INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Ontario Energy Board Staff (STAFF)

Reference:

Exhibit M8, pp. 7-8

Dr. Hopkins discusses capital recovery risk and notes that "...in practice, however, when a utility asset that was installed prudently becomes no longer used and useful, regulators commonly allow the continued recovery of some or all of the value of that asset".

Questions:

(a) Are there specific regulatory decisions supporting this statement that are particularly pertinent to the OEB's approach to treatment of stranded assets for Enbridge Gas associated with energy transition? If so, please provide references.

(b) If the OEB grants the approvals requested by Enbridge Gas related to new capital spending in this application (e.g., the forecast of 2024 capital expenditures underpinned by the Asset Management Plan), in Dr. Hopkins view to what degree (based on regulatory precedent) is this an acknowledgement that the OEB considers the investments described in the Asset Management Plan to be prudent, and thus likely eligible for rate recovery if stranded, particularly for capital expenditures that will not require a future project-specific approval (e.g., Leave to Construct approval) from the OEB?

(c) In your opinion, does the OEB need to provide additional guidance as to how it would assess the prudency of capital expenditures made over the rebasing term in relation to energy transition?

(d) If the OEB determines in this proceeding that Enbridge Gas shareholders, not ratepayers, would be responsible for energy transition-related stranded asset risk associated with new capital spending (or a subset of capital spending, e.g., capital spending for new customer connections), how would this affect Enbridge Gas's capital-recovery risk? Would this change any of Dr. Hopkins' recommendations? Please provide details as needed.

Responses:

(a) One resource for regulatory and legislative decisions regarding stranded assets is the publication S&P Capital IQPro - Regulatory Research Service, Utility Asset Securitization in the United States (June 30, 2021), available at: https://www.capitaliq.spglobal.com/web/client?#news/newsletters?ID=65256522&FID=408715729&RID=113840. This research note provides a detailed summary of many different instances of securitization associated with stranded assets, categorized by restructuring-related; generation-related; and storm-related. As stated in Dr. Hopkins' evidence, a stranded asset is one that one that is no longer used and useful in the provision of utility service, and is not fully depreciated. Dr. Hopkins is not aware of any of EGI's assets being "stranded", and specific considerations and recommendations of how to treat any EGI assets that may become stranded in future is beyond the scope of his engagement in this matter. Dr. Hopkins would note that in instances with which he is familiar, a finding of "prudence" is a precondition to consideration by utility regulators of recovery of stranded asset costs. Final decisions regarding prudence and recovery, in the context of the provided excerpt of Dr. Hopkins's testimony, are generally made after the asset has been constructed (e.g., at the time it becomes clear the asset will become stranded). Dr. Hopkins's evidence focuses on the actions that a prudent utility should be taking to consider and address the energy transition, including mitigating the risk of stranded assets and stranded costs.

(b) Approving the need for, and forecast cost of, a utility investment (through a Leave to Construct or "certification" application) is not the end of considerations of prudence. The same is true for expenditures that will not require a future project-specific approval—inclusion of the forecast cost of that expenditure in EGI's rates is not the end of considerations of prudence. To take a simple example, if EGI fails to use appropriate oversight of a contractor or appropriate procurement practices and incurs extra costs, this could be imprudent execution. The OEB's prudence review of costs incurred during this rebasing period must be retrospective, relating to the decision to invest:

i. Circumstances could change after the OEB's order in this case but before the decision to invest has been made. (The most obvious example is the publication of the Ministry of Energy's Cost-Effective Energy Pathways Study, but other market, policy, or financial factors could also change.) EGI has a responsibility to take the new situation into account and change its capital plan, regardless of what the OEB might have projected at the time of this order.

ii. It could become clear in the future that information was available to EGI, whether the utility used it or not, which should have resulted in avoiding or amending an investment. This information may be information about EGI and its own operations and business (to which EGI has better access than anyone else) or information about markets, policies, costs, risks, or other factors that should inform a decision.

The executive summary of *The Prudent Investment Test in the 1980s*, a research report by Burns, Poling, Whinihan, and Kelly of the National Regulatory Research Institute published in 1985,[1] contains a clear and cogent summary of the underlying philosophy and application of a prudence test for public utility investments. Some relevant excerpts include:

- "In our view, prudence always relates to a decision—or the absence of a decision where one is needed—such as the decision to construct a nuclear unit, to abandon a coal unit, or the use certain construction management practices." (page iii)

- "[T]he concept of prudence protects the rights of individuals not in control of investment decision making. It does not require perfection in decision making but

[1] Available at: https://ipu.msu.edu/wp-content/uploads/2016/12/Burns-Prudent-Investment-Test-84-16-85-1.pdf.

does require, for example, avoidance of deliberate exposure to substantial risk where the individuals not in control could suffer financially." (pages iii-iv)

- Four guidelines (page iv):[2]

    - 1) "[T]here should exist a presumption that the investment decisions of utilities are prudent. The presumption of prudence can be overcome, however, by the allegation of imprudence that is backed up by substantive evidence creating a serious doubt about the prudence of an investment decision."

    - 2) "[U]se the standard of reasonableness under the circumstances. That is, to be prudent, a utility decision must have been reasonable under the circumstances that were known or could have been known at the time the decision was made. A corollary to the standard of reasonableness under the circumstance is a proscription against the use of hindsight in determining prudence."

    - 3) "The proscription against hindsight makes it unwise for a commission to supplement the reasonableness standard for prudence with other standards that look at the final outcome of a utility's decision, though consideration of outcome may legitimately have been used to overcome the presumption of prudence."

    - 4) [D]etermine prudence in a retrospective, factual inquiry. The evidence needs to be retrospective in that it must be concerned with the time at which the decision was made."

- "The concept of prudence provides commission with a principle that does not necessarily require an 'all or nothing' decision in favor of one side, but can allow some sharing of the risks between investors and ratepayers. The prudent investment test is a tool that regulators are using to provide an answer to the question of who should bear which risks and associated costs." (page vi)

- "[S]tate commissions often apply the prudent investment test so as to hold utilities harmless, except for the consequences of decisions that were unreasonable at the time they were made. The test is used principally to hold utilities responsible for the risks over which management has substantial control." (page vi)

- "[The prudent investment concept] is not confined to the capital cost component of ratemaking, but has been used to assess the reasonableness of decisions involving operating expenses as well." (page vii)

(c) The OEB does not *need* to provide additional guidance, although it could do so. Responsibility for prudent capital decision-making remains with EGI in any case; EGI must

[2] Note that these guidelines are mirrored in the OEB's approach to prudence as laid out in *Enbridge Gas Distribution Inc. v Ontario Energy Board*, 210 OAC 4.

seek and utilize the best available information as that information becomes available over the rebasing term. The rebasing term begins before the Ministry of Energy's Cost-Effective Energy Pathways Study is complete, and ends after. EGI's capital decision-making should therefore be shaped by the results of the study, by any relevant information the EGI acquires during or after the study, and by uncertainty regarding the outcomes of the study. (For example, capital investments before the study is complete should be focused on low-regrets/no-regrets actions.) The OEB could explain in this case how it plans to review EGI's capital decisions during the rebasing period and in the next rebasing case, including how it will account for EGI's need to incorporate the results of the Ministry's study into its decisions.

(d) In Dr. Hopkins's opinion, it would be problematic to create a separate class of assets for which risk is allocated in a different fashion from the rest of EGI's rate base. First, it could be very difficult to determine conclusively which new assets face energy transition-related stranding risk, and which do not. Second, the ownership of the separate class of assets, and their associated risk, leads to difficult situations no matter how they would be assigned. For example, would EGI have both upside opportunity and downside risk associated with these assets? It does not make sense to reward EGI's investors with a greater return (or lower risk) because EGI is making investment decisions that the OEB is explicitly not willing to project will be prudent based on the information available at the time of the investment. Dr. Hopkins believes that the right course of action is to continue to hold EGI to prudent decision-making within its regulated business, including investments related to new customer connections. The modeling he presented in his testimony indicates that prudent decision-making within a fully regulated context can lead to successful energy transition for the gas system.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Ontario Energy Board Staff (STAFF)

Reference:

Exhibit M8, Q # 28 and 29, p.14

Dr. Hopkins notes that risks which can be better quantified and evaluated should be given greater weight, all else equal. In general, this means near-term, well understood risks should be given greater weight, while uncertain less established risks should be given less weight. Dr. Hopkins further states that given the potential for change and the ability to adapt, it is generally the case that risks should be given less weight the further they would manifest in the future.

Questions:

(a) Is Dr. Hopkins of the opinion that risks related to energy transition should be given less weight than other near-term risks? Please explain your response.

(b) Please identify the other near-term risks noted above?

Responses:

(a) Near-term risks due to energy transition, to the extent they exist, should be given comparable weight to near-term risks due to other causes, if the risks are comparably certain and their impacts are comparably well known. Two risks could be comparably certain and their impacts comparably well known, and yet have different impacts on the appropriate capital structure if the likelihood and/or consequence of one adverse outcome were materially less than the likelihood and/or consequence of the other adverse outcome. Dr. Hopkins is of the opinion that the risks related to energy transition are generally both less certain than other business risks, and expected to be manifest further in the future (thus providing an opportunity to take actions to mitigate them). These risks should therefore be given less weight in establishing the capital structure.

(b) Near term risks include cash-flow related risks associated with uncertainty in revenue and operating cost, due to variation between reality and the test year. Sources of such variation for gas utilities include the cost of gas and the weather, as well as the cost of operations and maintenance (such as the cost of leak repairs). EGI has variance accounts that allow it to see little risk from some of these sources of variation, but it is not entirely insulated (as evidenced by the minor fluctuations in its rate of return). Section V of Dr. Hopkins's testimony addresses these risks.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Ontario Energy Board Staff (STAFF)

Reference:

Exhibit M8, Q # 56 and 65, pp. 34 and 39

Dr. Hopkins evidence notes that at this time, Ontario does not have an established path forward to decarbonize the building and industrial sectors. That pathway is being developed through the Ministry of Energy's Cost-Effective Energy Pathways Study process. Once that path is clear and policies and programs are developed to accomplish it, those will become among the primary drivers for customer heating system choice. At this point, the right path forward would be for Enbridge Gas to wait until that study and policy-setting process is complete, then develop business-specific analysis of its future in the context established by that framework.

Question:

In light of the impending Ministry of Energy's Cost-Effective Energy Pathways Study, how does Dr. Hopkins propose that the Ontario Energy Board approach Energy Transition as it pertains to Enbridge Gas's current rebasing application?

