

US$290 billion by 2040, with 21% of this market (146 Mt/year) in North America.[7] The Hydrogen Council and McKinsey & Co. estimate that the global demand for hydrogen will reach 660 Mt by 2050[8] (current global demand is 94 Mt[9])—however, this figure has been disputed as it assumes high levels of international trade in hydrogen that is unproven economically.[10]

Demand will be heavily influenced by pricing structures of hydrogen production, which in turn is heavily influenced by energy and feedstock costs.[11] Among blue hydrogen production pathways, current prices vary from US$1.69 and US$2.55 per kg of hydrogen in 2022,[12] whereas green hydrogen costs between US$5.9 and US$9.5 per kg.[13]

## Hydrogen Opportunities for Canada

Analysis by the Policy Lab Project at McGill University estimates that Canada's hydrogen and related technology market (including fuel cell manufacturing) could generate $25 billion in revenue by 2030, and $47 billion by 2050.[14]

Canada has a number of advantages when it comes to the different hydrogen production pathways, as laid out in Table 1. There are use cases for hydrogen in a number of sectors in the immediate future, including heavy industry (e.g., chemicals, steel), which have a clear opportunity for making significant emissions reductions by replacing fossil feedstocks and fuel with clean hydrogen.[15] Demand for green hydrogen in North American steelmaking could reach 2 Mt by 2050 (a $4B market). Quebec could supply 125,000 tonnes of this market due to its supply of continuous low-carbon, low cost hydroelectricity, and supplies of high grade iron ore.[16]

Alongside domestic production needs, a significant trade market for hydrogen is being projected over the next 30 years. As noted above, the scale of this market is debated given the challenges and costs associated with hydrogen transportation (e.g., energy density of various hydrogen carrier mediums such as ammonia, or energy costs of cryogenic storage for liquid hydrogen).[17] Currently, transfer by pipeline is by far the most cost effective, with shipping costs varying on technological approach.[18] Canada may have an opportunity to drive a hydrogen export market, given its advantages in natural resource wealth, and key inputs for green hydrogen production,

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[7] Boston Consulting Group, 2021, Green Hydrogen is a Golden Opportunity for Quebec—If We Act Now
[8] Hydrogen Council, 2022, Global Hydrogen Flows
[9] Liebreich, 2022, The Unbearable Lightness of Hydrogen | BloombergNEF
[10] Ibid.
[11] IEA, 2017, SMR Based H2 Plant with CCS
[12] Oni et al, 2022, Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions
[13] Skadden, 2022, Growing Opportunities in Clean Hydrogen | Insights
[14] Farooq et al 2022, CHALLENGES AND OPPORTUNITIES IN SCALING CANADA'S CLEAN HYDROGEN ECONOMY
[15] IEA, 2022, Recommendations for the G7 – Achieving Net Zero Heavy Industry Sectors in G7 Members
[16] BCG, 2021, Green Hydrogen is a Golden Opportunity for Quebec—If We Act Now
[17] Liebreich, 2022, The Unbearable Lightness of Hydrogen | BloombergNEF
[18] Ibid.

which are worth exploring. However, they will require significant infrastructure investment, and the size of the market remains uncertain.[19]

The hydrogen opportunity is significant, but not limitless. It will be important to take a critical view toward the best use cases for the technology—focused on the clearest opportunities where electrification and other alternative decarbonization pathways are currently unviable. **Any ITC should therefore have a hierarchy of end uses based on factors including decarbonization potential, limited alternative options, the risk of locking in carbon intensive infrastructure**, etc. An example of a use case that would fit this criteria would be the production of green hydrogen as feedstock for ammonia, as it would have a significant decarbonization impact on the sector, there are few feedstock alternatives, and green ammonia produced using green hydrogen is the best-in-class, long-term solution.[20]

Consideration should also be given to who will benefit from the hydrogen opportunity in Canada, and how investment in hydrogen production sits within the government's framework for a just transition for Canada's communities. We recommend considering how to integrate Indigenous reconciliation and community participation when designing the ITC to ensure sustainable employment and prosperity opportunities for communities whose land and resources may be impacted by new hydrogen production facilities.

## 2. What would constitute appropriate carbon intensity tiers in the Canadian context? What makes such tiers appropriate?

