Before the Ontario Energy Board

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Enbridge Gas 2024 Rebasing

Prepared by:

Chris Neme

Energy Futures Group

Prepared for:

The Green Energy Coalition
Greenpeace Canada
Sierra Club Ontario Chapter

Environmental Defence

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I. Executive Summary

This report discusses the risk that infrastructure built pursuant to Enbridge's current application may ultimately be underutilized or stranded due to market forces and/or climate policy, and proposes steps that Enbridge and the Ontario Energy Board (OEB or Board) can take to mitigate those risks to consumers. The report is authored by Chris Neme, a Principal with Energy Futures Group (EFG). Mr. Neme and his firm are leading experts on the implications of decarbonization for gas customers and best practices to address those implications. Mr. Neme has decades of experience with Enbridge Gas and the Ontario regulatory context from approximately 30 years of work on gas and (to a lesser extent) electric DSM in the province, and participation in various OEB advisory committees on DSM, Gas IRP, and carbon prices. What follows are the key conclusions and recommendations of the report.

1. Key Conclusions

I conclude in this report that major declines in peak and annual gas demand are very likely in the future as efforts to decarbonize the Ontario economy accelerate. This is the conclusion of most independent decarbonization pathways studies. It is also consistent with an analysis of the availability and feasibility of the electric and gas technologies required for net zero greenhouse gas (GHG) emissions and the current cost effectiveness of electrification. It is even consistent with results of Enbridge's own decarbonization study if just one of the most glaring of the many flaws in the study is corrected. I discuss each of these points in some detail in Section III of this report.

The potential implications of declining gas peak demand and gas sales are significant and important. In a nutshell, there is a growing risk that current and any new gas capital assets will become underutilized, if not stranded. This creates significant risks for the ratepayers who would be saddled with paying for those assets in the future. It will likely also create significant inequities between customers today and those left on the system in the future who end up paying for an inappropriate and disproportionately large share of the cost of gas system assets – including assets that were intended primarily or exclusively to meet the needs of other customers who will have left the gas system. This will be particularly problematic for lower-income households who could face the biggest hurdles to exiting the system.

There are a variety of ways in which the Board should mitigate those risks. In particular, I recommend the following:

1. **Shorten new construction connection cost recovery periods**. There are two components to this recommendation:
    a. **Reduce the customer revenue horizon from 40 years to 15 years**. This will reduce the risk that new customers do not end up covering the full cost of their connection to the system through rates, let alone contributing to other system costs, if they electrify at the time that their new heating system needs to be replaced. Enbridge estimates this change would reduce system access spending by about $600 million over the 2024-2028 period.
    b. **Reduce the maximum customer connection horizon from the current 10 years to 5 years**. Given the likelihood that gas sales will begin to decline, it is prudent to put tighter limits on the sunsetting of connection offers to builders and developers.
2. **Reduce infill connection costs funded by rates to the amount that will be recouped from resulting gas bills over 15 years**. Analogous to the above recommendation, this will reduce the

risk that new customers do not end up covering the full cost of their connection to the system through rates, let alone contribute to other system costs.

3. **Require all new connections to be net-zero greenhouse gas emitting**. This would include requiring that all new connections install hybrid heating systems with a cold climate air source heat pump meeting the vast majority of heating needs (and a back-up gas furnace functioning only during the coldest hours of winter). Also, all gas provided to new connections would have to be biomethane (often called renewable natural gas or RNG). This recommendation is similar to a proposal that Energir, the Quebec gas utility, recently proposed for its upcoming rate case.
4. **Require Enbridge to immediately assess and report back to the Board by 2024 on the near-term and longer-term rates, costs of capital, affordability, and inter-generational equity impacts of alternative asset depreciation approaches**. The current approach to depreciation is highly problematic because it does not address decarbonization risks at all and implicitly assumes a 0% risk of underutilized or stranded assets even long past 2050. The Company should assess, among other things, a Units of Production approach, which could account for declining annual sales, and thus promote better inter-generational equity and help to ensure affordability as demand declines. Depreciation approaches that account for decarbonization should be studied now because delaying a shift in approaches will cause increasingly large rate shocks as time goes on.
5. **Require Enbridge to routinely assess trade-offs between repairing and replacing aging pipe.** The assessments should account for the possibility that a new pipe will be underutilized or stranded before the end of its life as a result of decarbonization policies or market forces significantly driving down gas demand in the future. They should include estimates of near-term cost savings and related differences in rate impacts, any potential differences in long-term costs and rate impacts, the magnitude of any differences in methane leaks, the nature of any differences in safety risks, and the long-term potential to save money by cost-effectively pruning the gas system.
6. **Improve IRP to reduce the risk of under-utilized or stranded assets**. There are two components to this recommendation:
    a. **End the interim prohibition on considering electrification measures as IRP Alternatives (IRPAs).** Things have changed since the Board put this prohibition in place in the gas IRP proceeding several years ago. Our understanding of decarbonization includes both recognition of the likelihood that significant electrification will occur and new direction from the Minister. Indeed, the Board recently required Enbridge to provide rebates for electric heat pumps through its DSM programs. It would be prudent to enable Enbridge to target electrification to areas that could simultaneously reduce other gas infrastructure investment costs.
    b. **Require analysis of IRPAs under multiple possible future load forecasts that include the effects of decarbonization of the economy.** To date, Enbridge has based its assessment of system needs and the role that IRPAs could play in cost-effectively deferring such needs on forecasts that do not reflect the likely impacts of decarbonization on demand. At a minimum, assessments of cost-effectiveness should consider demand declines as a material possibility.
7. **Consider the creation of a segregated fund for site restoration.** Enbridge currently retains billions of ratepayer dollars for future site restoration costs. This creates a material risk for

customers, which is increasing as decarbonization unfolds. A third-party study should be commissioned on a segregated fund restoration funds and how to maximize returns on the funds and minimize costs and liability for existing customers. This issue should be revisited in phase II based on that study.

8. **Reduce capital spending on gas assets whenever possible.** The risk of underutilized and stranded assets calls for maximizing scrutiny of opportunities to reduce capital spending that will be added to rate base, wherever that is possible, especially for long-lived infrastructure.

II. Introduction

On October 31, 2022, Enbridge Gas Inc. (Enbridge) filed its 2024 Rebasing application and evidence. The application requests approval of rates for the sale, distribution, transmission and storage of gas. The Company also requests approval of an incentive rate-making mechanism for 2025 through 2028. The Company's evidence is extensive, covering a wide range of information, including but not limited to its demand forecast, capital spending requirements under its asset management plan, its cost of capital, its revenue requirements, and rate design. For the first time, Enbridge's rebasing filing also includes discussion of the energy transition that will be necessary to decarbonize Ontario's (and Canada's) economy and the implications of that transition on many of the requests the Company is making in this proceeding.

This report discusses the risk that infrastructure built pursuant to Enbridge's current application may ultimately be underutilized or stranded due to market forces and/or climate policy. It also proposes regulatory steps the Ontario Energy Board (OEB or Board) should consider to mitigate those risks to consumers.

The report is authored by Chris Neme, a Principal with Energy Futures Group (EFG). Mr. Neme and his firm have extensive experience and expertise in both the development of policies and the assessment of options for, and implications of, decarbonization of fossil gas use in buildings and industry. That includes developing and conducting decarbonization pathways studies (e.g., in Massachusetts, Vermont and Delaware); helping clients review and provide input to similar studies led by other firms (e.g., the recent Massachusetts gas utilities study); reviewing and critiquing studies on renewable gas potential (e.g., a 2022 Michigan study); assessing the reasonableness of RNG pilot program proposals (Illinois); assessing the need for pipeline expansion in the context of local decarbonization policies (in testimony before the U.S. Federal Energy Regulatory Commission on behalf of the state of Washington); assessing the customer economics of electrification (e.g., in Illinois, Michigan, Nevada and British Columbia); supporting the design of electrification programs (e.g., in Michigan, Illinois and Massachusetts); and supporting the development of over-arching building decarbonization policies (e.g., Vermont's proposed Clean Heat Standard, Michigan's climate plan, and Illinois climate legislation).

Mr. Neme has filed expert witness testimony in 25 different OEB dockets, mostly on gas DSM issues, but also on gas integrated resource planning (in 2020) as well as on Enbridge and Union's carbon cap and trade policies (in 2018). He has also filed testimony on energy efficiency, electrification, integrated resource planning and other distributed energy issues in 45 DSM, IRP, and Rates cases before energy regulators in a dozen different jurisdictions, including the neighboring provinces/states of Quebec, Manitoba, Michigan and Ohio. Mr. Neme was recently appointed to the OEB's DSM Stakeholder Advisory Group, currently serves on the OEB's Gas IRP Working Group, previously served on OEB's Evaluation Advisory Committee and was also previously elected by Ontario stakeholders to serve on the province's Gas Technical Advisory Committee and numerous Enbridge and Union Gas DSM Audit Committees over the past 20+ years. He also previously served as an outside reviewer of Ontario studies on achievable efficiency potential and carbon price forecasts.

III. Major Declines in Gas Demand from Decarbonization Likely

1. Summary

Major declines in peak and annual gas demand are very likely due to decarbonization. I come to this conclusion for the following reasons:

- Most independent decarbonization pathways studies find that high levels of full electrification of buildings will be the least expensive decarbonization pathway.
- Even scenarios with significant hybrid gas-electric heating result in declines in gas demand because RNG feedstocks are expensive and very limited and the amount of hydrogen energy that can be safely blended with methane is very small.
- The Ontario electric grid is already very clean and the technologies required for electrification of buildings (e.g., electric heat pumps) are currently available, well tested, scalable, and have been consistently following a trend of increasing performance.
- The technologies required for high-gas pathways (e.g., gas heat pumps, 100% hydrogen furnaces and other appliances, and 100% hydrogen distribution systems) are largely unavailable today – i.e., they are much more uncertain than electric alternatives.
- RNG prices increase as overall consumption increases (i.e., it has a steep supply curve), which is much less the case with green electricity.
- Full electrification of homes is already highly cost-effective from a consumer price perspective in comparison to fossil methane heating, lowering total energy bills by 37-50% in the very first year and providing nearly $17,000 in 18-year net present value (NPV) savings. Full electrification will likely be even more cost-effective in comparison to decarbonized gas heating (e.g., RNG).
- Considerable GHG emissions persist with most forms of RNG and with blue hydrogen, and there is not yet scientific consensus on the true extent of those emissions, raising the risk that certain "low-carbon" gaseous fuels are actually inconsistent with net zero emissions goals at the volumes required.
- The Guidehouse pathways report that Enbridge is relying upon to support its vision of higher reliance on gaseous fuels is replete with errors and pro-gas biases (see below). Remedying only a few of these would swing the results such that the "electrification" scenario analyzed by Guidehouse is more cost effective, even though that scenario is poorly designed and not a least-cost electrification scenario.

2. Technical Options for Decarbonizing Fossil Gas Use in Buildings and Industry

Ontario is currently emitting approximately 150 million tonnes of carbon dioxide equivalents (CO_2e) per year.[1] The burning of fossil methane in homes, commercial buildings and industry is responsible for approximately one-third of those emissions. Canada has committed to achieving net zero emissions of CO_2e by 2050 and enshrined that target in legislation.[2] The country's 2030 Emissions Reduction Plan is

[1] Exhibit 1, Tab 10, Schedule 3, Page 2 (based on the latest publicly available data at the time of the application).

[2] Canadian Net-Zero Emissions Accountability Act (https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050/canadian-net-zero-emissions-accountability-act.html).

designed to reduce emissions from the buildings sector by 42% relative to 2019 levels.[3] For the fossil methane industry – Enbridge's business – reaching both the short term and longer-term emission reduction goals is going to require dramatic changes. Put simply, it is going to require massive levels of fuel-switching away from fossil methane.

Conceptually, there are essentially three categories of alternatives to fossil methane:

- **Electricity**. The current Ontario electric grid is already more than 90% carbon free[4] and will likely have to get even cleaner for the province to meet its emission reduction goals and the federal government's Clean Electricity Standard, which will require net-zero electricity by 2035.[5] There are a variety of electrification technologies that can be deployed to take advantage of a clean electric grid, including cold climate air source heat pumps (ccASHPs), ground source heat pumps, networked geothermal heating systems, heat pump water heaters, induction stoves/cooktops, and a range of industrial electrification technologies.
- **Biomethane (often called renewable natural gas or RNG)**. Biomethane is methane that is produced by decaying organic matter (e.g., from animal manure, crop residues, landfills and wastewater treatment plants). Biomethane is essentially chemically identical to fossil methane. Thus, burning of biomethane in a furnace produces just as much CO2e emissions as burning fossil methane. However, to the extent that emissions at the furnace "burner tip" are *offset* by elimination or reduction of emissions of methane – itself a potent greenhouse gas (GHG) – that otherwise would have been released to the atmosphere, the net effect of substituting biomethane for fossil methane can be a reduction in GHG emissions. As discussed further below, it is important to recognize that though biomethane is sometimes analyzed as if it is always zero emitting (simply because it is biogenic), the actual net effects on total CO2e emissions to the atmosphere varies widely depending on the source of the biomethane and existing regulations or standard business practices regarding methane emissions. Some forms of biomethane have net negative CO2e emissions (i.e., the benefits of eliminating methane emissions that would otherwise be emitted to the atmosphere are greater than the CO2 emissions that result from burning it); other sources of biomethane have emissions profiles not much better than fossil gas. Methane leaks in the gas transmission and distribution system – as well as leaks or incomplete combustion on the customer side of the meter – need to be reflected in estimates of any lifecycle GHG emission reductions associated with biomethane.
- **Hydrogen**. Hydrogen gas can potentially be substituted for fossil methane. The result can be substantial GHG emission reductions – if the hydrogen is produced through low or zero-GHG emitting processes. For example, when hydrogen is produced by electrolysis of water using renewable forms of electricity such as wind or solar power, no CO2e emissions are generated in

[3] The estimated reduction from 2005 building sector emissions levels of 84 Mt is 37% - or a reduction to 53 Mt. However, emissions grew from 84 Mt to 91 Mt between 2005 and 2019. Thus, getting to 53 Mt would require a 42% reduction from the 2019 level of 91 Mt (https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/factsheet-02-buildings.pdf).

[4] Independent Electric System Operator (IESO), *Pathways to Decarbonization: A report to the Minister of Energy to evaluate a moratorium of new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector*, December 15, 2022, p. 6.

[5] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html.

its production. This is known as "green hydrogen". Hydrogen can also be produced from fossil fuels, with a portion of the resulting CO2 combustion emissions captured and stored. This is known as "blue hydrogen". Note that there are always some GHG emissions associated with blue hydrogen because carbon capture and storage processes are never 100% and there are still fugitive emissions from the extraction and transportation of methane. Also note that hydrogen itself is an indirect greenhouse gas. Thus, leaks of hydrogen resulting from its production, transportation/distribution and movement through pipes and appliances in homes and businesses also need to be considered when assessing its lifecycle emission reduction potential.[6]

In addition to these fuel-switching options, energy efficiency or conservation can play an important role in reducing emissions in the near to medium term by reducing the amount of fossil fuel that needs to be burned to meet heating or other energy needs. In the longer-term, when fossil fuels need to have been fully replaced with low or zero-carbon alternatives, efficiency can still play an important role in reducing the costs of meeting heating and other energy needs by reducing the amount of alternative fuels (and related capital infrastructure) necessary to meet the energy needs of homes and businesses in a decarbonized future.

3. Electrification Dominates in Independent Decarbonization Pathways Studies

A. Overview

Over the past decade there have been numerous studies examining different pathways for decarbonizing buildings and industry in Canada, the United States, Europe and globally. Such studies typically assess the costs and emissions impacts of different combinations of technologies and low or zero-carbon energy. There are many potential combinations of technologies and energy sources that can be and have been analyzed. However, at a high level, all such scenarios can generally be categorized as permutations and/or combinations of one or more of the following three approaches:

- **High levels of full electrification**. In these scenarios, the vast majority of heating, water heating and other residential and commercial end uses, as well as a significant portion of industrial end uses, are fully electrified with heat pumps and other advanced electric technologies. However, alternative fuels such as biomethane and/or green hydrogen are often assumed to be necessary for those industrial customers for whom electrification is not easy or feasible. Significant investment in energy efficiency is typically assumed to be necessary to partially reduce the magnitude of new electric generating, transmission and distribution capacity needed to meet customers' energy demands, particularly at peak hours on cold winter mornings.
- **Hybrid gas-electric solutions**. These scenarios still include substantial amounts of electrification. However, while there is typically assumed to be some full electrification, most homes and businesses are assumed to install hybrid heating systems in which electric heat pumps are paired with gas furnaces, with the heat pumps providing the vast majority of heating needs over the course of the winter and the gas furnaces turning on to meet peak heating needs during only the coldest days or hours of the year. Use of the gas distribution system to meet peak heating needs means less electric generating, transmission and distribution system capacity needs to be built. The vast majority of the gas supplied to meet peak winter heating

[6] Poore, Colton, "Switching to hydrogen fuel can prolong the methane problem", Princeton University, March 13, 2023 (https://engineering.princeton.edu/news/2023/03/13/switching-hydrogen-fuel-could-prolong-methane-problem).

loads is typically biomethane (sometimes augmented with very small amounts of hydrogen blending). As in the high electrification scenarios, those industrial customers who cannot easily electrify are assumed to switch to biomethane and/or green hydrogen. These scenarios also typically include significant energy efficiency investments, though sometimes the magnitude of those investments is assumed to be lower than in high electrification scenarios.

