ONTARIO ENERGY BOARD

EB-2022-0200

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an application by Enbridge Gas Inc. to change its natural gas rates and other charges beginning January 1, 2024

Submissions of Environmental Defence

Re Enbridge's 2024 Rebasing Case – Phase I

September 19, 2023

Elson Advocacy
Professional Corporation
1062 College Street, Lower Suite
Toronto, Ontario
M4H 1A9

Kent Elson, LSO# 57091I
Tel.: (416) 906-7305
Fax: (416) 763-5435
kent@elsonadvocacy.ca

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Overview

Enbridge seeks to increase its rates based in part on plans to spend over $7 billion in capital over the next five years.[1] Most of these assets would not be paid off until the 2080s based on Enbridge's proposed depreciation methodology.[2] Not surprisingly, a great deal of this proceeding has been focused on the reasonableness of these investments in long-lived pipeline assets in light of the ongoing and accelerating transition away from the consumption of fossil fuels.

These submissions begin with a detailed assessment of the likely impacts of decarbonization on the gas system. All indications are that gas demand will decline over the next 30 years due to full electrification by the general service customers that provide 87% of Enbridge's revenue. The best-case scenario for Enbridge is that many will adopt hybrid heating instead (even though it is more expensive for households compared to fully-electric heating), but that still results in a reduction of over 90% in their annual demand.

Accordingly, these submissions recommend steps to mitigate risks and reduce costs for customers relating to decarbonization. The three most important steps are as follows:

- **Better planning:** Enbridge should be directed to develop an energy transition plan and account for decarbonization demand scenarios in all aspects of business planning, especially capital planning and depreciation proposals. Enbridge's current approach assigns a 0% probability to the demand reduction scenarios that are most likely in determining the financial parameters for capital projects and depreciation proposals.
- **Better and less risky customer connection approach:** Enbridge should be directed to end the subsidy for new customer connections or at least reduce it to reflect a 10-year revenue horizon. This would lower energy bills for existing customers *and* new homebuyers; more fairly allocate the cost of shared gas infrastructure; reduce risk; and reduce market distortions and perverse incentives for developers.
- **Better and less risky depreciation approach:** Enbridge should be directed to return in phase III of this proceeding with a proposal to move to a depreciation approach that adequately accounts for the energy transition (units of production), and in the interim, adopt Enbridge's depreciation proposal with adjustments necessary to stop the unsustainable growth in rate base.

Enbridge and a portion of its pipelines could play an important role in a decarbonized future by delivering RNG and high concentrations of hydrogen to industrial customers that are hard to electrify, but only if it cuts costs to compete with alternatives such as on-site electrolysers. This potential future is inconsistent with Enbridge's proposals, which would result in a bloated, quickly accelerating, and unsustainable rate base. Ontario needs to drastically de-risk its fossil gas system, reduce system-wide capital spending, and begin paying down existing infrastructure. Unfortunately, Enbridge's application does the opposite.

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[1] Exhibit 2, Tab 5, Schedule 2, Page 2 (Utility System Plan capital between 2024 and 2028 is $7,172.6, or $7,374.1 including the Panhandle Regional Expansion Project) (link, PDF p. 254).

[2] Exhibit I.4.5-ED-138 (The periods for new mains and services are between 55 and 60 years.) (link, PDF p. 1529).

The energy transition will cause gas demand declines

Enbridge's $7 billion capital plan and its depreciation proposal rely on unsupported implicit predictions about the role of gas pipelines in a decarbonized future. Its application is predicated on increasing demand, adding approximately 40,000 new customers each year for the next decade, and continuing forward with strong demand and revenue generation until the 2080s. Although Enbridge's formal forecasts only extend out 10 years, the economics underlying its capital projects are based on 40 years of strong forecast revenue (to the 2060s) and its proposed depreciation rates would not pay off those pipelines until the 2080s. Throughout its capital plan and depreciation proposals, Enbridge assigns a 0% chance that demand will decline and cause underutilized or completely stranded assets.

It is astonishing that Enbridge ignores the possibility of declining demand in its financial analyses despite the many reasons to believe that declining demand is a near certainty and massive declines are a significant possibility. As more fully detailed below, those reasons include the following:

1. **Fossil methane gas is a major source of carbon pollution** – one-third of Ontario's emissions are due to combustion alone and upstream leaks add at least an additional 40% to the harmful climate impact (likely more if the latest science and measurements are used);[3]

2. **Low carbon gases cannot replace more than a tiny portion of fossil gas** because of renewable natural gas ("RNG") potential is limited (~2.5% of throughput), blending of hydrogen into RNG is limited (~0.0035% of throughput), and 100% hydrogen is not feasible for the general service customers that generate 87% of Enbridge's revenue;[4]

3. **Electrification of building heat is extremely cost effective**, with households saving over $10,000 each compared to fossil gas, and even more when compared with heating with low carbon gases;[5]

4. **Government policy supports electrification**, including heat pump rebates, 0% interest loans for heat pumps, the price on carbon, federal climate legislation, official projections of a 41% decline in building emissions by 2030 from 2019 levels, provincial plans to build new electricity generation, and provincial directives to achieve lower energy bills regardless of the equipment used (which favours heat pumps as the cheapest option);

5. **Pathways studies forecast major declines**, with independent studies finding that high electrification pathways are cheapest and least risky, gas-sponsored studies promoting hybrid heating but still predicting demand declines, and the even the highly biased Guidehouse study finding electrification to be cheaper if one of many errors are fixed.

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[3] See page 5 below.
[4] See page 6 below.
[5] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 26 (link).

Fossil gas is a major source of carbon pollution

The fossil methane gas that flows through Enbridge's pipelines is a major source of carbon pollution. This puts the need and role of those pipelines into question as we reduce our carbon emissions to reach net zero over the next 30 years. Although this seems to be an obvious point, it is important to recognize how bad fossil methane gas is for the climate and how important it is to eliminate it to meet climate targets and avoid catastrophic climate change.

As a starting point, the *combustion* of fossil gas in Ontario generates approximately one-third of Ontario's carbon pollution.[6]

However, the impact is far greater if one accounts for upstream and downstream emissions, including leaks from extraction, transportation, storage, and end-use equipment, as well as emissions from the energy used in all those processes (e.g., compressors). Based on the default value for the Clean Fuel Standard, upstream emissions add over 40% on top of the combustion emissions for fossil methane gas.[7] The impact of upstream emissions is even greater if one focuses on the next twenty years, which many experts argue is critical when considering policies aimed at avoiding catastrophic climate change.[8] A tonne of methane is estimated to have 84 times the warming power of carbon dioxide over a 20-year period.[9]

Although upstream emissions occurring outside Ontario are not accounted for in Ontario's greenhouse gas emissions inventory, that does not make them irrelevant. Those emissions will need to be reduced regardless of their location, which will impact the price and availability of gas to Ontario consumers. At least some of those upstream emissions will be subject to a carbon pricing regime, which will also have impacts on prices in Ontario.

The picture is even worse because upstream emissions are considerably higher than those recorded in national inventories. [10] Canada has acknowledged this in its official National Inventory Report.[11] Studies cited in Canada's own National Inventory Report suggest that the actual upstream emissions are roughly twice those indicated in the National Inventory Report.[12] These discrepancies arise because the inventories are based on "industry self-reported bottom-up estimates" and there is "near scientific consensus that these self-reported bottom-up estimates are far below the actual emissions rates determined through top-down methodologies based on data collected from aircraft and satellites."[13]

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[6] See page 8 below.
[7] *Clean Fuel Regulations*, SOR/2022-140, Schedule 6, s. 8(d) (link, PDF p. 170); Exhibit L, p. 11 (link); EB-2020-0066, Exhibit JT1.7 (link, PDF p. 398); The default carbon intensity is 68 gCO2e/MJ for natural gas, this number can be broken out further to 48 gCO2e/GJ for emissions from end-use combustion, and 20 gCO2e/MJ related to upstream extraction, processing, transportation and distribution.
[8] Exhibit N.M10-EGI-107(a) (link, PDF p. 1).
[9] Environment and Climate Change Canada (link, Ex. K2.2, PDF p. 302).
[10] Canada's National Inventory Report (link, Ex. K2.2, PDF p. 6); Studies cited in the National Inventory Report suggesting that actual upstream emissions are roughly twice those reported in the National Inventory Report: KT9.5 (link); Exhibit KT9.6 (link). See also Exhibit N.M10.EGI.108, Attachment 2 (link, PDF p. 3).
[11] *Ibid*.
[12] *Ibid*.
[13] Exhibit M10 (link, PDF p. 5)

Studies of downstream methane leaks in cities across North America are also finding that actual top-down measurements find far higher emissions in comparison to bottom-up estimates used for official inventories.[14] Enbridge has acknowledged that they do not have an estimate for the *actual* upstream emissions nor measurements for behind-the-meter leaks in Ontario.[15]

There is no doubt that fossil methane gas is extremely harmful to the climate and must be eliminated over the next 30 years based on the combustion emissions alone. Depending on the true extent of the lifecycle emissions, fossil gas could be worse than coal, in which case these emissions need to be eliminated even faster.[16]

Low carbon gases cannot replace fossil gas

The only hope for the future of pipelines is low carbon gases – green hydrogen and RNG. However, these gases cannot replace more than a tiny portion of Ontario's current fossil gas consumption – particularly for the general service customers that provide 87% of Enbridge's distribution revenue.[17] Taken together, RNG plus hydrogen blending can replace at most 5.37% of the current fossil gas consumption even with highly optimistic assumptions about RNG potential and hydrogen blending feasibility, as detailed below.

RNG feedstocks are very limited

The potential for RNG to replace fossil gas is limited by the availability of feedstocks, such as agricultural by-products and municipal waste. A number of studies have been conducted to estimate the amount of RNG that would be feasible to produce from Ontario-based feedstocks. The estimates come to around 2.5% of Ontario's fossil gas consumption. The results are summarized in the table below:

Feasible RNG Potential – Percent of Current Fossil Gas Consumption	
Canadian Biogas Association Study	2.5%[18] (Ontario)
IESO, Pathways to Decarbonization Study (Interpreting Torchlight Bioresource Report)	2.5%[19] (Ontario)
Canada Energy Regulator, Canada's Energy Future 2023	3%[20] (Canada-wide)

[14] Exhibit N.M10.EGI.108, Attachment 2 (link, PDF p. 3); See also Exhibit K2.2, Tab 3 (link, PDF p. 12).
[15] Hearing Transcript Vol 2, p. 79, lns. 16-26 & p. 80, lns. 9-12 (link).
[16] Exhibit M10, p. 14 (link, PDF p. 14).
[17] Hearing Transcript Vol. 3, p. 12, lns. 15-25 (link).
[18] Hearing Transcript Vol. 2, p. 100, lns. 1-5 (link); Canadian Biogas Association study, p. 71 (link, Ex. K2.2, PDF p. 184); cited by Guidehouse in Exhibit I.1.10-ED-35 (link, Ex. K2.2, PDF p. 99).
[19] IESO Pathways to Decarbonization Study, Appendix B, p. 27 (link, Ex. K2.2, PDF p. 221); IESO Correspondence (link, Ex. K2.2, PDF p. 221); Hearing Transcript Vol. 2, p. 106, lns. 13-24 (link);
[20] Hearing Transcript Vol. 5, p. 176, ln. 3 to p. 177, ln. 8 (link).

Enbridge argues that Ontario will achieve far greater RNG volumes than any studies find feasible, even studies conducted by pro-biogas associations. They say this will occur through technological advancements and imports. Chris Neme and Dr. Hopkins both disagree that this is a reasonable assumption.[21] However, even if we assume that Ontario will achieve twice the amount found to be feasible in the two studies with Ontario-specific figures, that is still only 5% of Ontario's current fossil gas consumption.

Hydrogen blending is extremely limited

Enbridge's best current estimate is that hydrogen blending will be possible in the range of 5% to 20% by volume, which equates to 1.6% to 7.3% by energy content.[22] Although Enbridge seems to be optimistic about achieving the higher end of that range throughout its system, that appears to be inconsistent with the conclusions of a major study by the California Public Utilities Commission, which found as follows:

> This systemwide blending injection scenario becomes concerning as hydrogen blending approaches 5% by volume. As the percentage of hydrogen increases, end-use appliances may require modifications, vintage materials may experience increased susceptibility, and legacy components and procedures may be at increased risk of hydrogen effects.[23]

Even if we assume that hydrogen blending up to 7.3% of energy content is feasible, that is still extremely limited, and even more limited when it is considered as a percent of the RNG potential in a decarbonized gas system after fossil methane gas is phased out. If the RNG potential is very optimistically assumed to be 5% of current fossil gas consumption, and hydrogen is blended in at 7.3% by energy content, that means that hydrogen is only able to replace 0.37% of the current fossil gas consumption in a decarbonized gas system.[24] That is extremely low. Taken together, with high-end estimates for both RNG potential and hydrogen blending, a decarbonized gas system can replace a mere 5.37% of Ontario's current fossil gas consumption.[25] The low-end estimates come to 2.54% of Ontario's fossil gas consumption.[26] These are sobering numbers.

100% hydrogen blending is not feasible for general service customers

Green hydrogen may play a critical role in decarbonization for industrial uses, either through 100% hydrogen pipelines or on-site electrolysers. However, 100% hydrogen is not a reasonable solution to decarbonize the millions of buildings that constitute the vast majority of Enbridge customers and 87% of its distribution revenue. It is not reasonably possible to conduct the kind of simultaneous switchover that would be needed to convert these customers to 100% hydrogen.

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[21] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 32 (link); Hearing Transcript Vol. 5, p. 13, lns. 9-28 (link).
[22] Exhibit J2.11 (link, PDF p. 30).
[23] CPUC Hydrogen Blending Study, p. 4 (link, Ex. K2.2, PDF p. 237).
[24] Calculation: 5% x 7.3% = 0.037%.
[25] Calculation: 5% + 0.037%
[26] Calculation: 2.5% x 1.6% = 0.04%; 2.5% + 0.04% = 2.54%

Chris Neme, Dr. Asa Hopkins, and other pathways studies agree on this point.[27] Further, the discussion of the logistics of a simultaneous switchover with Ms. Martin at the hearing make it abundantly clear that this simply will not happen.[28]

In addition, 100% hydrogen would require far larger (or more) pipes because a given diameter of pipe can only delivery about 30% as much hydrogen-based energy as methane-based energy.[29] Further still, it would be necessary to design and bring to market 100% hydrogen equipment to replace all of the current methane gas uses. Some face particular challenges, such as hydrogen stoves with invisible flames. Safety is also a major concern because hydrogen is a smaller molecule with very different combustion characteristics than methane.

These are just some of the technical barriers that make 100% hydrogen unfeasible for the vast majority of Enbridge customers.

Carbon capture and storage

It is unclear whether carbon capture and storage is feasible even for large industrial facilities in Ontario in light of geological and other factors, let alone whether it is cost-effective. But even if it could overcome the many technical and economic hurdles for large industrial customers, carbon capture and storage is clearly not feasible as a decarbonization solution for Ontario households.

Electrification of buildings is extremely cost-effective

Electrification of buildings is taking place now and will continue to accelerate because consumers are increasingly learning that it can save them a great deal on their energy bills while providing environmental and other benefits.

Homeowners that electrify their space and water heating will save approximately $17,000 over the lifetime of their equipment.[30] This is a net present value that has discounted future savings, and therefore the gross savings are even higher.[31] Customers often focus on simple values such as the savings on their energy bills. For 2023, the annual energy bill savings are $683. However, those savings will increase as the carbon price increases by 20 cents per m^3 between now and 2030.[32] By 2030, the annual energy bill savings arising from electrification of household fossil gas uses will be $1,134.[33] That is a very attractive benefit to a consumer that is replacing their air conditioner or furnace and deciding whether to install a heat pump.

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[27] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 20-21 & 11 (link); Hearing Transcript Vol. 4, p. 172, lns. 19-25 (link).
[28] Hearing Transcript Vol. 2, p. 186, ln. 11 to p. 189, ln. 28 (link).
[29] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 21 (link);
[30] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).
[31] *Ibid*.
[32] Enbridge, Federal Carbon Charge (link).
[33] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).

This analysis of customer savings by Chris Neme of the Energy Futures Group is very robust. It has been tested by way of interrogatories and an oral hearing involving more than 30 intervenors. The full underlying modelling and all assumptions have been disclosed. In addition, Mr. Neme conducted a detailed sensitivity analysis that explored the following factors: lower gas commodity prices, worse heat pump efficiency, ineligibility for government rebates, higher heat pump cost, and the need for an electrical panel upgrade. He also did not account for a number of factors improving the cost-effectiveness of heat pumps, such as access to federal $40,000 interest-free loans. As detailed in his report, electrification remains cost-effective in all of the scenarios. As summed up by Mr. Neme: the "conclusion that electrification is cost-effective for customers today is very robust."[34]

The consumer savings from electrification will likely substantially increase in a future where the electricity system and gas system are both decarbonized.[35] Mr. Neme used conclusions from the IESO's Pathways to Decarbonization report and the cost of RNG to examine the impact on energy costs with decarbonized gas and electricity systems. He found that the energy cost savings from electrification in a future with fully decarbonized systems would be three times the savings today.[36]

As Mr. Neme explains, the savings from electrification increase because "[t]he incremental cost of RNG (relative to fossil gas plus a carbon tax) is simply much greater than the increase in the price of electricity that will be necessary to grow the electric grid so that it can serve electrified buildings."[37] Furthermore, Mr. Neme identifies three additional factors that will even further improve the economics of electrification: (a) the ability of electrifying customers to avoid fixed gas charges; (b) increasing gas distribution rates as customers exit the system; and (c) additional investments to make up for the fact that RNG is not always carbon neutral.[38]

Fully electrifying a home is also more cost-effective for Ontario households in comparison to using a hybrid heating system that relies on an electric heat pump coupled with a gas furnace for the coldest days.[39] That is primarily because backup heat is required only very infrequently and disconnecting from the gas system allows a customer to save $310 annually in fixed charges.[40] The savings from full electrification versus hybrid heating will increase with the proposed harmonized rates, which would bring the fixed customers charges to $398.25 annually[41] and increase the cost of gas at peak periods five-fold,[42] which presumably corresponds at least in part to the cold periods when backup gas would be used.

