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October 13, 2023

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Christopher P. Weafer

Dear Christopher P. Weafer:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) ~ Project No. 1599324

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 3 on Rebuttal Evidence

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On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-150-23 for the review of the LTGRP, FEI respectfully submits the attached response to CEC IR No. 3 on Rebuttal Evidence.

For convenience and efficiency, if FEI has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

EXHIBIT B-38: FEI PLANS FOR HYDROGEN BLENDING

87. Reference: Exhibit B-38, PAGE 2, A5

> blending identified by MS2S are well understood and can be addressed. For instance, Hawaii Gas has been blending an average of 12 percent hydrogen into its gas network for over 50 years,[1] and Hydrogen blending has been successfully demonstrated in various jurisdictions including Markham, Ontario, and Fort Saskatchewan, Alberta in Canada, as well as in various countries in Europe. These demonstrations emphasize safety and monitoring to ensure the successful integration of hydrogen into existing energy systems. Close collaboration between public stakeholders and a strong body of supporting technical evidence has been key to the success of these pilots.

87.1 Please name the Hawaiian Island(s) that are supplied by the gas network of Hawaii Gas incorporating an average of 12% hydrogen blend in the gas supply.

Response:

Hawaii Gas operates a gas distribution network of 1,100 miles of pipelines on the island of O‘ahu[1] that distributes an average of 12 percent hydrogen blend by volume in the gas supply.

87.2 Please specify as to whether the ~12% hydrogen blend is incorporated in the gas distribution systems of these Hawaiian Islands, or the transmission systems (if any) and/or whether or not any of this is notional on other systems.

Response:

The hydrogen blend is physically incorporated in both the gas transmission system and the gas distribution systems serving O‘ahu, which is Hawaii Gas’ largest utility distribution system.

87.3 Please confirm that all the classes or groups of Hawaii Gas customers (i.e. residential, commercial, small industrial, industrial, etc.) that are served receive an average of 12% hydrogen blend in the gas supply.

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[1] Hawaii Gas, “Decarbonization and Energy Innovation” (2022), online at: https://www.hawaiigas.com/clean-energy/decarbonization.

Response:

Please refer to the response to CEC IR3 87.2 confirming that hydrogen is physically blended into the gas system on O'ahu and thus, the system delivers hydrogen to all customers on the island. As such, all of these customers receive an average of 12 percent hydrogen blend in their gas supply. O'ahu residential customers receive 9 percent of Hawaii Gas' overall delivered energy across all islands, and O'ahu commercial and industrial customers receive 72 percent of Hawaii Gas' overall delivered energy across all islands.

87.4 Please name the typical customer end-use appliances (for each of the Hawaii Gas customer classes), which utilize an average of 12% hydrogen blend in the gas supply. Please comment on what end-user equipment/ appliances' tolerances and operating considerations have been observed in the experience of Hawaii Gas working with its customers?

Response:

Figure 5 of the April 6, 2023 Hawaii Gas Integrated Resource Planning Report[2] provides a high-level summary of end-use appliances in Hawaii. The 50+ years of combustion of synthetic natural gas in both legacy and new customer end-use appliances speaks to the high level of tolerance appliances have to an average 12 percent hydrogen blend.

87.5 Please indicate what work, if any, has Hawaii Gas undertaken on the gas metering side to accommodate hydrogen blending.

Response:

FEI understands that Hawaii Gas operates customer meters under the oversight of local regulatory bodies to ensure all custody transfer measurement aligns with local regulatory requirements.

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[2] Hawaii Gas, "Final IRP Report and Action Plan" (2023), online at: https://uploads-ssl.webflow.com/618c69307382fa36b31ac896/642f89e3171648bf86e7135e_Dkt%202022-0009%20Hawaii%20Gas%20Final%20IRP%20Report%20and%20Action%20Plan%2C%20filed%204-6-2023.pdf.

87.6 Please explain whether, in the experience of Hawaii Gas, there are any end uses on Hawaiian Islands, which aren't compatible with a hydrogen blend gas supply. Please elaborate on such end uses, and please explain what hydrogen separation technologies (if any) are employed by these customers, or Hawaii Gas to supply these customers.

Response:

Hawaii Gas has not publicly shared nor is FEI aware of any details regarding hydrogen incompatibility or hydrogen separation in the O'ahu service territory.

87.7 Please elaborate on the hydrogen blending demonstration carried out in Fort Saskatchewan, Alberta, and provide details (if available) related to the nature of load(s) served and any accommodations undertaken to facilitate the end use of hydrogen blends in natural gas supply.

Response:

According to publicly available information, ATCO is currently supplying 5 percent by volume hydrogen blends to ~2,100 residential and commercial customers in the municipality of Fort Saskatchewan.[3] Extensive testing has found that ATCO's planned hydrogen blend rates do not impact end use appliances or existing piping material. There are no noticeable changes in the gas supply at the proposed blend rates anticipated by ATCO.

