Before the Ontario Energy Board

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Enbridge Gas 2024 Rebasing

GEC FINAL ARGUMENT

Green Energy Coalition:
Greenpeace Canada
Sierra Club Ontario

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Introduction

GEC's primary focus in this proceeding has been on issues that are directly impacted by the impending energy transition, especially Customer Connections and Depreciation.

The current connection rules amount to a subsidy that distorts the market, hurts both existing and new customers, increases GHG emissions, and heightens the risk of stranded costs and a death spiral for the utility. The connection rules increase capital spending and rate base at a time when the opposite is needed.

The current and proposed depreciation methodologies unfairly burden future customers who will be obtaining far less energy from the gas grid and no more energy reliability than is currently delivered. Depreciation based on the physical life of the assets ignores this drop in customer value, and increases the likelihood of stranded costs. It artificially reduces current rates, encouraging connections and therefore gas consumption and emissions, and it raises future rates when the risk of a death spiral will be most acute. Depreciation that does not offset rate base growth, in a future characterized by shrinking energy delivery, is a recipe for disaster for both the customers and the company.

Delaying needed reform of the current connection and depreciation practices will cause waste, unfair cross-subsidy, and needless adverse environmental impact. It will ultimately hurt customers and sacrifice the long-term health of the gas distribution sector for the short-term benefit of shareholders.

Enbridge cites Ontario government support for hybrid heating, the absence of Ontario government policy on the energy transition, the forthcoming Electrification and Energy Transition Panel report, and the fact that the OEB Act does not explicitly include GHG reduction as an objective, to argue that "Decisions related to energy transition and how Enbridge Gas's system will support a net-zero future should not be made ahead of any policy-related decisions emanating from this important work." That reasoning is fallacious for several reasons:

- Enbridge's own evidence on equity thickness, depreciation and 'safe bets', highlights the reality of the energy transition, acknowledges "net zero by 2050", and proposes changes based thereon.
- Even if we assume a continued long-term and expanded government policy commitment to hybrid heating, which is the least impactful possible future for the gas sector and the one that Enbridge is lobbying for, the undisputed evidence

demonstrates that annual and peak energy sales to general service customers will fall dramatically.

- The Board's statutory objectives call for the protection of consumers, which certainly necessitates a consideration of inter-generational equity, a need to contain long-term cost of service impacts, and a need to manage the risks of stranding due to energy transition, and to do so on a timely basis.
- The Board's statutory objectives also call for the maintenance of a financially viable gas industry (as distinct from near-term shareholder returns). Surely reducing the risk of a death spiral fits squarely within that charge.
- The Act calls for rational expansion of the gas grid. There is nothing rational about policies that increase unfair cross-subsidies, encourage needless growth of rate base and ignore end-use customer economics.
- The Act calls on the Board to promote energy efficiency. That certainly warrants a move to eliminate connection policies (and misleading advertising paid for by customers!) discouraging the choice of more efficient electric heat pump technology.
- Carbon pricing is a reality and accordingly, reducing GHG emissions is part and parcel of protecting customer interests with respect to prices. Further, while the Board is not an environmental regulator, as part of its public interest mandate it must surely seek to avoid adverse environmental impacts due to its policies.
- The specific reforms to customer additions and depreciation policies we advocate in these submissions are entirely compatible with current and any foreseeable government policy direction. As Enbridge notes: "Enbridge Gas is cognizant that the energy landscape has shifted since 2013 and that an energy transition is underway, with governments at all levels setting GHG emission reduction targets."[1] (Emphasis added)
- The time to act is now, not five years hence for commencement in 2029. All the experts agree that delaying change increases eventual rate disruption.

[1] AIC p.13

Issue 3 – Has Enbridge appropriately considered energy transition and integrated resource planning?

Before turning to the specific questions enumerated in the sub-sections under Issue 3 we have the following submissions on Enbridge's general aproach to energy transition.

1. Enbridge's head in the sand assertion that the Board and the company must know the precise policy future before initiating changes to protect customers and the gas distribution system.

The future is uncertain. We can't know with any precision how government policy will evolve, what choices customers will make, and how the energy sector will evolve. But as Mr. Coyne of Concentric Energy Advisors noted, "Energy transistion is a fact".[2] And we can see that any future that respects the federally enacted target of net zero by 2050 will involve a significant reduction in the energy delivered by the gas grid. This is particularly true for general service customers. And this is so even if we accept the optimistic assumptions that Enbridge and its consultants offer for gas technology, RNG costs, and the availability and hydrogen delivery in their "Diversified" scenario.[3] Accordingly, the Board does not need to predict the future. A recognition of the common elements of likely futures is a sufficient basis for action.

As Enbridge itself argues:

> <u>"Uncertainty does not mean do nothing. Rather, it calls for implementing prudent steps to advance energy transition despite current uncertainty."[4]</u>

The scenario that illustrates the nature of the transition that Enbridge favours, the Diversified Scenario, has an 53% drop in energy delivered for general service customers, and the more realistic eletrification scenario sees an 88% drop -- which means at least a doubling and possibly an order of magnitude increase of delivery costs per unit of energy if utility costs are not reduced in step. It is obvious that future customers, if

[2] V. 8, p. 81 "…energy transition is broad public policy by the Canadian government, accepted policy by the Ontario provincial government, and globally, for that matter. So energy transition is a fact. I don't consider that speculative."

[3] At AIC p. 16 Enbridge refers to its P2NZ scenarios as "…important in the context of this case as information about the potential impact of various plausible and relevant scenarios."

[4] AIC p. 39, para.100

saddled with rate base and operating expense that is significantly disproportionate to the value they are receiving, will increasingly migrate away.[5]

The Diversified scenario is likely a highly conservative view of the decline in gas grid energy delivery. The IESO Pathways to Decarbonization study "Major scenario assumptions" included:

> **Buildings:** A nine-year transition from predominantly fossil-fuelled space and water heating to electric heat pumps, by 2030 for new residential and commercial buildings in Toronto, and by 2035 for the rest of the province. Technological improvement in cold-weather heat pump technology was assumed.[6]

The technological advance of electric heat sensitive end uses is already well on its way, as we see in Mr. Neme's response to J18.7 which finds 1742 electric heat pumps on offer that can function at -30C or lower. Of those, 683 are ducted models that typically replace gas furnaces. The 161 models listed that can provide at least 24,000 BTUs per hour of heating capacity at -30C still deliver an average of 86% of their full rated capacity at that low temperature. And more than half of that group maintain efficiencies between 177% and 233% at -30C, roughly twice as efficient as a gas furnace.

The importance of the dramatic drop in gas energy delivery to general service customers common to all scenarios is apparent given that residential and commercial customers are allocated 85.6% of rate base and provide 87% of distribution revenues.[7]

As customers leave, Enbridge's high fixed costs are a guarantee that rates will increase for those remaining, driving further departures, and risking a utility death spiral. As discussed below under Issue 15 - Depreciation, the reduction in energy service delivered to future gas customers dictates the need for a change in the allocation of capital costs as between customer generations to mitigate that risk and better ensure intergenerational equity. <u>The prediction of a decline in GJs delivered is not disputed by Enbridge – indeed it is predicted in all its future scenarios</u> which all show dramatic reductions in total annual and peak energy delivered to customers and particularly to general service customers.

Both Mr. Neme and Dr. Hopkins, offering the only testimony from witnesses qualified on energy transition aspects, noted how independent studies find that a highly electrified future is the most achievable and economic[8]. If those independent studies are

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[5] K2.1, p. 2, and V. 2, p. 5 et seq.
[6] J11.4, p. 27 of 42
[7] V.3, p. 12
[8] Ex. M9 and M8

indicative of the likely future, the degree of electrification will be far higher than the Enbridge/Guidehouse Diversified scenario and the urgency of the need to address that future is greater.

From a societal perspective, high electrification is the more cost-effective solution. Even the Guidehouse study, once corrected for just one of its many methodological failings and biases (the application of differing carbon charges to the two scenarios), shows that to be likely (see discussion below under Issue 3).

The same conclusion arrises from the perspective of general service customer costs. Mr. Neme found that a residential home owner will save over $18,000 NPV by switching to efficient electric heating.[9] And Enbridge witnesses acknowledged that the cost of hydrogen or RNG will be higher than unabated natural gas.[10] Thus, <u>regardless of the eventual outcome of the Electrification and Energy Transition panel (E&ET) studies and any resulting Ontario government policies, market forces are likely to increasingly drive customer and load migration from gas to electricity.</u>

End users will always want to have electricity, while for all but a few industries, gas is optional, as are its connection costs and fixed monthly charges.

The possible connection of the proposed Brooklyn North development of 14,000 homes illustrates the need to make decisions today that recognize the energy transition. As discussed below, the current connection policies and application of the EBO 188 and 134 guidelines distorts market choices and is likely to increase the end-use customer costs of energy service and exacerbate the problem of growing rate base costs spread over fewer units of energy. Thus every new subdivision or condo built with gas increases the cost to society, and to both the existing and the new customers.

<u>As Dr. Hopkins noted: "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."[11]</u>

Enbridge witnesses focussed on their hope that the pipes will be used to deliver hydrogen and RNG at peak to alleviate electricity system stress and provide resiliency. Even if that is so, which is highly doubtful given the costs, given the limited availablity of alternative fuels, and given the technical hurdles of hydrogen delivery, net zero by 2050

[9] Ex. M9, p. 23
[10] V. 11, p. 72, l. 18-21
[11] M8, p.46

means that energy delivered by gaseous fuels will plummet, which means that from a customer perspective, delivered value will plummet. So quite apart from societal economics, customer economics will assuredly mean that electrification will dominate.

Enbridge repeatedly made the apparently reasonable assertion that there needs to be integration of gas and electricity system planning. But somehow, Enbridge feels that it's somebody else's job to host that integration exercise (to "create a charter"). There is indeed the E&ET provincial panel currently considering several aspects of this question. But Mr. Coyne's observation is worth repeating: "Energy transition is a fact." There is much uncertainty about the precise pathway, but much that we do know, enough to support action now before the costs of inaction mount.