[34] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 24 (link).
[35] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 (link).
[36] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 (link).
[37] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 (link).
[38] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25-26 (link).
[39] Hearing Transcript Vol. 5, p. 172, ln. 17 to p. 174, ln. 7 (link).
[40] Enbridge Rate Zone (link); calculation: 22.88 x 12 x 1.13.

[41] Exhibit 8, Tab 2, Schedule 7, Attachment 2, Page 8 (link, PDF p. 759); calculation: $29.37 x 12 x 1.13.
[42] Exhibit 8, Tab 2, Schedule 7, Attachment 1, Page 9 (link, PDF p. 643); Exhibit 8, Tab 2, Schedule 7, Attachment 2, Page 8 (delivery increases from approximately 12 ¢/m³ to 68.3385 ¢/m³) (link, PDF p. 759) .

Furthermore, full electrification will likely become even more cost-effective versus hybrid heating in a future with fully decarbonized gas and electricity systems. As discussed above, the increase in cost for decarbonized gas outweighs the increase in cost for decarbonized electricity.[43]

In addition, fully electrifying a home results in considerably fewer carbon emissions in comparison to hybrid heating based on today's electricity generation mix.[44] The carbon reduction benefits from full electrification are likely to increase in light of the federal mandate for net-zero electricity generation by 2035.[45]

One might ask the following question: if heat pumps are so cost-effective, why are customers still installing gas furnaces? This is in part because it takes time for HVAC contractors to make the switch to heat pumps from furnaces and time for both contractors and consumers to learn that gas is no longer the cheapest way to heat a home. The cost-effectiveness of heat pumps is a relatively recent development driven by the following factors:

- **Improved cold climate performance:** In the past, heat pumps were inappropriate for our cold winters. Some contractors are not aware that this has changed. Cold climate heat pumps have high performance down to low temperatures (many down to -30°C). Even today, a standard cold climate heat pump can provide 100% of the heat in a Toronto home throughout a typical winter without supplemental heat.[46] But centrally-ducted heat pump units sold today also include a simple and cheap electric coil that fits into the air handler (i.e., blower fan unit) in the basement for supplemental heat for extremely cold days just in case. The technology continues to improve, and the best units have high heating capacities and efficiency levels in the range of 200% even at -30°C.[47]

- **Efficiency:** Heat pump efficiency has improved with advancements, such as variable speed compressors, which make them cheaper to operate both for heating and cooling.

- **Rebates:** Customers can now receive significant rebates and interest-free loans to purchase a heat pump (see below for details), which were not previously available.

- **Carbon price:** By 2030, the carbon price on gas will equal 32.40 cents/m^3.[48] By comparison, that amounts to over *three times* the price charged by Enbridge for methane gas in Toronto in January of 2020 (10.19 cents/m^3).[49]

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[43] See footnotes 35 to 38 above, and the text associated therewith.
[44] Exhibit J18.7, p. 4 (link).
[45] Canada 2030 Emissions Reduction Plan, p. 83 (link, Ex. K2.2, PDF p. 318).
[46] Guidehouse Heat Pump Study for Enbridge Gas, p. 10 (link, Ex. K2.2, PDF p. 285); This recent study prepared by Guidehouse for Enbridge shows that a cold climate heat pump can provide 100% of the heating for a Toronto home with a heating load of 2.5 tons. For Toronto homes that are larger or more leaky, supplementary electric resistance heating is forecast to only be required for 1 hour each year. The analysis is based on a standard cold climate heat pump as opposed to a top-of-the-line unit.
[47] Exhibit J18.7 (link).
[48] Enbridge, *Federal Carbon Charge* (link).
[49] Ontario Energy Board, *Historical Natural Gas Rates* (link).

We are beginning to see that awareness among customers that gas is no longer the cheapest option is steadily growing. For example, Enbridge is experiencing and forecasting steep declines in customers choosing to switch their homes from other fuels to gas (see page 31 below).

Government policy supports electrification

Government policy strongly supports electrification. This includes the following:

- The federal government is offering a $5,000 rebate for customers to switch to high-efficiency electric heat pumps as part of its Greener Homes Grant.[50] Enbridge customers are eligible for an additional $1,500.

- The federal government is offering an *additional* $5,000 rebate for customers to switch from oil to high-efficiency electric heat pumps if they earn a median income or lower (e.g., $122,000 after-tax income for a family of 4 in Ontario) through the Oil to Heat Pump Affordability Program.[51]

- The federal government is offering $40,000 in interest free loans, which can be put towards conversions to electric heat pumps, and not gas equipment, through the Greener Homes Loan.[52]

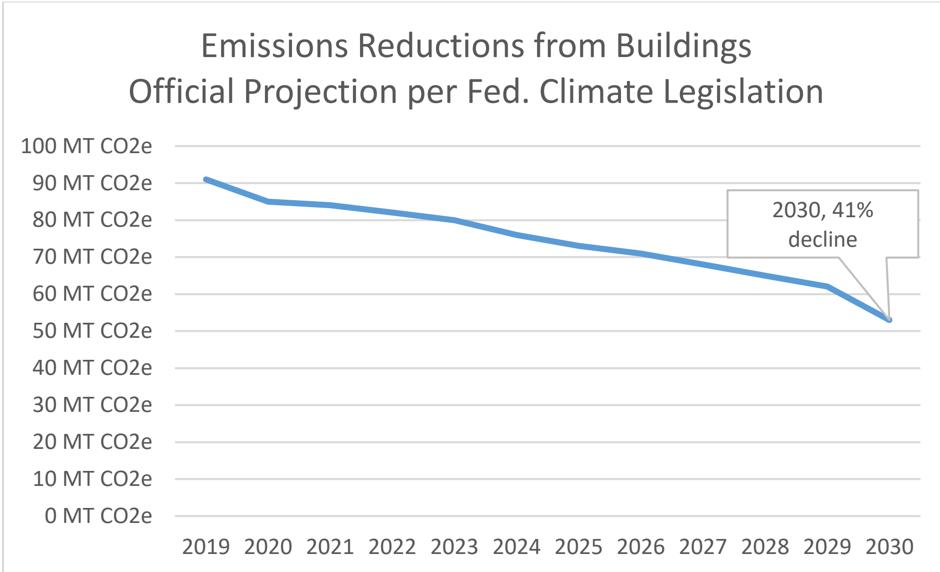
- The price on carbon will increase to 32 cents per m^3 by 2030.[53]

- Canada has passed the *Canadian Net-Zero Emissions Accountability Act*, which mandates official carbon emissions reduction targets, plans, and sector-by-sector projections;[54]

- Canada's official targets for overall emissions reductions pursuant to its climate legislation are net-zero by 2050 and 40 to 45 percent below 2005 levels by 2050; and[55]

- Canada's official projection for emissions reductions pursuant to its climate legislation is for emissions from buildings to decline by 41% by 2030 from 2019 levels, as illustrated in the chart below:[56]

[50] Government of Canada, *Canada Greener Homes* Grant (link).
[51] Government of Canada, *Oil to Heat Pump Affordability Program* (link).
[52] Government of Canada, *Canada Greener Homes Loan* (link).
[53] Enbridge, *Federal Carbon Charge* (link).
[54] *Canadian Net-Zero Emissions Accountability Act*, S.C. 2021, c. 22 (link).
[55] Canada, 2030, Emissions Reduction Plan Backgrounder (link, Ex. K2.2, PDF p. 306).
[56] Canada, 2030 Emissions Reduction Plan, p. 318 (link, Ex. K2.2, PDF p. 318); Canada, 2030, Emissions Reduction Plan Backgrounder (link, Ex. K2.2, PDF p. 313); Hearing Transcript Vol. 2, p. 134, ln 18 to p. 135, ln. 13 (link).



Enbridge refers to the "Powering Ontario's Growth" plan eight times in its submissions. But the plan *does not* call for continued gas expansion or anything close to the high-gas vision that Enbridge describes in its application. The plan merely says that gas will continue to play a critical role in Ontario.[57] That is obvious, as we cannot stop using fossil gas immediately and low-carbon gases could drive industrial decarbonization. Contrary to picture Enbridge attempts to paint, Ontario's plan focuses predominantly on the electricity sector. For instance, it describes how "electrification is playing a critical role in driving down emissions" in the building sector.[58] It also details major efforts to increase electricity generation and transmission.[59]

The core of Ontario's energy policy is to achieve lower energy bills. It is fuel agnostic. This policy is exemplified in a recent mandate letter from the Minister of Energy to the OEB. In the section on demand-side management (DSM), the Minister of Energy provided the following direction:

> It is also important that the DSM Framework be implemented in a way that enables customers to lower energy bills in the most cost-effective way possible, and help customers make the right choices regardless of whether that is through more efficient gas or electric equipment.[60]

A policy of lowering energy bills is equivalent to a pro-electrification policy when it comes to the vast majority of Enbridge customers – building owners – as that is the best and fastest way to lower their bills.[61]

Overall, federal policy is likely more relevant to anticipating future impacts of decarbonization on the gas system because the federal government has large and concrete programs in place that

[57] Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, p. 30 (link).
[58] Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, p. 18 (link).
[59] Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future*, p. 41-75 (link).
[60] Mandate Letter to the OEB, November 15, 2021, p. 3 (link).
[61] See page 8 above.

are helping customers save money by electrifying their space and water heating.[62] The federal government has concurrent jurisdiction over environmental matters and also exercises considerable spending power. At present, climate policy in Ontario is dominated by the federal government. Although the OEB is a provincial agency, it is extremely important that it account for the impacts of federal policies and programs on the future of the gas system.

Finally, we could see a ban on gas in new construction in Ontario in the future. The International Energy Agency recommends that a ban on new gas heating be instituted by 2025.[63] A long list of municipalities with over 15 million residents across the United State have instituted these bans.[64] Most recently, the State of New York passed a ban on gas in new construction for heating and cooking.[65] Enbridge certainly cannot rule out the possibility that a similar ban could come to Ontario in the coming years. Nor can it rule out a future extension to equipment replacement in existing homes long before the end of the economic life of the pipelines it is constructing today.

Pathways studies forecast major declines

Most independently-conducted assessments of decarbonization pathways have concluded that high electrification pathways are the most likely and most cost-effective pathways, even in colder climates, and that this will result in major declines in peak and annual gas demand.[66] This includes work completed by the Canadian Climate Institute, which Enbridge acknowledges provides credible, independent, expert-driven analysis on climate issues.[67]

Although gas-sponsored studies often find a greater role for hybrid heating systems, even they nevertheless predict major declines in gas.[68] For example, the Massachusetts hybrid scenario still found that approximately 20 percent of customers would fully electrify.[69] The report also recommended a full electrification mandate for new construction as one of the no-regrets policies.[70]

The Guidehouse pathways study supports electrification

The report prepared by Guidehouse is an outlier in comparison even to other gas-sponsored pathways studies. For instance, it differs from many other jurisdictions due to the prevalence of hydrogen in all scenarios and the absence of a scenario where the large majority of buildings

[62] See page 11 above for a list of those policies. For a discussion of the relevance of federal policy by Dr. Hopkins, see: Hearing Transcript Vol. 5, p. 30, ln. 22 to p. 32, ln. 19 (link).
[63] Exhibit I.1.3-SEC-7, Attachment 4, Page 28.
[64] Exhibit J8.3, Attachment 1.
[65] Exhibit J8.3.
[66] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 11 & 49 (link); Canadian Climate Institute, The Big Switch, May 2022, p. 5 (link, Ex. K12.3, PDF p. 69).
[67] Canadian Climate Institute, The Big Switch, May 2022, p. 5 (link, Ex. K12.3, PDF p. 69); Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 11 (link); Hearing Transcript Vol. 12, p. 115, ln. 19 to p. 116, ln. 3 (link).
[68] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 18 (link).
[69] Hearing Transcript Vol. 6, p. 68, ln 25 to p. 69, p. 22 (link).
[70] Hearing Transcript Vol. 6, p. 68, ln 25 to p. 69, p. 22 (link).

fully electrify.[71] It is also an outlier in considering 100% hydrogen delivery to residential and commercial customers as being a realistic option.[72]

The many flaws in the Guidehouse report are best described in Chris Neme's own words and via the summary table from his evidence:

> Overall, Guidehouse's assumptions are highly biased in favor of gas and not credible. There are numerous instances in which optimistic leaps of faith are made about equipment and systems necessary to make continued use of gaseous fuels look economically viable while much more conservative assumptions are made about electric alternatives. For example, Guidehouse assumes high penetrations of residential gas heat pumps and 100% hydrogen furnaces and appliances, despite the fact that these products are not even commercially available today. In contrast, Guidehouse assumes market penetration rates for electric heat pump water heaters in 2040 that are much lower than leading jurisdictions are achieving today through DSM programs. Similarly, Guidehouse assumes that the efficiency of electric heat pumps will degrade 2% per year after installation (based on an outdated study that doesn't apply to current electric heat pump technology) but that gas furnaces and gas heat pumps will experience no such degradation.
>
> To make it easier for the reader to begin to consider numerous concerns about the Guidehouse study in their totality, a summary is provided in Table 9 below. Note that the implications of correcting each Guidehouse error or bias are quantified and monetized where possible. However, that was not possible in many cases without the ability to run Guidehouse's model with changed assumptions. … Nevertheless, it is abundantly clear that correcting Guidehouse's errors and biases would result in the scenario that places greater emphasis on electrification being not just less costly, but substantially less costly than the scenario that relies more on gaseous fuels including 100% hydrogen. In fact, just correcting the first problematic assumption – the inappropriate use of a higher cost of carbon in the electrification scenario (with resulting higher emission cost even though the scenario produces fewer emissions!) – is enough to make the electrification scenario the lower cost option.

[71] N.M8.ED-3 (link, PDF p. 10)
[72] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 11 (link).

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

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

Dr. Hopkins agrees with Mr. Neme's conclusion that the Guidehouse report is biased in favour of gas.[73] During the oral hearing we asked Dr. Hopkins to comment on each of the critiques of the Guidehouse report listed in Table 9 above. Dr. Hopkins' views were entirely aligned with Mr. Neme's.[74] With respect to the price of carbon, Dr. Hopkins described the approach taken by Guidehouse as a "methodological error."[75] Correcting only this one bias and error, while fully ignoring the remaining 12 critiques listed above, swings the results such that the so-called electrification scenario is $26 billion cheaper than the high-gas scenario.[76]

Additional flaws and biases have come to light subsequent to Mr. Neme's report. For instance, it is now clear that Guidehouse assumed a production price for green hydrogen that is less than half of Enbridge's best estimate and less than one-quarter of the current retail price of grey hydrogen.[77]

In addition, Guidehouse's reliance on massive quantities of blue hydrogen (generated from methane gas with carbon capture) is unreasonable.[78] Blue hydrogen is inconsistent with decarbonization because its lifecycle emissions are far too high (see 18 below). Guidehouse assumed emissions that are 10 times lower even than the studies that Enbridge cites on this question (see page 19 below). Guidehouse re-ran its model with green hydrogen replacing the blue hydrogen, which changed the results by $34 billion against the high-gas scenario.[79] But, the true impacts are even higher because Guidehouse underestimates the cost of green hydrogen by at least a factor of two.[80] More importantly, the model re-run is of little value because Guidehouse forced it to select green hydrogen as the alternative, rather than examine whether greater electrification would be the optimal result when accounting for the true emissions from blue hydrogen.[81]

Finally, it is critically important to recognize what the Guidehouse model *does not* do. The model does not determine the optimal amount of fuel-switching from gas furnace to cold-climate heat pumps.[82] Nor does it determine that the cheapest decarbonization pathway involves increasing investment in pipelines versus a pathway involving more electricity.[83]

Unfortunately, Enbridge includes misleading statements in this application and in lobbying materials to suggest that Ontario will save huge sums if it actively pursues a decarbonization pathway that emphasizes gases versus higher electrification.[84] That conclusion simply cannot be drawn from the Guidehouse report, even if we put aside the many errors referred to above. Nor

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[73] N.M8.ED-4 (link, PDF p. 10-13)
[74] Hearing Transcript Vol. 5, p. 8-24 (link).
[75] Hearing Transcript Vol. 5, p. 10, ln. 23 (see also the preceding discussion at p. 8, ln. 6 to p. 10, ln. 23) (link).
[76] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 27-28 (link).
[77] Exhibit J2.8, Page 2 (link, PDF p. 27); ED-131 (link, PDF p. 35).
[78] Exhibit JT1.24 (The Guidehouse report assumes an average of 5 billion m^3 of blue hydrogen each year on average from 2030 to 2050 in the diversified scenario) (link, PDF p. 47).
[79] Exhibit JT9.16, p. 1 (link, PDF p. 3160).
[80] Guidehouse assumed a production price for green hydrogen that is less than Enbridge's best estimate and less than one-quarter of the current retail price of grey hydrogen. Exhibit J2.8, Page 2 (link, PDF p. 27); ED-131 (link, PDF p. 35).
[81] Hearing Transcript Vol. 2, p. 171, ln. 9 to p. 172, ln. 18 (link); see also Hearing Transcript Vol. 2, p. 159, ln. 6-10 (link).
[82] Hearing Transcript Vol. 2, p. 159, lns. 6-10 (link).
[83] Hearing Transcript Vol. 2, p. 159, ln. 23 to p. 160, ln. 1 (link).
[84] E.g., see Hearing Transcript Vol. 2, p. 160, ln. 11, p. 163, ln. 11,p.165, ln. 13 (link).

can the report support the other ways that Enbridge relies on it in its application: (a) to argue against decreasing investments in the gas system (and conversely, in support of its proposed increases in gas system investments);[85] (b) to support Enbridge's proposed spending relating to hydrogen;[86] (c) to support Enbridge's proposed spending relating to RNG;[87] (d) to argue against reduced depreciation periods as a tool to address decarbonization-related risks;[88] (e) to argue against the need for a segregated site restoration fund as a tool to address decarbonization-related risks;[89] (f) as a consideration in Enbridge's Asset Management Plan;[90] and (g) to argue that net-zero cannot be achieved without gaseous pipelines delivering RNG, hydrogen, and natural gas with CCUS.[91]

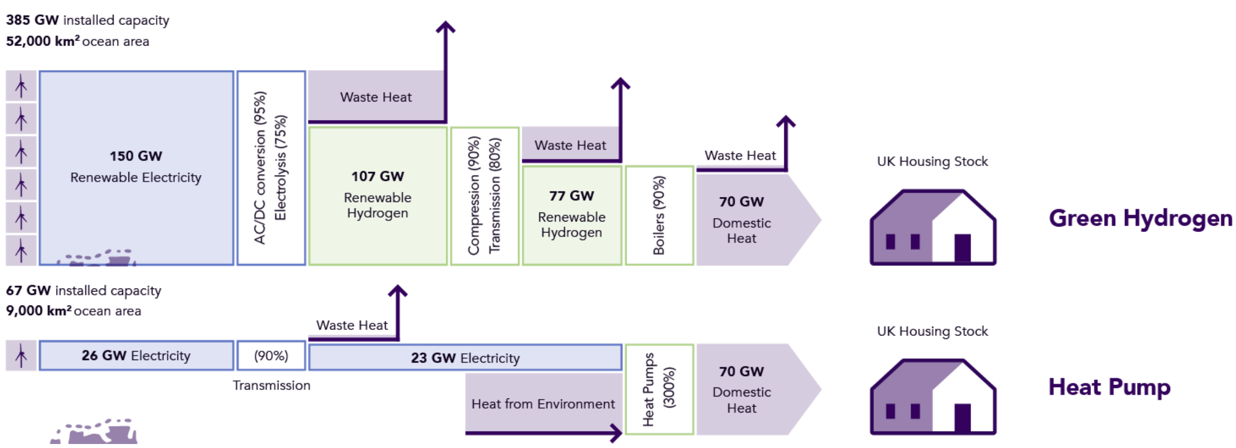
Neither the Guidehouse report, nor the conclusions Enbridge asks others to draw from it, are credible.