87.8 Please indicate whether or not Hawaii Gas has had any safety incidences related to gas leaks on its system and/or for customers and, if so, please provide information on the frequency and severity of the incidences.

Response:

FEI is not aware whether or not Hawaii Gas has had any safety incidents related to gas leaks on its system and/or for customers.

[3] ATCO, "Fort Saskatchewan Hydrogen Blending Project Info Sheet" (2022), online at: https://gas.atco.com/content/dam/web/projects/projects-overview/fort-sask-hydrogen-blending-info-sheet-june2022.pdf

88. Reference: Exhibit B-38, Pages 3 & 4, A6

> For clarity, the Supply Potential Study, filed as Appendix B-1 to FEI's Application, is a report prepared for FortisBC, BC Bioenergy Network, and the Provincial Government by Envint Consulting and Canadian Biomass Energy Research Ltd. It was commissioned to "estimate the technical supply potential of renewable and low-carbon gases in B.C., Canada and the United States".[6] In contrast, FEI's LTGRP provides a long-term outlook or forecast for its total supply of renewable and low-carbon gas.[7] FEI has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies (RNG, hydrogen, syngas and lignin).[8] The amount of each resource to be acquired and delivered to customers throughout the planning period will ultimately be predicated by several variables, including quantity and timing of resource availability, resource development and delivery, and location.[9]

88.1 In the absence of significant development of hydrogen, syngas and lignin applications by 2030, what would FEI's planned or forecast portfolio of renewable and low-carbon gases (by 2030) consist of?

Response:

Please refer to the responses to the BCUC IR2 72.9 series for FEI's strategy to seek all cost-effective renewable and low-carbon gas resources available to it. Please also refer to the response to BCUC IR1 74.2 for a comprehensive discussion of the initiatives that FEI expects to use to meet the 2030 GHG reduction goals if the contracted supply of renewable and low-carbon gas is lower than forecast.

88.2 In the absence of significant development of hydrogen, singas and lignin applications by 2030, does FEI foresee that (on the supply-side) RNG alone will contribute to its reaching its 2030 GHG reduction goals?

Response:

Please refer to the response to BCUC IR1 71.8. FEI considers that its Clean Growth Pathway is flexible enough to make adjustments to its decarbonization initiatives that will meet Provincial GHG reduction goals for 2030 if the development of hydrogen, syngas and/or lignin supplies is slower than anticipated in the 2022 LTGRP Application. Such adjustments could include greater supply of RNG as well as greater advancements of other low-carbon initiatives such as those outlined in the response to BCUC IR1 74.2.

88.3 FEI states that it has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies. What were the main obstacles to FEI developing these separate forecasts in the context of its 2022 LTGRP?

Response:

As stated in the 2022 LTGRP Application and referenced in the preamble, FEI has not developed a forecast of the individual components of the renewable and low-carbon gas portfolio as the supply development is still in the early stages, and insufficient information exists to forecast the volume for each component of its renewable and low-carbon gas portfolio at this time. FEI used the various supply potential studies referenced in the 2022 LTGRP Application and its understanding from discussions with industry experts to ensure the outlook provided on renewable and low carbon gas was reasonable. However, identifying this outlook as a “forecast” of renewable and low carbon gas supply mix would not provide additional meaning or value to the 2022 LTGRP Application at this early phase of development for these resources.

Please refer to the responses to BCUC IR1 52.4 to 52.6 for a discussion of risks and opportunities related to acquiring and producing the forecasted amounts of renewable and low-carbon gas.

88.4 FEI states that it has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies. Does FEI foresee that it would be in a better position to develop these separate forecasts in the context of its next LTGRP?

Response:

FEI anticipates that more information about the evolving market for renewable and low-carbon gas will be available in each of its successive LTGRPs, better positioning FEI to develop separate forecasts. The extent to which such information will allow FEI to develop a forecast for all the individual components of its renewable and low carbon supply portfolio for its next LTGRP is unknown at this time. Please refer to the response to BCUC IR1 1.1.2 and the discussion in Section 6.2.3 of the 2022 LTGRP Application.

89. Reference: Exhibit B-38, Page 4, A7

> **Q7: MS2S states (at page 4) that the cost of green hydrogen would exceed the current allowable maximum of $31/GJ specified by the GGRR and (on p. 5) that it would be an expensive alternative to natural gas, citing green hydrogen costs of approximately $38/GJ at average BC Hydro rates and approximately $14/GJ, which MS2S says is three times that of fossil gas. How does FEI respond?**
>
> A7: MS2S's evidence applies a static view of the price for green hydrogen, and a static view of policy, which is inappropriate during a time of rapid technological and policy development. FEI makes the following five points in further reply to MS2S.
>
> First, the maximum allowable price for hydrogen under the GGRR varies with the annual average All-items Consumer Price Index for British Columbia, as published by Statistics Canada. While the maximum amount in effect for 2021/2022 was $31 per GJ, for subsequent years, the maximum amount is calculated by multiplying the maximum amount in effect for the preceding year, and the sum of 1 plus the annual percentage change in the Consumer Price Index for the previous year. Appling this formula, the maximum allowable price for 2023/2024 is approximately $35.50 per GJ, not $31 per GJ as noted by MS2S.

