EB-2024-0111

Energy Futures Group Responses to Interrogatories on Exhibit M1

September 6, 2024

M1-CBA-1

Reference: Exhibit M1, page 19.

Preamble: Further, to reduce emissions, RNG procurement needs to be sourced from the development of new capacity, and not merely be repurposed or re-contracted from pre-existing RNG uses.

Question:

(a) Please confirm that the assertion "to reduce emissions, RNG needs to be sourced from the development of new capacity" is an assertion from the perspective of the world at large, and that from the perspective of an individual customer seeking to reduce their emissions to meet their legal obligation and/or personal emission reduction goals, individual customers can reduce their emissions by taking legal ownership of RNG sourced from existing capacity that is repurposed or re-contracted from pre-existing RNG uses.

Response:

a) Burning RNG produces the same volume of emissions at the point of combustion as burning fossil gas, with the only difference being that burning RNG may eliminate or reduce some emissions that otherwise would have occurred prior to combustion (e.g., from emissions of methane, which is itself a potent greenhouse gas), creating an offset to the combustion emissions. If RNG that is purchased was already being used for another purpose (e.g., such that there were no methane emissions to eliminate or translate into an offset), there may or may not be actual emission reductions as a result of the purchase (depending on a variety of factors). Whether purchases from existing sources would meet a legal obligation and/or personal emission reduction goals will depend on the nature of the legal obligation and/or the personal reduction goals.

M1-CBA-2

Reference: Exhibit M1, page 19-20.

Preamble: In Vermont, the Clean Heat Standard under final development specifically includes a requirement that Vermont Gas purchase the transmission pathway to its distribution system in Vermont before it can claim any GHG emission reduction from procured RNG.

Questions:

(a) Please provide of copy of the most recent version of the Clean Heat Standard referred to in the above excerpt.
(b) Is it the belief of the Energy Future Group that the cost of transmitting RNG from its source to the EGI franchise area to be consumed by EGI customers will not be accounted for by EGI under its proposal when considering the cost of RNG procurement?

Response:

a) The Affordable Heat Act, Vermont Legislature S.5 Act 18, as enacted can be found at:

https://legislature.vermont.gov/Documents/2024/Docs/ACTS/ACT018/ACT018%20As%20Enacted.pdf.

b) Based on the discussion of the "book and claim" accounting mechanism for RNG procurement, it was not clear to EFG that the costs for transmission rights for out of region procurement would be included in the cost for RNG procurement. We recommend that if out of region sources are eligible, that the costs for transmission of the RNG be accounted for and included in the costs.

M1-CBA-3

Reference: Exhibit M1, page 19.

Preamble: To protect ratepayers, we recommend the Company not be allowed to procure RNG with a price higher than $25.58/GJ, which already represents an extremely high cost per unit of emission reduction.

Question:

(a) Please confirm that Energy Future Group is suggesting a cap of $25.58/GJ on the purchase of any RNG under all procurement contracts, as opposed to a cap on the weighted average cost of RNG procured by EGI across all RNG purchases.

Response:

a) Confirmed, EFG recommends a cap for cost of procurement of no more than $25.58/GJ be applied to all contracts. The weighted average cost of RNG procured across all contracts would therefore by necessity be at or lower than the cap of $25.58/GJ for any individual contract in the portfolio. We also recommend procurement of RNG reflect differences in carbon intensity.

Ideally, if EGI accounts for variation in the carbon intensity of RNG sources as a factor in procurement, the price cap would be based on the cost per tonne CO2e reduction. The per contract price cap of $25.58/GJ would apply to an RNG source with 0 carbon intensity, offsetting 100% of the fossil gas emissions. With a GHG avoidance of 0.05 tonnes CO2e per GJ[1] of RNG, the cost per tonne of CO2e avoidance would be $511.60/tonne.

An RNG source with a negative carbon intensity would have higher price cap (for example if it offset 150% of the fossil gas emissions the cap would be 1.5*$25.58 = $38.37/GJ), while an RNG source with carbon intensity greater than zero, that only partially offsets fossil gas emissions would have a lower price cap (a 50% offset would have a cap of $12.79/GJ). Due to the higher and lower avoided emissions for these sources, the equivalent $/tonne CO2e also equal $511.60. In all three cases, the price caps reflect the relatively high cost for avoided emissions from RNG.

[1] EB-2024-0111, Phase 2 Exhibit 4 Tab 2, Schedule 7, p. 29.

M1-CCC-1

Reference: Exhibit M1

Question:

Please provide the Terms of Reference for this consulting engagement.

Response:

The terms of reference for this consulting engagement are in a letter to the OEB from Environmental Defence and the Green Energy Coalition dated June 11, 2024.

M1-CCC-2

Reference: Exhibit M1, page 7

Question:

The evidence points to "energy efficiency investments that reduce heating loads – e.g. weatherization of homes and businesses" as an example of a "safe bet" that is likely to play a significant role in the energy transition across a variety of plausible future scenarios. Is Energy Futures Group proposing that if the OEB approves the ETTF that energy efficiency investments should be funded through the ETTF? If so, how would this be different than EGI's DSM spending?

Response:

No. We are suggesting that it would be much more cost-effective to reduce emissions with increased DSM spending than from many (if not all) of the ETTF projects Enbridge is likely to fund under its proposal. Ideally, Enbridge should fund all DSM that is cost-effective relative to the cost of other greenhouse gas emission reduction investment alternatives. The Company's current DSM programs do not come close to capturing all cost-effective DSM. Though the Company is contemplating significant increases in DSM spending and savings (as shown in its recent DSM stakeholder presentations on possible future plans), even the increases Enbridge is contemplating would fall far short of all cost-effective DSM.

M1-CCC-3

Reference: Exhibit M1, page 9

Question:

EGI specifically identifies carbon capture utilization and storage (CCUS) technologies for both commercial and industrial applications as a potential priority for funding through the ETTF. Is EFG aware of other studies that have addressed CCUS technologies? If so, please identify those studies. Could further research by EGI be considered redundant in light of work that has been done or is currently being done in other jurisdictions?

Response:

EFG has not conducted an independent review of other CCUS projects or studies and doing so would be beyond the scope of the evidence we have been asked to prepare. However, a report by the Global CCS Institute identified 196 CCS projects across the globe, 30 of which were operational as of September 2022 (https://status22.globalccsinstitute.com/wp-content/uploads/2023/03/GCCSI_Global-Report-2022_PDF_FINAL-01-03-23.pdf). Enbridge itself is developing a project in Alberta (https://calgaryherald.com/business/energy/enbridge-carbon-capture-utilization-storage-project-capital-power-decision).

It is certainly possible that research conducted by EGI would be redundant with work being conducted in other parts of the world. It would depend on the nature of the potential project, including the extent to which it is focused on demonstrating the applicability of the technology to a range of potential Ontario businesses.

M1-CCC-4

Reference: Exhibit M1, page 9

Question:

Enbridge has suggested that it has an interest in potentially using ETTF funds to support development of end-use technology, such as residential furnaces and water heaters that can burn methane-hydrogen blends that contain more than 20% (by volume) hydrogen. EGI adds that a significant amount of work is needed to develop the end-use equipment for the residential, commercial and industrial application that would be compatible with higher blends of hydrogen. Is it EFG's view that such work is not in the best interests of EGI ratepayers?

Response:

Yes.

M1-CCC-5

Reference: Exhibit M1, page 10

Question:

EFG refers to an order by the Massachusetts Department of Public Utilities, for its state's gas utilities to invest in pilot projects to test the potential for cost-effective GHG emission reductions through networked geothermal systems. If the OEB approves an ETTF for EGI does EFG propose this type of study would be appropriate? If so, why should EGI natural gas ratepayers fund geothermal studies? Wouldn't it be more appropriate for these types of studies to be undertaken by government entities or funded through the electricity sector?

Response:

A pilot networked geothermal system could potentially be an appropriate investment for ETTF funds – to the extent that there is both an expectation that such systems could potentially be cost-effective decarbonization options for significant segments of the Ontario building stock and reason to believe that Enbridge investments in the technology could make a material difference in advancing the deployment of the technology in Ontario. EFG has not assessed the potential merits of investment in networked geothermal systems in Ontario.

To be sure, such a pilot could also be funded by government and/or the electricity sector. However, there is no single "correct" answer regarding who should fund such initiatives. One reason to potentially consider gas utility funding of a networked geothermal pilot is that future federal and/or provincial policy could put the onus of decarbonizing the gas sector on Enbridge. Guided in part by the "polluter pays" principle, that is what Clean Heat Standards recently adopted in Colorado and Vermont – and under development in Massachusetts and Maryland – would largely do. If the Company has direct experience with such projects, it will be better positioned to meet such future emission reduction obligations.

The development of networked geothermal systems also has potential synergies with gas utility expertise with laying pipe and is seen by some as potentially part of way to transition the natural gas utility industry's business model to one that is more sustainable in a decarbonizing future.

That said, our report suggests that the ETTF focus on low-carbon fuel for high-heat industrial processes since Enbridge is addressing energy efficiency and now some residential and commercial electrification through its DSM efforts.

M1-CCC-6

Reference: Exhibit M1, page 12

Question:

The evidence states that, "With respect to "maintaining customers choice", the ETTF should only invest in technology that is likely to offer customers better choices. Please provide examples of technologies that could offer customers better choices in this context.

Response:

The general point we were making in our report is that investing ratepayer funds in a technology that is unlikely to be cost-effective relative to alternatives for reducing emissions is problematic. The specific example we were addressing was gas heat pumps, which the Board has recently found to be less cost-effective than electric heat pumps. In that context, the better choices are electric heat pumps, as well as a variety of other efficiency measures. In other contexts, it will be a different mix of measures.

M1-CCC-7

Reference: Exhibit M1, page 12

Question:

The evidence states, "Since Enbridge is addressing energy efficiency and now some residential and commercial electrification through its DSM efforts, the logical choice for a targeted ETTF would be a low-carbon fuel for high heat industrial processes." Is EFG aware of this type of work being undertaken in other jurisdictions? If so, please identify the studies being undertaken. If so, would further research by EGI be considered redundant in light of work that has been done or is currently being done in other jurisdictions? If EGI undertakes a study or pilot regarding low-carbon fuel for industrial processes how should that work be funded – by all customers groups or by industrial customers consistent with DSM cost allocation?

Response:

EFG has not conducted an independent review of projects or studies related to applications of low carbon fuels to high heat industrial processes; nor is that within the scope of the evidence we have been asked to prepare.

It is certainly possible that research conducted by EGI on this issue would be redundant with work being conducted in other parts of the world. It would depend on the nature of the potential project. Generally speaking, we would expect much less impact (if any) from Enbridge trying to *develop a new technological solution* (i.e., where Enbridge is one player among many across the globe that might be working on something) than from efforts to *demonstrate the application of new technology in the Ontario context* (where Enbridge has local connections, understands the local economy and can help adapt technology to local conditions). All other things being equal, demonstrations of new technologies in Ontario – given the mix of local industrial customers, local energy prices, local weather, local workforce capabilities and other local factors – are more likely to advance the potential for the technology to be adopted in the province than demonstrations in other parts of the world. Other Ontario businesses – not just industrial customers but also engineers and others in the supply chain who influence investments – are more likely to be aware of the demonstration and to put credence in its potential applicability to their situation. In addition, piloting technologies in Ontario can build Ontario-based expertise and capacity.

We do not have an opinion on cost allocation for an ETTF focused on industrial processes. However, we note that there would be potential benefits for all customers to the extent that these investments may reduce the risk of stranding assets that are used by all customers or allow for the costs of those assets continue to be defrayed over a wider customer base that includes industrial customers.

M1-CCC-8

Reference: Exhibit M1, page 13

Question:

EFG is recommending that the OEB create a stakeholder advisory committee that would be expected to work with Enbridge on both the development of a scoring rubric, the actual scoring of different options and ultimately the selection of project funding priorities. Does EFG have examples of such committees that have been established in other jurisdictions? If so, please provide those examples.

Response:

Mr. Neme participated in an informal committee of this sort to prioritize Commonwealth Edison's electric DSM spending on research and development in the Chicago area and found the process to be helpful. In addition, though they are different, Mr. Neme has served for several years on the OEB's Gas IRP Committee and Energy Efficiency Stakeholder Advisory Group. His experience with those processes is that – though far from perfect – they provide a forum in which Enbridge has to at least listen to a broader range of perspectives.

Although EFG is not aware of such formal committees in other jurisdictions that are focused on development of new gas decarbonization solutions, we have not conducted a search or jurisdictional review to determine if such committees exist and cannot confirm whether or not they may exist elsewhere.

M1-CCC-9

Reference: Exhibit M1, pages 14-20

Questions:

(a) With respect to the recommendation to "redirect funds to more cost-effective uses" resulting from a reduction to RNG portfolio targets, please discuss how the savings available to be redirected should be calculated.
(b) With respect to the recommendation to "redirect funds to more cost-effective uses" resulting from a reduction to RNG portfolio targets, please advise what finding EFG is asking the OEB to make in the current proceeding (e.g., increase DSM funding by a specified amount calculated based on the savings from reduced RNG procurement relative to proposed or a more generic finding)?
(c) Please further discuss why procuring only new RNG supply and prioritizing the development of Ontario-based RNG maximizes ratepayer benefits. As part of the response, please consider that non-Ontario supply may be cheaper and/or result in greater carbon emission reductions.
(d) Please advise whether carbon charges, as they are calculated currently, would reduce more significantly if conventional natural gas is replaced with RNG with negative carbon intensity relative to RNG with positive carbon intensity.

Responses:

a) The savings could be calculated as the difference between the cost for procuring RNG for the LCEP program in each year as proposed, minus the cost for procuring RNG at the recommended reduced level which is ¼ of EGI's proposed annual levels.

RNG Procurement Savings = (RNG costs EGI proposed levels) – (RNG costs for reduced level of RNG procurement).

This can be readily calculated after procurement has occurred. Prior to knowing the costs for procurement, an initial estimate could be to assume that roughly 3/4ths of the proposed costs will be "saved" by reducing the amount of annual RNG procurement to ¼ of the proposed levels.

b) The LCEP RNG procurement is one of the decarbonization strategies EGI can pursue. EFG appreciates that DSM spending is not being adjudicated in this proceeding and we are not making recommendations on the specific regulatory mechanisms that could be used to increase DSM spending.
c) EFG's recommendation to prioritize new Ontario supplies is for the near term when the overall market supply and demand for RNG is in early stages of development. In the future, when there is a more robust continental market for RNG, it would be reasonable to purchase any RNG - from a new source or existing and regardless of where it is from - as long as it is the lowest cost per lifecycle GHG emission reduction.

