ONTARIO ENERGY BOARD

EB-2020-0091

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

AND IN THE MATTER OF a proceeding to develop an Integrated Resource Planning framework

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Submissions of Environmental Defence

Integrated Resource Planning

March 31, 2021

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Contents

Summary

This proceeding will establish an Integrated Resource Planning ("IRP") framework for Enbridge Gas. IRP has the potential to significantly reduce the costs and risks borne by ratepayers by ensuring a robust assessment of pipe and non-pipe options to address system needs. IRP is particularly important for the protection of customers in these times of decarbonization-driven energy transitions.

Environmental Defence has an important perspective to contribute to this proceeding. We have raised IRP in many OEB proceedings (e.g., the GTA pipeline, DSM mid-term review, London Lines, etc.). In each of these proceedings, the OEB has agreed that Enbridge should do IRP sooner and better. Environmental Defence also contributes its knowledge and expertise regarding decarbonization and how this will impact energy markets.

Environmental Defence has distilled its requests to the OEB down to three primary requests that we believe are absolutely essential. They can be summarized as follows.

(1) Cost-effectiveness comparisons: First, Environmental Defence requests that cost-effectiveness be determined according to the OEB's Total Resource Cost Plus test (TRC+), not the modified EBO 134 test as proposed by Enbridge. The TRC+ test is best suited for this task because:

1. The TRC and its cousin the PAC are used in every other jurisdiction for electric and gas IRP;

2. The TRC is used in New York, the leader in gas IRP;

3. The TRC been used by the OEB for almost 30 years;

4. The TRC is used in Ontario for electric IRP (i.e., non-wires alternatives or NWAs);

5. The TRC is a single test with a single cost-effectiveness threshold, but can be combined with the Program Administrator Cost test ("PAC") and Rate Impact Measure ("RIM") to provide more information about utility and rate impacts; and

6. The TRC can be used immediately and honed through future work.

In contrast, Enbridge's proposed modified EBO 134 test:

1. Is not used in any other gas or electric IRP jurisdiction;

2. Inaccurately undercuts non-pipe solutions by penalizing options that reduce consumption and by ignoring avoided customer gas costs in most stages;

3. Has no one stage that compares all relevant costs and benefits;

4. Primarily measures cross-subsidization between new and existing customers, not cost-effectiveness;

5. Is inconsistent with the tests used for electric IRP in Ontario; and

6. Cannot be used immediately, because details would need to be worked out beforehand.

(2) Decarbonization sensitivity analysis: Second, Environmental Defences asks that Enbridge be directed to conduct demand forecast sensitivity analysis with respect to decarbonization. This is important because:

1. Enbridge plans to assume the continuation of the status quo and a 0% chance of declining gas use in its IRP cost-effectiveness assessment;

2. Decarbonization will likely reduce gas demand through increased prices (RNG, hydrogen, carbon pricing, carbon capture) and through electrification (heat pumps);

3. Traditional infrastructure is highly subject to demand and price risks, whereas non-pipe solutions mitigate these risks and are more cost-effective with lower demand and higher gas prices; and

4. It is risky and inaccurate for Enbridge to assume one future scenario, especially when that is a status quo scenario that is inconsistent with reality.

(3) Oversight over rejections of non-pipe solutions: Third, Environmental Defence requests that decisions to reject non-pipe solutions should be the subject of an interrogatory process, and adjudication in the event of disputes, prior to the facility leave to construct application. This is important because:

1. It will be too late to change course and implement a DSM alternative after a decision is rendered in a facility leave to construct proceeding;

2. Interrogatories are needed to inform stakeholder input and potential challenges of Enbridge's IRP decisions;

3. Interrogatory processes do not absorb OEB resources and are well worth the effort required of Enbridge;

4. Although in theory Enbridge can be penalized at an LTC application for bad IRP decisions, this is difficult to implement in practice and does not give consumers the benefits of the non-pipe solution; and

5. Enbridge's incentives and past actions show that actual oversight is needed through interrogatories and adjudication in the event of disputes, not merely stakeholder consultation.

These are the three most critical adjustments needed to Enbridge's proposal. Although we make a number of secondary requests on page 20 below, the focus of Environmental Defence is on these three items.

Background: previous OEB IRP directions

The Board has directed Enbridge to practice Integrated Resource Planning many times over the past 30 years.[1] These directions date back to the OEB's IRP proceeding in the early 1990s.[2] This summary will focus on the directions provided by the OEB over the last decade. Through these directions, the OEB has repeatedly highlighted the importance of IRP, expressed concerns about the lack of progress by Enbridge in this area, and directed Enbridge to do IRP better and sooner.

In the decision in the GTA pipeline case (EB-2012-0451), the OEB directed Enbridge "to provide a more rigorous examination of demand side alternatives, including rate options, in all gas leave to construct applications."[3] The decision also directed Enbridge to incorporate IRP in its planning in a more systematic way:

> Environmental Defence urged the Board to send a signal to the companies that new supply-side investments will not be approved unless all lower cost DSM and/or interruptible service options have been explored and documented. Other parties agreed and argued that both Enbridge and Union should be required to do a better job…
>
> In light of the evidence presented, the Board concludes that further examination of integrated resource planning for gas utilities is warranted. The evidence in this proceeding demonstrates that the following issues should be examined:
> - The potential for targeted DSM and alternative rate designs to reduce peak demand
> - The role of interruptible loads in system planning
> - Risk assessment in system planning, including project prioritization and option comparison
> - Shareholder incentives.[4]

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

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

[2] EBO 169-III, *Report of the Board on the Demand-Side Management Aspects of Gas Integrated Resource Planning*, July 23, 1993 (link).

[3] Ontario Energy Board, *Decision in EB-2012-0451/0433, January 30, 2014*, p. 46-47 (GTA Pipeline) (link).

[4] *Ibid*.

> As part of all applications for leave to construct future infrastructure projects, the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development.
>
> In order for the gas utilities to fully assess future distribution and transmission system needs, and to appropriately serve their customers in the most reliable and cost-effective manner, the Board is of the view that DSM should be considered when developing both regional and local infrastructure plans. …The Board expects the gas utilities to consider the role of DSM in reducing and/or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative. If a gas utility identifies DSM as a practical alternative to a future infrastructure investment project, it may apply to the Board for incremental funds to administer a specific DSM program in that area where a system constraint has been identified.
>
> The Board is also of the view that the gas utilities should each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the DSM framework. The studies should be based on a consistent methodology to determine the appropriate role that DSM may serve in future system planning efforts. As part of the multi-year DSM plan applications, the gas utilities should include a preliminary scope of the study it plans to conduct and propose a preliminary transition plan that outlines how the gas utility plans to begin to include DSM as part of its future infrastructure planning efforts.[5]

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

> The OEB agrees that a case study, as proposed by Enbridge, would assist in assessing the merits of a transition plan. However, the OEB is concerned that the time required to complete a case study would delay the utilities' infrastructure planning activities proposal and the transition plan would not be available in time for the mid-term review.
>
> The OEB directs Enbridge and Union to work jointly on the preparation of a proposed transition plan that outlines how to include DSM as part of future infrastructure planning activities. The utilities are to follow the outline prepared by Enbridge, and should consider the enhancements suggested by the intervenors and expert witnesses. The transition plan should be filed as part of the mid-term review.[6]

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

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

> Stakeholders indicated reservations in the usefulness of the transition plan provided by the natural gas utilities. The OEB agrees that although the progress made is at an early stage, the transition plan does not advance the understanding of the role and impact that energy conservation can play in deferring or avoiding capital projects. Currently, leave to construct applications do not include a description of the DSM alternatives considered to help avoid and/or defer the proposed capital project. The natural gas utilities should continue to develop rigorous protocols to include DSM as part of their internal capital planning process. This should include a comprehensive evaluation of conservation and energy efficiency considered as an alternative to reduce or defer infrastructure investments as part of all leave to construct applications.[7]

In the 2019 Bathurst Reinforcement decision, the OEB again directed Enbridge "to provide sufficient and timely evidence of how DSM has been considered as an alternative at the preliminary stage of project development."[8] It also warned Enbridge that it "faces the risk that future application will be deemed incomplete."[9]

In the 2021 London Lines decision, the OEB directed Enbridge to do better once again and to conduct an "in-depth quantitative and qualitative analyses of alternatives".[10] In particular, the OEB said:

> However, despite the OEB approval of the application for leave to construct this Project, the OEB agrees with Environmental Defence that Enbridge Gas has an obligation to conduct a more rigorous Integrated Resource Planning assessment at the preliminary stage of projects development in future cases. As OEB staff also notes the failure to present detailed analyses makes it unlikely that Enbridge Gas would select an alternative including DSM or other non-build project option. The OEB acknowledges that more direction is likely to be provided to Enbridge Gas in future leave to construct projects as part of the ongoing IRP proceeding. In the interim, however, the OEB believes that all parties would be assisted if Enbridge Gas would, in the future, undertake in-depth quantitative and qualitative analyses of alternatives that specifically include the impacts of DSM programs on the need for, or project design of facilities for which Enbridge Gas has applied for leave to construct.[11]

These repeated directions from the OEB highlight the importance of IRP, the very slow progress by Enbridge to date, and the need for OEB oversight to ensure Enbridge does IRP better and sooner.