- **Mass distribution of 100% hydrogen.** This scenario assumes substantial amounts of electrification, but less than the two other scenarios because it is assumed that green and/or blue hydrogen will be distributed to large portions of existing residential and commercial gas customers, as well as to industrial customers. As with hybrid heating scenarios, significant investment in energy efficiency is typically assumed, but potentially at levels a little lower than for high electrification.

Most independently-conducted assessments of decarbonization pathways – i.e., those not sponsored by organizations with vested interests in the outcomes, such as gas utilities or organizations who are advocates for hydrogen – have concluded that high electrification pathways are the most likely and most cost-effective pathways, even in colder climates. That is the case for three recent studies for Canada, Quebec and New York, each of which is summarized below. While many if not most pathways assume 100% hydrogen is likely for some industrial customers, gas utility delivery of 100% hydrogen is generally not considered a realistic option for residential and commercial customers. A common gas utility vision of an alternative to high electrification is significant adoption of hybrid electric-gas heating systems. That was the conclusion of a recent study sponsored by the Massachusetts gas utilities, also summarized below.

B. Canada Study (by Canadian Climate Institute)

In February 2021, the Canadian Institute for Climate Choices (since renamed the Canadian Climate Institute) released a report documenting the results of its assessment of a wide range of pathways to achieving net zero GHG emissions across all sectors of the Canadian economy.[7] The study assessed more than 60 different potential economy-wide pathways through technical modeling, literature review, and input from experts. It assessed macro-economic outcomes (e.g., changes to the structure of the economy), microeconomic outcomes (e.g., impacts on household energy use and costs), emissions impacts, and feasibility. The study authors also sought and received input and feedback from a range of perspectives, including "academics, practitioners, individual companies, industry associations, federal and subnational governments, Indigenous Peoples, and labour unions."[8]

With respect to residential and commercial buildings, the report makes clear that electrification (and energy efficiency) will likely dominate decarbonization activity through 2035, with their model suggesting:

- sales of new electric heating systems overtaking sales of gas combustion furnaces between 2027 and 2032;
- the percentage of Canadian homes heating with heat pumps increases from about 2% in 2020 to between 15% and 20% by 2035; and

[7] Canadian Institute for Climate Choices, *Net Zero Future: Finding Our Way in the Global Transition*, February 2021 (https://climateinstitute.ca/reports/canadas-net-zero-future/).
[8] Ibid, p. 17.

- the percentage of Canadian homes heating with gas drops from a little over 70% in 2020 to between 50% and 55% by 2035.[9]

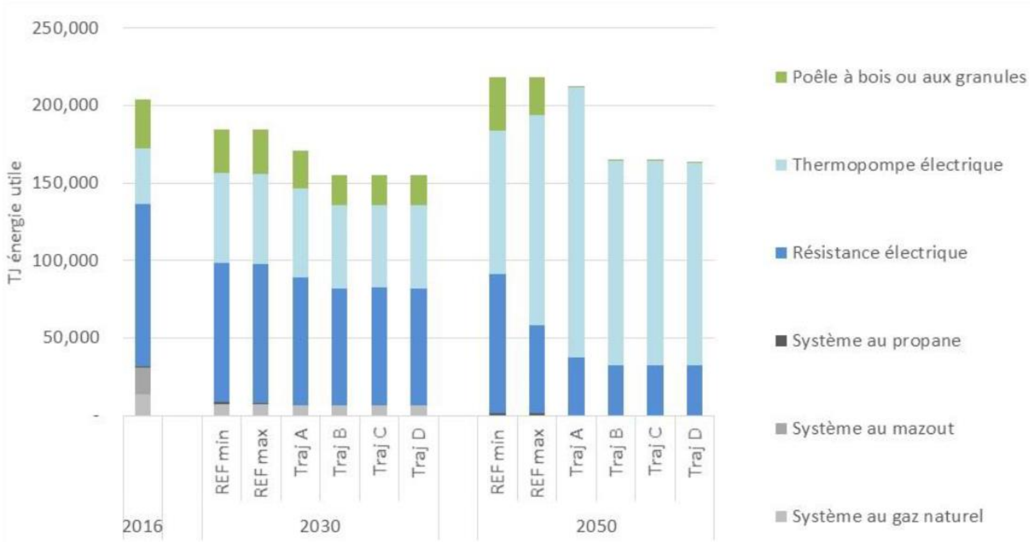
The study acknowledges that there is greater uncertainty with regard to the mix of technologies and fuels that will ultimately comprise the optimal solution to decarbonization by 2050. For example, it states that electric heating systems will heat between 52% and 100% of homes by 2050 (up from about 30% today), with the balance being met by wood (0% to 10%) and clean gases (0% to 40%).[10] All told, the study concludes that clean gases could potentially provide "a total amount of energy equivalent to 32 percent of today's natural gas demand in Canada's buildings."[11] However, the study notes that there are a number of barriers to clean gases playing even that large of a role. With respect to hydrogen, barriers include high costs, limits to the ability to blend hydrogen with methane, the "significant modifications to pipelines and distribution networks" required to carry more hydrogen than that, and the need to replace methane-burning equipment in homes and businesses with hydrogen-burning equipment. With respect to biomethane, the key barriers are both high cost and "limited" supplies of feedstock "making significant cost declines from economies of scale unlikely."[12] The bottom line is that "the future of clean gases in the buildings sector is complex and uncertain."[13]

C. Quebec Study (by Dunsky)

In June of 2021 the Quebec Environment Ministry released a report documenting the results of a study designed to identify the lowest cost pathway to decarbonizing the province's economy.[14] As Figure 1 shows, the study concluded that natural gas use (systeme au gaz naturel) for residential space heating would be cut roughly in half by 2030 (relative to 2016) and essentially disappear by 2050. Fuel oil (systeme au mazout) and wood heating (poele a bois ou aux granules) also large disappear by 2050 in the decarbonization scenarios (Trajectories A, B, C and D). There is no hydrogen use in the residential sector in any scenario. Nor is there any appreciable use of biomethane. All space heating essentially becomes electric.

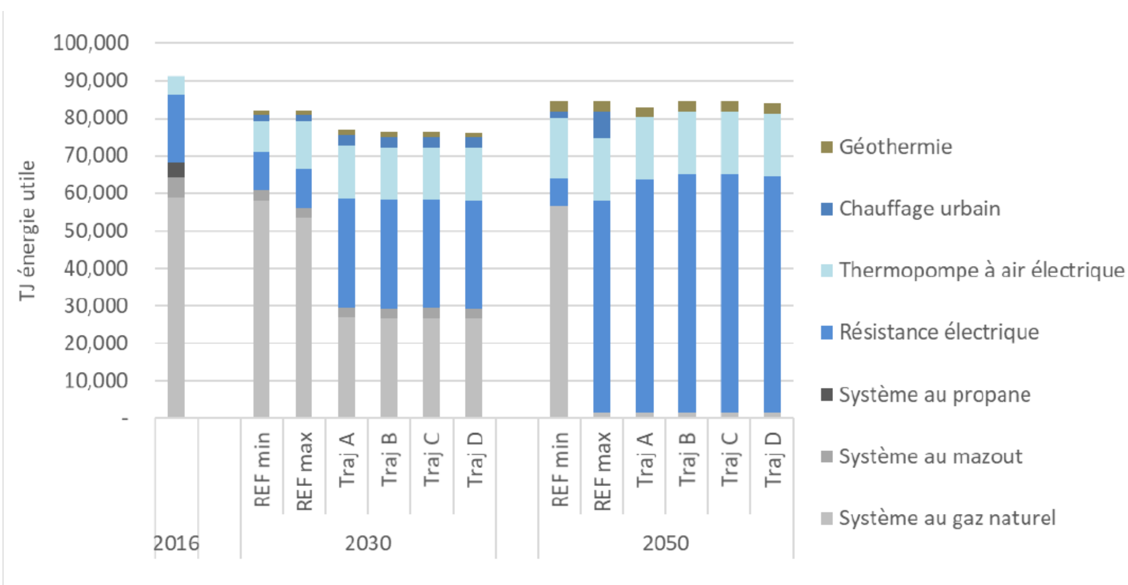
[9] Ibid, pp. 39-40.
[10] Ibid.
[11] Ibid., p. 43.
[12] Ibid., p. 44.
[13] Ibid.
[14] Dunsky, *Quebec GHG Emission Reduction Trajectories – 2030 and 2050*, prepared for the Ministry of Environment and the Fight Against Climate Change, June 2021 (available only in French at https://www.dunsky.com/wp-content/uploads/2021/09/Rapport_Final_Trajectoires_QC_2021.pdf)

Figure 1: Quebec Decarbonization Study, Forecast Change in Residential Heating Fuel Mix[15]



As Figure 2 shows, while the situation is slightly more variable in commercial and institutional buildings, there are still dramatic reductions in gas use for space heating in all decarbonization scenarios – on the order of 50% by 2030 (relative to 2016) and more than 95% reductions by 2050. As with residential buildings, there is no appreciable hydrogen or biomethane use.[16]

Figure 2: Quebec Decarbonization Study, Commercial and Institutional Buildings Heating Fuel Mix[17]



[15] Ibid, p. 22.

[16] Though not clear from the graphic because it illustrates only changes in volumes of gas consumed through the existing natural gas distribution system, the very small amount of gas consumption in the decarbonized scenarios for 2050 may be biomethane.

[17] Dunsky, p. 22.

D. New York Study (by E3)

In July of 2019, the state of New York enacted the Climate Leadership and Community Protection Act. The law requires the state to achieve a 40% reduction in GHG emissions (relative to 1990 levels) by 2030 and an 85% reduction by 2050. The law also created and instructed a 22-member Climate Action Council to develop and publish a plan with policy recommendations for meeting those emission reduction requirements. An initial draft plan was released in December 2021, following two years of investigation informed by input from seven sector-specific Advisory Panels, a Just Transition Working Group, stakeholders and the public. One key input to the development of the draft plan was a study (what the Council called an "integration analysis") outlining expected costs and benefits of different decarbonization pathways. The consulting firm Energy and Environmental Economics (E3) conducted the study.

The study started with the development of a business-as-usual (or reference case) scenario as well as a scenario based on initial recommendations of the Council's Advisory Panels. When analysis of that initial scenario suggested that the Council's recommendations were not enough to meet the state's GHG emission reduction goals, three additional scenarios were developed. Thus, the study ultimately assessed four GHG reduction scenarios (in addition to the reference case):

- **Scenario 1: Advisory Panel Recommendations** – including "rapid electrification of buildings and transportation, decarbonization of the power sector and ambitious reductions in non-combustion emissions";
- **Scenario 2: Strategic Use of Low-Carbon Fuels** – Advisory Panel recommendations adjusted for strategic use of biofuels as well as green hydrogen for difficult-to-electrify end uses.
- **Scenario 3: Accelerated Transition Away from Combustion** – Advisory Panel recommendations adjusted to accelerate electrification of buildings and transportation with a "very limited role" for biofuels and hydrogen.
- **Scenario 4: Beyond 85% Reduction** – Advisory Panel recommendations adjusted to include both accelerated electrification and targeted use of low-carbon fuels, plus additional reductions in "vehicle miles traveled" and innovation in methane abatement.[18]

The study found that Scenario 3, the scenario most emphasizing electrification and least invested in biofuels, had the lowest cost of the three scenarios that met the state's emission reduction requirements.[19] While Scenarios 2, 3 and 4 all produced greater benefits (in the form of GHG emission reductions and health improvements) than costs, net benefits were greatest for Scenario 3.

The study's results for the (residential and commercial) buildings sector include:

- "In all scenarios, electric heat pump space heating technology systems become the majority of new purchases by the late 2020s and no fossil-emitting appliances are sold after 2035."[20]

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[18] Energy and Environmental Economics (E3), *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, December 2022 (https://climate.ny.gov/resources/scoping-plan/), p. 14.

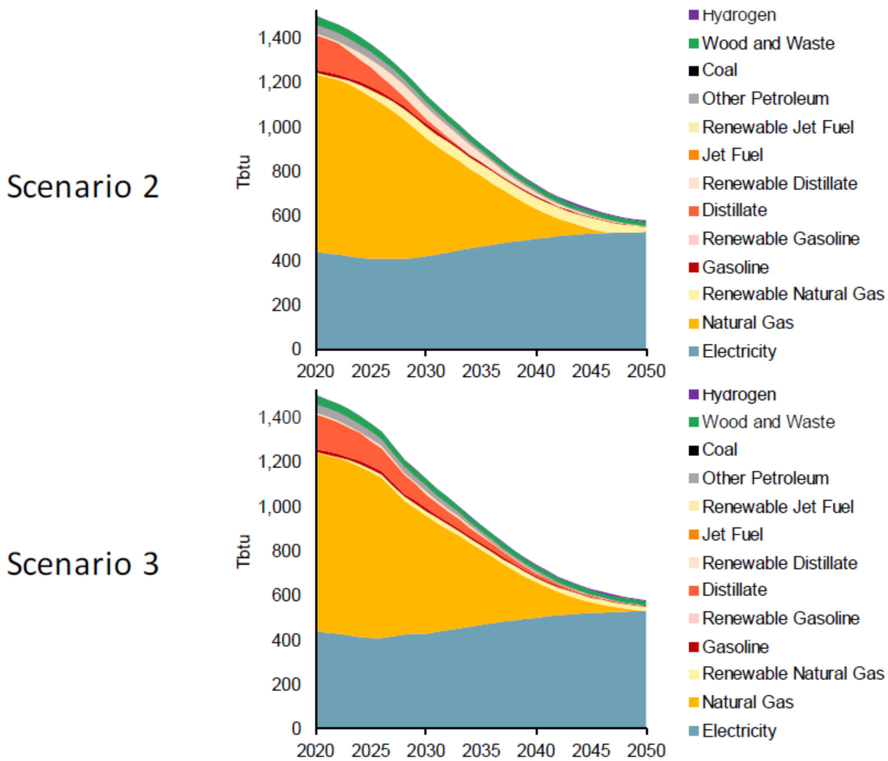
[19] The net present value (NPV) of the cost of Scenario 3 was $270 billion over the 2020 to 2050 analysis; the NPV of the cost of both Scenario 2 and Scenario 4 was $295 billion. Ibid, p. 8.

[20] Ibid., p. 31.

- The share of final energy demand met by electricity increases from 30% in 2020 to 89-92% in 2050 across scenarios 2 through 4.[21]
- Hybrid electric-gas heating systems play a limited role – 10% of heating systems by 2050, and only in Scenario 2.[22]
- The role of hydrogen in residential and commercial buildings is also very small, limited to the conversion of New York City's district heating system in Scenarios 2, 3 and 4.[23]

Figure 3 graphically illustrates these results for Scenarios 2 and 3.

Figure 3: New York Climate Council Study, Forecast Fuel Mix for Buildings in Scenarios 2 and 3[24]



The study results were more varied for industrial energy use, with energy efficiency, electrification, conversion to hydrogen, renewable natural gas, and carbon capture and storage for select industries (i.e., cement and iron and steel) playing roles in all scenarios. Hydrogen plays a bigger role in Scenario 2 while electrification plays a bigger role in Scenarios 3 and 4.[25]

E. Massachusetts Study (by E3)

In October of 2020, the Massachusetts Department of Public utilities ordered "an investigation into the role of local natural gas distribution companies (LDCs) in the Commonwealth's goal to achieve net zero greenhouse gas emissions by 2050."[26] As part of that effort, the gas utilities hired Energy and

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[21] Ibid.
[22] Ibid, p. 33 and Technical Supplemental Annex 2, "Scenario Detail" tab.
[23] Ibid.
[24] Ibid, p. 32 (this is a portion of the Figure 22 in the report).
[25] Ibid., pp. 56-57.
[26] https://thefutureofgas.com/overview

Environmental Economics (E3) to conduct a detailed assessment of a number of different pathways for decarbonizing fossil gas use in the state. The utilities also hired E3 and Scottmadden Management Consultants to develop a set of regulatory policy recommendations to support the energy transition.[27] This was not a truly independent study as it was sponsored by gas utilities with a vested interest in the continuation of the gas system. However, I discuss it here as it provides insight into the kind of decarbonization solutions that gas utilities are advocating for in some jurisdictions, which do not include anything close to the heavy reliance on 100% hydrogen as in Enbridge's vision.

The E3 decarbonization study ultimately included a reference case along with eight decarbonization scenarios. The assumptions regarding heating of residential and commercial buildings in those scenarios can be summarized as follows:[28]

- **Reference case**: 9% of residential homes and 10% of commercial buildings fully electrically heated in 2050, with most of the remainder using fossil gas.
- **High electrification**: virtually all buildings fully electrically heated by 2050, primarily through cold climate heat pumps.
- **Low electrification**: two-thirds of residential homes and 80% of commercial buildings fully electrically heated by 2050, mostly with cold climate air source heat pumps, with the remaining buildings primarily heating with renewable gas.
- **Interim 2030 Climate and Energy Plan**: comparable to high electrification scenario, but with accelerated adoption of heat pumps in the 2020s to meet the state's more aggressive 2030 emission reduction goals.
- **Hybrid electrification**: roughly 20% of residential and commercial buildings fully electrically heated by 2050, with virtually all of the rest adopting hybrid heating systems – e.g., cold climate heat pumps backed up by gas furnaces or boilers fueled by renewable gas.
- **Targeted electrification**: portions of the gas system decommissioned, roughly three-quarters of homes and nearly 85% of commercial buildings fully electrified by 2050, with most of the rest adopting hybrid heating systems fueled by renewable gas.
- **Networked geothermal**: networked geothermal electric heat wherever feasible – i.e., for about one-quarter of residential homes and half of commercial buildings by 2050 - with the remainder either fully electrified with air source heat pumps, ground source heat pumps or electric resistance heat (collectively about half of residential buildings and 35% of commercial buildings) or fueled by renewable gas (about one-quarter of homes and 15% of commercial buildings).
- **Efficient gas equipment**: roughly one-quarter of residential homes and 13% of commercial buildings fully electrified with most of the rest adopting high efficiency gas appliances (mostly gas heat pumps) fueled by renewable gas.
- **100% gas decommissioning**: 100% electrification of buildings by 2050 through a combination of networked geothermal, cold climate air source heat pumps and ground source heat pumps.