89.1 Please confirm what is the assumed BC Hydro (electrical) power rate that is used in the calculation of the maximum allowable price for 2023/2024 hydrogen (from electrolysis) of approximately $35.50 per GJ.

Response:

The maximum allowable price for hydrogen under the GGRR is set by an escalating formula provided in section 9 of the GGRR,[4] and not by reference to any assumed electrical power rate or forecast from FEI.

> **Maximum amount for costs**
>
> **9** For the purposes of sections 2 (3.8) (a), 6 (c), 7 (2) (b) and 8 (1) (b),
>
> (a) the maximum amount in effect in the 2021/2022 fiscal year is $31 per GJ, and
>
> (b) for fiscal years subsequent to the 2021/2022 fiscal year, the maximum amount is calculated on April 1 of each year by multiplying
>
> (i) the maximum amount in effect in the immediately preceding fiscal year, and
>
> (ii) the sum of
>
> (A) 1, and
>
> (B) the annual percentage change for the previous calendar year.
>
> [en. B.C. Reg. 134/2021, s. 3.]

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[4] *Greenhouse Gas Reduction (Clean Energy) Regulation*, B.C. Reg. 134/2021, online at: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012.

89.2 Please explain what forecast BC Hydro (electrical) power rate is used in the calculation of the maximum allowable price for 2030 & 2040 hydrogen (from electrolysis).

Response:

Please refer to the response to CEC IR3 89.1.

89.3 Please comment on any sensitivity analysis FEI may have undertaken to ascertain the impact of (electrical) power rate variability on hydrogen production costs (from electrolysis).

Response:

The BC Renewable Gas Potential Study,[5] Section 4.4.1, explores green hydrogen production potential in BC and models various cost curve scenarios. The sensitivity analysis in the Study only considers grid power supply to a green hydrogen producer at BC Hydro rates including escalation, or off-grid power from wind assets which are owned by the hydrogen producer and firming power is imported from the grid by the hydrogen producer at BC Hydro rates plus escalation. This analysis indicates that the levelized cost to produce green hydrogen would likely exceed the GGRR price cap (as it currently stands) prior to 2030. The following items were not considered in the Study which would improve the economics such that hydrogen could likely be produced at a levelized cost below the GGRR price cap prior to 2030:

- Investment Tax Credit schemes such as the proposed federal ITC to reduce capital costs;
- Flexible power supply tariffs that would make available lower cost off-peak or curtailed renewable energy from fluctuating output generating resources;
- Revenue from providing ancillary services to the power grid such as load balancing and frequency support; and
- Revenue from byproduct oxygen sales to adjacent industrial customers to displace higher cost oxygen that may be separately imported or produced onsite.

5 Exhibit B-1, Appendix D-2.

89.4 Please explain as to how the sensitivity analysis FEI may have undertaken to ascertain the impact of (electrical) power rate variability on hydrogen (from electrolysis) production costs has informed FEI's assessment of the availability of hydrogen (from electrolysis) production by 2030 and 2040.

Response:

Please refer to the response to CEC IR3 89.3.

89.5 Please explain what the technology assumption is with respect to the electrolysis process anticipated in the maximum allowable price for 2023/2024 hydrogen production and for 2030 and 2040 production.

Response:

FEI is not aware of any technology assumption with respect to hydrogen production in the maximum allowable price for 2023/24 or further out to 2030/40 in the GGRR. The price cap and the price escalation mechanism are set by the Province in the GGRR and represent the maximum price that FEI can pay to acquire (purchase and/or produce) renewable gas and low-carbon fuels using different resources, technologies, and pathways including Renewable Natural Gas (biomethane), clean hydrogen, synthesis gas, and lignin.

90. Reference: Exhibit B-38, Page 7, Q9/A9

Q9: In response to CEC's IR1 1.2, requesting that MS2S "confirm that the FEI existing system would not be permitted to operate with pressures in excess of its specific pipeline limits", MS2S states that it does not know which regulator is responsible for regulating the operating pressures of FEI's system, but says that FEI's "Lower Mainland CTS/VTS/EGP transmissions system operates well above" the typical pressure of US interstate pipelines, at 2,160 PSI. MS2S states that "The Canadian Standards Association (CSA) publishes a biennial update to its pipeline standards, but these are guidelines developed in concert with the oil and gas industry - not binding, enforced government regulations." What is FEI's response?

