# REPLY EVIDENCE ON THE GREENHOUSE GAS FOOTPRINT OF BLUE HYDROGEN

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## 1. Introduction

1. The purpose of this evidence is to provide a response to the evidence filed by Environmental Defense on the greenhouse gas (GHG) footprint of blue hydrogen, which was provided by Dr. Robert W. Howarth and Dr. Mark Jacobson (Howarth & Jacobson), as provided at Exhibit M10. This evidence will demonstrate that the literature shows that blue hydrogen can be a low-carbon substitute for natural gas under the right circumstances, and that those circumstances are achievable.

2. Enbridge Gas filed its 2024 Rates Application and the majority of its supporting evidence on October 31, 2022. For the first time in a rate application, Enbridge Gas has included energy transition related evidence, which is available at Exhibit 1, Tab 10. Included in this energy transition evidence at Exhibit 1, Tab 10, Schedule 5, Attachment 2 is the Pathways to Net-Zero Emissions for Ontario (P2NZ) Study, which was commissioned by Enbridge Gas and produced by Guidehouse. The purpose of the study was to demonstrate the role the gas system can play in supporting a pathway to net-zero GHG emissions in Ontario. In the P2NZ Study, two scenarios to achieve net-zero in Ontario were examined. The first was an electrification scenario that assumes aggressive electrification and the second was a diversified scenario that assumes a mix of electrification and wide-spread use of low and zero-carbon gases including renewable natural gas (RNG), hydrogen and natural gas with carbon capture, utilization and storage (CCUS).

3. During the course of this proceeding, a number of requests were made by Environmental Defence to re-run the P2NZ model with an alternate GHG emission

factor for fossil-fuel-based (or “blue”) hydrogen based on the life cycle emission intensity estimates found in Howarth & Jacobson’s paper “How green is blue hydrogen?”.[1] Enbridge Gas and Guidehouse initially declined to do so on the basis that they believe the blue hydrogen life cycle emissions intensity estimates presented in Howarth and Jacobson’s paper are not representative of blue hydrogen that could be produced in or imported to Ontario, both now and in particular in the future[2], and that accounting for life cycle emissions only for blue hydrogen and not for all other aspects of gas and electricity systems will lead to a biased result.

4. Ultimately, however, Enbridge Gas agreed to ask Guidehouse to run additional model scenarios which incorporated an emissions factor based on Howarth and Jacobson’s life cycle emissions intensity estimates, with Guidehouse noting that such a scenario would be “misrepresenting a situation”, please see TC Tr. Vol. 9 110. The results of this analysis, filed May 26, 2023, showed a slight narrowing of the cost gap between the electrification scenario and the diversified scenario, but ultimately “the results do not substantively change any conclusions in the P2NZ report” as provided at Exhibit JT9.16, part b).

5. On May 11, 2023, Environmental Defence filed expert evidence from Howarth and Jacobson, which included comments on an undertaking response (from Enbridge Gas) and an interrogatory response (from Guidehouse), and included two papers

[1] Howarth, Robert W. and Mark Z. Jacobson, 2021. How green is blue hydrogen? Energy Science and Engineering, Vol. 9, Issue 10, pages 1676-1687 https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956
[2] The reasons why Guidehouse and Enbridge Gas initially declined are presented in Guidehouse’s response to Exhibit I.1.10-ED-58 and Enbridge Gas’s response to Exhibit JT1.17.

written by the authors, “How green is blue hydrogen?”[3] and “Reply to comment on ‘How green is blue hydrogen?’”[4].

6. In response to the Howarth and Jacobson evidence, Enbridge Gas has reviewed a number of other blue hydrogen life cycle assessment studies, including peer-reviewed papers. With this submission, Enbridge Gas is presenting several of these research studies conducted by well-established academics, on life cycle GHG emissions for blue hydrogen. The additional research being presented clearly demonstrates that there is a range of scientific opinion on the life cycle GHG emissions for blue hydrogen and that it varies according to the blue hydrogen production process design and energy inputs.

7. The research studies that Enbridge Gas has reviewed, including that of Howarth and Jacobson, demonstrate that for blue hydrogen to be a low-carbon alternative to natural gas, certain conditions must be met. It is necessary that 1) the natural gas used to create blue hydrogen must come from a supply chain with low methane emissions and 2) the carbon capture efficiency must be as close to 100% as possible. The literature reviewed on methane leakage rates and on efficiency of carbon capture show that it is possible to achieve these conditions; therefore, Enbridge Gas believes it is possible for blue hydrogen to be considered a low-carbon alternative to natural gas, now and in the future.

## 2. Life Cycle Emissions of Blue Hydrogen

8. Life cycle analysis is used to examine the overall GHG impacts of a product’s value chain, including its entire life cycle from “cradle to grave”. For a fuel, this includes analysis of GHG emissions from feedstock extraction or cultivation and transport,

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[3] Howarth, Robert W. and Mark Z. Jacobson. October 2021. How green is blue hydrogen? Energy Science and Engineering, Vol. 9, Issue 10, pp.1676-1687. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956

[4] Howarth, Robert W. and Mark Z. Jacobson. July 2022. Reply to comment on “How Green is Blue Hydrogen?” Energy Science and Engineering, Vol. 10, Issue 7, pp.1955-1960. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.1154

feedstock processing into fuel, fuel transportation, storage and distribution, and the end use of the finished fuel. Life cycle analysis can be used to compare the GHG emissions of different fuel types. For example, a life cycle analysis for hydrogen can demonstrate the GHG reductions that can be achieved when switching from natural gas to hydrogen.