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

Cost-effectiveness test: use the TRC not EBO 134

Issue 6 asks, in part, what methodology should be used to evaluate and compare various pipe and non-pipe alternatives. An appropriate benefit-cost analysis is essential to ensure that costs and risks are minimized for consumers. Environmental Defence submits that the OEB's existing TRC+ should be used. This is the best option for the following reasons:

1. The TRC and its cousin the PAC are used in every other jurisdiction for electric and gas IRP. For example, the TRC is used for IRP in New York, Vermont, Rhode Island, Massachusetts, Oregon, and California.[12] This is important for two reasons. First, the TRC is a best practice and industry standard for IRP. Second, using the same test as other jurisdictions will make it far easier to learn from those jurisdictions.

2. The TRC is used in New York for gas IRP, which is the leader in gas IRP.

3. The TRC been used by the OEB for almost 30 years through demand-side management processes. This is important for three reasons. First, Enbridge, OEB staff, and intervenors are extremely familiar with the test. Second, it is more rational and consistent to use the same test in both contexts. Third, there will be significant regulatory efficiencies from using the same test in both contexts.

4. The TRC is used for electric IRP in Ontario. Under OEB guidelines, electric utilities may apply for investments in conservation and demand management ("CDM") to avoid or defer infrastructure investments.[13] The TRC is the primary cost-effectiveness test mandated in Ontario for these CDM investments.[14] The cost-effectiveness tests for gas and electric IRP should be consistent in Ontario. This will be particularly important for non-pipe solutions that may require co-operation or a joint program with the IESO.

5. The TRC is a single test with a single cost effectiveness threshold. However, Enbridge can be directed to also calculate the Program Administrator Test ("PAC") and the Rate Impact Measure ("RIM") as they do for DSM plan applications. [15] The TRC determines the ultimate cost-effectiveness from the societal perspective, but the Board can have

[12] Energy Futures Group, *Presentation to the OEB*, February 19, 2021, p. 9 (Some of these jurisdictions use a social cost test.) (link).

[13] OEB, *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*, EB-2014-0278, December 19, 2014, p. 4, s. 4.1 (link); OEB, *Filing Requirements For Electricity Distribution Rate Applications, Chapter 5, Consolidated Distribution System Plan*, July 12, 2018, p. 18, s. 5.4.1.1 (link).

[14] IESO, *Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide*, April 1, 2019, p. 8 (link).

[15] OEB, *Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015-2020)*, EB-2014-0134, December 22, 2014, p. 26 ("The natural gas utilities should also use the Program Administrator Cost ("PAC") test as a secondary reference tool to help prioritize programs that deliver the most cost-effective results. The PAC test measures the utility's avoided costs and the costs of DSM programs experienced by the utility system.") (link).

reference to the PAC, which assesses cost-effectiveness from the utility perspective, and the RIM, which assess rate impacts.

6. The TRC can be used immediately and honed through future work. Mr. Neme and Navigant both recommend future work on the specifics of any benefit-cost analysis. However, that could take some time. The TRC+ can be used immediately and then adjusted as needed.

Enbridge argues that the TRC is only meant for non-pipe solutions and is ill-suited for comparing those non-pipe solutions with traditional infrastructure. This argument is completely without merit. The TRC is being used for that exact purpose with respect to gas IRP in New York and with respect to electric IRP throughout the North America.[16] Furthermore, Enbridge has not been able to point to any aspect of the TRC which is inappropriate for IRP.

Although the TRC does not specifically measure utility impacts or rate impacts, that is by design. It is important not to conflate those impacts. Furthermore, although the TRC should be used to compare pipe and non-pipe solutions, we are not proposing that Enbridge be exempt from its existing requirement to meet the EBO 134 test in facility leave to construct applications.

There are many factors in support of the TRC. And none against.

In contrast, Enbridge's proposed modified EBO 134 is totally unsuited for the task of comparing pipe and non-pipe alternatives.

1. No other jurisdictions use anything like EBO 134 for gas or electric IRP. Ontario should not strike out on its own course absent strong reasons to do so. No such reasons are present.

2. Enbridge's proposed modified EBO 134 test inaccurately undercuts non-pipe solutions for two reasons. First, EBO 134 penalizes options that reduce consumption because distribution revenue is considered to be benefit. Generally speaking, it is the largest benefit under stage 1 of that test.[17] All things equal, if a solution results in less consumption (e.g., energy efficiency), it will result in less revenue, and thus fewer benefits according to the stage 1 test.[18]

   Second, Enbridge's proposal ignores avoided customer gas costs in stages 1 and 3 (see

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[16] Energy Futures Group, *Presentation to the OEB*, February 19, 2021, p. 9 (Some of these jurisdictions use a social cost test.) (link).

[17] Hearing Transcript, Vol. 2, March 2, 2021, p. 5 ("MR. ELSON: The main benefit are incremental revenues? MR. SZYMANSKI: It's one of the benefits. I wouldn't label it as main. MR. ELSON: Well, just talk about a facilities project. In a facilities project, that's where the bulk of the value will come from. At least in all the ones that I've ever seen. Is it different from your perspective? MR. SZYMANSKI: Within stage 1; that is correct. MR. ELSON: Thank you. And in essence, the more gas that is sold, the more that customers pay and the greater the benefit in this line? MR. SZYMANSKI: That's correct.") (link).

[18] Although a DSM solution may allow greater fixed charges by increasing the number of customers without increasing overall consumption, this would be offset by the loss of variable charges arising from less consumption.

below).[19] The lion's share of benefits from energy efficiency arise from avoided customer gas costs. Excluding those as Enbridge proposes would undercut this option.

Benefit/Cost	Stage 1	Stage 2	Stage 3
Benefits			
Incremental Revenues	x		
Avoided Utility Infrastructure Costs	x		
Avoided Customer Infrastructure Costs		x	
Avoided Utility Commodity/Fuel Costs	x		
Avoided Customer Commodity/Fuel Costs		x	
Avoided O&M	x		
Avoided GHG Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure	x		
Incremental O&M	x		
Incremental Taxes	x		
Incremental Utility Commodity/Fuel Costs	x		
Incremental Customer Commodity/Fuel Costs		x	
Incremental GHG Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

[20]

3. Enbridge's proposed test has no one stage that compares the relevant costs and benefits. For example, stage 2 includes customer avoided commodity costs but excludes the avoided infrastructure costs or the costs of the non-pipe alternative. This produces a flawed and misleading figure. See the table above for details.

4. EBO 134 was created for other purposes and is not suited for assessing pipe and non-pipe alternatives. Stage 1 is meant to determine whether incremental distribution revenues will pay for an infrastructure investment. Under stage 2, the utility can establish net-benefits if the investment would provide access to lower-cost gas (e.g., by providing more access to the Dawn Hub versus the Empress Hub). Stage 3 looks at non-energy benefits and costs, but is never determinative. These stages all centre on the need to avoid the subsidization of new customers by existing customers, not a comparison between pipe and non-pipe solutions.

5. Enbridge's modified EBO 134 test cannot be used immediately because details would need to be worked out beforehand. Even Enbridge acknowledges that "there is more work to do in order to determine all the appropriate inputs."[21] The makeup of the test has been a moving target throughout this hearing.[22] This is not acceptable. The OEB ordered

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19 Exhibit JT2.2, Page 1.
20 Exhibit JT2.2, Page 1.
21 Enbridge Gas Argument in Chief, Page 29 (link).
22 E.g. Exhibit JT2.2.

> Enbridge to conduct IRP many years ago.[23] There is no reason to wait until this EBO 134 test can be further developed. The TRC+ test can be used immediately.

Finally, we note that Mr. Neme's presentation includes a useful summary explaining the TRC, why the TRC is the best test for this purpose, and describing the flaws in Enbridge's approach. This presentation is attached for ease of reference and the relevant portion can be found at this link.[24]

Assess impacts of decarbonization on gas demand

Enbridge should be directed to consider the potential impacts of decarbonization on gas demand through a sensitivity analysis. Enbridge's planning implicitly assumes a 0% probability of declining gas demand. It also assumes that there will be no additional decarbonization policies. It even disregards the planned increase in carbon pricing to $170/tonne and instead assumes that the carbon price will be $50/tonne until the year 2060.[25]

This is done under the guise of not wanting to speculate or predict the future. However, assuming the continuation of the status quo over the lifespan of a 40-year asset is both speculation and a prediction of the future. This kind of speculation and prediction is highly problematic because decarbonization will certainly impact gas demand, perhaps by a very large degree, and these impacts would in many cases be determinative of a decision between a pipe or non-pipe solution.

Decarbonization will impact gas demand through increased prices and through electrification. No matter what technology wins the day, the impacts will be significant.

RNG and hydrogen will increase prices

Take, for starters, the technologies favoured by Enbridge – renewable natural gas and hydrogen. These decarbonization options are consistent with Enbridge's business model because they can be distributed by pipelines. However, they are very expensive. This has two important impacts on the choice between pipe and non-pipe solutions. First, the benefits of DSM increase as gas prices increase because the avoided costs increase.[26] Second, the benefits of pipeline projects decline as gas prices increase because this causes the demand driving the projects to decline.