**We recommend aligning with the carbon intensity tiers and thresholds developed by the U.S. initially, and applying a predictable tightening rate going forward to ensure that life cycle emissions continue to decrease in line with a net-zero trajectory.**

For reference, the U.S. proposes the following tiers (in kg $CO_2e$/kg hydrogen):

- $<0.45$ kg (30% credit)
- 0.45 to 1.5 kg (10%)
- 1.5 kg to 2.5 kg (7.5%)
- 2.5 kg to 4.5 kg (6%)

Meanwhile, the EU's sustainable investment taxonomy has set a threshold of 3 kg $CO_2e$/kg hydrogen (on a lifecycle basis).[21] Only hydrogen production that meets this threshold will qualify as a "sustainable" investment under the EU taxonomy.

Both the U.S. and EU's definitions will likely favour green hydrogen (produced via renewable electricity), although low-carbon blue hydrogen (via either SMR or ATR) could qualify depending on various factors (upstream methane leakage rates, $CO_2$ capture rate, long-term storage).

[19] Pflugmann and De Blasio, 2020, The Geopolitics of Renewable Hydrogen in Low-Carbon Energy Markets
[20] IEA, 2021. Ammonia Technology Roadmap
[21] Regulation (EU) 2020/852 of the European Parliament

Canada should aim to at least match this level of ambition when it comes to clean hydrogen production, for several reasons:

1. The U.S. and EU are likely to be key export markets for Canada as it ramps up hydrogen production.[22] Demand in these countries will be driven by domestic policies that require or encourage low-carbon hydrogen (ie, the U.S. tax credits, EU sustainable taxonomy). In addition to its taxonomy, the EU has also finalized a Carbon Border Adjustment Mechanism (CBAM) which will levy the EU carbon price on imports of hydrogen and other industrial products.[23] Other countries are also prioritizing clean hydrogen in their domestic strategies and subsidies.[24] It is therefore important that Canada's hydrogen production is clean enough to meet these standards.
2. Setting a high threshold will incentivize production of the lowest carbon hydrogen, regardless of production technology. This will support green hydrogen using renewable electricity, while creating added incentives to decarbonize electricity grids. For blue hydrogen, it will encourage producers to address emissions across the supply chain, including upstream methane leaks and emissions, high CO2 capture rates during production, and permanent CO2 sequestration.
3. It is also important to recognize that Canada's existing hydrogen production (about 3 Mt / year) is largely fossil fuel-based, resulting in GHG emissions. Therefore a first priority should be to clean up this existing production through upgrades and retrofits.

A tiered system is appropriate because the costs of green hydrogen remain higher than blue hydrogen in most locations (and both are more expensive than "grey" hydrogen produced without CCS). For example, green hydrogen costs are US$3-8.50 / kg, compared with $1-2 / kg for blue.[25] The IEA expects green hydrogen costs to fall and be competitive with blue by 2030. In the interim, the ITC should aim to make the lowest carbon intensity (i.e. green) hydrogen more cost-competitive to accelerate this trend. Thanks to a new production tax credit, producing green hydrogen in parts of the US is likely to be competitive with blue hydrogen.[26]

A tiered system can also recognize that some regions in Canada have greater potential in the short- to medium-term to produce low-carbon blue hydrogen. For example, several provinces still have highly carbon intensive electricity grids[27], where current green hydrogen production could be more carbon intensive than blue. There is also large CO2 permanent storage potential and expertise in western Canada, which could be utilized to support low-carbon blue hydrogen.

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[22] CBC News, August 2022, 'Hydrogen alliance' formed as Canada, Germany sign agreement on exports
[23] EURACTIV.com, December 2022, EU seals agreement on world's first carbon tariff
[24] IEA, 2021, Global Hydrogen REVIEW 2021
[25] IEA, 2021, Global Hydrogen REVIEW 2021
[26] Recharge, August 2022, How Biden's $3/kg green hydrogen tax credit could break open US production
[27] Government of Canada, 2022, Emission Factors and Reference Values

## 3. Under what carbon intensity tiers are the different clean hydrogen production pathways in Canada expected to be found?

Hydrogen carbon intensity varies widely, depending on the assumptions used, natural gas and supply chain emissions, electricity grid intensity, and other factors. Relatively few peer-reviewed studies exist that assess the life cycle emissions intensity of hydrogen production in Canada or globally.