9. Life cycle GHG values for a fuel are presented as a carbon intensity, which is the GHG emissions per unit of fuel produced. The units used can vary; however, common units include grams or kilograms of carbon dioxide equivalent per megajoule of fuel produced (for hydrogen $gCO_2e/MJ\ H_2$ or kg $CO_2e/MJ\ H_2$) and kilograms of carbon dioxide equivalent per kilogram of fuel produced (for hydrogen kg $CO_2e/kg\ H_2$).

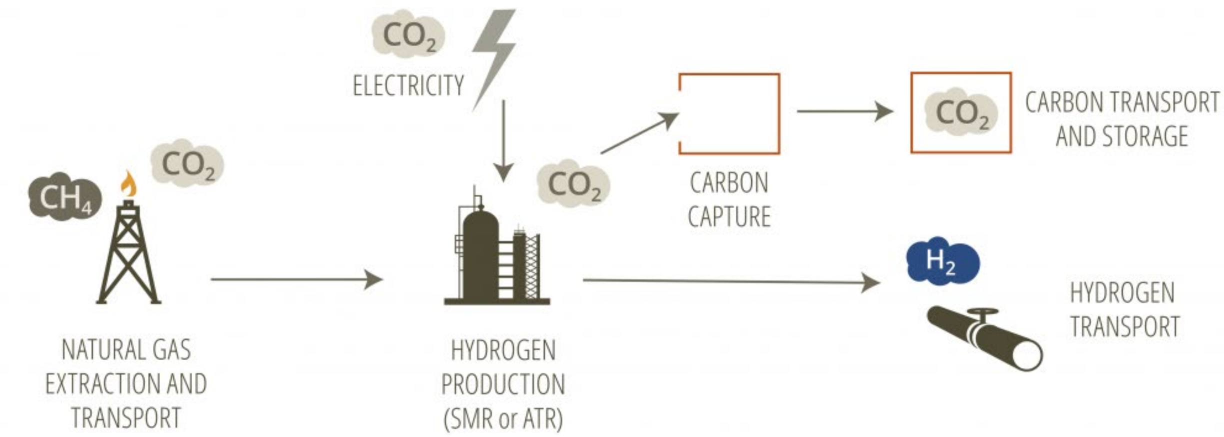
10. Although hydrogen does not emit any carbon dioxide ($CO_2$) when combusted by the end user, there may be GHG emissions released across the life cycle depending on the technology/process used to produce the hydrogen.

11. Blue hydrogen broadly refers to hydrogen produced from fossil fuels, commonly natural gas, paired with carbon capture and sequestration (CCS). The most common process for industrial-scale production of blue hydrogen is steam methane reforming (SMR); however, there are other processes such as autothermal reforming (ATR) that are also available and likely to be used to produce blue hydrogen.

12. As shown in Figure 1, the life cycle GHG emissions from blue hydrogen come from several activities in the production process, including:
    a) The upstream methane leakage rate of the natural gas used to produce the hydrogen;
    b) The emissions produced from energy used in the hydrogen production or carbon capture process;

c) The effectiveness of carbon capture used to capture emissions from the hydrogen production facility; and
d) Downstream emissions from the transportation and storage of carbon dioxide and hydrogen.

Figure 1: Sources of GHG Emissions in the Blue Hydrogen Production Process[5]




13. The life cycle GHG emissions for hydrogen are highly dependent on the technology/process used to produce the blue hydrogen (i.e., SMR, ATR), the upstream methane leakage rate for the natural gas used in the process and the efficiency of the carbon capture system. These aspects of hydrogen production will vary for each hydrogen production facility. For example, upstream methane leakage rates vary depending on the basin the gas is produced from (based on gas quality varying by basin) as well as between producers depending on the producers' practices to control methane leaks. Other aspects, such as the carbon intensity of the electricity used in the hydrogen production process, will also vary depending on the jurisdiction.

[5] Pembina Institute, August 2021. Carbon intensity of blue hydrogen production: Accounting for technology and upstream emissions, p.2. https://www.pembina.org/reports/carbon-intensity-of-blue-hydrogen-revised.pdf

14. Howarth and Jacobson found in their study that life cycle GHG emissions from production of blue hydrogen could be “quite high” and that the GHG footprint of blue hydrogen may be more than 20% higher than burning natural gas for heat.[6] However, they also demonstrated through sensitivity analysis that a lower life cycle GHG value can be achieved with lower upstream methane leakage rates and/or higher carbon capture efficiencies.[7]

15. Enbridge Gas found the following studies that demonstrate that the life cycle GHG emissions for blue hydrogen vary according to the blue hydrogen production process design and energy inputs. These studies also show, counter to what Howarth and Jacobson found, that with lower upstream methane leakage and higher carbon capture efficiencies blue hydrogen can be considered a low-carbon fuel as compared to natural gas.