Response:

Dr. Hopkins suggests that the Ontario Energy Board:

- Carefully monitor, and participate in as appropriate, the Ministry of Energy's Cost-Effective Energy Pathways Study. For example, the OEB could assist the study by identifying key information in its possession or key questions that it needs the study to answer.
    - If it has the authority to do so, order Enbridge to provide information requested by the Ministry of Energy's study team, and to make the provided information public unless confidentiality is absolutely required.
- Refrain as much as reasonably possible from making large irreversible decisions regarding long-lived assets, if those decisions would be made differently depending on the outcome of the Ministry of Energy's study.
- Seek no-regrets or low-regrets actions among the steps it orders Enbridge to take in this case.
- Order Enbridge to undertake detailed business analysis (of the sort described and modeled in his testimony) based on the outcome of the Ministry of Energy's study, and to share the outcome and methods of that analysis with the OEB and stakeholders.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Environmental Defence (ED)

Reference:

Report, Page 21

Question:

(a) Your report notes that energy transition is not a new issue for Enbridge. Please discuss whether and how this conclusion [*sic*] bolstered by:

i. The decarbonization analysis from 2015 prepared for Enbridge and filed in EB-2016-0004 in response to OGA interrogatory #3.[3]

ii. The request for accelerated depreciation by Union Gas in 2016 in relation to decarbonization uncertainties in EB-2016-0186.[4]

Response:

(a) Dr. Hopkins's conclusion that energy transition is not a new issue for Enbridge is bolstered by his consideration of the cited documents.

In particular, Dr. Hopkins notes that the 2015 analysis for Enbridge draws upon a similar set of resources (such as RNG and energy efficiency) as the resources considered in more recent energy transition discussions, and also that the 2015 analysis identifies a need for some kind of new technology to bridge a gap between what fuel-based approaches could accomplish and the province's carbon emissions cap. The analysis identifies deeper energy efficiency and conservation, beyond traditional programs. Electrification via heat pumps has emerged as a commonly cited approach that fills these gaps in the intervening years. Regarding Union Gas's request, Dr. Hopkins's conclusion is bolstered by the utility's proposed use and reflection of a provincial policy target when setting financial parameters.

See also N.M8.EGI-78.

[3] Response to OGA Interrogatory #3: https://www.rds.oeb.ca/CMWebDrawer/Record/526018/File/document
[4] Union Application, p. 2: https://www.rds.oeb.ca/CMWebDrawer/Record/531574/File/document

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Environmental Defence (ED)

Reference:

Report, Page 36-39 & 53

Question(s):

(a) Your report recommends analysis of future scenarios and the development of a plan based on that analysis. It also suggests waiting for the provincial government to make policy choices based on its pathways study. How should the scenario analysis and plan address the reality that policy directions often change with elections such that pro-gas or pro-electrification policy choices could change in the future?

(b) How should the analysis and plan address the possibility that the future for building heat could be determined more by (a) markets and/or (b) federal climate policy, as opposed to provincial climate policy?

Response:

(a) The unfortunate reality is that, in the limited time between now and 2050, there is little leeway for changes in policy direction if emissions goals are to be met. While this deadline is 27 years away, building heating systems have a typical lifetime of about 20 years. This means that most heating systems will be replaced only once between now and 2050. As a result, a pathway that depends on changing heating systems (whether to electric heat pumps or to systems capable of safely burning hydrogen) cannot succeed at using the most cost-effective natural equipment change-over point if policy direction waffles between multiple directions. Similar concerns apply to gas distribution infrastructure. Given this reality, scenario analysis must work within the constraints of the time and resources available to hit the required level of decarbonization. The analysis should also look at factors beyond policy, such as technology development and market factors, as part of building the worlds or paths explored. The net result is that the range of possible emissions pathways achievable without extraordinary expense is relatively narrow, and getting narrower, and the divergence in future policy direction that can cost-effectively achieve provincial targets will be similarly narrow.

(b) EGI's approach, guided by the OEB, should account for both provincial policy and other drivers for consumer behavior and supply resources (such as market forces and federal policy). Ideally, provincial policy would reflect those drivers as well. Overall, EGI should plan for the best available understanding of the future for its business, informed by market, provincial, and federal policy. Dr. Hopkins suggests giving particular weight to the forthcoming provincial policy because it is relatively timely and tailored to Ontario, but this does not mean that the utility should not also use all other information available to it in order to develop the best pathway that works with provincial policy and its larger context. This includes the impacts of the time-limited nature of the challenge discussed in part (a).

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

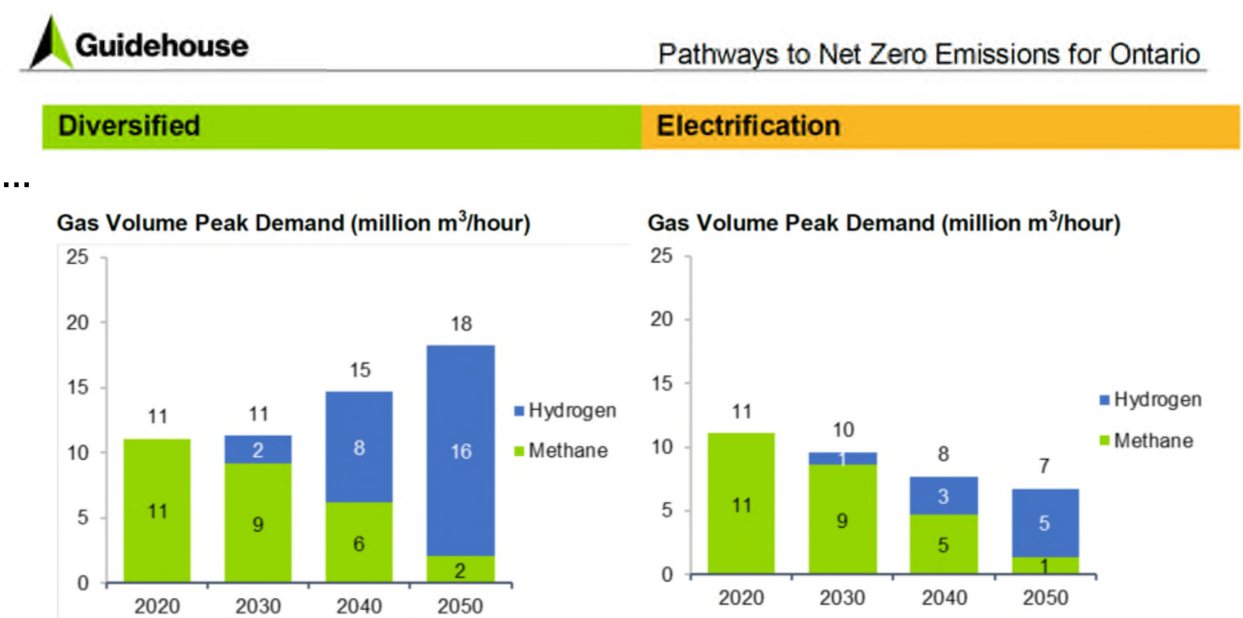
Answer to Interrogatory from Environmental Defence (ED)

<u>Reference:</u>

Report Page 36, Attachment 3

<u>Preamble:</u>

The Guidehouse Report includes the following figure at page 38:



<u>Question:</u>

(a) Your evidence calls on Enbridge to conduct a scenario analysis that "would develop a number of plausible future scenarios, assign those scenarios weights based on transparent assumptions about the futures they represent, and model the conduct of a prudently run utility adapting and managing itself in that scenario." Has Enbridge presented a sufficient range of plausible future scenarios in the Guidehouse report in light of the fact that (a) the so-called electrification scenario involves only a 36% decline in the gas volume peak demand (which drives infrastructure needs) and (b) both scenarios involve significant 100% hydrogen pipelines, including for residential customers? Please discuss.

(b) Would you agree that Enbridge's pathways work differs from many other jurisdictions due to the prevalence of hydrogen in all scenarios and/or the absence of a scenario where the large majority of buildings fully electrify?

Response:

(a) The two scenarios presented by Guidehouse do not sufficiently span the space of plausible scenarios. The results of these scenarios are not sufficient to determine a path forward for EGI, because:

i. The two scenarios do not present a wide enough range of potential futures,

ii. the analysis is not presented at the level of resolution required for EGI to make capital investment and financial plans, and

iii. EGI does not have the authority to make provincial decarbonization pathway decisions.

(b) Yes.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Environmental Defence (ED)

<u>Reference:</u>

Report, Page 36-39 & 53

<u>Preamble:</u>

Chris Neme concludes as follows at pages 39 to 49 of his report:

> "Overall, Guidehouse's assumptions are highly biased in favor of gas and not credible. There are numerous instances in which optimistic leaps of faith are made about equipment and systems necessary to make continued use of gaseous fuels look economically viable while much more conservative assumptions are made about electric alternatives. For example, Guidehouse assumes high penetrations of residential gas heat pumps and 100% hydrogen furnaces and appliances, despite the fact that these products are not even commercially available today. In contrast, Guidehouse assumes market penetration rates for electric heat pump water heaters in 2040 that are much lower than leading jurisdictions are achieving today through DSM programs. Similarly, Guidehouse assumes that the efficiency of electric heat pumps will degrade 2% per year after installation (based on an outdated study that doesn't apply to current electric heat pump technology) but that gas furnaces and gas heat pumps will experience no such degradation."
>
> …

Table 9: Summary of Concerns with Guidehouse's P2NZ Study

Assumption	Concern	Implications
Cost of CO2e Emissions	Guidehouse improperly treats carbon taxes as a societal cost and assumes a much higher cost of emissions for electrification scenario.	Using same cost of emissions reduces electrification scenario costs by ~$67+ billion. That's more than enough (without any other changes) to make it the lower cost option.
Load Shapes for Electrified End Uses	Guidehouse assumes all building end uses - including water heating, cooking and drying - have the same seasonal and hourly load profiles as space heating.	Winter morning peak demand from electrified building loads likely to be about 40% lower than estimated by Guidehouse.
Heating Equipment Efficiency Degradation after Install	Guidehouse assumes electric heat pump efficiency degrades 2%/year after installation based on reference for very different older generations of heat pumps. No degradation of gas furnace or gas heat pump efficiency assumed, despite the same report suggesting gas furnace efficiency also degrades .	Guidehouse estimates of added electricity consumption for ASHP space heating overstated by 18%. The adverse effect is 0.7 TWh in 2030, 2.6 TWh in 2040 and 3.3 TWh in 2050 more in the Electrified scenario than in the Diversified scenario.
RNG Availability	Guidehouse assumes that the entire "technical potential" for RNG in Ontario would be available, even though the expert report it references suggests it would be feasible to access less than one-quarter of that amount.	Substantially more expensive gaseous resources would have had to be deployed under the "Diversified Scenario" if RNG supply constraints were reasonably set, possibly making the Diversified scenario inconsistent with a net zero emissions objective.
RNG Costs	Guidehouse RNG cost is for landfill gas, but most of the RNG potential it assumed to be available is from other much more expensive sources. The most expensive source of RNG would set the market clearing price for all RNG.	RNG costs likely to be at least 3 times greater than assumed, improving the relative cost of Electrification Scenario by at least $28 billion. The difference could be much higher because Guidehouse assumes RNG potential four times what its own reference study says is feasible, which would require accessing even more expensive RNG
GHG Emission Reductions from RNG	Guidehouse's analysis does not address the full lifecycle emissions of biomethane. Thus, it overstates the amount of emission reductions RNG provides.	If lifecycle emissions were fully addressed, additional emission reduction measures would have to be deployed to achieve net zero emissions, adding significant cost, especially for the Diversified Scenario, potentially making it inconsistent with net zero emissions objective.
GHG Emission Reductions from Blue H2	See evidence of Professors Howarth and Jacobson	If blue hydrogen emissions are greater than assumed, it would make the Diversified scenario more expensive and/or inconsistent with net zero emissions objective.
Electric Demand Response Resources	Guidehouse did not consider or model the potential for demand response to be applied to newly electrified space heating and water heating loads.	Electric system capacity costs from electrification are overstated, but difficult to quantify the magnitude of the overstatement.
Gas Heat Pump Costs	Guidehouse used an informal estimate from a gas heat pump manufacturer rather than a much higher recent Enbridge estimate. Worse, it failed to recognize that the estimate it used was expressed in U.S. rather than Canadian dollars.	Converting to Canadian dollars results in an increase cost of $3 billion for the Electrification Scenario and $16 billion for the Diversified Scenario - improving the relative cost of the Electrification Scenario by $13 billion.
Home Weatherization Savings Life	Guidehouse conservatively assumed that insulation and other building envelop efficiency improvements would last only 20 years. Enbridge assumes a more reasonable 30 years in its DSM planning.	Using a 30 year life reduces the cost of the Electrification Scenario by $11 billion and the Diversified Scenario by $5 billion - improving the relative cost of the Electrification Scenario by $6 billion.
Electric Water Heating Efficiency	Guidehouse assumes only ~10% of gas to electric water heating conversions by 2040 and ~25% by 2050 are to efficient heat pump water heaters. Leading jurisdictions are already achieving market penetration rates higher than that. Other studies assume much higher heat pump water heating rates.	If 75% of all such conversions were to heat pump water heaters, total forecast electric demand would be about 8.2 TWh (about 2%) lower under the Electrification Scenario (and about 3.5 TWh lower under the Diversified Scenario.
Customer Conversion Costs	Guidehouse did not address customer conversion costs - other than costs of heating equipment. Behind-the-meter pipe retrofits, ventilation requirements and utility inspection costs could be substantial.	Likely bias against electrification because costs likely to be higher for conversion to 100% hydrogen than for electrification for residential and commercial customers.
Utility Distribution System Costs	Guidehoulse excluded the cost of converting the distribuiton system to 100% hydrogen and all other incremental gas and electric distribution system costs.	Likely bias against electrification becuase the costs for 100% hydrogen delivery to residential and commercial customers likely to be much higher than for electrification of those customers. Also, electrification will enable reductions in gas utility costs from fewer customers (e.g., fewer connections, meters, customer service reps, etc.) as well capital and O&M cost savings from pruning parts of the gas distribution system .

