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Enbridge Gas Inc.
2024 Rates Application – Phase 1
EB-2022-0200

Submission of the
Vulnerable Energy Consumers Coalition
(VECC)

September 20, 2023

Vulnerable Energy Consumers Coalition

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Submission Summary

1. In this argument VECC makes the following submissions:

    - The Board should take a cautious approach to "energy transition" keeping in mind the limited authority and jurisdiction it has in this proceeding to address those issues.
    - There should be no change, other than those required to harmonize the practices of the former utilities, to the rules governing expansion of the natural gas system and the connection of customers. The ELC charge should be adjusted only for inflation.
    - The proposed 2024 capital expenditures should be reduced from to reflect historical spending patterns and recognize rising connection costs.
    - Recovery of capital related to the integration costs of the amalgamation of Enbridge and Union Gas should be denied.
    - EGI should adopt the use of Average Life Group depreciation methodology.
    - The Board should not adjust the equity thickness as proposed and until it has made decisions with respect to rate design changes.
    - EGI should continue with the use of the existing average use accounts and until such time as it decides on EGI's rate design change proposals (Phase 2).
    - The Board should not approve the recovery of Union Gas's pre-2017 unamortized actual losses.
    - The Board should order the removal of the NGV program from regulated rates.
    - The Board should not provide service quality GDAR exemptions.
    - The Board should consider the establishing process to comprehensively consider a new framework for the regulation of natural gas which is based on a revised assessment of stranded asset risk.

2. VECC does not address all of the outstanding issues in this argument. On issues which nothing is said we take no position at this time.

Issue 2 – Benefits of Amalgamation

3. EGI claims substantial savings from amalgamation[1]:

    "*Customers are benefitting from the integration of Enbridge Gas Distribution and Union Gas. Despite the challenges of the global pandemic and with only five years to plan and carry out amalgamation initiatives, we will be passing $86 million in annual integration savings on to customers beginning in 2024. When you add in productivity initiatives, customers will benefit from more than $121 million in savings a year*"

[1] Exhibit I.1-Staff-1 page 3 of 4.

4. Various tables[2] and charts expounding the various “productivity initiatives” are largely based on a lot of “*what ifs”*. Savings are based on speculations of what costs would otherwise have been in the absence of certain initiatives. Measurable reductions are claimed to be the result of amalgamation irrespective of whether their causation can be determined with any certainty. No accounting is given to offsetting increases due to new requirements and procedures post amalgamation. or, as we outline below, in the degradation of quality of service metrics

5. The plain fact is that in 2018, the year prior to amalgamation, the two individual utilities had Operating, Maintenance and Administrative (OM&A) Costs, i.e., controllable costs, of $883 million. In 2023 that costs is estimated to be $1,021.7 million[3]. We calculate that on an inflationary basis the 2018 equivalent would be approximately $1,039.5 million.[4] The result are savings, but less than $18 million – or 2% of OM&A . Far less than the $86 million claimed

6. Nonetheless, however one measures it, some savings have been made with respect to reducing operating costs. The evidence is less clear on whether amalgamation has any long-term benefits with respect to capital investments. In any event, at this juncture the matter is of little import. Customers do not appear to be worse off. We would only caution the Board in considering all the issues over all of the phases of this proceeding that there are no overwhelming consolidation benefits for which EGI should be rewarded.

Issue 3 – Energy Transition

7. The Board’s objectives with respect to the regulation of natural gas are:

   1. To facilitate competition in the sale of gas to users.

   2. To inform consumers and protect their interests with respect to prices and the reliability and quality of gas service.

   3. To facilitate rational expansion of transmission and distribution systems.

   4. To facilitate rational development and safe operation of gas storage.

   5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer’s economic circumstances.

[2] See for example Exhibit 1, Tab 9, Schedule 1, Tables 2 & 3
[3] Exhibit 4, Tab 1, Schedule 1 Tables 1 &2
[4] We use the Bank of Canada inflation calculator as found at https://www.bankofcanada.ca/rates/related/inflation-calculator/

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2; 2009, c. 12, Sched. D, s. 2; 2019, c. 6, Sched. 2, s. 2.

All but, one of these objectives, the promotion of energy conservation and efficiency, serve the Board's obligation to regulate in a manner which promotes the expansion and viability of the natural gas system in Ontario.

8. An inordinate amount of time and effort in this proceeding has been spent on something called "energy transition." Yet what that term means both broadly and specifically in this case is somewhat in the eye of the beholder. It is not a term defined anywhere in the *Ontario Energy Board Act*. Nor does the concept exist in the *Electricity Act* or any other piece of legislation which governs the Board jurisdiction or which it otherwise is provided jurisdiction under which to act.

9. Board Staff provide their definition: "*Energy transition generally refers to the global shift away from using fossil fuels to a more sustainable, renewable energy future that includes more innovation and customer* choice." This seems reasonable enough. Though the term "more innovation" is somewhat superfluous. If customer choice is to be measured by the number of parties advocating for the elimination of natural gas, less, not more, customer choice is in the offing under some views of "energy transition." We would argue that while the term "energy transition" is currently in vogue a more accurate description of how climate change is being addressed is through policies which reduce carbon and other green house gases (GHG). In many places around the globe this includes carbon sequestration and the replacement of high GHG emitting carbon fuels (e.g., coal) with lower ones (i.e., natural gas).

10. How the pursuit of lower CHG emissions will proceed is anyone's guess at this point. As we said in our opening statement – when seismic change occurs anybody (and usually everybody) can be an expert. This proceeding has certainly had its share of such "transition experts". The truth is that nobody is an expert guide to an untread path. In our view the excessive time spent in this proceeding on energy transition pathway studies and routes to net zero are largely a waste of time and (ratepayer) monies.

11. In their argument Board Staff conclude that "…. *based on the record in this proceeding, there is a high probability that the energy transition will follow a pathway with a less significant role for gaseous fuels (even if those are low or zero carbon fuels) using Enbridge Gas's network than that described in the P2NZ Diversified Scenario*." We conclude that the "evidence" that this statement relies upon is simply speculative and unsubstantiated by any facts. If one were to follow the facts the conclusion (perhaps unfortunately), one would reach is that natural gas is likely to continue to be a fuel source for the foreseeable future because there is no plausible or

actionable plan to replace it. Furthermore, that plan – if and when – it comes will be at the hands of governments and not regulators.

12. In any event anyone can offer an "expert" futuristic vision. We believe it is important to consider that climate change brought on by GHG is a global phenomena and that Ontario's, let alone Canada's contribution GHG is - on an absolute basis – very small. A global perspective leads one to consider whether future government policies might recognize, especially as costs escalate exponentially to reach net-zero, that Canadians, may be better served by continued use of low carbon emitting natural gas to produce the wealth from which far more CHG reductions can be purchased from high emitting countries.[5] This is as plausible a future scenario as any the Board heard in this hearing and if true would leave the natural gas business in Ontario largely unchanged.

13. The question in this proceeding is what weight the Board should put on the various scenarios offered up under the guise of expertise and what costs should customers have to bear in the near term (5 years) to satisfy these various energy visions. Our conclusion is little to none.

14. There is no question that both at the Federal and Provincial level there have been a number of policy initiatives to reduce GHG emissions. However, in terms of actual legislation, and aside from the Greenhouse Gas Pollution Pricing Act (GGPPA) which establishes the federal carbon tax there is very little in the way of required action. The only other piece of major legislation - Canada Net-Zero Emissions Act - is largely an articulation of non-enforceable GHG emission targets. The reality is the challenges to reduce GHG are immense, the costs proportionally higher to reach net-zero are immense, and the technologies to do so still in their infancy.

15. Some parties appear to advocate for the Board to demand consumers make certain choices such buying heat pumps in lieu of (or in addition to as only the well off might propose) their existing furnaces. Yet the Board has no jurisdiction and certainly no public legitimacy to tell consumers what legally available appliances they can or cannot purchase. Nor does it have the jurisdiction to create costs for ratepayers in pursuit of that objective. As representatives of low income consumers we remain vigilant against the tendency of high income elites to use other people's money in pursuit of their favoured dreams.

16. As for heat pumps we recommend the Board familiarize itself with events in Germany where it was recently attempted to pass legislation mandating heat pumps[6]. Forcing

[5] The IEA states that "Coal has consistently remained in second place in the global energy mix, at more than a quarter of the total, or 162 EJ in 2019." https://www.iea.org/reports/world-energy-balances-overview/world

[6] https://apnews.com/article/germany-heating-bill-vote-blocked-court-fefec307d386b73faf32a3769ae65b80

consumers onto a specific consumption path is a difficult task, fraught with political overtones and certainly not a role – unless explicitly given – for regulators. Currently the issue of how consumers choose to heat their homes, what equipment with which they choose to do so and how they use energy, is left to consumers and private markets as governed by federal and provincial laws. The Board has no more the authority to encourage heat pumps than it does to discourage heated swimming pools. These are matters the OEB simply does not regulate.

17. We also posit that the Board does not possess the mandate to consider regulatory policies which restrict an Ontario resident's choice of natural gas as an energy source. In fact, one of the few pieces of Ontario legislation (i.e., actual implemented law as opposed to wishful political statements) is for the expansion of natural gas to new communities.