The distinction is that in the near-term the purchase of RNG that is not a new source may not reduce emissions (or not reduce them as much) if the existing use is not for meeting another entity's emission reduction goals. Also, in the short-run, investment in more local sources of RNG will help spur development of the Ontario market which can help avoid potential future transmission costs for supplies that are out of region. In the near term our recommendation would most likely translate to the LCEP procurement of RNG focusing on new Ontario manure anaerobic digestion systems at large farms where the direct atmospheric emissions of methane are reduced.

d) No, as currently calculated the carbon charges do not differ between RNG based on feedstock source.[2]

However, as discussed in the literature, our report and acknowledged by EGI, there are significant differences in the carbon intensity of RNG based on different feedstocks. If the primary objective of the LCEP is to reduce emissions, these differences should be reflected, even if they do not impact current methods for carbon pricing. The impact on carbon pricing could be considered a secondary as opposed to primary impact. Moreover, the calculation methods for carbon pricing could evolve over time to reflect variation of carbon intensity by RNG feedstock resource.

[2] EF-2-24-0111 Phase 2 Exhibit 4 Tab 2, Schedule 7, page 29.

M1-CCC-10

Reference: Exhibit M1, page 23

Question:

EFG provides examples of jurisdictions that have undertaken system pruning projects. Please provide examples of projects that EFG considers appropriate and potentially transferable to EGI's service territory.

Response:

In response to GEC-6, Enbridge provided links to a 2024 report by National Grid (a dual-fuel utility with gas customers in both Massachusetts and New York) and the Rocky Mountain Institute that documents nine case studies of non-pipe alternatives, including a number of gas system pruning projects undertaken in the U.S. and Europe. We would expect lessons learned from at least some of these projects to be potentially transferable to Enbridge.

M1-CME-1

Reference: Exhibit M1, page 14

Preamble: At pages 14, EFG recommends both that the LCEP should maximize ratepayer benefits by prioritizing the development of an Ontario-based RNG sources, as well as achieve the most cost-effective GHG reductions.

Questions:

(a) Would there ever be instances where the development of Ontario-based RNG sources would be antithetical to achieving the most cost-effective GHG reductions? In other words, procuring RNG from extra-provincial sources would be more cost effective?
(b) If a) is affirmative, please outline EFG's view on how to properly balance developing Ontario based RNG sources with achieving the most cost-effective GHG reductions.

Response:

a) Although an extra-provincial source could be less expensive in the short-run, there are significant longer-run benefits to procuring from Ontario-based sources. Please reference our response to M1-CCC-9. Also, price and volume caps can mitigate potential concerns about prices.

b) EFG's recommends that the LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits. It also recommends that, if out of region supplies are permitted, then transmission pathways and costs must also be included in the procurement contracts. Including transmission costs will impact the relative cost-effectiveness of contracts inside and outside Ontario.

If there are two identical sources of RNG and one is in Ontario but costs more (even after adjusting for different transportation costs), it may be appropriate to accept a local price premium for the in-region supply in light of the long-term benefits to Ontario customers. Enbridge could set a local price premium to use in its procurement processes.

M1.EGI-1

Reference: Exhibit M1, page 12

Preamble: Energy Future Group (EFG) states: "While Enbridge has not yet identified the range of technologies whose development it intends to fund in 2025, let alone over the next several years, it appears prepared to potentially fund a wide range of technologies. That could result in spreading funds across too many projects to have a material impact on the development of any of them."

Question:

Please clarify what "material impact" means for a technology that is still at the development stage. What are the criteria and threshold to determine whether it is a material impact or not?

Response:

By "material impact" we mean likely to accelerate and/or improve the development of a technology in a way that would not have occurred absent Enbridge's investment. Criteria to consider in that regard might include (but not be limited to):

- Lowering the cost of a technology;
- Increasing the efficiency or other important metric of efficacy of a technology;
- Advancing the date at which the technology is likely to be commercially available; and/or
- Advancing the likely pace at which the technology is likely to be adopted by Ontario customers.

Again, in all cases the question should be whether Enbridge's involvement is likely to change these things relative to what would have occurred in the absence of such involvement. Further, there should be an expectation that the change would be big enough to matter to future market adoption and future emission reductions.

M1.EGI-2

Reference: Exhibit M1, page 12

Preamble: EFG states: "Put another way, the marginal contribution that Enbridge could make to their market development is likely to be negligible if the Company's funds are not concentrated on field tests, demonstration projects and/or pilot programs in Ontario. In our experience, such field tests or demonstration projects often cost millions of dollars when undertaken at a scale necessary to produce enough data to evaluate and inform other potential future investments in the province."

Question:

Please provide a list of field tests and demonstration projects that you have experience with similar in size to those proposed in ETTF. Please include detailed description of such projects including costs.

Response:

Mr. Neme has been involved in tracking numerous energy efficiency R&D projects over the several decades of work in that industry. One relatively recent example is a Commonwealth Edison pilot project to test the efficacy of cold climate heat pumps in 80 different apartment units across seven buildings in the Chicago area. Another example is a similar DTE pilot test of cold climate heat pumps in low-income multi-family buildings in Detroit. In both cases, the lessons learned from the projects has led to deployment of full-scale programs promoting the technology across each utility's service territory. While we cannot provide the exact cost of the pilot projects, we can say that together they cost on the order of several million dollars to design, implement, evaluate and document results. A paper providing some details of the pilots can be found here: https://www.nrdc.org/sites/default/files/efficiency-programs-heat-pumps-building-decarbonization-michigan-illinois-report-202208.pdf.

M1.EGI-3

Reference: Exhibit M1, page 12

Preamble: EFG states: "An alternative to completely rejecting the fund would be to require that it be targeted solely to one major energy transition need that is universally recognized by the industry – not just by Enbridge – as a safe bet."

Question:

Please indicate examples of a major energy transition need that is universally recognized by the industry that EFG would support as being a funding recipient from the ETTF? Please provide references to substantiate the examples of universally recognized needs.

Response:

As stated on pp. 7-8 of our report, three types of investment that we have found to be universally identified as a safe bet for decarbonizing the gas utility system are (1) energy efficiency investments that reduce heating loads; (2) electrification of residential and commercial buildings; and (3) low carbon fuels for high-heat industrial applications. The studies Mr. Neme referenced in Phase 1 of Enbridge's rebasing proceeding highlight the importance of these measures.

As also noted in our report, since efficiency and most electrification measures are being advanced by Enbridge through its DSM programs, the most logical focus of an ETTF would be on low carbon fuel options for high-heat industrial process loads.

M1.EGI-4

Reference: Exhibit M1, page 13

Preamble: EFG states: "Finally, we recommend that the Board create a stakeholder advisory committee that would be expected to work with Enbridge on both the development of a scoring rubric, the actual scoring of different options and ultimately the selection of project funding priorities. Under its current proposal, the Company will ultimately make decisions on which technologies it will support with ETTF funds without any structured stakeholder input. Given the concerns noted above, creating a structured process for stakeholder input is important to ensuring effective ETTF spending."

Questions:

(a) Please elaborate on the proposed stakeholder advisory committee structure, for example, size, composition, frequency of meeting, level of involvement etc. What would be a reasonable amount of time for the committee members to accomplish the tasks proposed?
(b) Considering that the number of projects/ideas to be reviewed under the ETTF could be more than one hundred every year, what would be a reasonable range of expenditure for the proposed Stakeholder Advisory Committee for scoring of different options and ultimately the selection of project funding priorities?
(c) Please provide examples of stakeholder advisory committee from other jurisdictions and its involvement to manage a similar size technology innovation fund, if any.
(d) Please clarify what would be considered as "structured stakeholder input".
(e) Please clarify what would be considered to be "effective ETTF spending". What are the criteria to assess the effectiveness?

Responses:

(a) EFG does not have a detailed recommendation for how to structure an advisory committee. Some general guidance would include that it includes a diverse range of stakeholders but is small enough to effectively manage. It would probably make sense to meet more frequently initially – perhaps for the first year – in order to establish criteria for selecting projects and to provide input on initial project options. It might meet less frequently after that to review project progress and consider potential new projects.
(b) EFG has not developed a budget for such a committee. It is also far from clear why there would be more than one hundred potential projects to consider each year, particularly if the ETTF is focused on a specific area such as low carbon fuels for high heat industrial processes. Our recommendations would likely result in far fewer than one hundred potential projects.
(c) EFG has not conducted an assessment of the way in which technology innovation funds are managed in other jurisdictions.
(d) By "structured stakeholder input" we mean a process by which an intentionally diverse range of stakeholders are presented options, have an opportunity to engage in dialogue with Enbridge and each other about the options, and are then asked to provide feedback.

(e) By “effective ETTF spending” we mean spending on projects that are likely to have a material impact on the long-term deployment in Ontario of technology that is likely to be cost-effective (relative to other alternatives) for reducing emissions.

M1.EGI-5

Reference: Exhibit M1, page 8

Preamble: EFG states: "While there are some potential electrification options for some lower-heat industrial process loads..."

Questions:

(a) Please define lower-heat industrial process loads.
(b) Is industrial high pressure, high temperature steam considered high heat industrial process loads?

Responses:

(a) A recent American Council for an Energy Efficiency Economy (ACEEE) report on industrial heat pumps (IHPs) (https://www.aceee.org/research-report/ie2201) states that "Currently, a few IHPs can provide heat up to 160˚C (covering roughly 44% of industrial process heat needs), and further developments may raise this temperature ceiling to about 200˚C (covering roughly 55% of industrial process heat needs)." See Figure 1 below for further information from the report regarding the mix of process heating needs for five different industry types.

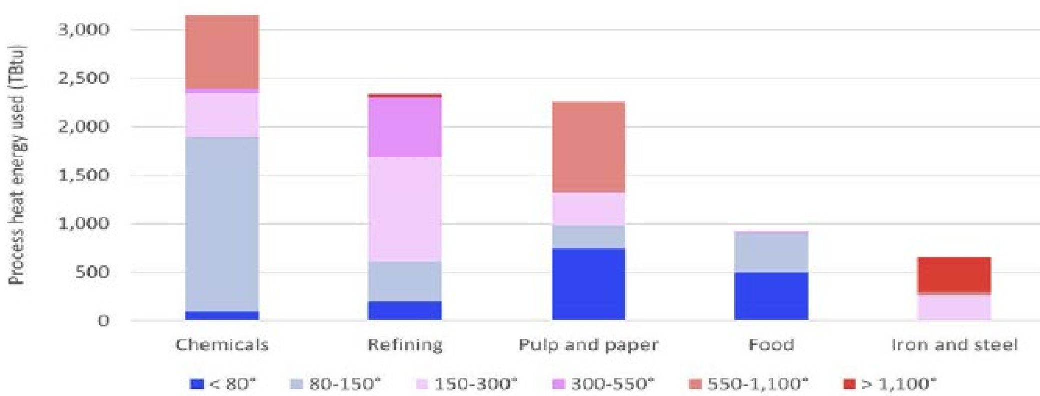

Figure 1. Process heat demand at different temperature (°C) levels in select U.S. Industrial l groups. Data source: McMillan 2019.

(b) Yes. That said, it may also be possible to reduce the amount of high-pressure, high-temperature heat generated at some industrial facilities as portions of thermal loads are often served with higher-quality steam than is necessary and could potentially be met instead with industrial heat pumps. ACEEE also recently published an interesting paper on this topic (https://www.aceee.org/topic-brief/2024/02/stop-waste-use-industrial-heat-pumps-rethink-thermal-loads).

M1.EGI-6

Reference: Exhibit M1, page 9, footnote 9

Preamble: "For example, the 2020 Canadian Climate Institute study (p. 59)..."

Questions:

Please provide a full copy of the referenced study in footnote 9.

Response:

The full report can be found here: https://climatechoices.ca/wp-content/uploads/2021/02/Canadas-Net-Zero-Future_FINAL-2.pdf

M1.EGI-7

Reference: Exhibit M1, page 10

Preamble: EFG states: "…a 30% hydrogen blend would be providing only about 1% to 3% of the total required GHG emission reduction."

Question:

Please clarify footnote 13 and how the 1 percent to 3 percent of the total required GHG emission reduction is calculated, including any assumptions on which these calculations were based.

Response:

A 30% hydrogen blend by volume would mean only 9-10% hydrogen by energy content. That is the one-tenth of remaining gas supply referenced in footnote 13. The decarbonization studies referenced by Mr. Neme in his report in Phase 1 of the Enbridge rebasing proceeding suggest that gas throughput is likely to have to be reduced by 70-90% or more to meet 2050 decarbonization goals – i.e., gas would supply only meet 10-30% of current energy needs. If 9-10% of that remaining gas energy supply is hydrogen (from a 30% blend by volume), that would account for only 1-3% of energy needs (i.e., at the high end, 10% of 30% is 3%).

M1.EGI-8

Reference: Exhibit M1, page 20

Preamble: EFG states: "Even at existing and potential new RNG production sites, the on-site use of biogas for heat or power production may be a more economically attractive and valuable emission reduction resource than injection into the gas distribution system."

Question(s):

Provide the cost of reducing emissions in $/tonne of CO2e emissions for on-site use of biogas to produce heat or power in Ontario. Please show the calculations and include source references. Enbridge Gas suggests the following assumptions be used; however, where EFG uses different assumptions, please provide the assumption used and the rationale.

- Use the assumptions and calculations provided at Phase 2 Exhibit I.4.2-ED-41 part a), Table 1
- Table 2 of the Ontario Energy Board Regulated Price Plan Price Report for November 1, 2023 to October 31, 2024, which shows 26.8 cents/kWh ($74/GJ) for bioenergy power (which includes biogas/landfill gas power).

Responses:

EFG has not conducted an analysis of the cost of reducing emissions in $/tonne of CO2e for on-site use of biogas to provide heat or on-site power in Ontario and doing so would be beyond the scope of the evidence we have been asked to prepare and be beyond the time available for interrogatory responses. However, we can provide the following commentary.

To be clear, EFG is not suggesting that use of RNG for other purposes will always be more economically attractive. However, it may be in some cases.[3] The economics of on-site use of RNG for thermal applications or for power generation will vary and be site specific. In general, however, on-site use can avoid costs for cleaning of the biogas to take it up to pipeline gas standards, for costs for pipeline injection, and for extension and new connection of a distribution line (in cases where a site is not already connected to the gas system costs).