[27] Both of these reports can be found in the "Customer Resources and Stakeholder Engagement Process" section of https://thefutureofgas.com/sep.
[28] See E3 and Scottmaden, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report, Technical Analysis of Decarbonization Pathways*, March 18, 2022, pp. 29-32 for high level descriptions of the scenarios, with details on assumed heating market shares by scenario from the Excel filed serving as Appendix 4, "Scenario parameters (detail)" tab.

In addition, in all decarbonization scenarios there is significant investment in energy efficiency, particularly building envelop efficiency. In all decarbonization scenarios all gas consumption is assumed to be renewable gas, which is primarily biomethane. The study assumed that when demand for gas outstripped available supply of biomethane, even more expensive synthetically produced methane could fill the gap. The study also assumed green hydrogen blending with methane – up to 20% by volume and 7% by energy content – was feasible. No scenario included either blue hydrogen or 100% hydrogen delivered to residential or commercial buildings, though some scenarios included 100% hydrogen delivery to at least portions of the industrial sector.

The study found the hybrid electrification scenario – which, as discussed below, still results in a 73% reduction in annual gas throughput and about a one-third decline in peak demand for gas by residential, commercial and industrial customers – to be the lowest cost. The high electrification scenario was found to be about 25% more expensive.[29] However, many parties raised concerns about a number of study assumptions that appeared to bias the results in favor of continued use of the gas system, including unreasonably high assumptions about the future cost of cold climate heat pumps; significantly understating cost savings from pruning of the gas distribution system, unrealistically optimistic assumptions about the availability of biomethane (RNG); assuming market clearing prices for biomethane would not be affected by higher market prices paid for synthetically produced methane; and failing to account for the fully lifecycle emissions impacts of producing, transporting and burning both biomethane and synthetically produced methane.[30] I was highly involved in this proceeding on behalf of a client and I believe it is likely that much higher levels of full electrification would have been found to be a lower cost pathway if these biases had been corrected.

F. Commonalities Across Studies

There are a number of commonalities to the conclusions of the studies discussed above. Chief among them are:

- Significant investments in building envelop energy efficiency upgrades – much broader and deeper than current utility efficiency programs are typically achieving – are cost-effective and critically important in every scenario.
- Significant levels of electrification are necessary, because of the limited availability of (and competing demands/uses for) biomethane, and the practical constraints of mass delivery of hydrogen and its cost.
- A significant portion of homes and businesses will become all-electric – meeting heating (and other end use needs) without any gas back-up – in every scenario. While that portion is obviously much smaller in scenarios emphasizing hybrid heating systems, it is still non-trivial.
- Delivery of 100% hydrogen delivery to residential and commercial buildings is generally seen as so unrealistic that it typically isn't even analyzed.
- Biomethane and/or 100% hydrogen will be necessary to decarbonize segments of the industrial sector.

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[29] E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 13.

[30] For example, see Sierra Club's comments at (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14922666).

As Table 1 shows, one result that flows from these conclusions is that annual gas energy throughput is going to decline dramatically – by 70% to 90% or more – over the next several decades.[31]

Table 1: Decarbonization Study Conclusions on Reductions in Annual Gas Energy Throughput by 2050[32]

	Canada	Quebec	New York (scenarios 2-4)	Massachusetts	
				Hybrid Electric Scenario	**High Electric Scenario**
Throughput Reduction:	**68% to 100%**	**~75% to 80%**	**91% to 94%**	**73%**	**84%**
Sectors Applicable to:	Buildings	Buildings & Industry	Buildings & Industry	Buildings & Industry	Buildings & Industry
Relative to Base Year of:	2020	2016	2020	2020	2020

Though decarbonization studies typically report on changes in both annual gas throughput and both annual electricity production and peak electricity demand, they do not always report on changes in gas peak demand. For the three independent studies noted above for Canada, Quebec, and New York, one can infer that the peak gas demand declines significantly because they mainly involve full electrification of home heating.

The Massachusetts' study is the only one of the four studies reviewed above that found hybrid heating to be the most cost-effective. Nevertheless, it too suggests that reductions in peak demand for gas from buildings and industry is inevitable if the economy is to be fully decarbonized by 2050. The declines are most dramatic in the "high electrification" scenario – on the order of a 90% reduction in peak day demand from residential, commercial and industrial customers by 2050 (relative to 2020 levels). However, even under the hybrid electrification scenario in which the majority of current customers use gas to meet peak heating demand on the coldest days and hours of the year, demand from all customers other than electric generators is about one-third lower in 2050 than in 2020.[33] This suggests that the energy transition is likely to not only eliminate future needs for capacity upgrades to the gas distribution system but to also reduce the need for and usefulness of much of the existing gas distribution system.[34]

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[31] Studies typically report changes in throughput just on an energy basis and not on a volumetric basis. Reductions on a volumetric basis can be smaller, to the extent that hydrogen – which carries only about 30% as much energy per cubic meter as methane – is utilized. However, even volumetric reductions will be substantial. For example, the reduction in annual *volumes* of gas consumed in New York in 2050 will still be 74% to 85% lower than in 2020 under the referenced decarbonization scenarios. That estimate was computed based on the forecast mix of biomethane and hydrogen (with hydrogen being the majority of forecast gas energy used in 2050) from the New York study's Technical Supplement Annex 2 (key drivers-outputs).

[32] Canadian Institute for Climate Choices, p. 40 (electric heat can comprise up to 100% of residential heating) and p. 43 ("clean gases could potentially provide a total amount of energy equivalent to 32% of today's natural gas demand from Canada's buildings"); Dunsky, p. 13; E3, *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, Tech Supplement Annex 2, "gas throughput" tab; E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 15.

[33] E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 65. Peak day demand also fell under the "efficient gas equipment" scenario, by about 25% by 2050.

[34] It should be noted that the Massachusetts study also found that total peak day gas demand would increase by 15-20% relative to 2020 by 2050 under the "high electrification" scenario because of significant use of gas generation to meet electric peak demands. This suggests that *some* gas infrastructure *may* need to be enhanced or developed. However, the extent to which that is the case may depend on the type of clean gas being used for peak

4. Practical Reasons to Expect Electrification Will Dominate Gas Decarbonization

In addition to potential cost advantages, a number of practical and market realities support the common conclusion of independent studies that electrification will dominate decarbonization of residential and commercial buildings and play an important role in decarbonizing industry.

A. Much Less Technological Uncertainty for Electrification Pathways

Electrification can be accomplished with existing technologies whose performance and costs are not only well known, but in many cases demonstrably improving over time. This is true of both renewable electric generation technology (e.g., wind and solar) and technology that needs to be deployed in homes and businesses (e.g., cold climate heat pumps).

This is not to say that there is absolute certainty regarding every element of a decarbonization pathway that relies heavily on electrification. However, the uncertainties are much smaller than for pathways relying much more heavily on clean gases. For example, we now have more than a decade of experience with the use of electric cold climate heat pumps, with sales growing quickly in several jurisdictions. For example, in the northeastern state of Maine, which has a population of a little under 1.4 million, more than 24,000 heat pumps were installed in just 2022.[35] On a per capita basis, that would be roughly equivalent to the installation of a quarter million heat pumps per year in Ontario. In contrast, gas heat pumps, which some studies assume would be critically important to reliance on clean gases are not even readily commercially available today, at least not for residential applications.

Similarly, hydrogen burning appliances cannot be purchased today; nor is there clarity on the likely leakage risks associated with hydrogen distribution pipes, let alone whether pipes that are currently carrying methane from customers' meters through their homes and businesses could carry hydrogen without substantial leakage and related safety risks. Indeed, a report by consultants involved in the design of a hydrogen pilot project in the United Kingdom suggests that rooms with hydrogen-burning equipment or substantial pipework "should have non-closable vents" with the equivalent of 100 square centimeters (or four inches by four inches square) of ventilation, potentially requiring the drilling of holes in walls, in order to mitigate the risk of hydrogen explosions.[36] The consultants and gas utility (Cadent Gas) subsequently suggested that most homes in the neighborhood in which a potential pilot hydrogen heating project would be initiated will not require the maximum ventilation because of how drafty or leaky much of the housing stock already is. The notion that one would want to rely on the

electricity capacity (biomethane or hydrogen) and the proximity of that fuel source to the siting of new gas-fired peaking power plants. In any case, to the extent that peak demand for peak gases for electric power plants would require new gas pipe, that investment will likely be very different – e.g., more transmission than distribution or distribution dedicated solely to electric power generators – than investments historically made by gas utilities to meet growing residential and/or commercial peak loads.

[35] Mitchell, Jennifer, "Maine Is On Track To Meet Its Goal of 100,000 New Heat Pumps Installed By 2025, Mills Says", published by Maine Public, September 24, 2021 (https://www.mainepublic.org/environment-and-outdoors/2021-09-24/maine-is-on-track-to-meet-its-goal-of-100-000-new-heat-pumps-installed-by-2025-mills-says).

[36] Gatten, Emma, "Hydrogen boilers might need 'four-inch holes in walls to prevent explosions' – Government-backed safety report recommends extra ventilation ahead of pilot scheme to run eco-friendly heating systems", published online in The Telegraph, 3 March 2023 (https://12ft.io/proxy?q=https%3A%2F%2Fwww.telegraph.co.uk%2Fnews%2F2023%2F03%2F03%2Fhydrogen-boilers-might-need-four-inch-holes-walls-prevent-explosions%2F%23%3A%7E%3Atext%3DL%E2%80%A6).

leakiness of existing homes – or to intentionally make them more leaky – in order to lessen the risk of hydrogen explosions is highly problematic, especially for colder climates like Ontario's.

B. No Practical Limits to Electrification Whereas RNG Supply is Very Limited

There are no practical limits to the ability to generate clean electricity. In contrast, the availability of biomethane (or RNG) is very limited. For example, a 2020 Torchlight Bioresources study completed for Natural Resources Canada found that the feasible annual RNG potential for Canada was only about 155 PJ which is equivalent to only 3.3% of Canada's current fossil methane consumption.[37] Moreover, it is not reasonable to assume that all feasible biomethane potential will be used to displace fossil methane currently used for heating buildings. Indeed, the Torchlight study itself concludes that "RNG is more price competitive with transportation fuels than with natural gas."[38]

Enbridge and its consultant, Guidehouse, have suggested that the theoretical "technical potential", rather than "feasible potential", should be considered. As discussed later in this report, that is a completely unreasonable position. As the Torchlight study itself states, and as discussed further later in this report, most of the technical potential will not be available for displacing fossil methane because of "competing uses for feedstock, seasonal feedstock supply risk, logistical constraints including the distance between many feedstocks and the closest natural gas pipeline, precommercial technologies for wood-based production and the high cost of RNG production from most pathways."[39] However, even if one ignores all of those limitations – as Enbridge and Guidehouse have – the total Canadian technical potential is equivalent to only about 17% of current Canadian consumption of fossil methane.[40]

C. Electrification Can Be Piecemeal, 100% Hydrogen Delivery Cannot Be (without New Pipes)

Adding electric loads to homes and businesses is fairly straightforward. Everyone with fossil gas service today also has electricity service. While some customers will require upgrades to electric panels to accommodate heat pumps, many will not. In any case, such upgrades are well understood and relatively modest in cost. And while substations and other elements of the electric distribution system may need to have capacity upgrades when enough customers electrify, some parts of the electric distribution system will likely be able to accommodate significant electrification without such upgrades, and the upgrades that are required will not need to all be made at the same time.

In contrast, there is currently no delivery system for bringing 100% hydrogen to homes and businesses as would be necessary for Enbridge's "vision" and Guidehouse's gas-centric decarbonization scenario. While some methane pipe may theoretically or technically be able to carry hydrogen, it is hard to imagine how conversion of the current methane distribution system to carrying 100% hydrogen distribution could realistically unfold.

In order to switch from methane to 100% hydrogen much of Enbridge's existing distribution pipe would need to be replaced, or if possible, treated or conditioned.[41] That would seem to require that methane

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[37] Stephen, Jamie et al. (TorchLight Bioresources), Renewable Natural Gas (Biomethane) Feedstock Potential in Canada, Final Report, funded by Natural Resources Canada, March 2020, p. iii.
[38] Ibid, p. 47.
[39] Ibid, p. 54.
[40] Ibid, p. 54.
[41] Guidehouse suggests that Enbridge's gas pipeline network "is ideally suited to be repurposed to a hydrogen network, as the province's newer pipelines, typically made of polyethylene, are already hydrogen-ready."

delivery be cut off to customers downstream of the conversion until the treatment is completed. What would customers be expected to use to heat water, cook food, etc. while that is happening?

Much more importantly, every methane-burning appliance (furnace, boiler, water heater, stove, dryer, etc.) downstream of the pipe being converted from methane-carrying to 100% hydrogen-carrying would need to have been converted to hydrogen burning before the utility distribution system switch-over occurs. All in-home piping would also have to be hydrogen-ready. Enbridge and its consultants have suggested that this can be accomplished if customers install hydrogen-ready equipment when existing equipment reaches the end of its useful life.[42] While there is no reason to expect that result to naturally emerge in the market, government policy could require all new gas-burning appliances (and the in-home piping serving them) to be "hydrogen-ready". However, there are at least three major problems with that vision.

- First, it is important to recognize that "hydrogen-ready" does not mean that a furnace or water heater or cooktop can instantaneously switch from burning methane to burning hydrogen. There are components of each appliance that will need to be switched at the time of conversion from methane pipe to 100% hydrogen pipe. That will require going into every home and business to make such conversions. How would Enbridge ensure it could even get into every home and business?
- Second, gas furnaces have an average measure life of about 18 years and gas boilers have an average measure life of 25 years.[43] Importantly, those are *averages*. Some furnaces last 25 to 30 years and some boilers last longer than that. Thus, even if government required all new gas-burning appliances to be hydrogen-ready as early as 2025, it is unlikely that *all* gas-burning appliances in a given community or neighborhood will be hydrogen-ready before 2050 if we relied exclusively on natural equipment turnover to reach that state. If we do not rely on natural equipment turnover to get to a fully hydrogen-ready state in all homes and businesses, there will be huge costs incurred to encourage and/or force customers to replace furnaces, boilers and/or other appliances before they planned to do so.
- Third, if Enbridge is prepared to switch a pipe carrying methane to 10,000 or 100,000 homes and businesses to 100% hydrogen, how will it know whether every single one of the tens or hundreds of thousands of individual appliances served by that pipe has been replaced with something hydrogen-ready so that it can switch to 100% hydrogen with minimum safety risk?

Another important issue is that, because hydrogen is less dense than methane, a given diameter of pipe can deliver only about 30% as much hydrogen energy as methane energy. That suggests that existing methane pipe could only be used to deliver hydrogen if peak demand from customers connected to the pipe is collectively reduced by 70%.

All of this suggests that the only plausible way to deliver 100% hydrogen on a mass scale to residential and small to medium business customers is to build a new hydrogen pipe distribution system in parallel to the existing methane distribution system. That would allow a gradual, customer-by-customer switch

(E1/T10/S5/Attachment 2, p. 60 of 88). However, only about 40% of Enbridge's distribution pipe is made from polyethylene (response to GEC-23b).

[42] Response to SEC-41(b).

[43] These are commonly assumed measure lives in utility DSM programs. For example, see Enbridge EB-2021-0002 Interrogatory Response I.5.EGI.GEC.9_Attachment 2, Tab Union-2019 rows 19 and 20.

from methane-burning to hydrogen burning just as electrification can proceed customer-by-customer.[44] However, the cost of building and operating a parallel 100% hydrogen distribution system – while still operating and maintaining a methane distribution system – would be prohibitive.

5. Customer Economics of Electrification Are Good Today, Likely to Remain Good

A. Customer Economics of Electrification Without New Decarbonization Requirements

As the discussion above suggests, the energy transition is going to require significant electrification of current fossil gas use, with independent assessments generally finding that extremely high levels of full electrification will be the most economic and most practical way to decarbonize buildings in the future. An assessment of the customer economics of electrification today could shed some light on how quickly the energy transition may begin to gain steam.

To that end, I assessed the impacts of electrifying a single-family Toronto home that is currently using gas. I found that a customer would begin saving on energy costs immediately and would save $16,749 (NPV) over the lifetime of the equipment if they electrify.

To represent the average home, I assume that 82% of such homes also use gas for water heating, 16% for drying and 30% for cooking.[45] I assumed average consumption levels for each end use; typical costs (including availability of federal Greener Home rebates), efficiencies (typically Energy Star levels) and measure lives for efficient gas and electric equipment;[46] and current (winter of 2022-2023) gas and electricity prices, adjusted into the future only for the impact of the increasing federal carbon tax. For heating equipment, I compare the purchase of a 95% gas furnace and SEER 14 central air conditioner to a cold climate air source heat pump (ccASHP) with a seasonal average coefficient of performance of 2.84 in 2023[47] and a cooling efficiency rating of SEER 18.[48] I assume that the customer fully electrifies at the time that it would otherwise be replacing both its gas furnace and central air conditioner. This requires additional capital costs for a new electric heat pump water heater, new electric stove and new electric dryer – costs that would not be incurred for another seven or eight years if the customer continued to use gas equipment for such end uses.[49] On the other hand, such a complete fuel-switch would enable customers to eliminate not only all variable gas charges, but also all fixed monthly gas charges. My results are expressed in 18-year net present value (NPV) terms, since 18 years is the assumed life of both gas furnaces and cold climate air source heat pumps. Because dryers, stoves and water heaters have

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[44] Note that is still not as flexible as electrification, which can occur not only customer-by-customer, but even appliance-by-appliance.