18. Nor does the Board have the legislative mandate to consider policies which encourage or discourage Ontario residents in their choice of energy source whether that be natural gas, electricity, fuel oil, or wood[7]. There are no "optimum energy source objectives" embedded in the *Ontario Energy Board Act*. We are unaware of any CHG requirements in the Board's governing legislation that authorizes it to cause costs on ratepayers. The *Act* certainly does not call for the elimination or even reduction of the natural gas sector – in fact it does the opposite.

19. Nor do we think EGI is bound by any legal requirement to work toward its own demise including by coordinating with electricity utilities for energy choices of developers or other purchasers of energy equipment. EGI, for its part, nevertheless shows a willingness to engage in energy planning.[8] Yet it seems to us that they must also remain cognizant that at some level, in the absence of actionable law, that some contemplated energy transition activities might be seen as a renunciation of their fiduciary duty to their shareholders.

20. We think the Board might consider the restrained views of its Federal counterpart, the Canadian Energy Regulator with respect to this topic[9]:

[7] According to Statistics Canada "*Approximately 1 in 50 Canadian households (2%) reported owning a heating stove, three-quarters of which were wood burning stoves. Households outside of Canada's large cities were four times as likely to report owning a heating stove than city folk (4% versus 1%), with 88% of households outside of big cities reporting a wood burning heating stove*. " https://www.statcan.gc.ca/o1/en/plus/2717-heat-how-canadians-heat-their-home-during-winter

[8] See EGI ACI pages 45-47

[9] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/canadas-energy-transition/canadas-energy-transition-historical-future-changes-energy-systems-update-energy-market-assessment-future-pathways.html

It is challenging to predict exactly how the energy transition will unfold in Canada. Canada's transitioning energy system may involve familiar methods of energy used in new ways. For example, using fossil fuels in more efficient ways, and developing more renewable sources of electricity for powering end-uses. The transition may also involve entirely new energy systems, such as advanced biofuels and electrolysis for hydrogen production. The pace of the transition will also place pressure on governments to develop regulations for new technologies as they emerge.

21. All of which is to say that natural gas may be with us for some time. Certainly the changes over the next 5 years covered by EGI's rate plan are likely to be minimal.

22. We also take exception to informal "letters from Ministers" which some believe the Board is bound to follow. The Board should not be seen as compromising its independence by taking informal direction from the government of the day on how to carry out its legislated mandate. The correct and appropriate way for the government of the day to direct the Board is through changes to its governing legislation or through the promulgation of directives as provided for in existing legislation. We are cognizant that the last large costly (and arguably non-economic) policy change in the energy sector desired by government - smart metering of the electricity residential sector – was carried out through explicit directives and an extensive legislative agenda. Given the disruptive and expensive nature of what is being speculated on in this proceeding the Board would require public legitimacy that can only be obtained by a clear legislated mandate. Letters from Ministers are far from meeting that standard.

23. We are also concerned (as we set out below) that even where this panel might consider making changes to policies that it does so in consideration of how the *OEB Act* contemplates the process for that being done. That a single panel's decision is ultimately reversible by a subsequent panel is one concern. The other is that the *OEB Act* purposely sets out how policies affecting both natural gas and electricity utilities should be undertaken under the rule making authority. Finally, we are concerned that if the panel seeks to act broadly beyond the proposals of the Applicant it must consider whether proper notice has been undertaken.

24. Fundamentally, we hold that a rate setting case is not the best forum in which to make substantive policy changes that affect not just natural gas utility rates but the entire structure of the industry. In our experience it is better that these issues be addressed discretely and in proceedings and with processes better suited to finding the best outcome and most economic implementation. While the Board panel may be sympathetic to the issues of GHG emissions reductions (as we are) and want to be proactive it must remain diligent in following the limitations of its authority. The Ontario Energy Board is not a body of elected representatives. It is not a policy arm of the Ministry of Energy. It is not even an energy planner like the IESO. It is an economic regulator whose jurisdiction is narrow and strictly spelled out. If the Board desires to incorporate the realities of GHG reduction policies into its regulation of natural gas it

seems to us that the best way to do that is to initiate a comprehensive forum into which to review all the affected parts of gas regulation. A renewed natural gas regulatory framework might be a worthy exercise but it would also likely be a lengthy and multiprong one.

25. In this regard to energy transition (or CHG reduction goals) our views are somewhat sympathetic to those of EGI when they state:

    "*Enbridge Gas is taking the appropriate measured and clear-eyed steps to evaluate and respond to energy transition in a way that is mindful of current Government of Ontario policy and maintains the gas distribution system as a reliable and cost-effective source of energy*." We generally agree with this sentiment. However, we also observe that EGI is rather selective in how and where it chooses to incorporates or not consideration of "energy transition." Its importance seems more apparent to the Utility when speaking to changes to capital structure and depreciation policy but grows increasingly silent when considering capital expenditures and other aspects of the business.

26. The inconvenient truth is that the Board's role in GHG reduction is necessarily limited by the specifics of its legislated mandate. The only objective that remotely touch upon that goal are those on conservation and energy efficiency. However, this objective must be read in light of the other seven, all of which points to maintaining the longevity of the natural gas system and include the requirement to facilitate the rational expansion of the transmission and distribution system. We do not think the Board can legitimately override the intent of the law by concluding that it is no longer rationale to expand the natural gas system. Whether we should work toward the elimination of natural gas as an energy source is a question for the people to decide through their elected assembly. To our knowledge that is a decision that has not yet been made.

Specific Energy Transition Issues

27. Having laid out our reservations we are not advocating a "do nothing" or "wait and see" approach. Our argument is that a measured campaign is prudent and that there are specific issues that should be examined in the near future with a focus on making the transition to a low carbon economy. This calls for a well thought out comprehensive exercise to revisit natural gas regulation in light of GHG reduction policies.

28. In this application there is no specific energy transition issue to be addressed by the Board in the setting of 2024 rates. With respect to EGI's "safe bets" proposals on the matter these are largely exploratory research or pilot projects. Provided their costs are minimal VECC takes no issue with them as they demonstrate a measured approach to uncertainty. In this regard we note that the issue of the Energy Transition Technology Fund (Issue 52) is to be dealt with in Phase 2 of this proceeding.

29. Energy transition only impacts this proceeding to the extent it influences the decision on a number of 2024 rate making issues. In our view the major issues the Board has to consider in light of energy transition are:

- Customer Connection policies
- Forecast Capital Expenditures
- Depreciation rates
- Deemed capital structure

We make our specific submissions on these issues individually below.

Non identified Issue - application of the revenue horizon parameter established in E.B.O. 188 continues to be appropriate in light of energy transition

30. We call this a "non-identified" issue because it was not included in the Board's issue list contained in Procedural Order of January 27, 2023. As far as we can gather no party made a submission with respect to the draft issues list to include the matter of reviewing customer connection policies. The matter only came to light in Procedural Order No. 6, issued on June 6, 2023. Changes to the E.B.O. 188 customer attachment model revenue horizon might have consequence for capital budgets, operating costs, and at the extreme the risk profile of the Utility (cost of capital) so we are not sure where it fits in the issues list.

31. We do not support changing the revenue horizon for a number of reasons including:
    - There has been insufficient notice.
    - There is a lack of comprehensive evidence and examination of that evidence including consideration of alternative proposals.
    - The proposal to change a single aspect of E.B.O. 188 is selective and does not examine alternatives to the address the reason for changing the revenue horizon.
    - The given reason for making the change – the ultimate demise of natural gas as a viable energy source is entirely speculative.
    - The process for making the change is deficient and in contravention of the *OEB Act* which requires the change to be made by way of its rule making authority.

32. The Board is certainly within its prerogative to explore issues of interest. However, the late identification of the matter raises a few problems. The first is that the Applicant has not led any direct evidence of the matter and so there is no specific proposal to which parties can respond. The second is that the issue itself is vague. This had led to a broad range of discussions around the issue of customer connection policies. Both of these problems add to the overriding issue of whether proper notice has been given.

This matter was raised by the Presiding Commissioner where this exchange took place:[10]

MR. STEVENS: I think from the Enbridge Gas perspective there was no contemplation within any of the evidence within any of the proposals that feasibility guidelines or connection rules would change. That is something that to my knowledge came up a little bit within some questions that were asked, but really the only party who has put forward evidence is Mr. Neme. And there is no sort of record to talk about alternatives or to talk about economic theory as to why different approaches should proceed, and that may well contribute to the fact that other people, whether it is developers, whether it is the Ontario government, interested parties, why they didn't feel it necessary to be part of this process at the moment. I can't speak for them. But I would say, had somebody contacted Enbridge Gas at the time that the notice was put out and said, you know, are there going to be different rules for customer attachments, the Enbridge Gas response would be, well, we haven't proposed anything different.

MR. MORAN: Right. And would you have updated your advice to them in light of Procedural Order No. 6?