Question(s):

(a) Your report recommends development of a scenario analysis and plan relating to decarbonization. In light of the above comments from Chris Neme, would you recommend that these be developed through a process whereby stakeholders have input throughout, or developed entirely by Enbridge?

(b) Do you agree that there appears to be a pro-gas bias in the Guidehouse report?

(c) Please discuss procedural mechanisms to avoid a pro-gas bias in the development of a scenario analysis and plan going forward.

Response:

(a) Scenario analysis should be conducted in a process with stakeholder input. See also N.M8.PP-1.

(b) Yes.

(c) See N.M8.PP-1.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Environmental Defence (ED)

Reference:

Report, Page 46 & Attachment 4, Pages 3 & 6

Question(s):

(a) The model in attachment 4 appears to run from 2023, starting with a rate base of under $15 billion. To help us better understand how waiting can make things worse (per p. 46 of your report), please re-run the model from 2029 onward on the assumption that Enbridge's application for 2024-2028 is approved as filed. In particular, please assume that rate base increases over that period in line with JT4.24, which shows rate base increasing to over $18 billion by 2028. If a re-run of the model is not possible, please comment on the likely impacts based on your professional opinion.

(b) Page 3 of Attachment 4 states, "[f]or retiring assets, STM adds 0.5 percent of plant each year by default." Please compare Enbridge's proposed spending with this figure. We ask this for the purposes of assessing the reductions in spending that may be appropriate.

Response:

(a) The following figures reproduce the figures from Sections 4.2 and 4.3 of Attachment 4 that change as a result of making the requested change to the Strategic Transition Model. I have added the residential rate trajectory from Attachment 4 to the graph of the residential rate trajectory under the requested assumptions, for comparison purposes.

Note that Dr. Hopkins made the following additional assumptions in order to run the model under the requested conditions:

i. Total sales, customers, and allocation of sales between classes remains constant until 2029.

ii. Trajectories for sales, customers, and allocations proceed linearly to the same fixed points at 2050 as in Attachment 4 (but with a higher slope given the shorter time period).

iii. The fraction of "retiring system" mains available to retire is similarly adjusted to grow linearly from 2029, rather than 2024 as in Attachment 4.

iv. All additional rate base in the requested case is added to the building sector (the retiring system), because the indefinite system parameters in Attachment 4 were intended to reflect a stable long-term approach to assets serving the industrial sector.

Figure 1. Version of Figure 3 from Attachment 4 corresponding to the requested modeling parameters. Calculated rate base (blue area) in the STM example scenario as a function of plant in service (black line) and accumulated depreciation reserve (yellow area). Results in nominal dollars.

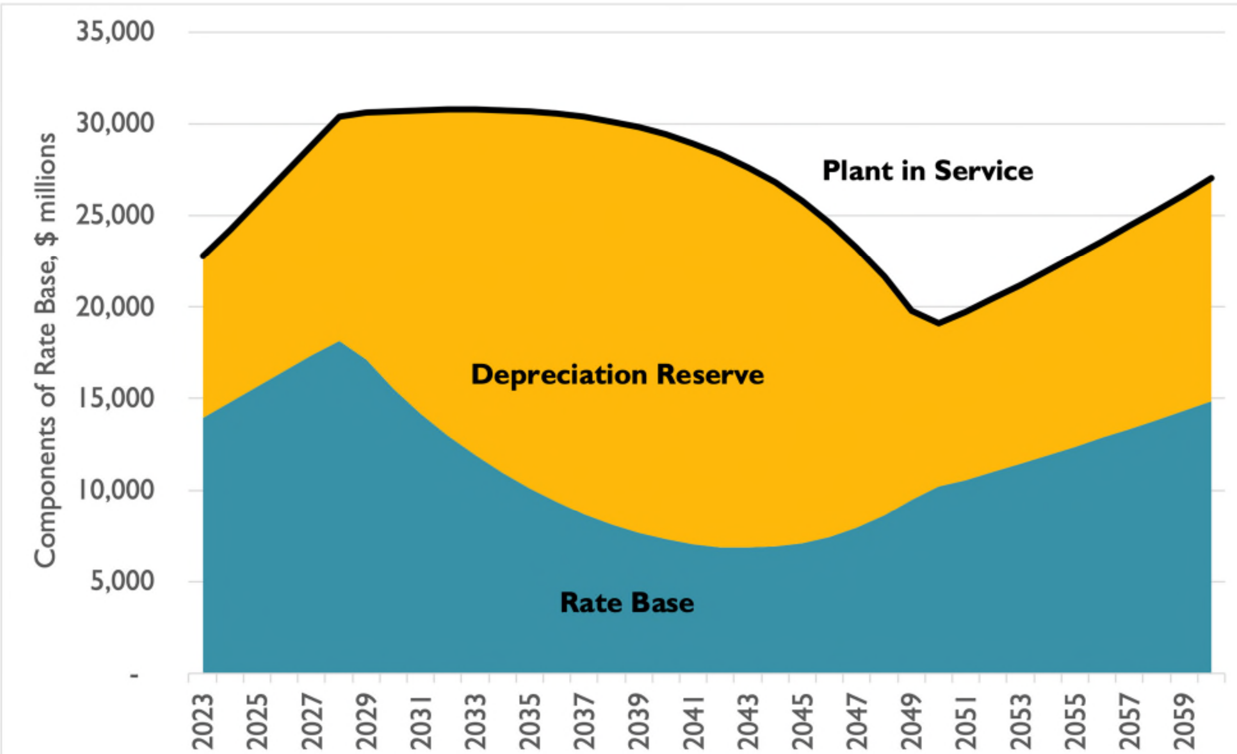


Figure 2. Version of Figure 4 from Attachment 4 corresponding to the requested modeling parameters. Gas delivery rate to buildings customers, calculated as revenue requirement divided by sales, showing cost components. Black line shows the total rate from Attachment 4.

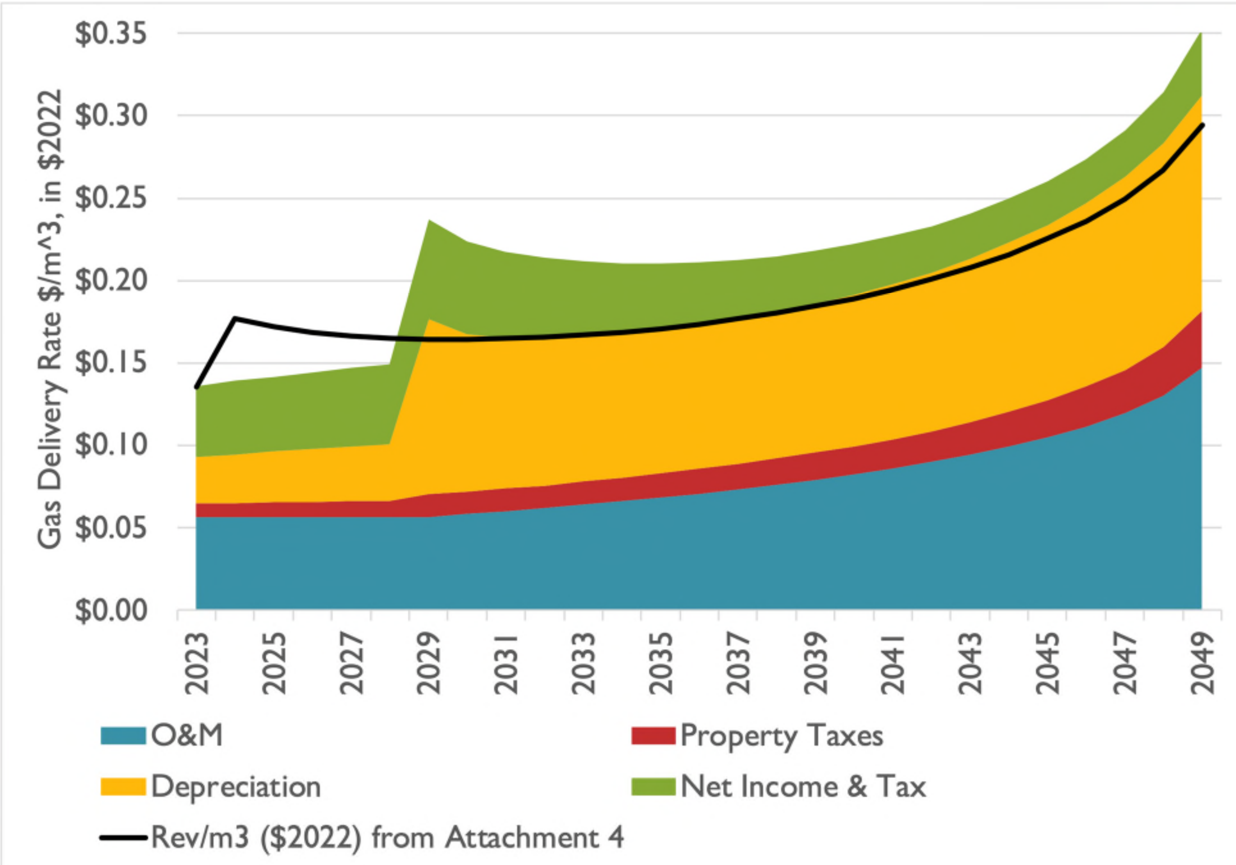


Figure 3. Version of Figure 6 from Attachment 4 corresponding to the requested modeling parameters. Revenue requirement for buildings customers (yellow line), and the revenue raised if rates were limited to an average of 20.8 cents per m3 (in $2020). The difference reflects potential capital recovery risk.