As we discussed above, we know today that in all contending future scenarios several common features emerge:

- We know with certainty that due to the lower heat content of hydrogen and the limited availability and affordability of RNG, gas energy delivery will drop and that will inevitably mean a drop in annual and peak energy sales and likely in customer numbers.
- We know that government policy favours electrification of heating, whether all electric or hybrid.
- We know that the provincial government has initiated expansion of electricity generation and has announced that it intends to make further such commitments in the near future.
- We know that the Federal Clean Energy standards will require dramatic reduction and eventual elimination of GHG emisions from electricity generation.
- We know that major municipalities are favouring policies that will move away from gas.
- We know that carbon prices are rising and that will impact the competitive situation of gas versus electricity.
- We know that improving technology, and government standards and incentive programs will all lower both annual and peak demands.

In discussing the relationship of the Posterity and Guidehouse scenarios to capital planning, Ms Wade said: "And I think we noted that these demand scenarios are not meant to be plans but, again, to understand common elements across the different scenarios, so that we can plan to, at least those common elements which have translated into the safe bet actions which we have had lots of discussion about."[12]

A "common element" in the scenarios is the dramatically lower levels of energy that will be delivered to customers. It is a safe bet action to plan with that common element in mind. This has immediate import for customer connection and depreciation policies.

Enbridge argues that all options should remain on the table. We don't disagree. But recognizing and responding to likely futures in a manner that limits risks is entirely compatible with that approach.

Enbridge is happy to point to the risks of energy transition to bolster their argument for thicker equity, but somehow unable to propose actions to mitigate those risks. The Board must not be so selective.

2. Enbridge's *ad terrorem* argument that electricity capacity expansion and capital costs will be unmanageable

Enbridge is, like an addict jonesing for a fix, unwilling to envision a future that doesn't involve system expansion, rate base growth and their assets remaining used and useful. But used and useful is not the same as fully utilized. And even if fully utilized in the sense of being full of hydrogen or RNG at peak times, those assets will not provide the same level of service to customers as at present. Thus, even in Enbridge's Diversified scenario significant electrification is foreseen, regardless of the possibility of rising electricity prices.

Energy transition <u>will</u> come at a cost. The question is not how much will electricity system costs rise, but rather, which path is societally less expensive and which path will be favoured by market forces as customers respond to rates and incentives? The answer to both questions is that a higher electrification pathway will be preferred.

The Guidehouse scenarios, which we address below, once corrected for even one of the many methodological failings in that effort, illustrate how from a societal perspective, electrification will be more economic.

And relative rates for the competing energy forms will also favour electrification. In contrast to a potential death spiral for the gas sector due to fixed costs spread over

[12] V. 12 p. 110

fewer GJs, high RNG market prices, and high hydrogen production costs, all driving away load and customers and driving up rates, any build up of capacity on the electricity system will be to accommodate added load over which the capital costs will be spread, mitigating the pressure on electricity rates.

But Enbridge argues that heating load could overwhelm the electricity system and the electrical system may not be able to handle the addition of the proposed 1.5 million homes.

However, as noted by Mr. Neme or referenced in the oral evidence by Dr. Hopkins: [13]

- The IESO anticipates that Ontario will remain summer peaking for several years, so equipping new and existing homes with electric heat pumps can actually lower peak electricity demand by displacing less efficient air conditioner load, buying time for the electricity system to accommodate the eventual switch to a heating season peak.
- No one is suggesting that all the current gas load will switch to electricity. Biofuels and hydrogen are likely to play a significant role for certain industries and parts of the transportation sector.
- Electricity technologies are far more efficient than available gas technologies for major peak system loads including space and water heating as well as for transportation. Mr. Neme pointed out how a GJ of gas load can be replaced by roughly a third or a sixth of a GJ of electricity load depending on the end use, mitigating the need for, and cost of, electricity system capacity expansion and the rate impact thereof.
- Steady improvements continue for highly efficient electric air source heat pump low temperature performance and implementation of heat pump water heating.
- Thermal energy storage which reduces heating peak demand is already being promoted in other provinces.
- Vehicle to load technology and other DER progress will mitigate the peak.
- Federal grant and loan programs funding improved efficiency of older housing stock, and new construction standards and practice achieving higher standards of building shell efficiency, will lower the peak demand impact of heating.
- The recent announcement by the Federal government of $40 billion in spending to incent electricity system enhancements will assist with meeting increased demand.

[13] V.5, p. 174 and J18.7

- The recent announcements by the province of new generation stations and the promise of further such commitments to come.
- Electrification relies on known and proven technologies and techniques whereas Enbridge's gas intensive hopes rely on a highly speculative hydrogen delivery strategy and unsupported assumptions about RNG cost and availability.
- Developing new communities doesn't happen overnight. The Auditor General recently reported that even if the Ford government's controversial awarding of Greenbelt development opportunities stands up, it can take a decade or more to provide infrastructure services to those lands.
- Nor will the energy transition occur overnight. Electricity infrastructure can be built up on a timely basis, which Ms Giridhar acknowledged:

> MR. MORAN: Right, and so as we go forward over year by year, would you agree that the electricity utilities and the IESO and Enbridge collectively are all able to see what's happening and to plan for the expansions they need to plan for?
>
> MS. GIRIDHAR: Absolutely…[14]

What the potential addition of 1.5 million homes does indicate, is that changes to gas connection rules and depreciation policies cannot wait for another five years if we are to avoid a commitment to a massive increase in rate base down the road that will exacerbate stranded cost risks and cause a massive increase in GHG emissions in an ecologically critical period.

3. Enbridge's unsubstantiated claim to reliability and resiliency

The company witnesses repeatedly resisted the suggestion of a declining role for gas by mentioning reliability and resiliency. That consideration may be relevant for gas-fired electricity generators, but is largely irrelevant for the vast majority of Enbridge's assets that serve general service customers whose gas furnaces and water heaters don't run without electricity and who are unlikely to invest in backup electricity generators.

Most general service customers today do not have back up power and there is no reason to assume that will change unless there is a dramatic decline in the reliability of

[14] V.11 p. 78

electricity, and there is no reason to assume, nor evidence to suggest, that the IESO and the government will not keep the lights on as reliably tomorrow as they do today.

Whatever reliability gas provides is already on offer today and will not be greater in future. But in the future, even in Enbridge's vision, the energy service gas provides will be far lower. In that context, Enbridge seems to be entirely out of touch with reality when it asserts that residential customers will spend hundreds or thousands for a backup power source and spend $600 annually ($9000 plus tax over 15 years) to remain connected for a diminishing amount of energy delivery.

It is anything but a 'safe bet' to assume that the drivers of decarbonization and the pressure of market forces on customer numbers will yield to some factually unsupported claim that general service customers will pay many thousands of dollars to hold on to gas service for a vanishing degree of service. Clearly, customer departures are likely as gas and delivery costs increase, and gas service declines. As we discuss below, Enbridge would dearly like to ignore that reality.

4. Enbridge's fear of acknowledging the likelihood of customer exodus

At the close of the customer attachments panel, in discussing the possibility of a shorter EBO 188 revenue horizon, Ms Giridhar stated:

> I think our main issue is not tying it so specifically to an expectation of how long customers would stay on the system because, really, from a decision-with-reasons perspective, that prompts very, very difficult depreciation and equity thickness questions for the company and investor response.[15] (emphasis added)

This fear seems to have distorted the company's evidence and position on the issues before the Board.

For example, the company inappropriately casts depreciation policy discussions as all or nothing choices – either depreciate assets steadily to the end of their physical life assuming all the customers remain and pipes are still providing full value, or truncate depreciation with an economic planning horizon as if the system will crash on a set date. Since we can't reliably predict that set date, Enbridge argues we must pretend that life will go on unchanged. As we discuss below, depreciation doesn't need be based on such

[15] V.11, p. 89

a simplistic choice. Utilizing a units of production depreciation methodology allows for a more realistic assumption of a gradual reduction in delivered annual and peak energy.

5. Enbridge's Hydrogen and RNG Pipe Dreams

One of Enbridge's most obvious failures to come to terms with the energy transition is its near blindness to the technical and cost barriers to its hydrogen and RNG vision. No one is suggesting that RNG and hydrogen won't play a role in the future. Rather, we submit that the scale and cost of these options that Enbridge assumes is unsupportable. These matters were addressed in the EFG report[16] and at length in the oral hearing, but warrant highlighting here as prime examples of Enbridge betting on a highly unlikely future but calling it a 'safe bet'.

The limited availability and corresponding high cost of RNG

The Torchlight study, that Guidehouse purportedly relied upon, found feasible (as distinct from technical) Canada-wide RNG potential of 155PJs, and the CER study, cited by Enbridge witnesses, found a feasible Canada-wide potential in the range of 10-15% of year 2050 gas consumption which works out to be about 140PJs.[17] These estimates are in the range of 3% of current gas consumption.[18]

The IESO concluded that the potential available RNG amounts to 26 PJ per year.[19]

The Canadian Biogas Association study found 23.4 PJ per year.[20]

Yet the Guidehouse Diversified scenario assumes 171 PJ per year of available and affordable RNG for Ontario consumption. This is simply unreasonable and contrary to all the available evidence.

The limited availability of affordable RNG inevitably means that there will be competition for the scarce resource. Out of province entities are already buying up Ontario RNG.[21]

As Enbridge stated to the E&ET Panel:

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[16] Ex. M9
[17] V.5, p. 176
[18] ibid
[19] V. 2, p.106
[20] V.2, p. 99
[21] Ex. M9, p.32

> "Most of Ontario's RNG is currently exported and, with other provinces setting ambitious RNG blending goals, this trend may continue. Such a trend may limit Ontario's ability to access the lowest-cost local RNG supplies in the near term."

