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.

ARGUMENT IN CHIEF OF ENBRIDGE GAS INC.

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Introduction

1. This is the Argument in Chief (Argument) of Enbridge Gas Inc. (Enbridge Gas or the Company) related to its application to approve rates for the sale, distribution, transmission, and storage of gas commencing January 1, 2024. Enbridge Gas also applies for approval of an incentive rate-making mechanism (IRM) for the years from 2025 to 2028.

2. Enbridge Gas filed its 2024 Rates Application and the majority of its supporting evidence on October 31, 2022, and the balance of its evidence on November 30, 2022.

3. In Procedural Order No. 2, the OEB set the Issues List for this proceeding, divided into Phase 1 and Phase 2.

4. Enbridge Gas answered interrogatories about its evidence (more than 1,500), and then a nine day Technical Conference was held, resulting in over 250 undertakings.

5. A Settlement Conference was held from May 29 to June 9, 2023. Enbridge Gas and intervenors reached a partial settlement whose proposal was filed June 28, 2023, was updated and refiled July 13, 2023, and was subsequently approved by the OEB on August 17, 2023.

6. The Parties reached complete agreement on the following Phase 1 issues:

Category	Issue Numbers
A. Overall	4
C. Volumes & Revenues	9-11
D. Operating Costs	19
G. Cost Allocation	24*
H. Rate Design	25-28*, 30
I. Deferral & Variance Accounts	31
J. Other	35-36, 39*

7. The Parties reached agreement on parts of the following Phase 1 issues:

Category	Issue Numbers
B. Rate Base	6
D. Operating Costs	12-14, 17-18
E. Cost of Capital	21
H. Rate Design	29
I. Deferral & Variance Accounts	32-33

* The Parties agreed that Issue 24 (cost allocation) and some / all of Issues 25-28 (rate design) and Issue 39 (storage space/deliverability methodology) should be deferred to a subsequent phase of the proceeding.

8. In Procedural Order No. 6, Issues 10, 34, 37, and 40 were directed to proceed directly to written submissions. As such, these Issues are discussed in detail in this Argument.

9. The Oral Hearing was held over 18 hearing days, between July 13, 2022, and August 11, 2022. The Oral Hearing addressed the remaining unsettled and partially settled Phase 1 issues. Enbridge Gas presented 9 witness panels, and there were 8 witness panels comprised of expert witnesses presented by other parties.

10. This Argument addresses each of the unsettled and partially settled Phase 1 issues. It is organized by issue, with a brief overview at the beginning.

11. In this Argument, Enbridge Gas has provided its preliminary response to many of the expected positions of other parties, particularly where there is intervenor evidence

on a topic. In many cases, though, Enbridge Gas does not know and/or does not want to presume the range and details of positions that others may advance. Enbridge Gas will respond as appropriate in Reply Argument.

Overview

12. On Day 1 of the Oral Hearing, parties were invited to provide their "Opening Statement". Mr. Kitchen went first, providing the Enbridge Gas perspective.[1] While a large amount of testimony was provided over the course of the Oral Hearing, Enbridge Gas maintains the key messages highlighted by Mr. Kitchen.

13. 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. Much of what will be included in 2024 rates has been resolved through the Settlement Proposal, but there are large and important items left to be decided.

14. Any decision on 2024 rates must be made in the context of current energy policy. At this time, there is no Government of Ontario policy that sets a path to net zero. That said, however, the Government of Ontario recently released the Powering Ontario's Growth report, indicating that natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective source of energy for space heating, industrial growth, and economic prosperity.

15. The Government of Ontario has initiated the Electrification and Energy Transition Panel (EETP) to help guide the government with energy transition. Among other things, the EETP will be looking at integrated planning between the gas and electricity sectors and reducing barriers to low-carbon fuels. A "key input" for the EETP is the "independent cost-effective pathways study" that is being prepared.

[1] 1 Tr.4-7.

Only after the EETP report is received and the Government of Ontario provides its resulting direction will there be clearer indications about any electrification path that Enbridge Gas and the OEB can rely upon.

16. In the Energy Transition section of this Argument, Enbridge Gas sets out its Key Messages that guide the Company's approach in its filing and in its current planning. These Key Messages emphasize the important role that the gas distribution system does and will serve to meet the energy needs of Ontarians. The Key Messages also speak to how Enbridge Gas is planning for and evolving to a lower-carbon future.

17. Enbridge Gas takes exception to the broad criticisms from other parties (seen in the "Closing Statements") of the Company's efforts in this regard. Simply stated, Enbridge Gas is taking the appropriate measured and clear-eyed steps to evaluate and respond to energy transition in a way that is mindful of current Government of Ontario policy and maintains the gas distribution system as a reliable and cost-effective source of energy.

18. Enbridge Gas is focused on addressing and enabling the Government of Ontario's policies and goals. As indicated in Minister Smith's letter to Enbridge Gas's President (Michele Harradence):

> Ontario has a robust and clear set of governance arrangements laid out in legislation and regulation. Under my direction, the Ministry of Energy is focused on developing electricity, natural gas, and fuel policies that maintain safe, reliable, and affordable energy supply, transmission and distribution systems across the province – ensuring we continue to power our growing economy.[2]

19. Minister Smith emphasized these same themes later in the same letter, when he wrote about the EETP's role, and the Government's expectations in that regard:

> As we embark on this energy transition journey, Ontario will need to rely on its diversified energy system that serves the needs of customers

[2] Letter from Todd Smith, Minister of Energy, to Michele Harradence, President Enbridge Gas, June 26, 2023, page 1 – filed at Exhibit J8.1, Attachment 1.

> safely, reliably, and affordably. It will also need to maintain a system that is economically competitive to attract investment, support industry and grow jobs.[3]

20. Simply stated, Enbridge Gas is taking the appropriate measured and clear-eyed steps to evaluate and respond to energy transition in a way that is mindful of current Government of Ontario policy and maintains the gas distribution system as a reliable and cost-effective source of energy.

21. This is consistent with the OEB's statutory objectives that include facilitating "rational expansion of (gas) transmission and distribution systems" and "the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas."[4] As the OEB itself pointed out in its own submissions to the EETP, the OEB's statutory objectives do not currently include specific reference to reducing greenhouse gas (GHG) emissions or to net zero.[5] The OEB recommended that adding a new objective would assist the OEB in considering GHG emissions or net zero (as applicable depending on the wording of the objective) as a factor in its rate, facilities, and other decisions.[6] The implication, of course, is that this jurisdiction is currently lacking.

22. A key theme in intervenor positions (and seen in Issue 3) is the question of identification and allocation of risk. Enbridge Gas submits that it is appropriately addressing risk through measured growth and continued focus on sustainment activities to provide safe and reliable service. The Company is incorporating Integrated Resource Planning (IRP) and appropriate demand assumptions to lower the risk of oversized or unnecessary assets being added.

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[3] Exhibit J8.1, Attachment 1, page 2.
[4] *Ontario Energy Board Act, 1998* (OEB Act), section 2.
[5] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, page 2. https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdf
[6] Ibid, page 15.

23. Enbridge Gas does not foresee a risk of stranded assets in the near term. Current Government of Ontario legislation and the currently announced measured-paced expansions of the electricity grid suggest that the risk of stranded assets is a longer-term risk and not anticipated over the near term. In the longer future, Enbridge Gas sees a continuing role for the gas distribution system which minimizes the risk of assets that are not used or useful. To the extent that the risks of assets being unused grows over time, then regulatory mechanisms can be applied at a later date, including different depreciation or rate treatment. At this time, however, there is insufficient information to make fundamental changes.

24. It is not appropriate to take the view that Enbridge Gas should be specifically at risk any more than is currently the case for stranded asset risks on new facilities and equipment that are added in the next five years to support the continued operation of the gas distribution system that serves almost 4 million customers. Such a finding would be inconsistent with the regulatory compact that requires a utility to make investments to serve its customers, but with the full opportunity to recover such costs. Similarly, Enbridge Gas should not be at risk for assets added to serve new customers, where the Company follows OEB-approved customer attachment policies (which are being reviewed in this case).

25. Enbridge Gas's proposed capital budget recognizes the continued need to meet the demands of new customers while providing safe, reliable, and resilient service to approximately 3.8 million existing residential, industrial, and commercial customers. Again, as indicated in the report of the government, natural gas accounts for approximately 40 percent of Ontario's energy mix and is the primary source of heat for Ontario families and homeowners.

26. Enbridge Gas acknowledges that customer additions policy is a main area of focus for parties and the Commissioners in this case. Unfortunately, this is not an item that other parties chose to focus upon in the expert evidence that they filed. As a result,

there is very little evidence about alternatives to the Company's current customer attachments policy. Enbridge Gas's proposal is based upon the OEB's direction in E.B.O. 188. That OEB direction has been consistently endorsed in other proceedings. In this Argument, Enbridge Gas sets out the reasons for its position that if changes are to be made to its proposed customer attachment policy (and in particular to the applicable revenue horizon), then this should be done in a measured way. Enbridge Gas highlights that any such changes will make the costs for new customers more expensive, something that is challenging at a time when the Government of Ontario is prioritizing affordable new housing.

27. With the amalgamation of Enbridge Gas Distribution (EGD) and Union Gas (Union) in 2019, Enbridge Gas embarked on an ambitious path to rationalize the organization, reduce duplication, and harmonize systems and policies over the five-year deferred rebasing term. In doing so, Enbridge Gas generated significant permanent savings of $86 million, which are now being flowed to ratepayers through rates now and beyond. Enbridge Gas submits that in keeping with the OEB's well-established benefits follow costs and beneficiary pays principles, the OEB should permit recovery of any undepreciated integration capital costs which generated those savings.

28. With respect to depreciation, Enbridge Gas's proposal reflects a more accurate depreciation and salvage methodology from what is currently in place for EGD and Union. The proposed level of depreciation expense also strikes a balance between addressing energy transition and considering ratepayer impacts.

29. Finally, Enbridge Gas is proposing to increase its equity ratio from a level of 36 to 42 percent, which will be phased in over the next 5 years. This proposal reflects changes in business, financial, and regulatory risk since it was last addressed by the OEB for EGD and Union. Enbridge Gas has currently the lowest equity ratio in North America, and it is lower than that of Ontario electric utilities. Enbridge Gas's proposal

to phase in the increase in equity ratio serves as a balance to the rate impacts while providing for an appropriate level of equity thickness.

30. A number of other issues are addressed in this Argument. Each section includes the Approvals Requested and an Overview.

31. In Exhibit J17.11, Enbridge Gas set out the revenue requirement and deficiency requested for recovery in Phase 1 of this proceeding, taking into account the Settlement Proposal and the Capital Update. Table 1 below, taken from Attachment 1 to Exhibit J17.11, is an updated version of the Drivers of Deficiency table from the pre-filed evidence[7]. In summary, the updated table shows that the currently requested 2024 delivery revenue deficiency is $186.3 million, which is a reduction of almost $60 million from the delivery revenue deficiency indicated in the Capital Update of $245.3 million.[8] Note that the Panhandle Regional Expansion Project (PREP) has been excluded from the indicated 2024 revenue deficiency calculation because it will be recovered via the levelized approach. The levelized deficiency attributable to 2024 would be $7.3 million.

[7] Exhibit 6, Tab 1, Schedule 2, Attachment 2, page 2.
[8] The delivery revenue deficiency in the Capital Update is seen at Exhibit 2, Tab 5, Schedule 4, Attachment 5, line 19 (June 16, 2023 update). The delivery revenue requirement after the Settlement Proposal is seen in Exhibit J17.11, page 3, line 24.

Table 1
2024 Test Year - Drivers of Delivery Revenue Deficiency

Line No.	Particulars ($ millions)	Gross (Deficiency)/ Sufficiency
1	Net sustainable synergies and productivity	74.2
2	Changes in accounting policy and methodologies	25.6
3	Impact related to ICM and Capital Pass Through	(42.0)
	Deferred Rebasing Impact	57.8
4	Cost pressures	(111.9)
5	Higher depreciation resulting from new depreciation study	(187.5)
6	Increase equity thickness from 36% to 38% in 2024	(26.1)
	Cost of Service Impacts	(325.5)
7	Removal NBV of WAMS	3.3
8	Removal 25% NBV of GTA overspend	3.4
9	Defer Dawn- Corunna to Phase 2	22.5
10	Adjustment to customer addition forecast	4.1
11	Reduction of O&M by $50M	50.0
12	GTA Land Removal from Opening rate base	1.7
13	Overhead Capitalization decrease as a result of settled O&M	(3.6)
	Settled Items	81.4
14	Total Gross 2024 Test Year Deficiency	(186.3)

32. Enbridge Gas's proposals in this case are pragmatic and they strike a balance between affordable, reliable and resilient energy delivery and energy transition taking proper account of current government policy, legislation and the OEB's statutory objectives. Enbridge Gas submits that the evidence in this case supports the recovery of the revenue requirement and deficiency described above. The specific Approvals Requested in this case are set out in each section of this Argument and summarized at the end.

A. Overall

Energy Transition

Overview

33. As noted in Enbridge Gas's opening statement for the hearing, any OEB decision on 2024 rates must be made in the context of current energy policy.[9] At this time, however, the provincial government has not yet set emissions reductions targets post 2030 and it has not yet set policy related to how the province will achieve a net-zero future; therefore, the nature and pace of how energy transition will unfold in Ontario remains unclear.

34. The Government of Ontario did, however, recently release the *Powering Ontario's Growth* Plan [10], which recognizes that natural gas and low-carbon fuels such as RNG and low-carbon hydrogen will continue to be crucial for Ontarians, providing reliable and cost-effective fuel for heating, industrial growth, and economic prosperity while also complementing clean electricity sources to support grid reliability, keep energy bills low, and contribute to the province's transition from higher carbon fuels cost-effectively during the transition. The Plan also underscores the fact that Ontario's electricity grid benefits from diverse resources like hydroelectric, nuclear, natural gas, solar, wind, and bioenergy, ensuring ongoing reliability since no single resource can meet all system needs at all times.

35. In addition, in late 2022, the Government of Ontario established the EETP. The EETP will advise the Government of Ontario on "the highest value short, medium, and long-term opportunities for the energy sector to help Ontario's economy prepare for electrification and energy transition."[11] To support this work, the Government of Ontario has also commissioned an independent Cost-Effective Energy Pathways

[9] 1 Tr.4-5.
[10] Exhibit K1.5.
[11] Ibid.

Study[12] (Government Pathways Study) to help better understand how Ontario's energy sector can best support electrification and the energy transition. The EETP report to the Ontario Minister of Energy is due in late 2023 and the Government Pathways Study sometime in late 2024.[13] Completion of this work is critical, as it will provide market signals for the long-term development of Ontario's energy sector. Decisions related to energy transition and how Enbridge Gas's system will support a net-zero future should not be made ahead of any policy-related decisions emanating from this important work.

36. Although clear policy on Ontario's energy transition pathway has not yet been set, Enbridge Gas is cognizant that the energy landscape has shifted since 2013 and that an energy transition is underway, with governments at all levels setting GHG emission reduction targets. With over 30% of Ontario's energy needs currently being served by natural gas, Enbridge Gas recognizes that it has and will have to continue to play a critical role, regardless of the pathway that comes to fruition, in supporting an orderly energy transition that achieves GHG emission targets while also preserving consumer choice and access to cost-effective, reliable, and resilient energy.

37. It is in this vein that Enbridge Gas has taken proactive steps to study, consider and include energy transition within its operations and business planning to assist with achieving provincial energy transition objectives and to mitigate stranded asset risks. Enbridge Gas's energy transition evidence in this proceeding presents the Company's energy transition plan (ETP), vision and associated proposed safe-bet actions (Safe Bets) including energy transition adjustments to its demand forecasts and proposals that support the ongoing and evolving energy transition in Ontario.

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[12] Ontario Tenders Portal. Cost-Effective Energy Pathways Study for Ontario. https://ontariotenders.app.jaggaer.com/esop/toolkit/opportunity/past/116724/detail.si
[13] Government of Ontario. (2023 July 26). Energy and electricity. Electrification and Energy Transition Panel. https://www.ontario.ca/page/electrification-and-energy-transition-panel

When the Government Pathways Study is completed and government policy direction is provided, Enbridge Gas will further evolve its ETP to reflect this policy work.

38. It is important to note that the energy transition is not a discrete issue in this proceeding; however, Enbridge Gas's evidence on this issue serves to set context about the energy landscape within which the Company is asking the OEB to set its rates for 2024 to 2028. Energy transition is captured in the Issues List under Issue 3 as follows:

39. Issue 3 – Has Enbridge Gas appropriately considered energy transition and integrated resource planning in relation to such things as:
    a) load forecast
    b) deemed capital structure
    c) depreciation rates
    d) forecast capital expenditures
    e) allocation and mitigation of risk

    to determine new rates that will be effective January 1, 2024, considering relevant government policies and legislation.

40. Enbridge Gas has addressed the rate-making considerations for these matters in its submissions on those issues instead of in this section on energy transition.

41. As noted by Ms. Giridhar[14], the Company has spent a lot of time considering how energy transition is factored into each of the various aspects of the Application. Enbridge Gas has sought to achieve the appropriate balance, given the level of uncertainty that currently exists, the timing for this Application, Enbridge Gas's obligation to serve existing and future customers and maintaining the safety and

[14] 17 Tr.15.

reliability of the gas system. Achieving this balance ensures that the Company continues to provide value to customers through the gas services provided and appropriately mitigates the risk of stranded assets.

42. What Enbridge Gas has included and proposed within its ETP aligns with the Powering Ontario's Growth Plan and the objectives that the Government of Ontario has set for the EETP, specifically advising on opportunities that:
    a) help enable investment and job creation in Ontario by keeping energy rates low;
    b) create a more predictable and competitive investment environment;
    c) meet energy needs and ensure a reliable, affordable, and clean electricity supply; and
    d) strengthen Ontario's long-term energy planning process by better coordinating the fuels and the electricity sectors.[15]

43. Some elements of the ETP are subject to OEB approval in this proceeding or elsewhere and other elements are not. In its recent submissions to the EETP, the OEB identified that its authority in relation to gas is not as broad as it is for electricity.[16] As the Ontario Minister of Energy (Minister) recited in his letter of June 26, 2023 to Enbridge Gas President, Michele Harradence, regarding governance arrangements during Ontario's energy transition, the OEB and the Independent Electricity System Operator (IESO) are enabled "to discharge their responsibilities to the sector and the public by focusing on their respective mandates and statutory obligations and delivering outcomes that promote the interests of consumers as well as the stability and sustainability of the energy sector."[17] In this respect, the Minister

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[15] Government of Ontario. (2023 July 26). Energy and electricity. Electrification and Energy Transition Panel. https://www.ontario.ca/page/electrification-and-energy-transition-panel
[16] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, page 18. https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdf
[17] Exhibit J8.1.

specifically cited the following two guiding objectives regarding the OEB's responsibilities related to gas under section 2 of the *OEB Act*:

a) To facilitate rational expansion of transmission and distribution systems; and
b) To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

44. Enbridge Gas has been prudent and thoughtful in developing its ETP in a moderate and measured manner, considering evolving government policies and varied interests and perspectives of many different stakeholders. Enbridge Gas started its ETP work with completing an Energy Transition Scenario Analysis (ETSA) to understand the impacts of energy transition on gas demand and commissioned the Pathways to Net Zero Study (P2NZ Study) to understand how Enbridge Gas's system can support a net-zero future. The P2NZ Study is important in the context of this case as information about the potential impact of various plausible and relevant scenarios. However, the P2NZ Study is not meant to be a prediction of the future, and a probability or a likelihood of either scenario occurring was not assigned or ever intended to be implied.

45. Enbridge Gas's preliminary work led to building the more specific elements of the ETP, such as maximizing energy efficiency, decarbonizing industrial and transportation sectors, optimizing energy system planning and supporting consumer choice and the energy transition journey. While Enbridge Gas awaits the results of the provincial energy transition policy work, it remains dedicated to implementing its ETP Safe Bets and to advancing elements of its ETP within its purview, subject to considering how the OEB's decision in this proceeding may impact upon those objectives.

46. Below is a summary of the Enbridge Gas evidence on energy transition organized by key messages. The key messages are:

1. The nature and pace of energy transition and electricity grid readiness in Ontario remains uncertain and further government direction is required.
2. Enbridge Gas's gas distribution, transmission and storage assets are invaluable for their reliability, resiliency, and low cost of service to Ontarians.
3. Enbridge Gas has taken steps that are moderate and appropriate to incorporate energy transition into its forecasting and planning, based on known data and information.
4. Enbridge Gas's Energy Transition Plan and Safe Bets are prudent, as they ensure continued progress towards a net-zero future despite current uncertainty.
5. Coordinated energy system planning is critical to support energy transition for both the gas and electricity sectors.
6. Low carbon fuels (RNG and hydrogen) and CCUS will have a critical role in achieving net zero.

47. This section of Argument concludes with Enbridge Gas's submissions on the evidence of Mr. Neme of Energy Futures Group.

Consequences Of Settlement Proposal

48. There was no settlement of this issue as part of the Settlement Proposal.

Outstanding Approvals Required

49. As noted, Enbridge Gas is not requesting OEB approval of its energy transition evidence as a discrete issue. Rather, it is a consideration in relation to matters listed in Issue 3, such as the load forecast, depreciation rates, capital expenditures, etc. Enbridge Gas has addressed the rate-making considerations for these matters in its submissions on those issues, instead of in this section on energy transition.

50. There are also two energy transition-related issues that will be dealt with as part of Phase 2 (Issue 52, "Are the specific proposed parameters for an Energy Transition

Technology Fund and associated rate rider appropriate?" and Issue 53, "Are the specific proposals to amend the Voluntary RNG Program and to procure low-carbon energy as part of the gas supply commodity portfolio, appropriate?").

Revenue Requirement Implications for 2024

51. Any implications for the 2024 revenue requirement are set out in the sections for the specific rate-related issues in connection with which energy transition is considered.

Evidence in Support

52. The evidence for this issue is found at Exhibit 1, Tab 10, Schedules 1 to 6, and Exhibit L. Enbridge Gas answered follow-up questions in associated interrogatories[18], Technical Conference testimony[19] and Technical Conference undertakings[20]. Enbridge Gas witnesses provided testimony about this issue on Days 1 to 4 of the Oral Hearing (Panel 1)[21].

53. Dr. Asa Hopkins of Synapse Energy Economics, Inc. provided a report about business risk and capital structure in the context of energy transition[22], and he provided testimony on Days 4 and 5 of the Oral Hearing (Panel 2)[23].

54. Chris Neme of Energy Futures Group provided a report about the implications of decarbonization with respect to the Application[24], and he provided testimony on Days 5 and 6 of the Oral Hearing (Panel 3)[25].

[18] Exhibit I.1.10.
[19] 1 TC Tr. 101-209, 2 TC Tr. 1-199, 3 TC Tr. 4-41, and 9 TC Tr. 1-188.
[20] Exhibits JT1.13-1.33, JT2.1-2.18, JT3.1-3.4 and JT9.1-9.24.
[21] 1 Tr.67-142, 2 Tr.1-194, 3 Tr.1-213 and 4 Tr.1-150.
[22] Exhibit M8.
[23] 4 Tr.154-194 and 5 Tr.1-168
[24] Exhibit M9.
[25] 5 Tr.170-196 and 6 Tr.3-178.

55. Ian Jarvis and Gillian Henderson of Enerlife Consulting Inc. provided a report about commercial sector gas demand forecasting and related matters[26], and they provided testimony on Day 7 of the Oral Hearing (Panel 4)[27].

56. Dr. Robert W. Howarth and Dr. Mark Jacobson provided a report about GHG emissions associated with blue hydrogen[28], and it was not discussed during the Oral Hearing.

Key Message 1: The nature and pace of energy transition and electricity grid readiness in Ontario remains uncertain and further government direction is required.

57. There is not yet clear Government of Ontario policy related to what emissions reductions targets will be in place post 2030 nor does policy exist related to which energy transition pathway the province will take to achieve a net-zero future. In addition, the IESO and electric local distribution companies (LDCs) have not yet created a clean electricity grid build out plan that can support the high-level of electrification required to satisfy increasing demand. This creates uncertainty about how, when and how much it will cost the Ontario economy to adapt to these electrification needs; for example, as noted within the OEB's submission to the EETP, "the IESO's Pathways to Decarbonization report provides an indication of some of the scope of investments that will be needed in the energy transition, although that report does not cover distribution-level costs, which will be incremental to the costs set out in that report".[29]

58. The federal government has set a GHG emissions reduction target of 40% to 45% below 2005 levels, and a target of net-zero by 2050. To date, however, Ontario has not committed to the steeper 2030 target, it has kept its target of 30% below 2005

[26] Exhibit M3.
[27] 7 Tr.3-66.
[28] Exhibit M10.
[29] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, pages 27-28. https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdf

levels by 2030[30] and it has not yet set a GHG reduction target beyond 2030. Ontario is well on its way to meeting their 2030 GHG emissions target, with emissions at 19% below 2005 levels in 2019 (166 million tCO2e), and 27% below 2005 levels in 2020 (150 million tCO2e).[31,32]

59. Although there is disparity in the targets, both the federal and provincial governments are aligned on the need to reduce GHG emissions; however, the lack of provincial policy related to targets post 2030 and how these should be met creates great uncertainty with regards to the pace and nature of Ontario's energy transition.

60. This uncertainty will exist until provincial policy direction has been set. In late 2022, the Government of Ontario established the EETP to advise on "the highest value short, medium, and long-term opportunities for the energy sector to help Ontario's economy prepare for electrification and energy transition, including long-term, integrated energy planning".[33] In addition, to support this work, the Government of Ontario commissioned its Pathways Study to better understand how Ontario's energy sector can best support electrification and the energy transition.[34] Policy direction is expected to come sometime after the government receives the EETP's reports and the outputs from its Pathways Study.

61. The OEB recognized the need to await central policy direction from the government in its Decision and Order related to Enbridge Gas's application for its DSM plan for 2022 to 2027:[35]

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[30] Exhibit 1, Tab 10, Schedule 6, page 2.
[31] Exhibit 1, Tab 10, Schedule 6, pages 2-4.
[32] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, April 14, 2022, Part 3, page 50. https://unfccc.int/documents/461919
[33] Exhibit J8.1, Attachment 1, page 2.
[34] Ibid.
[35] EB-2021-0002, Decision and Order, November 15, 2023, pages 3-4.

> The OEB is aware that the Government of Ontario appointed an Electrification and Energy Transition Panel on April 22, 2022 to provide advice to the Minister of Energy on various issues related to integrated long-term energy planning in Ontario.[36] The OEB is of the view that further direction and any mandate to electrify the energy system, or portions of it, will be developed with the necessary stakeholders, including the Government of Ontario and the Independent Electricity System Operator (IESO). Once the central policy is developed, further action can be taken to ensure all conservation activities in Ontario are working together to produce the greatest level of energy savings and reductions in greenhouse gas emissions.

62. In the OEB's EETP Submission, the OEB also recognized that facilitating the energy transition will be an iterative activity:

> The work of the energy sector to facilitate the energy transition – including that of the OEB – will be iterative. Given uncertainties related to the pace of change, the OEB will ensure that our approach to regulation remains adaptable, flexible, and responsive to changing expectations and needs. The energy transition represents massive change; but not all problems need to be solved immediately. Instead, an incremental and prioritized approach that tackles issues one at a time will allow us to move forward, assess and change course as necessary.[37]

63. It is important to note that not only is there uncertainty regarding policy, but there also exists significant uncertainties related to how fast the current electricity system can achieve the required level of build out in capacity, transmission, and distribution, even with policy support. For example, Enbridge Gas serves over 3.8 million customers in Ontario and provides energy to approximately 75% of Ontario homes for heating.[38] There is a focus on reducing GHG emissions from buildings but there are no specific sector targets (federal or provincial) for that sector.[39] This creates uncertainty about how building electrification would be accommodated, while also

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[36] Government of Ontario. (2022 March 24). Orders in Council. Order in Council 698/2022. https://www.ontario.ca/orders-in-council/oc-6982022
[37] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, page 12. https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdfhttps://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdf
[38] Exhibit 1, Tab 10, Schedule 2, page 1.
[39] Exhibit JT1.23.

meeting decarbonization targets, given the time it takes to plan and build new electric capacity and infrastructure.[40]

64. In the near term, the Government of Ontario has also called for an additional 1.5 million homes to be built, according to its *More Homes Built Faster Act, 2022*.[41] That would equate to 150,000 homes per year for each of the next 10 years. It is unclear how the basic electricity demand for these new homes can be satisfied, let alone full electrification of these homes or significant portions of the existing building stock, given the high risk for power shortages for Ontario this summer identified by the IESO.[42]

65. As we move through the current uncertainty, ensuring pathway optionality is maintained will be critical to ensuring that all means for achieving emissions reductions in the building sector are considered and evaluated from a holistic and comprehensive perspective. Mr. Elson asked Ms. Wade if there is a material chance that Ontario would see 30-40% decline in emissions from the building sector.

> MS. WADE: Again, I can't comment on what the percentage is. But I think <u>a very critical point in answering your question would be whether or not the electricity grid in Ontario is ready to take 30 to 40 percent emissions reduction by that point in time as well</u>.[43]

66. In addition, the extent to which a high electrification scenario could potentially unfold in Ontario may pose system reliability and operational considerations not currently contemplated nor assessed at a more granular or regional level. As Mr. Yauch confirmed with Ms. Roszell of Guidehouse, the P2NZ Study is a single node model for Ontario and the overall feasibility of a high electrification scenario has not been confirmed. Mr. Yauch also confirmed with Ms. Giridhar that a more granular

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[40] Exhibit 1, Tab 10, Schedule 2, page 26.
[41] S.O. 2022, Ch. 21, Royal Assent received November 28, 2022.
[42] Exhibit K6.1 Enbridge Gas Compendium for Panel 3 (IESO Reliability Outlook pages 8 and 14). Also see Exhibits J11.5 and J11.6 for more information on concerns with increased demand on the electricity grid.
[43] 2 Tr.140.

assessment related to operational considerations has not been completed by the IESO or others to date.[44]

67. Neither the planned actions of the IESO nor most electric LDCs, to date, address the uncertainty associated with how they will support decarbonization for either the building sector or the larger economy.[45] Similarly, the government's Powering Ontario's Growth Plan has a focus on economic development and electric vehicles (EVs) and not on the building sector. In the Plan, the government announced approximately 8,500 MW of new nuclear generation; however, that it is 10 to 15 years away at best[46] and this will not provide the grid capacity that would be required for a building sector that is transitioning to electrical heating.

68. Ms. Giridhar also discussed this when she highlighted to Mr. Shepherd that the level of electrification required to satisfy projected electricity demands in Ontario, in either a diversified or electrification pathway scenario, is untested in Ontario.

> MS. GIRIDHAR: …So this is driving the way we are looking at that diversified path forward because we can see the level of changes required, which are actually completely untested, just like some of the other solutions, such as CCUS and hydrogen. We look at the idea of electrifying 100 percent of energy needs. That is an untested proposition going from the 15 percent share it has today. We believe that our infrastructure has a significant role to play.[47]

69. In its Powering Ontario's Growth Plan, the government notes that "as rapid economic growth and electrification continue, demand for electricity will increase at a rate not seen since the 1970s" and "Demand for electricity is projected to increase at unprecedented rates over the next three decades as a result of the government's open for business approach and the energy transition."[48] It is, therefore, clear that as

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[44] Ibid.
[45] Exhibit 1, Tab 10, Schedule 2, pages 17-26.
[46] Exhibit K1.5.
[47] 3 Tr.24.
[48] Exhibit K1.5, pages 7 and 34.

energy transition unfolds in Ontario, the electrical system will be required to evolve in a manner and at a rate not previously anticipated or contemplated.

70. In addition to policy and electric grid readiness uncertainty, as part of the energy transition, there is also uncertainty related to the technological advancements required to decarbonize the current electricity and gas systems. Both the diversified and electrification scenarios will require deployment of new technologies like small modular reactors (SMR), hydrogen and CCUS that are all untested at scale.[49] Although some technologies are further along than others, it's important to note that there is as much risk in relying on developing technologies as there is in relying upon widespread adoption of technologies that are in the early stages of deployment, in the absence of policy mandates.[50] Stated another way, there are several "wild cards" related to how energy transition will unfold, including innovations in electrical storage, CCUS and hydrogen as noted by Ms. Giridhar.[51]

71. Because of this technology uncertainty, pursuing multiple technologies to maintain pathway optionality is critical at this point in time, as it is too early to take any emissions reduction solution off the table. Enbridge Gas has recognized and accounted for this in its ETP, through research and investments in emerging technologies such as hydrogen, CCUS and other low-carbon products and processes to be advanced with the Energy Transition Technology Fund (EETF).

72. It is evident from experiences in other jurisdictions and other energy transition-related studies (e.g., pathways studies) that while government policies, energy requirements and technological advancements remain uncertain and/or nascent in Ontario, it is imperative that pathway optionality is maintained. A good example of

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[49] Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 49.
[50] Energy and Environmental Economics (E3), Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan, December 2022, page 10. https://climate.ny.gov/resources/scoping-plan/
[51] 3 Tr.89.

maintaining pathway optionality is the pursuit of low-carbon gas use in Québec, where electrification of building stock heat is dominant. Mr. Poch and Ms. Murphy discussed policy proposals regarding RNG in Québec and it is evident that with the introduction of RNG blend mandates, the procurement of RNG has initiated early competition for RNG supply.[52] As further noted below in Key Message 6, as policies regarding low-carbon gas blend mandates are introduced, there will inevitably be an industry response that will stimulate an RNG market to further develop in Ontario and in other jurisdictions.

73. In response to the OEB Panel's undertaking to provide lessons learned regarding energy transition in other jurisdictions, IGUA expert Dr. Hopkins shared that in the face of policy uncertainty, a number of U.S. jurisdictions are pursuing multiple energy pathways simultaneously:

> California has begun pilots to study strategic gas system decommissioning, in partnership with the dual-fuel utility Pacific Gas & Electric. Washington, DC, has explicitly adopted electrification as its preferred pathway to decarbonization, but its gas utility has not yet changed course to reflect this policy choice. Meanwhile, Massachusetts is pursuing a phased approach, seeking to deploy hybrid heat pump systems to capture their immediate emission reductions, and then envisioning a transition to more complete electrification in a later phase.[53]

74. Based on the above, it is unclear and uncertain as to how the increasing electricity demand, in either scenario, will be satisfied in Ontario. What we do know is that there is a lack of concrete evidence in this proceeding to indicate that the Enbridge Gas system is not needed or preferred by customers for the foreseeable future, and especially for the years 2024 to 2028 for which Enbridge Gas is requesting OEB rate approvals. To the contrary, Enbridge Gas continues to receive thousands of gas service applications every month and is anticipating connecting approximately 40,000 new customers per year in 2024 to 2028.

[52] 2 Tr.67.
[53] Exhibit J5.2, page 3.

75. The ongoing need and consumer preference for the viability and maintenance of the gas system informed not only the ETP, but also the Company's depreciation proposal, capital budget, integrity management practices and other risk mitigation strategies dispersed throughout the Application and evidence. Critical decisions regarding what specific role Enbridge Gas's system and infrastructure can play to support a net-zero future should not be assumed or made in this proceeding ahead of any policy direction from the important work in which the Government of Ontario is currently engaged. A premature decision that is misaligned with eventual government policy direction may have the effect of devaluing the gas system and imposing unreasonable rate impacts on existing and potential future customers. This may, in turn, increase rather than mitigate any future risk of stranded assets.

76. Mr. Goulding also commented, in response to Three Fires counsel Mr. Daube asking about matters related to equity thickness, about the importance of not getting ahead of government's policy direction[54].

> MR. GOULDING: <u>There continue to be risks. We know that there is an energy transition task force that is yet to issue its report. We know that the government came out with a plan even before the energy transition task force had issued its findings. We know that there is a broad pathways study. In some ways, other than participating in those studies, one could argue that it would be imprudent for a company to come up with its own plan before seeing the outcome of all of those other activities.</u> (emphasis added)

77. While Enbridge Gas awaits further clarity and direction from the Government of Ontario, IESO and other stakeholders, it has developed its ETP (further outlined under Key Message 3) to ensure that the Company is well-equipped to support the energy transition in a manner that provides continued value, reliability, resiliency, affordability, and consumer choice to both its existing and future customers while not getting ahead of the government's policy decisions.

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[54] 9 Tr.93-94.

Key Message 2: Enbridge Gas's gas distribution, transmission and storage assets are invaluable in terms of their reliability, resiliency, and low cost of service to Ontarians.

78. Energy security and resiliency are paramount, and their importance cannot be understated. Enbridge Gas's infrastructure provides unparalleled energy storage and capacity to support the reliability, resiliency, and affordability of Ontario's energy system. Enbridge Gas's 150,000 kms of largely buried gas transmission, distribution and storage assets have a net book value of $16.7 billion in 2021[55] This is an extremely valuable asset for Ontario, as the majority is exempt from the weather related impacts that the electricity system faces and it delivers over four times the peak capacity delivered by the $25 billion invested in the electricity system.[56] The value of this system must be factored into Ontario's energy transition plans and policies.

79. According to the OEB's *2020 Yearbook of Natural Gas Distributors* (2020 Yearbook), Ontario's natural gas distributors received $5.1 billion in total revenue for services related to natural gas supply, transport, and distribution in 2019. During the same period, the 2020 Yearbook lists power and distribution revenues of $21.7 billion for Ontario's electricity distributors.[57] The inescapable conclusion is that Enbridge Gas's proposed 2024 test year revenues of $6.1 billion continue to be significantly less than electricity revenues including power and distribution revenues, net of certain taxpayer funded reductions to electricity bills.[58]

80. The unit capital cost of delivering annual and peak hour energy in the form of natural gas is, therefore, about one quarter of the unit cost of delivering annual and peak hour electricity in Ontario. These unit costs do not include the much higher cost of building out the electric system in today's dollars, nor do they reflect the much higher

[55] Exhibit I.1.10-SEC-28.
[56] Ibid.
[57] Exhibit 1, Tab 10, Schedule 2, page 13.
[58] Ibid, page 14 and Exhibit 2, Tab 5, Schedule 4, Attachment 5.

cost of burying electrical infrastructure underground to provide equivalent resiliency.[59]

81. On an annual basis, 30% of the energy used in Ontario is natural gas, this is two times the amount of electricity used. On a peak basis natural gas provides 3 to 5 times the energy that electricity does.[60] In opening remarks, some intervenors also emphasized and supported the critical importance of the gas system, as follows:

> MR. YAUCH: Given the importance of the gas fired generation to the reliability of the electricity grid, APPrO supports a robust, resilient, and cost effective natural gas grid in Ontario. APPrO also supports energy transition, supports the introduction of low carbon fuels that can utilize the province's reliable and resilient natural gas infrastructure in order to maintain the reliability of the grid that is expected to undergo significant and unprecedented change over the next few decades.[61]
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> MR. MONDROW: For some of these industries, increasing their use of gas is, in fact, the most effective decarbonization tool in their arsenal for the time being, and probably for some time to come. For them, medium- and long-term reliance on a gas delivery system will be necessary, perhaps long after smaller customers with more near- and medium-term options have left the system.[62]
>
> MR. BUONAGURO: Accordingly, greenhouse operators are very interested in not only maintaining just and reasonable rates in the short term, but also in maintaining the long-term viability of natural gas service.[63]

82. Even if an electrification pathway occurs, the gas system will be needed for quite some time to support the transition. For example, the scenarios modeled by the Canada Energy Regulator in its “Energy Futures 2023” report (CER Report), released June 2023, show natural gas being used in building heat beyond 2050 and a role for the natural gas system to support hydrogen, RNG, and CCUS into the future.[64]

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[59] Exhibit I.1.10-SEC-28.
[60] Exhibit I.1.10-SEC-28, page 2.
[61] 1 Tr.7-8.
[62] 1 Tr.36.
[63] 1 Tr.41-42.
[64] Exhibit K3.1, pages 5 and 20.

83. Enbridge Gas's system provides unmatched resiliency and reliability due to its significant underground assets and energy storage capacity. The system can quickly dispatch energy to both electricity and natural gas grids to meet peak demand periods. This supports resilience in two ways: (1) ensuring continued delivery of energy during extreme cold weather events; and (2) supporting Ontario's electricity system during times of extreme heat weather events. Enbridge Gas's system supports resilience in the electricity system by providing energy and storage services for gas-fired electricity generation.[65] This is particularly relevant on the coldest days of the year for backup energy when the power goes out for critical infrastructure like hospitals, warming centres and industry where energy resilience is paramount.

84. These reliability benefits of the natural gas system are acknowledged in the Government of Canada's recently released Draft Clean Electricity Regulations and Regulatory Impact Analysis Statement,[66] where it is noted that the balancing of three criteria – emission reductions, affordability and reliability – will require careful attention: "An electricity system that is neither affordable, nor reliable could discourage the transition to clean electricity generation needed to achieve the economy-wide net-zero target in 2050."[67] Natural gas, biomass (including RNG) or hydrogen fired generation, with appropriate constraints to mitigate or control emissions (such as carbon capture and sequestration technology), are clearly identified as technologies "needed to meet net-zero GHG emissions."[68]

85. Ms. Giridhar explained to Mr. Shepherd the value proposition of the gas system on Day 3 of the hearing as follows:

> MR. SHEPHERD: There are two different things here. One is that gas may be better than electric – that is your thesis – and therefore policy shouldn't encourage people to leave the gas system. The other possibility is electric is better than gas, but you would like the government to stop them from leaving the gas system. Which is it?

[65] Exhibit 1, Tab 10, Schedule 2, page 7.
[66] Exhibit J17.7.
[67] Ibid, page 134.
[68] Ibid, pages 130 and 131.

> MS. GIRIDHAR: It is the former, Mr. Shepherd, because <u>ultimately energy policy has to do what is right for Ontarians, and our view is that, while there are some forms of electricity that are non-emitting and therefore helpful in terms of meeting climate goals, the whole energy value proposition for customers is one that delivers not just lower emissions and ultimately net-zero emissions but also affordability, resilience, and reliability. Those are features of the diversified energy mix that we have today</u>.[69] (emphasis added)

86. Another perspective on electric system operation and reliability is that today, the IESO relies on natural gas fired generation for grid regulation. As energy transition unfolds, using the gas system for grid regulation may be further leveraged both on a macro and micro level, as is done in other jurisdictions. For example, in Québec, Énergir has requested that some homes remain on the natural gas grid in order to manage peak energy demand. Additional context and details were provided during the hearing:

> MS. WADE: I might just note Québec is an example where they obviously have a high degree of electric space heating, but have now launched a joint program in recognition of being able to support electrification in the province and support resilience of the energy system for those customers on the natural gas side. So I think, yes, I read what you are noting here, but I think we have to get down to each specific region to understand what is the resilience of each of those systems and how they might best work together.[70]

> MS. GIRIDHAR: a little bit of context in Québec, because I think it is instructive for the panel to hear this. There is an arrangement between Hydro Québec and Énergir that compensates Énergir for ensuring customers remain on gas on peak. This is in a province that 40,000 megawatts of hydroelectric power -- it is in a province where there are only 200,000 residential gas customers, and this is a province where they decided it was important to keep those 200,000 customers on gas for peak and incent Énergir to make sure that they can remain. No, obviously over time the use of that gas system may go down, but in terms of parallels, we are a province where we have 26,000 megawatts of electricity, a lot of it is non-limiting, obviously, but 3.8 million customers on natural gas for heat. So, we shouldn't take this lightly. I think we really need to understand what does it take to decarbonize the building sector?[71]

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[69] 3 Tr.16.
[70] 3 Tr.100.
[71] 3 Tr.101.

87. Unlike the underground assets that constitute the majority of the gas system, the electric system consists of above-ground infrastructure that is vulnerable to extreme weather and other damage-causing events and incidents. Costs to repair and bury electric system infrastructure are significant. For instance, Hydro Ottawa states on its website[72] that burying its electrical wires will cost $10 billion and take 90 years and that burying electrical infrastructure costs 11 times more than overhead infrastructure at $2-$4 million per kilometer.[73]

88. From the customer perspective, Enbridge Gas has conducted customer surveys related to customers' expectations regarding future natural gas usage. The majority of respondents indicated they expect their natural gas use to remain the same (71%), while 14% indicated they expect their natural gas use to increase.[74] It is too soon to assume what customers will do when they are faced with decarbonization decisions that could involve changes to their home. It is, however, likely that customers will pursue the solution that provides the greatest value for their equipment purchases; and that value will likely be determined based on more than just cost-effectiveness, it is expected to also include reliability and resilience of the energy service. Increased use of hybrid heating will also mitigate risks against stranded assets, making it a doubly attractive option for gas customers.

89. Enbridge Gas's residential customers will pay, on average, approximately $50/month in distribution revenues based on Enbridge Gas's proposal in this proceeding. This reflects the value of resiliency, reliability and security provided by the Enbridge Gas rate base and gas system.[75] This is excellent value given the extent and nature of the gas system. The gas system can provide resiliency, reliability and security both at the system level as well as the home or building level when combined with the

[72] Hydro Ottawa. (2022 July 13). Blogs & Articles. Between the lines: overhead vs underground. https://hydroottawa.com/en/blog/between-lines-overhead-vs-underground
[73] Exhibit I.1.10-SEC-13, Exhibit I.1.10-SEC-28.
[74] Exhibit I.1.10-STAFF-27, part c).
[75] Exhibit 1, Tab 10, Schedule 2, page 14.

back-up technologies that exist today (i.e., batteries and generators) and new technologies that are being developed (micro CHP) which can provide enough backup electricity to supply a home's typical electricity demand inclusive of furnace operations.[76] Preserving the ability of all customers to stay connected to the gas system keeps energy costs affordable for homes, businesses and industry, and as noted, mitigates the risk of stranded assets by allowing for a moderate and rationalized transition of the gas system to suit a future energy pathway.

90. Ms. Giridhar discussed the importance of consumer choice and resiliency of the gas system with Mr. Poch during the hearing:

> MS GIRIDHAR: …You know, our system, the gas distribution system, costs $3 billion per year and it delivers somewhere between 250 terawatt hours and 260 terawatt hours currently. I put it to you, Mr. Poch, that <u>even if that number declines significantly, in fact, even if it went down to the equivalent of 13 or 20 terawatt hours, which is what gas-fired generation provides today, you are looking at a very cost-effectively provided resilience, and to presume therefore that everybody would disconnect from natural gas because they have electrified many of the uses at home and that they would not care at all about resilience or insurance or the cost to the electricity system is premature.</u>[77]
>
> And:
>
> MR. POCH: My question was, don't you think it is – a lot of customers are going to opt for that.
>
> MS. GIRIDHAR: I think that is exactly what I am addressing. We don't know that for a fact because, as I said, the cost of resiliency has not been factored in, and I just want to put it back to you, Mr. Poch, that the current cost of staying connected to the gas system is $50 a month, assuming that all of our charges were fixed. In this scenario, let's say 40 percent get completely electrified in their building use. I don't think that we can conclude that they are not willing to pay, 60, 70, 80 dollars a month in the knowledge that on the coldest day of the year they will stay warm in their homes.
>
> <u>So I think it is premature to conclude that customers will electrify their appliances, are interested in disconnecting from the gas system altogether because, as you know, we have not yet costed out the value to customers of resilience. I mean, I think you could look at other things we do, for example, life insurance, there is all sorts of insurance we take on appliances, on our lives, on our cars, and people believe that it gives</u>

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[76] Exhibit J11.6.
[77] 2 Tr.20.

> them great value whether they need it or not. We know we live in a cold country and we have extreme temperatures.[78] (emphasis added)

91. Mr. Neme also agreed with retaining some optionality for consumers, in his exchange with Commissioner Moran:

> MR. MORAN: So, for people who currently have a gas furnace, if I understand what you're saying, don't rip that out. Add the heat pump and keep on going for now.
>
> MR. NEME: Well, no. I would encourage anybody who has a gas furnace and who is interested and willing, to rip it out and put in an all-electric heat pump with an electric-resistance backup; hopefully at the same time that you have upgraded the efficiency of your building envelope, if you haven't already. But I don't object to customers who may not quite want to go that far and want to go the hybrid route, and I also don't object to programs that the utilities can run that promote both, both the all-electric option and the hybrid option. Just recognizing that the most important thing is that we really get going, without locking ourselves into one definitive answer.
>
> MR. NEME: I think programs that promote both, and then kind of leave it to the market to determine what that mix of hybrid versus all-electric solutions are, is okay in the near term, as long as the hybrid solution is really a cold-climate heat pump.[79] (emphasis added)

92. Ultimately, it is much too premature to assume that existing or new customers will not see value (at a cost of ~$50/month) in staying or being connected to the gas system to fuel a gas or hybrid heating system for peak or back-up energy needs. The sections of this Argument related to Depreciation, Customer Attachments and Capital Expenditures address other aspects of stranded asset risk mitigation and how Enbridge Gas has proposed an appropriate balance for all elements given the demonstrated ongoing value and importance of the gas system.

Key Message 3: Enbridge Gas has taken steps that are moderate and appropriate to incorporate energy transition into its forecasting and planning, based on known information, and will continue to update adjustments and refine processes as energy transition evolves.