[3] Note for example, the 2020 Renewable Natural Gas (Biomethane) Feedstock Potential in Canada study conducted by TorchLight Bioresources for Natural Resources Canada, indicates that numerous existing landfills do not have natural gas pipeline access, and that a portion also use captured landfill gas for energy use on site, or capture and flare the existing gas, (TorchLight, 2020 p. 23).

M1.EGI-9

Reference: Exhibit M1, page 30

Preamble: EFG states: "The Company's assumption in the LCEP application that the carbon intensity of RNG can be assumed to be zero is not supported by these tables."

Questions:

(a) Please provide the specific text and reference from Phase 2 Exhibit 4, Tab 2, Schedule 7, where Enbridge Gas has indicated that the carbon intensity of RNG is zero.
(b) Please confirm that carbon intensities (i.e., lifecycle GHG emissions) are different from emission factors used to calculate facility emissions (i.e., direct end-use emissions) and are not interchangeable terms.
(c) Please confirm that carbon intensity is not used to calculate facility emissions in Version 7.0 of Canada's Greenhouse Gas Quantification Requirements for Canada's Greenhouse Gas Reporting Program.
(d) Please confirm that carbon intensity is not used to calculate facility emissions in Ontario Regulation 390/18: Greenhouse Gas Emissions: Quantification, Reporting, and Verification, or the March 2024 Version of the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions under Ontario's Emissions Reporting Program.

Responses:

a) In item 71 on page 28 of 32 EGI states the Greenhouse Gas Pollution Pricing Act (GGPPA) has inherently recognized RNG as being free of CO2 emissions. In item 76, the EGI further acknowledges: "the lifecycle emission benefits of using RNG; however, at this time, the CI score of RNG will not be the primary consideration when procuring RNG."

EFG acknowledges that EGI does not directly state the carbon intensity of RNG is zero. However, our understanding of the proposed accounting is that RNG impacts will be counted in that fashion. This potentially overstates the level of emissions reductions from landfill gas and wastewater treatment sourced projects, while understating the benefits from manure anaerobic digester sourced RNG.

While EGI may recognize that there are important levels of variation in the lifecycle carbon intensity for various RNG feedstock supplies, the proposed procurement will not treat carbon intensity (CI) as a primary consideration. If differences in carbon intensity do not affect decisions about what sources of RNG to procure, that is effectively treating them as if they all have the same carbon intensity. This is a problematic simplification, and we recommend CI be considered and accounted when emission reductions are calculated and that CI also inform procurement decisions.

b) Confirmed. If one focuses only on emissions at the point of combustion (direct end-use emissions), there is no difference between RNG and fossil gas.

c, d) In both cases, the methods and required reporting focus on the onsite facility combustion emissions and would treat all RNG as zero-emitting. While certain government reporting requirements do not account for lifecycle carbon intensities, EGI's proposal for LCEP program and RNG procurement can, and should account for differences in lifecycle emissions based on available information on the lifecycle CI's for various RNG feedstock streams for all of the reasons set out in the EFG report. See the EFG report for details.

M1.EGI-10

Reference: Exhibit M1, page 20

National Renewable Energy Laboratory. (2021 September). Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update, Table 1. https://www.nrel.gov/docs/fy21osti/80580.pdf

Ontario Energy Board. (2023 October 19). Regulated Price Plan Price Report November 1, 2023 to October 31, 2024, Table 2. https://www.oeb.ca/sites/default/files/rpp-price-report-20231019.pdf

Preamble:

Table 1
Total Life Cycle Greenhouse Gas Emissions for Electricity Generation Technologies and Percentage of Electricity Supply in Ontario

Electricity Generation Technology	Median Value Total Life Cycle Greenhouse Gas Emissions (gCO2e/kwh) (1)	% of Electricity Supply in Ontario (2)
Photovoltaic	43	2%
Hydropower	21	26%
Wind	13	9%
Nuclear	13	50%

Notes:
(1) Values have been reproduced from selected electricity generation technologies provided from the National Renewable Energy Laboratory report, Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update, Table 1
(2) Values have been reproduced from selected electricity generation technologies provided at the Ontario Energy Board Regulated Price Plan Price Report, Table 2

EFG states: "…the LCEP should be required to account for different carbon intensities in their reported emission reductions and prioritize newly developed, in region, supplies with negative or zero CI values."

Questions:

(a) Please confirm that the median lifecycle greenhouse gas (GHG) emission values for photovoltaic, hydropower, wind, and nuclear power as provided by the National Renewable Energy Laboratory September 2021 Update on Life Cycle Greenhouse Gas Emissions from Electricity Generation in Table 1 are not zero or negative, and that the majority of electricity supply in Ontario does not have zero or negative lifecycle GHG emissions.

(b) Please confirm that the use of RNG within Ontario's Emissions Performance Standard Program does not include considerations related to age of the RNG production facility or carbon intensity (or lifecycle GHG emissions) of the RNG supplies as per the March 2024 Version of the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions under Ontario's Emissions Reporting Program, Sections ON22.1 RNG Reporting Requirements and ON23.1 Calculation of RNG CO2 Quantity.

Responses:

a) The values in the middle column of Table 1 above are not zero or negative and they are consistent with those in the cited NREL report. However, they are median values from dozens of different estimates from different studies, at least some of which appear to suggest lifecycle emissions from these sources are zero (or very, very close to zero). That may be because different studies include different things in their definitions of lifecyle emissions. In particular, implicit in the median values referenced by Enbridge is accounting for not only direct operational lifecycle emissions but also one-time upstream and downstream embedded emissions, such as those associated with manufacturing and disposal of PV modules. Any comparison of such lifecycle emissions from renewable electric generation to lifecycle emissions from RNG would need to have consistent treatment of embedded emissions associated with RNG production and connection to the gas transmission and distribution system.

   Note also that the Enbridge table above leaves out the median value for generation from fossil fuels, including fossil gas generation which has a median emissions rate of 486g/C02e/kWh. In other words, the median weighted average lifecycle emission rates of the generation sources referenced by Enbridge's question are about 97% lower than the lifecycle emissions from fossil gas generation (put another way, the emissions rate from fossil gas generation is about 30 times the weighted average of the other referenced generation sources). For gas and other fossil fuels, most of the estimated lifecycle emissions are associated with combustion, while for renewables the embedded upstream and downstream emissions contribute the largest shares. Note these are all estimates of lifecycle emissions for electric generation.

   The same report indicates that biopower has a range of carbon intensities both above and below zero, based on the feedstock source.

b) EFG has not reviewed or analysed the March 2024 Version of the Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions under Ontario's Emissions Reporting Program, Sections ON22.1 RNG Reporting Requirements and ON23.1 Calculation of RNG CO2 Quantity, and therefore cannot comment on whether it requires a lifecycle carbon intensity or the age of RNG facilities be considered.

   As in our response to EGI-9 above, the fact that reporting requirements for facility level emissions consider only on-site combustion does not undermine the importance of focusing on lifecycle carbon intensity for RNG procurement in the LCEP.

We therefore maintain our recommendation that EGI's procurement of RNG for the proposed LCEP program consider and account for the wide variation in lifecycle CI from various RNG sources.

M1.EGI-11

Reference: Exhibit M1, pages 14 and 16

Preamble: Exhibit M1, page 14:

EFG states: "As detailed below, we recommend the following:

1. Redirect funds to more cost-effective uses: The OEB should require that the Company reduce the LCEP portfolio targets by a factor of 4, cap the price at $25.58/GJ, and redirect the savings to expanded energy efficiency."

Exhibit M1, page 16:

EFG states: "We recommend lower targets for the LCEP, and redirecting of the resulting savings towards alternative decarbonization investments such as increased energy efficiency."

Questions:

(a) Please confirm that the lower targets for the low carbon energy program as proposed in the recommendation will result in lower commodity costs for RNG, not "savings" as suggested at Exhibit M1, pages 14 and 16.
(b) Please confirm the recommendation as proposed would require Enbridge Gas to charge sales service customers an amount that is greater than the commodity cost Enbridge Gas would incur on behalf of sales service customers.

Responses:

a) EFG considers reduced expenditures for a lower level of RNG procurement to be "savings" when compared to the levels of procurement proposed by EGI. See response to M1-CCC-9 a).

b) Not confirmed. EFG's recommendation is that a reduction from the proposed levels of spending for RNG procurement can be redirected to increasing end use efficiency and that doing so can be expected to have a lower cost per tonne of reduction than the LCEP as proposed. However, we are not making suggestions in this proceeding regarding customers to be targeted with increased efficiency spending or allocation of costs.

M1.EGI-12

Reference: Exhibit M1, page 18

Preamble: EFG states: "Particularly in the near-term, during the proposed LCEP time horizon, RNG market development will not be limited by the amount of feedstock resources or by the potential number of sites that could be developed. Instead, the economics and comparative advantages of other competing renewable resources, utility and customer investment opportunities, and existing infrastructure and policy and planning factors are more likely to spur and or limit RNG growth."

Question:

Please confirm that the low carbon energy program will spur RNG growth and that in the near term RNG market development will not be limited by the amount of feedstock resources.

Response:

a) The LCEP can spur RNG growth, but the growth will be greater if the program is restricted to developing new sources with long-term contracts. It is unclear whether the growth would be significant if the program simply purchases from existing capacity. This alone does not answer the question of what level of RNG procurement the LCEP program should pursue, and what types of RNG projects will provide the greatest benefits.

At levels of RNG procurement proposed by EGI, and even more so at the levels we EFG has proposed (i.e., $1/4^{th}$ of the levels proposed by EGI), the RNG market is not likely to be limited by the amount of feedstock resources, at least not if sources outside of Ontario are eligible.

M1.EGI-13

Reference: Exhibit M1, page 21

Preamble: EFG states: "As detailed below, we recommend that the OEB require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months. This is possible because Enbridge can leverage its existing IRP Framework. Further, if the pilot is relatively small and inexpensive, which may be likely, an application for formal approval would not be necessary or reasonably justified."

Question:

Without formal approval from the OEB, what do you see as the proper regulatory oversight and review process for a system pruning IRPA, including the review or approval of the cost implications of potentially electrified solutions?

Response:

We would suggest that the Board can essentially give approval in this proceeding for funding of one or two small pilot pruning projects. That might include a cost cap that the Board would deem acceptable. This is no different than the Board approving a custom industrial DSM program but not every single unique installation rebated under that program. It is no less appropriate than the Board approving Enbridge's proposed ETTF funding of $5 million per year without knowing what specific projects it will fund. Indeed, approval to pursue the ETTF as proposed by EGI would be considerably broader and less defined in comparison to a pruning pilot.

M1.EGI-14

Reference: Exhibit M1, page 22

Preamble: EFG states: "We do not see the need for entirely new processes for many of these issues for system pruning. Put simply, system pruning options can and should largely be considered in much the same way that other IRPA projects are considered.

Similarly, we do not see a need for the Company to have to consult the IESO or local municipalities about such projects. Electrifying a few customers should not affect electric grid loads at a level important to the IESO and local municipalities do not need to be I involved in individual customers' fuel choices."

Questions:

(a) Given the goal that processes for developing system pruning pilots could potentially be replicated and scaled up in the future, please explain what the expected learnings from a pilot would be if it does not include testing the current IRP Framework and processes to identify and evolve where processes (including coordinated energy planning) must be modified for system pruning considerations.
(b) Please provide a conceptual example of the size and scope of a system pruning project that would be appropriate for a pilot project?

Responses:

(a) We would expect the pilot project learnings to be more around how to effectively engage customers, how to assess best approaches to electrifying loads, what such electrification might cost, and what might be involved in decommissioning gas connections. We do not think it is likely that key aspects of the IRP framework related to how to arrive at "go" versus "no-go" decisions will be different for pruning projects than for other types of non-pipe alternatives. That said, if there are lessons learned on such issues, they can be brought to the attention of the Board's IRP Committee and considered for potential modifications to the IRP framework. Put simply, it is often better to learn by doing than waiting years to study and design new processes for hypothetical applications.
(b) We would envision it most likely that a small pilot system pruning project would involve very few customers (fewer than 10) and have a modest cost (e.g., less than $1 million).

M1.EGI-15

Reference: Exhibit M1, pages 22 to 23

Preamble: EFG states: "It should also be noted that though it is not yet commonplace, several jurisdictions have begun to invest in gas system pruning. For example, as noted in a white paper recently published by National Grid (a large gas utility serving customers in several northeastern states) and the Rocky Mountain Institute (a non-profit advocacy organization promoting clean energy), Pacific Gas and Electric has already completed 85 pruning projects in its California gas service territory."

Questions:

(a) Please indicate if Pacific Gas and Electric (PG&E) operates as an integrated gas and electric utility.
(b) How would PG&E's approach to system pruning be different from Enbridge Gas's as a standalone gas utility? In your response, please include challenges that may exist for a standalone gas utility that wouldn't exist for an integrated gas and electric utility.
(c) Please confirm that the full reference as started above includes, "Pacific Gas & Electric (PG&E) has successfully completed 88 targeted electrification projects, including decommissioning 22 miles of transmission pipe and converting 105 customers from gas."
(d) What is the biggest system pruning project that EFG is aware of that has been completed for any North American gas utility, in terms of number of customers converted and value or size of gas system decommissioned?
(e) Please confirm that the Targeted Building Electrification and Gas System Decommissioning Pilot Project (for which PG&E is a project partner) as referenced in the white paper published by National Grid and RMI, launched in 2021 with a final report released in June 2024, took three years to develop an analytical framework for targeted electrification and strategic gas decommissioning and did not include implementation of gas decommissioning projects during this three-year period.

Responses:

(a) Confirmed.
(b) The principal difference is that electrification would have less of an impact on the profits of a dual-fuel utility than on the profits of a gas-only utility, probably creating less reluctance by dual-fuel utilities to embrace gas system pruning. However, they also share critical similarities, including the possibility of savings for all gas customers through system pruning projects that cost less than the infrastructure alternative and the possibility of savings for the participating gas customers through cost-effective electrification.

    Of course, a dual-fuel utility also has simultaneous insight into the impacts of electrification on its grid that a gas utility does not have. That is probably not particularly important for smaller gas decommissioning projects involving small numbers of customers and load. Individual customers convert to electricity all the time on their own and electric LDCs routinely adapt to such changes. More intentional engagement on electrification, perhaps even coordinated planning, could be important for larger projects. While that is obviously easier for a dual-fuel utility, it can be accomplished by gas-only utilities, such as Enbridge, through engagement with the local electric distribution Company.