Indeed, Enbridge goes on at length in its argument in chief about the growing demand in other jurisdictions for RNG.[22]

Despite that evidence of growing competition for a scarce resource, the Posterity and Guidehouse models that Enbridge relies upon to find 'safe bets' do not recognize that in a competitive market the price of RNG will be set by the market clearing price. They then compound that error by using production costs of the least expensive source (landfills) and further compound the error by omitting the financing and producer profit margins that would be included in the market clearing price (despite using market clearing prices in their scenarios for other inputs such as natural gas and electricity generation prices and end user equipment).[23]

The Enbridge sponsored Concentric report on cost of capital noted:[24]

> "Concentric is unable to draw conclusions regarding the long-term viability of RNG at this time. However, academics have noted a variety of financial, technical, and other barriers to widespread adoption of RNG. For example, one California study found that "relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough. The study went on to conclude that, after factoring in the more expensive forms of gas, "the commodity cost of blended pipeline gas is more than four to seven times that of natural gas today. Another California study noted that "RNG faces large technical obstacles. A study conducted by Washington State University's Energy Program indicated that "adequate opportunities exist for RNG production equivalent to 3 percent to 5 percent of current natural gas consumption".

Blending hydrogen with RNG will not avoid the problem of high RNG costs. Enbridge's Ms Teed Martin testified that hydrogen can be blended with RNG at a volumetric level of 15-30% which means it can only provide approximately 5-10% of the energy content

[22] AIC pp.53-54
[23] Ex. M9, p.33 and V. 2, pp. 67-68
[24] Exhibit 5, Tab 3, Schedule 1, Attachment 1, Page 36

(Ms Teed Martin later suggested lower values of 15-20% by volume providing 5 – 7% by energy).[25]

The cost and impracticality of concentrated hydrogen delivery

Given the limited availability of affordable RNG, it is not surprising that Enbridge assumes a heavy reliance on hydrogen for gaseous energy. Hydrogen, if produced by green electricity, is a valuable low or zero carbon energy medium that can be stored and utilized to meet intermittent loads. The Diversified scenario that Enbridge seems to be betting on has 81% of gas energy and 94% of volumes in 2050 comprised of hydrogen.[26] But hydrogen at high levels of concentration cannot be co-delivered with methane, so the practicality of switching over general service customers is daunting.

Electrification can be piecemeal, appliance by appliance, home by home. It is already occuring, spurred by the Federal Greener Homes program. In stark contrast, conversion to high concentraton hydrogen requires every gas consuming appliance in a home to be hydrogen ready, meters to be hydrogen ready and certified, requires every home on a main to be simultaneously so converted, requires piping and appliances in every home to be pre-inspected and then requires every appliance in every home on the main to be adjusted to accept hydrogen on the day of changeover, and requires segregated delivery of methane and hydrogen from upstream sources to adjacent neighbourhoods on differing conversion schedules.[27]

Even if the government mandated that all new appliances had to be hydrogen ready in 2025, how would it even be possible to enlist 100% of customers in a neighbourhood to switchover 100% of their gas appliances simultaneously, despite the fact that in 2045 or 2050 some will still be utilizing furnaces or water heaters or stoves in place today that are not capable of hydrogen conversion (the 18 year life for furnaces is an average with some lasting far longer)?

The simple fact that hydrogen is 70% less energy dense than methane means that the fixed costs of the system would be spread over far fewer GJs, so all else equal, the delivery cost would be on the order of 330% higher per GJ.

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[25] V.2, pp. 4 and 54 and see J2.11 for further elaboration

[26] V.5, p. 47

[27] Dr. Hopkins agreed, noting "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… N.M8.ED-7

The cost implication of fewer GJs being delivered annually and at peak is not limited to general service customers. Indeed, the Diversified scenario, despite 20% less peak energy use by the industrial sector sees an 84% increase in peak volume exacerbating the fixed costs per GJ concern. Enbridge witnesses could not predict how that volume need would be accomodated but acknowledged that it would likely require added investments in the system.[28]

A further uncertainty associated with Enbridge's hydrogen hopes is the question of GHG emissions from blue hydrogen. Drs. Howarth and Jacobson summarize their findings as follows:

> "…the greenhouse gas footprint of blue hydrogen is more than 20% greater than burning natural gas or coal for heat and some 60% greater than burning diesel oil for heat, again with our default assumptions. In a sensitivity analysis in which the methane emission rate from natural gas is reduced to a low value of 1.54%, greenhouse gas emissions from blue hydrogen are still greater than from simply burning natural gas…[29]

Both Guidehouse and Enbridge disputed the applicability of those findings by suggesting that they will achieve far lower methane leakage rates in future. However, the Howarth and Jacobson leakage assumption is based on empirical data from "top-down" emission studies using satellite and flyover surveys that find a 3.5% leakage rate. Dr. Howarth notes that 1% and 0.4% rates offered by Enbridge and Guidehouse do not appear to be supported by independent studies.

Enbridge's responding evidence canvasses studies looking at particular sites, small scale prototypes and possible future scaled up technology and boils down to a hope that average upstream emission rates can be better controlled in future. Enbridge concludes, *inter alia*, that: "The scientific community has provided a range of views on the life cycle emissions intensity of blue hydrogen; however, it has not coalesced around a single value because the value will vary for each hydrogen production facility."

Enbridge did have Guidehouse model the implications of Dr. Howarth's findings and the result is a shift from blue to green hydrogen in the results with an associated added $31 billion cost for the Diversified scenario.

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[28] V.2, p.14
[29] Ex. M10

6. The Inadequacy of Enbridge, Posterity, and Guidehouse, Scenario Analyses

The EFG report raises a number of concerns about the scenario analyses offered by the company in its evidence in addition to those already discussed. Before turning to that, it is important to note that even with numerous methodological biases in favour of gas, the scenarios, which were largely informed by Enbridge's initial assumptions, make clear that the energy delivered to remaining customers will decline dramatically and a huge rate level versus customer value issue is looming that could cause a death spiral if mismanaged. We address remedies responding to that concern below in our submissions on Issues 7 and 15.

The initially filed Guidehouse study concluded that the "Electrification scenario" would be $181 billion more expensive than the high gas scenario (the so called "Diversified scenario"). Following interrogatories, Guidehouse identified errors and reduced the gap to $167 billion. Following the technical conference and the OEB order to release the underlying model details, Guidehouse identified further problems and updates, which reduced the gap to $41 billion, a full $140 billion difference from its original report. The EFG report then went on to identify numerous remaining flaws in the Guidehouse scenario analysis, all tilting against electrification, including:

- Inappropriate Use of Higher Carbon Emissions Costs for the Electrification Scenario
- Inappropriate Application of Heating Load Shape to Non-Heating End Uses
- Outdated and Biased Assumption Regarding Electric Heat Pump Efficiency Degradations
- Dramatically Over-Estimating RNG Availability
- Unrealistically Low Costs Assumed for Biomethane
- Unrealistically Low Costs Assumed for Green Hydrogen
- Over-Estimating GHG Emission Reductions from Biomethane
- Potential Over-Estimation of GHG Emissions Reductions from Blue Hydrogen
- Ignoring Potential for Electric Demand Response from Building Loads
- Overly Optimistic Assumptions about Gas Heat Pumps
- Overly Pessimistic Assumption about Weatherization Savings Life
- Unreasonably Pessimistic Assumption about Electric Water Heating Efficiency
- Excluding Distribution Systems Costs and Customer Fuel Conversion Costs

We will not burden the Panel with a repetition of all the details of each of these criticisms. The EFG report speaks for itself and with very few exceptions there was little or no, even attempted, refutation of it provided by the company's expert witnesses.[30]

The bottom line, as Mr. Neme noted, is:

> *"If even one or a few of those errors are corrected, the high gas scenario is tens of billions of dollars more expensive than the scenario emphasizing higher levels of electrification."*

We asked Guidehouse to adjust the scenarios for just one of the errors Mr. Neme identified and to use the same carbon cost in the Electrification scenario as used in the Diversified scenario. Using the same carbon prices per tonne in each year that was used in the Diversified scenario the total emissions cost in real 2020 dollars for the Electrification scenario drops by $67 billion, making it $26 billion less expensive than the Diversified scenario.[31] That adjustment was done without re-optimizing the dispatch and as the response notes, "the values do not represent the least cost pathway that the model would determine for the Electrification scenario if the Electrification scenario were modeled with the [Diversified scenario] carbon prices in Table 2." Accordingly, as Mr. Neme noted, if the model is truly a cost optimization model, we could reasonably expect that a full optimization of the scenario would likely show an even larger cost advantage for electrification.[32]

We would be remiss not to point out that the need to adjust the scenarios to make an apples-to-apples comparison by using the same carbon pricing only arises because Enbridge, Posterity and Guidehouse chose to include carbon taxes in their societal cost analyses despite the fact that these taxes are transfers, not net societal costs, especially in Ontario where the carbon tax is refunded to customers.[33] If a means was needed to inspire more electrification in the modelling (which is doubtful as we have seen from Mr. Neme's customer cost analysis) the tax could be utilized without treating it as a cost or other policy tools could have been chosen such as government grants and loans (the actual current practice) or the use of appliance standards or building codes. One is left to ponder whether Enbridge directed or accented to the unequal application of the tax

[30] One notable exception was Mr. Ringo disputing Mr. Neme's 40% peak load reduction to account for Guidehouse's failure to use differing end-use appliance load shapes discussed at V.5, p. 177-180. Mr. Ringo's response would reduce that to 23%. Mr. Neme noted that even a 23% reduction in peak electricity demand might alone flip the results of the Guidehouse scenarios.

[31] JT9.1 where the Total Emissions Cost (real 2020$) falls from $179B to $112B

[32] M9, p.28

[33] Taxes are not net societal costs and taxes for other inputs to the Guidehouse scenarios such as sales taxes on end-use equipment were not included (J2.3)

and its treatment as a cost, intentionally, as a means to tilt the outcome against the electrification scenario.

The inclusion of the carbon tax but not the carbon credit to consumers is even more unsupportable when we see that Guidehouse did not include other taxes such as the HST on end use appliances in its analysis.[34]

Nor was the carbon tax included as an attempt to capture environmental externalities. This was suggested by Guidehouse in answer to I.1.10-GEC-38 where it said it "represents the impact of GHG emissions" but that was subsequently disavowed by Mr. Ringo.[35] That disavowal was not surprising, because the Diversified scenario has higher GHG emissions than the Electrified in all periods so an inclusion of externality monetization (which GEC would support) would favour electrification.[36]

The IGUA sponsored expert, Dr. Hopkins was asked if he agreed that the Guidehouse report has a pro-gas bias. He responded with an unqualified "Yes"[37].