A review of the available literature[28] suggests that green hydrogen, produced using 100% renewables and water electrolysis, will have life cycle emissions in the range of 0.5 to 2 kg CO2e per kg hydrogen. Green hydrogen produced using grid electricity could approach this level in provinces like Quebec, Manitoba, and B.C. with low emissions grids and abundant hydropower. In provinces with more fossil fuel-dependent grids, e.g. Alberta, Saskatchewan, and Nova Scotia, the life cycle emissions could be in the range of 20 to 25 kg CO2e per kg hydrogen. This is comparable to emissions from "grey" hydrogen (ie, produced using fossil fuels without CCS), and higher than simply burning natural gas.

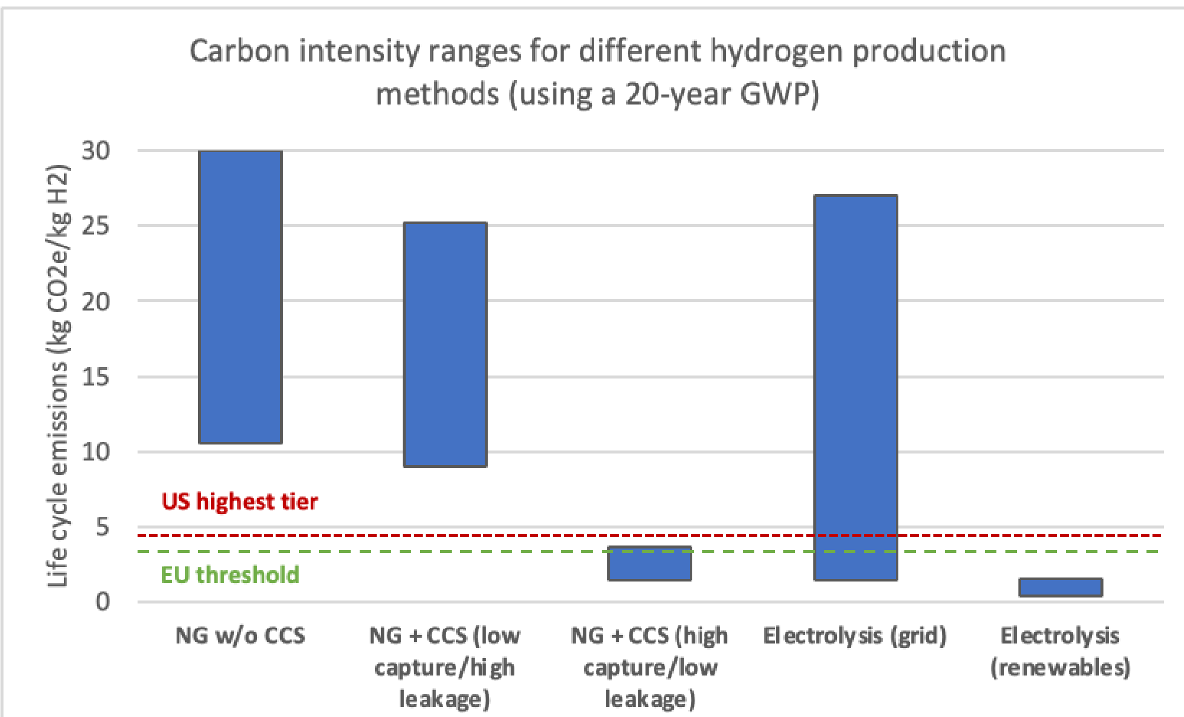


**Figure 1. Life cycle carbon intensity ranges for hydrogen production pathways.** NG = natural gas. CCS = carbon capture and storage. Red dotted line represents the upper tier of the U.S. hydrogen tax credit (4.5 kgCO2e/kg). Green dashed line represents the EU's sustainable taxonomy threshold for hydrogen (3 kgCO2e/kg). Note: the 20-year global warming potential (GWP) value for methane is used to reflect the importance of near-term mitigation of methane emissions. Source: Clean Energy Canada, based on NRCan; Bauer et al; Howarth & Jacobson; Zen; Pembina

[28] Baur et al. 2022; Pembina Institute, 2021; Zen, 2019; Howarth and Jacobson, 2021