(c) Confirmed. Our reference to 85 pruning projects was a typo. In re-reading the reference it is not entirely clear that all 88 projects referenced in the study were system pruning projects, though clearly some where since they enabled decommissioning of 22 miles of transmission pipe.

(d) EFG does not have data to answer the question.

(e) Not confirmed. While it is true that the referenced project was completed in June 2024, the suggestion that no gas decommissioning projects were undertaken in the three years leading up to the final project report is incorrect. It is important to note that the referenced project report (https://www.energy.ca.gov/sites/default/files/2024-06/CEC-500-2024-073.pdf) itself notes that PG&E implements small decommissioning projects (typically five customers or less) through what it calls its "Alternative Energy Program". The project referenced by Enbridge was intended to explore larger projects (i.e., 50 to 200 customers). Indeed, a September 2021 presentation by PG&E makes clear that between 2019 and 2021 the Company had "reached agreements with 68 customers to convert to options other than natural gas resulting in our ability to decommission gas assets." A copy of that September 2021 presentation is attached to this response and can also be found at https://gridworks.org/wp-content/uploads/2022/04/9.15.21_Gridworks_PGE-Alt-Energy_V4-2-2.pdf. Since the National Grid/RMI report (published in June 2024) stated that PG&E had converted 105 customers from gas, it is clear that additional small decommissioning projects were continuing while the project focusing on larger potential projects was underway.

M1.EGI-16

Reference: Exhibit M1, page 23

Preamble: EFG states: "Finally, we recommend that Enbridge consider strategies for addressing situations where most customers are prepared to fully electrify but a very small number or portion are not. When that occurs in a situation in which getting all customers to disconnect from the gas distribution system would provide significant economic benefits to gas ratepayers as a whole, it may be appropriate to consider options other than just incentives. One option might be different gas rates for such "hold outs" that would fairly reflect the cost they are imposing on the system."

Questions:

(a) Please provide a list of other jurisdictions in North America where a higher rate is charged for customers that "holdout" on system pruning projects.
(b) Please provide EFG's view on how the proposal of different gas rates for "hold outs" could be workable or reconcilable with the principle of non-discriminatory and postage-stamp rate-making.
(c) How have other jurisdictions dealt with this issue (has this included policy or legislative changes)?

Responses:

EFG has not assessed whether any other jurisdictions have adopted higher rates for "holdout" customers. We are also not making a recommendation that Ontario necessarily do so. Rather, we are suggesting that Enbridge explore approaches to addressing "holdouts" to facilitate decarbonization of the gas system in the most economic manner.

M1.EGI-17

Reference: Exhibit M1, page 23

Preamble: EFG states: "We also recommend that the Board require Enbridge to identify, develop and implement an initial system pruning project within 12 months."

Question:

Please confirm the steps that EFG suggests implementation within 12 months should include? For example, would this include identifying suitable pipeline segments for pruning, completing technical and economic evaluation, achieving consensus from all customers attached to the identified segment to fully electrify, filing an application to the OEB and receiving approval, and completing the necessary work to electrify each customer and decommission the pipeline segment?

Response:

As noted in several other parts of EFG's report, we are suggesting Enbridge ***begin*** (not complete) implementation of a pilot pruning project with 12 months. That would require identifying pipeline segments for pruning, including any technical and economic evaluation, and beginning the process of engaging with customers. For a very small project, we would not anticipate the need for an application to the OEB.

M1.EGI-18

Reference: Exhibit M1, page 26, Figure 2

Question:

Please provide all assumptions and calculations used in determining $755 annual heating cost for 'Electric Heat Pump' in a live excel file with sources stated.

Response:

Excel file is attached. As noted in our report, we used the same assumptions about gas and electricity prices that Enbridge used in its analysis. The only new assumptions were with regard to the annual average energy efficiency of a cold climate air source heat pump and a heat pump water heater. As also noted in our report (footnote 61), those assumptions were based on the assumptions Guidehouse has used for the current provincial gas efficiency potential study.

M1.EGI-19

Reference: Exhibit M1, pages 26 to 27

Preamble: EFG states: "Most notably, we would expect many of homes with electric resistance heat to require the installation of ducts in order to enable the installation of a gas furnace."

The above statement outlines EFG's view on the proportion of homes that have electric baseboards vs electric furnaces for space heating, without any supporting data.

Questions:

(a) Please confirm that it is EFG's position that electric resistance heating in Ontario is synonymous with baseboard heating. If yes, please provide all relevant Canadian sources to support the position. If not, please explain and provide all relevant Canadian sources to support the position.
(b) What proportion of homes that currently use electric resistance heating in Ontario have central air conditioning? Please provide all relevant Canadian sources to support the response.
(c) Please confirm that adding ccASHP to homes that don't currently have air conditioning will increase the homes annual electricity consumption, and summer peak demand.

Responses:

(a) Not confirmed. Electric resistance heating can have multiple forms, including both baseboard heating and electric resistance forced air furnaces. However, we expect electric resistance baseboard heating to be much more common. That is based on decades of experience in a variety of northern U.S. states as well as the anecdotal experience of Kai Millyard, Manager of Green Communities EnerGuide Auditing Services, who we asked about this. We would also note that a study of residential buildings that is currently underway in the state of Illinois has also found that customer reports of the prevalence of electric furnaces are significantly overstated (based on comparisons of customer survey responses to what on-site assessments find).
(b) EFG is unaware of data that would answer this question.
(c) ccASHP homes that do not have any form of air conditioning – whether central systems or window units – could increase *summer* electricity consumption and peak demand. However, our experience in New England is that many customers that have historically not had central air conditioning are adding it. Indeed, in many cases, initial interest in adding central cooling has been the impetus for ultimately installing heat pumps. In that context, though the installation of a ccASHP would increase summer electricity consumption and peak demands relative to the customer's previous situation, it might reduce consumption and peak demand relative to the alternative cooling option the customer might otherwise have installed.

M1.EGI-20

Reference: Exhibit M1, page 27

Preamble: EFG states: "[I]t is important to recognize that Ontario's electric grid is currently summer peaking. Because cold climate heat pumps are typically more efficient at cooling than the air conditioning systems they would displace, they should provide significant near-term benefits to the grid – both in reducing generating capacity needs and in reducing capacity constraints for the portions of the distribution system that are also summer peaking."

Questions:

(a) Are all homes in Ontario in an area where the electric grid is summer peaking?
(b) If the answer to (a) is no, what areas are not summer peaking? What would be the impacts to the grid in those areas if all homes were to convert to electric ccASHP.

Responses:

Generally speaking, with respect to electric generating capacity, what matters is the provincial grid as a whole. In that context, all Ontario homes are currently in a summer peaking system. However, there may be parts of the Ontario *distribution system* that are winter peaking. In such areas, homes that convert from fossil fuel heating systems to ccASHPs would likely lower demand for system peak generating capacity while increasing peak demands on the local distribution system. The reduction in demand for system peak capacity would reduce investment in new generating capacity. Where there are increases in peak demand on the local distribution there may or may not be added costs for upgrading distribution system capacity (e.g., substation capacity). Whether and where that occurs will depend on the extent to which there is excess capacity on the applicable elements of the existing distribution system.

M1.EP-1

Reference: OEB Rules of Practice and Procedure

Preamble: Quote from the OEB Rules of Practice and Procedure:

13A. Expert Evidence

13A.01 Where a party intends to engage one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise, Rule 13 applies to that evidence.

13A.02 An expert shall assist the OEB impartially by giving evidence that is fair and objective.

13A.03 An expert's written evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the OEB in Form A to these Rules, signed by the expert.

Question:

Please explain how Exhibit M1 adheres to the rules for Expert Evidence quoted in the Preamble.

Response:

The required information is contained in the EFG report, CVs, and Form As, which have all been filed.

M1-EP-2

Reference: Exhibit M1, page 7, Section B

Preamble: "The problem is that Enbridge's conclusions regarding what is a "safe bet" are fundamentally flawed. They are also clearly biased towards solutions that maximize the potential future role (and therefore profits) of the Company."

Questions:

(a) Please confirm that the conclusions of the co-authors regarding what is a "safe bet" are biased towards solutions that minimize the potential future and role of the Company.
(b) Please confirm that the co-authors want the use of natural gas to be eliminated as soon as possible no matter what it may cost the 3.8 million Enbridge Gas customers.

Response:

(a) Not confirmed. There is no bias in our conclusions. The safe bets that we have identified are consistent with findings of independent studies of decarbonization pathways for the fossil gas sector. By independent studies, we mean studies conducted by or for entities that do not have a financial interest in the study results.
(b) Not confirmed.

M1-EP-3

Reference: Exhibit M1, page 7, Section B

Preamble: "Weatherization will reduce annual gas use, reduce gas bills, reduce peak demand that drives gas infrastructure costs, and ultimately reduce impacts on the electric grid when buildings electrify their space heating."

Questions:

(a) Please define the term "weatherization."
(b) What percentage of the 3.8 million premises that are currently served by Enbridge Gas are weatherized?
(c) Are the co-authors recommending that all premises should be weatherized and that Enbridge Gas ratepayers be forced to pay for this weatherization in rates?
(d) How much time would it take to weatherize all currently un-weatherized premises?
(e) Please provide the co-authors' estimate of the cost of weatherization of all premises served by Enbridge Gas?

Response:

(a) By weatherization we mean upgrades to the efficiency of building envelopes, including through increased insulation levels in attics, walls and basements; improvements to air tightness (or reductions in air leakage); and improvements in the efficiency of heating distributions systems (e.g., through sealing of leaks in ducts).
(b) EFG does not have the data necessary to answer this question. Indeed, it is our understanding that such data do not exist as there has been no study documenting the characteristics of Ontario's residential building stock.
(c) Ideally, all premises for which weatherization is cost-effective should be weatherized. To the extent that does not occur naturally and/or through other non-utility programs, we would recommend that Enbridge programs incentivize such cost-effective weatherization.
(d) Without data on the number of homes that could benefit from different weatherization measures, it is not possible to answer this question definitively. However, based on anecdotal information and our experience with weatherization programs (run by utilities and government), it will almost certainly take at least two decades.
(e) EFG does not have the data necessary to answer this question.

M1-EP-4

Reference: Exhibit M1, page 8, Footnotes 8 and 9, the Canadian Institute for Climate Choices and the Canadian Climate Institute

Questions:

(a) Please confirm that the Canadian Institute for Climate Choices and the Canadian Climate Institute are the same organization and not two separate organizations.

(b) Have either of the co-authors or Environmental Defense, Greenpeace Canada or the Sierra Club Canada, ever been directly or indirectly involved with the Canadian Climate Institute/ Canadian Institute for Climate Choices.

(c) Are any members of the Board of Directors of the Canadian Climate Institute also on the boards of directors or members of the executive of the Environmental Defense, Greenpeace Canada or the Sierra Club Canada?

Responses:

(a) Confirmed.
(b) Neither EFG as a firm, nor Mr. Neme or Dr. Hill as individuals, have any formal or informal relationship with the Canadian Climate Institute/Canadian Institute for Climate Choices.
(c) This answer is from the evidence sponsors: No.

M1-EP-5

Reference: Exhibit M1, Page 8

Preamble: "There is no real debate about whether significant portions of current gas use will need to be electrified in order to decarbonize the fossil gas sector. The only questions are how much and how fast."

Questions:

(a) Please explain what a "real debate" is and why there is no such debate.
(b) Was there ever a debate about the need for electrification? If the answer is yes, when did this debate start and when did it end, where was it held, and who were the participants?
(c) Please confirm that electrification will require large quantities of copper and other metals which will need to be mined using explosives and heavy diesel powered mining equipment, processed using dangerous chemicals such cyanide, smelted using gas or coal furnaces, cast or rolled into shape using large amounts of energy, transported using diesel powered ships, trains and trucks, and installed using diesel powered heavy equipment and that electrification may actually release large quantities of carbon dioxide, other gasses and dangerous chemicals that is greater than are released by the natural gas sector.

Responses:

(a) The referenced statement in EFG's report speaks to the consistent conclusions of independent studies of pathways for decarbonizing the fossil gas industry.
(b) We are unaware of any recent independent study that suggests significant levels of electrification will not be necessary to economically decarbonize the fossil gas industry.
(c) Not confirmed. We are unaware of any studies that reach such conclusions.

M1-EP-6

Reference: Exhibit M1, Page 8, Table 1, Decarbonization Study Conclusions on Reductions in Annual Gas Energy Throughput by 2050

Preamble: "For example, Table 1 of that report – replicated below – shows that multiple studies in Canada and in northeastern U.S. states have concluded that massive reductions in gas throughput as a result of electrification will need to be part of any realistic transition to net zero emissions by 2050."

Questions:

(a) What is the relevance of Table 1 if it does not include Ontario but shows Massachusetts and has a 2016 as the base year for Quebec while others have 2020?
(b) Please confirm that "realistic transition to net zero" must include the estimate of the cost of transition and identification of who will be paying for it.
(c) Please explain what is "transition to net zero". Does it consist of complete elimination of natural gas?
(d) What are the co-authors' estimate of the cost of transition for Ontario?

Responses:

(a) Table 1 presents results of several independent analyses and one funded by gas utilities (Massachusetts) of pathways to decarbonize the gas sector across Canada and for three provincial/state jurisdictions with cold climates. As such they provide useful insights into what is likely to be the most realistic and economic approach to decarbonizing Ontario's gas sector. As also stated in our report, a more recently published report by the Canadian Climate Institute reaches similar conclusions, stating that "on a cost-optimal path to net zero, electricity will power most space heating in Canada." For Ontario specifically, the Canadian Climate Institute study estimates the least cost-path to net zero emissions would have 81% of residential heating met with all-electric heat pumps, 6% met with electric baseboards and 13% met with hybrid heat pumps (electric heat pumps with gas back-up) by 2050.[4] It is possible that the trend away from gas would continue after 2050, especially if the reduction in customer numbers increases gas costs. That fact that all of these independent studies have reached similar conclusions for similar climates suggests that these are not anomalous results.
The fact that the Quebec study estimates reductions in gas throughput by 2050 relative to 2016, whereas the other studies compare estimated 2050 throughput relative to 2020 does not materially affect the conclusion that future gas sales are likely to have to decline dramatically in the most likely and economic approaches to decarbonizing the gas sector.
(b) Our use of the term "realistic transition to net zero" was intended to reflect both the technical feasibility of different decarbonization measures (e.g., limits on availability of RNG) and the relative costs of different decarbonization pathways. All of the studies referenced in our report consider and focus on both of those things. We agree that the

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[4] Canadian Climate Institute, Heat Exchange: How Today's Policies Will Drive or Delay Canada's Transition to Clean Reliable Heat for Buildings, June 2024, Figure B, p. 13 (https://climateinstitute.ca/reports/building-heat/).

question of who should pay for the energy transition is an important one that must be addressed by policy-makers.