A9: First, the operating pressure of FEI's transmission and distribution pipelines is regulated under the Oil and Gas Activities Act25 (OGAA) framework. FEI must operate its pipelines in accordance with the OGAA Pipeline Regulation,[26] which incorporates the Canadian Standards Association (CSA) "CSA Z662, Oil and Gas Pipeline Systems" standard.[27]

Second, MS2S is incorrect that the "Lower Mainland" system operates at 2,160 PSI. The Coastal Transmission System (CTS), which serves Lower Mainland and Fraser Valley customers, operates at a maximum of 583 PSI. The Vancouver Island Transmission System (VITS) serves customers on Vancouver Island, Squamish, Sunshine Coast and Whistler, and operates at a maximum of 2,160 PSI. The operating pressures of these individual transmission systems are set in accordance with CSA Z662 as required by the *Pipeline Regulation*.

90.1 What is the typical pressure (or range of pressures) that most US interstate pipelines are presently operated at?

<u>Response:</u>

FEI cites the following publicly-available information from the U.S. Energy Information Administration:

> The U.S. natural gas pipeline network is a highly integrated network that moves natural gas throughout the continental United States. The pipeline network has about 3 million miles of mainline and other pipelines that link natural gas production areas and storage facilities with consumers. In 2021, this natural gas transportation network delivered about 27.6 trillion cubic feet (Tcf) of natural gas to about 77.7 million consumers.[6]

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6 U.S. Energy Information Administration (EIA), "Natural gas explained: Natural gas pipelines" (November 18, 2022) online at: https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

According to a public report commissioned by the Interstate Natural Gas Association of America, "natural gas interstate transmission systems operate at pressures on the order of 500 to 1,800 psi".[7]

90.2 Please confirm that, directionally, risks associated with hydrogen blending in gas pipelines are generally higher where higher operating pressures are concerned. For example, when operating at 2,160 PSI versus 583 PSI.

Response:

The integrity risk that hydrogen embrittlement poses to a steel pipeline operating at high pressures generally depends upon the following:

1. the presence of imperfections in the steel wall of the pipeline such as crack-like defects on the inside of the pipeline;
2. the presence of atomic hydrogen generated from the disassociation of hydrogen gas molecules introduced as a blend in the gas stream; and
3. high operating pressure pipelines that experience large dynamic pipeline pressure swings, for example, in the form of diurnal pressure variations between morning and evening gas demand variations.

From the perspective that these factors are relevant at high operating pressures, pressure is a general determinant of the risks faced by pipelines operating at high pressures. However, the difference in risk faced by pipelines operating at various high pressures is more complex and must consider the above factors as they apply to a specific pipeline. Therefore, it is not possible to categorically state that a transmission pressure pipeline operating at a higher maximum operating pressure would automatically face a higher integrity risk from hydrogen embrittlement as compared to a transmission pressure pipeline operating at a lower, but still high, maximum operating pressure.

Given the complex nature of the analysis required, FEI has planned the BC Gas System Hydrogen Blending Feasibility and Technical Assessment project to complete the necessary analysis to determine the risk to FEI's transmission system pipeline assets from hydrogen blending and inform FEI's near-term and long-term hydrogen blending strategy goals and roadmap plan.

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[7] Interstate Natural Gas Association of America, "The Interstate Natural Gas Transmission System: Scale, Physical Complexity and Business Model" (August 23, 2010) online at: https://ingaa.org/the-interstate-natural-gas-transmission-system-scale/.

90.3 Please qualify and/or quantify (where possible) the order-of-magnitude by which risks associated with hydrogen blending in gas pipelines increases (if that is the case) from a lower operating pressure (such as 583 PSI) to a higher operating pressure (such as 2,160 PSI).

Response:

The risk as requested cannot be quantified at this time. Please refer to the response to CEC IR3 90.2.

90.4 Please confirm that the quality and strength of a pipeline is also a key factor in determining what level of operating pressure a pipeline can operate at safely.

Response:

FEI confirms that the pipeline material specification including properties, such as the quality of the steel used to manufacture the pipe and the strength of the finished pipe product, are key factors in determining a pipeline's maximum allowable operating pressure.

90.5 Please delineate all risks under consideration for pipelines containing hydrogen blends (i.e. a range of hydrogen blend concentrations).

Response:

The types of risk and the magnitude of the risk in terms of stipulating a range of hydrogen blend concentrations will vary depending on numerous factors, some of which include pipe material, distribution pressure service or transmission pressure service, location (rural right of way or urban location), vintage, and other considerations. FEI will need to engage industry experts to complete a thorough risk assessment and advise on the acceptable blend limits across all its gas system and behind-the-meter customer infrastructure before FEI will be able to delineate all risks as requested in this IR. As discussed in the response to CEC IR3 90.2, FEI plans to complete this work as part of the BC Gas System Hydrogen Blending Study and Technical Assessment which will include activities to complete a Quantitative Risk Analysis (QRA).