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[78] 2 Tr.22.
[79] 6 Tr.175.

93. While the methodologies related to volumes and load forecasting were not agreed to by the parties in the Settlement Proposal, the parties did agree to these forecasts for the purpose of setting 2024 rates.[80] No parties other than Enbridge Gas filed evidence proposing specific forecasting methodologies for OEB approval.

94. Enbridge Gas has deemed it prudent to take additional actions, in the light of the evolving energy transition, to consider and incorporate energy transition into the Company's forecasting and planning processes. These actions, as outlined in its evidence and summarized below[81,82] helps to mitigate the risk of stranded assets within and beyond the five-year regulatory plan period:

   a) In 2020 to 2021, Enbridge Gas conducted an ETSA with the assistance of Posterity Group, to understand the impacts of energy transition and the associated climate policies on natural gas annual and peak demand in Enbridge Gas's distribution system. The outputs from the ETSA project include modeled annual volumetric gas demand, system peak hour and peak day demand according to customer and fuel types, and GHG emissions at an end-use level for a 20-year period (2019 to 2038) under four theoretical scenarios (only the last two of which achieve net-zero by 2050):
      i. Reference case (business as usual)
      ii. Steady progress (incorporating proposed policies with reasonable certainty of implementation)
      iii. Diversified portfolio (assuming wide-spread use of low-carbon gasses, CCUS and electrification)
      iv. Electricity centric (assuming aggressive electrification with limited role for low-carbon gasses and CCUS)
   b) Enbridge Gas's modeled results from the ETSA project, along with a review of current climate policies and input from stakeholder engagement were used to

[80] Exhibit O1, Tab 1, Schedule 1, pages 26-29.
[81] Exhibit 1, Tab 10, Schedule 4, pages 13-14.
[82] Exhibit I.1.10-STAFF-34, part a).

inform which energy transition adjustments the company considered and included for the following forecasting and planning elements:

i. Average use
ii. Customer additions
iii. Volume forecast
iv. Design hour
v. Design day[83]

The consideration and inclusion of energy transition adjustments did not replace Enbridge Gas's OEB-approved forecasting methodologies.[84]

c) Enbridge Gas adopted moderate adjustments for reduced gas use and customer additions where known information or strong signals existed. Enbridge Gas did not make any further adjustments where it had insufficient information to do so as it would be imprudent and premature and could impact the safety and reliability of the system.[85]

d) Enbridge Gas is, and will continue to, evolving its forecasting and planning processes to ensure it is incorporating the most up-to-date information available, both at the system and local level, for new construction and existing customers, as well as for updates to annual and design hour and design day demand for gas.[86] This will include conducting ongoing monitoring of federal, provincial and municipal policies across all sectors, including buildings, industry, transportation, electricity generation and policies supporting energy efficiency, electrification, low carbon fuels and CCUS. It will also include ongoing monitoring of market trends and stakeholder insights. As previously done, any known information or strong signals will be incorporated.[87]

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[83] Details provided at Exhibit I.1.10-STAFF-34 part a), pages 3-12.
[84] Exhibit 1, Tab 10, Schedule 5, pages 3-4 and Attachment 1.
[85] These assumptions resulted in a reduction to 2024 customer numbers of 321, rising to a reduction of 4,017 by 2028, and a reduction in 2024 volumes of 1.1M m^3, rising to a reduction of 13.8M m^3 by 2028: see Exhibit I.1.10-STAFF-31, Attachment 1.
[86] Exhibit 1, Tab 10, Schedule 4, Table 2.
[87] Exhibit I.1.10-STAFF-24.

e) As part of its energy transition adjustment analysis, Enbridge Gas does not conduct probabilistic modelling, as developing a probabilistic and impact ranking type of approach for energy transition related assumptions would require information that does not currently exist. In the absence of the requisite information, establishing probabilities would require a qualitative approach. This would not be appropriate, as the qualitative information used would not be based on tacit knowledge or experience; instead, it would be based upon stakeholders' own siloed forward-looking perspective of which pathway should come to fruition, resulting in an inherently biased and/or highly debatable set of probabilities. As such, coming to an agreed upon set of probabilities at this time would be difficult, if not impossible, and Enbridge Gas believes this time-intensive process would not be of value in an ever-changing energy transition environment absent clearer signals related to policy and technologies.[88]

f) All energy transition related adjustments will be reflected in Enbridge Gas's AMP updates to ensure that facilities projects' underlying needs/constraints (e.g., minimum five-year demand forecast) have a high degree of certainty when they are brought forward for approval.[89] This is addressed further in the Capital Expenditures section of this Argument.

g) In addition to the above noted ETSA work, in 2021, Enbridge Gas commissioned the P2NZ Study, conducted by Guidehouse. This study was completed to understand how Enbridge Gas's system could play a role in a net-zero future. The P2NZ built upon the ETSA work and found that a diversified scenario achieves net zero at a lower cost with more system reliability and resiliency, relative to an electrification scenario. The P2NZ's diversified scenario would also increase the need for pipeline infrastructure to deliver large quantities of low carbon fuels like hydrogen and RNG.[90]

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[88] Exhibit J14.9.
[89] Exhibit 1, Tab 10, Schedule 4, page 13.
[90] Exhibit 1, Tab 10, Schedule 5.

h) Both the ETSA and P2NZ were based on scenario analyses and were intended to inform Enbridge Gas of the potential impact of various plausible and relevant scenarios. However, they were not meant to be a prediction of the future, and a probability or a likelihood of either study scenario occurring was not assigned or ever intended to be implied.[91] As Ms. Wade discussed with Mr. Daube, the assignment of probabilities to scenario analyses becomes inherently more theoretical as the number of unknowns (i.e., critical drivers, potential policy outcomes, costs, etc.) increase over a longer time period.[92]

i) Enbridge Gas has also incorporated the IRP framework into the AMP process to, where possible, defer or avoid new infrastructure. This supports Enbridge Gas in managing the uncertainty related to energy transition.[93] This is addressed further in the Capital Expenditures section of this Argument.

j) Enbridge Gas has also included enhancements to the Distribution Integrity Management Program (DIMP), which will allow the Company to further optimize its vintage steel main replacement program.[94] This is addressed further in the Capital Expenditures section of this Argument.

95. Through the above noted actions of (1) monitoring and incorporating, where prudent, external energy transition signals, (2) executing IRP, (3) implementing enhancements to the distribution integrity management program and (4) pursuing coordinated system energy planning, Enbridge Gas is minimizing the risk of stranded assets. This comprehensive energy system planning ensures infrastructure investments are prudent and that assets will remain used and useful into the future. Additionally, as government policy and direction become more certain, the risk of

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[91] 1 Tr.80.
[92] 4 Tr.71.
[93] Ibid, page 15.
[94] Exhibit 1, Tab 13, Schedule 3.

stranded assets will be further reduced as Enbridge Gas works to incorporate such new policies and directions into its forecasting and planning processes.

96. Dr. Hopkins specifically acknowledged the importance of Enbridge Gas's commissioning of the ETSA and P2NZ studies and preliminary work on RNG and hydrogen as risk mitigation activities in the light of energy transition:

> DR. HOPKINS: The most important actions that EGI has taken to date are to commission the studies from Posterity Group and Guidehouse submitted in this proceeding. These could provide the foundation on which to build a risk analysis that would evaluate scenarios for the likelihood and consequence of capital risk events. However, given the provincial pathways study now underway, the outcome of that process should form the foundation for EGI's decision-making and modeling. The utility could nonetheless use the already characterized scenarios to develop and test its modeling tools. [95]

97. The OEB panel heard a number of disparate views on how Enridge Gas should incorporate energy transition adjustments into its demand forecasting process and mitigate stranded asset risk through its various rate-making tools. They ranged from Mr. Neme's aggressive electrification scenario on the one hand, to IGUA's equity thickness and depreciation experts on the other hand, concluding that Enbridge Gas's risk profile has not changed since 2012 and that a reduction in depreciation expense by several million dollars is appropriate. It is notable that the Enbridge Gas expert witnesses on cost of capital and depreciation from Concentric, in essence, agree with Enbridge Gas's moderate approach to forecasting and risk mitigation for energy transition, based on their specific expertise and experience with these matters throughout North America. OEB Staff experts from LEI opined that the Company does face a change in risk which warrants a full fair return standard review, but they failed to compare the risks that the Company faces from an energy transition perspective to the risks that the electric LDCs face.

[95] Exhibit M8, pages 54-55.

98. Further details about these experts' views are discussed in the Equity Thickness and Depreciation sections of this Argument. A more complete response to Mr. Neme's evidence is provided at the end of this Energy Transition section.

99. It is left to the OEB to reconcile these disparate views. However, 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. A detailed explanation of how the Company has factored energy transition into its system forecasts at both the system and local level is provided in the evidence.[96] 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.

Key Message 4: Enbridge's Energy Transition Plan and Safe Bets are prudent, as they ensure continued progress towards a net-zero future despite current uncertainty.

100. Uncertainty does not mean do nothing. Rather, it calls for implementing prudent steps to advance energy transition despite current uncertainty. Enbridge Gas has done just that by developing an ETP with a set of prudent Safe Bets. Enbridge Gas's Safe Bets are` prudent, despite current uncertainty, as they drive near-term emissions reductions and are required regardless of the pathway that comes to fruition and/or maintain pathway optionality without overinvesting in one particular pathway and/or maintain a safe and reliable system in a way that considers pathway uncertainty. These Safe Bets ensure critical progress is made towards a net-zero future; however, importantly, they do not get out ahead of the Government of Ontario's energy transition work and policy decisions.

[96] Exhibit I.1.10-STAFF-31.

Table 2
Summary of Energy Transition Related Rebasing Proposals[97]

Safe Bet	Enbridge Initiative	Proposal Related Evidence
Maximizing Energy Efficiency	DSM	Not applicable
Investing in Renewable Natural Gas (RNG)	Voluntary RNG Program	Exhibit 4, Tab 2, Schedule 7
	RNG upgrading	Exhibit 2, Tab 6, Schedule 2
Decarbonizing the Industrial and Transportation Sectors	Industrial fuel switching	Exhibit 2, Tab 6, Schedule 2
	Carbon Capture and Sequestration (CCS)	Not applicable
	Natural Gas Vehicle (NGV) Program	Exhibit 1, Tab 14, Schedule 2 Exhibit 2, Tab 6, Schedule 2
Integrating Gas and Electric System Planning	Optimizing energy system planning	Not applicable
Supporting Consumer Choice and the Energy Transition Journey	Hydrogen Blending Grid Study (HBGS)	Exhibit 4, Tab 2, Schedule 6
	Low Carbon Energy Project (LCEP) Phase 2	Exhibit 4, Tab 2, Schedule 7
	Energy Transition Technology Fund (ETTF)	Exhibit 1, Tab 10, Schedule 7
	Maintaining the Gas System – via Integrated Resource Planning (IRP) and Scope 1 & 2 emissions reductions focus	IRP: Exhibit 2, Tab 6, Schedule 2, Appendix B Scope 1 & 2: Exhibit 2, Tab 6, Schedule 2

101. In addition to providing a basic description of the Safe Bets, Table 2 sets out where the subject matter of the Safe Bet is addressed in this Application, or elsewhere, in further detail. Any rate-making implications of the Safe Bets 2024 to 2028 rates are addressed in the specific sections to which the Safe Bets relate.

102. Some intervenors have expressed concern that Enbridge Gas has not proposed greater initiatives with respect to energy transition in this Application. As noted by Ms. Wade in discussion with Mr. Shepherd, there remains uncertainty in Ontario due to the absence of policy direction, and while there is an increased concern and focus related to energy transition, there is no definitive direction nor pathway set by government to indicate which pathway will come to fruition.[98] Ms. Wade continues on:

[97] Full table can be found at Exhibit 1, Tab 10, Schedule 6, pages 15-18.
[98] 3 Tr 28.

> MS. WADE: I would just add as well that I think our safe bets included within the energy transition plan provide a guide to the work that we are focusing on today. So it is not we are just waiting. I think we've also put forward a number of safe bets, as you have seen in the evidence, that continue our progress towards the energy transition while we also, you know, wait for guidance and further policy from the government.[99]

103. Although Enbridge Gas's Safe Bets were developed prior to the government's Powering Ontario's Growth Plan release, they strongly align with what is laid out in this Plan, including a focus. Specifically, the Government of Ontario focuses on consumer choice, affordability, coordinated energy planning, hybrid heating, energy efficiency, industrial decarbonization, and the use of low carbon fuels in the gas system. In addition, the Safe Bets align with the CER report as well as with the OEB's recommendations to the EETP and other federal and provincial policies.[100]

Key Message 5: Coordinated Energy System Planning will support energy transition for both the gas and electricity sectors.

104. Enbridge Gas recognizes coordinated energy system planning as one of the critical Safe Bets for a successful and orderly energy transition in Ontario. Coordinated gas and electric system planning is considered a safe bet as it supports cost-effective near term GHG reductions, it is required regardless of which pathway comes to fruition and it supports maintaining the gas system in a way that considers pathway uncertainty. The scale of electrical generation required to achieve net zero will be tremendous, regardless of the pathway; therefore, leveraging the infrastructure and system planning expertise across the energy sector is critical.

105. Coordinated gas and electric system planning, both at the provincial and regional level, would enable the in-depth discussions required to ensure that the same energy demand is not forecasted or planned for by both sectors and that the demands placed on each system are looked at collectively, for example looking at the energy demand from vehicles and building heating together. In addition,

[99] 3 Tr.25.
[100] Exhibit 1, Tab 10, Schedule 6, pages 15-18.

coordinated system planning would optimize the system by considering and prioritizing consumer choice, system reliability and resiliency, and affordability - both in the short and long term. This would ensure that planning decisions aren't made based on a shorter-term, siloed view but instead on the longer-term implications for the province.[101] Ms. Wade reiterated that coordinated gas and electric planning is critical to identifying the optimal solution for Ontario in her exchange with the commissioners as part of the Capital Expenditures panel testimony.

106. An example of how coordinated planning benefits consumers is hybrid heating. Hybrid heating can drive significant reductions in annual natural gas use as compared to the sole use of a natural gas furnace. Hybrid heating enables electricity to be used when a heat pump can operate most efficiently, and then switches to gas during peak winter heating periods when an electric heat pump can no longer perform efficiently. This drives the reduction of GHG emissions while reducing peak electricity demands, which reduces electrification costs by the elimination of infrastructure build-up to meet peak electric energy demands. Not only does a hybrid heating system avoid creating undue burden on the electrical grid from peak winter heating, but it also avoids potential GHG emissions associated with gas-fired power generators who may be dispatched to meet these peak demands[102]. With the gas and electric sectors working together, the benefits and the potential of a coordinated solution could be understood and planned for within each region and the implementation could be done in partnership to ensure success within the market.[103]

107. Coordinated energy planning also supports Enbridge Gas's IRP in a number of ways. First, coordinated energy planning would ensure that the demand forecast

[101] Exhibit 1, Tab 10, Schedule 6, page 29.
[102] Exhibit J11.6.
[103] A good example of gas and electric utilities working together is the partnership between Énergir and Hydro-Québec to convert gas heating systems to a hybrid heating system. Énergir (2022 May 19). Green light to launch dual energy offer to decarbonize the heating of buildings. https://www.energir.com/en/about/media/news/decision-decarbonation-des-batiments-binergie/

being used in its IRP alternative (IRPA) analysis reflects the electricity sector assumptions, plans, and costs. In addition, coordinated energy planning would allow for joint delivery of an IRPA in an area where both the electric and gas systems are facing a constraint. This could contribute to a greater customer experience and take-up.

108. The concept of integrated energy planning was recognized and discussed as part of the OEB's Framework for Energy Innovation Working Group (FEIWG). Specifically, "the FEIWG recommends that the distributors (natural gas and electricity), transmitters and the IESO co-ordinate planning and forecasting in the energy sector. The FEIWG recognized the importance of breaking down energy silos including those between natural gas and electricity planning, as reflected in the OEB's recent acceptance of the Regional Planning Process Advisory Group's recommendation to enhance the coordination of other planning processes with regional planning. More work in this area is warranted."[104]

109. All of the above is consistent with the Government of Ontario's stated 'integrated planning process', as noted in the Powering Ontario's Growth Plan, the government: "is developing an integrated planning process that looks at the province's energy mix and system as a whole (electricity, oil and natural gas), unlike previous governments, which built and planned energy systems in isolation, and it is taking the necessary steps to ensure the province is set up for success."[105] It goes on to say that "natural gas currently plays a pivotal role in supporting grid reliability – with the ability to respond to changing system needs in ways other forms of supply simply cannot."[106]

[104] Framework for Energy Innovation Working Group Report – Report to the OEB. June 30, 2022, page 16. https://www.rds.oeb.ca/CMWebDrawer/Record/750359/File/document
[105] Exhibit K1.5.
[106] Exhibit K1.5, page 42.

110. In addition, just last month, the OEB restated its views and acknowledged the critical nature of coordinated planning between the natural gas and electricity sectors in its EETP Submission:

> Coordination and planning alignment between the natural gas and electricity sectors is critical given the magnitude of change and infrastructure development that will be required to support the energy transition. The purpose of a coordinated energy planning framework is to support a cost-effective energy transition that ensures that investments in energy resources align with long-term goals and deliver reliable, sustainable, and affordable energy. Any new energy planning framework must give careful consideration to the roles of all energy sector participants, in particular the Ministry of Energy, the Independent Electricity System Operator (IESO), the OEB, and natural gas and electricity utilities.[107]

111. The OEB goes on to note that:

> Although the OEB's perspective is that a single plan is best for Ontario in the long term, given the inherent challenge of undertaking coordinated planning at the provincial level, the OEB believes that taking an iterative approach that evolves from existing processes and that builds incrementally after each cycle would make coordinated planning initially more manageable and ultimately more successful.[108]

112. Enbridge Gas agrees with the OEB that an iterative and methodical approach to coordinated energy system planning would garner the most success as it allows for continued innovation and development of low carbon technologies to develop over time and it allows for strategy refinement to be made regarding energy systems interconnectedness. Additionally, iterations would ensure that initial assumptions and solutions are re-evaluated and confirmed prior to the continued presupposition of a solution for a region/area, which may have unique considerations and constraints to synthetize into a regional coordinated energy system plan. Enbridge Gas believes that OEB's approach aligns with the definition of Safe Bets.[109]

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[107] Report of the Ontario Energy Board to Ontario's Electrification and Energy Transition Panel, June 30, 2023, page 4 https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-07/oeb-report-EETP-20230630-en.pdf
[108] Ibid, page 36.
[109] Exhibit 1, Schedule 10, Tab 6, page 14.

113. Enbridge Gas has undertaken many efforts to enable coordinated planning to date, including submissions to the OEB[110], Government of Ontario and EETP[111], initial planning discussions with the IESO and several electric distribution companies, and ongoing stakeholder relations with municipal governments.[112] Enbridge Gas recognizes, however, that for coordinated energy planning to be successful there must be commitment and actions taken by others in the industry, including the Government of Ontario, IESO, OEB and electric utilities. This will be extremely difficult to achieve without formal guidance and direction from the province. In fact, as recently as July 2021, the OEB identified in their IRP Decision and Order that without the Government of Ontario's review of the long-term energy planning framework, fully coordinated IRP between gas and electricity is premature and aspirational:

> Enbridge Gas can also seek opportunities to work with the IESO or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas. However, the OEB is not establishing this as a requirement for Enbridge Gas. While in the longer term, there may be an opportunity to have integrated energy resource planning with the optimal fuel choice between all energy sources, the OEB concludes that this would be an excessively challenging requirement during this first-generation IRP framework. <u>As discussed in chapter 5 ("IRP Framework and Definition of IRP"), directing integrated energy planning between gas and electricity is premature and remains an aspirational goal. Within the Ontario government's review of the long-term energy planning framework, approaches to selecting optimal energy choices may be assessed.</u>[113]

114. Without a recognized framework or governance structure and approval of resource needs, the development of an efficient and effective coordinated planning process between the gas and electric systems cannot successfully be achieved. Ms. Wade reiterated that need for this structure in her in her exchange with the commissioners as part of the Capital Expenditures panel testimony:

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[110] Exhibit J3.4.
[111] Exhibit K1.4.
[112] Exhibit 1, Tab 10, Schedule 6, page 19.
[113] EB-2020-0091, Decision and Order, pages 35-36.

> MR. MORAN: Right. So Mr. Coyne talked about how energy transition has been in earnest for the last five years. Why haven't you been doing that for the last five years? It sounds to me like what you're waiting for is somebody to tell you or give you guidance. Why are you waiting for guidance to start that kind of conversation?
>
> MS. WADE: I'll start and then, if there is someone else who wants to add on. I think that there have been ongoing discussions with the electricity sector. I think, over the last five years, there's been a lot of change in understanding that the uncertainty is growing and, with that recognition, we've started to do proactive outreach to the IESO and to the LDCs, say, for the pilots and in the St. Laurent area. I think I would just come back to -- I think it was Ms. Giridhar who had noted that there has to be a joint priority placed on this and perhaps, say, a charter so that all parties have the resources and see it as a priority to come to the table together with us to be able to do that.[114]

115. The inference that Enbridge Gas has not been doing its part to facilitate coordination of planning is simply false. As noted above, Enbridge Gas has been making numerous efforts to engage with the LDCs, municipalities, the IESO, OEB and the Government of Ontario to coordinate energy planning. Enbridge Gas cannot force these parties to the table.

116. Enbridge Gas believes that having the OEB and government support, endorse and authorize coordinated gas and electric planning is paramount to ensuring that this it is prioritized for all stakeholders and that Ontario’s energy transition is successful; that is, that the most cost-effective, reliable, and resilient pathway to net-zero is understood, planned for, and implemented. Enbridge Gas provided this recommendation to the OEB to support their submission to the EETP.[115]

117. Enbridge Gas would also like to highlight the following additional recommendations that it provided in its submission to the OEB:

[114] 14 Tr.125-126.
[115] Exhibit J3.4.

a) innovation across the energy sector should be enabled equally between electricity and low-carbon gas projects as to ensure that energy system needs are reviewed in balance with other economic considerations in Ontario; and
b) LTC decisions should be based on a holistic approach with the near and long-term energy system needs and pathway optionality considered.

118. These recommendations will ensure that the most prudent infrastructure investments are made to support future energy needs while also ensuring GHG emission reduction in the near term.

119. While near and long-term energy transition planning policy certainty or direction develops, it is Enbridge Gas's hope that, at minimum, support and guidance for a more coordinated approach to gas and electric system planning will move forward quickly, as it will not only enhance energy system readiness, but it can better inform and guide these plans and decisions.[116]

120. Evolving the coordination of gas and electric system planning will be required regardless of the pathway that unfolds, to ensure that required energy system changes are properly understood, planned for, and implemented in a safe, reliable, resilient, cost-effective, and secure manner throughout the transition.

<u>Key Message 6: Low carbon fuels (RNG and hydrogen) and CCUS will have a critical role in achieving net zero.</u>

121. Ontario has the benefit of an extensive gas distribution and storage system that has great system reliability and resiliency, which has provided energy security to Ontarians at a low cost for many decades. Leveraging this asset in the short term with an eye to future adaptation to lower carbon fuels is necessary to ensure that assets are prudently invested in in the short term and that they remain in use and useful into the future. The electric system in Ontario today is not able to supply

[116] 3 Tr.148.

power to fully support transition of the natural gas heating load, and there is no current plan for such a transition. As noted by Ms. Giridhar under cross-examination by Mr. Elson:

> One of the things that we can agree on, irrespective of how the future might unfold, I would say there is widespread consensus that low-carbon gases have a role to play, both RNG and hydrogen. CER has just validated that; the Ontario government has its hydrogen strategy; the Canadian government has a hydrogen strategy.[117]

122. A role for RNG, hydrogen and CCUS in achieving net-zero is supported by the federal and provincial governments, as evidenced by the following:

a) Both the federal and provincial governments have published hydrogen strategies.[118]

b) The Government of Ontario published a discussion paper on geological carbon storage in 2022 and a CCUS roadmap in 2023.[119] To realize its CCUS roadmap, the Government of Ontario amended the *Oil, Gas and Salt Resources Act* to remove the prohibition on geological carbon storage,[120] and has proposed an authorization process to allow for carbon storage test or demonstration projects,[121] as well as amending the *Greenhouse Gas Emission Performance Standards Regulation* to recognize carbon capture and storage as a means of reducing facility emissions.[122]

c) The CER Report notes that emerging technologies such as CCUS paired with natural gas and low carbon fuels can have a key role in reaching net zero.[123]

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[117] 2 Tr.130.
[118] Exhibit 1, Tab 10, Schedule 6, pages 6-7.
[119] Government of Ontario. (2023 April 11). Environment and energy. Geologic carbon storage. https://www.ontario.ca/page/geologic-carbon-storage
[120] Government of Ontario. (2023 May 3). Proposed amendments to the Oil, Gas and Salt Resources Act, to remove the prohibition on carbon sequestration. https://ero.ontario.ca/notice/019-6296
[121] Government of Ontario. (2023 April 3). Proposed changes to the OGSRA to regulate projects to test or demonstrate new or innovative activities, such as geologic carbon storage, and to safeguard people and the environment. https://ero.ontario.ca/notice/019-6752
[122] Government of Ontario. (2022 December 13). Emissions Performance Standards (EPS) program regulatory amendments for the 2023-2030 period. https://ero.ontario.ca/notice/019-5769
[123] Exhibit K3.1, page 11.

d) Canadian Institute for Climate Choices (CICC), released February 2021, "Canada's Net Zero Future: Finding our way in the global transition" which identified hydrogen and RNG as a promising option for cost-effective emission reductions in older buildings connected to the gas distribution network. [124]

e) The Powering Ontario's Growth Plan notes:

> Natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective fuel supply for space heating, industrial growth, and economic prosperity. With developments in energy efficiency, and low-carbon fuels such as RNG and low-carbon hydrogen, the natural gas distribution system will help contribute to the province's transition from higher carbon fuels in a cost-effective way.[125]

RNG as a Safe Bet

123. Enbridge Gas considers the increase in RNG into the gas supply to be a Safe Bet as it meets the ETP criteria of providing an immediate opportunity to reduce GHG emissions, is required regardless of the energy transition pathway that unfolds and maintains consumer choice to have access to the gas distribution network.

124. The use of RNG in the gas system can realize two major environmental benefits: methane produced from the decomposition of organic matter that would have been released to the atmosphere is captured and converted to useful energy; and the emissions related to the use of natural gas have been avoided.[126] It is important to note that the claiming or reporting of these distinct emission reduction benefits by Enbridge Gas or its customers depends on the design and requirements of the applicable GHG emission reporting and regulating programs.

125. The Federal *Greenhouse Gas Pollution Pricing Act* (GGPPA) implicitly recognizes RNG (identified as biomethane) as a zero-emission factor fuel since it is exempt from the federal carbon charge. The emission factor for RNG is considered zero as

[124] Exhibit K6.1, page 37
[125] Exhibit K1.5, page 30.
[126] Exhibit J4.3.

the carbon dioxide released from the end use combustion of RNG is biogenic[127] and displaces the use of natural gas. The emission factor represents the direct emissions produced from the combustion of a unit of fuel and is zero for all types of RNG.

126. The term carbon intensity is used to represent the GHG releases or removals that occur across the full fuel lifecycle (expressed on a per unit of fuel basis) and varies according to specific RNG types and projects[128]. Where the production of RNG has prevented the release of methane that would have otherwise been released to the atmosphere, these emission reduction benefits are recognized in the carbon intensity and often lead to a negative value. In this respect, the concept of additionality is reflected in the fuel carbon intensity values since only the emission reductions that would not have otherwise occurred are accounted for. Enbridge Gas is not required by federal or provincial regulations to report on or lower the carbon intensity of the gas it distributes and does not include the GHG emission reduction benefits associated with the upstream production of RNG (i.e., avoided methane) in its corporate or government reporting[129].

127. RNG should be considered as a green molecule in the same way as renewable electricity creates green electrons and then added to the electric grid from renewable sources and used across the grid. This is further explained by Ms. Giridhar:

> MS. GIRIDHAR: I don't believe there is any difference in relation to green electrons either, or renewable energy credits related to renewable electricity projects. I think the same principle applies; the exact electron arriving at somebody's doorstep may not be the one emanating from a wind turbine or solar, but they have rights to the environmental attributes. And that is a way of making sure the industry grows and is sustainable.[130]

[127] Exhibit J4.1.
[128] Ibid.
[129] Ibid.
[130] 4 Tr.13.

128. In this context, the addition of RNG to the gas distribution system provides a GHG emission reduction even if the customer who procures the RNG does not directly use it on their premise. In his testimony on equity thickness, Mr. Goulding of London Economic International agreed that RNG is an important focus for LDCs:

> MR. GOULDING: I actually believe that LDCs should be carefully studying RNG, that costs of RNG are going to fall if there is more focus on it as a resource. It is never going to replace, in my opinion, the entirety of the gas that is supplied through a local distribution network, and clearly any LDC would be foolish to invest in networks solely for the purpose of something that was insufficient to utilize the networks in which we are investing. But I also think that RNG is part of a portfolio of solutions that any LDC should be exploring and looking at cost-effective ways to incorporate -- so perhaps a little different take than both where you are going with your question and the view of Concentric here.[131]

129. Building upon its experience with the voluntary RNG program for general service customers commenced in September 2020,[132] Enbridge Gas considers RNG a Safe Bet and is continuing to support development of the RNG market in Ontario through certain proposals in this Application:

a) Low Carbon Voluntary Program – to be addressed in Phase 2
b) Energy Transition Technology Fund – to be addressed in Phase 2
c) Continued support of RNG producers through injection services (as of 2022, four RNG production sites have successfully delivered RNG into Enbridge Gas's system)[133] and increasing RNG in Enbridge Gas's gas supply portfolio[134] throughput has increased from 0.007% in 2018 to 0.032% in 2022.[135]
d) Natural Gas Vehicle Program[136] – addressed later in this Argument.

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[131] 9 Tr.84.
[132] Updated results on the VRNG Program are provided at Exhibit 4, Tab 2, Schedule 7.
[133] Exhibit 1, Tab 10, Schedule 6, page 21.
[134] See Exhibit 4, Tab 2, Schedule 7 and Exhibit I.1.10-GEC-1, the latter explaining how throughput has increased from 0.007% in 2018 to 0.032% in 2022.
[135] Exhibit I.1.10-GEC-1.
[136] Discussed in detail at Exhibit 1, Tab 14, Schedule 2.

130. Although these issues will be more relevant to Phase 2, Enbridge Gas notes the following points about the prudence of pursuing RNG opportunities as part of its ETP to respond to Mr. Neme's criticisms that RNG availability is over-stated, and its cost is understated.[137]

131. RNG supply that will be available to Enbridge Gas and other Ontario market participants to be consumed and distributed within Ontario is not limited to just RNG supply produced within Ontario. Like natural gas, RNG can be produced and added to the system anywhere in North America and notionally delivered in Ontario.

132. RNG will have access to the same North American pipeline system as natural gas. Dawn is directly interconnected to 10 major upstream pipelines and RNG production from across North America will be able to access Dawn and the Ontario market through these pipelines. Currently, natural gas produced in Ontario accounts for less than 1% of the throughput of natural gas in the province[138] and therefore Ontario is a net importer of the majority of the natural gas consumed. As the RNG market develops, Ontario production may be higher in RNG than natural gas. RNG produced in the province and produced across North America will be actively traded to counterparties across the continent. RNG production has expanded at a rapid rate and increased exponentially over the past several months. There are currently 281 operational RNG facilities in North America, with a total of 757 RNG facilities that are operational, under construction and in the planning phase.[139]

133. Other jurisdictions in Canada, such as British Columbia (BC) and Québec, are investing in RNG as an addition to their natural gas supplies, with RNG targets of up to 15% in 2030 in BC:[140]

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[137] Exhibit M9, pages 31-34.
[138] EB-2022-0094, Exhibit EGI-OPI-13.
[139] Exhibits J2.5, I.1.10-ED-14 and I.1.10-SEC-61.
[140] Exhibit 4, Tab 2, Schedule 7, Attachment 2, Appendix A Utility RNG Programs - Jurisdictional Review.

a) BC: The CleanBC plan (2018) includes a proposal for a renewable gas mandate (including RNG, hydrogen, synthetic gas, and lignin) of 15% renewable gas content in the province's natural gas system by 2030. To help achieve this objective, the BC government amended the *Greenhouse Gas Reduction Regulation* in 2021 to increase production and use of renewable gas in the province, allowing natural gas utilities to increase the amount of RNG and other renewable gases they may acquire and supply from 5% to 15% of their total annual supply of natural gas.
b) FortisBC: Released a Clean Growth Pathway to 2050 report in 2018, which included an objective to increase RNG use to achieve a 10% zero-carbon fuel supply by 2030 and 30% by 2050. In 2020, the BC Utilities Commission approved FortisBC's application for a ratepayer funded Clean Growth Innovation Fund, which added ~$0.40/month to customers' bills, with the intent to invest the money into innovative energy projects focused on technologies like RNG and H2 and carbon capture. In 2021, FortisBC submitted a Revised Renewable Gas Program application proposing to continue growing their renewable gas portfolio to meet the 15% renewable gas mandate set by the government of BC.
c) Québec: In 2019, the government of Québec released a renewable natural gas mandate which requires natural gas distributors in the province to blend a minimum of 1% RNG into the gas system by 2020, increasing to a 5% by 2025. With the release of Québec's 2030 Plan for a Green Economy, a proposal was included to increase the renewable natural gas mandate to 10% by 2030.
d) Énergir: In 2021, Énergir released its Climate Resiliency Report, which included a target to increase the injection of RNG into the gas network, reaching at least 10% of distributed volumes by 2030.
e) Gazifère: Since 2020, Gazifère has distributed RNG into its system to achieve the 1% blend mandate set by the government of Québec and is subject to the same Plan for a Green Economy, increasing to 5% by 2025.

134. Currently, utilities and other purchasers of RNG are understood to be importing RNG from across North America to their respective jurisdictions.[141] As filed in their 2023-2024 Rate Case,[142] the largest natural gas utility in Québec (Énergir), imports 74% of their RNG from outside of their territory. As of 2021, FortisBC indicated that they expected to import 74% of their RNG supply from across North America, of which 18% is expected to be supplied from Ontario.[143]

135. Buyers in the province and outside of the province are not constrained to Ontario RNG. With current incentives for clean technology production in the US as part of the IRA, RNG supply has been developing in the US and being imported to Canada.

136. As has been demonstrated above, North American supplies of RNG can be easily imported to Ontario, and the development of RNG supplies has been growing at a rapid pace. In addition to the rapidly increasing availability of first-generation RNG (i.e., anaerobic digestion based) supplies, Enbridge Gas has observed growth in the technical and commercial readiness of second-generation RNG (i.e., agricultural and forestry-based feedstocks) projects.[144] The CICC has indicated that the development of second-generation biofuels (both liquid and gaseous) may play an important role in meeting Canada's 2050 net zero goals but considered the development of these second-generation biofuels uncertain (i.e., a wild-card).[145] As noted in the exchange between Ms. Murphy and Mr. Poch, Enbridge Gas has assessed the development of second-generation RNG as highly feasible in light of the developments it is aware of:

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[141] Exhibit J2.5.
[142] Énergir, s.e.c. R-4213-2022. page 1. https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4213-2022/doc/R-4213-2022-B-0187-DemAmend-PieceRev-2023_06_22.pdf
[143] FortisBC Energy Inc. (2021 Dec 17). Comprehensive Review and Application for Approval of a Revised Renewable Gas Program. https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf
[144] Exhibit JT2.7.
[145] Exhibit M9.

> MS. MURPHY: Jennifer Murphy, Enbridge Gas: We did reference that in our -- I have just pulled up, on my side, JT2.7 from the technical conference. It is a project that I think is a good example of what our earlier point was, that there is ongoing evolution. And this is an example of a project that is taking wood waste and turning it into RNG, where TorchLight Bioresources said that wood waste wasn't feasible. Here is a project that is doing just that. I have, I would say, limited knowledge of the project. I am not sure if anyone else on the panel might also have some input.[146]

137. CHAR Technologies provides a good example of how second-generation RNG projects can create multiple environmental benefits and revenue streams, where its Thorold plant can create both RNG[147] and bio-coal[148] that would replace natural gas and fossil-based coal, respectively.

Hydrogen as a Safe Bet

138. Based on the provincial and federal hydrogen strategies, there are clear external signals that show that hydrogen can play an important role in energy transition. Enbridge Gas also believes that its system can support the delivery of hydrogen. Beginning to plan for hydrogen is a Safe Bet as it ensures this pathway is viable, without presupposing government energy transition strategies, and does not over-invest in a hydrogen pathway prematurely.

139. While electrification is a powerful tool for reducing the GHG emissions in many sectors, electrification is not practical for all sectors. Sectors like heavy transport or industries with high-temperature processes like steel manufacturing or chemical production have considerable carbon footprints. Hydrogen and CCUS are especially attractive options for these hard-to-abate sectors.[149]

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[146] 2 Tr.66.
[147] Exhibit JT2.7.
[148] Exhibit KT2.1, page 27, 28.
[149] Exhibit K1.4, page 10.

140. The federal hydrogen strategy states low-carbon fuels will serve 60% of energy needs and supports hydrogen blending and 100% hydrogen pipelines. The federal hydrogen strategy also supports hydrogen in buildings.[150]

141. The Ontario hydrogen strategy recognizes that hydrogen and RNG will be critical to meeting Ontario's GHG reduction goals. Hydrogen has a role in vehicles, space and water heating and industry.[151]

142. It is more cost-effective to leverage existing infrastructure where possible instead of building new infrastructure. Integration of hydrogen and hydrogen technologies into energy systems can add value by enhancing the productivity and flexibility of deployed assets, namely the $16.7 billion net book value of Enbridge Gas assets and gas system. Hydrogen offers a significant means of seasonal energy storage at energy densities not matched by electric batteries. There is also additional value for hydrogen use in renewable electricity projects, which may otherwise curtail generation during periods of excess capacity.

143. Enbridge Gas views the introduction of hydrogen into its gas system as a gradual transition, as explained by Ms. Giridhar:

> MS. GIRIDHAR: Mr. Elson, Malini Giridhar. I think Ms. Teed Martin has already indicated that we see this as being a journey. We would start with blended hydrogen. If we were to take the path, then we would gradually increase the blend percentage. I am assuming beyond a point, I don't know whether that is 30 or 40 percent, the characteristics of the appliance would be closer to 100 percent hydrogen than a zero percent hydrogen.
>
> And so, you know, we have to think that these sorts of innovations would occur that would allow that sort of evolution to 100 percent hydrogen. I don't think we are looking at zero hydrogen to 100 percent hydrogen in chunks of thousand customers in the city of Toronto within a month.[152]

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[150] Exhibit I.1.10-GEC-48.
[151] Exhibit 1, Tab 10, Schedule 6, page 10.
[152] 2 Tr 190.

144. Enbridge Gas believes blends of up to 100% hydrogen will eventually be required in any pathway to net-zero, particularly for high-temperature industrial processes and heavy-duty transportation. While the role of hydrogen blending in reducing GHG emissions is supported by hydrogen strategies developed by both the provincial and federal governments, there remains some uncertainty over specifically how hydrogen will contribute to the pathway to net-zero in Ontario. Despite current uncertainty, to recognize these federal and provincial strategies and to maintain pathway optionality and the role that hydrogen could play in a diversified pathway, Enbridge Gas must, at minimum, take the following steps to prepare for wider-scale hydrogen blending in the future:

a) Implement Phase 2 of the Low-Carbon Energy Project (LCEP) – this will be addressed in a future LTC application to the OEB.
b) Complete a Hydrogen Blending Grid Study (Grid Study)[153]

145. Hydrogen is required in both the diversified and electrification scenarios in the P2NZ Study and plays a role in the decarbonization of all sectors: buildings, industry, and heavy transportation.[154] That is, the supply of hydrogen in the diversified scenario is 800 PJ in Ontario, with 54 PJ imported by 2050. In the electrification scenario, hydrogen supply is 262 PJ in Ontario, with 5 PJ imported by 2050.[155] The IESO's Pathway to Decarbonization Study similarly demonstrates a role for hydrogen in supporting the decarbonization of electricity generation in Ontario where it suggests 15,000 MW of hydrogen-fired power generation is included in the 2050 grid supply mix[156].

146. The P2NZ Study demonstrates that the electricity and gas systems become more interconnected on the path to net-zero. It is critical for electricity supply to scale up

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[153] Exhibit 1, Tab 10, Schedule 6, pages 32-33.
[154] Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 4.
[155] Exhibit JT1.28 (which supersedes Exhibits I.1.10-GEC-37, I.1.10-PP-4, I.1.1-ED-42).
[156] Exhibit K3.3, page 28.

production of green hydrogen to meet hydrogen demand. Hydrogen plays a role for electricity storage and for peak electricity supply through hydrogen-fired generation.[157]

147. While the original P2NZ Study assumes a certain share of blue versus green hydrogen in the diversified and electrification scenarios, additional sensitivity analysis completed by Guidehouse[158] demonstrated that altering blue hydrogen emission factor assumptions based on competing views of the appropriate values did not change the key conclusions of the P2NZ Study, notably that reaching net zero by 2050 is still possible (due to the shifting of some blue hydrogen to green hydrogen), and the cost delta between the two scenarios, while potentially narrower, still supports the value of a diversified scenario pathway in Ontario. Enbridge Gas therefore concludes that the "colour" of the hydrogen is less important than the GHG emissions intensity of the hydrogen in use. Enbridge Gas will uphold GHG emission intensity thresholds put in place by governments and/or Enbridge Inc. in its choice of low-carbon fuels in its distribution system.[159]

148. Enbridge Gas is successfully conducting hydrogen blending today, providing an approximately 2% blend with the natural gas system to approximately 3,600 customers in Markham as part of the LCEP approved by the OEB in October 2020, further details of which are provided in evidence.[160] Some other gas distributors are also having success with hydrogen blending for decades, such as Hawaii Gas, which has been blending up to 15% hydrogen with no known adverse effects since the 1970s.[161] Further, existing end use appliances are likely to be able to

[157] Exhibit 1, Tab 10, Schedule 5, page 16.
[158] Exhibit JT9.16.
[159] Exhibit L, pages 21-22.
[160] Exhibit 4, Tab 2, Schedule 6.
[161] 2 Tr.116.

accommodate up to 20% blends.[162] Hydrogen blending pilot projects at different blends are being conducted in North American and around the world.[163]

149. In response to concerns raised by Energy Probe in their “Closing Submission”[164], Enbridge Gas confirms that it would require (and would seek) legislative changes to support the distribution of hydrogen at high blend volumes.[165] The Company expects that changes to legislation could also apply to Municipal Franchise Agreements, such that they could all be legislatively amended to include hydrogen. Note, though, that no legislative changes are required to support the Company’s proposed activities over the next five years.

150. Blending 20% hydrogen would save 2.3 MtCO2e from end-user emissions.[166] This amount of savings represents avoided emissions from natural gas and would be the same regardless of the type of hydrogen.[167] Blending 20% hydrogen into the entire natural gas grid (subject to a full system feasibility study, described below) could yield approximately 2.3 million tonnes of carbon dioxide equivalent (tCO2e) of GHG emissions reduction annually across the system, or the equivalent of removing over 500,000 cars off the road for one year.[168]

151. Intervenors raised some concerns about the safety of blending hydrogen into the gas system.[169] These safety concerns should not prevent pursuit of hydrogen as a distribution fuel source because Enbridge Gas has direct experience and expertise, such as that of Ms. Teed-Martin who sits on the CSA Z21/83 Joint Gas Technical Committee Hydrogen Communication Level 1, that will serve it well in deploying

[162] 1 Tr.120.
[163] Exhibits I.1.10-PP-12 and I.2.6-PP-36.
[164] 18 Tr.114-115.
[165] This is explained in evidence at Exhibit 1, Tab 10, Schedule 6, page 34.
[166] Exhibit 4, Tab 2, Schedule 6, page 6.
[167] Exhibit I.4.2.-ED-125.
[168] Exhibit 4, Tab 2, Schedule 6, page 6.
[169] For example, 1 Tr.20.

hydrogen more broadly. As required by the CSA Z662 *Oil & Gas Pipeline Systems Code*, Enbridge Gas plans to conduct a full evaluation of the hydrogen-readiness of the gas grid by end of 2026 at an approximate cost of $12 million, included in the AMP. This grid study will evaluate major aspects of the Enbridge Gas system's readiness to accept higher amounts of hydrogen to achieve maximum GHG emission reductions, building upon the technical assessment framework Enbridge Gas already has in place. [170]

152. Safety is one of Enbridge Gas's values and is a top priority in all its operations and this will be no different for hydrogen blending and delivery. While some intervenors expressed a concern about potential leakage and explosiveness of hydrogen, Ms. Teed-Martin explained how the gas system is compatible with hydrogen and can be operated to minimize these risks:

> MR. LADANYI: You know that. So methane, CH4, is a much heavier and larger molecule, with a molecular weight of 16 grams per mole. You agree with that? That is basic physics. Compared to methane, hydrogen has a greater potential for leakage through seals, gaskets and through pipe wall. Do you agree with that?
>
> MS. MARTIN: No, I do not. <u>The latest research shows that if a system -- it depends upon the pressures it is running at. But if the system is running at IP pressures, if it is methane tight, it is hydrogen tight</u>.[171] (emphasis added)
>
> MR. LADANYI: Yes, of course. So I said for hydrogen, it is four percent and 75 percent. And for natural gas, it is seven percent and 20 percent. So the objective is to show that hydrogen has a much larger explosive range, particularly in a confined space like a home, than methane would, or natural gas.
>
> MS. MARTIN: I think we filed in one of our undertakings the upper and lower explosive limits. My understanding for methane, I thought it was five percent but -- subject to check. But your upper and lower limit on pure hydrogen is correct.
> <u>I would add, though, that our aim is to eliminate leaks altogether and, if we do have a loss of containment, we do not want to exceed the lower explosive limit. And if you compare hydrogen to methane, they are very similar in terms of the lower explosive limit</u>.[172] (emphasis added)

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[170] Exhibit 4, Tab 2, Schedule 6, pages 16-18 and Exhibit J18.4.
[171] 1 Tr.99.
[172] 1 Tr.101 and Exhibit J1.3.

And:

> MS. MARTIN: That said, there is new information. There was a study that just came out June 6th of this year, so less than a month ago, and it was from the Department of Energy in the U.S., and it concluded that hydrogen has negligible impact even at 100 percent -- at a concentration of 100 percent on medium-density polyethylene both vintage and modern.
>
> So like I say, things are evolving rapidly. There is more research coming out every day. So anyway -- and that study informs my opinion here today. That was new information for me.[173] (emphasis added)

153. Mr. Goulding of LEI also explained the prudence of a natural gas utility investing in hydrogen delivery:

> MR. GOULDING: …I think that a forward-thinking natural gas utility is going to be constantly exploring different new ways to use its network.
>
> And when I think about what is a company investing, particularly in the regulated business, I am always thinking about whose dime are they actually putting at risk. So I would be particularly focused on whether they are spending ratepayer money, money that is recovered through regulated rates, but I think I would argue that it's to the benefit of regulated customers that there be some investment in thinking about hydrogen.
>
> You know, I think it's reasonable to have skepticism about going all-in about -- and, again, I'm just using numbers as examples -- but, if you told me, Hey, we are going to increase our rate base by 50 percent and all of that is for preparation for hydro, then, as an Enbridge customer, I would expect I would be intervening myself. But, if you said, We are investing much smaller proportion of the overall rate base to make ready our network for new opportunities, new products that we can transport through our network, I would think that that was prudent.
>
> So it's really about the magnitude of the investments as much as it is the particular target of those investments.[174] (emphasis added)

154. Dr. Hopkins agrees that gas utilities should be exploring hydrogen:

> The first essential step is for the utility to develop a business plan for managing the firm in the changing public policy and competitive context in which it operates… Such a plan should also inform analysis of, and selection of, additional mitigating actions. These actions could include… Evaluation of low-carbon fuels such as green hydrogen or biomethane, including costs and availability as well as impact on pipeline performance

[173] 2 Tr 24.
[174] 9 Tr 101-102.

> and leakage. This should include consultation with experts in different end-use markets, including industrial customers, to identify where these fuels will deliver the greatest overall benefit (such as in meeting needs that cannot be electrified).[175]
>
> And:
>
> In terms of concrete actions to test pathways and understand performance risks (and business opportunities), 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, 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.[176] (emphasis added)

155. The broader use of hydrogen than exists today in Ontario does have uncertainty, as its widespread use as an energy source is nascent and further research and development is required to maximize hydrogen's future path. The Enbridge Gas network is ideally suited to facilitate the increasing use of hydrogen, as the existing system can be repurposed to a hydrogen network that can service the needs and demands of multiple sectors. Creating multiple revenue streams and markets for the wide-spread use of hydrogen is critical to providing positive returns on investment and for establishing the economies of scale required to lower the cost of hydrogen production as discussed by Ms. Giridhar with Mr. Mondrow of IGUA[177].