16. Romano et al. wrote a peer-reviewed paper in response to Howarth and Jacobson’s study called “Comment on “How green is blue hydrogen?”, which was published in the journal Energy Science & Engineering in July 2022.[8] Romano et al. show that: 1) Howarth and Jacobson have used a simplified method to estimate the energy consumed in the production of blue hydrogen, which led to an overestimation of the natural gas consumed and therefore the $CO_2$ emissions produced, and 2) the assumed methane leakage rate is at the high end of the estimated emissions from current natural gas production in the US and cannot be considered representative of all natural gas and blue hydrogen value chains globally.[9] On the GHG reduction

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[6] Howarth and Jacobson, October 2021, p.1676.
https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956
[7] Ibid, p.1684.
[8] Romano, M.C., C. Antonini, A. Bardow, V. Bertsch, N.P. Brandon, J. Brouwer, S. Campanari, L. Crema, P. Dodds, S. Gardarsdottir, M. Gazzani, G.J. Kramer, P.D. Lund, N. MacDowell, E. Martelli, L. Mastropasqua, R.C. McKenna, J. Garcia Moretz-Sohn Monteiro, N. Paltrinieri, B.G. Pollet, J.G. Reed, T.J. Schmidt, J. Vente and D. Wiley. July 2022. Comment on “How green is blue hydrogen?” Energy Science and Engineering, Vol. 10, Issue 7, pp.1941-2575.
https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.1126
[9] Ibid, p.1945.

potential of blue hydrogen, Romano et al. show that when using ATR with a low methane leakage rate, high carbon capture efficiency (above 90%), and decarbonized power supply, that the overall GHG emission reduction compared to direct combustion of natural gas is close to 90%.[10] Romano et al. suggest that there is a large potential to lower methane leakage rates through voluntary and government mandated efforts to reduce methane emissions.[11] They also state that the carbon capture rate used by Howarth and Jacobson is based on data from existing plants that are designed and operated to capture carbon for enhanced oil recovery, not blue hydrogen production, and that in a carbon-constrained future carbon capture plants would reasonably be expected to be designed to maximize the carbon capture as far as economically viable.[12] Further, there is scientific and technical evidence that carbon capture efficiencies higher than 90% can be achieved in commercial plants.[13]

17. Bauer et al. wrote a peer-reviewed paper called "On the climate impacts of blue hydrogen production", which was published in the journal "Sustainable Energy & Fuels in 2022.[14] Bauer et al. show that the GHG impacts associated with blue hydrogen vary over large ranges and depend only on a few key parameters: 1) the methane emission rate of the natural gas supply chain, 2) the $CO_2$ removal rate at the hydrogen production plant, and 3) the global warming potential applied.[15] On the GHG reduction potential of blue hydrogen, Bauer et al. state that under certain conditions, specifically "state-of-the-art reforming with high $CO_2$ capture rates combined with natural gas supply featuring low methane emissions" that blue

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[10] Romano et al. July 2022, p.1951. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.1126
[11] Ibid, p.1950.
[12] Ibid, p.1946.
[13] Ibid, p.1946.
[14] Bauer, C., K. Treyer, C. Antonini, J. Bergerson, M. Gazzani, E. Gencer, J. Gibbins, M. Mazzotti, S.T. McCoy, R. McKenna, R. Pietzcker, A.P. Ravikumar, M.C. Romano, F. Ueckerdt, J. Vente and m. van der Spek. 2022. On the climate impacts of blue hydrogen production. Sustainable Energy and Fuels, Vol. 6, pp.66-75. https://pubs.rsc.org/en/content/articlepdf/2022/se/d1se01508g
[15] Ibid, p.66.

hydrogen "is compatible with low-carbon economies and exhibits climate change impacts at the upper end of the range of those caused by hydrogen production from renewable-based electricity".[16] Bauer et al. state that currently operating blue hydrogen production facilities remove only 50-60% of the overall (plant-wide) carbon emissions produced; however, these examples are not representative of the hydrogen CCS plants planned in Europe and the U.S. where rates higher than 90% are expected.[17] Additionally, commercial and demonstration scale plants have consistently achieved more than 92% and as high as 99% capture of carbon in various other applications.[18]

18. Oni et al. wrote a peer-reviewed paper called "Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions", which was published in the journal "Energy Conversion and Management" in February 2022.[19] Oni et al. state that methane emissions rates assumed by Howarth and Jacobson are 1.5 to 2.2 times higher than current Canadian and US estimates; however, Canadian methane regulations have reduced emissions by 9% between 2014 and 2019 and are aiming to reduce fugitive methane by 45% by 2025.[20] They also state that the global warming potential considered by Howarth and Jacobson is debatable because the assumed values show one extreme and result in higher GHG emissions from blue hydrogen.[21] Oni et al. provide a comparative analysis of life cycle emissions and production costs for a modeled hydrogen plant (607 tonnes $H_2$/day capacity) in Alberta, Canada using three different production