In summary, **GEC submits that the Posterity and Guidehouse reports are severely flawed and biased. Given that Enbridge has proffered the Guidehouse report to government agencies and the E&ET panel, we would urge the Panel to explicitly state that the report should not be relied upon given its biases, limited scope, and numerous flaws in methodology.**

7. Issue 3 – Energy Transition – specific issues list sub-topics

Adequacy of energy transition and IRP consideration in relation to load forecast:

The record is clear that the energy transition is likely to dramatically affect loads in future in all scenarios considered. GEC does not suggest that energy transition will immediately impact the load forecast for 2024. The implications of energy transition for the load forecast over the proposed IRP period are less clear, but the manner that the load forecast will adjust can be addressed in phase II. **While we do not take issue with the load forecast for 2024, the assumption of relatively steady demand utilized to justify growth investments is no longer supportable.** As the Guidehouse scenarios depict, both annual and peak demand is likely to drop as efficiency improves and fuel

[34] V.2, p. 32 and J2.3
[35] V.2, p.29
[36] V.2, p. 33
[37] N.M8.ED-4(b)

switching takes hold. We discuss the problem of Enbridge;'s longer term load projections below, under Customer attachment policies and EBO 188 Guidelines.

Adequacy of energy transition and IRP consideration in relation to deemed capital structure:

All parties recognize that the impending energy transition creates a risk for Enbridge which could evolve to a potential death spiral if inadequately managed and that risk must be considered in determining capital structure and return. Key questions before the Board related to the implications of energy transition for equity thickness are:

- To what extent can Enbridge and the Board mitigate that risk?
- How soon might that risk materialize?
- How do equity investors view that risk?

GEC's submission will focus on the first of those considerations. In our view Dr. Hopkins' report clearly illustrates that timely business planning and regulatory adjustments can mitigate the risk of the energy transition leading to a death spiral and thus reduce the need for increased equity thickness.[38]

Dr. Hopkins noted that changing depreciation to a Units of Production approach (a matter we address in further detail below) could improve financial indicators and also reduce the need for increased equity thickness.

Dr. Hopkins calls for a scenario based analysis to inform a regulatory and business strategy that will mitigate energy transition risks. While recognizing the economy of awaiting the E&ET Panel study results, he suggested much analysis can begin in this proceeding or a subsequent phase, such as analysing alternative depreciation.[39] He also noted how changes to investment planning revenue horizons or depreciation are adjustable and reversible in contrast to spending on capital projects.[40]

He suggests that it would be inappropriate to raise rates to adjust equity thickness at this time, in the absence of sufficient analysis of risk mitigation approaches. GEC recognizes the need for an appropriate deemed capital structure to attract capital at optimal rates and to properly protect or reward investors, but the utility and its shareholders should not benefit by an avoidance of a proper analysis.

In relation to deemed capital structure, Enbridge has simply failed to adequately consider options such as capital spending constraints and altered depreciation to

[38] Ex. M8
[39] V.5, pp.141-142
[40] V.5, pp. 138-139

address energy transition risks. GEC submits that it would be inappropriate to significantly raise rates to adjust equity thickness at this time, in the absence of sufficient analysis of risk mitigation approaches

Adequacy of energy transition and IRP consideration in relation to depreciation:

As noted, a Units of Production depreciation approach regularly appears as a key element of a strategy to mitigate energy transition risk both in Dr. Hopkins' review of the recommendations of studies in other jurisdictions, and in his illustrative model.

It is apparent that Enbridge has not seriously considered a U of P depreciation approach. Concentric noted that it is a renewed consideration elsewhere but, presumably at Enbridge's request, only analysed an Economic Planning Horizon approach (EPH) to address energy transition rather than the graduated approach of U of P. EPH would truncate depreciation at a given date which has the obvious shortcoming of limiting the depreciation period for a given asset group despite the fact that it may remain in use by some customers to some extent. U of P need not give rise to that problem.

As we address below under Issue 15 – Depreciation, **Enbridge has failed to consider Units of Production depreciation, the obvious prime contender for a depreciation approach that recognizes energy transition and would mitigate the risk of energy transition.**

Adequacy of energy transition and IRP consideration in relation to forecast capital expenditures:

Mr. Neme discusses changes to the application of the EBO 188 guideline that are appropriate to consider in light of the energy transition. Shortening or eliminating the period of expected revenue in the cost/benefit analysis of customer attachments and system expansions to reflect the likely future reduction of gas customer numbers would clearly impact the number of such capital expenditures that pass the tests. It would lead to higher CIACs that would either reduce utility capital expenditures where the customers pick up the tab, or would simply deter customer additions. **In its capital planning Enbridge appears to have simply failed to consider the reality of reduced customer numbers due to energy transition considerations.**

Enbridge has also failed to implement IRP in a manner that would optimize customer savings and lower capital spending. As the following exchange makes clear, Enbridge has not embraced the idea of customer least cost:

> MR. MORAN: Right. To your knowledge, has there ever been a situation where Enbridge, after a conversation with a developer, the developer said, you know what? I think I am

> better off just building an electric subdivision. Has that ever happened?...
> MS. BURNHAM: So not to my knowledge.[41]

GEC submits that **enhancing the IRP guidelines is appropriate to make promotion and funding of electrification a mandatory consideration where desireable for customer or societal economics, or the attainment of net zero by 2050**.

Adequacy of energy transition and IRP consideration in relation to allocation and mitigation of risk:

For all the reasons listed in the sub-sections above, it is apparent that **Enbridge has not adequately considered the implications of energy transition for the allocation and mitigation of risk as between ratepayers and shareholders and as between generations of customers.**

Please see our more detailed discussion of these isues below in regard to depreciation and capital spending as impacted by customer connection policies.

Issue 7 – Capital Expenditures

Capital Budget

Our submissions will focus on the long-term implications of capital spending in the context of the impending energy transition. We do note the evidence of significant capital spending increases in recent periods and projected in this proceeding. For example, K11.2 at p. 14 (SEC Capital AMP Compendium) sets out the series of significant capital spending increases since EB-2020-0181. Capital spending is far outpacing depreciation with rate base growing from $7.9 billion at the time of the last rebasing in 2013 to $16.2 billion proposed for 2024.[42]

[41] V.14, p. 124
[42] V. 11, p. 107

We also note that 55% of the GDS 2023 scorecard performance pay incentive structure incents EBITDA growth performance.[43] And as acknowledged by the company witneses, the incentive structure disincents DSM and IRP success beyond that planned.[44]

Enbridge's highly misleading claim to customers that electric heating is 43% more expensive than gas (without disclosing that the comparison assumes resistance heating rather than the more realistic heat pump assumption for a customer making that choice today) further illustrates the company's focus on growth rather than customer service.[45]

In short, this is a company and corporate culture that is focussed on capital spending and rate base increases despite the dangers of that course as we emabark on energy transition.

We understand that SEC and ED will be providing detailed submissions on the potential to reduce overall capital spending. We have conferred with those parties and in the interests of cost containment, and efficiency for the Panel, we will rely upon and not repeat those submissions. We will therefore limit our submissions to the question of capital spending proposed for customer connections and related concerns with respect to the EBO 188 and EBO 134 tests used to justify capital spending as well as needed changes to the IRP protocol.

We focus on customer connections because this is a component of the capital budget for which safety and security of supply does not constrain cutbacks, and a spending component that risks exacerbation of both stranding risks and undue cross-subsidies. The mismatch between the long revenue horizon in the EBO 188 test and the shrinking future of gas utilization is mirrored in the EBO 134 test.

The capital budget for system access (customer connections excluding community expansion projects) for 2024 is $304.1 million and $1,313.2M over the 2024-28 period.[46] With the cost of meters added the total increases to $1.579 billion.[47] GEC submits that the Board should require a 100% CIAC policy which would reduce the capital budget by $1.579 billion. Alternatively, reducing the revenue horizon in EBO 188 to 10 years would decrease system access spends by $853 million over the 2024-28 period.[48]

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[43] JT1.8 att 2
[44] V. 11, p. 201
[45] K2.1, p. 37
[46] I.ADR-6: The infill ('conversion') portion of connections is $27.8M. The community expansion capital budget for 2024 would add a further $11.2 million
[47] J13.5 and J13.7
[48] K10.2, p. 139 (EG's Customer Attachment Compendium Table 2)

However, to avoid severe market distortions we advocate for full collection in a CIAC and not via a revenue horizon (see below).

Enbridge is required by section 42(1) of the Act to connect potential customers (where capacity and safety allows) if they are adjacent to an existing pipeline. The Act does not require the connection to be offered at no cost (i.e. without a CIAC, SES or TCS). Further that section of the Act does not apply to the bulk of proposed additions to non-infill projects.

For 2024, Enbridge forecasts 41,648 customer additions of which 33,609 are for residential new construction and 1,879 are for commercial new construction.[49]

Non-infill projects account for approximately 80% of connections.[50] Accordingly, the ability to restrict connections is not constrained by the Act in most cases.

Even in an infill situation, where connection is mandated, the average residential connection on the legacy Enbridge system costs $6,626.[51] Few such connections would be likely if the full cost of the connection was required of the customer up front (or even the $5,991 hard connection costs without normalized reinforcement – see below). Thus the extent of connections and the associated spending is, in practice, in almost all cases, effectively governed by the application of the EBO 188 guidelines as incorporated into GDAR section 2.2.1 and the Board approved connection policies.

Customer Attachments Policies and EBO 188 Guideline Application Issues

There are at least four issues that arise from the current connection policies and the application of the EBO 188 guideline which includes a feasibility test based on 40 years of revenue for general service customers and which Enbridge applies assuming full continued utilization:

- Distorting of the market and ignoring customer economics
- Increasing GHG emissions
- Exacerbation of stranded or underutilized asset risks
- Inadequate revenue recovery leading to undue cross-subsidies

[49] Ex. 3, T. 2, S. 6, Att. 1, p.1 and V.11, p.63: $27.8M of the $304.1M attachment budget is for infill 'residential conversion'
[50] I.2.6-ED-94, Table 4
[51] J13.8

Distortion of the market and ignoring customer economics

New subdivisions account for approximately 80% of connections.[52] The choice to hook up to gas is thus largely one made by developers. But the full cost of that decision is borne by the gas consumers who will occupy the dwellings and, to the extent those customers don't stay on the system or continue to pay distribution charges at current levels, part of the cost will be borne by the totality of remaining gas customers or be stranded.