33. Ultimately EGI took the position that it would not argue that notice was insufficient despite the fact that it also thought the issue might be of interest to municipalities and developers.[11] We think Enbridge is being too polite. It is clear to us that there is a potential notice issue and depending on the breadth of the decision the Board considers making. The issue of whether customers, including developers, should pay additional amounts is rather fundamental to the issue of rate making and ratepayers interests. We do not see how it is possible that a party having reviewed the original application, the application notice or even the first order setting out the relevant issues would now be aware of the potential financial consequence of this issue to them. It belies belief that those parties would continue to follow the proceeding after promulgation of an issues list to find buried in the 6th procedural order of the case an issue of interest. We would also add that one's opinion as to whether parties as significant as municipalities and developers, would or would not have intervened had they known of the matter is simply speculation. The purpose of notice is to find that out. We submit there is a notice issue the Board needs to consider in reviewing "this" issue.

34. The second problem we find is the vagueness of the issue- what exactly is "this" issue? Is it revenue horizon or is the Board grappling with the idea that the natural gas system is going to collapse in less than 40 years? Procedural Order No. 6 raises a specific question: is the application of the revenue horizon parameter established in E.B.O. 188 appropriate in light of energy transition? However, the breadth of examination during the

[10] Transcript Volume 3, July 17, 2023 pages 211-21
[11] Transcript Volume 4, July 18, 2023, pages 1-2

hearing went well beyond that singular point. This is perhaps inevitable since if one is changing E.B.O. 188 on the premise of more effective economic outcomes or minimizing the risk of stranded assets then many aspects of the policy need to be examined. Most notably the question as to whether or not the "portfolio" approach embedded in E.B.O. 188 addresses the issue of subsidization sufficiently. Another is whether the customer attachment policy is correct in light of changing the revenue horizon. There are other aspects of the revenue forecast that impact the cost-benefit analysis of the project. For example, it has come to our attention in recent proceedings[12] that the volume forecast associated with some expansion projects are likely overestimated due to the application of system wide consumption averages which are not necessarily representative of the consumption patterns of the various types of newly attached customers.

35. In addition to the host of question that changing one aspect of the policy raise there are other potential changes on the horizon that may affect the current customer attachment economic modelling. Most notable of these is EGI's proposed change to a "fixed/variable" rate design. Given the movement from reliance on volume based revenues to customer attachment based revenue how might that alter the policy? When will the Board examine this question? If it is prudent to examine the impact of that change (if approved) why isn't it best to do so in conjunction with a review of the revenue horizon?

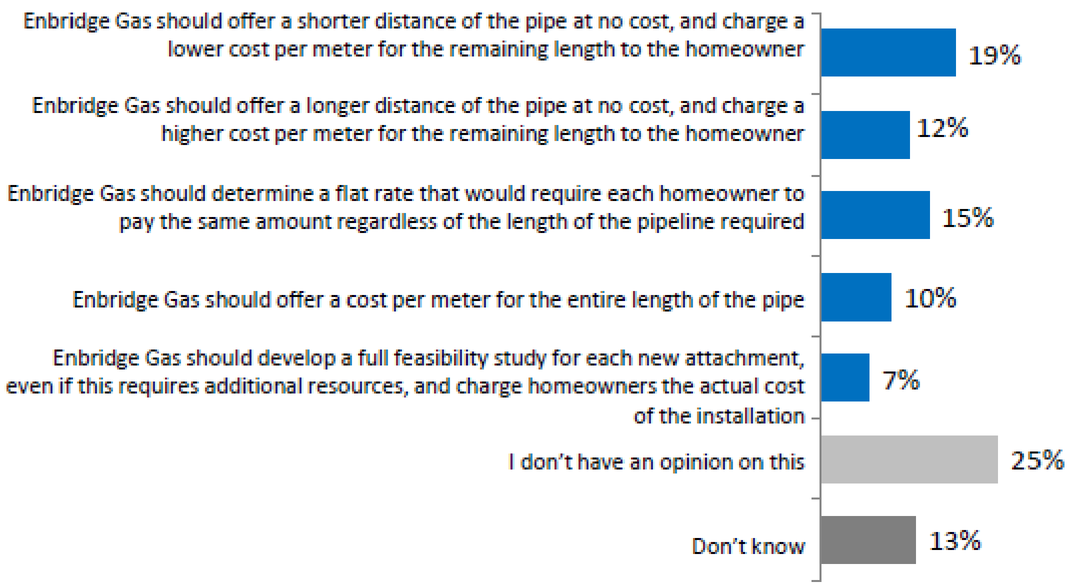
36. Even if this panel of the Board is inclined to make a singular change it must consider the reason for doing so. The apparent reason is that some say there will be no natural gas in 40 years. The only thing we are certain of is that there will be change in 40 years and a large number of those speculating in today's proceeding will not be around to see it. Yet suppose one agrees - the gas world is heading for an inevitable collapse. What is the magic in 20 years? Why not in 10 years or 35 or something else? In any event why is changing the revenue horizon the best way to address the "death of gas" issue? Would it not be better to raise the required PI for any project included in the portfolios? It seems to us that doing so would have a similar effect as lowering the revenue horizon. The difference being that in raising the revenue horizon customers are forced to pay more costs if they want service. Perhaps the result is to lower the number of attachments. Or it may be that through contributions (CIAC) customers just pay more money to the Utility. Perhaps not a problem for the well off – but certainly one for the consumers VECC represents. On the other hand, raising the portfolio PI requirement would have the effect of lowering the number of projects undertaken. At first glance that seems fairer. Moreover, if the objective is reducing customers attaching the portfolio approach may be more likely to achieve the desired result. And since PIs inevitably improve under shorter payback periods it would appear to achieve the same benefit as

[12] See EPCOR Southern Bruce CVVA Application, EB-2022-0184

raising the revenue horizon. Is the Panel certain that changing portfolio PI's is not a better or more fair policy to address stranded asset risk[13]?

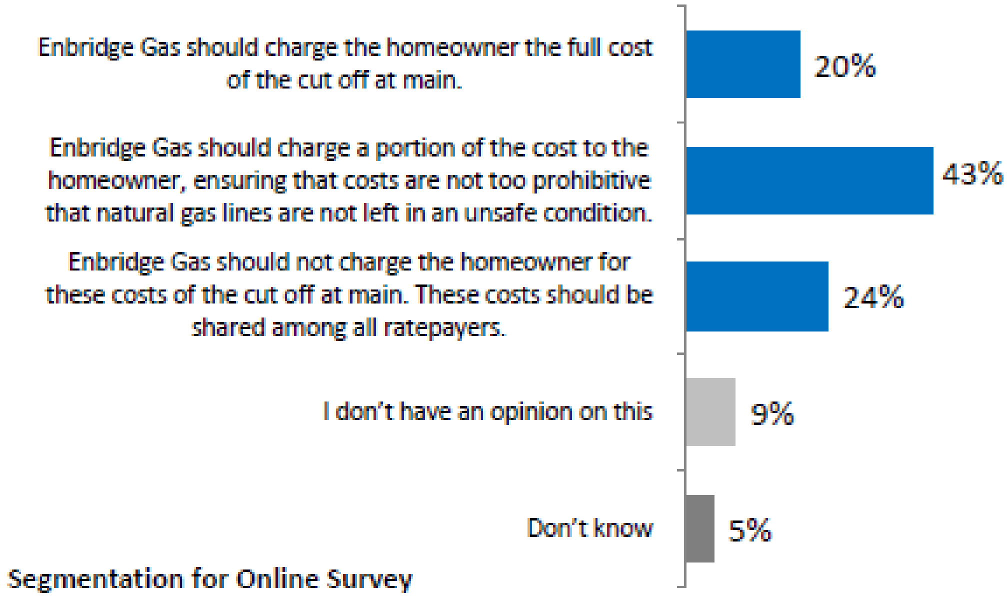
37. Since no evidence on this issue was by the Applicant the matter was not well explored in this proceeding. As such there are no answers to our questions. There is however much speculation and intervenor "evidence" given under the guise of cross-examination as well as lots of claims as to what is "obvious." E.B.O. 188 was years in the making. Changing one aspect of the policy while ignoring all others in light of no evidence and based on two days of hearings is, in our view, an invitation to unintended consequence and unfair results.

38. We would also point out that very little attention was paid to what customer actually think about the matter. Since the matter of extending the revenue horizon was not on EGI's radar it is unsurprising no direct questions on the matter were asked but some related ones were as shown below[14].



[13] In looking at portfolios the Board might wish to examine why community expansions are not in the investment portfolio or why the rolling portfolio does not include infill customers – see Transcript Volume 11, July 31, 2023, pages 38-

[14] Exhibit 1, Tab 6, Schedule 1, Attachment 1



39. What we take from these responses that consumers have no overwhelming interest in raising the cost of connection. Whether they think making major changes to the cost of how they connect to the Utility or that an "exit" fee should charged if they quit their service is unknown. They were not asked because EGI was not proposing such changes. One is left to ask – if the Board is interested in customer feedback on utility capital plans why would they not be interested in hearing what customers think about major changes to how they access the service?

40. In sum it is not that VECC position that there should be no changes to the policies of E.B.O. 188. In fact, quite the opposite. We think the policy needs a total refresh based on changing circumstances (included heightened stranded asset risk due to energy transition) and the number of innovations such the SES and other Community Expansion policies which arguably also should be included in the Board's Distribution Access System Rule (GDAR).