Hydrogen is ineffective for decarbonizing buildings

Hydrogen is ineffective for decarbonizing buildings, including both green hydrogen (generated from green electricity) and blue hydrogen (converted from methane with carbon capture).

Green hydrogen generally inferior to electrification

Green hydrogen, which is generated from renewable electricity via electrolysis, is generally not a viable decarbonization solution for uses that can be electrified cost-effectively, like heating for buildings. For instance, it is roughly six times more efficient to use renewable energy to power a heat pump directly versus converting it to green hydrogen and running that through a furnace, as illustrated in the following figure:[92]



[85] Exhibit 1, Tab 10, Schedule 5, Page 12-13, Para. 36 (link, PDF p. 1691).
[86] Exhibit 4, Tab 2, Schedule 6, Pages 5-17, Paras. 11, 17, 38, 42, & 46 (link, PDF p. 242, 244, 251-252, 253 & 254-255).
[87] Exhibit 4, Tab 2, Schedule 7, Page 10, Para. 22 (link, PDF p. 267).
[88] Exhibit 4, Tab 5, Schedule 1, Page 16, Para. 35 (link, PDF p. 845).
[89] Exhibit 4, Tab 5, Schedule 1, Page 19, Para. 43 (link, PDF p. 848-849).
[90] Exhibit 2, Tab 6, Schedule 2, Page 34 (link, PDF p. 440).
[91] Exhibit 1, Tab 10, Schedule 5, Page 14, Para. 41 (link, PDF p. 1692).
[92] Exhibit N.M2-ED-2/Appendix B, p. 3 (link); The precise difference in efficiency between using electricity directly in heat pumps versus converting it to hydrogen for use in furnaces will vary based on assumptions. We asked Enbridge to provide its best estimate and it declined to do so in Exhibit I.4.2-ED-129 (c) (link, PDF p. 89).

Blue hydrogen emissions are too high

The lifecycle carbon emissions associated with blue hydrogen are much too high for it to play a significant role in decarbonation. Drs. Howarth and Jacobson summarize the problem with blue hydrogen as follows:

> Greenhouse gas emissions are higher from blue hydrogen than from burning natural gas mainly because approximately 1.6 to 1.7 MJ of natural gas are required to make 1 MJ of hydrogen, which results in greater upstream unburned methane emissions from natural gas production, storage, and transportation. Emissions also arise as a result of less-than-perfect rates of carbon capture and in relation to the energy needed to run the stream reforming process and the carbon capture process.[93]

Drs. Howarth and Jacobson's work is based on: (a) actual top-down upstream emissions rates; (b) a broad meta-analysis of upstream emissions rates; and (c) real-world data from real-world steam methane reformation and carbon capture facilities.[94] In addition, Drs. Howarth and Jacobson conduct a sensitivity analysis using much lower upstream emissions rates and differing global warming potential (20 and 100 years), as well as considering the possibility of powering the steam methane reformation process with renewable electricity.[95] Based on this detailed and robust analysis, they nevertheless conclude that there is "no role for blue hydrogen in a carbon-free future."[96]

Although some other papers find lower emissions, they have one or more of the following flaws:

- Using outdated self-reported bottom-up estimates of upstream unburned methane emissions from gas production, storage, and transportation (despite the near scientific consensus that these self-reported bottom-up estimates are far below the actual emissions rates determined through top-down methodologies based on measured data);[97]

- Using high carbon capture rates based on *theoretical* facilities (real-world performance is much poorer);[98]

- Disregarding the combustion of gas used to power the conversion from methane to hydrogen (steam methane reformation) or other aspects of the lifecycle emissions that must be accounted for;[99]

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[93] Exhibit M10 (link, PDF p. 2 – see also the figure on page 14).
[94] Exhibit M10 (link).
[95] Exhibit N.M10-EGI-108 (link, PDF p. 15)
[96] Exhibit M10 (link, PDF p. 16).
[97] Exhibit M10 (link, PDF p. 5); Canada's National Inventory Report (link, Ex. K2.2, PDF p. 6); Studies cited in the National Inventory Report suggesting that actual upstream emissions are roughly twice those reported in the National Inventory Report: KT9.5 (link); Exhibit KT9.6 (link). See also Exhibit N.M10.EGI.108, Attachment 2 (link, PDF p. 3).
[98] Exhibit M10 (link, PDF p. 21).
[99] Exhibit M10 (link, PDF p. 4).

- Assuming that unburned methane leakage in gas production, storage, and transportation can and will be drastically reduced in the future (even though there are significant technical barriers and reduction targets are counted from national inventory levels that are known to greatly undercount emissions);[100] and

- Cherry-picking emissions measurements from too narrow a sample set (results from top-down measurements vary too widely to rely on measurements from one study, etc.).[101]

Although the three studies cited in Enbridge's reply evidence on blue hydrogen find somewhat lower emissions from blue hydrogen, they are far higher than the emissions assumed by Guidehouse and too high to be consistent with a carbon-free future. The following table compares the emissions from blue hydrogen generated by steam methane reformation in: (a) the Howarth and Jacobson study; (b) the three papers cited in Enbridge's reply evidence on blue hydrogen; and (c) the non-peer reviewed assumption used in the Guidehouse report:

GHG Emissions from Blue Hydrogen (SMR)	
Source	**GHG Emissions Intensity (gCO_2e/MJ H_2)**
Howarth and Jacobson	57 to 77
Romano et al (cited in Enbridge reply)	46
Bauer et al.	52 to 103
Oni et al.	57 to 70
Assumption Guidehouse, Pathways to Decarbonization	5.5

The papers cited by Enbridge also suggest that lower emissions can potentially be achieved with a different methane-hydrogen conversion process using an oxygen-blown autothermal reformer (ATR). However, even Guidehouse rules out ATR, reasoning as follows: "Unlike SMR, the ATR process requires an additional oxygen supply, which can lead to additional emissions and costs if the oxygen is not supplied as a by-product from a separate process."[102] Drs. Howarth and Jacobson also rule out ATR as a realistic option for those same reasons, and because (a) it has never been used commercially for this purpose and (b) it produces less hydrogen per unit of input methane, leading to greater upstream emissions.[103]

[100] Exhibit M10 (link, PDF p. 5).
[101] Exhibit N.M10-EGI-108 (link, PDF p. 3)
[102] Exhibit KT9.2 (link, PDF p. 26).
[103] Exhibit M10 (link, PDF p. 22).("Regarding Case no. 2, as far as we aware, blue hydrogen based on ATR has never been attempted in commercial operation. Romano et al. give no examples of actual commercial efforts to use ATR, and Kim et al. note in a 2021 paper that the required need for pure oxygen has been an impediment to ATR use by industry. The "overall carbon capture rate of around 93%" used by Romano et al., then, is hypothetical and dependent upon the 98% efficiency that they "assumed in the MDEA unit," which has not been tested in any actual plant. Further, it is important to note that ATR produces less hydrogen per input of methane from natural gas than

Enbridge touts hydrogen as a fuel that helps counteract the "life-shortening effect on Enbridge Gas's system" from decarbonization.[104] That may come true for the green hydrogen in large pipes that serve large industrial customers. But it does not apply to any hydrogen used in buildings nor for blue hydrogen for any decarbonization uses.

Electrification is feasible

Enbridge suggests that Ontario likely cannot manage to expand its electricity infrastructure fast enough to meet the needs from electrification. However, it provides no studies that state this, and instead puts forward misleading figures that overstate the problem. Mr. Neme responded to one of those misleading figures in his testimony as follows:

> MR. POCH: Okay. The Enbridge panel made several references to the challenges of Ontario switching from getting, as they put it, only 15 percent of its energy to 100 percent of its energy from electricity. Can you comment on that? Is it feasible?
>
> MR. NEME: Sure. Let me start by saying that the suggestion that we are going from 15 percent of the energy being supplied by electricity to 100 percent can be a little bit misleading for a couple of reasons. First, I believe we are actually starting at higher than 15 percent. I believe the number for Ontario is more like 21 or 22 percent.
>
> But, much more importantly, … even if we were to go to 100 percent does not mean a four- or five-fold increase in the amount of electricity that needs to be produced. That is because the electrification measures are a lot more efficient than the fossil fuel systems that they are replacing. Heat pumps are on the order of three times more efficient than a gas furnace. Heat pump water heaters are on the order of five or six times more efficient than a gas water heater, and electric vehicles are on the order of three to five times more efficient than internal-combustion gasoline-powered vehicles. So it is not as large a jump as one might think, just by looking at those two numbers, 15 and 100.
>
> In addition, I don't think any party, certainly not my position, believes that we actually have to go to 100 percent of energy being supplied by electricity. There is going to be a role, I believe and I believe most parties believe, for biofuels in the future.
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> I think that is particularly true for important segments of the industrial sector and probably for important segments of the transportation sector, as well.

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does SMR, and so at least 38% more natural gas feedstock is required for ATR. This of course leads to greater methane emissions from the production, processing, storage, and transport of the needed natural gas, a fact apparently not included in the analysis of Romano et al.")

[104] Exhibit 1, Tab 10, Schedule 4, Page 17, para. 52 (link, PDF p. 1675).

> So, as to the feasibility of growing the electric grid – it is going to have to grow substantially. As to the feasibility of doing that, I think it is eminently feasible. Everybody has an electric meter today. We know what technologies – we have them today – that need to be installed in order to electrify. The electrification can proceed at a gradual pace, not only building by building but even appliance by appliance within the buildings. We know that those technologies are getter more efficient, too. In addition, we know how to add generating capacity on the grid. We know how to add storage. We know how to upgrade the [transmission and distribution] system. This can all be accomplished with technology and know-how that we have today. That is not to say it is going be easy or without cost, but it is eminently doable. I think that is underscored by every study that I have seen that suggests that a high-electrification pathway is possible, including the Ontario IESO's own high-electrification pathways study.

Dr. Hopkins also agreed that Enbridge's commentary "misrepresents the magnitude of the challenge" of electrification.[105] He also agreed that there is a possibility that expanding the electrical system could result in *lower* electrical costs on a unit basis if we are able to move from the hub-and-spoke model we currently use to a move efficient approach with the pursuit of new approaches or technological advances.[106] Expanding and decarbonizing the electricity system is already entirely feasible with existing technologies. Although prices may modestly increase, this will be offset by greater savings arising from the higher efficiency of electric equipment, lowering overall energy bills.[107] And this is comparing electrification to the status quo of continuing to burn fossil fuels – the energy bill savings will be even greater in comparison to expensive low-carbon gases and even greater still if technological advancements or new decentralized approaches to the electricity system mean that we can lower electricity prices at the same time.

Summary re likely gas declines

For the reasons set out above, the likely impact of decarbonization on the gas system is major declines in peak and annual demand as most or all of the general service customers that provide 87% of Enbridge's revenue leave the system. The best-case scenario for the gas system is that many adopt hybrid heating instead, but that scenario is constrained by the potential RNG available. In addition, the hybrid heat scenario still involves huge declines in annual demand, some decline in peak demand, and increasing pressure on customers to exit the system entirely.

Enbridge's pipelines could play a critical role in delivering RNG and 100% hydrogen to Ontario's industrial customers. However, this potential role is put in jeopardy if steps are not taken today to de-risk Enbridge's business and reduce rate base. More generally,

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[105] Hearing Transcript Vol. 4, p. 180, ln. 20 to p. 181, ln. 14. (link).
[106] Hearing Transcript Vol. 4, p. 179, lns. 15-19 and p. 180, lns. 3-10 (link).
[107] Canadian Climate Institute, p. 8 (link, Ex. K12.3, PDF p. 103); Enbridge acknowledged that the Canadian Climate Institute provides credible, independent, expert-driven analysis on climate issues at: Hearing Transcript Vol. 12, p. 115, ln. 19 to p. 116, ln. 3 (link); Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 25 & footnote 52 (link).

Enbridge must abandon the assumption underlying its capital and depreciation proposals that major declines in demand have a 0% chance of occurring and therefore can be completely ignored in economic analysis.

The OEB should require regular energy transition plans (issue 3)

In line with the recommendations of Dr. Asa Hopkins and Chris Neme, Enbridge needs to vastly improve its planning processes across its business with respect to energy transition plans, especially in relation to capital planning and depreciation. This is needed because there is now much more uncertainty regarding future demand and revenue levels over the 40-year economic horizons used for the capital planning economic tests (EBO 134 & 188) and over the 60-year depreciation periods of pipelines. These uncertainties create major risks for existing customers, which are discussed more fully below, especially with respect to capital planning.

In particular, Environmental Defence requests that the OEB direct Enbridge to develop an energy transition plan as soon as possible, to be updated on a regular basis. As set out below, the energy transition plan should involve: (a) a demand scenario analysis; and (b) business planning based on that demand scenario analysis.

Part 1: Demand forecast scenario development and analysis

The energy transition plan should set out at least three future scenarios with respect to gas demand. The utility cannot continue to rely on a single forecast because that amounts to predicting a single future, which is impossible in these uncertain times. As described by Dr. Hopkins:

> There is uncertainty about what is coming and what the exact shape of the energy transition will look like. And so good planning in the face of uncertainty takes a range of different potential futures into account and help[s] you evaluate what your … possible actions would be going into that range of futures.[108]

An analysis of multiple scenarios will still be required even after the provincial government releases its pathways study. The study is unlikely to predict a single future. Furthermore, it will simply be a study and may or may not become a policy, let alone be realized in concrete programs or directives. The same is true for the final report of the Electrification and Energy Transition Panel. Even if those do result in concrete policy that calls for the pursuit of a specific course of action, it is too risky to assume that there will be zero changes in policy and zero changes in government between now and 2050. Also, policy is only one factor. Customer economics and customer preferences are also critically important.

The plan would also unavoidably require an assessment of the probability of each scenario occurring. As Dr. Hopkins describes, this is a challenge, but it can be accomplished on a rough basis and is necessary in order to make decisions.[109] It is better to consider the weight that should

[108] Hearing Transcript Vol. 5, p. 27, lns. 7-14 (link).
[109] Hearing Transcript Vol. 5, p. 54, ln. 15 to p. 56, ln. 3 (link).

be applied to each scenario rather than ignore the reality that some may be considerably more likely than others.

The core of each scenario will be a forecast of customer numbers and demand (annual and peak) by customer class. At least three scenarios would be required, and at least one would need to reflect a potential high-electrification future.

Part 2: Business planning and modelling

Once scenarios have been developed, they would be used throughout energy transition-related business planning and modelling. For example, Enbridge would look at how their proposed rates, depreciation, and capital proposals would fare in each scenario. Most critically, each scenario could be examined to assess whether the proposed trajectory for rates and rate base (including depreciation and capital spending) would be sustainable, and the degree to which stranded assets and a death spiral are a risk. Attachment 4 to the evidence of Dr. Asa Hopkins, *Modelling the Strategic Transition of a Gas Utility White Paper*, provides an excellent example and discussion of the kind of business planning and modelling that is needed once scenarios have been defined.[110]

Ensure independence

Both Chris Neme and Dr. Hopkins note that the development of energy transition scenarios is at high risk of being highly biased. This is also illustrated by the Guidehouse report prepared by Enbridge. Environmental Defence requests that the OEB adopt the recommendations of Dr. Hopkins to avoid this problem:[111]

- The scenarios should be developed and analyzed by a consultant retained by the OEB;[112]
- Stakeholders should have access to the results, methods, and tool – not only through an appendix containing the assumptions, but through a discovery process, including interrogatories; and[113]
- Stakeholders should be allowed to define scenarios in the level of detail they are capable of.[114]

However, part 2, the business planning and modelling can likely be conducted by the utility independently.[115]

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[110] Exhibit M8, Attachment 4 (link, PDF p. 90).
[111] Exhibit N.M8-PP-1
[112] Hearing Transcript Vol. 5, p. 58, lns. 3 to p. 59, ln. 16 (link).
[113] Hearing Transcript Vol. 5, p. 59, ln. 17 to p. 61, ln. 4 (link).
[114] Hearing Transcript Vol. 5, p. 61, ln. 5 to p. 62, ln. 26 (link).
[115] Hearing Transcript Vol. 5, p. 63, lns. 3-21 (link).