156. Using the existing system allows consumers to continue benefitting from the reliability and resiliency inherent in the system and the competitiveness it offers Ontario's industries.[178] It is expected that this hydrogen network will also represent a critical role in enabling future reliability and decarbonization needs of the electrical grid as the IESO's Pathway to Decarbonization Study demonstrated 15,000 MW of

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[175] Exhibit M8, pages 53-54.
[176] Exhibit M8, pages 54-55.
[177] 3 Tr.161.
[178] Exhibit K1.4, page 11.

hydrogen-fired power generation could support peak demand needs[179] in a 2050 net-zero scenario.

CCUS as a Safe Bet

157. CCUS is an emerging technology, and it has a key role to play in helping Ontario's large final emitters achieve GHG reduction targets and to produce hydrogen cost-effectively, preserving jobs and fostering economic development. On a provincial level, there have been regulatory changes that will further its development (i.e. underground geological storage). It is also imperative that CCUS is deployed for manufacturing processes that have GHG emissions unrelated to energy consumption. It has been recognized by the Canadian Institute for Climate Change[180] that CCUS may have a significant role in achieving net-zero goals and the CER recognizes the key role of CCUS in pathways to reaching net zero.[181]

158. Enbridge Gas is interested in exploring the viability of "utility scale" CCUS in Ontario as the province has substantial geological resources to support CCUS and federal and provincial governments are in support of its further development. Enbridge Gas believes that CCUS is viable because 1) there is strong interest from large emitters in Ontario; 2) Ontario has the geology to support/realize economies of scale to keep costs down and make GHG reductions cost effective; and 3) as detailed above, the Government of Ontario is actively advancing legislative changes and consulting on regulatory mechanisms to facilitate CCUS in Ontario.

159. To provide a sense of scale, the Wabamun hub project outside of Edmonton, Alberta, that Enbridge Inc. (EI) is developing with other industry and Indigenous partners, is targeting 4MT/yr. The P2NZ Study indicates 16-26 MT/yr CO2 capture required in ON per year by 2050. CCUS also allows for customer choice in terms of

[179] Exhibit K3.3, page 28.
[180] Exhibit M9, page 11
[181] Exhibit K3.1, page 11.

operational flexibility and costs. For these reasons, Enbridge Gas considers CCUS to be a Safe Bet.

160. Ontario's energy transition planning must factor all energy sources into a technology-agnostic plan and not bet on a subset of technologies to achieve a net zero future. The federal and provincial governments have a significant opportunity to better integrate and enable low-carbon opportunities, including renewable electricity, battery storage, as well as hydrogen, RNG, and CCUS. As the Government of Ontario establishes its approach to energy transition, it is imperative to prioritize near-term decarbonization opportunities while advancing the building blocks for long-term prospects. This will ensure that Ontarians continue to benefit from affordable, resilient, and reliable energy sources. Low carbon gases not only contribute to immediate GHG emission reductions, but also pave the way for a smooth transition toward achieving net-zero targets.

Response to Chris Neme Evidence

161. ED and GEC sponsored evidence from Chris Neme of Energy Futures Group.[182] This evidence addressed a number of issues, all connected to the topic of energy transition.

162. While Enbridge Gas does not plan to respond to all aspects of Mr. Neme's evidence in this Argument, there are a few areas where the Company believes it is appropriate to provide preliminary responses. These are set out below.

163. Enbridge Gas will likely have more submissions to offer in Reply Argument.

[182] Exhibit M9.

Critiques of Guidehouse P2NZ Study

164. A large part of Mr. Neme's report is directed at setting out his concerns with the approach and conclusions in the P2NZ Study. Mr. Neme provides a long list of concerns with the P2NZ Study, concluding that the electrification scenario should be viewed as less costly than the diversified scenario.[183]

165. As explained above, Enbridge Gas submits that the P2NZ Study is important in the context of this case as information about the potential impact of various plausible and relevant scenarios. However, the P2NZ Study is not meant to be a prediction of the future, and a probability or a likelihood of either scenario occurring was not assigned or ever intended to be implied.

166. That being said, the Company believes that the P2NZ Study provides important information to show one vision of how the gas distribution system will continue to be used or useful in the future.

167. Enbridge Gas disputes that the concerns raised by Mr. Neme are fair and/or as impactful as asserted. Three examples follow.

168. Mr. Neme asserts that the use of different carbon pricing for the electrification and diversified scenarios is not appropriate.[184] Enbridge Gas does not agree. As explained, the use of higher carbon pricing for the electrification scenario is appropriate because there is more need to move people away from GHG-emitting sources in an electrification scenario.[185] This is the approach that was used by Posterity Group in their demand forecasting scenarios that was an input into the

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[183] See Exhibit M9, pages 26-41.
[184] Exhibit M9, pages 27-28.
[185] 2 Tr.34-35. See also Exhibit I.1.10-GEC-24, part b) and Exhibit I.1.10-GEC-38, part b).

P2NZ Study.[186] This is the same approach that was used by IESO in its Pathways study, where different carbon pricing was used for different scenarios.[187]

169. Mr. Neme says that Guidehouse has included over-reliance on “blue hydrogen” by not using appropriate emissions factors.[188] In response to this position, Guidehouse re-ran its model with a variety of emissions factors for blue hydrogen. The result was that more “green hydrogen” was included in the diversified pathway, but the cost difference of the scenario still left the diversified pathway as being less expensive that the electrification pathway.[189] As stated by Guidehouse, “The results do not substantively change any conclusions in the P2NZ Study.”[190]

170. Mr. Neme asserts that the cost and availability of RNG assumed by Guidehouse are overstated.[191] Enbridge Gas does not agree. The Company’s views of the role and potential of RNG are set out above.

Customer Economics of Electrification

171. Mr. Neme’s report includes discussion about what he says is the relative cost advantage for customers of choosing cold climate air source heat pumps (ccASHPs) for their building heat.[192]

172. There are many assumptions built into Mr. Neme’s analysis.[193] This was not the topic of any significant discussion during the hearing. ED and GEC may say that the lack of probing into the analysis signifies there is no reason to question Mr. Neme’s

[186] Exhibit 1, Tab 10, Schedule 5, Attachment 1, page 38.
[187] IESO Pathways to Decarbonization Report, December 15, 2022, page 11; filed at Exhibit I.1.10-EP-7.
[188] Exhibit M9, pages 35-36.
[189] Exhibit J9.16.
[190] Ibid, page 2.
[191] Exhibit M-9, pages 31-34.
[192] Exhibit M-9, pages 22-26.
[193] Many of the assumptions are described at Appendix A to Exhibit M9.

conclusions. Enbridge Gas says that the lack of attention on this item signifies that it is not a central question to be answered in this proceeding.

173. Enbridge Gas acknowledges that more consumers may choose ccASHPs in the future. There are a few things to keep in mind here, though. First, the evidence in this case is that these appliances still require some other heat source on cold days, and that their efficiency declines at lower temperatures.[194] Second, there is evidence to show that hybrid heating, with gas furnaces to supplement ccASHPs on cold days, is a promising solution for the purposes of resilience and moderating peak electricity system impacts.[195] Third, there is no evidence that ccASHPs are currently leading to large numbers of customer departures from the natural gas system and in fact, the data shows that there is no shift in this trend from historical departures.[196]

174. As Mr. Goulding explained in his exchange with Mr. Ladanyi of Energy Probe about how customers may react to the federal carbon charge, customers are not always open to change and there is a fair amount of inertia:

> MR. GOULDING: So I think that you are right that there are uncertainties around how customers will respond to the carbon charge. But I think we also know that there is a fair amount of inertia with regards to the way in which customers behave. And we also have to the think about the way in which the prices of alternatives change. And we have seen that electricity costs can also increase. We have heard the head of Toronto Hydro publicly say that he was anticipating the need for rate increases of 10 to 15 percent per year for the foreseeable future.
>
> And while that may have been hyperbole, I do think it is important when we are doing these comparisons to note that, you know, the increases in the commodity cost of natural gas don't exist in a vacuum -- I am misspeaking slightly -- in the externality costs that are applied to the commodity cost of natural gas, would be a more precise way of saying that.

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[194] See Exhibits J11.5 and J11.6.
[195] See Powering Ontario's Growth, at page 27, for discussion of hybrid heating as an Government of Ontario promoted program; Exhibit K6.1, page 45. See also "Hybrid heat in Québec: Energir and Hydro-Québec's collaboration on building heat decarbonization", found at Exhibit K6.1, pages 39-44. These items were both discussed with Mr. Neme in cross-examination: 6 Tr.32-35.
[196] 11 Tr.25-26 – Enbridge Gas is seeing around 2,000 customers leave the system per year (much less than customer additions) and this includes seasonal disconnections and other reasons.

> But it is important to note that while Enbridge has no certainty about customer behaviour in the period between 2023 and 2030, they can note that customers are reasonably sticky, and that it is reasonable to believe that there will be some increases in the costs of alternatives.[197]

175. Enbridge Gas submits that these factors should lead the OEB to be cautious in following Mr. Neme in making sweeping conclusions at this time as to the pace and scope of electrification for residential customers. There is no evidence to suggest that this is actually happening in Ontario.

Lack of Grounding in Current Government of Ontario Policy

176. Mr. Neme's evidence makes no reference at all to current Government of Ontario policy.[198] However, he agrees that Government of Ontario policy is very important.[199]

177. The Powering Ontario's Growth report represents a very recent view of Government of Ontario policy.[200] It shows that the Government of Ontario plans for large growth in demand from electric vehicles – at an average growth rate of 17% per year.[201] The Powering Ontario's Growth report relies on the IESO's Annual Planning Outlook. The most recent version of that document indicates that on an overall basis, Ontario is forecast to see a limited amount of residential sector electricity demand growth in the years from now until 2043 – an average of about 1% growth per year.[202] Mr. Neme agreed that this is the forecast based on current Government of Ontario policy.[203] Taking into account the planned demand for electric vehicles, this shows that current Government of Ontario policy does not in any way plan for building heat electrification at anything close to the level assumed by Mr. Neme.

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[197] 9 Tr.99.
[198] 6 Tr.13-14.
[199] Ibid.
[200] Mr. Neme agreed to this proposition – 6 Tr.15.
[201] See Powering Ontario's Growth, at page 38; Exhibit K6.1, page 17. This was discussed with Mr. Neme at 6 Tr.17-18.
[202] IESO Annual Planning Outlook, Ontario's electricity system needs: 2024-2043, December 2022, at page 20; Exhibit K6.1, pages 19-23.
[203] 6 Tr.19-20.

178. As discussed with Mr. Neme, the Government of Ontario has initiated the EETP to help guide the Government with energy transition.[204] Among other things, the EETP will be looking at integrated planning between the gas and electricity sectors and reducing barriers to low-carbon fuels. A "key input" for the EETP is the "independent cost-effective pathways study" that is being prepared.[205]

179. It seems obvious, and Mr. Neme has agreed[206], that until the EETP report is received and the Government of Ontario provides its resulting direction, it cannot be said that the Government of Ontario has chosen an unambiguous electrification pathway. And we will not know that for a year or more.

180. The report filed by Mr. Neme does not acknowledge this uncertainty. It does not reference Government of Ontario policy at all. Enbridge Gas submits that this is important context against which to measure the certainty expressed by Mr. Neme about the fast-approaching wide-spread electrification of most or all energy needs currently served by natural gas.

Lack of Attention to Current Electricity System Capacity

181. Mr. Neme seems to have no concerns that electrification of residential customers can proceed quickly and with no practical limits. The evidence suggests otherwise. And Mr. Neme concedes that he does not have personal knowledge of Ontario's electricity capacity.[207]

182. As set out in the Powering Ontario's Growth report, natural gas accounts for around 44% of Ontario household energy consumption (with gasoline accounting for another

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[204] 6 Tr.20-23.
[205] The EETP's work is discussed in the Powering Ontario's Growth report, at pages 79-81; Exhibit K6.1, pages 26-28.
[206] 6 Tr.23.
[207] 6 Tr.49 and Exhibit N.M9.EGI.98.

41%).[208] Electrification will be an immense task if both of those fuels are to be replaced.

183. Ontario already has an electricity capacity shortfall in summer of 2023.[209] That is before the electrification that Mr. Neme assures is coming quickly. There is certainly no evidence to support a conclusion that there is either generation or distribution capacity available to accommodate near-term electrification. Mr. Neme agreed that there could be challenges in electrifying the province's planned additional 1.5 million new homes under the *Building New Homes Faster Act*.[210] And that does not take into account electrification of transportation or the assumed transition (by Mr. Neme) of most every current gas customer whose equipment reaches end of life (which, by his estimate would be 1/18th of customers each year since he assumes that a furnace has a 18 year life[211]).

184. Enbridge Gas submits that this is all reason to be skeptical about the certainty with which Mr. Neme presents his electrification-based recommendations.

Mr. Neme's Proposals

185. Mr. Neme starts and finishes his report with recommendations for the OEB to adopt to mitigate risks of energy transition. It remains to be seen how many of these will be pursued and proposed by ED and GEC, but Enbridge Gas will provide its preliminary responses below.

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[208] Powering Ontario's Growth report, at pages 12-13; Exhibit K6.1, pages 5-6. This was discussed with Mr. Neme at 6 Tr.15-16.
[209] IESO Reliability Outlook, July 2023 to December 2024, pages 1 and 26; Exhibit K6.1, pages 8 and 15. This was discussed with Mr. Neme at 6 Tr.16-17.
[210] 6 Tr.49-50.
[211] 6 Tr.94-95.

186. Mr. Neme includes recommendations related to customer attachments, including reducing the revenue horizon and the customer attachment horizon.[212] These are addressed in the Customer Attachment section of this Argument.

187. Mr. Neme also suggests that all new attachments should be required to have customers use non-emitting fuels such as RNG.[213] It is not clear that parties are pursuing this recommendation.[214] It should be noted that Mr. Neme did not provide any response when asked how it can be said that the OEB has the legal authority to impose this requirement.[215] Neither of Mr. Neme's sponsors (ED or GEC) added anything to the interrogatory response on this topic.

188. Mr. Neme proposes that Enbridge Gas study and report back to the OEB on several different depreciation-related items so that the OEB can review and determine an appropriate approach.[216] Mr. Neme acknowledges that he is not an expert in this area (depreciation) and that he is not making any substantive proposal.[217] Enbridge Gas submits that had ED and GEC wished to deal with different depreciation proposals in this case (such as Mr. Neme's suggestion of a "units of production" approach) then they should have provided expert evidence on the topic. They chose not to do so. The Company's position in relation to the depreciation issues is set out later in this Argument.

189. Mr. Neme submits that Enbridge Gas should be assessing the potential for repairing rather than replacing aging pipe.[218] He conceded in discussions with CCC that Enbridge Gas may already do this.[219] Mr. Neme further submits that Enbridge Gas

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[212] Exhibit M9, page 4 and 42-44, Recommendations 1 and 2.
[213] Exhibit M9, pages 5 and 44, Recommendation 3.
[214] 3 Tr.196.
[215] Exhibit N.M9.EGI.88.
[216] Exhibit M9, pages 5-6 and 44-47 and 49, Recommendations 4 and 7.
[217] 6 Tr.51-52.
[218] Exhibit M9, pages 5 and 47-48, Recommendation 5.
[219] 6 Tr.100.

should reduce capital spending where possible.[220] Enbridge Gas believes that its practices and proposals are aligned with these items. Details about the Company's capital plan are set out later in this Argument.

190. Mr. Neme sets out two recommendations for Enbridge Gas to adopt to improve the IRP processes used by the Company.[221] First, Mr. Neme proposes that the prohibition on electrification measures as IRPAs should be removed. Second, Mr. Neme proposes that Enbridge Gas should use multiple demand forecasts or scenarios when assessing the potential for IRPAs to meet identified needs.

191. On the first of these items, Enbridge Gas notes the OEB's direction in the IRP Framework that was established two years ago. In the Overview of its Decision for the Integrated Resource Planning Framework for Enbridge Gas, the OEB noted as follows:

> Enbridge Gas also proposed non-gas IRP Alternatives, specifically electricity-based alternatives. The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives.[222]

192. While Enbridge Gas is proposing <u>very limited</u> use of electric IRPAs in the very recently filed IRP Pilot Projects Application[223], the OEB has yet to decide on that case. It is not clear to Enbridge Gas that this case is the appropriate place for the OEB to revisit and rewrite the IRP Framework. There is no full record on which to make determinations.

193. The Company has not put forward a proposal about the nature and treatment of permissible electric-based IRPAs (including funding, rate base treatment and

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[220] Exhibit M9, pages 6 and 49, Recommendation 8.
[221] Exhibit M9, pages 5 and 48-49, Recommendation 6.
[222] EB-2020-0091 Decision and Order on an Integrated Resource Planning Framework for Enbridge Gas, July 22, 2021 (IRP Framework Decision), page 4. Fuller discussion is found at pages 31-36 of the Decision and Order.
[223] EB-2022-0035.

incentives) in this rebasing case. As explained on a number of occasions, this is an example of an activity that requires coordination and integrated planning with electric utilities. There are locational impacts and considerations from targeted electrification and the electricity distribution system needs to be able to accommodate this. Ms. Wade explained this in response to a question from Commissioner Duff:

> So, for example, if we were to go into a specific geotargeted area and look at a need on a pipe and try to reduce the need on the pipe using electric measures, so basically a geotargeted air-source heat pump-type of program. So that would be a big reduction of heat on a customer's load.
>
> However, we are not sure if the local grid could actually take on that peak. And so, in the very early discussions that we have had with our LDC partners, I would say there is concern that we would come in and geotarget without them being at the table to ensure that they could take up that increasing load on the winter peak. And we also haven't had discussions with customers yet, say, for example from a resiliency perspective. So we are not sure yet, even if that would be palatable to these communities.
>
> But I think from an overarching perspective, it is something that could be revisited if done in partnership with an LDC.[224]

194. Enbridge Gas believes strongly in the importance of coordination between gas and electric distributors. However, integrated energy planning is an activity that should be done in an organized and defined manner, where all parties have common understandings as to the benefits and goals of integrated coordination. This is not simple. It is something that is being addressed by the EETP. In the OEB's recent decision establishing an IRP Framework for Enbridge Gas, the OEB recognized that integrated energy planning between gas and electricity is an "aspirational goal" that will require further consideration before establishment and implementation.[225]

195. None of this is intended to say that Enbridge Gas is opposed to appropriate inclusion of electric IRPAs and in fact, Enbridge Gas proposed this to the OEB in the IRP

[224] 14 Tr.87. See also 6 Tr.200-201.
[225] IRP Framework Decision, pages 35-36.

Framework proceeding and this was rejected. However, considering the complexity of the issue, and the fact that there is no evidence or proposal being made, Enbridge Gas believes that this would be better addressed where and when there is a full review of the IRP Framework.

196. On the second of these items, Enbridge Gas does not agree that each project should be subject to a multitude of demand forecasts. Ms. Wade explained the Enbridge Gas position in response to questions from CCC at the hearing:

> I think what Mr. Neme here is speaking about, if I can interpret his suggestion or proposal here, is that it would almost be like a pathways study within a specific geotargeted area, to understand what the costs and benefits would be to customers in that area should an electrification pathway come to fruition and/or a low-carbon fuels.
>
> And so I just note that this would be a very time-intensive process. It would require significant level of effort to be able to do that scenario analysis, and I think we are still evaluating.
>
> At this point, it feels like I am not sure the value that would be provided to the Board in the decision of the IRP alternative as opposed to the best available information that we have at the time with the commitment to continually iterate the analysis and come back and re-evaluate any scenario or, sorry, any assessments that we have done with any new information that we have.[226]

197. Mr. Neme responded to Ms. Wade's statements, indicating that his proposed process does not need to be as complex as indicated. However, in his answer he pointed to his view that the complications can be avoided through using assumptions. Enbridge Gas observes that including assumptions almost always leads to debate as to whether they are fair. In response to further questions on his proposal on this item, Mr. Neme conceded that he is not aware of any other regulator who has required a muti-scenario analysis as he proposes.[227]

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[226] 3 Tr.201-202.
[227] 6 Tr.121-123.

B. Rate Base (Exhibit 2)

Rate Base

198. Issue 6 – Is the 2024 proposed rate base appropriate?

Consequences Of Settlement Proposal

199. The parties resolved most aspects of proposed 2024 rate base in the Settlement Proposal. Essentially, the rate base additions and value up to the end of 2022 is resolved, based on the Enbridge Gas filing at the time of the Settlement Proposal (before the Capital Update, filed June 16, 2023).[228] The one exception is that there is no resolution about whether integration capital costs should be included in opening rate base for 2024. There is also no resolution as to capital additions to rate base for 2023 and 2024.

200. The details are set out in the Settlement Proposal, at Issue 6:

> Parties accept the methodology presented by Enbridge Gas for the determination of working capital and rate base. Final forecast 2024 working capital amounts and rate base cannot be determined until other unresolved issues are determined.
>
> No items related to 2024 capital budget and associated rate base are settled. There is a partial settlement on the 2024 opening rate base.
>
> The only unsettled aspects related to 2024 opening rate base are: (i) the inclusion of Enbridge Gas's integration capital costs from the deferred rebasing term in opening rate base for 2024; and (ii) additions to 2024 opening rate base resulting from 2023 changes.
>
> Parties accept Enbridge Gas's rate base up to and including 2022, subject to, (i) agreement to remove the forecast residual net book values of the overspend on the WAMS project and 25% of the overspend on the Enbridge Gas Distribution GTA Reinforcement Project from opening rate base for 2024; and (ii) the appropriateness of including integration capital costs in rate base. Enbridge Gas estimates that the impact of removing the forecast residual net book values of the WAMS overspend and 25% of the GTA Project overspend from 2024 opening rate base is approximately $41 million, comprised of $6 million related to the WAMS project and $35 million related to the GTA Reinforcement Project.

[228] See Settlement Proposal, page 25 (Issue 6) – filed at Exhibit O1, Tab1, Schedule 1.

> Parties agree that Enbridge Gas will not include any amounts in 2024 opening rate base for the Dawn to Corunna project (approved in EB-2022-0086). Instead, the determination of the allowed recovery for, and method for recovery of, Dawn to Corunna project costs will be made in Phase 2 of this proceeding, including the issue of how much (if any) of the value of the project should be allocated to Enbridge Gas's non-utility operations. Parties agree that the impacts of the OEB's decision on the rate base treatment of the Dawn to Corunna project will be recoverable from customers as if it were included in the 2024 rate base and when final rates for 2024 are set following Phase 2 of this proceeding.
>
> …
>
> There is no agreement on appropriate treatment of the Natural Gas Vehicles (NGV) Program (Issue 34), and if different treatment of the NGV Program is ordered than proposed by Enbridge Gas, then corresponding changes may be necessary to 2024 opening rate base.[229]

201. The result is that there are four unsettled aspects to this issue, each of which are addressed in this Argument:
    a) Inclusion of integration capital in 2024 rate base;
    b) 2024 opening rate base amounts resulting from 2023 rate base additions;
    c) 2024 rate base amounts resulting from 2024 rate base additions; and
    d) Consequential changes to 2024 rate base from other determinations.

Outstanding Approvals Required

202. Enbridge Gas requests approval of its as-filed 2024 proposed rate base, including the impacts of the Capital Update, subject to three adjustments.[230] The three differences between what is filed in the Capital Update and what is requested for approval in Phase 1 of this proceeding are:
    a) Changes are made to 2024 opening rate base to reflect the agreement in the Settlement Proposal to remove approximately $41 million related to WAMS and GTA Project overspend;[231]
    b) The rate base value of the Dawn to Corunna project has been removed (on an interim basis), as this is being determined in Phase 2 of the proceeding

[229] Settlement Proposal, Issue 6, pages 24-25 – filed at Exhibit O1, Tab 1, Schedule 1.
[230] Exhibit 2, Tab 1, Schedule 1, pages 5-6.
[231] Settlement Proposal, Issue 6, pages 24-25 – filed at Exhibit O1, Tab 1, Schedule 1.

(after which time all or some of the value will be added back into 2024 rate base, depending on the OEB's determination); and

c) The land purchased for the GTA West REWS project ($24.5 million) is removed from 2024 rate base for rate making purposes.[232]

203. The Company notes that the basis for the Settlement Proposal was the property, plant and equipment values included in the 2022 Estimate rate base (evidence dated March 8, 2023), not the 2022 Actual rate base property, plant and equipment values that underpinned the Capital Update (evidence dated June 16, 2023, and July 6, 2023). This is noted in footnote 5, on page 24 of the Settlement Proposal. This footnote was included in the Settlement Proposal because the 2022 Estimate net property, plant and equipment rate base value, calculated on an average of monthly averages basis, was $20.3 million lower than the 2022 Actual net property, plant and equipment rate base value that underpinned the Capital Update.[233]

204. While the Settlement Proposal was based on the 2022 Estimate rate base values, the Company believes the 2022 Actual rate base values that underpinned the Capital Update should serve as the appropriate foundation for determining the 2024 rate base value (i.e. for which to add 2023 and 2024 capital activity), as they reflect actual 2022 capital activity (i.e. additions, retirements). Importantly, the 2022 Actual rate base values result in a lower 2022 ending net property, plant and equipment balance to be carried forward into 2023 and 2024, thus lowering the rate base values in each of those years, which benefits customers.

205. The ending 2022 Actual net property, plant and equipment balance of $14,895.0 million ($23,402.3 million gross plant less $8,507.3 accumulated depreciation) is $13.3 million lower than the 2022 Estimate net property, plant and equipment

[232] Exhibit J14.13.
[233] As seen at row 3 of Table 11 in the Capital Update evidence at Exhibit 2, Tab 5, Schedule 4, dated June 16, 2023.

balance of $14,908.3 million ($23,535.2 million gross plant less $8,626.9 accumulated depreciation).[234]

206. While the 2022 Actual net property, plant and equipment rate base value, calculated on an average of monthly averages basis is higher than the corresponding 2022 Estimate net property, plant and equipment rate base value, due to the timing of capital activity that occurred in 2022 actuals as compared to the activity forecast in the 2022 Estimate, it is the 2022 ending net property, plant and equipment balance carried forward that will impact 2023 and 2024 rate base values. As such, despite the higher average of monthly averages balance, the Company believes the 2022 Actual net property, plant and equipment balance reflected in the Capital Update, which is lower than the ending 2022 Estimate net property, plant, and equipment balance, is the appropriate foundation for determining 2023 and 2024 rate base values.

Revenue Requirement Implications for 2024

207. If Enbridge Gas's proposed 2024 rate base is approved as requested (including the Dawn to Corunna project), the revenue requirement will be similar to that filed as part of the Capital Update, filed June 16, 2023, but amended to reflect the implications of the Settlement Proposal.

208. If the OEB determines that amounts proposed for inclusion in 2024 rate base should be adjusted, that will impact the revenue requirement. However, the impact of such adjustments will depend on the magnitude of the adjustment and the timing of when

[234] The lower ending net property, plant and equipment balance contained in 2022 Actual rate base can be seen by comparing the ending 2022 gross property, plant and equipment and accumulated depreciation balances in Tables 1 (line 6, column d) and 2 (row 7, column d) of Exhibit 2, Tab 2, Schedule 1, filed July 6, 2023, which was filed in support of the Capital Update, versus the same tables and evidence, dated March 8, 2023, that supported the 2022 Estimate. It should also be noted that comparing the average of monthly averages gross property, plant and equipment and accumulated depreciation values, contained in row 7, column d) of Table 1 and row 8, column d) of Table 2, also illustrates the higher 2022 Actual net property, plant and equipment rate base value of $20.3 million noted in the prior paragraph.

the relevant item was forecast to be added to rate base. An item that was forecast to be added to rate base during the course of 2024 will only be partially effective from a cost of capital and depreciation perspective, and could result in other offsetting revenue requirement implications (such as to revenues and taxes), meaning that the rate base impact of its removal may be modest, and or may even increase revenue requirement depending on the size and timing of the offsetting items.

Evidence in Support

209. Enbridge Gas has filed detailed evidence about its rate base and capital budget. This evidence is found throughout Exhibit 2. Enbridge Gas has answered interrogatories about this evidence[235], and provided testimony at the Technical Conference[236], and answered undertakings[237] arising from that testimony and filed one ADR response.[238]

210. Enbridge Gas witnesses provided testimony about the outstanding aspects of this issue through three witness panels. The Customer Attachments witnesses (Panel 10) spoke about 2023 and 2024 customer additions capital.[239] The Capital Budget witnesses (Panel 11) spoke about the 2023 and 2024 capital budgets.[240] The Integration Capital witnesses (Panel 12) spoke about the integration capital amounts sought for inclusion in 2024 rate base.[241]

211. There is no intervenor evidence on this issue, except to the extent that intervenor evidence touches on the implications of the 2024 capital budget.

[235] Exhibit I.2.
[236] 4 TC Tr.200-217, 5 TC Tr.5-203 and 6 TC Tr.1-48.
[237] Exhibits JT4.22-4.25, JT5.1-5.47 and JT6.1-6.5.
[238] Exhibit I.ADR.50.
[239] 10 Tr.76-205 and 11 Tr.2-90.
[240] 11 Tr.91-203, 12 Tr.1-118, 13 Tr.1-192 and 14 Tr.1-142.
[241] 14 Tr.143-208.

Overview

212. Enbridge Gas submits that no adjustments are required to the 2024 opening rate base, other than as already agreed through the Settlement Proposal.

213. There are only two aspects of the 2024 opening rate base that are unresolved – inclusion of integration capital amounts and 2023 rate base additions.[242]

214. Enbridge Gas submits that it is appropriate to include integration capital amounts in 2024 rate base. The total undepreciated integration capital amounts that Enbridge Gas proposes to include in 2024 rate base is $119 million.[243] Under the OEB's general principle of "benefits follow costs", it is appropriate that customers pay the ongoing costs of technology assets, in the form of depreciation, that will continue to benefit them after rebasing.

215. In its rebasing O&M cost forecasts, the Company has credited customers with substantial sustained operational savings from integration (of $86 million) that will benefit customers every year.[244] The capital projects that underlie the integration capital amounts will continue to benefit customers also. These capital projects are largely initiatives that needed to be completed by the EGD and/or Union in the absence of amalgamation. They are called "integration" because they involve combining activities or processes of the EGD and Union during the deferred rebasing term.[245] However, the projects fulfil functions that must be undertaken by any utility, whether it is stand-alone (like EGD and Union) or amalgamated (like Enbridge Gas).

[242] Note that the rate base and revenue requirement implications of the Dawn to Corunna Project are being addressed in Phase 2.
[243] 14 Tr.155.
[244] See Exhibit 1, Tab 9, Schedule 1, page 5.
[245] Ibid, page 3.

216. While the OEB's MAADs policy indicates a general expectation that utilities will self-fund integration activities, it does not specifically speak to how long-lived capital asset costs should be treated. Additionally, the MAADs policy indicates that a utility may have a deferred rebasing term of up to ten years, in order to recover its costs of integration. Enbridge Gas only received a five-year deferred rebasing term. The Company could have decided to not pursue technology enhancements as the deferred rebasing term would have been insufficient to recover the depreciation through synergies given the life of the underlying assets. However, the Company recognized that this would have been inconsistent with the MAADs policy, which is intended to incent the delivery of benefits and would not have benefited customers, nor realized the value of integrating the utility.

217. Enbridge Gas recognized that the intent of the MAADs framework was to deliver efficiencies. By integrating technology platforms, Enbridge Gas was able to reduce costs, increase efficiency and as a result, deliver value to customers through the deferred rebasing term and beyond. Enbridge Gas believed that the regulatory principle of benefits follow costs would be maintained at rebasing and made necessary investments quickly, in the expectation that while it would shoulder the associated costs during the shorter deferred rebasing term, the remaining undepreciated capital costs would be paid by customers after rebasing.[246]

218. With one exception related to customer additions, Enbridge Gas is not aware of specific concerns from other parties about the proposed 2023 rate base additions included in 2024 rate base.[247]

219. The Company expects that parties may question whether the full amount of 2023 rate base additions related to customer additions should be included in 2024 rate

[246] Exhibit J14.13.
[247] Again, note that the treatment of the Dawn to Corunna Project is a Phase 2 issue.

base because of the fact that the overall profitability index (PI) of the 2023 customer additions portfolio is less than 1.0.

220. Enbridge Gas submits that it is appropriate for all rate base amounts related to 2023 customer additions to be included in 2024 rate base. Enbridge Gas has explained the cost pressures that it has faced in recent years related to customer additions, and the steps taken to remedy these items. Importantly, Enbridge Gas has maintained an overall PI of well above 1.0 for the years since it last rebased in 2013. This means that the total amount being included in 2024 rate base for customer additions capital from 2014 to 2023 is forecast to be more than fully recovered in rates, based on the feasibility tests in place at the time. On a forecast basis, Enbridge Gas would recover around $75 million more in revenues than the associated costs for customer additions over the 2014 to 2023 period. It is unfair to pick out one year in isolation and indicate that a portion of customer addition costs from that year should be disallowed.

221. To the extent that parties raise other concerns related to 2023 rate base additions, Enbridge Gas will respond in Reply Argument.

222. Enbridge Gas will address the 2024 capital budget under Issue 7. The Company acknowledges that changes from the as-filed 2024 capital budget will have implications for proposed 2024 rate base. Such implications will be addressed through the Rate Order process.[248]

[248] Changes that could result from the NGV issue, as well as from updates to relevant to working capital, will also be reflected through the Rate Order process. The implications of the OEB’s Decision related to the inclusion of the Dawn to Corunna project in rate base will be reflected through the Phase 2 Rate Order process.

Integration Capital

223. The Company's evidence sets out the updated integration capital expenditures during the deferred rebasing term. These are summarized in Table 3 below.[249]

Table 3
Integration Capital Investments

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Bridge Year	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	CapEx						
1	Business Development & Regulatory		0.6	2.0			2.6
2	Customer Care	6.7	27.7	32.0	0.8		67.3
3	Distribution Operations	11.3	7.1	19.0	19.8	17.0	74.2
4	Energy Services	3.6	3.7	8.0	5.6	3.0	23.9
5	Engineering & STO		0.2	2.0	0.3		2.5
6	Overheads	7.6	11.0				18.6
7	Total Annual CapEx	29.1	50.4	63.0	26.5	20.0	189.0
8	Net Book Value (included in rate base forecast)						119.0

Notes:
(1) Distribution Ops: Work Mgmt. phases utility work, construction, meters, customer attachment.
(2) CapEx is reflective of year spent.
(3) Overheads are included at the project level starting in 2021.
(4) Associated impact of NBV reflected in the 2024 Test Year revenue requirement is $28 million.

224. The largest integration capital expenditures were in "pillar technologies": one Customer Information System (CIS) and one Asset and Work Management (AWS) system. The CIS investments are included in Customer Care and the AWS investments are noted in Distribution Operations.[250]

[249] Exhibit 1, Tab 9, Schedule 1, Table 6, page 21.
[250] Exhibit 1, Tab 9, Schedule 1, pages 19-20.

225. Ms. Lindley provided details about these two projects in Examination in Chief for Panel 12:

> Over the past five years, the largest investments in integration capital were largely in long-life pillar systems, technology systems, that benefitted day-to-day customers, but also our day-to-day business operations. In fact, 75 percent of the integration capital was focused on two key system[s]; our CIS system, the customer [information][251]system, and the AWM system, the asset work management system.
>
> The benefits that are associated with the CIS system were realized in customer care and they are largely related to the elimination of the duplicate vendor system that was managed, but also gave a common platform for customer interaction; Chatbot, IVR, those types of things.
>
> On the asset and work management side, that was a common, scalable platform that was implemented in phases, and it enabled the savings that were largely in distribution operations for the work and resource strategy initiative, which had consistency of contractor usage and also enabled the integration of the work management teams, which included the centre consolidation.
>
> The benefits of those, as I mentioned, are in distribution operations, both from an operational perspective but also from a financial perspective. But not only did those systems integrate the companies, they also extended the useful life of those assets and they also will benefit into the future.[252]

226. Ms. Lindley further explained and provided references for the fact that these major projects (replacement of existing systems) were already planned by Union before amalgamation and included in the Union Asset Management Plan.[253] Thus, while the projects could be considered “integration” because they brought together applications for the amalgamated utility, they are also projects that would have been needed for Union as a standalone utility. Importantly, as Ms. Lindley explained, the projects were done for less cost than would have been the case within the standalone utility.[254]

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[251] Note that the text of the transcript mistakenly says “integration”.
[252] 14 Tr.146-147.
[253] 14 Tr.147-148. See also Exhibit K14.2, Enbridge Gas Compendium for Panel 12, which includes excerpts from Union AMPs for the Banner, CARs and Service Suite systems which were all replaced through integration capital projects.
[254] 14 Tr.148.

227. Beginning in 2024, Enbridge Gas will reflect the impact of the efficiencies and cost savings resulting from the amalgamation in its going-forward rates. The expected annual synergy savings of $86 million resulting from all integration initiatives are reflected in revenue requirement.[255] These are savings that repeat for customers each year going forward. To achieve these savings, Enbridge Gas funded the $280 million of integration O&M costs during the deferred rebasing term from synergy savings.[256]

228. During the deferred rebasing term, Enbridge Gas expended $189 million in integration capital, of which the $70 million cost depreciated during the deferred rebasing term was funded from synergy savings.[257] This is because during the deferred rebasing term, the Company must fund all planned capital expenditures up to the ICM threshold (which is what is funded by base rates) before having access to ICM funding, and this calculation does not take account of any amounts funded for the integration projects. In other words, during the deferred rebasing term, base rates fund business "as usual" needs while the Company is expected to fund the integration projects from savings achieved through efficiencies.[258]

229. Enbridge Gas submits that it is appropriate to include integration capital undepreciated amounts, totaling $119 million, in 2024 rate base to be subject to recovery through rates going forward. These investments were made throughout the deferred rebasing term to deliver the highest level of sustainable savings and operational benefits. As demonstrated in Exhibit J14.11, Enbridge Gas generated sufficient synergy savings to fund integration projects during the deferred rebasing term, but with no excess. The sustainable synergy savings are being reflected in

[255] Exhibit 1, Tab 9, Schedule 1, pages 4-5 and 16.
[256] Ibid pages 16-19. See Exhibit J14.11 which shows that synergy savings funded integration costs during the deferred rebasing term.
[257] 14 Tr.202-203. See Exhibit J14.11 which shows that synergy savings funded integration costs during the deferred rebasing term.
[258] This was discussed further in submissions in the 2020 ESM proceeding (EB-2021-0149) – see, for example, Enbridge Gas Reply Argument at page 5.

base rates starting in 2024, meaning that they will accrue to ratepayers, not the Company.

230. Much of the residual net book value of the projects pertains to in-service additions in 2021, 2022, and 2023, which Enbridge Gas will not have had the opportunity to fully depreciate by the end of the approved 5-year deferred rebasing term.[259] Enbridge Gas understands that the OEB decided that a 5-year deferred rebasing term was sufficient but notes that the evidence in the MAADs proceeding was that Amalco required a longer deferred rebasing term to recover these capital costs.[260]

231. In the O&M budgets in this case, the Company has credited customers with $86 million in sustained operational savings from integration that will benefit customers every year.[261] The projects that underlie the integration capital amounts will continue to benefit customers also and are largely projects that needed to be completed by the legacy utilities in the absence of amalgamation. Ms. Ferguson explained the Company's position in testimony:

> Given that this capital investment that has occurred through the deferred rebasing period has been funded by the synergies generated by the integration and the system improvements made, it is appropriate from the Company's perspective that the undepreciated capital remain that's remaining at the end of 2023 continues to be recovered through those synergies that were used to derive them.[262]

232. All of the foregoing is consistent with the OEB's MAADs policies, and with the overarching OEB principle that benefits follow costs.[263] The MAADs policies recognize that an amalgamated utility will absorb the costs of the transaction during

[259] Exhibit 1, Tab 9, Schedule 1, page 23.
[260] See, for example, EB-2017-0306/0307, Exhibit J2.4.
[261] These savings are included in the pre-settlement O&M budget amounts.
[262] 14 Tr.149.
[263] In the Enbridge Gas 2020 Deferrals case (EB-2021-0149), the OEB indicated that "[a]ny interpretation of the MAADs policy by the OEB can be dealt with in the rebasing proceeding" – Decision and Order dated January 27, 2022, at page 10.

the deferred rebasing term, while also retaining corresponding efficiency benefits.[264] The MAADs policies further indicate that benefits from efficiencies and synergies are to be passed on to customers at rebasing.[265]

233. No mention is made in the MAADs policies of the rebasing treatment of remaining costs necessary to achieve the amalgamation efficiencies and synergies. Indeed, no mention at all is made of capital costs (which, unlike operating expenses are not all expensed at once such that there is nothing left over to consider at rebasing). There is no differentiation made as to types of costs (operating or capital) in the MAADs Handbook when the OEB indicates that "[i]ncremental transaction and integration costs are not generally recoverable through rates".[266] As explained by Ms. Ferguson in testimony, the word "generally" signals that some circumstances may warrant recovery of "integration" costs.[267] Enbridge Gas submits that the current circumstances warrant recovery, where the capital costs are not necessarily "incremental" (because they were already forecast by the legacy utilities on a standalone basis) and where the undepreciated capital costs support ongoing operational benefits to customers.

234. To Enbridge Gas's knowledge, this is the first OEB rebasing case following a MAADs approval for the amalgamation of two large utilities. Enbridge Gas is not aware of any rebasing case following a MAADs approval where the OEB has considered the treatment of undepreciated capital costs related to integration of the utilities. Interestingly, a review of past MAADs proceedings indicates that amalgamating utilities typically do not identify significant capital costs related to

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[264] OEB Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, pages 11-12 (Deferred Rebasing); and Ratemaking Associated with Distributor Consolidation Report of the Board, July 23, 2007, page 4, section 2.2.1 (Time to Retain Savings to Offset Costs).
[265] OEB Handbook to Electricity Distributor and Transmitter Consolidations, pages 17-18 (Future Rate Structures); and Ratemaking Associated with Distributor Consolidation Report of the Board, page 7, section 2.2.2 (Net Impacts at Time of Rate Rebasing).
[266] OEB Handbook to Electricity Distributor and Transmitter Consolidations, page 8.
[267] 14 Tr.163.

integration. This highlights that the type of costs that Enbridge Gas has highlighted as "integration capital" costs are likely treated as business as usual by other amalgamating utilities and therefore subject to ordinary treatment where remaining undepreciated costs will be included in rate base post-rebasing.

235. Presumably, the OEB's benefits follow costs and beneficiary pays principles should apply such that these costs are recoverable from customers. That is consistent with the fact that, under financial accounting rules, the costs of the integration investments are expensed, as depreciation, over the period when they are providing value. Considering that this value is credited to customers through rebasing, so too should the future/ongoing costs for assets that will continue to benefit customers be charged to customers on a go-forward basis starting at that time.[268]

236. The intervenor position (as indicated in opening statements) that Enbridge Gas should bear all integration costs for all time, even where those costs extend into the time when customers receive the advantages and savings from integration, is inconsistent with the benefits follow costs principle. If that approach is adopted by the OEB, it could have a chilling impact on future amalgamations and on utilities committing appropriate capital resources to fully recognize available amalgamation savings. It will also operate as a discouragement to amalgamating utilities to spend any amounts classified as "integration capital" during the deferred rebasing term even if that would benefit customers on an ongoing basis. All of this flies in the face of the Minister of Energy's direction to the OEB to continue to encourage "optimal efficiency" of the distribution sector, which has been achieved in previous years through utility mergers/acquisitions.[269]

[268] Exhibit 1, Tab 9, Schedule 1, page 24.
[269] Minister of Energy Mandate Letter to the OEB, November 15, 2021, page 4. The Minister's Letter of Direction for 2022 (October 21, 2022) again encourages the OEB to help LDCs pursue efficiencies through consolidation – see page 2.

237. Based on questions asked by SEC during examination of Panel 12 during the hearing, it appears that an argument may be advanced that Enbridge Gas earned enough over allowed return on equity (ROE) during the deferred rebasing term to fund the remaining integration capital.[270] That is not the test. There are many reasons that led to Enbridge Gas earning above OEB-approved ROE during the deferred rebasing term. There is no reason or evidence to support a conclusion that all of the Enbridge Gas earnings above allowed ROE were based on synergy savings. The Company's evidence is that synergy savings almost exactly funded integration costs, with virtually no resulting excess revenues.[271]

238. In any event, had Enbridge Gas chosen to defer some or all of the integration capital projects, then it would have earned more, and it would have included some projects in its future capital plans where they would be funded by customers. Enbridge Gas did not take that approach. It implemented these capital projects in a timely manner to benefit operations and customers as soon as practical.

239. Enbridge Gas does not want to presume the intervenor argument on this topic but may offer further submissions in its Reply Argument.

2023 Additions to 2024 Opening Rate Base

240. In the Capital Update, Enbridge Gas indicates that in-service additions in 2023 total $1,428.1 million.[272] This results in an approximate increase to rate base of $1,347.6 million in 2024.[273] These figures include $343.0 million related to the Dawn to Corunna project, which is to be addressed in Phase 2.[274] The amount of 2023 in-service additions requested to be included in 2024 rate base in Phase 1 is

[270] See, for example, 14 Tr.168.
[271] Exhibit J14.11.
[272] Exhibit 2, Tab 2, Schedule 1, page 3, line 3.
[273] See Exhibit J13.15, Attachment 1.
[274] See note 1 at Exhibit 2, Tab 1, Schedule 1, page 5.

approximately $1,004.6 million.[275] This includes rate base additions related to planned 2023 integration capital expenditures of $20 million (which is a reduction from the originally filed forecast expenditure of $43.6 million).[276]

241. Details about the Company's proposed capital expenditures in 2023 are set out in the Capital Update evidence.[277] As explained, the 2023 capital budget is now $178.5 million less than originally forecast, largely because of the deferral of PREP.

242. Limited questions have been asked to obtain specific information about the Company's capital spending plans and activities during 2023.

243. There is no outstanding issue in this case about the rate base impacts of the customer additions portfolio for the years from 2014 to 2022.[278] However, the Company expects that parties may question whether the full amount of 2023 rate base additions related to customer additions should be included in 2024 rate base because of the fact that the overall PI of the 2023 customer additions investment portfolio is less than 1.0.

244. Enbridge Gas acknowledges that the Guidelines set out in Appendix B of the E.B.O. 188 Decision indicate where the PI for the all customer additions is less than 1.0 in a given year, then: (a) the utility will be required to provide a complete variance explanation in its rates case and the OEB will determine whether or not an

[275] This is equal to the rate base impact in 2024 of 2023 capital additions as noted above ($1,347.6 million) less Dawn to Coruna rate base amount of $343.0 million.
[276] See Exhibit 2, Tab 5, Schedule 3, Table 11, line 13.
[277] See Exhibit 2, Tab 5, Schedule 4 – details of the difference between the originally filed and updated 2023 capital budgets are found at pages 14 to 18. See also Exhibit 2, Tab 5, Schedule 1, pages 8-13 for a high-level discussion about 2023 to 2032 capital expenditures. Discussion of the comparison of 2022 and 2023 capital expenditures is found at Exhibit 2, Tab 5, Schedule 3, pages 28-32.
[278]As noted, the rate base amounts for capital additions up to 2022 are settled, except for integration capital.

acceptable explanation has been provided; and (b) the implications of a negative NPV or PI less than 1.0 will be determined by the OEB on a case by case basis.[279]

245. For 2023, the forecast PI for customer additions capital is 0.91. This results from the forecast costs of additions being higher than the forecast revenues from those new customers calculated in accordance with E.B.O. 188 (which is the standard currently in place). The difference between forecast costs and forecast revenues is $26.8 million.[280]

246. Enbridge Gas has provided evidence in this case as to the reasons why the customer additions investment portfolio PI has been below 1.0 in the most recent years, including 2023.[281] The Company's evidence was summarized and expanded upon by Ms. Burnham in her evidence in chief for the Capital Expenditures Panel.[282] Ms. Burnham noted the following contributing factors:

a) The costs for customer connections have increased substantially in recent years – on a simplified average basis, they have increased by about $2,000 per customer from 2019 to 2024;

    i. Contributing factors include labour inflation, municipal and conservation authority permitting, materials cost increases, supply chain disruptions, enhanced sewer safety program costs, municipal changes to restoration requirements and impacts of new soil handling regulations;

b) Costs for infill customers have been particularly challenging because Enbridge Gas has not been allowed to increase its customer contributions until its rebasing case. This is a result of the OEB's 2019 Rate Decision,

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[279] E.B.O 188 Final Report of the Board, January 30, 1998, Appendix B (OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario), section 3.3, paras. 338-341 – filed as part of Exhibit K10.5. For discussion, see 10 Tr.192-196.
[280] See Exhibit I.2.6-SEC-118, part a).
[281] Pre-filed evidence on this topic is found at Exhibit 2, Tab 5, Schedule 3, pages 16, 21 and 26, and Exhibit 2, Tab 5, Schedule 4, pages 8, 16 and 21.
[282] 11 Tr.100-103.

which held that contribution in aid of construction (CIAC) is a rate, and it cannot be changed without OEB approval.[283] Enbridge Gas was not in a position to change "rates" during the deferred rebasing term;

c) A complicating factor for Enbridge Gas has been the time gap between when estimates are made under the feasibility guidelines and CIAC is determined and the time when the projects are executed. Through the 2021 to 2023 period, inflation and construction costs have been significantly higher and changed more rapidly than in the past, leading to a gap between the forecast and actual costs to add customers; and

d) Enbridge Gas has pursued and implemented different measures to mitigate these cost pressures. There is an updated proposal for increased extra length charge for infill customers. The Company has recently completed an RFP for a construction services contract which, starting in 2024, will drive further certainty on customer attachment pricing through the next five years. Additionally, Enbridge Gas has diversified its supply chain to better manage supply shortfalls and ensure more consistent pricing.