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[16] Bauer et al. 2022, p.66. https://pubs.rsc.org/en/content/articlepdf/2022/se/d1se01508g
[17] Ibid, pp.67-68.
[18] Ibid, p.68.
[19] Oni, A.O., K. Anaya, T. Giwa, G. DiLullo, and A. Kumar. February 2022. Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions. Energy Conversion and Management, Vol. 254, pp.1-17. https://doi.org/10.1016/j.enconman.2022.115245
[20] Ibid, p.2.
[21] Ibid.

technologies with and without carbon capture. While Oni et al. found that the life cycle emissions for blue hydrogen produced using SMR were in line with the findings of Howarth and Jacobson, the results of the analysis showed that ATR with carbon capture and natural gas decomposition (also known as methane pyrolysis) technologies achieved the lowest life cycle emissions and were 57% to 66% lower than SMR without carbon capture, respectively.[22]

19. Table 1 provides a comparison of GHG emissions intensities found in the literature. Column (b) provides the GHG emission intensities provided by the papers cited above, including that provided by Howarth and Jacobson. For ease of comparability, Enbridge Gas has converted all values to be based on a 100-year global warming potential (GWP) of 34, a higher heating value of 141.88 MJ/kg $H_2$ and common units of $gCO_2e$/ MJ $H_2$.

Table 1
Comparison of GHG Emissions Intensities Found in Literature

| Line No. | Source | Scenario | GHG Emission Intensity – units used in source document (units as noted) | GHG Emissions Intensity – standardized units ($gCO_2e/MJ\ H_{2\ HHV}$) |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 1 | Howarth and Jacobson[23] GWP100 = 34 | SMR, methane leak rate 3.5%, carbon capture rate = 85% reactor, 65% flue gas | 77 $gCO_2e/MJ\ H_{2\ HHV}$ | 77 |
| 2 | | SMR, methane leak rate 1.45%, carbon capture rate = 85% reactor, 65% flue gas | 57 $gCO_2e/MJ\ H_{2\ HHV}$ | 57 |

[22] Oni et al. February 2022, p.9. https://doi.org/10.1016/j.enconman.2022.115245
[23] Howarth and Jacobson. October 2021, p.1684. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956

| Line No. | Source | Scenario | GHG Emission Intensity – units used in source document (units as noted) | GHG Emissions Intensity – standardized units ($gCO_2e/MJ\ H_{2\ HHV}$) |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 3 | Romano et al.[24], GWP100=29.8 | SMR, leak rate 3.5%, overall carbon capture rate = 90% | 40 gCO2e/MJ $_{HHV}$ | 46 |
| 4 | | ATR, leak rate 0.2%, overall carbon capture rate = 93% | 11 gCO2e/MJ $_{HHV}$ | 12 |
| 5 | Bauer et al.[25] GWP100=not provided[26] | SMR, methane leak rate 8%, overall carbon capture rate = 55% | 0.10 $kgCO_2e/MJ\ H_{2\ LHV}$ | 103 |
| 6 | | SMR, methane leak rate 1.5%, overall carbon capture rate = 55% | 0.05 $kgCO_2e/MJ\ H_{2\ LHV}$ | 52 |
| 7 | | ATR, methane leak rate 1.5%, overall carbon capture rate = 93% | 0.03 $kgCO_2e/MJ\ H_{2\ LHV}$ | 31 |
| 8 | | ATR, methane leak rate 0.2%, overall carbon capture rate = 93%. | 0.02 $kgCO_2e/MJ\ H_{2\ LHV}$ | 21 |
| 9 | Oni et al.[27] GWP100=not provided[28] | SMR, carbon capture rate = 52% reactor, 0% flue gas, methane leakage rate not provided. | 8.20 $kgCO_2e/kg\ H_2$ | 70 |

[24] Romano et al. July 2022, p.1949. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.1126
[25] Bauer et al. 2022, p.4. https://pubs.rsc.org/en/content/articlepdf/2022/se/d1se01508g
[26] GWP was assumed as 27.9 based on Table 7.SM.7, in the The Earth's Energy Budget, Climate Feedbacks, and Climate Sensitivity Supplementary Material. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change.
[27] Oni et al. February 2022, p.9. https://doi.org/10.1016/j.enconman.2022.115245
[28] GWP was assumed as 27.9.

| Line No. | Source | Scenario | GHG Emission Intensity – units used in source document (units as noted) | GHG Emissions Intensity – standardized units ($gCO_2e/MJ\ H_{2\ HHV}$) |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 10 | | SMR, overall carbon capture rate = 85, methane leakage rate not provided | 6.66 kgCO2e/kg H2 | 57 |
| 11 | | ATR, overall carbon capture rate = 91%, methane leakage rate not provided. | 3.91 kg $CO_2e$/kg $H_2$ | 34 |
| 12 | | NGD, without carbon capture, methane leakage rate not provided | 4.89 kg $CO_2e$/kg $H_2$ | 42 |

20. Table 1 demonstrates the wide range of emissions intensity values that have been determined in the research studies that Enbridge Gas has reviewed. Only one study found a value higher than Howarth and Jacobson; however, Bauer et al. estimated this high value using an extremely high methane leakage rate of 8%, whereas their estimates with lower methane leakage rates demonstrated lower emission intensity values for blue hydrogen. Overall, the emission intensities for blue hydrogen ranged from 12 to 102 $gCO_2e/MJ\ H_{2\ HHV}$. For reference, the emission intensity used in the P2NZ report was 5.5 $gCO_{2e}/MJ\ H_2$, as provided at Exhibit JT9.15. As a comparison, the default carbon intensity of natural gas as reported in the Clean Fuel Regulation is 68 gCO2e/MJ[29].