Timing and process

The energy transition plan should be filed and considered along with each rebasing application and treated as an integral to justifying capital spending, depreciation rates, and other financial parameters. Interim updates could be filed in annual rates cases in a process similar to the annual maintenance plan. However, the rebasing applications would be the most appropriate place to fully test the appropriateness of the plan as that would be necessary to approve capital spending and grant other approvals.

Safe bets (issue 3)

Enbridge outlines a vision for energy transition in Ontario that calls for large investments in pipelines and continued use of pipeline-delivered fuel to meet the needs of all customers classes. This is not surprising seeing as Enbridge is a pipeline company. We do not believe it would be productive to respond to this vision or each of the "safe bets" outlined by Enbridge in the abstract as Enbridge is not asking the OEB to approve this vision or its list of safe bets. Instead, we have addressed the energy transition in relation to the specific application elements that require approval, as detailed below. However, we make the following brief three observations:

- Enbridge argued in its application that "decreasing investments in the gas system will result in the inability to achieve net-zero by 2050."[116] This is a preposterous and obviously self-serving assertion, which is contrary to extensive evidence outlining the feasibility and cost-effectiveness of decarbonization through electrification (see page 20 above).

- Some of the safe bets are stated at such a high level as to be largely meaningless and vulnerable to misinterpretation. References to a "diversified pathway" and "leveraging the gas system" can encompass an extremely wide range of energy transition outcomes including Enbridge's vision of massive volumes of RNG and hydrogen serving all customer types and a much more likely outcome where most or all general service customers electrify while pipelines provide 100% hydrogen and RNG to large volume customers. Statements about the appropriateness of diversified pathways and leveraging the gas system are therefore open to being misconstrued.

- Finally, Enbridge has missed the most important safe bet – avoiding and deferring capital spending where possible. This safe bet was repeatedly emphasized by Dr. Hopkins and Chris Neme.[117] As discussed with Dr. Hopkins: "once you have spent the money and the pipe is in the ground, you can't take it back again."[118]

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[116] Exhibit 1, Tab 10, Schedule 5, Page 12 (link, PDF p. 1690).
[117] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 49 (link).
[118] Hearing Transcript Vol. 5, p. 37, ln. 11 to p. 38, ln. 23 (link).

Capital and rate base (issues 6 to 7)

Enbridge is proposing to spend over $7 billion in capital over the next five years.[119] This capital spending far outstrips the amounts that customers will be paying through depreciation and will add $2 billion to rate base (as shown below). This is on top of approximately a doubling of rate base over the past 10 years.[120] This is unsustainable and far too risky, particularly in light of the potential impacts of energy transition on demand and revenue.

Table 1
2024 to 2028 Rate Base

($ millions)	2024	2025	2026	2027	2028
Rate base	16,212.3	16,275.4	17,366.8	17,820.6	18,136.5

[121]

As a high-level target, the capital envelope should be reduced such that, when coupled with the depreciation approach approved by the OEB, we achieve declining rate base. Even if a high electrification scenario is not considered to be likely, but merely a possibility, it is too risky to be allowing rate base to increase at this time. Instead, it should be decreasing to protect against the possibility of rates rising to unaffordable levels in the coming decades and to help maintain the competitiveness of the gas system, particularly as a delivery mechanism for green hydrogen and RNG to large volume customers.

Of course, the capital envelope must at least be large enough to allow Enbridge to ensure safety and reliability. However, a combination of the items set out below and those discussed in the submissions of other intervenors should be sufficient to stop the growth of rate base. For any gap that remains, depreciation should be accelerated to make up the difference.

Disallow connection costs; alternatively, set a 10-year horizon

Enbridge plans to spend $1.579 billion over the next five years on capital infrastructure to connect new customers to its system, including $359 million in 2024.[122] This $1.5 billion would be recovered from existing customers and is net of any contributions in aid of construction. The large majority would be used to defray the costs of developers seeking to connect new subdivisions to the gas system.[123] As detailed below, Environmental Defence requests that the OEB disallow this spending or, in the alternative, reduce the amount to reflect a 10-year customer revenue horizon (this would be approximately a 50% cost reduction), subject to some limited exceptions noted below.

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[119] Exhibit 2, Tab 5, Schedule 2, Page 2 (Utility System Plan capital between 2024 and 2028 is $7,172.6, or $7,374.1 including the Panhandle Regional Expansion Project) (link, PDF p. 254).
[120] Exhibit 2, Tab 1, Schedule 1, Plus Attachment, Page 4 (link, PDF p. 4)
[121] JT4.24 (link, PDF p. 1784).
[122] Exhibit J13.7 (This includes a) direct capital cost, b) capitalized overheads, c) meter costs, and d) fixed EA overheads. EA overheads refer to payments to the external "extended alliance" of contractors – see Technical Conference Transcript Vol. 5, p. 25. For a breakdown of the direct capital costs and meter costs, see J13.5.).
[123] Exhibit I.2.6-ED-94, Page 5 (link, Ex. K10.3, PDF p. 14).

Enbridge's proposed $1.5 billion in connections capital is based on a status quo application of gas expansion guidelines developed over 25 years ago.[124] The guidelines allow Enbridge to give developers a discount on the cost to connect their subdivisions to the gas system equal to up to 40 years' of forecast revenue from the forecast customers that will be connected in the subdivision.[125] This acts as a cross-subsidy from existing customers to new customers.[126] Eliminating this subsidy would:

1. **Reduce energy bills** by saving existing customers $1.5 billion in capital expenditures[127] and by saving potential new homebuyers over $10,000, to the extent that ending the subsidy causes developers to install heat pumps instead;[128]

2. **Fairly allocate costs** by ensuring that developers bear the cost to connect their subdivisions and ensuring that revenue from new customers goes towards repaying the entire system, not just the incremental infrastructure needed to connect them to the system;

3. **Reduce risk** and fairly allocate risk by ensuring that existing customers are not on the hook for revenue shortfalls when new customers leave the system; and

4. **Reduce market distortions** by removing the subsidy for developers to install gas and by mitigating the split incentive problem, whereby developers choose and pay for the heating equipment but homebuyers pay the energy bills.

Reduce energy bills

Of all the issues in this proceeding, connections capital likely has the greatest potential to achieve significant bill reductions – both for existing customers and for potential new customers. For existing customers, the potential bill reductions are obvious – a complete disallowance would save existing customers approximately $1.5 billion.[129] That amounts to approximately $400 for each of Enbridge's customers, which is over 60% of what the average residential

[124] E.B.O. 188, Final report of the Board & Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998 (link).
[125] *Ibid*.
[126] This discount is accurately described as a subsidy for two reasons. First, neither the developers nor the new customers need to provide a guarantee or any security in support of the 40 years of forecast revenue. It would be equivalent to a car lease that you can simply decide not to pay if you crashed the car or give it away. Second, the new customers pay $0 toward the rest of the gas system aside from the incremental costs attributable to their connection (see discussion starting on page 28 below). If new customers stay on the system for a very long time after connecting to the system, the subsidy is better described as a lost leader – but that is no longer likely.
[127] Exhibit J13.7 (For details on the amounts included in these figures, see footnote 122 above) (link, PDF p. 305).
[128] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).
[129] Exhibit J13.7 (link, PDF p. 305). The exceptions discussed below would reduce the savings, but only by a small amount because the connection capital related to community expansions is modest (see Exhibit J13.5). In addition, only "a very small" portion of the connections capital is for industrial customers, which are subject to a maximum revenue horizon of 20 years (see Exhibit J10.10). For details on the amounts included in these figures, see footnote 122 above.

customer pays in distribution rates to Enbridge for an entire year.[130] A reduction to a 10-year horizon would save approximately $850 million.[131]

Counterintuitively, potential new customers have even more to gain. If residential developers are no longer able to avoid most or all of the cost to connect their subdivisions to the gas system, at least some will decide to install heat pumps instead. Whenever this occurs, the new homeowners will immediately begin saving over $600 each year in reduced energy costs, increasing to over $1,000 annually by 2030 as carbon prices increase.[132] Over the equipment lifetime, they would save over $10,000 (NPV).[133]

Some homebuyers in new subdivisions could end up paying more to connect to the gas system, but that will only occur where (a) the developer forgoes the heat pump option and (b) the developer is able to pass along the cost of the contribution in aid of construction to the home buyer. Even in those limited circumstances, whatever cost is passed along would be incorporated into the home price, would be a tiny proportion of the home price, and would be financed at secured mortgage rates (which are less than the cost of capital that would apply were the costs to be added to rate base). Most importantly, the best option to avoid the possibility of increased costs is to completely eliminate the subsidy for developers, which would also completely eliminate the market distortion caused by the subsidy (see p. 31 below) and maximize the probability that developers will choose heat pumps instead.

In sum, this change would benefit the vast majority of consumers, and will benefit the greatest number of consumers if the subsidy is completely eliminated.

This result is somewhat counterintuitive. It arises because of two fundamental changes that have occurred since 1998 when the OEB first developed its gas expansion guidelines:

1. It used to be assumed that new homes would remain connected to the gas system indefinitely. Under this assumption, the up-front connection subsidy was a loss leader, wherein existing customers would benefit from the stream of income that would accrue for decades after the end of the 40-year horizon. That assumption no longer holds[134] – new customer connections are now expensive and very risky for the existing customer base.

2. Gas used to be the cheapest way to heat homes. Under that assumption, gas expansion was in the public interest as it would enable lower heating costs overall. But that assumption no longer holds either – electric heat pumps are far more cost-effective, with the average customer eligible to save over $10,000 over the equipment lifetime compared

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[130] Calculation for cost per customers: ~$1.5 billion divided by 3.8 million customers (customer numbers per OEB Yearbook of Gas Distributors, 2021-2022, p. 4, link); calculation for percent of residential distribution charges: $400 divided by $600 (average annual residential customer distribution charges per Enbridge Argument in Chief, p. 31, para. 89).
[131] Exhibit J13.7 (link, PDF p. 305). See the caveat at footnote 129 above.
[132] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link). The carbon price is slated to increase by 20 cents per m^3 between now and 2023 (per Enbridge at link).
[133] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).
[134] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9 (link).

> to gas equipment.[135] Subsidizing developers to install gas is no longer in the public interest and now will result in unnecessarily high gas bills for customers.

Completely eliminating the connection cost subsidy for developers is clearly the best option in terms of reducing energy bills. Reducing the horizon to 10 years would help, but would continue to burden existing customers with $729 million in connection capital[136] and would continue to subsidize developers to install gas equipment that will saddle homebuyers with higher-than-necessary energy bills.

Fairly allocate costs

Eliminating the connection subsidy would more fairly allocate costs between new and existing customers, including both the cost of the incremental assets needed to serve the new customers *as well as the cost of the remainder of the common assets that new customers benefit from and should contribute to.* If a customer stays with the system until the end of the revenue horizon, whether it be 10 or 40 years, they will pay only for the incremental assets needed to serve their new connection.[137] Those are primarily the cost of the service line and meter, but also include an amount for incremental normalized upstream reinforcement costs.[138] However, this does not include paying for the remainder of Enbridge assets that they benefit from, whether they be pre-existing upstream pipes, storage, or corporate real estate.[139]

When a customer leaves on or before the end of the revenue horizon, they have not paid their fair share of those common assets that make up the large majority of rate base.[140] This is not fair from a cost allocation perspective and is inconsistent with the "beneficiary pays" principle because new customers benefit from those common assets from day one.

In addition, the contribution in aid of construction (CIAC) calculations do not include the cost to safely disconnect a customer's service line and meter, which amounts to approximately $3,700.[141] A customer leaving the system after the end of the revenue horizon will have burdened existing customers with those disconnection costs and contributed nothing beyond the incremental costs attributable to their connection.

Board Staff argue that customers have not had a "free ride" as long as they remain on the system long enough to exactly pay off their connection cost because CIAC calculations include normalized reinforcement costs.[142] However, those normalized reinforcement costs are still incremental costs attributable to the new customer connection – they do not reflect a "fair share"

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[135] Evidence of Chris Neme, May 11, 2023 (updated May 30th), Ex. M9, p. 23 (link).
[136] Exhibit J13.7 (For details on the amounts included in these figures, see footnote 122 above) (link, PDF p. 305).
[137] Hearing Transcript, Vol. 10, p. 91, lns. 19-21; p. 100, lns. 17-23; p. 103, ln. 26 to p. 104, ln. 4; p. 106, lns. 8-15; p. 142 & 143 (link).
[138] E.B.O. 188, Final report of the Board & Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998, Appendix B, s. 2.1 (link).
[139] Hearing Transcript, Vol. 10, p. 91, lns. 19-21; p. 103, ln. 26 to p. 104, ln. 4; p. 106, lns. 8-15; p. 142 & 143 (link).
[140] Exhibit J10.8 (link, PDF p. 85); Exhibit J13.8 (link, PDF p. 306).
[141] Exhibit I.1.6-SEC-84, Attachment 1, Page 43 ("Average cost for a cut off at main is approximately $3,700.").
[142] Board Staff Submissions, September 12, 2023, p. 26.

of the entire set of common assets in rate base that all customers benefit from.[143] For an average new connection in 2024, normalized reinforcement costs are a mere $635, which comes to approximately $1 per month over 40 years (less if the future flow of income is discounted to a net present value pursuant to EBO 188).[144] This amount is very small because it merely reflects a share of the previous 10-years of reinforcement costs and not any of the other myriad of common capital costs included in rate base.[145]

Board staff notes that "existing customers are made better off for projects with a PI >1" as long as new customers stay to the end of the revenue horizon. That is true (if we ignore the cost to safely disconnect an existing customer's service line and meter). [146] But even if a new customer has paid some amount towards the common assets for a brief period, that does not mean that they have paid their fair share of these assets from a cost allocation perspective. Nor does it mean that the modest potential future returns to existing customers are worth incurring the connection costs up front and bearing 100% of the risk of a "premature" exit.

These fairness issues are one reason why the OEB should not set the horizon based on the average period that new customers are expected to remain with the system (as Enbridge proposes).[147] If the average customer leaves at the end of the revenue horizon, existing customers will be required to cover the disconnection costs and 100% of the common asset costs that all customers benefit from, which is not fair and contrary to the beneficiary pays principle.

No potential unfairness

Enbridge witnesses suggest that lowering the connection horizon would be unfair to new customers by making them pay for assets twice. There is no merit to this argument. EBO 188 requires that CIACs be calculated with reference only to incremental costs associated with those new customers.[148] Whatever capital costs are covered by a CIAC are not added to rate base, and therefore would be recovered only once. Incremental O&M costs included in CIACs are tied to the duration of the revenue horizon and would be reduced to zero if the horizon is reduced to zero.

Finally, Enbridge witnesses suggest that the change would be unfair as between new customers and recently-connected customers. There is always potential for unfairness in some sense of the word when a rule is changed because some customers will be covered by the new rule and some by the old. But that is no reason to remain with the status quo.

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[143] Hearing Transcript, Vol. 10, p. 91, lns. 19-21; p. 100, lns. 17-23; p. 103, ln. 26 to p. 104, ln. 4 (link).
[144] Exhibit J13.8 (link, PDF p. 306).
[145] Hearing Transcript, Vol. 10, p.102, lns. 23-27 (link).
[146] Board Staff Submissions, September 12, 2023, p. 26.
[147] Enbridge Argument-in-Chief, August 18, 2023, para. 277 (Enbridge recommends a 30-year horizon based on "a high-level assumption that around half of the newly attached customers will maintain gas appliances at the time that their furnace reaches end of life.") (link, PDF p. 100)
[148] E.B.O. 188, Final report of the Board & Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998, Appendix B, s. 2.1 (link); Hearing Transcript, Vol. 10, p. 91, lns. 19-21 (link).

It is instructive to consider Enbridge's proposal to increase the extra length charge (discussed below) to roughly five times the current amount.[149] Enbridge provided strong justification for this increase, as well as cogent reasoning to explain why the proposal is not unfair as between customers who will pay the lower charge today and those that will pay quintuple that amount in the future.[150] That reasoning applies equally to the fairness question raised by a change in the revenue horizon.

Reduce and fairly allocate risk

Eliminating the connection subsidy would greatly reduce the risk of stranded assets. If a customer leaves before the end of the revenue horizon, the cost of their service line and meter is stranded. Even if a customer stays until the end of the revenue horizon, there will still be stranded assets because the pipe and meter will need to be safely disconnected from the system at some point, at an average cost of $3,700.[151]

Eliminating the new connection subsidy would also allocate the risk more fairly and appropriately. If a developer pays 100% of the connection costs through a CIAC, existing customers have been largely insulated from the stranded asset risk (aside from potential disconnection costs). Existing customers should not bear these risks as they are powerless to mitigate them and do not benefit from the underlying assets.

Eliminating the connection subsidy would also reduce macro-level risk of unaffordable rates and a death spiral. This step alone would save existing customers approximately $1.5 billion over 2024-2028, which is roughly three-quarters of the overall increase in rate base forecast over that period.[152] As discussed above, increasing rate base when demand is likely to decrease is too risky. It is difficult to see how the OEB could reverse Enbridge's proposed rate base increases without eliminating the connection subsidy. Elimination of the subsidy is therefore an important step in the overall de-risking of Enbridge's application.

A reduction of the horizon to 10-years would reduce risks and allocate them more appropriately. However, a complete end to the subsidy would be the most appropriate from a risk perspective. A death spiral would be calamitous for existing customers with expensive gas equipment that is far from the end of its life. Even a small chance that a death spiral would occur should be assiduously mitigated, including through an end to this subsidy.