247. In an exchange with Commissioner Duff, Ms. Burnham expanded upon the lessons learned from the Company's connection cost challenges over the past three years. Ms. Burnham confirmed some of the items noted in the final bullet above, and then noted the following:

> From a customer perspective, we are communicating with our customers that, if there are major cost changes between the time [audio dropout] and the time we go to construct, we will be coming back to talk about potential changes in an aid to construct, or not. So we will go back to the customers. We want to let them know well in advance that that's going to be happening.
>
> And then, again, just from a project execution perspective, we are watching inflation closely so that, when we do the estimates, we are including the right amount of inflation on those projects. We run the economics and we feel they will be better reflective of the time we go to construct, so, you know, I would say there is a lot of micro activity happening to drive that certainty but then a lot of macro activity

[283] EB-2018-0305, Decision and Order, September 12, 2019, pages 34-36.

> happening in terms of our contractual agreements and our supply chain.[284]

248. Enbridge Gas submits that it has provided adequate explanation as to why its PI has been below 1.0 in recent years, and the steps being taken to remedy the situation.

249. Enbridge Gas submits that this is not the extraordinary circumstance where portions of the difference between forecast costs and revenues for 2023 customer connections should be disallowed from inclusion in 2024 rate base.

250. In Table 4, Enbridge Gas sets out its investment portfolio PI for customer additions for each year from 2013 to 2023. This information was provided in the updated response to Exhibit I.2.6-SEC-118, and Enbridge Gas has now added additional columns to show the cumulative PI and cumulative difference between net cash inflow and outflow over the noted years.

[284] 14 Tr.79-80.

Table 4
Investment Portfolio PI by year

Line No.	Year	PV Cash Inflows ($ millions)	PV Cash Outflows ($ millions)	Difference ($ millions)	PI
		(a)	(b)	(c)=(a-b)	(a)/(b)
1	2014	246.1	219.8	26.3	1.12
2	2015	228.9	217.0	11.9	1.05
3	2016	243.2	224.3	18.9	1.08
4	2017	253.3	199.2	54.1	1.27
5	2018	224.3	209.2	15.1	1.07
6	2019	263.9	241.6	22.3	1.09
7	2020	265.1	250.9	14.2	1.06
8	2021	262.9	301.3	(38.4)	0.87
9	2022	290.1	312.7	(22.6)	0.93
10	2023	266.7	293.5	(26.8)	0.91
12	Total	2,544.5	2,469.5	75.0	1.04

251. As can be seen, Enbridge Gas has maintained a cumulative PI of above 1.0 for its customer attachment investment portfolio over the years since it last rebased in 2013. This means that the total amount being included in 2024 rate base for customer additions capital is forecast to be more than fully recoverable in rates, based on the feasibility tests in place at the time that the customer connections were completed. On a forecast basis, Enbridge Gas will recover around $75 million more in revenues than the associated costs for the customers added over the 2014 to 2023 period.

252. Enbridge Gas submits that it would be unfair to pick out one year in isolation and indicate that a portion of customer addition costs from that year should be disallowed, while not also giving credit for the fact that there is a “sufficiency” for other years.

253. Enbridge Gas is not aware of other areas where parties might raise specific concerns about the 2023 additions to rate base. To the extent that parties raise such concerns in their submissions, Enbridge Gas will respond in Reply Argument.

2024 Rate Base Amounts resulting from 2024 Rate Base Additions & Consequential Changes to 2024 Rate Base from Other Determinations

254. Enbridge Gas will address the 2024 capital budget under Issue 7. The Company acknowledges that changes from the as-filed 2024 capital budget will have implications for proposed 2024 rate base and the 2024 Test Year Net Property Plant and Equipment balance. Such implications will be addressed through the Rate Order process.[285]

255. Enbridge Gas acknowledges that there could also be changes to the 2024 rate base from determinations of other issues, including Issue 34 (regulated treatment of NGV) as well as issues (such as capital budget) whose determination could impact the calculation of working capital amounts for 2024. Again, these implications will be addressed through the Rate Order process.

Customer Attachment Policy

256. The OEB has identified customer attachment policy as an item of specific interest in this proceeding. In Procedural Order No. 6, the OEB identified as a matter of particular interest whether Enbridge Gas's application of the revenue horizon parameter established in E.B.O. 188 continues to be appropriate in light of energy transition.

257. Enbridge Gas observes that while there is no specific issue in Phase 1 directed at customer attachment policy, the topic does have relevance to three issues on the

[285] The implications of the OEB's Decision related to the inclusion of the Dawn to Corunna project in rate base will be reflected through the Phase 2 Rate Order process.

Issues List: Issue 3 (Consideration of Energy Transition), Issue 6 (Rate Base) and Issue 7 (Capital Budget). As part of this item, Enbridge Gas requests approval of its proposed extra length charge (ELC), which is the only unsettled part of Issue 29 (Miscellaneous Service Charges).

258. Considering that this item is likely to be dealt with by other parties as a separate item in their submissions, Enbridge Gas is also presenting its own submissions on a stand-alone basis. Enbridge Gas acknowledges that the OEB's determinations on this item may impact the Company's proposed 2024 rate base (Issue 6) and proposed 2024 capital budget (Issue 7). The capital budget implications of this item are addressed along with the other items relevant to the 2024 capital budget under Issue 7. There could also be impacts on depreciation (Issue 15).

Consequences Of Settlement Proposal

259. This item is not addressed in the Settlement Proposal.

Outstanding Approvals Required

260. Enbridge Gas seeks approval of its harmonized customer attachment policies, effective January 1, 2024.

261. Enbridge Gas also seeks approval of its proposed updated ELC.

Revenue Requirement Implications for 2024

262. The proposed revenue requirement assumes approval of the Enbridge Gas harmonized customer attachment policies on an as-filed basis.

263. If the OEB amends the revenue horizon parameter included in Enbridge Gas's proposed customer attachment policies that will impact the Company's forecast capital budget. That, in turn, will impact the 2024 revenue requirement. There could

or should also be corresponding impacts to customer connections asset lives and associated depreciation expenses.

264. Enbridge Gas has provided high-level evidence about the potential impacts on the 2024 capital budget from reducing the revenue horizon parameter.[286] Note, however, that the magnitude of these impacts on revenue requirement will be much smaller, because there is minimal test year impact from capital additions.

Evidence in Support

265. Enbridge Gas filed its proposed harmonized customer connection policies at Exhibit 1, Tab 15, Schedule 1 (including Attachment 1). The evidence about the capital costs associated with customer connections is found at Exhibit 2. The evidence about the ELC is found at Exhibit 8, Tab 3, Schedule 1, pages 10 to 13.

266. Enbridge Gas has answered follow-up questions in associated interrogatories[287], Technical Conference testimony[288], Technical Conference undertakings[289] and filed several ADR responses.[290]

267. Enbridge Gas witnesses provided testimony about customer attachments and related budget amounts at the Oral Hearing. The Customer Attachments witnesses (Panel 10) spoke about the customer attachment policy and associated costs.[291]

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[286] See, for example, Table 1 titled "Customer Connections Capital Expenditure Supported by Different Revenue Horizons ", filed at Exhibit K10.2 page 139. This presentation was expanded and corrected in Exhibit J10.11.
[287] See Exhibit I.1.15 and Exhibit I.8.3. General questions about capital budgets and rate base are found at Exhibit I.2.
[288] 3 TC Tr.41-163 (Customer Attachments) and 3 TC Tr.164-216 (Service Charges and other topics). The testimony about capital budgets and rate base are found at 4 TC Tr. 200-217, 5 TC Tr.5-203 and 6 TC Tr.1-48.
[289] Exhibits JT3.5-3.38. The undertakings from the capital panel are found at Exhibits JT4.22-4.25, JT5.1-5.47 and JT6.1-6.5.
[290] Exhibit I.ADR.1-7.
[291] 10 Tr.76-205 and 11 Tr.2-90.

The Capital Budget witnesses (Panel 11) spoke further about the 2023 and 2024 capital budgets.[292]

268. Mr. Neme, the witness on behalf of GEC and ED, included recommendations about customer connections in his report, and in his testimony.[293]

Overview

269. Enbridge Gas's harmonized customer connection policies are submitted for approval in this case. The Company's evidence meets the OEB's filing requirements and includes discussion of changes made to the policies since the last cost of service application.

270. Enbridge Gas achieved partial harmonization of its connection policies as a result of the OEB's approvals in the Company's application for System Expansion Surcharge (SES), Temporary Connection Surcharge (TCS) and Hourly Allocation Factor (HAF).[294] The balance of connection policies not addressed within that proceeding are addressed by the proposal in this proceeding, which has been developed in accordance with the principles and guidelines prescribed in various OEB reports[295] and decisions[296].

271. EGD and Union policies have been and still are subject to the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (E.B.O. 188), which provides for a common analysis and reporting framework. As a result, Enbridge Gas's proposal to harmonize these policies results in minimal change because the policies were already broadly similar.

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[292] 11 Tr.91-203, 12 Tr.1-118, 13 Tr.1-192 and 14 Tr.1-142.
[293] Exhibit M9, pages 4-6 and 42-44. See also 5 Tr.170-196 and 6 Tr.3-179.
[294] EB-2020-0094, Decision and Order, November 5, 2020.
[295] E.B.O. 188, The Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, January 30, 1998.
[296] EB-2020-0094, Decision and Order, November 5, 2020.

272. Over the course of the proceeding, it has become clear that the OEB Commissioners, and many parties, favour revisiting the revenue horizon associated with the Company's customer attachment policies. The concern that is raised is that there is uncertainty around whether new customers will remain attached in 40 years, so the revenue horizon should be revisited.

273. Enbridge Gas notes that the currently applied 40-year revenue horizon was developed through a lengthy and comprehensive E.B.O. 188 proceeding, which involved a great deal of evidence commencing with a Report of the Board, third party expert evidence, a Utilities Common Submission and submissions by many parties. Through an ADR process an agreement was established leading to an approval of the current Appendix "B" System Expansion Guidelines. By contrast, in this case the only party to provide "evidence" for a proposal other than a 40-year revenue horizon is ED/GEC (through Mr. Neme) and that evidence amounts to less than 6 pages.

274. If the OEB believes that it is appropriate to change the 40-year revenue horizon that was agreed and approved in the E.B.O. 188 case through this proceeding, then Enbridge Gas submits that a measured approach is appropriate.

275. As explained throughout the Energy Transition section of this Argument, there remains great uncertainty as to the timing and impacts of energy transition. To move immediately to a revenue horizon of 20 years or less presupposes future Government of Ontario policy and it will result in wide ranging impacts across the province with much higher connection costs for consumers and small businesses with Contribution in Aid of Construction (CIAC) amounts that may be prohibitive or that will at least lead to further cost increases and energy access issues for new housing developments that are intended to be affordable.

276. Enbridge Gas submits that no change is required from the Company's proposal. However, should the OEB take a different view, Enbridge Gas submits that maximum extent of such a change should be to reduce the revenue horizon from the current E.B.O. 188 approach of 40 years to 30 years. Any further reduction is not supported by the evidence or current Government of Ontario policy.

277. If the OEB decides that a different revenue horizon is appropriate, a change to a 30-year revenue horizon would be supportable in that would include a high-level assumption that around half of the newly attached customers will maintain gas appliances at the time that their furnace reaches end of life. This is a balanced assumption, based on limited information known now and taking into account the continued prospects for hybrid heating.

278. A change to a 25-year revenue horizon would make new connections more expensive for customers, as the CIAC would increase significantly. Enbridge Gas understands that other parties might justify this approach based on seeking alignment with the customer connection feasibility parameters for electricity customers set out in the Distribution System Code (DSC). Enbridge Gas submits that the different assets and asset lives associated with connection assets for gas and electricity connections support a different approach.

279. Enbridge Gas did not anticipate a change to the revenue horizon applicable to customer attachments when it prepared its evidence. If a reduction in revenue horizon is ordered, then there are several items that will have to be amended within the Enbridge Gas customer connection policy proposal. These include the following:
   a) Consideration will have to be given to how the Government of Ontario mandated Community Expansion Program can continue. The evidence is that it would require more than $26 million in additional subsidy funding if the revenue horizon is reduced to 25 years. One solution would be to treat the

Community Expansion Program as being subject to different (existing) customer attachment guidelines.

b) The currently proposed ELC will no longer be sufficient. Enbridge Gas may propose that a fixed CIAC would be appropriate for infill customers and/or may propose an updated ELC.

c) The currently used SES or TCS rates would likely no longer be useful. Currently they allow for up-front costs for CIAC to be spread up to a term of 40 years. The resulting amounts if the revenue horizon is shortened may make use of these rates unlikely.

d) There may be a need for a new variance account to cover the uncertainty around the number of customer connections and associated capital costs under a shorter revenue horizon.

e) It may be necessary to make changes to the Company's current depreciation proposal. As set out at Exhibit J13.6, the plant accounts (assets) associated with customer connections have asset lives that are generally 40 years or more. It does not make sense to assume that new customers will remain for substantially less time than the asset lives associated with the connection assets.

f) Enbridge Gas will require some time to fully implement a change to a shorter revenue horizon. Commitments and/or guidance have been provided to new customers as to the amount of their CIAC for upcoming new connections. Time will be required for system changes to implement new feasibility determinations. Enbridge Gas proposes, therefore, that any new customer attachment policy should apply on a prospective basis, for any new customers who approach the Company from and after January 1, 2025, and that currently planned additions be exempt from the new rules. As described below, a later date may be necessary. For example, it may take longer for implementation of new ELC and/or SES or TCS charges or other treatment of infill customers that would have to be approved by the OEB through a follow-up process.

Enbridge Gas Proposed Harmonized Customer Connection Policies

280. Enbridge Gas's customer connection policies have been designed to facilitate the rational expansion of the natural gas system. Adherence to these policies will ensure that system expansion projects meet all financial compliance requirements and will not result in undue cross subsidization.[297]

281. On the topic of cross subsidization, Enbridge Gas takes issue with the suggestion by Mr. Neme (taken from his testimony but not mentioned in his report) that the difference between the up-front cost to connect a customer and the immediate revenues from that customer constitutes a subsidy.[298] That is not the proper way to look at this item. As the OEB has said for many years, there is no cross-subsidization where the PI is above 1.0 and costs are collected over time. Ms. Giridhar explained this in testimony:

> The OEB has ruled in numerous occasions that applying E.B.O. 188's prescribed feasibility guidelines and ensuring the attachment of customers on an average PI of 1.0 would ensure that the incremental revenues generated from an expansion will, over time, cover the costs of the expansion and not result in a subsidy from existing customers to new customers.
>
> On the other hand, requiring new customers to pay their full connection costs upfront and pay the distribution charge regulated by the Board we believe would result in a cross-subsidy from new customers to existing customers.
>
> So I just wanted to emphasize, you know, how we look at the word "subsidy" here. There is in fact no instance in Ontario where gas or electric customers are required to pay their full connection costs upfront, and pay the same distribution charges as existing customers.[299]

282. Indeed, Enbridge Gas customers have benefited for many years by the addition of new customers to the system. As shown in evidence, the rolling PI of customer

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[297] Exhibit 1, Tab 15, Schedule 1, page 1.
[298] See, for example, Exhibit M9, pages and 6 Tr.90, 116 and 135.
[299] 10 Tr. 81-82.

additions over time is above 1.5.[300] This means that new customers have consistently lowered the cost of service for all customers.[301] If anything, new customers have cross-subsidized existing customers over time.

283. Enbridge Gas's customer connection policies include the method of feasibility assessment[302], minimum profitability standard and portfolio approach[303], feasibility assessment inputs[304], and the CIAC collection, allocation, and refund policy.[305] The evidence also describes the SES, TCS and HAF mechanisms used by Enbridge Gas[306] and the proposed updated ELC[307].

284. As described in evidence, the Company's customer connection policies are consistent with OEB direction in past proceedings. In particular, Enbridge Gas continues to recognize and apply the customer connection feasibility guidelines prescribed in the E.B.O. 188 report.

285. The intent and implication of the OEB's E.B.O. 188 report was summarized in the OEB's Decision in the 2016 Generic Proceeding on Community Expansion as follows – "[t]he E.B.O.188 guidelines provide for economic growth of the natural gas distribution system with limited cross subsidies to some projects within a portfolio in any given year."[308] In that case, the confirmed the continued application of E.B.O. 188, noting that it "functions well" except in the case of discrete new areas that are not contiguous to the existing distribution system.[309]

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[300] Exhibit I.2.6-SEC-118 part b).
[301] 10 Tr. 82 and 10 Tr.141.
[302] Exhibit 1, Tab 15, Schedule 1, pages 3-5.
[303] Ibid, page 5.
[304] Ibid, pages 6-8.
[305] Ibid, pages 8-10.
[306] Ibid, pages 11-13.
[307] Ibid, page 11 and Exhibit 8, Tab 3, Schedule 1, pages 10-13.
[308] EB-2016-0004 Decision with Reasons, November 17, 2016, page 17 – Included at page 76 of Exhibit K10.2.
[309] EB-2016-0004 Decision with Reasons, page 18 – Included at page 77 of Exhibit K10.2.

286. Mr. Macpherson explained how Enbridge Gas applies (and proposes to continue to apply) the E.B.O. 188 Guidelines:

> So, in the E.B.O. 188, prescribed feasibility analysis determines whether a new customer, or a project attachment or expansion, meets financial requirements. This is done by evaluating project revenues and costs and discounting them at the company's after-tax, weighted-average cost of capital. The output of a feasibility analysis is the profitability index, or PI, which measures the value of a project's revenues against its costs.
>
> A PI of 1 or greater indicates that a project's revenues over its life cycle of 40 years will be equal to or greater than the cost, and validates that a project is feasible and the associated customers can be connected without the need to charge a contribution in aid of construction, CIAC. When the PI is less than 1, Enbridge Gas's customers cover the shortfall by one of the current OEB-approved methods, as determined by Enbridge Gas. These are by paying an up-front CIAC to lower the capital costs sufficient to bring the PI up to 1, or to pay a volumetric surcharge, which is a system expansion surcharge or a temporary connection surcharge, at a rate $0.23 per cubic metre for a predefined term up to 40 years, which is determined based on the number of years required to achieve PI of 1. Enbridge Gas applies the 40-year revenue horizon consistently for all residential customers because this is what E.B.O. 188 requires. There is no discretion allowed or prescribed.
>
> The last point: The customer attachment horizon of 10 years, is prescribed by the OEB at paragraph 3.3.2 of 188 maximum, and Enbridge Gas applies the customer forecast in that manner. For instance, in a typical subdivision project, we may have an attachment period of three to five years based on the known plans of subdivision connections and developers and municipal plans. So we use this 10-year period at our discretion, based on the information at hand.[310]

287. Two key takeaways are that Enbridge Gas uses a 40-year revenue horizon to calculate feasibility and uses a customer attachment horizon of up to 10 years. A shorter revenue horizon is used for attaching large customers (either 20 years or such lower timeframe as the customer requests, to align with their contract).[311]

288. There was a lot of discussion during the hearing as to whether the use of a 40-year revenue horizon (or a 10-year customer attachment horizon) is "mandatory" under

[310] 10 Tr.79-81.
[311] See 10 Tr.151-152 and 11 Tr.48.

the E.B.O. 188 Guidelines.[312] Enbridge Gas takes the position that the 40-year revenue horizon is mandatory, based on the wording of Section 2.2(b) of the Guidelines found at Appendix B to the E.B.O. 188 report. That provision says that a "specific parameter" is "a customer revenue horizon of 40 years from the in-service date of the initial mains".[313] Section 2.2.2 of the Gas Distribution Access Rule (GDAR) states that a gas distributor shall assess expansion to its gas distribution system in accordance with the Guidelines contained in the E.B.O. 188 report.[314]

289. However, the Company submits that the question of whether these timeframes are mandatory or not under E.B.O. 188 Guidelines is not an item that the OEB must decide. That being said, Enbridge Gas takes the view that if the OEB prescribes a different revenue horizon, then the OEB would be effectively amending or updating the E.B.O. 188 Guidelines in this proceeding. That would require a change to the wording of Section 2.2.2 of the GDAR which currently requires compliance with the E.B.O. 188 Guidelines.

290. Enbridge Gas 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. However, there are a couple of process-type questions that the OEB should answer before doing so.

291. The OEB should assess whether there is a full and sufficient record in this proceeding to make changes to the long-standing principles and directions determined in E.B.O. 188. That process involved a wide range of stakeholders, many of whom submitted evidence and proposals for consideration.[315] The outcome

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[312] See, for example, 10 Tr.92-98.
[313] E.B.O. 188 Report, Appendix B, Section 2.2 (b) - Included at page 51 of Exhibit K10.2. The words "up to 40 years" are not used in the Guidelines.
[314] GDAR, section 2.2.2 – Included at page 138 of Exhibit K10.2.
[315] According to the Enbridge Gas records, there were 24 intervenors participating in the E.B.O. 188 proceeding, and of those 13 parties filed evidence.

was the product of two separate ADR processes where all of the various evidence and proposals were taken into account.

292. In the recent Elexicon/Sustainable Brooklin Decision, the OEB made clear that it will not lightly depart from established rules such as those set out in the DSC and must take the current policies of the Government into account.[316]

293. In this case, the only proposal in evidence for a change to the revenue horizon is the evidence from Mr. Neme. That evidence amounts to a total of six pages or less and apparently is not definitive – in his report, Mr. Neme suggests a revenue horizon of 15 years[317], but then stated in testimony that a different (shorter) revenue horizon might be better[318]. Mr. Neme did not look at the implications of other potential different revenue horizons, including alignment with electric distributors who have a 25-year revenue horizon. He admitted that he is only tangentially familiar with E.B.O. 188 and is not an expert on connection policies.[319] Mr. Neme completed his analysis on a conceptual level, and did not engage with any HVAC contractors, electricity distributors, builders, businesses, or prospective customers to understand the impact of these proposed changes nor did he engage with current Enbridge Gas customers to assess their intention to electrify and leave the system.

294. In other contexts where Enbridge Gas is requesting approval of new methodologies in this rebasing case, the Company presented discussion and evaluation of alternatives. In some of these cases, expert evidence was provided.[320] As Enbridge Gas is not seeking a fundamental change to its customer attachment policies, it did not prepare and provide such evidence to support a full examination of the wide

[316] EB-2022-0024 Decision and Order – Phase 2, July 6, 2023, pages 2 and 23-24.
[317] See Exhibit M9, pages 4-5 and 43.
[318] 6 Tr.116.
[319] 6 Tr.149.
[320] For example, there is the Guidehouse Report on alternate forecasting methodologies and the Concentric report on depreciation.

range of potential options and impacts if the longstanding (and recently OEB-endorsed) E.B.O. 188 customer attachment policy is to be changed.

295. Given the lack of evidence about proposals for different customer attachment parameters, the OEB could fairly determine that this question is better addressed in a separate subsequent process, particularly where the question being addressed goes beyond revenue horizon alone. There are broad implications from changing the customer attachment parameters, including likely disabling impacts for the Government's Natural Gas Expansion Program [321], higher costs for development of new housing and unanswered questions about whether there is electricity system capacity for customers who may not choose to connect to the gas system for building heat and other purposes.[322]

296. The OEB should also consider whether changes to the customer attachment policy, which effectively amends E.B.O. 188, can be made without also changing the GDAR. As noted above, Section 2.2.2 of the GDAR specifically directs gas utilities to follow the E.B.O. 188 Guidelines in attaching customers (and reporting on customer attachments). Taking that into account, if the OEB is seeking to change customer attachment parameters, it may be more appropriate to do this through a rulemaking process which would also see changes to the GDAR.

297. In a recent decision in the OEB's hearing to consider questions raised by Ontario natural gas producers,[323] the OEB recognized that under recent changes to the OEB Act, rule-making authority rests with the Chief Executive Officer of the OEB rather than with Commissioners:

> As a general proposition, a panel of Commissioners does not have jurisdiction to create, amend or revoke rules relating to "establishing conditions of access to transmission, distribution and storage services

[321] 10 Tr.86.
[322] This was discussed with Mr. Neme – see 6 Tr.48-50. See also the testimony from Ms. Giridhar at 11 Tr.6.
[323] EB-2022-0094.

> provided by a gas transmitter, gas distributor or storage company" pursuant to section 44 of the OEB Act. Rule making authority is assigned to the Chief Executive Officer under section 44 the OEB Act and the process for making section 44 rules is set out in section 45 of the OEB Act.[324]

298. Taking this into account, the OEB may determine that it is appropriate for all issues related to changes to E.B.O. 188 parameters and corresponding changes to the GDAR to be determined together in a rulemaking proceeding.

Enbridge Gas Preliminary Response regarding Reduction of Revenue Horizon

299. In Procedural Order No. 6, the OEB asked Enbridge Gas to consider whether Enbridge Gas's application of the revenue horizon parameter established in E.B.O. 188 continues to be appropriate in light of energy transition.[325]

300. Enbridge Gas questions whether there is a sufficient evidentiary record to conclude that a different revenue horizon is appropriate and to also determine and specify the appropriate new revenue horizon. Enbridge Gas observes that reductions to the revenue horizon will run counter to the existing principles applied by the OEB to enable access to the gas system and ensure affordability for customers.

301. Enbridge Gas submits that any reduction in the revenue horizon should balance the interests of existing customers and new customers. Specifically, any reduction in the revenue horizon must strike the appropriate balance between the needs of existing and new customers in the context of the Government's policies, such as the Natural Gas Expansion program, the *More Homes Built Faster Act*, and the affordability concerns that have been raised both in the Powering Ontario's Growth Report as well as the Minister of Energy's response letter to Ms. Harradence.[326]

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[324] EB-2022-0094, Decision and Procedural Order No. 3, November 17, 2022, pages 14-15.
[325] Procedural Order No. 6, June 23, 2023, page 6.
[326] 6 Tr.88. See Exhibit J8.1, Attachment 1, for a copy of the letter.

302. As explained throughout the Energy Transition section of this Argument, there remains great uncertainty as to the timing and impacts of energy transition. To move immediately to a revenue horizon of 20 years or less presupposes future Government of Ontario policy. This change will make new connections much more expensive, with CIAC amounts that may be prohibitive or that will at least further increase the cost of new housing, which is intended to be affordable. There is also a potential issue with a significant mismatch between the customer attachment revenue horizon assumptions and the depreciation value for customer attachment capital.[327]

303. Customer attachments assume that the customer will be initially connected to the gas system. It is fair to assume that such new customers will have new gas appliances. For the purpose of determining the appropriate revenue horizon (that is the assumption of how long the customer will remain a gas customer), a key question is what will prompt the customer to leave the gas system.[328] Mr. Neme agrees that an appropriate way to look at this is to consider what a customer will do at the time that it comes time to replace their furnace and/or water heater (the most expensive gas appliances).[329]

304. Enbridge Gas submits that determining a revenue horizon other than 40 years therefore requires the OEB to make findings or assumptions about customer behaviour in 18 to 20 years from now (equating to the lifespan of a furnace). It is difficult to make any conclusion on that question at this time. There is no Government policy in Ontario mandating a switch away from gas heating. Enbridge Gas has provided evidence from Guidehouse about a diversified pathway that would see customers continue to be attached to gas. Enbridge Gas has also explained how a hybrid heating solution could grow in popularity, where customers would

[327] 11 Tr.41-42.
[328] 6 Tr. 87.
[329] 6 Tr.42-43.

remain connected to natural gas for peak heating requirements.[330] Recent experience in Québec (an already electrified jurisdiction) shows the potential for continued use of gas in a hybrid heating context.[331]

305. In Examination in Chief, Ms. Giridhar spoke about how one might consider an appropriate revenue horizon, with reference to a customer's future behaviour.[332] In Table 5, Enbridge Gas sets out how different revenue horizons might be determined, based on what assumptions are made around customer choices at the time that they are faced with equipment replacement decisions.[333] As can be seen, even if one assumes that only 50% of customers replace their gas appliances at end of life, that still equates to an average 30 year term where a customer is connected (and that is assuming that not a single customer remains on the system after 40 years).

Table 5
Impact on Customer Revenue Horizon based on Equipment Replacement Assumptions

Customers Renewing at Equipment End of Life	Years of Revenue		Blended Revenue Horizon
	Yrs. 1-20	Yrs. 21-40	
100%	20	20	40
75%	20	15	35
50%	20	10	30
25%	20	5	25
10%	20	2	22
0%	20	-	20

Note - Assumes 20-year equipment life

306. Enbridge Gas submits that no change is required from the Company's proposal. However, should the OEB take a different view, Enbridge Gas submits that the

[330] See discussion above, in the Energy Transition section of Argument. See also 10 Tr. 178-179.
[331] See also "Hybrid heat in Québec: Energir and Hydro-Québec's collaboration on building heat decarbonization", found at Exhibit K6.1, pages 39-44. This was discussed with Mr. Neme in cross-examination: 6 Tr.32-35.
[332] 10 Tr.87-88.
[333] Exhibit K10.2, page 140.

outside bounds for a change to the revenue horizon would be for the current E.B.O. 188 approach to be shortened from 40 years to 30 years.[334]

307. As can be seen in Table 5 a change to a 30-year revenue horizon would include a high-level assumption that around half of newly attached customers will maintain gas appliances at the time that their furnace reaches end of life. If the OEB decides that a different revenue horizon is appropriate, then estimating that no more than half of customers will convert away from natural gas is a balanced assumption, based on limited information known now and taking into account the continued prospects for hybrid heating.

308. A change to a 25-year revenue horizon implies that only one quarter of customers would maintain gas appliances at the time that their furnace reaches end of life. There is no evidence to support such a conclusion. In terms of impacts, a change to a 25-year revenue horizon would make new connections more expensive for customers, as the CIAC would increase significantly. The evidence is that a typical new customer will see their CIAC increase by $1,140.[335]

309. Enbridge Gas understands that that other parties might justify a 25-year revenue horizon based on seeking alignment with the customer connection feasibility parameters for electricity customers set out in the DSC.[336] In response, Enbridge Gas notes that there are valid reasons for different treatment. Enbridge Gas submits that there is no unfairness between these policies which are similar in nature, but which reflect the forecast useful life of electricity and gas distribution assets.[337] The DSC was established approximately 2-years after E.B.O. 188. Presumably, there was full awareness of the differences in approach to revenue horizon at the time that

[334] This was discussed by Ms. Giridhar at 11 Tr.88-89.
[335] Exhibit J10.11.
[336] See Distribution System Code, Appendix B.
[337] Note that the Decision in the Elexicon/Sustainable Brooklin case referred to a 27-year useful life for assets - EB-2022-0024 Decision and Order – Phase 2, page 9.

different parameters were adopted, and the OEB accepted that different treatment was warranted. And presumably the OEB was aware of the differences between E.B.O. 188 and the DSC when it recently confirmed the appropriateness of Enbridge Gas applying E.B.O. 188 parameters (in the Community Expansion and SES/TCS/HAF proceedings).[338]

310. Enbridge Gas expects that other parties will have extensive arguments about proposed changes to the revenue horizon that should apply to feasibility assessments for new customer connections. Rather than speculating about what may be said, Enbridge Gas will provide its responses in Reply Argument.

311. Enbridge Gas did not anticipate a change to the revenue horizon taken from E.B.O. 188 and applicable to current customer attachments policy when the Company prepared its evidence. If a change is ordered, then there are several items that will have to be amended within the Enbridge Gas proposal.

312. First, it is very likely that the Government of Ontario mandated Natural Gas Expansion Program will not succeed with a shorter revenue horizon unless the amount of government subsidies increase. Enbridge Gas calculates that if the revenue horizon is reduced to 30 years, the current Government of Ontario subsidy would have to increase by around $26 million for currently approved projects.[339] This would require a change in the Expansion of Natural Gas Distribution Systems Regulation under the *OEB Act*, which sets out the approved subsidy amounts for approved community expansion projects.[340] It should be noted here that Enbridge

[338] EB-2016-0004 Decision with Reasons, page 18 and EB-2020-0094 Decision with Reasons, November 5, 2020, at pages 18 and 24.
[339] 10 Tr.86.
[340] Government of Ontario. (2023 March 10). O. Reg. 24/19: EXPANSION OF NATURAL GAS DISTRIBUTION SYSTEMS. https://www.ontario.ca/laws/regulation/190024

Gas is currently in the process of working on 22 community expansion projects that were awarded in Phase 2 of the Government's Natural Gas Expansion Program.[341]

313. Additionally, customers in the Government of Ontario mandated Natural Gas Expansion Program projects pay their CIAC through an SES charge, which recovers the additional costs over a long period of time.[342] Generally, the SES is charged over a period of up to 40 years.[343] If the revenue horizon is changed, and the time to pay the SES is reduced, then the amount of the charge will have to go up making it more likely that eligible customers will decide not to convert to natural gas, putting the success of the Natural Gas Expansion Program at further risk.

314. One solution would be to treat the Community Expansion project as being subject to different customer attachment guidelines, perhaps by retaining the current 40-year revenue horizon. Again, however, there is no evidence about how this would be accomplished. Any such change would likely have to be addressed in the GDAR, where Section 2.1.1 requires Enbridge Gas to provide gas distribution services in a non-discriminatory manner.[344]

315. Second, the proposed ELC will not be sufficient to cover revenue shortfalls for infill customers where feasibility is determined using a shorter revenue horizon. Enbridge Gas will have to recalculate the ELC and may also propose that an additional CIAC would be appropriate for infill customers (to cover any revenue shortfall not covered by the ELC). Enbridge Gas estimates that on average, if a 30-year revenue horizon was used instead of 40, each infill customer would have to pay $2,500 in CIAC to

[341] 11 Tr.11. The phase 2 projects are noted at https://www.ontario.ca/page/natural-gas-expansion-program
[342] EB-2020-0094 Decision and Order, page 7.
[343] Exhibit JT3.5.
[344] GDAR, Section 2.1.1.

cover their cost to connect to the gas system, because the currently proposed ELC would be insufficient.[345]

316. Of course, the magnitude of the required changes to ELC and/or CIAC for infill customers will vary depending on different required revenue horizons.[346] Enbridge Gas has provided preliminary information as to how infill customers would be charged much higher ELCs for connection in the context of different revenue horizons in Exhibit J10.7. The much higher ELC would likely lead Enbridge Gas to reassess the suitability of the ELC approach and propose alternative methods for review and approval by the OEB. Alternatives include a straight fixed charge, a per metre charge that would apply to the entire service length, a combination of these or a full feasibility analysis for each infill service based on estimated costs and revenues to determine a CIAC. The examples provided by Enbridge Gas show that a standard fixed charge for infill customers could be around $2500 to $3000 with a 25 to 30 year revenue horizon. Once the Company determines an appropriate proposal, it would be appropriate to undergo additional customer engagement before filing with the OEB for final review and approval.[347]

317. Third, there is uncertainty as to the level of customer attachments that will result from a shorter revenue horizon. Enbridge Gas has provided forecasts of reductions to capital costs on the assumption that all forecast customers still attach but pay a CIAC.[348] Some customers may choose not to attach because of a high CIAC. This will impact the customer-attachment related capital costs. Should the OEB reduce the revenue horizon used for determining customer attachment feasibility, Enbridge Gas submits that it may be appropriate to introduce a deferral or variance account. A deferral or variance account could address the uncertainty the Company has with

[345] 10 Tr.85.
[346] 10 Tr.134.
[347] Exhibit J10.7. See also 10 Tr.135-137.
[348] Exhibit J10.11.

regards to how customer behaviour would be impacted by a change to the revenue horizon and the associated impacts it would have on required contributions in aid of construction. A change in the revenue horizon could impact the level and/or mix of customer additions that would occur, which in turn could impact actual versus forecast capital requirements and revenues. As such, the deferral or variance account could potentially track variances in customer attachment costs and revenues relative to what is reflected in 2024 rates. A change to the revenue horizon would also result in implementation costs[349], which could be tracked in a deferral or variance account.[350]

318. Additionally, it may be necessary to make changes to the Company's current depreciation proposal. As set out at Exhibit J13.6, the plant accounts (assets) associated with customer connections have asset lives that are generally 40 years or more. It does not make sense to assume that new customers will remain for substantially less time than the asset lives associated with the connection assets. Implications of this issue are described in Exhibit J18.5.

319. Finally, Enbridge Gas notes that it will require some time to fully implement a change to a shorter revenue horizon. The time required will depend in part on the magnitude of the changes directed by the OEB.

320. There will be a large number of systems and operational changes that will need to be implemented to reflect a new revenue horizon approach into the Company's customer feasibility calculations and determinations. These are described in detail at Exhibit J10.13. This process cannot start until the OEB's Decision is received and, in the case of infills, until the OEB's Decision on a new ELC or other similar charge is received. Enbridge Gas suggests that as a preliminary estimate, it is reasonable to

[349] As described at Exhibit J10.13.
[350] Exhibit J10.12. See also 6 Tr.85 and 6 Tr.187-190.

expect that implementation could be ready within 12 months of an OEB Decision – tentatively stated here to be an implementation date of January 1, 2025.

321. Commitments have been made and/or information has been provided to new customers as to the amount of their CIAC, if any. The customers have made plans on that basis. Builders and developers have sold homes and condominiums based on an understanding of their costs to connect to the distribution system. Businesses including design build companies also operate on similar assumptions and rely on Enbridge Gas's offer to connect in the establishment equipment selection and ultimately pricing. The same is true of infill customers. It would not be appropriate or fair to change the rules for committed customers and require a new or increased CIAC.[351]

322. As noted, the time required for implementation of a new customer attachment policy will depend in part on the magnitude of the changes directed by the OEB. Enbridge Gas's current proposal is that any new customer attachment policy should apply on a prospective basis, for any new customers who approach the Company with a new connection request from and after January 1, 2025. However, implementation could take longer. For example (and this is not meant to be an exhaustive list), it may take longer for implementation of new ELC and/or SES or TCS charges or other treatment of infill customers that would have to be approved by the OEB through a follow-up process. Should Enbridge Gas require a later implementation date, it would make a request to the OEB.

323. Customers who have requested service in writing, received commitments and/or indications about CIAC requirements (or lack thereof) for new connections prior to that date should be subject to the existing rules even if the connection is not

[351] Exhibit J10.13.

completed until after January 1, 2025 (or such later date as the new policies come into effect).

Enbridge Gas Preliminary Response regarding Other Amendments to Customer Attachment Policy

324. In addition to reductions to the revenue horizon that might be reflected in Enbridge Gas's customer attachment feasibility calculations, it appears from the questions asked at the hearing that parties may propose other amendments to the Enbridge Gas customer attachment policy. Items noted include consideration of what costs to include in feasibility assessment[352], assessment of the proper amount of revenues (related to customer volumes) to include in feasibility assessment[353], different customer connection horizon[354], deposits from connecting customers[355] and exit fees[356].

325. One suggestion that was made during the Oral Hearing was that new customers might be treated entirely separately with their own rate.[357] While Enbridge Gas will wait to see whether this proposal is endorsed by any parties, the Company does want to offer a couple of preliminary responses. First, this proposal is not consistent with usual accepted ratemaking principles (such as postage stamp rates), nor with Section 2.1.1 of GDAR, which indicates that "[a] gas distributor shall provide gas distribution services in a non-discriminatory manner". Second, both the creation and the administration (financial and asset tracking) of such a rate would be immensely complex. There is no evidence as to whether this is even feasible.

[352] See, for example, 6 Tr.100-113.
[353] 10 Tr.181-185.
[354] 10 Tr.91 and 137.
[355] 10 Tr. 138-139.
[356] 10 Tr.173 and 11 Tr.46-47.
[357] See, for example, questions from Commissioner Moran at 11 Tr.74.

326. In any event, there is no evidence from other parties as to what exactly they will propose, nor as to the implications of such changes.

327. Enbridge Gas will respond to intervenor positions and proposals in Reply Argument. As part of that response, Enbridge Gas will likely point again to the concern that there is an insufficient record upon which the OEB can evaluate the implications of proposed changes and what other options might exist.

<u>Overhead Capitalization</u>

328. Issue 8 – Are the proposed harmonized indirect overhead capitalization methodology and proposed 2024 overhead amounts appropriate?

<u>Consequences Of Settlement Proposal</u>

329. While the parties resolved most aspects of proposed 2024 rate base in the Settlement Proposal, there was no agreement reached in respect of the proposed overhead capitalization methodology (O/H Methodology) and proposed 2024 overhead amounts.

330. The Settlement Proposal deals with overhead capitalization issues in several places. First, under Issue 12, which relates to 2024 operating and maintenance expenses, the Settlement Proposal states:

> Parties agree to an overall O&M budget envelope as follows.
>
> The 2024 as-filed O&M budget, net of overhead capitalization and exclusive of DSM costs set and approved in the EB-2022-0002 DSM Framework proceeding, will be reduced by $50 million to $821 million. Applying Enbridge Gas's proposed overhead capitalization methodology, this adjustment results in a gross O&M budget of $1,113 million, exclusive of DSM-related amounts, which represents a reduction in the gross O&M budget of $68 million. Capitalized overhead is consequently reduced to $292 million, which represents a $18 million reduction from the as-filed amount. The net O&M budget, after $292 of overhead capitalization, is $821 million ("Net O&M Budget").
>
> Parties agree that this gross O&M budget is reasonable in the context of a proposed capital budget (before updates) of $1,491 million.

> It will be open for Parties to argue that a different capitalized overhead amount would be appropriate if a different overhead capitalization methodology is approved and/or if a different capital budget is approved. In the event that the OEB approves a capitalized overhead amount that is different from $292 million, all Parties agree that any resulting adjustment of the O&M budget envelope to account for the reduced/increased portion of gross O&M being recovered as capitalized overhead is an item for Parties to argue and the OEB to consider. Other than as set out in this paragraph and in relation to NGV (see below), the settled Net O&M Budget envelope of $821 million (exclusive of DSM) is not subject to adjustment.[358]

331. In the Settlement Proposal at Issue 13, which deals with 2024 proposed compensation related costs, the parties agreed as follows:

> As Issue 7 and 8 remain unsettled, in the context of a different capitalization methodology and/or different capital budget it remains open to Parties to argue the appropriateness of, a) compensation related costs directly assigned to capital, and b) the compensation related costs that are included in the $292 million in overhead capitalized amount based on Enbridge Gas's proposed capitalization methodology.[359]

332. In respect of Issue 14, which relates to proposed shared services and corporate service costs, the Settlement Proposal, reads:

> As part of the settlement of the overall net and gross O&M budget amounts, Parties agree that there is no remaining issue to be determined in relation to 2024 proposed shared services and corporate services costs. As the Parties have agreed to an overall adjustment to O&M, there is no specific agreement to the proposed CFCAM, but Parties accept the total O&M amounts noted in Issue 12.
>
> As Issue 7 and 8 remain unsettled, it remains open to Parties to argue, in the context of a different capitalization methodology and/or different capital budget, the appropriateness of, a) shared services and corporate service costs directly assigned to capital, and b) the shared services and corporate service costs included in the $292 million in overhead capitalized amount based on Enbridge Gas's proposed capitalization methodology.[360]

333. Finally, under Issue 6, which asks if the 2024 proposed rate base is appropriate, the Settlement Proposal includes the following paragraph:

> Parties also agree that the acceptance of overhead capitalized amounts

[358] Exhibit O1, Tab 1, Schedule 1, pages 30-31.
[359] Ibid, page 32.
[360] Ibid, page 33.

> in Incremental Capital Module (ICM) projects being included in 2024 opening rate base is without prejudice to the rights of Parties to argue in the future, including in Phase 2 of this proceeding when the proposed IRM plan is reviewed and in any future Leave to Construct (LTC) proceedings, that overhead capital amounts should not be included, in whole or in part, in ICM amounts. In making such arguments, Parties are free to refer to and rely on any information and evidence on previous ICM projects, notwithstanding their acceptance of those amounts in 2024 opening rate base.[361]

334. The result is that there is no settlement in respect of the proposed O/H Methodology, nor the amounts proposed to be capitalized.

Outstanding Approvals Required

335. Enbridge Gas requests approval of its O/H Methodology and resulting capitalized overhead amounts for the 2024 Test Year. As the O/H Methodology was implemented January 1, 2020, the resulting impact of the use of the harmonized methodology through 2023, in comparison to the overhead capitalization methodologies employed by EGD and Union, have been recorded in the Accounting Policy Changes Deferral Account (APCDA) which was approved in the MAADs proceeding. The amounts recorded in the APCDA arising from the implementation of the O/H Methodology are dealt with under Issue 33 which deals with the proposal to dispose of balances in certain deferral and variance accounts.

336. Enbridge Gas also requests approval for the inclusion of $292 million of overhead capitalized amounts in the OEB approved capital budget for the Test Year. With OEB approval for this amount being included in the capital budget, there would be no need to change net O&M which is settled at $821 million. If, however, the full $292 million of proposed overhead capitalized amounts is not approved for inclusion

[361] Exhibit O1, Tab 1, Schedule 1, page 25.

in the approved capital budget, the difference will need to be added to the net O&M total of $821 million.[362]

Revenue Requirement Implications for 2024

337. The O/H Methodology as approved by the OEB will result in a rate which when applied to forecast O&M will generate the amount of overhead costs that will be added to future projects that are rate based. However, should the OEB require changes to the O/H Methodology such that the amount of overhead costs proposed to be capitalized is revised, the net O&M figure of $821 million will need to be adjusted to account for the change. As a simple example, if the OEB approves an overhead capitalization of $280 million, which is a reduction of $12 million from that proposed by the Company, the net O&M will need to be increased by $12 million to $833 million. A more detailed indication of the revenue requirement changes that would be required if overhead capitalization amounts are reduced from what is proposed is included in the response by the Company at Exhibit J16.3.

Evidence in Support

338. Enbridge Gas has filed detailed evidence about its proposed O/H Methodology at Exhibit 2, Tab 4. This evidence includes an overhead capitalization study undertaken by Ernst & Young LLP (EY), a firm with expertise and experience reviewing and providing utilities with advice in respect of overhead capitalization methodologies. This study is found at Exhibit 2, Tab 4, Schedule 2, Attachment 1.

[362] Note that the Capital Update did not reflect the adjustment that needs to be made to the capitalized overhead ($18 reduction, to a total of $292 million) based on the agreed upon O&M budget envelope under the Settlement Proposal and the application of Enbridge Gas's proposed overhead capitalization methodology.

339. Enbridge Gas answered follow-up questions in associated interrogatories,[363] Technical Conference testimony,[364] Technical Conference undertakings[365] and filed several ADR responses[366].

340. Enbridge Gas witnesses provided testimony about this issue on Days 15 and 16 of the Oral Hearing (Panel 14).[367]

341. There is no intervenor evidence on this issue.

Overview

342. As noted by Company witness, Mr. Healey, it is common practice by regulated utilities to capitalize a portion of their operating and maintenance expense.[368] This is simply a reflection of the fact that some of the overhead costs incurred by a utility indirectly support the utility's capital projects and should therefore be allocated to such projects. EGD has had approval for its O/H Methodology going back to the 1999rates application. EGD received subsequent approvals for its methodology including at its 2014 to 2018 IRM application.[369] Union has similarly received approvals from the OEB for its overhead capitalization methodology.[370]

343. It should be recalled that the OEB has approved overhead capitalizing methodologies for regulated utilities in the province for decades. Given this and prior OEB approvals specifically for EGD and Union, Enbridge Gas submits that the indirect overheads which support capital projects should continue to be allocated to

[363] Exhibit I.2.4
[364] 4 TC Tr.2-198.
[365] Exhibits JT4.2, JT4.19, and JT4.21.
[366] Exhibit I.ADR.34 and 35.
[367] 15 Tr.116-191 and 16 Tr.2-67.
[368] 15 Tr.116.
[369] E.B.R.O. 497 Decision, Issue 3.8; EB-2011 0354, Settlement Agreement, Issue B.1 and Issue D.1; EB-2012-0459, OEB Decision pages 30-33 and 41-51.
[370] EB-2005-0520 Settlement Agreement, Issue 3.11; EB-2011-021, Settlement Agreement, Issue 3.1.

capital projects as they are and continue to be part of the cost to complete capital projects.

344. With the amalgamation of the legacy utilities, given the differences between the OEB-approved overhead capitalization methodologies for the two utilities, it became a practical necessity to develop a harmonized approach. This will ensure that like costs are treated the same way. The Company's goal was to develop a methodology which benefited from the best practices of the prior methodologies and to make adjustments to ensure a better link between indirect costs incurred and capital activity.[371]

345. To assist in the development of a harmonized approach, Enbridge Gas retained EY to provide advice and recommendations based upon its experience and expertise in respect of the review and development of overhead capitalization policies. EY's report entitled Enbridge Gas Inc.: Overhead Capitalization Study dated May 15, 2020, is filed at Exhibit 2, Tab 4, Scheduled 2, Attachment 1. With the assistance of EY, Enbridge Gas developed the proposed O/H Methodology which is included in evidence.