91. Reference: Exhibit B-38, Page 9, A10

> FEI expects to initially blend hydrogen into the distribution pipeline network,[32] which is considered less vulnerable to the effects from hydrogen embrittlement, and constitutes 94 percent of FEI's total pipeline infrastructure.[33] Approximately 65 percent of the distribution lines are made of polyethylene materials, which are not compromised by the presence of hydrogen in the gas stream.[34] The remaining 35 percent of the distribution lines are made from a type of steel that is less susceptible to hydrogen embrittlement.[35] Based on the combination of materials and low operating pressures of the distribution system, distribution lines are generally considered compatible with hydrogen blend concentrations well beyond that of appliances and potentially compatible with up to 100 percent hydrogen. Some components of the distribution network may need to be upgraded or replaced beyond a certain hydrogen blend concentration, but this equipment is relatively easily upgraded or replaced, if required.[36] FEI will execute system-wide technical analysis and community level demonstration projects, as well as secure all necessary regulatory approvals, before blending hydrogen into its gas infrastructure.[37]

91.1 Please provide the operating pressure (or the range of operating pressures) for FEI's distribution pipeline networks in BC.

Response:

The distribution system consists of four basic distribution pressure classifications as follows:

- 700 kPag (102 psig) DP systems found primarily in the Coastal System of the Province.
- 550 kPag (80 psig) DP systems found on Vancouver Island system.
- 420 kPag (61 psig) DP systems found widely throughout the Province.
- 140 or 175 kPag (20-25 psig) DP propane vapour systems throughout the Province.

91.2 Please elaborate on and, if possible, quantify in terms of probability and consequences for the magnitude of the statement 'less susceptible', which FEI uses to describe the hydrogen embrittlement effects associated with FEI's distribution lines that are not made of polyethylene materials.

Response:

As described in the preamble, "...distribution lines are generally considered compatible with hydrogen blend concentrations well beyond that of appliances and potentially compatible with 100 percent hydrogen." It is not possible for FEI to further elaborate on the quantification of risk (probability and consequence) associated with blending hydrogen in distribution lines at this time, as this analysis has not yet been completed.

91.3 As it concerns the effects from hydrogen embrittlement, what is FEI's present assessment of the compatibility (with hydrogen blend concentrations) of the materials used in the gate station pressure regulators, which serve its distribution pipeline network?

Response:

FEI has not yet completed an exhaustive hydrogen compatibility review of its gate station assets. Individual technical assessment of FE's gate stations and their components will be evaluated in the system-wide technical analysis referenced in response A10 of FEI's Rebuttal Evidence to MS2S. However, FEI currently operates a large fleet of Mooney Flowgrid regulators within its current gate stations that control the gas flowing from the high pressure network to the low-pressure network, which have seen 10-15 percent by volume hydrogen blends in the Hawaii Gas network for decades.[8] Furthermore, manufacturers and suppliers of gas system components, such as the regulators that FEI mentioned above, continue to prepare their products for the hydrogen market by validating their products for hydrogen blended service.[9]

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[8] Online at: https://pgjonline.com/magazine/2023/february-2023-vol-250-no-2/features/say-aloha-to-new-trend-of-hydrogen-blending-with-hawaii-gas.

[9] Baker Hughes, "Hydrogen Processes Energy Transition Challenges Innovative Valve Solutions", (January 2023), online at: https://dam.bakerhughes.com/m/5fafbf240a823f83/original/BH-Valves-Hydrogen-BR-34612A-0921b-English.pdf.

92. Reference: Exhibit B-38, Page 10, A11

> MS2S quotes an excerpt from the report that indicates Australia's agreement not to support the blending of hydrogen in existing gas transmission networks until further evidence emerges that hydrogen embrittlement issues can be safely addressed.[40] This quote, taken alone, may provide the impression that Australia does not support hydrogen blending in general. However, the report also notes that Australia's HyP Murray Valley project, if completed, will be the largest hydrogen blending project in the world, and is one of several hydrogen blending projects in Australia.[41] Australia has also initiated regulatory reforms to bring hydrogen blends under the national gas regulatory framework, in order to ensure regulatory barriers would not restrict proposed investments in renewable gas projects such as hydrogen blending, and to ensure existing regulatory protections apply.[42]

92.1 Please elaborate on the nature of Australia's HyP Murray Valley project. Does it involve hydrogen blending in a gas transmission or a gas distribution network? What type of customers does it intend to serve?

Response:

FEI understands that the project will supply blended hydrogen into the existing gas distribution networks to more than 40,000 commercial, residential, and industrial customers.[10]

92.2 Presently, what is the status of Australia's HyP Murray Valley project?

Response:

The objective of A11 of FEI's Rebuttal Evidence was to demonstrate that MS2S's suggestion that Australia does not support hydrogen blending is an incomplete interpretation of the Carbon Intensity of Hydrogen Production Methods report.

FEI understands that work is currently focused on engineering, design and approvals. Production from the facility and delivery to customers is expected to commence in early 2025.[11]

92.3 Please provide any relevant material to the Australian plans for blending hydrogen that are not currently on the record in this proceeding but may assist interveners

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[10] Australian Gas Infrastructure Group, "Hydrogen Park Murray Valley", online at: https://www.agig.com.au/hydrogen-park-murray-valley.