Enbridge argues that changes to the customer attachment policies will increase customer costs, "something that is challenging at a time when the Government of Ontario is prioritizing affordable new housing".[53] But based on the evidence before the Board it is easy to see that electrification is a lower cost option for customers. As seen below, in his Table 3, Mr. Neme found that an existing customer will be well ahead economically by converting to electricity and leaving the gas grid in a range of futures.[54]

Table 3: Change in Total Cost from Electrification of Single-Family Toronto Home, Today and in 2030

	without Electrification	with Electrification	$ Change	% Change
2023 Electrification				
18-Year NPV of Energy Bills	$28,268	$15,249	($13,018)	-46%
18-Year NPV of Equipment Costs	$10,264	$6,534	($3,730)	-36%
18-Year NPV of Total Costs	$38,531	$21,783	($16,749)	-43%
2030 Electrification				
18-Year NPV of Energy Bills	$29,760	$14,826	($14,933)	-50%
18-Year NPV of Equipment Costs	$10,264	$6,366	($3,898)	-38%
18-Year NPV of Total Costs	$40,023	$21,192	($18,831)	-47%

For a homeowner in a new subdivision there is a similarly compelling case for electrification. While that homeowner would not benefit from the Greener Homes grant, it would avoid the cost of changing over other gas appliances such as a water heater, stove or dryer prematurely, costs that are included in the EFG existing customer scenario where the changeover occurs as dictated by the life of the furnace or air conditioner.

However, since Enbridge collects much if not all of the cost of connection in rates rather than up front, it artificially lowers the cost for the developer and thus creates a classic

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[52] I.2.6-ED-94

[53] EG AIC p.9

[54] M9 pp. 20 et seq.

split incentive situation, distorting the market. Society and the specific customers would find it cheaper to avoid the costs of connection and the escalating gaseous fuel costs, and to choose efficient electric appliances at the outset if they had that choice. But Enbridge hides all or most of the cost of connection from the developer, who then can install conventional gas equipment and the connection cost gets borne by the eventual resident and other gas customers or is stranded.

All buildings connect to the electricity grid. Thus a developer appropriately faces connection fees for electrical service regardless of the choice of heating equipment. It should be noted that almost all new homes are equiped with air conditioning and thus 200 amp service. As a result, the electricity distribution system capacity required is largely unaffected and the connection costs are largely unavoidable. In contrast, the gas system connection and capacity costs are fully avoidable. Because the bulk of gas connection costs are collected in rates the developer does not see this avoidable cost (except to the extent a P.I. of less than 1 adds a CIAC). The customers buy homes with gas furnaces that will cost them many thousands more to operate compared to efficient electric appliances. Even if the end use customer eventually fully electrifies, the system will not avoid the sunk connection cost.

The split incentive problem for developments illustrates why it is important that any solution to the market distortion concern must not allow Enbridge to avoid charging the developer for the full connection costs by utilizing the SES or TCS alternatives, as passing costs along to customers via TCS or SES would amount to the same splitting of incentives.[55]

As illustrated by the sensitivity analyses Mr. Neme offered, his results are quite robust regardless of assumptions about federal grants, gas prices, and heat pump efficiency changes.[56] The customer economics that Mr. Neme calculated are conservative. As even Ms Giridhar acknowledged, the company's presumed reliance on RNG and hydrogen will be more costly than natural gas.[57]

Mr. Neme addresses the cost of RNG in the second part of his customer economics analysis which shows how the volumetric cost advantage of electricity will likely increase over time in a decarbonized future. He shows how the cost of a GJ of heating with no new decarboniztion policy is 171% higher with a fossil gas furnace than with an electric heat pump. And with decarbonization requiring the use of RNG the cost of a GJ from an

[55] See discussion at V.10 p. 128
[56] M.9, p.24
[57] V. 11, p. 72

RNG furnace is 521% of the cost of using an electric heat pump. And these numbers don't even include the savings from avoiding fixed monthly gas distribution charges. As Mr. Neme discusses in J18.7, many electric heat pumps are now on the market that can meet peak heating demand in almost all locations without electric resistance or gas back up.

Increased GHG emissions

Enbridge treats Net Zero by 2050 as a get out of jail free card for the intervening years. But reducing emissions between now and 2050 is arguably more important if we are to reduce the risk of hitting ecological tipping points. This is especially true for methane leaks at all points of the system, including upstream and at customer locations, because methane is over 80 times more impactful than carbon dioxide in the first 20 years. Enbridge does not report on, or even know, what methane emissions are from customer premises due to uncombusted methane exhausted from furnace and water heater vents each time appliances start up, a growing concern that Mr. Neme noted in his report.[58]

Ms Giridhar incorrectly suggested that using a hybrid furnace at peak times would reduce emissions relative to electric heat pumps with resistance backup that relies on gas-fired electricity generation. Mr. Neme explains in J18.7 the several reasons why Ms Giridhar's assertion is wrong, including the fact that the high efficiency of the many models of currently available electric heat pumps that can operate at or below -30C can produce a significant amount of heat, at efficiencies roughly twice as great as those of the best gas furnaces – i.e. efficiently even at -30C. Mr. Neme notes that Guidehouse's analysis for Enbridge of that very question shows how annual GHG emissions for the all-electric option are lower in all four Ontario regions it considered. Furthermore, that comparison is largely irrelevant for customers connecting today who will typically use conventional (non-hybrid) gas furnaces and water heaters that will burn methane at all times of operation during this critical decade or two. This is particularly so for customers today who buy a new home in a subdivision as it will likely be equipped with a non-hybrid fossil gas furnace –- installed by developers who are encouraged to connect to gas due to the rules allowing Enbridge to amortize connection costs into rates.

Exacerbation of stranded or underutilized asset risks

As noted above, the capital budget could be reduced by $1.579M over the 5 year rate period if connections were avoided or funded by CIAC rather than by assuming rate

[58] V.2, p. 87 and M9, p. 35

revenue will cover the bill.[59] If we assume that the risk of stranding, if not managed, is likely to come home to roost in 20 years, the problem will be a multi-billion dollar one.

Inadequate revenue recovery leading to undue cross-subsidies

Currently, the EBO 188 assessment of profitability utilizes a 40 year revenue horizon. EBO 188 allows for a project (as opposed to the portfolio) to proceed if it achieves a P.I. of .8 over 40 years, in which case the payback period to achieve full cost recovery could be longer than 50 years given discounting.

Exhibit JT 3.11 (updated) indicates that the average cost to connect a home in 2023 in the EGD service area is $5673 which is expected to take 31 years to achieve assuming the current mix of expected project profitability, and assuming that customers remain connected and continue to provide distribution revenue at current levels throughout that period. The expected cost for 2024 is $5991 excluding Normalized System Reinforcement Costs which would add $635 for a total of $6,626.[60]

In cross we suggested that a customer who leaves the system before 31 years has elapsed, will, when its furnace or air conditioner needs replacement, leave an unpaid connection tab for others to bear. The average life expectancy of furnaces is roughly 18 years.

Ms Giridhar responded that because normalized reinforcement costs are included in the EBO 188 calculation of connection costs, a new customer is contributing to common costs before it fully covers its EBO 188 connection costs and that excising a full connection charge at the time of connection would be a cross subsidy to other customers. However the evidence suggests otherwise. First, as noted above, the bulk of connection costs are the direct customer hook up costs ($5,991 of the $6,626).[61] Accordingly, even if we view normalized reinforcement costs as a full accounting of the common cost, Ms Giridhar's suggestion will only pertain if a sufficient number of years have passed such that the direct costs of $5,991 (which excludes the $635 normalized system reinforcement) have been covered. And even at the end of the revenue horizon period her assertion is only accurate if the normalized reinforcement cost calculated is equal or greater than total allocated undepreciated rate base divided by total customer

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[59] I.ADR-6. The saving is $773M if the connection horizon was reduced from 40 to 10 years, $485M for a 15 year horizon (I.ADR.2 and I.ADR.4)

[60] J.13.8

[61] Exhibit JT3.11 as updated on 2023-07-06 provided a figure of $4,412. That value was changed to $5,673 in the 2023-07-26 update to the exhibit and a note in that update clarifies that "The average costs provided in the original response represented only the direct capital cost and excluded the incremental overheads e.g., normalized system reinforcement…". And in J13.8 for 2024 the figure for costs exclusive of normalized reinforcement is $5,991.

number in that customer category. Put another way, paying back normalized reinforcements costs which are a proxy only for the marginal costs of upstream reinforcement to support the customer addition, is only a contribution to common costs if the marginal reinforcement costs account for a full share of all common costs and if those costs were collected as an extra charge on the new customer. New customers benefit from all the invested capital and should not be allowed to avoid paying their fair share toward all the sunk and ongoing costs.

The current EBO 188 P.I. rule of 0.8 over 40 years would allow for an individual project to make no contribution to the larger set of common costs for up to 50 years. It would allow for a portfolio payback (requiring a P.I. of 1) of up to 40 years.

Further, the company assumes that distribution revenue from the new customer will not decline over time. But, as discussed above, as well as below in regard to depreciation, the future that Enbridge envisages will be characterized by far lower annual and peak energy delivery to average general service customers as well as lower peak demand due to equipment and building efficiency improvements. So regardless of rate structure, revenues from rates that can be charged without driving customers away are surely likely to decline, and the actual payback period is likely to be far longer than the 31 years that the company suggests or the 40 or 50 years that EBO 188 allows.

During the decades that a new customer is paying off its $5,991 of direct connection costs it makes that much less of a contribution to common costs. During that period a long-standing customer who has paid off its connection costs will have contributed the same amount, i.e. $5,991 to common costs.

Those new customers who leave at any point before they have paid their connection costs will have avoided a full contribution to common costs for that period and will also leave an unpaid connection cost tab. The sum of those two costs will be borne by other customers and will add up to $5,991 at any point in time prior to the time when the direct costs have been repaid (up to that point in time, as the unpaid tab declines the period of free riding is extended).