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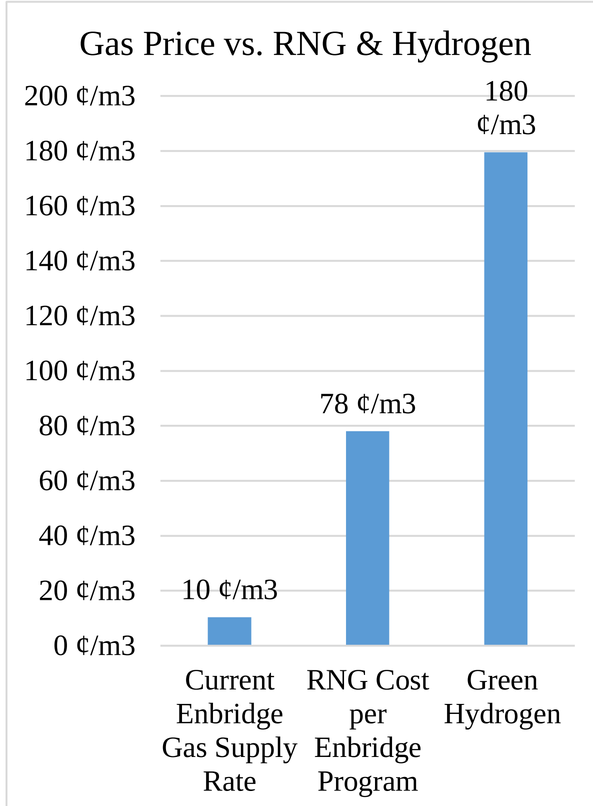
[23] See starting at page 4 above.
[24] Energy Futures Group, *Presentation to the OEB*, February 19, 2021, p. 9 (Some of these jurisdictions use a social cost test.), pp. 9-17 (link).
[25] Hearing Transcript, Vol. 2, March 2, 2021, p. 42 ("MS. GIRIDHAR: I can confirm that until the 170 dollars is legislated, we will continue to use the 50 dollars per tonne. MR. ELSON: So that would be assuming that the carbon price is going to be 50 dollars per tonne until the end of the economic analysis, which for a 40-year asset would be roughly 2060, right? MS. GIRIDHAR: Correct.") (link).
[26] Hearing Transcript, Vol. 2, March 2, 2021, p. 17 ("MR. ELSON: If the price of gas goes up, the benefits of energy efficiency go up, because avoided costs go up, all things being equal, right? MS. GIRIDHAR: Correct.") (link).



As illustrated on the right, RNG and green hydrogen are many times more expensive than fossil gas.[27] Decarbonizing the gas system in whole or in part through these methods will greatly increase prices. Furthermore, the figures to the right significantly underestimate the cost. For example, the RNG cost shown to the right (78 ¢/m3) represents the cost in Enbridge's existing RNG program, which is small and focuses on the most cost-effective RNG.[28] The cost of RNG from animal manure is 87 ¢/m3 to 166 ¢/m3 and the cost from source separated organic waste is 290 ¢/m3.[29] These sources constitute over 70% of Ontario's RNG potential.[30]

The economics of decarbonization through hydrogen are even worse. Hydrogen is a smaller molecule and so will leak from existing infrastructure at higher concentrations. It also burns differently, and so will cause explosions and fires at higher concentrations.[31] Reaching net zero via hydrogen would require replacing all pipes and all consumer equipment. Also, these pipes would need to be significantly larger because a cubic metre of hydrogen has only one-third the energy as a cubic metre of fossil gas.[32] Even the infrastructure required for hydrogen blending at low concentrations is extremely expensive, costing over $4,000 per tonne of avoided CO_2e.[33]

Non-pipe solutions, such as targeted energy efficiency programs, are far more cost-effective if the price of gas they help to avoid is multiple times higher. The difference is stark and obvious. If energy efficiency programs are saving $1.80 per m3 (the cost of green hydrogen) instead of $0.10 per m3 (the cost of fossil gas), their benefits increase 18 times over.

Traditional pipeline infrastructure is far more risky when potential price increases are considered. Price increases reduce demand, especially over the long run. If decarbonization

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[27] OEB, Natural Gas Rates, (link); EB-2020-0066, Exhibit I.STAFF.8, Page 3 (link, PDF p. 22); Exhibit J2.2 (updated); Hearing Transcript, Vol. 2, March 2, 2021, p. 45 (link).
[28] EB-2020-0066, Exhibit I.STAFF.8, Page 3 (link, PDF p. 22).
[29] EB-2020-0066, Exhibit I.STAFF.8 (link), Page 3; Hearing Transcript, Vol. 2, March 2, 2021, pp. 45-46 (link).
[30] *Ibid*.
[31] EB-2019-0294, Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 14 (link, PDF p. 40); EB-2019-0294, Evidence of the Technical Standards and Safety Authority, July 8, 2020 (link).
[32] EB-2019-0294, Exhibit B, Tab 1, Schedule 1, Page 3, link).
[33] Exhibit I.ED.11(b), p. 3 (link, PDF p. 198); Exhibit I.ED.8(g), p. 1-2 (link, PDF p. 196-197).

futures are considered, there are many scenarios that would eliminate the need for pipeline reinforcement projects long before they have been paid for.

Electrification will reduce demand

Decarbonization of the gas system may also be achieved in whole or in part through electrification. This would directly impact gas demand. Even a modest amount of electrification will result in declining gas use that would render gas reinforcement projects unnecessary. Assuming the status quo, which Enbridge proposes to do, ignores this possibility to the detriment of customers.

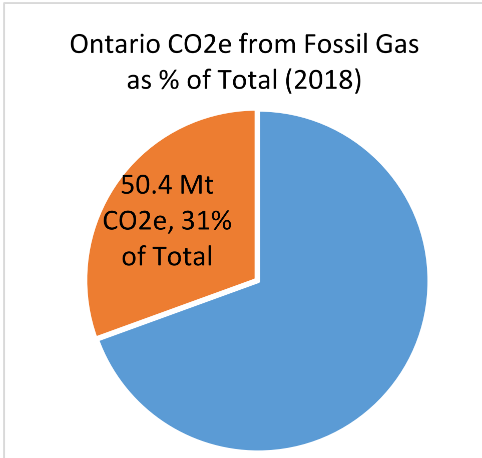
Enbridge's forecast of continually increasing gas demand assumes that there will not be significant fuel switching away from gas to electricity. This appears to hinge on Enbridge's belief that electrification would require unsustainable electricity price increases. But this is not true. First, modest electrification of heating in the range of 10% would cause electricity prices to *decrease*. Because we are a summer peaking jurisdiction, increased winter demand would allow fixed generation, transmission, and distribution costs to be spread over more customers and more kilowatt hours.[34] Electrification would initially result in *lower* electricity unit costs.

Second, even greater amounts of electrification will not necessarily increase electricity costs, let alone do so to the degree that would rule out further electrification. Although electrification will require investments in the electricity sector, these are far lower than what Enbridge supposes.[35] Furthermore, additional electricity investments need not mean higher unit prices because costs will be spread over greater consumption.[36] The impact on unit prices would depend on the difference between the long-term marginal cost of new electricity infrastructure relative to current average rates.[37] It is quite likely that any change in unit rates would be modest.

We are not asking Enbridge to assume one decarbonization future or another. It is Enbridge that is making predictions about the future and betting ratepayer funds on that prediction. For example, Enbridge's demand forecast assigns a 0% probability to declines in gas use due to electrification. Environmental Defence is merely asking that Enbridge not be allowed to make this bet with ratepayer funds, and instead be required to conduct a sensitivity analysis to consider other possible futures and how they impact its decision-making.

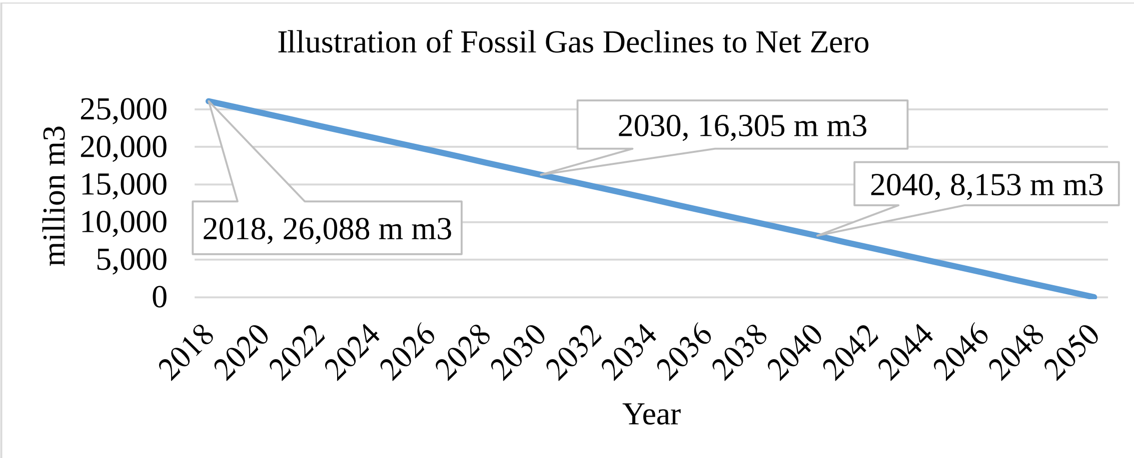
Status quo is not a reasonable assumption

Finally, we note that the GHG emissions from fossil gas are far too large for Enbridge to assume that the status quo will continue. In Ontario, GHG emissions from the consumption of fossil gas constitute over 30% of the province's entire emissions (see right).



[34] Hearing Transcript, Vol. 4, March 4, 2021, p. 98 (link).
[35] Hearing Transcript, Vol. 4, March 4, 2021, pp. 95-97 (link).
[36] Hearing Transcript, Vol. 4, March 4, 2021, p. 99 (link).
[37] *Ibid*.