Overhead Capitalized Costs

346. As noted by EY, overhead costs that can be linked to the creation of capital relate to spending that supports the production or construction of an asset but cannot be directly associated with any particular asset or project, are appropriate to capitalize. Overhead costs include, as an example, the time spent by managers and supervisors involved in supporting multiple projects but cannot track time to specific projects due to the volume of the projects they support. These expenses are also the result of the supervision and administration of activities that are charged directly to capital projects because the support functions enable various departments that

[371] A comparison of the legacy methodologies is set out at Exhibit 2 Tab 4 Schedule 2, pages 14-16.

perform the capital function to complete their work. As noted in the response to Exhibit J16.3, the Company requires support function resources to manage the thousands of concurrent and often multi–year capital projects that are undertaken. This includes the initiation, feasibility, planning, approval, design, permitting, stakeholder and customer engagement, construction, governance, supervision, commissioning, records and close out phases of these projects. Stated simply, functions that support, supervise and monitor direct capital project activities will and should have an appropriate portion of their costs allocated to indirect capital overhead. A fuller list of support functions include: budgeting/reporting, building maintenance, IT helpdesk, human resources, legal, regulatory, strategic development, procurement, plant accounting and accounts payable.[372] It should be noted that some of these support functions are undertaken at the corporate level by EI.[373] Accordingly, a portion of the proposed capitalized overheads are central function costs. The basic premise behind the allocation of indirect overhead costs is that it is linked to the root cause of the capital activity, reflects the actual capital activity and is indicative of the operations of the business[374.]

The Methodology

347. As noted in the pre-filed evidence and as confirmed by Mr. Healey at the Oral Hearing[375], Enbridge Gas developed its methodology following four guiding principles:

a) establish a single, consistent methodology for Enbridge Gas;
b) promote accuracy and transparency through a streamlined model that reflects the underlying capital activity;
c) support the practical implementation of the model allowing for regular (annual) updates; and

[372] Exhibit 2, Tab 4, Schedule 2, Attachment 1, page 6.
[373] Ibid, pages 8 and 9.
[374] Ibid, page 6.
[375] Exhibit 2, Tab 4, Schedule 2, page 8 and 15 Tr.117.

d) comply with U.S. GAAP accounting standards and the OEB's Uniform System of Accounts, which requires that the assignment of overhead costs to particular jobs or units shall be on the basis of a reasonable allocation of actual costs.

348. The O/H Methodology uses four cost categories: operations costs, business costs, shared services costs and pension and benefits costs. Each cost category has a cost driver applied, typically determined by the nature of the underlying cost relationship or linkage to capital activity. Cost drivers include capital expenditures, time analysis, weighted average rates and burdening. The specifics of how overheads are capitalized for each of the cost categories is set out in detail in the pre-filed evidence.[376] Mr. Healey noted in direct examination that for the purposes of harmonizing the prior methodologies, predominantly only historic methods of cost causality have been proposed from the previous approved methodologies[377]. Ms. Yan further confirmed this while under cross examination stating that the proposed O/H Methodology was built predominantly based on the historical methods approved by the OEB and therefore is not a completely new methodology.[378]

349. The only new form of cost causality proposed is the addition of geographic diversity which was added to accommodate the scale of the amalgamated utility. Mr. Healey noted that Enbridge Gas believes that this adds additional accuracy and generates a more accurate overhead capitalization amount.[379]

350. The operations costs category consists of groups that support the Company's core field operations within its 7 geographic regions. These groups provide oversight and support for direct capital activity. The methodology used to determine overhead

[376] Exhibit 2, Tab 4, Schedule 2, pages 9-14.
[377] 15 Tr.118.
[378] 16 Tr.27.
[379] 15 Tr.118.

capitalization for this category is detailed in the pre-filed evidence and utilizes an allocation rate for each region, as noted earlier, as a cost driver given the different level of capital activities in the various regions. Appropriately, the customer attachment group is considered 100% capital due to the fully capitalizable nature of the activity supported whereas leak survey and locates are considered 100% O&M as they are preventive measures which do not contribute to asset creation.[380]

351. The business costs category includes certain department/groups within the Company that support core operations. These include Engineering, Asset Management, System Improvements, and Integrity. To determine overhead capitalization for this category, a time analysis methodology is conducted annually. This analysis begins with managers identifying all of the activities carried out by their teams. Each employee's time is then allocated among the various activities using an activity template. Activities are classified as Capital or O&M based on U.S. GAAP and OEB guidance. A weighted average rate of capital time relative to O&M is then calculated which is then consolidated for each respective director group and weighted to derive an average rate for the group. A validation is then performed, and the director level weighted average is applied to all costs incurred within the group to determine the overhead capitalization amount.[381]

352. For shared service costs, a single overhead capitalization rate was calculated by taking a weighted average of operations costs and business costs capitalization rates and non-capitalizable costs (groups that do not support capital activity), which have a capitalization rate of 0%. It is submitted that a single rate is the most appropriate way to proceed as the groups in this cost category support all of the business activities of Enbridge Gas.[382] The calculations underlying the single

[380] Exhibit 2, Tab 4, Schedule 2, page 10.
[381] Ibid, page 11.
[382] Exhibit 2, Tab 4, Schedule 2, page 12.

overhead capitalization rate proposed for shared services were provided in response to an interrogatory from Energy Probe.[383]

353. The pension and benefit costs category contain pension and benefits incurred by Enbridge Gas including short and long term incentive pay and employee medical, dental, disability and statutory benefits as provided in evidence.[384] For labour that is directly charged to capital projects, a burden rate for pension and benefits is applied to appropriately reflect the entire compensation costs associated with employees. Indirect capitalized labour costs need to be similarly treated and salary grade burden rates provided by HR are used as an input to calculate a single weighted average burden for all employees. Burden rates apply only to Company employees.

354. The methodology to determine burden rates for each organization level is as follows: a) an average burden rate is determined for each component (incentive pay, pension and benefits) by organization level; and b) the combined average burden rate by organization level is calculated by adding each of the components together (incentive pay, benefits and pension).[385] The pre-filed evidence provides the details on each of these three components and how they contribute to and are calculated for the purposes of the burden rate[386]. A weighted average burden rate of 41.7% was determined for the 2024 Test Year. The calculations supporting this figure are included in Table 1 in the pre-filed evidence.[387]

355. To ensure that overhead capitalization rates closely reflect the underlying capital activity, the inputs to the harmonized methodology are updated annually. Calculations are carried out on the latest actuals for operations costs and a

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[383] Exhibit I.2.4-EP-14, Attachment 1.
[384] Exhibit 2, Tab 4, Schedule 2, page 12 and Exhibit 2, Tab 4, Schedule 3.
[385] Exhibit 2, Tab 4, Schedule 3, page 2.
[386] Ibid, pages 2-5.
[387] Exhibit 2, Tab 4, Schedule 2, page 14.

prospective time study is used for business costs. Both rates are applied to the prospective year.[388]

356. While the Company acknowledges that the proposed O/H Methodology has generated modestly higher (1.1%) overhead amounts to be capitalized in 2024 relative to the legacy approved methodologies, Enbridge Gas believes this is simply a function of the accuracy of the proposed O/H Methodology. Further, as referenced in Exhibit I.ADR.35, the variance between the old and harmonized methodologies could fluctuate year-over-year due to changes in department level spend, new business program adds, changes in capitalization rates based on annual rate studies, and future organizational changes. This was the result in 2022 when the harmonized methodology resulted in a lower capital amount in comparison to the historic methods (Exhibit JT4.21). From a rates perspective, the modest increase in capitalized overheads of $15.4 million in the test year[389] correspondingly reduces O&M which has a softening impact on rates.

357. In terms of the allocation of capitalized overheads to plant assets, the proposed O/H Methodology adopted the methodology previously used by Union. Under this approach, allocating capitalized overheads is based on forecasted capital additions by asset class. The benefit of this approach is that it aligns capitalized overhead to the projects and asset classes they are supporting in a given year, it is administratively practical and less costly than alternatives and involves annual adjustments to allocations based on forecasted capital.[390]

358. In the oral hearing, Company witness Ms. Dreveny explained how the allocation of capitalized overheads to capital expenditures works:

> So, in total, when we are talking about capital and the allocation of overheads, we come to a percentage based on the total amount of

[388] Ibid.
[389] Ibid, page 19, Table 4.
[390] Exhibit 2, Tab 4, Schedule 2, page 20.

> overheads and the total amount of direct capital spend. At the most granular level, we would allocate that to a project. So, as an example, I have a project that is $5 million in direct capital. I have an overhead rate of 24%. I apply that rate and it drops out what the overhead amount is.[391]

359. From the cross-examination questions directed at Company witnesses, it appears that certain parties favour capitalizing overheads as it reduces O&M and revenue requirement while others prefer to see such costs remain in O&M and not be added to rate base. Regardless of the position taken, the fact is that capital projects require the support of many departments within the Company and central functions. Where this support is, as a practical matter identifiable, the costs are directly allocated to a capital project. Where it is impractical to specifically identify a capital project which certain activities support, consistent with historical practice, it is appropriate to generate a methodology which calculates that portion of overheads which should be capitalized and that this methodology should include the pension and benefits burden. The Company notes that in accordance with the OEB's Filing Requirements for Natural Gas Rates Applications at Section 2.2.4, capital costs are required to be fully burdened. The Company submits that such amounts are as appropriate to capitalize as are those costs which are directly linked to each capital project. If the indirect overheads are not included, the amounts being capitalized do not represent the full cost of the capital project.

Benchmarking

360. The Enbridge Gas panel was specifically asked a question by Commissioner Elsayed about whether the Company completed a benchmarking study and the possible benefits of such a study. Mr. Healey responded confirming that beyond the retention of EY and its assistance advising about methodologies used by other utilities, no formal benchmarking activity took place. Mr. Healey however advised that public information about the O/H Methodologies used by various utilities is not readily available. He added that even when information is available, it is subject to

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[391] 15 Tr.4.

inferences about how companies apply definitions and methodologies. Stated differently, simply comparing overhead capitalization rates without inquiring further into the unique circumstances of a particular utility and its cost structures might be of limited value.[392]

361. Company witnesses were also taken to a Hydro One capitalization of common corporate costs review completed by PwC.[393] Company witness Mr. Healey noted under cross examination that this Hydro One report highlighted in numerous areas why the public information available in respect of utility overhead capitalization policies was extremely limited. The report noted that there is no unilaterally applied methodology and each company's methodology is highly dependent on the organization itself. In the case of Hydro One specifically, it undertakes a great percentage of capital projects internally. Mr. Healey also noted that the Hydro One report was of limited relevance given that it applied only to the question of capitalizing common corporate costs.[394] The fact that the Hydro One report is dedicated solely to common corporate costs means that the 18% rate set out in the report is not comparable to the Enbridge Gas proposed overhead rate which includes more than common corporate costs.[395]

Changes to the Capital Budget

362. Several parties asked questions about the potential impact on overhead capitalized amounts if the OEB requires a material decrease in the Company's proposed capital budget for 2024. Company witness Mr. Healey explained that it is important to understand that the proposed O/H Methodology utilizes both historical and prospective estimates for the bases of cost causality. Operations costs are allocated based on the most recent year's actual spend to determine the following year's

[392] 16 Tr.59-60.
[393] Exhibit K15.4.
[394] 16 Tr.16-18.
[395] 15 Tr.150.

budgeted overhead capitalization rate. As a result, the capitalized amount would not be expected to change based on a prospective update to the capital program[396].

363. Mr. Healey further noted that business costs are allocated based on a prospective estimate of time required to support the following year's capital program and would be somewhat responsive to the filed capital program, but do not directly correlate and are not scalable. For example, a reduction in the capital budget does not simply imply a reduction in hours that are required to support the capital program overall. Only after a prospective time study is performed can management determine the impact on overhead capitalization rates.

364. The fact is that O&M costs indirectly supporting capital projects would not respond immediately, even to a material shift in the capital program, given that most of the reductions would be expected to impact direct costs for these projects. It is only over the medium term, that a continued reduction of the capital portfolio would the Company anticipate workforce-related costs to start to decline to reflect a sustained change in the capital program.[397]

365. In its response to Exhibit J16.3, the Company explains in some detail how a change to the capital budget does not translate into a similar or perhaps any reduction in O&M. Enbridge Gas explained why this is so and provided examples in its response, which states in part:

> The capital portfolio considers thousands of projects, the reduction in the dollars spent or a nominal reduction in the number of projects performed, would not be expected to reduce the support required in the near term. For reference, the project count in 2022 exceeded 4,000 individual investments and program activities. Additionally, reduction of dollars spent on projects does not necessarily mean a proportional reduction of total number of projects. In many cases, projects would have to be split into phases executed over multiple years with smaller scopes to be completed in each year so the most urgent needs can be addressed as soon as practicable. For example, pipeline replacements may be phased

[396] 15 Tr.121.
[397] 15 Tr.122.

> into multiple years with shorter lengths of pipe being replaced in each phase; but each phase will require a similar degree of effort to plan and support. This approach, of course would mean more capital spent to achieve the same scope of work over a longer period; but would ensure the most urgent needs are addressed promptly.[398]

366. As an example, referenced during the Overhead Capitalization Panel, Asset Management, which is tasked with the optimization of the capital portfolio would not simply increase or decrease head count of full-time employees in response to the annual fluctuations in the level of invested capital or quantum of projects as the functions would still be required, irrespective of a prospective change in the annual capital program.

367. As another example, within the supply chain management department, irrespective of the amount of capital or the number of projects, the work required would still be the same. Whether the function is purchasing 1 million units of a particular part or asset, or purchasing 100,000 units, the steps in the process, specification confirmation, approvals, procurement, and inventory support of that item is the same. Similarly, within finance, the invested amount of capital and the number of projects will not have an impact on the finance activities required such as processing journal entries, budgeting forecast and reporting. The work and effort are still the same.

368. In addition, as parties are aware, a substantial portion of the Company's capital projects are undertaken and completed by third party contractors. If there is a material change to Enbridge Gas's capital budget, the reduction will, to a large degree, impact the extent to which third party contractors are engaged. As well, it logically follows that if replacement projects are cancelled, it may require additional operations and maintenance activities to retain the same level of safety and reliability in lieu of asset replacement.[399] As noted by Mr. Healey while under cross

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[398] Exhibit J16.3, page 2.
[399] This is discussed in Exhibit J16.3.

examination, the Company's workforce is not determined by the capital budget. There is no linear relationship between the capital budget and the workforce.[400]

369. In response to a question from Commissioner Duff[401] about energy transition risks such as declining utilization and stranded assets and the appropriateness of capitalizing overheads in light of these risks, Ms. Dreveny responded stating:

> I guess I would point to the fact that the overhead methodology, in itself, does have linkages to the asset management plan, and will look at what's coming up in terms of that. So, as we get further into energy transition and we have a better understanding of how that will impact our future spend, I think the overhead methodology is sound, as it will take into account what those future trends may be.
>
> As an example, if we were going to see a change in the nature of the spend, say a decrease as a result of energy transition, that would translate its way back to the indirect overheads through this methodology.[402]

370. Mr. Healey then added that because the methodology is updated on an annual basis, if we see a transition as a result of energy transition, it would be reflected and updated on an annual basis.[403] The impact of this as a practical matter is that base capitalization rates will be set based on the 2024 forecast amounts. This base amount will not change, nor will the Company track actuals versus the amounts included in rates for 2024 or the next IRM (2025 to 2028). However, on an actual basis, Enbridge Gas will update annually so that the overhead amounts that are recorded and allocated to rate base during this time reflect the most up-to-date information.

371. In a subsequent question from Commissioner Duff asking about the impact of the decisions that will be made by the OEB in this proceeding on things like the quantum of overhead costs Ms. Dreveny responded saying:

[400] 15 Tr.158.
[401] 16 Tr.52.
[402] 16 Tr.53.
[403] Ibid.

> I think I would consider it in terms of some of the commentary that we've heard from Mr. Sanders on the capital panel, where, you know, if we were to receive a decision that was going to reduce the amount of capital spend, what would we do. Because I think that sort of informs the basis of all this.
>
> So depending -- if there was a decision to make any changes, at the core of the capital piece we would need to take that away, reassess what it means in terms of the projects and what we need to execute on to maintain the safety, the reliability, all of those aspects to our capital plan, and, once that was known, I think it then turns over to the overhead capitalization piece and the management of all those. Recognizing that all of this doesn't, you know, turn on a dime, there is time required, right? Assuming we're going to get a decision late in the year and then we have to reassess what's happening with our capital basically immediately, there's no immediate change, I guess, expected with the overheads. That would take some time, to consider what have we changed in terms of our projects; what does that mean in terms of the support functions within the company that are managing all of that, all of those pieces. So I think I would still point back to: As long as our methodology is sound, once all of those decisions are made, the methodology will reflect that. It's just not an immediate one-for-one. It's not -- I guess, scalable might be the right word for it.[404]

372. It is submitted that the evidence of the Company is that the proposed O/H Methodology will in time be responsive to both the decisions of the OEB in this proceeding and energy transition impacts. This said, because the costs to operate and maintain the system safely and reliably are the aggregate of the net O&M amount of $821 million and the $292 million that is proposed to be capitalized, it would not be prudent to reduce the latter figure without adjusting the net O&M figure as a result.

373. Finally, Commissioner Moran asked a question toward the end of the panel’s appearance about the impact on rates if none of the indirect overheads proposed by Enbridge Gas were capitalized[405]. Enbridge Gas responded to this question by undertaking Exhibit J16.3. The impact on the revenue requirement has been

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[404] 16 Tr.57-58.
[405] 16 Tr.63.

calculated to be an increase of approximately $348 million[406]. For the reasons stated above and, in the response to Exhibit J16.3, the Company does not believe such a change is appropriate.

<u>2024 Capital</u>

374. Issue 7 – Is the forecast of 2024 capital expenditures underpinned by the Asset Management Plan, and in-service additions appropriate?

<u>Consequences Of Settlement Proposal</u>

375. No items related to 2024 capital budget and associated rate base were settled. There is a partial settlement on the 2024 opening rate base (as discussed under Issue 6).

<u>Outstanding Approvals Required</u>

376. Enbridge Gas requests approval of its as-filed 2024 Test Year capital expenditures (as underpinned by the AMP) and resulting in-service additions, including the impacts of the Capital Update.[407]

377. The Capital Update excluded forecast expenditures and in-service additions related to PREP, for which Enbridge Gas is requesting approval of a separate levelized recovery mechanism (as well as an associated variance account under Issue 32) to include the project's revenue requirement impacts in a rate rider that will be in effect upon approval of the LTC and ultimate in-servicing.[408]

<u>Revenue Requirement Implications for 2024</u>

378. As outlined in the Capital Update, the forecast impact on the 2024 Test Year revenue requirement is a deficiency of $268.5 million, which reflects the removal of

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406 Exhibit J16.3.
407 Exhibit 2, Tab 1, Schedule 1, pages 5 and 6.
408 Exhibit 2, Tab 5, Schedule 4, Section 4.1.

PREP from base revenue requirement and, on an interim basis, the removal of deficiency from Dawn to Corunna (which is subject to determinations in Phase 2 of this proceeding).[409]

379. Where the OEB determines that amounts proposed as part of 2024 capital expenditures should be adjusted, that will impact revenue requirement. However, the impact of such adjustments will depend on the magnitude of the adjustment and the timing of when the relevant item was forecast to be added to rate base. An item that was forecast to be added to rate base during the course of 2024 will only be partially effective from a cost of capital and depreciation perspective, and could result in other offsetting revenue requirement implications (such as to revenues and taxes), meaning that the rate base impact of its removal may be modest, and or may even increase revenue requirement depending on the size and timing of the offsetting items.

Evidence in Support

380. Enbridge Gas has filed detailed evidence about its capital budget and associated rate base additions. This evidence is found throughout Exhibit 2. Enbridge Gas has answered follow-up questions in associated interrogatories[410], Technical Conference testimony[411], Technical Conference undertakings[412] and filed several ADR responses.[413] Updates to 2023 and 2024 capital forecasts as part of the Company's 2024 budget development process resulted in changes to planned capital expenditures, which were filed with the Capital Update.[414]

[409] Exhibit 2, Tab 5, Schedule 4, pages 35-36.
[410] See Interrogatories related to Exhibit I.2
[411] 4 TC Tr.201-217, 5 TC Tr.5-203 and 6 TC Tr.1-48.
[412] Exhibits JT4.22-4.25, JT 5.1-5.47 and JT6.1-6.5.
[413] Exhibit I.ADR.8, 12, 13, 16, 16, 21, 26 and 39.
[414] The Capital Update included updated Exhibit 2 evidence filed on June 16, 2023, and associated changes to evidence, interrogatory responses and undertaking responses filed on July 6, 2023.

381. Enbridge Gas witnesses provided testimony on, among other things, the Company's capital forecast and AMP, including the underlying asset management and planning processes, known investment needs and compliance/service obligations driving the forecast, and the incorporation of energy transition considerations and integrated resource planning within capital planning on Days 11 to 14 (Panel 11)[415].

Overview

382. Enbridge Gas submits that its 2024 capital forecast (underpinned by the AMP) and in-service additions are appropriate, as the investments comprising the forecast have undergone rigorous evaluation and prioritization through the Company's capital budgeting and asset management processes and the investments are required to sustain assets and meet service and compliance obligations.

383. The proposed investments are necessary to ensure the continued safe, secure, reliable, and resilient operation of the Company's natural gas system, which represents a critical component of Ontario's energy delivery systems. For context, Enbridge Gas currently delivers around 30% of the province's annual energy requirements, which equals about 770 PJ or 214 TWh, while meeting peak energy requirements of 8 PJ which is 4 to 5 times the peak of Ontario's electricity system.[416] The Company's gas assets are significant in scope and scale, commensurate with the energy supplied to millions of customers across the province.

384. Enbridge Gas's natural gas system comprises utilization, distribution, transmission, and storage assets and is supported by business systems that include Technology and Information Services (TIS), Fleet and Equipment, and Real Estate and Workplace Services (REWS). Key components of the gas system were summarized in the Capital Budget Panel's evidence in chief during the Phase 1 hearing:

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[415] 11 Tr.91-203, 12 Tr.1-118, 13 Tr.1-192 and 14 Tr.1-142
[416] 11 Tr.94-95.

a) The utilization assets are the meters, regulators, and customer connections currently supplying 3.8 to 3.9 million residential, commercial, agricultural, industrial and generation customers.
b) The distribution assets include approximately 150,000 km of main and service pipelines and 36,000 measurement and pressure regulation stations.
c) The transmission system consists of over 3,600 km of critical supply pipelines which are operated over 30% of the specified minimum yield stress and are powered by 53 compressors at four primary sites totaling 800,000 horsepower.
d) The storage assets are considered critically important for Ontario and in North America. The combined utility storage facilities of Dawn and Corunna have approximately 199 PJ or 55 TWh and can deliver 6.4 PJ/d, which is the equivalent of 73,000 MW. The utility storage is a portion of Enbridge Gas storage facilities' total capacity and deliverability.[417]

385. The planned investments represent the lowest capital envelope needed to safely operate and maintain the natural gas system, respond to demand growth, invest in low-carbon solutions, and ensure ongoing reliability of service. The AMP underpinning the capital forecast is primarily focused on the sustainment and replacement of existing assets. More specifically, 65% of the AMP’s capital forecast for 2023 to 2032 are required to either reactively address failed/damaged assets or plan for the replacement of assets that are expected to fail within 1 to 20 years (where such failures cannot be adequately mitigated via maintenance or component replacements to achieve safe and reliable outcomes). Further, 84% of these sustainment and replacement expenditures are required for gas infrastructure,[418] and only 6% of the total capital expenditures from 2024 to 2028 relate to the replacement of assets to manage longer-term failure risk at the asset population

[417] 11 Tr.95-96.
[418] Exhibit 2, Tab 5, Schedule 1, paragraph 24, Tables 1 and 2, and Figure 2.

level.[419] In other words, the majority of capital requirements for the foreseeable future are required for maintaining gas infrastructure, not expansion of gas infrastructure.

386. Approximately 32% of capital expenditures relate to growth investments from 2023 to 2032. The growth investment category is largely comprised of investments related to customer connections, at 20% of the total 2023 to 2032 forecast, with some larger investments to support major transmission reinforcements comprising approximately 8% of the total AMP forecast. All reinforcements will be subject to IRP evaluations to seek opportunities to reduce, defer or delay scope associated with these investments.[420]

387. The gas system is expected to continue playing a critical role in meeting Ontario's energy needs over the 2023 to 2032 period. Growth-related investments in this period begin to decline, reflecting the expectation that although near-term gas demand remains strong, over time fewer customers are forecasted to attach to the gas system and those customers using gas will use less. Growth capital reflects the need to fulfill known and forecasted customer requests for access to gas and to the affordable, reliable, and resilient energy source it provides. Enbridge Gas believes that these growth-related investments can be transitioned to deliver low and zero carbon energy, and that these investments maintain consumer choice and economic competitiveness, two critical elements of the energy transition.[421]

388. While there is uncertainty around Ontario's potential pathways to a net-zero future, Enbridge Gas has considered and accounted for energy transition in its capital plan in a number of ways, including: incorporating energy transition assumptions as part of demand forecasting, embedding IRP alternatives into planning processes,

[419] 14 Tr.137-138.
[420] Exhibit 2, Tab 5, Schedule 1, paragraph 26.
[421] Ibid, paragraph 25.

adopting an Enhanced Distribution Integrity Management Program (EDIMP), studying how the existing grid can accept more hydrogen (up to 100%) in the future, supporting customer conversions away from higher emissions fuels (including as part of Ontario's Natural Gas Expansion Program (NGEP) to expand gas access to unserved communities), and continuing investments in RNG.[422]

389. The Issue 7 submissions below further discuss:

a) Enbridge Gas's rigorous approach for asset management and investment planning, including a robust framework for selecting and prioritizing investments to drive value for ratepayers and the Company, how repair versus replace decisions are made, as well as the 2024 budgeting process that resulted in the Capital Update;
b) key asset needs and compliance/service obligations driving the capital forecast (as underpinned by the AMP) across the main asset categories. As noted above, PREP has been excluded from the Capital Update and Enbridge Gas is requesting a levelized recovery mechanism for PREP, separate from base revenue requirement; and
c) incorporation of energy transition considerations and IRP in the capital planning context (which relate to Issue 3 as well).

<u>Asset Management and Planning Approach</u>

Overview of Asset Management Framework

390. Underpinning Enbridge Gas's proposed capital expenditures is a robust asset management framework that incorporates value-based decision making based on a holistic evaluation of cost, risk, and performance. Developed based on the IAM Conceptual Asset Management Model and in alignment with ISO 5500X[423], this framework directly supports the achievement of Enbridge Gas's strategic priorities.

[422] 11 Tr.103-104.
[423] Exhibit 2, Tab 6, Schedule 2, page 29.

The 2022 Enbridge Enterprise Strategic Priorities that guided the development of the AMP are: safety and operational reliability, adapt to energy transition over time, disciplined capital allocation, maintain financial strength and flexibility, extended growth, execute capital program, and optimize the business case.[424] These priorities are translated into a series of policy statements that guide all aspects of asset decisions.[425] These policies are further supported and operationalized through asset management strategies and the asset investment planning and management (AIPM) process to execute upon said strategies.[426]

391. The asset lifecycle management and extension strategies behind asset intervention decisions are outlined in the Asset Management Plan, together with proposed investments that have been assessed and prioritized based on best available information to ensure safe, reliable, and resilient service for customers.

392. An important part of asset planning is the inclusion of customer needs and preferences into the analysis of alternatives, pacing and optimization of capital plans.[427] The customer engagement activities undertaken in 2021 and early 2022 saw over 12,000 customers participate in various forums, such as focus groups, interviews, telephone surveys and online workbooks. These extensive engagement efforts allowed Enbridge Gas to understand and integrate customer feedback into key stages of business planning, including (1) first phase engagement results that qualitatively informed customer needs and priority outcomes in advance of detailed planning, (2) second phase survey results that explored high level investment and rate design choices, and (3) third phase results regarding customer support for

[424] The 2022 Enbridge Enterprise Strategic Priorities that guided the development of the AMP are: safety and operational reliability, adapt to energy transition over time, disciplined capital allocation, maintain financial strength and flexibility, extended growth, execute capital program, and optimize the business case. See Exhibit 2, Tab 6, Schedule 2, Section 2.2.2.
[425] Exhibit 2, Tab 6, Schedule 2, Sections 3.1.1 and 3.1.2.
[426] Ibid, Section 4.
[427] Exhibit 2, Tab 6, Schedule 1, paragraph 63.

specific investment choices.[428] These customer engagement results demonstrate, among other things, that customers value the safe, reliable, cost-effective, and environmentally responsible provision of natural gas[429], and allowed Enbridge Gas to ensure that its decision-making framework, asset management goals, and investment focus areas are aligned with identified customer preferences.[430]

393. Additionally, in keeping with continuous improvement, the asset management framework and resulting 2023 to 2032 AMP reflect a number of changes and refined features, including but not limited to energy transition-related adjustments, integrated resource planning, ongoing consolidation of asset data, updated understanding of asset condition and strategies, ongoing integration of asset standards, improved quality assurance behind investment value assessments (including the Copperleaf value framework, as discussed below), and continuous evaluation of facility emission reduction opportunities.[431]

Asset Investment Planning and Management (AIPM) Process

394. In terms of the specific AIPM process, the first step is to identify investment need, which represents either a risk or opportunity to the organization. Identified needs can either be entered directly into the Company's asset management planning and optimization tool (Copperleaf) or arise through the Risk Management process.[432]

395. Once the asset manager validates that the identified need aligns with applicable asset strategies and capital intervention is required, solution planning and value assessment can begin. Cost estimates are developed for each solution option, along

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[428] Exhibit 1, Tab 6, Schedule 1, pages 2 to 3.
[429] Exhibit 2, Tab 6, Schedule 1, paragraph 64.
[430] Ibid, Section 2.4.1.
[431] Exhibit 2, Tab 6, Schedule 2, Section 3.2.
[432] Ibid, Section 4.3. Also see Exhibit I.2.6-CCC-48, which indicated that 13 investments (or 1.7% of the total number of 2024 investments) were prioritized through Gas Distribution & Storage's Risk Management process for the 2024 budget.

with a scope and preferred timing.[433] The value of each investment option is quantified through Copperleaf's Value Framework or, in some cases, evaluated via the Risk Management process. Under the Value Framework, value models leverage quantitative data for frequencies, probabilities and consequence impacts to determine financial or non-financial value measures.[434]

396. The proposed investments are grouped into three categories: (i) Mandatory – required to address a risk or opportunity within a timing window (i.e. exceeding established risk upper threshold, third party relocation, program work with sufficient history and risk to warrant continuation, and connection projects that meet economic feasibility tests); (ii) Compliance – required within a fixed time frame to comply with applicable laws, regulations, codes, standards and policies; and (iii) Value-Driven – timing is determined based on investment value to ratepayers and the Company.[435] Across the investment categories, Enbridge Gas strives to capture and leverage the right asset data (including condition), which is foundational to all asset management activities and supports asset analytics and modelling.[436]

397. By placing value measures on an economic scale, the Company is able to objectively evaluate an investment's independent value and its relative standing among other investments through the Copperleaf optimization process.[437] Investments that rely on the Risk Management process is typically more complex, and associated timing is confirmed outside of Copperleaf optimization.[438]

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[433] Exhibit 2, Tab 6, Schedule 2, Section 4.3.2.
[434] Financial value measures are estimated based on potential financial losses or gain in cash flow or avoided expenses. Non-financial value measures are correlated with tangible qualities that can be converted into monetary values in either value units or CA$, thus allowing them to be combined with financial value measures and investment cost through NPV calculation to determine the total investment value. See Exhibits I.2.6-CME-18a) and I.2.6-CCC-49.
[435] Exhibit 2, Tab 6, Schedule 2, Table 4.1-2.
[436] Ibid, Section 4.1.6.
[437] Ibid, Table 4.1-3.
[438] Ibid, pages 46-47.

398. During the optimization step, proposed investments are reviewed with business stakeholders to ensure all known risks and opportunities are captured, following which a multi-year investment plan is created through Copperleaf based on asset management principles. Value-driven investments using the Copperleaf Value Framework are free to shift within the optimization time frame, whereas mandatory investments arising from the Risk Management process are slotted at the required time or constrained to be completed by a specified time. Using Copperleaf, the overall portfolio is iteratively optimized and analyzed by varying the net direct capital per year, highlighting the effects of project timing, option selection and value. The results from these scenarios are reviewed with asset managers to find the combination of investment options and start dates that best meet business needs within specified constraints.[439]

399. The resulting scenario is then reviewed and refined to deliver a final portfolio recommendation, and the recommended portfolio is approved once validated against timing and resourcing constraints. The use of Copperleaf enables ongoing refinement of investments in the plan and periodic review of changes and updates to understand their impact.[440]

400. As projects are executed, scopes may change or new projects may arise, resulting in cost pressures (increases or decreases) to the current portfolio. In response, Enbridge Gas makes trade-off decisions based on value and available capital. All requests for emerging or revised investments are verified for alignment to the asset class strategies described in the AMP[441], and supported with clear purpose, need and timing to allow for evaluation. An overall review is conducted to understand the relevant uncertainties and to ensure that as much risk or opportunity is addressed as possible within the constraints of the portfolio. The execution of the annual work plan

[439] Exhibit 2, Tab 6, Schedule 2, Section 4.3.3.
[440] Ibid, Section 4.3.4.
[441] 14 Tr.78.

is monitored and adjusted monthly through the forecasting process and informs the Company's asset management performance.[442]

401. Enbridge Gas actively monitors AIPM performance, by evaluating the end-to-end process, delivery of the approved portfolio relative to plan, adherence to asset class strategies, and accomplishment of specific asset management objectives.[443]

Asset Lifecycle Management and Extension Strategies

402. As noted above, Enbridge Gas's budget forecast is supported by asset lifecycle management and extension strategies as outlined in the AMP. It is important to note that while the plan speaks primarily to activities supported by capital investment, it also describes various O&M activities to support asset lifecycle management, including condition monitoring and operating standards for distribution pipes[444] and stations[445], sampling and replacement of utilization assets[446], inspection and maintenance of compression, dehydration and LNG assets[447], preventative maintenance of REWS assets, and maintenance of Fleet and Equipment assets[448].

403. In addition, the AMP includes various capital programs that serve to extend asset life. Examples include the Transmission Integrity Management (TIMP) Integrity Retrofits and Digs[449], Corrosion Prevention Program[450], Distribution Stations Painting Program[451], High Performance Coating Program[452], Well Testing and

[442] Exhibit 2, Tab 6, Schedule 2, Section 4.3.5.
[443] Ibid, Section 4.3.6.
[444] Exhibit 2, Tab 6, Schedule 2, page 82, Table 5.2.3-2.
[445] Ibid, page 125, Table 5.2.4-2.
[446] Ibid, page 150, Table 5.2.5-3.
[447] Ibid, page 180, Table 5.3.4-1.
[448] Ibid, page 228, Table 5.5.4-1.
[449] Exhibit 2, Tab 6, Schedule 2, page 107, Section 5.2.3.6.1.1.
[450] Ibid, page 108, Section 5.2.3.6.2.1.
[451] Ibid, page 141, Section 5.2.4.6.4.2.
[452] Ibid, page 192, Section 5.3.5.4.10.

Acid[453], and Well Cathodic Protection[454]. Through such programs, the Company has been able to extend many assets' lifecycle, with some steel pipelines exceeding 90 years of age[455], and in some cases well past expected service life such as heating systems which are in excess of 63 years of age[456].

404. Notwithstanding these rigorous lifecycle management and extension activities, many assets continue to deteriorate in condition over time, which will eventually result in failure in the absence of effective and timely intervention. Failure of gas carrying assets is generally associated with loss of containment and/or disruption of flow, risking significant impact to customers and the public. As noted by Mr. Sanders in his evidence-in-chief on the Capital Budget Panel:

> If not prudently managed, the potential risk of failures aren't theoretical or pure business calculation. Rather, they entail significant potential impact to Ontarians, and entail -- and their everyday livelihood, ranging from the obvious of providing heat on extremely cold days, to large sectors of the economy that are directly enabled by natural gas.[457]

405. Enbridge Gas has a responsibility to take reasonable steps to prevent asset failures/disruptions and has taken a data-based approach to plan for renewal of assets prior to failure, examples of which can be found throughout Section 5 of the AMP (and as discussed later under Issue 7).

406. As a potential way to enable a more targeted approach to address risk of failure for a subset of distribution pipes, Enbridge Gas's implementation of EDIMP will augment existing asset data and provide new insights into asset health. It is important to note, however, this program will target 8,000 km out of 32,802 km of steel distribution pipes[458]; and it will not address the full 17,423 km of pre-1971 vintage steel mains[459]

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453 Exhibit 2, Tab 6, Schedule 2, page 200, Section 5.3.6.3.1.3.
454 Ibid, page 200, Section 5.3.6.3.1.5.
455 Ibid, page 86, Figure 5.2-6.
456 Ibid, page 126, Table 5.2.4-3.
457 11 Tr.100.
458 5 TC Tr.71.
459 Exhibit 2, Tab 6, Schedule 2, page 86.

that are expected to experience increasing failure rates over the next 20 years[460], the remaining 148 km of Bare and Unprotected Steel mains[461], or the copper risers and services whose failure frequencies are also increasing[462].

407. For the majority of the distribution mains and service of piping not assessed through the EDIMP, technology does not currently exist to increase Enbridge Gas's understanding of the condition of these assets at a localized level without directly exposing the pipelines. In most cases, such assessments would be comparable cost-wise to replacements. Where inspections identify pipelines requiring replacement, additional costs would be incurred to plan and execute such projects at a later date, thereby resulting in both added costs and additional disruption to customers and the public. As such, to ensure the most cost-effective and predictable approach, Enbridge Gas has put forward proactive replacement programs in the AMP to target assets where maintenance or other component-specific replacements cannot adequately mitigate the associated risk.

408. In Enbridge Gas's view, running assets to failure is not an acceptable asset management practice nor a sustainable way to operate a critical component of Ontario's energy delivery system.[463] There are parties to this proceeding who have questioned whether there is an option to repair assets to extend asset life and to limit or defer capital spend, given potential uncertainties over future gas utilization. In this regard, Enbridge Gas has clarified that the decision to repair only arises *after* asset damage or failure is discovered.[464] The implication of deferring a capital replacement that is otherwise needed within a certain time window to avoid expected

[460] Exhibit 2, Tab 6, Schedule 2, pages 92-93.
[461] Exhibit I.2.6-SEC-129; Exhibit 2, Tab 6, Schedule 2, page 109.
[462] Exhibit 2, Tab 6, Schedule 2, page 117 and EB-2017-0306/EB-2017-0307 Exhibit C.STAFF.54, Attachment 1, page 143.
[463] 11 Tr.99.
[464] 12 Tr.94-95.

asset failure and address condition issues is that these known risks are left inadequately treated under a run-to-failure approach.

409. Of course, asset failures may still occur despite Enbridge Gas's lifecycle management and extension activities. Nonetheless, the strategies and investments set out in the AMP are necessary to manage failure frequencies and avoid the escalation of failure frequencies to an unmanageable level.[465] Enbridge Gas's maintenance, condition monitoring, corrosion prevention, damage prevention, integrity management and proactive replacement programs are all intended to monitor the condition of assets and proactively address identified unacceptable risks before they materialize. Such programs meet or exceed code requirements and industry standards to assess condition and risk associated with distribution pipeline assets, and Enbridge Gas aims to continuously improve these practices (e.g., through the EDIMP). The condition and risk-based findings from such programs are built into any planned replacement decisions. As a result of these diligent efforts, Enbridge Gas's proactive replacement investments have historically allowed the Company to sufficiently manage failure risks as assets continue to age and deteriorate in condition, while replacing only a fraction of a percent of the total installed assets per year.[466]

Capital Update

410. Since the rebasing application was filed in October 2022, Enbridge Gas has prepared updated 2023 and 2024 capital forecasts as part of its normal corporate budgeting exercise in support of the 2024 budget, which has resulted in changes to the planned capital expenditures compared to the October filing and the subsequent March update.[467] As explained by the Capital Budget Panel in their evidence-in-chief during the Phase 1 hearing:

[465] 11 Tr.99.
[466] 11 Tr.100.
[467] Exhibit 2, Tab 5, Schedule 4, Table 1.

> Overall capital requirements have experienced changes as a result of project deferrals, emerging needs, and inflationary pressures. During the technical conference, Enbridge Gas indicated that it would report on any updates to the capital budget as set forth in the pre-filed evidence, stemming from its 2024 budgeting process, as soon as the information could be provided in advance of the oral hearing, should it be required. While our practice is to follow the corporate budget process, the capital update was completed on an … accelerated timeline compared to what we would typically do, to ensure that we had the information available in time for the hearing.[468]

411. The Capital Update used the AMP as a starting point and projects were moved on an exception basis to accommodate the cost pressures due to carry over work from 2022 and emerging business requirements identified for 2023 and 2024. As a result, some investments were deferred to future years.[469]

412. As further explained during the Oral Hearing, the corporate budgeting exercise is an annual process that involves all business units under EI (and not just the Gas Distribution & Storage business unit which Enbridge Gas forms a part of). In addition to capital, this process covers other budget components such as O&M and revenue. The typical process is to start in the March to April time frame, complete a business unit review over the summer months, provide the budget for corporate parent approval around September, and obtain ultimate approval from the EI Board of Directors in and around November.[470] This timeline provides context for the above-noted statement that the Capital Update followed an “accelerated timeline”, so as to put the best available information on the record as soon as reasonably feasible. While the Capital Update represents an adjustment to funding and/or shift in timing for certain investments compared to the AMP, the strategies underlying planning decisions and initial portfolio optimization remain unchanged.[471] Moreover, the 2024 capital forecast did not change significantly as a result of the Capital Update and

[468] 11 Tr.94.
[469] Exhibit 2, Tab 5, Schedule 2, paragraph 8. These deferrals included the Crowland Storage Transfer, Wilson Avenue, Port Stanley, East Kingston Creekford Road Projects, Kennedy Road Land Purchase and several smaller projects moved to future years (as described in Exhibit 2, Tab 5, Schedule 4).
[470] 14 Tr.88.
[471] Exhibit 2, Tab 5, Schedule 2, paragraph 3; 11 Tr.125.

remained relatively flat when compared to the October 2022 filing (including amounts related to PREP).[472]

2024 Capital Budget

413. Enbridge Gas's capital forecast for the 2024 Test Year totals $1,470.3 million, excluding PREP amounts.[473] This includes expenditures for maintaining pipeline integrity of the distribution and transmission systems, ensuring compliance with regulations, supporting the demand for customer and system growth, investing in Enbridge Gas facilities and expenditures related to system changes as a result of implementing rebasing proposals and technology investments to ensure continued reliability and security.[474] Enbridge Gas is also committed to investing in energy transition, including low-carbon strategies to reduce greenhouse gas emissions and renewable energy opportunities to "green the grid".[475]

414. Enbridge Gas has undertaken diligent efforts to prudently manage capital costs and prioritize only the core activities necessary to sustain the utility business and ensure safe and reliable gas service. At the same time, it must contend with the realities of cost escalations in the market, meet applicable compliance requirements, and respond to known system needs and customer demands through condition and risk-based asset management decisions. In addition to inflationary cost pressures across many asset classes due to higher material and contractor costs, programs driving increasing capital requirements in recent years and into 2024 include customer connections, compliance-driven meter exchange program, and increased focus on integrity management in order to ensure the safety of the system.

[472] This breakdown can be derived based on the categorization of capital expenditures set out in Exhibit 2, Tab 5, Schedule 1, Table 2 (after removing PREP).
[473] Exhibit 2, Tab 5, Schedule 2, Table 1.
[474] Ibid, paragraph 10.
[475] Exhibit 1, Tab 10, Schedule 6.

415. As part of the Capital Update, Enbridge Gas prepared an alternative view of its capital expenditures to enhance stakeholder understanding of the proposed investments in the context of both business drivers and immediacy of need.[476] In Exhibit 2, Tab 5, Schedule 1, Table 1 sets out six general investment categories: replacement, sustainment, growth, business sustainment, emissions reductions, and energy transition. In particular, the replacement category further divides into reactive replacements due to damaged or failed assets, as well as proactive replacements to address short term failure risk, long term failure risk, or long term cost effectiveness[477]; the sustainment category focuses on extending or maintaining the function of existing assets, including investments to address known safety/reliability risks and compliance obligations; and the growth category includes customer connections (including community expansion) and system reinforcements.

416. The majority of the capital expenditures between 2023 and 2032 relate to sustainment of Enbridge Gas's business and replacement of assets requiring risk mitigation. As noted above, about 65% of the capital expenditures from 2023 to 2032 pertain to sustainment and replacement, of which 84% is required for gas infrastructure. Further, approximately 68% of the replacement related investments in the 2024 to 2028 forecast would be considered short term or reactive. Growth spend constitutes about 32% of 2023 to 2032 capital expenditures and is largely comprised of investments related to customer connections at 20% of the total 2023 to 2032 forecast, with some larger investments to support major transmission reinforcements comprising about 8% of the total AMP forecast.[478] Similarly, with respect to the 2024 Test Year (excluding PREP), 63% of the capital forecast relates to replacement and

[476] 11 Tr.97.
[477] Short term replacements address risk of failure within 1-20 years; long-term replacements address failure risks beyond 20 years, and are paced to balance workload and prevent unmanageable escalations in failure frequencies; and long term cost effectiveness relates to multiple component reliability concerns within Distribution Stations with varying timelines of expected failure and the opportunity to pursue a full replacement more cost-effectively than multiple replacements over time (Exhibit 2, Tab 5, Schedule 1, Table 1).
[478] Exhibit 2, Tab 5, Schedule 1, paragraph 24.

sustainment (with only 3% of the replacements focused on long-term planning) and 28% relates to growth demands arising out of customer connections and system reinforcements.

417. By main asset categories, the bulk of the 2024 capital budget comprises the following:

a) $592.9 million for Distribution Operations (i.e., distribution pipe, distribution stations, and utilization assets);
b) $400.5 for Growth Projects (i.e., customer connections, system reinforcements including hydrogen blending, and community expansion);
c) $115.5 million for Storage and Transmission Operations (i.e., compression stations, transmission pipelines and underground storage assets);[479]
d) $102.4 million for TIS;
e) $63.0 million for REWS; and
f) $31.5 million for Fleet and Equipment.

418. For clarity, categories of spend that are included in the capital budget but not in the AMP (other than their associated asset strategies that are reflected in the AMP) are community expansion, RNG and CNG.[480] Further, the capital budget costs are inclusive of indirect overhead capitalization amounts.[481] Should the OEB require changes to Enbridge Gas's overhead capitalization methodology, the amount of overhead costs to be capitalized will need to be revised accordingly and a corresponding adjustment will also need to be made to the net O&M costs. Please see Enbridge Gas's submissions under Issue 8 for further details.

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[479] Excluding PREP amounts ($194.9 million for 2024) for which a separate levelized mechanism is being sought.
[480] Exhibit 2, Tab 5, Schedule 2, page 2 and Exhibit J12.4.
[481] Note that the Capital Update did not reflect the adjustment that needs to be made to the capitalized overhead ($18 reduction, to a total of $292 million) based on the agreed upon O&M budget envelope under the Settlement Proposal and the application of Enbridge Gas's proposed overhead capitalization methodology.

419. 2024 capital expenditures are discussed below by asset category. Detailed Investment Summary Reports for material new projects over $10 million can be found in Appendix A to the AMP as updated by Exhibit J13.11.

Distribution Operations

420. Distribution Operations investments of $592.9 million for 2024 include the maintenance and renewal of distribution pipelines ($357.1 million), distribution stations ($83.5 million) and utilization assets ($152.3 million).[482]

421. Based on the outcomes of the DIMP and Transmission Integrity Management Program (TIMP), Enbridge Gas determines the need to maintain or replace pipeline assets. The DIMP and TIMP identify system integrity and reliability risks with pipeline assets, which are then prioritized based on risk to determine the timing of investments. In response to the OEB's direction in the St. Laurent LTC Decision[483], Enbridge Gas has also re-evaluated a subset of the DIMP Assessment Program and implemented the EDIMP[484] with the goal of providing more detailed condition assessments for certain pipeline assets. Additionally, the IRP assessment process is applied to evaluate the preferred facility solution and compare it to IRP alternatives to meet specific system needs. Significant distribution pipeline investments in the 2024 budget include St. Laurent Phase 3 – North/South (NPS12/16 Steel), St. Laurent Phase 3 – Coventry/Cummings/St. Laurent (Plastic) and St. Laurent Phase 4 – East/West (NPS12 Steel) replacement projects.[485] These phases of the St. Laurent project will be brought to the OEB for LTC approval in Q4 2023[486], supported by all the integrity data that has been gathered for the pipeline (including data from crawler tool inspections and integrity digs subsequent to the OEB's St.