[45] Response to GEC-61, Attachment 1.

[46] Note that to represent the average home, I multiply water heating, drying and cooking equipment costs and energy costs by the assumed saturation of those gas appliances.

[47] This is the same assumption as Guidehouse used for new ccASHPs purchased in 2023 in its Pathway to Net Zero study for Enbridge (JT1.28, Attachment 3, "HP Turnover" tab).

[48] New ccASHPs tend to be much more efficient at cooling that the vast majority of new central air conditioners. In a review I conducted in the Summer of 2022 of nearly 400 cold climate, centrally-ducted ccASHPs listed by the Northeast Energy Efficiency Partnerships (https://ashp.neep.org/#!/product_list/) with heating capacities between 35,000 and 40,000 Btuh at 5 F, only about 3.5% had a SEER rating below 17 and more than half had a SEER rating of 20 or higher.

[49] I assume that the average stove lasts 15 (gas) to17 (electric) years, the average water heater lasts about 15 years and average dryer lasts 13 years, so on average (i.e., assuming the average appliance is roughly halfway through their useful life), an existing home would need to replace those pieces of gas equipment (absent an electrification investment) in roughly 7 to 8 years.

slightly shorter lifespans, the analysis accounts for a portion of future replacement costs for those appliances. I also assess how the economics would change in 2030, assuming the only difference between now and then are increases in the federal carbon tax and small improvements in cost and efficiency of cold climate air source heat pumps.

As Table 2 shows, full electrification in 2023 of a Toronto single-family home currently using gas for heating, water heating, cooking and drying would reduce energy bills by about 37% in the first year and by 46% over the 18-year life of a new cold climate heat pump. A similar electrification decision in 2030 would cut energy bills approximately in half, both in the first year and over the long-term.

Table 2: Change in Energy Bills from Electrification of Single-Family Toronto Home, Today and in 2030

	without Electrification	with Electrification	$ Change	% Change
2023 Electrification				
1st Year (2023) Energy Bills	$1,841	$1,158	($683)	-37%
18-Year NPV of Energy Bills	$28,268	$15,249	($13,018)	-46%
2030 Electrification				
1st Year (2030) Energy Bills	$2,260	$1,126	($1,134)	-50%
18-Year NPV of Energy Bills	$29,760	$14,826	($14,933)	-50%

As

Table 3 shows, with application of federal Greener Homes and Enbridge rebates, the NPV of the cost of installing new electric equipment – *even though any water heater, stove and dryer would be installed much sooner than gas replacements would have been required* – would be less than the NPV of the cost of equivalent gas equipment. The total 18-year NPV of costs for both energy and equipment would be about 43% less for electrification undertaken in 2023 – and about 47% less for electrification undertaken in 2030 – than continued use of gas.

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

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

I tested the sensitivity of these results to several assumptions. Results of those sensitivity tests are as follows:

- If federal Greener Home rebates are not applied, the NPV of capital costs of electrification are about $4300 higher than for non-electrification in 2023 (about $3900 higher in 2030). This is largely because of the need to invest in a new water heater, stove and dryer sooner than would be necessary if just replacing current gas equipment when it reaches the end of its life. However, the substantial energy bill savings are unaffected by this change so total costs are still 23-28% lower with electrification.
- If I use ICF's 4th Quarter 2022 forecasts of gas commodity prices – i.e., dropping by almost 50% in inflation-adjusted terms by 2028, then gradually climbing back up again (but never again reaching prices experienced this past winter) – energy bill savings are only slightly lower (e.g., 44% savings over an 18-year period starting in 2023 instead of 46%), with total savings not changing considerably.
- Excluding assumed ccASHP efficiency and cost improvement assumptions has no effect on 2023 NPVs and reduces total cost savings from a 2030 installation by just a couple of percentage points. This is partly because I used Guidehouse's conservative assumptions about the likely magnitude of future ccASHP technology and market improvements.
- If I assume that the season average heating efficiency of ccASHPs is 15% worse than assumed by Guidehouse (i.e., season average COP of 2.41 instead of 2.84), the 18-year NPV of energy bill savings from a 2023 installation decline from 46% to 38% - i.e., still substantial; the NPV of total (energy plus capital) costs declines from 43% to 38% - also still substantial.
- My analysis did not assume and an electric panel upgrade would be required. Some homes will need such upgrades; others will not. However, the cost of panel upgrades - $2000 or less on average[50] – would not significantly change the conclusion that electrification is very cost-effective for customers.

The conclusion that electrification is cost-effective for customers today is very robust.

B. Customer Economics of Electrification in a Decarbonized Future

Developing specific estimates of the cost-effectiveness of customers investing in electrification at various points between 2023 and 2050 in a future in which policies and markets drive full decarbonization of buildings by 2050 would require detailed economy decarbonization modeling that is well beyond the scope of this report. However, evidence available from other modeling efforts and our understanding of likely future prices for biomethane suggest that the customer economics of electrification will actually become more compelling than they are today.

Consider the comparison in Table 4. The first two columns compare (1) the current variable cost to residential customers of fossil gas with a $170/tonne carbon tax to (2) the current variable cost of electricity to residential customers in Toronto. While electricity is more expensive per unit of energy delivered to the home, it is much less expensive per unit of heat produced for the home because electric heat pumps are about three times more efficient than efficient gas furnaces. In terms of dollars per unit of heat produced for the home, fossil gas would be 71% more expensive even if no new policies requiring the decarbonization of the gas sector are adopted. The second two columns provide a similar

[50] EB-2021-0002 Exhibit I.10h.EGI.Staff.77, p. 10.

comparison, but under a scenario in which there is a policy requiring net zero emissions by 2050, with customers either consuming RNG that costs $62/GJ (but no carbon tax) or electrifying and paying 25% higher electric rates than today. $62/GJ is the cost of the most expensive source of RNG in the Torchlight study upon which Enbridge has relied for its estimates of biomethane (or RNG) potential.[51] As with all commodity markets, the most expensive source of RNG will ultimately set the market clearing price for all RNG. The 25% increase in electric rates is the mid-point of the range of increases by 2050 that the IESO recently estimated for a scenario with very high levels of electrification of buildings.[52]

Table 4: Volumetric Cost of RNG Heat vs. High Electrification Heat

	Without New Decarbonization Policy		**With Full Decarbonization Policy**	
	Fossil Gas vs. Electric Heat		Biogas vs. Electric Heat	
	$170/tonne Carbon Tax		$62/GJ RNG	
	No Further Decarb Policy		IESO 25% Rate Increase w/Hi Electrification	
	Fossil Gas Furnace	**Electric Heat Pump**	**RNG Furnace**	**Electric Heat Pump**
$/m3 or $/kWh *input*				
Commodity	$0.22		$2.41	
Transportation	$0.05		$0.05	
Distribution	$0.12		$0.12	
Carbon Tax	$0.29		$0.00	
HST	$0.09		$0.34	
Total	$0.76	$0.13	$2.91	$0.17
$/GJ of Energy *Input*	$20.49	$37.05	$78.25	$46.31
Heating Efficiency	95%	293%	95%	293%
$/GJ of Heat *Output*	**$21.57**	**$12.65**	**$82.37**	**$15.81**
Gas Price as % of Electric	171%		521%	

Put simply, the current cost advantages of electrifying building space heating will be substantially greater in a decarbonized future. The 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.

Moreover, the comparison in Table 4 likely understates the extent to which the economics of electrification will improve in a decarbonized future.

- First, the analysis only compares the variable or volumetric cost per GJ of gas and electric heat. Customers who fully electrify will also eliminate fixed monthly gas charges.

[51] Torchlight, p. 44. Figure 26 shows costs which I assumed to be in 2020 dollars. I have increased them by 12.45% to express them in 2023 dollars per a consumer price index calculated available from the Bank of Canada (https://www.bankofcanada.ca/rates/related/inflation-calculator/).

[52] IESO, Pathways to Decarbonization: A report to the Minister of Energy to evaluate a moratorium on new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector, December 15, 2022 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization), p. 32. The 20-30% increase is inclusive of costs of adding peak generating capacity, transmission capacity and distribution capacity. Though the IESO only explicitly modeled generation and transmission costs, it added a 25% “contingency” cost to its estimates which it says is intended, in part, “to capture out-of-scope costs (e.g., the build-out of distribution infrastructure…).” (p. 17).

- Second, the analysis holds transportation and distribution charges for gas constant at today's prices. However, as Table 1 above shows, decarbonization studies suggest total gas energy throughput will decline by 70-90% or more by 2050. Even the Guidehouse pathways study commissioned by Enbridge suggests that gas energy sales to residential and commercial customers will be reduced by about 50% (Diversified scenario) to nearly 90% (Electrification scenario) by 2050.[53] As gas sales decline, rates will go up because the past capital investments, as well as the fixed cost of operating the system, will have to spread over a smaller volume of sales.
- Third, the analysis does not account for the fact that RNG will not produce 100% reductions in lifecycle emissions, so additional emission reduction investments will need to be made on the gas system. In addition to those factors, any decarbonization approach that relies on delivery of 100% hydrogen to residential and commercial customers will result in huge additional gas distribution system costs that will need to be recovered in rates.

My conclusion that the customer economics of electrification will improve in a decarbonized future is consistent with the results of the recent decarbonization study funded by the Massachusetts gas utilities – despite its significant biofuel biases. For example, that study found that low-income energy burdens (the percent of income required to pay energy bills) would increase less – in most cases significantly less – for those customers who become all-electric than for those customers who remain on the gas system. Moreover, it found that energy burdens would be lowest – and lower than today – for customers who fully electrified under a high electrification scenario.[54]

6. Study Used by Enbridge to Support Vision of Hydrogen Future Is Fatally Flawed

A. Overview

Enbridge commissioned Guidehouse to conduct a decarbonization study that analyzed two pathways to net zero GHG emissions in Ontario by 2050. One pathway emphasized significant levels of electrification of buildings, but still maintained the entire existing gas system. The other included some electrification, but placed greater emphasis on substitution with biomethane and a significant commitment to delivering 100% hydrogen (instead of methane) to large numbers of residential and commercial customers. The initially filed study concluded that the so-called "Electrification scenario" would be $181 billion more expensive than the high gas scenario (what Guidehouse called the "Diversified scenario"). Following interrogatories, Guidehouse identified errors and reduced the gap to $167 billion. Following the technical conference and the OEB order to release the underlying model details, Guidehouse identified further problems and updates, which reduced the gap to $41 billion, a full $140 billion difference from its original report.

While the corrections that Guidehouse has made to its analysis are important, a number of significant problems remain, many if not all of which are likely to bias results against electrification and in favor of gaseous fuels.[55] Thus, the study remains fundamentally flawed and its conclusions remain highly misleading. If even one or a few of those errors are corrected, the high gas scenario is tens of billions of

[53] E1/T10/S5 Attachment 2, p. 29 of 86.
[54] E3 and Scottmaden, *Technical Analysis of Decarbonization Pathways*, p. 17.
[55] Note that my review has been necessarily less than comprehensive, given both the number of assumptions that have gone into the model and Guidehouse's inability to make the model available for us to run to better understand how it works.

dollars more expensive than the scenario emphasizing higher levels of electrification. In the following subsections, I discuss several key concerns.

B. Inappropriate Use of Higher Carbon Emissions Cost for Electrification Scenario

Guidehouse treats carbon taxes as a cost. However, carbon taxes are not costs in societal-level analyses such as this one.[56] Rather, they are transfer payments. That is always true in societal cost-effectiveness assessments, but even more obvious in this case because carbon taxes are returned to Ontarians through direct payments.[57] As Table 5 shows, Guidehouse's mistreatment of carbon taxes in its analysis is particularly problematic because it assumed a much higher carbon price – on the order of 70% higher after 2030 – would get applied to the "Electrification" scenario than to the "Diversified" scenario.[58]

Table 5: Guidehouse Assumed Cost of Carbon Emissions (nominal $/tCO2e)[59]

	2020	2030	2040	2050
Diversified Scenario	$28	$166	$206	$251
Electrification Scenario	$28	$282	$351	$427

This fundamentally distorts the results of Guidehouse's analysis. As noted above, after its most recent changes, Guidehouse is estimating that its Electrification scenario is $41 billion more expensive than its so-called Diversified scenario. However, that includes $57 billion in supposedly higher carbon emissions costs for the electrification scenario.[60] In other words, ***Guidehouse's Electrification scenario would be lower cost than its Diversified scenario if the only change made to its analysis was to use the same carbon price in both scenarios*** (or if no carbon cost was included at all).

If the cost of carbon emissions is to be included in a societal cost assessment of decarbonization pathways, that cost should be an estimate of the damage caused by each tonne of carbon emissions. The environmental, public health and other damage caused by a tonne of carbon emissions is the same regardless of the source of the emissions or the scenario under which the emissions took place. So the societal cost of carbon is the same for all emissions under all scenarios.

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[56] In its response to GEC-15c, Guidehouse itself acknowledges that its analysis assesses economics from a societal perspective: "the Total Energy System Costs in the P2NZ represent ***total costs to society*** and do not reflect the retail energy prices customers would pay." (emphasis added)

[57] https://www.canada.ca/en/department-finance/news/2022/03/climate-action-incentive-payment-amounts-for-2022-23.html.

[58] Guidehouse says it did this because carbon taxes would need to be higher to drive high levels of electrification. [response to GEC-24(b)] Aside from the huge and fundamental methodological problem of treating carbon taxes as societal costs, the notion that carbon taxes would need to be higher to drive electrification than to drive investment in gas heat pumps at mass scale (when they aren't really even available in the market today), gas-burning equipment capable of burning hydrogen, and other components of a decarbonization pathway the emphasizes continued burning of gaseous fuels is, at best, completely unsubstantiated. As explained in the previous section of this report, the customer economics of electrification are already compelling and are likely to get substantially better in a decarbonizing future. Moreover, carbon taxes are but one instrument for advancing decarbonization investments. Government can also regulate the types of heating equipment sold in the market, provide rebates for lower emitting equipment (as the federal Greener Home program is currently providing for electric heat pumps), etc.

[59] JT1.28-Attachment 5, "Carbon Costs" tab, rows 11-13.

[60] E1/T10/S5 Attachment 2, p. 46 of

It is worth noting that Guidehouse's analysis concluded that carbon emissions in the 2030s and 2040s would actually be *lower* under the electrification scenario than under diversified scenario.[61] In other words, if the same societal price of carbon was used in both scenarios, the result the electrification scenario would have looked even more favorable than it does when just eliminating the extra $57 billion in cost that Guidehouse inappropriately assigned to it. In fact, simplified calculations provided by Guidehouse suggests that changing the carbon price outside of the model – after the model optimized electric system dispatch at the higher carbon price – would lower the carbon cost of the Electrification scenario by $67 billion.[62] Guidehouse cautions that may not be the correct estimate of the amount by which the Electrification scenario cost would be reduced had a lower carbon price been used because its model could have optimized dispatch of resources differently. That may be true. However, if the model is truly optimizing for cost, further optimization should only make the total cost of the Electrification scenario even less costly. In other words, the $67 billion reduction in cost should be the *minimum* reduction in total cost of high Electrification that would result from use of a lower carbon cost.

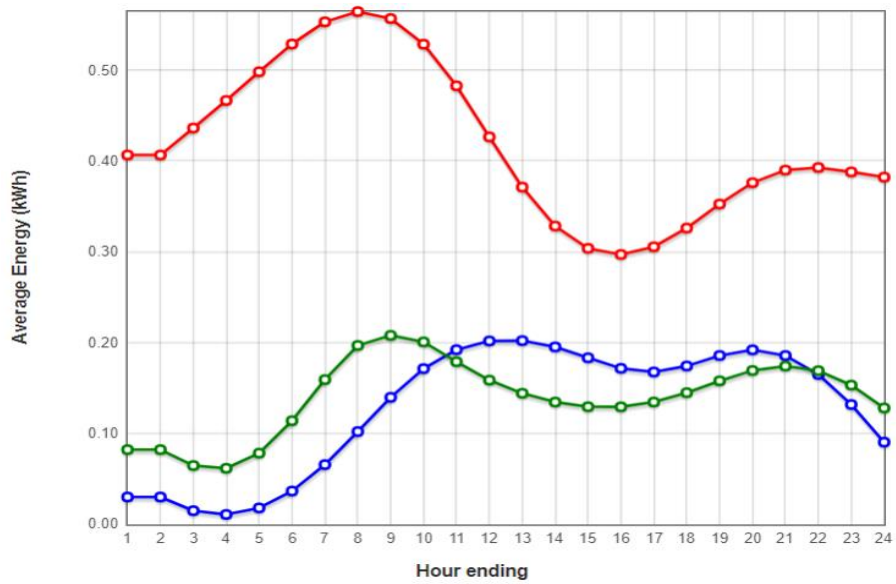
C. Inappropriate Application of Heating Load Shape to Non-Heating End Uses

In order to estimate the costs to the electric grid of adding new loads from electrification, one must develop assumptions about what seasons of the year and what times of day the electrified loads will add demand to the grid. Those load profiles are commonly referred to as "load shapes". Assumptions about the extent to which electrified loads will add demand during peak hours – typically cold January mornings in Ontario – are particularly important because they drive modeling assumptions about how much new generating capacity (or storage) and related transmission and distribution system capacity needs to be added to the grid.