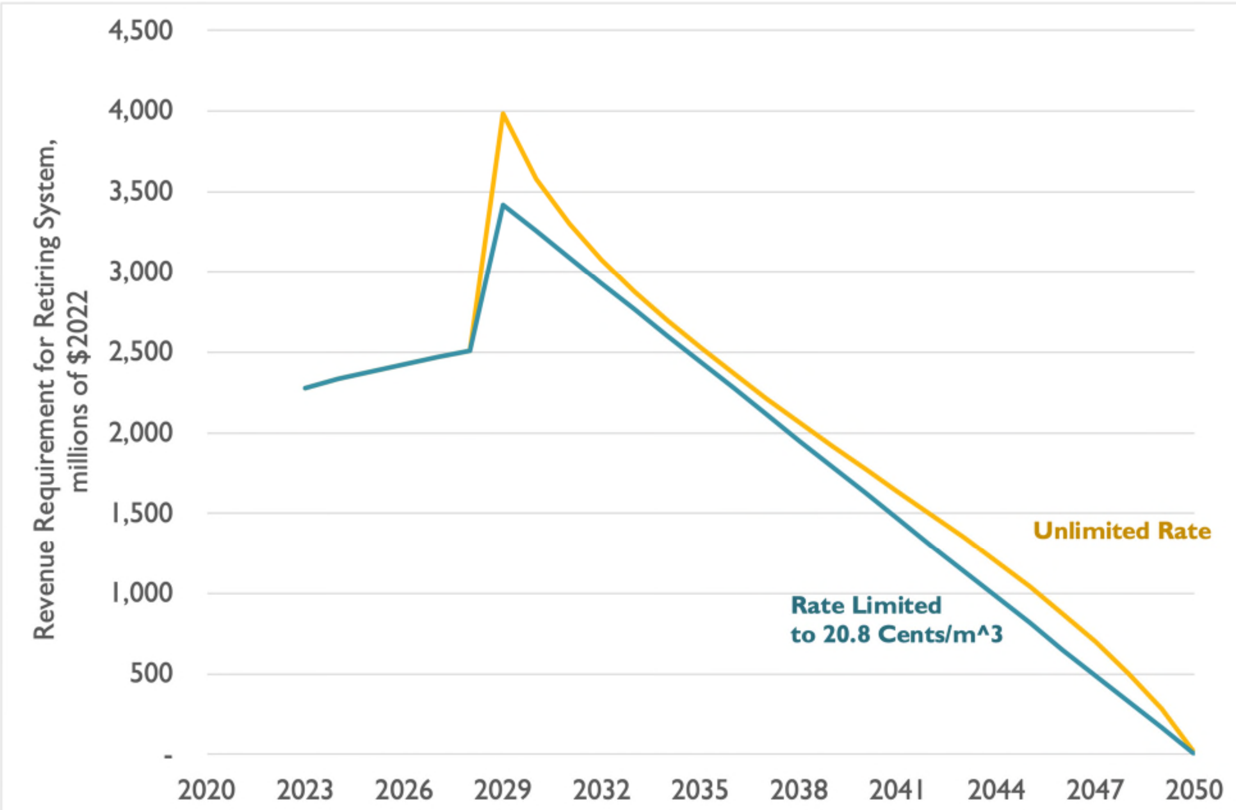
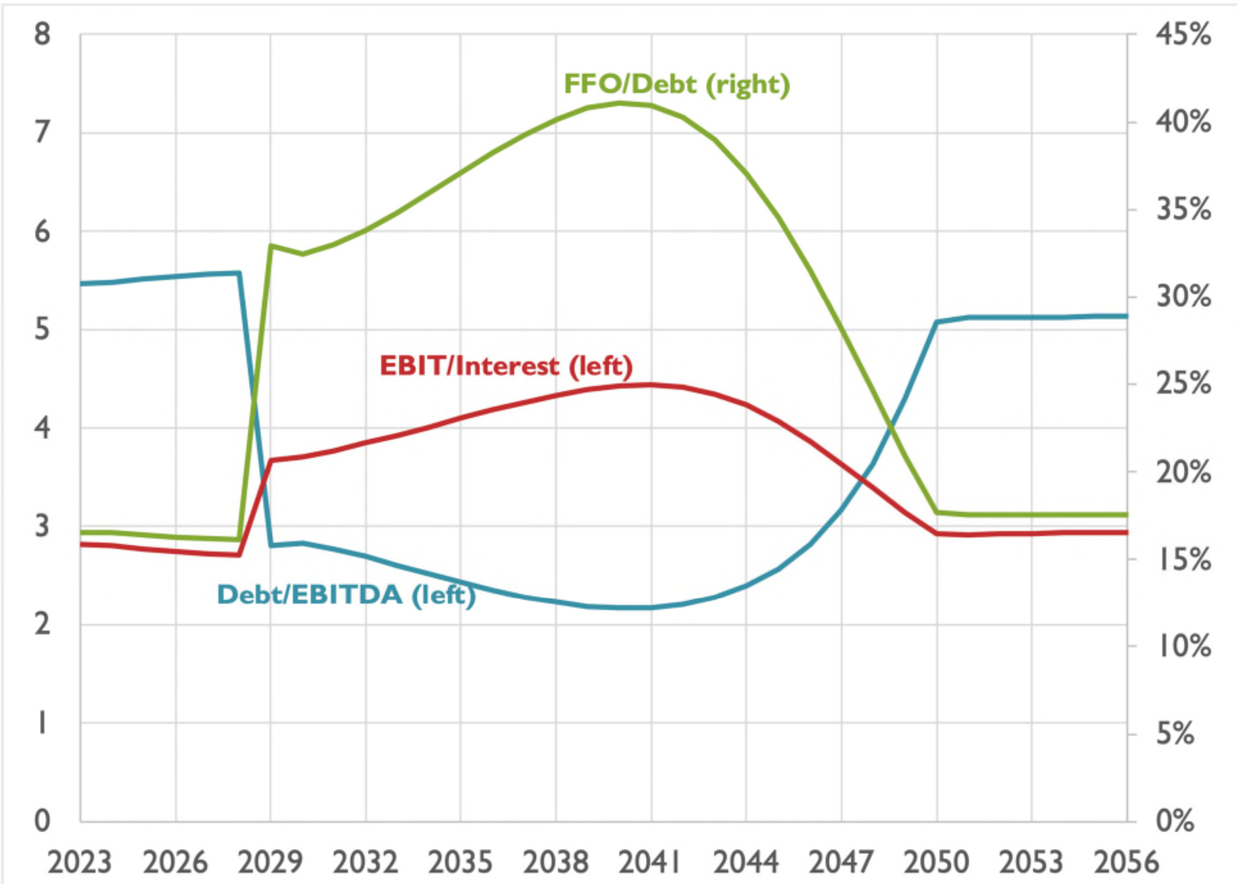


Figure 4. Version of Figure 7 from Attachment 4 corresponding to the requested modeling parameters. Financial parameters for the hypothetical utility, showing EBIT/Interest and Debt/EBITDA on the left-hand scale and FFO/Debt on the right.



(b) Enbridge's proposed capital spending exceeds the values used by default in the STM. The STM default parameters add $316 million in capital in 2024 (about 1.4 percent of plant in service), of which $225 million are for the indefinite system and the remainder are for the retiring system. According to Exhibit 2, Tab 1, Schedule 1, Attachment 1, Page 5 of 5, Enbridge expects gross plant to increase by $1,113 million in 2024 (about 4.4 percent of plant). Enbridge's planned capital additions must exceed this number, to account for retirements.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Environmental Defence (ED)

<u>Reference:</u>

Report, Page 46 & Attachment 4, Page 6

<u>Preamble:</u>

Page 46 notes: "Waiting makes things worse. The longer the utility waits to change its approach (in a world where building-sector customers and sales are falling toward zero), the larger the rate shock and the larger the potential amount of stranded costs to mitigate."

<u>Question(s):</u>

(a) In light of the comment that "waiting makes things worse," please comment on the specific no-regret or low-regret steps that could be taken in the 2024-2028 period to mitigate long-term risks relating to decarbonization, including the possibility of falling building-sector sales.

(b) In addition to other steps you may recommend in (a), please also comment on the following:

i. Reduce capital spending: A number of the proceedings described in Attachment 3 resulted in recommendations to reduce capital spending, such as the recommendation in the Massachusetts proceeding to "[m]inimize or avoid gas infrastructure projects to reduce costs that need to be recovered from gas system customers." This could be adopted for Enbridge over the 2024-2028 timeframe.

ii. Reduce rate base: Enbridge's application would have rate base increasing to over $18 billion by 2028 (JT4.24). A potential recommendation could be to have rate base decline over 2024-2028, or for it to decline by a certain percent each year.

iii. Reduce revenue offsets for contributions in aid of construction (CIAC): The connection costs funded by connecting customers through CIACs are currently offset by the forecast distribution revenue from those customers over 40 years. A reduction is justified because it is no longer a foregone conclusion that a new customer will stay with gas indefinitely. If they leave "early," existing customers bear the stranded asset costs. A 10-year horizon could be justified on the following factors: (a) fuel switching is most likely as an air conditioner or gas furnace nears the end of its life, (b) early switching is possible to save costs, get government rebates, or reduce emissions, (c) a customer would need to remain with the system long after paying off their connection costs to pay their "fair share" of the remaining capital infrastructure they have benefited from, and (d) erring on the side of a shorter horizon is a more prudent "safe bet."

iv. Cap infill connection costs funded by existing ratepayers: For infill connections (i.e. connections for existing buildings), Enbridge proposes that existing customers cover the cost of the meter and up to 20 m of service line through rates (which comes to about $6,000 per Ex. 8-3-1 p 13)). That would not be paid off by via the customer's distribution charges for about 40 years (per JT3.19). The portion covered by rates could be capped at, say, 10 years for the reasons noted above.

v. A temporary moratorium on new residential gas connections: A moratorium could be placed on new residential gas connections to eliminate the risk that those costs would be stranded and to eliminate the need for further transmission or distribution growth projects. The moratorium could be reconsidered following the preparation of the scenario analysis and plan proposed in your evidence.

vi. Modestly accelerated depreciation for residential pipes: The current depreciation approach assumes there is a 0% (or almost 0%) chance of pipes being underutilized or no longer used and useful before the end of their physical lives. To provide some balance in the interim, and avoid possible future rate shocks, depreciation of residential pipes could be modestly accelerated for the 2024-2028 period.