[29] The Government of Canada. Clean Fuel Regulations (SOR/2022-140). Schedule 6, 8. (d). May 29, 2023. P.170. https://laws-lois.justice.gc.ca/PDF/SOR-2022-140.pdf

21. The large variability of blue hydrogen emissions intensity provided in Table 1 demonstrates that the life cycle emissions intensity of blue hydrogen needs to be evaluated on a case-by-case basis, which considers project-specific assumptions.

## 3. Blue Hydrogen Life Cycle Analysis Assumptions and Life Cycle Methodological Choices

### *3.1. Methane Leakage Rate*

22. As noted by Howarth and Jacobson, there are numerous studies on methane leakage rates, which show varying rates of methane leakage: "Note that there has been an explosion in the number of new studies on CH4 emissions from the natural gas industry over the past decade, with more than 1700 papers published over the past decade".[30]

23. In their study, Howarth and Jacobson used a methane leakage rate of 3.5%, which is comprised of an estimated 2.6% from natural gas production and processing and 0.8% from natural gas storage, transportation and distribution, and then multiplied by the ratio of 2015 natural gas production to consumption. The leakage rate for natural gas production and processing were developed from measurements obtained between 2012 and 2019 from 12 peer reviewed studies[31], normalized to 2015 production data[32]. The methane leakage estimate for natural gas storage and transportation was obtained from one peer reviewed study conducted in 2018 for six urban centers in the Northeast U.S.[33]

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[30] Howarth and Jacobson. July 2022, p.1956. https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.1154
[31] Howarth and Jacobson. October 2021, p.1679. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956
[32] Exhibit N.M10-EGI-109, part (c), p2.
[33] Plant, G., Kort, E., Floerchinger, C, Gvakharia, A, Vimon, I., Sweeney. July 2019. Large Fugitive Methane Emissions From Urban Centers Along the U.S. East Coast. Geophysical Research Letters. pp.7857-8581. https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2019GL082635

24. Howarth and Jacobson also explored the impact of a range of methane leakage values in their sensitivity analysis, which were 1.45%, 2.54% and 4.3%, which are based on values the authors found in peer-reviewed studies.[34] Howarth and Jacobson comment that the two lower values "come from solid, peer-reviewed studies".[35]

25. In addition to the two studies identified by Howarth and Jacobson that found methane leakage rates lower than 3.5%, Enbridge Gas found the following studies that also demonstrate lower leakage rates for natural gas produced in North America.

26. Littlefield et al. wrote a peer-reviewed paper called "Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways", which was published in October 2022 in the journal Environmental Science and Technology.[36] Littlefield et al. demonstrated that life cycle GHG emissions and methane emission rates vary according to the region and type of natural gas production (described as technobasins) and the location and distance to consumption. The results of their study show that the "cradle to delivery" (excludes end-use) life cycle GHG emissions and methane emission rates in 2017 within the United States varied from 8.1 to 41 $gCO_2e/MJ$, and 0.4 to 4.2%, respectively, with a national production weighted average of 1.24% of methane emissions.

27. MacKay et al. wrote a peer-reviewed paper called "Methane emissions from upstream oil and gas production in Canada are underestimated", which was published in April 2021 in the journal "Scientific Reports". MacKay et al. measured

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[34] Howarth and Jacobson, October 2021, p.1683.
https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956
[35] Howarth and Jacobson, July 2022, p.1956.
https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.1154
[36] Littlefield, J., S. Rai and T. Skone. October 24, 2022. Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways. Environmental Science & Technology, Vol. 56, pp.16033-16042.
https://pubs.acs.org/doi/10.1021/acs.est.2c01205

methane emissions at 6,650 sites between 2015 and 2018 for six major oil and gas producing regions in Canada and found that newer developments in British Columbia (BC), such as Peace River with a methane emission rate of 0.04%, had the lowest emission intensities in North America.[37] This study also confirms that regulations can and have had a significant impact on emission rates, as they measured a nearly three-fold decrease in site level emissions in Peace River, BC, between 2016 and 2018 following the introduction of new regulations in 2017 that have reportedly eliminated all venting. The authors noted that “emission intensities for all producing regions in Canada, except for Lloydminster [Alberta] and Medicine Hat [Alberta], were lower than the US average of 2.3% (of gross production) recently reported by Alvarez et al. (2018)”.[38]

28. Johnson et al. wrote a peer-reviewed paper called “Creating measurement-based oil and gas sector methane inventories using source-resolved aerial surveys”, which was published in April 2023 in the journal Communications Earth and Environment. Johnson et al. measured an upstream leakage rate of 0.38% for natural gas produced in British Columbia in 2021[39], which corresponds well with the MacKay et al. observations.[40] With the inclusion of transmission, storage and distribution segments, the authors estimated the methane emissions for British Columbia produced natural gas at 0.42%.