Guidehouse made the simplifying assumption that all electrified building loads would have the same load shape as electrified heating loads.[63] Put another way, it assumed that the ratio of electricity demand on the winter peak hour to annual electricity consumption would be the same for water heating, drying, cooking and other electrified end uses as for space heating. That assumption is highly inaccurate and problematic. Space heating is a much "peakier" load than other loads that could be electrified. For example, as Figure 4 shows, load shapes developed by the Electric Power Research Institute suggest that residential space heating demand at 8 a.m. on a peak winter day in New York state (the red line) is nearly three times as large as residential water heating demand (green line) and between five and six times as large as clothes drying demand (blue line) per 1000 kWh of annual consumption.[64] Similarly, as Figure 5 shows, commercial space heating demand at 8 a.m. on a winter peak day in New York (blue line) is nearly seven times as large as commercial water heating demand (red line) per 1000 kWh of annual consumption.[65]

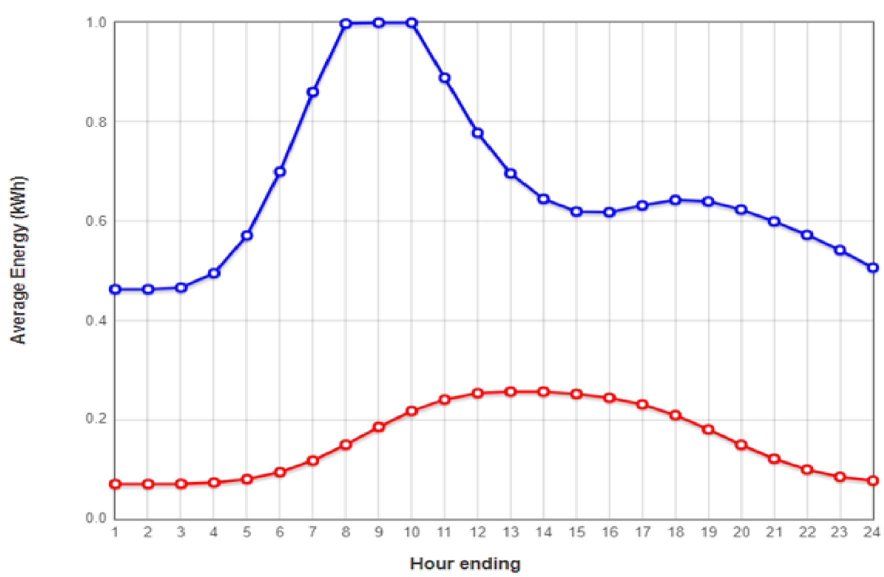
[61] E1/T10/S5 Attachment 2, p. 5 of 88.
[62] JT9.1.
[63] Transcript of Technical Conference March 23, 2023, p. 15, lines 25-27 and p. 16, lines 7-8.
[64] https://loadshape.epri.com/enduse
[65] Ibid.

Figure 4: Winter Weekday Load Shapes by Residential End Use (per 1000 kWh/year in New York)



Region	Sector/End Use	Season	Day Type
NYPCC/NY	Res. Clothes Dryer	Off Peak	Peak Weekday
NYPCC/NY	Res. Heating	Off Peak	Peak Weekday
NYPCC/NY	Res. Water Heating	Off Peak	Peak Weekday

Figure 5: Winter Weekday Commercial Load Shapes (per 1000 kWh/year for New York)



Region	Sector/End Use	Season	Day Type
NYPCC/NY	Com. Heating	Off Peak	Peak Weekday
NYPCC/NY	Com. Water Heating	Off Peak	Peak Weekday

By assuming that all electrified loads have the same load shape as space heating loads, Guidehouse has significantly overstated the amount of new electric generating capacity and transmission capacity that would be needed to serve electrified non-space heating loads. That may not matter much if almost all of the electrified loads – or at least all of the difference in electrified loads between the two scenarios analyzed – were space heating. However, as Table 6 shows, Guidehouse estimates that less than half of the difference in annual electricity sales between the Diversified pathway and the Electrified pathway is attributable to space heating. Thus, the difference in winter morning electric peak demand from buildings in the diversified and electrification scenarios – as well as the difference in related capital investments in electric generating, transmission and distribution capacity in the two scenarios – is probably on the order of 40% less than Guidehouse has estimated.[66]

Table 6: Guidehouse Estimate of Total and Heating Annual Electricity Consumption by Pathway (TWh) [67]

	Diversified			Electrification			Difference		
End Use	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Space Heating	31.3	38.8	35.1	35.2	55.0	55.9	3.9	16.2	20.8
Total	118.0	134.2	141.3	125.8	172.4	187.2	7.8	38.2	45.9
Heat % of Total							50%	42%	45%

That may help explain why Guidehouse's estimate of electric peak demand under the electrification pathway (82 GW, or about 3.5 times current peak demand) is so much greater than the IESO's estimated peak demand (60 GW or about 2.5 times current peak demand) in its high electrification pathway analysis.[68] It is worth noting that other studies also typically find the increase in electric peak demand by 2050 under high levels of electrification to grow much less than Guidehouse's study has. For example, the E3 New York study found that electric peak demand in 2050 would be about 1.6 times current peak demand under the scenario with the highest levels of electrification.[69]

D. Outdated and Biased Assumption Regarding Electric Heat Pump Efficiency Degradations

In modeling the impacts of electrifying space heating with air source heat pumps, Guidehouse starts with an assumption about the average annual heating efficiency of a new electric heat pump (e.g., COP of 2.84 for 2023) and then assumes that efficiency degrades by 2% per year through the 18-year life of the unit.[70] The result is that Guidehouse assumes that the average electric heat pump in use in any given year is about 15% less efficient (i.e., requiring 18% more electric energy) than if no such degradation adjustments were made.[71] Guidehouse based its heat pump efficiency degradation assumption on a

[66] If 45% of the difference in annual electricity consumption is space heating and the actual winter peak demand for the other 55% is, on average, only about 25% as great as for space heating, the total peak demand per annual kWh would be about 40% less than if all added electric load was space heating [0.45 + (0.25*0.55) = 0.5875].
[67] Response to ED-47(d) and (e).
[68] IESO, pp. 26-27.
[69] Energy and Environmental Economics (E3), *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, December 2022 (https://climate.ny.gov/resources/scoping-plan/), p. 24 and Technical Supplement Annex 2: Key Drivers Outputs, "Electric Load and Peak by Scenario" tab.
[70] JT1.28 Attachment 3, "HP Turnover" tab, row 140.
[71] These values were derived by changing the efficiency adjustment value to zero in JT1.28 Attachment 3, "HP Turnover" tab, row 140 and seeing how that changed the estimated average stock efficiency values on row 12 of the "Equipment Efficiencies" tab of the same file.

2006 report published by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL).[72]

This assumption is problematic for two reasons. First, the reference is very outdated and not applicable to current advanced heat pump technology. NREL's table with degradation factors for split system heat pumps has separate rows for pre-1981 models, models installed between 1981 and 1991 and models installed after 1991. Also, degradation factors are provided only for single-speed heat pumps, whereas cold climate air source heat pumps (ccASHPs) are typically (if not always) variable speed models. ccASHPs are also fundamentally different in many other ways than heat pumps sold in the 1970s, 1980s and 1990s, including the use of inverter-driven modulating compressors and much more sophisticated controls. Put simply, Guidehouse uses a reference for obsolete equipment without any data or justification for why it would apply to current technology.

Second, Guidehouse does not appear to have made any comparable adjustments to the actual operating efficiencies of gas equipment. The dated NREL report on which Guidehouse relied for electric heat pump efficiency degradation assumptions also includes degradation assumptions for gas furnaces which Guidehouse seems to have ignored. Not surprisingly, the NREL report did not have efficiency degradation assumptions for gas heat pumps, since such products aren't even commercially available today, let alone in 2006 when the report was published. However, there is no basis for assuming that the performance of current generations of cold climate electric climate heat pumps will degrade over time while gas heat pump performance will not.

Put simply, Guidehouse' selective use of an outdated assumption about the degradation of performance of electric air source heat pumps without any degradation factor for gas equipment biases its study against electrification. Eliminating the electric air source heat pump degradation would have the effect of reducing total annual electricity consumption by 1.2 TWh in 2030, 4.8 TWh in 2040 and 5.6 TWh in 2050 in the Electrification scenario and by 0.5 TWh in 2030, 2.2 TWh in 2040 and 2.3 TWh in 2050 in the Diversified scenario.[73] In other words, Guidehouse's inappropriate and selective application of its electric heat pump efficiency degradation assumption has a 0.7 TWh in 2030, 2.6 TWh in 2040 and 3.3 TWh in 2050 bigger impact on the Electrification scenario than on the Diversified scenario.

E. Dramatically Over-Estimating RNG Availability

Guidehouse has assumed in its decarbonization pathways modeling that the amount of biomethane that is available is equal to the *technical* potential found for Ontario – 224 PJ per year[74] – in the 2020 Torchlight Bioresources study referenced above. As discussed above in a previous section of this report, Torchlight states that it is "unrealistic" for biomethane production to reach anything close to its estimates of technical potential because of "competing uses for feedstock, seasonal feedstock supply risk, logistical constraints including the distance between many feedstocks and the closest natural gas pipeline, precommercial technologies for wood-based production and the high cost of RNG production

[72] https://www.nrel.gov/docs/fy06osti/38238.pdf

[73] These values were derived by eliminating the residential heat pump degradation factor in the "HP_Turnover" tab of JT1.28 Attachment 3, adjusting commercial heat pump efficiency assumptions so that they are equal to residential efficiencies in the "Equip_Efficiencies" tab, and seeing how that changed estimated electricity consumption in the "Summary" tab.

[74] Response to ED-31(a) and Torchlight, p. 52.

from most pathways."[75] Though the study did not estimate feasible potential by province, its estimate of feasible potential for the country was on the order of one-quarter of technical potential (excluding wood-to-gas potential).[76] Thus, Guidehouse has assumed that the amount of biomethane that could displace fossil methane is on the order of four times the amount found by experts in the field to be "feasible".

Enbridge is contending that is a reasonable assumption on the grounds that "over the time horizon of the study (2020 to 2050), policies and regulations will be implemented that support RNG demand creation and that near-term economic, logistical and/or technological challenges associated with realizing RNG supplies are overcome."[77] I disagree. Consider that part of the potential the Torchlight study assumed to actually be "feasible" are resources that would cost in excess of $2.40/m3. Adding significant transportation costs for resources currently deemed too far from the nearest methane pipeline just isn't realistic. It is also not realistic to assume that competing demands for biomethane – potentially including demands for harder to decarbonize sectors of the economy – will just disappear or be outbid by the gas utility. At a minimum, if Guidehouse was going to assume that 100% of technical potential was available, it should have assumed that the cost of acquiring that potential would be much higher than the cost of the feasible potential. As discussed in the next subsection, Guidehouse definitely did not do that.

It is also not realistic to assume that Ontario will achieve significant net out-of-province RNG imports as RNG will be in high demand in many places. Net exports are just as likely. For instance, Vermont Gas is currently planning to acquire RNG from a food processing facility in London, Ontario.[78]

F. Unrealistically Low Costs Assumed for Biomethane

Guidehouse has effectively assumed a biomethane cost of about $0.86/m3.[79] As discussed in previous sections of my testimony, that is only about one-third of a reasonable cost estimate. Again, in a competitive market, the most expensive unit of production that is purchased will set the market price for all products. A proper analysis would use a supply curve to reflect the fact that biomethane becomes more expensive as the demand increases and as more and more difficult and expensive feedstocks are accessed. As the assumed RNG demand increases, so does the cost.

Guidehouse suggests that it used a lower cost because it analyzed only production costs and not market clearing prices (which would include financing costs, profits and other factors).[80] There are several problems with this response:

- First, an analysis of the societal costs of decarbonization should be based on market prices that will be paid for different decarbonization investments. Societal costs include financing costs and profits. The businesses that produce the products included in the Guidehouse analysis would not exist and would not supply those products if they couldn't finance their production and make a profit on their sale. This is why we use avoided costs – based on market prices for the

[75] Torchlight, p. 54.
[76] Ibid, pp. 54-56.
[77] JT1.15.
[78] https://www.sevendaysvt.com/vermont/hot-air-vermont-gas-says-its-reinventing-itself-to-help-the-climate-critics-call-its-strategy-greenwashing/Content?oid=36110392.
[79] Figure provided by Guidehouse on March 24, 2023.
[80] Response to ED-36.

most expensive unit of energy avoided – when assessing the societal cost-effectiveness of DSM and other programs.

- Second, it is important to note that at least some of the other costs included in Guidehouse's analysis are market clearing prices that include costs of financing and profits. In particular, the costs that Guidehouse assumes for heating equipment and building envelop efficiency measures are based on estimates of actual market prices for such products, including profits earned all along the supply chain (from manufacturer to distributor to contractor to end use customer). In other words, Guidehouse's stated approach is internally inconsistent.
- Third, Guidehouse's decision to focus on "production costs" rather than market clearing prices for gas and electric system supply has the effect of systematically biasing the analysis against electrification and in favor of gaseous fuels, particularly biomethane. Put simply, the supply curve for electricity, for which there is no practical resource limitation, is much flatter than the supply curve for biomethane whose availability is very limited and spread across a much wider range of small sources.

Fourth, Guidehouse based its estimate of the cost of all RNG on a study documenting the cost of RNG from landfills.[81] However, landfills are generally considered the least expensive source of RNG. For example, the 2017 study to develop a marginal GHG emission abatement cost curve that was commissioned by the Ontario Energy Board reported a levelized cost of energy for landfill gas of $0.33 to $0.82 – or a midpoint cost estimate of $0.58 – per m3.[82] The same study reported midpoint cost estimates that were about four times greater for gas from waste water treatment facilities, twice as great for gas from manure, five times greater for gas from source separated organics, and about twice as great for gas from agricultural residues. Maybe more importantly, as shown in Table 7, the 2020 Torchlight study whose estimates of RNG potential Guidehouse relied upon (though it unreasonably focused on technical potential instead of feasible potential) clearly concluded that landfill gas would be much less expensive on average than other sources of RNG. Put simply, it is wrong to base estimates of the cost of all RNG on the least expensive of the many potential sources of RNG – particularly when the study is assuming that the amount of RNG that would be acquired was much greater than what industry experts suggest is the most that is even feasible (including consideration of economics) to acquire.

[81] Technical Conference Day 1 (March 22, 2023), pp. 173.

[82] ICF, Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities (EB-2016-0359), submitted to the Ontario Energy Board, July 20, 2017, pp. 54-55. (https://www.oeb.ca/sites/default/files/OEB_MACC%20Report_20170720.pdf).

Table 7: Torchlight Study Estimated RNG Production Costs by Feedstock [83]

Scenario	Feedstock	Specific CapEx ($ M)	CapEx ($/GJ)	Feedstock ($/GJ)	OpEx ($/GJ)	Total ($/GJ)
SW Ontario Corn	Corn Silage & Chicken Litter	20	21.90	7.90	11.80	41.60
Urban Organics & Manure	SSO & Hog Manure	35	38.30	-5.00	20.60	53.90
Prairie Crop Residues	Straw	27.5	30.10	8.50	16.20	54.80
Landfill Gas (best case, upgrader only)	Landfill Gas	2.5	1.85	2.15	2.1	6.10
Landfill Gas (likely)	Landfill Gas	7.5	8.20	3.00	4.40	15.60

If the market clearing price for RNG would be set by the most expensive resource in the Torchlight study – Prairie crop residues – the cost of the Diversified scenario would by about $50 billion higher than estimated by Guidehouse and the cost of the Electrification scenario would be about $22 billion higher over the 2030 to 20250 period. In other words, using a more accurate estimate of RNG costs would improve the relative cost of the Electrification scenario by about $28 billion. That is a very conservative estimate of the impact of Guidehouse's biased assumption because it doesn't account for the even more expensive RNG that Guidehouse assumed could become available but that the Torchlight study considered infeasible, in part because of cost.

G. Unrealistically Low Costs Assumed for Green Hydrogen

Guidehouse appears to have assumed unrealistically low costs for green hydrogen in its analysis. Specifically, it has assumed that hydrogen costs would range from $2.50 to $3.00 per kg in 2030, $1.80 to $2.20 per kg in 2040 and $1.50 to $1.90 per kg in 2050. These ranges cover estimated costs for hydrogen produced in Ontario, Quebec, western Canada, New York, the PJM region and Michigan.[84] By comparison, Enbridge itself recently estimated that costs in Ontario would be $4.37 to $5.46 per kg – about twice the Guidehouse estimate for Ontario in 2030.[85] The Guidehouse estimated costs are also much lower than those estimated by E3 in the recent New York decarbonization study. For example, Guidehouse estimated that green hydrogen produced in New York would cost $2.70/kg in 2030, $1.90/kg in 2040 and $1.70/kg in 2050. E3's estimates for the same state were about 50% higher.[86]

Enbridge and Guidehouse imply that at least part of the reason their cost estimates are lower is that they are estimated costs of production and not retail costs that would include the effects of financing of capital investments, profits or market clearing prices. As discussed in the preceding subsection of this report on the cost of RNG, that is not a reasonable explanation and results in an analysis that is biased in favor of gaseous fuels.