<u>Response:</u>

(a) Utility finance is generally designed to provide stability, through the use of mechanisms that spread costs out over time. When working with the need to make changes in a limited time period, these mechanisms make the challenge more difficult. The primary difficulties in which "waiting makes things worse" have to do with the long lifetimes of capital assets. So, the effective near-term actions that can buy time and provide optionality going forward relate to treatment of capital: 1) limiting capital additions and 2) accelerating depreciation. Of these, the first is more important (because depreciation can be adjusted in the future, but capital cannot be un-invested).

One other area that the utility could look to as part of forward-looking near-term actions would be to take actions that can lower future operations and maintenance costs. In analysis that Dr. Hopkins has conducted, it is relatively straightforward to reduce capital costs and associated stranded cost risk (such as through accelerating depreciation), but maintaining reasonable rates also requires keeping O&M costs as closely proportional to sales as possible.

(b) Items (iii), (iv), and (v) on this list are specific examples of item (i). All four of these are examples of limiting capital additions, as I stated in (a). Item (vi) on this list is an application of the other mechanism I stated in (a).

i. Limiting capital spending to essential items would be an effective way for EGI to change approach to limit the need to take additional mitigating measures to limit business risk and ratepayer cost. The illustrative modeling that Dr. Hopkins conducted using the Strategic Transition Model used this approach by limiting the amount of capital invested in the retiring system.

ii. This item would be the result of the other items on this list, but it would be inappropriate to decree a change in rate base absent the other items. That is, in order to achieve a certain decrease in rate base there would need to be some amount of change in plant in service and some amount of change in the reserve for depreciation.

iii. This appears to be a reasonable step, reflective of a reasonable cost allocation between new and existing customers based on changing expectations for gas use. The horizon should be updated to match the provincial pathway when that is known.

iv. Same as (iii).

v. A moratorium without exceptions may not be reasonable. For example, if a customer elected to cover the entire cost of connecting to the system, thereby creating no costs for existing customers, it may not be reasonable to prevent their interconnection. (This would equivalent to items (iii) or (iv), but with a zero-year horizon.) Where moratoria have been used, they commonly relate to limited upstream pipeline capacity to serve new customers.

vi. Accelerated depreciation is consistent with intergenerational equity, given the available information regarding future pipeline energy demand. For example, allocating costs over time on a “units of production” or “utilization” basis enhances intergenerational equity by recovering equal costs per estimated unit of energy delivered. This would be consistent with item (iv).

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Environmental Defence (ED)

<u>Reference:</u>

Attachments 3 & 4

<u>Questions:</u>

(a) Based on your review and involvement in decarbonization proceedings and studies, please comment on the likelihood of a substantial portion of buildings being served by pipelines carrying 100% hydrogen with 100% hydrogen boilers by 2050 in Ontario. Please explain and comment on the factors addressed in Mr. Neme's report on pages 20-22.

(b) Do you agree that the greatest uncertainty for the future role of gas in buildings is whether it will be feasible and cost-effective for customers to adopt hybrid RNG/electric heating (with RNG used for peak heating needs) instead of fully electric heating?

(c) Please list which of the steps discussed in M9-ED-6 would support or be consistent with a future with significant levels of hybrid RNG/electric heating?

(d) Is there a concern that significant levels of hybrid RNG/electric heating could negatively impact industrial customers by negatively impacting the cost and availability of RNG due to it being a scarce resource?

(e) Enbridge states: "Furthermore, the sensitivity analysis found that decreasing investments in the gas system will result in the inability to achieve net-zero by 2050, with significant residual GHG emissions remaining." (Exhibit 1, Tab 10, Schedule 5, Page 13) Do you agree that Enbridge or Guidehouse have established that decreasing investments in the gas system will result in the inability to achieve net-zero by 2050? Please discuss.

<u>Responses:</u>

(a) It is highly unlikely that a substantial portion of buildings would be served by 100 percent hydrogen in Ontario in 2050. Such a future would require the large-scale changeover of customer equipment to support a new fuel. Mr. Neme is right to highlight the practicalities of the proposed switchover for customers. When taking action consistent with net zero at the end of equipment life, customers are as or more likely to switch to electric equipment compared to hydrogen equipment, absent strong policy-based incentives to do so and a clear pathway to affordable and reliable heat using the new system. Electric heat pumps offer air conditioning; induction stoves will likely be more attractive than cooking with invisible hydrogen flames. If changes beyond end-use equipment are required to support hydrogen (such as re-piping within buildings), customers are even more likely to choose electric options.

(b) Yes.

(c) All of the steps discussed in N.M8.ED-6 would be consistent with a future with significant levels of hybrid RNG/electric heating. The precise form in which capital spending would be reduced in item (i) (e.g., focused on new customers, as highlighted in items (iii), (iv), and (v) on the list) might differ between planning for a future with extensive hybrid heating vs. an all-electric future. For an all-electric future, capital spending could be reduced through retiring rather than replacing some pipes, whereas maintaining the option for hybrid heating would favor repairing over retiring. One way to limit potential asset risk in capital planning while reducing capital additions would be to focus near-term capital expenditures on “trunk” lines that serve many customers, rather than on “leaves” that serve only a few customers.

(d) The extent of such a conflict would depend on how the hybrid heating systems were configured. If the RNG portion of hybrid heating systems were only to be used on the coldest of days, the amount of fuel required could be small, and limit conflict with industrial customers. This situation would, however, present the greatest challenge to traditional utility ratemaking and the cost of maintaining an extensive gas distribution system.

(e) Dr. Hopkins disagrees with Enbridge on this statement. As he showed in his illustrative analysis using the Strategic Transition Model, reduced capital investments associated with a limited conception of the role of the gas utility (e.g., through reduced miles of pipe and number of customers) can reduce business risk and be consistent with net zero.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8

Preamble:

Throughout the evidence of Dr. Hopkins there are many references to "investors." It is not clear if Dr. Hopkins is referring to equity investors or debt investors.

For example,

At page 7, Dr. Hopkins states:

"If circumstances change in the meantime, the **investors'** returns may be higher or lower than expected. These business risks are manifested in volatility in the rate of return earned by utility shareholders." (emphasis added)

Also at page 7, Dr. Hopkins states:

"This capital risk is sometimes referred to as "stranded cost" or "stranded asset" risk, although I want to make a clear distinction between a stranded cost and an actual loss to **utility investors**." (emphasis added)

At page 9, Dr. Hopkins states:

"There are two potential sources of **investor risk** associated with stranded assets." (emphasis added)

At page 23, Dr. Hopkins states:

"I agree that **investors** look to the long term, while they also look to the near term. **Investors** look at risks across all timeframes and consider the picture as a whole, and they consider the likelihood of different outcomes over time. Standard financial evaluation includes discounting future returns, relative to near-term returns, when considering the value of an investment." (emphasis added)

Question:

Please confirm that Dr. Hopkins is referring to equity investors throughout the evidence. If not confirmed, please clearly state for each reference to "investor" or "investors" in the evidence which type of investor Dr. Hopkins is referring to.

Response:

In the first example on page 7, Dr. Hopkins is referring to equity investors, as implied by the following sentence.

For the other examples given, the statements apply to both equity and debt investors, although the way in which risks may manifest, and their likelihood, vary between equity and debt investors. Debt investors take less risk, and expect to receive a lower average return, than do equity investors.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 3

Question:

Please list the cases in which Dr. Hopkins has provided recommendations on either the authorized return on equity or the appropriate capital structure for a regulated utility. Please include the jurisdiction in which the evidence was filed, the docket or case number for each proceeding and the date Dr. Hopkins' evidence was filed.

Response:

Régie de l'énergie du Québec, R-4156-2021, evidence filed August 4, 2022

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 8

Preamble:

At page 8, Dr. Hopkins states:

"In practice, however, when a utility asset that was installed prudently becomes no longer used and useful, regulators commonly allow the continued recovery of some or all of the value of that asset. So, the mere existence of stranded assets does not immediately or necessarily create losses to investors."

Question:

In Dr. Hopkins' opinion, does the potential disallowance of some or all of the value of stranded assets affect how investors would perceive the business risk of the utility that owns those assets? In other words, is it necessary for there to be an actual disallowance of stranded assets before investors factor that risk into their assessment? Please explain.

Response:

Investors evaluate the likelihood and consequence of disallowance (for any purpose) when considering the business risk of a utility. The likelihood does not have to be 100 percent before it would figure in their assessment of the risk of an investment.

When considering investor perception of business risk for the purposes of rate setting, regulators should consider what the investor perception would be in the event that the utility management acts prudently. In the hypothetical case in which a utility experiences a disallowance for imprudent actions, or a greater likelihood of disallowance due to such actions, investors might rightly see that as indication of heightened business risk, and yet it would not be appropriate for regulators to set a greater equity thickness or return on equity in response to this perception. In the particular case of stranded assets, therefore, if imprudent utility management led to a higher likelihood of disallowance of recovery of stranded costs, investors would rightly perceive an increased business risk and yet the regulator should not account for this when setting the capital structure.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 9

Preamble:

At page 9, Dr. Hopkins states:

In some jurisdictions, regulators and legislatures have created securitization structures in which shareholders are paid for their investment in a set of assets no longer in service. The cost of this payment is then transferred to a bond-funded structure (with explicit or implicit ratepayer and/or taxpayer support) and the costs are paid back to bondholders over some period. Securitization can lower ratepayer costs by paying only the cost of the new debt, rather than the higher weighted average cost of capital, and potentially spreading costs over a longer period than the asset life.

Question:

Please provide examples of securitization financings that have spread costs over a longer period than the asset life. Are such structures common among securitizations?

Response:

Dr. Hopkins was considering cases such as:

1) In the case of electric sector restructuring, stranded costs associated with generation assets divested by vertically integrated utilities may be recovered over some fixed period, even if the generation assets themselves remain in service (for their new owners) for a shorter or longer period of time.

2) In the case of coal plant retirement or storm recovery (two other common uses of securitization), the assets no longer in service generally include a range of components with different service lives – some longer and some shorter. Securitization combines all of these lives into one period for debt recovery, which may or may not be the weighted average of what the service life might otherwise have been.

The opposite can also happen: because securitization results in a lower cost of capital for the assets in question, it can be affordable for ratepayers to pay off the debt more quickly than would have been the case if the assets had remained in utility rate base and been used for their full engineering life.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 10

Preamble:

At page 10, Dr. Hopkins states:

"The equity share of the capital structure should most directly reflect the risks regarding return on invested capital in the period until the next time the capital structure is evaluated, with less weight given to risks that extend further out in time. Thus, short-term risks should be the primary driver for considering changes to the capital structure."

Question:

(a) Has Dr. Hopkins analyzed whether the current deemed equity ratio of 36% is reasonable for Enbridge Gas given the Company's relative business risk as compared to other large gas distribution companies in Canada and the U.S.? If so, please provide that analysis.

(b) Has Dr. Hopkins analyzed when the long-term business risk (i.e., capital recovery risk) for Enbridge Gas might be expected to increase due to the energy transition? If so, please provide that analysis.

(c) In Dr. Hopkins' opinion, is it important for Enbridge Gas to have the financial strength it needs to manage the effects of the energy transition as well as other business risks? Please explain why the current deemed equity ratio of 36% is reasonable for Enbridge Gas.