29. Balcombe et al. wrote a paper called “Methane and CO2 emissions from the natural gas supply, an evidence assessment”, which was published in 2015. This study

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[37] MacKay, K., Lavoie, M., Bourlon, E., Atherton, E., O’Connell, E., Baillie, J., Fougere, C., and Risk, D., 2021. Methane emissions from upstream oil and gas production in Canada are underestimated. Scientific Reports, 11:8041. https://www.nature.com/articles/s41598-021-87610-3.pdf
[38] Ibid, p.4.
[39] Johnson, M., B. Conrad and D. Tyner. April 25, 2023. Creating measurement-based oil and gas sector methane inventories using source-resolved aerial surveys. Communications Earth & Environment. 4: 139, p.5. https://doi.org/10.1038/s43247-023-00769-7
[40] Mackay et al., p.3. https://www.nature.com/articles/s43247-023-00769-7

was completed by academics at the Sustainable Gas Institute at the Imperial College in London and was reviewed by an expert advisory group, which consisted of independent experts. Balcombe et al. found that upstream leakage rates for natural gas ranged from 0.2% to 10%; however, the majority of the estimates are between 0.5% and 3%, with an average of 2.2%.[41] This study included a review of 240 academic papers, government reports and industry and non-government organization papers published between 1993 and 2015. More than half of the papers were based on the US or North America. The authors state that "the highest estimates are generally acknowledged as being unlikely to be representative across large regions but may occur for specific supply chain routes".[42]

30. The above noted studies demonstrate that there is a wide range of methane leakage rates and that there is no scientific consensus on the exact leakage rate for natural gas produced or consumed in North America. As demonstrated by the papers above and summarized by Howarth and Jacobson in Exhibit N.M10-EGI-108, emissions can vary depending on temporal variation, measurement methodology, the actions of operators and regulator enforcement, and location. Howarth and Jacobson further state "the number of variables and the modest number of well-done top-down studies make it difficult or impossible to determine which studies are most representative of the actual reality"[43]. Enbridge Gas agrees with this statement and suggests, based on the range of natural gas leakage rates identified in the studies listed above, that it is reasonable to assume that upstream natural gas leakage rates are currently lower than the 3.5% used by Howarth and Jacobson in their analysis.

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[41] Balcombe, P., K. Anderson, J. Speirs, N. Brandon and A. Hawkes, 2015. Methane and CO2 emissions from the natural gas supply, An evidence assessment. Sustainable Gas Institute, p.18. https://www.imperial.ac.uk/media/imperial-college/research-centres-and-groups/sustainable-gas-institute/SGI_White_Paper_methane-and-CO2-emissions_WEB-FINAL.pdf
[42] Ibid.
[43] Exhibit N.M10-EGI-108, p.2.

31. Further, Enbridge Gas suggests that upstream methane emissions will decline over time due to 1) federal and provincial/state level methane regulations in both Canada[44] and the U.S.[45], and 2) voluntary methane reporting and reduction programs such as MiQ[46] and the Oil and Gas Methane Partnership 2.0 (OGMP 2.0)[47].

32. Both Canada and the U.S. have set ambitious methane reduction targets, aiming to reduce methane emissions from the oil and gas sector by 75% over 2012 levels and 87% below 2005 levels, respectively, by 2030.

33. Ahead of regulation, natural gas producers are already working to reduce methane emissions and are becoming certified under voluntary programs. For example, natural gas producers who are certified under the MiQ Standard are required to deploy methane monitoring technology to detect unintended methane emissions and to repair or replace leaking equipment in a timely matter. To become certified, a producer's methane emissions must be audited and verified by an accredited, third-party certifying body.

34. As of May 2023, all gas producers certified under MiQ have achieved a verified emission leak rate below 0.20% (grade C), with 78% of gas producers certified have achieved a verified emission leak rate below 0.05% (grade A).[48] Although these MiQ certificates represent only the production of natural gas, adding in 0.62% leakage rate from natural gas storage and transportation assumed by Littlefield et

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[44] A summary of the Federal Methane Regulations is provided in Exhibit 1, Tab 10, Schedule 3, Section 2.1, paragraphs 15 to 17.
[45] Delivering on the U.S. Methane Emissions Reduction Action Plan, November 2022, p. 4. https://www.whitehouse.gov/wp-content/uploads/2022/11/US-Methane-Emissions-Reduction-Action-Plan-Update.pdf
[46] MiQ. 2023. https://miq.org/
[47] Oil and Gas Methane Partnership. What is OGMP 2.0? A solution to the methane challenge. https://ogmpartnership.com/a-solution-to-the-methane-challenge/
[48] MiQ. 2023. https://miq.org/

al. would lead to a life cycle upstream methane leakage rate of between 0.67 to 0.82% for natural gas produced at these certified facilities.