41. Our final point is on the issue of process. Creating a new maximum revenue horizon would be a change to the policies of E.B.O. 188. E.B.O 188 is incorporated into GDAR by reference and the current rule provides the Utility flexibility up to 40 years. The suggested changes would take away some of that flexibility which makes the proposal a rule change.

42. The reason for E.BO. 188 policies being incorporated by reference in the GDAR is that their existence pre-dates the changes to legislation in the late 1990's that gave the Board new powers to regulate the electricity distribution sector (a task formerly done by the then Ontario Hydro). Those changes included rule making powers under Section 44 of the Act which substantively mimic the code making powers given under the licensing framework of the electricity sector.

43. Codes and rules allow the Board to set policies which have unique characteristics. First, they bind all utilities to whom they apply to. This is especially important in the electricity sector where there are a large number of distribution utilities. It is less so the case in natural gas, especially post amalgamation, but it remains the case that the promulgated rules apply to more utilities than just EGI.

44. The second important difference is that codes and rules are binding on subsequent panels of the Board. The same is not true of a particular Board decision. Good regulators (like the OEB) do strive for consistency and certainty. But Board decision also often show an evolution of thinking or different assessments made by different commissioners (members) and that occur over time and as understanding evolves.

45. Finally, the process for establishing and modifying codes and rules is different than for a Board Decision. Recently the *OEB Act* was changed to give the authority to make rules to the Board's Chief Executive Officer – though we think nothing precludes that Office from utilizing Board Commissioners in processes that assist in making those decisions. The rule making process also has its own notice provisions (Section 45(2)) and that process includes an opportunity for parties to comment (Section 45(3

46. In our submission the most this Board panel may do is make a recommendation to the Chief Executive Officer to make a change to the GDAR. If accepted that would trigger the processes under which rule making must take place. We think this Panel of the Board should not make that recommendation, but rather, as we discuss later, recommend that the GDAR undergo a comprehensive review in light of energy transition.

47. EGI has proposed modest changes to its policies for the simple objective of harmonizing the practices of the former utilities with respect to customer connections. These are[15]:

- CIAC allocation and collection policies not previously included in the policy;
- Extending the extended the refund policy to all applicable customers to be consistent with the proposal to harmonize the EGD and Union rate zones into one rate zone.
- Some minor adjustments to the polices to better align;
- Expansion of the qualification time for a customer to request a CIAC refund from 5 to 10 years to match with the attachment horizon as prescribed in E.B.O. 188.
- A proposal that that residential infill customers be provided with the first 20 metres of service at no cost;
- A change to the current street service alteration charge to an extra length charge (ELC) from \$32 or \$45 per additional meter as is currently approved for the EGD and Union rate zones to a uniform charge of \$122 per additional meter.

[15] Exhibit 1, Tab 15, Schedule 1, page 2 and Exhibit 8, Tab 3, Schedule 1, page 11

48. All of the proposed changes are modest harmonization proposal. The extra length charge is not and is a three fold increase over the previous charge. In our submission, pending a full review of customer attachment policies the ELC charge should be set at $45 with an $55 increment added to account for inflation since its last review or a charge of $100 per additional meter.

RATE BASE

Issue 6 and 7 – 2024 capital additions

49. The issues to be resolved for 2024 rates are (1) the inclusion or not of amalgamation integration costs, (2) 2023 additions to 2024 opening rate base; (3) 2024 rate base additions. The ancillary issue is if and how any decrease in rate base should impact the settled amount of OM&A.

Integration Capital

50. EGI proposes to include $119 million of integration capital in its 2024 rate base. VECC opposes this proposal. Integration projects are just that – invested in for the purpose of integrating the systems of the former Enbridge and Union utilities. EGI's argument for their inclusion rests on two premises. The first is, in the colloquial, "these investments would have been made in any event." The second is that the Board's decision to grant a five year deferral period rather than the 10 years sought prejudiced EGI's ability to recoup its amalgamation investments.[16]

51. EGI's integration capital are largely information technology investments. VECC takes no issue as to their being used or useful. The issue is whether they are properly assigned to the cost of amalgamation and therefore not to be recovered by ratepayers. EGI spends much of its argument focusing on amalgamation savings and costs. These are no more relevant to the matter of deciding the issue than had EGI failed to delivery any savings. The issue is only whether ratepayers should pay for the cost of capital projects related to integration. Whether they received a benefit or not is beside the point. In any event, as outlined above we hold the savings to customers are significantly less that the $86 million claimed.

[16] EGI Argument-in-Chief, August 18, 2023, pages 80-82

52. We also do not think relevant EGI's argument that a decision to exclude integration costs would have "*a chilling impact of future amalgamations*.[17] From our experience in the electricity sector avoidance of consolidating utilities is arguably in the best interest of ratepayers. Again, the issue of what affect if any the Board's decision has on other utilities is irrelevant to the question as to whether ratepayers are justifiable charged for integration projects.

53. We are also not in support of the Board Staff's proposal which attempts to modify the MAADs policy by using the approved rate deferral period (5 years rather than 10) to prorate the cost of integration capital. The matter is one of principal - are integration costs to be recovered by ratepayers?

54. It is important to note that the MAADs decision explicitly recognized EGI's submission that a ten year deferred rebasing period was necessary to allow it to integrate and have sufficient time to make the capital and system investments necessary to generate integration synergies.[18] Notwithstanding that understanding the MAADs decision did not carve out an exception to the policy that integration or consolidation costs are not recoverable from ratepayers. In fact, the Decision reads: "*The OEB finds that five years provides a reasonable opportunity for the applicants to recover their transition costs*."

55. In our submission, granting the Utility's proposal would be contrary to the MAADs decision. The Board was at the time aware of the possibility that all integration costs might not be recouped in the 5 year period. In that Decision it made explicit that it heard the Applicant's plea. Nonetheless it found that five years would be a reasonable amount of time. Arguably this was to provide EGI the incentive to complete its work in as quick and efficient manner as possible.

56. To now provide for full recovery of those costs ignores the MAADs decision and nullifies its intent. It surely cannot be the Board's intent to reverse itself now with the benefit of hindsight.

57. It is important that the Board consider that integration costs will continue to be incurred post 2024. These include the GTA West and East facilities project as well as all the costs that will go to implementing a harmonized rate system. As it stands these post 2024 projects will ultimately form part of the recoverable rate base of the Utility. It would be reasonable for the Board at the appropriate time to exclude these capital investments from recovery in rates. While that determination will necessarily be made at a later time it is also quite possible EGI will be allowed recovery under the ambit of "business as usual" of an amalgamated entity. We make the point here only to remind the Board that

[17] Enbridge Argument-in-Chief, August 18, 2023, page 88
[18] Decision and Order, EB-2017-0306/307, August 30, 2018page 6

a disallowance of the integration capital costs in this proceeding does not mean that EGI may not ultimately recover some integration costs contrary to a strict reading of the MAADs policy.

2024 Capital Additions

58. The first thing to note about EGI's capital additions proposals is the extraordinary level of increase since 2013. If energy transition has had any impact since the signing of the Paris Climate Accord (2016) it is certainly not discernable from a review of investments in Ontario's natural gas infrastructure over recent years. In fact, quite the opposite is true. In the period from 2013 to 2018 total capital expenditures were $1.232 billion. In the period from 2019 to 2023 they rose to an average of $1.247 billion. In the 2024 to 2028 period they will continue to rise to $1.435 billion.[19] In fact the future amounts are even higher as they exclude the Panhandle Regional Expansion Project (PREP).

59. The increase in proposed capital expenditures in 2024 is in the range of 50% as compared to that in 2018 and 2019 - the years before and after amalgamation. On its own accord this is an extraordinary increase in the spending. In light of the conservative approach, one might expect in EGI's investments plans give the discussions around GHG emission reductions the increase calls into question the prudence of EGI's investment plan.

60. In fact, EGI incorporates little change over the plan in light of energy transition as shown in the table below[20]:

Table 1
2024-2028 Customer Connections Capital Requirements
with and without Energy Transition

	2024	2025	2026	2027	2028	Total	
Required Capital without Energy Transition	238,675,320	238,545,114	239,078,774	239,387,911	235,132,110	1,190,819,229	/u
Required Capital with Energy Transition	236,832,600	234,769,423	233,697,979	234,745,169	230,502,934	1,170,548,105	/u
Total Additional Capital Reflected in AMP	1,842,720	3,775,691	5,380,795	4,642,742	4,629,176	20,271,124	/u

61. In line with our observations about the state of knowledge of what energy transition will actually mean to future of natural gas in Ontario, we are not surprised with their assessment. What is of surprise is that EGI has done very little to study the prudence of particularly large long-term investments.