The two figures below illustrate the conflict between Enbridge's demand forecast and the need to achieve net zero emissions by 2050. The first figure shows a decline from current consumption levels of fossil gas to net zero. Although this is shown in a linear fashion, this is merely an illustration of the declines needed over the next 30 year, not a prediction of our trajectory. The second figure shows the latest demand forecast from Enbridge's gas supply plan.



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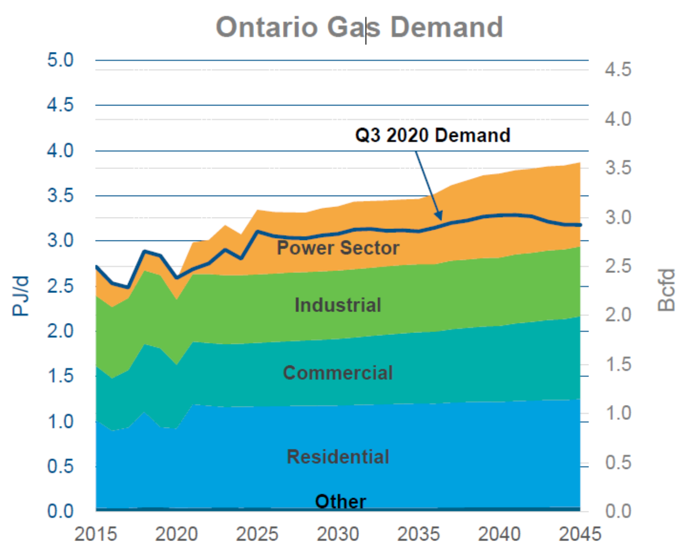

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There is an obvious disconnect between Enbridge's gas supply forecast and net zero by 2050. Although we cannot rule out the possibility that gas use is somehow able to continue expanding up until 2050, we also cannot rule out the possibility that it declines as a result of decarbonization measures, which could be a modest decline or a steep decline.

[38] Ontario Energy Board, *Yearbook of Natural Gas Distributors*, 2018 (total gas volumes = 26,088 million m3) (link, PDF p. 2)
[39] EB-2021-0004, 2021 Annual Gas Supply Plan Update, Enbridge Gas Inc., February 1, 2021, p. 13 (link).

If Enbridge is asking for billions of ratepayer dollars to expand and replace portions of the gas system to meet increasing demand, it needs to grapple with the possibility of declining demand and increased prices. Assuming the status quo is a prediction and is one that is exceedingly unlikely. Enbridge is free to make that bet with its own capital but should not be allowed to do so with ratepayer funds.

Stranded assets are a real risk

The above sections deal primarily with importance of accounting for the possibility of flat or declining gas use in comparing pipe and non-pipe solutions. But there is also the serious possibility of much more significant declines causing a self-reinforcing spiral of stranded assets. It would not be hard to reach a tipping point at which fossil gas is no longer the most cost-effective option for heating homes and businesses. We should consider and prepare for that possibility. If it comes to pass, ratepayers would be much better off if they invested in non-pipe solutions that provide benefits no matter what the fuel source (e.g., home retrofits). In contrast, investments in pipes will need to be written off.

Stated somewhat differently, non-pipe solutions are a form of hedge against the possibility of stranded assets. There are already huge investments in gas pipelines. Diversifying those with investments in efficiency that will still be useful across fuel types is good for customers.

We are not putting forward a prediction that Ontario’s gas pipelines will become stranded assets. It is Enbridge that is making the predictions. It is assuming that this risk is so low that it can be disregarded when assessing the cost-effectiveness of pipe versus non-pipe solutions. That is not an assumption they can make.

Take, for example, the possibility of a tipping point between electric heat pumps and fossil gas furnaces. Enbridge acknowledged that air source heat pumps already have lower annual operating costs in some areas where there is a 23-cent gas expansion surcharge.[40] And that assessment was made without regard to the increases in carbon pricing up to $170 per tonne. It was also made without regard to the latest electric heat pumps on the market, which can achieve over 200% efficiency (i.e., a coefficient of performance of over 2), even at negative 21 degrees Celsius.[41] If heating equipment is replaced every 10 or 15 years, a switch away from fossil gas can happen relatively quickly once that tipping point is reached.

Enbridge is banking on decarbonization technologies that require pipelines. However, they cannot say with any certainty that those technologies will be adopted in whole or to any significant degree. The following comparison of decarbonization options, made entirely with Enbridge and OEB figures, suggests that decarbonization will involve significant declines in gas use through efficiency and electrification.

[40] Exhibit J2.6.
[41] Hearing Transcript, Vol. 4, March 4, 2021, p. 97 (link).

Comparison of Ontario Fossil Gas Decarbonization Options		
	Cost-effectiveness ($/tCO$_2$e, combustion only)	**Decarbonization potential** (% of Ontario gas demand)
Cost-effective energy efficiency	$0 to -$140 (i.e. savings)[42]	25%[43]
Heat pumps	$130 to $200[44] (commodity & capital cost)	Near 100%[45]
RNG	$338[46]	2.5%[47]
Hydrogen	>$900 (commodity cost) + ~$4,000 (capital cost) [48]	6%[49]

Decarbonization sensitivity analysis details

Again, Environmental Defence is not asking that Enbridge predict one future over the other. It is simply requesting that Enbridge be required to consider the impacts of decarbonization on demand and price forecasts. This can easily be done through the kind of sensitivity analysis outlined by Mr. Neme.[50] It would be as simple as running the TRC calculations based on two

[42] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 14 (link); Per Exhibit JT1.7 in EB-2020-0066 (link, PDF p. 398), if upstream emissions are accounted for, the cost is $0 to -$108/tCO2e.

[43] Navigant, *2019 Integrated Ontario Electricity and Natural Gas Achievable Potential Study*, prepared for the IESO and OEB, December 18, 2019, p. ix (link).

[44] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. A-4 to A-5 14 (link) (heat pumps are $130/tCO$_2$e for new homes and $200/tCO$_2$e for existing homes according to this study, but prices are declining significantly as cold climate heat pumps become more commonplace); Per Exhibit JT1.7 in EB-2020-0066 (link), if upstream emissions are accounted for, the cost is $101 to $155/tCO2e.

[45] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 25 (link).

[46] EB-2020-0066, Exhibit I.SEC.15 (link); Per Exhibit JT1.7 in EB-2020-0066 (link, PDF p. 398), if upstream emissions are accounted for, the cost is $262/tCO2e.

[47] EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. 47 (link); This report estimates a potential of 627 million m^3/yr, which is 2.41% of Ontario's consumption of 26 billion m^3/yr. This potential was considered achievable by 2028 based on a study conducted in 2013. In Exhibit JT1.5 (link), Enbridge estimates the potential as 402 million m^3/yr by 2025, which is 1.55% of Ontario's gas consumption of 26 billion m^3/yr.

[48] Exhibit I.ED.11(a)&(b), p. 2-3 (link, PDF p. 197-198); Per Exhibit JT1.7 in EB-2020-0066 (link, PDF p. 398), if upstream emissions are accounted for, the cost is over $700/tCO2e for commodity costs and over $3,000 for capital costs.

[49] Enbridge is proposing to blend 2% hydrogen by volume. Because hydrogen is less energy dense, this amounts to 0.6% by energy content. See Exhibit I.ED.12, p 14-15 (h)&(i), link, PDF p. 15-16. No studies are testing blending beyond 20% by volume (per Exhibit I.ED.7, link, PDF p. 177), which equates to 6% by energy content.

[50] Energy Futures Group, *Presentation to the OEB*, February 19, 2021, p. 21 (link).

additional scenarios. Doing so would provide raw outcomes that could inform Enbridge and OEB decisions. Illustrative probabilities could be assigned to the scenarios to develop a single cost-benefit figure. Also, an inflection point could be calculated to determine the scenario probability at which the IRPA becomes more cost-effective.[51]

Enbridge may argue that this will require too much work. However, Mr. Neme confirms that this kind of analysis is “not onerous.”[52] The scenarios, analysis, and calculations would be similar in most cases. Also, good planning is clearly worthwhile. The cost of the staff hours required to conduct a sensitivity analysis are dwarfed many times over by the sums at issue with IRP and by the risks that this analysis can help to protect against.

In many ways, we are simply asking that Enbridge be directed to conduct an accurate cost-benefit analysis. It is not appropriate to assume that decarbonization efforts will remain the same as the status quo up to 2060 and to assign a 0% probability to declining gas use. Doing so over all of Enbridge’s projects exposes its customers to major financial risks.

This is a *financial* issue, not environmental activism. The financial risks associated with continued investments in fossil fuels are widely acknowledged by financial leaders. For example, Mark Carney recently warned that global warming could render the assets of many financial companies worthless because they have been too slow to cut investment in fossil fuels.[53] Future decarbonization scenarios need to be taken into account to ensure Enbridge is putting in place appropriate measures to protect consumers and to keep energy costs as low as possible.

Oversee decisions to reject non-pipe solutions

Environmental Defence’s third major request is that the decision to reject non-pipe solutions be subject to an interrogatory process, and adjudication in the event of disputes, prior to the leave to construct application for the traditional infrastructure project. Although Enbridge does not believe this oversight is necessary, it stated that the most appropriate mechanism would be to include these issues within the scope of its annual rates cases.[54] Environmental Defence is agnostic to the specific mechanism. Oversight of these decisions every one, two, or three years would be sufficient, whether as part of the annual rates cases or otherwise.

Interrogatories are low burden but high value

Environmental Defence is requesting both an interrogatory process and an opportunity for adjudication in the event of disputes. We will address the need for an interrogatory process first. An interrogatory process is a very low burden but high value aspect of any oversight mechanism.

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[51] *Ibid.*
[52] *Ibid*.
[53] Financial Post, *Global warming could render the assets of many financial companies worthless, Mark Carney warns*, December 30, 2019, (link).
[54] Exhibit J1.3.

Enbridge is proposing a number of "meetings" and the posing of "questions." However, under Enbridge's proposal the utility would not be required to answer relevant questions as it would in an interrogatory process.[55] There is a world of difference between a process involving questions that Enbridge *may* voluntarily answer in comparison to an interrogatory process where Enbridge *must* answer relevant interrogatories.

An interrogatory process is essential for stakeholder input. If stakeholders are going to provide recommendations to Enbridge regarding non-pipe solutions, they need to have access to the information necessary to do so. Furthermore, an interrogatory process is essential for stakeholders to decide whether they will seek adjudication of Enbridge's decisions to reject non-pipe solutions for a specific project.

LTC hearings are too late

Adjudication of decisions to reject non-pipe solutions is essential because it will generally be too late to adopt non-pipe solutions at the conclusion of a facility leave to construct application.[56] In all previous leave to construct hearings where the OEB has directed Enbridge to do better with respect to IRP it has been too late to fully consider and implement non-pipe alternatives.[57] As OEB staff noted in their presentation for this proceeding, "[l]ack of adequate lead time to meet system need has been persistent stumbling block to IRPA consideration in LTC applications."[58] This arises in part because many non-pipe solutions require a longer lead time. Even those that do not require additional lead time may be impossible to implement simply because the utility has only completed the planning for the facility option without creating a backup plan for a non-pipe solution.

Leaving the adjudication of IRP decisions to the leave to construct proceeding will have the effect of denying the OEB the opportunity to do anything but approve the facility option. Although Enbridge can be penalized, that does not remedy the negative impact on rates and consumers from the lost opportunity to implement a more cost-effective and less-risky option.

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[55] Technical Conference Transcript, February 10, 2021, p. 76 ("MR. ELSON: I think you were not talking about a formal interrogatory process where you're required to answer any relevant questions; am I correct? MR. STEIRS: We are not talking about formal interrogatory process. MR. ELSON: Okay. And there isn't a mechanism to require Enbridge to answer questions, it is a more informal process where you will make best efforts? MR. STEIRS: The Board's review of our ultimate proposal, whether that be a facility or a non-facility project, would be the formal time.") (link).

[56] Hearing Transcript, Vol. 2, March 2, 2021, p. 91 ("MR. STIERS: I think that the concept that the leave to construct may need to occur as close to the identified need being realized and that that might limit the time available to consider broader alternatives, including IRPAs…") (link).

[57] Ontario Energy Board, *Decision in EB-2012-0451/0433, January 30, 2014*, p. 46-47 (GTA Pipeline) (link); Ontario Energy Board, *DSM Framework,* December 22, 2014, p. 35-36 (link); EB-2018-0097, Decision and Order, January 3, 2019, pp. 6-7 (Bathurst Reinforcement) (link); EB-2020-0192 (London Lines), OEB Decision and Order, January 28, 2021, p. 20 (link).

[58] Board Staff Presentation, February 19, 2021 (link).

Enbridge incentives and actions show the need for oversight

Enbridge argues that its stakeholder meeting model will be sufficient to ensure that non-pipe alternatives are selected where they are the optimal solution. However, experience suggests otherwise. Mr. Neme has participated in many IRP processes in the past. In his view, Enbridge's model "will not come close to the level of detail and discussion" necessary to appropriately address Enbridge's IRP decisions.[59]

Furthermore, Enbridge has a number of incentives to favour traditional pipeline-based solutions. These incentives will only be partially addressed by allowing rate basing of IRP expenses. For example, this will not address Enbridge's significant upstream interests. Nor will it overcome the institutional inertia and individual tendency to continue doing what Enbridge's core business always has been – building pipelines.

Enbridge's track record on IRP also shows the need for oversight. As noted from page 5 to 8 above, the OEB has had to repeatedly direct Enbridge to conduct IRP both for individual projects and in its overall planning.

Finally, the risk of a penalty is insufficient motivation. In most cases, the facility option will be the only one left for the OEB to approve. This leaves the OEB in a difficult position. It will be very challenging for the OEB to require that Enbridge follow-through with the facility option without allowing a return for this investment.

Procedural options

When asked to comment on pre-LTC procedures to adjudicate the appropriateness of decisions to decide against non-pipe alternatives, Enbridge stated as follows:

> [i]f the Board were to ultimately determine that some form of adjudicative process was appropriate to establish as part of an IRP Framework then the Company believes that, because its annual updates to the Asset Management Plan are proposed to be filed as part of its annual rates setting proceedings, it would be most appropriate for the Board to expand the scope of those annual rate setting proceedings to include a third phase (Phase 3) dedicated specifically to IRP related adjudication. To ensure that it maintains regulatory efficiency, the Board should limit the expanded scope of Phase 3 to those IRP decisions not to pursue investment in IRPA(s) raised by intervenors that cannot be resolved through the Company's proposed stakeholder engagement process (Component 2). The Board should ensure that the scope established for Phase 3 adjudication does not allow re-hearing of the elements of the IRP Framework previously decided upon by the Board.[60]

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[59] Presentation Day Transcript, February 19, 2021, p. 64 (link).
[60] Undertaking J1.3

Environmental Defence agrees that this would be an appropriate process, including with the restrictions noted by Enbridge above. However, the same outcome could be achieved through other mechanisms. For example, the OEB could restrict the adjudication of IRP disputes to every other year or address these issues in separate IRP hearings.

Secondary Requests

In addition to the three primary requests highlighted above, Environmental Defence also makes the following secondary requests.

Adopt detailed recommendations by the Energy Futures Group

Environmental Defence asks that the OEB adopt all of the detailed recommendations made by the Energy Futures Group.[61] We have not reiterated all of those recommendations here as they are described and justified in detail in Mr. Neme's evidence.

Binary pre-screening: don't exclude subdivisions and small main extensions

Enbridge proposes five "binary pre-screening" criteria. These criteria have evolved over time. Environmental Defence requests that the third criterion, "customer-specific builds," be narrowed to ensure that it does not screen out non-pipe alternatives for new subdivisions and small main extensions. Enbridge describes this criterion as follows:

> If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear determination for a facility option and either the choice to pay a Contribution in Aid of Construction ("CIAC"), or to contract for long-term firm services delivered by such facilities (**including new subdivision or small main extensions**) then it is not appropriate to conduct IRP analysis for those projects.[62]

The reference to "including new subdivision or small main extensions" is concerning. These are highly cost-effective opportunities for energy efficiency and fuel switching because they involve new construction. Where a project will serve a larger area, the most cost-effective non-pipe solutions may involve targeting these customers for DSM. Environmental Defence asks that Enbridge address this in its reply and confirm that it will not be excluding including new subdivision and small main extensions from consideration of non-pipe solutions, failing which Environmental Defence requests directions from the OEB.

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[61] Energy Futures Group, *Best Practices for Gas IRP and Consideration of "non-Pipe" Alternatives to Traditional Infrastructure Investments*, November 23, 2020 (link).
[62] Exhibit J1.4, p. 2.

Implement like-for-like treatment of risk and incentive

Environmental Defence strongly supports Enbridge's proposal of "like-for-like" treatment of risk and incentives for pipe and non-pipe solutions. This would mean that non-pipe solutions would be included in rate base and Enbridge would earn a return on them. This is essential to at least partially address the disincentives against non-pipe solutions that Enbridge faces. Although adjustments may be necessary to ensure appropriate incentives where non-pipe solutions are significantly less expensive, that can be addressed on a case-by-case basis.

The same is true for risk. Enbridge should not bear more risk for non-pipeline solutions than it does for traditional infrastructure projects.

Allow a wide range of activities

Environmental Defence strongly supports Enbridge's proposal to include a wide range of activities in the IRP framework, including electric heat pumps. This would be consistent with past OEB guidelines and decisions. In short, fuel switching (i.e., electrification) has always been an element of demand-side management as defined by the OEB.[63] It would be contrary to this past guidance to carve fuel switching out of the IRP framework.

Furthermore, Enbridge has provided two important caveats that will protect consumers. First, Enbridge has stated that it will not look to directly offer non-pipe solutions unless there is "no current competitive market."[64] Second, Enbridge has clearly stated that is not seeking any kind of "pre-approval" for any particular IRPA.[65] The specifics of any IRPA will be fully tested in the course of a future IRP application.

Conclusion

IRP has the potential to significantly reduce the costs and risks borne by ratepayers. This has always been important, but is particularly pertinent today because of the energy transitions that are occurring due to decarbonization. IRP is a tool that can lower costs while also diversifying away from traditional pipeline investments that may or may not be used and useful in the future. Energy efficiency is a particularly safe bet.

However, the full potential for IRP can only be realized if a reasonable cost-effectiveness test is used such as the TRC, the potential impacts of decarbonization on demand forecasts are accounted for, and Enbridge's decisions to reject non-pipe solutions are subject to interrogatories and adjudication, in the event of a dispute, early enough to actually affect the outcome. With

[63] E.g. EB-2008-0346, OEB, *Demand Side Management Guidelines for Natural Gas Utilities,* June 30, 2011 p. 4 ("The natural gas utilities may pursue DSM activities that support fuel-switching away from natural gas…") (link); EB-2016-0359, ICF, *Marginal Abatement Cost Curve*, July 20, 2017, prepared for the OEB, p. A-4 to A-5 14 (link).
[64] Enbridge Gas Argument in Chief, Page 20 (link).
[65] Enbridge Gas Argument in Chief, Page 21 (link).

these elements, Ontario could finally realize the kind of early and robust IRP that the OEB has been pursuing for decades.

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Ontario Gas IRP Framework Recommendations

PRESENTATION TO THE ONTARIO ENERGY BOARD IN EB-2020-0091

Chris Neme

February 19, 2021

Energy Futures Group

Vermont-based distributed energy consulting firm established in 2010

Areas of Expertise

Energy efficiency, demand response & renewable energy:

- Technology assessment
- Market assessment
- Program design
- Integrated resource planning
- Cost-effectiveness analysis
- Policy development
- Building codes
- Evaluation

Range of Clients

- Governments
- Advocates
- Regulators
- Utilities

EFG Net Zero Office Building

Clients in 7 Canadian provinces, 40 U.S. states, several European countries, and China.

Presentation Outline

- Planning Process/Timeline
- Economic Analysis
- Uncertainty and Risk
- Pilots
- Shareholder Incentives

Planning Process & Timeline

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Key Decision Points

1. Identification of system needs
   - 10 years into the future
   - Macro-level forecast assumptions (economic growth, carbon prices, DSM impacts, etc.)
   - Approach to localized peak assessments
2. “Pre-screening” of IRPA applicability
   - E.g., qualitative criteria, such as whether need is load related or emergent safety issue
3. Determination of optimal solution (non-pipe, pipe or mix)
   - Is there enough potential IRPA capacity to meet/defer need?
   - Is the IRPA likely to be cost-effective (relative to infrastructure option)?
   - How do risks of pipe and non-pipe solutions compare?
4. Development of IRPA plan and/or infrastructure proposal
   - What resources are included?
   - How will they be acquired?

Recommendation – Need Two Things:

1. Robust *formal* stakeholder process – addressing all 4 decision "steps"
   - Why: improves decision-making, minimizes disputes and regulatory costs
   - How: formal committee structure similar to Vermont System Planning Committee
     - Could be run by OEB Staff (akin to current Ontario gas DSM Evaluation Committee)
     - Appointed members to represent range of stakeholders and expertise
     - Quarterly full committee meetings, various subcommittees as needed
       - Transparent/Public so that anyone who wants to attend can do so
2. Regulatory process(es) – *timely* adjudication of all decisions to pursue/reject IRPAs
   - Why: there will otherwise be (A) bias toward pipe-based solutions; (B) not enough time to change
   - How: require formal approval of Asset Management Plan (AMP)
     - 10-year forecast of needs
     - All key decisions/analyses need to be documented in AMP
     - Needs to allow for discovery on AMP
     - Board adjudication of all decisions to proceed with or reject IRPAs reflected in AMP
       - Pre-screening of IRPAs in Asset Management Plan (AMP)
       - Assessment of viability & economics of IRPAs in AMP
     - Note: specifics of IRPA or infrastructure plan addressed in LTC, IRPA Plan

To extent needed if not resolved via consensus in stakeholder process and/or if Board has concerns

Problems w/Enbridge Proposal

- 1-day stakeholder meeting per year
  - Enbridge suggests this where most questions can be posed and answered
  - Woefully inadequate to consider all key decisions points for all parts of system
- Conclusions documented in Asset Management Plan, but…
  - No formal interrogatory process on IRPA decisions
  - No adjudication of IRPA decisions
- No adjudication until LTC, IRPA proposal, or rate-basing (for <$10M)
  - Often too late to consider and implement non-pipe solutions…
  - …so Board will often be left with no real choice

Economic Analysis

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Recommendation (1)

- Adopt TRC+ test as *initial* primary cost-effectiveness test
  - Provides a comprehensive view of cost-effectiveness
  - Consistent with OEB DSM Framework
  - North American best practice for NPAs/NWAs
    - Consistent with guidance from National Standard Practice Manual (NSPM) for DERs
    - NY, VT, RI, MA, CA, OR all use TRC or SCT
    - MI, ME use UCT
    - No jurisdiction uses anything like Enbridge's proposed DCF+
- Consider requiring secondary analyses to add perspective
  - UCT test
  - Rate impact assessment (see NSPM for DERs, Appendix A)

Several other jurisdictions have done exactly this: e.g., NY, VT, CA

Total Resource Cost (TRC) – Definition and How it Works

- Combined perspective of gas utility system + IRPA program participants
- Ontario has used it for almost 30 years (DSM)
- Use of the TRC to analyze IRPAs:
  1. Sum the NPV of all benefits, including the avoided cost of the pipeline option
  2. Sum the NPV of all costs born by the utility and program participants
  3. If the benefit-cost ratio is ≥ 1, the IRPA is more cost effective than the pipeline
  4. The net of the NPV figures is the savings/cost of the IRPA vs. the pipe solution
- TRC application to IRPAs is same as for DSM, with one exception:
  - uses specific avoided cost of the pipeline option for IRPA
  - uses system-wide average (generic) avoided T&D costs for DSM

Recommendation (2)

- Initiate Board process to assess test refinements per NSPM principles
  - Address utility system impacts not currently captured in Ontario TRC+
  - Identify impacts to add to utility system impacts – based on energy policy goals
  - Assess through stakeholder process
  - Similar to Guidehouse's recommendation
- This should be done *after* initial IRP framework is put in place
  - Do not need to hold everything else up
  - Revise framework if selected test is different than TRC+

Options for Cost-Effectiveness Tests

	UCT	TRC	SCT	Possible Future Ontario Test
Benefits				
Avoided infrastructure costs	X	X	X	X
Avoided gas commodity/fuel costs	X	X	X	X
Avoided O&M costs	X	X	X	X
Avoided carbon taxes	X	X	X	X
Other gas utility system impacts	X	X	X	X
Other (non-Gas) Fuel Savings		X	X	?
Customer non-Energy Benefits		X	X	?
Other Societal Benefits			X	none, partial or all
Costs				
Reduction in Revenue				
Utility IRPA costs	X	X	X	X
Increased gas commodity/fuel costs	X	X	X	X
Increased O&M costs	X	X	X	X
Increased carbon taxes	X	X	X	X
Increase in other (non-gas) fuel costs		X	X	?
Increased customer costs		X	X	?
Other Societal costs			X	none, partial or all

Per National Standard Practice Manual (NSPM) Core Principles:

1. All gas system impacts must be included
2. Policy goals should dictate what other impacts should be included (identified through proposed stakeholder process)
3. Revenue impacts are neither costs nor benefits and therefore are not relevant to cost-effectiveness analyses

Refinements to Capture Other Utility System Impacts

- TRC – and all other tests – should include all utility system impacts
- Historic Ontario application of TRC+ has excluded some utility system impacts
  - E.g., gas price suppression effects, option value, & hedge value
- All of these should be accounted for because:
  - Ignoring these factors assigns a value of $0 to them, which is incorrect
  - Leading jurisdictions account for these and/or are currently examining them
  - They meet the OEB's definition of TRC[1]
  - The OEB has said demand reduction impact on gas prices should be addressed in the future[2]
- Values can be estimated and/or derived from other jurisdictions

[1] OEB, DSM Framework, December 22, 2014 (EB-2014-0134), p. 32: "The TRC test measures the energy related benefits and costs of DSM programs experienced by both the gas utility system and program participant."
[2] OEB, *Decision and Order on Applications for Approval of the 2015-2020 DSM Plans*, EB-2015-0029/0049, January 20, 2016, p. 87.

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Enbridge Proposed Discounted Cash Flow + “test”

Benefit/Cost	Stage 1	Stage 2	Stage 3
Benefits			
Incremental Revenues	x		
Avoided Infrastructure Costs	x	x	
Avoided Commodity/Fuel Costs	x	x	
Avoided O&M	x		
Avoided GHG Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure	x		
Incremental O&M	x		
Incremental Taxes	x		
Incremental Commodity/Fuel Costs	x	x	
Incremental GHG Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

Notes:

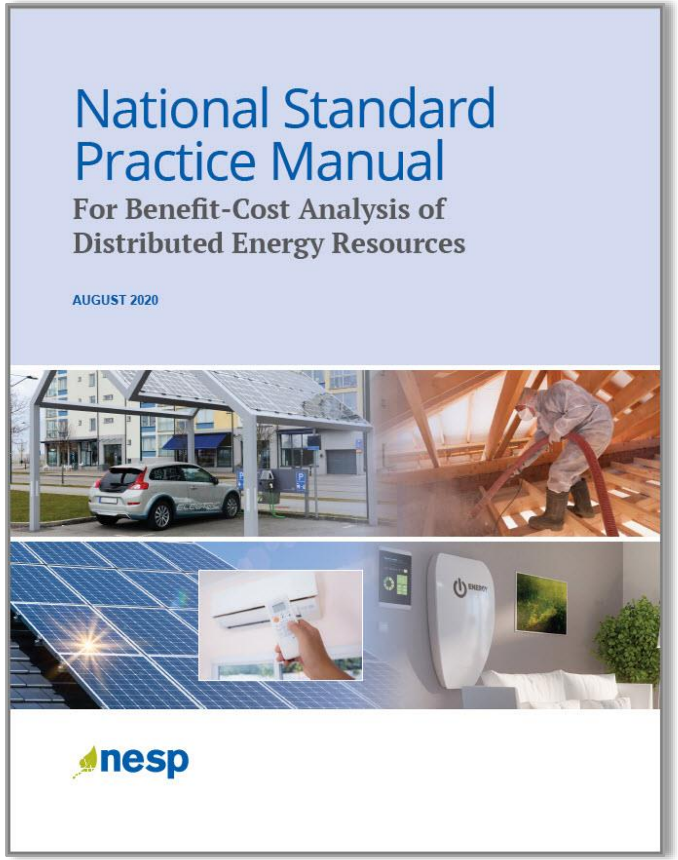
1. Table from Enbridge response to Staff.20
2. Enbridge appears to suggest that both infrastructure option and IRPA option would be analyzed relative to a hypothetical “do nothing” baseline
3. Avoided infrastructure costs and avoided commodity costs in Stage 1 are only portions of such costs associated with utility gas use (customer portions captured in Stage 2) – per Enbridge Tech Conference responses
4. Not clear how other fuel impacts – e.g., electrification of gas use – would be captured. Presumably in Stage 2, but at customer cost or actual cost to electric grid (i.e., electric avoided costs).
5. GHG emissions refers to carbon taxes (per Enbridge Tech Conference responses)

Enbridge Proposed DCF+ Test is Fundamentally Flawed

- It doesn’t answer the core question of what is “least cost”
  - No single stage provides a holistic view of cost-effectiveness
  - Mathematical sum of 3 stages has no economic meaning
    - mixes “apples” (cost-effectiveness factors) with “oranges” (rate impact factors)
    - Enbridge’s claim that its test provides same info as ConEd (NY) test framework is incorrect
      - The sum of the three stages ≠ Societal Cost Test (or TRC)
- The test is inconsistent with the TRC+ test Ontario uses for DSM
  - It is economically irrational to use different tests for different purposes
- EBO 134 designed to ensure existing customers don’t subsidize new customers
  - This has little to do with a comparison of pipe vs. non-pipe alternatives
- *Differs from all other jurisdictions pursuing non-pipe or non-wire solutions*

Cost-Effectiveness vs. Rate Impacts

- Regulatory starting point should be goal of minimizing costs
  - Requires analysis that tells us what it is "least cost"
- Reasonable to consider rate impacts & equity
  - But should be a *secondary* consideration (vs. "least cost")
  - And requires separate analysis



Principle #8: "Cost-effectiveness analyses answer fundamentally different questions than rate impact analyses. Cost-effectiveness analyses should therefore be conducted separately from rate impact analyses." (*NSPM for DERs,* p. 2-3)

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Addressing Equity Concerns

- Rate impacts and equity should be considered in context
  - Not narrowly focused on one project, but across all utility investments and over time
  - Recognize utility investments routinely have inequities
    - Customers whose peak demands are flat or declining still pay for capacity upgrades
- Consider trade offs between lower costs and any equity concerns
  - How many customers benefit (over time)
  - How many customers do not benefit (over time)
  - How much higher total cost is acceptable to achieve greater equity
- Consider range of options to address equity
  - More holistic DSM programs – everyone has option to participate
  - Promoting broader participation by customers – more participation
  - Rate design

Not just in NPS Framework, but across all areas of regulation

Risk

Recommendations on Risk

1. Require sensitivity analyses of climate policy scenarios
   - How does need change?
   - How does value of IRPA benefits change?
   - How does cost-effectiveness change?
2. Require analysis of other economic risks
   - Quantify economic risk mitigation benefits of IRPAs – for future inclusion in TRC
3. Support reasonable planning conservatisms to address reliability risk
   - including starting IRPA investments early
4. Consider amortizing investments over no more than 20 years
   - To reduce risk of stranded assets
   - Note: most IRPAs will have useful lives of 20 years or less anyway

Why Sensitivity Analyses of Climate Policy Risk?

- Economy needs to be largely decarbonized by 2050
  - Canada committed to net-zero emissions of greenhouse gases
- Options for decarbonizing gas industry
  - Electrification – heat pumps now viable in very cold climates – and continually improving
  - RNG – but expensive and availability limited (could displace only small/modest fraction of current gas use)
  - Hydrogen – but expensive and no evidence of ability to replace more than 6% of natural gas use[1]
  - Sequestration – serious questions about viability
- Impacts on gas industry could be huge
  - Just carbon tax increase to $170/tonne would more than triple commodity costs (adding $0.33/m3)
  - Other policies could have even bigger impact
- No longer credible to assume no risk in pipe investments
  - Very real possibility that they will be underutilized or stranded over next 50 years
- Not a question of making an uncertain assumption about "policy"
  - Assuming no risk and/or no cost is still making an assumption (*zero is a number!*)
  - Enbridge already making assumptions (e.g., $50/tonne carbon tax post-2022)

[1] No studies have tested blending beyond 20% by volume (per EB-2019-0294, Exhibit I.ED.7, link, PDF p. 177), which equates to ~6% by energy content. Enbridge is piloting 2% by volume (less than 1% by energy content).

Sensitivity Analysis – How It Works

- Calculate the TRC ratio and net cost/benefit for 3 scenarios
  - Business as usual
  - Moderate climate impacts (e.g., gas cost increases due to RNG mandate, etc.)
  - Significant climate impacts (e.g., electrification “tipping point” reached)
- Uses:
  - Raw outcomes can inform decisions
  - Probabilities can be assigned to the scenarios to develop a single cost-benefit figure
  - An inflection point can be calculated to determine the probability at which the IRPA becomes more cost-effective (if it is cost-effective for scenario 2 and 3 but not 1)
- Not onerous – calculations would be similar in most cases

Two Flavors of Risk

- Reliability Risk
  - Peak demand forecast uncertainty: under-estimation leads to reliability concern
  - IRPA performance uncertainty: under-performance leads to reliability concern
- Economic Risk
  - Peak demand forecast uncertainty: over-estimation leads to unnecessary investment
  - Gas market price uncertainty: prices can affect economics of investment choices
  - Investment cost uncertainty: costs can affect economics of investment choices
  - Environmental regulation uncertainty: can affect future gas prices, demand & need
  - Stranded asset risk: potential for assets to not be used/useful over 50-year recovery

Need to consider and address both types of risk in planning and analysis of IRPAs

Options for Addressing IRPA *Reliability* Risk

- Base forecast of need on extreme weather
  - Enbridge already doing this
- Apply "adder" to assumed IRPA resource need
  - ICF: size DSM at 116% to 121% of need to be 95% to 98% certain it will be met
  - Could be calibrated down during course of IRPA projects based on actual results
- Start investment in IRPA early
  - Leaving time to change strategy or even "pull the plug" if not working
  - May not add cost if IRPA has other benefits (e.g., avoided energy cost, carbon taxes)

Many IRPA Options Reduce *Economic* Risk

- More modular nature "buys time" to calibrate needs forecast

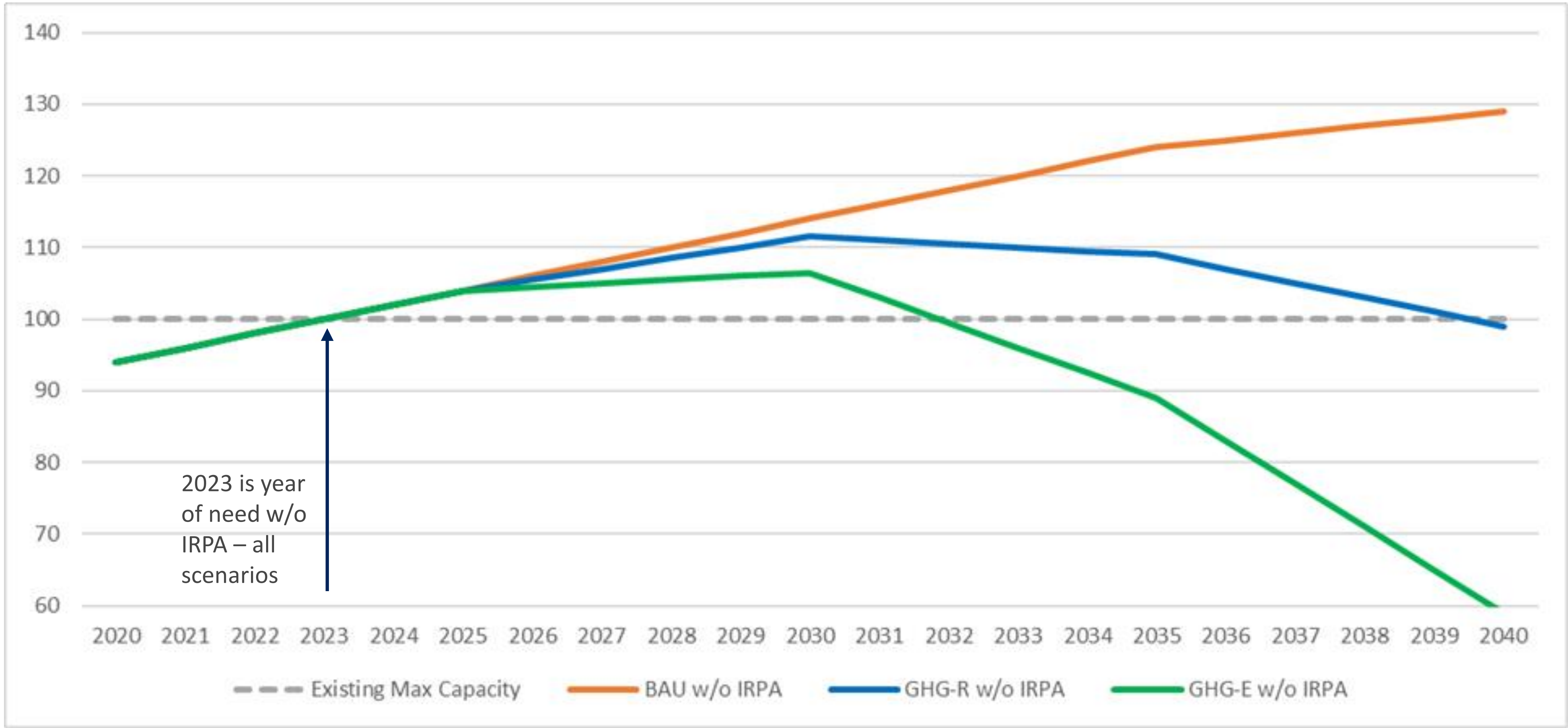
  "…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."

  (ConEd 2010, regarding non-wires solutions projects)

  - This should be reflected in refinements Ontario application of TRC+ test ("option value")
- DSM insulates customers from future gas price uncertainty
  - like fixed price contract (which typically come with price premiums – value to certainty)
  - This should be reflected in refinements to Ontario application of TRC+ ("hedge value")
- IRPAs reduce risk of "stranded assets"
  - Many IRPA investments have 15-20 year lives vs. 50 years for new "pipe"
  - Future climate policy could affect ability to recover costs over 50 years
- Many IRPAs reduce GHG emissions, reducing future compliance costs

Climate Policy Could Affect Size, Duration of Infrastructure Need

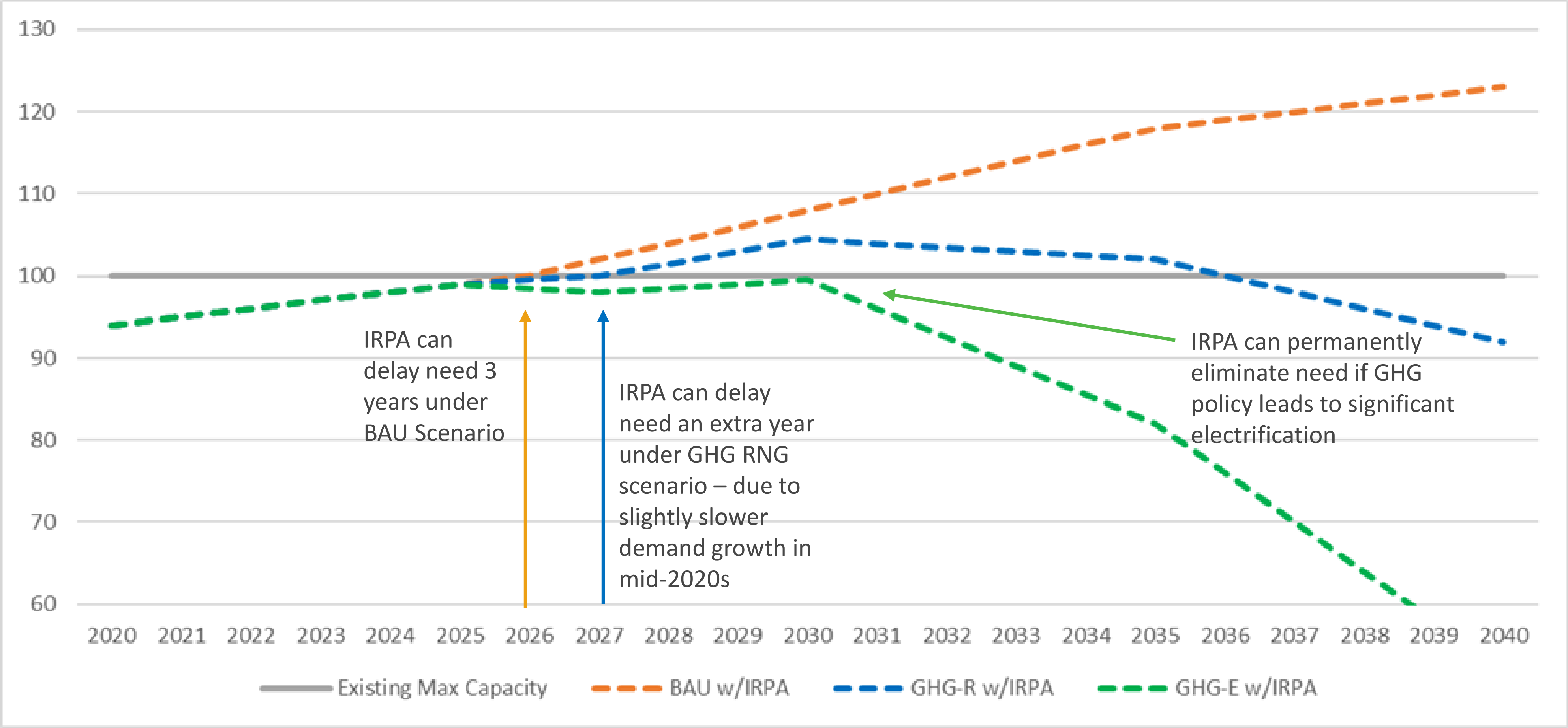
Hypothetical Peak Loads Relative to Max Capacity w/o Non-Pipe Solution (*Neme, Fig. 5*)



Size of need over time is smaller under both climate policy scenarios, but more so under electrification scenario

Climate Policy Could Affect Length of Infrastructure Deferral

Hypothetical Peak Loads Relative to Max Capacity w/Non-Pipe Solution (*Neme, Fig. 6*)



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Climate Policy Could Affect Economics of Non-Pipe Solutions

Hypothetical Economics of Non-Pipe Solutions (*Neme, Table 3*)

	Scenario	Cost of Infra-Structure Upgrade (2020 $) (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 2023 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 - Renewable Gas	$100	$20	$32	($12)	7	($84)	$89	$76	$13	$97
3	GHG Regs - Electrification	$100	$20	$16	$4	7	$28	$89	$0	$89	$61

- NPS not cost-effective under "business as usual" scenario.
- NPS very cost-effective under both climate policy scenarios.
- NPS cost-effective even if BAU scenario has 80%+ probability.

Gas avoided cost doubles under RNG scenario, increasing other benefits of IRPA

Need forever eliminated under electrification scenario

Pilots

Pilot Projects Should be Comprehensive Non-Pipe Solutions

- Enbridge's historic and proposed new pilots are too narrow
  - E.g., measuring peak impacts of EE measures, estimating DR savings potential
  - These are discrete subsets of what ultimately needs to be learned
  - No reason to learn everything sequentially – it will take forever
- Much more value in piloting comprehensive non-pipe solutions projects
  - Identifying projects whose needs are far enough out to allow for failure
  - Estimating how much would be required to defer a pipe investment
  - Developing a package of IRPA resources forecast to achieve deferral
  - Acquiring/Deploying those resources
  - Evaluating results
  - Adjusting resource/deployment strategy over time
    - in response to market feedback
    - Adjusted for changing demand/needs forecast over time

Design Pilots to Maximize Learnings

- Try both (1) utility-run pilot; and (2) RFP-driven pilot
  - Test differences in cost, effectiveness at ramping quickly, innovation, etc.
  - Learn about different approaches to integration w/existing DSM programs
- Intentionally pursue multiple IRPA resource types
  - Don’t necessarily pursue least cost portfolio
  - Explicitly test EE, DR, electrification, supply-side options
    - But the least cost within each such category
  - Similar to Maine’s Boothbay non-wires solution pilot

	RFP I*	RFP II	Totals	Pct.	Units	Weighted 3 Year Price	Weighted 10 Yr. (Levelized) Price
Efficiency	237.00	111.25	348.25	19%	7	$23.51	$10.47
Solar	168.83	106.77	275.60	15%	14	$46.05	$13.19
BUG (same)	500.00	500.00	500.00	27%	1	$17.42	$20.63
Demand Response	0.00	250.00	250.00	13%	1	$110.00	$57.65
Battery	0.00	500.00	500.00	27%	1	$163.70	$75.99
Total	905.83	1468.02	1873.85		24		

- Initial target of 2.00 MW
- RFP specified min 0.25 MW from 4 diff DERs
  - EE
  - DR
  - Renewable DG (rooftop PV)
  - Non-renewable DG
- Adjusted goal to 1.80 MW – forecast calibration
- Note: final result a little different than this table

Shareholder Incentives

Recommendations

- Shareholder incentives are necessary and appropriate
  - Enbridge has inherent conflicts due to shareholders' upstream interests
  - Penalties for poor planning "after the fact" not a good substitute
    - Realistically hard to impose – and therefore so rare as to not be helpful
    - Even if considered, are too late and $ is wasted
- Start with capitalizing/rate-basing IRPAs
  - Amortize over life of IRPA
- Assess whether adjustments needed
  - Based on experience with different costs of IRPAs vis-à-vis infrastructure
  - Recognizing that rate-basing does not incent cost minimization (non-pipe or pipe)

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