Response:

(a) No. Dr. Hopkins focused his analysis on the question of whether Enbridge's business risk has been conclusively shown to have increased since the equity ratio was last set.

(b) See Attachment 4 to Dr. Hopkins's testimony for the most responsive analysis that Dr. Hopkins has performed.

(c) Yes, it is important for Enbridge Gas to have sufficient financial strength to carry out its obligations to its customers and regulators. The Ontario Energy Board determined that an equity ratio of 36 percent was appropriate for Enbridge's business risk in 2012, and did not change that ratio during the Union Gas-EGD merger proceeding and rebasing case. Because Dr. Hopkins showed that there is no conclusive evidence in this proceeding that EGI's overall business risk has increased, he believes that the OEB's previous determination of a reasonable equity ratio should stand.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, pages 11-12

Preamble:

At pages 11 and 12, Dr. Hopkins states:

"Viewed as a whole, this business risk summary does not appear to be consistent with EGI's and Concentric's claims that business risk is increasing, primarily driven by capital risk associated with energy transition."

Question(s):

(a) Please confirm that Figure 1 of Concentric's report identifies other business risks that have increased for Enbridge Gas since 2012, apart from energy transition risk, such as volumetric risk, financial risk, and operational risk.

(b) Has Dr. Hopkins taken into account those other business and operating risks in his evaluation of Enbridge Gas's business risk and capital structure?

Response:

(a) Yes, Figure 1 of Concentric's report identifies other risks that Concentric states have modestly increased, and others that have remained neutral or are expected to modestly decrease. It is only in respect of the energy transition that Concentric has identified a "significant increase" in business risk.

(b) As Dr. Hopkins details in his testimony, these five risk categories are manifestations of two underlying types of risk: operation/volatility risk and capital risk. For example, near-term volatility in volumes sold can result in operation/volatility risk, while the long-term changes in volumes are primarily manifestations of energy transition and could be related to capital risk. Dr. Hopkins has accounted for these other risk categories as part of his analysis of operational/volatility-related risks and capital-related risks.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, pages 11, 13, 20, and 27-28

S&P Global, "Alectra Inc. Outlook Revised To Negative On Heightened Regulatory Lag; 'A-' Ratings Affirmed," May 11, 2023.[5]

S&P Global, "Toronto Hydro Corp. Outlook Revised To Developing From Positive Due To Heightened Regulatory Lag; Ratings Affirmed," May 11, 2023.[6]

Preamble:

At page 11, Dr. Hopkins states:

"S&P gives EGI a rating of Excellent, its top rating."

At page 13 Dr. Hopkins states:

"Ontario's "transparent, consistent, and predictable" regulatory regime (as described by S&P) is the foundation of EGI's low business risk."

At page 20, Dr. Hopkins states:

"The OEB's "transparent, consistent, and predictable" regulation of EGI (to quote S&P) gives me confidence that the OEB will ensure that EGI plans appropriately to adapt to the policy and market contexts in which it finds itself over the course of the energy transition in the coming decades."

At pages 27 and 28, Dr. Hopkins states:

"OEB consideration of EGI's plans in the context of the Ontario Ministry of Energy's Cost-Effective Energy Pathways Study will similarly reflect the transparent, consistent, and predictable regulatory process in Ontario, which is a key component of S&P's evaluation of EGI's business risk as "Excellent.""

At Alectra Inc. Outlook Revised To Negative On Heightened Regulatory Lag; 'A-' Ratings Affirmed's report, S&P states:

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[5] S&P Global. (2023, May 11). Alectra Inc. Outlook Revised To Negative On Heightened Regulatory Lag; 'A-' Ratings Affirmed. https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/2985484
[6] S&P Global. (2023, May 11). Toronto Hydro Corp. Outlook Revised To Developing From Positive Due To Heightened Regulatory Lag; Ratings Affirmed. https://disclosure.spglobal.com/ratings/pt/regulatory/article/-/view/type/HTML/id/2985450

"However, should we reassess Ontario's regulatory construct downward, we would likely reconsider our assessment of Alectra's business risk profile within its excellent business risk profile category."

At Toronto Hydro Corp. Outlook Revised To Developing From Positive Due To Heightened Regulatory Lag; Ratings Affirmed's report, S&P states:

"However, should we reassess Ontario's regulatory construct downward, it would likely weaken our relative assessment of THC's business risk profile within its current business risk profile category."

Question(s):

(a) In Dr. Hopkins' opinion, what effect would a reassessment downward of Ontario's regulatory construct by S&P have on S&P's business risk rating for Enbridge Gas?

(b) What effect would a reassessment downward of Ontario's regulatory construct by S&P have on Dr. Hopkins' assessment of business risk for Enbridge Gas, if any?

(c) In Dr. Hopkin's opinion do you consider the risk of potential stranded assets as an example of the risk natural gas utility companies are facing due to energy transition regardless of the timing of that risk?

Response:

(a) Dr. Hopkins's understanding is that S&P weighs many factors in assessing the business risk of companies it evaluates. If one of those factors changes downward, and others do not, S&P may decide to shift its assessment downward in response. The regulatory construct can have different effects on different companies, and may change as a result of the specific regulatory framework for different sectors (i.e., electricity vs. gas), so it is not a certain thing that a reassessment of the regulatory construct for one company would necessarily have a material effect on S&P's assessment of Enbridge. The extent to which a reassessment by S&P of Ontario's regulatory construct for large electricity distribution companies, particular companies or in general, could affect S&P's business risk rating for Enbridge Gas would depend on the rationale for such reassessment, and the extent to which such rationale applied equally to the OEB's approach to regulating Enbridge Gas.

(b) Please see response to part a). In addition, Dr. Hopkins's assessment of Enbridge's business risk would be informed by his own analysis of the stated drivers for a reassessment by S&P and the potential of those drivers to impact Enbridge.

(c) The risk of potential stranded costs, associated with stranded assets, is a risk that natural gas utilities are facing due to energy transition, and both its likelihood and consequence should be assessed. The net effect of that risk, after accounting for both prudent actions to mitigate that risk and other aspects of business risk, should be accounted for when assessing overall business risk.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, pages 14 and 24
City of Toronto Item - 2023.IE3.3[7]

Preamble:

At page 14, Dr. Hopkins states:

"The most important feature is not necessarily the timing of the risks, so much as their certainty. It happens that near-term risks tend to be better understood and characterized, and the range and likelihood of possible outcomes is more certain."

"But given the potential for change and the ability to adapt, it is generally the case that risks should be given less weight the further they would manifest in the future."

At page 24, Dr. Hopkins states:

"Furthermore, even if growth were somehow required to recover already invested capital, the Concentric report presents no tangible evidence that gas bans are a risk in Ontario, recognizing that "it is not aware of any building gas bans" in Ontario."

Question(s):

(a) Dr. Hopkins states elsewhere in his evidence that the energy transition is a long-term risk rather than a short-term risk, and that the deemed equity ratio for Enbridge Gas should not be increased due to long-term risks. Please reconcile this statement with the first sentence of Dr. Hopkins' report on page 14 where he indicates that the most important feature is not necessarily the timing of the risk, but the certainty of those risks.

(b) Does Dr. Hopkins agree that there is a relatively high degree of certainty that some form of energy transition will occur in Ontario which will affect the business risk of gas utilities such as Enbridge Gas?

(c) In Dr. Hopkins' opinion, does the May 10, 2023 City of Toronto adoption of Item – 2023.IE3.3 that would "direct the Chief Planner and Executive Director, City Planning, in consultation with the City Solicitor and the Executive Director, Environment and Climate, to review options to discourage the installation of new combustion uses of methane

[7] City of Toronto. (2023, May 10). Item -2023.IE3.3. https://secure.toronto.ca/council/agenda-item.do?item=2023.IE3.3

("natural gas") as part of the update to the Toronto Green Standard to Version 5," provide tangible evidence that gas bans are a risk in Ontario?

Response:

(a) Dr. Hopkins's evidence does not state that "the deemed equity ratio for Enbridge Gas should not be increased due to long-term risks." Please see Q&As 28, 29, 44, 84, 85, and 86 in Dr. Hopkins's evidence for his thinking regarding the generally greater uncertainty in relation to long-term risks.

(b) Dr. Hopkins agrees that there is a relatively high degree of certainty that some form of energy transition will occur in Ontario. How that transition affects the business risk of gas utilities will depend on the form the transition takes and how the utility and regulator manage the utility's course through the transition.

(c) The Toronto adoption of that item provides tangible evidence that Toronto City Council is reviewing options to discourage the installation of new combustion uses of methane as part of the update to the Toronto Green Standard to Version 5. Whether such review will consider and/or identify a "gas ban" as an appropriate option is entirely speculative at this time. Accordingly, Dr. Hopkins would not consider this Toronto City Council motion as "tangible evidence that gas bans are a risk in Ontario" sufficient to alter his assessment of Enbridge's energy transition related business risk at this time. As discussed in Q&A45 in Dr. Hopkins's evidence, restriction on new gas uses does not necessarily present a business risk to the gas utility, and the same would equally apply to measures to "discourage" new combustion uses of methane.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 14

Preamble:

At page 14, Dr. Hopkins states:

"Risks which can be better quantified and evaluated should be given greater weight, all else equal. In general, this means near-term, well-understood risks should be given greater weight, while uncertain, less established risks should be given less weight."

Question(s):

(a) Would Dr. Hopkins agree that an assessment of business risk generally tends to be more qualitative in nature because many business risks are difficult to quantify?

(b) Has Dr. Hopkins performed any analysis that compares the business risk or deemed capital structure of Enbridge Gas to other large gas distribution companies in Canada or the U.S.? If so, please provide that analysis. If not, what is the basis for Dr. Hopkins' conclusion that the current deemed equity ratio of 36% for Enbridge Gas is reasonable and meets the fair return standard?

Response:

(a) The question is unclear as to what other action the assessment of business risk would be "more qualitative" than. Where only qualitative assessment is possible, that qualitative assessment should incorporated into an assessment of business risk; where quantitative assessment is possible it should be conducted and then incorporated. The modeling approach that Dr. Hopkins suggested in his testimony would illuminate the likelihood and consequence of adverse business outcomes for EGI, and thereby provide a quantitative assessment of business risk associated with energy transition.

(b) See N.M8.EGI-70.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 18

Preamble:

At page 18, Dr. Hopkins states:

"To compare volatility, I used the calculated 0.64 percent standard deviation of EGI's achieved returns over its four-year existence as a combined company."

Question(s):

(a) Please provide the working papers supporting Figure 1 and Figure 2 in Dr. Hopkins' report in Excel format. Please also provide the working papers supporting Dr. Hopkins' calculation of standard deviations.

(b) Why has Dr. Hopkins used the standard deviation to evaluate volatility of earned returns for Enbridge Gas instead of the coefficient of variation?

Response:

(a) The requested workpapers in Excel format have been filed separately,

(b) When comparing volatility between time periods for an asset with a relatively stable mean, such as the returns of EGD, EGI, and Union Gas, there is no material difference between using the standard deviation and the coefficient of variation.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 20

Preamble:

At page 20, Dr. Hopkins states:

“The OEB’s “transparent, consistent, and predictable” regulation of EGI (to quote S&P) gives me confidence that the OEB will ensure that EGI plans appropriately to adapt to the policy and market contexts in which it finds itself over the course of the energy transition in the coming decades.”