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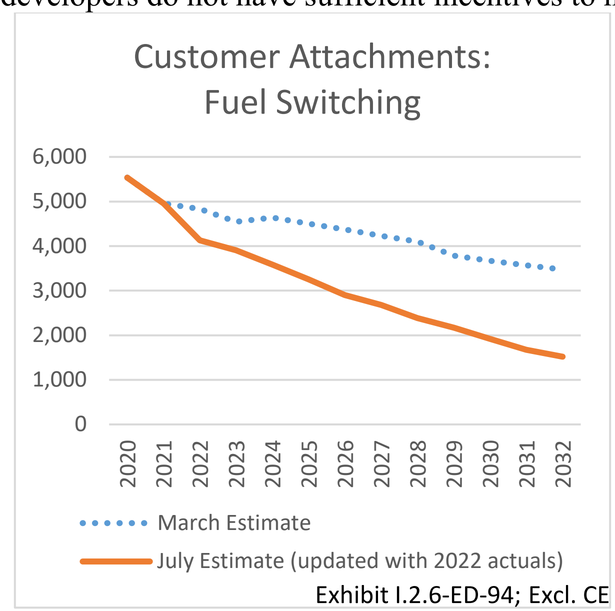
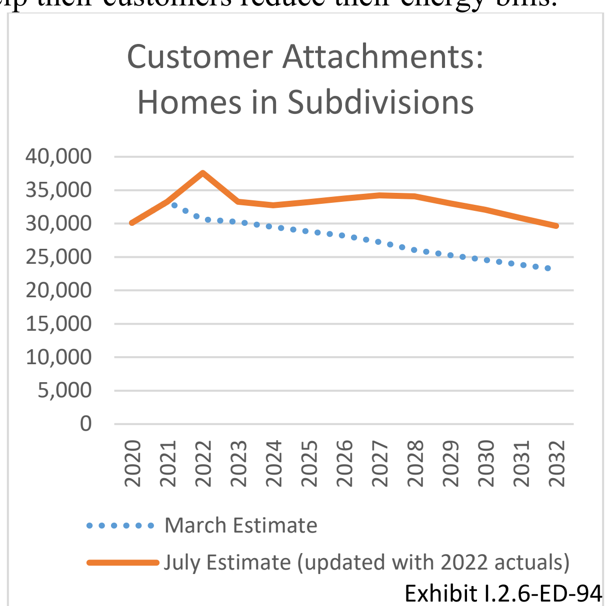
[149] Hearing Transcript, Vol. 10, p. 131 (link) (The proposed charge is $159/m beyond 20 m.); Exhibit 8, Tab 3, Schedule 1, Page 10 (The current charges are $32/m beyond 20 m in the Enbridge rate zone and $45/m beyond 30 m in the Union rate zone.) (link, PDF p. 1194).
[150] Hearing Transcript, Vol. 10, p. 132, ln. 5 to p. 133, ln. 4 (link).
[151] Exhibit I.1.6-SEC-84, Attachment 1, Page 43 ("Average cost for a cut off at main is approximately $3,700."). (link, PDF p. 893); Exhibit 8, Tab 3, Schedule 1, Page 35 (Noting that abandoned natural gas lines and meters pose a safety and operational risk.) (link, PDF p. 1219).
[152] Exhibit J13.7. (link, PDF p. 305)The exceptions discussed below would reduce the savings, but only by a small amount because the connection capital related to community expansions is modest (see Exhibit J13.5). In addition, only "a very small" portion of the connections capital is for industrial customers, which are subject to a maximum revenue horizon of 20 years (see Exhibit J10.10). For details on the amounts included in these figures, see footnote 122 above.

Reduce market distortions

An elimination of the new connection subsidy would also help to reduce market distortions that harm consumers and result in sub-optimal economic outcomes. There is a significant split incentive problem because developers choose the HVAC equipment installed in subdivisions while homebuyers pay the energy bills. As a result, developers have little to no incentive to choose the optimal equipment that will have the lowest overall lifetime cost.[153] The new connection subsidy exacerbates this problem by allowing developers to avoid a major portion of the up-front costs of the gas equipment – namely the cost of the new pipes, meters, and other connection assets. Ending the connection subsidy would help to reduce this distortion and result in more economically rational decision-making.

The split incentive issue is evident in a breakdown of Enbridge's customer attachment forecast. Enbridge forecasts a precipitous decline in customers deciding to switch to gas (where the homeowner themselves decides) but robust continued attachments in subdivisions (where the developer decides).[154] Furthermore, Enbridge filed an update in July after reviewing 2022 actuals showing an even faster decline in fuel switching coupled with even more robust growth in subdivision attachments. [155] This is shown in the figures below, where the blue dotted lines are the forecasts per the March interrogatory responses and the orange lines reflect the July update. It appears that homeowners are steadily learning that gas is no longer the cheapest option but developers do not have sufficient incentives to help their customers reduce their energy bills.





[156]

[153] Although in theory homebuyers could demand the lowest-cost heating equipment from developers, this is unlikely because of the market failures of imperfect information and transaction costs. Homebuyers have many other considerations that rank much higher than HVAC equipment when buying a home and, in many cases, likely do not have information on future HVAC costs.

[154] Exhibit I.2.6-ED-94 (link, PDF p. 452-457)

[155] Exhibit I.2.6-ED-94 (March 8, 2023 version versus July 6, 2023 update).

[156] Exhibit I.2.6-ED-94 (March 8, 2023 version versus July 6, 2023 update); As per Enbridge's categorization, fuel switching excludes community expansion.

Alignment with the electricity system

It appears that some parties may advocate for the revenue and customer attachment horizons to match the 25- and 5-year horizons applicable to the electricity sector. However, that kind of simple uniformity is misguided because it does not account for a number of important differences that support ending the subsidy in the gas sector (or at least greatly reducing it below 25 years), such as the following:

1. **Customer-level risk:** There is little to no risk that homes will abandon the electricity system, stranding the connection assets, unlike in the gas sector.

2. **Deposits:** Unlike the gas sector, developers must pay 100% of the electric system connection costs up front and are only refunded portions of those costs over five years as the actual attachment and revenue forecasts materialize.[157]

3. **Liability for capital cost overruns:** Unlike the gas sector, developers are responsible for paying the full amount of electricity connection capital cost overruns.[158]

4. **Macro-level risk:** There is little to no risk that decarbonization will result in a death spiral for electricity distributors nor the corresponding need to reduce risk and rate base as in Enbridge's case.

5. **Market distortions:** There is no market distortion in the electricity context with respect to HVAC choices because developers need to put in electricity infrastructure regardless of the choice of heating equipment.

6. **Public interest benefits:** There are significant benefits to assisting customers connect to the electricity system, both for the new customers who require it for a myriad of uses, and for the existing customers who will benefit over time from the indefinite stream of revenue from new customers after the end of the revenue horizon period.

The 25- and 5- year horizons from the electricity sector are only relevant in that it is clear that the horizons for the gas sector should be much lower.

Sufficiency of evidence

Enbridge argues that there is insufficient evidence to change the revenue horizon or that the process has somehow been deficient.[159] That is an absurd argument for Enbridge to make. First, the appropriateness of the proposed capital spending has always been a live issue because Enbridge is seeking $1.5 billion in connection capital, including $359 million in 2024, which requires OEB approval.[160]

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[157] Distribution System Code, July 1, 2022, ss. 3.2.20, 3.2.21, 3.2.23 (link, Ex. K10.3, PDF p. 35-36).
[158] *Ibid.*
[159] Enbridge Argument-in-Chief, August 18, 2023, para. 273 (link, PDF p. 99).
[160] Exhibit J13.7 (link, PDF p. 305); In addition, customer connection capital was set out in Enbridge's initial application materials in, for example, Exhibit 2, Tab 5, Schedule 2, Page 2.

Enbridge's arguments about the sufficiency of evidence are also completely backwards. Enbridge has the burden to justify the $1.5 billion in connection-related capital spending is seeks, with evidence. Enbridge has had ample opportunity to submit any evidence on this topic. Enbridge should have considered this issue in detail before filing its application and addressed it explicitly. It is patently obvious that spending $1.5 billion to connect new customers with a plan to recoup those connection costs well into the 2060's is risky and should be re-evaluated in the context of decarbonization.

Enbridge had additional opportunities to submit evidence on this topic as the proceeding progressed. Even if Enbridge can say they did not anticipate the issue initially (which would be concerning), the issue gained greater prominence when Environmental Defence brought a motion on April 10, 2023 to obtain Enbridge estimates of customer connection costs with a lower revenue horizon.[161] After receiving Mr. Neme's evidence discussing this issue, Enbridge could have sought to file reply evidence (as it did with respect to blue hydrogen). It did not do so. Enbridge filed brief additional evidence regarding connection costs along with its examination-in-chief. It could have sought to file more but it did not do so. Enbridge cannot now complain that the record is too thin, and the OEB can be confident that Enbridge has said what it needs to say on the topic.

In any event, there are extensive materials on the record in support of eliminating or at least greatly reducing the connection subsidy. Enbridge refers to there being "six pages" of evidence on this topic. However, a far greater proportion of Mr. Neme's evidence addresses this issue. In particular, the many pages of Mr. Neme's report regarding the likelihood of electrification are specifically invoked by Mr. Neme as justification for the change in connection policy.[162] Furthermore, an entire witness panel was cross-examined on the topic, as were many other witnesses in other panels by multiple intervenors with multiple perspectives.

No change to GDAR needed

Contrary to Enbridge's submissions, no change is required to the Gas Distribution Access Rule ("GDAR") to reduce the connection capital sought by Enbridge. Enbridge argues that s. 2.2.2 would require an amendment. However, s. 2.2.2 simply refers to EBO. 188 generally without specifically mandating a specific revenue horizon, and so no change to s. 2.2.2 is required.[163] Enbridge also argues that it would be more appropriate to defer the issue to be dealt with through rulemaking under s. 44 of the *Ontario Energy Board Act* (the "*OEB Act*").[164] However, this not a rulemaking issue – it is a question of whether to approve Enbridge's proposed customer connection capital costs, which is squarely within the OEB's mandate to fix just and reasonable rates under s. 36 of the *OEB Act*.[165]

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[161] Environmental Defence Correspondence re Motion, April 10, 2023 (link).
[162] Evidence of Chris Neme, May 11, 2023 (updated May 30th) (link).
[163] Gas Distribution Access Rule, March 1, 2020, s. 2.2.2 (link) ("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.).
[164] Enbridge Argument-in-Chief, August 18, 2023, para. 296 (link, PDF p. 107).
[165] *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, s. 36 & 44 (link).

Furthermore, no formal change to EBO 188 is required as it sets out a *maximum* revenue horizon. The relevant portions of EBO 188 are set out below.

> 3.2.1 The ADR Agreement set the following parameters for the DCF analysis:
>
> …
>
> (b) Customer Revenue Horizon
>
> The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service.
>
> …
>
> 3.3 BOARD'S COMMENTS AND FINDINGS
>
> …
>
> 3.3.2 The Board notes that the proposed customer attachment forecast horizon of 10 years is a maximum and adopts this as part of the Guidelines in Appendix B.
>
> …
>
> 3.3.6 The Board accepts that the DCF calculation will be based on a set of common elements as proposed in the ADR Agreement.
>
> APPENDIX B
>
> …
>
> 2. STANDARD TEST FOR FINANCIAL FEASIBILITY
>
> The standard test for determining the financial feasibility at both the project and the portfolio level will be a DCF analysis, as set out below.
>
> …
>
> 2.2 Specific Parameters
>
> Specific parameters of the common elements include the following:
>
> (a) a 10 year customer attachment horizon;.
>
> (b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers);[166]

The combination of ss. 3.2.1 and 3.3.6 make it clear that the revenue horizon is a maximum. Although s. 2.2 of Appendix B does not specify whether the revenue horizon is a maximum, that is also true for the attachment horizon, and the main body of the OEB report clearly notes that they are both maximums in (see sections 3.2.1, 3.3.2, & 3.3.6).

In any event, even if we are wrong about all of the above, the EBO 188 Guidelines are not binding on the OEB in deciding the appropriate customer connection capital costs to include in just and reasonable rates under s. 36 in this proceeding.[167] There is no regulatory impediment to the OEB deciding in this case the appropriate customer connection capital costs to be included in rates.

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[166] E.B.O. 188, Final report of the Board & Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998 (Final report: link; Appendix B: link), emphasis added.

[167] *Pollution Probe Foundation v. Ontario Energy Board*, 2012 ONSC 3206 (link).

Delayed implementation not warranted

A change to the connection subsidy should be implemented immediately. Again, Enbridge is proposing $359 million in 2024 connections-related capital costs.[168] The amounts that are at risk of being stranded are simply too great to wait until 2025 as Enbridge proposes.

Furthermore, the market distortions caused by the subsidy result in irreversible decisions that harm homebuyers, saddling them with unnecessarily high energy costs for many years.

Enbridge argues that it needs a year to make administrative changes.[169] That is not reasonable. The DCF calculations underlying the calculation of CIACs are simple enough to conduct in Excel. Even if they need to be conducted manually for a short period of time, that is far preferrable to incurring hundreds of millions of dollars in costs that are at risk of being stranded. It is unacceptable for Enbridge to say, in essence, that the OEB has no choice but to approve its proposed connections capital for 2024 because it is not ready to make the necessary administrative changes.

That said, it is reasonable for customers to be allowed to continue with the previous rules if they received a *binding* commitment from Enbridge by September 1, 2023 as to a CIAC amount. And if Enbridge makes binding commitments between now and the end of the year for work that will take place in 2025, and those are commitments are inconsistent with the OEB's order, Enbridge shareholders should be responsible for meeting those commitments, not ratepayers.

Enbridge proposes an excessively broad grandfathering for all customers "who have requested service in writing, received commitments and/or indications about CIAC requirements (or lack thereof)." The mere request for service or receipt of "indications" about CIAC requirements is an insufficient reason to apply the old rules in 2024.

Natural Gas Expansion Program impacts

Enbridge argues that the existing rules should be applied to projects subject to the Natural Gas Expansion Program. If this exception is made, it should apply only to the specific projects listed in O. Reg. 24/19.

Contrary to Enbridge's submission, this exception would not contravene s. 2.1.1 of GDAR, which requires that gas distributors "provide gas distribution services in a non-discriminatory manner."[170] Not all differentiation is discrimination. Furthermore, s. 2.1.1 requires non-discrimination in the provision of services, it does not require identical treatment with respect to distribution charges nor does it prohibit the application of different criteria for different groups of customers. Enbridge's interpretation would lead to the absurd conclusion that all distribution rates are contrary to GDAR unless they are levied on the same basis for all customers classes.

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[168] Exhibit J13.7 (link, PDF p. 305) (For details on the amounts included in these figures, see footnote 122 above).
[169] Enbridge Argument-in-Chief, August 18, 2023, para. 279(f) (link, PDF p. 101).
[170] Gas Distribution Access Rule, March 1, 2020, s. 2.1.1 (link).

However, Enbridge should still be required to maintain an overall Investment Portfolio designed to achieve a profitability index of greater than 1, as calculated with the new revenue horizon for individual customers. The projects under O. Reg. 24/19 represent only approximately 3% of the overall connection costs in 2024.[171] Because they are only a very small proportion of the overall portfolio, Enbridge should be expected to balance them out with more profitable projects.

Large volume customers

Large volume facilities are subject to a 20-year maximum revenue horizon and raise different considerations. With respect to the financial interests of existing customers, it would be reasonable to maintain the 20-year maximum revenue horizon for large volume customers, but only if they provide full financial security for the full connection capital costs. Full security would be prudent in light of the uncertainty around the future of gas.[172]

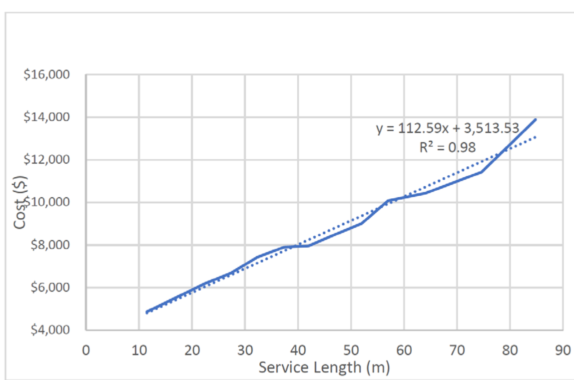
Needless to say, Environmental Defence does not support capital spending related to increased large volume fossil gas use. However, we recognize that this is a broader issue beyond the scope of this proceeding.

Extra length charge

Enbridge has a different methodology for calculating connection costs for individual homes connecting to their gas network, which it calls "infill" connections. Instead of calculating a CIAC for each project as in the case of residential developments, Enbridge uses the extra length charge ("ELC"). Enbridge is proposing to harmonize and increase the extra length charge to $159 per meter beyond 20 meters. This charge is derived such that the incremental connection costs for infill customers will be recouped via 40 years of revenue.

The charges for infill customers would need to be updated to reflect a new revenue horizon. Environmental Defence proposes that infill connections be charged the full connection cost based on the length of the connection (see below). Although the cost will of course increase, they can be paid over time through the temporary connection surcharge for individual homeowners.

Figure 2: Average Service Cost, 2018 to 2020



[171] J13.5 (link, PDF p. 303).
[172] Although Enbridge obtains financial assurances from these customers, it is not clear if they amount to actual security for the full connection capital costs.

Alternatively, the OEB could require Enbridge to propose revised charges for infill customers within a short period following the OEB decision.

Finally, it is worthy to note that infill customers who switch to gas from propane are more likely to leave the gas system even sooner, adding to the importance of adjusting the approach to infills. These customers generally keep their existing furnaces and have them retrofitted to burn methane gas. That means their equipment end of life will be sooner than with new construction. Infill customers may well switch away from gas in just a few years after connecting to the gas system, especially if they are below the 20-meter threshold and pay nothing for their connection.

Temporary connection surcharge

Enbridge has an unwritten policy that they will not offer the temporary connection surcharge ("TCS") to developers.[173] If they did offer the TCS to developers, it would allow those developers to avoid up-front connection costs and instead pass them on to the gas bills of the future homeowners. Enbridge declined to commit to maintain this policy. The OEB should direct Enbridge to maintain this policy in order to protect future gas customers and to avoid creating a new and even worse split incentive problem as between developers and future homebuyers.