Staff's suggested 20 year horizon only slightly reduces the split incentive issue and does not address the cross-subsidy. Nor does the inclusion in the P.I. test of of $635 toward normalized reinforcement costs. The simple fact is that with distribution charges at $50 a month, the new customer will pay $12,000 over 20 years but has imposed a $5,991 cost on the system for a net contribution of $6009. Existing customers will have contributed 12,000 in that same period.

Enbridge argues its historic P.I. of 1.5 means that new customers are helping to lower existing customer costs. That may have been the case historically, but is not the case in a future where a significant portion of the new customers don't stick around for 40 or 50 years to cover their connection costs. While a mismatch between an individual customer's revenue contribution and the average costs of service is inevitable in a postage stamp rates world, in the past the average impact over time from any cohort of new customers would have been neutral or helpful to pre-existing customers. The advent of energy transition has shifted that expected result.

Altering the Customer Attachment Rules and the Application of EBO 188

The market distortion problem discussed above suggests that CIACs should cover the full cost of a connection. To the extent that this deters connections the GHG emission problem will be mitigated.

As we noted in our closing submission, the Board's statutory objective is not to expand the gas system willy nilly, it is to facilitate rational expansion of transmission and distribution systems. There's nothing rational about skewing the market and increasing the risk of a death spiral. Even if attachments are not curbed, the problems of stranded asset risk and cross-subsidy will be reduced by such an approach.

If that approach is taken, the 25 year old EBO 188 rules and the related connection rules could be simplified to require the CIAC to cover 100% of hard connection costs.

Enbridge argues that a "blended" revenue horizon could be 30 years based on an assumption that 50 percent of new customers remain on the gas system when their heating or cooling equipment needs replacement.[62] However, that approach carries the risk of underestimating departures with no remedy available to address the revenue shortfall, and more critcally, it would not address the market distortion issue. Further, the EBO 188 test assumes full utilization at current levels throughout the revenue period, an assumption that clashes with Enbridge's own scenarios that predict enhanced energy efficiency of buildings and appliances which will reduce both energy and demand. Accordingly the 'blended' horizons that Enbridge suggests would not come close to achieving a P.I. of 1.

62 K10.2 Table 2 and AIC at p. 110

Mr. Neme suggested a compromise value of 15 years (and a shorter connection horizon) to reduce the risks of stranding and excessive cross-subsidy but noted that there are compelling arguments for full CIAC, notably the market distortion concern.

For 2024 Enbridge estimates that 80% of customer attachments will be for houses in residential developments (subdivisions).[63] **GEC submits that the the dominant role of developments in the customer attachments forecast suggests that the market distortion concern necessitates that 100% of general service connection costs be required as a CIAC for all connections. Consistent with that, GEC submits that the EBO 188 guidelines and related connection rules should be adjusted to require a CIAC for 100% of connection costs.**

As discussed above, **to avoid market distortion developers should not be eligible to utilize the TCS or SES amortization mechanisms.**

Mr. Ladanyi, on behalf of Energy Probe, suggested that the revenue horizon for gas should be comparable to that in the DSC for electricity. That suggestion fails to recognize that a key rationale for a 100% CIAC or a much shorter gas revenue horizon is that gas customers will use less in future and have a high likelihood of departing the system. In contrast, electrical customers are likely to use more electricity in future and unlikely to ever leave the electricity system. It also fails to recognize the distinction discussed above, that the bulk of the costs of electricity connection for developments are not avoidable (new homes still get 200 amp service to accommodate air conditioning) whereas the gas connection costs are avoidable. Put another way, the marginal cost of connecting electric heat to the distribution grid is close to zero. Thus, the break-even point for electric heat in new grid connections is instantaneous.

Ms Giridhar and Enbridge in their argument-in-chief suggested that a change to the revenue horizon would require several other changes to matters such as the extra length charge and the community expansion program. Attachments under the community expansion program are forecast to amount to 566 of the approximately 41,000 connections forecast for 2024 (i.e. 1.4%).[64] It might be necesarry to address that sub-group distinctly but that tail should not be allowed to wag the dog on this issue. Similarly, the rules for extended service line costs can be easily adjusted to conform to any change in the connection policies and the application of EBO 188. Enbridge provides a list of possible related changes in its argument-in-chief. GEC submits that Enbridge could propose appropriate changes in light of a Board determination on the

[63] I.2.6-ED-94 updated shows 32,761 of 41,193 attachments are for subdivision homes in 2024
[64] I.2.6-ED-94

issue of revenue horizon and the proposed related changes could be addressed in subsequent phases of this proceeding, or by written process. Enbridge acknowledged that all needed changes could likely be in place for 2025.[65] However, we are concerned that any delay in application will precipitate a rush by developers for connection agreements with a corresponding cost and risk to the system. Accordingly we would urge the Board to direct that new connection charges will apply to all connections not committed to as of the date of the Board's Decision.

There was some discussion of whether the EBO 188 guidelines would need to change and whether that would require the OEB CEO to promulgate a rule change. However, counsel for Enbridge had indicated that the company accepts that the matter can be addressed by the Panel in the proceeding. EBO 188 refers to maximums, and is only a guideline. Even if a CEO rule promulgation is required, this panel can make that recommendation. However, GDAR section 2.2.2 reads: A rate-regulated gas distributor shall assess and report on expansion to its gas distribution system in accordance with the guidelines contained in the E.B.O. 188 Report. Accordingly, no change is needed to the GDAR, in any event.

As to the question of whether this proceeding is the right forum, Enbridge in its argument suggests that the only evidence addressing the matter is Mr. Neme's. This is a surprising argument given all the subsequent evidence filed in IRRs, undertakings and in the oral phase of the hearing, and especially given the fact that Enbridge was alerted by the Panel in its Procedural Order that it wished to hear about the matter. Enbridge was at liberty to file reply evidence, it didn't.

Capital Spending justified by EBO 134

EBO 134 uses a 40-year revenue assumption in its stage one test. As discussed above in regard to EBO 188, assuming constant demand and energy and therefore a constant

[65] J.10.13 "Considering all of the implementation impacts as described above, Enbridge Gas believes (though this may be optimistic) that an implementation date of January 1, 2025, would likely be appropriate. This timing would allow Enbridge Gas to consider the extent of the impacts stemming from an OEB decision, prepare and file an updated connection policy and other related evidence, complete the regulatory approval process for a new ELC or fixed CIAC for infill customers, as well as updated SES and TCS, and implement all necessary business process and system changes. Should Enbridge Gas require a later implementation date, it would make a request to the OEB."

revenue stream is an assumption which must be questioned given the impending energy transition.

GEC submits that the revenue period in the EBO 134 test be altered, to 15 years, to reflect the high likelihood of declining energy delivery via the gas system on average to all classes of customers.

Implications for IRP

As noted above and discussed in the EFG report Ex. M9 at page 48, GEC submits that **the prohibition on electrification measures as IRPA's should be removed and the IRP guidelines should be enhanced to make promotion and funding of electrification a mandatory option for consideration** where desireable for customer or societal economics, or the attainment of net zero by 2050. Enbridge argues that this hearing is not the place to alter the IRP rules. Our proposal is simply that these options be required considerations. The acceptability of any particular course of action can then be determined with a fuller record in light of the details at play in the particular circumstance of a project proposal. The Board could then adjudicate on the appropriate course of action.

Further, as discussed above in regard to customer connections, and below in regard to depreciation, **a shorter revenue period and declining use should be utilized in IRP analyses. GEC submits that a 15 year revenue period should be utilized in IRPA analysis to help reduce stranding risks**.

Also discussed in the EFG report, and illustrated by way of example in Appendix B of that report, **IRPAs should be assessed under multiple future load forecasts to determine the optimal solution given the range of potential futures**. This approach would allow for a quantification of the "option value" that can be obtained by repair versus replace deferrals in capital planning.

A related matter arrises due to Enbridge's suggestions to the E&ET panel that the monetary threshold for Board leave to construct be doubled and the diameter of exempt pipelines be increased.[66] At a time when growing rate base risks stranded costs, reducing OEB oversight and transparancy is the exact wrong direction. **We respectfully**

[66] Enbridge's Feedback on the Electrification and Energy Transition Panel's Consultation, June 30, 2023 at p. 7

encourage the Board to express its view of Enbridge's request to reduce Leave to Construct oversight in its reasons in this case.

Issue 15 - Depreciation

As we have suggested above, a failure to recognize the declining value of energy services that customers will receive from the gas system will result in severe inter-generational inequity and increase the risk af an uncontrolled flight from the grid with a concomitant risk of a death spiral.

Concentric agreed that generational fairness requires a response:

> "Concentric agrees that any customer or customer group should only be responsible for the consumption of the service value of the assets that they have access to. As such, in the circumstance where the demand on a gas distribution system decline, generational fairness would indicate that the remaining net book value of the system to be recovered from the later customers would be consistent with the system that had largely been consumed by earlier users when the system was operating at higher capacity levels."[67]

In its Argument in Chief Enbridge acknowledges:

> "Intuitively, if there is a material risk of declining throughput in future years, it follows that business as usual depreciation calculations such as the ALG procedure should be avoided and a more accelerated recovery of depreciation undertaken."[68]

Addressing the energy transition will first and foremost require a confrontation with Enbridge's plans for increasing customer connections and increasing rate base. There are $16 billion of assets in service today and Enbridge proposes adding a further $7.3 billion over the next five years.[69] With current policies, many of those capital additions will be amortized into rates over 40 or 50 years. (55 years for plastic services account 473.01.[70]) Current rates of depreciation ($892.4 M in 2024[71]) will not reduce rate base

[67] Ex.I.1.10-GEC-66 (b)
[68] AIC para. 488
[69] Ex. 2, T.5, S.1, P. 13 Table 2 updated 2023-07-06
[70] J13.6
[71] EG Depreciation compendium page 4

as fast as Enbridge is increasing it ($1,470.3 in 2024[72]). The inequity of leaving that growing mortgage to customers who will be receiving a fraction of the energy that current customers receive is apparent.