[482] The asset management strategies for Distribution Pipe, Distribution Stations and Utilization are found in the AMP (Exhibit 2, Tab 6, Schedule 2), Sections 5.2.3.2, 5.2.4.2 and 5.2.5.4 respectively.
[483] EB-2020-0293, Decision and Order, May 3, 2022.
[484] Exhibit 1, Tab 13, Schedule 3.
[485] Exhibit 2, Tab 5, Schedule 2, paragraph 19.
[486] Note that Exhibit I.2.6-SEC-117, Table 1 misstated the forecast LTC filing date for St. Laurent as "Q4 2024". Q4 2023 is the correct timeline.

Laurent decision, which already led to the identification and emergency replacement of a high risk pipe section in the fall of 2022).[487]

422. Distribution station assets include stations with auxiliary equipment, distribution system stations, and customer stations. With more than 36,000 stations of varying degrees of complexity and criticality, Enbridge Gas continues to develop analysis to establish age, condition and risk to formulate the appropriate maintenance and replacement strategies.[488] The bulk of capital spend in this category stems from the targeted replacement or rebuild of components at stations with auxiliary equipment (which tend to more complex and handle higher pressure/volumes) as well as distributions system stations with identified condition and legacy design issues (which tend to be smaller stations that nonetheless may supply hundreds of customers each).[489] CNG and RNG stations are also included within this category in support of Enbridge Gas's low-carbon strategy.[490]

423. Utilization investments are driven by the demand for new meter purchases for customer additions, meter replacements pursuant to the Meter Exchange Government Inspection (MXGI) program, and regular refits due to condition. Notably, expenditures have increased due to supply chain issues related to COVID-19[491], which led to decreased availability of diaphragm meters and required the sourcing of alternate meters. While Enbridge Gas is not asking for the approval of an Advanced Metering Infrastructure (AMI) program in this Application, it launched an AMI pilot in 2022 and will use the results to define the scope of AMI investments as part of future AMPs. The strategies for utilization assets focus on continuing the MXGI program to replace meters before failure and comply with Measure Canada's seal life and

[487] 11 Tr.188-189.
[488] Exhibit 2, Tab 6, Schedule 2, Section 5.2.4.
[489] Ibid, Sections 5.2.4.6.1.1 and 5.2.4.6.2.1.
[490] As noted above, CNG and RNG-related amounts are included in the capital budget but are outside of the AMP spend for Distribution Stations ($83.5 million in 2024).
[491] 11 Tr.133.

extension requirements, as well as on remediating high-priority condition issues identified through the DIMP.[492]

Growth Projects

424. Growth projects include customer connections, system reinforcements (including hydrogen blending through Phase 2 of the LCEP) and community expansion pursuant to the Government of Ontario's NGEP. Customer growth continues to drive capital requirements with approximately 40,000 customers forecast to be added in 2024.[493] The long-range forecast that underpins the customer connection forecast in the AMP shows a gradual decline in the annual customer attachments over the 10-year planning period.[494] However, Enbridge Gas must continue to respond to known and expected customer growth on its system now and in the near term, while following a rigorous process to closely monitor (and if necessary, make adjustments for) energy transition impacts going forward. For instance, in 2022 Enbridge Gas saw higher than expected customer additions[495], and is seeing customer additions trending higher than forecast in 2023.

425. The 2024 capital forecast for customer connections is $304.1 million, which was derived based on the updated customer connection forecast for 2024 and estimated costs for customer connections given the proposed connection policy[496]. As part of Phase 2 of Ontario's NGEP, community expansion projects to connect communities without natural gas access are forecast to cost $11.2 million in 2024 (net of NGEP funding). Many of these projects will still require the OEB's approval where leave-to-

[492] Exhibit 2, Tab 6, Schedule 2, Section 5.2.5.9.
[493] Exhibit 2, Tab 5, Schedule 2, paragraph 13.
[494] Exhibit I.2.6-ED-94 outline the 10-year customer additions forecast for Enbridge Gas and the energy transition forecasting assumptions for customer additions is provided at Exhibit 1, Tab 10, Schedule 4.
[495] Exhibit I.3.2-LPMA-22, Attachment 1 (see 2022 actual); Exhibit 3, Tab 2, Schedule 6, Attachment 1 (see 2022 estimate).
[496] Exhibit 1, Tab 15, Schedule 1, Attachment 1.

construct[497] is required. For clarity, community expansion investments are not included in the AMP but are part of the capital budget. Enbridge Gas's customer connections portfolio has experienced significant inflationary and other cost pressures in recent years. Please see the Argument submissions under Issue 6 regarding the various factors contributing to cost increases in customer connections (resulting in investment portfolio PI of less than 1.0 from 2021 to 2023) and the mitigation measures pursued by Enbridge Gas to mitigate and stabilize costs going forward.

426. System reinforcement projects total $85.2 million in 2024 and are required to maintain minimum pressures and ensure that demand for natural gas can be met under design day scenarios. This total includes $9.5 million for hydrogen blending[498], which relates to phase 2 of the LCEP that was completed in Markham in 2021. Phase 2 of the LCEP involves expanding hydrogen blending to an additional 12,400 customers. Enbridge Gas will also conduct a study to identify and prioritize which sections of the gas grid are best suited for future hydrogen blending and to determine any required upgrades.[499]

427. The OEB has identified the customer attachment policy as a topic of interest in Phase 1 of this proceeding. Although not an enumerated item on the Issues List, the customer attachment policy relates to a number of issues, including Issue 7. In addition to the submissions in this Argument under the Customer Attachment Policy section, Enbridge Gas notes that, if the OEB is seeking to change the revenue

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[497] As part of Enbridge Gas's feedback on the Ontario Electrification and Energy Transmission Panel's consultation (submitted on June 30, 2023), the Company has suggested ways to streamline the leave-to-construct criteria and review process for smaller pipeline projects, as part of the Government of Ontario's red tape reduction initiatives (see Compendium K1.4). For clarity, no changes with respect to the leave-to-construct criteria or process are being requested in this rebasing case.
[498] The Enbridge Gas hydrogen strategy is provided at Exhibit 4, Tab 2, Schedule 6. Section 3.3 of the AMP (Exhibit 2, Tab 6, Schedule 2, page 35) describes how low-carbon technologies and energy transition are included in the AMP.
[499] Exhibit 2, Tab 5, Schedule 2, paragraph 17.

horizon component of the feasibility assessment in this or another proceeding, there would be potentially a significant impact on the customer attachment portion of the 2024 capital budget.

428. Based on high level assumptions, Enbridge Gas has filed illustrative information regarding the possible impact of a shorter revenue horizon on the 2024 capital budget, as reproduced in Table 6: [500]

Table 6
Customer Connections Capital Expenditure Supported by Different Revenue Horizons

Line No.	Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer
	(Years)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	($ millions)	
1	40	304	248	258	254	250	1,314		
2	30	229	227	239	241	253	1,190	124	645
3	25	210	208	219	221	235	1,094	220	1,140
4	20	188	185	196	198	205	972	342	1,774
5	15	146	144	153	154	159	757	557	2,890
6	10	89	88	93	95	96	460	853	4,428

Note: 40-year revenue horizon reflects the Company's most updated capital forecast

429. The impact estimates outlined in the table were prepared based on a simplistic analysis (given the interest shown by the OEB and parties on this topic during the course of the Oral Hearing). It was assumed that every customer is assessed on the average connection cost and pays the contribution in aid of capital (CIAC) as an

[500] The table from Exhibit J11.1 is reproduced herein for ease of reference. J11.1 updated Table 1 (Customer Connections Capital Expenditure Supported by Different Revenue Horizons) from Exhibit K10.2 page 139 to incorporate a 20-year revenue horizon scenario and also provided certain corrections to Table 1, as noted in Exhibit J10.11. Also see J13.8, which updated Table 1 to include meters and other costs associated with new customer connections.

offset to capital cost to connect to gas. However, there are many more variables at play, including whether these customers actually decide to connect to gas in light of escalated CIACs and the fact that the CIAC payable by each customer could differ significantly based on the customized connection cost calculation for each connection.[501] Nonetheless, as a directional illustration, the table demonstrates the potentially significant implications of a shorter revenue horizon on the customer attachment-related capital forecast. This would in turn impact on the 2024 revenue requirement (though the impact will be smaller due to there being minimal test year impact from capital additions). There could or should also be impacts to customer connections asset lives and the Company's current depreciation proposal (see the Customer Attachments section and Depreciation section (Issue 15) of this Argument).

Storage and Transmission Operations

430. Investments in Storage and Transmission Operations total $115.5 million for 2024 (excluding PREP amounts) and include the Compression Stations and Transmission Pipelines and Underground Storage asset classes.

431. This total includes $46.3 million for Compression Stations. Enbridge Gas maintains a large fleet of compressors that operate to inject and withdraw natural gas from storage operations and transport natural gas along its network of transmission pipelines. Investments are required to both maintain and modernize the compressor fleet. The renewal strategy for compression assets targets the overhaul of compressor components based on run time, inspection, condition, OEM recommendations and subject matter advisor review. Full replacement is generally based on design life, historical obsolescence, and OEM equipment support.[502] Significant projects in 2024 include the Hagar 412FKR357 Major Overhaul and

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[501] 10 Tr.84.
[502] Exhibit 2, Tab 6, Schedule 2, Section 5.3.5.4.

Foundation Work, restoration costs for the Dawn to Corunna project and initial development costs for the Waubuno Compression Lifecycle.[503]

432. Investments related to Transmission Pipe and Underground Storage total $69.2 million for 2024, and include integrity projects required to maintain storage assets, replacements for pipelines and well equipment, and growth-related reinforcement projects. A significant maintenance project in 2024 is the PCRW (Crowland): Wells Upgrade. Growth-related reinforcement projects for 2024 include PREP and the Dawn Facilities portion of PREP. As noted above, Enbridge Gas is proposing a levelized treatment for PREP and has excluded the associated capital expenditures from the Capital Update.

433. PREP is a large project ($358 million inclusive of overheads) that is required to serve increasing demands in the Panhandle Market and is subject to LTC approval (EB-2022-0157). As noted in the updated LTC application filed on June 16, 2023, PREP consists of pipeline facilities and stations work forecast to be in service in 2024, and yard facilities that are forecast to be in service in 2025. Both the timing of the ongoing LTC application and the project's magnitude as one of the largest growth-driven investments ever undertaken by Enbridge Gas make PREP unique and, in Enbridge Gas's view, justify the proposed rate treatment.[504] For instance, while St. Laurent will be a large project, its 2024 in-service capital additions and revenue requirement ($76 million and sufficiency of $2 million, respectively) are much less when compared to PREP (which has 2024 in-service capital of $252 million and sufficiency of $14 million).[505]

434. Under the levelized proposal, the costs and incremental revenues attributable to PREP's forecast 2024 in-service component would be excluded from the

[503] Exhibit 2, Tab 5, Schedule 2, paragraph 24.
[504] 13 Tr.25.
[505] Exhibit JT13.1.

determination of the 2024 base revenue requirement. In this way, if forecast timing or costs are altered, or if OEB approval is not granted, then no adjustment to base rates or revenue requirement will be necessary. Subject to OEB approval of the PREP LTC application, Enbridge Gas proposes to separately calculate the forecast net revenue requirement of the project for the 2024 Test Year and each year of the 2025 to 2028 term, for inclusion into rates in a levelized manner. A separate unit rate will be calculated, based on the average of the 5-year net revenue requirement for the project, which would be implemented in the 2024 Test Year and remain fixed and in place for the duration of the IR term (or for the remainder of the term following OEB approval). The average unit rate would eliminate the rate fluctuations that would occur if the project's annual revenue requirement was treated as a Y factor each year.[506] As further discussed under Issue 32 (DVAs), Enbridge Gas proposes to establish an associated variance account, the PREP Variance Account (PREPVA), that would capture any variance between the project's actual net revenue requirement and the actual revenues collected through the average unit rate that would be in place over the IR term.

TIS

435. TIS investments total $102.4 million in 2024. These expenditures are required to ensure reliable TIS asset/system operations, reduce operational and cybersecurity risks, and enhance systems/processes for the integrated utility to address evolving business needs and implement changes as a result of 2024 rebasing.[507] Investments for each TIS asset category (Infrastructure, Software and Communications)[508] are prioritized to ensure functional fit of solutions, performance as intended over asset lifecycle, protection against threats and vulnerabilities,

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[506] Exhibit 2, Tab 5, Schedule 4, pages 30-31.
[507] Exhibit 2, Tab 5, Schedule 2, paragraph 27.
[508] TIS assets include: (1) Infrastructure – laptops/desktops, desktop sustainment equipment, and network and security infrastructure hardware; (2) Software – vendor applications, custom in-house applications, and application infrastructure software; and (3) Communications – mobile phones and field devices. (Exhibit 2, Tab 6, Schedule 2, page 234).

availability when and as required, ability to deliver support and maintenance services to address issues and maximize asset life, and continuous improvement in asset management and decision-making.[509]

436. To extend asset life and limit capital spend, Enbridge Gas generally optimizes its renewal cycle for TIS Infrastructure to be slightly longer than industry practice (e.g. 4-year cycle for laptops/desktops, versus 3-years based on industry best practice) or than the applicable warranty period (e.g., 5-year cycle for core and security infrastructure, versus 4-year warranty).[510] Software applications are generally managed through maintenance releases and defect fixes, until replacement is required due to business requirement changes or cessation of vendor support.[511]

437. Significant TIS capital spend in 2024 includes Contract Market Harmonization and Contract Market Systems – Technology Obsolescence and General Service Rebasing Changes. These projects are expected to be completed after 2024 during the next IR term and are required to, among other things, address technology obsolescence, enhance customer experience and ensure rates-related system requirements.[512]

REWS

438. REWS investments total $63.0 million for the 2024 budget, including expenditures related to workplace furnishings, building systems management, land purchases, construction of new facilities, renovations of current buildings, and opportunities to improve energy efficiency.[513] REWS assets include properties[514] (buildings and land) and furnishings. The requirements for these properties are primarily based on

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[509] Exhibit 2, Tab 6, Schedule 2, Section 5.6.1.
[510] Ibid, Section 5.6.8.2.
[511] Ibid, Section 5.6.8.3.
[512] Exhibit 2, Tab 5, Schedule 2, paragraph 27; Exhibit 2, Tab 6, Schedule 2, Section 5.6.8.3.1.
[513] Ibid, page 11.
[514] Properties are further categorized into regional operations and administrative centres, operations depots, land, operations micro-depots and head office.

function and headcount.[515] The Company undertakes facility assessments based on industry best practices to assess, among other things, property condition, operational functionality, gaps in service area coverage, and quality of indoor environments.[516]

439. Based on these assessments, Enbridge Gas targets and prioritizes REWS spend to address deficiencies such as inadequate building or yard size (which under-serve business demands), compliance issues (e.g., non-conformities with current Building Code standards), and inefficiencies or safety risks from site area constraints or configurations. These investments can take the form of renovations, new construction, site relocation or consolidation (including disposal), and continuing maintenance, and are important to protect health and safety, maintain efficiency of operations and administrative functions, and pursue building GHG emissions reduction.[517] Significant REWS projects in 2024 include construction for the Station B New Building (Toronto) and South Merivale Operations Centre (SMOC)/Coventry Facility Consolidation (Ottawa), both of which are required to replace or consolidate facilities that no longer meet operational requirements and are expected to be completed in 2025 and 2026 respectively.[518]

Fleet and Equipment

440. Investments in this category total $31.5 million for 2024, including expenditures related to vehicles, equipment and tools required for safe and efficient business operations.[519] Fleet and Equipment consists of three asset subclasses: Fleet (light, medium and heavy duty vehicles), Heavy Equipment (backhoes, trailers, compressors, forklifts, welders and boring equipment) and Tools (ranging from gas

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[515] Exhibit 2, Tab 6, Schedule 2, page 210.
[516] The resulting Functional Obsolescence or Adequacy Index scores illustrate functional condition as a percentage ratio of required functional upgrade costs divided by the asset's replacement value to meet functional needs. See Exhibit 2, Tab 6, Schedule 2, page 213, and Section 5.4.5.4.1.
[517] Exhibit 2, Tab 6, Schedule 2, Sections 5.4.5.5 and 5.4.7.1.
[518] Exhibit 2, Tab 5, Schedule 2, paragraph 26 and Exhibit 2, Tab 6, Schedule 2, Section 5.4.7.1.
[519] Ibid, paragraph 28.

surveyors and concrete saws to fusion machines, pipe squeeze-off tools and stop-tap tooling equipment). Enbridge Gas sustains the integrity of these assets through a strong maintenance program and leverages risk, cost, and performance information to drive asset decisions.[520] The optimal replacement strategy for all fleet vehicles is informed by analysis of cost curves for maintenance to achieve the lowest lifecycle cost, and replacement decisions are evaluated against this analysis as well as vehicle age, mileage, hours of use, condition, risk of failure and functional requirements. Heavy Equipment is evaluated based on detailed physical condition assessments and business needs, which inform the refurbishment vs replace decision and the optimal replacement cycle. Tools are replaced reactively based on obsolescence, condition and approval for use given evolving standards/practices.[521] The 2024 Fleet and Equipment budget is required to meet Enbridge Gas's vehicle replacement strategy and in response to limited purchases in 2023 caused by supply chain delays and reprioritization of replacements.[522]

Incorporation of Energy Transition in Capital Planning

441. While there is uncertainty regarding Ontario's potential pathways to a net-zero future, Enbridge Gas recognizes the importance of, and has started to pursue, prudent steps to advance energy transition, including safe bet actions that are necessary and prudent regardless of the pathway ultimately chosen for the province.[523] The proposed capital plan reflects a number of these steps as well adjustments to planning approach. As Mr. Wellington stated in his evidence-in-chief during the Oral Hearing:

> MR. WELLINGTON: Thank you, Mr. Stevens. Yes. So, in consideration of energy transition, in our capital plan, clearly there are important discussions ongoing about the province's energy transition and the different pathways that we need to take to achieve our net zero goals, all the while ensuring that we achieve the most affordable, reliable, and resilient result.

[520] Exhibit 2, Tab 6, Schedule 2, page 226.
[521] Ibid, Section 5.5.8.
[522] Exhibit 2, Tab 5, Schedule 3, pages 30 and 34.
[523] Exhibit 1, Tab 10, Schedule 6.

> Although there is some uncertainty, Enbridge has taken steps that are reflected in our capital plan, and I'd like to just take a moment to highlight a few of those steps.
>
> The first of them is that we consider energy transition assumptions in our growth reinforcement forecast.
>
> We have started embedding IRP alternatives into our planning process and we are starting to see the fruits of that.
>
> We have implemented a new enhanced distribution integrity management program, which will give us a more specific understanding of asset conditions so that we can reduce the extent to which we replace some of those assets.
>
> We have included a hydrogen study that will help us understand the ability of our grid, to accept more hydrogen in the future and whatever modifications may be necessary, if any, up to and including 100 percent hydrogen.
>
> We have included investments that consider, or allow for, the conversion of some customers to lower-carbon fuel, as well as including RNG investments in our portfolio.
>
> So the proposed plan must ensure that we can continue to be stewards of our natural gas infrastructure and ensure its safety and reliability, while considering optionality in the future of energy transition.[524]

442. Enbridge Gas is actively monitoring for clearer signals at a localized level as to how energy transition may impact utilization of its assets. Having said that, the signals must be both location and time specific to allow for prudent and data-based decision making and to avoid adverse consequences to reliable, safe, and resilient operations. It is not appropriate to include probabilistic modeling as part of the Company’s energy adjustments without such a reasonable degree of clarity.[525] Detailed explanation of how Enbridge Gas has factored energy transition into its system forecasts at both the system and local level is provided in the evidence.[526] As discussed in the Energy Transition section of this Argument (under Key Message 3), Enbridge Gas believes it is important to base forecasting and planning

[524] 11 Tr.103-104.
[525] 14 Tr.115.
[526] Exhibit J14.9 and Exhibit I.1.10-SEC-31.

assumptions on reasonably clear information and signals, especially in light of the in-progress and evolving government initiatives relating to energy transition. Further, with respect to a related planning notion suggested by Mr. Neme that each project be subject to a multitude of demand forecasts, Enbridge Gas has set out at the end of the Energy Transition section the reasons why such an approach would not be of value in practice.

443. In totality, Enbridge Gas believes the above-outlined steps and changes demonstrate an appropriate consideration of energy transition in the context of capital forecasting and in relation to the allocation and mitigation of associated risks (see Issue 3 on the Issues List). Each of these items is further discussed below, with cross-reference to related submissions under Issue 3 as applicable.

Incorporating Energy Transition Assumptions into Forecasting

444. As discussed in this Argument under Issue 3 (see Key Message 5), Enbridge Gas has incorporated consideration of energy transition into its forecasting to mitigate the risk of stranded assets within and beyond the 5-year IR period. Given that the forecasted number of customers and their gas use are important inputs into the AMP and directly affect the scope/timing of capital solutions, Enbridge Gas views this as a crucial step to assess and reflect the expected impact of energy transition on capital expenditures. The assumptions around potential impact were developed based on the Energy Transition Scenario Analysis (ETSA) study[527], current climate policies[528], input from stakeholder engagement[529], and understanding of market trends. As a result of this review, certain adjustment factors were developed and applied to the Company's forecasts and/or input variables, where deemed appropriate.[530]

[527] Exhibit 1, Tab 10, Schedule 5, Section 1 and Attachment 1.
[528] Exhibit 1, Tab 10, Schedule 3, Section 2.
[529] Exhibit 1, Tab 10, Schedule 5, Section 2.
[530] Exhibit 1, Tab 10, Schedule 4, paragraph 7.

445. These factors currently lead to reductions in the following areas over time: customer additions through new constructions and replacement conversions, existing customers once they reach end of equipment life, general service annual volume forecast, and design hour growth rate over time.[531] Since customer additions and design hour demand are inputs for design day demand, the various adjustments are also accounted for in the design day demand forecast.[532] These assumptions then flow into downstream planning activities, including impact on the AMP in the form of reduced distribution system needs and fewer reinforcements – translating to a reduction of $66 million (excluding overheads) to the Distribution Reinforcement Capital forecast relative to the previously filed AMP.[533] Based on Enbridge Gas's forecast, its distribution, transmission and storage assets will be used or useful in the 2024 to 2028 period and the Company does not foresee any set of circumstances where there would be a material risk of stranded assets during this time.[534]

446. Enbridge Gas recognizes that the incorporation of energy transition assumptions into the forecasting process has had a relatively small impact during the rate rebasing period,[535] and the impact beyond 2028 becomes greater.[536] However, the evidence demonstrates that Enbridge Gas is appropriately accounting for known energy transition factors, incorporating changes as policy signals become more certain, and building increased transparency into its forecasting and planning processes. Enbridge Gas will continue to monitor and evaluate any new climate policies being developed or implemented to determine the impact on Company forecasts.[537] It will also revisit its demand forecast annually relative to actuals and determine if scope or timing adjustments to the AMP are warranted (whether in relation to reinforcements,

[531] Exhibit 1, Tab 10, Schedule 4, pages 5-11.
[532] Ibid, pages 11-12.
[533] Ibid, paragraphs 36, 38-40.
[534] Exhibit I.1.10-OGVG-1 part e) and f).
[535] Exhibit 1, Tab 10, Schedule 4, paragraph 8 and 11 Tr.164.
[536] For instance, by 2032 annual additions are reduced by 4,774 customers per year (Exhibit 1, Tab 10, Schedule 4, paragraph 39).
[537] Exhibit 1, Tab 10, Schedule 4, paragraph 7.

relocations or replacements).[538] Where changes to demand forecasts occur, system needs can be re-evaluated along with the associated projects or alternatives prior to their planning and execution.[539]

447. Additionally, while the Company's demand forecast extends out to the end of the AMP window (i.e., 2023 to 2024 AMP is supported by a 2022 to 2032 demand forecast), Enbridge Gas will take into account relevant information gained beyond the end of that timeframe, including, for example, any municipal energy plans or electric local distribution company (LDC) plans.[540] Moreover, consideration of updated information will occur as part of Enbridge Gas's ongoing process to develop the AMP, which entails an AMP filing every two years and an update or addendum to the AMP in the intervening years.[541]

448. As a development that could impact Enbridge Gas's demand forecast, the Government of Ontario has called for an additional 1.5 million homes to be built in Ontario, according to its *More Homes Built Faster Act, 2022*.[542] Meeting this goal would require 150,000 homes to be constructed per year over the next decade. This government measure was not yet known at the time the Company's demand forecast was prepared and, therefore, does not have corresponding adjustments in Enbridge Gas's projected customer additions.[543] Directionally, this will result in some upward impact on customer attachments over the next decade, although the exact magnitude of impact and any required plan adjustments will not be defined until further details become available, such as the likely locations and types of homes to be built. For instance, as discussed during the hearing, the North Brooklin Community is an example of a large-scale subdivision development that seeks

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[538] 11 Tr.163-164.
[539] Exhibit 1, Schedule 10, Schedule 4, Section 2.2.
[540] 11 Tr.162-163.
[541] Exhibit 2, Tab 6, Schedule 1, paragraph 4.
[542] S.O. 2022, Ch. 21, Royal Assent received November 28, 2022.
[543] 14 Tr.130-131.

sustainability and is expected to have some level of gas service.[544] Enbridge Gas will closely monitor any development in this regard and incorporate any associated assumptions and updates into its attachment forecast and customer connections budget as appropriate. Should the OEB choose to reduce the revenue horizon for customer attachment feasibility analysis, it is important to recognize that this change could lower both the number of attachments and the associated capital budget, which would also be reflected in future forecasts.

Incorporating IRP into Asset Management Process

449. Enbridge Gas considers IRP a key component of its Energy Transition Plan and has incorporated IRP into its asset management process in accordance with the OEB's IRP Decision and Order and IRP Framework.[545] The above-described AIPM process includes IRP assessment to determine whether an IRPA evaluation is required for each system need and, if so, whether a cost-effective IRPA exists. The ability to defer or avoid infrastructure helps Enbridge Gas to manage the uncertainty stemming from energy transition[546], ensuring that the Company will be better positioned when energy policy unfolds in a more concrete way, regardless of which pathway comes to fruition.[547]

450. Enbridge Gas applies the IRP Binary Screening and the IRPA evaluation, to determine the best approach to meet identified system needs/constraints. In a project-specific application (LTC or IRP Plan), the utility demonstrates that it has followed this process including the results of the analysis at each of the following

[544] 14 Tr.131.
[545] EB-2020-0091.
[546] Note that the Settlement Proposal included agreed upon modifications to the IRP Operating Cost and Capital Cost Deferral Accounts. In effect, each account will be modified to recognize offsetting amounts in the account balances to reflect avoided operating cost or avoided revenue requirement amounts already included in rates, as applicable, related to facilities projects that are delayed, avoided or downsized by IRP.
[547] Exhibit 1, Tab 10, Schedule 15, paragraph 43.

stages: identification of constraints, Binary Screening, two-stage (technical and economic) evaluation, and periodic review.[548]

451. In particular, the Binary Screening is intended to screen out projects falling under the categories of projects that do not warrant IRP evaluation as noted in the OEB's IRP Decision[549] Projects that have passed the Binary Screening will then undergo technical evaluation, which assesses the technical feasibility and likelihood of each IRPA eliminating, reducing, or deferring the project scope. IRPAs include CNG, market-based supply side, demand response, enhanced targeted energy efficiency, and other technologies that can reduce or shift peak hour consumption.[550] Enbridge Gas is targeting the completion of technical evaluation of growth projects in the AMP by the end of 2023.

452. With 2022 being the first year that the Company has implemented the IRP assessment process, projects were evaluated after the capital portfolio was produced during the AIPM process. It is anticipated that over the next couple of years, IRP assessment would also occur during the Solution Planning and Value Assessment step, so as to ensure all projects have been assessed and re-evaluated as required.[551] Enbridge Gas intends to file a 2025 to 2034 AMP with the OEB in October 2024. IRP evaluations will also continue as part of the alternatives assessment for any leave-to-construct projects.[552]

453. Appendix B of the AMP reflects the current state of Enbridge Gas's IRP assessment process which includes identifying the projects that passed or failed the Binary Screening and a status update on the technical and economic evaluations of those

[548] Exhibit 2, Tab 6, Schedule 1, Section 4.3.4.1.
[549] EB-2020-0091 Decision and Order, pages 47-49.
[550] Exhibit I.2.5-PP-31, part c). Also see Exhibit I.2.6-STAFF-81, part a) and Exhibit 2, Tab 6, Schedule 2, Section 6.3.4.
[551] Exhibit 2, Tab 6, Schedule 2, Section 4.3.4.1.
[552] Exhibit 2.6-SEC-70.

projects that passed the Binary Screening.[553] The number of gas carrying projects passing Binary Screening was 886, and 1,392 projects failed the Binary Screening.[554]

454. If during the AMP's update process there is a material change to the scope of a project that had previously failed a Binary Screening and it now passed, the project will undergo a technical evaluation. In addition, all projects, including those that had failed the Binary Screening, will have their scopes confirmed at the detailed design phase before filing an LTC application, if applicable, and if the scope has changed materially another Binary Screening and technical evaluation will be completed. In addition, if there is potential for other IRPAs to be implemented due to changes in the IRP framework, these projects will be re-evaluated.[555] An addendum to the Enbridge Gas AMP will be filed by Q4 2023 which will include IRP updates.[556]

455. To provide learnings and a better understanding of the impact of IRPAs on avoiding, deferring, or reducing facility projects, two pilot projects – Parry Sound Pilot Project and the Southern Lake Huron Pilot Project (EB-2022-0335) – were filed with the OEB on July 19, 2023. As a major milestone in the ongoing IRP efforts, the pilots will also provide learnings on the DCF+ economic evaluation, IRPA program designs, implementation, and evaluation of IRPAs. The potential for scalability and transferability of the pilot learnings to other projects are a key consideration.[557] The next major step will be the first non-pilot IRP Plan, which Enbridge Gas hopes to file with the OEB by early to mid 2024.[558]

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[553] See updated Appendix B in Exhibit I.2.6-STAFF-82, Attachment 1.
[554] Exhibit I.2.5-PP-31 part e).
[555] Ibid.
[556] Ibid, part b).
[557] Exhibit 2, Tab 6, Schedule 2, Section 6.3.5.2.
[558] 14 Tr.85-86.

456. Enbridge Gas will continue to assess investments in the 10-year capital plan for IRPA feasibility. It will also continue with regional IRP stakeholder and Indigenous engagement activities pursuant to the IRP Decision, with the goal of gaining additional insights into region-specific energy transition plans, policies and targets and continuously improving Enbridge Gas's forecasting, AMP and IRP processes based on such insights.[559]

Enhanced Distribution Integrity Management Program (EDIMP)

457. Enbridge Gas has a set of robust practices for assessing distribution pipeline asset condition and risk that meet or exceed code requirements and industry standards and has continued to improve on those practices through programs such as the Enhanced DIMP or EDIMP.[560]

458. The EDIMP addresses the concerns raised by the OEB in Enbridge Gas's St. Laurent Ottawa North Replacement Project, which stated:[561]

> The OEB suggests Enbridge Gas take a proactive approach to inspecting and maintaining the subject pipeline until it can be demonstrated that pipeline replacement is necessary. This may include development and implementation of an in-line inspection and maintenance program using available modern technology as discussed in the next section. The evidence in this proceeding revealed that Enbridge Gas does not currently have the necessary infrastructure to carry out such in-line inspections in the St. Laurent Pipeline.

459. Based upon this direction from the OEB, Enbridge Gas has initiated a multi-pronged integrity plan to further establish the condition of St. Laurent Ottawa North Pipeline.

460. As part of the EDIMP, Enbridge Gas is focusing on a subset of the DIMP pipelines that are high pressure and large diameter[562] and that would benefit from more

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[559] Exhibit 1, Tab 10, Schedule 15, paragraph 46.
[560] 11 Tr.98.
[561] EB-2020-0293 Decision and Order, May 3, 2022, page 16.
[562] The proposed criteria are: operating at pressures above 700 kPa; NPS 6 or greater; over 1km in length; and older than 50 years of age (Exhibit 1, Schedule 13, Schedule 3, paragraph 10).

extensive condition monitoring.[563] As noted above, this program targets 8,000 km (out of 32,802 km) of vintage steel distribution pipes, many of which are vital mains supplying some of the large service areas that were the first to receive natural gas in the 1950s or 1960s.[564] Resulting information will be used to complete risk assessments and ultimately inform recommendations for required asset intervention to support continued safe, reliable and resilient operations.

461. Accurately understanding asset condition is crucial to the appropriate selection and right-sizing of asset intervention strategies through data- and risk-driven decisions. Along with demand forecasting improvements to reflect energy transition factors and IRP assessments to identify potential non-pipe alternatives, EDIMP is another tool that could help to potentially delay or avoid costly and time-consuming pipe replacement projects and to identify proactive mitigation projects which may extend the life of the asset.[565] If found to be feasible, such life extension and deferral or avoidance of capital replacements would directly support Enbridge Gas's efforts to mitigate energy transition risks and identify non-pipe solutions.

462. The actual outcome of EDIMP efforts will of course depend on the specific findings from the field.[566] There may be circumstances where asset replacements are deferred or avoided as mentioned above based on EDIMP data, or where replacements are found to be necessary due to identified end-of-life condition and associated failure risks. In either scenario, the ultimate asset management decision would be anchored by enhanced condition data regarding key pipeline assets and there would be a high degree of certainty regarding the underlying asset need/constraint as well as the chosen asset strategy.

[563] Exhibit 1, Tab 13, Schedule 3, page 4.
[564] 5 TC Tr.71 and 4 Tr.99.
[565] Exhibit 1, Tab 13, Schedule 3, paragraphs 15-16.
[566] 11 Tr.190-191.

463. To provide greater regulatory visibility, as part of the Settlement Proposal related to the DIMP Costs Variance Account (which will cover both DIMP and EDIMP), Enbridge Gas has committed to provide annual reporting on actual DIMP/EDIMP spending, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP/EDIMP work done during the past year.[567]

Critical Role of Low Carbon Fuels in Achieving Net-Zero

464. Enbridge Gas believes that low carbon fuels (RNG and hydrogen) have a critical role Ontario's net-zero future, regardless of the pathway that will materialize.[568] As RNG becomes more available, Enbridge Gas's RNG strategy[569] will continue to support customer stations that allow producers to inject their lower-carbon fuel into the distribution system, which is also one of the Safe Bet actions under the Company's Energy Transition Plan.[570] RNG-related amounts total approximately $94.6 million in 2024 and $316.5 million over the AMP period.[571] With respect to hydrogen, Enbridge Gas is building on the success of the LCEP[572] (providing ~2% blend to approximately 3,600 customers in Markham), and moving forward with Phase 2 of the LCEP to expand hydrogen blending to an additional 12,400 customers. Enbridge Gas will also conduct a hydrogen feasibility study regarding the grid potential to accept increased blending and assess required upgrades.[573] The hydrogen feasibility study has a 2024 forecast of $5.8 million ($15.4 million over the AMP period), and the LCEP Phase 2 has a 2024 forecast of $1.9 million ($9.0 million over the AMP period).[574]

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[567] Exhibit O1, Tab 1, Schedule 1, page 56.
[568] 2 Tr.130.
[569] Exhibit I.2.6-PP-38.
[570] Exhibit 1, Tab 10, Schedule 6, page 1 and Exhibit 2, Tab 6, Schedule 2, Section 5.2.4.6.1.7.
[571] Exhibit JT5.9 (Capital Update).
[572] Exhibit 4, Tab 2, Schedule 6.
[573] Exhibit 2, Tab 5, Schedule 2, paragraph 17.
[574] Exhibit 2, Tab 6, Schedule 1, Table 5 (Investment Code 736974 – Hydrogen Blending Phase 2) and Table 6 (Investment Code 736975 - Enbridge Gas Distribution System Hydrogen Feasibility Study).

465. As these topics are discussed extensively under the Energy Transition section of the Argument, please refer to that section for further details.

D. Operating Expenses (Exhibit 4)

Depreciation Expense

466. Issue 15 – Are the proposed harmonized depreciation rates and the 2024 Test Year depreciation expense appropriate?

467. Issue 16 – Are the proposed 2024 Site Restoration Costs appropriate, and should the OEB establish a segregated fund for the Site Restoration Costs?

Consequences Of Settlement Proposal

468. There was no settlement of either of these issues.

Outstanding Approvals Required

469. Enbridge Gas requests approval of the harmonized depreciation methodologies proposed by Concentric Energy Advisors (Concentric) as set out in their 2021 depreciation study as updated by the Capital Update.[575] In summary, Enbridge Gas seeks approval for the harmonization of certain former EGD and Union assets into specific accounts, the use of the Equal Life Group (ELG) depreciation methodology and the continued use of the Constant Dollar Net Salvage (CDNS) methodology for calculating net salvage previously approved by the OEB for use by EGD for all applicable Enbridge Gas assets. Enbridge Gas further seeks approval for the survivor curve and net salvage parameter determinations made by Concentric as set out in its 2021 depreciation study as updated.

[575] Exhibit 4, Tab 5, Schedule 1, Attachment 1. (Updated by Exhibit 2, Tab 5, Schedule 4, pages 4, 6, 28, 29 and 36, and Attachment 1).

Revenue Requirement Implications for 2024

470. Based on the methodologies proposed by Concentric and its recommended determinations in respect of survivor curves and net salvage parameters, the depreciation expense provision for 2024 is calculated at $879 million.[576]

471. This depreciation expense represents an increase of $141.9 million over the forecasted 2024 depreciation accrual at current (2023) depreciation rates of $737.1 million.[577]

Evidence in Support

472. Enbridge Gas filed detailed evidence about the proposed harmonized depreciation expense methodologies at Exhibit 4, Tab 5. This includes the 2021 depreciation study prepared by the depreciation experts Mr. Larry Kennedy and Ms. Amanda Nori of Concentric. This study was subsequently updated with the use of additional historical Union retirement data.[578] Enbridge Gas answered follow-up questions in associated interrogatories[579], Technical Conference testimony[580], Technical Conference undertakings[581] and filed several ADR responses[582].

473. Enbridge Gas witnesses provided testimony about this issue on Days 16 and 17 of the Oral Hearing (Panel 15)[583]. The Enbridge Gas panel also consisted of two depreciation experts, Mr. Kennedy and Ms. Nori.

474. OEB Staff engaged Mr. Bowman and Mr. Mahmudov of Intergroup Consultants Ltd. (Intergroup) to undertake an assessment of the evidence of Enbridge Gas on

576 Exhibit J17.1, Attachment 1.
577 Exhibit J16.5, Attachment 1
578 Exhibit 2, Tab 5, Schedule 4, pages 4, 6, 28, 29 and 36; and Attachment 1.
579 Exhibit I.4.5.
580 4 TC Tr.2-198.
581 Exhibits JT4.3-4.18 and JT4.20.
582 Exhibits I.ADR.22 and I.ADR.25.
583 16 Tr.69-199 and 17 Tr.1-172.

proposed depreciation parameters including the Concentric depreciation study. Intergroup's study was filed as Exhibit M1. Intergroup provided testimony on Days 17 and 18 of the Oral Hearing (Panel 16)[584]. IGUA engaged Mr. Dustin Madsen of Emrydia Consulting Corporation (Emrydia) to prepare testimony in relation to depreciation matters. Emrydia's study is filed as Exhibit M5. Mr. Madsen provided testimony on Day 18 of the Oral Hearing (Panel 17)[585].

<u>Overview</u>

475. With the amalgamation of EGD and Union, it became apparent that certain similar assets at each of the two legacy utilities were classified differently. Enbridge Gas also believed it was appropriate to undertake an up-to-date depreciation study for the purposes of this rebasing application and to consider how the different depreciation methodologies used by the two legacy utilities should be harmonized. Enbridge Gas retained Concentric for these purposes.

476. Concentric completed an extensive and detailed review of all relevant data and the different methodologies and parameters used by the two legacy utilities. Aside from using different average service lives, Iowa curves and salvage parameters for numerous assets, EGD determined its depreciation expense using the Average Life Group (ALG) Methodology whereas Union utilized the Generational Arrangement (GA) methodology. In respect of net salvage, EGD used the CDNS method while Union used the Traditional Approach. As well, Union used amortization accounting for certain assets while EGD did not. Concentric's review of the various asset classes also highlighted differences in the classification of similar distribution and transmission assets for depreciation purposes.[586]

[584] 17 Tr.172-201.18 Tr.1-60.
[585] 18 Tr.60-83.
[586] Exhibit 4, Tab 5, Schedule 1, page 9.

477. Following completion of its review of the various methodologies and parameters used by the two legacy utilities, Concentric recommended that Enbridge Gas:

a) Adopt the ELG depreciation methodology applied on a remaining life basis;
b) Continue to use the CDNS methodology for the purposes of net salvage with the use of a discount rate of 3.75%;[587]
c) Harmonize certain assets which were included by EGD and Union in different accounts;
d) Harmonize average service lives and Iowa curves for the various asset classes;
e) Reclassify appropriate assets into amortization accounts where appropriate;
f) Harmonize the net salvage parameters for appropriate asset accounts; and,
g) To not utilize an Economic Planning Horizon (EPH) for all or any subset of accounts at this time.

478. Enbridge Gas notes that in Procedural Order No. 6, the OEB stated that the following matters are of particular interest to it:

- The risks that have been identified in relation to the energy transition, including the risks that assets may be stranded, <u>and the regulatory options to mitigate those risks in relation to system access and system renewal investments</u>.
- Regulatory options for managing revenue related to site restoration costs.[588]

479. In respect of matters relating to future site restoration costs, for reasons stated in this argument and in evidence, Enbridge Gas does not propose the creation of a segregated fund. This argument will now examine the various methodologies and parameters for which approval is sought under the following subheadings.

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[587] Exhibit 4, Tab 5, Schedule 1, Attachment 1, page 24.
[588] Procedural Order No. 6, July 23, 2023, page 5.

Reclassification of Certain Assets

480. Union used both distribution and transmission classifications for pipelines but the definitions for the Union North and Union South rate zones were not aligned. As well, EGD and Union did not similarly classify all assets. Enbridge Gas understandably was desirous of harmonizing the classification of assets and asked Concentric to advise on the impacts of the reclassifications and the appropriate treatment of the reclassified assets from a depreciation perspective.[589] The proposed reclassification of assets is set out in Tables 3 through 7 of the pre-filed evidence.[590] The harmonization of these assets within the amalgamated utility, it is presumed, is not contentious. However, it is understood that the movement of EGD's regulators into account 474 from 473.01, which relates to metal services, and the corresponding impact on the depreciation expense is an open issue which is discussed specifically below.

481. The Company further notes that in the Capital Update filed in June 2023, it proposed a revised depreciation rate for account 472.35 Mainway. The Concentric Depreciation study initially proposed a truncation date of 2023 for the Mainway asset as it was expected to be retired as part of the facility consolidation for the new Greater Toronto Area (GTA) West site. The update noted that Enbridge Gas is re-evaluating the costs and timing of the GTA East and West projects due to delays to the construction schedules and a forecasted increase in the construction costs for the facilities. The revised truncation date for the Mainway asset is now 2027. The depreciation rate has been updated to 14.21% and the revised depreciation expense for the 2024 Test Year is $2.6 million.[591] This change is reflected in the depreciation expense updates that have been filed in Exhibit 2, Tab 5, Schedule 4, page 29; and Attachment 1.

[589] Exhibit 4, Tab 5, Schedule 1, page 10.
[590] Ibid, pages 10-15.
[591] Exhibit 2, Tab 5, Schedule 4, page 29.

Depreciation Methodology

482. As noted in the Concentric study, there are various methods which a regulated utility can consider for the purposes of calculating the depreciation provision. EGD and Union employed different depreciation methodologies. EGD used the ALG method while Union employed the GA method. Following its review of the previous depreciation studies completed for the legacy utilities and relevant data, Concentric recommended the use of the ELG method as it more accurately reflects the actual life of the assets used.[592] The Concentric study proceeded to then calculate the annual and accrued depreciation using the straight-line method and ELG procedure applied on a remaining life basis for most accounts. In respect of certain asset accounts, Concentric recommended the approach Union followed where the annual and accrued depreciation expense is based on amortization accounting. It is Concentric's expert opinion that the use of the ELG procedure enhances the generational equity to all customers and is particularly appropriate given the energy transition issues which have been considered throughout this proceeding.

483. In a response to OEB Staff, Concentric confirmed that the ELG procedure has long been recognized as the most precise procedure by depreciation authorities as the ELG procedure uses more complex mathematical calculations relative to the ALG procedure. [593] Concentric noted that until the advent of supportive computer programs, the ALG procedure was more widely used but with the advancement of supportive applications, the ELG Methodology is a practical and one that is used in many provinces across the country and in other industries throughout North America.[594]. In the same interrogatory response to OEB Staff, Concentric noted the following two significant advantages of the ELG procedure over the ALG procedure:

> Firstly, the use of the ELG procedure was the best available match to the historic procedures approved for Union Gas. Secondly, given the potential changes in use of fossil fuels and the unknown impact of such

[592] Exhibit 4, Tab 1, Schedule 1, Attachment 1, page 16.
[593] Exhibit I.4.5-STAFF-173, page 2.
[594] 16 Tr.110.

> change on the Enbridge Gas system, the use of the ELG procedure best reduced the future risk of intergenerational inequity.[595]

484. In the same response, Concentric further discussed the benefits of the ELG Methodology from the perspective of generational equity stating:

> Specifically in the circumstances of Enbridge Gas, the above generational equity concerns are particularly relevant given the energy policy requirements that are emerging in the natural gas utility sector. As such, the ELG calculations which more closely align the depreciation rates to the retirement dispersion patterns inherent in the Iowa curve selections, will lessen the impact to customers from any type of energy transition, thereby reducing the impact of potential future carbon-based energy policies.[596]

485. While under cross examination about Concentric's recommendation to use the ELG Methodology, Mr. Kennedy stated:

> It is an accepted procedure with or without energy transition, but it definitely does provide increased or decreased risk of unrecovered investment, and so, given that we saw that wave of energy transition coming, we thought that was the logical first step[597]

486. Mr. Kennedy further added while still under cross examination:

> And it was my opinion that the equal life group procedure better addresses intergenerational equity issues in many circumstances. It is maybe heightened in this period of energy transition, but it is a method that we have used in many provinces across the country. It has been used for many decades in other industries throughout North America. So it does have some very significant intergenerational benefits.
>
> And my view in this response was highlighting that, in this case, it is particularly relevant to deal with those intergenerational equities that may occur in the case of energy transition.
>
> The beauty, I think, of the recommendation we are making is that ELG is perhaps the right method anyway, regardless of energy transition. But it is a great first step into that transition, on a very thoughtful and considered approach.
>
> If, in fact, energy transition occurs at the pace that it may be going, the system may have many assets that would exist on very long-lived assets where they won't need an EPH. But there definitely is going to be interim retirement activity. There has been for many decades, historically, and

[595] Exhibit I.4.5-STAFF-173, page 3.
[596] Ibid.
[597] 16 Tr.102.

> there will be going forward. And the equal life group deals with those intergenerational equities related to those interim retirement transactions.
>
> It also provides the benefit that in the case of energy transition requiring accelerated levels of retirement on some assets -- some, may not all -- it provides the benefit to reduce the intergenerational inequity issues with regard to that scenario.[598]

487. Concentric noted in evidence that the approval and use of the ELG procedure in the calculation of the depreciation rates is key to minimize the risk of under recovery of the investment in property, plant and equipment.[599] Stated differently, as the ELG procedure has a higher accrual rate in the earlier years of an account[600], a fact which OEB Staff depreciation expert Mr. Bowman confirmed at the hearing[601], this has a resulting decrease in the risk of stranded assets and costs. This is demonstrated in the response at Exhibit J17.4 to the request that Concentric populate a table with the depreciation impacts using assumptions posed by SEC. Attachment 1 to the response confirms Concentric's explanation of how the ELG Methodology works in comparison to the ALG methodology. In the scenario given and subject to the assumptions listed in the response, the ELG procedure recovers a modestly higher depreciation amount from the beginning but in time there is a pivot such that in the later 15 years in this hypothetical example the depreciation expense under the ELG Methodology is less than is the case under the ALG methodology.

488. Intuitively, if there is a material risk of declining throughput in future years, it follows that business as usual depreciation calculations such as the ALG procedure should be avoided and a more accelerated recovery of depreciation undertaken. Collectively looking at the views expressed by the Concentric depreciation experts, it is submitted that the conclusion that can be reached is that Concentric views the ELG procedure as an appropriate but balanced or moderated response to the

[598] 16 Tr.110-111.
[599] Exhibit I.4.5-ED-139.
[600] Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 14 and 15.
[601] 17 Tr.184.

impacts of energy transition and in particular the concerns expressed in regard to stranded assets.