Thirty and twenty-year horizons are too long

If a different revenue horizon will be chosen, Enbridge recommends a 30-year horizon based on "a high-level assumption that around half of the newly attached customers will maintain gas appliances at the time that their furnace reaches end of life."[174] Board staff recommends a 20-year horizon based on a similar kind of analysis around the average time a customer will remain with the system.[175] Both periods are too long. Both are based on the premise that the horizon period should equal the approximate average period that customers will remain with the system. However, that is an inappropriate basis to set the revenue horizon, and will result in a horizon that is much too long because:

- It does not address cost allocation fairness for common assets as between new and existing customers;[176]
- It does not account for the cost to safely disconnect service lines and meters for exiting customers, which would only be repaid if customers remain connected for many years after the end of the revenue horizon period;[177]
- It inappropriately allocates the risk of stranded assets to existing customers;

[173] Hearing Transcript, Vol. 10, p. 128 (link).
[174] Enbridge Argument-in-Chief, August 18, 2023, para. 277 (link, PDF p. 100).
[175] Board Staff Submissions, September 12, 2023, p. 26.
[176] See p. 28 above.
[177] See p. 28 above.

- It would result in higher energy bills for existing customers versus an end to the subsidy (or a 10-year period);[178]

- It would do less to reduce market distortions and address the split incentive between developers and homebuyers (or a 10-year period), resulting in higher energy bills for many new homebuyers;[179] and

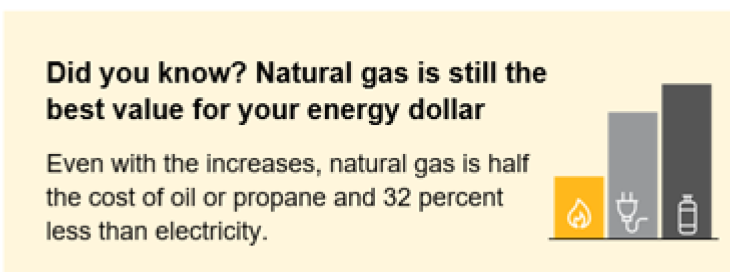
- It would do too little to reduce overall macro-level risk by allowing too much connection capital to be added to rate base ($1.146 billion for 30 years and over $1 billion for 20 years).[180]

The subsidy should be eliminated, or reduced to an amount corresponding to a 10-year horizon at most.

Require unbiased information on energy options

Environmental Defence requests that the OEB require Enbridge to provide its customers with unbiased information on their energy options, including to prospective fuel switching customers as proposed by OEB Staff. Environmental Defence supports the submissions of OEB Staff on this issue and will not repeat those same points here. We add the following additional comments.

First, Enbridge should be required to provide unbiased information in all of its communications with customers, including existing customers, not only its communications to prospective customers who are considering a switch to gas. The bill insert discussed during the hearing (shown below) would be interpreted by many customers as meaning that the cheapest way to heat a home is with gas and that gas is cheaper than electric heating. That is not the case seeing as electric heating with heat pumps is much more cost effective (as discussed above).



[181]

Second, Enbridge should immediately update its online "Calculate Your Savings" tool to include heat pumps in the annual cost comparison.[182] This could easily be accomplished using the information from the Guidehouse report on annual heat pump costs commissioned by Enbridge.[183] This should also account for the fixed monthly customer charge and either include

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[178] See p. 26 above.
[179] See p. 26 and 31 above.
[180] Exhibit J13.7 (link, PDF p. 305) (For details on the amounts included in these figures, see footnote 122 above).
[181] Exhibit K2.1 (link, PDF p. 37)
[182] https://www.enbridgegas.com/residential/new-customers/community-expansion/calculator
[183] Guidehouse Heat Pump Study for Enbridge Gas, p. 10 (link, Ex. K2.2, PDF p. 285).

the savings from more efficient cooling or explicitly note that they are excluded. Although Enbridge's update to this tool should be reviewed in phase III, the initial update need not wait until phase III.

Finally, one of the objectives that the OEB is required to be guided by in carrying out its responsibilities is "[t]o inform consumers and protect their interests with respect to prices and the reliability and quality of gas service."[184] Directions to Enbridge to provide only unbiased information on energy options would fit squarely within both aspects of this mandate to inform and protect consumers.

Disallow recovery of 2023 connection cost shortfall

Environmental Defence requests that the OEB disallow the $26.5 million shortfall in 2023 connection capital.[185] For the following reasons, the revenue shortfall was not prudent and ratepayers should not bear the cost:

- Under EBO 188, ratepayers should not be liable for revenue shortfalls that were due to a lack of prudence by Enbridge.[186] Enbridge must notify the OEB of variances between actual and forecast portfolio NPVs, and "provide explanations of the reasons for the variations and the corrective actions taken or proposed." It is telling that Enbridge did not provide those explanations in its application materials, addressing them only when made to do so by intervenor interrogatories, contrary to the process envisioned by EBO 188.

- EBO 188 requires that the investment portfolio for customer connections be designed with a profitability index greater than 1 (e.g., 1.1) to avoid potential revenue shortfalls.[187]

- Contrary to Enbridge's assertion, price escalation due to supply chain and pandemic-related issues is not an adequate justification for the revenue shortfall. Enbridge experienced revenue shortfalls in 2021 and 2022 of over $60 million due to supply chain and pandemic-related issues.[188] By 2023, it would have been readily apparent that corrective action was required to prevent a continuation of those shortfalls. At that time, it would have been prudent for Enbridge to take the following steps:

    - Include a much larger contingency when estimating capital costs;

[184] *Ontario Energy Board Act*, *1998,* s. 2(2) (link).
[185] Exhibit I.2.6.SEC-118 (link, PDF p. 1726-1727); Hearing Transcript Vol. 13, p. 17, ln. 9 (link).
[186] EBO 188, p. 32, s. 6.3.9 ("The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers.")
[187] EBO 188, p. 11, s. 2.3.10 ("The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts.")
[188] Exhibit I.2.6.SEC-118; Hearing Transcript Vol. 13, p. 17, lns. 7-9 (link).

- Advise developers that they will be liable to pay the actual capital costs if they deviate from the estimate (as developers are required to do for electricity connection assets);[189]

- Request security for connection costs to cover cost overruns and revenue shortfalls (as developers are required to provide for electricity connection assets);[190] and

- Return to developers prior to finalizing pipeline connections to obtain a greater capital contribution where actual costs were higher than forecast.[191] Enbridge acknowledges that this was possible (i.e., not ruled out by contractual obligations), but that it chose not to do so.[192] If the costs overruns were reasonably incurred as Enbridge suggests, they should have been recouped from developers.

- Contrary to Enbridge's assertion, the OEB's decision not to approve an updated methodology for the extra length charge for infill customers in 2019 does not justify the revenue shortfall. For Enbridge to make this argument, it would need to explain how much of the shortfall is actually attributable to the extra length charge being too low. It declined to do so.[193] But even if it could attribute a portion of the shortfall to that issue, it would still not be justified for two reasons:

    - Enbridge should have designed its overall portfolio more conservatively to achieve a portfolio profitability index of greater than 1. This would have been feasible because infill customers are such as small proportion of overall connections (10% in 2023).[194]

    - Allowing Enbridge to rely on this excuse is contrary to the incentive ratemaking framework. In the 2019 rates decision, the OEB ruled as follows: "It is important during an IRM period that charges to customers are not increased for providing the same services, and services to customers are not diminished. A utility is expected to manage its costs through productivity improvements, not through material changes to the condition of services to customers." Allowing Enbridge to put these costs on customers today would be contrary to the 2019 rates case ruling.

- Enbridge may argue that it should not be penalized for 2023 because in so many other years it has achieved a profitability index greater than 1 and its current rolling portfolio profitability index is greater than one. This is not a sufficient justification and is contrary

[189] Distribution System Code, July 1, 2022, ss. 3.2.20, 3.2.21, 3.2.23 (link, Ex. K10.3, PDF p. 35-36).
[190] *Ibid*.
[191] Hearing Transcript Vol. 13, p. 17, lns. 20-24 (link).
[192] *Ibid*.
[193] Exhibit J13.3 (link, PDF p. 301)
[194] Exhibit I.2.6-ED-94 (link, PDF p. 452-457).

to the accountability mechanism set out in EBO 188. *Each year's* portfolio must be profitable.[195]

- Furthermore, Enbridge's profitability index figures are fundamentally flawed because they do not track the actual revenue beyond the first year.[196] Although the *current estimate* of the 2023 shortfall is $26.5 million, the number could well grow if customers reduce their consumption or completely exit the gas system before the end of the revenue horizon. If Enbridge is only subject to a $26.5 million reduction, it may be lucky because the actual shortfall at the end of the revenue horizon could be much larger.

Require demand scenario analysis in capital planning

Environmental Defence requests that the OEB require Enbridge to assess capital projects with reference to at least three demand forecast scenarios reflecting the range of potential energy transition futures. Enbridge's current approach is totally inaccurate and creates far too much risk of underutilized and stranded assets. When considering and planning a capital project, Enbridge uses a single 10-year demand forecast based on a single future scenario of continued strong gas demand.[197] Enbridge does not re-run the economic analysis based on different scenarios, such as a scenario where demand initially increases but then declines.[198] Similarly, Enbridge does not conduct a sensitivity analysis of the project economics or comparison of alternatives based on differing energy transition scenarios.[199] The same is true for the overall capital plan. Enbridge does not conduct an energy transition sensitivity analysis on the overall capital plan or compare different capital portfolios based on different demand scenarios.[200]

This is a major problem. It means that Enbridge is making a single prediction about the energy transition and using that single prediction for each individual project and for the entire capital plan as a whole.

Although the formal Enbridge forecast is 10 years, Enbridge acknowledges that there is an "implicit 40-year forecast" underlying the 40-year revenue forecast used in the economic test.[201] The economic tests for both distribution and transmission pipelines both determine whether a pipeline is cost-effective with reference to 40 years of revenue, which factors into the 40-year discounted cash flow analysis. That amounts to an implicit assumption that demand will be sufficient to support the 40-year revenue projections. That used to be a safe assumption. But that is no longer a safe assumption, even if the revenue is held constant for the remaining 30 years beyond the explicit 10-year forecast. Not only is Enbridge is making a single prediction about the energy transition, it is making a single prediction that stretches out 40 years – until 2064 for pipelines coming into service next year.

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[195] EBO 188, p. 32, s. 2.3.10, 6.3.9.
[196] Exhibit J13.4 (link, PDF p. 302).
[197] Hearing Transcript Vol. 12, p. 105, lns. 3-4 (link).
[198] Hearing Transcript Vol. 12, p. 107, lns. 20-23 (link).
[199] Hearing Transcript Vol. 12, p. 108, lns. 14-20 (link).
[200] Hearing Transcript Vol. 12, p. 109, lns. 1-4 (link).
[201] Hearing Transcript Vol. 12, p. 107, lns. 11-14 (link).

Enbridge may respond by noting how energy transition assumptions have been used to adjust various demand forecasting parameters. However, those adjustments are very minor – "insignificant" in the words of Ms. Wade.[202] More importantly, this still results in a single prediction about the future and still excludes a sensitivity analysis of the project economics based on a high-electrification scenario.

Enbridge witnesses argued that it is not possible to develop energy transition scenarios because it is too hard to predict what will change in the future. But that misses the fact that Enbridge already is making a 40-year prediction. That prediction is based on a future that roughly aligns with the status quo. That is still a prediction and is far less robust than looking at a number of different future scenarios.

Enbridge suggests that it would be far too onerous to examine every project through with, say, three demand forecasts. We disagree. The utility would need to develop demand scenarios for its energy transition plan (or as part of its annual maintenance plan development, if the concept of an energy transition plan is not adopted). For an individual project, it would then be largely mechanistic to apply those demand trajectory scenarios to the revenue forecast and discounted cash flow tables. Although it would be additional work, it would not be onerous.

Enbridge suggests that a demand forecast sensitivity analysis is an entirely foreign concept. However, over 35 years ago, in EBO 134, the OEB encouraged gas utilities to undertake more formal risk measurement and run sensitivities on the discounted cash analysis variables:

> 6.69 The Board encourages the use of more formal risk measurement in the feasibility test and it would not discourage the use of sensitivity analyses of variables being regularly employed in the test.

It is standard when seeking billions of dollars in capital spending to conduct a sensitivity analysis on the key variables underlying the purported cost-effectiveness of that spending. In the current context where future demand is not certain, the demand forecast is one of the key variables that should be included in that sensitivity analysis.

Neglecting to consider the possibility of a high-electrification scenario through a demand sensitivity analysis could result in bad investment decisions and major costs and risks for customers, including the following:

- **Revenue shortfalls and uneconomic projects:** The economic tests determine whether the present value of the stream of future revenue will cover the upfront cost. If the revenue forecast does not materialize because of lower-than-expected demand, the project will become uneconomic. We may not know whether this has happened for decades. At present, it is not even tracked and reported on. Ratepayers will be liable for making up the shortfall.

[202] Hearing Transcript Vol. 11, p. 164, ln. 19 (link).

- **Premature replacement:** Demand forecasts can have an impact on decisions between replacing an aging pipeline versus pursuing an inspection/repair program.[203] A pipeline could be prematurely and mistakenly replaced at great cost if the decision is based on a demand forecast that turns out to be wrong.[204]

- **Forgoing a cost-effective non-pipeline solution:** Demand forecasts can have an impact on decisions between pipeline and non-pipeline solutions.[205] For instance, if a capacity deficit is forecast to only last for five years, versus 40 years, it will be much easier and cheaper to address with non-pipeline alternatives, such as demand response and efficiency, all other things being equal. Overestimating the demand or the duration of a capacity deficit will favour the pipeline option in comparison with the non-pipeline solutions. If the demand forecast is wrong, we may miss an opportunity to implement a more cost-effective non-pipeline solution.

- **Insufficient capital contributions:** Capital contributions toward pipeline projects are based on revenue projections. If the revenue and demand are overestimated, there will be an insufficient capital contribution and the existing customer base will be liable to make up the difference.

- **Stranded assets:** An unforecasted drop in demand from new *or existing* customers can easily strand a reinforcement project. For example, the $358 million panhandle regional expansion project is meant to address rising demand, mainly from greenhouses, outstripping the current capacity of 737 TJ/day. If the project is built, but overall demand declines back down to 737 TJ/day after a decade of electrification, the $358 million in reinforcement assets will no longer be needed and any portion that is undepreciated represents a stranded asset.[206]

In short, demand forecasts are extremely important in capital planning, that importance is heightened due to the uncertainty caused by the energy transition, and the possibility of declining demand ought to be formally considered in a scenario analysis for Enbridge's capital projects.

Account for option value in capital planning

Environmental Defence requests that Enbridge be required to account for the "option value" from deferring projects in its capital planning. If a project is deferred for, say, five years, the utility could gain useful information in that time that has considerable value. For example, it could learn that the demand no longer justified pursuing the project at all or that the pipe can be downsized. Even a small chance that you may learn in five years that you can completely avoid a pipeline costing hundreds of millions of dollars is worth a lot. That is option value – also known as optionality.[207]

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203 Hearing Transcript Vol. 12, p. 96, lns. 3-12 (link).
204 *Ibid.*
205 Hearing Transcript Vol. 12, p. 92, lns. 6-27 (link).
206 Hearing Transcript Vol. 12, p. 85, ln. 24 to p. 86, ln. 9 (link).
207 Hearing Transcript Vol. 12, p. 99, lns. 20-27 (link); Hearing Transcript Vol. 5, p. 37, ln. 11 to p. 38, ln. 23 (link).

Optionality is particularly valuable in light of the uncertainty around the energy transition. In the past, with steadily increasing gas demand, the chances of avoiding a project or downsizing a project was minimal. That is no longer the case. Deferrals are now an important tool to avoid some of the mis-steps that can arise due to demand forecasts that turn out to be wrong (listed on the previous page). Enbridge ought to be formally accounting for this benefit in its cost-effectiveness calculations and its capital planning.

Enbridge does not quantify option value in its capital planning.[208] This skews its capital planning results in favour of more pipelines and against non-pipeline alternatives (e.g., efficiency, demand response, etc.) and programs to inspect and repair pipes instead of replacing them. Non-pipeline alternatives and inspect/repair programs are methods to defer infrastructure and the true benefits of deferral have not been reflected unless option value is factored into the cost-benefit analysis.

Quantifying option value requires judgment and is not a science. However, it is more accurate and appropriate to attempt to quantify this benefit and include it in cost-effectiveness calculations rather than ignore it completely. Stated differently, Enbridge is already making an implicit assumption in its cost-effectiveness calculations that the option value arising from deferrals is $0. That is clearly wrong and best efforts to arrive at an option value to include in comparisons of alternatives would clearly be an improvement.

Integrated resource planning: allow heat pumps and improve results

Environmental Defense requests that the OEB allow Enbridge to consider electricity-based non-pipeline solutions in its integrated resource planning. Although the first-generation integrated resource planning framework ruled out electricity-based alternatives, it also explicitly made this an interim determination and noted that this could "evolve as energy planning evolves, and as experience is gained with the IRP Framework."[209] There has been a sufficient passage of time and a sufficient evaluation of energy planning to revisit this, including the following:

- **Government policy:** Since the integrated resource planning decision was issued, the Minister of Energy has directed the OEB to pursue lower energy bills whether that be through more efficient gas *or electric equipment*. [210] Although the direction was made in the context of demand-side management, it is analogous to IRP in that the direction condones spending on electric equipment where that would lower energy bills.