While much of the oral evidence focussed on the immediate rate impact of choosing the Average Life Group (ALG) versus the Equal Life Group (ELG) depreciation methodology, it is apparent that neither of these approaches are designed to address the challenge, and particularly the uncertainty, of the energy transition. This is also true for an Economic Planning Horizon (EPH) approach.

Units of Production Versus Historical Methodologies Based on End of Physical Asset Life

Depreciation experts are first and foremost in the business of fitting Iowa curves to historical data sets. They will deviate from simple statistical projection where obsolescence is obvious or some other factor presses them to colour their selection, but they are a profession dedicated to conservatism and a reluctance to recognize change. Even in the choice of ELG rather than ALG as a means to begin to recognize the emerging energy transition, both techniques that rely primarily on historical data, two of the three depreciation experts were discomfitted.

But today all acknowledge that we face an unprecedented situation. The company and all of the depreciation, capital structure, and energy transition experts have acknowledged that methane delivery to general service customers will be largely or entirely gone in 25 years, long before the physical service life of many of the assets. And if Enbridge adds over 7 billion dollars of assets in the next five years as they forecast, that mismatch will be amplified.[73]

The depreciation experts and the company respond by pondering the application of an Economic Planning Horizon (EPH or truncation date) for various assets. This is the traditional tool used when the service life of a group of assets is predicted to end at a particular point in time before the physical end of service life of some or all of the group.

An EPH may well be appropriate at some future time when we can predict a date for an end to service for some or all of the company's assets, but according to the experts we have not attained an adequate degree of confidence about such a date or the likelihood of that ocurrence yet. And while the company's vision of the future clearly sees declining energy flows it imagines continued service lives past 2050.

[72] Ex. 2.1.1 page 5
[73] Ex. 2.5.2, p.2

In that circumstance the company and Mr. Kennedy raise the concern that assets could continue to provide value to some customers past the truncation date and that would amount to a free ride at the expense of current ccustomers. Arguably, despite that problem, an EPH might be a better approach than the status quo which suffers the opposite inequity – current customers getting a free ride at the expense of future customers plus the added problem of maintaining high future rates that can drive a death spiral. Nevertheless, the EPH approach does not match costs and value over time. Only the Units of Production approach does so, but the depreciation experts were not yet ready to go there.

In considering the reluctance of the depreciation experts to propose any departure from history-based and end-of-asset-physical-life-based depreciation, to address energy transition, it is important to note the these depreciation experts are not energy transition experts, and indeed, in some cases did not base their recommendations on a rigourous review of the company's evidence including the Guidehouse scenarios or of the critiques thereof.[74] Nor did Mr. Kennedy request a probabilistic assessment to rely on.

> MR. DAUBE: So you'd want to see both impact and probability of the scenarios. Is that right?
>
> MR. KENNEDY: That's correct, sir.
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> MR. DAUBE: You didn't ask Enbridge for that additional analysis?
>
> MR. KENNEDY: We discussed the fact that they had a study under way to review the potential pathways and a consultant working on that. We were updated with the results. <u>I had not seen the study at the time I wrote my report, though.</u>
>
> <u>MR. DAUBE: And you didn't ask for anything more than that?</u> I think this is right. I'm just confirming.
>
> MR. KENNEDY: <u>Yes.</u> And, sir, I think we had a number of discussions about where that study was and the preliminary indications from such a study. (Emphasis added)

Thus the depreciation experts seem to demand a more certain prediction of the future before responding with a significant change in approach but ignore even the company's relatively clear acknowledgement of the minimum, and not insignificant, change that is coming.

[74] See Kennedy at V. 17, p. 7, and at p. 80, and Mr. Masden at V.18, p. 79 indicating it was not within his retainer to review the scenarios.

What we see the company acknowledging, and the energy transition experts agreeing with, is that by 2050 there will be, at the very least, a dramatic drop in energy delivery to the bulk of customers. The Diversified scenario, developed by Guidehouse and based largely on assumptions provided by Enbridge (or agreed to in discussions that Posterity and Guidehouse had with the company) shows a 53% decline in annual energy delivery and a 50% decline in peak energy delivery to general service customers, and a 20% decline to industrial customers in coincident peak energy delivery.[75]

The evidence of both Mr. Hopkins and Mr. Neme, the two experts on aspects of the energy transition who testified before the Board, suggest that the declines will be greater or akin to those we see in the Electrification scenario: an 89% drop in energy in the buildings sector.[76]

Faced with those scenario results it is revealing that Enbridge had Concentric offer an illustration of the impact of EPH but not the obviously more applicable Units of Production alternative. We are tempted to assume that Enbridge chose a strawman that would be easy to knock down rather than a realistic approach designed for the task for fear that acknowledging the decline explicitly would impair shareholder value.

A Units of Production, or perhaps a more appropriately named Units of Consumption based depreciation methodology would match the depreciation expense over time to the value customers receive. It can still terminate depreciation for a given group of assets if expected delivery of service is foreshortened, analogous to an EPH if that is desired at any point. Like all depreciation methodologies it can distinguish between asset groups and thus between customer categories and it can be adjusted as we go as we learn with greater precision what the future is likely to hold.

Mr. Kennedy champions the ELG approach as a first step response to the likelihood of energy transition. While ELG does accelerate some depreciation expense compared to ALG, it is just a less aggregated statistical method and still assumes that assets provide full value to customers until they reach their physical end of life. Almost coincidentally it may help ease inter-generational equity concerns somewhat in the interim, but it fails to properly respond to the task over time.

Mr. Bowman agreed that ALG, ELG and EPH do not address declining use *per se* for assets that remain in service.[77]

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[75] See GEC Compendium K2.1 at p. 2 and discussion at V.2, p.5 et seq
[76] See GEC Compendium at p. 4
[77] V.18, p. 2

Mr. Madsen indicated that in some cases he chose shorter lives for assets in light of the impending energy transition.[78] But, again, instead of addressing the decline of customer value his approach looks at service life duration. Further, leaving it to the experts to pick and choose what statistics to ignore is not a particularly defensible or transparent approach to regulation in the current circumstances.

Mr. Bowman provided a refreshingly honest appraisal of his profession's approach and its shorcomings. He offered disdain for practitioners who deviate from theoretical rigour and tinker with the numbers to address energy transition. Rather, he called on the Board to confront the issue if it foresees a need to address it (as he apparently does), and to holistically, explicitly, and directly respond, using a combination of the tools at hand, including depreciation, stranding risk allocation, and rate design, amongst others. While he feels that other matters dominate that need, in particular capital additions, he acknowledged that depreciation was part of the full picture that has to be considered.[79]

Both Dr. Hopkins and Mr. Neme cite units of production depreciation as an appropriate course of action.[80]

All three depreciation experts acknowledged that Units of Production was an appropriate method to respond to a forecast of inter-generational inequity due to declining customer value, but they were deterred by the difficulty of its application.[81] Again we see a fixation on a need for statistical certainty obscuring the simple fact that all parties accept that the future holds a 50 - 90% decline in energy delivery to general service customers.

We asked Mr. Bowman:

> …isn't it fair to say that the units-of-production approach is the only one that's going to do anything at all to help with this mismatch between the level of depreciation and the service being received as we spoke of a few minutes ago?
>
> MR. BOWMAN: The units of production is the only approach that has been discussed here, that tracks the

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[78] V.18, p. 82
[79] M1, p. 6 and V. 18, p. 7
[80] Dr. Hopkins notes at N.M8.ED-6 (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.
[81] See Mr. Kennedy at V. 16, p. 112 *et seq*.

> value of the system in regard to depreciation in relation to the throughput or delivered energy of the system as opposed to the years in which the system is providing service. I agree with that.[82]

However Mr. Bowman questioned whether energy delivery (GJs) will be the measure of 'value' in the emerging transition, citing Ms Giridhar's oft-repeated remarks about reliability and resiliency. He is not an energy transition expert, and when pressed, acknowledged that assuming the IESO and the government do their job of keeping the lights on as reliably tomorrow as they do today, by 2050 even if the gas system is characterized by hydrogen and limited RNG providing peaking service to the customers who remain on the system with hybrid furnaces, <u>the big difference between today and 2050 for general service customers is likely to be that they get the same reliable peak service from gaseous fuels that they do today, but less gas energy at other times</u>.[83] The upshot of that is that while gaseous fuel delivery at peak times in the future may be viewed as an important option from an energy planner's perspective, from the customer's perspective, that's less valuable than what they get today.

Mr. Kennedy agreed that fewer GJs delivered means "less value of assets" and that fairness would require less allocation of depreciation to those later customers.[84]

Further, if inter-generational equity is the concern, it is the customer perspective that matters. Even if energy planners felt that there is societal value to maintaining the gas grid as a means to limit investment in electrical capacity, that would not offset the loss in value from a customer perspective when comparing a future peaking service to the current full heating plus annual appliance energy delivery service. And, as discussed above, the best evidence before the Board shows that electrification is also preferable from a societal perspective both economically and ecologically, not just from the customer perspective.

Mr. Madsen did suggest that U of P is not the only method that could accelerate and ramp down depreciation over time to match a prediction of declining delivery of value, but it it clear that it is the mechanism specifically and most appropriately suited for that purpose.

As Mr. Kennedy noted:

[82] V.18, p. 10
[83] V.18, p. 3-6 (emphasis added)
[84] V.16, p. 196-197

> …if we assume that every household is going to consume 25 percent less energy and there would still be 75 percent of the volumes left on the system over that 20-year period, that would tell me that we probably aren't going to have retirement of very many assets because we're still having to deliver volume into those residences. That is a scenario where, a method like the unit of production or in this case unit of consumption approach, I think we would review it a bit more significantly. I do think the time is emerging that that method may be used in these kind of circumstances.[85]

We can only wonder how a 25% decline in energy warrants consideration of a U of P approach but the fact that Enbridge sees a likely future with a 50% decline isn't good enough. Mr. Kennedy had earlier suggested that the ELG approach could somehow accommodate an adjustment to recognize fewer units of energy being delivered over time but acknowledged his approach had not explicitly done so:

> MR. POCH: …And has -- in your study in this hearing, has that -- has that kind of adjustment been made in any case, going forward?
>
> MR. KENNEDY: Not directly, sir, no. I mean, it's in the back of our minds, but not directly in terms of being quantified, absolutely not.
>
> MR. POCH: So the adjustments in this case are simply where some group of those assets, you know it's going to be -- they are going to be retired sooner than -- and then some defined group, than the larger group, and you can quantify that?
>
> MR. KENNEDY: Yes, we can hope to try to quantify that, yes.[86]

Furthermore, the other methods are simply not up to the task. For example, Mr. Kennedy's advocacy of the ELG approach as a step in the right direction to deal with energy transition was put in perspective by Mr. Bowman when he noted:

> If you're adding a billion-and-a-half dollars a year but your overall depreciation expense on the company is only something like $800 million, you're not achieving net declines in rate base.