(c) "Net zero" means that as many greenhouse gas emissions are being removed from the atmosphere as are being put into it. While it will almost certainly involve very large reductions (i.e., 70-90% or more) in the consumption of fossil gas if the lowest cost decarbonization pathways are pursued, it likely will not mean the complete elimination of such consumption. For example, some current emissions from burning fossil gas may in the future be captured and utilized or stored (carbon capture, utilization and storage, or CCUS), if such facilities prove successful. Also, some sources of RNG, such as methane from dairy farms that would otherwise be release to the atmosphere, have negative lifecycle greenhouse gas intensities. To the extent that those sources of RNG are utilized, some fossil gas can be burned while still achieving net zero, although those resources with negative carbon intensities may be more effectively used (from a societal perspective) to offset very hard to avoid emissions in other sectors.

(d) EFG has not developed such an estimate. It is our understanding that the Ontario provincial government has funded a study of pathways to decarbonizing the province which would presumably provide such an estimate. However, a report on that project has not yet been released.

M1-EP-7

Reference: Exhibit M1, page 9

Preamble: "However, because electrification is a far better alternative, CCUS is not even mentioned by other studies – not even in the Massachusetts study funded by the state's gas utilities – as a viable option for commercial customers."

Questions:

(a) Does Massachusetts have large underground storage reservoirs like Ontario?
(b) Please confirm that availability of underground storage may have been the reason why it was not mentioned in the Massachusetts study.

Responses:

(a) EFG does not have that information.
(b) Not confirmed. Mr. Neme was part of a stakeholder process through which the study was scoped and reviewed. Over the course of many months of discussions there was never any discussion of local underground storage constraints being a reason to not consider CCUS for commercial customers.

M1-EP-8

Reference: Exhibit M1, page 10

Preamble: "It is worth noting that some leading gas utilities in other jurisdictions are funding pilot projects that focus on electrification. For example, the Massachusetts Department of Public Utilities, the state's energy regulator, recently issued an order that supported its state's gas utilities' proposal to invest in pilot projects to test the potential for cost-effective GHG emission reductions through networked geothermal systems."

Questions:

(a) Are some gas utilities considered to be "leading gas utilities" based on objective assessment criteria or just in the opinion of co-authors?
(b) Is Enbridge Gas a leading gas utility? Please explain the co-authors' answer.
(c) Is the Massachusetts Department of Public Utilities the regulatory body with the authority to approve rates and other charges of utilities in that state, similar to the authority of the OEB in Ontario?
(d) Why should the OEB follow what the Massachusetts Department of Public Utilities is doing?

Responses:

(a) By "leading" we mean gas utilities that are most actively pursuing strategies to begin to achieve long-term decarbonization of their systems, based on the authors' understanding of what many gas utilities across North America are doing in this regard. In some cases, including in Massachusetts, there are legislative and/or regulatory policies requiring, encouraging or supporting the development of gas utility decarbonization strategies.
(b) No. Enbridge is behind industry leaders in several ways. For example, it's energy efficiency program savings levels are well below industry leaders, it has yet to implement a project supporting a cost-effective non-pipe alternative (let alone a cost-effective system pruning project) as some other gas utilities have, and it has not put forward a comprehensive decarbonization plan. It is also worth noting that in its order in Phase 1 of this proceeding, that the Ontario Energy Board (OEB) itself suggested that Enbridge is not addressing the challenges posed by the energy transition, stating:
   - *"The OEB concludes that Enbridge Gas' proposal is not responsive to the energy transition and increases the risk of stranded or underutilized assets, a risk that must be mitigated."*
   - *"In the face of the energy transition, Enbridge Gas bears the onus to demonstrate that its proposed capital spending plan, reflected in its Asset Management Plan, is prudent, having accounted appropriately for the risk from the energy transition. The record is clear that Enbridge Gas has failed to do so."*

- *"When looked at through the 40-year lens, what Enbridge Gas proposes looks very much like business as usual and is not sustainable."* [5]

(c) Yes.

(d) We would not suggest that the OEB blindly follow what the Massachusetts regulator – or any other regulator – is doing. However, the Massachusetts regulator has focused in a much more extensive and comprehensive way on the question of what it will take to decarbonize the gas system than the vast majority of energy regulators. Thus, conclusions that it has reached at least merit consideration by the OEB.

[5] OEB, Decision and Order, EB-2022-0200, December 21, 2023 (pp. 19 and 21).

M1-EP-9

Reference: Exhibit M1, page 11

Preamble: "Similarly, Vermont Gas Systems is supporting a pilot project to produce and use green hydrogen by one of its largest industrial customers (a microchip manufacturing facility)."

Questions:

(a) Is the customer being charged the total cost of green hydrogen or is the cost of green hydrogen being subsidized by all customers of Vermont Gas?
(b) What are the sources of electricity used to produce the green hydrogen for this customer of Vermont Gas?

Responses:

a) It is our understanding that the cost of engineering, environmental work and permitting (about $200,000) will be born all Vermont Gas customers. The initial plan was for a significant portion of the cost of the electrolyzer itself to be covered by a grant from the U.S. Department of Energy. We do not have definitive information on whether the rest of the cost may borne by Vermont Gas customers. However, since Vermont Gas plans to own and operate the electrolyzer, we would not be surprised if that would be the case.
b) Vermont Gas has stated that "all of the hydrogen produced by the (project) will be zero carbon" and that as the customer transitions to 100% renewable electricity, it will become 100% renewable as well.[6]

[6] https://epuc.vermont.gov/?q=downloadfile/686743/193230

M1-EP-10

Reference: Exhibit M1, page 12

Preamble: "The only reason gas heat pumps reduce GHG emission is because they are an efficiency measure. Similarly, the only reason gas heat pumps reduce peak loads is because they are an efficiency measure. In other words, there is not any extra GHG reduction or peak load reduction benefit "beyond energy efficiency." With respect to "maintaining customer choice", the ETTF should only invest in technology that is likely to offer customers better choices."

Questions:

(a) Do the customers have a right to decide what is a better choice or are the co-authors the only ones who decide what is a better choice?

(b) Please confirm that the cost of natural gas compared to the cost of electricity may influence the decision by customers to what is the better choice.

Responses:

(a) Customers always have the final say in what heating system they will use. That is not at issue here. Rather, the question is whether Enbridge should invest its ratepayer funds in the development of gas heat pump technology and markets when gas heat pumps are unlikely to be an economic alternative to electric heat pumps in a decarbonizing future.

(b) Fuel prices undoubtedly affect many customer decisions.

M1-EP-11

Reference: Exhibit M1, Page 13

Preamble: "If such a targeted ETTF were to be approved, the Board should also require that Enbridge develop a scoring rubric for prioritizing different potential low-carbon alternatives for high-heat industrial process needs. At a minimum, scoring criteria should include:

- the lifecycle carbon intensity of the options (the lower the better);
- the potential for the cost per tonne of GHG emission reduction to be lower than other alternatives; and
- the likelihood that the project will accelerate adoption of the technology by Ontario customers."

Questions:

(a) Considering that many components for low carbon alternatives will be imported from China, such as heat pumps currently are, how should the scoring rubric account for the GHG emissions during the manufacture of these components.
(b) Considering that complex components of low carbon alternatives may have a shorter life than conventional simpler components, how should the scoring rubric account for different service lives?
(c) Considering that complex components of low carbon alternatives may require greater use of difficult to recycle metals and non-metallic materials, how should the scoring rubric account for disposal difficulties and costs?

Responses:

(a) It is important to recognize that residential electric heat pumps are an alternative to the combination of a gas furnace and central air conditioners. It is also important to recognize that a heat pump is very similar in design and function to a central air conditioner, with the principal difference being that it can operate in reverse in the winter (removing heat from the outside and moving it inside). Thus, while we have not attempted to trace or estimate the embodied carbon associated with the manufacture, shipping and sale of heat pumps, it would not be surprising if it was less than the embodied carbon associated with the furnaces and central air conditioners that they would displace.

Our recommendation to focus on "lifecycle" emissions intensity was based on lifecycle emissions from the production, transportation and consumption of fuel and not necessarily going the next step of assessing embodied carbon. That would be much more complicated, including consideration of emissions associated with the production, transportation and installation of gas pipe, different gas consuming equipment (and their alternatives), etc.

(b) We do not necessarily agree with the premise of this question. That said, assessments of emissions impacts and costs of reducing emissions should account for differences in the lives of any emission reduction measures.
(c) We do not necessarily agree with the premise of this question. That said, to the extent that some technologies have different disposal costs than others, it would be reasonable to include such differences in assessing the relative cost per tonne of emission reduction if they are sufficiently material.

M1-EP-12

Reference: Exhibit M1, Page 13

Preamble: "Finally, we recommend that the Board create a stakeholder advisory committee that would be expected to work with Enbridge on both the development of a scoring rubric, the actual scoring of different options and ultimately the selection of project funding priorities."

Question:

Are the co-authors recommending that their clients, The Green Energy Coalition and Environmental Defense be represented on the stakeholder advisory committee?

Response:

We have not made specific recommendations regarding the membership of the proposed stakeholder advisory committee. That said, it would be reasonable to include a representative of the environmental community.

M1-EP-13

Reference: Exhibit M1, Page 21

Preamble: "As detailed below, we recommend that the OEB require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months."

Question:

Are The Green Energy Coalition and Environmental Defense, the clients of the co-authors represented on the IRP Working Group?

Response:

Mr. Neme serves on the IRP Working Group. However, he does not represent either GEC or ED in that role.

M1-EP-14

Reference: Exhibit M1, Page 22

Preamble: "Conceptually, as long as customers can be severed from the system without causing safety or reliability issues for other gas customers, there should not be technical constraints to pruning."

Question:

Do the co-authors believe that the safety or reliability issues of the customers being severed should not be considered?

Response:

Of course not.

M1-EP-15

Reference: Exhibit M1, page 22

Preamble: "Similarly, we do not see a need for the Company to have to consult the IESO or local municipalities about such projects. Electrifying a few customers should not affect electric grid loads at a level important to the IESO and local municipalities do not need to be I involved in individual customers' fuel choices. While consultation with the local distribution company could be important to ensuring any local electric distribution capacity constraints are identified, that is no different than the consultation Enbridge presumably undertook as part of its non-pruning IRPA pilot project proposal which included partial electrification of set of customers."

Questions:

(a) How many local electric distribution companies are there in Ontario and how may of them are regulated by the OEB?
(b) Do the co-authors believe that every feeder of every one of those electricity distribution companies has adequate spare capacity to supply customers switching from gas to electricity?

Responses:

(a) It is our understanding that there are about 60 local electric distribution companies (LDCs) in Ontario and that they are all regulated by the OEB. However, we have not confirmed whether there are exceptions to this for the purpose of answering this interrogatory.
(b) We do not have insight into the excess capacity of each electric feeder in Ontario. It is possible that some may have insufficient excess capacity to accommodate contributions to peak demand from a customer switching from gas to electricity. However, that has always been the case, with the LDCs presumably investing in their systems as needed to accommodate such added loads. Of course, that is true as well for any other added loads, such as when a residential customer adds central air conditioning for the first time or when a business expands. It is worth noting that Enbridge rebated almost 15,000 electric heat pumps in 2023. The implications of a pruning pilot that might electrify five customers (or less) are negligible in comparison.

M1-EP-16

Reference: Exhibit M1, pages 22 and 23

Preamble: "For example, as noted in a white paper recently published by National Grid (a large gas utility serving customers in several northeastern states) and the Rocky Mountain Institute (a non-profit advocacy organization promoting clean energy), Pacific Gas and Electric has already completed 85 pruning projects in its California gas service territory."

Questions:

(a) Have either of the co-authors or their clients, Environmental Defense, Greenpeace or the Sierra Club, ever been directly or indirectly involved with the Rocky Mountain Institute?
(b) Please confirm that many gas customers of the Pacific Gas and Electric company in California use gas only for cooking and water heating.

Responses:

(a) Neither EFG nor Mr. Neme or Dr. Hill has any formal relationship with the Rocky Mountain Institute. Counsel for Environmental Defence and the Green Energy Coalition are not aware of any formal involvement with RMI and believe the question with respect to those entities is not relevant.
(b) EFG does not have data to definitively answer the question. That said, data from the 2020 U.S. Residential Energy Consumption Survey (RECS) suggests that 78% of all California residential households use natural gas for water heating and 64% for space heating (https://www.eia.gov/consumption/residential/data/2020/index.php?view=state#hc). Thus, while some California residential customers have gas water heating without having gas space heating, a large majority of residential gas customers have both. Moreover, those data are for California as a whole. Because it serves the northern part of the state where the climate is a little colder than other major population centers like Los Angeles and San Diego, we would expect an even higher percentage of PG&E customers to have both.

M1-EP-17
Reference: Exhibit M1, Page 23

Preamble: "Finally, we recommend that Enbridge consider strategies for addressing situations where most customers are prepared to fully electrify but a very small number or portion are not. When that occurs in a situation in which getting all customers to disconnect from the gas distribution system would provide significant economic benefits to gas ratepayers as a whole, it may be appropriate to consider options other than just incentives. One option might be different gas rates for such "hold outs" that would fairly reflect the cost they are imposing on the system. However, consideration of this option should not hold up initiation of small pilot pruning projects for which there are no "hold outs"."

Questions:

(a) Please confirm that customers disconnecting from the distribution system would result in the costs of operations, maintenance and return of the common facilities such as compressors, regulating stations, storage and transmission being recovered from fewer customers, which would increase their rates.
(b) The so called "holdouts" are likely to be long time loyal customers of Enbridge Gas. For various reasons including the cost of conversion they would prefer to continue using gas instead of converting to electric space and water heating. Why do the co-authors recommend that they be punished?

Responses:

(a) While it is true that such customers' contributions to Enbridge system costs would be shifted to other customers, such cost shifts could pale in comparison to the cost savings that could be realized by all customers as a result of Enbridge not having to replace pipe or other infrastructure as a result of system pruning.
(b) First, we would expect that Enbridge would have to be prepared to cover the cost of conversions and that doing so would be cost-effective. Second, EFG is not making a recommendation that Ontario establish different rates for holdouts. See M1.EGI-16. Finally, to the extent that further exploration suggests that this approach may have merit, it would not be a "punishment". Rather, it would be a reflection of the cost that they are imposing on the gas system by deciding not to leave it.