[11] Australian Gas Infrastructure Group, "Hydrogen Park Murray Valley", online at: https://www.agig.com.au/hydrogen-park-murray-valley.

and the Commission in fully understanding this particular rebuttal of MS2S evidence.

Response:

A survey of publicly available material on hydrogen blending projects in Australia is not necessary to fully understand FEI's Rebuttal Evidence to MS2S's suggestion that Australia does not support hydrogen blending. The references to Australian blending projects in A11 of FEI's Rebuttal Evidence to MS2S are examples that demonstrate Australia is, in fact, a jurisdiction in which hydrogen blending is supported.

93. Reference: Exhibit B-38, Page 40, A16

> **Q16: MS2S claims that hydrogen prolongs the lifetime of methane in the upper atmosphere, effectively making it a GHG (page 16). How does FEI respond?**
>
> A16: For clarity, MS2S does not challenge the well-established fact that hydrogen is carbon-neutral at the point of combustion. Rather, MS2S cites three reports for the proposition that hydrogen fugitive emissions (i.e., from hydrogen production or pipeline leakage) prolong the lifetime of methane in the upper atmosphere, impacting climate warming. FEI has acknowledged that hydrogen leakage along supply chains will be an important consideration and additional analysis may be required to understand potential environmental impacts from deploying hydrogen, particularly at large scale into the future.[56] However, FEI refers to the British Columbia report on the Carbon Intensity of Hydrogen Production Methods as the most up to date reference on lifecycle carbon intensity for hydrogen production methods,[57] and notes that, to FEI's knowledge, there has been no guidance provided on any potential indirect global warming potential of hydrogen, including by a leading world authority, the Intergovernmental Panel on Climate Change, or from the British Columbia or federal governments.[58] FEI expects that future policy developments will consider any contribution of hydrogen leakage as Scope 1 emissions and compare it to the reduction of emissions from the use of hydrogen to displace fossil fuels.
>
> FEI will monitor the changing state of climate science to minimize indirect warming potential associated with all GHGs. With respect to developing its plan to evaluate the integration of hydrogen, FEI will rely on the emission factors for hydrogen as established by government authorities where available.

93.1 Please explain whether FEI is aware of other authorities (other than those mentioned in the referenced paragraph above) that may have studied, written about or produced reports on the indirect global warming potential of hydrogen.

<u>Response:</u>

There are many publicly available third-party sources of information on this topic. FEI will continue to monitor the changing state of climate science to minimize indirect warming potential associated with all GHGs. With respect to developing its plan to evaluate the integration of hydrogen, FEI will rely on the emission factors for hydrogen as established by government authorities where available.

93.2 Please provide the estimated quantity of natural gas that leaks from the FEI transmission and distribution networks (on a % and GJ basis) and confirm that if hydrogen was blended into the FEI distribution networks any leakage would potentially reduced natural gas leakage and that this would reduced the introduction of methane CH4 into the atmosphere as a GHG.

Response:

The presence of hydrogen could displace a percentage of leaked methane; however, FEI has not completed a thorough lifecycle analysis to evaluate this displacement.

FEI's estimate of natural gas leakage from the transmission system and distribution system is presented in the table below. FEI's policy is to continue to reduce fugitive emissions of methane from the gas system and by extension, reduce the potential for hydrogen leakage from the gas system resulting from any hydrogen distributed as a blend with conventional gas in the gas system. A gas distribution system that is 'leak tight' will remain 'leak tight' with hydrogen.[12]

2022 Transmission System Fugitive	182,588	**GJ**
	0.079	**%**
2022 Distribution System Fugitive	147,342	**GJ**
	0.064	**%**

93.3 Please provide an assessment of how much the hydrogen H2 would impact lengthening of the methane time in the atmosphere until it breaks down versus the introduction of new methane time in the atmosphere.

93.3.1 If so, please provide details and links to such reports and/or literature (if available).

Response:

FEI expects that emissions factors would include an assessment of how much the hydrogen would impact lengthening of the methane time in the atmosphere until it breaks down versus the introduction of new methane time in the atmosphere.

Please also refer to the response to CEC IR3 93.1.

[12] Canadian Gas Association, "Enabling Higher-Hydrogen Blending in the Natural Gas Distribution System", (October 2022), online at: https://www.cga.ca/wp-content/uploads/2022/10/CGA-Hydrogen-Blending-Greater-than-5.pdf.

94. Reference: Exhibit B-38, Page 15, A17

> **Q17: MS2S claims that there are additional GHG emissions implications of the source ("colour") of the hydrogen used. Has FEI taken into account the lifecycle emissions of different sources of hydrogen?**
>
> A17: Yes. Lifecycle emission factors represent the GHG emissions from upstream fuel production to fuel consumption at the end use appliance.[59] In Table 1-2 of the Application, FEI provides an estimate of the lifecycle GHG intensity associated with green hydrogen and blue hydrogen. Green hydrogen was assumed to have a lifecycle emission factor of close to zero, as it was assumed to be made from a low-carbon source of electricity (hydro, wind or solar). Blue hydrogen's lifecycle emissions estimate was based on the emissions from producing natural gas, the efficiency of conversion to hydrogen, and energy inputs

94.1 Does FEI envision the forthcoming hydrogen 'economy' in B.C. to be self-contained (i.e. exist in isolation from hydrogen production activities of other provinces or jurisdictions), or does FEI envision a 'pan-Canadian' or a 'pan-Pacific North-western' type of hydrogen economy? Please elaborate.

Response:

FEI anticipates that a low-carbon hydrogen economy will ultimately include aspects of local, national, North American and global markets. However, FEI's development of hydrogen supply for its customers is not dependent on a particular combination or pathway.

Please refer to the responses to BCUC IR1 52.4 and 61.3 for FEI's views on acquiring low-carbon hydrogen supply from various sources and geographical areas and the ongoing activities to support hydrogen technology development.

94.2 Given the answer to the above question, please comment on the appropriateness of FEI's assumption of using a single lifecycle emission factor of close to zero for green hydrogen in its 2022 LTGRP.

Response:

Please refer to the response to MetroVan IR1 1.2 for further discussion on the lifecycle emission factors adopted as part of the forecasting conducted for the 2022 LTGRP Application. Further to the evidence presented in the referenced documentation, the Province released a study on the carbon intensity of hydrogen production methods in BC.[13] This study only examines green hydrogen produced from power supplied from the BC power grid and calculated a lifecycle carbon intensity of approximately 10 kgCO_2e/GJ. This value is slightly higher than the minimum value in FEI's referenced evidence which examined the carbon intensity of green hydrogen produced

[13] Exhibit A2-2, Carbon Intensity of Hydrogen Production Methods.

using electricity supplied from wind farms with limited grid power used to backup the power supply from the wind resources.

94.3 Presuming that a portion of the green hydrogen that would be supplied to FEI over the course of the next 20 years is produced in other provinces or jurisdictions, how would FEI account (in its LTGRP) for the (potentially varying) lifecycle emission factors associated with the green hydrogen produced outside of B.C.?

Response:

FEI interprets this question to be asking how it will account for the varying lifecycle emissions associated with hydrogen supply. Similar to existing renewable natural gas sources, FEI anticipates that the lifecycle GHG emissions associated with hydrogen production will be quantitatively assessed on an annual or biennial basis for each production facility, whether it is within or outside of BC.

94.4 Please provide the estimates for the costs of producing green hydrogen based on technology developments over the period of time from 2023 to 2030, 2040 and 2050.

Response:

Please refer to Section 4.4 of the BC Renewable Gas Supply Potential Study that presents levelized green hydrogen production cost curves that consider long-term capital and operating cost reduction due to technology developments out to 2050.[14] Please also refer to the responses to BCUC IR1 62.9 and 71.8.1 and FEI's Rebuttal Evidence to MS2S Evidence (A7) for a discussion of FEI's considerations for hydrogen costs.

94.5 Please confirm that there is an expectation that the development of the electrolysis technology for producing green hydrogen is targeting to move from $3/kg or $5/kg to $2/kg and perhaps as low as $1/kg.

[14] Exhibit B-1, Application, Appendix D-2.

Response:

Yes, the North American hydrogen market, primarily incented through recently-announced strategic government support in the United States (US), is targeting a reduction in the cost to produce clean hydrogen to $1 USD per kg (approximately $7 per GJ) by 2030.[15] FEI is monitoring hydrogen market development closely in Canada and the US and expects that supplies of lower cost clean hydrogen from outside BC will form an important component of FEI's future gas supply mix. The responses to BCUC IR1 62.2 and 62.3 outline how it expects to be able to purchase on-system and off-system hydrogen and how the purchase of hydrogen from suppliers outside of BC would contribute to FEI's decarbonization plans.[16]

94.6 Please provide for the record any information FEI has access to which provides a perspective on the potential for FEI to access much less expensive green hydrogen in the future.

Response:

Please refer to the response to CEC IR3 94.5.

[15] US Department of Energy Office of Energy Efficiency & Renewable Energy, "Hydrogen Shot", online at: https://www.energy.gov/eere/fuelcells/hydrogen-shot

[16] See also: Response to CEC IR3 94.6.

EXHIBIT B-38: FEI SERVING THE MARKET FOR LNG AS A MARINE FUEL

95. Reference: Exhibit B-38, Page 17, A19

> When estimating potential reductions in GHG emissions from the use of LNG as a marine fuel, FEI used third-party carbon intensity measurements specific to FEI's LNG production facility at Tilbury. The ICCT reports that MS2S relies on for its lifecycle emissions analysis are not specific to the BC LNG supply chain or the Tilbury facility, but rather are based on global LNG input factors.[63] Using BC-supply factors is important in ascertaining emissions, as Tilbury is the only LNG facility currently operating in western North America that powers its liquefaction process with renewable electricity, and because BC's upstream natural gas production emissions management regime is one of the most stringent in the world.[64] According to the independent consultancy Sphera, the carbon intensity of LNG from FEI's Tilbury facility is 29 percent lower than the global average.[65] With the CleanBC Plan initiatives implemented by 2030, the carbon intensity of LNG produced in BC in 2030 can be about 50 percent lower than the current global LNG supply average.[66] The low emissions factor of BC's upstream natural gas production was recently recognized by a US regulator, when the Puget Sound Clean Air Agency required the owner of a new LNG project in Washington to ensure its sole source of natural gas supply comes from BC or Alberta.[67]

95.1 Please provide the approximate share of the daily LNG production at FEI's Tilbury, which is sold to displace vehicle transportation diesel and marine transportation diesel or bunker fuel.