Regarding "blue" hydrogen, there is significant variation in life cycle carbon intensity estimates. **Only blue hydrogen produced with very low upstream methane leakage rates (<0.5%) and very high CO2 capture (90-95%) can approach the intensity levels required by the U.S. and EU systems** (see chart). Reported capture rates range from 53% to 90%.[29] As Bauer et al. point out in a 2022 peer-reviewed study, blue hydrogen can only be considered "low-carbon" under two strict conditions: 1) minimizing methane emissions across the natural gas supply chain, including extraction, storage, and transport; and 2) employing advanced steam methane reforming or auto-thermal reforming technologies that ensure consistently high CO2 capture rates and integrates hydrogen production and CCS. Other studies suggest that powering the SMR process with clean electricity can further reduce carbon intensity (by around 66%); however, this could represent an opportunity cost where that clean electricity would be better used to produce green hydrogen (via electrolysis) or decarbonizing other sectors.[30]

4. **What levels of support would be appropriate for each carbon intensity tier, including the proposed top rate of at least 40 percent?**

The level of support should be based on carbon intensity, determined through a robust, credible and verified life cycle assessment of hydrogen production that takes into account both natural gas supply chain emissions, upstream electricity emissions, and the rate and permanence of carbon capture and storage.

The top rate of 40% must support the lowest carbon hydrogen production in Canada, which would be green hydrogen produced using wind or hydro power. Green, renewable hydrogen is being prioritized by countries around the world in long term decarbonization strategies, and Canada must prioritize reducing the costs and other barriers to production.[31]

Green hydrogen is currently more expensive than blue hydrogen, in part due to high capital costs of electrolysers (ranging from US$500 to $1,800/kW)[32]. The IEA, BloombergNEF and other analysts expect these costs to fall over the coming decade, due to learning effects, higher production volumes, and supply chain optimization. In the interim, policy support is needed to scale up production capacity and associated infrastructure.[33] A 40% tax credit could help accelerate this process, bringing capital costs down to the point at which green hydrogen production becomes competitive with blue, or even grey, hydrogen (as is already the case in the U.S.[34] and EU[35]).

The tax credit design should also recognize that green hydrogen from renewables will not be sufficient to meet expected demand for hydrogen in the short term. That is why a technology neutral system based on verified life cycle emissions performance is key to support the

[29] Howarth and Jacobson, 2021, How green is blue hydrogen?
[30] Ibid.
[31] IEA, Global Hydrogen REVIEW 2021
[32] IEA, September 2022, Electrolysers – Analysis
[33] BNEF, March 2020, Hydrogen Economy Outlook Key Messages
[34] Recharge, August 2022, How Biden's $3/kg green hydrogen tax credit could break open US production
[35] Wall Street Journal, July 2022, Green Hydrogen Is Cheaper Than LNG in Europe

development of hydrogen supply chains in regions with higher potential for blue hydrogen (i.e. low-cost natural gas and permanent carbon storage) than low-carbon green hydrogen. As the figure above shows, the best-performing blue hydrogen (with very low methane leakage rates and 90-95% capture rates) would qualify under the U.S. tax credit system, while blue hydrogen that results in high methane supply chain emissions and with lower capture rates would not qualify.

The ITC design should recognize that blue hydrogen is a transitional technology, and that as cost differentials between blue and grey hydrogen come down, so should the level of tax subsidy. The IEA estimates that blue hydrogen with 90-95% capture rate can be cost competitive with grey hydrogen at a carbon price of US$70/t CO2 (CA $95/tCO2).[36] As Canada's carbon price is planned to reach $95/tonne in 2025, the ITC could be gradually phased out for lower tiers and the carbon price fully applied to further incentivize a shift from grey to blue.

Finally, consideration should be given to the end use of the hydrogen in the design of the tax credit. Demand for clean hydrogen will likely exceed supply in the short to medium term, and hydrogen should not be viewed as a silver bullet solution to all sectors. We recommend developing a hierarchy of end uses based on factors including decarbonization potential, limited alternative options, the risk of locking in carbon intensive infrastructure, etc., and applying this to projects seeking the tax credit to ensure that the highest level of support only goes to projects that truly align with net-zero pathways.