35. Based on the voluntary reduction emissions today and the methane regulations which are in place today, which are continuing to evolve, Enbridge Gas believes there is a clear pathway to lower upstream methane emissions in the future.

### *3.2. Blue Hydrogen Production*

36. Howarth and Jacobson's paper estimated the life cycle emissions for blue hydrogen that is produced using the SMR process with CCS. While most industrial-scale hydrogen production today uses the SMR technology, Enbridge Gas notes there are additional processes such as ATR that are also available and likely to be used to produce blue hydrogen. ATR is an established technology for syngas production with numerous applications and has large scale system offerings by well-established technology providers such as Haldor Topsoe[49] and Air Liquide[50].

37. Energy and carbon capture efficiencies are influenced by the design and type of hydrogen production systems. As an example, the SMR process requires heat for reforming reactions to occur, whereas the ATR process includes partial oxidation which produces the heat required for reforming reactions, thereby lowering fuel needs and combustion emissions.[51] SMR can also achieve greater process efficiency where excess process steam is utilized to generate electricity[52], as

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[49] Topsoe. SynCOR-Autothermal Reformer (ATR). 2022. https://www.topsoe.com/our-resources/knowledge/our-products/equipment/syncortm-autothermal-reformer-atr?hsCtaTracking=7a94fb27-7f73-4264-9406-6e2166f8b929%7Cd630e8cf-c719-41d7-a23e-411c56653fc3

[50] Air Liquide Engineering & Construction. Low-carbon Hydrogen: A portfolio of technologies for low-carbon hydrogen production, purification and recovery. 2023. https://engineering.airliquide.com/technologies/low-carbon-hydrogen#:~:text=Autothermal%20Reforming%20(ATR)%20is%20a,low%2Dcarbon%20hydrogen%20at%20scale

[51] Oni et al., February 2022, p.5. https://doi.org/10.1016/j.enconman.2022.115245

[52] Bauer et al., 2022, p.67. https://pubs.rsc.org/en/content/articlepdf/2022/se/d1se01508g

opposed to combusting natural gas specifically for electricity generation as assumed by Howarth and Jacobson. Additionally, the recovery of tail gas (residual products from hydrogen separation) can be used to provide heat and further reduce system energy needs[53].

38. A peer-reviewed paper by Antonini et al.[54] demonstrates how design selection within individual technologies and between technology types can influence the emission intensity of blue hydrogen. The Antonini et al. analysis considers configurations using SMR and ATR systems and two different types of carbon capture technologies (solvent based and novel pressure swing adsorption). The results indicate that for SMR systems, the introduction of a low-temperature water-gas shift increased carbon capture efficiency, but there was no notable difference between the use of carbon capture systems.[55] For the ATR system, the selection of carbon capture technology was able to influence overall carbon capture rates. Between the SMR and ATR carbon capture equipped systems, the ATR systems were able to achieve higher overall carbon capture rates (85 to 98%).[56]

39. Enbridge Gas notes that newer technologies such as methane pyrolysis (also called natural gas decomposition), despite currently having a lower technology readiness level than SMR or ATR, have the advantage of capturing carbon from the decomposition of methane and producing solid carbon (carbon black) for marketable uses instead of GHG emissions. While the majority of methane pyrolysis demonstrations have been at the laboratory and pilot scale[57], Monolith

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[53] Antonini, C., K. Treyer, A. Streb, M. van der Spek, C. Bauer and M. Mazzotti, 2020. Hydrogen production from natural gas and biomethane with carbon capture and storage – A techno-environmental analysis. Sustainable Energy & Fuels. p. 2970. https://pubs.rsc.org/en/content/articlepdf/2020/se/d0se00222d
[54] Ibid.
[55] Ibid, p.2979.
[56] Ibid.
[57] Schneider, S., Bajohr, S., Graf, F., and Kolb, T. July 15, 2020. State of the Art of Hydrogen Production via Pyrolysis of Natural Gas. ChemBioEng Reviews 7, No. 5, pp 150-158. https://onlinelibrary.wiley.com/doi/pdf/10.1002/cben.202000014

Materials has been operating a commercial-scale (5,000 tonnes per year hydrogen capacity) methane pyrolysis facility in Hallam, Nebraska since 2020, with a reported carbon intensity of 0.45 $kgCO_2e/kg\ H_2$ (3.17 $gCO_2e/MJ\ H_2$[58]) [59].

40. Another blue hydrogen technology at a pilot-scale level of development (technology readiness level of 4-5) by the Gas Technology Institute (GTI) is Sorbent Enhanced Reforming, which reportedly has the potential to achieve near 100% carbon capture rates, with a 50% reduction in capital expenditure as compared to SMR or ATR[60].