489. Enbridge Gas accepted and proposes for approval by the OEB the recommendations made by Concentric about utilizing the ELG Methodology. Ms. Giridhar, who is a member of the executive team responsible for regulatory strategy around rebasing, confirmed that she was personally involved in the decisions made about such matters and that the executive team was informed by the energy transition issues. She specifically stated while under cross examination by counsel for IGUA that:

> The ability to address intergenerational equity by ensuring that the consumption of the asset reflects the benefits at the same time period in which the benefits are derived was inherently attractive. And the reason it is attractive is that, as a result of energy transition, we certainly -- whether we adopted EPH or not, which also we investigated, so clearly that was a driver, we wanted to make sure that we weren't starting off on the wrong foot.
>
> You don't want to be attributing the consumption of...an asset today, into the future.[602]

490. The intervenor depreciation witnesses, Intergroup and Emrydia, both recommend the use of the ALG procedure. It appears that their support for the use of the ALG procedure is based on the fact that it is more commonly used and a simpler methodology but neither Intergroup nor Emrydia were able to point to any fault with the ELG Methodology that would warrant not considering it. Indeed Mr. Madsen agrees that the ELG procedure may provide for a more theoretically accurate calculation of depreciation expense[603]. Concentric did not accept that the ALG procedure as suggested by Mr. Madsen will better fit the retirement pattern of assets than the ELG procedure. Mr. Kennedy made it clear under cross examination that the ELG procedure, while more complex, is more precise because you have distinct subgroups of assets for each asset class and a distinct depreciation provision for

[602] 16 Tr.90-92.
[603] Exhibit M5, page 17.

each subgroup.[604] Enbridge Gas notes that Mr. Madsen failed to point to any depreciation textbook or study for his unfounded assertions that the ALG methodology has been determined to be superior by any depreciation authority.[605]

491. Surprisingly, while both Intergroup and Emrydia took the view that energy transition issues are real and present, as noted by Mr. Kennedy, they did not recommend the adoption of the ELG procedure nor take a more moderate view on the average service lives and Iowa curves for various assets despite being tools available to address energy transition issues.[606] As stated by Mr. Kennedy while under cross-examination by counsel for GEC:

> I would suggest that the use of the average life group method is one that really kind of in essence puts your head in the sand. Particularly using an average life group method with the significant extending of average service life estimates, that's really ignoring the impact of energy transition; whereas the equal life group with a moderated life estimate increase or in most cases decreases is a step in that direction at this point in time.

492. In the Intergroup report, Mr. Bowman confirms that the reasons given by Concentric in support of using the ELG procedure are the common list of the benefits of the ELG.[607] He acknowledges that it is in use in various jurisdictions but that its use is not common. This said, it appears that Intergroup's main objection to the ELG procedure is as follows:

> The justification for adopting ELG due to a pending energy transition is misdirected. The issue of energy transition is a significant matter of policy that should be addressed directly through decisions of the regulator, not through the selection of a technical change in depreciation methodology.[608]

493. While Mr. Bowman of Intergroup claimed during the Oral Hearing to have had an "eye to energy transition" he stated that it is difficult, if not premature, to think about

[604] 16 Tr.127.
[605] Exhibit N.M5.EGI-37, page 1, paragraph (a).
[606] 16 Tr.73-74.
[607] Exhibit M1, page 25.
[608] Ibid, page 6.

how to adjust depreciation estimates and calculations for some of the energy transition concerns[609]. In other words, Mr. Bowman and, as is clear from the Emrydia report, Mr. Madsen, did not view energy transition concerns as being relevant for the purposes of proposing the appropriate depreciation methodology even though the ELG Methodology clearly modestly accelerates the recovery of depreciation in the earlier years of an account. While both Messrs. Bowman and Madsen may point to the fact that their reports predate the OEB‘s statement that it had particular interest in the: ”risks that have been identified in relation to the energy transition, including the risk that assets may be stranded“[610] as stated in Procedural Order No. 6, Enbridge Gas submits that this explanation would be unsatisfactory. The fact is that both the Company and Concentric considered energy transition issues throughout the application including in respect of depreciation. Intergroup and Emrydia should have, but failed to, appropriately include energy transition issues in their analysis.

494. Enbridge Gas and Concentric are of the view that by using the ELG Methodology they have taken a moderate but appropriate step in addressing energy transition issues.[611] As noted by IGUA expert witness, Dr. Hopkins, accelerated depreciation is a tool which is advocated in leading states in the United States.[612] Dr. Hopkins' report stands for the proposition that "business as usual", depreciation expense methodologies are no longer appropriate. While Messrs. Bowman and Madsen do not support the use of the ELG Methodology, both acknowledge that the ELG Methodology is a more aggressive depreciation methodology as it recovers a larger portion of the depreciation expense in the earlier years of an account.

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[609] 17 Tr.182.
[610] Procedural Order No. 6, June 23, 2023.
[611] 16 Tr.73-74 and 79.
[612] Exhibit M8, pages 40-42, Attachment 3.

495. In the end, it appears that the biggest reason why both Intergroup and Emrydia oppose the use of the ELG procedure is because it would yield a modestly higher depreciation expense compared to ALG (by approximately $72.6 million based on the 2021 depreciation study).[613] The difference between the ELG and ALG methodologies in the Test Year is $83.4 million.[614] This is of course a reflection of the fact that the ELG Methodology does recover a greater amount upfront.

496. It is noteworthy that several of the parties to this proceeding appear to agree with the need to implement a much more aggressive depreciation methodology, perhaps even implementing EPH's at this time. While more will be said about EPH's under a separate heading below, Enbridge Gas believes the OEB should be concerned about requiring the use of methodologies which would likely have undesirable consequences and accelerate the risk of stranding assets by encouraging customers to leave the system precipitously. As noted by the OEB Staff's expert witness, Mr. Goulding of LEI, accelerating depreciation to such an extent that it discourages customers from remaining on the system would be an unwelcome result[615].

<u>Net Salvage Approaches for Site Restoration Costs</u>

497. The purpose of net salvage is to recover sufficient funds to meet annual site restoration and removal costs and to add to the site restoration accrual balance which will be available for future use. For context, Concentric estimated the cost today to decommission all of the Company's assets currently in service would be approximately $6.9 billion.[616] To date, Enbridge Gas has accumulated net site restoration costs of $1.6 billion.

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[613] Exhibit K16.2.
[614] Exhibit J17.9, Attachment 1.
[615] 9 Tr.143.
[616] Exhibit JT4.15.

498. All of the depreciation experts agree that the net salvage methodology and parameters used should fully recover forecast site removal and future site restoration cost amounts. Indeed, Mr. Bowman was adamant that his recommendations were never intended to reduce the annual net salvage provision to only $5 million which was the preliminary determination made by Concentric should the net salvage parameters of Intergroup and Emrydia be applied.[617] In response to undertaking Exhibit J16.6, Concentric recalculated the impact and determined that the net salvage accrual using the ALG procedure with a discount rate of 6.03% would decline even further to $325,472. In oral evidence, Mr. Bowman, stated that he hoped his recommendations would lead to an increase in the net salvage.[618] The evidence forecasts annual removal costs alone at around $60 million.[619] Directionally, the evidence shows that annual removal costs have been on the rise and could fluctuate significantly depending on the assets being retired. For example, in 2022, Enbridge Gas' site restoration costs net of proceeds were $64.1 million, and are forecasted to be $97.1 million in 2023.[620] The important starting point for any discussion about net salvage therefore is that whatever methodology is chosen, it must demonstrate an ability to recover sufficient funds to cover both annual site removal costs and add to the accrual balance for future use. Under the CDNS as proposed by Concentric using a 3.75% discount rate, the provision that would be generated in the Test Year is $96.3 million.[621] As noted in the response to undertaking Exhibit J17.5, the use of a discount rate higher than 3.75% would jeopardize the likelihood that sufficient funds will be recovered. This is a result that none of the depreciation experts would support.

[617] Exhibit K16.2.
[618] 17 Tr.186.
[619] Exhibit 1.1.8-STAFF-17, part f) and 16 Tr.75.
[620] Exhibit 2, Tab 2, Schedule 1, page 4, Table 2, line 5.
[621] Exhibit J17.5.

499. It should be recalled that EGD received approval to use the CDNS method from the OEB in its 2014 to 2018 Rate Application.[622] Mr. Bowman accepts the fact that Enbridge Gas's current depreciation expert, Mr. Kennedy, proposed the CDNS methodology in EGD's 2014 to 2018 Rate Application and that this methodology was accepted by the OEB. Mr. Bowman also accepted the fact that the description of the CDNS methodology that Mr. Kennedy proposed in the earlier EGD proceeding is identical with the methodology proposed here and that the OEB-approved discount rate for net salvage purposes was 3.095%.[623]

500. In response to concerns expressed that the CDNS methodology as approved by the OEB was not recovering sufficient removal and site restoration costs,[624] Mr. Bowman was taken to the table filed in evidence which sets out the historical amounts of net salvage recovered.[625] This table clearly shows that Enbridge Gas has been recovering annual site removal costs and it has been adding to the site restoration accrual balance. Mr. Bowman accepted that this appears to be the case.[626] It is therefore factually apparent that the CDNS methodology which the OEB previously approved and which Enbridge Gas proposes in this proceeding is working appropriately. However, from Exhibit J17.5 and Exhibit J17.9, it is also apparent that CDNS will only continue recovering sufficient net salvage amounts as long as an appropriate discount rate is applied. The impact of utilizing the CDNS method using various discount rates on the depreciation provision has been calculated and included in the undertaking response to OEB Staff at Exhibit J17.9 and Exhibit J17.5. The results show that the CDNS methodology using a discount rate of 3.75% (or lower) with Concentric's recommended ELG method, average service lives and survivor curves provides for the recovery of sufficient removal and site restoration costs. It is clear from these responses, that when using the CDNS methodology with

[622] EB-2012-0459, Decision with Reasons, July 17, 2014.
[623] 18 Tr.34-37.
[624] 18 Tr.32.
[625] Exhibit I.4.5-IGUA-13, Attachment 1, page 1, Table 1.
[626] 18 Tr.37.

a discount rate higher than 3.75% there is a material reduction in the net salvage recovery. This is not appropriate because, as noted by Mr. Bowman, you are really just pushing the problem into the future.[627]

501. While Concentric has proposed a discount rate of 3.75%, if the objective is to ensure that both the annual site removal costs are funded and that there is an appropriate contribution to the Site Restoration Costs (SRC) accrual balance, a somewhat lower discount rate such as that approved by the OEB and currently used by EGD of 3.095%[628] could be considered or the rate approved by the Canadian Energy Regulator (CER) its June 15, 2023 report of 3.25%[629] The impact on the net salvage recovery of using these different discount rates is as set out in the responses to Exhibit J17.5.

502. While there was some confusion expressed by Messrs. Bowman and Madsen about how the CDNS method should mathematically be calculated, two important facts are not in dispute. First, all of the depreciation experts agree with the use of the CDNS net salvage methodology. Second, the CDNS method proposed by Mr. Kennedy in this proceeding is the same CDNS method he proposed which was approved by the OEB in 2014. As demonstrated in evidence, this methodology has worked.

503. The Company acknowledges that the Traditional Method is more commonly used and would generate a higher net salvage provision than CDNS. While the Traditional Method was considered by Concentric but not proposed, it would also achieve the objective of ensuring that reasonable amounts of net salvage are collected (when compared to CDNS with discount rates higher than 3.75%), as is demonstrated in Exhibit J17.9.

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[627] 18 Tr.33.
[628] EB-2012-0459.
[629] CER Report: Five-Year Review of Abandonment Cost Estimates and Set-Aside and Collection Mechanisms 2021, June 2023, ss 4.5.3 and 5.2. See also Exhibit K16.2.

504. In the end, the concerns expressed by Messrs. Bowman and Madsen about Mr. Kennedy's methodology double counting inflation is not correct. This erroneous assumption is demonstrated in the detailed response provided at Exhibit I.ADR-22. As well, Mr. Kennedy confirmed in oral evidence that his methodology does not double count inflation.[630] The fact that the concerns expressed by intervenor depreciation experts that this double counting of inflation would lead to an under recovery of the appropriate net salvage amounts has been proven wrong as noted above. There is therefore nothing in evidence which supports any suggestion that the CDNS methodology as proposed by Mr. Kennedy should be revised. The only real issue is the discount rate and, on this point, given that all experts agree that the net salvage provision must recover annual and future site restoration costs, the discount rate should not be greater than 3.75%.

505. In this regard, Enbridge Gas notes that both Messrs. Bowman (initially) and Madsen proposed using a significantly higher discount rate than the 3.75% proposed by Concentric. Once the impact of using such a high discount rate was made clear to Mr. Bowman, he changed his recommendation and opined that the discount rate should not exceed 3.75%, lest the Company might not recover the required net salvage accrual. Mr. Bowman specifically stated in his oral direct evidence that he would not recommend using a discount rate higher than 3.75% with Concentric's CDNS approach.[631] Mr. Bowman also stated that he would not be troubled if the OEB were to determine that the Traditional Approach was appropriate (instead of CDNS) and increased the net salvage accrual even further.[632]

506. Concentric believes that the discount rate should be based on a long-term conservative outlook with the goal of collecting the appropriate amount from

[630] 16 Tr.169-171.
[631] 17 Tr.180.
[632] 17 Tr.182-183.

customers so that it is available when needed in future. The proposed 3.75% rate is comparable, as noted earlier, to the rate of return (3.25%) used by the CER in respect of its segregated funds which use long-term Government of Canada marketable bond rates.[633]

Average Service Lives, Survivor Curves and Net Salvage Parameters

507. It should be noted that Concentric, Intergroup and Emrydia have not proposed changes to the account parameters for a number of asset classes. For those accounts where changes are proposed, Mr. Kennedy and Ms. Nori confirmed that they had recommended changes to several accounts to reflect both the historical average service lives of both EGD and Union (which were often different) but also in reflection of energy transition issues. Mr. Kennedy stated in his oral evidence the following:

> Concentric has taken a moderated approach to the selection of average service life estimates for long-lived asset groups, but we have lengthened the average service life estimates from the longer of the Union -- or legacy Union or legacy Enbridge systems, in only seven accounts. This moderated approach was followed to provide for the consideration of energy transition.
>
> This is not the time, in my view, to be lengthening average service life estimates without the significant and very specific consideration given to the issues of energy transition.
> In contrast, both Mr. Bowman and Mr. Madsen have lengthened the average service life estimates beyond the Concentric recommendations in 14 accounts.
>
> Both Mr. Madsen and Mr. Bowman have indicated that they did not consider energy transition to be a relevant factor in the selection of average service life estimates.
>
> The use of average service life estimates recommended by Mr. Bowman and Mr. Madsen result in a reduction of depreciation expense, again based on the 2021 balances, of $212.5 million as compared to the Concentric recommendations.[634]

[633] Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 23-24; Exhibit K16.2; and 16 Tr.74-75.
[634] 16 Tr.73-74.

508. In the end, Concentric's recommendations were based upon appropriate relevant data and investigations, including discussions with Enbridge Gas management, peer review analysis and with a view to energy transition issues.[635] In oral evidence, Mr. Kennedy advised that Concentric is recommending a moderated and considerate approach to energy transition. By comparison, Mr. Bowman and Mr. Madsen have both stated they have not considered this as a significant topic, as witnessed by the significant decrease they propose to the depreciation expense relative to the currently approved level of depreciation expense.[636]

509. In an interrogatory response to Enbridge Gas, Mr. Bowman confirmed that Intergroup did not review documents regarding energy transition for Enbridge Gas or for Ontario broadly in the preparation of the evidence outside of Concentric's report.[637] Intergroup further stated in another interrogatory that: "opinions regarding the appropriate lives for assets, outside of major questions of energy transition, are set out in the Intergroup report Exhibit M1".[638] When asked to identify where Emrydia considered in its report the initiatives being led by the OEB to examine energy transition and its impact on consumers and rate regulated utilities in Ontario, Mr. Madsen responded stating that the evidence did not. The response added: "Emrydia's retainer was to address EGI's proposed depreciation policy and provision including site restoration costs."[639]

2. As noted above, where Concentric has shortened the lives or increased the lives of assets, Mr. Kennedy advised that Concentric's recommendations were based upon appropriate relevant data and investigations undertaken by Concentric as well as with a view to energy transition issues.[640] In contrast, Intergroup and Emrydia

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[635] 16 Tr.73-74 and Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 24-34.
[636] 16 Tr.79.
[637] Exhibit N.M1.EGI-2.
[638] Exhibit N.M1.PP.4.
[639] Exhibit N.M5.EGI-31.
[640] 16 Tr.73-74; and Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 24-34.

proposed a lengthening of the average service lives in 14 accounts and changes to certain net salvage parameters in comparison to Concentric's recommendations, all of which greatly reduces the recovery of net salvage. It should be noted that each of the recommendations made by Mr. Bowman and Mr. Madsen would result in a decrease in the depreciation expense and net salvage.

510. While under cross-examination, Mr. Bowman acknowledged that his proposed changes to only the six accounts he commented on with the lengthening of the average service lives plus the adoption of the ALG methodology would decrease the depreciation expense by $102.3 million (2021 depreciation study).[641] Importantly this reduction does not include the approximate $69 million decrease in net salvage that would not be recovered due to the recommended change to the net salvage parameters recommended by Mr. Bowman.[642]

511. Mr. Madsen in his report recommended changes to the average service lives of a number of additional accounts. In every case, Mr. Madsen proposed an increase in the average service life. Under cross-examination, Mr. Madsen acknowledged that he also supported all of the proposed average service life extensions proposed by Mr. Bowman as well as Mr. Bowman's net salvage parameter changes which would lead to a further reduction of $69 million in net salvage. Mr. Madsen confirmed under cross-examination that the calculations made by Enbridge Gas as to the impact of the proposed changes by Mr. Bowman and Mr. Madsen would result in an approximate $285 million decrease in the depreciation expense for the 2021 study period and an approximate $319 million decrease to the forecasted 2024 depreciation provision.[643]

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[641] 18 Tr.31-32; and Exhibit K16.2.
[642] Exhibit M1, page 11, Table 1.
[643] 18 Tr.86-89. Mr. Madsen confirmed the calculations in Exhibit K16.2, page 4, were in the ballpark.

512. The impacts of using the ALG procedure and all of the extensions of the average service lives of the accounts recommended by Messrs. Bowman and Madsen would result in a depreciation provision forecasted for 2024 of only $572.6 million.[644] This compares to the $771.6 million[645] using current 2023 depreciation rates. These figures were all presented to Messrs. Bowman and Madsen in Exhibit K16.2. See Table 7. As noted during the Oral Hearing and in Exhibit K16.2, the table did not include the minor changes recommended by Concentric once they received the additional Union historical retirement data which led them to recommend changes to several average service lives and this resulted in a small change in the depreciation provision. These have been included in the response to undertaking Exhibit J17.9.

[644] This figure has been updated in response to Exhibit J17.6 Attachment 1 to $561.9 million.
[645] This figure has been updated in response to Exhibit J17.6 Attachment 1 to $737.1 million.

Table 7

Exhibit K16.2 - Depreciation Provision Comparison of Major Accounts with Intervenor Proposed Lives

ENBRIDGE GAS INC. DEPRECIATION PROVISION COMPARISON

		Equal Life Group (ELG)	Average Life Group (ALG)			
Asset Account	Concentric Recommended Life and Curve	Concentric Depreciation Provision TOTAL (1)	Concentric Depreciation Provision TOTAL Change (revised to ALG)(2)	Alternative Recommended Life and Curve	Depreciation Provision for Alternative Life and Curve @ CARF Discount Rate TOTAL Change (2)	Depreciation Provision for Alternative Life and Curve @ WACC Discount Rate (6.03%) TOTAL Change (2)
442.00	40-S5	105,928	-1,910	N/A	-	-
443.01	45-R4	55,594	-3,896	N/A	-	-
443.02	55-R4	229,183	-15,230	N/A	-	-
451.00	55-R4	1,102,904	-32,677	N/A	-	-
452.00	40-R3	4,114,129	-772,270	45-R2.5	- 1,053,046	- 1,239,324
453.00	45-R2.5	5,515,551	-976,515	N/A	-	- 860,284
454.00	40-R2	175,831	-41,125	N/A	-	-
455.00	55-R3	5,130,627	-631,859	N/A	-	- 246,673
456.00	40-R4	19,661,453	-1,591,481	44-R4	- 2,778,143	- 3,601,335
457.00	35-R3	2,003,634	-251,015	40-R2.5	- 450,804	- 578,553
461.00	60-R4	1,507,598	-98,041	N/A	-	-
462.00	50-S4	3,377,914	-101,519	N/A	-	- 143,044
463.00	55-S4	157,646	-9,235	N/A	-	- 8,398
464.00	50-S4	65,185	-2,807	N/A	-	- 2,915
465.00	60-R4	49,201,674	-3,455,165	70-R4	- 9,313,524	- 12,269,725
466.00	30-R4	37,417,456	-3,016,025	37-R4	- 9,515,433	- 10,311,121
467.00	40-R4	12,112,032	-864,381	N/A	-	- 960,745
471.00	60-R4	1,150,753	-78,740	N/A	-	-
472.00	40-S0.5	7,005,487	-1,849,963	N/A	-	-
472.31	40-S0.5	1,325,428	-145,152	N/A	-	-
472.32	40-S0.5	991,735	-106,536	N/A	-	-
472.33	40-S0.5	2,365,393	-12,230	N/A	-	-
472.34	40-S0.5	704,663	-75,952	N/A	-	-
472.35	40-S0.5	8,045,939	-4,055	40-S0.5 - No Truncation	- 7,627,722	- 7,627,722
473.01	45-S1	19,924,844	-4,106,311	50-L1	- 4,740,643	- 6,795,099
473.02	55-S3	121,567,634	-11,318,080	60-S3	- 15,563,480	- 30,900,537
474.00	25-SQ	43,329,780	0	50-L1	- 33,157,286	- 33,157,286
475.00	25-SQ	10,469,399	0	N/A	-	-
475.21	55-R3	112,249,761	-14,315,765	70-R3	- 37,193,539	- 50,737,563
475.30	60-R4	94,562,548	-6,729,388	70-R2	- 24,407,105	- 38,290,145
476.00	17-S2.5	365,238	-40,166	N/A	-	-
477.00	40-R2	27,440,188	-5,957,636	N/A	-	172,266
477.01	35-R3	4,800,551	-625,185	N/A	-	-
478.00	15-S2.5	104,686,373	-13,266,942	25-L1.5	- 62,641,782	- 62,641,782
482.00	40-R1.5	191,336	-71,751	N/A	-	-
482.01	40-R1.5	3,400,629	-110,229	N/A	-	-
482.04	40-R1.5	9,286,663	-1	N/A	-	-
482.05	40-R1.5	1,544,848	-156,562	N/A	-	-
482.51	40-R1.5	3,906,954	-542,506	N/A	-	-
482.52	40-R1.5	2,814,701	-30,937	N/A	-	-
483.00	15-SQ	1,200,881	108,435	N/A	-	-
484.00	12-L2.5	6,268,747	-1,184,789	N/A	-	-
485.00	17-L1.5	3,658,037	-864,297	N/A	-	-
486.00	15-SQ	9,529,666	0	N/A	-	-
487.70	15-SQ	86,895	0	N/A	-	-
487.80	20-SQ	288,265	3,283	N/A	-	-
488.00	10-SQ	2,946,627	0	N/A	-	-
490.00	4-SQ	4,041,429	229,827	N/A	-	-
490.00 (Post 2023)	4-SQ	0	0	N/A	-	-
490.30	10-SQ	502,763	0	N/A	-	-
491.01	4-SQ	13,604,128	219,841	5-SQ	- 3,126,833	- 3,126,833
491.01 (Post 2023)	4-SQ	0	0	5-SQ	-	-
491.02	4-SQ	3,892,471	98,081	5-SQ	- 931,868	- 931,868
491.02 (Post 2023)	4-SQ	0	0	5-SQ	-	-
491.03	10-SQ	7,217,716	137,659	N/A	-	-
Software Intangibles - 10YR	10-SQ	0	0	N/A	-	-
491.04	10-SQ	9,153,464	0	N/A	-	-
TOTAL OF COLUMN CHANGES			**-72,661,198**		**-212,501,208**	**-264,258,686**
AGGREGATE OF PROPOSED CHANGES			**-72,661,198**		**-285,162,406**	**-336,919,884**
TOTAL DEPRECIATION ACCRUAL (2021 STUDY) @ ENBRIDGE GAS OR INTERVENOR PROPOSED DEPRECIATION RATES		**786,456,273**	**713,795,075**		**501,293,867**	**449,536,389**
FORECASTED 2024 DEPRECIATION ACCRUAL @ ENBRIDGE GAS OR INTERVENOR PROPOSED DEPRECIATION RATES (3)(4)		**892,400,000**	**810,700,000**		**572,600,000**	**509,900,000**
FORECASTED 2024 DEPRECIATION ACCRUAL @ CURRENT DEPRECIATION RATES (5)			**771,600,000**			

Enbridge Gas notes that applying Emrydia and InterGroup's recommended changes to asset lives under the ALG procedure and a 6.03% WACC would result in an annual net salvage provision of only $5 million. This amount is significantly less than Enbridge Gas's forecasted annual site restoration costs of $60 million (Exhibit I.1.8-STAFF-17 Part f).

NOTES

(1) Exhibit 4, Tab 5, Schedule 1, Attachment 1, Pages 40 and 41. Does not reflect the revised depreciation rates filed in the Capital Update (Exhibit 2, Tab 5, Schedule 4, Attachment 1) which reduced the study year depreciation accrual by $2.4 million.

(2) Applicant response to ADR Information Request - Exhibit I.ADR.22

(3) Concentric provision at proposed rates under ELG and ALG: Exhibit I.4.5-STAFF-170, Attachment 1

(4) For illustrative purposes only. Does not include the updated capital expenditures, rate base and depreciation rates reflected in the June 16, 2023 Capital Update.

(5) Exhibit 4, Tab 5, Schedule 1, Attachment 2, Page 9

513. Mr. Madsen specifically expressed concern about Concentric's evidence about recommending shorter average service lives due to energy transition issues. The Emrydia report states:

> This concern is emphasized by the statements from Concentric supporting its transition to the ELG procedure, including a perceived need to move closer to an economic life for the assets and the results achieved by the economic planning horizon calculated by Concentric. As noted earlier, the use of lives of assets as well as the selected depreciation procedure should be based first on the underlying data supporting the recommendations. If an economic life is warranted for consideration due to external factors, that adjustment should be made separately rather than indirectly through life reductions that are not life reductions…[646]

514. Stated differently, Mr. Madsen is saying that energy transition issues should play no role in the determination of the appropriate depreciation methodology nor the selection of the appropriate survivor curves for particular assets. Mr. Madsen would continue with the status quo and introduce an EPH at some point in the future. The Company submits that this would not be a prudent course of action and would greatly increase the risk of stranding assets.

515. The Company submits that what Intergroup and Emrydia are proposing would take Enbridge Gas in the wrong direction in light of the energy transition issues that have been discussed in the proceeding. While there is admittedly still much uncertainty as to the impact of energy transition on Enbridge Gas in the future, common sense alone dictates that there should not be a material decrease in the depreciation expense given the concern about the stranding of assets in future. The intervenor experts are proposing a decrease of over $200 million (excluding the impact of the changes to the net salvage parameters which Mr. Bowman calculates at approximately $69 million) versus the 2024 forecast using current depreciation rates of $771.4 million.[647]

[646] Exhibit M5, page 39.
[647] Based on Exhibit K16.2. Please note the update in the response to Exhibit J17.6 to $737.1 million, which represents a decrease of over $175 million (excluding the $69 million impact from changes to the net salvage parameters Mr. Bowman recommends).

516. What is clear from the evidence filed by the depreciation experts is that the data and analysis of peer groups will in many instances demonstrate a range of average service lives for various assets. It is then the job of the depreciation expert to apply professional judgment to recommend the appropriate average service life and Iowa curve. It is clear from the written and oral evidence that the professional judgment of one depreciation expert may not be identical to that of another and thus there may be several recommendations made in respect of the same asset group which both experts consider to be reasonable. Indeed, many of the EGD and Union asset accounts had different average service lives and used different Iowa curves even though the assets were in many instances very similar. Obviously, as the asset life parameters were previously approved by the OEB, the evidence supported the use of those particular parameters at the time. What this demonstrates is that a range of reasonable average service lives exists in many instances.

517. With this in mind, for the purposes of determining the appropriate parameters for applicable asset accounts at this time, Enbridge Gas submits that it is most appropriate to consider energy transition issues and that prudence requires the exercise of caution for the purposes of selecting the applicable average service life and survivor curve. Where there is a range of average service lives, in light of energy transition issues, the depreciation expert should err on the side of moderation and caution and propose an average service life at the shorter end of the range or apply a more modest increase if the data so warrants. This is precisely what Concentric confirmed in evidence that it did. Messrs. Bowman and Madsen did not do this. Enbridge Gas submits that it is simply not prudent to ignore the risks of energy transition and the stranding of assets.

518. Finally, it is the expectation of the Company that a further depreciation study will be completed for the purposes of the next rebasing application. At that point, there will be further Government policy in place dealing with the energy transition and there

will be a more developed sense of its impact on the Company in the future. The depreciation study would then consider the existing methodologies and parameters for the various accounts and the net salvage recoveries and make further recommendations with the benefit of the knowledge and experiences gained.

Regulators Account 474

519. Historically, EGD included Regulators in its services-metal account 473.01. Union recorded Regulators in Account 474. The most recently OEB-approved life and curve for account 473.01 was 45-L1.5 for EGD and 50-R1.5 for Union. This means that the approved average service lives for metal services was 45 and 50 years, respectively for EGD and Union.

520. Union's Regulators were included in Account 474 which had an OEB-approved average service life of 20 years. Based on the data and investigations undertaken, Concentric has proposed a modest increase in the service life for Account 474, Regulators, to 25 years. Concentric has also proposed as part of the reclassification of accounts the movement of the EGD Regulators from Account 473.01 to 474. This of course makes sense from a pure depreciation theory perspective because Regulators have much shorter average service lives than metal services. This reclassification of EGD's Regulators into the appropriate account however means that there has been an under recovery over time of the appropriate depreciation expense in respect of EGD's Regulators. Concentric calculates this amount to be approximately $124.9 million.[648] Mr. Madsen confirms in his report that this figure is correct[649] however he disagrees with Concentric's proposed means of recovering the under recovery which is to apply a depreciation rate of 8.86%.[650] For clarity, Concentric proposes to apply a depreciation rate of 8.86% comprised of a whole life

[648] Exhibit I.4.5-IGUA 19, Attachment 1.
[649] Exhibit M5, page 71.
[650] Please see Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 3-18 & 3-19 and Exhibit I.4.5-IGUA-19, part a).

depreciation rate of 4% and recovery of the previous under collection at a rate of 4.86%. This compares to the rate proposed by Mr. Madsen of 2.08%.[651]

521. Rather than recognizing the under recovery, Mr. Madsen recommends that the OEB direct Enbridge Gas to apply the rate approved for Account 473.01 to the Regulators account and to apply a 50-L1 curve[652] (i.e. to apply an average service life of 50 years - twice that applicable to Regulators). Enbridge Gas notes that Mr. Madsen adduced no evidence in his report or at the hearing to support a 50-year average life for Regulators. His report calculates that his proposed change would result in a $34.4 million reduction in the depreciation expense.[653] Aside from there being no evidence to support such a dramatic change, it would put future customers at risk of having to pay the yet undepreciated portion of Regulators when they are retired long before turning 50. Future customers would then be responsible for the balance of the undepreciated portion of the Regulators which in many instances could be another 25 years. Enbridge Gas submits that Emrydia's position is not supportable.

522. For the above reasons, Enbridge Gas submits that the average service lives, survivor curves and net salvage parameters proposed by Concentric, as updated, are reasonable and should be adopted.

Economic Planning Horizon Discussions

523. It is expected that certain parties will recommend that the OEB Direct Enbridge Gas to apply EPH to all or some subset of its assets. Stated simply, an EPH would set a terminal date for assets and the depreciation expense would be calculated such that the assets would be fully recovered by the terminal date.

[651] Please see Exhibit J16.6.
[652] Exhibit M5, page 74.
[653] Ibid, see also Exhibit K16.2, page 5.

524. In an attempt to illustrate the impact of an EPH on the depreciation expense, Concentric generated the calculations for an EPH of 2050 on relevant Company assets and calculated the required depreciation expense (2021 study period) at $1.042 billion.[654] This compares to the depreciation expense calculated in the 2021 study using Concentrics recommendations of $786.4 million. The forecasted depreciation expense for the 2024 Test Year with a 2050 EPH would be approximately $1.2 billion.[655]

525. While Enbridge Gas believes that while the use of an EPH in respect of particular accounts may be an appropriate tool to consider in the future as a risk mitigation strategy to address energy transition issues, it is of the view that an EPH is not appropriate at this time. This view is shared by all of the depreciation experts that have appeared in this proceeding. This said, if changes to the customer attachment revenue horizons are required by the OEB, as noted in the response to undertaking Exhibit J18.5, it may be appropriate to change the parameters for the services and other affected account(s) to reflect the changes and possibly consider an EPH.

526. While Concentric notes that there will likely be impacts on the natural gas distribution business as a result of the energy transition, much remains unknown including the introduction of hydrogen which may have a life lengthening impact on the system and that there may be a change in the utilization of a large group of assets in the future.[656] This said, Concentric notes that future depreciation studies may require the introduction of an EPH into rates calculations.

527. Mr. Bowman in his report found that Concentric's 2050 EPH calculations were mathematically sound and agreed that it was not appropriate to use them for the

[654] Exhibit 4, Tab 5, Schedule 1, Attachment 1, Table 1, pages 317-318.
[655] Exhibit 1, Tab 10, Schedule 4.
[656] Exhibit 4, Tab 1, Schedule 1, Attachment 1, page 19.

purposes of setting the 2024 depreciation expense.[657] Mr. Madsen similarly did not support the use of an EPH.[658]

Segregated Fund for Site Restoration Costs

528. Enbridge Gas responded to the OEB's earlier directive to EGD to examine the issue of whether a segregated fund for SRC should be established and to present such findings in EGD's next rebasing application.[659] Enbridge Gas specifically examined issues relating to the establishment of a segregated SRC fund in detail in its pre-filed evidence.[660]

529. As noted in evidence, in response to this directive, Enbridge Gas conducted internal research and looked for examples of other utilities that may have considered a segregated fund approach. Enbridge Gas could not find any examples of other utilities using segregated funds for SRC. The net salvage approach is currently commonly used by many utilities across North America.[661]

530. Enbridge Gas weighed and compared the advantages and disadvantages of a segregated fund. In comparing these, the Company came to the conclusion that the disadvantages outweighed the advantages at this time. The key factors which led Enbridge Gas to not recommend a segregated fund include the fact that it would result in an increase to rate base with an associated revenue requirement impact of $93 million in the test year and an annual increase in the revenue requirement every year thereafter of at least $3.1 million.[662] Enbridge Gas also believes that a segregated fund would be more costly to set up and operate and that there may be

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[657] Exhibit M1, pages 65-66.
[658] Exhibit M5, page 28.
[659] EB-2012-0459, pages 62-64.
[660] Exhibit 4, Tab 5, Schedule 1, pages 17-20; also see Exhibit I.4.5-ED-136.
[661] Ibid.
[662] Ibid, page 19.

tax issues that would require resolution. As well, the Company does not expect a large-scale retirement of assets for many years to come.

531. Concentric was also asked at the technical conference for its thoughts on how a segregated fund for SRCs could be set up in a manner which minimized the impacts. Concentric responded noting that there are a number of issues that require resolution or direction from the OEB prior to being able to develop even a high-level model associated with the implementation of the segregated fund for SRC. Concentric pointed to the fact that the National Energy Board (now the CER) underwent a process of creating site restoration funds for large diameter pipes in 2008. The process took over two years and examined a long list of issues that Concentric believes would arise again. Concentric concluded that many of these same issues would need to be considered and determined by the OEB and that same amount of time and care would probably be required of the OEB.[663]

532. The concept of a segregated fund for SRC was considered further in the response to an undertaking given to Commissioner Duff at Exhibit J17.10. In this response, the revenue requirement impacts as noted above were confirmed. The response also noted that should the OEB decide to require a segregated fund, a phasing in might be appropriate in light of the outstanding issues that require determination and to mitigate the rate impact.

533. Enbridge Gas notes that the net book value of its plant is approximately $16 billion and that it remains highly valuable and extremely resilient to weather events including those precipitated by climate change. The Company acknowledges that there may be sign posts that would trigger the Company to consider proposing a segregated fund approach in the future including government policies that direct customers to disconnect from the natural gas network or various municipalities and

[663] Exhibit JT4.16.

landowners requesting the removal of infrastructure.[664] These signposts have not yet arisen.

534. The Company, as noted in the response to Exhibit J17.10, has considered the scenario of there being a large increase in retirements and associated costs of retirement. Were this to occur earlier than expected something that the Company considers unlikely, there would be a reduction in accumulated depreciation and an increase in rate base due to the higher debt and equity financing required. The more probable event is that with the planned depreciation study update for the next rebasing, the retirements would be forecast, and depreciation rates would be adjusted in anticipation of the retirements.

535. It should be recognized that the currently approved CDNS methodology, proposed initially in 2013 by Mr. Kennedy, is recovering the annual costs of removal and it is adding to the site restoration accrual balance.[665] It is functioning as intended. Enbridge Gas notes that customers benefit from the use of net salvage recoveries given that the funds are used in lieu of raising additional debt. This reduces the revenue requirement and by extension rates. As noted in the response to the undertaking given to Commissioner Duff at Exhibit J17.10, Enbridge Gas estimates that the lower rate base which is the result of the SRC accrual has resulted in customer savings of approximately $1,029 million between 2013 and 2022.

536. The other options available for managing revenue related to site restoration costs include: (a) expensing removal costs as they are incurred; and (b) capitalizing the costs of removal by adding it to the installation cost of a replacement. These options as well as the CDNS and the Traditional Method for net salvage were considered fully by Concentric in its report.[666] Concentric specifically identified the advantages

[664] Exhibit I.4.5-SEC 193.
[665] Exhibit JT4.16.
[666] Exhibit 4, Tab 5, Schedule 1, Attachment 1, pages 20-23.

and disadvantages of each and based upon its analysis, it proposed the CDNS methodology previously approved by the OEB. As noted earlier, all of the depreciation experts agree on the use of the CDNS methodology. No expert in this proceeding advocates a segregated fund at this time.

PDO/PDCI Payments During Deferred Rebasing Term

537. Issue 18 – In relation to the 2024 Test Year gas cost forecast,

   f) Is the 2024 Test Year Parkway Delivery Commitment Incentive (PDCI) Forecast appropriate?

Consequences Of Settlement Proposal

538. While parties agreed to the proposed updated Parkway Delivery Obligation (PDO) Framework and the 2024 forecast of PDO/PDCI costs as part of the Settlement Proposal[667], there was no agreement as to the treatment of 2019 to 2023 PDO/PDCI costs that have been recovered from ratepayers as part of the OEB-approved Settlement Framework for Reduction of Parkway Delivery Obligation (PDO Settlement Framework).

Outstanding Approvals Required

539. Enbridge Gas is requesting that no adjustments be made to the 2019 to 2023 PDO/PDCI costs that have been recovered from ratepayers.

Revenue Requirement Implications for 2024

540. There are no 2024 revenue requirement implications for this issue.

[667] Exhibit O1, Tab 1, Schedule 1 – see Issues 18(e) and (f). Note that the Settlement Proposal includes some agreed modifications from the Enbridge Gas proposal as-filed.

Evidence in Support

541. In the MAADs Decision, Enbridge Gas was directed to provide additional PDO reporting as part of the Rebasing proceeding (PDO Directive Reporting).[668] The intent of the PDO Directive Reporting was to support that earnings were not enhanced contrary to the intent of the PDO Settlement Framework during 2019 to 2023.

542. Enbridge Gas filed detailed evidence at Exhibit 4, Tab 7, Schedule 1, and answered follow-up questions in associated interrogatories[669], Technical Conference testimony[670] and Technical Conference undertakings[671].

543. Enbridge Gas witnesses provided testimony about this issue on Day 7 of the Oral Hearing (Panel 5)[672].

544. There is no intervenor evidence on this issue.

Overview

545. The recovery of the Dawn Parkway System demand costs associated with the PDO shift through rates during the period 2019 to 2023 is consistent with the intent and guiding principle of the PDO Settlement Framework. This has not improperly enhanced earnings. As such, there is no basis to require Enbridge Gas to refund amounts collected between 2019 and 2023.

546. Denial by the OEB in this Application of the recovery of the Dawn Parkway System demand costs associated with the PDO shift, which were recovered through rates during 2019 to 2023, would be contrary to the intent and guiding principle of the

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[668] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018 (MAADs Decision), page 49.
[669] Exhibit I.4.7.
[670] 6 TC Tr.138-188 and 7 TC Tr.1-86.
[671] Exhibits JT6.16-JT6.20 and JT7.1-JT7.8.
[672] 7 Tr. 68-179.

PDO Settlement Framework. The guiding principle was to keep the Company whole rather than to enhance or reduce its earnings during the operation of the IRM. Denied revenue recovery at this time would result in reduced earnings of the Company since it has lost the revenue from Rate M12 turnback used for the PDO shift and would no longer have the ability to market the capacity to recover that lost revenue.[673]

<u>Factual Context</u>

547. The following sections provide a description of the PDO Directive Reporting, PDO Settlement Framework and Union's 2013 Cost of Service (which occurred prior to the PDO Settlement Framework).

PDO Directive Reporting

548. In its MAADs Decision, the OEB considered issues raised by intervenors about whether Union had inappropriately collected twice for Dawn Parkway System capacity that has been used to reduce the PDO. The OEB found that there was not enough evidence to determine the issue and indicated that evidence should be filed in the [Enbridge Gas] rebasing case.[674]

549. The OEB indicated at the time of rebasing it would:

> Review the costs and amounts recovered through rates to ensure that ratepayers are not paying twice for the required capacity and the legacy Union Gas is not enhancing earnings contrary to the intent of the PDO settlement agreement.[675]

550. Additionally, the OEB required Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing term.[676]

[673] This was summarized by Ms. Mikhaila at 7 Tr.170-171.
[674] MAADs Decision, pages 48-49.
[675] Ibid, page 49.
[676] Ibid.

551. Enbridge Gas has provided the actual costs and amounts recovered through rates for the years 2019 to 2022.[677] Through this tracking, it is evident ratepayers are not paying twice for the capacity required for the PDO shift as the actual costs incurred by Enbridge Gas were marginally higher than the amounts recovered through rates.

552. As stated in evidence:

> Through rates, the Company has recovered the actual PDO costs during the deferred rebasing term with the exception of the differences described above that have resulted in a revenue shortfall to the Company. From 2019 to 2022, the variance in the total PDO costs ranges from a revenue shortfall of $0.73 million to $1.16 million (Table 1, line 12). This shortfall demonstrates that the Company has not over collected for the PDO over the IR term.[678]

PDO Settlement Framework

553. The OEB-approved PDO Settlement Framework set out the framework and cost consequences under which direct purchase (DP) customers would shift the requirement for obligated deliveries at Parkway to obligated deliveries at Dawn. The PDO Settlement Framework was the outcome of a request from large volume DP customers to eliminate the PDO and shift their obligated delivery point to Dawn.[679]

554. The intention of the PDO Settlement Framework was to rectify an inequity that existed between DP and other customers. DP customers were conferring a benefit on all users of the Dawn Parkway System as a result of being contractually obligated to deliver at Parkway.[680] The guiding principle of the PDO Settlement Framework was to keep the Company whole rather than to enhance or reduce its earnings during the operation of the IRM in place following the 2013 Cost of Service case.[681]

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[677] Exhibit 4, Tab 7, Schedule 1, page 12.
[678] Ibid, page 13.
[679] 7 Tr.107.
[680] EB-2013-0365 Settlement Framework for Reduction of Parkway Delivery Obligation, June 3, 2014 (PDO Settlement Framework), at page 1, paragraph 1 – filed at Exhibit K7.3, page 23.
[681] PDO Settlement Framework, page 1, paragraph 3.

555. The PDO reduction, including the costs recovered through rates by the Company, has been accomplished in precisely the manner contemplated and agreed to by the parties as outlined in the PDO Settlement Framework.

556. As of November 1, 2022, the PDO has been reduced by 377 TJ/d as a result of the PDO Settlement Framework.[682]

a) DP customers without Rate M12 service shifted 200 TJ/d of PDO to Dawn under the PDO Framework.[683] Permanent Dawn Parkway System capacity was required to facilitate the 200 TJ/d PDO shift for these customers and was available as a result of 242 TJ/d ex-franchise Rate M12 Dawn to Kirkwall service turnback that occurred between 2015 and 2017.[684]
b) DP customers without Rate M12 service shifted an additional 27 TJ/d of obligated deliveries at Parkway to Dawn, effective November 1, 2022.[685] The temporary Dawn Parkway System capacity required to facilitate the 27 TJ/d PDO shift was available as a result of a contracted market-based exchange service.
c) DP customers with Rate M12 Dawn to Parkway service shifted 151 TJ/d of PDO to Dawn using the Dawn Parkway System capacity they turned back.[686]

557. The PDO Settlement Framework provided for recovery through in-franchise rates of the permanent Dawn Parkway System capacity used to facilitate the PDO shift for customers. Recovery of Dawn Parkway System capacity used for the PDO shift is described in the PDO Settlement Framework as the inclusion of the annual demand costs in delivery rates of in-franchise customers beginning January 1, 2015.[687]

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[682] Exhibit I.4.7-FRPO-169, Attachment 1, line 15.
[683] Ibid, line 9.
[684] Exhibit I.4.7-FRPO-169, Attachment 2, line 1. 242 TJ/d of Dawn to Kirkwall service turnback created the equivalent of 200 TJ/d of Dawn to Parkway capacity necessary for 200 TJ/d PDO shift.
[685] Exhibit I.4.7-FRPO-169, Attachment 1, line 10.
[686] Ibid, line 14.
[687] PDO Settlement Framework, page 3, paragraph 1 (e) and page 4, paragraph 2 (iii).

Union's 2013 Cost of Service

558. Prior to the PDO Settlement Framework, Union had 210 TJ/d of excess Dawn Parkway System capacity in its 2013 Cost of Service. At the time, certain parties submitted that a deferral account should have been established to capture variances related to the long-term transportation revenue forecast, both positive and negative, because it was possible that the excess capacity could be contracted in 2013. In its Decision, the OEB accepted Union's forecast and did not require Union to adjust estimated revenues as was suggested by some parties and rejected the request to establish a deferral account. The OEB noted that it believed Union should continue to bear this forecast risk.[688] As a result, revenue generated by the Company from the sale of the 210 TJ/d of excess Dawn Parkway System capacity accrues to the Company and is included in utility earnings, subject to earnings sharing.[689]

<u>*Enbridge Gas Submissions*</u>

559. The PDO Settlement Framework to reduce the PDO was agreed to in 2014 which was subsequent to Union's 2013 Cost of Service. The context of keeping Union whole as a guiding principle in the PDO Settlement Framework was relative to the 2014 to 2018 IRM in place at the time which included the ability for the Company to market the 210 TJ/d of excess Dawn Parkway System capacity. This was explained by Enbridge Gas's witnesses during cross-examination in this proceeding.

> MS. MIKHAILA: In 2013 cost of service, Union had the ability to market the 210 TJs of excess capacity for contracting, and any revenue would be to Union at the time and included in utility earnings, subject to earnings sharing. And that is the context against which Union was to be kept whole of the PDO settlement framework.[690]
>
> MS. MIKHAILA: And it does state in that guiding principle that it's during the operation of the IRM, not a recalculation of a 2013 forecast.[691]
>
> MS. MIKHAILA: Yes, that is the guiding principle, was to keep Union whole at the state, the framework, we were under at the time the PDO settlement framework was set, and so denial of recovery of those costs

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[688] EB-2011-0210, Decision and Order, October 24, 2012, page 22.
[689] Exhibit I.4.7-STAFF-187, part b).
[690] 7 Tr.105-106.
[691] 7 Tr.107.

> at this time would not be keeping Union whole to the framework we were under, and it would have reduced our earnings.[692]

560. The Dawn Parkway System capacity for the PDO shift for customers without Rate M12 service was made available as a result of Rate M12 Dawn to Kirkwall service turnback between 2015 and 2017. Revenue from the Rate M12 Dawn to Kirkwall service that was turned back formed part of Union's 2013 Cost of Service revenue forecast upon which rates are currently based. Use of the Dawn Parkway System capacity for the PDO shift resulted in a state where the Company lost the opportunity to market that capacity to other shippers in order to replace the lost revenue that resulted from the turnback of Rate M12 service.

561. The inclusion of the Dawn Parkway System demand costs associated with the permanent capacity used for the PDO shift in rates during the IRM was intended to provide the Company with recovery of the revenue it was no longer receiving from the Rate M12 Dawn to Kirkwall service due to the turnback of the capacity.

562. While questions asked by intervenors lead Enbridge Gas to assume that some parties may oppose the Company's position, the precise nature and details of the opposition is unknown.[693] Enbridge Gas will respond as appropriate in Reply Argument.

563. One submission that Enbridge Gas expects to see is a suggestion from FRPO that this issue should be postponed to a later phase of the proceeding. This expectation is based upon FRPO's "Closing Submission". FRPO submitted in its Closing Submission that the OEB may need further evidence to make a determination on Issue 18(f).