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[83] Torchlight, p. 44.
[84] E1/T10/S5 Attachment 2, p. 70 of 88.
[85] JT1.19.
[86] Energy and Environmental Economics (E3), *Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan*, December 2022 (https://climate.ny.gov/resources/scoping-plan/), Annex 1: Input Assumptions, "hydrogen costs" tab. Note: E3 reports costs in US dollars per MMBtu. I converted them to CDN$/kg using the same higher heating value of 141.88 MJ/kg used by Enbridge and a $1.36 exchange rate.

H. Over-Estimating GHG Emission Reductions from Biomethane

Guidehouse's modeling of net zero emissions pathways assumes that all biomethane has zero GHG emissions, other than emissions that occur as a result of leaks in the Ontario transmission and distribution system. The basis for this assumption is that since biomethane is "biogenic", its emissions should be assumed to be zero. That assumption is flawed and results in an analytical bias against electrification and in favor of biomethane.

First, it is important to acknowledge that burning biomethane produces the same amount of CO2 emissions at the "burner tip" as burning fossil methane. The only reason biomethane may be considered lower GHG-emitting than fossil methane is that its combustion can eliminate other GHG emissions (e.g., methane emissions). In other words, there are some "offsetting" emissions reductions that can be credited to biomethane use. That said, the magnitude of those offsets – or the net lifecycle emissions impacts of biomethane – varies considerably, depending on the source, how it is collected, how it is converted into methane gas, how it is delivered to gas utility pipe, how it is already regulated and other factors. While some sources of biomethane actually have a negative net lifecycle GHG emissions impact, those sources (e.g., dairy farm manure) represent very small portions of the total biomethane resource potential. Most of the bigger sources of biomethane have lifecycle GHG emissions that, though better than fossil gas, are not zero. It is worth noting that the Torchlight study on which Guidehouse relied for its estimates of biomethane potential, uses an average 65% lifecycle GHG emission reduction factor when calculating emissions impacts relative to fossil gas.[87]

Second, to my knowledge, lifecycle emission reduction factors do not yet account for impacts of emissions on the customer's side of the meter. There is a growing body of evidence that suggests a non-trivial portion of methane delivered to home and business appliances is emitted to the atmosphere rather than burned and turned into carbon dioxide.[88] Because methane is a much stronger greenhouse gas than carbon dioxide – with 28-36 times the global warming potential over 100 years and 84-87 times the global warming potential over 20 years[89] – such leaks represent a significant level of GHG emissions that RNG will not and cannot reduce. The GHG emissions resulting from leaks from a home's cook stove will occur in exactly the same magnitude if the fuel being delivered to the home is biomethane as if the fuel delivered to the home was fossil methane.

These realities need to be reflected and accounted for in any analysis of pathways to decarbonizing our buildings. Put simply, Guidehouse's assumption that all RNG is zero-emitting does not address these realities and therefore artificially makes scenarios that rely more heavily on biomethane appear lower cost than the scenario would actually need to be in order to achieve comparable levels of GHG emission reductions as the scenario that relies more heavily on electrification.

I. Potential Over-Estimation of GHG Emissions Reductions from Blue Hydrogen

Guidehouse has assumed that approximately 4800 PJ (395 billion m^3) of blue hydrogen would be consumed between 2030 and 2051 in its Diversified scenario. At that scale of consumption, it is critically important that assumptions about lifecycle emissions from the production, transportation and consumption of the fuel are properly and reasonably estimated. This report does not address the

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[87] Torchlight, p. 58.

[88] For example, a recent Stanford study found that "natural gas stoves emit up to 1.3% of the gas they use as unburned methane" (https://news.stanford.edu/2022/01/27/rethinking-cooking-gas/).

[89] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

reasonableness of Guidehouse's assumptions about blue hydrogen emissions. The issue is instead addressed by Environmental Defence witnesses, Professors Howarth and Jacobson.

J. Ignoring Potential for Electric Demand Response from Building Loads

Guidehouse's modeling did not include any amount of demand response from the building sector in its modeling of the electric grid impacts of electrification. This is a significant omission that skews the results against electrification.

It is admittedly difficult to precisely estimate the extent to which peak demands from space heating can be shifted to off-peak hours. However, we know that the number is not zero today and is highly likely to improve over time. For example, new electric heat pumps that are coupled with thermal storage that would enable demand response have begun to emerge onto the market.[90] Hydro Quebec and Efficiency Nova Scotia currently offer financial incentives for electric thermal storage.[91] The electric utility industry also has a long history of deploying demand response to reduce water heating contributions to system peak. There are now also a number of electric utility initiatives promoting behind the meter battery storage.[92] The potential for EV batteries with bidirectional chargers to shift peak load is but one example of likely further developments on this front. The bottom line is that assuming zero demand response potential likely biases a decarbonization analysis against electrification.

K. Overly Optimistic Assumptions about Gas Heat Pumps

Guidehouse assumes that half of all homes that remain gas heating in 2040 would be heated with gas heat pumps. That level of market penetration for a product that isn't even commercially available yet is completely unrealistic.

Guidehouse also assumes that the initial cost of a gas heat pump combined with a new air conditioner was $12,200 in 2020. That cost estimate assumes $8000 for a gas heat pump plus $4200 for an air conditioner.[93] It was based on an "informal survey" by one manufacturer of gas heat pumps.[94] However, that estimate was expressed in 2019 U.S. Dollars. Guidehouse did not convert the estimate to Canadian currency or to 2020 dollars. If it had, the cost would instead be more like $16,500.[95] Correcting that error increases the sum of annual heating equipment costs by about $3 billion under Guidehouse's Electrification Scenario and by about $16 billion under its Diversified Scenario. In other words, it makes the relative economics of the Electrification Scenario look about $13 billion better.

L. Overly Pessimistic Assumption about Weatherization Savings Life

Guidehouse has assumed that building envelop efficiency improvements save energy for an average of 20 years.[96] That is an unreasonably short period of time. In fact, Enbridge itself currently assumes that

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[90] https://www.harvest-thermal.com/product

[91] See https://www.hydroquebec.com/residential/energy-wise/windows-heating-air-conditioning/thermal-storage/ and https://www.efficiencyns.ca/tools-resources/guide/ets-system-rebate-guide/.

[92] My electric utility, Green Mountain Power, is but one example (https://greenmountainpower.com/rebates-programs/home-energy-storage/).

[93] JT1.28, Attachments 8 and 9, "End-User Costs" tab.

[94] EB-2021-0002, Exh 1.10i.EGI.CCC.40, Attachment 1, p. 31 of 160.

[95] Assuming 1% inflation from 2019 to 2020 (https://www.bls.gov/data/inflation_calculator.htm) and 1.34 USD to CDN exchange rate as of April 14, 2023 (https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/).

[96] JT1.28, Attachments 8 and 9, "End-User Costs" tab, row 99.

all insulation measures installed through its DSM programs have a life of 30 years.[97] Changing the assumption from 20 years to 30 years has the effect of reducing the sum of annual weatherization costs, net of salvage value in 2050, by $11 billion for the Electrification Scenario and by $5 billion for the Diversified Scenario.[98] In other words, it makes the relative economics of the Electrification Scenario look about $6 billion better.

M. Unreasonably Pessimistic Assumption about Electric Water Heating Efficiency

As Table 8 shows, Guidehouse assumes that a significant majority of residential gas water heaters that are electrified would be converted to relatively inefficient electric resistance models (Energy Factors of 0.90 to 0.92) rather than to electric heat pump water heaters that typically four times more efficient (Energy Factors of 3.50 to 4.00).[99] Most notably, Guidehouse assumes that by 2040 more than 90% of the gas water heaters that are electrified would be converted to electric resistance models in the Electrification Scenario. While the portion converted to heat pump water heaters increases by 2050, it is still only about one-quarter) of all electrified gas water heaters.

Table 8: Guidehouse Assumptions Regarding Residential Water Heater Conversions by Scenario and Year

		Electrification Scenario				Diversified Scenario			
Current Type	**New Type**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Elec Resistance	Elec Heat Pump	0%	0%	30%	50%	0%	0%	30%	50%
Gas	Elec Resistance	0%	4%	60%	70%	0%	5%	5%	25%
Gas	Elec Heat Pump	0%	4%	6%	25%	0%	1%	7%	10%
Gas	Gas Heat Pump	0%	1%	4%	5%	0%	1%	57%	65%

It is also notable that Guidehouse has assumed that a larger proportion of electrified gas water heaters would be heat pump models under the Diversified scenario (over half in 2040) than under the electrification scenario (less than 10% in 2040). In other words, it assumes a much higher portion of gas to electric conversions are efficient in the Diversified scenario than in the Electrification scenario. In addition, Guidehouse has assumed that 30% of homes that currently have electric resistance water heaters would convert to heat pump models by 2040 and 50% by 2050. Why would a much higher percentage of homes with existing electric resistance water heaters be willing to convert to heat pump models than homes with existing gas water heaters?

Put simply, Guidehouse's assumption about the electrification of gas water heaters in the Electrification scenario is incredibly conservative. While the current North American market share for electric heat pump water heaters (as a percent of all electric water heaters sold) may be modest, in at least some jurisdictions in which DSM programs are promoting them, market shares have increased to about 30%.[100] In the context of aggressive climate policies and changes to the technology to make it easier to

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[97] EB-2021-0002 I.9.EGI.GEC.7 Attachment 1.

[98] Estimated by changing the measure life assumption for retrofits in cell I101 of the "End-User Costs" tabs of JT1.28 Attachments 8 and 9. Changes in costs can be found on row 108 of the same tabs.

[99] Guidehouse's assumed efficiencies for heat pump water heaters, starting at an Energy Factor of 3.02 and improving to just 3.18 by 2030, are themselves very conservative. For example, the models typically sold by Home Depot and Lowe's today have Energy Factors between 3.75 and 4.00.

[100] For example, Efficiency Vermont estimates that it is currently achieving about a 30% market share for electric water heater replacements through various efficiency rebate offerings (personal communication with Phil Bickel, Vermont Energy Investment Corporation, 4/18/23).

install, such as development of plug-and-play" 120 volt models,[101] even higher market shares should become possible relatively quickly. In fact, an "advanced water heating initiative" led by several leading energy efficiency organizations with support from the U.S. Department of Energy and the Energy Star program have set a goal of achieving a 100% market share by 2030 for high efficiency, grid-connected heat pump water heaters in residential markets.[102] It is also worth noting that the E3 decarbonization pathways study completed for the Massachusetts' gas utilities assumed that, depending on the scenario, between 64% and 86% of all electric water heaters would be heat pump water heaters by 2050.[103] Guidehouse has suggested that it assumed low market shares for electric heat pump water heaters because of experience with barriers to adoption of the technology to date, including higher first costs and some anecdotal information about some customers not liking them.[104] For reasons just stated, that is not reasonable, particularly when one contrasts that conclusion with Guidehouse's assumption in its Diversified Scenario of massive deployment of gas heat pumps – a technology that also has a high first cost (much higher than that of heat pump water heaters) and that the gas industry has struggled to develop for more than two decades and is still not commercially available for residential applications.

Guidehouse's decision to assume unreasonably high levels of inefficient water heating electrification has a significant impact on its estimates of electricity required to electrify. Specifically, if three-quarters of all residential and commercial electrified gas water heaters adopted heat pump water heaters (and only one-quarter adopted electric resistance water heaters), the total incremental load from building electrification would be about 6.5 TWh per year lower in 2040 and 8.2 TWh lower in 2050 under the Electrification Scenario; it would be about 1.1 TWh lower in 2040 and 3.5 TWh lower in 2050 under the Diversified Scenario.[105] In other words, it would have a much bigger impact on Guidehouse's estimate of the cost of the Electrification Scenario than on its estimate of the cost of the Diversified Scenario.

N. Excluding Distribution Systems Costs and Customer Fuel Conversion Costs

The Guidehouse study excluded costs associated with creating a distribution system for delivering 100% hydrogen to numerous residential, commercial and industrial customers. It also excluded the cost of converting the methane-carrying pipes and methane-burning appliances in those customers' buildings to pipes that can carry 100% hydrogen and appliances that can burn 100% hydrogen. These are huge omissions.

As discussed in a previous section of this report, it is hard to imagine how the delivery of 100% hydrogen to large numbers of residential and commercial customers could be accomplished without massive investment in a new hydrogen distribution system.

Similarly, significant costs will have to be incurred to enable the substituting of 100% hydrogen for methane in homes and commercial buildings. Methane burning equipment that is also hydrogen-ready will likely be a least a little more expensive than equipment built only to burn methane. Then there will

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[101] Gupta, Smita (New Buildings Institute), Scaling Up Market Transformation for Heat Pump Water Heaters, January 19, 2022 (https://newbuildings.org/scaling-up-market-transformation-for-heat-pump-water-heaters/).
[102] Ibid.
[103] E3 and Scottmaden, *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report, Technical Analysis of Decarbonization Pathways*, March 18, 2022, Appendix 4 (input assumptions), "Scenario parameters (detail)" tab.
[104] Technical Conference Transcript, April 27, 2023, p. 22, line 21 through p. 23, line 19.
[105] Values estimated using JT1.28 Attachment 3.

be significant costs to ensure that all customers downstream of a 100% hydrogen injection point have nothing but hydrogen-ready appliances, plus the cost of physically converting such appliances from methane-burning to hydrogen-burning (as discussed above, hydrogen-ready equipment still requires physical changes to burners, controls, etc.), plus costs to ensure that the pipes and equipment in every single individual home and business can actually safely burn hydrogen (assuming it is even possible without significant new ventilation additions), before hydrogen can start to be delivered instead of methane. Such interventions – potentially a couple of on-site visits for every building switching from methane to 100% hydrogen – will be quite costly and logistically challenging, to say the least.

Guidehouse notes that its analysis also excludes electrification costs associated with upgrading the electric distribution system and upgrading electrical systems in homes and businesses to accommodate larger electric loads. However, those omissions are highly unlikely to be comparable to the costs of creating a new 100% hydrogen delivery system and new hydrogen burning systems in buildings.

While it is true that electric distribution system investments will be necessary to accommodate high levels of electrification, some electrification can occur today without any distribution system upgrades. The same cannot be said of 100% hydrogen delivery to any customer or group of customers. Moreover, electrification can enable some reductions in gas distribution system costs. For example, if new homes and commercial buildings are all-electric, both the costs of connecting them to the gas system and the cost of running gas pipe on the customer side of the meter (i.e., to different appliances in the home or business) are avoided. For that matter, if an existing gas home or commercial building is fully electrified, the need to maintain or replace the gas meter, the need to send gas bills and other gas utility costs of serving those customers are avoided. It is also possible that electrification can eliminate some gas system expansion costs or even allow pruning of parts of the gas system to avoid on-going system maintenance costs. Importantly, there are no electric analogs to these opportunities for gas utility system cost reductions. Because every gas-connected customer is also an electric customer, there are no cost savings to the electric system from continuing to use gas.

Furthermore, while some homes will require electrical panel upgrades in order to electrify space heating, some will not. And for those that do, the costs are generally well-understood and relatively modest.

The bottom line is that omission of both distribution system and customer conversion costs from Guidehouse's study almost certainly biases the results against electrification and in favor of the scenario contemplating mass delivery of 100% hydrogen.

O. Summary

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. It should also be noted that for the flawed assumptions whose impacts I attempted to quantify, my estimated impacts do not account for interactions with other assumptions. Nor do they account for how changing an assumption might change resource choices that an optimization model might make. 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.

Finally, it is worth noting that the scenarios analyzed by Guidehouse were developed by or with Enbridge. They were not necessarily optimized. And while they were designed to achieve net zero emissions by 2050 – though unlikely to actually do that, at least from a lifecycle emissions basis – they produce much lower emissions reductions from the buildings sectors by 2030 (9% in the Diversified Scenario and 13% in the Electrification Scenario relative to 2020) than the projections set out in Canada's 2030 Emissions Reduction Plan and its Green Building Strategy.

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

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

IV. Protecting Consumers in the Context of Future Decarbonization

While there is always uncertainty about how the future will unfold, it is very likely that decarbonization of the economy (i.e., achieving net zero GHG emissions by 2050) will ultimately mean very high levels of electrification of buildings and, to a somewhat lesser extent, electrification of industrial operations.[106] The uncertainty is when the gas system will begin to shrink, how fast the shrinking will accelerate, and exactly how much smaller the gas system will ultimately become. This reality has major implications for gas distribution system investments that regulatory policy and decisions should address and reflect in order to protect consumers. What follows are discussions of several ways in which the Board should consider addressing and reflecting the likely implications of decarbonization.

1. Modify Policy on New Connections to Reduce Risk of Stranded Assets

Regulatory policy on new connections should be reconsidered in light of the likelihood of extensive electrification and the significant savings customers can achieve by switching from gas to electric heating. The costs of new connections are largely socialized in rates, to be repaid over long periods (40 years) through forecast distribution rate revenue from the newly connected customers. This creates a major risk for existing customers. If new customers convert to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. The same is true of existing homes or businesses that consider connecting to the gas system today.

In addition, modifying policy on new connections could cause an immediate reduction in rates by reducing gas connection infrastructure costs and/or reducing the portion of those costs borne by existing ratepayers.

The cost of new connections in the context of decarbonization also creates the risk of unfair cost allocation. Even if a new customer remains on the system long enough to pay for the costs to connect them to the system, they would still not have contributed at all to the cost of the remaining system. It is unclear how long they would need to remain with the system in order to pay a fair share of the costs of the gas system, but merely remaining long enough to pay their own connection costs is clearly insufficient.

Also, if most new homes and businesses are ultimately going to have to become all-electric – and/or going to want to become all-electric because of significant cost advantages relative to very expensive biomethane and/or hydrogen – it is much easier and less costly to design and build those homes and businesses as all-electric buildings from the get-go. If they are instead built to burn methane, the task of decarbonizing Enbridge's system will get harder and more expensive because of the additional emission reductions required – with all gas customers collectively absorbing that added cost.