[19] Exhibit 1.2.5-SEC-107
[20] I.2.6-Staff-72

62. We also observe that EGI's overall cost of connecting customers is increasing rapidly. Between 2014 and 2018 the combined utilities added 264,409 customers at a cost of $790.3 million. Between 2019 and 2024 EGI has added, or is forecasts to add, 256,214 customers at a cost of $1,326.8 million.[21] Meaning the average connection costs has increased from just under $3,000 per customer to around $5,200 per customer. This is significantly more of an increase than one would expect from inflation alone. The customer cost related investment increase over this period is even higher if one includes the customer related Utilization investments.[22]

63. Likewise, we would direct the Board's attention to similar large increases since post amalgamation in the areas of Distribution Pipe, Fleet and Equipment, Real Estate and Workplace Services. Addressing the concern of this high spending Board Staff have laid out detailed and articulate arguments for a reduction of $271.5 million. We do not disagree with their overall assessment and proposed reductions. From our standpoint it is difficult to be concise as to where large capital budgets should be trimmed in pursuit of a more reasonable capital program. If the Board simply recognized that the cost of adding customers (connection and utilization capital) should be kept in line with inflation the reductions in 2024 capital might well exceed Staff's recommendation.

64. An alternative approach to making a reasonable reduction to the 2024 capital budget/additions is to consider past spending. In the 2019 to 2022 period EGI's average additions were $1,186.3 million. The rate plan annual spending is significantly more than that averaging closer to $1,468 million.[23]

65. We also agree with EGI's caution that adjustments to 2024 capital expenditure might have the counter intuitive result of increasing revenue requirement or at least not lowering it as much as one might expect. We have noted this phenomenon in a number of electricity distribution cost of service proceedings. Our observation is that in the absence of specific direction a utility is inclined to make any required reductions (at least notionally for the purpose of the rate calculation) to those areas which have very high depreciation/CCA allowance tax implications. Generally, this applies to information technology (TIS) area of investment. We note that EGI's Technology Information Services investment for 2024 to 2026 are at historically high levels. Should the Board accept the various arguments for a reduction to 2024 capital investments they should be clear to EGI where the expected reductions are to be made. For example, it might use some form of Board Staff's specific proposal or instruct EGI to make a prorated reduction to all or subsets of the capital expenditures by asset class. Clarity in this rate

[21] Exhibit 3, Tab 2, Schedule 6, Attachment 1 (additions) / Exhibit I.2.5-SEC-107 (connection costs)
[22] Utilization include "*meter purchases, the Meter Exchange Government Inspection (MXGI) Program, and regulators. Expenditures are driven by the demand for new meters related to the customer additions, the replacement of meters (MXGI) and regulator refits*." : Exhibit 2, Tab 5, Schedule 2, page 9
[23] Exhibit I.2.5-SEC-108 and as calculated in Exhibit K11.2 SEC_EGI_Capital_AMP_Compendium.

making exercise does not preclude EGI from spending its capital budget where it feels it is best served (though we note they will later be subject to scrutiny for those decisions).

66. While we understand EGI's cautious approach to energy transition's impact on capital expenditures we observe that if the Board is inclined to substantively factor that issue into other areas (e.g., depreciation and capital structure) then it would be inconsistent not to make a related reduction to the capital/in-service dollars for 2024. At a minimum the Board might caution EGI that rate recovery of no longer used and useful assets is premised on those investment assets having been prudent in the first instance. In our view it might later be seen as questionable for EGI to be embarking on historically high levels of investment in the face of its current uncertain future.

Issue 8 – Indirect Overhead Capitalization

67. EGI frames the issue of overhead capitalization as one of harmonizing the practice of the two former utilities. However, the harmonized methodology does not produce dissimilar results to the historical ones.[24] In our view there are two important issues with respect to indirect overhead capitalization policies of EGI. The first is whether its practices are consistent with either the results of those utilities using (M)IFRS standards or other utilities in Ontario reporting under USGAAP. The second is whether it is appropriate the assign indirect capitalization post cost of service to any subsequent ICM (or ACM) projects.

68. With respect to the issue of whether EGI should follow the practice laid out in IFRS accounting standards we agree with Board Staff – they should. First because nothing precludes a Canadian utility reporting under USGAAP from adopting the IFRS standard. Second, we submit EGI's practice is an exception to that of other regulated utilities in Ontario and not just those adopting (M)IFRS. Hydro One, an electric utility that similar to EGI report on the basis of USGAAP, differentiates itself from utilities like EGI by noting that its higher overhead capitalization in comparison to other electricity distributors is related to the higher amount of capital work that is done by internal labour (as opposed to EGI which outsources large parts of its capital program).[25] We also note that while EGI's overhead capitalization rates are in around 23% range [26] those of Hydro One are in the range of 8-9%.[27]

[24] See Exhibit 2, Tab 4, Schedule 2
[25] See for example, Hydro One EB-2021-0110, Exhibit I, Tab 2, Schedule C-Staff-182
[26] Exhibit 2, Tab 4, Schedule 2, page 17
[27] See Hydro One EB-2021-0110 Exhibit C, Tab 8, Schedule 2, page 5:

Table 1 - Overhead Capitalization Rates and Amounts for Transmission and Distribution

Overhead Cost Category	Test Years (%)					Test Years ($M)				
	2023	2024	2025	2026	2027	2023	2024	2025	2026	2027

69. As we explored at the hearing it is incumbent on EGI to determine whether the results of its overhead capitalization policy produce reasonable results. This is especially true if the results fall far outside the norm of other utilities regulated by the Board. Yet EGI has not done this and the report the produced was not an expert independent study undertaken with the objective of comparing and understanding the differences in the capitalization rates of EGI as compared to other utilities.[28] We support the suggestion made in the questions of Commissioner Elsayed that benchmarking EGI's capitalization rates to that of other utilities would be beneficial.

70. Moreover, if the Board is concerned as to what it might do to address energy transition in natural gas regulation, then we suggest it take a closer look at the issue of overhead capitalization. It is clear that it is well within the Board's authority to establish different capitalization policies irrespective of whether the utility reports under USGAAP or (M)IFRS.[29] Our hypothesis is that if such an exercise were undertaken it would find that EGI capitalizes much higher amount of labour costs than any other Ontario utility. [30]

71. The result of capitalization is to defer current costs for future recovery. For the purpose of rate calculations returns of the utility are derived exclusively from the return on invested capital. The more capital – the more return, that is the benefit to shareholders. The benefit to ratepayers is that higher capitalization makes more affordable the services of the utility by amortizing certain costs rather than expensing them. The result is to make services more affordable albeit at a higher total eventual cost to ratepayers. If the Board were inclined to create incentives for customers to consider alternative sources of energy (or more efficiently use natural gas) it might find that EGI's current capitalization policy has the effect of encouraging higher natural gas use by making it more affordable in term. VECC generally favours proposals that make service more affordable. Yet we are also aware of how capitalizing costs has intergenerational impacts. The price of affordability is that consumers ultimately pay more than they would otherwise as compared to if the costs were expensed.

72. Our submission is that while the Board might approve EGI's harmonized capitalization practices and the capitalization amount of $292 million for this rate plan the policy should be revisited as part of a comprehensive program renew natural gas regulation in light of energy transition pressures. In that review EGI should be required to make a comparison of its policy to those of other Ontario utilities. The information needed for that exercise is already on the public record as part of numerous cost of service filings.

Transmission	8.0%	8.0%	9.0%	9.0%	9.0%	118.1	119.7	121.0	122.3	123.9
Distribution	9.0%	9.0%	9.0%	9.0%	9.0%	89.9	91.0	94.9	94.2	95.7

[28] See Transcript Volume 16, VECC examination pages 14-21
[29] Board Staff's extensive cross-examination on this point at Transcript Vol. 16 pages 22-41
[30] The exception being perhaps Ontario Power Generation which functions and is regulated in an entirely different manner than a distribution utility.

73. The other issue we ask the Board to consider is whether it is appropriate that EGI should include capitalized overheads in projects for which it receives rate rider interim recovery as would the case in an ICM or pending LTC project. Consider EGI's position that should the Board reduce the 2024 capital budget there would no associated decrement in overheads. Or its position that should the Board directly reduce the inclusion of $292 million in overhead then there would need to be a full offset in an increase in OM&A costs[31]. In essence what happens is that at the time of cost of service rate setting proceeding a given amount of overheads (direct and indirect) are incorporated into rates. If there are no ICM or other rate rider recovered capital projects during the rate period that amount of overhead cost continues to be recovered in rates. The notional amount of overhead recovery would in fact increase in line with the annual rate adjustment approved as part a rate plan. This remains the same whether EGI invests in more or less actual capital during the rate plan.

74. The only time this would change is if the Utility has an ICM or LTC project approved and seeks to recover incremental amounts through a rate rider. In that case it would be EGI's policy to incorporate incremental amounts of indirect overhead costs. This would be the case even if there were no actual increase to the pool of costs from which indirect overheads are drawn. In fact, the total eligible pool of costs might have decreased since the time they were reviewed to incorporate indirect overheads into cost of service rates. Furthermore, the methodology employed by EGI is based on historical data meaning that an ICM/LTC's overhead allocation is not based on that actual project but rather the practice for projects in past periods.

75. Whether the potential for double counting costs or allowing incremental operating costs to seep back into incentive rates is a question worth examining. We acknowledge this is not an issue particular to EGI. However, if EGI is an outlier in the level of indirect overheads it is allowed to recover then any flaw in the policy to allow indirect overhead recovery in ICM/LTC projects is more pronounced.