- **Improved cost-effectiveness:** The cost-effectiveness of electricity-based integrated resource planning has improved drastically since the integrated resource planning decision was issued. The federal government now provides $5,000 rebates for electric heat pumps and Enbridge's demand-side management program provides an additional $1,500 while also expanding eligibility and increasing the measure-wide incentive limit to $10,000. This will lower the incremental cost of a non-pipeline alternative relying on

[208] Hearing Transcript Vol. 12, p. 100, lns. 22-28 (link).
[209] OEB Decision and Order, July 22, 2021, EB-2020-091, p. 35 (link).
[210] Mandate Letter to the OEB, November 15, 2021, p. 3 (link) ("It is also important that the DSM Framework be implemented in a way that enables customers to lower energy bills in the most cost-effective way possible, and help customers make the right choices regardless of whether that is through more efficient gas or electric equipment.").

heat pumps. Enbridge can leverage this pre-existing funding, plus modest spending on marketing and incremental incentives, to pursue a geographically-targeted program far more cost-effectively.

- **Insufficient non-pipeline solutions:** Over two years has passed since the integrated resource planning framework was put into place, which followed direction after direction from the OEB to pursue integrated resource planning (see Appendix 1 on page 54 below). However, Enbridge's rebasing application still proposes $7 billion on pipeline solutions and $0 for non-pipeline solutions. All we have thus far is pilots that have just been applied for. The experience of the past two years suggests that Enbridge would benefit from additional tools.

Finally, any electricity-based non-pipeline solution would be presented to the OEB for approval in an integrated resource planning application. Therefore, the OEB would have the opportunity to scrutinize any electricity-based proposals that Enbridge may put forward.

Environmental Defense requests that the OEB direct Enbridge to increase its efforts with respect to integrated resource planning in light of the complete lack of non-pipeline solutions included in its rebasing application. The Board has directed Enbridge to pursue integrated resource planning many, many times over the past 30 years.[211] The list and details on previous OEB directions is so long that we have attached at as an appendix (see Appendix 1 on page 54 below). Enbridge is moving at a snail's pace. That was deemed unacceptable by the Board in a number of previous proceedings and is even more unacceptable today as the energy transition accelerates and the benefits from deferring and avoiding infrastructure grows.

One example of how Enbridge could increase its efforts is to improve its approach to demand response (i.e., interruptible rates) as part of its integrated resource planning. When considering non-pipeline-based alternatives, Enbridge will sometimes explore interruptible rates, but at the standard rates. Instead, Enbridge should be reaching out to customers to specifically ask them if they would accept additional incentives beyond the standard interruptible rates, as long as those incentives would come to less than the cost of the capital project. There are many more suggestions from the IRP Technical Working Group. Overall, Enbridge appears to need yet another direction from the OEB to treat integrated resource planning as a greater priority and begin achieving real and concrete results for ratepayers.

Encourage a voluntary LTC application for the Wilson Ave project

Environmental Defense requests that the OEB encourage Enbridge to file a leave-to-construct application for the Wilson Avenue project. This is warranted due to the high cost of the project and the similarities to the St. Laurent project, which was denied leave to construct by the OEB.

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[211] E.g. EBO 169-III*, Report of the Board on the Demand-Side Management Aspects of Gas Integrated Resource Planning*, July 23, 1993, pp. 1-4; Ontario Energy Board, *Decision in EB-2012-0451/0433, January 30, 2014*, p. 46-47 (GTA Pipeline) (link); Ontario Energy Board, *DSM Framework,* December 22, 2014, p. 35-36 (link); EB-2018-0097, Decision and Order, January 3, 2019, pp. 6-7 (Bathurst Reinforcement) (link); EB-2020-0192 (London Lines), OEB Decision and Order, January 28, 2021, p. 20 (link).

The project is estimated to cost $110 million.[212] Enbridge acknowledges that it has similarities with the St. Laurent project in that it is a fairly large pipeline replacement project for integrity reasons in an urban area with a significant cost.[213] The only reason that the Wilson Project does not require a leave-to-construct application whereas the St. Laurent Project did, is that the former does not need to be realigned and therefore no land-related permissions are required, so the criteria under s. 90 of the *OEB Act* are not triggered.[214]

Although Enbridge is not *required* to seek leave to construct under s. 90 of the *OEB Act*, it may voluntarily seek leave to construct under s. 91 of the *OEB Act*.[215] In light of the outcome of the St. Laurent case, and the uncertainties around the energy transition, the OEB should encourage Enbridge to take this step. Although the OEB may or may not have the jurisdiction to require this to occur, it can certainly express its view that Enbridge would be wise to seek approval to ensure cost recovery.

Enbridge may argue that the best approach is for the prudence of this investment to be determined after it is built at the next rebasing case when Enbridge seeks to add it to rate base. However, rebasing cases are already complex and a $110 million project would benefit from scrutiny though its own proceeding. Finally, from a practical perspective, it may be easier for the OEB to consider whether to grant leave to construct beforehand rather than retrospectively review a project and consider whether to cause the Enbridge shareholder to assume $110 million in costs.

Remove hydrogen blending phase II pilot

Enbridge is proposing to spend roughly $9 million on a second phase of its hydrogen blending pilot, including $1,920,837 in 2024.[216] This project would involve expanding the number of homes that would receive a blend of green hydrogen and gas. This should be removed from the 2024 spending because it is highly unlikely that hydrogen will be an effective way to heat homes in the future for three reasons:

- Directly using electricity in heat pumps is roughly six times more efficient than converting it to green hydrogen and burning it in furnaces (see the figure and discussion on page 17 above). Blue hydrogen is inconsistent with decarbonized future because its emissions are too high (see discussion on page 18 above). Therefore, hydrogen for home heating makes little sense.

- Hydrogen can only be blended at very limited concentrations. Due to those limitations, the limits on RNG feedstocks, and the need to phase out fossil gas, hydrogen blending

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[212] Hearing Transcript Vol. 13, p. 2, ln 28 to p. 3, ln. 4 (link).
[213] Hearing Transcript Vol. 13, p. 3, ln. 25 to p. 4, ln. 2 (link).
[214] Hearing Transcript Vol. 13, p. 4, lns. 4-11 (link).
[215] *Ontario Energy Board Act*, s. 91 ("91 Any person may, before constructing a hydrocarbon line to which section 90 does not apply or a station, apply to the Board for an order granting leave to construct the hydrocarbon line or station.")
[216] Exhibit 2, Tab 6, Schedule 1, Page 47 (link, PDF p. 398).

can only replace a miniscule percent of Ontario's current fossil methane gas consumption – 0.37% (see footnote 24 on page 7 above and the accompanying text).

- A hydrogen/RNG blend will be considerably more expensive than using an electric heat pump (see footnote 35 on page 9 above and the accompanying text).

Furthermore, the OEB only very reluctantly approved the first phase of this project. In its decision it held as follows:

> There was general agreement by intervenors that hydrogen is an expensive fuel source compared to natural gas, could be dangerous at high concentration levels (see next section), and cannot make a significant reduction to the carbon emission levels in gas delivery. VECC noted that "there are no compelling reasons of energy efficiency, security of supply or safety to blend hydrogen into the natural gas distribution system." SEC commented that "hydrogen is fundamentally an energy storage medium" and will never replace natural gas. OEB staff noted that the OEB's Marginal Abatement Cost Curve did not include the cost of hydrogen as an abatement option – noting that it was more expensive than other abatement options such as energy efficiency and Renewable Natural Gas (RNG).
>
> … The OEB agrees that <u>despite the apparent limited potential of hydrogen blending</u>, the learning from the proposed Project would be beneficial and the Project should proceed.[217]

Although leave to construct would be sought for this project, it should not presumptively be included in 2024 rates in light of the above.

Focus hydrogen study on large volume customers

Enbridge is proposing to spend roughly $15 million on a hydrogen feasibility study, including $5,762,510 in 2024.[218] Environmental Defence strongly supports efforts by Enbridge to pursue and enable the delivery of 100% hydrogen to large volume customers. This could potentially allow for some of Enbridge's assets to be re-purposed to extend their economic life in the face of decarbonization. It is therefore worth pursuing for all ratepayers.

However, Environmental Defence requests that the OEB provide two directions regarding the hydrogen study:

- The study should be focused on the provision of green hydrogen to large volume customers in high concentrations up to 100%. For the reason set out above, it is highly unlikely that hydrogen will be an effective way to heat buildings. If there are unexpected developments in the future that make hydrogen for building heating more likely, the issue

[217] OEB Decision and Order, October 29, 2022, EB-2019-0294, p. 7 (link).
[218] Exhibit 2, Tab 6, Schedule 1, Page 47 (link, PDF p. 398).

can be revisited. In the meantime, millions of dollars in ratepayer money should not be wasted on exploring that option.

- Enbridge should be directed to conduct stakeholder sessions on the specific questions to be posed to the consultants as part of this study and on key study activities. This may help reduce the kind of pro-gas bias seen in the Guidehouse Pathways report discussed above.

Enbridge was unable to provide an estimate of the savings that could be achieved by limiting the scope of the report as proposed above. However, there would likely be significant savings as it would avoid the need to explore use of hydrogen in household equipment and in the aging smaller pipes that serve most households. It would also allow a focus on higher concentrations.

In stakeholder sessions, Environmental Defence would request that the study assess the feasibility and cost to serve hard-to-electrify industrial customers with 100% hydrogen and provide, for example, the following information:

- A categorization of industrial customers based on how difficult they are to electrify and how likely they would be to adopt 100% hydrogen if it were available;

- Tables showing the gas demand for each industrial category (based on likelihood of 100% H2 adoption) by geographic region;

- An assessment of the most and least favourable regions for 100% green hydrogen adoption, including maps showing the demand from hard-to-electrify customers in different regions of the province;

- As assessment of the economics of customers choosing pipeline-based green hydrogen versus service from on-site electrolysers and storage; and

- An assessment of the transportation price thresholds at which pipeline-based green hydrogen becomes more economic than on-site electrolysers and storage depending on a set of scenario parameters.

This information would assist in energy transition planning. For instance, knowing the threshold price for customer cost-effectiveness could guide near-term depreciation and capital budget decisions.

Reduce capital envelope

Enbridge's proposed overall capital budget is unnecessarily inflated because of a series of flaws in its capital planning processes that a bias the analysis in favour of investing more in pipelines. These include the following:

- **Flawed demand forecasting:** Enbridge does not account for the possibility of declining demand in its capital planning process. If this was corrected, some projects would not pass economic tests or would be deferred (see page 41 above).

- **Ignore option value:** Enbridge ignores key benefits to deferring projects which, if properly considered, would improve the cost-effectiveness of non-pipeline solutions and inspect/repair options vis-à-vis traditional pipeline projects (see page 43).

- **Integrated resource planning:** Out of over $7 billion in capital spending, Enbridge has proposed no actual non-pipeline alternatives (aside from uneconomic pilots). This is after being told to conduct robust integrated resource planning multiple times over the past 30 years. Better resource planning would result in lower capital spending, and some 2024 spending can and should be deferred to allow that planning to take place.

- **Design day:** Enbridge did not consider or account for the warming effects of climate change on design temperatures when developing its latest design day methodology.[219] This is despite evidence that extreme cold temperatures are warming even faster than extreme warm temperatures, consistent with warming being greater in the winter than summer.[220] Pursuant to the settlement agreement, the design day methodology will be a live issue in future leave to construct applications. A change could lower design day demand and lower the capital spending needed to meet it. This could prove to be important in relation, for instance, to the $970 million Enbridge plans to spend on new transmission assets to serve growth in its Asset Management Plan.[221]

- **EDIMP:** Enbridge has only just started implementing the Enhanced Distribution Integrity Management Planning (EDIMP) mandated by the St. Laurent decision. This has already caused the deferral of some spending, such as the $110 million Wilson Avenue project.[222] Full implementation should result in further deferrals and reductions in capital spending.

- **EBO 134:** Enbridge is facing challenges to its application of EBO 134, including whether it should be seeking contributions from large customers driving needs and whether its calculation of purported stage 2 benefits is fundamentally flawed for failing to account for the greater efficiency of heat pumps.[223] These issues could help to bring down rate base capital spending on transmission projects.

We acknowledge that it is a challenge to translate these pro-infrastructure biases into a specific dollar reduction to apply to the proposed 2024 capital budget. However, these biases should be considered, and we propose one of two options. The OEB could apply an approximate percentage reduction based on these biases. Alternatively, the OEB could consider these biases when accepting specific capital disallowances proposed by other intervenors.[224] These pro-gas-infrastructure biases underlying the entire capital budget can provide the OEB with additional confidence that Enbridge will have a sufficient budget be able to appropriately maintain its system despite the specific reductions in capital suggested by others.

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[219] Exhibit I.4.2-ED-120 (link, PDF p. 67).
[220] Environment and Climate Change Canada, *Canada's Changing Climate Report*, 2019 (link, Ex. KT6.2, PDF p. 141).
[221] Exhibit 2, Tab 6, Schedule 2, Page 203 (link, PDF p. 609).
[222] Hearing Transcript Vol. 3, p. 3, lns. 5-24 (link).
[223] Exhibit K12.3 (link, PDF p. 34).
[224] We have coordinated with a number of other intervenors and we understand that they will be putting forward strong cases for capital budget disallowances

Lastly, Enbridge may argue that these issues are best dealt with as part of leave to construct applications. However, a great deal of the proposed capital spending does not require leave to construct. Furthermore, even for projects that do require leave to construct, a decision denying leave will not automatically result in the costs coming out of the 2024 capital budget underpinning rates. Enbridge has said repeatedly that they would simply reallocate the budget elsewhere. In other words, the money would still be spent.

Risk allocation

Finally, Environmental Defence supports efforts to put the risk of stranded and underutilized assets on Enbridge with respect to any new infrastructure. However, we believe this will be too constrained by practical realities and regulatory jurisprudence to adequately address energy transition risks. From a practical perspective, Enbridge is too big to fail. In particular, customers are too reliant on Enbridge in the short and medium for it to be allowed to assume financial risks that could result in bankruptcy. From a jurisprudential perspective, it will be difficult to hold Enbridge responsible for shortfalls when the OEB approves its capital budget and specific leave to construct applications. Furthermore, the mere *risk* of being held responsible for stranded or underutilized assets is not sufficient.

Ultimately, the OEB needs to actively ensure that Enbridge reduce risks for customers, including with the various steps discussed above.

Load forecasting methodologies (issue 11)

Issue 11 asks: "Are the proposals for harmonized load forecasting methodologies (heating degree days, average use, weather normalization, heat value, customer additions) and the 2024 Test Year results from those methodologies appropriate?" Enbridge is not asking for approval of its load forecasting methodology for capital planning writ large. As such, we consider issue 11 to be settled.[225] Any issues with respect to load forecasting for capital planning are addressed above: see page 41 above regarding the need for demand forecast scenarios and page 49 above regarding the need to review design day assumptions for the purposes of capital planning.

Depreciation (issue 15)

Environmental Defence requests that the OEB require Enbridge to return in phase III of this proceeding with a proposal to move to a units of production methodology for depreciation options that adequately account for the energy transition. In the interim, Environmental Defence requests that the OEB approve Enbridge's depreciation proposal with reductions to the depreciation period of the four largest asset classes as necessary to ensure that the depreciation expense is sufficient to stop rate base from growing.

Both the current and proposed depreciation approaches assume that there is a 0% chance that assets will be underutilized or stranded due to decarbonization. Although the proposed approach results in a modest acceleration of depreciation, it still does not explicitly account for the energy

[225] Exhibit O1, Tab 1, Schedule 1, Page 29-30.

transition and stranded asset risks. It continues to assume that the pipelines put in the ground today will be used and useful and economically viable until the 2080s.[226] This is far too risky. Depreciation must be accelerated to account for the energy transition.

Enbridge has emphasized how accelerated depreciation beyond its proposals would increase the revenue requirement. However, this is not money lost to ratepayers, as in the case of unnecessary capital spending or paying a greater cost of capital. Instead, accelerated depreciation means that ratepayers pay off Ontario's gas assets faster. It also means that ratepayers pay less to finance rate base by paying it off faster.

The units of production methodology is ideal because it matches depreciation to utilization. For example, depreciation expense will decline as the number of customers falls or their annual usage falls (e.g., with hybrid heating). This is important for equity because future customers who use the pipes less versus today's customers will pay less. It therefore better matches the benefits and the costs over time. It is also important for maintaining competitive rates – if future customers use the pipes only for a peaking service with hybrid heating, they will abandon the system entirely if rates climb too high. The units of production approach would help to protect against that.

Units of production is the only methodology that can appropriately capture a possible future scenario where a significant portion of general service customers move to hybrid heating. This methodology would pay down a greater proportion of the gas assets now when customers are using gas pipelines for 100% of their heating needs, and less in the future when customers are receiving fewer benefits (i.e., gas for just a few days a year) and have a greater incentive to fully switch from gas to avoid monthly gas distribution charges. Although full electrification is more likely than hybrid heating (see page 9 above), there are still benefits to adopting an approach that can capture a scenario involving a large degree of hybrid heating.

We cannot wait until the next rebasing case to properly account for decarbonization in depreciation amounts. That is why we request that the OEB require Enbridge to return in phase III of this proceeding with depreciation options that adequately account for the energy transition, including a units of production approach. The longer that we wait for accelerated depreciation, the greater the rate shock when that is implemented and the more likely that the future rates will cause customers to leave the system. For example, implementing a 2050 economic planning horizon in 2035 would cause an additional $400 million increase in the revenue requirement in comparison to implementing that in 2024.[227] This is an illustration of how much harder it is to accelerate depreciation to address the energy transition as time passes. In addition, the acceleration will likely become harder still if the customer base decreases.

However, choosing the best methodology is not sufficient. Enbridge also must use appropriate demand forecast assumptions underlying that methodology. Adopting the units of production approach based on a status quo demand forecast of steady demand will do nothing to account for the energy transition. When Enbridge returns with a units of production approach it should

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[226] Exhibit I.4.5-ED-138 (The depreciation periods for new mains and services are between 55 and 60 years.) (link, PDF p. 1529).
[227] Exhibit JT4.17 (link, PDF p. 1759-1761).

include, for example, an analysis of a scenario involving a forecast 95% decline in annual demand from buildings by 2050 (representing a rollout of hybrid heating wherein gas is only used on the coldest days, or full electrification of most but not all buildings) and a 50% decline in demand from industry (representing electrification, efficiency, and some H2 not delivered by Enbridge).