Thus, the Board should consider several policies for both mitigating the risk of stranded or underutilized assets from new connections and leveling the playing field between gas and electricity.

[106] Moreover, even if Enbridge's much less likely vision of the future were to become reality, there would still be considerable electrification, reductions in annual gas throughput and reductions in gas peak demands.

A. Shorten New Construction Connection Cost Recovery Periods

The Board direct Enbridge to shorten new construction connection cost recovery periods. Enbridge is proposing to maintain most of its existing policies with respect to recovering costs associated with connection of new small volume customer buildings – e.g., new residential subdivisions and new small commercial developments. In particular, it is not proposing any changes to the following existing policies:

- **Customer connection horizon of 10 years**. This is the period of time within which a new building must be connected to the gas system in order to be subject to an agreement on any terms regarding costs of connections, including contributions in aid of construction, system expansion surcharges or temporary connection surcharges.
- **Customer revenue horizon of 40 years**. This is the period of time over which additional revenue collected from new connections must be sufficient to cover connection costs minus any initial contributions or surcharges. Note that the comparable horizon for electric connections in Ontario is 25 years.[107]

These policies have been in place since the Board's decision in 1998 in the EBO 188 case. However, our understanding about the future use of the gas distribution system is very different today than it was 25 years ago. As discussed in this report, it is highly likely that many if not the vast majority of existing residential and commercial gas customers will have to electrify in the next couple of decades for the Ontario economy to fully decarbonize. Even in Enbridge's preferred "diversified scenario" from the Guidehouse P2NZ study, 36.5% of existing residential gas customers are assumed to have converted to electric heat pumps by 2040.[108]

In that context, the case for greater certainty about revenue recovery from any new connections – to guard against the risk of stranded assets – is very compelling. Since the typical life of a new gas furnace is estimated to be 18 years, and it is most likely that a customer will electrify at the time that they need to replace their heating system, a maximum customer revenue horizon of 15 years would be much more appropriate. That said, some customers will electrify sooner, such as when they replace a central air conditioner and/or in an effort to save energy costs or to decarbonize.

Given the uncertainty about the pace of decarbonization and its impact on the gas system, it would also make sense to tighten up the maximum customer connection horizon. A reduction from 10 years to the 5 years used on the electricity system is reasonable.

It is worth noting that Enbridge has estimated that reducing the maximum customer revenue horizon to 15 years would reduce system access spending by about $600 million over the 2024-2028 period.[109]

B. Reduce Infill Connection Costs Funded by Rates

A similar change is warranted for infill connections. The portion of the infill connection costs covered by rates should be limited to those costs that would be recouped over 15 years. In contrast, Enbridge's proposed harmonized connection policy would fund the majority of infill connection costs from rates (e.g. the meter and up to 20 meters of service line) even though this cost would not be recovered from

[107] www.oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code_AppB.pdf
[108] JT1.28, Attachment 3, "DivScen_Assumptions" tab, rows 23-24.
[109] JT5.21, p. 3.

those customers' distribution charges until after 2050.[110] If the new customer converts to all-electric buildings 10 or 15 years from now, the capital cost of having connected them to the Enbridge system will not have been fully recovered under current connection rules, creating a stranded asset that customers still on the gas system will have to pay. Even if they stay just long enough to pay off their individual connection costs, they would have had a "free ride" by not contributing any costs to the overall system beyond their own service line and meter.

C. Require All New Connections to Be Net-Zero GHG

From a public policy perspective, there are compelling arguments for a moratorium on new gas connections. Indeed, the state of New York just enacted legislation that would ban the use of fossil gas and other fossil fuels in most new buildings.[111] An alternative to a new connections moratorium would be to require that (1) all new gas connections be heated with hybrid systems comprised of cold climate electric heat pumps with gas furnaces used only for back-up heat on the coldest hours and days of the year; and (2) all of the gas supplied on those coldest hours and days of the year will be net-zero GHG-emitting with the new customers bearing the full cost of that more expensive gas (i.e., without cross-subsidies from existing gas customers).

Energir, the Quebec gas utility, recently announced that it will seek approval in its next rate case for a similar, though less restrictive policy. It would give potential new customers the option of either a 70% electric / 30% RNG option or a 100% RNG option.[112] Given the significant limitations on RNG availability, it would be more prudent to limit this offer, at least for residential and commercial buildings, to cold climate electric heat pump-gas furnace systems in which the electric heat pump delivers much more than 70% of heating needs – probably 90% or more – in most of Ontario.

2. Align Depreciation and Rate Design with Expectation of Declining Gas Throughput

The proposed approach to depreciation is highly problematic because it does not address decarbonization risks at all and implicitly assumes a 0% risk of underutilized or stranded assets even long past 2050. Given the almost certain inter-generational inequities that will arise from decarbonization of the gas system in Ontario under the Company's current or proposed approach to asset depreciation, the Board should consider and implement alternative approaches. Specifically, the Board should require Enbridge to assess near-term and longer-term rates, costs of capital and inter-generational equity impacts of (1) maintaining its currently proposed Equal Life Group (ELG) depreciation method, (2) adopting an Economic Planning Horizon (EPH) for new assets, (3) adopting an EPH for all assets, and (4) switching to a Units of Production (UOP) method of asset depreciation. That analysis should be performed using load forecasts consistent with the most likely decarbonization pathway or pathways.

The Board should require that Enbridge file this analysis in 2024. It is important that this happen as soon as it reasonably can. The longer we wait, the closer we get to the point when gas sales are likely to decline, reducing the ability to mitigate against inter-generational inequities. Also, the longer we wait, the greater the short-term adverse effect on customers still on the system. For example, Enbridge estimates that adopting a 2050 EPH in 2024 would increase the amount of revenue required to be collected from ratepayers in that year by $257 million, but waiting to adopt a 2050 EPH until 2028 will

[110] JT3.11.
[111] https://www.washingtonpost.com/climate-environment/2023/05/03/newyork-gas-ban-climate-change/.
[112] https://www.energir.com/en/about/media/news/vers-la-carboneutralite-des-batiments/

result in an increase of $342 million and waiting until 2030 will result in an increase of $405.[113] In other words, there is an opportunity cost to waiting to make changes to depreciation approaches.

As the earlier sections of this report make clear, much of the existing Enbridge Gas distribution system – particularly the parts of the system predominantly serving residential and commercial buildings – will be used much less in a decarbonized future than they are today. For example, as shown in Table 1 (section II((2)(F) above), decarbonization studies generally suggest annual gas sales to residential, commercial, and industrial customers will decline by 70-90% or more by 2050. Even the fundamentally flawed and biased study conducted by Guidehouse for Enbridge suggests that gas sales to residential and commercial customers will decline dramatically by 2050.[114]

Put simply, decarbonization is likely going to result in far fewer gas customers paying for undepreciated gas asset costs than are paying for them today, with the cost of those assets being recovered over a much smaller volume of gas sales than is the case today. At best, this raises a serious concern about inter-generational equity. It could lead to what is sometimes called a "death spiral" in which increasing electrification leading to higher gas rates drives even more customers to electrify with only those customers least able to afford to leave the system left paying for it. That kind of feedback loop and its effects on levels of electrification is typically not accounted for in decarbonization studies.

In its filing, Enbridge has proposed a shift from an "Average Life Group" (ALG) approach for depreciating gas assets to an "Equal Life Group" (ELG) approach. Enbridge's consultant, Concentric Energy Advisors, explains that the new ELG approach will create greater inter-generational equity than the current Enbridge ALG approach by better aligning the timing of asset cost recovery with the mix of different expected lives of the different assets within an asset group.[115] That is a good thing. However, it is important to recognize that the ELG approach only addresses one form of inter-generational inequity – accounting for the fact that some types of equipment have shorter lives than the average life of all equipment with which they are grouped. It does not address inter-generational inequities associated with the likely decline in the level of use of assets in the future relative to today.[116]

Enbridge states that it considered the potential for introduction of an "Economic Planning Horizon" (EPH) which would require that recovery of all past and new capital investments be achieved by a fixed date – e.g., 2050 – in order to account for the impact that the energy transition would have on the economic life of Enbridge's assets. The Company concluded that an EPH "is not appropriate at this time" because of the possibility that low carbon fuels such as biomethane and hydrogen would be "viable sustainable alternatives" to fossil gas. Enbridge pointed to the Guidehouse P2NZ study as evidence that its gas system "will be a key contributor to achieving net-zero in the province."[117] Those statements

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[113] JT4.17.
[114] Under its Electrification Scenario, Guidehouse estimates total annual gas sales to residential and commercial customers to be nearly 90% less than in 2020; even under its Diversified Scenario, total annual gas sales to residential and commercial buildings are estimated by be about half as large as in 2020. (E1/T10/S5/Attachment 2, p. 29 of 86) Moreover, much of the remaining gas throughput will be hydrogen, most if not all of which will have to be delivered through new dedicated hydrogen distribution pipes rather than existing methane distribution pipes.
[115] E4/T5/S1 Attachment 1, p. 15 of 451.
[116] In response to a question from GEC attorney David Poch, Larry Kennedy of Concentric Energy Advisors confirmed that their current study did not adjust ELG for the impacts of future declines in gas throughput. Transcript of Technical Conference, March 27, 2023, p. 127, lines 7-19.
[117] E1/T10/S4 p. 18 or 20.

ignore the reality that even the gas utility's most optimistic view of the future will involve significant loss of customers and gas energy sales. They also do not account for the fundamental flaws in the Guidehouse report, discussed above.

Enbridge's consultant, Concentric Energy Advisors, also addressed the potential application of an EPH. Concentric observed that "while there is strong evidence that the future of natural gas in Ontario may be impacted by climate change legislation, it is still unknown to what extent this change will impact EGI's system." Concentric concluded that additional study of the changes that climate policy will have on Enbridge should be undertaken before adopting an EPH.[118] This response is less than satisfying. While it is certainly true that there is some uncertainty about the future impacts of the energy transition on the gas utility, the uncertainty is more about the magnitude and precise timing of the decline in use of the system, not whether there will be a decline. Furthermore, an EPH can be adjusted over time.

Concentric acknowledges that "intergenerational equity would require that the original cost of investment of an asset is recovered by the customers who gain the benefit of the assets." However, it suggests that an EPH is not the appropriate mechanism to address intergenerational inequities resulting from a substantial reduction in customer load because some customers will still be using the assets after the EPH cut-off date.[119] Concentric is suggesting that if gas assets will not be retired, there would be an inter-generational inequity associated with the fact that the much smaller number of customers still using the gas system after 2050 would benefit – at the expense of current customers and those still on the system through 2050 – if an 2050 EPH were adopted. However, Concentric never addresses why that inequity should rule out adoption of an EPH while the inequity associated with future customers paying much more for an asset per unit of gas energy consumption does not rule out use of a ELG approach to depreciation that does not account for such reductions in energy throughput. Surely it is possible that the inequity of post-2050 customers getting a "free ride" would be outweighed by the increase in equity resulting from assigning a larger portion of the costs of gas assets to the 2020s and even the 2030s when many more customers are using the system. Note that New York regulators recently required gas utilities in that state to file depreciation studies that examine several scenarios, including one in which all new gas assets are fully depreciated by 2050 and another in which all gas assets are fully depreciated by 2050. These studies are intended to "inform future discussions of how best to recover costs of assets and reduce potential stranded costs in the LDC's respective rate proceedings."[120]

Concentric did suggest a potential alternative to EPH as a way to address inter-generational inequities caused by gas customers exiting the system and gas sales declining over time: a "units of production" (UOP) depreciation method.[121] Under a UOP, annual depreciation expense is proportional to expected usage in a given year relative to total expected lifetime usage. As explained during the Technical Conference, this method may offer greater flexibility to periodically adjust for evolving expectations

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[118] E4/T5/S1, Attachment 1, p. 19 of 451.
[119] Response to GEC-66c.
[120] State of New York Public Service Commission, Order Adopting Gas System Planning Process, Case 20-G-0131 and Case 20-G-0297, May 12, 2022, pp. 61-62.
[121] Response to GEC-66d.

about changes in use of the gas system.[122] The challenge would be in reaching agreement on estimates of expected long-term changes in gas consumption.

UOP depreciation is beginning to be considered in some other jurisdictions. For example, Pacific Gas and Electric (PG&E), a very large dual-fuel utility in California, proposed in its 2023 general rate case application that its regulators approve a proposal "to use the units of production method of cost recovery for depreciation of PG&E's gas distribution facilities due to the anticipated reduction in throughput as the state reduces its reliance on natural gas as a fuel."[123] Similarly, the Massachusetts gas utilities recently provided the following recommendation to their regulators:

> *The Department should investigate the role of accelerated depreciation to align cost recovery of gas distribution costs with the utilization of the distribution system rather than the useful life of the assets that make up the distribution system. The Consultants offered an example, known as Units of Production ("UOP") depreciation method. The UOP method is recognized by the National Association of Regulatory Utility Commissioners. The LDCs encourage the Department to investigate this cost recovery option in order to mitigate customer affordability and equity concerns to the extent that gas customers decrease over time as the LDCs pursue decarbonization and electrification strategies.*[124]

Regardless of the specific approach taken, it is important that steps be taken as soon as possible to align depreciation approaches with the likely declines in gas throughput to ensure equity and ongoing affordability.

3. Require Assessment of Repair vs. Replace Trade-offs for Aging Pipe

One important way to reduce the risk of stranded or under-utilized gas system assets, and related long-term adverse gas rate impacts, is to reduce the magnitude of new investment in such assets – whenever that can be done safely, without significant risk of system reliability problems and at reasonable cost. Put simply, there is an economic value to "buying time" by deferring capital investments in gas distribution system infrastructure when there is a known and substantial risk that those assets could become stranded or under-utilized. That value should be reflected in regulatory decisions on such investments.

To that end, the Board should require Enbridge to explicitly assess the potential for repairing (whenever that is feasible) rather than replacing aging pipes – and to conduct that assessment in a way that accounts for the possibility that a new pipe will be underutilized or stranded before the end of its life. Such assessments should include estimates of any potential near-term cost savings and related differences in rate impacts, any potential differences in long-term costs and rate impacts, the magnitude of any differences in methane leaks, the nature of any differences in safety risks, differences between how long repairs would last relative to life of a new pipe, the long-term potential to prune the gas system so that the pipe is no longer needed in the context of future decarbonization pathways, and other relevant factors. That kind of analysis would enable the utility, stakeholders and the Board to

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[122] Technical Conference, March 27, 2023, p. 128 line 26 through p. 129 line 6.

[123] PG&E, 2023 General Rate Case Application, June 30, 2021, p. 10.

[124] Massachusetts Gas LDCs, Common Regulatory Framework and Overview of Net Zero Enablement Plans, regulatory proceeding D.P.U. 20-80, p. 21 (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633273).

routinely assess cost, stranded/under-utilized asset risk, and other trade-offs of a repair vs. replace decision. For example, it may be reasonable to accept a shorter-term fix with lower cost for 10-15 years (and perhaps even again in another 10-15 years) if there is any chance of eliminating the need for the pipe replacement by pruning the gas system over the next couple of decades.[125]

4. Improve IRP to Reduce Risk of Stranded/Under-Utilized Assets

A second important category of capital investments is upgrading the capacity of pipes to ensure reliability can be maintained for growing methane peak demands. Two years ago, the Board issued an order on Gas Integrated Resource Planning (IRP). However, our collective understanding of the potential implications of the energy transition has evolved significantly since evidence was presented in that case. Thus, at least two modifications to the policy the Board put forward in that case should be considered in this proceeding.

A. Removing Prohibition on Electrification Measures as IRPAs

The Board should remove the current restriction on considering electrification measures as potential IRPAs. IRPAs are the term used in the OEB policy for non-pipeline alternatives to distribution needs. Gas utilities in other jurisdictions have begun to assess and even propose IRPAs that include electrification in order to cost-effectively avoid expensive gas distribution system upgrades. Concern about the risk of stranded gas assets, given the likely shrinking of the gas system as economies decarbonize, has been an important part of the context for those developments. For example, last year Pacific Gas and Electric Company (PG&E) proposed a pilot project in which it would retire a natural gas pipeline by electrifying 1200 housing units on the California State University Monterey Bay campus. As the Sustainability Director for the University stated "As California shifts to electrification, any new investments in natural gas infrastructure risks becoming a stranded asset. It is like buying a fax machine in 1999."[126] "PG&E estimates that the cost to gas customers to complete this alternative zonal electrification work will be less than the cost to replace the gas system."[127] Further, "the net present value of cash costs of electrification for…the Project have a value of $14.4 million, and the value of the benefits of the Project (i.e. avoided costs of conventional gas pipe replacement) are approximately $15.4 million, resulting in a net benefit of approximately $1.0 million to customers."[128] A regulatory decision on the case is still pending.

B. Require Analysis of IRPAs Under Multiple Possible Future Load Forecasts

Load forecasts drive determinations of needs to upgrade gas transmission and/or distribution system capacities, the timing of those needs, the extent to which deployment of IRPAs could defer such needs, and therefore the relative cost-effectiveness of traditional supply and IRPA solutions to addressing the need. To date, the load forecasts that Enbridge has used to assess needs have not reflected the potential for peak demands to begin to decline in the future as climate policy and related market trends accelerate electrification. To be fair, Enbridge needs to ensure that its customers' peak hour energy needs are met, so it cannot rely on uncertain estimates of when gas demand will begin to decline in

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[125] Note that the pruning of the methane delivery system could be enabled either by electrification of a neighborhood or community and/or by bringing new 100% hydrogen pipe to the area.