5. **What equipment is required at clean hydrogen production facilities? Is there equipment that is external to the facility that may be needed to support clean hydrogen production and how should the government consider eligibility for that equipment under the clean hydrogen investment tax credit or other investment tax credits?**

The different pathways for clean hydrogen production have varying equipment requirements, and external inputs. For the production of green hydrogen via water electrolysis, the key equipment required is electrolyzers. There are a variety of different underlying technological approaches to achieving water electrolysis. There are currently six major groups of electrolyzer technology with different advantages and disadvantages, and not all are available at a commercial scale: Alkaline, acidic, acidic/alkaline amphoteric, solid oxide, microbial and photo-electrochemical.[37] Of these, Alkaline and Proton Exchange Membrane (acidic) are the two fully commercialized approaches, with Alkaline representing the industry standard.[38]

This variance in technology approaches means that average costs for a 1 MW electrolyzer unit vary from US$550 (for mainstream alkaline technology) to US$6500 for solid oxide variants.[39] As noted, these costs are predicted to fall through further innovation, increased production

[36] IEA 2021, Global Hydrogen REVIEW 2021
[37] Oxford Institute for Energy Studies. 2022. Cost-competitive green hydrogen: how to lower the cost of electrolysers?
[38] Ibid.
[39] Ibid.

volumes, and supply chain improvements. It will also be a priority to reduce energy consumption as currently renewable electricity costs can make up 50-90% of green hydrogen production.[40]

Currently, there is a global shortage of electrolyzers, partly driven by tight supply chains for the critical minerals required for their manufacture including platinum and iridium.[41] Consideration should be given to the fact that Canada has a significant opportunity given our critical minerals resources, and existing hydrogen manufacturing hubs in Ontario.[42] A hydrogen ITC must sit within a coherent hydrogen strategy for ensuring adequate supply, and maximizing the economic opportunity for Canada through all stages of the hydrogen supply chain.

In light of costs associated with power generation, **we recommend that the ITC cover both the purchase of electrolyzers and investment in on-site clean power generation powering the facility itself.** In addition, Canada should evaluate the opportunity to support electrolyzer manufacturing given our existing expertise and critical mineral supply chain. As noted in our response to question 10, ensuring consistent electrical loads to electrolyzers can extend their operational lifespan, a further reason to provide eligibility to power generation. Additionally, water purity also impacts operational lifespan, and therefore **water purification technology should also be included in the ITC.**

For **blue hydrogen pathways, the primary technology that should be eligible for the ITC is CCS equipment itself,** as this is the differentiator between existing grey SMR/ATR production. Equipment and technology related to the **two most developed methane pyrolysis technology pathways: thermal and plasma pyrolysis[43], should also be eligible for the ITC.** However, given that this pathway remains at a less mature technology readiness level, any facility seeking tax credit for this approach should undergo additional evaluation in terms of technology viability, agreed carbon intensity and production volumes, with ongoing assessment and evaluation.

External to blue and turquoise hydrogen facilities will be **carbon transportation and storage equipment which should also be eligible.** However, in these cases, how the ITC interfaces with the CCUS ITC will be important to **ensure facilities are not able to receive overlapping credits**, as the hydrogen production tax credit in the US Inflation Reduction Act sets out.

For all eligible colours of hydrogen production, **equipment that facilitates the storage and transportation of the hydrogen should also be eligible for the ITC**, as this is a considerable expense, and effective transportation and storage solutions are key to developing the overarching hydrogen infrastructure that will underpin the success of the sector.

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[40] IEA 2021, Global Hydrogen REVIEW 2021

[41] Recharge, January 2022, Could a critical raw materials shortage derail forecast massive green hydrogen growth?

[42] Government of Ontario, April 2022, Ontario's Low-Carbon Hydrogen Strategy

[43] Government of Canada, 2020, Hydrogen Strategy for Canada

6. **Life cycle carbon intensity calculation:**
    a. ***Are there any concerns with using the Government of Canada's Fuel Life Cycle Assessment Model for calculating the life cycle carbon intensity of clean hydrogen production?***
    b. ***What additional guidance or support could be provided to help with the calculation of life cycle carbon intensity of clean hydrogen production with this model?***
    c. ***What should be included in the scope of the life cycle carbon intensity calculation? How could this extend to clean hydrogen that is produced alongside co-products, or as a by-product of an industrial process?***

We support the use of the Government of Canada Fuel LCA Model, which is transparent, open access, follows ISO standards and guidelines, and is Canadian context-specific. It will also support alignment between the Hydrogen ITC and related federal policies (e.g. Clean Fuels Regulation). **We recommend the Fuel LCA Model ensure the following concerns are addressed in future updates:**