In the interim, Environmental Defence requests that the OEB adopt Enbridge's depreciation proposal with accelerating adjustments as necessary to prevent rate base from continuing to increase. Some witnesses argued against aspects of Enbridge proposals from traditional depreciation perspectives, calling for changes that would decelerate depreciation. However, even if all of those criticisms were warranted (which we need not comment on), they are far outweighed by the lack of consideration of the energy transition, which operates in the opposite direction. By failing to account for any possibility of stranded assets or declining benefit to customers, Enbridge's proposal would certainly depreciate assets too slowly and be too risky.

Adjustments could easily be made to Enbridge's depreciation proposal to ensure that the depreciation expense is sufficient to stop rate base from increasing. In particular, the depreciation period for the top four asset classes could easily be adjusted downward to the extent necessary to meet that goal.[228] This adjustment would be logical as a small adjustment to the methodology to address risk and prevent rate base from increasing in the interim. Whether this will be needed, and the extent of the adjustment, will depend on the OEB's decision with respect to capital.

Site restoration costs and a segregated fund (issue 16)

Environmental Defence requests that the OEB defer the decision on a segregated site restoration fund and direct Enbridge to return at the next rebasing case with a study that explores how best to design such a fund to minimize costs for ratepayers and maximize the return on the capital retained in the fund.

As part of the depreciation expense, Enbridge collects funds from customers that it sets aside for the decommissioning of pipelines. Enbridge is holding $1.6 billion of ratepayer dollars for site restoration, which is forecast to increase to $1.8 billion by 2028.[229] If there is a death spiral and bankruptcy, ratepayers or taxpayers would have to foot the bill for site restoration costs. Even if the risk of that is very low, the sums at stake are huge. The full site restoration costs for all Enbridge assets in service today is $6.9 billion.[230]

Furthermore, the lack of a segregated site restoration fund may make it impossible for the OEB to hold Enbridge responsible for investments that were not prudent in light of the energy transition in the future. The risk of losing the billions of dollars that Enbridge will hold for future decommissioning will weigh against the OEB in this situation.

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[228] See Exhibit 4.5-ED-138 for Enbridge's proposed depreciation periods for the four largest asset classes, which include various types of mains and services.
[229] Exhibit I.4.5-ED-136 (link, PDF p. 1522).
[230] Exhibit JT4.15 (link, PDF p. 1753-7154).

However, these risks will not materialize within the next five years. Therefore, there is time to study the issue better. Enbridge's evidence on a segregated fund is not an impartial review of options and instead reads like an argument against a segregated fund. The OEB would benefit from evidence that explicitly explores how a segregated fund could be designed and implemented in a way that minimizes costs for ratepayers and maximizes returns on the capital retained in the fund. Enbridge should be directed to do this as a next step, with the final decision on whether to implement a segregated fund deferred to that time.

Environmental Defence requests that the OEB not apply a reduction to the proposed site restoration costs. Like with depreciation more broadly, any reasons to reduce the amounts are far outweighed by the lack of consideration of the energy transition, which operates in the opposite direction by increasing the changes of accelerated retirements (e.g., safely disconnecting the service line and meter for homes that exit the system).

Volume Variance Account (issue 32)

Environmental Defence requests that the OEB approve the requested volume variance account. This proposed variance account would harmonize the previous average-use variance accounts and replace them with an account that reduces volumetric risk in a symmetric and revenue-neutral manner for both customers and Enbridge Gas, including weather-related risk.

There is no real benefit to making Enbridge bear weather-related risk. Enbridge will not bear that risk for free. It is and will continue to be reflected in the cost of capital. It does not make sense to pay Enbridge to bear this risk.

Furthermore, making Enbridge bear this risk will not give it incentives to act more prudently because Enbridge does not control the weather. This is different, for instance, from making Enbridge bear the risk of cost overruns.

Overall, it is better for ratepayers to help Enbridge mitigate the risks it faces but cannot control rather than increase costs to customers though a higher equity/debt ratio.

Natural Gas Vehicle Program (issue 34)

Environmental Defence requests that the OEB deny approval to expand the Natural Gas Vehicle Program to the Union rate zone and treat it as a utility activity unless Enbridge commits to restrict it to the delivery of RNG to the heavy transportation sector. Enbridge has not established that the Natural Gas Vehicle Program as it is currently designed is good for ratepayers or good for the environment.

With respect to the financial interest of ratepayers, Enbridge notes that the program is profitable. However, it is also risky in the context of decarbonization. The combustion of fossil methane gas in vehicles is inconsistent with a decarbonized future. Although the infrastructure could be used for RNG in the future, it is not clear whether that will be an avenue to decarbonize heavy transportation. It is certainly not an avenue to decarbonize light transportation.

With respect to the present-day environmental impact, Enbridge notes that the combustion emissions from methane gas are lower than those from petroleum. However, the lifecycle emissions from natural gas vehicles may in fact be higher when one accounts for the unburned methane emissions in extraction, transportation, storage, and end-user equipment. As noted above, these emissions are much higher than once thought.[231] In this context, it cannot be said with any confidence that a natural gas vehicle is greener even in comparison to petroleum. It certainly results in far more carbon emissions than alternatives for light transportation and buses, such as electric vehicles.

In addition, Enbridge does not actually know the unburned methane emissions from its own distribution pipelines.[232] Nor does it have measurement for behind-the-meter leaks.[233] Enbridge has agreed to determine an appropriate way to accurately measure fugitive emissions from its system, including consideration of top-down measurements.[234] This is important for unaccounted-for gas, but also in order to justify and understand the impacts of replacing fossil fuels such as petroleum or heating oil with natural gas. Until that work has been done, Enbridge is not in a position to say that natural gas is better for the climate than those other fossil fuels.

Even if there were to be a benefit from replacing petroleum with fossil gas, it is likely to be very minor, and significant emissions will still remain. It is no longer sufficient to pursue half-measures that result in small reductions, and investments in such measures are likely not cost-effective as they are inconsistent with where Ontario needs to be in the very near future.

Conclusion and list of requests

As detailed above, Environmental Defence requests that the OEB:

1. Direct Enbridge to develop **energy transition plans** containing future demand scenarios and business modelling based on those scenarios, which would be: (a) filed asap, (b) updated at least with each rebasing application, and (c) developed in a process to avoid pro-gas bias (e.g. OEB-retained consultant for scenario assessment and stakeholder involvement);

2. Disallow Enbridge's proposed $1.5 billion **subsidy for new gas connections** ($359 million in 2024) or at least reduce it to reflect a 10-year revenue horizon (approximately a 50% reduction), subject to limited exceptions (projects selected under O. Reg. 24/19,

[231] See pages 5 to 6 above, including footnotes 7 to 16 and the text corresponding thereto.
[232] The greatest source of "unaccounted-for gas" is "unknown," representing roughly 50% of UFG per Exhibit JT3.9.
[233] Hearing Transcript Vol. 2, p. 80, lns. 9-12 (link)
[234] Exhibit O1, Tab 1, Schedule 1, Page 37 ("In relation to fugitive emissions, which are a component of UFG, Enbridge Gas has agreed to investigate and determine an appropriate way to accurately measure fugitive emissions, including consideration of top-down measurements (i.e. by aircraft, satellite, and/or towers), with the goals of: (a) confirming the volume of fugitive emissions, (b) determining if recent UFG increases could be due to fugitive emissions, and (c) attempting to locate specific fugitive sources that can be mitigated. This would include all kinds of assets (transmission, rural & urban distribution, and storage). Enbridge Gas will file a robust investigation plan for consideration and determination in the 2023 deferral and variance account proceeding, which filing shall include justification of the planned approach including, without limitation, whether it will include aerial (i.e., top-down) investigation.").

customers who received binding commitments on CIAC amounts before September 2023, and industrial customers who provide full security for their forecast revenue);

3. Require Enbridge to provide its customers unbiased **information on their energy options**, including to prospective fuel switching customers as proposed by OEB Staff;

4. Disallow recovery of the **$26.5 million shortfall in 2023 connection capital;**

5. Require **demand scenario analysis in capital planning**, including analysis of a high-electrification scenario in the EBO 134 and 188 economic tests;

6. Require Enbridge to explicitly quantify and account for the value of **optionality** achieved through deferrals when assessing infrastructure alternatives;

7. Allow Enbridge to consider **electricity-based integrated resource planning alternatives;**

8. Direct Enbridge to escalate its efforts on **integrated resource planning** and achieve concrete results;

9. Encourage Enbridge to file a voluntary leave to construct application for the $110 million **Wilson Avenue project** under s. 91 of the *OEB Act*;

10. Remove the **hydrogen blending phase II pilot** from the proposed rates;

11. Direct Enbridge to focus its **hydrogen feasibility study** on hydrogen for industrial customers and to conduct funded stakeholdering on the questions to be asked to consultants and on draft results;

12. **Reduce the capital envelope** to reflect the pro-infrastructure biases in its capital planning processes, either as an independent rationale or as a supporting rationale for other capital reductions recommended by other parties;

13. Require Enbridge to return in phase III of this proceeding with a proposal to move to a **units of production depreciation methodology** that adequately accounts for the energy transition;

14. Approve **Enbridge's depreciation proposal** as an interim step, with reductions to the depreciation period of the four largest asset classes to the extent necessary to ensure that rate base does not grow while a new depreciation methodology is developed;

15. Defer the decision on a **segregated site restoration fund** and direct Enbridge to return at the next rebasing case with a study that explores how best to design such a fund to minimize costs for ratepayers and maximize the return on the capital retained in the fund;

16. Approve the **volume variance account**; and

17. Deny approval to expand the **Natural Gas Vehicle Program** to the Union rate zone and treat it as a utility activity unless Enbridge commits to restrict it to the delivery of RNG to the heavy transportation sector.

Enbridge's application discusses the risks to its shareholders related to the energy transition at length in its application (e.g. regarding the equity/debt ratio). However, its shareholders have the power to mitigate those risks. This requires wide-eyed capital planning that is consistent with all futures, including a high-electrification future. It also requires a much greater focus on Enbridge's potential future in delivering hydrogen and RNG to hard-to-electrify industrial customers.

Enbridge spends little time discussing the risks to gas customers. Customers can only mitigate these risks by switching away from gas. But many customers have relatively new equipment and/or restricted discretionary household budgets that effectively lock them into the gas system for the short or medium term. Enbridge's risky approach to the energy transition will hurt these customers through rate increases, which for many vulnerable consumers will lead to hard choices between paying for necessities like food or keeping their house warm. Even in this proceeding today, the OEB received approximately 400 comments from Ontarians decrying the requested increase, many with stories of personal hardship from paying gas bills. It will only get worse if we do not stop unsustainable increases in rate base.

Enbridge has already invested a great deal in infrastructure that will likely be stranded in the future. For instance, it has applied the 40-year maximum revenue horizon for the approximately 40,000 customers it connected this year. There is a good chance many will disconnect over the coming decades, leaving other ratepayers to cover the shortfalls. In some ways everything seems fine now, but irreversible decisions are being made today that will have serious consequences somewhere between five and twenty years from now. The real challenge is this: once we reach a tipping point, and customer numbers are declining, leading to increasing rates, it is too late. Our future selves may point back to today and wish more had been done while there was still time.

Appendix 1: Summary of OEB directives re IRP

The Board has directed Enbridge to practice Integrated Resource Planning many times over the past 30 years.[235] These directions date back to the OEB's IRP proceeding in the early 1990s.[236] This summary will focus on the directions provided by the OEB over the last decade. Through these directions, the OEB has repeatedly highlighted the importance of IRP, expressed concerns about the lack of progress by Enbridge in this area, and directed Enbridge to do IRP better and sooner.

In the decision in the GTA pipeline case (EB-2012-0451), the OEB directed Enbridge "to provide a more rigorous examination of demand side alternatives, including rate options, in all gas leave to construct applications."[237] The decision also directed Enbridge to incorporate IRP in its planning in a more systematic way:

> Environmental Defence urged the Board to send a signal to the companies that new supply-side investments will not be approved unless all lower cost DSM and/or interruptible service options have been explored and documented. Other parties agreed and argued that both Enbridge and Union should be required to do a better job…
>
> In light of the evidence presented, the Board concludes that further examination of integrated resource planning for gas utilities is warranted. The evidence in this proceeding demonstrates that the following issues should be examined:
> - The potential for targeted DSM and alternative rate designs to reduce peak demand
> - The role of interruptible loads in system planning
> - Risk assessment in system planning, including project prioritization and option comparison
> - Shareholder incentives.[238]

In the 2014 DSM Framework decision, the Board again directed Enbridge to conduct IRP and develop a consistent IRP methodology:

> As part of all applications for leave to construct future infrastructure projects, the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development.
>
> In order for the gas utilities to fully assess future distribution and transmission system needs, and to appropriately serve their customers in the most reliable and

[235] E.g. EBO 169-III, *Report of the Board on the Demand-Side Management Aspects of Gas Integrated Resource Planning*, July 23, 1993, pp. 1-4; Ontario Energy Board, *Decision in EB-2012-0451/0433, January 30, 2014*, p. 46-47 (GTA Pipeline) (link); Ontario Energy Board, *DSM Framework,* December 22, 2014, p. 35-36 (link); EB-2018-0097, Decision and Order, January 3, 2019, pp. 6-7 (Bathurst Reinforcement) (link); EB-2020-0192 (London Lines), OEB Decision and Order, January 28, 2021, p. 20 (link).
[236] EBO 169-III, *Report of the Board on the Demand-Side Management Aspects of Gas Integrated Resource Planning*, July 23, 1993 (link).
[237] Ontario Energy Board, *Decision in EB-2012-0451/0433, January 30, 2014*, p. 46-47 (GTA Pipeline) (link).
[238] *Ibid*.

> cost-effective manner, the Board is of the view that DSM should be considered when developing both regional and local infrastructure plans. …The Board expects the gas utilities to consider the role of DSM in reducing and/or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative. If a gas utility identifies DSM as a practical alternative to a future infrastructure investment project, it may apply to the Board for incremental funds to administer a specific DSM program in that area where a system constraint has been identified.
>
> The Board is also of the view that the gas utilities should each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the DSM framework. The studies should be based on a consistent methodology to determine the appropriate role that DSM may serve in future system planning efforts. As part of the multi-year DSM plan applications, the gas utilities should include a preliminary scope of the study it plans to conduct and propose a preliminary transition plan that outlines how the gas utility plans to begin to include DSM as part of its future infrastructure planning efforts.[239]

In the 2016 DSM Plan decision, the OEB found that Enbridge's proposed next steps would cause "delay" and directed them to develop an IRP transition plan:

> The OEB agrees that a case study, as proposed by Enbridge, would assist in assessing the merits of a transition plan. However, the OEB is concerned that the time required to complete a case study would delay the utilities' infrastructure planning activities proposal and the transition plan would not be available in time for the mid-term review.
>
> The OEB directs Enbridge and Union to work jointly on the preparation of a proposed transition plan that outlines how to include DSM as part of future infrastructure planning activities. The utilities are to follow the outline prepared by Enbridge, and should consider the enhancements suggested by the intervenors and expert witnesses. The transition plan should be filed as part of the mid-term review.[240]

In the 2018 DSM Mid-Term Review decision, the OEB expressed concerns about the lack of progress on IRP and directed Enbridge to do better.

> Stakeholders indicated reservations in the usefulness of the transition plan provided by the natural gas utilities. The OEB agrees that although the progress made is at an early stage, the transition plan does not advance the understanding of the role and impact that energy conservation can play in deferring or avoiding capital projects. Currently, leave to construct applications do not include a description of the DSM alternatives considered to help avoid and/or defer the proposed capital project. The natural gas utilities should continue to develop rigorous protocols to include DSM as part of their internal capital planning

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[239] Ontario Energy Board, *DSM Framework,* December 22, 2014, p. 35-36 (link).
[240] EB-2015-0029/0049, *Decision and Order*, January 20, 2016 (2015-2020 DSM Plans), p. 84 (link).

> process. This should include a comprehensive evaluation of conservation and energy efficiency considered as an alternative to reduce or defer infrastructure investments as part of all leave to construct applications.[241]

In the 2019 Bathurst Reinforcement decision, the OEB again directed Enbridge "to provide sufficient and timely evidence of how DSM has been considered as an alternative at the preliminary stage of project development."[242] It also warned Enbridge that it "faces the risk that future application will be deemed incomplete."[243]

In the 2021 London Lines decision, the OEB directed Enbridge to do better once again and to conduct an "in-depth quantitative and qualitative analyses of alternatives".[244] In particular, the OEB said:

> However, despite the OEB approval of the application for leave to construct this Project, the OEB agrees with Environmental Defence that Enbridge Gas has an obligation to conduct a more rigorous Integrated Resource Planning assessment at the preliminary stage of projects development in future cases. As OEB staff also notes the failure to present detailed analyses makes it unlikely that Enbridge Gas would select an alternative including DSM or other non-build project option. The OEB acknowledges that more direction is likely to be provided to Enbridge Gas in future leave to construct projects as part of the ongoing IRP proceeding. In the interim, however, the OEB believes that all parties would be assisted if Enbridge Gas would, in the future, undertake in-depth quantitative and qualitative analyses of alternatives that specifically include the impacts of DSM programs on the need for, or project design of facilities for which Enbridge Gas has applied for leave to construct.[245]

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[241] EB-2017-0127/0128, *Report of the Ontario Energy Board, Mid-Term Review of the Demand Side Management (DSM) Framework for Natural Gas Distributors (2015-2020)*, November 29, 2018, p. 20-21 (link).
[242] EB-2018-0097, Decision and Order, January 3, 2019, pp. 6-7 (link).
[243] *Ibid*.
[244] EB-2020-0192 (London Lines), OEB Decision and Order, January 28, 2021, p. 20 (link).
[245] EB-2020-0192 (London Lines), OEB Decision and Order, January 28, 2021, p. 20 (link).