[126] https://csumb.edu/news/news-listing/east-campus-may-become-californias-largest-electrification-project/

[127] Ward, A. & Pendelton, J. (August 10, 2022). Application of Pacific Gas and Electric Company (U 39 G) for Approval of Zonal Electrification Pilot Project and Request for Expedited Schedule. Filed before the Public Utilities Commission of the State of California. P. 1.

[128] Ibid. P. 4.

identifying potential capacity needs that must be addressed. However, it can and should consider those uncertain futures when assessing the relative merits of different approaches – both traditional supply investments and IRPAs – to meeting those potential needs. The Board should require them to begin to do so. More specifically, the Board should require that Enbridge examine the need for capacity upgrades and assess the relative cost-effectiveness of IRPAs – both rate impacts akin to Phase 1 of the recently approved IRPA cost-effectiveness framework and customer and societal impacts akin to Phases 2 and 3 of the framework[129] – under both Enbridge's traditional load forecast and under a forecast (or two) of accelerating electrification consistent with decarbonization pathways studies. A conceptual illustration of how such scenario analyses could framed is presented in Appendix B to this report.

5. Segregated Fund for Site Restoration

There are compelling arguments for site restoration funds to be moved to a protected and segregated fund as the need for a future gas pipeline system is increasingly in question. The obvious rationale is to protect future customers and taxpayers from this future liability, including in a "death spiral" scenario (discussed above). The risk is material and the potential magnitude of the risk is in the billions of dollars. However, I have not attempted to determine the net financial impact on customers. I recommend that the issue be addressed in the next phase of this proceeding based on a deeper analysis by a third party that would provide a full and balanced examination of the cost impacts and recommendations on the design and implementation of a segregated fund that would maximize returns on funds held for site restoration costs, minimize administration costs, and minimize liability for customers.

6. Reduce Capital Spending Where Possible

The risk of underutilized and stranded assets calls for additional efforts to reduce capital spending, wherever that is possible, especially on long-lived infrastructure. A number of my recommendations will achieve that end, but could be others. Utilities and regulators always should seek to avoid unnecessary capital spending, but even greater scrutiny is required in the current context.

V. Conclusion

Major declines in peak and annual gas demand are very likely in the future as efforts to decarbonize the Ontario economy accelerate. This is the conclusion of most independent decarbonization pathways studies. It is also consistent with an analysis of the availability and feasibility of the electric and gas technologies required for net zero greenhouse gas (GHG) emissions and the current cost effectiveness of electrification. It is even consistent with results of Enbridge's own decarbonization study if just one of the most glaring of the many flaws in the study is corrected.

The potential implications of declining gas peak demand and gas sales are significant and important. In a nutshell, there is a growing risk that current and any new gas capital assets will become underutilized, if not stranded. This creates significant risks for the ratepayers who would be saddled with paying for those assets in the future. It will likely also create significant inequities between customers today and those left on the system in the future.

To mitigate these risks, we recommend that Enbridge and/or the OEB take the steps in section IV of this report above.

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[129] Including changes to Phases 1, 2 and 3 of cost-effectiveness framework proposed by Gas IRP Working Group.

Appendix A: Assumptions for Customer Economics of Electrification

Table 10: Equipment Cost, Efficiency and Energy Consumption Assumptions

	2023 Initial Capital Cost	Life	Level-ized Annual Cost	2023 Avg Heating COP	2030 Avg Heating COP	Avg Cooling SEER	Other COPs	Annual Gas m^3	Annual Electric kWh Heating	Annual Electric kWh Cooling	Annual Electric kWh Other	Annual Electric kWh Total
Heating/Cooling												
Current Avg Furnace + Central A/C				0.90		13		2117	631	779		1,410
New Gas Furnace + Central A/C	$8,000	18	$632	0.95	0.95	14		2006	631	723		1,354
cold climate ASHP	$4,600	18	$363	2.84	2.93	18			7,279	563		7,842
Water Heating												
Current Stock Avg gas water heater							0.63	441				-
Gas Water Heater	$3,016	14.5	$278				0.83	335				-
Heat Pump Water Heater	$1,111	15.1	$99				3.73		808			808
Drying												
Gas Dryer	$1,223	13	$123				3.48	53			108	108
Electric Dryer	$998	13	$100				3.93				608	608
Cooking												
Gas Range	$1,195	15	$107					94				-
Electric Range	$1,476	17	$121								290	290

Table 11: Current Residential Energy Price Assumptions (2023 $)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Gas																		
Fixed Annual Charges	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310	$310
Variable Charges																		
Commodity	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221	$0.221
Transportation	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050
Distribution	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118	$0.118
Carbon Tax	$0.126	$0.152	$0.176	$0.200	$0.223	$0.245	$0.266	$0.286	$0.286	$0.286	$0.286	$0.286	$0.286	$0.286	$0.286	$0.286	$0.286	$0.286
HST	$0.067	$0.070	$0.074	$0.077	$0.080	$0.082	$0.085	$0.088	$0.088	$0.088	$0.088	$0.088	$0.088	$0.088	$0.088	$0.088	$0.088	$0.088
Total	$0.582	$0.611	$0.639	$0.666	$0.692	$0.717	$0.741	$0.763	$0.763	$0.763	$0.763	$0.763	$0.763	$0.763	$0.763	$0.763	$0.763	$0.763
Electric																		
Fixed Annual Charges	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561	$561
Variable Charges																		
Commodity	$0.093																	
Transmission	$0.019																	
Wholesale Mkt Serv	$0.005																	
Riders	$0.001																	
HST	$0.015																	
Total	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133	$0.133

Appendix B: Hypothetical Example of IRP Scenario Analysis

In many respects, the most important aspect of risk for gas infrastructure investments today is the potential for climate policy to (1) render such investments unnecessary, at least in the medium to long run, if gas demands are going to decline because of either increased electrification and/or much higher gas prices associated with renewable gas; and (2) add value to efficiency resources and electrification because of both avoided future carbon emission compliance costs (beyond those currently reflected in carbon taxes) and/or higher avoided costs of gas associated with low-GHG gases. Conceptually, one can conceive of three potential futures related to climate policy:

1. Canada does not follow through on its commitment to achieve net zero greenhouse gas emissions, or at least lowers its ambition and imposes no new requirements on fossil gas;
2. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met with a combination of electrification and low-GHG gases; and
3. Canada follows through on its net zero emission commitments, adopts additional policies requiring increasingly stringent reductions in the consumption of fossil gas, and those requirements are met largely with electrification of gas end uses.

Enbridge could be required to estimate how the need for an infrastructure capacity upgrade would be affected under each of these scenarios, how gas prices would likely change under each of them, and how the resulting net present value of net benefits from investing in non-pipe solutions would change under each. Of course, there could be hybrids of the three scenarios as well. And there could be variations on the second and third scenarios in terms of the timing of requirements. Such hybrids and variations could also be considered.

A hypothetical example can help to conceptually illustrate the importance of multiple scenario analyses. Consider the three scenario assumptions in Table 12, along with the related graphic depictions of demand growth without non-pipe solutions in Figure 6, and with non-pipe solutions in Figure 7. As Figure 6 shows, under the electrification scenario the duration and the magnitude of the need for additional capacity is very different than under the other two scenarios. As Figure 7 shows, because the maximum load without a non-pipe solution never gets to be more than 4% higher than the existing capacity, it is possible to completely eliminate the need with five years of a non-pipe solution.

Table 12: Hypothetical Characterization of Three Scenarios for Gas Infrastructure Need

Scenario		2024 Peak Demand	Max Capacity w/o Upgrade	Annual Demand Growth 2025 to 2029	2030 to 2034	2035 to 2039	2040 to 2044	Max Annual EE IRPA Savings	Year Upgrade Needed w/o IRPA	Upgrade Deferral Year w/Max EE
1	Business as Usual	94	100	2.0	2.0	2.0	1.0	1.0	2027	2030
2	GHG Regs - Electric/RNG/H2	94	100	2.0	1.5	-1.0	-2.5	1.0	2027	2031
3	GHG Regs - Electrification	94	100	2.0	0.0	-6.0	-6.0	1.0	2027	indefinitely

Figure 6: Peak Loads Relative to Maximum Capacity without Non-Pipe Solution

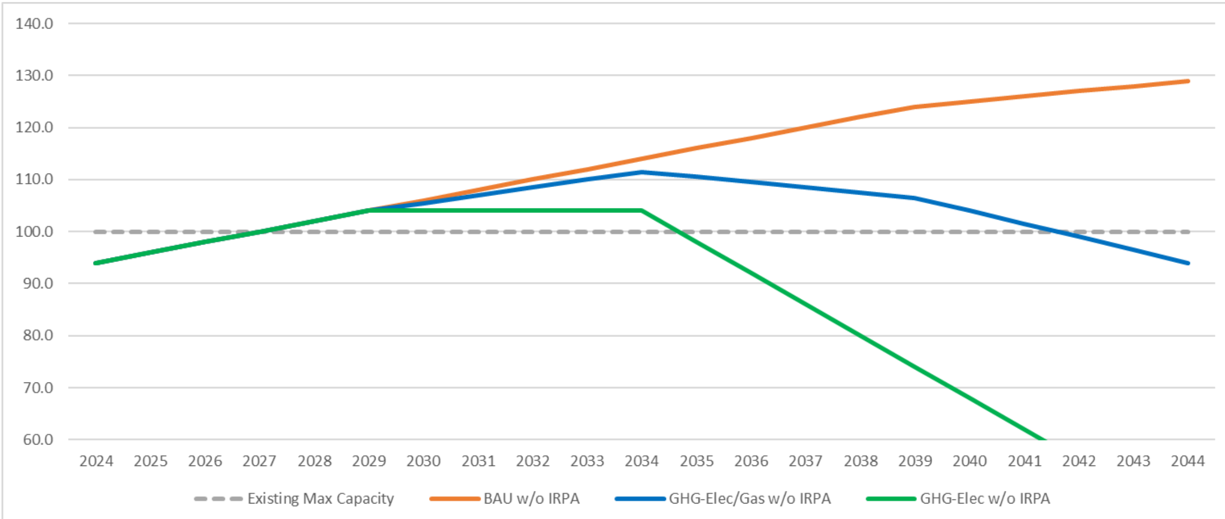
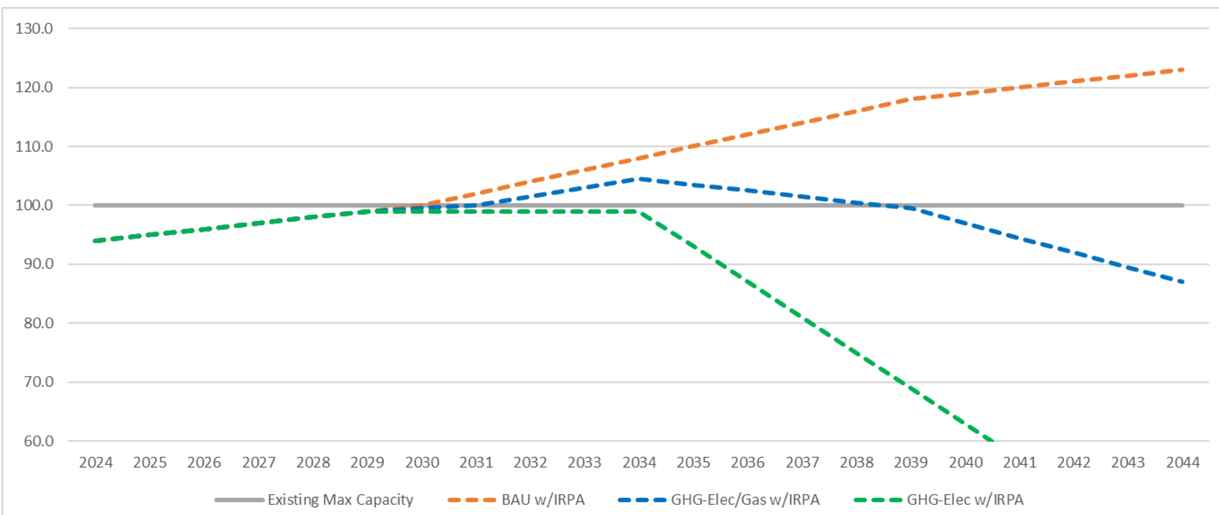


Figure 7: Peak Loads Relative to Maximum Capacity with Non-Pipe Solution[130]



Importantly, different scenarios could not only affect the viability a non-pipe solution for addressing reliability needs; they could also affect the economics of non-pipe solutions. Consider the hypothetical societal economics of the non-pipe solution scenarios example presented in Table 13. In this simplified example, the cost of the infrastructure upgrade is $100 in 2024 dollars (column a), which translates to a net present value (NPV) of $89 (column g) if installed in 2027 – assuming a 4% real discount rate. The cost of the energy efficiency IRPA is $20. However, energy efficiency has non-T&D deferral benefits such as avoided energy costs. The hypothetical value of those additional benefits is $16 in the Business as Usual (BAU) scenario. Put another way, the value of the T&D deferral benefit would need to be greater

[130] Non-pipe solutions are assumed to run only for as many years as they can defer the infrastructure investment or – for the electrification scenario – for as long as needed before naturally-occurring (including policy driven) demand reductions without non-pipe solutions are enough to eliminate the need for continued IRPA investment.

than $4 per year of non-pipe solution deployment in order for the non-pipe solution to be cost effective to Enbridge customers as a whole and/or society.

Under the BAU scenario, six years of the non-pipe solution – from 2024 to 2030 – would be required to defer the T&D upgrade by three years from 2027 to 2030. If the upgrade is deferred to 2030, the NPV of the project cost would decline to $79 (column h), or a $10 savings (column i). That T&D deferral benefit is not enough to cover the $21 NPV difference (column f) between six years of the non-pipe solution cost and the other non-T&D benefits provided by the efficiency programs, so the non-pipe solution would not be cost-effective. However, the non-pipe solution would be cost-effective under either of the Greenhouse Gas (GHG) regulation scenarios. In the electrification/low-GHG gases scenario, the reason is that the value of avoided energy costs (column c) is assumed to be 50% greater (because of assumed very high cost of low-GHG gases) as under the Business-as-Usual scenario, making the efficiency investments cost-effective even without any T&D deferral benefit ($12 in savings per year). In the electrification scenario, though avoided energy costs are the same as in the BAU scenario, the fact that electrification lowers peak demand relative to the BAU scenario means that the non-pipe solution completely eliminates the need for the infrastructure project. That has much greater value (column i) than just deferring it (as in the other two scenarios).

Table 13: Hypothetical Scenarios of Non-Pipe Solution Cost-Effectiveness [131]

	Scenario	Cost of Infra-Structure Upgrade (2024 $) (a)	EE IRPA Annual Cost (b)	Cost Savings (Excl T&D) from 1 Year of IRPA (c)	Net Cost (Excl T&D) from 1 Year of IRPA (d)	Years of EE IRPA Required (e)	Net Cost (Excl T&D) from Multiple Years of IRPA (f)	NPV of 2027 T&D Upgrade w/o IRPA (g)	NPV of Deferred T&D Upgrade w/IRPA (h)	NPV of IRPA Deferral Benefit (i)	NPV of Total Net Benefits of IRPA (j)
1	Business as Usual	$100	$20	$16	$4	6	$21	$89	$79	$10	($11)
2	GHG Regs - Electric/RNG/H2	$100	$20	$24	($4)	7	($24)	$89	$76	$13	$37
3	GHG Regs - Electrification	$100	$20	$16	$4	5	$18	$89	$0	$89	$71

Again, this is just a set of hypothetical scenarios presented for illustrative purposes. It is also presented only from an all customers or societal cost-effectiveness perspective. A similar comparison of the net present value of rate impacts would also be appropriate for informing decisions. Nevertheless, this example clearly illustrates how cost-effectiveness could be very sensitive to assumptions about the future, particularly with respect to climate policy. In fact, even if one assumed that there was an 80% likelihood that the BAU scenario would become reality, and that there was only a 10% chance of each of

[131] Note that the net benefits shown in the last column of this table is only illustrative of the cost-effectiveness of a non-pipe alternative in the context the hypothetical futures characterized. It does not suggest that a renewable gas approach to addressing climate policy goals would be lower cost than an electrification approach. Economic trade-offs between renewable gas and electrification would need to be assessed under an IRP analysis applied to the entire energy system, including gas commodity costs and the costs of electric alternatives, rather than to just non-wires alternatives to traditional T&D investments. In fact, it is possible, if not likely, that non-pipe solutions would look better under a renewable gas scenario than under an electrification scenario precisely because a switch to renewable gas would be more expensive (leading the avoided costs of gas, a potentially key benefit in deploying non-wires solutions, to be dramatically higher) than electrification.

the other two scenarios becoming reality, the probability weighted average result would be that the non-pipe solution was cost-effective (i.e., a different conclusion than if one only looked at a BAU scenario).

The Board, Enbridge and other stakeholders should have the opportunity to see how these different future scenarios affect the cost-effectiveness of IRPAs. While it will always be impossible to empirically assign probabilities to each scenario analyzed, it is important that all parties understand how sensitive the cost-effectiveness of different solutions are to assumptions about the future. In the hypothetical case presented here, the business-as-usual load forecast would have to have a nearly 90% probability of being the most accurate forecast for a traditional supply-side investment to be the most cost-effective solution. Given what we know about current government policy and related market trends, that should raise concern about approving such an investment. On the other hand, if an IRPA was cost-effective only if one assigned a 90% probability to a fully electrified future with dramatic annual reductions in peak demand beginning within the next 5-10 years, the decision might be very different.