76. In our view the issue of the appropriate way to address indirect overhead allocations in ICM or LTC projects could be included in the study we recommend be undertaken to benchmark and do a detailed review of EGI's overhead capitalization policies.

Impact on OM&A

77. The settlement agreement leaves open how reductions of the 2024 capital budget or removal of the proposed integration capital would affect gross OM&A through an adjustment to overhead capitalization. In our submission it would be wrong for the Board to allow EGI to simply shift the result of its decision from on basket to another. To

[31] Enbridge Argument-in-Chief, August 18, 2023, pages 120-121

make such an adjustment would be to accept that there is no relationship between overhead capitalization and capital activity. This may indeed be the case with EGI but it should not be. Accepting the premise would be to accept that a given amount of dollars is spent on capital activity irrespective of what activity occurs. If the Board accepts that then it follows it must accept our argument that no subsequent overhead should be assigned to project after the initial cost of service rates are established.

Issue 15 – Depreciation Expense

78. VECC supports most of the recommendations of Board Staff's sponsored depreciation experts from Intergroup Consultants (Mr. Bowman and Mr. Mahmudov) We note that Intergroup's report is largely in agreement with that of EMRYDIA (Mr. Madsen) sponsored by IGUA.[32] Both Staff and IGUA have made detailed submissions on this issue therefore, in the interest of brevity, we will provide only a summary of ours.

ALG or ELG

79. Both experts agree that EGI should maintain the Average Life Group (ALG) methodology. We also do not think moving to ELG is warranted. There is a significant increase in depreciation costs under the ELG methodology as shown in the table below:[33]

Table 1

Depreciation Method Comparison

Depreciation Method ($ millions)	2024	2025	2026
ALG	810.7	856.6	905.6
ELG	892.4	961.5	1,014.8

[32] Exhibits M1 and M5 respectively.

[33] Exhibit I.4.4-OGVG-6 where EGI also notes: *"Both the ELG and ALG estimates for 2025 and 2026 do not reflect the corrections from March 8, 2023 and are overstated by approximately $30 million each year, respectively*". We note Board Staff in their argument uses a figure of 899.6 as the impact of the application of ELG as proposed by EGI.

80. This table shows the magnitude of the impact for just the first 3 years of the plan (in the interrogatory response EGI said they were unable to project further that 2026). For 2024 these amounts were subsequently changed to reflect capital updates and the result is that the difference in methodologies amounts to $83.4 million or 45% of the entire 2024 deficiency of $186.3 million.[34]

Table 1
Updated IGUA Chart Reflecting Capital Update

	($ millions)	Source	Cumulative Impact Revised Depreciation	Cumulative Revenue Requirement Impact
EGI Proposed 2024 Depreciation Provision	879.0	J17.9		
2024 Depreciation Provision at Current Rates	737.1	J17.9		
Proposed vs Current Provision	141.9	Calculated		
Impact of Replacing ELG with ALG	(83.4)		795.6	1,082.4
Impact of Emrydia + Intergroup Average Life Estimate Changes (Using ELG)	(233.7)	J17.9, calculated	561.9	764.5
Impact on Discounted Net Salvage @ 6.03% vs. 3.75%	(62.4)	J17.9, calculated	499.5	679.6

81. EGI's expert -Concentric -holds that ELG has two significant advantages as compared to the use of the ALG procedure.

"*Overall, Concentric views that the use of the ELG procedure for this EGI study has two significant advantages as compared to the use of the ALG procedure. Firstly, the use of the ELG procedure was the best available match to the historic procedures approved for Union Gas. Secondly, given the potential changes in use of fossil fuels and the unknown impact of such change on the Enbridge Gas system, the use of the ELG procedure best reduced the future risk of intergenerational inequity*."[35]

82. While Concentric made the above statement in response to an interrogatory and made other statements during hearing testimony with respect to the interplay survivor curves and energy transition, the original evidence makes no explicit or rigorous connection between the depreciation policy and uncertainty of asset recovery due to energy transition. In any event it would be wrong, as we argue above, to make changes to depreciation methodologies based on speculation as to how GHG reduction policies might ultimately affect EGI asset lives.

83. Concentric's second reason to move to ELG is that it best matches the historic procedure used by Union Gas. This of course ignores the fact that the larger of the two former utilities, Enbridge Gas Distribution, used ALG. It also ignores the fact that Union

[34] Undertaking J16.7
[35] I.4.5-Staff-173

never used ELG but rather something called “generational arrangement” and while Concentric posits that “generational arrangement” is more closely associated with ELG than ALG there is little actual evidence that is true.

84. To us the entire reason EGI is proposing a change to ELG is to accelerate the recovery of its investment costs. It does so under the guise of energy transition and even though they claim in other places, like capital budgeting, no change is necessary. In considering the question of changes to depreciation methodologies we think the Board might consider these points made by the National Association of Regulatory Commissioners (NARUC) in their depreciation primer:[36]

In particular, the Accelerated Method of depreciation, by allowing greater depreciation expenses in the early years of the life of an asset, reduces the risks of investment recovery that are associated with a longer period. Greater flexibility in the recognition of investment costs and of associated depreciation expenses can lead to smoother tariffs at times when other cost elements, such as the cost of capital, are low.

On the other hand, Accelerated depreciation methods create instability in tariffs, as the cost of depreciation and thus prices would tend to be higher in the early years of the asset's life and decrease in the long term as the asset ages. Moreover, as depreciation is one of the main building blocks of Allowed Revenue, the Accelerated Method may remove an asset owner's incentive to continue to use the asset once it is fully depreciated.

Once the asset is fully depreciated, the utility only earns revenue from associated operational expenses as neither depreciation nor return on the asset apply. In such a case, the utility may not have an incentive to properly maintain assets and may aim to replace the depreciated assets even if it remains fully functional

<u>Survivor Curves and Service Lives</u>

85. With respect to issues of Survivor Curves and Services lives we endorse the recommendations of InterGroup. However, with respect to Survivor Curves in particular, we believe that professional judgement so prevails that the Board might adopt any (or any combination, recommended by the three experts in this proceeding. As a matter of consistency we believe the best practice is set out in InterGroup's evidence.

<u>Net Salvage Constant Dollar Net Salvage</u>

86. CDNS is a continuation of the practice of Enbridge Gas Distribution. What parties do not agree on is whether the method is being properly calculated. Mr. Bowman and Mr.

[36] DEPRECIATION EXPENSE: A PRIMER FOR UTILITY REGULATORS, NARUC Publication for USAID., May 2021 https://www.naruc.org/international/news/tariff-toolkit-depreciation-expense-a-primer-for-utility-regulators/

Madsen both concur that it is not and that EGI double counts inflation. Concentric's expert, Mr. Kennedy disagrees. The issue of whether Concentric's model is faulty also impacts the disagreement of the experts have as to the appropriate discount rate to be used.

87. Having read and listened to the testimony we tend to favour the opinion of Mr. Brown – his explanations are articulate and from what we can gather unrefuted in detail. In their response EGI simply argues that the results are those they are seeking - the recovery of sufficient funds to cover both annual site removal costs and add to the accrual balance for future use. To which we think Mr. Brown is making the point that EGI's desired result is achieved, at least in part, because they are making two offsetting errors – double counting inflation and using the wrong discount rate.

88. With respect to the discount rate, it would seem intuitive for there to be a relationship to the chosen discount rate and the cost of financing rate base. Concentric's objection to using a weighted average cost of debt is that it "….*is derived from historical debt issuances that may not be the best representation of a company's current risk profile and the future cost of debt. The CARF was determined to be the most appropriate rate to use in the CDNS calculations. Enbridge Gas's CARF is calculated as the forecasted 30-year Government of Canada bond rate plus Enbridge Gas's credit spread*.[37]" There is no evidence which shows why the spread between government bonds and Enbridge Gas's credit spread, which is also based on historical debt issuances, is to be preferred. CARF[38]

Concentric did not consider that a WACD would be appropriate for the CDNS calculations as the rate is derived from historical debt issuances that may not be the best representation of a company's current risk profile and the future cost of debt. (I.4.5-Staff-168)

89. EGI is wrong to say "*there was some confusion expressed by Messrs. Bowman and Madsen about how the CDNS method should mathematically be calculated*."[39] We do not think either of the two experts were confused, though we think EGI's expert may be. Further we do not think EGI has clearly refuted the InterGroup objections[40]:

- *While the Net Salvage requirement in column H of Exhibit I.4.5-IGUA-14 Attachment 1 is accurate, it is already in dollars-of-the-day for when the retirement will occur in the future*.

Is that true or not?

[37] Exhibit I.4.5-Staff-168
[38] See Exhibit I.4.5-IGUA 10 in which only one other example of its use could be shown.
[39] Enbridge Argument-In-Chief, August 18, 2023, page 188
[40] Exhibit M1, page 9

- *It is not necessary to further inflate these dollar values before discounting them to the current day, as* [sic] *is part of the Concentric calculations*.

  Is that true or not and if not explain why is this point incorrect?