1. **Ensure that values for methane leakage rates are up to date, accurate, and verified**. Recent peer-reviewed estimates suggest that methane emissions from oil and gas production in western Canada are 50-60% higher than reported in Canada's National Inventory.[44] The significant variability in leakage rates means that accuracy and transparency are critical in calculating blue hydrogen emissions. As demonstrated in other studies, the rate of upstream methane leakage is one of the main factors behind the carbon intensity of blue hydrogen.[45]
2. **Provide a 20-year GWP option for methane calculations**. The model currently relies on a 100-year GWP value for methane, which potentially underestimates the near-term warming impacts of methane leaks from natural gas production and supply chains. Applying a 20-year GWP value of 86 (rather than the conventional value of 34) would reflect the urgency of reducing methane emissions in the next decade, and would incentivize blue hydrogen producers to address methane leaks and upstream emissions sooner rather than later. Prioritizing methane reductions in this way also supports the Government's target and proposed regulations to reduce methane emissions 75% by 2030.[46] We recommend that this option be included in the next update to the Fuel LCA Model, and that users are provided guidance as to how to switch GWP values in conventional LCA software.

**We also recommend the scope of life cycle carbon intensity calculation should include the following at minimum:**

- Upstream:

[44] Chan et al 2020, Eight-Year Estimates of Methane Emissions from Oil and Gas Operations in Western Canada Are Nearly Twice Those Reported in Inventories; Mackay et al 2021, Methane emissions from upstream oil and gas production in Canada are underestimated
[45] Bauer et al 2022, On the climate impacts of blue hydrogen production; Howarth and Jacobson, 2021, How green is blue hydrogen?
[46] Government of Canada, 2022, Proposed regulatory framework for reducing oil and gas methane emissions to achieve 2030 target

    - Natural gas emissions from all parts of the supply chain, including fugitive emissions;
    - Electricity emissions intensity reflecting the source, whether provincial grids or off-grid renewables;
    - Embodied emissions associated with plant and infrastructure construction.
- Production:
    - Energy use emissions whether electricity or natural gas;
    - Carbon capture rates at the hydrogen plant, including all CO2 exhaust streams;
- Downstream:
    - Hydrogen leakage from transportation and storage;
    - CO2 leakage from transportation and storage.

7. **Once hydrogen is being produced, by how much would the carbon intensity differ from the carbon intensity that was expected based on the design of the plant? Does this differ by production pathway? Is it possible to ensure that the carbon intensity of the clean hydrogen produced will be within a certain band and would this change over time? For the different clean hydrogen production pathways, what ongoing monitoring and calculations are done to measure carbon intensity once a clean hydrogen facility begins production?**

Carbon intensity will likely differ from design expectations depending on externalities that would vary by pathway. For example, for blue hydrogen, the variable emissions that are associated with upstream natural gas extraction and processing which may change over time, or the emissions of the electricity grid powering a green hydrogen facility. Clean Energy Canada is not in a position to explore the more specific levels of variation that might occur.

For ensuring that clean hydrogen remains in an agreed carbon-intensity band over time, and ongoing monitoring, **we recommend designing an approach based on the Investment Tax Credit for Carbon Capture, Utilization and Storage recovery mechanism**[47]:

1. Ensuring carbon intensity will be within a given band could be achieved by requiring updates on the project from the ITC recipient to provide current information on project execution and measured carbon intensity (verified over time as described in our response to question 9).
2. If intensity is not initially met, a grace period could be provided to give facilities time to solve any known operational issues, and improve efficiencies—this timeline could follow a similar approach as the CCUS ITC, with per kg carbon intensity measured each year, and then normalized over 5 year periods.
3. The overall ITC could be contingent over an agreed period e.g., 20 years—if carbon intensity goes above the agreed range for a 5 year period, then recoveries are introduced.

[47] Department of Finance, 2022, Additional Design Features of the Investment Tax Credit for Carbon Capture, Utilization and Storage: Recovery Mechanism, Climate Risk Disclosure, and Knowledge Sharing

4. The recovery mechanism could be used to return funds to the government based on a structured system (e.g., if carbon intensity is 10% higher then this would trigger a clawback of a pre-agreed percentage of the ITC).