M1-EP-18

Reference: Exhibit M1, Page 25

Preamble: "Electric ccASHPs have the lowest annual energy bills. As Figure 2 shows, using all of the same assumptions that Enbridge is using, plus reasonable assumptions about the average seasonal efficiency of ccASHPs and heat pump water heaters, we calculate that ccASHPs can be expected to have significantly lower average annual heating bills than all the other heating fuel options that Enbridge is currently comparing."

Questions:

(a) Please file your calculations including all assumptions.
(b) Does a Cold Climate Air Source Heat Pump use electric resistance heating when the outdoor temperature is below a certain setting?
(c) Are any ccASHPs manufactured in Canada?
(d) Do the co-authors assume that all homes have air ducts and air handling circulation fans?

(e) Do the co-authors assume that all homes have the same amount of insulation?
(f) Many rental apartment buildings in Ontario built in the sixties and seventies have electric resistance baseboard heating. The co-authors recommend that their owners consider heat pumps. Please explain how such buildings would be converted to heat pumps.

Responses:

(a) See response to EGI-18.
(b) It depends on the local climate, how the system is sized and whether it is an all-electric system or has fossil fuel back-up.
(c) EFG does not know the answer to this question.
(d) No. However, for homes that do not already have it, ductwork would be needed for either a new air source heat pump or a new gas furnace. Also, air source heat pumps can be installed without ducts using what are commonly referred to as ductless mini-split systems.
(e) No.
(f) Cold climate ductless mini-split heat pumps can be retrofitted in such buildings to efficiently displace a significant portion of the inefficient electric resistance heat.

M1-EP-19

Reference: Exhibit M1, page 29

Preamble: "There is one element that is present in all of the aspects of Enbridge's application discussed in our report, namely a very strong bias in favor of actions that support the continued use of and expansion of gas infrastructure. Our recommendations, summarized in the executive summary above, attempt to put customer interests first, as much as is possible in the context of the proposals that have been included, and not included, in the Company's application."

Questions:

(a) Please confirm that Enbridge Gas is not forcing customers to use gas and that a vast majority of its 3.8 million customers want to continue using gas instead of converting to electricity.
(b) Why do the co-authors believe that they know better than the customers themselves what are customer interests?

Responses:

(a) Enbridge does not force customers to use gas. We cannot speak to the extent to which existing gas customers would prefer to continue to use gas.
(b) Nothing in our report suggests we know Ontario customers' interests better than they do.

M1.Staff-1

Reference: GEC-ED Evidence, p.8,11-12; Exhibit 1, Tab 17, Schedule 1, pp. 2-17

Preamble: Energy Futures Group notes that the Massachusetts Department of Public Utilities has required utilities seeking pilot funding for renewable natural gas or hydrogen blending to explain why the end use is "hard to decarbonize" by other means (i.e., difficult to electrify). Energy Futures Group notes that electrification is currently less suitable for most higher-heat industrial processes and proposes that the logical choice for a targeted energy transition technology fund (ETTF) would be low-carbon fuel for high- heat industrial processes.

Questions:

(a) Please provide references or links to any studies Energy Futures Group is aware of that examine which sectors and end uses currently served by natural gas are hard to decarbonize, based on technical and economic factors, including those that support Energy Futures Group's statement that high-heat industrial applications are the most promising sector/end use to target.
(b) Based on the above referenced studies and Energy Futures Group's expertise, are there any other sectors/end uses/applications Energy Futures Group believes are hard to decarbonize and would potentially be suitable for funding through the ETTF?
(c) Would Energy Futures Group's proposal for a targeted ETTF focused on low- carbon fuel for high-heat industrial processes encompass technologies in all of the following areas: supply of low-carbon fuel, distribution to industrial customers, end use equipment? Why or why not?
(d) Would Energy Futures Group's proposal for a targeted ETTF encompass carbon capture utilization and storage technologies and efficiency improvements to end use equipment, for high-heat industrial applications (in addition to utilization of low-carbon fuels)? Why or why not?
(e) Please comment as to Energy Futures Group's views as to whether technology development related to Enbridge Gas's Asset Life Extension proposal (i.e., supporting asset life extension of gas transmission and distribution infrastructure to avoid pipeline replacements and stranded assets for remaining customers), could be an appropriate area of focus for funding through the ETTF.

Responses:

(a) The studies referenced in Table 1 of our report generally support the notion that, among energy end uses currently served by fossil gas, high-heat industrial process loads are the most difficult to decarbonize. Indeed, in discussing the development of scenarios for analysis in its Massachusetts study, E3 included the following bullet:
   - "*Hard-to-electrify sectors of the economy*. Certain end uses, largely in the industrial sector, do not lend themselves well to electrification, particularly in high-temperature industrial process heating. These applications may see continued

use of gas, either in the form of renewable gases (i.e., biomethane, synthetic gas, or hydrogen) or in combination with carbon capture and storage (CCS)."

Similar conclusions have been reached by the following organizations:

- The International Finance Corporation which references "hard-to-abate sectors, such as cement, steel, glass & chemical sectors, and the heavy-duty transport sector" (see https://www.ifc.org/en/events/2023/decarbonizing-hard-to-abate-sectors).
- The Rocky Mountain Institute which states that "More than one-third of emissions come from heavy transport such as trucks and planes and heat-intensive manufacture of materials such as steel and cement. These sectors are considered hard to abate… (see https://rmi.org/insight/decarbonizing-our-toughest-sectors-profitably/).
- Deloitte which makes reference to iron and steel, road freight, aviation, chemicals, cement and shipping as "hard-to-abate" industries (see: https://www2.deloitte.com/us/en/pages/consulting/articles/decarbonization-technology-hard-to-abate-sectors.html).

(b) As the above references and our report suggest, high-heat industrial process energy needs are the most important of the sectors served by fossil gas to target.

(c) All aspects associated with helping industrial customers with high-heat industrial process energy needs to convert from fossil gas to a low carbon fuel would be reasonable to address.

(d) It may be reasonable to consider CCUS for industrial customers if there was an expectation that would be more cost-effective than alternatives (e.g. use of a low carbon fuel), feasible, and non-duplicative. Generally speaking, efficiency improvements to end use equipment might be best addressed through Enbridge's DSM programming. However, to the extent that an investment well above the Company's per customer or per DSM project spending limit would be necessary to explore an innovative efficiency improvement, it would be reasonable to consider funding that effort through the ETTF.

(e) Investment in gas asset life extension (to avoid more expensive replacements) is fundamentally different than developing solutions for reducing Enbridge's greenhouse gas emissions, which is what we understand the purpose of the ETTF to be.

M1.Staff-2

Reference: GEC-ED Evidence, p.20, 30; Exhibit I.4.2-ED-52 (e); Clean Fuel Regulations: Specifications for Fuel LCA Model CI Calculations; Exhibit 4, Tab 2, Schedule 7, p.32

Preamble: Energy Futures Group recommends that the Low-Carbon Energy Program should procure renewable natural gas (RNG) based on the cost per tonne of avoided lifetime greenhouse gas emissions, using the United States Environmental Protection Agency's GREET model or similar life-cycle basis methodology to calculate life-cycle carbon intensity (CI). Enbridge Gas has previously suggested that the method or tool to calculate the CI of RNG projects should comply with the requirements of the program to which RNG projects are seeking to be a registered participant, noting that RNG projects seeking to create Clean Fuel Regulations (CFR) credits must determine the CI of their project using Environment and Climate Change Canada's OpenLCA model. This methodology is documented in more detail in the document linked above. Enbridge Gas has also proposed that it may purchase RNG with CFR credits, if the benefits, less expenses, generated from CFR credit sales will reduce the incremental cost of low- carbon fuel.

Questions:

(a) Is Energy Futures Group familiar with the CI methodology used for the Clean Fuel Regulations, and if so, does Energy Futures Group have any technical concerns with using this methodology more generally as the basis for any calculations of CI for RNG?
(b) From a policy perspective (i.e., separate from any concerns noted in Energy Futures Group's response to part(a) regarding methodologies used to calculate CI), please describe why Energy Futures Group's proposal that RNG should be procured based on the cost per tonne of avoided lifetime greenhouse gas emissions is preferable to Enbridge Gas's proposal to incorporate the economic value of CFR credits into its procurement decisions.

Responses:

a) EFG has conducted a cursory review, but not a detailed technical assessment of the CI methods used for the Clean Fuel Regulations due to time constraints in responding to interrogatories.

   We note the Fuel Life Cycle Assessment Methodology considers the CO2 combustion emissions from biogenic sources as zero, based on the assumption that biogenic CO2 emissions are balanced by carbon uptake.[7] This zero-emission impact assumption for RNG applies only to the end-use combustion stage of the lifecycle assessment. Section 3.5.4 addresses lifecycle modeling for other stages of waste material feedstocks, giving an example of the potential for avoided direct methane emissions from anaerobic digester

[7] Environment and Climate Change Canada, 2024. Fuel Life Cycle Assessment Methodology. p. 16.

production of RNG. Section 3.5.4 briefly discusses how general modeling approaches can be applied to estimate an appropriate lifecycle avoided emissions for low carbon intensity fuels.[8] Additional time would be required to analyze the method used in the Clean Fuel Regulations.

b) The cost per tonne of avoided lifetime GHG emissions is preferred because it provides a direct metric of the costs incurred by RNG procurement and the resulting reduction in actual GHG emissions to the atmosphere.

In comparison, the economic value of CFR credits is an indication of the status of how the market is meeting broader CFR requirements. The economic value of CFR credits will reflect their tradable nature, the overall levels of compliance, and credit supply/demand, for a range of RNG and non-RNG resources. Therefore, it is less suited to indicating the cost per tonne of reduction from the LCEP and the proposed RNG procurement.

[8] Ibid., p. 52.

M1.Staff-3

Reference: GEC-ED Evidence, pp.14-16; Exhibit I.4.2-ED-48

Preamble: Energy Futures Group states RNG procurement only delivers a one-time reduction in emissions, and that in contrast to RNG, investments in energy efficiency, electrification and other measures typically provide emission reductions for decades. Energy Futures Group compares the cost of emissions reductions from RNG versus demand-side management (DSM), and also proposes capping the price paid for RNG at $25.58/GJ.

Questions:

(a) Please confirm that the estimate of the costs of emissions reductions from DSM referenced by Energy Futures Group already accounts for the longer time period over which DSM measures deliver emissions reductions. If confirmed, is Energy Futures Group suggesting that there are other reasons why the shorter time period of emissions reductions achieved from RNG procurement (relative to DSM) is undesirable?

(b) Is Energy Futures Group proposing that the cost for any RNG procurement be capped at $25.58/GJ, or that the average cost of Enbridge Gas's RNG supply be capped at this level?

Responses:

a) Confirmed in part. The simple $/TCO2e estimates for the DSM measures account for the longer measure lives, but as noted, are based solely on DSM spending and do not include energy cost savings. The much higher cost per tonne of RNG at $511.60/TCO2e, reflects the shorter measure life.

   Our point is carbon emissions reductions from DSM investments, even when based solely on DSM spending and not accounting for the benefits of energy savings, are significantly less costly per tonne of emission reduction than the proposed procurement of RNG.

b) The former, any procurement be capped at $25.58/GJ. See response to M1-CBA-3.

M1.Staff-4

Reference: GEC-ED Evidence, pp.19-20; Exhibit I.4.2-Staff-37

Preamble: Energy Futures Group states that "to reduce emissions, RNG procurement needs to be sourced from the development of new capacity, and not merely be repurposed or re- contracted from pre-existing RNG uses." Energy Futures Group also recommends prioritizing the development of Ontario-based RNG sources, and notes that Vermont Gas is required to purchase the transmission pathway to its distribution system in Vermont before it can claim any GHG emission reduction from procured RNG.

Questions:

(a) Does Energy Futures Group believe that physical transmission of RNG (such as the Vermont Gas example) is necessary to address concerns regarding additionality/incrementality of greenhouse gas emissions reductions from RNG, or can this concern be addressed through regulatory or contractual arrangements?
(b) Please comment on Enbridge Gas's responses to Exhibit I.4.2-Staff-37, regarding double-counting, additionality considerations, and the information provided to potential voluntary participants in the Low-Carbon Voluntary Program. Does Energy Futures Group agree with Enbridge Gas's proposals on these issues, or have any additional recommendations as to whether and how to modify the Low-Carbon Voluntary Program to address these issues?

Responses:

a) Concerns regarding additionality/incrementality of greenhouse gas emissions can be partly addressed through regulatory or contractual arrangements. However, purchasing physical transmission pathways is a more robust and failsafe mechanism. Moreover, it means treating RNG the same way as – i.e., as a true substitute for – fossil gas (for which Enbridge and all other gas utilities always purchase transmission pathways).

   Transmission pathway rights and a preference for Ontario-based sources are also recommended for different reasons. The recommended requirement to purchase transmission system pathway rights is meant to reflect the full costs of RNG delivery to the Ontario distribution system. This will appropriately improve the cost-effectiveness of Ontario-based RNG projects in comparison to out-of-province projects. Also, when fossil methane consumption is largely eliminated, RNG is more likely to need to be physically transported. Accounting for transportation in decision-making now when projects are being developed will improve cost-effectiveness in the future.

   Ontario-based RNG development will benefit Ontario ratepayers in the long-run. Ontario-based sources will have fewer transmission costs now and in the future. Ontario-based RNG development will also mitigate energy transition risks to Ontario customers related to long-term transmission pipelines (e.g. price and availability of gas transmission pathways in the future) and RNG regulation in other jurisdictions (e.g. mandating preferential access to RNG from hard-to-decarbonize sources).

b) EGI response to Staff 37 indicates that CFR credits cannot be used to reduce the on-site facility emissions (Scope 1 emissions). They also note that “environmental attributes” are a generic category including, but not limited to carbon offsets, CFR credits and the ability to claim on-site GHG reductions. The distinction between CFR credits for primary suppliers and GHG reductions for scope 1 end users can, in theory, avoid double counting with accurate accounting, verification and transparency of attribute ownership. It is also possible that without very careful accounting and verification double counting or misunderstanding of attribute ownership and use could occur.

   With respect to additionality, EGI responds that while additionality is a fundamental requirement for carbon offsets, it is not required for consumers of RNG to claim a reduction in on-site GHG emissions. While accurate from an accounting and reporting perspective, it is also true to say that if RNG is merely repurposed from an existing user, who reverts to fossil fuel use, there is a change in who is emitting, but there is no additional reduction in emissions. If, as we argue it should be, the design objective of the LCVP is to reduce total net emissions, then additionality should be considered, and strictly relying on accounting and reporting requirements may not be sufficient.

   Accurate and balanced communications and marketing to customers in the LCVP program and about the LCEP program impacts is critical. It should be designed to help consumers, regulators and other stakeholders clearly understand the complexities of attribute ownership, emissions accounting and reporting. Care needs to be taken to distinguish between emission reductions for an individual customer and broader total reductions. A statement such as “RNG will play a major role in meeting total emission reduction targets” is an example of the type of marketing and communications that should be guarded against. As we have discussed in our testimony and interrogatory responses, it is more accurate to indicate RNG is likely to play a complementary role in reducing emissions at both the facility and total levels. Marketing and communications giving the impression that RNG will be a major contributor to total emissions reductions risks being “greenwashing” and misleading.

M1.Staff-5

Reference: GEC-ED Evidence, p.23; Exhibit I.1.17-ED-31

Preamble: Energy Futures Group recommends that Enbridge Gas consider strategies for addressing situations where most customers are prepared to fully electrify but a very small number or portion are not, as part of its system pruning pilot proposal.

Question:

Is Energy Futures Group aware of any relevant learnings from electrification programs/pilots in other jurisdictions that may address this issue? Please provide any relevant learnings regarding either utility strategies to address this circumstance, or regulator actions to address concerns regarding a gas distributor's obligation to provide service (i.e., requirements similar to section 42(2) of the OEB Act – see Enbridge Gas's response in Exhibit I.1.17-ED-31).

Response:

We have not researched this specifically and our recommendation is that Enbridge do so. We are not aware of examples of how other jurisdictions have addressed or are considering addressing this issue, other than some proposals to remove or modify gas utilities' obligation to serve.

M1-PP-1

Reference: Maximize ratepayer benefits: The LCEP should exclusively procure new RNG supply (not recontract for existing supply) and heavily prioritize the development of Ontario-based RNG sources to increase overall supply and maximize long-term benefits. [Page 2]

Questions:

(a) What approach is practical for the OEB to ensure that RNG is incremental to the current market. Wouldn't this take building specific RNG facilities from scratch that do not already have purchase or emission credit commitments to other market participants?
(b) Given that the current RNG (or related emission credits if credits are stripped from RNG) is over subscribed and taken outside Ontario (e.g. for Fortis BC or US uses), how would Enbridge be able to ensure that any RNG purchased is incremental market supply.
(c) Enbridge previously confirmed that RNG ceases to be RNG if the emission credits (attributes) are separated and sold off. What controls would be needed through an OEB Decision to ensure this does not occur?
(d) Given the cost, current market demand and maximum blending of RNG proposed by Enbridge, would it not just be better to have Enbridge support the development of incremental RNG production rather than purchase it for mandatory blending targets in Ontario?

Responses:

a) Yes, requiring new RNG facility development or ones that do not have pre-existing purchase of emission credit commitments to other market participants could be a practical approach to ensuring the LCEP is promoting new capacity.
b) Similar requirements for new facilities or ones that do not have pre-existing commitments could be used to ensure new capacity.
c) The procurement of RNG through the LCEP should be required to retain emission credit attributes.
d) Both direct project support and procurement of RNG and subsequent blending can support low carbon gas as a decarbonization strategy. That said, Enbridge support for the development of incremental RNG production could have some "market transformation" benefits, but by itself would not contribute to reducing the Company's GHG emissions. Only actual purchases of and transportation to Enbridge customers will directly reduce emissions.

M1-PP-2

Reference: Achieve the most cost-effective GHG reductions: The LCEP should procure RNG based on the cost per tonne of avoided lifecycle GHG emissions to reflect the major variance in carbon intensity of different RNG sources and to minimize the cost of carbon emissions reductions. [Page 3]

Questions:

(a) Please confirm that the cost per tonne recommended to be used for RNG purchases is the full lifecycle emissions of the RNG (lifecycle emissions for production of the RNG, combustion, etc.) against the full lifecycle to of the baseline fuel (i.e. natural gas in the case of an Enbridge natural gas customer).

(b) Please explain why a lifecycle calculation for GHG reductions is better than the approach proposed by Enbridge (i.e. counting emissions only from the end use natural gas combustion emissions displaced).

Responses:

a) Confirmed.

b) The lifecycle assessment of the RNG avoided impacts is important because of the substantial variation in lifecycle carbon intensity depending upon the feedstock source, and project specific variables. The avoided end-use combustion method does not account for these differences.

M1-PP-3

Reference: PollutionProbe_IR_AppendixA_CSAClassificationReport_20240823, Page 20. Standards organisations such as CSA recognize lifecycle assessment for carbon (GHG) emissions as a best practice and notes that the International Organization for Standardization (ISO) has produced several emissions standard documents that are used in North America and across the world including the following which address use of LCA methods and calculation of GHG emissions, including:

- ISO 14040, Environmental management – Life cycle assessment – Principles and framework outlines the four phases of an LCA study, including goal and scope definition, inventory analysis, impact assessment, and interpretation. The framing of an LCA following ISO 14040 can apply to both attributional and consequential models.
- ISO 14044, Environmental management – Lifecycle assessment – Requirements and guidelines, outlines the details for conducting an LCA for practitioners.

Questions:

(a) Are the ISO standards noted above aligned with EFGs recommendations for recognized best practice standards for calculating lifecycle emissions for fuels used (including in Ontario)? If there are additional standards that the OEB should consider, please provide them.

(b) Is using lifecycle analysis and calculations for emissions reductions a regulatory best practice that the OEB should apply for Enbridge low carbon fuels and GHG reduction comparisons? Please explain the answer.

(c) What would be the impact if the OEB were to adopt the Enbridge proposed approach (natural gas displacement at end use combustion) over the more holistic lifecycle emissions approach to calculate net emission reductions.

Responses:

a) EFG has not conducted a detailed review of ISO 14040 or 14044, but we note these are cross referenced in the Environment and Canada Climate Change Lifecycle Assessment Methodology referenced in our response to Staff-2.

We anticipate these standards would be suitable to be proposed as methods to account for the lifecycle carbon intensities of RNG procurement. We note that it may not be necessary or valuable to conduct highly detailed LCA analysis for each individual RNG project, and that reference to average carbon intensity ranges by feedstock source and project type may be suitable. Appendix A in our report provides examples of such ranges. In our report we recommended the use of the GREET model or similar lifecycle basis methodologies. We do not have other specific recommendations for standards.

b) Yes. As explained in our report, the variation of carbon intensities for RNG is based on consideration of the lifecycle emissions. Our recommendations provide a reasonable means for EGI to include the carbon intensities of various RNG procurement options in their decision making.

c) If Enbridge's approach is adopted, it will not consider the lifecycle carbon intensity of RNG in procurement decisions. The result could be that the RNG procurement is concentrated on lower cost resources that have lower emission reduction benefits. This means customers would pay more per tonne of *actual* greenhouse gas emission reduction achieved than necessary. In other words, the RNG purchases will not be as economic or cost-effective as they should be.

RNG and fossil gas have the same emissions impact at the point of combustion. What allows RNG to reduce emissions are the differences in emissions from the upstream lifecycle stages. Lifecycle analyses indicate that landfill gas and wastewater treatment sourced RNG can partially, but not fully displace emissions from fossil gas (per GJ of displaced fossil gas). Manure anaerobic digestion, by avoiding direct emissions of methane to the atmosphere, has the potential to *more* than fully offset emissions from fossil gas (per GJ of displaced fossil gas).

To the extent that RNG sources with relatively high lifecycle carbon intensities such as landfills have lower costs per unit of energy than RNG sources with relatively low (or even negative) carbon intensities such as dairy farms – which is often the case – adopting Enbridge's approach of treating all such RNG sources as equal will have the effect of driving the Company's RNG investment to higher emitting options. Depending on the magnitude of differences in price and carbon intensity, it could drive Enbridge to invest in RNG that costs considerably more per unit of actual emission reduction than alternatives that it rejects.

M1-PP-4

Reference: Achieve timely progress: The OEB should require that Enbridge develop its approach to system pruning in consultation with the IRP Working Group within 6 months and begin implementation on a small pilot within 12 months.

Questions:

(a) Please comment on the importance of the OEB setting a specific time requirement (e.g. withing 6 months for approach and 12 months for a pilot) for developing the approach to system pruning in consultation with the IRP Working Group and implementing the pilot.
(b) Enbridge has failed to implement the two IRP pilots prior to the end of 2022 as order by the OEB. What OEB controls would need to be in place for a pruning pilot to be more successful and implemented on time, compared to the other 2 IRP pilots that the OEB ordered in 2021.

Responses:

(a) The reason we suggest the OEB establish a timeline for getting started is that (1) Enbridge has significant financial disincentives to pursue system pruning, even if it would reduce customer costs; (2) often one can learn faster by doing than by studying; (3) experience with the IRP process has been that it has taken a really long time to just propose a non-pruning pilot of non-pipe solutions. In that context, we thought it important that the Board establish an expectation that Enbridge move expeditiously.
(b) EFG has recommended concrete direction from the OEB regarding pilot timelines and approval to proceed with one or two modest pilots. We are suggesting that such modest pilots should be able to be developed and proceed without requiring an additional application to the Board, which is different from how the process for the IRP pilots ordered in 2021 has unfolded. EFG does not have specific additional suggestions as to what the Board should do if the Company does not proceed within an expected timeframe.

M1-PP-5

References: M1 EFG Evidence Section 3 on ETTF and PollutionProbe_IR_AppendixD_NZAB_Principles_20240823

Questions:

(a) EFG warns of the dangers of simply approving spending on anything that reduces GHG emissions, i.e. the first in the list of Enbridge ETTF Criteria. The Net Zero Advisory Board also warns of actions that create "dead ends" by reducing GHGs in a manner that will not enable a Net Zero emission future (essentially locking in bad decisions). Is this principle the same as what EFG is flagging to the OEB? If not, please explain.
(b) If the OEB were to provide incremental innovation funding beyond that which Enbridge already has through rates, would changing the first criteria from "Reduce GHG emissions" to "Aligns with Net Zero emissions" be more in alignment with best practice and support of the Energy Transition?
(c) EFG highlights the inherent Enbridge bias towards shareholder profit and activities to prolong the natural gas system. What effective option are open to the OEB to overcome this bias if ratepayers funds were to be leveraged for innovation funding? Would decision making through an arm's length or independent Advisory Group be one option?.
(d) With arms length innovation funds already existing in the market, what incremental benefit is there for Enbridge to start another gas centric innovation fund (ETTF)?

Responses:

a) The concern we expressed is different than the concern about locking in bad decisions. Our concern is that funds could be spent on technologies that are unlikely to play significant roles in the ultimate pathway to achieving net zero rather than spending it on things that we have good reason to think will be more viable – practically and economically – and contribute more substantially to achieving net zero in the long-run. That should be a concern whether or not the investment would contribute to locking in a bad decision.
b) Aligning with an economically optimal path to achieving net zero emissions would be a better criterion.
c) Enbridge's biases could be mitigated through mechanisms, such as the Advisory Group that we recommend in our report, that require input on decisions from other parties.
d) We have not assessed to the extent to which there are other innovation funds in the Ontario market. Nor have we assessed where any such funds might be focusing investment. That said, an Enbridge fund that has a very targeted focus on a "safe bet" such as low carbon fuels for high heat industrial processes could provide incremental benefit, relative to the work of other funds, because Enbridge could have a better understanding of the energy needs of such industrial customers.

M1-PP-6

References: M1 EFG Evidence Section 5 on IRP / system pruning and PollutionProbe_IR_AppendixC_OEB_IRPTWG_2023Report_20240823

Questions:

(a) EFG highlights the lack of progress since 2021 on Enbridge implementing the OEB required IRP Pilots and Enbridge's proposed approach to only consider a system pruning pilot in the future with the IRP TWG, rather than taking action now. What options could the OEB consider through the Phase 2 Decision or other mechanisms to get IRP on track, including advancing a timely pruning pilot?

(b) IRP TWG comments in the most recent 2023 OEB IRP TWG Report mimic the concerns and lack of progress reflected in the OEB IRP TWG annual reports since 2021, as discussed in Phase 1 of the Rebasing proceeding. What approach does EFG recommend for the OEB to address those concerns?

(c) Enbridge's Asset Management Plan continues to favor Capital gas infrastructure over IRP alternative and no version of the Capital plan has included a list of any IRP alternatives to be installed in lieu of traditional pipeline assets. What recommendations does EFG have for the OEB to fix this issue (e.g. mandatory minimum percentage of IRPAs, an independent audit of Enbridge processes and areas of improvement, etc.)?

(d) Enbridge has identified their obligation to serve as a gas distributor as a barrier to IRP and system pruning. Would any of the following (or other) options be effective in resolving that barriers:
   a. OEB explicitly identifies IRP alternatives as equivalent to providing gas service under the obligation to serve.
   b. OEB ensuring that customers remaining on pipelines that are targets for pruning pay the full costs related to the continuance of those specific pipelines.

Responses:

a), b) and c)

With respect to system pruning pilots, see response to PP-4.

With respect to non-pipe solutions more generally, one option would be to establish a framework in which Enbridge can earn shareholder incentive for pursuing cost-effective alternatives to traditional supply projects.

We would also suggest that the OEB modify the previously approved DCF+ framework for assessing "cost-effectiveness" of IRPAs. Currently, stage 1 of the framework assesses rate impacts rather than addressing the question of which option is lowest cost. Rate impacts and cost-effectiveness are two very different things. While stages 2 and 3 of DCF+ (when added to Stage 1) could provide insight into whether an IRPA is lower cost than a traditional supply-side investment,[9] the Board's current direction is to give greater weight to stage 1 results.

d) We do not see how an obligation to serve would be a barrier to investment in non-system pruning IRPAs.

An obligation to serve could be a barrier to some potential system pruning projects – to the extent that there are customers who choose not to leave the system. As we suggested in our report, one option that could be explored to address such holdouts would be higher rates that reflect the cost their decisions impose on the system.