- Concentric also applies an equal CDNS net salvage percentage to each vintage, which is not correct. The accruals rate for old vintages under CDNS are by definition higher than for earlier vintages.

  Does Concentric apply equal percentages to each vintage?

  Does Concentric disagree that the accruals rate for old vintages are higher than for earlier vintages?

Clear answers to these questions might help the Board in its determination of this issue.

90. If, this is just a "math problem" as EGI seems to believe, it should be easy to clear it up. We also agree with Mr. Brown that it would be incorrect to apply a higher discount rate to an error prone model. If it cannot be determined with clarity whether the model contains the argued error then the prudent thing to do is to order EGI to propose an alternative methodology. As it stands CDNS is not used anywhere else in Canada or the United States and in the words of Mr. Kennedy of Concentric "*due to the complexity of the calculations*.[41]

Issue 16 – Segregated Fund for Site Restoration Costs

91. EGI is not a proponent of a segregated fund for site restoration costs. Neither are we. There is no precedent for such a fund for site restoration funds outside of the nuclear energy industry.

92. The Board ordered in EB-2012-0459 the investigation of a segregated fund in its decision to allow Enbridge Gas Distribution CDNS (it was using the Traditional Method). Given what now appear to be significant disputes about the mathematical integrity of the application of CDNS perhaps the 2014 panel had a premonition for a need for an alternative?

93. In any event we do not see a segregated fund as an alternative to CDNS (or a modified traditional method). The Board may wish to return to the issue of a segregated fund if "energy transition" appears to be leading to massive disruption of the natural gas system.

[41] Transcript Volume 16, pages 172.

COST OF CAPITAL

Issue 20 Capital Structure

94. Enbridge's proposal is to increase its equity thickness over a period of time from 36% to 42%. The first step of that would take place for 2024 where they seek an increase to 38% and subsequently increase in each following year by 1% until 2028.

95. There are two main things to be said about this proposal. It is true that EGI as compared to most other utilities has an inordinately low equity ratio. What the historical reasons for this are goes to the second issue – the inadequateness of all the evidence on this topic. If the Board were inclined to change the current ratio it would seem to us it would want to understand why it is was set low in the first place. It might also want detailed analysis using well established, accepted and rigorous models like CAPM, DCF and other methods to see how cost of capital parameters should be adjusted.

96. None of the evidence, not that of Concentric of behalf of the Applicant, London Economics International (LEI) on behalf of Board Staff, or that of Dr. Cleary on behalf of IGUA go to first principles and use the well established cost of capital estimation methodologies. Each select, or is selective, in choosing different aspects of cost of capital studies. All seem premised on the idea that financial and business risk are assigned to equity return and capital structure in some formulaic way. Yet it is not at all clear that that assignment to the different components of cost of capital is widely used or accepted outside of the OEB's jurisdiction[42]. Which means it is not clear that even if one accepts the notion EGI has a higher risk than in the past that this should result in a change in capital structure as opposed to a change in the rate of equity returns.

97. We also note that very little attention is given to countervailing risk factors. EGI is a much larger utility than the pre-amalgamation entity. That might that mitigate risk. EGI is also proposing to move to a more fully fixed rate structure providing it with greater protection against the risk of volume changes and weather (it is also proposing changes to variance accounts to do the same in the interim). While that is touched upon in the Concentric evidence very little analysis is put into understanding how changing to a fixed rate structure impacts risk.

98. The evidence of Dr. Cleary for IGUA uses largely the same techniques as that of Concentric and yet he comes to very different conclusions. Dr. Cleary recommends no change. LEI again, using very much the same techniques as the other two, recommends a compromise of 38% for the entire period of the rate plan. As so there is

[42] Transcript Volume 8,pages 134

no definitive winner and the Board might be tempted to agree with Staff and go with the LEI compromise. We do not think that is the best approach.

99. We accept that at some level the case can be made for some adjustment to capital structure simply due to EGI's being such a significant outlier as compared to almost all other Canadian utilities. But much of the argument on this issue rests on the risk impacts of "energy transition." In this regard we think the evidence of Dr. Hopkins worth considering.[43] What we find compelling in that evidence is that it carefully considers the "energy transition" issues and presents what we think is a reasonable way forward on the issue of cost of capital and on other related issues. His recommendations to the Board are that it[44]:

- *Determine that EGI's volatility/operational business risk has stayed the same or decreased since 2012 (depending in part of how the OEB decides regarding EGI's rate design and weather variance proposals).• Determine that EGI has not demonstrated that its capital-related business risk has increased.*

- *Weigh the more certain and near-term volatility/operational business risk more heavily than more uncertain and longer-term capital-related business risk when making an overall determination on business risk, and thereby conclude that EGI has not shown that its business risk is higher than it was in 2012.*

- *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.*

- *Require EGI to bring that analysis and associated plans to bear in developing its net rebasing application*.

100. We think this is a reasonable approach. We would add to it a full review of all aspects of EGI's cost of capital is warranted. In that review the Board (Staff) should engage independent cost of capital experts to revisit from first principles the methodologies that were used to establish the rate and structure in place today.

101. In the interim we do believe EGI has made the case for some change. In our view a conservative change - to 37% equity structure - is prudent as it is unlikely to be found out of keeping with other Canadian utilities.

[43] Exhibit M8

[44] Ibid, page 6

Issue 34 – NGV Program

102. VECC proposes that the Board eliminate the NVG program from its regulated rate calculations. It is not clear why this program should be included as part of a regulated utility. The former Union Gas eliminated this program prior to amalgamation (the Board might ask itself why). Now EGI wants to expand it back to those franchises.

103. The activity would seem to run counter to the goal of eliminating or reducing the number of vehicles which use carbon based fuels. We disagree with EGI that NGV's are an energy transition "safe bet". It seems to us they go to the opposite of CHG reduction. And after decades in place NGV make up a miniscule of the vehicle market and are being abandoned in favour of electric and hybrid electric vehicles. NGVs are Blackberrys in a world discovering iPhones.

104. EGI's extensive arguments to retain the NGV program within the regulated structure bring to mind Shakespeare - "*The lady doth protest too much, methinks*". EGI claims rate of return for this program in 2022 of 14.2% and estimates in 2023 and 2024 it will be 10.9% and 10.5% respectively[45]. Which causes us to ask – if this is such a successful program why does it need to reside within the regulated utility? Are EGI's shareholder adverse to making exceptional returns on a non-regulated business? They certainly do not have this aversion with respect to the natural gas storage business. Or is it, as we suspect, that upon close and independent scrutiny one would find explicit and implicit subsidies from rates paid by ratepayers to this business?

105. Like the hot water tank rental business, which the Board ordered removed from the regulated business, there is no inherent logic or reason to retain what amounts to an appliance use of natural gas within the monopoly. Board Staff's argument in support of continuation of its inclusion is based on their faith in the accounting procedures of EGI to show the fully allocated costs and the revenue of this venture. We are less sure that EGI can execute the detailed accounting that ensures the elimination of explicit and implicit subsidies in terms of the employee effort or use of regulated resources.

106. EGI also proposes certain changes to they way it contracts with customers. Is the Board prepared – or jurisdictionally entitled – to arbitrate disputes that occur within the NGV program? What is the Board's call centre script for NGV complaints – "yes we regulate this activity, but no we cannot help you – because we really don't regulate this activity?"

107. In our submission the Board must answer the question as to why NGVs should fall within the ambit of the regulated utility. The *OEB Act* does not carve out a place for

[45] See Exhibit 1, Tab 14, Schedule 2, Attachment 1

it. Nor is there evidence that private markets are incapable of filling the demand for NGV fueled vehicles. What precisely is the reason the Board finds it good policy to deregulate large amounts of natural gas storage yet at the same time finds it necessary to coddle a small NGV business within the protective walls of the regulated utility?   It certainly cannot be "energy transition" since the business long predates that issue.

108. If the Board is inclined to approve continuation of the NGV program within the regulated business then in our submission it should undertake (not have EGI undertake) a truly independent audit of this program. Without that it would be hard, we submit, for ratepayers not to suspect that they are being taken out to lunch with this program.

DEFERRAL AND VARIANCE ACCOUNTS

Issues 31-33 Deferral and Variance Accounts

VVA

109. Our two submissions with respect to deferral and variance accounts are with respect to the proposed Volume Variance Account (VVA)and the recovery of the unamortized actuarial loses booked into the Accounting Procedures Changes Deferral Account (APCDA). We submit neither should be allowed.

110. With respect to the VVA we do not think this account should be expanded in scope from the average use accounts currently used in the legacy rate zones. In EGI's words the current proposal:

> "…*supports transition to Straight Fixed Variable and Demand (SFVD) proposal. Enbridge Gas requires a mechanism that provides similar de-risking of fixed cost recovery to that resulting from the SFVD rate design for general service customers until fully implemented*."

111. The proposed VVA introduces a fundamental change to the decades-long accepted way volume and weather risk are treated. The issue as to how weather risk should, or should not, be addressed will be considered in detail in Phase 2 when the rate design proposals of EGI are examined. As such it is premature to make such a fundamental determination and for such a short term purpose. The interim solution is to maintain the scope of the current normalized average use accounts. We would not object if EGI as part of its SFVD proposal were to seek the VVA as an alternative if the SFVD is not approved. That is, we still might object, but then the discussion and analysis of regulatory treatment of weather risk is limited to one forum.