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[85] V.17, p. 166
[86] TC4 March 27, p. 127

> So, the type of numbers we're talking about for some of the -- you know, ELG is a move in the right direction. ELG is, you know, 70 or 80 million dollars. It is not dealing with the difference between a growing rate base versus a declining rate base.[87]

In contrast, if a U of P approach is adopted that explicitly reduces rate base in step with declining energy delivery, it will by definition respond adequately. Of course, Mr. Bowman's comment also highlights the pressing need to reduce capital expenditures.

Mr. Kennedy acknowledged that deferring depreciation with a future where there are dramatic drops in energy delivery like that envisioned in the Guidehouse scenarios can bring on a death spiral.[88] He added:

> Dr. Bonbright would have told us in his 1961 textbook that one should err to that sort of earlier recovery of the capital simply to avoid that death spiral in later years.

As is apparent from Dr. Hopkins' evidence, any fuller appraisal of the options available for addressing the risks of energy transition as has occurred elsewhere suggests that a units of production approach will emerge as the appropriate part of the response.

Implementing Units of Production Based Depreciation

Mr. Kennedy suggested that devising a set of units of production depreciation schedules is a major task that could take at least a year. We fear that the gentleman doth protest too much. Depreciation practitioners may be expert at fitting historical data to Iowa curves to derive annual values but they have no particular expertise at predicting energy transition pathways, and it would be a misstep and a waste of time and resources to ask them to do so. If instead the Board were to suggest one or more assumptions about the expected decline in customer value by 2050 for the major customer segments and ask the company to provide depreciation schedules for the relevant asset groups consistent with those assumptions, the task would appear to be relatively straightforward.

We are not suggesting that anyone, including the Board, can predict the future with certainty. But it does seem obvious that business as usual is not a reasonable assumed

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[87] V.18, p.8
[88] V.17, p.6-7

trajectory for the gas system. Choosing a conservative prediction of a transformed future and adjusting that in subsequent rate cases offers a means to improve equity, reduce risk to the company and its customers, and ease in rate adjustments to avoid disruptive change.

Delaying responding to the energy transition will decrease equity and make rate change more disruptive. The increasing rate impact of a delayed change was discussed by Mr. Neme for an EPH scenario and it was agreed by Mr. Kennedy that the same concern would apply to a delay in applying a U of P approach.[89]

Dr. Hopkins agreed that the Board need not await the E&ET panel findings before beginning its consideration of changes to depreciation to address energy transition.[90]

The Guidehouse scenarios, as flawed as they are, do provide a sense of the range of futures that might emerge. For the reasons discussed above under Issue 3 we submit that even the electrification scenario likely underestimates the extent of the transition away from gas that is likely. That said, the scenarios could be relied upon to suggest a conservative way to ease in depreciation rates that anticipate the transition. **We suggest that the Board retain experts or direct Enbridge to retain experts to produce Units of Depreciation based depreciation schedules commensurate with a range of futures bracketed by the Guidehouse scenarios. The allocation of depreciation expense over time should be based on annual energy delivery, which as discussed above, is the appropriate value measure from a customer perspective. The depreciation schedules could be based on a simple linear decline in energy delivery from 2024 onward passing through the point estimates that the scenarios indicate for 2050 for the major customer segments. GEC submits that a third set of assumptions might be to assume the mid-point of the two scenarios. The Board could then consider the outcomes and impacts in a subsequent phase of this proceeding or in a subsequent rate proceeding. If necessary, a phase in period could be employed to avoid rate disruption.**

Given that producing, and considering those schedules is unlikely to be feasible for 2024 implementation, we propose that the Board determine that such a change will be implemented for the 2025 rate year, or if necessary, the 2026 rate year. Whether that can be integrated with a longer IRP period or require a rate period of one to two years we leave to the Board or possibly for consideration in phase two. But we strongly urge the Board to plan for depreciation reform and implementation expeditiously to

[89] See V. 17, p. 20
[90] V. 5, p. 141-142

smooth the transition, enhance inter-generational equity and reduce stranding and death spiral risks for the company. As we noted in our closing address, this accords with the Board's statutory objectives of:

- Protecting the interests of consumers with respect to prices and the reliability and quality of gas service.
- Facilitating the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

ELG vs ALG in the Interim?

Since the Board is unlikely to have before it a set of fleshed out Units of Production depreciation schedules that could be implemented for the 2024 rate year, it is necessary to pick an approach for the interim period assuming that harmonization to a single approach is desireable.

Mr. Kennedy was emphatic and persuasive about the need to acknowledge the energy transition in making the choice between ALG and ELG. ELG does have the benefit of accelerating depreciation which both improves inter-generational equity in a declining energy use world and leaves less undepreciated capital in the event of a sudden collapse.[91] In contrast, the examinations of the consumer intervenors tended to focus on the scale of the jump in revenue requirement with a switch to ELG and emphasized the virtue of gradualism.

As we have discussed above, any delay in adjusting depreciation will increase inter-generational inequity and could invoke more disruptive sudden rate change.

Accordingly, **while we caution that ELG is not a solution to the challenge of energy transition, it might be the more desireable interim arrangement for the next year or two.**

[91] V. 16, p. 193

Issue 20 – Capital Structure

We will leave a detailed parsing of the evidence to others and simply observe that Enbridge has failed to adequately consider energy transition for the reasons we list above under Issue 3. As Dr. Hopkins illustrated by simplified example and by reference to studies elsewhere, a prudently planned response to energy transition can minimize and possibly eliminate the risks of the energy transition including stranding, a death spiral, and inter-generational inequity. To reward shareholders (and penalize customers) with a higher equity thickness in the absence of such an analysis seems unwarranted and unfair. Addressing this question promptly with a proper record offers a further reason to consider a shorter rate period.

GEC submits that limiting the term of the rebasing and possible IRP to a one- or two-year period would allow Enbridge to provide a fuller analysis of risk mitigation options which would allow the issue of equity thickness to be considered with a proper evidentiary base that includes strategies to respond to the energy transition.

List of Key GEC Recommendations

Energy Transition

GEC submits that the Posterity and Guidehouse reports are severely flawed and biased. Given that Enbridge has proffered the Guidehouse report to government agencies and the E&ET panel, we would urge the Panel to explicitly state that the report should not be relied upon given its biases, limited scope, and numerous flaws in methodology.

Load Forecast - GEC does not take issue with the load forecast for 2024. However, the assumption of relatively steady demand utilized to justify growth investments is no longer supportable.

Capital Budget - Altering the Customer Attachment Rules and the Application of EBO 188:

GEC submits that the Board should require a 100% CIAC policy for new general service connections which would reduce the capital budget by $1.579 billion.

GEC submits that the the dominant role of developments in the customer attachments forecast suggests that the market distortion concern necessitates that 100% of connection costs be required as a CIAC for all general service connections. Consistent with that, GEC submits that the EBO 188 guidelines and related connection rules should be adjusted to require a CIAC for 100% of connection costs.

To avoid market distortion developers should not be eligible to utilize the TCS or SES amortization mechanisms.

GEC submits that the revenue period in the EBO 134 test also be altered, to 15 years, to reflect the high likelihood of declining energy delivery via the gas system on average to all classes of customers.

Implications for IRP:

GEC submits that the prohibition on electrification measures as IRPAs should be removed and the IRP guidelines should be enhanced to make promotion and funding of electrification a mandatory option for consideration.

GEC submits that a shorter revenue period and declining use should be utilized in IRP analyses. A 15 year revenue period should be utilized in IRPA analysis to help reduce stranding risks.

IRPAs should be assessed under multiple future load forecasts to determine the optimal solution given the range of potential futures.

GEC respectfully encourages the Board to express its view of Enbridge's request to reduce Leave to Construct oversight by raising the exempt project limit and pipeline diameter size.

Depreciation:

GEC submits that the Board should retain experts or direct Enbridge to retain experts to produce Units of Depreciation based depreciation schedules commensurate with a range of futures bracketed by the Guidehouse scenarios. The allocation of depreciation expense over time should be based on annual energy delivery, as the appropriate value measure from a customer perspective. The depreciation schedules could be based on a simple linear decline in energy delivery from 2024 onward passing through the point estimates that the scenarios indicate for 2050 for the major customer segments. GEC submits that a third set of assumptions might be to assume the mid-point of the two scenarios. The Board could then consider the outcomes and impacts in a subsequent phase of this proceeding or in a subsequent rate proceeding. If necessary, a phase in period could be employed to avoid rate disruption.

Given that producing, and considering those schedules is unlikely to be feasible for 2024 implementation, we propose that the Board determine that such a change will be implemented for the 2025 rate year, or if necessary, the 2026 rate year.

We caution that ELG is not a solution to the challenge of energy transition, though it might be the more desireable interim arrangement for the next year or two.

Capital Structure:

In relation to deemed capital structure, Enbridge has simply failed to adequately consider options such as capital spending constraints and altered depreciation to address energy transition risks. GEC submits that it would be inappropriate to significantly raise rates to adjust equity thickness at this time, in the absence of sufficient analysis of risk mitigation approaches

GEC submits that limiting the term of the rebasing and possible IRP to a one- or two-year period would allow Enbridge to provide a fuller analysis of risk mitigation options which would allow the issue of equity thickness to be considered with a proper evidentiary base that includes strategies to respond to the energy transition.

All of which is respectfully submitted this 19th day of September, 2023D

On behalf of GEC