This would provide an incentive to both deliver on the principally agreed carbon intensity, but also ensure this is maintained. Over time, the Output Based Pricing System on industrial emissions would also work to incentivize further efficiencies in production, and allow for the phasing out of the ITC.

## 8. How could life cycle carbon intensity calculations at the stage of plant design, and once a plant has actually started operations, be verified?

**We recommend that all life cycle carbon intensity calculations undertaken during a facility design and operation meet the following criteria:**

1. Align with internationally recognized and standardized approaches for life cycle emissions assessment of hydrogen production. Existing systems that should be explored include the International Partnership for Hydrogen in the Economy's (IPHE's) Hydrogen Production Analysis Task Force (H2PA TF),[48] and the European approach known as CertifHy,[49] which has been developed with over 100 industry partners.
2. Annual data collection and reporting as part of a public Climate Risk Disclosure report, at risk of penalty for failure to publish data, following a similar approach to the CCUS ITC.[50]
3. Independently verified through impartial, third-party analysis. This verification should include analysis of the plant design and any reported data, as well as site inspections to verify any and all emissions sources throughout the facility, and confirm emissions in the plant's supply chain (e.g., electrical energy source, gas feedstock if blue hydrogen). This third-party verification should take place at the initial completion of a facility, and every 5 years thereafter—aligned with the recovery mechanism detailed in question 8.

To deliver these criteria effectively, **Canada must work with international colleagues to ensure that clean hydrogen standards are set internationally, widely adopted, and that guidelines for the measurement and evaluation of operations can be carried out consistently**. In addition, resources must be allocated to ensure third party verification can be effectively carried out.

## 9. What is the typical service life of a clean hydrogen production facility and what are the risks that a project may not operate through to the end of its useful life?

The typical service life of a clean hydrogen facility varies depending upon the specific technology pathway, and in cases where the TRL of the approach has not yet reached full commercial maturity (e.g., turquoise and red hydrogen), that information may be unknown.

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[48] IPHE WP Methodology Doc Oct 2021

[49] CertifHy

[50] Department of Finance, 2022, Additional Design Features of the Investment Tax Credit for Carbon Capture, Utilization and Storage: Recovery Mechanism, Climate Risk Disclosure, and Knowledge Sharing

For green hydrogen production, the International Renewable Energy Agency estimates that alkaline electrolyzer stacks (the term for how electrolyzer machines are orientated and operate together within a facility) have a current lifetime of approximately 60,000 hours of operation, while PEM stacks are between 50 and 80,000. These are forecast to increase to 100,000 and 120,000 hours respectively by 2050.[51] The machinery themselves also have a physical durability greater than 30 years.[52]

Factors that impact the service life of the majority of electrolyzer technologies include: operating conditions (e.g., stability in atmospheric conditions, temperature etc.), how variable the electrical load rate is (important for systems supplied with variable, renewable electricity sources such as wind), and the purity of the water fed into the system.[53]

These factors present as the key risk factors for a project. Therefore, ensuring that a project has effective mitigation strategies for these risks will be important when evaluating for ITC eligibility. In addition, **widening ITC eligibility to power generation and water purification facilities, as set out in our response to question 5, will support investments that extend facility service life.**

For blue hydrogen production pathways, SMR/ATR facilities have a lifespan of up to 50 years,[54] and CCS systems are estimated by the Global CCS Institute to have an operating life of approximately 30 years (acknowledging that there are limited real-world examples to draw from, and multiple technology approaches that may lessen or increase this).[55] Therefore, **CCS equipment may need to be replaced or upgraded in a different timeframe than the SMR/ATR/Gasification facility equipment. Any ICT should be designed to reconcile these differences.** Irrespective of useful life, upgrades may be economically viable as the result of increases in efficiency and operating cost reductions. Additionally, any retrofitting of CCS technologies onto existing hydrogen facilities should ensure the remaining lifespan of the facility is accounted for when undertaking a Life Cycle Assessment of emissions intensity.

## Contact


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[51] IRENA, 2020, Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal
[52] Oxford Institute for Energy Studies, 2022, Cost-competitive green hydrogen: how to lower the cost of electrolysers?
[53] Ibid.
[54] IEA, Ammonia Technology Roadmap
[55] Global CCS Institute, March 2021, TECHNOLOGY READINESS AND COSTS OF CCS

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