Response:

In 2022, FEI sold 1.6 PJ of LNG to its transportation customers, displacing diesel and heavy marine fuels, representing about 12 percent of the maximum annual production capacity at Tilbury.

95.2 Please provide information on any other likely or possible markets for LNG, which FEI may find it appropriate to pursue.

Response:

Please refer to Sections 3.5 and 3.6 of the 2022 LTGRP Application. FEI believes that the marine market has the greatest potential in terms of market size and potential environmental benefits to the region.

95.3 Given the answer to the above question and presuming that by 2030 the carbon intensity of LNG produced in B.C. will be about 50% lower than the current global LNG supply average, please comment on the expected impact that B.C. facilities will have (by 2030, 2040 and 2050) on potential reductions in GHG emissions from the use of LNG as a marine fuel globally or for other potential LNG market uses.

Response:

FEI cannot speak to the potential GHG emissions reduction impact that other BC facilities may have. However, according to the Sphera study,[17] using BC LNG supply with the 2018 CleanBC plan initiatives implemented by 2030 would reduce carbon emissions by 24-30 percent when used by ocean going 2-stroke slow speed engines compared with diesel fuel. Thus, a one million tonne LNG marine fuel market in the Port of Vancouver by 2030 could reduce global GHG emissions by about 1.2 million tonnes of CO_2e annually.[18] Carbon emissions can be reduced even further by the transition of conventional LNG to renewable and low carbon gases. Seaspan's LNG-powered vessels have piloted the use of RNG, and it is expected that this action can reduce GHG emissions by upwards of 85 percent when compared to diesel fuel.[19]

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17 Sphera, "Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver – Final Results" (March 2020) (Sphera Port of Vancouver Report) online at: https://www.cdn.fortisbc.com/libraries/docs/librariesprovider5/sustainability-in-all-we-do/lifecycle-ghg-emissions-of-the-lng-supply-at-the-port-of-vancouver-footnote-8.pdf.

18 Affinity, "Study on the Air Quality Benefits to the Port of Vancouver by Adopting LNG as a Marine Fuel" (October 2022) (Affinity Carbon Solutions) online at: https://talkingenergy.ca/sites/default/files/2023-02/Affinity%20Report%20%233%20-%20Rec%27d%20SN%2002.25.23%20Vancouver%20Air%20Quality%20Report%2012.10.2023.pdf.

19 Seaspan RNG Pilot online at: https://www.seaspan.com/press-release/seaspan-ferries-to-reduce-greenhouse-gas-emissions-through-using-carbon-neutral-renewable-natural-gas-in-lng-powered-vessels/.

96. Reference: Exhibit B-38, Page 19, A19

> FEI has reviewed the ICCT Reports in detail and has identified issues with the reliability of their data and analysis. Neither the ICCT EU Report nor the ICCT Emissions Factors Report claim to meet the leading international standards on lifecycle assessment (ISO 14040/14044) or claim to be peer-reviewed. With respect to the prevalence of high methane slip engines, the ICCT EU Report uses outdated vessel fleet data that is dominated by older, obsolete 4-stroke low pressure dual fuel diesel electric engine technologies which have relatively high levels of methane slip. This technology has been and will continue to be upgraded by engine manufacturers to further reduce methane slip, and is largely limited to short-sea, coastal vessels. SEA-LNG, a multi-sector industry coalition, has raised the same concerns with the ICCT EU Report in the past.[75] The ICCT EU Report also fails to acknowledge the aggressive technical measures being implemented by marine engine manufacturers to minimize and eliminate methane slip.

96.1 What percentage of the global fleet of 'obsolete 4-stroke low pressure dual fuel diesel electric engine technologies' does FEI expect will be upgraded annually going forward?

<u>Response:</u>

FEI is not able to predict the vessel replacement schedules of shipowners, or the project schedules of engine manufacturers. However, as stated in A22 of FEI's Rebuttal Evidence to MS2S, starting on page 21, the transition away from heavy fuel oil and diesel will be precipitated by the implementation of international and regional greenhouse gas reduction programs.

96.2 In the opinion of FEI, how many years will it take manufacturers to fully upgrade the global fleet of 'obsolete 4-stroke low pressure dual fuel diesel electric engine technologies'?

<u>Response:</u>

Please refer to the response to CEC IR3 96.1.