Question:

Is it Dr. Hopkins’ position that OEB regulation can mitigate all business risk for Enbridge Gas, including risk associated with the energy transition, or are there certain business risks that cannot be mitigated by regulation?

Response:

The referenced quote is intended to emphasize that the OEB’s regulatory framework will ensure that EGI plans appropriately to adapt over the course of the energy transition. It is thus incorrect to conclude from the referenced statement that OEB regulation *per se* mitigates business risk of Enbridge Gas (though elsewhere in his evidence Dr. Hopkins does attribute business risk mitigation benefits to certain aspects of the regulatory framework applied to Enbridge Gas).

While in theory, the OEB could insulate OEB investors from all risk, Dr. Hopkins does not believe that would be appropriate or consistent with the setting of just and reasonable rates. The OEB can weigh the costs and benefits of taking different risk mitigating steps for investors, and the associated potential transfer of risk to ratepayers, and strike an appropriate balance.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 21

Preamble:

At page 21, Dr. Hopkins states:

"To the extent that EGI acts imprudently by failing to appropriately plan for the energy transition or by poorly managing the transition, it may experience lower returns and/or fail to recover its capital."

Question(s):

As discussed on page 18 of Exhibit 1, Tab 2, Schedule 1, one way that Enbridge Gas has identified to manage the energy transition is to increase its deemed common equity ratio over the course of the PBR plan from 36% to 42% to maintain the Company's financial strength and continued access to capital at a reasonable cost.

Given the above-referenced passage from Dr. Hopkins' evidence, should the management of Enbridge Gas be held responsible for poorly managing the energy transition if the OEB rejects the proposed change in the Company's capital structure, as Dr. Hopkins recommends?

Response:

Prudent management of the energy transition involves gathering the best available information, considering many different potential actions (both physical and financial) and selecting the actions that lead to the best overall outcome for the utility and its ratepayers. The management of Enbridge Gas should be held responsible for conducting prudent analysis of the range of options available to it, within its market, regulatory, and policy context (e.g., of Ontario and Canada), and selecting a portfolio of actions that contribute to a successful energy transition. Insufficient evidence of such analysis or option selection has been presented by Enbridge to justify a change in equity thickness as a primary component of an overall prudent energy transition strategy.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 21

Preamble:

At page 21, Dr. Hopkins states:

"Ontario's climate plan has called for a dramatic reduction in emissions (including a reduction in emissions from natural gas) since at least 2016."

Question(s):

(a) Is it Dr. Hopkins' testimony that the energy transition started for Enbridge Gas in Ontario in 2016 or earlier?

(b) In Dr. Hopkins' opinion, has the pace of the energy transition remained about the same since 2016, or has it accelerated in recent years? Please elaborate.

Response:

(a) Yes.

(b) The implications of the energy transition have become clear to more people and businesses in the years since 2016, and emission reduction targets have generally become more ambitious (e.g., net zero instead of an 80 percent reduction by 2050). However, the broad strokes of the energy transition (including the relative likelihood of a substantial reduction in gas system throughput) have been known since 2016 or earlier.

For example, the report *Pathways to Deep Decarbonization in Canada*, published in 2015 as part of a series of national deep decarbonization analyses coordinated by the Sustainable Development Solutions Network, shows electrification displacing pipeline gas in the buildings sector as part of a pathway to 89 percent GHG reduction from the energy sector by 2050. (The report is available at: https://ddpinitiative.org/wp-content/pdf/DDPP_CAN.pdf.)

More specifically for EGI, Union Gas in 2016 requested accelerated depreciation (20 years) for the Panhandle Reinforcement Project (EB-2016-0186), based on the potential useful life of the asset being shorter than the standard 50-year expectation due to Ontario's climate change plans. While the OEB did not grant this request, the denial was not based on a rejection of the risk, but rather than the issue should be addressed for the system as a whole and that the question requires a "comprehensive review." (EB-2016-0186, Decision and Order of February 23, 2017) This indicates that the energy transition has been a live issue for gas utility capital planning in Ontario since at least 2016.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 25
Exhibit I.5.3-STAFF-204, Attachment 1
Technical Conference Transcript Day 8

Preamble:

At page 25, Dr. Hopkins states:

"In fact, Concentric cites Enbridge's 2021 Sustainability Linked Bond (SLB) issuances as an example of the impact of investors' ESG concerns, and this shows a small reduction in the cost of debt for Enbridge."

Enbridge Gas seeks to clarify that Enbridge Inc, and not Enbridge Gas has issued Sustainability Linked Bonds.

Exhibit I.5.3-STAFF-204, Attachment 1 contains the Enbridge Inc prospectus for Sustainability Linked bonds.

At TC Tr. Vol 8 page 7, lines 7 to 9, Mr. Reinisch states:

"As of right now we have not yet issued a sustainability linked bond for EGI. Our sustainability-liked debt has been issued out of Enbridge Inc."

Question:

Please confirm that only Enbridge Inc., the parent company of Enbridge Gas, has issued Sustainability Linked Bonds and that Enbridge Gas has not issued Sustainability Linked Bonds?

Response:

Confirmed.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 27

Preamble:

At page 27, Dr. Hopkins states:

"As a result, Massachusetts gas utilities and their regulators have a better sense of their future and path through the energy transition than other gas utilities. In short, and contrary to Concentric's claims, regulatory attention to energy transition issues reduces uncertainty and lowers risk."

Question:

Please explain how regulatory attention to energy transition issues necessarily reduces uncertainty and lower[*sic*] risk for gas utilities if the policy environment in a state or province requires strict reductions in carbon emissions by a date certain, provides incentives for fuel switching, requires the use of electricity in new buildings, or imposes restrictions or outright bans on natural gas usage.

Response:

Policy certainty, resulting in part from regulatory attention, reduces uncertainty for utility management because with policy certainty the utility necessarily knows more about the context it will be operating in and the future it is planning for. For example, relative policy certainty allows the utility to better determine its appropriate depreciation rates and capital investment plans, thereby lowering capital risk. Regulators have an obligation to set just and reasonable rates and to offer the utility a reasonable path to recover its prudently invested capital with a fair return. Regulators do not have an obligation to support any particular number of customers, volume or value of sales, or level of customer growth. By providing clear policy guidance as to the trajectory of these parameters, however, regulators and other policymakers can assist utilities in making prudent capital, operating, and financial choices, thereby reducing uncertainty and lowering risk.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, pages 33 and 45

Preamble:

At page 33, Dr. Hopkins states:

"While gas had a greater advantage over electricity in 2015, the overall effect of change in electricity and natural gas bills from 2015 to 2022 is to leave natural gas with a noticeable continuing advantage."

At page 45, Dr. Hopkins states:

"Proactive planning regarding asset retirements, with depreciation approaches tailored to assets retiring in any given year, can reduce and potentially eliminate stranded cost risks—even in a case that has a more extreme version of building sector departure from the gas system than modeled by Guidehouse in its electrification case."

Question(s):

(a) Would Dr. Hopkins agree that the relative price of natural gas and electricity from 2015-2022 is not the only relevant consideration in assessing competitive risk?

(b) Has Dr. Hopkins considered whether other factors such as environmental regulations, financial incentives, and policy considerations will also affect the competitive position of natural gas relative to electricity on a going forward basis? If so, what do those other factors indicate? If not, why not?

(c) Has Dr. Hopkins considered the aggregate effect on natural gas prices in Ontario of the increased carbon tax, if combined with accelerated depreciation? If so, please discuss how these modifications would affect the competitiveness of natural gas relative to electricity on a going-forward basis.

(d) The report filed by Mr. Chris Neme on behalf of GEC and ED suggests that both the "death spiral" and stranded assets are high probability events for Enbridge Gas by 2050. Assuming this is true, how does this change Dr. Hopkins' assessment of competitive risk for Enbridge Gas?

Responses:

(a) Yes.

(b) Dr. Hopkins believes that the other factors listed in question (b) will affect the competitive position of natural gas relative to electricity in the future, as they do today. Dr. Hopkins has not made any projections or calculations of combinations of carbon taxes and accelerated depreciation. As a general matter, and with other factors held constant, factors which increase the cost of natural gas delivered to customers, or increase the relative cost of installing equipment that uses natural gas, will tend to increase the chance that customers will choose to use other fuels. However, there is unlikely to be a direct or linear relationship between delivered natural gas prices, equipment costs, and gas utility business risk. As described in his testimony, Dr. Hopkins encourages EGI to undertake such calculations and analysis as part of a broader market and policy analysis in order to better understand the market context in which it needs to make prudent decisions about its capital, operational, and financial actions.

(c) See (b).

(d) Dr. Hopkins does not agree that Mr. Neme's report makes the suggestion cited in the question. Dr. Hopkins views competitive position primarily as a cause of potential capital risk, rather than a separate type of risk. A conclusion that 'the "death spiral" and stranded costs are high probability events for Enbridge Gas by 2050', would have the following implications:

i. The assumed existence of a "death spiral" implies that it must become very attractive for customers to reduce use of pipeline gas; it is likely that this reflects a strong and continuing competitive position for electricity at some point.

ii. The assumed existence of stranded costs implies that capital risk manifests in the form of assets that are no longer used and useful before the end of their useful life, and before they are fully depreciated, and that utility management fails to foresee or adequately act to mitigate stranded cost risk.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 35

Preamble:

At page 35, Dr. Hopkins states:

"Risk is composed of the combination of likelihood and consequence. A capital risk analysis should include identification and analysis of the circumstances under which a utility would fail to recover its invested capital along with a fair return, the extent of the shortfall, and the likelihood of such circumstances. The most obvious way to conduct such an analysis would be through scenario analysis."

Question(s):

(a) Is it Dr. Hopkins' position that equity investors regularly perform the analysis he describes on pages 35-39 of his report in assessing risk related to investing in local gas distribution companies such as Enbridge Gas? If so, please provide examples with citations to such analyses.

(b) Is it Dr. Hopkins' position that S&P performs the analysis he describes on pages 35-39 of his report in assessing business risk for local gas distribution companies such as Enbridge Gas? If so, please provide citations to S&P reports demonstrating such analyses.

Responses:

(a) Dr. Hopkins expects that most equity investors do not conduct analysis at the level of detail that he describes in his evidence, although the level of detail and research likely varies based on the amount of capital an investor plans to invest in a company. Investors are unlikely to have access to the quantity and quality of information required to conduct such analysis. Dr. Hopkins also believes that equity investors expect the management of the utility company, which has access to the best available information, to conduct detailed analysis of the future of the firm, and to be informed by such analysis when making business decisions and in dealing with regulators.

(b) Dr. Hopkins is not aware of the details of the analysis that S&P performs when making its business risk assessments.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 47
Exhibit I.1.8-STAFF-14, Attachment 6, pages 47-57.

Preamble:

At page 47, Dr. Hopkins states:

“EGI is arguing that its consultants know better than S&P and that its business risk has increased despite S&P not identifying that risk in rating reports for the company. My analysis shows that EGI faces small, if any, capital risk from an ambitious electrification scenario; this aligns with S&P’s silence regarding this risk.”