*3.3. Carbon Capture Rate*

41. In their study, Howarth and Jacobson used a carbon capture rate of 85% from the SMR, and a capture rate of 65% where emissions from flue gas are captured, which was determined based on a review of a 2017 study plus data from two commercially operating facilities using CCS.[61]

42. Bauer et al. indicate that the carbon capture rates observed from these "first-of-a-kind" facilities are not representative of blue hydrogen plants planned in the US or Europe.[62] The expectation by Bauer et al. is that future blue hydrogen plants will achieve plant-wide carbon capture rates of 90% or greater, and indicate that the relevant carbon capture technologies have been deployed at the Petra Nova (coal combustion gas) facility in Texas, and the Coffeyville Resources (ammonia

[58] Converted using high heating value of 141.88 MJ/kg hydrogen.

[59] Monolith Materials. September 27-28, 2021. The Hydrogen to Power a Green World. As presented in U.S Department of Energy Enabling an Accelerated and Affordable Clean Hydrogen Future – Fossil Energy Sector's Role, Workshop Final Report. https://netl.doe.gov/sites/default/files/netl-file/21CHF_FinalReport.pdf

[60] Lesemann, M., J. Mays, P. Clough, J. Oakley, T. Adedipe and A. Duncan. November 10, 2022. Hydrogen Production with Integrated $CO_2$ Capture via Sorbent Enhanced Reforming. 16th International Conference on Greenhouse Gas Control Technologies, GHGT-16. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4273308

[61] Howarth and Jacobson. October 2021, p. 1684. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956

[62] Bauer et al., 2022, p. 68. https://pubs.rsc.org/en/content/articlepdf/2022/se/d1se01508g

production) facility in Kansas, and have achieved removal rates of 92% and 93%, respectively.[63]

43. An analysis of life cycle emissions for various blue hydrogen cases was undertaken by Pettersen et al. where the authors considered overall carbon capture rates of 98% as feasible based on studies performed by engineering contractors and technology providers[64]. Life cycle emission estimates for the various blue hydrogen plant configurations completed by Antonini et al. used lower and upper bounds for carbon capture rates of 90% and 98%, respectively.

4. Conclusion

44. Based on the literature review conducted, Enbridge Gas found that the life cycle GHG emissions for blue hydrogen are highly dependent on the technology/process used to produce the hydrogen, the upstream methane leakage rate for the natural gas used in the process, and the efficiency of the carbon capture system. The scientific community has provided a range of views on the life cycle emissions intensity of blue hydrogen; however, it has not coalesced around a single value because the value will vary for each hydrogen production facility.

45. Howarth and Jacobson state that the life cycle emission intensity of blue hydrogen is higher than that of natural gas.[65] The studies Enbridge Gas reviewed do not support this definitive position, instead showing that under the right conditions (low upstream methane leak rate and high carbon capture efficiency) blue hydrogen can be considered a low-carbon substitute for natural gas. Enbridge Gas also reviewed studies on methane leak rates and carbon capture and found that these conditions can be met today and are likely to improve further over time.

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[63] Bauer et al., 2022, p. 68. https://pubs.rsc.org/en/content/articlepdf/2022/se/d1se01508g
[64] Pettersen et al. September 2022. Blue hydrogen must be done properly. Energy Science & Engineering, Vol 10, Issue 9, p.3228. https://doi.org/10.1002/ese3.1232
[65] Howarth and Jacobson, October 2021, p.1684. https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956

46. When Guidehouse completed a sensitivity analysis on the emissions factors for blue hydrogen using the P2NZ model (as provided at Exhibit JT9.16), they demonstrated that the impacts of changing these assumptions to values supported by Howarth and Jacobson do not significantly change the outcomes of the study, which found that a diversified pathway is the most optimal pathway for Ontario to reach net-zero emissions. The impact of increasing the blue hydrogen emission factor was to shift from blue hydrogen to green hydrogen (hydrogen produced through electrolysis).

47. This demonstrates that the “colour” of the hydrogen is less important than the GHG emissions intensity. Enbridge Gas believes it likely that in the future the governments of Canada and/or Ontario will establish guidelines on the GHG emissions intensity of hydrogen, similar to the work undertaken in the US to establish a “Clean Hydrogen Production Standard”.[66] The 2020 “Hydrogen Strategy for Canada” references the European based “CertifHy” program (certification of a 60% GHG emission reduction as compared to natural gas SMR based hydrogen production without CCS) as an example of how “clean” hydrogen could be defined.[67] Should this not occur, Enbridge Gas could also set a life cycle GHG emissions intensity threshold for the hydrogen it procures in the future, which could be part of the hydrogen procurement process.

48. Whether imposed by government or developed by Enbridge Gas, a life cycle GHG emissions intensity threshold will ensure that only hydrogen that is considered “low

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[66] The US Department of Energy has developed a “Clean Hydrogen Production Standard (CHPS), which requires hydrogen to meet a “well-to-gate” life cycle GHG emissions standard of ≤ 4.0 $kgCO_2e/kg\ H_2$ (< 28 $gCO_2e/MJ_{H2\ HHV}$). https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf

[67] The Government of Canada. December 2020. Hydrogen Strategy for Canada. pp.36. https://natural-resources.canada.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

carbon" is blended into the gas distribution system. Any hydrogen that has a life cycle GHG emissions higher than the GHG emissions intensity threshold would not be considered a low carbon fuel and Enbridge Gas would not consider it as part of the Company's energy transition plan.