[9] We say "could provide" because there are problems with the way Enbridge has been estimating costs and benefits, particularly in Stage 3, which need to be fixed. For example, the Company has historically valued carbon emission reductions using the federal carbon tax rather than Canada's social cost of carbon. In addition, the Company has historically only counted increases in jobs and GDP resulting from construction of distribution system infrastructure as Stage 3 benefits without either (1) subtracting jobs and GDP the result from the increased costs imposed on its customers to pay for such investments (i.e. they are not computing net changes in jobs or GDP); or (2) estimating net job impacts and GDP growth that IRPAs such as energy efficiency might produce. These issues are currently being discussed within the Board's IRP Working Group.

M1-PP-7

Reference: PollutionProbe_IR_AppendixB_MuncipalSlidesIRPPilot_20240823. Enbridge recently did a municipal presentation on the Southern Lake Huron IRP Pilot. Appendix B includes the context slides provided (full deck is available via Updated: 2024-06-28, EB-2022-0335, Exhibit I.PP-15, Attachment 1). Similar slides were used in other municipal presentations.

Question:

Please comment on EFGs views on the accuracy of Enbridge's claim that the Enbridge Diversified Scenario (per the Guidehouse Pathways to Net Zero report commissioned) provides a Net Zero option at a lower costs than the Electrification Scenario.

Response:

Mr. Neme's report in Phase 1 of this proceeding demonstrated that the Guidehouse analysis of what it called a "diversified scenario" was fundamentally biased and flawed and that correcting just one of the many biases/flaws would change the conclusion such that the high electrification scenario was the lower cost option.

M1-PP-8

Reference: Enbridge Gas will incorporate energy transition sensitivity analysis, which will examine how long the pipeline is expected to be needed under different energy transition scenarios, and additional statistical modelling of residual risk for repair alternatives. [Phase 2 E1/T17/S1, Page 7]

Question:

Given the challenges Enbridge has encountered implementing IRP, identifying IRP alternative and even initiating IRP Pilot projects, what advice does EFG have for the OEB to ensure the timely incorporate energy transition sensitivity analysis into the Capital planning process.

Response:

Enbridge has begun attempts to incorporate energy transition sensitivity analysis into capital planning for specific leave to construct applications. We do not have sufficient time to provide an assessment of those efforts in this interrogatory response, but a cursory review suggests that there is much room for improvement. There may be value in the Board establishing a generic requirement regarding the kinds of sensitivities that should be analyzed for all future leave to construct projects.

M1-PP-9

Questions:

(a) In EFG's experience in other jurisdictions, what is the role of rate payers and the regulated utility to fund hydrogen production technologies?
(b) Please comment on EFG's opinion of spending more rate payer funding on hydrogen projects and research before Enbridge has filed the results of the $16 million Hydrogen Study Enbridge has undertaken to inform whether parts of the systems can be compatible with blends of hydrogen.
(c) In EFG's experience in other jurisdictions, what is the role of rate payers and the regulated utility to fund carbon capture utilization and storage (CCUS) technologies?

Responses:

(a) EFG has not conducted an assessment of how other jurisdictions are addressing the issue of gas ratepayer funding of hydrogen production technologies.
(b) It depends on what is meant by "hydrogen projects and research". If the question is about hydrogen blending with methane for widespread distribution through Enbridge's system, that is an imprudent focus for gas utilities. Most importantly, even under the most optimistic assumption about levels of hydrogen blending that can be burned with current furnaces, boilers, water heaters and other gas appliances, such blending would contribute very little – i.e., at most between 1% and 2% - of needed emission reductions. In addition, because hydrogen is much less dense than methane, hydrogen blending reduces the effective capacity of gas pipes, accelerating the date at which any future capacity constraints are realized and the date at which upgrade costs would be incurred. See our Phase 1 report for more details.

    If the question instead refers to the production and use of hydrogen to substitute for fossil gas at industrial facilities with high-heat process needs, such investment should be welcomed.
(c) EFG has not conducted an assessment of how other jurisdictions are addressing the issue of gas ratepayer funding of CCUS technologies or their application.

M1-PP-10

Reference: Exhibit I.1.10-PP-16 asked Enbridge to explain how low-carbon fuels can achieve net-zero if they have a lifecycle emissions value greater than zero.

Enbridge responded: Please see the response at Exhibit I.1.10-PP-15, part c) on how low-carbon technologies can support achieving a net zero economy. Similarly, each low-carbon fuel does not need to achieve net-zero on its own. Net removals of carbon dioxide from the atmosphere can be achieved where the biogenic emissions released from the combustion of biomass derived fuels, such as RNG, are captured and sequestered, which is often referred to as bioenergy with carbon capture and storage (BECCS). The negative emissions from BECCS can be used to net out GHG emissions remaining in the economy, which has been identified by Canada's Energy Regulator as playing an important role in achieving net-zero.

Question:

Please provide EFG's response to the question and perspective in relation to Enbridge's response.

Response:

Emissions from RNG that does not have a zero or negative carbon intensity can be reduced by effective carbon capture and storage. Effective carbon capture and storage is dependent upon many factors and adds costs. As economies strive to meet net zero targets or requirements, there may or may not be strategic applications for carbon capture and storage, but these opportunities will still need to be compared to alternatives such as increased efficiency and decarbonized electrification.

EFG has noted that EGI's proposed RNG procurement is already expensive compared to other options for reducing emissions. Further, EGI is not proposing BECCS for the LCEP program. Doing so would only increase costs, likely significantly, and further the gap between the costs for the proposed program and more cost-effective alternatives.

M1-PP-11

Reference: Enbridge Gas intends to conduct a jurisdictional scan to review how other natural gas utilities present energy comparison data in their marketing materials and identify best practices. The Company will use this information to determine if further changes should be made, and will consider if additional energy technologies, such as, but not limited to, electric ccASHPs should be added. [Phase 2 E1/T16/S1, Page 23]

Questions:

(a) Please provides EFGs opinion on the value and likely impact of limiting the proposed jurisdictional scan only to gas utilities.
(b) Given the broader fuel agnostic relevance of ccASHPs and other efficient and lower GHG emitting technologies, please provide any comments on the value of replacing Enbridge's proposal with a jurisdictional scan be conducted through an independent third party in partnership with the OEB, IESO and other relevant stakeholders (perhaps even the DSM SAG).

Responses:

(a) It is highly problematic, as other gas utilities also have a disincentive to show any fuel other than the one that they sell as the least cost option.
(b) Frankly, we do not see the need for a jurisdictional scan. Enbridge purports to be presenting to customers the difference in operating costs associated with different fuels. As we explain in our report, in that context there should be no question as to whether cold climate air source heat pumps are included in the comparison. One might debate the assumed average operating efficiency of such heat pumps, and perhaps that could be reasonably considered by the DSM SAG or other bodies, but that should be the only debatable issue. Concerns raised by Enbridge about capital costs – many of which apply to conversions to gas as well – should all be addressed in footnotes or other related materials.

M1-TFG/MC-1

Reference: Exhibit M1, pp. 6-7, 12-13

Preamble: Energy Futures Group ("EFG") notes in its report, "Enbridge Gas 2024 Rebasing Phase 2" (the "Report"), that Enbridge Gas Inc.'s ("EGI") proposed Energy Transition Technology Fund ("ETTF") should only invest in technology that is likely to offer customers better choices.

EFG suggests that the ETTF (i) is heavily biased towards solutions that rely on gas pipelines and the future role (and therefore profits) of EGI, and (ii) spreads funding across too many projects to have any material impact.

The Report notes that the proposed ETTF will support end-use energy efficiency technology not covered by DSM funding.

EFG recommends that the Board either reject the ETTF or require it to be targeted solely on major energy transition needs that are universally recognized by the industry.

Questions:

(a) Please describe the general characteristics or structure of an energy transition/innovation fund that could both: (i) facilitate the ability of utilities like EGI to obtain funding for worthwhile innovation proposals; and (ii) operate substantially free of the bias concerns raised in the Report.
(b) Please comment on what the likely advantages and disadvantages would be of establishing a centralized energy transition/innovation fund, such as a fund administered by the OEB or otherwise on behalf of the provincial government, pursuant to which Ontario utilities could apply for funding of proposed energy transition/innovation projects. As part of your answer, please consider the advantages and disadvantages of such a hypothetical fund as compared with the prospect of an increasing number of "energy transition" funds administered by individual energy utilities in Ontario .
(c) Please comment on whether and how a centralized and independent source of energy transition/innovation funding in Ontario would address and alleviate the concerns and issues related to the ETTF, as identified in the Report.
(d) Are you aware of any centralized sources for energy transition technology funding instead of utility managed funds in other jurisdictions? If yes, please discuss how they operate and how regulated entities apply for and receive funding for proposed projects.
(e) Assuming an energy transition/innovation fund could overcome the concerns, including relating to bias, raised in the Report, what is the minimum amount of funding that would be necessary to provide a material impact on addressing energy transition risks and supporting the development and use of technologies that support the energy transition in Ontario?
(f) Please provide examples of the types of technologies under a hypothetical energy transition/innovation fund that you believe would provide the greatest value to Ontario

ratepayers. In your response, please provide examples of energy transition/innovation funds that provide funding for the identified technologies and the types of projects funded.

Responses:

(a) Energy transition funds that are managed by the OEB, another government agency or a non-profit organization empowered by government and given direction to be fuel-neutral could theoretically accomplish that objective. If the funding is to be managed by Enbridge, the best that can be done is for the Board to put constraints on what can be funded (as we recommend) and to initiate a formal stakeholder process to provide input on project selection (as we have also recommended).
(b) See response to part "a". Note that there would still be value to having a stakeholder advisory group for a Board managed fund. Enbridge could potentially be one of the stakeholders.
(c) If the OEB were to manage the fund, concerns about bias in favor of investments that advance gas shareholder interests should be alleviated.
(d) EFG is not aware of examples of independently-run energy technology transition funds.
(e) EFG has not done analysis of a range of potential projects that would be necessary to inform an answer to this question.
(f) As noted in our report, we believe the most appropriate focus would be on the deployment and testing of the use of low carbon fuels for industrial customers with high-heat process needs.

M1-TFG/MC-2

Reference: Exhibit M1, p. 13

Preamble: EFG recommends that the Board consider creating a stakeholder advisory committee for the ETTF that would work with EGI on the development of a scoring rubric, the actual scoring of different options, and the selection of project funding priorities.

Questions:

(a) How could the ETTF, or a similar hypothetical energy transition/innovation fund, be improved to support and ensure Indigenous participation and funding for Indigenous-led projects?
(b) Are there examples of Indigenous participation in comparable energy transition/innovation funds to the ETTF that could provide helpful precedents for Indigenous participation? If yes, please describe the fund(s) and how they support Indigenous participation.
(c) How should EGI, or a similar hypothetical energy transition/innovation fund, encourage Indigenous participation in the stakeholder advisory committee? In your response, please discuss how to ensure (i) meaningful Indigenous participation in the selection of project funding priorities through the ETTF, (ii) Indigenous engagement and participation in projects funded by the proposed ETTF, and (iii) adequate consideration of the interests of First Nations and Indigenous communities.
(d) To the extent not already addressed in your answers above, please comment on relevant issues related to improving Indigenous participation in the (i) ETTF, (ii) stakeholder advisory committee, and (iii) projects funded through the ETTF.

Responses:

(a) One option might be for an Indigenous representative to be on a stakeholder review committee. Another might be to ensure that the system for comparing options includes criteria that provide a scoring "bonus" for projects that support Indigenous people and other communities of interest.
(b) EFG has not conducted the research necessary to answer this question.
(c) As noted in response to part "a" of this question, one option might be to have an Indigenous representative appointment to a stakeholder advisory group. We do not have a definitive recommendation beyond that, as we are not experts in ways to successfully engage Indigenous communities. We might suggest that the Board and Enbridge solicit input from Indigenous communities about how they would like to be engaged and have their input considered.
(d) See response to parts "a" and "c" above.

M1-TFG/MC-3

Reference: Exhibit M1, pp. 14-20

Preamble: EFG notes that under the Low-Carbon Energy Program ("**LCEP**") proposal, EGI could procure renewable natural gas ("**RNG**") supplies from anywhere across North America and recommends that the LCEP should prioritize or be restricted to support the development of regional (i.e., Ontario-based) RNG projects and infrastructure.

EFG recommends that the Board cap the price at which EGI can procure RNG at $25.58/GJ.

Questions:

(a) How should EGI and/or Ontario policy work to encourage the development of RNG projects and infrastructure to ensure the supply of Ontario RNG satisfies the demand anticipated in your proposals?
(b) What does the recommendation to prioritize the procurement of Ontario-sourced RNG mean for Ontario First Nations and Indigenous groups that may be interested in developing RNG projects?
(c) Please comment on whether the price cap will limit the ability of First Nations and Indigenous groups to develop RNG projects? In your response, please consider the unique challenges of many First Nations including (i) access to capital, (ii) location (remote and near-remote), and (iii) the economic realities of many of Ontario's First Nations that may impact the price at which RNG is financially viable.
(d) Please comment on how the recommendation to prioritize and/or restrict the development of RNG projects benefits or disadvantages Ontario First Nations and Indigenous groups interested in producing and supplying RNG. In your response, please discuss any unique benefits and/or disadvantages for Ontario First Nations and Indigenous groups as compared to non-Indigenous suppliers and producers, if any.
(e) Please comment on setting targets under the LCEP for procuring RNG from First Nations and Indigenous-owned suppliers in Ontario.

Responses:

a) The proposed LCEP program should encourage development of RNG projects and resources. Our recommendation to reduce the total level of procurement from 4% to 1% of supply with a focus on Ontario supply, as opposed to out-of-region sourcing, will help match Ontario supply with the program's target.

b) Our recommendations that procurement prioritize new in region projects can benefit First Nation or Indigenous groups interested in RNG development. That said, the relative economics for individual RNG production sites in Ontario, whether First Nation/Indigenous or not, will vary according to levels of existing infrastructure and feedstock resources.

c) The recommended price cap equates to offering a high price for new RNG development while remaining consistent with EGI's proposed structure for limiting per customer rate impacts for the LCEP procurement. EFG has not considered, and does not take a position on, whether a higher price cap for the development of new RNG by First Nation or Indigenous groups is appropriate. However, to the degree such projects have higher development costs (for example an RNG site that does not have current gas connection), and their development is aligned with policy objectives, a differentiated price cap, or other mechanism, such preferential scoring in procurement or a percent set-aside could be considered.

d) Remote sites, or sites without more limited existing infrastructure (such as an anaerobic digester, or a landfill site with existing gas capture) will face higher costs for RNG development than those that are closer to the existing gas system, or those with some existing infrastructure. This applies to sites whether or not they are affiliated with First Nation or Indigenous groups.

e) See response to c).