At Exhibit I.1.8-STAFF-14, page 47, The S&P Global Ratings Report refers to the Outlook period used in the credit opinion:

“We expect Enbridge Gas Inc. (EGI) to maintain its financial performance throughout our two-year outlook period.”

At Exhibit I.1.8-STAFF-14, page 48, The S&P Global Ratings Report refers to the Outlook period used in the quantitative evaluation of Enbridge Gas’ FFO to debt credit metric:

“This leads us to forecast FFO to debt of 11%-12% during our two-year outlook period.”

Question(s):

(a) Does Dr. Hopkins agree that equity investors do not necessarily consider the same risk factors as credit rating agencies in evaluating the business and financial risk of a regulated utility such as Enbridge Gas? If he does not agree, please explain why not.

(b) Please confirm that the outlook period used by S&P in its report dated July 21, 2022 covers only a two-year period.

(c) Does Dr. Hopkins agree that the S&P reports relied upon in his response to question 76 on page 47 do not include any references to risks facing Enbridge Gas in the 2025-to-2028 time horizon?

Responses

(a) Any given investor may not necessarily consider the same risk factors as any other investor, or as credit rating agencies. Equity and debt investors take different amounts of risk, are more exposed to different kinds of risk, and expect different returns. However, the list of risk factors they consider for a given company may be more similar.

(b) Confirmed that the quantitative analysis presented in the outlook covers a two-year period. The report makes reference to events in 2024, so other parts of the assessment appear to extend to at least three years. S&P does not put an explicit timeframe on its assessment of qualitative factors.

(c) S&P does not put an explicit time horizon on its consideration of EGI's business risk. The risk factors discussed by S&P in the "business risk" section of the referenced report (namely the regulatory framework, commodity risk, size of the customer base, cash flow stability, weather, and geographic footprint) are also risks that Concentric identified as risks facing EGI during the 2025-28 time horizon.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 52
Exhibit I.5.3-ED-143

Preamble:

At page 52, Dr. Hopkins states:

"Without a comprehensive understanding of the risks and the utility's plan to mitigate them, it would be inappropriate to reward the company's shareholders with a greater equity share and thereby charge ratepayers a higher rate to compensate the utility for risks that may not occur, and that prudent utility management could mitigate."

In Exhibit I.5.3-ED-143, question part b) states:

"Please describe in simple terms how increasing the equity ratio helps Enbridge to (i) mitigate risks or (ii) be compensated for assuming higher risks?"

Response to interrogatory:

i. Credit rating agencies and debt investors evaluate the riskiness of investing capital in Enbridge Gas. The higher the equity ratio, the lower the risk to debt holders. With increasing business risks to Enbridge Gas as a result of factors such as Energy Transition, the riskiness of investing in Enbridge Gas's debt, all else being equal, increases. Higher equity thickness would offset the increased business risks. Therefore, increased equity thickness would support Enbridge Gas's continued access to capital at reasonable costs.

ii. Increasing the equity thickness does not compensate Enbridge Gas for assuming higher risks. The return on equity compensates equity investors for assuming risk and Enbridge Gas is not proposing to change the OEB's prescribed Return on Equity formula.

Question(s):

(a) Please confirm that the applicant's proposal to increase equity thickness will increase the amount of capital shareholders have at risk.

(b) Does Dr. Hopkins agree that all else being equal, an increase in equity thickness reduces the riskiness of investing in Enbridge Gas debt, and thus benefits debt investors?

<u>Responses:</u>

(a) Confirmed. However, Dr. Hopkins would make two additional points regarding the impact on shareholders:

i. The shareholder capital invested will now be less risky, if the return on equity is fixed. This is because variance in cash flow will now be spread over a larger amount of equity. This improves the risk/return performance for equity owners.

ii. If the utility's market value is greater than its book value, an increase in equity thickness also creates an additional return to existing shareholders even without a change in the return on equity.

(b) Yes. As stated above, it also reduces the riskiness of equity, relative to returns, and thus benefits shareholders.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Enbridge Gas Inc. (EGI)

Reference:

Exhibit M8, page 53

Preamble:

At page 47, Dr. Hopkins states:

“Without a comprehensive understanding of the risks and the utility’s plan to mitigate them, it would be inappropriate to reward the company’s shareholders with a greater equity share and thereby charge ratepayers a higher rate to compensate the utility for risks that may not occur, and that prudent utility management could mitigate. Paying more now, without taking prudent actions to reduce the need to pay more later, is neither just nor reasonable.”

Question(s):

(a) In Dr. Hopkins’ opinion, is it important for Enbridge Gas to have the financial strength it needs to manage the effects of the energy transition as well as other business risks?

(b) If requesting a higher deemed equity ratio is one way for Enbridge Gas to prudently manage the energy transition in order to reduce the need to pay more later, why would Dr. Hopkins object to such a proposal?

Responses:

(a) Yes.

(b) Dr. Hopkins does not see sufficient evidence in this proceeding that EGI has developed a comprehensive plan to manage the energy transition (of the sort he recommends in his testimony). EGI has not shown that a higher deemed equity ratio is necessarily an integral part of a prudent energy transition plan, or is the best way to improve or maintain financial strength. For example, Dr. Hopkins’s evidence shows that the company’s financial strength can increase substantially without a change in equity thickness, depending on the company’s capital investment and depreciation approaches. Specifically with respect to this question, EGI has not presented any approach or analysis that shows that a higher equity ratio now would allow EGI to “manage the energy transition in order to reduce the need to pay more later.”

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Pollution Probe (PP)

Reference:

"Require EGI to conduct a detailed business analysis, along the lines of the illustrative examples I provide in my testimony, following the publication of Ontario's ongoing pathways study and the conclusions of the Electrification and Energy Transition Panel, to inform its capital and operational plans." [IGUA_IntrvEVD_Exh M8_Asa Hopkins_EGI Rebasing_20230511, Page 6]

Questions:

Enbridge analysis and related evidence in the Rebasing application was not done in partnership or collaboration with other relevant stakeholders (e.g. IESO). The studies put forward were not peer reviewed or open for stakeholder comments, which has led to significant gaps and updates required. For example, the Guidehouse Net Zero study is on its third publication in less than a year resulting in over $140 billion in corrections to the modeling and related report. What process would you recommend to the OEB to enhance the value and credibility of the analysis if the OEB adopts the recommendation for EGI to conduct additional analysis as outlined above?

Response:

The OEB faces an interesting challenge. On one hand, the information that is required to do this kind of analysis right gets into a level of detail that exceeds what utilities can easily share with outside participants, and requires expertise and experience with gas system operation to fully use. This includes geographic information (which assets are where; how old are they and what are they made of; and how are they connected to other assets), operational information (how do different assets contribute to the safe and reliable operation of the gas system; what are the capabilities and expertise of field staff and contractors), and business/financial information (what do actions cost, what are their implications for the financial strength of the company). In addition, utility management is composed of the people selected by the asset owners to undertake these kinds of planning exercises. These reasons support having utility employees and experts under contract to the utility conduct some or all of the energy transition planning.

On the other hand, utility staff and management bring an inherent perspective and bias to conducting this work, by virtue of their roles and responsibilities: their incentives are not fully aligned with the public interest. In addition, experts outside of the gas utility have valuable information and insight to contribute to a successful planning exercise. These experts include institutional stakeholders (such as IESO and electric distribution companies), market actors (such as HVAC installers, manufacturers, and distributors), and advocates who can reflect different customer and resident interests (including low-income and energy justice interests).

There have not been any perfect examples of how to resolve this tension. For example, even the promising Massachusetts process fell short: it welcomed stakeholder input, but was ultimately driven by the utilities and yet did not take advantage of access to nonpublic information about gas system planning, operations, and the utility business. It also did not get to the level of business planning required to get to real answers.

Dr. Hopkins offers a few ideas and principles in hopes of helping the OEB find a good path forward:

- Any consultants retained to conduct analysis should be contracted to the OEB, not to a utility. The OEB should lend its authority to the consultant to ensure they get necessary information.

- The OEB should be prepared to require the utilities to conduct analysis and share the results, methods, and tools with the OEB (and its consultants as appropriate), with appropriate security and confidentiality constraints. Results and summary methods should be made public. It is important that oversight confirm that these analyses are conducted from the standpoint of "the best possible version" of each case. That is, utilities should model what they would do when trying to make the best business decisions within the context of each scenario.

- Allow stakeholders to define scenarios, in the level of detail they are capable of. The OEB should provide a venue for stakeholders to develop a limited set of scenarios reflecting different approaches, working with OEB and its experts to make sure the scenarios cover all appropriate parameters. The OEB's experts should analyze these scenarios, and have the utilities do their part (with OEB oversight) to provide the detailed insight necessary to evaluate each scenario.

- The OEB's process should be guided by provincial and federal policy and pathway decisions. It most likely would not helpful for the OEB to develop scenarios that are inconsistent with core tenets and principles of the provincial pathway.

INDUSTRIAL GAS USERS ASSOCIATION (Hopkins)

Answer to Interrogatory from Pollution Probe (PP)

Reference:

The OEB has enabled Enbridge to put forward alternative investments or Integrated Resource Plan (IRP) alternatives [Reference: EB-2020-0091 Decision and related IRP Framework] that would earn shareholder profit and could be capitalized in a manner similar to utility natural gas capital assets. This provides an option for Enbridge to mitigate investment risk for natural gas assets if it were a valid concern. The lack of use for this tool suggests that Enbridge still prefers investing in traditional natural gas assets to alternatives that do not use natural gas.

Questions:

(a) Please provide any comments on this tool that the OEB has already provided Enbridge and how it could be used to mitigate future asset risk should it become any risk become relevant.

(b) Please provide any comments on the responsibility for Enbridge to use those tools (e.g. IRP alternatives) to mitigate risks if they are truly concerned about non-recovery of stranded natural gas assets.

Responses:

(a) In Dr. Hopkins's experience, it takes some time for non-traditional approaches to become integrated into utility planning practice. It may be too early to conclude that the IRP Alternative tool is not well designed. Dr. Hopkins has identified some lessons from similar processes that may be relevant. These lessons are similar to (but not identical to) the choices reflected in the IRP Framework established by the OEB in EB-2020-0091. Dr. Hopkins suggests:

i. Look out at capital needs at least a decade into the future in order to identify needs in time to bring them through a planning process and scale demand-side options or non-traditional supply-side options.

ii. Include all types of utility investments in the range of potentially avoidable investments; allow all potential solutions to be used in a portfolio to address them.

iii. The screening for alternative solutions should include assessment of long-term implications and consistency with provincial policy.

iv. The utility should report to stakeholders and the regulator on all investments that are screened for alternatives, and why the investments screened in or out for consideration.

v. Recurring (e.g., quarterly) stakeholder meetings to review the investments to be screened, the screening process, and the status of implementation for alternatives that screened "in" can develop trust and understanding among stakeholders and utilities.

(b) Enbridge has a responsibility to pursue least-cost service through prudent investment, financial, and operational decisions. IRP Alternatives should be a tool that EGI uses, and the OEB expects to be used, as part of that obligation. Enbridge should take prudent actions, informed by analysis of risks of all sorts (including the risk of underutilized or stranded assets), as part of an integrated planning approach.