APCDA

112. EGI seeks the recovery of $155,164 million in unamortized actual loses that go to the period prior to February 2017. We submit these costs are not reasonably recovered from ratepayers. The costs and their accounting pre-date the establishment of the APCDA. As such EGI or its predecessors was required to seek Board permission to establish account to capture the amounts in question. They are not related to accounting changes that occurred as part of, and subsequent to, the amalgamation of Enbridge Gas and Union Gas therefore they are not eligible for entry into the account.

113. To us the fundamental issue is that EGI's evidence is that the MAADS amalgamation apparently triggered the push-down account which caused the amounts to be put into the APCDA. But the APCDA was established to capture post amalgamation changes. The loses relate to the pre- 2017 period in the Union franchise. The MAAD's decision was on August 30, 2018. The MAADs process occurred from the beginning of 2018 and culminated in a decision on August 30, 2018. Therefore, the issue of the recognition of the pension loses was knowable at the time of the MAADs proceeding.

114. We pursued this timing issue and all that was provided in response was[46]:

> *"So, following the merger of Enbridge and Spectra, there was no impact at the utility level. We just continued on as we were, as independent entities, and then we entered into the amalgamation or the MAADs proceeding. Following the MAADs proceeding and the approve -- or the Board gave approval to amalgamate, that's when the utilities started to look at what the accounting implications were of an actual amalgamation transaction, and that's when the pushdown accounting became apparent to us as to -- because it was only the amalgamation that required the pushdown accounting, and so it was in assessing what those implications were that we at the utility ultimately became aware of the pushdown implications."*

115. These amounts if anything, are a cost of amalgamation and one that was not revealed to the Board at the time.

116. We also agree with the tenor of the cross-examination of Schools Energy Coalition at the hearing which convincingly showed that the liability of the actuarial losses were incorporated in the price of the EGI Inc and Spectra transaction. The result is that if the Board decides to disallow the recovery of the sought amounts no harm will be visited upon shareholders.[47]

[46] Transcript Volume 15, August 8, 2023 pages 92-93
[47] Transcript Volume 15, pages 28-60

Issue 37 – 2024 ESM

117. It is the norm for earning sharing mechanisms, when they are approved, to begin in the first year of a rate plan. We see no reason to depart from that practice in this case. Earning sharing mechanisms provide comfort to ratepayers that, in return for not having their rates reviewed annual, receive benefit of any windfall.

118. We submit the Board should for 2024 adopt EGI's proposed 50/50 150 basis point banded ESM. In this case the proposed ESM deferral account (ESMDA) would apply in 2024.

Issue 40 – Partial exemption for Performance Measures

119. EGI is seeking to have exemptions for three performance measures set out in the GDAR

- Call Answering Service Level
- Time to reschedule a missed appointment
- Meter Reading Performance Measurement targes

120. We submit the Board should not grant the requested relief and for two reasons. It is not merited on the facts as the current inability to meet the requirements are due to the management of the amalgamated utility to do what the prior separate utilities were able to achieve. The second reason is that changes to the performance measures are properly made under the Board's rule making authority.

121. A review of the measures EGI is seeking relief from and the historical data on the ability to meet those metrics prior to amalgamation suggest that EGI's predecessors were able to meet all the performance measures with the exception of "Time to Reschedule Missed Appointments." For that metric both former utilities were within .03% of meeting the target.[48]

122. When queried as to the reasons for these shortfall post amalgamation EGI said, among other things:[49]

> *Enbridge Gas began a significant effort to align systems and processes following amalgamation which affected metric performance. At the same time factors*

[48] Exhibit 1, Tab 7, Schedule 1
[49] Exhibit I.1.7-VECC-9

including the COVID-19 pandemic, staffing issues and extreme weather events further impacted results.

…

There were significant changes for the organization with system integration and subsequent process alignment, temporarily impacting productivity. In addition, some metrics were impacted by similar alignment activities and reporting practice adjustments. For example, emergency call handling process alignment resulted in an increased number of calls being classified as an emergency, which marginally impacted response volumes in the field and ultimately the Emergency Response
SQR results…

123. They also provided this snapshot of the number of customer calls pre and post amalgamation:

Table 1

Year	Number of Calls	
	EGD	Union
2013	2,615,084	1,157,206
2014	2,747,715	1,285,561
2015	2,862,347	1,193,792
2016	2,654,978	1,110,893
2017	2,378,139	1,151,592
2018	2,478,162	1,082,381
	EGI	
2019	3,588,323	
2020	3,001,431	
2021	3,609,331	
2022	3,615,137*	

*preliminary result

124. These tables show that with respect to customer contacts the two prior utilities were not only able to substantially meet all the GDAR requirement, but were able to do so at times when customer calls were substantially higher than was the case post amalgamation.

125. The evidence is clear that the main reasons for EGI not being able to sustain metrics that were attainable by the prior individual utilities were: primarily related to changes to system during amalgamation and Pandemic related issues. Neither should remain a sustainable reason for not meeting these metrics.

126. The Utility proudly boasts that:[50]

"*Customer Care restructuring alignment in 2019 delivered $2.7 million and VWO in 2020 delivered $2.9 million per year in sustainable savings. One of the most significant benefits of integration was achieved through the Customer Information System (CIS) consolidation which delivered $16.1 million in O&M savings starting in 2022*"

But the Board needs to ascertain whether these savings were made at the expense of meeting the required metrics

127. In our submission the Board should not be approving – even on a temporary basis – reductions in previously attainable performance metrics which are ultimately due to either cost reduction exercises or the inability of EGI management to successfully integrate customer related performance. The Board is responsible for setting just and reasonable rates which include, as it has already established and as the prior utilities has shown is attainable, appropriate service standards.

128. With respect to process and as we outlined in our arguments with respect to customer connections changes to GDAR, including exemptions, must adhere to the provisions of Sections 44 and 45 of the Act. Panel members cannot issue those exemptions (otherwise the powers of the Chief Executive Officer to make rules would be made somewhat moot). In our submission this Panel should not recommend to the Chief Executive Officer a change in GDAR to exempt EGI from any of its service quality requirement.

Issue 41 – Implementation of 2024 rates

129. This is one of the most complex cases the Board has had to preside over. It is the first natural gas cost of service proceeding in a decade for some rate franchises. It tackles the harmonization of two of the largest regulated utilities in Canada all under the uncertainty of decarbonization policies and pressures. With a large number of intervenors to satisfy (or at least try to) EGI has acted in a timely manner and worked cooperatively to structure matters in an efficient way. As such we hold that the Applicant should be allowed to implement the Board's decision for 2024 rates for January 1, 2024.

[50] Exhibit 9, Schedule 1, page 9

Conclusions

130. We would not want our submissions to be read as some denial of changing events. Changes are happening and dramatic changes may indeed be in the offing. What we believe is that extraordinary change demands extraordinary solutions. A natural gas rates case already struggling with the issues of amalgamating two of the largest utilities in the country simply is not that place. In fact, it may be premature to address some issues until other issue of amalgamation, like rate harmonization and rate design changes, are completed. If for no other reason than the Utility itself must have the capacity to address pressing amalgamation work and how to deal with an uncertain future. The Board and its staff also need to shepherd significant resources as do intervenors if they are to be of assistance. And single panels of the Board, no matter how wide their experience, good their intentions, or wise their decision making are not placed to make fundamental change to the approach to natural gas regulation.

- Yet fundamental change is what is called for. For that we believe the Board should take the time and consider what needs to be addressed, within what forums and process they are best considered and the order in which these issues should be tackled. From this hearing one can garner a partial list of the task ahead for renewing the framework for natural gas regulation in Ontario. These are:
- A multi-faceted assessment on the potential of stranded assets due to foreseeable CHG reduction policies (and which forms the basis of all that follows).
- Identification of how and where natural gas regulation might be coordinated with that of electricity regulation (including a review of the required harmony between the sectors on such issues such as customer attachment policies and the cost of capital)
- A comprehensive review of E.B.O 188 and customer attachment policies including the review and incorporation of Community Expansion policies under a revised Access Rule;
- A consideration of policies -including termination fees – that might be enacted to mitigate stranded costs and assist in the orderly reduction of natural gas use (under Access Rules or otherwise implemented)
- A comprehensive review of depreciation for natural gas assets in light the assessed stranded asset risk.
- A comprehensive review of cost of capital (structure and cost rates) in light of the assessed risk.

- This is not an exhaustive list (or even a necessarily correct one). The first place to start is to engage the regulated community of electric and gas, intervenors and specialist, in order to develop a comprehensive set of issues and a plan to address them. We suspect some will find our suggestion too daunting a task or too long a process. If so, that concern may be mitigated in part by importing some the work in proceeding to form the starting point for a comprehensive regulatory review. Irrespective we do admit it will be a difficult task. To that we can only respond that monumental change requires monumental effort to address.

VECC submits that it has acted responsibly and efficiently during this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED