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BY EMAIL and RESS

September 19, 2023
Our File: EB20220200

Ontario Energy Board
2300 Yonge Street
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Toronto, Ontario
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Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2022-0200 – Enbridge Gas Inc. 2024-28 Phase 1 – SEC Final Argument

We are counsel to the School Energy Coalition ("SEC"). Attached, please find SEC's Final Argument.

Yours very truly,
Shepherd Rubenstein P.C.

Mark Rubenstein

cc: Brian McKay, SEC (by email)
Applicant and intervenors (by email)

EB-2022-0200

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Inc., pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2024

FINAL ARGUMENT OF THE SCHOOL ENERGY COALITION (PHASE 1)

September 19, 2023

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TABLE OF CONTENTS

1 GENERAL COMMENTS

1.1 *Introduction*

1.1.1 On October 31, 2022 the Applicant Enbridge Gas Inc. ("Enbridge", or the "Applicant") filed a cost of service Application seeking approval for rates effective January 1, 2024, including a process for adjusting rates for the following four years to December 31, 2028.

1.1.2 In Procedural Order No.1, dated December 16, 2022, the Ontario Energy Board ("OEB") split a number of items, including rate-setting for 2025-2028, from the rest of the Application. Rates for 2024 are the subject of the current Phase 1 proceeding.[1]

1.1.3 This is one of the largest and most consequential rate proceedings in the history of the OEB. In addition to dealing with more than $16B of revenue requirement over the five-year rate term, it also seeks approval of more than $7B of new capital spending to add to rate base, all of which represents future liabilities that may be imposed on ratepayers.

1.1.4 All of these billions of dollars are set against a backdrop of the existential threat to Enbridge (and some or all of its ratepayers) represented by climate change and the movement away from combustion of fossil fuels. This change – called in the proceeding and this Final Argument the "Energy Transition" – is the biggest change affecting Enbridge since at least the shift from manufactured gas to natural gas in the 50s and 60s, if not ever.

1.1.5 Unfortunately, Enbridge has not appropriately considered the Energy Transition in the context of its business and capital planning that underlie the spending proposals in its Application. It has downplayed the impact of the Energy Transition on the company in its evidence, except to increase its revenue requirement. There is no serious proposal to mitigate the risks of the Energy Transition or to fairly allocate those risks between the company and its ratepayers. Enbridge's approach is neither just nor reasonable, and it does not protect customers with respect to price.

1.1.6 The case included multiple rounds of interrogatories on the evidence of the Applicant, which was updated a number of times. It also included several expert reports[2] and

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[1] *Procedural Order No.1* (EB-2022-0200), December 16 2022, p.5

[2] Expert reports were filed by OEB Staff, Industrial Gas Users Association ("IGUA"), Building Owners and Managers Association ("BOMA"), Federation of Rental-housing Providers Owners ("FRPO"), Green Energy

written discovery on those reports. There were two technical conferences totaling nine days, as well as less formal discovery by GEC, ED and the School Energy Coalition ("SEC") relating to the Energy Transition Scenario Analysis ("ETSA") and Pathways to Net Zero ("P2NZ") studies. The evidentiary part of the proceeding culminated in an 18 day oral hearing that ended on August 11, 2023.

1.1.7 Enbridge filed its Argument-in-Chief on August 18, 2023. This is the Phase 1 Final Argument of SEC.

1.1.8 The Commissioners will be aware that the intervenors have worked together throughout the proceeding to avoid duplication, including sharing ideas, positions, and drafts, and dividing responsibilities in cross-examination and other aspects of discovery. That has continued in the argument phase. SEC has been assisted in preparing this Final Argument by that co-operation amongst parties. In addition, in a number of cases throughout this Final Argument we have been able to refer to or rely on the submissions of another party on an issue, rather than embark on our own written analysis of the issue.

1.1.9 There is an issues list in this proceeding, approved by the Commissioners on January 27, 2023, but many of the issues were settled in whole or in part in the Settlement Proposal approved by the Commissioners on August 17, 2023.[3] SEC has therefore generally organized this Final Argument in the same manner as Enbridge's Argument-in-Chief, to be most convenient to the Commissioners.

1.1.10 Where SEC does not state its position, approval of Enbridge's position or any other position should not be assumed. Silence is just silence.

1.2 ***The Energy Transition – The Role of the OEB***

1.2.1 ***Enbridge Reaches Out to the Minister.*** Perhaps the most jarring event in the proceeding came with the disclosures in Undertaking J8.1 of an exchange of correspondence between Enbridge President Michelle Harradence and Energy Minister Todd Smith.

1.2.2 Ms. Harradence's February 2nd letter was sent shortly after the decision of the Commissioners on the Issues List, and only a couple of weeks after Enbridge had accepted the near-unanimous position of the parties that the Energy Transition should be

Coalition ("GEC") and Environmental Defense ("ED").

[3] *Decision on Settlement Proposal* (EB-2022-0200), August 17 2023

a key focus of the proceeding.[4]

1.2.3 In that letter, copied to the CEOs of the OEB and IESO and all members of the Electrification and Energy Transition Panel, the President of Enbridge refers specifically to this rates proceeding, including the focus by some parties on the Energy Transition, and asks the Minister to send "a clear signal…on the respective roles and responsibilities" of the OEB and other agencies involved in the energy sector.[5]

1.2.4 After implying that the OEB – and the Commissioners in this case – may not be completely clear on their role and responsibilities related to the Energy Transition, the letter specifies what Enbridge fears: "an OEB decision that signals the retirement of all gas infrastructure and economy wide electrification".[6]

1.2.5 Despite the tone of the letter suggesting that Enbridge was, without saying it in so many words, seeking to go 'above the heads' of the Commissioners to their 'boss', the response of the Minister, sent almost four months later on June 26, 2023, is careful to a) set out without embellishment the statutory frameworks under which the OEB and IESO operate, and b) express the Minister's confidence in the OEB and its ability to understand and deliver on its mandate.[7]

1.2.6 Neither the original letter, nor the response, were voluntarily disclosed to the Commissioners or the parties. It appears that an expert witness accidentally referred to the Minister's response during the oral hearing, which led to Enbridge being required to disclose both letters.[8]

1.2.7 Whatever one thinks of the propriety of the President of a utility asking the Minister to take action with respect to a specific proceeding while it is actively being considered by an independent regulatory body, one thing is crystal clear: On the need for clarity on the role and responsibilities of the OEB relating to the Energy Transition, <u>Ms. Harradence is not wrong</u>.

1.2.8 While it may have been more appropriate to ensure that jurisdictional clarity is

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[4] It did so reluctantly, as evidenced by Enbridge's opening statement. See below.
[5] Undertaking J8.1, Attachment 2, p.2
[6] Undertaking J8.1, Attachment 2, p.2
[7] Undertaking J8.1, Attachment 1
[8] Tr.8, p.83-84

determined within this proceeding, by the Commissioners legally responsible to interpret their mandate and decide on the scope of the proceeding[9], the need for the Commissioners to be precise in understanding their role is undisputed.

1.2.9 ***The Enbridge Position.*** The position of Enbridge appears to be that, until the government establishes an energy policy direction to implement the Energy Transition, the Commissioners hearing this case, and the OEB, have to simply pretend that the Energy Transition is not happening, and may not make determinations about how the Energy Transition will unfold.

1.2.10 This is clearly set out in the opening statement by Mr. Kitchen on behalf of the Enbridge. There, he started his presentation by saying::

> *"Although energy transition has become the dominant issue in this proceeding, it is important to recognize that the primary purpose of this application is to set rates effective January 1, 2024. <u>Any decision on 2024 rates must be made in the context of current energy policy</u>. At this time, there is no government policy that sets a path to net zero*."[emphasis added][10]

1.2.11 Mr. Kitchen then refers to government comments that all options remain open in the Energy Transition, and speaks no more about it.[11]

1.2.12 In his characterization of the jurisdiction of the Commissioners, Mr. Kitchen is mistaken on at least three grounds:

(a) The case is a five year rate plan, in which 2024 is the base year. Any consideration of the relevant policy environment for rates must consider the direction of government policy, federal, provincial and municipal, as well as the current policies.

(b) During the rate period, capital spending will create obligations that last well into the future and, based on the positions taken by Enbridge[12], those obligations continue forever to fall on the backs of the ratepayers. Current energy policy cannot

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[9] SEC perhaps has more confidence in the Commissioners to make jurisdictional decisions like this, informed by the evidence before them and their knowledge of the underlying issues in the case, than Enbridge does. However, that confidence – or lack thereof - is not really relevant. The law allocates the interpretation of jurisdiction in a live proceeding to the Commissioners hearing the case, not to the Minister.

[10] Tr.1, p.4

[11] This position is repeated in the Argument-in-Chief, para.14

[12] 1.10-SEC-28, p.2 and Tr.3, p.13-14, among other references. See also Argument-in-Chief, para, 24.

reasonably be expected to continue unchanged for the entire useful lives of those capital assets.

(c) Government policy is not the basis of the Energy Transition. Government policy is developed to encourage, or restrict, the energy choices of individuals and businesses. It is those actual energy choices that will have an impact on Enbridge's business, and are the engine for the Energy Transition. The Energy Transition is a shift **by society** away from fossil fuels. Government policy facilitates, even guides, but the market determines the actual environment Enbridge will face in the future.[13]

1.2.13 Thus, to urge the Commissioners to do nothing for the next five years, while we all await government pronouncements, is to urge the OEB to decline its jurisdiction and bury its head in the sand. This makes no sense.

1.2.14 SEC notes that the other extreme – a decision by the Commissioners to require a societal shift away from fossil fuels, at a given pace and in a stipulated manner – is also neither appropriate nor legally correct. The *OEB Act* contains no jurisdiction to do so.[14]

1.2.15 Between the extremes of ignoring reality completely, and arrogating to themselves the role of determining Ontario public policy in the energy sector, there is a middle ground in which the OEB has a well-defined and important role.

1.2.16 ***The Statutory Mandate.*** The key is to be clear about the difference between assessing 'how the Energy Transition **should** unfold' vs. assessing 'how the Energy Transition **will likely** unfold'. The former is about establishing a policy direction. The latter is about forecasting.

1.2.17 The statutory jurisdiction being exercised in this case is the obligation to establish "just and reasonable rates".[15] It is trite law to say that this involves consideration of the objectives of the OEB as set out in the *Ontario Energy Board Act* ("*OEB Act*"), adherence to the case law that mandates giving utilities the opportunity to recover prudently incurred costs plus a fair return on invested capital over the long-run[16], and

[13] As Dr. Hopkins points out, government policy affects how consumers make choices: Tr. 4, p.148

[14] On this, SEC agrees at a high level with Enbridge, where Enbridge notes that "net zero" is not one of the OEB's statutory objectives (See Argument-in-Chief, para. 21)

[15] *Ontario Energy Board Act, 1998*. section 36(2)

[16] See *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44, para 16-17

many other well-known rules.[17]

1.2.18 In practice, what this means is that the Commissioners look at what the Applicant is proposing over the rate period – operating expenses, asset management plan ("AMP"), customer and revenue forecasts, etc. – and determine if those proposals appropriately consider not only the interests of the customers and the shareholders, but also the risks that each may face arising out of any given planning decision. To do this, the Commissioners necessarily must forecast the environment within which the utility will operate over the rate period, including economic, market, policy and regulatory realities it will be facing. This includes forecasting the probability that the operational realities the utility and its customers face will evolve over that period.

1.2.19 Forecasting is an essential element of this process. Ontario uses a forward test year approach, which means that internal and external elements all must be forecast in order to determine the rates that are just and reasonable during that period, i.e. justified to recover prudently incurred costs. In the context of a rate case, the Commissioners must consider forecasts of economic activity, demographic changes, commodity constraints, asset condition, safety risks, labour costs, and many other things. This is because costs are prudent – or not – only in the context of the real world, not in the abstract.

1.2.20 In forecasting, the OEB generally approve an expected result – customer growth, for example – on which the business plan is based. This is done based on the evidence presented, which is always incomplete (because it is about the future), and the judgment of the Commissioners as to the likely future based on that evidence.[18] The Commissioners then, either directly or by implication[19], assign responsibility for the risks of variances from that predicted future either to the ratepayers (e.g. through a deferral or variance account), or the shareholders.

1.2.21 For example, the risk that the customer additions will grow more slowly than the base forecast is usually assigned to the shareholders. If customer additions are low, management is expected to manage within that variance, for example by cutting costs. Similarly, if customer additions are higher, more revenue is generated, but also

[17] That jurisdiction can also include important policy determinations, but they are determinations with respect to regulatory policy, not public policy relating to energy.

[18] One of the main reasons we have expert tribunals like the OEB is because this judgment requires specialized expertise that is normally not found in more generalized adjudicative bodies.

[19] If an express determination of risk is not made, then in general the risk falls on the shareholders.

potentially more initial costs are incurred. This also must be managed, or borne by the shareholders. The same is true of weather.[20]

1.2.22 The opposite is true of inflation, or the impacts of DSM programs, just to name two examples. As proposed by Enbridge, the annual IRM rate adjustment will reflect actual inflation, in effect assigning inflation risk to the customers through their rates. If average use changes because of natural or program-driven conservation, a variance account captures the financial impact of that risk and flows it back on disposition to or from the ratepayers.

1.2.23 It is even possible to allocate a variance risk to both the customers and the shareholders. This is essentially what is done with a whole package of risks through the establishment of an Earnings Sharing Mechanism ("ESM") and various deferral and variance accounts.

1.2.24 There is nothing unusual about a panel of OEB Commissioners forecasting, based on evidence, the future impacts of a given external factor, approving prudent costs based on that forecast, and assigning the risk of variances to shareholders, ratepayers, or both.

1.2.25 The Energy Transition is just another one of those future external factors that must be forecast, and the risk of variance assigned. It may be more important than many other forecast items, but it is still just a forecast of an uncertain future, and the impacts of that future on revenues, costs, rates and risks.

1.2.26 The Commissioners do not have to reinvent the wheel here. This is a task within the core competency of the OEB, and one that is central to its jurisdiction and mandate.

1.2.27 By contrast, it would be an error for the Commissioners to try to determine what **<u>should</u>** happen. It is not the mandate of the OEB or this panel to make a determination, for example, that full electrification is the best government policy, or the most appropriate way to lower greenhouse gas emissions.

1.2.28 Instead, the question the Commissioners must ask and answer is: What Energy Transition future should a prudent utility in the position of the Enbridge assume in its capital and long-term planning? This is in essence a determination of what **<u>will</u>** most likely happen based on the evidence.

[20] In this Application, Enbridge has proposed to shift weather risk to ratepayers. SEC disagrees, and discusses this later in this Final Argument.

1.2.29 That determination also includes an assessment of the risk that the planning assumption is wrong, identification of prudent mitigation plans to minimize the impact of that risk and others, and assignment of responsibility for that the various risks to the shareholders, the ratepayers, or both.

1.2.30 ***Government Policy.*** This does not mean that government policy is irrelevant. Government policy, whether current, forecast, or potential, is always a relevant factor that will influence the future to be assumed for planning purposes. Governments at all levels are actors in society whose decisions often affect future realities.

1.2.31 However, SEC submits that the OEB must be pragmatic. Government policies will change many times over the lives of the assets that Enbridge is putting in the ground today, with changes of external circumstances, changes of Ministers, changes of government, and evolving public sentiment, all as new information becomes available. Policy changes will happen at different times at different levels of government, and will have both direct and indirect impacts. Any given announced, implemented, or planned policy cannot be treated as if it will be a roadmap for the next forty years.

1.2.32 What is certainly true, however, is that Enbridge's 'wait and see' approach to government policy on the Energy Transition is imprudent, and adds unnecessary risks, which it expects to be borne by ratepayers. If there is no government-mandated path to net zero, that does not mean that the status quo is the appropriate planning assumption. It is probably, in fact, the least appropriate assumption to make.

1.2.33 Indeed, based on the evidence before the Commissioners in this case, no-one appears to think that using the status quo as the base planning assumption is prudent. Even Enbridge thinks that big changes are coming[21], and the future is not going to be like the past.

1.2.34 ***The Enbridge Transition Plan.*** This case is unusual in another important respect. Normally, the Commissioners are presented with a detailed plan from an applicant, which forms the starting point for an analysis of the forecasts, the issues, and the resulting planning decisions. Then the other parties provide a critique of that plan, and perhaps even alternatives of their own, to assist the Commissioners in considering Enbridge's

[21] Tr.3, p.6

plan.[22]

1.2.35 That paradigm – Enbridge proposes, the OEB assesses – is lacking here. Although Enbridge has a section in their evidence on the Energy Transition, it is devoid of any serious analysis.[23] Basically, it is *delay, delay, delay*. Enbridge's approach is 'Keep deploying as much capital as possible until they tell us to stop'.[24]

1.2.36 What the OEB should have seen in this Application is a detailed review of the risks associated with the Energy Transition, and the possible responses of the utility to each of those risks, both to protect the shareholders and the ratepayers.[25]

1.2.37 SEC would have expected to see, just as one example, a detailed assessment of the capital projects in the AMP, in which each was assigned a probability of stranding. The overall probabilistic stranding risk should have been calculated, and there would be a number for the Commissioners to consider.[26]

1.2.38 SEC would also have expected to see an options analysis, a business case writ large.[27] Not only did we not see that, but some of the options that Enbridge has considered, and is in fact implementing[28], are not even mentioned in the evidence. Even the steps they **<u>are</u>** taking have not been shared with the regulator.

1.2.39 Enbridge will not expressly admit that the Energy Transition is an existential threat[29], but does admit that it will result in significant changes to its business.[30] Yet, it has filed an

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[22] It is interesting that Enbridge, in an analogous context (customer connections policy), affirms almost word for word that this is the normal way things should be done: "discussion and analysis of alternatives", "expert evidence", and "evidence to support a full examination of the wide range of potential options and impacts…": Argument-in-Chief, para 294.

[23] As we note in Section 2 of this Final Argument, the mass of information from the Posterity and Guidehouse work is not only misdirected, but is largely unhelpful to the Commissioners in deciding on a prudent plan going forward.

[24] See JT4.24 updated, where rate base is expected to increase until at least 2032.

[25] For example, Enbridge finally admitted that if there is less reliance on the natural gas system, they would cut headcount (Tr. 3, p.73-74).

[26] SEC is aware that other parties may be suggesting just such an analysis, as we do later in this Final Argument, and the same proposal was made by some of the experts in the depreciation analysis.

[27] For example, see the discussion at Tr.3, p.25-27

[28] Like Enbridge Sustain, their unregulated business within the regulated utility that is already offering financed solar, geothermal, ccASHPs, and other unregulated non-gas solutions to the marketplace on an energy-as-a-service basis using utility personnel.

[29] Tr.10, p.89

[30] Tr.3, p.4

Application that does not include the deep dive into responses to that threat that would be normal for a business in this situation. Either Enbridge has not done that detailed analysis[31] – which would be nothing short of shocking – or they have not shared their full strategy with their regulator.

1.2.40 This puts the Commissioners in the unenviable position of having to fashion a viable transition plan for the utility out of the whole cloth or, in the alternative, having to simply assign all Energy Transition risk to the shareholders.[32] Our substantive submissions on the Energy Transition later in this Final Argument will deal with both of these approaches.

1.2.41 ***Conclusion.*** SEC expects that a number of parties will weigh in on the role of the OEB and this panel of Commissioners relating to the Energy Transition.

1.2.42 In our view, the Commissioners should do what OEB adjudicative panels always do in a rate proceeding. They should:

(a) Establish a forecast of Energy Transition impacts (both in the rate period and beyond) based on their assessment of the evidence.

(b) Test Enbridge's capital and operating plans and other assumptions against the Energy Transition forecast, and approve only capital and operating plans that are prudent based on that test.

(c) Identify (and quantify, if possible) the risks associated with the Energy Transition, including different paths forward.

(d) Order Enbridge to implement mitigation where available to minimize the impacts and the risks of variances on those impacts.

(e) Allocate responsibility for those risks to shareholders, ratepayers, or both.

1.2.43 In taking this approach, the Commissioners should follow tried and true methods of

[31] Their own internal management reporting doesn't even provide risk estimates. See K3.2, p.67

[32] Or, potentially, shortening the rate approval period and sending Enbridge back to do a proper plan for the Energy Transition. While on the face of it a waste of regulatory resources, this may in fact be the most efficient approach given where we are today. This is discussed more later in this Final Argument.

assessing evidence, determining prudence, and analyzing risks. The Energy Transition is a unique and important situation, it is true, but it is still fundamentally about figuring out what is likely to happen based on evidence. This is what the OEB does best.

1.3 *Summary of Submissions*

1.3.1 The positions of SEC as set out in this Final Argument can be summarized as follows:

1.3.2 ***The Energy Transition - Options and Recommendation.*** The OEB should consider one of three approaches to the Energy Transition:

(a) ***Incremental.*** To reduce/manage risk while avoiding a death spiral driven by rate increases, implement incremental risk reduction measures that balance upward and downward pressure on rates, as detailed later in this submission.

(b) ***Risk Reallocation***. Adjust the regulatory compact for Enbridge on a go-forward basis so that assets added in 2024 and beyond that become stranded, underutilized, or uneconomic are no longer recoverable from customers in rates. This shifts the responsibility for the Energy Transition over to the shareholders.

(c) ***Planning Pause.*** Set rates without the depreciation and equity thickness proposals, and with the capital in-service additions equal to the depreciation expense in the year. This will produce flat or declining rates and no increase in rate base. Allow Enbridge to rebase at any time, but only when they file a fulsome and detailed Energy Transition plan including an options analysis.

1.3.3 The Option (a) and option (c) approaches can be implemented in a viable manner based on the current record, and both have strengths and weaknesses. Option (b) may have practical or technical barriers that are not solvable in this proceeding, so may be premature. On balance, SEC prefers option (c), since it has the advantage of getting to the transition away from fossil fuels based on more comprehensive and rigorous evidence, and creates a higher sense of urgency for Enbridge.

1.3.4 ***Stranded Assets.*** The OEB should require Enbridge to provide an expert analysis of the accounting and regulatory options for dealing with assets at risk of impairment due to the Energy Transition. In the meantime, starting in 2024, Enbridge should carry out a 'probability of underutilization' analysis for all assets brought into service, and file that analysis annually with the OEB.

1.3.5 ***Integration Capital.*** The unamortized balance of capital additions relating to the merger should not be recovered from customers. Not only is that contrary to OEB policy and the decision in the MAADs proveeds, but Enbridge has already recovered more than enough to offset these costs through excess earnings during the deferred rebasing period. OEB policy is working exactly as intended.

1.3.6 ***2023 Capital Additions.*** The OEB should disallow $26.5M in 2023 in-service additions as a result of Enbridge's imprudent actions in not seeking additional capital contributions from connecting customers due to increases in capital costs. This has resulted in an Investment Portfolio Profitability Index below the required 1.0.

1.3.7 ***2024 Capital Expenditures/In-Service Additions***. Enbridge has not justified its significant proposed increase in 2024 capital expenditures and in-service additions compared to its historic levels. The evidence raises significant concerns about Enbridge's capital planning process, both in the context of the Energy Transition and otherwise. It also reveals a significant amount of flexibility as to which capital projects are actually required to be undertaken in 2024 and the test period. Enbridge has the ability to reduce its capital spending to align with what SEC proposes in the context of its Energy Transition recommendations. Generally speaking, this means that capital expenditures should be reduced enough that in-service additions equal depreciation.

1.3.8 ***Customer Attachment Policy.*** The customer connections rules should be restructured to reflect the underlying policy drivers. This means the connection period should be five years, as with electricity distributors, and the revenue period should be until the time of natural replacement of the gas furnace, likely 15 years.

1.3.9 ***Integrated Resource Planning.*** In all scenarios, Enbridge should be required to dramatically increase its emphasis on shorter term, less capital intensive (and less carbon intensive) means of meeting the energy requirements of customers.

1.3.10 ***Overhead Capitalization.*** The OEB should make several adjustments to Enbridge's proposed harmonization policy to more accurately reflect the overhead costs that should be capitalized. It should also require Enbridge to complete an independent third-party assessment of its overhead capitalization methodology as part of its next rebasing. If the OEB approves, as SEC argues, a test year capital expenditure budget that is below that requested by Enbridge, it should both reduce the amount of overheads that are capitalized and reduce the gross O&M budget. It should not allow Enbridge to either redistribute those amounts to other capital projects or increase the net O&M budget. Cost should go down if the work to be done goes down.

1.3.11 ***Depreciation Expense.*** Except in the context of a balanced set of changes to Enbridge rates in which the upward pressure from depreciation is offset by lower rate base, the status quo depreciation methodologies should be retained until a depreciation study that considers the Energy Transition is completed and filed.

1.3.12 ***Historic PDO/PDCI Payments.*** Enbridge should be required to refund to customers amounts reflecting the double recovery of capacity used to implement the shift in Customer deliveries from Parkway to Dawn between 2019 and 2023. The double recovery, while permissible during Union Gas' IRM term as a result of the PDO Settlement Agreement, was no longer appropriate after the merger.

1.3.13 ***Equity Thickness.*** Given the absence of any operational or asset management changes, or revenue growth reductions, that reflect the risks of the Energy Transition, Enbridge has effectively denied the risk for which it is seeking a greater equity thickness. 'Business as usual' approach necessarily implies that equity thickness should not be changed.

1.3.14 ***Deferral and Variance Accounts.***

(a) ***Volume Variance Account.*** The OEB should approve a modified account that does not include the impact of weather.

(b) ***Accounting Policy Changes Deferral Account***. Enbridge should not be allowed to recover the Union Pre-2017 Actuarial Losses component of the account. Allowing it to do so would result in a windfall for Enbridge's shareholders, who have already recovered those amounts twice. The amounts would also constitute retroactive ratemaking.

(c) ***Tax Deferral Variance Account.*** Consistent with SEC's position regarding integration capital, Enbridge should be permitted to keep the amount at issue in the account.

1.3.15 ***Other Revenue – Property Dispositions.*** 100% of the proceeds from disposition of buildings and 50% of the net gains (or losses) from the disposition of land should be credited to ratepayers as Other Revenue. SEC accepts Enbridge's proposal to create a deferral account to capture property dispositions, but the account must capture all property dispositions over the entire rate term.

1.3.16 ***2024 ESM.*** The OEB should approve an ESM for 2024, as Enbridge (and its predecessor companies) have had a long-standing ability to consistently over-earn every year, including in years in which rates have been rebased. Ratepayer protection is required even in 2024.

1.3.17 ***SQR Exemption Request***. The OEB should reject Enbridge's request for a partial exemption from certain Service Quality Requirements ("SQR") as a result of its inability since the merger to meet the required targets. Enbridge should be focused on meeting the SQR targets, something it committed to do as part of the MAADs application.

2 THE ENERGY TRANSITION

2.1 *Introduction*

2.1.1 ***Forecasting the Future.*** As difficult as it may be, the Commissioners are faced with the need to assess the factual environment within which the Application before them will play out. The Energy Transition will have implications for the prudence of the various proposals being made, and the Commissioners must determine prudence in order to determine just and reasonable rates.

2.1.2 As noted in Section 1.2 of this Final Argument, the role of the Commissioners in this situation is to assess the likely trajectory of the Energy Transition and its impacts on what is being done today. Those impacts will be related, not just to 2024, but throughout the five-year rate term. During that rate period, for assets being put in service those impacts will continue to be relevant for the useful lives of those assets, Further, for long-term decisions being made by Enbridge and its customers those impacts will continue to be relevant for the period of application of those decisions.[33]

2.1.3 Further, since the likely trajectory of the Energy Transition cannot be predicted with certainty, the prudence analysis must include identification, allocation, and mitigation of risks.

2.1.4 ***The Fight for Survival.*** Prudence analysis is nothing new for the OEB, but a review such as this one – where a major utility is essentially fighting for survival – does not come up very often.

2.1.5 Ms. Roszell, a Director with Guidehouse, described it this way:

> *"I think we can all agree based on the opening remarks which everyone made that we are tackling what is one of the most complex issues that humanity has ever faced."*[34]

2.1.6 In cross-examination, Enbridge Vice-President of Business Development Regulatory Malini Giridhar agreed.[35] In fact, asked if the Energy Transition is an "existential threat"

[33] For example, when a school chooses in 2024 between a new gas boiler and a geothermal heating system, that choice will have implications for both Enbridge and the school for a very long time.

[34] Tr.2, p.4 and K3.2, p.88. Throughout this Final Argument, we have sought to include references to our compendia where this may be a more convenient place to access the material.

[35] Tr.3, p.6

to Enbridge, Ms. Giridhar did not answer the question directly[36], but said, instead:

> *"Fair to say that Enbridge Gas Inc. is in the business of delivering natural gas, which has an associated GHG emission. So, yes, I agree with you that Enbridge Gas Distribution needs to transform itself over the coming decades."*[37]

2.1.7 The seriousness of the problem is brought home when one realizes that 87% of Enbridge's revenue requirement comes from the general service classes[38], which in practical terms means almost entirely from buildings – homes, apartments, office buildings, schools, hospitals, etc.[39] Yet in study after study it is clear that the path to net zero necessarily involves no longer burning fossil fuels for building energy needs like space and water heating.

2.1.8 In almost every independent review, the solution for buildings is electrification. The Canada Green Buildings Strategy, for example says:

> *"Electrification of space and water heating (allowing for flexibilities such as hybrids where full electrification is not feasible) – and ensuring that buildings are well insulated – will be essential components of decarbonizing the buildings sector."*[40]

2.1.9 Similarly, Canada's Energy Future 2023, a publication of the Canada Energy Regulator, has this to say about the change in buildings:

> *"The residential sector made up 13% of Canada's end-use energy demand, and 6% of its GHG emissions in 2021. The commercial sector, which includes buildings like offices, restaurants, and schools, made up 11% of Canada's end-use energy demand, and 7% of its GHG emissions in 2021. Most energy use in both sectors is electricity and natural gas, and in some regions refined petroleum products (RPPs) and biomass are also key fuels. When combined, GHG emissions in both sectors are referred to as the "buildings sector" for the purposes of GHG emission reporting. GHGs in the buildings sector are primarily the result of burning natural gas and fuel oil for heating buildings and water. In the Global and Canada Net-zero scenarios, we project that*

[36] Although she clarified this subsequently (see Tr.10, p.89).
[37] Tr.4, p.6
[38] K3.2, p.3; Tr.3, p.12
[39] Tr.3, p.13
[40] K3.2, p.47

> *energy use patterns change considerably in both sectors. The electrification of space and water heating, along with rapid improvements in the efficiency of buildings, are core to this sector's transformation."*[emphasis added][41]

2.1.10 Enbridge agrees that fossil fuels have to decline significantly[42], and even notes that we cannot get to net zero if we continue to use gas furnaces[43], but does not accept the conclusion of others that electrification is the likely alternative. While it admits that non-emitting electricity has to be a significant part of the solution[44], Enbridge prefers a future in which its distribution system is still needed.

2.1.11 In fact, that is Enbridge's overt strategy today. They are not hiding it:

> *"I think it is fair to say that what we believe we should be doing is highlighting to the political class, as well as several stakeholders, the value and benefits of preserving the gas system. And I think you can see that in this proceeding, as well."*[emphasis added][45]

2.1.12 Ultimately, while no-one likes to talk about it, this is about the 'death spiral'. If 87% of revenue comes from general service customers, mainly for their buildings, and building uses move from natural gas to electricity[46], Enbridge will have to look to the contract customers, who are more price sensitive, to cover their costs.[47] This would necessarily involve substantial increases in rates for industrial customers, for whom the bulk of the gas is being delivered.[48] It is not a leap in logic to say that many of those customers will cease taking gas delivery in that situation, leaving Enbridge with no-one to pay for tens of billions of dollars of existing infrastructure.

2.1.13 This is the death spiral.

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[41] K3.1, p.47; We note that the Argument-in-Chief, at para.82, Enbridge mischaracterizes the conclusions of this study, saying that it shows "natural gas being used in building heat beyond 2050". In fact, the study notes that there would be a few exceptional situations in which there was no replacement for natural gas in a building, but that electrification would be the solution for almost all buildings. Nothing in the CER study in fact suggests that all or even most of the natural gas distribution system we currently have will be needed in 2050.

[42] Tr.3, p.10

[43] Tr.3, p.92

[44] Tr.3, p.93

[45] Tr.4,81

[46] Enbridge in fact argues "[t]here is no evidence to suggest that this is actually happening in Ontario", as support for its opposition to taking any serious action now (See Argument-in-Chief, para. 175).

[47] 1.10-SEC 28, p.2 (K3.2, p.8)

[48] Tr.3, p.19

2.1.14 SEC notes that the death spiral is not just a risk for Enbridge. The disruption associated with this kind of forced change affects customers (including former customers) and the economy as a whole.

2.1.15 ***Implications of this Threat.*** The Commissioners cannot prevent the death spiral. What they can do, faced with the Application before them, is push Enbridge in the direction of operational and policy choices that minimize the risk of the death spiral, and facilitate a more controlled transition from gas to other energy sources.

2.1.16 In the context of a significant change such as this, though, SEC believes that the Commissioners should accept some perhaps obvious truths:

(a) Enbridge is in a desperate situation, and this is the point in time where the utility and its customers need the objectivity and sound judgment of the regulator the most. The OEB cannot assume that Enbridge's proposals in the context of the Energy Transition will be entirely rational, clear-eyed, and in the public interest. They will be coloured by the extreme nature of the downside risk they are facing.[49]

(b) Big problems are not solved by delay. The bigger the train coming down the track, the more important it is to move early – even on the basis of incomplete information – rather than wait until the last minute. Enbridge is proposing a 'wait and see' approach before doing anything impactful. This is wrong, and will unnecessarily harm the customers.

(c) There is an important role for public policy, and that may influence the timing and severity of the change that is coming. In the meantime, though, the OEB as regulator still has to deliver on its own important role in ensuring that the actions of the utility going forward minimize the costs and risks associated with the Energy Transition. Doing nothing is still a choice, and based on the evidence in this proceeding clearly the wrong choice.

2.2 ***Experts Describe the Future – Posterity/Guidehouse Reports***

[49] That does not imply that Enbridge is being in any way dishonest or improper in their Application or in the evidence they have presented. Rather, it is a recognition that, whenever the Commissioners hear proposals from a utility (or anyone else, for that matter), they have to consider the practical circumstances of those doing the proposing.

2.2.1 This case has been blessed with a plethora of experts prepared to tell the Commissioners what will, should, or might happen in the future, perhaps more than any other case in recent memory. Of those experts, at least five of them[50] were retained to speak primarily about the Energy Transition, and at least six others[51] considered the Energy Transition as a component of their work on equity thickness or depreciation. Enbridge put forward two exports who directly spoke to the issue of the Energy Transition – Prosperity and Guidehouse.

2.2.2 ***General Comments.*** Although Posterity Group and Guidehouse prepared separate studies independently of each other, the Energy Transition Scenarios Analysis (ETSA)[52], and Pathways to Net Zero (P2NZ)[53] respectively, they were part of a continuous and integrated process in collaboration with Enbridge, by which Enbridge sought to explain how they see the Energy Transition unfolding, and argue for their preferred approach.[54] Thus, SEC will consider the two studies together.

2.2.3 SEC believes that, by the end of Panel 1 in the oral hearing, and perhaps much earlier than that, the Posterity/Guidehouse analysis had been so thoroughly debunked that no-one who heard their evidence would rely on it. Interrogatories and technical conference questions identified major flaws, some of which required material changes to the results. Then, in the oral hearing it became clear that even the modified results were so weak, and so dependent on questionable assumptions, that the witnesses were constantly having to explain their limited scope[55], and the fact that there was no intention to optimize the options, or even make them representative or comparable.

2.2.4 For example, in the opening statement of the Panel 1 witnesses, Ms. Wade said:

> "*It is important to reiterate that these two scenarios when defined <u>were not intended to be used as a plan for Enbridge Gas</u>, and they were not intended to be interpreted as the only two ways that Ontario could achieve net zero. There*

[50] Posterity Group (Shipley and Tiessen), Guidehouse (Roszell and Ringo), Synapse (Hopkins), Energy Futures Group (Neme), and Enerlife (Jarvis and Henderson)

[51] Concentric (Coyne and Dane), Concentric (Kennedy and Nori), London Economics (Goulding, Nayak and Pinjani), Dr. Cleary, Intergroup (Mahmudov and Bowman), and Emrydia (Madsen).

[52] 1-10-5, Attachment 1

[53] 1-10-5, Attachment 2

[54] Although, having seen the results of these studies, Enbridge now says that their preferred approach, although a gaseous fuels future, is not the same as the Diversified option in those studies. (Tr.3, p.22)

[55] This continued on in the Argument-in-Chief, for example at para.44, 66, 94(h), and elsewhere.

> *are other diversified scenarios that could have been modelled…. The same holds true for the electrification scenario. There are many different permutations of this pathway that could have been modelled… Each pathway chooses specific assumptions or inputs as part of their scenario definition, based on information that is available at the time of modelling and based on plausible changes to what we know today. Enbridge Gas does not believe that different assumptions make a scenario right or wrong. They are just that, different scenarios with different assumptions"* [emphasis added] [56]

2.2.5 At best, their evidence appears to show that fuel switching to electricity is the likeliest future for most energy uses that now rely on natural gas.[57] That is not what Enbridge intended, but it is in fact consistent with similar studies in other jurisdictions.[58]

2.2.6 Against that backdrop[59], and also understanding that some other parties will likely be providing a more fulsome unpacking of it[60], SEC will not go into the problems of these scenario models in detail, particularly the technical issues, which we will leave to others. Instead, we will simply highlight some of the more important general problems that have been identified in the evidence.

2.2.7 ***"Collaborative" Process = Lack of Independence.*** At various stages of cross-examination (as well as in the Technical Conference), parties pursued the question of whether Enbridge simply directed the results of the Posterity/Guidehouse analysis. At some points it even became repetitive and tedious.

2.2.8 The external experts objected, but did emphasize time and again that their work was done "collaboratively" with Enbridge.[61] Enbridge did not say to either Posterity or Guidehouse 'Here is a question on which we need your expert opinion. Please go away and study it, then come back with your answer.' Nothing like that.

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[56] Tr.1, p.82

[57] The published results are in fact within the likely uncertainty band for a study of this sort (Tr.3, p.129-30), even before adjusting for the many remaining problems. Correcting for the carbon charge, by itself, means that this "straw man" electrification scenario is still cheaper than a gaseous fuels model, even the optimistic one presented by Enbridge. Correcting for the other known problems shifts that balance further. Even after putting a thumb on the scale, the studies can't get to the result intended, a need to retain the gas distribution infrastructure.

[58] Including the CER Study (K3.1) and the Canada Green Building Strategy (K3.2, p.47)

[59] And the detailed evidence of Mr. Neme critiquing these studies: See M9, p.26-39 and Tr.5, p.170-180

[60] SEC is aware that GEC and ED will be providing detailed comment on these two studies.

[61] Tr.3, p.110,126

2.2.9 What we know, at least, is:

> ***(a)*** Many of the assumptions, parameters, and methods of calculation were simply stipulated by Enbridge.[62]
>
> ***(b)*** For virtually every other matter on which an expert judgment was required, the judgment was subject to approval by Enbridge. This included assumptions, choices of critical drivers, conclusions from the data, and many other things.[63]
>
> ***(c)*** No attempt was made to optimize the scenarios or how they were modelled to get the best possible reflection of the future. Instead, the analysis was 'If A and B and C are true [all approved or stipulated by Enbridge], what result do we get?' The studies were not goal-driven.

2.2.10 In addition, as noted below many aspects of the studies were obviously questionable, yet were accepted by the experts at the direction of Enbridge.

2.2.11 ***Inclusion of Apparently Expert Opinions Without any Study.*** The Guidehouse study includes a series of recommendations on things like resilience and planning processes and other items that were a) not within the scope of their declared expertise, and b) not the subject of any research or study on which to form the basis of those opinions.[64]

2.2.12 Those policy recommendations are very similar to the policy recommendations that Enbridge has been making during its lobbying efforts.[65]

2.2.13 ***Carbon Charge Treated as a Cost, and Different Amounts Assumed.*** As noted in Mr. Neme's evidence[66], it is not correct to treat the carbon charge as a cost, because it is fully refunded. It is a transfer between persons for policy reasons. Overall, the cost to society is zero.

2.2.14 However, having treated it as a cost, Guidehouse also assumed a different level of carbon

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[62] For example, the amount of hydrogen to be included in the scenarios was stipulated by Enbridge (See Tr.3, p.108-109)
[63] Tr.3, p.103-4
[64] Tr.3, p.118
[65] Tr.3, p.126-9
[66] M9, p.27

charge in the gaseous fuels and the electrification scenarios.[67] For example, in 2038 the carbon charge is assumed to be $200/tCO2 for gaseous fuels, and $338/tCO2 for electrification The result of this was to increase the cost of the electrification scenario relative to gaseous fuels by $57M, more than the difference in the overall costs of the scenarios. Pressed on this, the Guidehouse witness was dismissive of the impact on the modelling results.[68]

2.2.15 ***Enbridge Volume Forecast is Higher than the Reference Case.*** The studies included gas volumes for a Reference Case (no Energy Transition impacts on load), the Diversified Case (the gaseous fuels future, 45% hydrogen, 45% electrification), and the Electrification Case (10% hydrogen, 85% electricity). Predictably, the gas volumes are highest for all years in the Reference Case, then the Diversified Case is lower, and the Electrification Case is lower still.

2.2.16 The volume forecast in the current proceeding is higher than even the Reference Case.[69] This implies that none of the impacts of the Energy Transition are reflected in the volume forecast in this proceeding.

2.2.17 The situation, however, is somewhat more complicated than that. The 10-year AMP in this proceeding, and the capital spending forecasts contained within it, are based on volume assumptions that are higher still. However, as noted in Undertaking J3.1, the capital plan is based on a design hour demand forecast, which calculates peak and is adjusted for number of customers. For the period of the AMP, that forecast is slightly lower (3.5%) than the Reference case used by the consultants[70], but still significantly higher than the Diversified Case (5.6%) and the Electrification Case (16.3%).[71] It is clear that even the impacts of the Diversified Case have not been fully factored into the capital plan, let alone the Electrification Case.[72]

2.2.18 ***Assumed a Reduction in Capital Spending Increases Emissions.*** Asked to model the impact on its study results of a reduction in capital spending, Guidehouse concluded that

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[67] Undertaking JT2.9, p2-3
[68] Tr.3, p.120-121
[69] Tr.3, p.56-7
[70] See Undertaking J3.1 and 10-SEC-31, Attachment 1, p.34, which allow a calculation for 2028.
[71] Ibid
[72] Enbridge has essentially admitted thiswhere it said: "Enbridge Gas recognizes that the incorporation of energy transition assumptions into the forecasting process had a relatively small impact during the rate rebasing period." (Argument-in-Chief, para. 446)

reducing capital spending on gas infrastructure would increase GHG emissions.[73]

2.2.19 When asked about this unusual result, the Guidehouse witness said that the assumed reduction was applied to GHG abatement activities, which resulted in higher emissions.[74] It appears from the exchange with the witness that this assumption was stipulated as part of the scenario.

2.2.20 ***Customer Behaviour Assumed to be Solely Price-Driven.*** Some parties were taken aback with an exchange between SEC counsel and the Posterity witnesses. It is worth including the full exchange:

> *"MR. SHEPHERD: ... If you look at page 25 of our materials, you said: "The maximum setting for the climate change assumption was average annual temperature increases of 3.3C to 5.9C by 2100."*
> *That, I sort of had a quick, you know, stop, when I read that. It is, like, 5.9C? Seriously? So you didn't actually implement that. That is not the number you used in your scenarios. Right? <u>You actually used 3.4C by 2050, as the maximum.</u> Right? That is on page 31 of our materials.*
> *MR. TIESSEN: ...<u>That sounds correct</u>, in terms of the sensitivity. Yes.*
> *MR. SHEPHERD: So here is what I didn't understand: You said, and what that will do, 3.4 degrees – which to my mind it means there is riots in the street but, <u>to your mind, it means there is a four percent decline in gas use because it will be a little warmer</u>? I don't get that. <u>Did you not look at behaviour?</u>*
> *MR. SHIPLEY: <u>No. We modelled what houses and buildings would do.</u>*
> *MR. SHEPHERD: So you didn't look at how the market would react to 3.4 degrees?*
> *MR. TIESSEN: No – that is correct. We did not; that was not part of the scope of that driver.*
> *MR. SHEPHERD: So you didn't think that if half of Florida is underwater, that people will get off fossil fuels faster in Ontario? You don't think so? Or you just didn't look at that?*
> *MR. TIESSEN: The scope of that driver was focused on understanding what a warming impact would have on gaseous load for Enbridge's customers.*
> *MR. SHEPHERD: <u>Well, if the temperature goes up 3.4 degrees by 2050, I can assure you that there will be more than a four percent decline in Enbridge's load. Don't you agree with that?</u>*
> *MR. TIESSEN: <u>It is not clear to me what Enbridge's load would look like in that scenario that you are outlining</u>."*[emphasis added][75]

[73] 1-10-4, Attachment, p.5

[74] Tr.3, p.125-6

[75] Tr.3, p.105-6. Clearly the experts did not apply a sanity check to their conclusions.

2.2.21 Pressed on this point, the witnesses later noted that customer behavior was modelled in the context of price changes.[76] In effect, as long as natural gas is cheap, customers will continue to use it, regardless of all other factors.

2.2.22 It is not clear whether this restriction on the scope of the critical driver, excluding expectations of non-price customer behaviours, was stipulated by Enbridge or developed collaboratively between Posterity and Enbridge.

2.2.23 ***No Early Retirements of Equipment for Fuel Switching.*** Although it did not come out until the end, the Posterity component of the study, which looked at fuel switching, assumed that no fuel switching away from gas happened except at time of natural replacement.[77]

2.2.24 While it is true that changing your heating system is more likely to happen when you have to change your furnace and/or air conditioner anyway, assuming zero early replacements is an unreasonable assumption. If that were true, initiatives like the Canada Greener Homes Program (in Ontario, HER+) would be hard pressed to achieve their stated goals.

2.2.25 ***Assumed Preference for Gas Heat Pumps.*** In the gaseous fuels scenario, Guidehouse included gas heat pumps, a less efficient and less mature technology than electric heat pumps, because they assumed that "customers would continue to prefer gas heating equipment."[78]

2.2.26 ***Problematic Assumptions for Hydrogen and RNG.*** Many of the assumptions related to hydrogen and RNG in the gaseous fuels scenario are real head-scratchers.

2.2.27 For example, in 2050 it is assumed that RNG will provide volumes equal to almost 19% of current fossil gas throughput.[79] The record in this proceeding does not appear to show how this could be possible.[80]

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[76] Tr.3, p.106-7

[77] Tr.4, p.56

[78] Tr.3, p.122

[79] 1.10-ED-40, p.4 (K3.2, p.74)

[80] Enbridge is proud of the fact that RNG in its system increased from 0.007% in 2018 to 0.032% in 2022 [see Argument-in-Chief, para. 129(c)]. At this rate of increase, RNG would be 0.175% in 2050, less than 1% of that target assumption. SEC does not doubt that this rate of increase could be accelerated, subject to competition from

2.2.28 As another example, it is assumed that more than 10 billion cubic meters of fossil gas and blue hydrogen will be used annually, both relying on carbon capture and storage.[81] At the present time CCS technologies and storage locations capable of this result do not appear to be available.

2.2.29 While Enbridge assumes that its system can be repurposed to carry hydrogen[82], it is only aware of 40% that it believes is hydrogen ready[83], and its own study of the ability of the system to carry hydrogen or hydrogen blends will not be complete until 2026.[84] Despite this, Guidehouse effectively assumes that the system can carry hydrogen, as it has assumed zero cost for upgrading or replacing the distribution system.[85]

2.2.30 These are just a few of the many examples of assumptions relating to hydrogen and RNG that may not be realistic.[86] While we know that all assumptions were at least approved by Enbridge, some of these may have been stipulated directly. For example, costs relating to allowing the system to handle hydrogen appear to have been excluded because they were outside the scope of the study as determined by Enbridge.

2.2.31 ***Conclusion.*** The Posterity/Guidehouse evidence was designed to show that a particular gaseous fuels option (coyly called the Diversified option) with 45% hydrogen and 45% electrification is a cheaper solution than a particular electrification option with 10% hydrogen and 85% electrification.[87] Once errors and some of the poor assumptions were fixed, the evidence showed that the electrification option is cheaper, which led Enbridge witnesses and their experts to claim that these are just two possible scenarios, and conclusions can't be drawn from them.[88]

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other uses and other jurisdictions, but this appears to be a stretch. In any case, the onus is on Enbridge to demonstrate that their assumptions are reasonable, and they have made no attempt to do so in this case.

[81] 1.10-ED-40, p.4 (K3.2, p.74)

[82] 1-10-5, p.15

[83] 1.10-GEC-23

[84] 4-2-6 and Tr. 3, p.41

[85] "Costs for upgrading methane distribution pipelines to accept hydrogen blending and for the hydrogen distribution system within Ontario are outside the scope of the P2NZ analysis and not included" (1.10-ED-63, p.2)

[86] In addition, Guidehouse admits for example that they did not do any sensitivities on RNG or hydrogen availability: (See Tr. 4, p.69)

[87] Percentages from Undertaking J3.3

[88] For example, see Argument-in-Chief, para. 44

2.2.32 SEC submits that these studies are so badly flawed as to be misleading, and they are not helpful to the Commissioners in assessing the likelihood of any given Energy Transition future. The record includes better, more independent studies, both from experts who appeared before the Commissioners, and from other bodies that have studied the Energy Transition. They consistently conclude that the Energy Transition will involve broad electrification of building energy needs.

2.2.33 Therefore, SEC submits that the Commissioners should reject the Posterity/Guidehouse studies.

2.2.34 ***Clear Statement by the Commissioners.*** In addition to the above, SEC requests that the Commissioners, in their decision in this case, take a somewhat unusual step. The Posterity/Guidehouse analysis is being used by Enbridge,, not just in this proceeding, but also in public consultations, lobbying, and other activities.[89]

2.2.35 In those other cases, whether those receiving the results are politicians at all levels, government bureaucrats, or other stakeholders, the recipients of the analysis do not have the benefit of the rigorous review of evidence undertaken at the OEB. It is easy for third parties to look at the ETSA and P2NZ studies as if they were really independent studies producing actionable conclusions. This would be unfortunate.

2.2.36 SEC therefore asks the Commissioners to consider making a clear statement in the decision as to the value – or lack thereof – of these two studies, and to provide a public warning about the limits of their usefulness. An analysis by the Commissioners of the evidence revealing the truth of these studies could go a long way to preventing other parties from relying on them incorrectly.

2.3 ***<u>What Do We Know For Sure?</u>***

2.3.1 As with most complex problems, a good approach here is to segregate what we know from what we do not know. This obvious step not only narrows down the list of complexities. Often it also makes organizing the problem easier. To this end, it is worthwhile to step back and assess what facts are actually not in dispute (or should not be).

2.3.2 ***Fossil Fuel Combustion Must be Reduced as Fast as Possible***. The imperative of

[89] For example, see Enbridge's submissions to the Electrification and Energy Transition Panel, p.1,4,8 (K1.3)

reducing GHG emissions means that all parties agree (or should agree[90]) that we will have a declining trajectory of fossil fuel combustion. This includes Enbridge[91], all of the experts, and all of the environmental groups and ratepayer representatives. There are disagreements on pace, and on what we will use in place of fossil fuels, but almost all appear to agree on the basic principle.

2.3.3 In fact, as Enbridge has noted a number of times[92], both of their scenarios for 2050 have zero unabated natural gas in the energy mix.

2.3.4 A necessary result of this decline is that the unit cost of delivering natural gas must rise over time, since the costs of delivery are fixed and the volumes will go down. This will have an impact on the cost-effectiveness of natural gas as an energy solution.

2.3.5 It is worth noting that this 'agreed fact' is about a common acknowledgement that the future, in this context, will not be the same as the past. One cannot just draw a trendline from past data to forecast future data. An inflection point is changing the trendline. That is why it is so disheartening to see arguments like this one from Enbridge:

> *"Enbridge Gas maintains that it is not appropriate to take any approach to forecasting and planning for the gas system that is not based on strong signals or concrete data and analysis of what is actually happening in Ontario. .. The importance of having actual data upon which to base forecasting and planning assumptions is especially important in the light of in-progress government initiatives that are specifically designed to address these issues for the broader energy industry."*[93]

2.3.6 This is just one example of many, in the evidence and in the Argument, where Enbridge selectively champions current data, and the current reality, and decries any forecasting that assumes the future may be different. It is not possible to plan for a changing future by assuming it will be the same as the past.

2.3.7 ***In the Past, Every Time We Needed More Electricity, We Were Able to Produce It.*** There has been much hand-wringing in this proceeding about the challenge of replacing

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[90] Some parties may be climate change deniers, and so have a very different perspective on the issues in this proceeding.

[91]See for example Tr.3, p.10,89

[92] See, e.g.1.10-ED-40

[93] Argument-in-Chief, para. 99

natural gas with electricity.[94] Many, including Enbridge, have suggested that we should not (and by implication, will not) reduce natural gas use until we have a clear plan for how we will produce the electricity we will need to replace it.[95]

2.3.8 So, for example, some including Enbridge have emphasized the new winter peak electricity needs that will have to be met, expressing concern that it will simply not be possible.[96] We will still, Enbridge says, need the gas distribution system for those cold winter days.[97]

2.3.9 With respect, this is simply not correct. Ontario has never had a problem producing enough electricity for its needs. When we plan for electrical capacity, the issue is not whether we can find it, or build it, but what is the optimum portfolio of electricity sources to achieve the goals of reliability, resiliency, and availability at the lowest possible cost. We always know we can do it. It is always about choosing how to do it.

2.3.10 As Dr. Hopkins has pointed out, "[w]e are not suffering from a limited amount of sun and wind in the way that there is a limited amount of biogenic feedstock for RNG…"[98] That does not even take into account the emerging potential for DERs of all types, and the government's re-commitment to nuclear.

2.3.11 The same, by the way, holds true for our distribution and transmission systems. To the extent that we need to increase their capacity, whether in total or at peak, we know how to do that.[99] We do not need to invent anything new.

2.3.12 In addition, whatever challenges there may be in having sufficient future electricity capacity to replace the energy from natural gas, those challenges have limited relevance

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[94] See, for example, Argument-in-Chief para. 63-69

[95] Tr.1, p.73-74

[96] Referring to the idea that the electricity system will be able to handle increased electrification, Enbridge says: "The evidence says otherwise." (Argument-in-Chief, para. 181). With respect, the evidence says nothing of the sort. Enbridge could have led evidence seeking to show that full electrification is impossible. They did not. Instead, they waved their hands around, raising the spectre of higher cost and barriers to success without any evidentiary base at all. Saying there is evidence is not the same as providing evidence. Given that Ontario has never failed to provide the electricity needs of the province when called on to do so, there was a clear onus on Enbridge to demonstrate that this time we would fail. Pointing to IESO studies that address the challenges of meeting electricity load (which is, by the way, IESO's job) does not show that we will not be able to meet Ontario's electricity needs in the future.

[97] See for example, Undertaking J11.5, p.8

[98] Tr.4, p.169

[99] Again, Dr. Hopkins hits the nail right on the head: Tr.4, p.174

to the question the OEB will need to address in this or future Enbridge rate cases. The Energy Transition is being *driven* by broader by societal and customer actions, not by the actions of Enbridge, the OEB, or the IESO.[100]

2.3.13 ***It Is Reasonable to Assume the Federal Carbon Charge Will Continue Into the Foreseeable Future.*** Again, there are disagreements on how long the carbon charge will continue to rise (as opposed to plateau at some point), and Enbridge has even expressed doubt[101] as to whether it will continue to be refunded to the public, as is currently the case. However, no-one has suggested that the current carbon charge, increasing until at least 2030, will end.

2.3.14 The implication of this is that the delivered cost of natural gas to customers will continue to rise over time, and thus natural gas will see its price advantage eroding even further. Coupled with naturally declining volumes, and the rise in unit prices that must follow, natural gas will increasingly be less competitive as an energy source for many end uses.

2.3.15 ***Gas Infrastructure Being Put In the Ground Today Has Its Cost Amortized Over 30-50 Years.*** Since this is well beyond the period where the full gas distribution system, as we currently understand it, could be needed, there is a high probability that some or all of these assets will be either stranded, underutilized, or uneconomic.

2.3.16 The only way this looming problem can be avoided is to repurpose the gas distribution infrastructure to deliver something else. RNG can never reach sufficient volumes to fill the pipes.[102] The only solution currently seen is hydrogen. As noted earlier, Enbridge does not yet know how much of its system can handle hydrogen[103], and plans to do a study between 2023 and 2026 to find out.[104] Meanwhile, new assets being brought into service use the previous engineering standards, meaning that many of those will likely not be hydrogen compatible.[105]

2.3.17 None of this is controversial. However, the necessary result – inevitable stranding/underutilization of the new capital now being proposed for 2024 – is resisted by

[100] Although we note that there are still some at Enbridge who doubt whether we can ever find a cost-effective path to net zero: see for example Tr.1, p.123.
[101] Tr.3, p.39
[102] Tr. 4, p.162-169
[103] Tr. 2, p.49
[104] Tr. 3, p.41,135
[105] Tr. 3, p.78

Enbridge. At the same time, Enbridge has taken no steps to analyze the long-term utilization of those assets.[106][107]

2.3.18 We also know that waiting 5 years until Enbridge is next scheduled to rebase to begin to address the problem will just make things worse. Mr. Bowman from InterGroup put it best when describing the problem, albeit in the context of the appropriate depreciation methodology, Enbridge, he said, is "still spending another billion-and-a-half dollars on new assets, and so, by the time we sit here five years from now if this is a 5-year rate period, we'll be talking about almost half of the assets in the ground were new after this hearing occurred."[108]

2.3.19 ***Some Customer Segments Are More Able to Shift Away From Fossil Fuel Risks Than Others.*** The Energy Transition is not an equal opportunity set of risks. For some customers it is a much bigger problem than for others.

2.3.20 By way of example, in the medium term many commercial and institutional customers will reduce or eliminate their reliance on natural gas, not only for financial and risk management reasons, but also to meet environmental and social goals. Big users of gas for space and water heating, like schools, municipalities, hospitals and chain stores, are already planning their own eventual Energy Transition. For those customers, the Energy Transition is going to happen anyway, largely on their own schedules.

2.3.21 Contrast that with industrials, some of whom need very high heat sources that cannot be provided by electricity in a manner adequate for their needs.[109] Industrials pay only a small portion of the costs of the gas distribution infrastructure, and most of that infrastructure is not relevant to their needs in any case. For them, the problems Enbridge may face with the Energy Transition could create a very real threat to their economics.

2.3.22 Less focus has been placed on vulnerable gas customers, like low income, seniors, and tenants, but they are also at high risk. Residential users in multi-million dollar GTA homes are already starting to look at expensive geothermal systems and other such

[106] Tr. 11, p.151

[107] SEC notes the interesting exchange at Tr. 4, p.118. Counsel for IGUA asked "Does Enbridge expect to get 40 years of revenue from a new customer?". Counsel for Enbridge intervened to say another witness panel would be better suited to answer that question. To the best of our knowledge, that question was never answered.

[108] Tr.18, p.8

[109] We exclude industrial uses of natural gas as feedstock, since this often does not involve combustion and has a very different GHG profile.

alternatives to natural gas. They do this because they can afford it. Contrast that with vulnerable gas customers, who cannot afford it, and in any case often face the split incentive barrier: landlords pay the capital costs of new equipment, but flow through operating costs like natural gas to tenants.

2.3.23 ***Alternatives Based on Electricity are More Mature Technologies Than Hydrogen Alternatives.*** Electrification is possible with current solutions that are proven to work. Hydrogen and other gaseous approaches might be possible with future solutions that are currently under development.

2.3.24 SEC wants to be very clear that it strongly supports hydrogen. The potential of hydrogen solutions is undoubted, for at least two categories of uses in Ontario:

(a) ***High Heat Combustion.*** At present hydrogen is the only carbon-free material that can be produced in large quantities, and can be combusted to generate the high heats needed for some industrial and other purposes. Although there are many challenges in handling hydrogen, it is more and more accepted that the shift in some industries from natural gas will be to green hydrogen. A recent paper by Deloitte and the Renewable Energy Collaborative, published in April of this year, discusses this in some detail.[110]

(b) ***Energy Storage***. Hydrogen can be used like a battery to store energy from another source – typically electricity – until it is needed. While the production of green hydrogen through electrolysis, and then the combustion of that hydrogen in gas turbines, is not the most efficient process in the world, it will likely compete in the future with battery storage to add dispatchability to electricity systems relying heavily on renewables (which generate at will), and nuclear (which cannot be turned off easily). Simply put, our current gas turbines may well be replaced with hydrogen turbines for peaking power.

2.3.25 In addition, hydrogen will likely become a key fuel for heavy equipment and transportation, and for aviation. This, like the other uses above, will not save the bulk of the gas distribution infrastructure.

2.3.26 But, as much as hydrogen has great potential in the future, none of us will be heating our homes with hydrogen any time in the next few decades. The delivery mechanism doesn't

[110] See for example, Deloitte, Assessment of Green Hydrogen For Industrial Heat, April 2023

exist, and the end use equipment necessary for a hydrogen solution is not readily available, or in many cases not even invented yet. By contrast, we can heat our homes with electricity today using mature, efficient, and reliable existing technologies.

2.3.27 Dr. Hopkins, quoted in the Argument in Chief[111], essentially agrees with SEC's view on hydrogen:

> "*EGI's preliminary work on renewable natural gas and hydrogen could provide some important information to reduce uncertainty and thereby lower risk. It is important that these pilots and other research and development actions be grounded in the eventual roles for different fuels. For example, <u>the value of testing hydrogen blending for residential heating applications (where blending limits will constrain its potential impact, and competitive technologies are available) is very different from the value of piloting hydrogen and other low-carbon gases for industrial applications</u>.*"[emphasis added][112]

2.3.28 ***Conclusion***. The Energy Transition is a big, and complicated, problem. However, by identifying the things we know for sure, we can put the issues that still have to be addressed in proper focus.

2.3.29 We do not have to speculate about whether natural gas use is going to decline. It will.

2.3.30 We do not have to agonize over how to get electricity for cold winter days. It will be there, and we will identify where it will come from through system planning processes that we already know and use.

2.3.31 We do, however, have to focus on who is most at risk in the Energy Transition, and make sure their often divergent interests are addressed.

2.3.32 We also need to focus on the immediate risk that capital expenditures right now will be stranded, underutilized, or become uneconomic for the remaining customers.

2.3.33 We have to accept that the technologies that are and will be available to replace natural gas for general service customers in the short and medium term are based on electricity, not hydrogen.

[111] Argument-in-Chief, para 154
[112] M8, p.55

2.3.34 None of these conclusions should be controversial.

2.4 *Stranded Assets*

2.4.1 One of the major risks associated with the Energy Transition falls under the general rubric of "stranded assets". This problem actually has a few different components.

2.4.2 ***When Is An Asset Stranded?*** In a classic sense, an asset becomes stranded when it is non-performing, what in the regulatory context would be an asset that is no longer used and useful.[113]

2.4.3 In the broader accounting sense, on the other hand, an asset is stranded if its value is less than its carrying cost. Lloyd's of London defines it as follows:

> *"Stranded assets are defined as assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities."*[114]

2.4.4 A similar definition is widely used throughout the world in many business contexts, especially as it relates to the Energy Transition and its impact on those in the fossil fuel business. In essence, what it means is that an asset is stranded if it no longer can be expected to earn its original economic return.

2.4.5 Under both USGAAP and IFRS, accountants are expected to test assets for impairment by comparing the income they are expected to generate in the future against their current carrying cost (and, in the case of IFRS, the fair market value of the asset less cost of sale). An asset which has its value impaired has to be written down, and the decline in value booked as a loss.

2.4.6 ***Stranding of Regulated Assets.*** Generally speaking, regulated utilities do not take asset impairment charges on regulated physical infrastructure just because assets are underutilized relative to the original plan.

2.4.7 The theory appears to be that the Fair Return Standard is calculated based on what **the utility** is entitled to receive in rates, not based on the value being delivered to **the ratepayers**. A pipe that is installed on the assumption that it will serve 1000 new

[113] Even Enbridge accepts this definition (Tr.14, p.109)
[114] https://www.lloyds.com/strandedassets

customers is not written down or considered impaired because it actually only serves 50 customers. From the point of view of the utility, it still expects to recover the full capital cost in rate revenue, so there is no impairment of carrying value. The impairment of the value to the ratepayers is not considered relevant.

2.4.8 The obvious exception to that is assets that are no longer used and useful at all. For example, in Germany, when a decision was made to close down nuclear stations before the end of their useful lives, that changed the ability to earn revenue from those assets, and they were considered impaired.[115]

2.4.9 ***The Impact of the Energy Transition on Asset Impairment.*** The Energy Transition raises the question of whether the conventional approach to asset impairment (i.e. stranding) for regulated entities is still applicable. If it is known that some portion of assets being put into service right now are not going to be fully utilized as planned in the future, does that change the responsibility of the utility with respect to those assets?

2.4.10 As SEC discusses in Section 3 of this Final Argument**,** Enbridge proposes to spend large amounts of new capital over the period 2024-2028, despite knowing that there is a likelihood some or all of that capital will not be fully utilized over its life as a result of declining demand. Notwithstanding this knowledge, Enbridge plans to add the full cost of that capital to rate base, presumably anticipating that it will be able to recover it in rates over time, whatever the level of its utilization to benefit customers.

2.4.11 In fact, Enbridge is not even making any attempt to assess the risk of stranding and future value declines of these new assets.[116]

2.4.12 SEC submits that this is no longer a sensible and prudent approach.

2.4.13 Enbridge should be required to assess the probability of full future utilization of each asset at or before the time it is brought into service. To the extent that it cannot demonstrate that the full value will likely be delivered to the ratepayers, it should not be allowed to add the full value to rate base.

2.4.14 A simple example may be appropriate. If Enbridge proposes to replace the pipes serving

[115] See, for example, E.O.N. making good progress implementing its strategy: retaining its nuclear power business in Germany means spinoff can remain on schedule, October 2015

[116] For example, see Argument-in-Chief, para. 4(b),(e), and (h)

a town or part of a town, it should prepare a calculation of the cost to do so, and the revenues it expects to generate from the customers in that town over time that are fairly applicable to these new pipes (as opposed to the rest of the system). This can all be done through normal cost allocation processes.

2.4.15 That calculation should include the probability that some or all of those customers will move away from using natural gas, whether or not there are external incentives to do so. It should also include the probability that some or all of that replacement system may have to be replaced in the future prematurely in order to carry hydrogen.

2.4.16 If, after taking into account those contingencies, the applicable revenue is not sufficient to cover the cost to build, Enbridge should either not build, or should segregate the cost that is covered by future revenues from the cost that is not.

2.4.17 Right now, Enbridge is putting assets into service knowing that in all probability some of them will become stranded. They likely can predict which assets are most at risk (for example an asset servicing a residential neighborhood versus industrial use). However, they do not need to worry about that, because they assume that the ratepayers will be required to pay for stranded or impaired assets just as much as for fully utilized assets.

2.4.18 SEC submits that practice should stop.

2.4.19 ***SEC Recommendation.*** SEC understands that such a change cannot be implemented on the evidence before the Commissioners in this proceeding. Instead, SEC submits that the Commissioners should order Enbridge to:

(a) Commission a study, for delivery to the OEB no later than the next rebasing, that analyses the accounting and regulatory rules associated with impairment of regulated assets in the context of the Energy Transition, and provides options for how the potential declining value of those assets to ratepayers can or should be reflected in the financial and/or regulatory records of the utility.

(b) Carry out a probabilistic assessment of future stranding/impairment for all assets brought into service in 2024 and thereafter, and file that assessment with the OEB annually until further notice.

2.5 ***Ratepayer vs. Shareholder Risk – The Regulatory Compact***

2.5.1 There has been much discussion in this proceeding about the regulatory compact, which– as described by Enbridge – is that once the regulator opines that a capital expenditure is prudent[117], the utility acquires an absolute right to recover the cost of that expenditure, and the fair return on the unrecovered rate base, no matter what happens in the future. All of the risk related to the eventual use and value of the asset falls on the ratepayers.[118]

2.5.2 SEC does not agree that Enbridge's interpretation of the regulatory compact is correct, nor is it consistent with the major case law on the subject.

2.5.3 However, in our view the issue does not arise in this proceeding, so the Commissioners do not need to go down the path of trying to figure it out. There is no point in this proceeding in which the Commissioners have to determine, for a future point in time, whether or under what circumstances the Applicant will be entitled to recover the capital expenditures it incurs over the next rate period.[119]

2.5.4 The one exception to that may be the Risk Reallocation approach described below, but we have concluded that option is premature in any case.

2.5.5 It therefore does not fall to the Commissioners to determine whether the SEC view that in law a set of risks relating to capital assets are specifically assigned to the shareholders, or the Enbridge view that prudently incurred capital spending is absolutely recoverable, is correct, None of the issues in this proceeding turn on an interpretation of the regulatory compact in Ontario and Canadian regulatory law.

2.5.6 In addition, SEC notes that the Energy Transition may present a new fact situation that has not previously been considered by the courts. Even to the extent that there is a right of recovery, what if there is no-one left to pay?[120]

2.5.7 SEC believes that understanding the legal aspects of the regulatory compact is in fact

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[117] Perhaps even if an expenditure is in fact prudent, whether or not the regulator says so (See Argument-in-Chief, para 24).

[118] Argument-in-Chief, para. 24. Despite having the opportunity to provide a more complete argument with respect to its view (see SEC's request, Tr.18, p.127), it appears that Enbridge plans to leave this for Reply, leaving whatever positions they assert unrebutted.

[119] Or, indeed, existing capital previously deployed.

[120] This was part of the analysis in the National Energy Board decision in the TransCanada Mainline Toll Restructuring case (See *Reasons for Decision* (National Energy Board – RH-003-2011, March 2013).

going to be important as the Energy Transition unfolds. However, SEC does not believe that it arises in this case.

2.6 *Possible Approaches by the Commissioners*

2.6.1 SEC submits that, at least conceptually, there are three types of approaches the Commissioners could take to deal with the Energy Transition. Variations on each of these may be proposed by parties in this proceeding:

(a) ***Incremental.*** This involves approving a combination of modifications to existing approaches, whether proposed by Enbridge or the parties or developed by the Commissioners, that incrementally reduce the potential impacts of the Energy Transition.

(b) ***Risk Reallocation***. Instead of trying to make the changes themselves, the Commissioners could transfer the problem to the shareholders by assigning the risks of the Energy Transition to them. This involves trusting market forces to generate pragmatic solutions.

(c) ***Planning Pause***. The Commissioners could focus on the fact that they should have had the benefit of a more detailed Energy Transition Plan from the start. This means sending Enbridge away to develop such a plan before authorizing any more rate increases.

2.6.2 The sections below deal with each of these possibilities in turn.

2.7 *Incremental*

2.7.1 This is the classic regulatory approach to deal with periods of change. The Commissioners can look at all of the various components of the Application before them, and identify areas in which they can either approve requests from Enbridge (with or without changes), or modify other parts of the Application, to incrementally reduce the risks (to the shareholders or the ratepayers) of the Energy Transition.

2.7.2 ***Relevance of Expected Energy Transition Scenario.*** This is also the approach that relies most heavily on the Commissioners' view of how the Energy Transition will actually unfold. If the Commissioners believe that the likely future is one in which the gas system continues to expand to serve the bulk of Ontarians, but the gaseous fuels delivered will change over time to hydrogen, then ratepayer money could be spent like venture capital on hydrogen or RNG research and development. Conversely, if the Commissioners believe that the likely future is one in which most building uses are electrified, then spending today should be focused on minimizing the risk of asset stranding or underutilization.

2.7.3 SEC believes that the evidence supports the latter future as being the most likely. However, even if the gaseous future ends up emerging, there is no downside to implementing incremental changes that focus on minimizing the risk of asset stranding or underutilization. On the other hand, if the Commissioners approve a modified Application reflecting a gaseous fuels changeover, and what actually unfolds is electrification, the cost of forecasting incorrectly could be substantial.

2.7.4 In short, the risks of being wrong are asymmetrical. This implies that the electrification future should be assumed for planning purposes. Since this is, in the opinion of SEC (and most expert commentators), the most likely future anyway, that works well.

2.7.5 SEC therefore recommends that, if the OEB wishes to respond to the risks of the Energy Transition with incremental modifications to the Application, it should do so with the assumption that they are addressing an electrification future.

2.7.6 ***Criteria for Incremental Modifications.*** In determining what to approve or not approve relative to the Energy Transition, SEC believes that specific criteria should be followed.

2.7.7 This approach is essentially a stopgap measure, moving in the right direction carefully while awaiting better information and analysis on which to base more decisive actions.[121] It is important that it be balanced and non-disruptive, yet directionally sound. That implies that the following criteria should be followed:

(a) ***Rates.*** Measures included should carefully balance upward and downward pressures on rates, so that rate increases, if any, are modest. This limits the risk that the solution will actually accelerate the move off gas in the short term through unintended price signals.[122]

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[121] In some respects this is a more robust version of "safe bets".

[122] See Tr.9, p.143 for comments from Mr. Goulding of LEI.. Enbridge, in discussing depreciation, appears to agree, saying: "Enbridge Gas believes the OEB should be concerned about requiring the use of methodologies which

(b) ***Risk Reduction.*** Each measure selected should demonstrate a meaningful reduction of Energy Transition risk.

(c) ***Existing Tools.*** Measures should be based on existing tools and be consistent with good regulatory policy. The intention is not to experiment.

(d) ***Prudence.*** Following on the last, the measures should be reasonable and prudent steps, not radical changes.

(e) ***Planning.*** The decision of the Commissioners should in any case include a direction to Enbridge to produce a detailed Energy Transition plan, such as that described by Dr. Hopkins[123], within a finite time frame.

2.7.8 ***Minimum Incremental Responses.*** Based on the above criteria, SEC suggests that a minimum feasible combination of Energy Transition measures would include the following:

(a) ***Capital Expenditure Limits.*** The OEB must require Enbridge to begin to substantially reduce its proposed capital spending in 2024 and over the test period. The OEB should approve a capital expenditure and in-service additions budget that targets maintaining its rate base at existing levels each year.[124] This would result in an in-service addition budget that equals the depreciation expense. Based on Enbridge's proposed depreciation methodology this would result in a 2024 in-service additions budget of $878M.[125] Excluding the Panhandle Regional Expansion Project ("PREP"), this would result in a reduction of the 2024 test year in-service additions, compared to what has been requested, of $422.9M.[126]

(b) ***Integrated Resource Planning.*** Enbridge should be required to ramp up its IRP

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would likely have undesirable consequences and accelerate the risk of stranding assets by encouraging customers to leave the system precipitously." (Argument-in-Chief, para. 496).

[123] M8, p.53-4, and that report in general.

[124] More specifically, the target should be to keep the Net PP&E component of rate base constant.

[125] 2-2-1, p.4, Ln 3 (2023-07-06). SEC recognizes that there is an interrelationship between the approved in-service additions and the depreciation expense. A lower 2024 test year in-service additions would result in a lower depreciation expense.

[126] 2024 In-Service Additions of $1300.0M (2-2-1, p.3, Ln 3(2023-07-06)) – 2024 Depreciation Expenses of $878M (2-2-1, p.4, Ln 3 (2023-07-06))

efforts to fill the gap created by the lower capital budget.

(c) ***Customer Connections Policy.*** The changes to the customer connections policy proposed elsewhere in this Final Argument – a five-year connection period to align with the DSC, and a 15 year revenue period to coincide with time of natural replacement of the furnace – should be implemented. This removes the bias in the current policies in favour of gas over electric, promotes customer choice, and reflects a more realistic assumption of how much revenue a new gas customer will deliver. The new policy should apply to infills, new subdivisions, and community expansions.[127]

(d) ***Depreciation.*** The harmonized depreciation approach proposed by Enbridge (adjusted to fix its most obvious flaws), or another approach that directly reflects the useful life impacts of the Energy Transition, should be approved and implemented. This shortens the period over which the Applicant recovers capital, and thus reduces the amount of potential stranded or underutilized assets. If Enbridge's proposal is used, the Commissioners should require a depreciation study that expressly deals with the Energy Transition, to be filed in the next rate case. This would leave Enbridge's proposal as an interim measure until a more comprehensive response to the Energy Transition can be implemented.

(e) ***Equity Thickness***. LEI's proposal to increase Enbridge's equity thickness by 2% should be approved. This proposal, which on its own is not justified, is acceptable when paired with strong capital expenditure mitigation and other measures such as those described here. Enbridge's proposal to have further increases after 2024 should be denied.

(f) ***Hybrid Heating.*** Enbridge strongly supports hybrid heating. The Commissioners should allow this initiative, but with the condition that it apply only where there is an existing gas furnace, and the new equipment is an electric cold climate heat pump and a smart controller. This supports the market for heat pumps, without creating additional gas connections or new furnaces that could become stranded.[128]

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[127] See Section 3.11.30 for further discussion related to community expansion.

[128] See Argument-in-Chief, para. 90-92. Mr. Neme agrees that allowing customers to decide whether to keep their gas connection or not can be a good transitional approach. However, SEC notes that the current Enbridge program focuses on new construction. Argument-in-Chief, para. 106, for example, ignores this.

(g) ***Community Expansion***. Enbridge should be required to ensure that its information packages and public messaging, in new communities it plans to serve, fully and fairly provide information on the homeowners' gas and non-gas options for space and water heating, and other uses that might include gas. This will facilitate more informed customer choice, and should discourage any new connections that may ultimately be short-lived.

2.7.9 SEC notes that another measure that could be part of an Energy Transition approach is the redesign of residential rates, either as proposed by Enbridge or in some other form. However, that issue is part of Phase 3, and so the Commissioners have not yet seen the full evidence on it in order to make a determination.

2.7.10 There are many other things that could be included in an Incremental approach, but are not appropriate because they have not been reviewed in sufficient detail in this proceeding. For example, one could implement some form of accelerated depreciation (beyond what has been proposed) and changes in cost allocation to reduce reliance on general service customers. Those and other options may be worth considering in the future, if appropriate evidence is provided to the OEB on which to make those decisions.

2.8 ***Risk Reallocation***

2.8.1 Several parties have floated the idea of reallocating the risks associated with new (but not existing) capital spending from the ratepayers to the shareholders.

2.8.2 On the face of it, this is an attractive concept for ratepayers. It provides the utility with flexibility to invest in the system based on real operational needs, while at the same time protecting the ratepayers from excessive investment that cannot be recovered in the future.

2.8.3 In the simplest case, the regulator can simply state that it is not approving the capital expenditures, or opining on whether they are necessary or prudent. Expressly, or even by implication, the regulator can say to Enbridge 'you incur these expenditures, you bear the risk'. This means that Enbridge would only be able to recover that capital as long as, and to the extent that, it is providing value sufficient to recover the cost in rates.

2.8.4 ***Enbridge's Position.*** Enbridge, predictably, does not like this concept at all. When Presiding Commissioner Moran floated a similar concept to the witnesses as a hypothetical, Ms. Giridhar said:

> *"I would suggest, Commissioner Moran, that <u>that would have a chilling effect on our ability to invest capital in the business.</u> The decisions that we would make are in the context of government policies that exist at a point in time. Given the mismatch between the useful life of our assets and the ability – I think that there was another individual that talked about political risk, policies may change.*
> *I think to hold Enbridge's investors responsible for events or energy transition that occurs in a way that couldn't have been factored in at a point in time would not be in keeping with the regulatory compact as we see it. So I think <u>we need a level of regulatory certainty for our investors to want to invest in the business</u>."* [emphasis added][129]

2.8.5 It is worth noting that, from the point of view of a ratepayer, what Enbridge is saying there is 'We will take those risks with <u>your</u> money, but we won't take those same risks with <u>our</u> money'. This puts a different spin on the concept of prudence.

2.8.6 In its Argument-in-Chief, Enbridge seems to challenge the OEB's ability to make such a decision. It says that this would be contrary to the regulatory compact that requires the company to make necessary investments, and then has the right to recover its full costs of those investments.[130]

2.8.7 ***SEC Position.*** SEC disagrees that the regulatory compact requires that the utility is permitted, in all circumstances, to recover the full cost of assets even if it is later shown that they no longer are used or useful, which may include assets that are underutilized. Both the prudence standard (when the asset is initially approved) and the used and useful standard have a role to play in rate-setting.[131] The OEB has broad discretion in setting just and reasonable rates. That discretion includes adapting to changing circumstances, such as the impact of the Energy Transition.

2.8.8 At the same time, SEC has come to the view that implementing a regulatory model that explicitly allocates the entire asset recovery risk to the utility is premature for a number of reasons.

[129] Tr.4, p.145-6
[130] Argument-in-Chief, para.41
[131] See *Reasons for Decision* (National Energy Board – RH-003-2011, March 2013

2.8.9 First, the OEB would need to better understand the magnitude of the risk, and the implications of shifting it entirely onto the shareholder. At this time, and as discussed later, Enbridge has not done even the most rudimentary analysis to determine the risk on both its existing assets or any new assets.[132] As a first step, the OEB should require Enbridge to assess the risk and report with the details to the OEB. SEC has recommended elsewhere in this Final Argument that, starting in 2024, Enbridge assess the impairment risk of each new capital addition, and provide an annual report to the OEB with those assessments.

2.8.10 Second, SEC recognizes that shifting this risk entirely on to Enbridge at this stage will result in changes to how the company operates. Considering the magnitude of capital spending, even if rate base does not grow (as SEC has proposed), the issue needs to be considered more broadly. The Commissioners would need to be confident, based on more complete evidence than is currently available, that there are no unintended consequences that may impact existing customers' ability to receive safe, reliable service that is priced in a reasonable way.

2.8.11 Third, the OEB will need to consider in much greater detail than has been explored in this proceeding what that specific risk reallocation approach would look like. This may involve providing the company with new tools to manage the risks that have not been considered to date. For example, when the then National Energy Board considered the need to restructure TransCanada's Mainline because it reached a level of fundamental risk, it provided the company with new tools and flexibility to manage the new risk that it was being required to bear.[133]

2.8.12 Fourth, the OEB will need to look carefully at the mechanics of a risk reallocation, including the process of determining prudence, the timing and amounts of capital to be included in rates, and other such issues.

2.8.13 ***Conclusion***. SEC believes that the Risk Reallocation approach in some form may need to be considered in the future, but is premature at this time.

2.9 ***Planning Pause***

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[132] Tr.11, p.150

[133] *Reasons for Decision* (National Energy Board – RH-003-2011, March 2013, p.2-3

2.9.1 ***A Proper Approach to Planning.*** The third approach starts with the understanding that, if this process had unfolded in the optimal way, it would have started with a detailed Energy Transition Plan from the Applicant.

2.9.2 That plan would have included an analysis of all of the risks, and an assessment of Enbridge's potential actions in the event each of those risks come about. It would have looked at impacts on workforce, and system planning policies, and customer connection policies, and many other things. Even if the ultimate 'business case' developed was the Gaseous Fuels option (i.e. some variation on the Diversified Scenario), it would include thorough consideration of the alternatives, such as electrification, and the off-ramps for the preferred option in the event that circumstances change.

2.9.3 Dr. Hopkins discusses this at some length in his report[134], and SEC agrees at a high level with his review. In fact, it is surprising that Enbridge has not done such a plan, if not for regulatory purposes, at least for its own understanding of its survival strategies.

2.9.4 If this had been done, the Commissioners would have a package of risk analysis, options, and contingencies, which would allow a robust consideration of Enbridge's plan.

2.9.5 Enbridge has not done this. Instead, the Application claims that no planning is possible until Ontario government policy is established, which will be in 2024 or 2025. It offers in the meantime a series of 'safe bets' that are, for the most part, things it is already doing or is mandated to do.[135] It seeks to bump up current revenues on the excuse of the Energy Transition (through equity thickness and depreciation changes), while taking no steps to mitigate risks such as stranded assets.

2.9.6 The discussion of the Energy Transition in this proceeding would have been much more productive if Enbridge had prepared an actual Energy Transition Plan.

2.9.7 ***Pressing the Reset Button.*** This raises the question of whether the Commissioners could simply identify the lack of a proper plan, and require that Enbridge prepare one.

2.9.8 SEC is aware that one or more parties may in fact propose a shorter approval period for rates in this proceeding, precisely for the purpose of allowing the Applicant to go back and prepare a detailed Energy Transition Plan. A two-year approval, with limited

[134] Most of Ex. M8 is useful in this respect, with particular value at 30-32, 35-38, 40-42, and 53-54
[135] Tr.3, p.29 et seq.

adjustments to rates and policies today, would allow the Commissioners to come back in 2025 with a full record on the Energy Transition to consider.

2.9.9 The problem with that approach is that a fixed time period may be too short or too long. It also may be seen by Enbridge as a message from the OEB to try to seek a political solution here, rather than a regulatory one. Having this dealt with by lobbying, rather than through evidence and rigorous analysis, may not be the best option.

2.9.10 SEC believes that there is an alternative way of doing this that accomplishes the same thing with more flexibility. The Commissioners could approve rates for up to five years, 2024-2028, but with very limited increases, if any at all. The depreciation and equity thickness proposals would be denied, since in this context they would be premature, and similar to the Incremental approach, over $7B of new capital spending would be reduced to less than $4.5B, essentially enough to keep rate base at its current level (see paragraph 2.7.8a).

2.9.11 The result of this would be rates that are flat or, given the claimed merger savings, declining.

2.9.12 However, the Commissioners would also direct Enbridge to go away and do a comprehensive Energy Transition Plan. Enbridge can take as much time as it needs to do that, and can wait for whatever policy direction it thinks is essential to its planning. When Enbridge comes back to the OEB with a plan that complies with that direction, that will kick off the next rebasing. It can be in two years, or five years, or ten years, but rates will not be increased from the 2024 rebasing level above inflation less productivity until that plan is tabled. Further, the ICM mechanism would not be available during that period, as a defence against increasing potential stranded assets.

2.9.13 SEC notes that the time and effort spent in this proceeding on the Energy Transition would not be totally lost. It would simply be augmented by additional and more thorough evidence.

2.9.14 ***Conclusion.*** SEC submits that a Planning Pause of the type proposed is a feasible approach to ensure that thoughtful planning for the Energy Transition takes place as soon as possible. It protects the ratepayers through control of rate increases, and it gives Enbridge full flexibility to carry out its own planning on its own schedule.

2.9.15 More important, perhaps, this approach makes no major changes to the status quo (except the defensive step of curtailing new capital so that it remains at historical levels rather than continuing to ramp up) until there is a much more complete evidentiary record on which to base decisions.

2.10 ***SEC Recommendation***

2.10.1 SEC submits that either the Incremental or the Planning Pause approach can be implemented in this proceeding, with positive benefits for both Enbridge and its customers. At this time, we do not believe that the Risk Reallocation approach can be implemented because of limitations in the evidentiary record.

2.10.2 As between the two feasible options, SEC recommends the Planning Pause approach, because the result is a more robust plan built on a better foundation. However, we would not consider implementation of the Incremental approach to be incorrect or problematic.

3 RATE BASE & CAPITAL SPENDING

3.1 *Overview*

3.1.1 Enbridge seeks approval of 2024 rate base, in-service additions, and capital expenditures that are significantly higher than in the past. All of this is happening at a time when capital spending needs to be reduced to reflect changes brought about by the Energy Transition.

3.1.2 The growth in Enbridge's rate base since its predecessor companies were last rebased has been substantial. The total OEB-approved 2013 rate base for Enbridge Gas Distribution and Union Gas was approximately $7.9B.[136] The proposed rate base for Enbridge for the test year 2024, excluding PREP is more than double at $16.2B.[137]

3.1.3 As part of the proposed 2024 rate base, Enbridge is seeking to include in its rates capital undertaken for the purpose of integrating Enbridge Gas Distribution and Union Gas because of the merger. This amount should be disallowed as it is contrary to OEB policy.

3.1.4 Enbridge is seeking approval for a 2024 test year capital expenditure budget of $1,470.3M and an in-service additions budget of $1,301M.[138] In reality, these amounts are significantly higher. In the Capital Update, Enbridge excluded both the capital expenditure and in-service additions related to the PREP, which it still plans to construct in 2024 and recover from ratepayers.[139] When PREP is included in the forecast, Enbridge plans to spend $1,665.1M in capital expenditures[140] and put $1,565M into service.[141] Over the five-year rate term, it proposes to spend an unprecedented $7.4B on capital expenditures.[142]

3.1.5 The proposed capital expenditures for 2024 reflect a material increase in capital spending compared to historical levels. When PREP is included, the capital expenditures for the

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136 2-1-1, p.4

137 Tr,11, p.197; 2-1-1, p.5

138 2-2-1, p.3. SEC notes that there is an inconsistency in the 2024 test year in-service additions of $1,300.9M shown in the pre-filed evidence 2-2-1, p.3 (2023-07-06) and $1,313.6M shown in 2.6-SEC-108 (2023-07-06) and Undertaking J11.7.

139 Tr.11, p.11

140 K11.2, p.9

141 K11.2, p.9

142 K11.2, p.9

2024 test year show a 43% increase over the annual average of the last five years of actuals (2018-2022).[143] On an in-service additions basis, the increase is 32%.[144]

3.1.6 Even without considering the impacts on its planning process and broader business due to the Energy Transition, the level of capital spending for which Enbridge is seeking approval is neither just nor reasonable. When Energy Transition is factored in, the unreasonableness of the request becomes even more stark.

3.1.7 Enbridge's planning process barely acknowledges the Energy Transition. Ms. Wade stated that, over the rate term, "the adjustments that [Enbridge] have made are not significant."[145] What is being incorporated into the capital planning process consists only of limited adjustments based on carbon pricing, voluntary fuel switching, some coordination with electricity LDCs, and the OEB's required IRP process.[146] Nowhere does the plan consider the risk of underutilized and stranded assets in a future where customers will be consuming significantly less natural gas.[147] Enbridge’s goal is to increase its rate base and expand its system. The implications of declining future use are considered problems for the future, not for today.

3.2 ***SEC Recommendation***

3.2.1 As proposed in paragraph 2.7.8a, Enbridge’s 2024 capital expenditures and in-service additions should be approved at a level that ensures that rate base grows little, if at all, during the rate term. This would result in a total 2024 in-service additions budget (inclusive of PREP) of approximately $878M.

3.2.2 The analysis below regarding Enbridge’s capital expenditure and planning process provides more than sufficient support that the OEB can require the necessary capital reductions while maintaining safe and reliable gas service during the rate term.

3.2.3 The OEB should also disallow the inclusion of the undepreciated costs of integration capital costs in rate base as doing so would be inconsistent with both the MAADs Handbook and MAADs Decision. It should also disallow $26.5M of 2023 in-service additions related to Enbridge’s imprudent actions in not seeking additional capital

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[143] Tr.11, p.113; K11.2, p.6
[144] Tr.11, p.120; K11.2, p.9
[145] Tr.11, p.165
[146] Tr.11, p.165-166
[147] Tr.10, p.182; Tr.11, p.192

contributions from connecting customers as forecast capital costs increased.

3.2.4 While SEC has proposed capital reductions beginning in 2024 as a way to balance the short-term needs of the company with the Energy Transition risk identified, the same criticisms discussed below regarding its planning process, equally apply to the 2023 capital expenditures and in-service additions. If the OEB agrees with our approach to setting 2024 rates, then it could make similar reductions to the 2023 bridge year capital additions as well.

3.2.5 SEC also believes the OEB should require Enbridge to start seriously considering Energy Transition risk in its capital planning process. This is a necessary requirement to mitigate risks and to properly assess the reasonableness of those capital expenditures.

3.3 Integration Capital

3.3.1 Enbridge seeks to include in its 2024 opening rate base $119M of integration capital.[148] The amount represents the undepreciated capital costs of integration capital additions as of the end of 2023.[149]

3.3.2 SEC submits the amounts should not be included in 2024 rate base. It is contrary both to the MAADs policy articulated in its MAADs Handbook[150] and to the decision approving the amalgamation of Enbridge Gas Distribution and Union Gas ("MAADs Decision").[151]

3.3.3 ***OEB Policy and MAADs Approval Are Clear That Integration Costs Are Not Recoverable.*** The OEB's MAADs Handbook is clear that "[i]ncremental transaction and integration costs are not generally recoverable through rates" [emphasis added].[152] In return, the OEB allows distributors to defer rebasing "to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction."[153] The MAADs Handbook does not restrict the period during which integration costs are not recoverable from ratepayers, nor their type.

[148] Tr.14, p.152, 1-9-1, p.21 (K14.3, p.22)
[149] Tr.14, p.152, 1-9-1, p.21 (K14.3, p.22)
[150] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016
[151] *Decision and Order* (EB-2017-0306/307), August 30, 2018
[152] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p.8 (K14.3, p.40)
[153] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p.9 (K14.3, p.41)

3.3.4 A utility is allowed to defer rebasing to allow it to benefit not just from savings achieved as a result of the amalgamation, but also from any efficiencies gained during the previous and the deferred incentive regulation periods. This is a bedrock principle of the OEB's MAADs policy. For Enbridge, this was significant because both of its predecessor companies had over-earned in every single year since they last rebased.[154]

3.3.5 In the MAADs Decision the OEB references this as part of its approval of only a 5-year deferred basing period, commenting that "[d]uring the last rate setting frameworks, both Union Gas and Enbridge Gas earned more than the OEB-approved return as evidenced by the earnings sharing mechanisms for both utilities."[155] By deferring rebasing, "[c]ustomers will not benefit from any efficiency gains from this previous period until the end of the rebasing period."[156]

3.3.6 Enbridge did not rebase in 2019, and so did not need to pass on those efficiencies already gained for a further five years.

3.3.7 This is all to help offset the costs of the transaction, which the OEB does not guarantee will be sufficient. It is not, as Enbridge implies, that the integration costs are to be paid only from the specific integration savings.[157] Rather, it is the broader savings that are achieved by deferring rebasing.

3.3.8 In the MAADs Decision approving the merger between Enbridge Gas Distribution and Union Gas Ltd., the Board approved a deferred rebasing period for the new, combined Enbridge of five years, on the basis that it "provides a reasonable opportunity for the applicants to recover their transition costs."[158]

3.3.9 The OEB turned out to be correct. Five years was more than sufficient to recover its integration costs. The evidence is that at the end of 2022, year four of the five-year deferred rebasing period[159], Enbridge had cumulatively over-earned by $231.4M.[160] The amount is net of integration costs and savings during that period, none of which was required to be shared with customers.[161] If the OEB requires, consistent with OEB policy

[154] 5.3-IGUA-30, Attachment 1
[155] *Decision and Order* (EB-2017-0306/307), August 30, 2018 p.23 (K14.3, p.38)
[156] *Decision and Order* (EB-2017-0306/307), August 30, 2018 p.23 (K14.3, p.38)
[157] Argument-in-Chief, para. 227
[158] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.22 (K14.3, p.37)
[159] Tr.14, p.169
[160] Undertaking J14.10, Attachment 1; Tr.14, p.168
[161] Undertaking J14.10, Attachment 1

and the MAADs Decision, the remaining $119M of undepreciated integration capital to be funded by Enbridge's shareholders, Enbridge would still have over-earned during the four-year period by over $112M.[162]

3.3.10 Enbridge, at the oral hearing and in its Argument-in-Chief, trots out several new arguments that were not mentioned in its written evidence to avoid the clear application of the OEB's policy and the MAADs decision.

3.3.11 First, it hangs its hat on the fact that the OEB was not unequivocal on the treatment of integration costs in the MAADs policy when it said that they "are not generally recoverable."[163] While the use of the term "generally" does signify that in some exceptional circumstances the OEB may allow recovery, integration-related capital costs like these are surely not that situation.

3.3.12 There is nothing exceptional about Enbridge incurring both capital and O&M costs, whether long-lived or otherwise. Integration capital costs are not unique, and the OEB, in the MAADs Handbook, was not blind to this fact. The filing requirements attached the MAADs Handbook explicitly require the identification of all incremental costs of the transaction and use as an example the purchase of new IT systems.[164]

3.3.13 The OEB was well aware during the Enbridge Gas Distribution/Union Gas MAADs proceeding that Enbridge was planning to spend amounts on integration-related capital costs[165] and made no such carve-out to its policy when it approved the five-year deferral period meant to allow it the opportunity to recover its transition costs.[166] In fact, in that MAADs proceeding, Enbridge's support for its proposed 10 year deferred rebasing period was based on the time it said it required to recover the total integration capital costs—not just the revenue requirement related to those costs during the deferred rebasing period.[167]

3.3.14 Second, Enbridge is also incorrect when it claims that denying recovery of the undepreciated integration capital costs would be inconsistent with the 'benefits follow

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[162] Tr.14, p.170

[163] Argument-in-Chief, para. 22

[164] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, Schedule 2 - Filing Requirements for Consolidation Applications, p.6

[165] See 1-9-1, p.3, Table 1 which shows the forecast capital investment costs that were provided in the MAADs proceeding.

[166] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.22 (K14.3, p.37)

[167] See for example, EB-2017-0306/0307, Reply Argument, para. 75-77; EB-2017-0306/0307, Exhibit B-1, p.26; EB-2017-0306/0307, Undertaking J2.4;

costs' principle.[168] Enbridge has not provided any evidence that the specific integration capital costs are the primary drivers of most of the integration savings. If anything, the evidence suggests otherwise. Most of the achieved savings, all of which are O&M costs[169], have nothing to do with integration-related capital projects.[170] They are related to things like organizational restructuring (e.g., reduction in headcount due to position redundancies) and the alignment of processes and procedures.[171]

3.3.15 Enbridge was granted the deferred rebasing period based on a set of 'rules' that allowed it to benefit, while having to bear all the integration costs. It would be grossly unfair for the OEB to now allow it to pass on a significant amount of integration costs to customers, especially after it has reaped those benefits.

3.3.16 The OEB should also be cautious of Enbridge's claims that it "credited" customers with $86M in savings from the integration in its 2024 O&M budget.[172] Enbridge has not actually credited customers with anything. The amount represents its calculation of annual savings achieved in 2023, based on various cost-saving measures. Essentially, it is an avoided cost analysis.[173] As the O&M budget has largely been settled, this claim was not subject to examination during the oral hearing and remains untested.

3.3.17 Third, for the first time during the oral hearing, Enbridge argued that some of the integration capital projects would have been necessary regardless of the amalgamation.[174]

3.3.18 At this stage, it is impossible to determine which projects would have been undertaken, as well as their scope and timing. What is known is that, until its examination-in-chief, Enbridge had never put forward this position. It had always maintained that integration capital consisted of "expenditures required to integrate EGD and Union onto common systems, processes, and facilities."[175] Furthermore, a review of the list of projects[176] reveals that many would not have needed to be completed either in the absence of the merger or within the time frame required by the merger. The latter category is particularly difficult to separate. Most of the integration capital projects are IT related,

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[168] Argument-in-Chief, para. 236
[169] 1-9-1, p.25
[170] 1.9-CCC-25d; Undertaking JT 1.9, Attachment 1
[171] 1.9-CCC-25d, also see Attachment 1; Undertaking JT 1.9, Attachment 1
[172] Argument-in-Chief, para. 231
[173] See Undertaking JT 1.9
[174] Tr.14, p.147
[175] 2-5-3, p.18 (K14.3, p.8)
[176] 1-9-1, Attachment 1 (K14.3, p.30-33)

which generally have a shorter lifespan than other utility assets. Therefore, if Enbridge is merely undertaking IT work that it would have had to do a few years later as a result of the integration, then the replacement for that new IT system will also occur earlier than it would have otherwise.

3.3.19 Fourth, Enbridge argues that if the OEB does not allow the inclusion of undepreciated capital costs into the opening rate base, it will have "a chilling impact on future amalgamations and on utilities committing appropriate capital resources to fully recognize available amalgamation savings."[177] As it relates to the impact on future amalgamations, this is an issue that utilities can raise in the context of the OEB's announced MAADs policy review[178], not a reason to retroactively apply a new interpretation to benefit Enbridge. The merger was not driven by forecast savings and capital recovery policy; rather, it was the natural result of a decision made in 2017 by their conglomerate parent companies, Enbridge Inc. and Spectra Energy, to amalgamate.[179]

3.3.20 ***Enbridge Has Borne None of the Integration Capital Costs.*** Enbridge has not actually borne any of the costs of integration capital during the deferred rebasing period. When it claims that "integration capital was not recovered through base rates during the deferred rebasing term"[180], this is not actually correct. Like all of its other capital, excluding ICM projects which are individually approved and funded by a rate rider, it is funded from the revenue raised from base rates during the IRM period. Individual capital projects are not approved until they are sought to be added to the test year rate base.[181]

3.3.21 According to Enbridge's logic, no non-ICM capital costs are recovered through base rates during the IRM term. We know this is not true. Enbridge further tries to claim that these costs were funded from integration savings but has filed no evidence demonstrating that the integration spending was in any way connected or contingent on achieving any integration savings.[182] Regardless of how one views the matter, Enbridge has significantly over-earned, even after including integration costs in its earnings-sharing calculation to reduce earnings. Therefore, it cannot credibly claim that it shouldered any

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177 Argument-in-Chief, para. 236

178 See OEB Letter, Re: Evaluation of Policy on Utility Consolidations Ontario Energy Board (EB-2023-0188), July 27 2023

179 See Press Release: 'Enbridge and Spectra Energy to Combine to Create North America's Premier Energy Infrastructure Company with C$165 Billion Enterprise Value' (K15.2, p.18)

180 2-5-3, p.2-3 (K14.3, p.3-4)

181 Tr.14, p.159

182 Argument-in-Chief, para. 237

of the integration capital costs.

3.3.22 Enbridge is correct that it excluded integration capital from the calculation of the ICM materiality threshold[183], but based on SEC's review, this exclusion did not actually affect the amount of incremental funding it received.[184] At the very least, as Ms. Dreveny put it, "I don't think it would have had a huge bearing, no."[185]

3.3.23 ***OEB Staff's Proposal Contrary to MAADs Decision***. The OEB should also reject the OEB Staff submission that Enbridge be allowed to add 50% of the undepreciated integration capital costs to the rate base, on the basis that the MAADs policy was developed in the context of permitting a 10-year deferred rebasing period.[186] SEC submits that this entirely ignores the OEB's MAADs Decision when it approved the merger.

3.3.24 In the MAADs Decision, the OEB rejected Enbridge's argument for a 10-year deferred rebasing period and explicitly found that the 10-year deferred rebasing in the MAADs Handbook was adopted to incentivize the consolidation of electricity distributors. It stated that the situation for the merging gas utilities (Union Gas and Enbridge Gas) was very different.[187] In the specific context of the merger, the OEB approved a 5-year rebasing period, which it found would provide Enbridge a reasonable opportunity to recover its transition costs.[188] To allow the company to now recover 50% of the undepreciated capital related integration costs is directly contrary to the MAADs Decision.

3.3.25 ***Post-Deferred Rebasing Period Integration Capital Projects Similarly Not Recoverable.*** Starting in 2024, Enbridge has stopped categorizing expenses as integration capital, even though they meet its own definition of "expenditure required to integrate EGD and Union onto common systems, processes, and facilities."[189] SEC submits that capital expenses which are required to integrate the two former companies should be considered integration costs and should not be recoverable from ratepayers, regardless of when they were incurred—either during or after the deferred rebasing period.

183 2-5-3, p.2 (K14.3, p.3); Tr.14, p.157-158; Argument-in-Chief, para. 228
184 Enbridge had approved ICMs in EB-2018-0405, EB-2019-0194, EB-2020-0181, and EB-2021-0148
185 Tr.14, p.158-159
186 OEB Staff Submission, p.57
187 *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.23 (K14.3, p.38)
188 *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.22 (K14.3, p.37)
189 2-5-3, p.18 (K14.3, p.8)

3.3.26 Two of these projects, the construction of the GTA East and West facilities at a total cost of $67.3M[190], were deferred as part of the Capital Update from 2023 to 2026.[191] The deferral of those two projects was the reason the amount that Enbridge sought to add to the rate base in 2024 was reduced as part of the Capital Update.[192] The fact that they were deferred in time does not change the admitted driver of the project. Real estate consolidation projects are the clearest examples of projects that would never have been undertaken at all in the absence of the merger.

3.3.27 There are also other projects that meet the same definition[193], including the Contract Market Harmonization project ($19.2M) and the General Service Rebasing Changes project ($17.9M).[194] Enbridge admits that both projects are required to implement rate harmonization, which is only necessary as a result of the merger.[195] Without a merger, there would be no need to harmonize rate classes across what would otherwise be different utilities. While not mentioned in Undertaking J14.13, Ms. Dreveny stated during the oral hearing that the London Facilities project ($49.5M)[196] was similar to the GTA East and West projects, as they are all consolidation projects driven by the merger.[197]

3.3.28 Although none of the above projects are forecast to be in service in 2024, SEC submits that the OEB should make it clear to Enbridge now that these costs will never be recovered from customers, consistent with the MAADs Handbook and the MAADs Decision.

3.4 ***Capital Update***

3.4.1 Enbridge filed its application in late fall 2022, which included forecast capital spending beginning in 2023. Roughly half a year later, it filed its Capital Update, resulting in very significant changes to its AMP. This update was necessitated by changes in its capital plan that arose during the 2024 budget process.[198]

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190 See 1-9-1, Attachment 1 (2022-10-31) Lines 1 and 5
191 Tr.14, p.145, 177
192 Tr.14, p.145
193 Undertaking J14.13
194 2-6-2, Appendix A, p.61 (K14.3, p.53)
195 Tr.14, p.180-181
196 Tr.14, p.181
197 2-6-2, Appendix A, p.61 (K14.3, p.53)
198 2-5-2, p.1

3.4.2 SEC recognizes that circumstances change - some projects get delayed, and new requirements arise. What is concerning is the extent of changes to Enbridge's capital plan over such a short period.

3.4.3 For the year 2023 alone, excluding PREP, Enbridge deferred or canceled 387 projects, amounting to approximately $277M in capital spending.[199] When the delay of the PREP project from 2023 to 2024 is factored in, the total capital spending for projects initially included in the AMP for 2023, but now excluded, is approximately $553M.[200] More than a third of the forecasted 2023 projects included in the AMP were delayed or canceled, measured in total spending. To fill the 'gap' in its forecast budget, Enbridge brought forward and added a large number of new projects to 2023.[201] As Mr. Wellington agreed, this represents a very significant amount of change in a short amount of time.[202]

3.4.4 All of this reflects a capital planning process that clearly lacks a firm grasp of the projects it needs to undertake, and what it will actually complete. Enbridge was already making material changes to its spending forecast well before it filed the Capital Update. These changes became apparent when it submitted interrogatory responses in March 2023, revealing that several significant capital projects were not progressing on schedule, with some not moving forward at all.[203]

3.4.5 How Enbridge set the updated 2023 and 2024 capital budgets is even more concerning. It did not re-run its planning or prioritization process with updated information.[204] Instead, it merely adjusted the 2023 and 2024 capital budgets without using its prioritization system, which is designed, in part, to determine the timing of various projects. Enbridge plans to re-run this prioritization process during its next AMP update, to be filed in October of next year[205]

3.4.6 Essentially, for 2023 and 2024, Enbridge manually determined which projects would be deferred and which would be advanced. Given the magnitude of these changes, the systematic process outlined in the AMP was effectively discarded for the Capital Update. Enbridge cannot on one hand claim that the "AMP is optimized to ensure effective

[199] Tr.11, p.109; JT 5.12 (K11.2, p.217)
[200] Tr.11, p.122
[201] 2-5-4, p.3
[202] Tr.11, p.122
[203] See for example, 2.6-SEC-117
[204] Tr.11, p.122-123
[205] Tr.11, p.122-123

allocation of the approved capital envelope dollars"[206], yet disregard that very optimization process as part of the Capital Update. As a result, it is now unclear how the OEB can have any confidence in the proposed spending levels and the underlying planned capital work for the bridge and test years.

3.4.7 The number of projects that are not merely deferred by a year or two but are either canceled or postponed beyond 2032 is also substantial. Comparing the projects listed in the original response to interrogatory 2.5-CCC-50, which details every capital project and its spending for each year within the 10-year AMP period, with the updated version filed with the Capital Update, reveals a significant number of projects that are no longer being pursued.[207] It is concerning that so many capital projects, once deemed urgent enough to be included in the 2023 and 2024 capital budgets, now appear to be unnecessary, at least for the next decade. Enbridge's response during the oral hearing was that the work will likely still be completed and reintroduced in its next AMP planning process.[208]

3.4.8 While Enbridge's response may partially address one question, it raises a host of new ones. We do not know which projects will be reintroduced into the AMP or when. More challenging is that the 10-year AMP, along with a substantial portion of the significant pre-filed evidence, interrogatories, and Technical Conference undertakings based on that AMP, are no longer accurate. Enbridge has not adequately updated the other years, even though it is aware that certain projects will neither occur as initially forecasted nor proceed at all within the AMP period.[209]

3.4.9 In short, the capital evidence in this proceeding is, by Enbridge's own express admission, materially wrong.

3.5 ***Utility System Plan Evolution***

3.5.1 Enbridge's AMP is a core part of its broader Utility System Plan ("USP"). This is the fourth USP that Enbridge has filed since the merger. Each iteration involves Enbridge asking for and spending more money than the last.[210]

3.5.2 When it originally filed its first USP as part of its 2019 rates application, Enbridge

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[206] Undertaking J12.4, p.1
[207] 2.6-CCC-50
[208] Tr.11, p.124
[209] Tr.11, p.125-126
[210] Tr.12, p.12

forecast spending of $4,974M over the 2021 to 2025 period.[211] Just two years later, when it filed a new USP as part of its 2021 rates application, its forecast spending for the same period had increased by more than $1.3B, totaling $6,305M.[212] After filing this application and adjusting to remove non-core spending that was not included in previous USPs[213], the forecast spending for the same period increased yet again to $6.9B.[214] The trend continued after the Capital Update; when including the PREP (which had been included in all other versions of the USP), the forecast capital spending for the 2021 to 2025 period now exceeds $7B.[215]

Capital Expenditures by USP Categories								
Total Expenditures ($M)	**2021**	**2022**	**2023**	**2024**	**2025**	**2021-25**	**Non-Core**	**Adjusted 2021-25**
EB-2018-0305 (1)	1,037	961	1,011	988	977	4,974	0	4,974
EB-2020-0181 (2)	1,271	1,406	1,164	1,352	1,112	6,305	0	6,305
Application (3)	*1,223*	1,403	1,562	1,491	1,471	7,150	245	6,905
Capital Update (4)	*1,248*	*1,378*	1,408	1,469	1,624	7,127	326	6,801
Capital Update (w PREP) (5)	*1,248*	*1,412*	1,431	1,664	1,631	7,386	326	7,060

Italics denotes actuals (1) EB-2018-0305 C1-1-1, p.39 [K12.1] (2) EB-2020-0181, C-1-1, p.45 [K11.2, p.11] (3) 2-6-1,. p.38 [K11.2, p.12] (4) 2-6-1, p.38 (Updated) [K11.2, p.13] (5) Ft 4 with addition of PREP

3.5.3 Enbridge has not demonstrated that there were any fundamental flaws in its previous AMPs that would require such a significant increase in spending over the same period in each subsequent version. When asked about the change, Enbridge pointed to an AMP developed based on its "understanding of our asset health and risk at that point in time, as well as, it would not have considered any inflation."[216]

3.5.4 SEC understands that as time goes on, Enbridge will have new or better information regarding the condition of its assets and risks. However, one would expect that the additional information would generally not point in only one direction - toward greater assets requiring replacements and higher risk. New information, especially its impact on risk, and particularly as it implements a more robust planning process, should also lead, in certain circumstances, to a more nuanced understanding of its assets' condition and the risks they may pose. Mr. Wellington was correct when he commented that "things would

[211] EB-2018-0305, C1-1-1, p.39 (K12.1)
[212] Tr.11, p.127; EB-2020-0181, C-1-1, p.45, Figure 6 (K11.2, p.11)
[213] Tr.12, p.8; Tr.11, p.130
[214] 2-6-1, p.38 (October 31, 2022) (K11.2, p.12)
[215] 2-6-1, p.38 (June 16, 2023) (K11.2, p.13), with the addition of PREP spending
[216] Tr.12, p.12

be expected to change over time, and it could be for better or it could be for worse."[217] It seems that for Enbridge, time only results in things getting worse (i.e., increasing the proposed capital spending).

3.5.5 Regarding inflation, it is incorrect to say that previous AMPs, and thus USPs, did not incorporate inflation. Each of the previous AMPs was based on current-year costs with an inflation rate applied.[218] While over the last two years, actual inflation may have been materially higher than what was forecast, that, at best, accounts for only a small portion of the total increase in proposed capital spending.

3.6 ***Capital Planning Process and Execution***

3.6.1 The core of Enbridge's capital planning process is the categorization of proposed capital work into three main categories of investments: compliance, mandatory, and value-driven.[219]

3.6.2 Compliance investments are capital work to meet laws, regulations, codes and standards and internal policies.[220] Mandatory investments includes those where a risk threshold has been exceeded, involve third-party relocations, or meet the economic feasibility tests in EB0 134 and 188.[221] Both of these categories of capital work must be completed within a required time frame.[222] [223]

3.6.3 Value-driven investments encompass all others, where Enbridge determines timing based on its value framework, which measures the benefit to ratepayers of the specific project.[224] Compliance and mandatory projects have fixed timing, whereas value-driven projects can have either fixed timing, when the project needs to be completed within a specific time frame because it's a multi-year project, or flexible timing (i.e., timing optimized based on value).[225]

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[217] Tr.12, p.12

[218] See EB-2018-304, C1-2-1, p.47 and EB-2020-0181, C-2-1, p.65

[219] SEC notes that the Capital Update does not appear to follow this normal methodology.

[220] Tr.11, p.136-137; 2-6-2, p.46 (K11.2, p.35)

[221] Tr.11, p.136; 2-6-2, p.46 (K11.2, p.35)

[222] 2-6-2, p.46 (K11.2, p.35); Tr.11, p.139

[223] It should be noted that the use of the terms Compliance and Mandatory are reflections of Enbridge's view that these projects must be done, and in a predetermined time frame. It is not clear that an independent view of the projects put in those categories would determine that they are all correctly characterized as such.

[224] Tr.11, p.137; 2-6-2, p.46 (K11.2, p.35)

[225] 2-6-2, p.46 (K11.2, p.35); Tr.11, p.139

3.6.4 After inputting all possible investments into its optimization software, Copperleaf, Enbridge sets a total overall budget for the 10-year AMP period. Based on that constraint, the software determines a proposed annual budget and project list by optimizing the project categories based on the investment categories and value scores.[226] The total value of all investments that were considered averaged $1.429B per year over the AMP period.[227]

3.6.5 Enbridge ultimately settled on an average annual capital expenditure budget during the AMP period of $1.33B per year (pre-Capital Update, approximately $1.2B per year plus an annual increase for inflation)[228], representing approximately 93% of the possible spending.[229]

3.6.6 Enbridge chose this budget constraint on the basis that when it ran the optimization software for any lower amount it failed, as it could not accommodate all investment with fixed timing.[230] This is highly misleading.

3.6.7 It may be the case that the optimization failed because not all investments with fixed timing could be accommodated, but that is only after Enbridge included $181M a year in non-fixed timing value-driven projects.[231] If it had further deferred or cancelled those projects, which have flexible timing, it could have reduced its proposed spending by at least that amount per year.[232] When asked about this, its only response is that if it had done so it could not maintain safe and reliable operations.[233] Clearly, that cannot be the case as those projects, by definition, are not either compliance or mandatory based, and so the risk threshold is not so high as to require the work to be done in a specific time frame.

3.6.8 All of this is on top of approximately $198M a year in value-driven projects that have fixed timing.[234] For value-driven projects, fixed timing is input so that multi-year projects in Copperleaf do not get pushed into a single year.[235] However, this does not mean that

[226] 2-6-2, p.253 (K11.2, p.21)
[227] Tr.11, p.139; 2.6-SEC-140, Attachment 3 (K11.2, p.29)
[228] Tr.11, p.140; 2-6-2, p.253 (K11.2, p.21)
[229] Tr.11, p.141
[230] Tr.11, p.140; 2-6-2, p.253 (K11.2, p.21)
[231] Tr.11, p.141; K
[232] Tr.11, p.143
[233] Tr.11, p.143
[234] Calculated based on the information provided in 2.6-SEC-141, Attachment 3 (July 7, 2023)
[235] 2-6-2, p.256 (K11.2, p.24)

there is no flexibility regarding when the project begins. In doing so, is treating a project that is not mandatory as if it were. This appears to be a significant flaw in how its optimization process works.

3.6.9 The level of flexibility that Enbridge has is supported by a review of its, somewhat different, classification of its material capital projects, which it defines as projects over $10M.[236] For these projects, Enbridge classifies them as 'Compliance,' 'Must Do' (further broken down into intolerable risk, third-party relocation, and must-do work with sufficient history and risk), or neither.[237] The 'Must Do' category generally equates to mandatory investments.[238]

3.6.10 The total number of material capital projects (as part of the Capital Update) included in the AMP is 46 projects valued at $2.27B (excluding capitalized overheads). The total number of 'Compliance' or 'Must Do' projects represents 14 projects with a total cost of $1.45B.[239] This means that 70% of the material capital projects, representing about 35% of the total material capital project costs, are not 'Compliance' or 'Must Do'.[240]

3.6.11 All of this suggests significant flexibility regarding the level of capital work that Enbridge claims must be done.

3.6.12 Enbridge's track record demonstrates that even if the OEB accepted the proposed capital work was appropriate, it will not be able to actually execute it. Enbridge's recent history shows that it undertakes less capital work than it has forecasted each year. Over the past 5 years, it has underspent on average by more than 5%. This includes a reduction to the 2023 forecasted capital expenditures of 9.7% compared to what was filed in the initial application (inclusive of PREP), and it was filed with more than 6 months left in the year. The same issues that plagued Enbridge in 2023, that required the Capital Update, are likely to once again occur in 2024, a year where it proposes to undertake even more capital work.

[236] Tr.11, p.167

[237] Tr.11 p.167-168

[238] Tr.11, p.168; 2.6-SEC-149b (K11.2, p.77)

[239] Tr.11, p.169-170. This includes $347M for the Dawn to Curunna project, which Enbridge notes should be included as 'Must Do – Intolerable Risk' (See 2.6-SEC-149b(iii))

[240] Tr.11, p.170-171

Capital Expenditures ($M)	2019	2020	2021	2022	2023
Forecast (1)	1,085.7	1,081.0	1,428.1	1,444.3	1,605.7
Actual/Revised Forecast (2)	1,087.4	1,007.2	1,310.8	1,437.1	1,450.1
Variance	***0.2%***	***-6.8%***	***-8.2%***	***-0.5%***	***-9.7%***
Average Annual Variance					***-5.0%***
(1) 2019-22: 2.5-CCC-49e; 2023: 2-1-1, p.5 (2022-10-31)					
(2) K11.2, p.6					

3.7 *Value Framework*

3.7.1 Enbridge's value framework assesses projects across different asset types to determine their relative value to ratepayers.[241] For each potential investment, Enbridge measures the impact of the project on various metrics that reflect the change in risk if the work is completed, while also quantifying all other benefits.[242] It then translates these risk changes and quantified benefits into monetary terms.[243] These quantified benefits are then compared against the cost of the investment to arrive at a value score, which is expressed in thousands of dollars.[244]

3.7.2 Enbridge's value framework essentially performs a cost-benefit analysis. It calculates the costs and compares them against the benefits. However, when reviewing the list of projects that Enbridge proposes for 2023 and 2024, a significant number have a negative value score, meaning the costs of the projects outweigh the benefits.

3.7.3 A review of the list of projects and their scores in Undertaking J14.6 (which is based on the updated version of Undertaking JT 5.13) supports this. Of the value-driven projects being undertaken in 2023 and 2024, 77% and 73%, respectively, have negative value scores, meaning the costs exceed the calculated benefits. This represents more than $111M in spending over those two years on projects that do not pass Enbridge's own cost-benefit analysis. These projects should not proceed, and those that have are, on their face, imprudent.

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241 Tr.11, p.148

242 Tr.11, p.148

243 See Undertaking JT 5.10; 2.6-CCC-49. The company, and its parent Enbridge Inc. use the models and methodology across all its affiliates. It has spent considerable effort in developing the measures and model, so much so that it has sought (and received) confidential treatment over derivation of specific value (*Decision on Confidentiality* (EB-2022-0200), July 12 2023, p.5,8).

244 Tr.13, p.138

Undertaking J14.6		
	2023	**2024**
Total # Value-Driven Projects	113	128
No. Value -Driven Projects (Value Score >=0)	26	35
No. Value-Driven Projects (Value Score <0)	87	93
Total Value-Driven Capital Expenditures	$51,275,838	$101,301,339
Value-Driven CapEx (Value Score >=0)	$8,524,288	$32,873,887
Value-Driven CapEx (Value Score <0)	$42,751,550	$68,427,452

3.7.4 The list of value-driven projects that Enbridge actually forecasts to undertake is much larger than what is included in Undertaking J14.6. While the reason for this discrepancy is unclear, the undertaking appears to reflect only a small portion of the total value-driven spending that Enbridge has planned for 2023 and 2024.[245] When one extrapolates the percentage of value-driven capital expenditures in 2023 and 2024 that have a negative value score to the total value-driven spending, this results in $602M in spending that is prima facie imprudent.

3.7.5 During the oral hearing, when presented with questions about why it was pursuing so many projects with negative value scores, Enbridge's witnesses cited several reasons, including existing commitments, operational risk, and the notion that the reduction in risk captured does not indicate which risks are higher.[246] Mr. Wellington, when pressed on why these negative value scores were being prioritized, commented that "[t]he value score is, I'd say, one dimension of many that we have to consider."[247] This statement just confirms the undeniable conclusion that the value score means little to Enbridge.

3.7.6 Even if one views the value-driven projects solely as a comparative exercise used for prioritization purposes, the choices of investments that remain in the capital plan, and those removed as part of the Capital Update, demonstrate that Enbridge is making imprudent decisions. Enbridge disproportionately removed projects with higher value scores.[248] Contrary to Enbridge's suggestion that this may be the impact of certain real estate investments that have high value scores such as furniture projects[249], the pattern is consistent across most asset classes, including core capital asset work such as distribution

[245] See 2.6-SEC-141, Attachment 3. A review of the table shows that Enbridge forecasts to spend in 2023 $462,5M, and in 2024 $340.3M on value-driven projects.

[246] Tr.13, p.141-142

[247] Tr.13, p.142

[248] See the sorted version of Undertaking JT 5.13 included in K11.2, p.52-76

[249] Tr.11, p.158

pipe.

3.7.7 Once again, when presented with this information at the oral hearing, Enbridge's response raised more questions about the competence of its capital planning process. Mr. Wellington said that one reason might be that the asset class manager would have understood the priority of the project relative to others.[250] However, the entire point of the value framework is to objectively prioritize projects based on their relative value scores across asset types.[251] Enbridge should be prioritizing projects based on these value scores. If Enbridge believes that this process is not properly assessing relative value, then the entire Value Framework needs to be thoroughly reassessed, and the OEB cannot rely on it at all for the purposes of supporting the proposed budget.

3.7.8 Enbridge's AMP may say that it has a "clear framework for asset investment decision-making", but the evidence tells the opposite story.[252] Enbridge prioritizes capital spending even when the analysis indicates it should be doing significantly less.

3.7.9 ***Value Framework Measures.*** Enbridge's framework includes many different value measures that capture the benefit or change in risk by undertaking a specific project.[253] However, what it does not include is any assessment of the risk associated with doing the project itself. This is a significant omission in assessing the value of a given project to ratepayers.

3.7.10 ***Value Measures Do Not Consider Risk of Undertaking the Project Such as Underutilization.*** In the context of the Energy Transition, investing in new capital assets, many of which have a long physical asset life, includes the risk that the asset will be underutilized or even stranded. Enbridge does not have, or at least has not admitted to using, any measure as part of its value framework that addresses future utilization and the risk of underutilization of an asset.[254]

3.7.11 SEC submits that this is extremely problematic. Enbridge recognizes that some assets have physical lifespans of over 60 years[255] , while both its overall AMP planning horizon

[250] Tr.11, p.160
[251] 2-6-2, p.47
[252] 2-6-2, p.45 (K11.2, p.34)
[253] 2-6-2, p.47-48 (K11.2, p.36-37)
[254] Tr.11, p.150
[255] Tr.11, p.150

and the load forecast it may use to assess any specific investment cover only 10 years.[256] Mr. Sanders, Enbridge's Senior Vice President of Operations, candidly admitted when asked directly how Enbridge was considering future underutilization in asset planning, "it's not something that we're doing actively, right now."[257]

3.7.12 The entire concept of a future where an asset would be underutilized seems almost foreign to Mr. Sanders and Enbridge. Mr. Sanders said he had "never seen the circumstance where an asset would be underutilized," and believes that assets "will continue to be used and useful into the future."[258]

3.7.13 This reflects a fundamental problem in how Enbridge views the future, highlighting why a robust risk analysis needs to be incorporated into its value framework and capital analysis. It is undeniable that the risk exists. How it is measured and considered is a different question, but one which, to date, Enbridge has not addressed.

3.7.14 Enbridge currently forecasts demand only out to 10 years[259] and does not consider any scenarios of declining demand on a project-by-project basis, whether before or after that forecast period.[260] The consideration of future underutilization risk should be no different from the many other risks that it does consider as part of its value framework, some of which are undoubtedly already not easy to measure.

3.7.15 ***GHG Emissions Measure.*** One of the metrics Enbridge does consider is avoided GHG emissions that result from completing a proposed investment.[261] However, this metric is too narrow, as it only focuses on the its own GHG emissions, and not those of its customers.[262]

3.7.16 Moreover, it asymmetrically measures only reductions in Enbridge's GHG emissions, not emissions that will be increased by the investment. For example, a new pipeline may require incremental compression, which would increase GHG emissions.[263] A proper

[256] Tr.12, p.150
[257] Tr.11, p.151
[258] Tr.11, p.152
[259] Tr.12, p.105, 107
[260] Tr.11, p.107
[261] Tr.11, p.153; 2.6-CCC-49, p.6-7 (K11.2, p.140-141); 2-6-2, p.45 (K11.2, p.34)
[262] Tr.11, p.154
[263] JT 5.10, Attachment p.129-134

measure, or potentially a separate measure, would examine changes in GHG emissions resulting from the investment, both from Enbridge and downstream of it. This would ensure that it assesses the overall impact of the investment on GHG emissions.

3.7.17 ***Hydrogen Ready Measure.*** One of the potential future options that Enbridge sees for its gas infrastructure is the delivery of 100% hydrogen.[264] A significant question that arises from this vision is whether its existing infrastructure can physically handle higher blends of hydrogen, up to 100%. Enbridge is only now beginning to embark on an engineering study to determine if this is even possible.[265]

3.7.18 In the meantime, Enbridge proposes to continue investing in new gas infrastructure that may not be compatible with high concentrations of hydrogen. This means that even if a hydrogen-based future for Enbridge becomes a reality, a significant portion of the capital spending made during the rate term may need to be replaced with infrastructure capable of handling such high hydrogen concentrations. This could lead to premature replacement and stranded assets. Given that Enbridge has not yet conducted a study, it has not even considered evaluating the risk that the billions of dollars it plans to invest in the coming years can accommodate high blends of hydrogen.[266] This is yet another unmeasured risk that customers are presumably expected to bear.

3.8 Energy Transition Risks

3.8.1 ***Capital Planning and Risk Analysis.*** In addition to not considering Energy Transition in its Value Framework methodology, Enbridge does not consider its risks in any aspect of the capital planning process. The only place it may factor into capital planning is in the context of the load forecast. However, even this is limited to a 10-year planning horizon, despite Enbridge expecting assets to be in service for 60 or more years.[267]

3.8.2 At the highest level, Enbridge's corporate risk register does not even mention Energy Transition risk explicitly, nor the risk of stranded or underutilized assets. At the more granular level, the capital, Ms. Wade testified that the company has not even attempted to quantify the risk (by assessing probability and consequence) of reduced customer

[264] Tr.11, p.153
[265] Tr.2, p.113-114
[266] Tr.11, p.153
[267] Tr.12, p.105; 1-10-4

connections to its system.[268]

3.8.3 In its lengthy response to Undertaking J14.9, Enbridge provides a host of reasons why developing a probabilistic impact assessment of Energy Transition risks would be impossible.[269] Enbridge believes that even attempting such an analysis would be a "time-intensive process that would not be of value in an ever-changing energy-transition environment, absent clearer signals related to policy and technologies."[270]

3.8.4 SEC submits that the OEB needs to send a strong message to Enbridge that this is unacceptable. If Enbridge is seeking to spend ratepayer funds to construct long-lived assets, it needs to consider all the risks, even if they may be hard to quantify.

3.8.5 This is especially troubling considering that the one place Enbridge does consider Energy Transition risk is in the context of business risk[271], where it is seeking to increase the equity thickness and earn a higher return on its investment. Considering the risk to ratepayers and Enbridge, Energy Transition risk analysis and assessment should be a fundamental component of all aspects of its business including, most importantly, its capital planning process.

3.8.6 ***Internal Incentives.*** Enbridge's internal incentives undermine the need to take the Energy Transition seriously, as demonstrated by the measures including its corporate scorecard.

3.8.7 Its corporate scorecard[272] is designed to provide high-level direction to employees.[273] It applies to the entire organization and all its employees, outlining the most important priorities on which they should focus.[274] All Enbridge employees are compensated based on the results of the scorecard.[275]

3.8.8 SEC's concern is that the scorecard primarily focuses on the growth of its distribution system, thereby actively discouraging efforts to reduce the need for new capital projects.

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[268] Tr.14, p.112, 114-115
[269] Undertaking J14.9
[270] Undertaking J14.9
[271] Tr.8, p.17-18; 5-3-1, Attachment 1, p.6
[272] The corporate scorecard that applies to Enbridge Gas Inc. is the Enbridge Inc. GDS (gas distribution and storage) business unit scorecard (See Undertaking JT 1.8). Enbridge Gas Inc makes up the vast majority of GDS business unit. (Tr.11, p.197).
[273] Tr.11, p.197
[274] Tr.11, p.197

3.8.9 The second-largest key performance indicator on the 2023 corporate scorecard, following adjusted EBIDTA, is EBIDTA generated by growth capital, which constitutes 20% of the scorecard's total value.[276] Growth capital includes customer connections and reinforcements.[277] As Mr. Sanders confirmed, this underscores its significant goal of expanding the system through new customer connections and increased capacity.[278]

3.8.10 Enbridge acknowledges that incremental steps to avoid customer connections or reinforcements would negatively impact its performance on its growth capital measure. This applies to DSM, IRP, and any fuel-switching programs (including those that prevent new connections from being established in the first place).[279]

3.8.11 The OEB cannot take Enbridge's Energy Transition plans seriously if its employees are financially penalized by its parent company for actions that reduce Energy Transition risks.

3.8.12 Furthermore, there are no corporate measures that specifically incent efficiency and productivity, or that reward Enbridge employees generally for completing capital work on-time and on-budget, whether on a project-specific or aggregate basis. This is especially important considering the increase in capital costs for projects, as revealed in the Capital Update. Customers would hope for an alignment of interests in these areas, demonstrated by their inclusion as high priorities on Enbridge's corporate scorecard.

3.9 *Impact of EDIMP*

3.9.1 The OEB should also adjust Enbridge's test year capital budget to account for delays and deferrals of projects due to its new Enhanced Distribution Integrity Management ("EDIMP") activities, which were not considered as part of its AMP.

3.9.2 As a result of the OEB's decision to deny approval for constructing Phases 3 and 4 of the St. Laurent project, Enbridge initiated EDIMP activities.[280] The goal of EDIMP is to enable a more rigorous review of the condition of certain pipelines to identify areas that could benefit from proactive mitigation projects, which may extend the life of the

[275] Tr.11, p.197
[276] Undertaking JT1.8, Attachment 2 (K11.2, p.208)
[277] Tr.11, p.199
[278] Tr.11, p.199
[279] Tr.11, p.203
[280] 1-14-3, p.3-4 (K11.2, p.130-131)

asset.[281] Due to the timing of the St. Laurent decision, it had not yet factored the impact of undertaking EDIMP activities into its forecast budget.[282] As part of the approved Settlement Proposal, a variance account was established to capture variances in approved integrity management costs, including those related to EDIMP activities.[283]

3.9.3 Enbridge acknowledges that one of the "desired outcomes" of the EDIMP activities will be reduced capital spending. But, as a result of the timing of the AMP's development in relation to the commencement of EDIMP work, Enbridge has not included any deferrals or delays in its 2024 budget.[284] Ratepayers might expect such adjustments, especially considering the subset of existing distribution pipelines that it claims would benefit from EDIMP.[285] Mr. Wellington concurred that work could be deferred or delayed in 2024 due to EDIMP activities.[286]

3.9.4 SEC submits that the implementation of EDIMP, which is not reflected in the AMP, is another reason to reduce the 2024 capital budget. Ratepayers have consented to a variance account to fund cost-effective EDIMP activities, and there should be an expectation that this will yield material savings by identifying cost-effective mitigation measures to extend the lifespan of replacement projects and reduce the overall capital budget.

3.10 ***Lack of Productivity And Efficiency Savings***

3.10.1 SEC submits that while Enbridge has provided evidence regarding efficiency and productivity savings achieved and budgeted as part of its O&M budget, it has provided no evidence on any similar measures undertaken and budgeted as part of its capital work. For a capital-intensive company like Enbridge, which proposes to significantly increase capital spending, SEC would have expected it to prioritize finding efficiencies and to include them in its forecast budget to reduce cost impacts on customers. Enbridge has done neither of these things.

3.10.2 ***Integration Savings and Efficiency Savings.*** Enbridge's evidence regarding savings achieved as part of integration and other productivity initiatives reveals that it has not

[281] 1-14-3, p.5 (K11.2, p.132)
[282] 1-13-3, p.6 (K11.2, p.133)
[283] Settlement Proposal, p.31; Tr.11, p.189
[284] Tr.11, p.190-191
[285] 1-13-3, p.4 (K11.2, p.4)
[286] Tr.11, p.191

done much, if anything, to achieve efficiencies related to its capital budget. All of the productivity savings included in the evidence, whether resulting from the merger and otherwise, relate to OM&A.[287]

3.10.3 When confronted with Enbridge's own evidence, Mr. Wellington responded by saying, "we don't do a very good job of quantifying where we may have capital savings from certain programs," and then pointed to what he admitted was "a small example" regarding a program to extend well life.[288]

3.10.4 But as Enbridge admitted, nowhere in the evidence does it quantify any capital-related savings tied to integration or other productivity initiatives.[289] This is not just about capital programs that result in savings by avoiding the need for other, more costly, capital work, but also about savings from initiatives to reduce the cost of the capital work it does undertake. Enbridge, which has averaged more than $1.15B in capital spending per year over the last five years, should heavily focus on ways to reduce the cost of executing its program. The fact that it filed no evidence, even when asked[290], demonstrates that it has not sufficiently focused on continuous improvement in capital execution.

3.10.5 ***Embedded Savings.*** As part of Enbridge's forecast bridge and test year O&M budget, it included a forecast of the impact of various productivity initiatives that it had planned or intended to undertake, along with the expected savings that would be achieved. The forecasted savings included not only those planned initiatives at the time, but also an allowance for additional savings that had not yet been identified but were embedded within the forecast budgets.[291] This is a type of stretch factor that Enbridge incorporated into its O&M budget to account for incremental productivity and efficiency savings that it expects to achieve. The embedded productivity savings resulted in a reduction of $49.2M to the otherwise forecasted O&M budget over the 2023 and 2024 period.[292]

3.10.6 However, Enbridge has not similarly included any embedded productivity savings in its direct capital budget.[293] When asked why, Mr. Sanders did not know.[294]

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[287] Tr.11, p.177-178; I.ADR.23 (K11.2, p.82); 1.9-SEC-90 (K11.2, p.81)
[288] Tr.11, p.179
[289] Tr.11, p.179
[290] 1.9-SEC-90 (K11.2, p.81)
[291] 4-4-2, p.9
[292] 4-4-2, p.9
[293] Tr.11, p.180
[294] Tr.11, p.183

3.10.7 SEC submits that the OEB should incorporate into any approved 2023 and 2024 test year capital budget embedded productivity for direct capital spending. There is no reason that Enbridge should not be including forecast incremental savings it can and should be striving to achieve in the next two years, which underpin its test year rates. Enbridge's consistent track record of over-earning demonstrates that it will find ways to achieve efficiency.[295] For the test year, those should be included within the capital budget and rate base.

3.10.8 Other utilities have included such forecasts in the past. For example, Hydro One Networks Inc., as part of its EB-2019-0082 application, included what it called "undefined productivity savings," which were savings that were not identified at the time it developed the capital budget.[296] These undefined productivity savings were a bottom-line reduction to the overall proposed capital budget.[297]

3.11 ***Customer Attachment Policy***

3.11.1 SEC is aware that other parties will be providing detailed submissions on changes to the customer connections policy currently described in E.B.O. 188. We particularly draw the OEB's attention to the submissions of GEC and ED in this regard.

3.11.2 It is therefore not necessary for us to provide lengthy analysis on this point that would likely repeat much of what others are saying. There appear to be a few main questions to be addressed, and we will do so simply.

3.11.3 ***Connection Horizon.*** First, Enbridge's customer connections horizon, based on its interpretation of E.B.O. 188, is 10 years[298], and in the Distribution System Code ("DSC") is 5 years.[299] There does not appear to us to be any reason why they would be different. The connection horizon is about how many new customers can be expected to attach to the new service. Homes that are attaching to gas are also attaching to electricity.

3.11.4 To say that five years of attachments is a reasonable range for electricity and ten years is a reasonable range for gas is patently illogical. They are the same homes.

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[295] 5.3-IGUA-30, Attachment 1
[296] *Decision and Order* (EB-2019-0082), April 23 2020, p.43-45,83
[297] *Decision and Order* (EB-2019-0082), April 23 2020, p.83
[298] Tr.10, p.91
[299] Distribution System Code, Appendix B, Methodology and Assumptions for An Economic Evaluation, p.4

3.11.5 SEC therefore submits that, unless the DSC is to be amended to extend the connection horizon for electricity[300], the connections horizon for gas should be changed to be consistent with the DSC, i.e. 5 years.

3.11.6 ***Revenue Horizon.*** The revenue horizon is a more difficult question, because the external forces influencing whether a connection will generate electricity distribution revenue vs. gas distribution revenue, and if so for how long, are quite different.

3.11.7 In the case of electricity, if you ask the question how long will this new connection be generating revenue for the distributor, the reasonable answer is "indefinitely". There is no reason to think that newly built homes will no longer need delivery of electricity at some time in the foreseeable future. In the case of electricity, the question is therefore partly associated with the average life of the assets being installed, and partly how long the existing customers should be financing the incremental cost of connecting the new customers. In the latter case, it is like an amortization period. The assumption in the DSC, 25 years, is conveniently the common amortization period traditionally used for residential mortgages, so it has some logic behind it.

3.11.8 The situation with gas connections is quite different. If you ask how long a new home can reasonably be expected to use its new gas connection, it is no longer "indefinitely", as it is with electricity. The answer is likely to be equal to the expected life of its biggest gas appliance, the furnace, which is around 15 years.[301] It is at the time of natural replacement that the owner of a home is mostly likely to assess whether gas should continue to be their heating source.

3.11.9 SEC believes that, for a new home connected in 2024, by no later than 2039 it is reasonable to expect many homeowners to shift away from fossil fuels. Some will be earlier, some will be later, but at that point the Energy Transition will be well underway, the cost of gas heating will be higher than today, and a new generation of homeowners will be more attuned to the environmental attributes of their consumption choices.

3.11.10 SEC therefore submits that a 15 year revenue horizon is a reasonable policy at the current

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[300] Which may or may not be a good idea, but is clearly out of scope for this proceeding.

[301] This has been the subject of disagreement in this proceeding, but most people start to consider whether to replace their furnace after 15 years. Mr. Neme uses 18 years (Tr.6, p.94-95), while Enbridge argues it should be 20 years (Tr.4, p.109).

time.[302]

3.11.11 SEC notes that Enbridge argues the revenue horizon should not be changed, for the unlikely reason that there is not enough evidence to choose an alternative time frame.[303] SEC disagrees. As we have noted elsewhere in this Final Argument, choosing the status quo (the 'do nothing' option) is itself a choice. It seems self-evident that, of all the choices, 40 years is the least likely to be a reasonable estimate of revenues from a new customer.

3.11.12 ***Impact on New Housing.*** Using a 5 year connections horizon and a 15 year revenue horizon will likely result in a contribution in aid of construction that is, on average, about \$2,890[304] or more. Enbridge argues that this increases the cost of new housing, and is therefore contrary to Ontario government housing policy.[305]

3.11.13 SEC believes this is nothing more than a red herring. The issue is not whether the house is more expensive. The issue is whether homebuyers will be allowed to choose their energy source, without an unrealistic subsidy from the gas company biasing their choice.

3.11.14 Right now builders install gas heating in houses with no connection cost in many cases. They therefore take the path of least resistance, and use gas heating in almost all new homes. It is simpler, cheaper and easier for them than providing a heating choice to their buyers.

3.11.15 Once the connection cost is adjusted to be more in line with reality, builders will be incented to offer their buyers a choice between, for example, a) a conventional gas furnace and water heater, with air conditioning from a heat pump, vs, b) a cold climate air source heat pump for heating and air conditioning, at slightly higher cost of equipment but avoiding the gas connection cost, vs. c) a geothermal system, at even higher net capital cost but much lower annual costs.

3.11.16 Not all buyers will choose fossil fuels.[306] In fact, as time goes on, the percentage of

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[302] As the Energy Transition gathers steam, it may be reasonable to select an even shorter revenue horizon, as some would propose today, but by that time the number of consumers voluntarily choosing space and water heating using fossil fuels may be much lower.
[303] Argument-in-Chief, para. 300
[304] Undertaking J10.11
[305] Argument-in-Chief, para.26
[306] Enbridge appears to agree. See for example, Argument-in-Chief para. 317, 429.

buyers who choose fossil fuels will decline. This will be particularly critical as buyers more and more become aware of the reductions in their annual heating bills associated with cold climate heat pumps.[307] If they have to bear a fair upfront price for their gas connection, and choosing the environmentally sound option instead makes them eligible for grants and loans, and their annual cost is lower, SEC believes that many will choose not to take natural gas. Getting the connections math right levels the playing field to facilitate this customer choice.

3.11.17 In the result, SEC believes that adjusting the customer connections policy to something that reflects the current reality is not a housing affordability issue at all. Rather, it is a customer choice issue.

3.11.18 ***Commissioners Have The Authority To Change The Connection and Revenue Horizons.*** Some parties[308] may argue that the Commissioners in this proceeding cannot modify the customer connection feasibility parameters in E.B.O. 188, as these have been incorporated by reference into the Gas Distribution Access Rule ("GDAR").[309] The argument is that the OEB cannot change these parameters as GDAR requires Enbridge to apply E.B.O. 188, and GDAR can only be amended by the OEB's Chief Executive Officer[310] under the specific notice procedures set out in section 45 of the *OEB Act.*[311]

3.11.19 Enbridge's specific position on this question is unclear. It says that a change in the revenue horizon "would effectively be amending or updating E.B.O. 188 Guidelines", which "would require a change to the wording of Section 2.2.2 of the GDAR."[312] However, it goes on to say that "[i]t does not dispute that the OEB can direct a treatment for customer attachments that is different from what is set out in E.B.O. 188.[313]

3.11.20 SEC agrees that E.B.O. 188 has been incorporated by reference into GDAR, and that the Commissioners are not empowered under the OEB Act to amend GDAR. However, that is not what is being proposed. Requiring a shorter customer connection horizon and revenue horizon does not amend GDAR, as it is consistent with E.B.O. 188. The 10-year

[307] See the Guidehouse memo to Enbridge dated May 31, 2023, filed as K2.4 in this proceeding, but originally filed as Exhibit ED-16, Attachment 2 in EB-2022-0249 (at page 8 of 21).

[308] Gas Distribution Access Rule, section 2.2.2

[309] Gas Distribution Access Rule, section 2.2.2

[310] *Ontario Energy Board Act, 1998*. section 44

[311] *Ontario Energy Board Act, 1998*, section 45

[312] Argument-in-Chief, para. 289

[313] Argument-in-Chief, para. 290

customer connection and 40-year revenue horizons are only maximum periods; they are not mandatory requirements. Shorter periods are permitted.

3.11.21 The specific feasibility parameters at issue here were adopted in E.B.O. 188 through the approval of an ADR Agreement (now what would be referred to as a Settlement Proposal). Both the length of the customer attachment[314] and the revenue horizons[315] in the ADR Agreement were described in E.B.O. 188 as being maximums. Further, the OEB, in its findings with respect to the customer attachment forecast, explicitly commented that the "proposed customer attachment forecast horizon of 10 years is a maximum," and adopted this as part of the Guidelines in Appendix B.[316] Requiring a specific utility, Enbridge, to apply a customer attachment and revenue horizon that is below that maximum is consistent with E.B.O. 188.

3.11.22 With respect to the 40-year revenue horizon, Enbridge argues that this is mandatory because of the wording in Appendix B to E.B.O. 188.[317] Appendix B provides that a "specific parameter" is a "customer revenue horizon of 40 years from the in-service date of the initial mains (20 years for large-volume customers)."[318] SEC disagrees with Enbridge's interpretation.

3.11.23 Appendix B, as the name suggests, is an appendix to the E.B.O. Final Report and serves as a guideline to consolidate the feasibility analysis approved in the ADR Agreement and the main E.B.O. 188 Report into a single document.[319] It must be read in light of E.B.O. 188, which ultimately governs what the OEB decided. Appendix B does not perfectly reflect the wording and intent of what was decided by the OEB in E.B.O. 188. For example, in the exact same section of Appendix B, it also discusses that a "specific parameter" for the customer attachment horizon is 10 years.[320] However, as referenced

[314] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.14 (K10.5, p.27): “A maximum 10 year forecast horizon will be utilized. For customer attachment periods of greater than 10 years an explanation of the extension of the period will be provided to the Board.” [Emphasis added]

[315] *Final Report of the Board* (E.B.O. 188), January 30 1998,, p.15 (K10.5, p.27): “The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service.” [Emphasis added]

[316] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.15 (K10.5, p.27)

[317] Argument-in-Chief, para. 288

[318] Appendix B, *Ontario Energy Board Guidelines For Assessing and Reporting on Natural Gas System Expansion in Ontario* section 2.2(b) (K10.5, p.53)

[319] Appendix B, *Ontario Energy Board Guidelines For Assessing and Reporting on Natural Gas System Expansion in Ontario* (K10.5, p.50)

[320] Appendix B, *Ontario Energy Board Guidelines For Assessing and Reporting on Natural Gas System Expansion*

above, the OEB statement in E.B.O. 188 that this is only a maximum does not actually appear anywhere in Appendix B. All of this highlights the need for the OEB to consider both documents when determining what is required by E.B.O. 188. This interpretation is also consistent with GDAR, which incorporates the E.B.O. 188 Report, not just Appendix B.[321]

3.11.24 If the Commissioners disagree with SEC's interpretation of E.B.O. 188, they also have the authority to exempt Enbridge from Section 2.2.2 of GDAR.[322] This would be in the public interest, and would be appropriate in this specific context. Incorporating standard customer feasibility into a sector-wide rule made sense at the time when there were two large OEB-regulated natural gas utilities. However, this has changed since the merger of Enbridge Gas Distribution and Union Gas, where the combined Enbridge now serves 99.7% of all customers.[323]

3.11.25 ***Impact of SEC Proposal on Capital Expenditures.*** Based on Enbridge's analysis provided in Undertaking J10.11, the implementation of a 15-year revenue horizon would reduce 2024 capital expenditures by $158M.[324] The numbers are lower in the subsequent years of the rate term, averaging about $100M a year between 2025 and 2028.[325]

3.11.26 If anything, SEC's proposed change understates the actual reduction in system access capital expenditures.

3.11.27 First, Enbridge has not undertaken any analysis regarding the impact of a reduction in the connection horizon which, directionally, will similarly require additional CIAC payments and reduce net system access spending.

3.11.28 Second, Enbridge's analysis assumes that all customers now faced with a CIAC

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in Ontario section 2.2(a) (K10.5, p.53)

321 Gas Distribution Access Rule, section 1.2.1: "“E.B.O. 188 Report” means the Report of the Board, January 30, 1998 in the Matter of a Hearing to Inquire into, Hear and Determine Matters Relating to Natural Gas System Expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.;"

322 See Gas Distribution Access Rule, section 1.5.1. The request by any intervenor or OEB Staff to change the customer attachment or revenue horizon can be interpreted as a request to the OEB to exempt Enbridge from those specific requirements in E.B.O. 188, on the condition that it adopts the proposed (or otherwise ordered) new time horizons.

323 Yearbook of Natural Gas Distributors, p.15

324 Undertaking J10.11 (2024 40 year revenue horizon system access CapEx ($304M) – 15 year revenue horizon System Access CapEx ($146M))

325 Undertaking J10.11

requirement (or a higher one) will pay it and connect.[326] We (and Enbridge) know this is not going to happen.[327] A higher CIAC will result in reduced customer connection and, consequently, lower system access spending than presented in Undertaking J10.11.

3.11.29 Additionally, Enbridge's analysis makes no reduction in capitalized overheads because of the change and simply reallocates the same costs to a smaller number of projects.[328] As discussed in detail in Section 3.14, SEC does not believe this is appropriate.

3.11.30 ***Community Expansion.*** SEC recognizes that a change in the customer attachment and revenue horizon will have a unique impact on community expansion projects, which are supported by funding through the Government's Natural Gas Expansion Program.

3.11.31 SEC proposes that the appropriate course of action is to exempt from the proposed changes any project that has been granted Phase 2 funding under the Government's Natural Gas Expansion Program.[329] Furthermore, for any existing community expansion project[330], within the first 10 years (the existing 10-year customer attachment period), the new requirements would not apply. These are appropriate transitional measures to implement the proposed changes and would not breach the requirements for non-discriminatory treatment of customers.[331]

3.11.1 ***Compliance With E.B.O. 188.*** Enbridge is required under E.B.O. 188 to maintain a Profitability Index ("PI") in its Investment Portfolio greater than 1.0.[332] It has failed to meet this requirement since 2021[333], meaning that, even by its own interpretation of E.B.O. 188, existing customers will subsidize new customers. While Enbridge recognizes that it is "liable for managing its portfolio at a PI greater than 1.0," it has not, in fact, provided the "reporting to the OEB as required in E.B.O. 188."[334]

3.11.2 E.B.O. 188 requires that in each rate case, Enbridge must provide various information

[326] Tr.10, p.84
[327] Tr.10, p.186-187
[328] Undertaking J10.11
[329] See Schedule 1 to Ontario Regulation 24/19
[330] Existing community expansion projects are any that have been granted funding under Phase 1 or 2.
[331] Gas Distribution Access Rule, section 2.2.1. Even if the OEB disagrees, it can exempt Enbridge from section 2.2.1 as it relates to sub-set of customers.
[332] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.11 (K10.5, p.24); 2-6-1, p.42 (K10.5, p.3)
[333] 2.6-SEC-118 (K10.5, p.69); Tr.10, p.193
[334] Tr.10, p.192; 1.15-ED-83, p.3

regarding the test and historic year Investment Portfolio, including annual portfolio NPV, total capital, and Profitability Index ("PI").[335] The intent is to "provide the Board and interested parties with sufficient information to monitor the utilities' expansion activities and their associated rate impacts."[336] If there are variances, utilities must provide "explanations of the reasons for the variations and the corrective actions taken or proposed."[337] With this information, the OEB can "judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers."[338]

3.11.3 Until SEC submitted an interrogatory[339], Enbridge had not provided any information in its application regarding the performance of its attachment projects and portfolio.[340] It is the company that has the obligation to discharge its burden by demonstrating that it has met the existing requirements of E.B.O. 188 and that its costs are prudent.[341] SEC submits that Enbridge has not met this burden with respect to the amount it seeks to add to the rate base in 2023.

3.11.4 In 2023, Enbridge forecasts that the Investment Portfolio PI will be 0.91, representing an NPV of $26.5M below the required annual PI of 1.0. Enbridge argues that its poor performance is due to costs being higher than forecast, primarily because of higher than expected inflation and supply chain issues.[342] While SEC does not dispute that these issues affected Enbridge's costs, the concern is that ot did not mitigate them appropriately within the context of its customer connection obligations.

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[335] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.32 (K10.5, p.45); Appendix B, *Ontario Energy Board Guidelines For Assessing and Reporting on Natural Gas System Expansion in Ontario,* section 3.1 (K10.5, p.54--55)

[336] Appendix B, *Ontario Energy Board Guidelines For Assessing and Reporting on Natural Gas System Expansion in Ontario*, para 266 (K10.5, p.1)

[337] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.32 (K10.5, p.45)

[338] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.32 (K10.5, p.45)

[339] 2.6-SEC-118 (K10.5, p.69). Even then the information that has been provided has been incomplete. When SEC requested the supporting information regarding its Rolling Project Portfolio PI, Enbridge refused on the basis that it would "[v]ery time consuming to extract all the details from the individual models and aggregate the information up to the level of cash inflows, cash outflows and PI." (See Undertaking JT 3.17, K10.5, p.71) This is even though E.B.O. 188 "emphasizes that the utilities must maintain clear records at a project specific level that will allow for inspection and/or reporting of individual projects as may be deemed necessary from time to time." (*Final Report of the Board* (E.B.O. 188), January 30 1998, p.32 (K10.5, p.45))

[340] See 2-6-1, p.42-59 (K10.5, p.2-9) where the company provides information on its obligations under E.B.O. 188 but no actual information regarding its performance.

[341] *Final Report of the Board* (E.B.O. 188), January 30 1998, p.32 (K10.5, p.45); *Ontario Energy Board Act, 1998*, section 36(6)

[342] Tr.12, p.2

3.11.5 Enbridge admits that it saw the impact of high inflation and supply chain issues as early as late 2021 and into 2022.[343] Yet, with that information, it never revisited with developers or other customers who were going to be connecting, to re-run its customer feasibility assessment and potentially require greater CIAC payments (if any were required to begin with) before beginning construction.[344] Enbridge confirmed that it could have taken these steps but chose not to because it had not had a practice of doing so before.[345]

3.11.6 Considering the magnitude of the inflation and supply chain impacts, as well as the fact that its PI was below 1.0 in both 2021 and 2022, Enbridge should have (and still could) re-run its customer connection feasibility assessment and require those connecting customers to pay higher CIAC payments, reflecting the increased capital costs. Enbridge chose not to and asks that all existing customers absorb the difference. These actions are unreasonable, and on that basis, the OEB should disallow $26.5M in 2023 in-service additions.[346]

3.12 ***Integrated Resource Planning***

3.12.1 ***Lackluster Implementation.*** Enbridge is required to file an annual report with respect to its IRP activities, including an independent report of its working group, so the Commissioners in this case have good visibility into many of the issues surrounding Enbridge's implementation of IRP.

3.12.2 In its first annual working group report, filed June 10, 2022, Enbridge found that all seven of the non-Enbridge working group members had serious concerns about the work Enbridge was doing on IRP.[347] The concerns ranged from the slow start, to little progress on pilots (which ultimately failed to meet the deadline imposed by the OEB in the IRP Decision), to lack of transparency, to refusal to provide relevant information because the rebasing Application was in process. OEB Staff on the working group largely agreed

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[343] Tr.12, p.6; These issues was well known across the utility sector. In early February 2022, Hydro One Networks Inc. decided that it had to file an update to its evidence as a result of "unprecedented inflationary pressures". See *Decision and Procedural Order No.4 On Settlement Conference Adjournment* (EB-2021-0110), February 18 2022, p.3)

[344] Tr.12, p.5

[345] Tr.12, p.5, Tr.13, p.17-18

[346] 100% of customer connections capital expenditures are in-serviced in the year they are incurred (See 2.6-SEC-109, Attachment 1)

[347] EB-2022-0110, Exhibit H, Attachment 1, p.26 et seq

with those concerns.

3.12.3 In its second annual working group report, filed May 2023, Enbridge found that six of the seven non-Enbridge working group members still had serious concerns.[348] While recognizing that there had been some progress, the working group members continued to see Enbridge's performance as below a reasonable level. An additional concern – failure to utilize the working group as a resource – was also added. Many working group members felt that Enbridge treated the working group as a gating process rather than a positive resource. OEB Staff was less critical, but still expressed concerns, including the need to make productive use of the working group.

3.12.4 The comments of the working group members are not the only evidence of poor performance. More than two years after the OEB decision mandating IRP, and at the end of a rebasing Application in which more than $7B of additional capital additions are proposed, Enbridge has not identified one of those projects that can be deferred or replaced by IRP. Twenty (about 1.5%) have been identified as technically able to be replaced by IRP, but no economic assessment has yet been done. IRP has been screened out for all other projects.[349]

3.12.5 Enbridge has in fact done one IRP project, in Kingston. It did not displace gas use, and was in any case implemented without telling the working group that it was planned. Enbridge has also finally filed an application for two pilot projects, neither of which had to pass an economic test because they were pilots.

3.12.6 Against this backdrop, four issues arise in this proceeding relating to IRP.

3.12.7 ***Electrification IRPAs.*** Some parties, notably GEC and ED, would like Enbridge to be given the authority to include IRPAs that are based on electrification. SEC opposes that change, for three reasons.

3.12.8 First, Enbridge has not demonstrated that it should be involved in electrification solutions. It is not in that business, and we have electricity utilities who are. Further, Enbridge has a conflict of interest, because by definition it will prefer gas solutions.[350]

[348] Review of Enbridge Gas Inc. 2022 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities (EB-2021-0246), March 30 2023

[349] Enbridge admits that the AMP contains no IRP projects (Tr.3, p.48).

[350] It has a second conflict of interest because it has a business, Enbridge Sustain, that is in the competitive

3.12.9 Second, the IRP Decision is only two years past, and during that proceeding there was a thorough review of whether to allow Enbridge to deliver electrification options. In this proceeding, no similar review has taken place. SEC submits it would be inappropriate for this panel of Commissioners to overrule the recent decision of another panel of Commissioners, based on an evidentiary record that is not close to being as thorough on this topic.

3.12.10 Third, this is a problem that does not need to be solved. The working group has supported Enbridge's pilot application including an electrification component, which can be approved by the Commissioners hearing that case as an exception to the normal rule. One of the reasons for the working group support is that the pilot allows Enbridge and the OEB and stakeholders to learn about inclusion of electrification in IRP. Depending on the results of that pilot, that will be the time to consider whether Enbridge should get into the regulated electrification business.

3.12.11 SEC does, however, agree with OEB Staff that, whenever Enbridge seeks a Leave to Construct, it should be required to show information from impacted electricity distributors on their load forecasts.[351] It would be appropriate for Enbridge to go a step further, and ask electricity distributors whether they are able to displace, defer or alleviate some or all of the capital spending in the Leave to Construct through electrification options.

3.12.12 ***Stranded Asset Risk.*** Enbridge has opposed putting a value on stranded asset risk of infrastructure options as part of the economic evaluation of IRPAs.[352] On the other side, Enbridge is eager to include risks of geotargeted DSM and other IRPAs in the evaluation, through derating methodologies and other means.

3.12.13 SEC believes that the amount of a capital project that can be included in rate base should be reduced by the probabilistic risk of the assets being stranded or underutilized. However, we have noted elsewhere in this Final Argument that it is probably premature to implement that.

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electrification business, but is not regulated.

[351] OEB Staff Final Argument, p.42

[352] See Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning (IRP): Report of the IRP Technical Working Group (EB-2021-0246), May 30 2023, p.53

3.12.14 In the absence of a rate base rule that only allows the true future value of capital spending into rate base, to be recovered from customers in rates, at the very least the comparison of options between IRPAs and conventional capital spending should reflect that valuation. Every conventional capital spend will have some level of stranded asset risk. That should be valued when comparing that option to the cost of the IRPAs.

3.12.15 ***Repair Options.*** SEC agrees with OEB Staff[353] and EFG[354] that Enbridge should expressly consider the options of repair and/or life extension as part of the analysis of IRPAs. Right now, Enbridge sees repairing assets to extend their life as being equivalent to a run-to-failure' approach, which is not correct.

3.12.16 ***IRP Effort***. In the context of SEC's recommendations that significant reductions to capital additions be made, SEC submits that the OEB should encourage Enbridge to fill that gap – if Enbridge perceives that there is such a gap – with IRP solutions.[355] To date, it is clear that Enbridge has not fully embraced IRP. The Commissioners should encourage them to do so.

3.13 <u>***Panhandle Regional Expansion Program Rate Treatment***</u>

3.13.1 As part of the Capital Update, Enbridge removed the PREP project, which is forecast to be completed in 2024, from its proposed capital additions and rate base. Instead, Enbridge proposed a unique rate treatment for the project.[356] SEC submits that the OEB should deny approval of this proposed rate treatment. It benefits Enbridge's shareholders to the detriment of ratepayers, is contrary to its proposed rate plan, and is not being applied fairly to all other projects that could offer benefits to customers.

3.13.2 Enbridge's proposal consists of three parts. First, it proposes that the costs of PREP during the proposed rate term (2024-2028) be recovered through a separate rate rider that would only be applied if Leave to Construct approval is granted.[357] Second, the rate rider would be set based on a levelized net revenue requirement over the rate term. Enbridge would separately calculate the net revenue requirement of the project for each year between 2024 and 2028 and determine an average annual revenue requirement to be

[353] OEB Staff Final Argument, p.41
[354] M9, p.48-54
[355] As part of the approved Settlement Proposal, the Parties agreed to continue (with modifications) the existing IRP Operating Cost and IRP Cost Deferral Accounts (Settlement Proposal, p.54).
[356] 2-5-4, p.30
[357] 2-5-4, p.31

recovered through a separate rate rider.[358] Third, the OEB would establish a variance account (PREP VA) to record the difference between actual project costs and revenues collected from the rate rider.[359]

3.13.3 Enbridge claims that the PREP rate treatment is being proposed because the project has yet to receive Leave to Construct approval.[360] This is simply not credible. When the application was originally filed, the project had also not received Leave to Construct approval; in fact, that proceeding was at a similar stage compared to when the Enbridge filed the Capital Update.[361]

3.13.4 Moreover, Enbridge is not seeking similar treatment for any of the $88M worth of other projects included in its 2024 rate base that have yet to receive Leave to Construct approval.[362] Enbridge's general position, as articulated in Undertaking J13.2, is that it would be inappropriate to have variance accounts to capture the impacts of projects that do not proceed.[363]

3.13.5 The real reason that Enbridge is proposing this rate treatment as part of the Capital Update is that the forecast in-service date of the project has been delayed from 2023 to 2024. This will have a substantially different impact on its proposed rates, as the first year of the project has a negative revenue requirement. This is neither new nor uncommon for Enbridge, and is a result of a combination of the half-year rule and the high CCA rates applied for tax purposes. These are compared to the monthly rate base and depreciation in-service approach, and the comparatively lower depreciation rates used for its capital assets.[364]

3.13.6 When the Application was originally filed, and the project was going into service in 2023, Enbridge was more than happy to apply the normal ratemaking treatment to the project, as the impact on the company's earnings in the bridge year would be positive. Now that the project is going into service in 2024, and there is a negative revenue requirement in the test year, Enbridge proposes this levelized approach, which it

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[358] 2-5-4, p.31
[359] 2-5-4, p.31
[360] 2-5-4, p.30
[361] On December 5th 2022, Enbridge asked the OEB to place the PREP LTC application in abeyance.
[362] Tr.12, p.24-25; 2.6-SEC-114, Attachment 1 (K11.2, p.90)
[363] Undertaking J13.2
[364] Tr.12, p.26

recognizes is an exception to the normal rules of cost of service ratemaking.[365]

3.13.7 None of this is specific to PREP. A similar revenue requirement trajectory occurs with many of Enbridge's other capital projects. While it may be that because of the size of the 2024 PREP in-service additions ($252M) it has a very significant impact ($14M 2024 sufficiency)[366], a similar impact is occurring for many other projects. Combine enough of these projects, and you will find a similar total for 2024 in-service additions with a similar total sufficiency.[367]

3.13.8 Tellingly, when PREP was scheduled to go in-service in 2023, and Enbridge would have benefited from the sufficiency, it did not propose a levelized approach.

3.13.9 Further, SEC invites the Commissioners to compare Enbridge's proposed rate treatment for PREP with that of the Dawn to Corunna project, which will be addressed in Phase 2. This project is of a similar size to PREP, with $342.2M in 2023 in-service additions, and as set out in Undertaking J13.20, it will have a significant negative revenue requirement (-$30.6M) in its first year of operations (2023).[368] Similar to PREP, this is largely driven by the negative taxes as a result of the capital cost allowance deduction that significantly exceed the depreciation expense in the first year.[369] Enbridge is not proposing a similar levelized rate treatment, which would provide ratepayers with the full benefit of the project's sufficiency— a benefit that the company's shareholders will enjoy in 2023. The disparate treatment is especially unfair, given that with the Dawn to Corunna project, Enbridge benefits in 2023 from the project going significantly over-budget.[370]

3.13.10 There are likely many other projects that are forecast to go in-service in 2023, which will similarly result in a net income benefit for Enbridge that year. No levelized treatment is being proposed, as it seeks to add the costs to the opening rate base in 2024.

3.13.11 SEC submits that the appropriate rate treatment for PREP is to include the project in the 2024 rate base, as would normally be the case, with a variance account in place solely to

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[365] Tr.12, p.30

[366] 2-5-4, Attachment 2

[367] This explains why the 2024 revenue requirement associated with all $1,314M (excluding PREP) in-service additions is only $10M (2.2-OGVG-3d)

[368] Undertaking J13.20, Attachment 1.

[369] Undertaking J13.20, Attachment 1, Ft 4. Enbridge will benefit from a -$38.8M tax deduction as a result if the income tax timing difference as compared to $3.4M depreciation expense in 2023.

[370] Tr.12, p.31. Enbridge benefits in 2023 because as the capital costs increase (and thus the depreciation expense), so will the tax benefit.

capture outcomes if the project is denied Leave to Construct or if the approved costs change from what has been proposed.

3.13.12 This approach acknowledges that Enbridge should not be able to selectively adopt beneficial aspects of cost of service ratemaking while disregarding those that are not advantageous. At the same time, it recognizes that the OEB's evaluation of the prudence of the PREP and its costs is not being determined in this proceeding, but in the Leave to Construct proceeding.

3.13.13 SEC submits that this principle should extend to any 2024 in-service additions subject to Leave to Construct approval. The OEB should establish a 'Leave to Construct Variance Account' to capture the revenue requirement included in base rates if the project is denied. Since these projects typically result in a negative revenue requirement, this approach will most likely benefit Enbridge. Unlike its proposed PREP VA, this account would not serve as a true-up for project costs or revenues. Like any other test year in-service additions, the risk of cost overruns (or the benefit of lower actual costs) should be borne by Enbridge until the next rebasing application.

3.13.14 OEB Staff recommends similar treatment for the St. Laurent project as Enbridge has proposed for PREP.[371] As the project is subject to a Leave to Construct requirement, SEC supports variance account treatment for the project, especially considering the previous denial of approval [372] However, for the same reasons that SEC objects to levelized cost treatment for PREP, those reasons also apply to any other test year capital additions, including the St. Laurent project. This proposed treatment is unfair to ratepayers.

3.14 ***Overhead Capitalization***

3.14.1 Enbridge seeks approval for its harmonized overhead capitalization methodology and the resulting amounts. The effect of the proposed change is an increase of $15.4M in the overhead costs that Enbridge seeks to capitalize, compared to the legacy methodologies of Enbridge Gas Distribution and Union Gas.[373]

3.14.2 ***Capitalization Methodology.*** SEC has several concerns regarding the proposed capitalization methodology.

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[371] OEB Staff Submissions, para. 64

[372] See *Decision and Order* (EB-2020-293), May 3 2022 (K11.2, p.102)

[373] 2-4-2, p.17, Table 3 (K15.4, p.19)

3.14.3 First, too much of the methodology is based on historical capital vs. O&M spending, which is then applied to the test year. In the present case, this reflects the last year of actuals available when Enbridge set its budget in 2023, which was for the year 2021.[374]

3.14.4 As SEC has argued throughout these submissions, Enbridge needs to significantly reduce its level of capital expenditures. The impact of its proposed methodology, if the OEB agrees with SEC, would not fully be reflected in the capitalized overhead rate until at least 2026, when the 2024 actuals will be available for budgeting.[375] This will lead to an inflated capital budget and rate base, resulting in higher earnings on equity over the asset's life.

3.14.5 Enbridge's methodology is primarily based on determining capitalization rates for two cost categories: operations and business units. The other two cost categories, shared service, and pension and benefit costs, are calculated as derivatives of the operation and business unit cost capitalization rates.[376] The capitalization rates for the operations are determined entirely based on the historical split between capital and OM&A work.[377] This category represents 38% of total capitalized overheads, or about 69% of the two "core" cost categories upon which the other two are based.[378]

3.14.6 SEC submits that this approach is not appropriate. Overhead capitalization rates should be based on forecast capital work, to more accurately reflect both the costs incurred and the capital work undertaken (i.e., cost causality). This is especially true when there is significant year-over-year variability in historical capitalization rates, as is the case for the operations cost category.[379]

3.14.7 Even for business unit cost capitalization rates, which are based on a forecast of capital work to be done in the year[380], Enbridge could improve accuracy by updating the rates throughout the year to better reflect the actual mix of capital vs. O&M work done. As it

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[374] Tr.15, p.135; 2-4-2, p.14 (K15.4, p.16)

[375] Tr.16, p.37

[376] Tr.15, p.135. 2-4-2, p.12-13 (K15.4, p.14-15); The capitalization rate for pension and benefits costs is a derivative of each of operations, business unit, and shared services cost category capitalization rates. Shared services cost category is a derivate of the operations and business unit capitalization rates.

[377] Tr.15, p.135; 2-4-2, p.14 (K15.4, p.16)

[378] Based on 2-4-2, p.17, Table 3 (K15.4, p.19)

[379] For example, in 2020 the capitalization rate based on the proposed methodology for the operations category is 31%, the next year it 2022 the rate jumped to 35.2% (See 2.5-Staff-55, Attachment 1, p.1-2 (K15.4, p61-62.))

[380] 2.4-Staff-54b (K15.4, p.57)

stands, Enbridge sets the rates in advance and does not change them.[381] In contrast, Hydro One, as an example, "reviews its overhead capitalization rates on a monthly basis to determine if the rates need to be updated to reflect in-year changes in capital spending and the associated support costs."[382] The OEB should order Enbridge to adopt a similar policy.

3.14.8 Second, Enbridge is treating certain costs, which it admits should be direct in nature, as indirect overheads. Enbridge proportionately allocates capitalized indirect overhead costs to each of its projects each year based on their share of the total capital expenditures.[383] An identified best practice is that costs that can be directly charged to capital projects should be, as this "eliminates estimation and provides the most accurate and reliable information."[384] Despite this, Enbridge's evidence shows that even in cases where the costs could be directly allocated, they are not.[385] It says it does this because current processes are not designed to capitalize these specific costs to a project.[386] The OEB should require Enbridge to directly allocate costs that are direct in nature.

3.14.9 The OEB should require Enbridge to make the above adjustments to its proposed overhead capitalization methodology. It should also require Enbridge to file an independent third-party assessment of its overhead capitalization policy at its next rebasing application. At that time, the OEB and parties will be in a better position to assess the reasonableness of the capitalization policy in full.

3.14.10 While Enbridge filed a report by E&Y as part of its Application, that report merely reflects the work the firm did assisting the company in developing its harmonized overhead capitalization policy.[387] E&Y was not retained to provide an assessment of a proposed policy, but to offer advice and assistance in developing a new harmonized methodology.[388] It was not acting as an independent expert and was not appropriately qualified as such. Considering the magnitude of the total capitalized overheads, the increase in the rates as a result of the harmonized methodology compared to the legacy methodologies, and the natural bias for Enbridge to capitalize large amounts, an

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[381] Tr.15, p.138
[382] EB-2021-0110, Exhibit C, Tab 8, Schedule 2, p.4 (K15.4, p.71)
[383] Tr.16, p.15-16
[384] 2-4-2, Attachment 1, p.17 (K15.4, p.40)
[385] 2.4-Staff-52, p.2
[386] 2.4-Staff-52, p.2
[387] 2-4-2, Attachment 1 (K15.4, p.25)
[388] 2-4-2, Attachment 1, p.5 (K15.4, p.28)

independent review is required. This is especially important considering there is no 'standard' approach.[389] The assessment should include a thorough review of the methodologies used by utilities in North America.

3.14.11 ***Reduced Capital Expenditures Must Result in Reduced Gross O&M.*** As part of the approved Settlement Proposal, the Parties agreed to a gross test year OM&A amount, in the context of a proposed capital expenditure budget of $1,491M (before the Capital Update). Based on Enbridge's methodology, that gross OM&A budget resulted in a capitalized overhead amount of $292M and a net O&M budget (exclusive of DSM) of $821M.[390] What was explicitly left open for parties to argue, and for this panel to decide, was the impact on both the capitalized overhead amount and the net O&M budget that would result if the OEB approved a different overhead capitalization methodology or test year capital budget.[391]

3.14.12 If the OEB approves, as SEC suggests, a test year capital expenditure budget that is materially below that requested by Enbridge, it should both reduce the amount of overheads that are capitalized and also reduce the gross O&M budget. The OEB should not allow Enbridge to refuse to make changes to its gross O&M budget of $1,113M[392], and simply increase the net O&M budget as a result of the reduced capitalized overhead amount. A reduction in the capital budget should reduce the amount of capitalized overheads but make no change to the net O&M budget.

3.14.13 SEC does not dispute that "annual fluctuations in the level of invested capital or the quantum of projects"[393] may not result in material changes to the gross O&M budgets that support, in addition to its O&M activities, its capital work. However, a material reduction in test year spending, which SEC believes is warranted, should signal to Enbridge that similar reductions ought to be made over the test period, resulting in a reduction in the gross O&M budget. If Enbridge expects to do less capital work than forecast, the costs that support that work should be reduced correspondingly. This is especially important in the context of the Energy Transition, where Enbridge will need to lower its overall spending due to a reduced need for its products, such as gas distribution and transportation infrastructure.

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[389] Tr.15, p.117

[390] Settlement Proposal, Issues 12

[391] Settlement Proposal, Issues 12-14

[392] Gross O&M Budget of $1,113M = Net O&M budget of $821 (exclusive of DSM) + $292M of capitalized overheads (See Settlement Proposal, Issue 12)

[393] Argument-in-Chief, para. 363; Undertaking J16.3, p.2

3.14.14 The relationship may not be perfectly linear, but it simply cannot be said that there is no relationship. Enbridge's position that "a change to the capital budget does not translate into a similar or perhaps any reduction in O&M" is simply not credible, and indicates a troubling corporate budgeting and planning process.[394] Enbridge's spending, which includes costs supporting its capital program, must have a relationship with the level of capital work that is approved for execution.

3.14.15 At the oral hearing, when asked about this, Enbridge initially resisted the notion that there was any relationship.[395] However, Mr. Healey eventually admitted that "there is a relationship" between capital spending and gross O&M, especially when asked whether an increase in capital expenditures would lead to an increase in gross O&M.[396] Surprisingly, not a single person on the panel, including the Manager of Operations and Maintenance, could speak to the actual impact on gross O&M.[397]

3.14.16 Costs of business units such as Major Projects, Engineering, Asset Management, System Improvement, and Integrity & IMS, clearly have a direct relationship to the amount and size of the capital budget that Enbridge undertakes.[398] Operational Group costs, which "provide oversight for and support direct capital activity"[399], are capitalized primarily on the basis of the allocation of labor and materials used by each region.[400] Less capital work done by those regions means less oversight and support required, and fewer costs each group needs to incur.

3.14.17 Even Shared Services costs have some relationship to the amount of capital work being done. If less capital work is to be done, customers should expect a need for fewer individuals in a host of 'back-office' roles (e.g., fewer lawyers to manage capital contracts, fewer individuals in finance tracking capital costs, etc.). There should also be less need for IT resources and systems to support the forecast level of capital work.

3.14.18 Enbridge, in responding to Undertaking J16.3, which asks an entirely different question, tries to provide additional support for its position, which is reiterated in its Argument-in-

[394] Argument-in-Chief, para. 365
[395] See for example, Tr.15, p.155
[396] Tr.15, p.158
[397] Tr.15, p.159
[398] 2-4-2, Attachment 1, p.21-22 (K15.4, p.43-44)
[399] 2-4-2, p.9 (K15.4, p.11)
[400] 2-4-2, p.10 (K15.4, p.12)

Chief, by offering two examples: its asset management and supply chain departments.[401]

3.14.19 With respect to its asset management department, as noted earlier, it is not annual fluctuations in spending that would be expected to result in changes in the number of employees working in that business unit.[402] Rather, a material reduction in spending that is expected to persist over the rate term (and beyond) would likely lead to such changes. . In short, a smaller construction company needs less resources throughout its organization.

3.14.20 As for the supply chain example, the claim is made that there is no difference in work required to purchase a million units of an asset as compared to 100,000 units.[403] That may or may not be the case, but spread across its entire asset base, one would expect less work would be needed if there were a material reduction in capital work.

3.14.21 Regardless, we do not doubt that Enbridge can identify one or two areas where there would be minimal, if any, change resulting from a material reduction in the capital budget; however, across its entire operations, there should be significant cost reductions in such a scenario.

[401] Undertaking J16.3, p.2; Argument-in-Chief, para 363-364
[402] Undertaking J16.3, p.2; Argument-in-Chief, para 363
[403] Undertaking J16.3, p.2; Argument-in-Chief, para 364

4 OPERATING EXPENSES

4.1 *Depreciation Expense*

4.1.1 ***The Enbridge Proposal.*** Enbridge has proposed, through the Concentric report[404], an increase in annual depreciation expense included in rates of about $187.5M.[405] The genesis of this analysis was the need to harmonize the depreciation methodologies of Union Gas and Enbridge Gas Distribution into one comprehensive methodology across the entire rate base. The methodology proposed, Equal Life Group (ELG), is a change from Average Life Group (ALG), which is the methodology Enbridge Gas Distribution used previously.

4.1.2 This increase in depreciation expense is the main reason for the 6% rate increase proposed in this Application.[406]

4.1.3 OEB Staff led the evidence of Intergroup[407], and IGUA led the evidence of Emrydia[408], in each case challenging the conclusions of Concentric, and the Enbridge proposal. GEC/ED witness Energy Futures Group also spoke to depreciation, suggesting consideration of a units of production approach,[409], which as noted by Dr. Hopkins is under active consideration by utilities in Massachusetts to deal with the Energy Transition.[410]

4.1.4 ***Analytical Approach.*** SEC breaks down the depreciation issue into three steps. First, leaving aside the Energy Transition, and just focusing on the technical evidence of the experts, what is the most reasonable result? Second, if the Energy Transition is to be factored into depreciation expense, what is the appropriate way to do so? Third, given the evidence currently on the record in this proceeding, is there a transitional approach that should be considered?

4.1.5 ***Appropriate Technical Result.*** SEC understands that other parties will go into greater detail on the relative merits of the proposals of the three depreciation experts, and does

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[404] 4-5-1,Attachment 1
[405] Undertaking J17.11, Attachment 1, p.5
[406] It is larger than the deficiency of $186.3M (Undertaking J17.11)
[407] M1
[408] M4
[409] M9, p.5-6, 44-47
[410] M8, p.40

not feel it needs to add further analysis to that. SEC generally agrees with the submissions on this topic provided by IGUA.

4.1.6 After hearing their evidence, and cross-examining each, SEC has concluded that, aside from the Energy Transition, the evidence of Intergroup and Emrydia is to be preferred over the evidence of Concentric. There were too many instances of obvious technical problems with the Concentric evidence, well described in the critiques from the other experts.

4.1.7 ***Considering the Energy Transition.*** When the Energy Transition is taken into account, the situation changes. Logic dictates that assets with less certain expected useful lives should be amortized over shorter periods. In effect, capital should be recovered faster if your future ability to use it economically (and therefore collect its cost) is in doubt.

4.1.8 However, SEC agrees with Intergroup[411] and Emrydia[412] that the proper way to do this is with an express adjustment to the useful lives of the assets or the depreciation methodology. It is not sound analysis to say that higher depreciation is directionally sensible, and therefore any way to get there is good enough.[413]

4.1.9 This in fact raises a fundamental question. Depreciation studies, including the ones filed in this proceeding, are at their essence analyses of past data and continuation of the results into the future. The expected life of an asset is calculated through an Iowa curve, for example, which uses historical data exclusively.

4.1.10 This only works if the future is expected to be the same as the past. Once the Energy Transition is factored in, that assumption is no longer true. By definition, the future is <u>not</u> going to be the same as the past.

4.1.11 The Commissioners in this case have no credible evidence as to the appropriate depreciation of assets going forward if the Energy Transition is taken into account. None of the depreciation evidence looks at how the future will be different, and what that means for the lives of assets, whether new ones or existing ones. In fact, Enbridge appears to be at least hopeful that the past will continue into the future, with perhaps some manageable adjustments. As noted earlier, their strategy is to try to convince

[411] M1, p.25
[412] M5, p.39
[413] See Argument-in-Chief, para. 494

everyone that their system will still be needed in the future.

4.1.12 The two alternatives suggested, the Economic Planning Horizon, or EPH[414], and the units of production method[415], have only been proposed as concepts. No work has been done to assess how either would be implemented in the case of Enbridge, despite the estimate of the impact being substantial. Like any other depreciation methodology, they still have to be implemented based on a rigorous analysis, which is lacking here.

4.1.13 SEC believes that the Commissioners should order Enbridge to review depreciation methodologies (like EPH and units of production) that take into account the Energy Transition, including details of how they would be implemented and calculations of their impacts. This should be done in conjunction with a detailed risk analysis, and the Energy Transition Plan we have discussed elsewhere in this Final Argument.

4.1.14 This has to be approached with technical and conceptual thoroughness. The Commissioners will need that at some point in the not-to-distant future, and so should require that the work be done and filed, either in the next rebasing or earlier.

4.1.15 ***What To Do In The Meantime?*** This leaves the Commissioners with what to approve in rates for the next few years. The Concentric study is flawed, but would increase depreciation, which is probably directionally correct. The Intergroup and Emrydia work is more technically sound, but would reduce depreciation, contrary to the Energy Transition imperative.

4.1.16 The safest solution is to maintain the status quo until better information is provided on which to make an informed decision. While it is perhaps less than optimal that the Union Gas and Enbridge Gas Distribution service territories would continue to have different depreciation methodologies, that has been the case so far, and the utility has been able to manage it. The alternative of having a new methodology that is known to be incorrect is even less palatable.

4.1.17 The other possible solution is to fix the main flaws in the Concentric studies, and implement that as a temporary measure while proper studies are going on. Other parties will be able to identify in their submissions the main corrections that are needed, relying on the Intergroup and Emrydia evidence the Commissioners have already heard. The

[414] Tr.3, p.197; Tr.16, p.73; Tr.17, p.67
[415] M9, p.44; Tr.5, p.64; Tr.17, p.1

result would be a small increase in depreciation in 2024.

4.1.18 ***SEC Recommendation.*** SEC recommends that, all other things being equal, the best solution is to maintain the status quo until a proper depreciation study that considers the Energy Transition is provided to the OEB. There is a lot to be said for insisting on rigorous evidence before making a change that could mean hundreds of millions of dollars of increased rates, year after year.

4.1.19 However, SEC notes that we have also described an approach to the Energy Transition that involves a balanced set of measures in the near term, including capital expenditure restraint. SEC called this the Incremental approach. If the Commissioners elect to go in that direction, SEC believes that implementing the Concentric recommendations, with the main flaws corrected, could be a reasonable part of that approach.

4.2 ***Historic PDO/PDCI Payments***

4.2.1 As part of the MAADs proceeding, FRPO (supported by LPMA) argued that the OEB should adjust base rates to remedy the problem of ratepayers paying twice for the capacity used to implement the Parkway Delivery Obligation ("PDO") Settlement Agreement. In its MAADs Decision, the OEB determined that there was insufficient evidence but required Enbridge "to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing period."[416] It did this so that "[t]he OEB at the time of rebasing will review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity and that the legacy Union Gas is not enhancing earnings contrary to the intent of the PDO settlement agreement."[417] The intent of the OEB's decision was to allow a more thorough review of the matter at rebasing.

4.2.2 FRPO has provided detailed submissions on this issue, including important background and context regarding the PDO Settlement Agreement.

4.2.3 In simple terms, Union Gas' approved 2013 rates included costs for all the Dawn Parkway assets, but featured a revenue forecast that was 210 TJ less than what the system

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[416] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.48-49

[417] *Decision and Order* (EB-2017-0306/307), August 30, 2018 p.49. While there was no variance account established, there is no disagreement amongst the parties that the amounts were encumbered as a result of the MAADs decision and the OEB has authority to make an adjustment to these historic amounts. (See *Union Gas Limited v. Ontario Energy Board*, 2015 ONCA 453)

could actually accommodate.[418] Union Gas had the ability to sell 210 TJ of excess capacity and keep the incremental revenue, subject only to potential earnings sharing—which has not been in place since 2018. Customers are paying for that excess capacity without receiving the revenue benefit.[419]

4.2.4 As part of the subsequent PDO Settlement Agreement[420], the capacity required to facilitate the shift of obligated customer deliveries from Parkway to Dawn ("PDO Shift") was paid for by all ratepayers through an incremental cost included in rates. Central to the PDO Settlement Agreement was the guiding principle to "keep Union whole rather than to enhance or reduce its earnings," as compared to the situation it would have been in absent the agreement.[421] Therefore, even though customers were paying for the 210 TJ of excess capacity in the base rate[422], and 200 TJ of that was used to facilitate the PDO Shift by winter 2017/18[423], the company was compensated through the annual PDO cost adjustment, making this arrangement acceptable.[424]

4.2.5 When FRPO argued in the MAADs proceeding that customers were paying twice for the same capacity, it was correct. However, at least through the end of the Union Gas IRM period, this was acceptable under the terms of the PDO Settlement Agreement.

4.2.6 The issue in the MAADs proceeding was what to do going forward, beginning in 2019. FRPO requested a base rate adjustment to remedy the double recovery.

4.2.7 SEC agrees with FRPO that the OEB should refund customers the amount included in PDO costs that they were already paying through the excess capacity in base rates, beginning January 1, 2019.

4.2.8 While the double recovery was permissible through the Union Gas IRM period according to the terms of the PDO Settlement Agreement, it became inappropriate as of December 31, 2018. An important component of the PDO Settlement Agreement was the expectation that Union Gas' IRM term would end on December 31, 2018. The same

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[418] 4.7-FRPO-169 (K7.3, p.14); Tr.7, p.104, 106
[419] Tr.7, p.104
[420] EB-2013-0365, Appendix B, Settlement Framework For Reduction of Parkway Delivery Obligation (K7.3, p.23)
[421] Tr.7, p.106-107
[422] Tr.7, p.104
[423] 4.7-FRPO-169, Ln 9 (K7.3, p.14)
[424] Enbridge agreed that "surplus capacity is surplus capacity regardless of the source". (See Tr.7, p.107-108)

guiding principle discussed above pertains to keeping Union whole "during the operation of the Incentive Regulation Mechanism ('IRM') through December 31, 2018."[425]

4.2.9 In the MAADs Decision, the OEB allowed similar base rate adjustments for time-limited items.[426] For example, it permitted the then-applicants to remove from Union Gas rates a deferred tax benefit that had been included in base rates and that had been drawn down by the end of 2018. [427] Here, the PDO Settlement Agreement was entered into on the premise that Union Gas would rebase by the end of 2018. The double recovery benefit that had been allowed should be removed, as it would have been if a 2019 rebasing had occurred.[428]

4.2.10 Requiring Enbridge to repay customers for the PDO costs included in rates, which were facilitated by the excess capacity included in base rates, is equivalent to if the OEB had granted the base rate adjustment in the MAADs proceeding.

4.2.11 SEC has reviewed FRPO's calculations and believes they are a reasonable calculation of the amount that should be refunded to ratepayers.

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[425] EB-2013-0365, Appendix B, Settlement Framework For Reduction of Parkway Delivery Obligation (K7.3, p.23); Tr.7, p.107

[426] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.38

[427] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.38

[428] For 2024, the double recovery has been eliminated.

5 COST OF CAPITAL

5.1 ***Equity Thickness***

5.1.1 ***The Proposal.*** Enbridge has proposed to increase its equity thickness, over a period of five years, from 36% to 42%, largely due to the increased risks arising out of the Energy Transition. The overall impact on revenue requirement is estimated to be $80.6M[429], and the incremental rate increase is 2.7%, or about 0.5% per year over five years.

5.1.2 The issue, however, is more subtle than that.

5.1.3 Ratepayer and environmental groups mostly take the position that the Energy Transition is creating greater risks, many of which should fairly and as a matter of law fall on the Enbridge and its shareholders. At the same time, those parties resist rate increases, particularly those that directly increase compensation to shareholders for their capital.

5.1.4 On the other side of the debate, Enbridge takes the position that a) the Energy Transition will not mean the gas system will be at risk, because it will evolve, and b) in any case the regulatory compact establishes that the utility has an absolute right to collect the cost of capital assets from customers in rates. The risk of stranded, underutilized, or uneconomic assets is on the customers. Against that, Enbridge argues that the utility and its shareholders have increasing risk as a result of the Energy Transition, and should be compensated for it.

5.1.5 One could be forgiven for thinking that everyone is speaking out of both sides of their mouths.

5.1.6 ***Connecting Risk and Equity Thickness.*** In SEC's view, there are clearly greater risks arising out of the Energy Transition. It is hard to argue against that.

5.1.7 On the other hand, the issue of equity thickness depends on whether those risks are those of the shareholders, or the ratepayers. It is only if the shareholders are bearing those risks that there could be any case for increasing equity thickness.

5.1.8 Further, even if some or all of the risks are borne, as a matter of law or policy, by the shareholders, compensation for those risks should only arise if Enbridge is taking all

[429] Undertaking J9.1, Attachment 1

reasonable steps to mitigate those risks. Enbridge cannot allow a risk to exist unmitigated, and then ask the ratepayers to compensate it for its own inaction.

5.1.9 On the first question, the interpretation of the regulatory compact in this situation is not clear. While it is undoubtedly true that the utility and its shareholders are not fully insulated from the risk of stranded, underutilized, or uneconomic assets[430], a determination of the dividing line between shareholder and ratepayer responsibility is a broader question that has been debated by courts and regulators multiple times. As SEC noted earlier, it does not need to be determined in this case, and there is insufficient evidence on the record to do so.

5.1.10 On the second question, though, the evidence is quite clear. Enbridge is not only refusing to rein in its capital spending, but it has not even taken any steps to assess the risks that its assets will cease to be fully useful. These are the main steps currently available to mitigate the risk of under-recovery of invested capital. Enbridge is expressly declining to mitigate.

5.1.11 ***SEC Recommendation.*** SEC submits that by declining its responsibility to mitigate the Energy Transition risk, Enbridge has disqualified itself from asking for greater compensation for that risk. Enbridge has told the Commissioners that it does not need to take any significant steps to protect against the impacts of the Energy Transition. It can continue operating its franchise on a "business as usual" basis, and it proposes to do so. In those circumstances, no further equity thickness is warranted.

5.1.12 SEC therefore proposes that, unless a comprehensive mitigation plan, including at the very least substantial reductions in new capital additions, is implemented at the same time, the proposal to increase the Enbridge equity thickness should be denied.

5.1.13 Of course, SEC has elsewhere in this Final Argument set out a possible regulatory response to the Energy Transition, which we have called Incremental. A key principle in that proposal is that there is a balancing of measures being implemented. It includes a substantial reduction in capital spending over the next five years, a component that is critical for its success. At the same time, with that strong mitigation effort built in, SEC believes that residual risk associated with the Energy Transition can appropriately be reflected in a higher equity thickness. In that respect, SEC supports the 2% one-time

[430] If for no other reason than a death spiral by definition means the customers are not going to pay for the costs of those remaining assets.

increase proposed by LEI.[431]

5.2 ***Expert Evidence***

5.2.1 The Commissioners heard from multiple experts on the cost of capital implications of the Energy Transition.

5.2.2 However, on the construction of the issue that SEC has proposed, their evidence does not have to be reviewed in any detail.

[431] M3, p.50; Tr.9, p.61

6 DEFERRAL AND VARIANCE ACCOUNTS

6.1 *Volume Variance Account*

6.1.1 Enbridge has proposed the creation of a Volume Variance Account ("VOLUVAR") to replace its two existing average use true-up accounts for each of the Enbridge Gas Distribution (Average Use True-up Variance Account) and Union Gas (Normalized Average Consumption Account) Rate Zones.[432]

6.1.2 The two existing accounts, while slightly different due to the underlying rate methodologies, both true up normalized average use per customer for general service rate classes on a weather-normalized basis.[433] The proposed VOLUVAR would be similar but, for the first time, would capture average use variances due to weather.[434]

6.1.3 Enbridge now does not want to bear any weather risk. As it says, the VOLUVAR "provides a similar de-risking of fixed cost recovery to that resulting from the proposed SFVD rate design for general service customers."[435] Enbridge proposes that the VOLUVAR would be in place only until, if approved, it implements its proposed SFVD rate design.[436]

6.1.4 Enbridge also relies on the results of a benchmarking study, undertaken by Guidehouse[437], which, among other things, looked at the revenue stability mechanisms of ten peer utilities.[438] The results of the study do demonstrate that most utilities have some form of either explicit or implicit revenue stability mechanisms, but only half do so in a way that protects the company from weather variances the way that Enbridge is proposing. The other half either do not have a similar mechanism, or they asymmetrically cap any true-up in favor of customers.[439]

6.1.5 SEC submits that the OEB should approve the proposed VOLUVAR, but only if it captures variance on a weather-normalized basis, similar to the existing accounts.

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[432] Tr.15, p.18; 9-1-2, p.26 (K15.2, p.2)
[433] 9-1-2, p.27 (K15.2, p.3)
[434] Tr.15, p.19
[435] Argument-in-Chief, para. 659
[436] Tr.15, p.14; Argument-in-Chief, para.659
[437] 3-2-2, p.6-9 (K15.2, p.6-9)
[438] Tr.1, p.26-27
[439] Tr.15, p.27-28; 3.2-FRPO-69a (K15.2, p.10-11)

6.1.6 If the primary intent, as it appears, is that Enbridge seeks to move to a more fixed revenue stream, and the inclusion of weather impacts on average use as part of the VOLUVAR is really just a bridging mechanism to SFVD rates, then that is really putting the 'cart before the horse.' The proposal for a new SFVD rate design is an issue for Phase 3, where the broader question of the appropriate way for Enbridge to collect its approved revenue requirement (primarily fixed vs. variable delivery rates) will be considered.[440] At that time, the OEB could revisit the issue as part of a more fulsome consideration.

6.2 ***Accounting Policy Changes Deferral Account***

6.2.1 Enbridge seeks approval to collect from customers the $140.2M balance in the Accounting Procedures Changes Deferral Account ("APCDA").[441] The APCDA was approved as part of Enbridge's MAADs proceeding[442] and is designed to record the impact of accounting changes that affect the revenue requirements arising from the merger of Enbridge Distribution and Union Gas.[443]

6.2.2 The largest component of the APCDA balance is $156M in Union Gas unamortized pre-2017 actuarial losses and prior service costs. These amounts reflect losses arising from changes in actuarial assumptions and actual experience of Union's pension and OPEB plans before February 27, 2017, the date of the Enbridge Gas Distribution and Union Gas merger ("Union Pre-2017 Actuarial Losses").[444]

6.2.3 SEC submits that the OEB should disallow recovery of the Union Pre-2017 Actuarial Losses component of the APCDA. Allowing Enbridge to recover these amounts would result in a windfall for Enbridge's shareholders, who have either implicitly or explicitly already recovered these amounts not just once, but twice already. Additionally, recovery would be impermissible retroactive ratemaking, as these amounts are not appropriately captured by the terms of the APCDA.

6.2.4 ***Background.*** On September 6, 2016, Enbridge Inc. and Spectra Energy Corp. ("Spectra Energy") announced they had entered into a merger agreement. At the time, Enbridge Gas Distribution was a subsidiary of Enbridge Inc., and Union Gas was a subsidiary of

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[440] Settlement Proposal, p.43
[441] Argument-in-Chief, para.244
[442] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.47
[443] *Rate Order* (EB-2018-0305), October 24 2019, Appendix I, p.7 (K15.2, p.31)
[444] Tr.15, p.29-30

Spectra Energy.[445]

6.2.5 While styled as a merger, the transaction should be more appropriately classified as an all-stock acquisition by Enbridge Inc. of Spectra Energy.[446] Enbridge Inc. paid Spectra Energy shareholders 0.984 Enbridge shares for each Spectra Energy share, which, as the announcement press release noted, represented an 11.5% premium on its then-current share price.[447] Regardless of how the transaction is considered, it involved two highly sophisticated parties agreeing on a valuation for each company to determine how much Enbridge Inc. stock would be paid to Spectra Energy shareholders.

6.2.6 The transaction closed on February 27, 2017. As required by the applicable US GAAP accounting rules, specifically ASC 805 Business Combinations, on that date Enbridge Inc. was required to write off to goodwill, which is not recoverable in rates[448], any previously unrecognized prior service cost gains or losses that were previously recognized in other comprehensive income.[449] As a result of ASC 805 and ASC 715, these eliminated amounts are to have no effect on the company's pension costs.[450]

6.2.7 Enbridge complied with the relevant accounting standards, and wrote off $250M gross ($185M net of deferred taxes) of Union Pre-2017 Actuarial Losses, which had resided in Accumulated Other Comprehensive Income on its balance sheet.[451]

6.2.8 Almost two years later, upon the merger of Enbridge Gas Distribution and Union Gas, Enbridge determined that it could now treat the previously written-off Union Pre-2017 Actuarial Losses as a temporary deferred asset for 2017 and 2018. This was because there was a "regulatory requirement to capture all impacts to revenue requirement resulting from accounting changes from the merger",[452] stemming from the OEB's approval of the APCDA.[453] When the account became effective, the Union Pre-2017 Actuarial Losses would again be reclassified from a deferred asset to the APCDA.[454]

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[445] Tr.1, p.30
[446] K15, p.19
[447] K15, p.19
[448] Tr.15, p.37
[449] Undertaking JT3.31, Attachment 1, p.4 (K15.2, p.40); Tr.15, p.37
[450] Undertaking JT3.31, Attachment 1, p.4 (K15.2, p.40)
[451] Undertaking JT3.31, Attachment 1, p.4 (K15.2, p.40)
[452] Undertaking JT3.31, Attachment 1, p.4 (K15.2, p.40)
[453] Tr.15, p.51
[454] Undertaking JT3.31, Attachment 1, p.4 (K15.2, p.40)

6.2.9 Both Enbridge Inc. and Spectra Energy had teams of lawyers, financial advisors, and accountants negotiating the terms of the deal and the price.[455] They would have had access to certain financial and operational information, including financial statements and regulatory books, from each other.[456] They would also be well aware of the accounting implications of the transaction[457], including the fact that the Union Pre-2017 Actuarial Losses would be required to be written off.[458]

6.2.1 At the time of the MAADs proceedings, Enbridge, specifically Enbridge Gas Distribution and Union Gas, did not believe these amounts were recoverable. They did not request approval of a deferral account to capture the Union Pre-2017 Actuarial Losses, and in fact, specifically opposed the creation of the APCDA which had been proposed by intervenors.[459]

6.2.2 ***Windfall to Enbridge Shareholders.*** Knowing that if the transaction was approved, $250M related to Union Pre-2017 Actuarial Losses would have to be written off, it was almost certainly, at least implicitly, considered in the price Enbridge Inc. agreed to pay for Spectra Energy shares. The Union Pre-2017 Actuarial Losses were effectively recovered as a reduction in the price of the transaction. Put another way, if the amount had been recoverable at the time, the price that would have been paid would have been higher. Allowing Enbridge years later to reverse the accounting decisions made by Enbridge Inc. and to allow recovery of these amounts constitutes a windfall to Enbridge Inc. shareholders, paid for by Enbridge customers.

6.2.3 Enbridge's position is that the APCDA properly captures these amounts, based on the requirement for the company to adopt push-down accounting from its parent, Enbridge Inc., as of the effective date of the Enbridge Gas Distribution and Union Gas merger.[460] Union Pre-2017 Actuarial Losses remained on Union Gas' books until January 1, 2019. Absent the merger, these losses would have remained on the books and would have been drawn down in the normal course.[461]

6.2.4 SEC disagrees with Enbridge's view of what would have happened. If there had not been

[455] Tr.15, p.30, 38
[456] Tr.15, p.30
[457] Tr.15, p.30, 37
[458] Tr.15, p.30, 39-40
[459] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.46
[460] Argument-in-Chief, para. 690, 692
[461] Argument-in-Chief, para. 694

a merger between Enbridge Gas Distribution and Union Gas, the same issue of an unfair windfall gain would have arisen. These amounts would still not have been recoverable from ratepayers.

6.2.5 Alternatively, even if the losses were not considered as part of the determination of the price paid by Enbridge Inc., the requirement for Enbridge Inc. to balance the books at closing is a cost of the transaction. The OEB's policy is clear. Transaction costs are not recoverable from ratepayers.[462] The fact that the transaction was between Enbridge Inc. and Spectra Energy, as opposed to between Enbridge Gas Distribution and Union Gas, is irrelevant. The intent is that ratepayers should not be required to pay for costs that result from decisions made by a utility's shareholders (direct or indirect).

6.2.6 Fundamentally, it was the Enbridge Inc. and Spectra Energy transaction that necessitated the write-off of these amounts, not the merger between Enbridge Gas Distribution and Union Gas. Enbridge has stretched the intent of the APCDA to argue that the Union Pre-2017 Actuarial Losses meet the definition set out in the MAADs Decision and the APCDA Accounting Order.

6.2.7 ***Amounts Are Impermissible Retroactive Ratemaking.*** The APCDA was not made effective until January 1, 2019, whereas Enbridge was required to apply push-down accounting retrospectively to February 27, 2017.[463] Enbridge could not then, after the fact, reclassify these written-off Union Pre-2017 Actuarial Losses as deferred asset on what it recognizes is a "temporary" basis[464] to allow it to then transfer the amount on January 1, 2019, to the APCDA. This is clearly impermissible retroactive ratemaking. Enbridge cannot reclassify the amounts for 2017 and 2018 as a deferred asset, on the basis that the OEB later established a deferral account with a future effective date.

6.2.8 ***Ratepayers Have Already Paid These Balances in Base Rates***. The second time that Union Pre-2017 Actuarial Losses have efficiently paid for the Union Pre-2017 Actuarial Losses is through amounts collected from customers base rates since 2013.

6.2.9 As part of Union's approved base rates, which were established in 2013, an amortization expense of $28.1M was included.[465] The amount Union collected grew each year as a result of annual IRM adjustments and customer growth. Even though an amortization

[462] *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016, p.11 (K14.3, p.43)
[463] Undertaking JT3.31, Attachment 1, p.4-5 (K15.2, p.40-41)
[464] Undertaking JT3.31, Attachment 1, p.4 (K15.2, p.40)
[465] Tr.15, p.58; Undertaking JT3.37, Attachment 1, p.3 (K15.2, p.65)

expense was included in the base rates, the amount the Enbridge, and previously Union Gas, amortized each year was less, through the end of 2023.[466] The difference between what was collected in base rates and what was actually amortized over that period boosted Enbridge's earnings to the benefit of its shareholders.[467]

6.2.10 It is not as if either company spent that money on other things that benefit customers. Both Union Gas and Enbridge over-earned in each year, well in excess of the difference.[468] While some of that excess earning would have been shared with customers through the ESM mechanism, it would have been only a small portion after the application of the specific deadband and sharing methodology in place at that time.

6.2.11 The analysis that the Ontario Greenhouse Vegetable Growers ("OGVG") walked Enbridge and the Commissioners through during the Oral Hearing (Exhibit K15.3) demonstrates that the company collected $164.4M in excess amortization costs, an amount greater than the proposed balance of $156M. Enbridge should not be allowed to once again recover these costs that have already been effectively paid for by customers.

6.2.12 ***OEB Staff's Analysis.*** OEB Staff takes a different approach to the issue of double recovery of Union Pre-2017 Actuarial Losses. It argues that customers should get the benefit of the amortization costs embedded in base rates, as compared to the actual amortization costs, between 2019 and 2023 only, as the APCDA was in place to capture the difference during that time.[469] This would reduce the amount to be collected from ratepayers by $80.2M.[470]

6.2.13 OEB Staff's approach, while valid, does not go far enough considering the context discussed above. Ratepayers should get the benefit of the entire amount included in base rates since 2013.

6.2.14 Even if OEB Staff's approach is to be considered, their calculation needs to be adjusted to address two problems. First, OEB Staff's calculation uses $27.1M a year as the amortized costs embedded in rates.[471] The correct amount is $28.1M which includes $1M

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[466] Tr.15, p.58; Undertaking JT3.37, Attachment 1, p.3 (K15.2, p.65)
[467] Tr.15, p.61
[468] 5.3-IGUA-30, Attachment 1
[469] OEB Staff Submissions, p.126-127
[470] OEB Staff Submissions, p.126-127
[471] OEB Staff Submission, p.126, Table 22. The $27.1M number is derived from Undertaking JT 3.37, Attachment 1, p.3, Line 6

of OPEB amortization costs included in approved 2013 rates.[472] Enbridge is seeking recovery of both the pre-2017 pension and OPEB actuarial losses and prior service costs.[473] Second, the amount included in base rates needs to be adjusted upwards to reflect annual Price Cap Adjustment which inflates base rates, as well as incremental customer growth which allows for increased revenue of the total amount of base rates collected over 2013 amount. Based on the analysis included in K15.3, this would reduce the proposed recovery by an additional $32.6M (total reduction from the requested amount of 110.8M).[474]

6.2.15 ***Balance and Recovery Approach.*** If the OEB, contrary to SEC's submissions, accepts that the Union Pre-2017 Actuarial Losses are recoverable from ratepayers, there are two further issues for the OEB to consider: what is the appropriate balance to dispose of, and how should it be recovered from ratepayers?

(a) ***Gross vs. Net Balance***. Enbridge calculates the balance to be recovered at $156M, which represents the forecast year-end 2023 balance in the APCDA related to Union Pre-2017 Actuarial Losses.[475] Over the 5 years these amounts were included in the APCDA, Enbridge annually continued to amortize the losses against the initial balance of $211M in a similar way as it had done pre-merger.[476]

It appears that Enbridge transferred the gross Union Pre-2017 Actuarial Losses to the APCDA, not the net amount, which accounts for deferred income taxes that acts as an offset. The difference is substantial. In the memo used to support the accounting treatment, it had at the time forecast that the net year-end 2018 balance would be $154M, with $55.6M in deferred taxes.[477]

It would be entirely unfair if customers were required to pay the gross amounts, while Enbridge gets the deferred tax benefit that only exists as a result of the costs that it is seeking to recover. The remaining deferred tax balance should be applied against the balance in the APCDA before any amount is approved for disposition.

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[472] JT 3.37, Attachment, p.3, Line 10 (K15.2, p.64)
[473] Argument-in-Chief, para 681
[474] See K15.3, Ln 11 for the appropriate amounts to include as embedded amortization costs in rates (Row B in OEB Staff Submission, Table 22).
[475] Tr.15, p.60; 9-2-1, Attachment 2 (K15.2, p.13)
[476] Tr.15, p.63-64; 9-2-1, Attachment 2 (K15.2, p.13); Undertaking JT 3.37, Attachment, p.1 (K15.3, p.61)
[477] Undertaking JT3.31, Attachment 1, p.21 (K15.2, p.57)

As this matter was not canvased during the oral hearing, there is limited evidence on the nature of the deferred taxes. SEC requests that Enbridge address this issue in its reply argument.

(b) ***Disposition Approach***. Enbridge is seeking approval to dispose of the total balance over one year. This approach differs from the usual method for treating pension and OPEB actuarial gains and losses in ratemaking, where a specific methodology is used to amortize the balance each year.[478] Enbridge has been using this approach for the Union Pre-2017 Actuarial Losses in the APCDA since 2019.

Enbridge has stated that it can continue to gradually draw down the balances and thus smooth the impact of recovering the Union Pre-2017 Actuarial Losses, if approved by the OEB. This would be done through the creation of a new deferral account.[479] The remaining Union Pre-2017 Actuarial Losses at the end of 2023 would be transferred to the new account effective January 1, 2024, and Enbridge could recover a set amount on an annual basis to be applied against the balance.

SEC submits that this approach is preferable and aligns with what the OEB approved in EB-2011-0354, with respect to the Enbridge Gas Distribution Transition Impact of Accounting Change Deferral Account ("TIACDA").[480] Mr. Small indicated that a recovery period of 20 years, similar to the TIACDA, would be appropriate.[481]

6.3 ***Tax Variance Deferral Account***

6.3.1 Enbridge proposed to dispose to the benefit of customers $7.3M related to the impact of the taking advantage of accelerated CCA for integration capital projects brought in-service by the end of 2023.[482]

6.3.2 SEC submits the disposition of the balance in the account is tied to the OEB's findings regarding the appropriateness of including the undepreciated capital cost of integration capital projects in 2024 opening rate. If the OEB agrees with SEC's position that to include integration capital costs in rate base would be inappropriate, then the balance in

[478] Tr.15, p.90
[479] Undertaking JT 3.33 (K15.2, p.60)
[480] Undertaking JT 3.33 (K15.2, p.60)
[481] Tr.15, p.67
[482] Undertaking J15.1

the TVDA should not be credited to customers. As ratepayers would not be paying for the integration capital projects, they should not receive any amounts related to the company taking advantage of the accelerated CCA. If the OEB disagrees with SEC on recovery of integration capital, then the balance should be disposed of to the benefit of ratepayers.

7 OTHER ISSUES

7.1 *Other Revenue – Proceeds From Disposition of Property*

7.1.1 As part of its Capital Update, Enbridge forecasts the disposal of a single property in the 2024 test year, with proceeds expected to be $6.3M.[483] This is a revision from a previous forecast of four properties, with total proceeds from disposition estimated at $30-31M.[484] Enbridge has not included any proceeds from dispositions in its 2024 Other Revenue forecast.[485]

7.1.2 Its approach to the proceeds from the disposition of property is unfair and contrary to previous OEB decisions.

7.1.3 The OEB determined that this issue would be dealt with in writing only[486], so the record is not entirely clear regarding Enbridge's specific approach to the disposition of property. As SEC understands it, Enbridge allocates the gains (or losses) from a sale between building and land. The gains (or losses) allocated to the building are then credited to accumulated depreciation.[487] The gains (or losses) allocated to the land are credited to income.[488] Customers only benefit in that year if earnings sharing is triggered.

7.1.4 ***Buildings.*** SEC is confused by how Enbridge deals with the proceeds from dispositions allocated to the building. Enbridge only mentions that the gains (or losses) are allocated to accumulated depreciation, but does not address the proceeds related to the net book value of the building (i.e., the rest of the proceeds allocated to the building that are neither a gain nor a loss). Those amounts should be credited to depreciation unless the Enbridge also removes (or credits) those amounts separately, not just from the rate base[489], but also from depreciation. If not, then customers continue to pay for those assets through depreciation even though they have been sold.

7.1.5 ***Land.*** SEC does not agree with Enbridge that customers should receive none of the gains (or losses) from the sale of non-depreciable property. While there is no definitive policy

483 2.6-SEC-137 (Updated)
484 2.6-SEC-137
485 Technical Conference Transcript, Vol 5, March 28, 2023), p.27
486 See Procedural Order No. 6
487 2.6-VECC-18 (Updated)
488 2.6-VECC-18 (Updated)
489 See Undertaking J12.1 where the company shows the entries made again the rate base calculation, but not the depreciation expense.

on the issue, the OEB has, for the most part, consistently found that it is appropriate to share with customers the gains (or losses) from the disposition of non-depreciable property, which includes land.[490]

7.1.6 Enbridge is correct that the land is non-depreciable, but it is included in rate base. It would seem unfair to customers that while they pay for Enbridge's cost of capital on the value of the land, which includes a return on equity component, they do not share in any of the gains of disposition. Enbridge admits as much it says that it "reasonable to include proceeds from the sale of land that had been included in rate base as part of all other income to be shared in accordance with any ESM allocation in years when an ESM applies."[491] It is reasonable, but what is not is that customers would only get to share in the benefit if ESM is triggered, especially when Enbridge does not propose one for 2024.[492]

7.1.7 Enbridge's proposal would seem especially unfair for customers who are asked to pay for the replacement property, including the now more likely higher cost of land, which will be included in the rate base, but then not be able to share in the benefit of the sale of the disposed property.

7.1.8 For example, the 2024 property that Enbridge plans to dispose of is its South Merivale Operating Centre (SMOC).[493] The facility is part of a sale and consolidation of two properties, and the construction of a new $46.4M building in Ottawa, to be paid for by customers.[494]

7.1.9 ***SEC Proposal.*** 100% of the proceeds from the disposition of buildings, and 50% of the net gains (or losses) from the disposition of land, should be credited to ratepayers. Unless the land is replaced with other land to be used for utility purposes. In that case 100% of the appreciation of value of the land should be credited to ratepayers, since the new land will presumably have similar market appreciation built into its cost.

7.1.10 SEC accepts Enbridge's view that, since the disposition of property is not a regular occurrence, the amounts should not be included in base rates that underpin the incentive-

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[490] See *Decision and Rate Order* (EB-2019-0022/0031), January 23 2020, p.18-19
[491] Argument-in-Chief, para. 726
[492] Argument-in-Chief, para. 273
[493] 2.6-VECC-18b
[494] Tr.12, p.13-14; 2-6-2, Attachment A, p.61, Ln 32 (K11.2, p.205)

ratemaking term but should be captured by way of a deferral account.[495] However, that new deferral account should be in place not just for 2024, but throughout the entire IRM term, to capture all property dispositions until the next rebasing. Enbridge cannot have it both ways. Moreover, this approach better aligns with the fact that, while the disposition occurs in a single year that may or may not be a test year, the underlying or replacement property costs are paid for by customers through rates over many years.

7.1.11 This is consistent with the OEB's policy with respect to electricity distributors, which requires the utility to identify gains or losses on individual assets in its subsequent rate filing.[496] The OEB has found that this encumbers them in the same way that a deferral account would, allowing the it to retroactively share those gains with ratepayers, regardless of timing.[497]

7.2 ***2024 Earning Sharing Mechanism***

7.2.1 As part of Enbridge's proposed incentive ratemaking framework, it proposes an earnings sharing mechanism (ESM), commencing in 2025, which is the first year its rates would be set by way of an incentive mechanism.[498] It does not propose to include an ESM in the 2024 test year.

7.2.2 Enbridge's position is that an ESM for the test year is not appropriate because ratepayers are protected from substantial returns over the approved ROE through the test of the evidence presented in this proceeding.[499] It argues that there is no OEB policy that requires or recommends an ESM in a year when rates are set on a cost of service basis.[500]

7.2.3 SEC submits that Enbridge is unique in this regard, it or its predecessor companies have over-earned (i.e., a comparison of actual vs. allowed ROE) in every single year since at least 1990 for Enbridge Gas Distribution and 2007 for Union Gas.[501] This includes many cost of service applications for Enbridge Gas Distribution and at least the last two for Union Gas.[502] Its remarkable financial performance, even in years when it rebases its

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[495] Argument-in-Chief, para. 719-720

[496] See Accounting Procedures Handbook For Electricity Distribution Utilities, see articles 315 and 410

[497] *Decision and Rate Order* (EB-2019-0022/0031), January 23 2020, p.19

[498] 9-1-2, p.27-28

[499] Argument-in-Chief, para. 768

[500] Argument-in-Chief, para. 770

[501] 5.3-IGUA-30, Enbridge Gas Distribution also over-earned in 2003, 2004, and 2007. For years 2002-2002 and 2005-2006, the company was unable to provide information on its earnings in those years.

[502] Union Gas (2007 in 2005-0520, 2013 in EB-2011-0210)

rates, demonstrates that the hearing process is not sufficient to protect customers, and an ESM is warranted.

7.2.4 The fact that there is no specific OEB policy regarding ESM in cost of service applications does not mean that an ESM should not be implemented where warranted, as is the case here, or that it has not been applied before. The OEB has approved ESM for the first year of a multi-year plan in all of the most recent Custom IR proceedings for other large utilities, where the first year is set on a cost of service basis.[503] Contrary to Enbridge's suggestion[504], this includes proceedings where there was no settlement.[505] In fact, for large utilities, not including an ESM is the exception, not the rule.

7.2.5 SEC proposes that the specific terms of the ESM for 2024 (i.e., deadband, level of sharing, etc.) be determined as part of Phase 2, where the consideration of the ESM mechanism (Issue 45 - Is the proposed earnings sharing mechanism appropriate?) will be addressed. Since there was no specific evidence regarding the ESM included in Phase 1 for parties to test, it would be best to defer that aspect of the issue until Phase 2. All that the OEB would need to determine in Phase 1 is that any approved ESM determined as part of Issue 45 would apply to 2024.

7.3 ***Dawn Parkway Turnback Risk***

7.3.1 Issue 38 asks, "How should Dawn Parkway capacity turnback risk be dealt with?" The genesis of the issue lies in the approved settlement of the Union Gas Lobo C Compressor/Hamilton-Milton Pipeline Project Costs (2016 Dawn Parkway System Expansion) application.[506] As part of that approved settlement, the parties agreed that the issue of Dawn-Parkway capacity risk should be addressed in Union's next cost services proceeding.[507]

7.3.2 SEC accepts the conclusion from both Enbridge (and its expert, ICF) and FRPO's expert,

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[503] See *Decision on Settlement Proposal and Order on Rates, Revenue Requirement, and Charge Determinants* (EB-2021-0110), November 29, 2022, Settlement Proposal, p.26 (Hydro One); *Decision and Order* (EB-2020-0290), November 15 2021, Schedule A, Settlement Proposal, p.18 (Ontario Power Generation) *Decision and Order* (EB-2019-0261), November 19, 2020, Schedule A, Settlement Proposal, p.34 (Hydro Ottawa); *Decision and Order* (EB-2018-0165), December 19 2019, p.42 (Toronto Hydro)

[504] Argument-in-Chief, para. 770

[505] See for example *Decision and Order* (EB-2018-0165), December 19 2019, p.42; *Decision and Order* (EB-2017-0049), March 7 2019, p.40

[506] *Decision and Order* (EB-2014-0261), April 30, 2015, Appendix C, Settlement Proposal, p.5-6

[507] *Decision and Order* (EB-2014-0261), April 30, 2015, Appendix C, Settlement Proposal, p.5-6

Mr. Rosenkranz, who agree that there is limited risk of turnback on the Dawn Parkway system during the proposed rate term (2024-2028).[508] However, this does not address the broader issue of Dawn Parkway turnback risk over the long-term. This is important because Enbridge has plans over the next six years to construct two new expansion projects that will add new Dawn Parkway capacity (Kirkwall Hamilton NPS 48 and Dawn-Enniskillen NPS 48) at a total cost of approximately $584M.[509]

7.3.3 Similar to the rest of its capital planning, the company's current approach assesses the need for facilities based on a 10-year demand forecast. As discussed in detail earlier in these submissions, this approach is problematic in the context of the Energy Transition. Demand is expected to drop over the medium and long-term, while the assets may have a physical lifespan extending in some cases beyond 60 years.

7.3.4 SEC wishes to comment on certain measures, in scope for Phase 1[510], discussed during the proceedings to mitigate turnback risk specific to the Dawn Parkway system.

7.3.5 First, unlike many other pipelines (including TCE Energy)[511], if Enbridge is undertaking a Dawn Parkway expansion project, it does not require existing customers with contracts to extend them—commonly referred to as a "term-up" provision.[512] The benefit of such a provision is that it requires existing customers to commit to capacity, thereby reducing the chance of turnback soon after a new build. SEC supports the use of term-up provisions for any new Dawn Parkway expansion projects, but this only mitigates the risk of turnback in the short term, as these provisions are usually valid for only about 5 years.[513]

7.3.6 Second, Mr. Rosenkranz proposes that as part of the mandated reverse open season, Enbridge should be allowed to offer a buyout option.[514] As SEC understands the proposal, existing customers with contracts could bid a price they would be willing to accept in return for releasing their capacity. Enbridge would accept the bid if it proved to be more cost-effective than the costs to construct the expansion.

[508] Tr.8, p.32
[509] 2-6-2, Appendix A, p.60 (K7.3, p.9)
[510] Dr. Rosenkranz proposes a change to the cost allocation of the Dawn Parkway system (M4, p.14). As a result of the approved Settlement Proposal, cost allocation is to be dealt with in Phase 3.
[511] Tr.7, p.76, 83
[512] Tr.7, p.75
[513] Tr.7, p.78
[514] M4, p.15 (K7.3, p.3)

7.3.7 SEC is intrigued by the concept. It is a form of demand-side IRP that deserves serious consideration. That said, it is not ready to be implemented without significant further study at this time. There are too many outstanding questions about how this would work in practice, to which Mr. Rosenkranz did not have the answers.[515] The OEB should require Enbridge to consider the concept and bring it forward to be considered as part of the IRP Technical Working Group.

7.3.8 The best way to mitigate Dawn Parkway turnback risk is to avoid further expansions altogether, a conclusion that will likely become evident with a full assessment of the Energy Transition risks. Enbridge must be required to assess not just short-term turnback risk but also future underutilization risk when considering a Dawn Parkway expansion project.[516] All cost-effective options to avoid construction need to be considered and thoroughly assessed in any Leave to Construct application. To do this properly, Enbridge must ensure that any Dawn Parkway Leave to Construct application is brought sufficiently in advance of the capacity need.

7.4 ***SQR Exemption Request***

7.4.1 Enbridge seeks a partial exemption for three GDAR service quality requirements ("SQR") performance measures. For each of the Meter Reading Performance Measurement ("MRPM"), Call Answer Service Level ("CASL"), and Reschedule a Missed Appointment ("TRMA") performance measures, Enbridge seeks an exemption from its existing target to substitute a reduced target.[517] It requests that the partial exemption be retroactive to January 1, 2023, and last at least until the OEB orders otherwise (or until the OEB conducts a review of the SQR measures in GDAR).[518] SEC submits that the OEB should deny the requested exemptions.

7.4.2 Enbridge has provided several reasons for requesting that the OEB approve a reduced target for these three measures, but central to all of them is that it is no longer able to

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[515] See Tr.8, p.36-37; 40-41

[516] For example, as part of the approved Settlement Proposal, there was agreement to introduce a Parkway delivery recall condition for any new customers offered the opportunity to move volumes from Parkway to Dawn in the event of a new Dawn to Parkway build is planned. (See *Decision on Settlement Proposal* (EB-2022-0200), August 17 2023, Schedule A, Approved Settlement Proposal,p.37-38)

[517] 1-7-1, p.14

[518] Argument-in-Chief, para. 811

meet them.[519] Its answer to the reduced level of service quality in recent years is to seek to reduce the level of service quality that the OEB requires. This approach is entirely inappropriate and is directly contrary to the OEB's objective to "protect [customers'] interests with respect to... quality of gas service."[520]

7.4.3 The degradation of Enbridge's service quality performance is troubling, especially considering the commitment made during the MAADs application, which the OEB relied upon when granting approval. In the MAADs decision, the OEB found that the "proposed transaction will not lead to any adverse impact with respect to the reliability and quality of service, and the OEB finds that the no-harm test is met in this regard."[521] In particular, the OEB noted that it accepted Enbridge's position that "efficiencies can be gained without compromising the ability of Amalco to maintain current levels of reliability and quality of service," and that the "new gas utility will be subject to the same requirements under the OEB's Gas Distribution Access Rules (GDAR)."[522]

7.4.4 Enbridge's compliance with the three SQRs at issue began after the merger.[523] Having now broken its commitment to maintain Enbridge Gas Distribution and Union Gas service quality levels, Enbridge seeks to lower the service quality it is expected to achieve. The OEB should hold the company to its own commitment.

7.4.5 SEC is most concerned with the request for a partial exemption from the MRPM performance measure target. Enbridge seeks to raise the target (i.e., lower the required service quality) for the percentage of meters with no reads for four or more consecutive months from 0.5% to 2%.[524] Enbridge's recent lack of compliance with the existing MRPM target resulted in its entering into an Assurance of Voluntary Compliance ("AVC").[525] The AVC outlined the significant impact on customers due to Enbridge's non-compliance, based on specific complaints that the OEB received regarding its meter reading performance. This includes "[m]any complaints related to long periods of estimated bills due to the company not completing meter reads, which then resulted in some residential and commercial customers receiving large 'catch-up' bills that were as high as several hundred or thousand dollars more than what they were reasonably

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[519] 1-7-1, p.3,6, 19
[520] *Ontario Energy Board Act, 1998*, section 2(2)
[521] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.13
[522] *Decision and Order* (EB-2017-0306/307), August 30, 2018, p.13
[523] 1-7-1, p.3,6, 19
[524] Argument-in-Chief, para. 803
[525] *Assurance of Voluntary Compliance* (EB-2022-0188), September 12 2022

expecting." [526]

7.4.6 SEC member schools have been negatively impacted by the high number of estimated bills, particularly in Enbridge's Union South Rate Zone.

7.4.7 Enbridge's non-compliance with the MRPM performance measure, which is included on its OEB-approved scorecard[527], was also noted as part of the company's 2021 DVA/ESM disposition. As part of the approved Settlement Proposal, "Enbridge Gas acknowledge[d] that its meter reading performance has negatively impacted customer billing," and that "[a]ll parties, including Enbridge Gas, are concerned with the meter reading and billing issues encountered."[528]

7.4.8 Increasing the existing target fourfold, as Enbridge proposes, would only exacerbate the problem of estimated bills and provide relief to the company for poor performance. Enbridge should focus on improving its service quality, not on asking to be let off the hook.

7.4.9 SEC submits that the OEB should send a clear message to Enbridge and deny the request to lower its SQR obligations.

7.5 ***Rate Implementation***

7.5.1 SEC does not object to a effective date of 2024 rates being January 1, 2024.

[526] *Assurance of Voluntary Compliance* (EB-2022-0188), September 12 2022, p.7
[527] 1-7-1, Attachment 1
[528] *Decision on Settlement Proposal and Rate Order* (EB-2022-0110), November 8 2022, Schedule A, Settlement Proposal, p.21

8 COSTS

8.1 *Costs*

8.1.1 SEC hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that SEC has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible.

All of which is respectfully submitted.

Mark Rubenstein
Jay Shepherd

Counsel for the School Energy Coalition