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[692] 7 Tr.112.
[693] For example, FRPO referred to a "base rate adjustment" on at least one occasion (see 13 Tr.71). It is not clear what FRPO will propose in this regard – does FRPO propose to effectively re-write history as to what should have been in the MAADs decision and utility rates effective as of 2019? That seems implausible, but in any event Enbridge Gas will reply when details are more clear.

564. Enbridge Gas does not agree.

565. In the MAADs Decision, the OEB found it needed more evidence on this item and the OEB instructed Enbridge Gas to file evidence in this rebasing case. The Company did so. Parties have had full opportunity to ask questions about the evidence. FRPO complains that it has been hampered in its efforts. That is not a fair characterization. Through the course of this case, FRPO has had opportunity to get further information through interrogatories (FRPO asked 62 pages of interrogatories, amounting to more than 500 questions (including subparts)), and Technical Conference (FRPO reserved 180 minutes for Panel 5, which dealt with PDO/PDCI, which was almost double the time for all other parties combined) and Oral Hearing (FRPO reserved more time than any other party for Panel 2 and asked follow-up questions with the Capital Panel).

566. Enbridge Gas submits that the record is now sufficient to determine Issue 18(f). Providing FRPO the opportunity to again pursue this item in Phases 2 and 3 of the case will prolong what is already an ambitious remaining process.

E. Cost of Capital (Exhibit 5)

Equity Thickness

567. Issue 20 – Is the proposed 2024 Capital Structure, including return on equity appropriate?

568. Issue 21 – Is the proposed 2024 cost of debt and equity components of the Capital Structure appropriate?

569. Issue 22 – Is the proposed phase-in of increases to equity thickness over the 2024 to 2028 term appropriate?

Consequences Of Settlement Proposal

570. While the parties did not agree to the settlement of Issues 20 and 22, an agreement was reached under Issue 21 to the as-filed debt rates and the use of the OEB's formula to set ROE. The actual ROE to be used will be as reflected in the OEB's 2024 cost of capital parameter letter, expected to be issued in October 2023. The agreed to rates for debt cost and equity will be applied to determine the revenue requirement for 2024 when all components have been determined.

Outstanding Approvals Required

571. Enbridge Gas requests approval from the OEB of an increase to its equity thickness from 36% to 42% but proposes a phase in of the increase such that in 2024, equity thickness would be 38% for rate making purposes and there would be an increase of 1% in each of 2025, 2026, 2027 and 2028 such that for 2028 the capital structure for Enbridge Gas for rate making purposes will be 42% equity and 58% debt.

572. Enbridge Gas further requests approval for a phase-in approach to the 1% increase in equity thickness in each of the years 2025 through 2028 by an annual base rate adjustment of $13.6 million.[694]

Revenue Requirement Implications for 2024

573. As noted above, the final cost of capital cannot be determined until the OEB releases its 2024 cost of capital parameter letter expected in October 2023. Enbridge Gas's forecast of the revenue requirement implications for 2024 of its proposed cost of capital are $952.2 million.[695]

[694] Exhibit 5, Tab 3, Schedule 1, pages 5- 6 (Updated by Exhibit JT9.1 Attachment 1).
[695] Exhibit 5, Tab 2, Schedule 1, Attachment 6, page 2 (Updated 2023-06-16 by Exhibit 2, Tab 5, Schedule 4, Attachment 5, page 3).

Evidence in Support

574. Enbridge Gas has filed detailed evidence at Exhibit 5. The evidence includes the detailed reasons for the increase in equity thickness and impacts of what the Company proposes. Importantly it includes the report of the cost of capital experts, Concentric Energy Advisors (Concentric) dated October 17, 2022, which is filed as Exhibit 5, Tab 3, Schedule 1, Attachment 1. Enbridge Gas answered follow-up questions in associated interrogatories[696], Technical Conference testimony[697] and Technical Conference undertakings[698].

575. Enbridge Gas witnesses provided testimony about the equity thickness on Days 8 and 9 of the Oral Hearing (Panel 7).[699] The Enbridge Gas panel consisted of Ms. Ferguson, Mr. Reinisch, and Mr. Small. The panel also consisted of Messrs. Coyne and Dane from Concentric. Both Mr. Coyne and Mr. Dane were qualified by the OEB as experts in Rate Regulated Utility Capital Structures which includes equity thickness and the Fair Return Standard. Several undertakings were given which were subsequently responded to.

576. OEB Staff engaged London Economics International (LEI) to review the Company's capital structure proposal and prepare a report following a review of the analysis of risk set out in the Application. LEI's report is marked as Exhibit M2. LEI witnesses Messrs. Goulding, Pinjani and Nayak provided testimony on Day 9 of the Oral Hearing (Panel 8).[700]

577. IGUA engaged Dr. Cleary to prepare testimony in response to the request by Enbridge Gas to increase its allowed equity thickness. Dr. Cleary's report is marked as Exhibit M6. He appeared as a witness in the Oral Hearing in Panel 9 on Day

[696] Exhibit I.5.
[697] 7 TC Tr.165-186 and 8 TC Tr.1-23.
[698] Exhibits JT7.23-JT7.26, JT8.1-JT8.3.
[699] 8 Tr.49-209 and 9 Tr.1-58.
[700] 9 Tr.60-159.

10.[701] IGUA also engaged Dr. Hopkins of Synapse Energy Economics. His report is marked as Exhibit M8 and states that the purpose of his testimony was to analyze the business risk facing Enbridge Gas as presented by the Company and Concentric. Dr. Hopkins appeared in the Oral Hearing as Panel 2 on Days 4 and 5.[702]

Overview

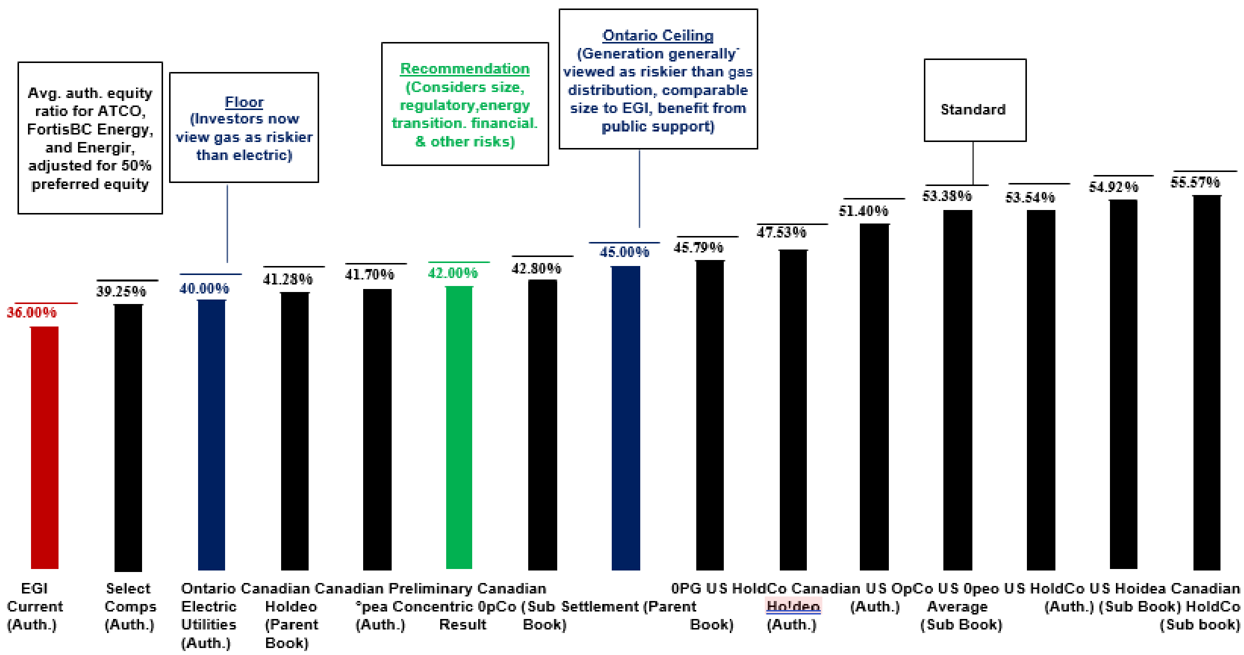
578. Enbridge Gas's capital structure has the lowest equity component, at 36%, of all investor owned natural gas utilities in North America.[703] It is lower than the Canadian average as acknowledged by every expert to this proceeding that has measured the averages[704], it is 4% below the deemed equity structure of Ontario's electric LDCs and it is significantly below the average of equity ratios in U.S utilities which exceed 50%. Enbridge Gas's current equity ratio does not meet the legally mandated Fair Return Standard (FRS)[705].

579. Enbridge Gas engaged Concentric to undertake a detailed review of its capital structure in light of applicable OEB policies, including changes in the Company's risks and to apply the principles of the FRS for the purposes of opining on the appropriate capital structure for Enbridge Gas. Concentric ultimately determined that there has been a significant change to the business and financial risk of Enbridge Gas and that, based upon a detailed analysis of comparable utilities of like risk, Enbridge Gas's capital structure should consist of between 40% and 45% equity. Concentric recommends a specific deemed equity thickness of 42%, which is informed by its proxy group analysis. Figure 1 illustrates a range of equity thickness ratios which vary based on the risk profile of a company. The Concentric

[701] 10 Tr.4-74.
[702] 4 Tr.153-194 and 5 Tr.1-167.
[703] 8 Tr.53; Exhibit 5, Tab 3, Schedule 1, Attachment 1 including Figure 45.
[704] See Exhibit M2, page 46 and Exhibit M6 page 24.
[705] This is the view of experts Concentric as set out in their report at Exhibit 5, Tab 3, Schedule 1, Attachment 1.

recommendation is in between the less risky Ontario electric LDCs, which has a floor of 40% and the riskier Ontario Power Generation with a ceiling of 45%.

Figure 1: Key Data Points in Equity Thickness Recommendation[706]



580. The OEB confirmed in its Report of the Board on the Cost of Capital[707] (OEB Cost of Capital Report) that the fair return standard as articulated by the National Energy Board (now the Canadian Energy Regulator) in its RH-2-2004 Phase II Decision:

> Frames the Discretion of a Regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the Tribunal. Meeting the standard is not optional; it is a legal requirement.[708]

581. The FRS requires that a fair reasonable return on capital should:

a) Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);

[706] Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 127, Figure 45.
[707] EB-2009-0084, OEB Report on the Cost of Capital.
[708] Ibid, page 18.

b) Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and

c) Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[709]

582. The OEB went on to make the following observations about the FRS in the OEB Cost of Capital Report[710]:

583. FRS expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective.[711]

584. That the overall ROE must be determined solely on the basis of a company's cost of equity capital and that the impact of any resulting rate increase is an irrelevant consideration in that determination. This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs[712].

585. All three standards (comparable investment, financial integrity and capital attraction) must be met, none ranks in priority to the others. Focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to the comparability test is not sufficient to meet the FRS[713].

586. An allowed ROE is a cost and is not the same concept as a profit. The concepts are not interchangeable from a regulatory perspective[714].

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[709] EB-2009-0084, OEB Report on the Cost of Capital, December 11, 2009, page 18; Decision and Order of the OEB on Union Decision and Order dated October 25, 2012, EB 2011-0210, page 49 and the Decision on Equity Ratio and Order, February 7, 2013 in respect of Enbridge Gas Distribution, EB 2011-0354, page 2/3.
[710] EB-2009-0084, OEB Report on the Cost of Capital, December 11, 2009, pages 19-20.
[711] Ibid, page 19.
[712] Ibid.
[713] Ibid.
[714] Ibid, pages 19-20.

587. Utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The OEB acknowledged that Equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors[715].

588. Finally, the OEB stated that it was of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the OEB is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. The OEB cited with favour the following (reproduced in part):

> The fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory.[716]

589. The OEB Cost of Capital Report undertook a detailed consideration of the role of the comparable investment standard of the FRS. While this will be addressed more fully below, it is noteworthy that the OEB referenced in its Cost of Capital Report the following principles as stated by the Supreme Court of Canada in respect of the "fair return" for a regulated company in its *Northwestern Utilities v. City of Edmonton* (1929) case. In its decision, the Supreme Court found that:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[717]

[715] EB-2009-0084, OEB Report on the Cost of Capital, December 11, 2009, page 20.
[716] Ibid.
[717] Ibid, page 17 and Concentric Report, Exhibit 5, Tab 3, Schedules 1, Attachment 1, page 7.

590. The Company notes that the OEB for reasons of regulatory efficiency has set a threshold test which must be met before it undertakes a full FRS review. The OEB Cost of Capital Report includes the following on dealing with capital structure:

> As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals. For gas utilities, the deemed capital structure is determined on a case by case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utilities' capital structure will only be undertaken in the event of significant changes in the Company's business and/or financial risk.[718]

591. It is therefore appropriate to first turn to the question of whether there has been a significant change in the business or financial risk of Enbridge Gas.

Changes In Enbridge's Business and/or Financial Risk

592. As noted by the OEB in the EGD and Union 2013 Rates Applications,[719] for the reasons of regulatory efficiency and predictability, the OEB's policy does not require a full FRS analysis in each case but the OEB will perform a full review of capital structure in instances where there is a significant change in risk.[720] It follows that where there has been a significant change in risk, it is reasonable to assume that a change to a company's capital structure may be needed in order to meet the FRS. As noted by Enbridge Gas witness Ms. Ferguson, in its 2013 decision for legacy EGD, the OEB concluded that new environmental policies had not changed EGD's risk since 2007 but there was no mention of energy transition because it was not an issue at that time[721]. In comparison to the situation in 2013, in Procedural Order No. 6, the OEB stated that it is particularly interested in the risks that have been identified in relation to energy transition including the risk that assets may be

[718] EB-2009-0084, OEB Report on the Cost of Capital, December 11, 2009, page 49.
[719] EB 2011-0210 and EB 2011-0354, the OEB applies the FRS while promoting regulatory efficiency and predictability.
[720] EB 2011-0354, Decision on EGD's Equity Ratio and Order, February 7, 2013, page 5.
[721] 8 Tr.52.

stranded. [722] This is a stark difference from 10 years ago and clearly demonstrates this is the largest risk facing the Company today.

593. The Company engaged Concentric to first consider and follow the OEB's approach to assessing capital structure by beginning with a detailed risk analysis of the amalgamated Enbridge Gas and to specifically study changes in Enbridge Gas's risk profile relative to the time when the OEB previously assessed the Company's capital structure in 2012. Concentric noted that in actuality, a full FRS review had not been undertaken for over 16 years and since 2007.[723]

594. Concentric witnesses, Mr. Coyne and Mr. Dane were both qualified as experts in rate regulated utility capital structures. Messrs. Coyne and Dane have appeared previously on this subject as experts in Ontario and other jurisdictions in Canada and on dozens of occasions in the United States. Concentric is considered one of the leading and most experienced experts on the subject of utility capital structures and the evaluation and determination of a fair return for regulated utilities.

595. Concentric summarized its findings in respect of the changes in business and financial risk that Enbridge Gas has and will face:

> Concentric concludes in this section that while the Company's risk level for its regulated operations remains the same in some areas of the business, the overall risk for these operations has significantly increased since 2012, primarily due to the following factors:
>
> a) The Energy Transition (described in more detail herein) began in earnest in the last five years. As equity investors and credit rating agencies widely acknowledge, it substantially affects the risk profile of North American gas distribution utilities, including Enbridge Gas.
>
> b) An uncertain economic outlook, increased competition from electricity (i.e., the Energy Transition), and the OEB's encouragement of competition from alternative gas suppliers in the Company's service territory have combined to increase the Company's volumetric risk relative to the Company's previous equity thickness proceedings. Regulatory mechanisms provide

[722] Procedural Order No. 6, June 23, 2023, page 5.
[723] 8 Tr.54.

short-term insulation, but do not change the long-term challenges facing the Company.

c) The Company has experienced a gradual weakening in its debt-related credit metrics (i.e., FFO/Debt and Debt/EBITDA) since 2012. The Company's credit spreads on debt issuances have widened slightly since 2012.

d) The complexities of operating gas utilities have increased, putting pressure on the Company regarding project permitting, execution, and cost recovery. Successful management of the associated rate impacts depends on supportive regulation by the OEB and active management of changing asset life cycles through depreciation practices.

Concentric concludes that, taken as a whole, this shift in risk profile is sufficient to warrant a reassessment of Enbridge Gas' equity ratio".[724]

596. In response to an interrogatory from OEB Staff, Concentric summarized its views as follows:

> Concentric recommends that the Company's deemed equity ratio be increased from 36% to a range of 40% to 45%, with a point estimate of 42%. That recommendation is based on Concentric's analysis that Enbridge Gas's risk profile has changed materially, and further based on Concentric's Fair Return Standard analysis. The Energy Transition, including its impact on stranded cost risk and reductions in growth opportunities, is a key element of Concentric's risk assessment, but it is not possible to isolate its effects from the overall risk assessment of Enbridge Gas. As summarized in Concentric's report, the recommended capital structure and associated increase in the equity ratio are based on a number of factors. While Concentric concluded that the Energy Transition makes the Company's business significantly riskier today than it was in 2012 from an investor's perspective, Concentric's study also encompassed other primary aspects of the Company's risk profile, including volumetric risk, financial risk, operational risk, and regulatory risk, as well as a comparison of Enbridge Gas's risk relative to comparable proxy groups of firms with equity ratios ranging from 39.25% to 55.57%, Exhibit. 5, Tab 3, Schedule 1, Attachment 1, page 127.[725]

597. In reaching the above conclusions, Concentric undertook a comprehensive and detailed review of relevant jurisdictions and utilities across North America as well as macroeconomic factors and other risk indicators. Concentric considered, in respect of energy transition issues, the government policy and legislative initiatives in Canadian and U.S. jurisdictions. Concentric noted the existence of the Canadian

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[724] 8 Tr.17-18.
[725] Exhibit I.5.3-STAFF-207, pages 1-2.

carbon charge under the *Greenhouse Gas Pollution Pricing Act* and the actions of various municipalities in response to climate change concerns. Concentric identified the status of bans on gas in buildings by the U.S. States[726] which it updated in an undertaking response during the Oral Hearing.[727] Concentric identified various investor actions in response to energy transition issues. These include, as acknowledged by Dr. Hopkins under cross examination, the prohibition by certain equity investors from investing in fossil fuel industry companies like natural gas distributors.[728] Mr. Coyne stated he has never seen this occur in his history of working with energy investors with some saying they simply cannot invest in a natural gas utility, the investment committees will not allow them to do so.[729]

598. Concentric identified a long list of North American utilities which have established net zero targets of 2050 or earlier concluding that even where public policy measures do not yet require emission reductions, investors are pressuring companies to alter their business profiles.[730] In its report beginning at page 29, Concentric reviewed the response of multiple regulators to energy transition issues.[731] For example, in Massachusetts, the Office of the Attorney General is asking questions including: “Should shareholders pay for the diversification and expansion of the LDC’s business operations to meet GHG emissions limits?” and “Can the LDC sustain the current business model as the Commonwealth takes affirmative action to electrify and decarbonize the heating sector”.

599. With specific application to Ontario, Enbridge Gas witness Ms. Ferguson noted that the OEB itself has recognized the risk facing Enbridge Gas in its report to Ontario’s

[726] Exhibit 5, Tab 3, Attachment 1, page 23.
[727] Exhibit J8.3.
[728] 5 Tr.147-148.
[729] 8 Tr.111.
[730] Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 28.
[731] Ibid, page 29.

Electrification and Energy Transition Panel. Ms. Ferguson quoted at page 23 of the report which states:

> Electrification, the transition to renewable gases, carbon capture and storage, and hydrogen provide uncertainties that are unique to natural gas distributors. These uncertainties give rise to increasing risks that require natural gas distributors to consider the role of the resources and infrastructure can play in a net zero future.[732]

600. In addition, expert witness Mr. Coyne quoted the Ontario Minister of Energy's letter dated June 26, 2023, produced at undertaking Exhibit J8.1. The Minister stated in this letter:

> The government has established the Electrification and Energy Transition Panel to provide strategic advice on the highest-value, short-medium and long-term opportunities for the energy sector to help Ontario's economy prepare for electrification and the energy transition.[733]

601. In Mr. Coyne's view while under cross examination, two aspects of this quote are meaningful. The Minister of Energy is focusing on short, medium and long-term solutions and focusing on electrification as a primary solution to transition. In Mr. Coyne's view, from an Enbridge Gas standpoint, "it is clearly not business as usual".[734]

602. In this proceeding, there is evidence that Enbridge Gas faces a foundational change to its business, significant uncertainty about how it will be permitted to operate in the future and recover not only a return <u>on</u> capital but a return <u>of</u> its capital. The issue of energy transition and related issues about the possibility of stranded assets, whether capital projects should proceed, the appropriate depreciation methodology and the appropriate revenue and customer horizons for customer attachments took up a substantial portion of hearing time. As confirmed by expert witness, Dr. Hopkins[735], on behalf of IGUA, energy transition issues did not arise and were not considered by

[732] 8 Tr.65-66.
[733] 8 Tr.83-84.
[734] Ibid.
[735] 5 Tr.150.

the OEB the last time that the capital structure of Union and EGD was considered. Stated bluntly, if the energy transition risks which the Company faces are insufficient to meet the threshold question asked by the OEB for the purposes of determining whether a full FRS review should be undertaken, one must question what it would take to meet the threshold. There are parties to this proceeding which are advocating that the business of natural gas distribution must not only change but substantially decline, if not completely cease to exist. These are foundational changes which are only accelerating, as confirmed by expert witness, Dr. Hopkins,[736] and as demonstrated by the number of actions taken by various jurisdictions across North America to restrict and in some cases prohibit the expansion of natural gas distribution to new customers.

603. Enbridge Gas notes that the experts engaged by OEB Staff, LEI, opined that there has been an increase in business risk for Enbridge Gas despite the advantages from amalgamation, particularly due to the increase in risks associated with energy transition.[737] It is important to note that LEI was engaged by OEB Staff to perform an independent review of Enbridge Gas's business risks and to undertake an analysis of whether its capital structure meets the FRS. By comparison, Dr. Clearly, one of the experts engaged by IGUA, did not undertake an independent and full review of the FRS, and also opportunistically selected certain isolated factors (e.g. credit metrics and bond yields) to fashion an argument that nothing has changed. Enbridge Gas submits that greater weight should be placed on the independent determinations made by LEI about the change in risk and specifically that the threshold test has been met and that a review of the FRS should be undertaken. As a result, LEI recommended an increase in Enbridge Gas's equity thickness.

[736] 5 Tr.149.
[737] Exhibit M2, page 20.

604. The survey of analysis of gas utility futures undertaken by IGUA's expert, Dr. Hopkins, in respect of eight U.S. jurisdictions confirms the findings of Concentric that energy transition issues are accelerating and pose an increasing risk to gas utilities.[738] Dr. Hopkins identifies many of the same issues in the U.S. jurisdictions that have been raised in this proceeding including issues associated with stranded assets, various approaches to cost recovery such as accelerated depreciation, exit charges or transferring costs to electric customers.[739]

605. Collectively, the opinions of the experts including Concentric, LEI and Dr. Hopkins stand for the proposition that energy transition issues are real and live today, they are accelerating, and they represent foundational risks to the business of natural gas distributors. There can be no question that there has been a significant change in the business and financial risks faced by Enbridge Gas in the last 11 years, which is the last time the capital structures of the utilities were examined. The Oral Hearing in this proceeding is a testament to this conclusion given that energy transition issues were addressed in some way by every panel to this proceeding.[740]

606. Concentric also considered whether there have been changes to the volumetric, financial, operational, and regulatory risks of Enbridge Gas. Over thirty pages of its report are devoted to reviewing relevant circumstances and data that ultimately supported the conclusions reached by Concentric. In respect of volumetric risk, Concentric acknowledged that the Company has and is likely to continue to have a variety of rate making mechanisms which will protect against this risk in the short term, including the straight fixed variable rate design that is proposed but in the long term, it is much more difficult for regulation to protect against volumetric risks.[741]

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[738] Exhibit M8, Attachment 3, Survey of Analysis of Gas Utility Futures, May 1, 2023, Hopkins and Deleon.
[739] Exhibit 5, Attachment 3, page 3.
[740] Indeed Procedural Order No. 6 specifically stated that the: "OEB asks Enbridge to ensure that energy transition witnesses are available on subsequent witness panels so that energy transition matters arising from the evidence provided by those panels can be addressed as they arise" , Procedural Order No. 6, July 23, 2023, page 5.
[741] Exhibit 5, Tab 3, Attachment 1, page 59.

607. Concentric added to this comment that it will be more difficult for regulatory mechanisms to provide protection against risk in the long term in an interrogatory response to OEB Staff which asked for evidence of investors showing concern about a death spiral scenario. In the response Concentric states:

> Concentric's reference to a death spiral is based on its knowledge of the potential pathways for gas utilities under alternative policy frameworks designed to curtail carbon emissions in order to reach mandated carbon reduction targets in both Canada and the U.S. In Concentric's work for infrastructure investors, in the past two years we have had several indicate it was no longer possible for their funds to invest in gas utilities. These decisions have been based on a combination of new restrictions on investments in fossil fuel-based companies, concerns regarding future restrictions on gas use, and uncertainty regarding earnings and the potential for stranded assets.[742]

608. In assessing the financial risk, Concentric determined based upon its review that the credit metrics and comparative metrics of Enbridge Gas have weakened. Although the IGUA expert, Dr. Cleary suggests that the debt rating agencies are not concerned with Enbridge Gas since the business risk is unchanged, this view is not correct. As Mr. Reinisch explained during his direct testimony on the rating agencies:

> Although neither S&P Global nor DBRS calls out equity thickness specifically in their reports, both acknowledge that the financial risk facing Enbridge Gas Inc. is significant. Given the significant financial risk, it is important to note that the business risk is what allows Enbridge Gas to maintain its current credit rating. Should there be a change in the future with respect to that business risk, there is only one direction for that business risk to go, and that is weaker, which puts at risk the current Enbridge Gas rating.[743]

609. It is noteworthy that while the most recent S&P Report dealing with Enbridge Gas dated July 14, 2023, which was produced as Exhibit K8.2 during the proceeding, did not indicate any change to Enbridge Gas's ratings, the S&P rating in respect of Southern California Gas (SoCalGas), which was introduced at Exhibit K8.3 dated May 12, 2023, showed that S&P recently revised its outlook on SoCalGas to

[742] Exhibit I.5.3-STAFF-208, page 1.
[743] 8 Tr.62.

negative from stable due to energy transition issues. In all material ways, Enbridge Gas is a very good comparator to SoCalGas. The ratings downgrade serves as a harbinger of future action from ratings agencies across the industry and highlights the risks of waiting for a credit rating downgrade before strengthening Enbridge Gas's balance sheet. It is important to recall that Company witnesses were asked to determine what equity thickness was used by S&P for the purposes of its July 14, 2023, rating for Enbridge Gas. In its response to undertaking Exhibit J8.2, the Company advised that S&P Global used a forecasted equity thickness of approximately 39% for 2024 and 2025.[744]

610. In terms of operational risks, Concentric noted that they have increased due to: energy transition and anti-carbon sentiment; climate change and severe weather; higher insurance costs, safety requirements and cyber security concerns and more stringent engineering regulations.[745]

611. Finally, from a regulatory risk perspective, Concentric found that this risk has decreased modestly assuming that the Company's straight fixed variable rate design is approved by the OEB.

612. It is anticipated that some parties may take the position that energy transition risks will play out over the longer term and that the OEB should conclude that the risks in the shorter term are not sufficient to warrant a full FRS review. What this position misses, first of all, is the fact that the determinations made by the OEB in this proceeding will be influenced by energy transition concerns and risks. These impacts will apply during the term of the IRM and are therefore current and real. Further, as noted by Mr. Coyne of Concentric while under cross examination, equity investors see that they need to make decisions today based on how they see energy

[744] Exhibit J8.2.
[745] Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 75.

transition risks unfolding even though some of these risks cannot be fully calculated and forecast at this time. Mr. Coyne stated:

> I wish it was more unambiguous than it is, but that is really where we are with energy transition. By its nature, it is ambiguous. By its nature, it will unfold over a timeline, but investors don't have the luxury of sitting back and waiting. Some may, and decide that I will go hands-off until I see how it unfolds. Others will say no, and others, as we have seen in the marketplace, have decided I will, but it is a more expensive place for me and therefore I require a higher return.[746]

613. Mr. Coyne added:

> Energy transition, if I could just add one more thought, is going to unfold over decades, but that doesn't mean that the company can stand still. It needs to be taking actions today, to respond to political pressures and public policies and customer preferences today. It can't wait until all that is to be known is known. So it affects operations today, it affects risk today, even though all the knowns will not be knowns for decades to come.
>
> And that is why I believe that our recommendation of coming up to what we believe is a minimum threshold for equity thickness is an appropriate first step as the company leans into the kind of financial strength it needs to manage through the transition.[747]

614. Still under cross examination, Mr. Coyne further stated:

> And today, it is such a fundamental change in risk for the company's business profile, it is hard to envision any scenario that is an upside scenario for a gas distribution company in the face of energy transition. It is only a matter of by what degree will we see the company's business profile and risk impacted by energy transition.
>
> So we just see it as a wholly different business environment that could have even been envisioned in 2013. These policies just weren't on the table.[748]

<u>Response to IGUA Witnesses</u>

615. Enbridge Gas and its expert witnesses from Concentric had no opportunity to comment on the reports of the IGUA expert witnesses Dr. Hopkins and Dr. Cleary

[746] 8 Tr.143-144.
[747] 8 Tr.146-147.
[748] 8 Tr.151.

until the Oral Hearing. Accordingly, in direct testimony, Mr. Dane provided the following assessment of the conclusions reached by Dr. Cleary:

> The IGUA witnesses, Dr. Cleary and Dr. Hopkins, take the view that there has been no fundamental increase in the company's risk, and therefore no change in the equity ratio is warranted. Dr. Cleary's approach to measuring risk is overly narrow and backward-looking.He focused on the company's historical ability to earn its allowed return, current credit ratings, and near-term credit metrics. None of these measures is indicative of an equity investor's required return, which is forward-looking and considers both near-term and long-term risk.
>
> Nearly all of the third-party evidence Dr. Cleary cites is from debt-focused credit rating agencies, not the equity investor community. And, further, Dr. Cleary states his disagreement with certain findings in third-party investor materials that conflict with his own views, even though those third-party investor views reflects those of the market.
>
> In addition, Dr. Cleary dismisses all other North American utilities, including other Ontario utilities, as being useful in an analysis of Enbridge Gas's equity ratio, therefore rendering a comparable return analysis impossible.
>
> In our experience, regulators recognize that no company is a perfect comparator, but find that proxy company analysis is a meaningful, and often necessary, step in meeting the fair return standard. Dr. Cleary, however, asks the Board to rely solely on his, quote, absolute basis analysis of Enbridge Gas's equity thickness, despite the fact that both Concentric and LEI provided significant industry and market data regarding utility equity levels and both concluded that an increase in Enbridge Gas's equity ratio is warranted.
>
> Further, in his analysis that attempts to demonstrate that Enbridge Gas is essentially the lowest-risk utility in North America, Dr. Cleary makes inappropriate comparisons between book equity returns at U.S. and Canadian holding companies and Enbridge Gas's earned regulatory returns at the operating-company level. These returns are not calculated on the same basis and cannot be used to draw relevant conclusions for setting Enbridge Gas's equity ratio, as any reasonable analysis would have to account for the significant accounting differences between book returns at the holding-company level and regulatory returns at the operating-company level.
>
> In effect, Dr. Cleary eliminates any reasonable comparison to Enbridge's North American peers and therefore dismisses the importance of meeting all three prongs of the fair return standard.[749]

[749] 16 Tr.59-61.

616. Concentric expert witness Mr. Dane offered the following assessment about the conclusions reached by IGUA witness Dr. Hopkins:

> Dr. Hopkins recognizes that the energy transition to a decarbonized future is happening and will impact Enbridge Gas's business, but he believes that further scenario modelling of different futures for Enbridge Gas is necessary to better understand how these risks will unfold; this, despite the fact that Dr. Hopkins acknowledges that no other regulatory jurisdiction has done the type of analysis he is suggesting.
>
> We agree that further modelling of these risks will be beneficial, but just the fact that such work is necessary underscores the fundamental shift in the business environment for utilities such as Enbridge Gas, which is a clear distinction from the business environment 10 or even five years ago. An equity investor does not have to wait for the additional modelling suggested by Dr. Hopkins to understand that these risks exist, and there is no credible scenario identified where Enbridge Gas has less risk than it did in 2012 or in 2018.[750]

617. Enbridge Gas submits that looking at the sheer volume and totality of the evidence in this proceeding which relates to energy transition issues and its impacts on gas distributors across North America, it is simply disingenuous to suggest that there has been no change to the business and financial risk of the Company.

FRS Review

618. Concentric analyzed the equity ratios of four proxy groups of other North American utilities screened for risk characteristics similar to Enbridge Gas. For the purposes of its FRS analysis, it reviewed three separate measures of the equity ratios of similarly situated regulated utilities:
    a) The historical equity ratios maintained by comparable publicly traded holding companies (to the extent applicable);
    b) The historical book equity ratios maintained by the gas operating subsidiaries of those holding companies; and
    c) The equity ratios authorized by the regulators of those gas operating subsidiaries.[751]

[750] 16 Tr.62-63.
[751] Exhibit 5, Tab 3, Schedule 1, Attachment 1, page 79.

619. The four proxy groups examined were Canadian operating companies, Canadian holding companies, U.S. operating companies and U.S. holding companies. Before turning to the Concentric findings, it is appropriate first to reference the OEB's views on the relevance of considering U.S. proxy groups.

620. The OEB notes in the OEB Cost of Capital Report that during the EB-2009-0084 proceeding, many intervenors representing ratepayer groups did not consider U.S. utilities as comparators for the purposes of the FRS. The OEB identified, at footnote 15, at page 22, that IGUA was one of the ratepayer groups that took this position. In response, the OEB stated:

> The Board disagrees and is of the view that they [US Utilities] are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed.[752]

621. The OEB then went on to state that:

> The Board is of the view that the US is a relevant source for comparable data.[753]

622. The above determinations by the OEB are inconsistent with the recommendations made by Dr. Cleary on behalf of IGUA who ruled out the use of any U.S. comparators and indeed only found three Canadian natural gas utilities as proper comparators and even those were of limited value.[754] Enbridge Gas submits that it is therefore not possible to conclude that Dr. Cleary undertook a comparable investment standard analysis as required by the FRS.

623. Following Concentric's review of proxy groups across North America it had screened for relevancy as comparators, Concentric recommended that Enbridge Gas's authorized equity thickness fall within a range of 40% to 45%. Concentric

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[752] EB-2009-0084, OEB Report on the Cost of Capital, December 11, 2009, page 22.
[753] Ibid, page 23.
[754] Exhibit M6, pages 3-4.

recommended an equity thickness of 42%. It is this equity ratio which Enbridge Gas has proposed in this Application. Concentric noted that Enbridge Gas has the lowest deemed equity ratio of any investor-owned gas utility in North America despite its average risk profile. In addition, in recent years the OEB's adjustment formula has provided ROEs that are among the lowest of any investor owned electric or gas utility in Canada or the U.S. A combination of the lowest deemed equity ratio and low authorized ROE in recent years places Enbridge Gas at a competitive disadvantage in terms of attracting capital and compensating existing shareholders. Concentric found that the Company's current deemed equity thickness does not satisfy the comparable investment standard component of the FRS.[755]

624. By comparison, LEI has recommended an increase in equity thickness to 38%. LEI acknowledged that the comparable investment standard should include a review of appropriate comparators in the U.S. and as a result, LEI applied a screen and generated a total of 38 North American peer groups (the majority of which were in the U.S.). Despite this, there is no indication in LEI's report, as confirmed under cross examination, that it applied any of the information determined in respect of the U.S. comparator groups for the purposes of recommending the 38% figure for deemed equity. The LEI report specifically states that:

> Relative to US companies, while Canadian companies have lower average equity ratios and lower average ROEs, it is notable that the US companies had similar equity ratios (averaging more than 50% in 2011) and higher ROE (averaging c.9.9% in 2011) when the OEB decided to retain the equity ratio of 36% for EGD and Union.[756]

625. The above statement from LEI's report clearly indicates that it believes that because the differences existed when the OEB last considered the equity thickness of EGD and Union, the fact that such differences exist today is of no concern. By LEI's own admission, the customer weighted average of equity ratios in the U.S. have

[755] Exhibit 5, Tab 3, Schedule 1, Attachment 1, pages 120-122.
[756] Exhibit M2, pages 45-46.

increased from 50.9% to 51.4%.[757] LEI admitted under cross examination that the appropriate customer weighted average in Canada is 38% (LEI admitted that Centra Gas Manitoba Inc. which is owned by Manitoba Hydro and in turn by the government of Manitoba and its 30% equity ratio should not be included in the Canadian comparator group). LEI simply proposes the weighted average of the Canadian utilities it examined being 38% be applied to Enbridge Gas. There is no evidence that LEI relied upon any of the U.S. comparators for the purposes of this recommendation. LEI's report does not indicate that its recommendation for 38% was influenced in any way by the US comparators.

626. U.S. comparators were not considered relevant because LEI believed that the spread between U.S. and Canadian equity ratios was viewed as appropriate by the OEB in 2013. LEI ultimately agreed under cross examination that the OEB in fact did not undertake a comparable investment analysis in 2013 in respect of both EGD and Union. Thus, the appropriateness of the spread in equity ratios was NOT considered by the OEB at that time. Enbridge Gas submits that the much higher equity thickness that exists in the U.S. and the increasing spread between U.S. and Canadian equity ratios should have been taken into consideration by LEI for the purposes of adjusting its recommendation to a figure greater than 38%.

627. Equally telling is the fact that LEI did not consider the fact that Ontario's electric LDCs have deemed equity ratios of 40%. Ontario electric LDCs were not used as part of LEI's comparable investment standard analyses other than to state that the equity thickness difference between gas distributors and electric distributors has historically existed. There can be no question that Ontario's electric LDCs do not face the foundational sort of risks that are faced by Enbridge Gas. The fact that the equity thickness of electric utilities operating in the same geographic areas and under the jurisdiction of the same regulator as Enbridge Gas have a significantly

[757] Exhibit M2, Figure 30, page 46.

higher equity thickness should have been a matter considered by LEI as part of its FRS and comparable investment standard review.

Implementing the 42% Equity Thickness Rate

628. While the FRS analysis has determined that the appropriate equity thickness for Enbridge Gas is 42%, Enbridge Gas is mindful of the potential impact on rates should the deemed equity thickness be increased from 36% to 42% in the test year. For this reason, Enbridge Gas has proposed that the increase in equity thickness be phased in over the IR term. In 2024, the equity thickness would be increased to 38%. The equity thickness would then be increased in each of the four following years by 1% such that in 2028, the equity thickness would meet the FRS at 42%.

629. The Company provided its forecast utility cost of capital for the test year at Exhibit 5, Tab 1, Schedule 1, Table 3.[758] The forecast figures will of course be revised for the purposes of actual rates for debt cost and equity following the OEB's release of its 2024 Cost of Capital parameter letter expected in October 2023 and to reflect the Settlement Proposal and the decisions of the OEB in this proceeding.

630. As noted in evidence[759], the proposed increase in equity thickness will be partially offset by corresponding reductions in debt financing. In the pre-filed evidence[760], Enbridge Gas calculates the revenue requirement variances to be captured through base rates due to the adjustments in 2025 through 2028 as a result of the annual increase of 1% to equity thickness. The Company has calculated that the net increase from 38% to 42% is $54.5 million[761]. To recover this change over the four years, base rates would be adjusted in each of 2025 through 2028 by 25% of this

[758] Exhibit 5, Tab 1, Schedule 1, page 4, updated March 8, 2023. See also J9.1 Attachment 1 with revisions due to the Capital Update.
[759] Exhibit 5, Tab 3, Schedule 1, pages 3-6.
[760] Ibid, pages 5- 6 (Updated by Exhibit JT9.1 Attachment 1).
[761] Ibid, page 6 (Updated by JT 9.1 Attachment 1).

figure in each year or $13.6 million[762]. This way, the impact of the increase in equity thickness is smoothed from a rates perspective over the 5 years.

I. Deferral & Variance Accounts (Exhibit 9)

Deferral and Variance Accounts

631. Issue 32 - Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?

632. Issue 33 - Is the proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?

Consequences Of Settlement Proposal

633. The Settlement Proposal defines the limited outstanding scope of these issues.

634. In Issue 32 of the Settlement Proposal, the parties agreed upon the Deferral and Variance Accounts to be created and/or continued with one exception. There is no agreement as to whether Enbridge Gas should create a Volume Variance Account (VOLUVAR).[763] This item is also noted in Issue 9 of the Settlement Proposal.[764]

635. Additionally, since the time of the Settlement Conference, Enbridge Gas has added requests for two new deferral accounts – the Panhandle Regional Expansion Project Variance Account (PREPVA) and the Short-term Storage and Other Balancing Services Account for the Union rate zones. These requests are not addressed in the Settlement Proposal and are outstanding.

[762] Exhibit 5, Tab 3, Schedule 1, page 6, (Updated by JT 9.1 Attachment 1).
[763] Exhibit O1, Tab 1, Schedule 1, page 57.
[764] Ibid page 27.

636. In Issue 33 of the Settlement Proposal[765], the parties agreed to the clearance of Deferral and Variance Accounts as proposed by Enbridge Gas, except for two contested items to be determined by the OEB:
   a) The 2020 to 2023 balances in the Tax Variance Deferral Account (TVDA) which relate to accelerated Capital Cost Allowance (CCA) for integration capital projects; and
   b) The balance in the APCDA.

Outstanding Approvals Required

637. Enbridge Gas requests that the OEB approve the establishment of the VOLUVAR and PREPVA, effective January 1, 2024. Enbridge Gas also requests the continuation of the Short-term Storage and Other Balancing Services Account on an interim basis until such time that the outcomes of the OEB's decision in Phase 2 and/or Phase 3 related to storage issues are known.

638. Enbridge Gas requests that the OEB approve the clearance of the balance in the TVDA related to accelerated CCA for integration capital projects, such that those who are paying towards the undepreciated costs of the integration capital projects receive the credit balance in the TVDA. If the OEB finds that the undepreciated costs of the integration capital projects are appropriately part of 2024 rate base (as Enbridge Gas proposes), then the balance in the TVDA should be credited to ratepayers. If the OEB does not agree with Enbridge Gas and disallows the undepreciated costs of the integration capital projects from 2024 rate base, then Enbridge Gas should receive the credit balance in the TVDA.

639. Enbridge Gas requests that the OEB approve the clearance of the balance in the APCDA as filed.

[765] Exhibit O1, Tab 1, Schedule 1, page 58.

Revenue Requirement Implications for 2024

640. There are no 2024 revenue requirement implications for these issues. Any clearance of deferral accounts is done by way of rate rider.

Evidence in Support

641. Enbridge Gas has filed detailed evidence included in Exhibit 9 – the proposed accounts are at Tab 1 and the requests for clearance are at Tab 2.[766] Enbridge Gas's request for the PREPVA was included in the Capital Update, in connection with the request for levelized treatment for the PREP.[767] Enbridge Gas's request for the Short-term Storage and Other Balancing Services Account for the Union rate zones is set out in an updated interrogatory response.[768]

642. Enbridge Gas answered follow-up questions interrogatories about the Deferral and Variance Account evidence[769], Technical Conference testimony[770], Technical Conference undertakings[771] and filed several ADR responses.[772]

643. Enbridge Gas witnesses provided testimony about the outstanding aspects of Issues 32 and 33 on Day 15 of the Oral Hearing (Panel 13).[773]

Overview

644. Enbridge Gas submits that creation of the VOLUVAR is appropriate.

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[766] Note that the Guidehouse Report titled "Natural Gas Volume Forecasting Benchmarking Study", filed at Exhibit 3, Tab 2, Schedule 2, is relevant to the request to establish the VOLUVAR.
[767] Exhibit 2, Tab 5, Schedule 4, page 31 and Exhibit 2, Tab 5, Schedule 4, Attachment 2 (draft Accounting Order for PREPVA).
[768] Exhibit I.9.1-SEC-220, updated August 1, 2023.
[769] See Exhibit I.9, as well as Exhibit I.3.2.
[770] 3 TC Tr.164-216.
[771] Exhibits JT3.26 and JT3.38.
[772] Exhibit I.ADR.44, 38 and 49.
[773] 15 Tr.6-115.

645. In large part, the proposed VOLUVAR reflects the long-standing approach of the legacy utilities to keep the utility and ratepayers whole from the impacts of changes in average use. That is particularly appropriate where there is no other means to reflect the revenue impacts of successful Demand Side Management (DSM) programs. It is also important in the context of other energy efficiency initiatives, including hybrid heating that reduce average use.

646. The proposed VOLUVAR also includes symmetrical treatment of volume variances related to weather being different from forecast/normal. This is consistent with the Company's Phase 3 proposal for fixed distribution rates (referred to as Straight Fixed Variable with Demand (SFVD)). Essentially, neither Enbridge Gas nor ratepayers should bear the risk of weather leading to higher or lower revenues. As shown in the evidence, over time this risk is symmetrical, but it can be impactful in a single year.

647. The proposed PREPVA will record differences between the amounts recovered in rates for the PREP versus the actual revenue requirement for the project. This is similar to the approach for ICM projects in the current deferred rebasing term.

648. The Company has explained that it should have included the Short-term Storage and Other Balancing Services Account as one of the accounts to continue until after Phase 2 and/or Phase 3 issues are determined. Enbridge Gas does not expect that there will be any opposition to the continuation of this account, which benefits ratepayers.

649. The main item of contention with the APCDA balance appears to be the inclusion of the Unamortized Pre-2017 Actuarial Losses and Prior Service Costs from Union that have been carried forward. Enbridge Gas submits that these are amounts that are properly included in the APCDA, and properly recoverable from ratepayers. The amounts sought for recovery were part of the Union balance sheet up until the time

that EGD and Union amalgamated. At that time, U.S. GAAP accounting rules allowed that the pension receivable be placed in a regulatory account for future recovery. Enbridge Gas included the pension receivable amount in the APCDA and drew it down between 2019 and 2023. The remaining balance is appropriately collectible from ratepayers, just as would have been the case had there been no amalgamation between EGD and Union.

650. In relation to the TVDA, Enbridge Gas does not believe that there is any opposition to the proposal that whoever is paying towards the undepreciated costs of the integration capital projects (ratepayers or the Company) should receive the credit balance from the TVDA.

Proposed Establishment of Deferral and Variance Accounts

651. As explained, there are three unsettled requests for establishment of new (or continued) accounts. Each is described below.

Volume Variance Account (VOLUVAR)

652. Enbridge Gas is proposing to update the following existing variance accounts and replace the existing accounts with one Enbridge Gas account:
   a) EGD – Average Use True-up Variance Account (AUTUVA)[774]
   b) Union – Normalized Average Consumption (NAC) Account[775]

653. Enbridge Gas is proposing to establish one variance account for Enbridge Gas to replace the AUTUVA and the NAC Account. The new VOLUVAR will record the

[774] For the EGD rate zone, the AUTUVA was established to record the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes, embedded in the volume forecast that underpins rates and the actual weather normalized average use experienced during the year.
[775] For the Union rate zones, the NAC Account was established to record the impact to delivery and storage revenue and costs resulting from the difference between the target NAC included in OEB-approved rates and the actual NAC experienced during the year for general service rate classes.

revenue impact, exclusive of gas costs, of the volumetric forecast variance resulting from actual average use per customer and weather experienced during the year for the general service rate classes.[776]

654. In large part, the proposed VOLUVAR reflects the long-standing approach of EGD and Union to keep the utility and ratepayers whole from the impacts of changes in average use. That is particularly appropriate where there is no other means to reflect the revenue impacts of successful DSM programs. Without variance account protection, Enbridge Gas loses incentive to maximize DSM results, because the resulting reduced volumes lead to revenue declines that are not credited back to the utility.[777] Additionally, variance account treatment of average use variances also addresses changes that result from increasingly efficient appliances, hybrid heating (which is encouraged by the Government of Ontario), changes to building codes and other efficiency related changes that the OEB encourages.

655. In the MAADs Decision, the OEB recognized the importance of reflecting DSM impacts in a variance account. The OEB directed Enbridge Gas to file a proposal in the rebasing application that includes a proposal for a lost revenue adjustment mechanism (LRAM) that includes general service customers.[778] It was left to Enbridge Gas to decide whether to propose continuation of the AUTUVA and NAC or something different.

656. Considering the uncertain energy transition pathway, average use decline is a concern. Although major drivers that could impact average use per customer are included through the Company's proposed average use forecast methodology[779], there are some uncertain factors that cannot be fully captured within the economic

[776] Exhibit 9, Tab 1, Schedule 2, page 26. See also 15 Tr.12-13.
[777] 15 Tr.13.
[778] EB-2017-0306/EB-2017-0307 Decision and Order, August 30, 2018, page 35.
[779] EB-2022-0200 Exhibit 3, Tab 2, Schedule 5.

forecast, which depending on the factor, may cause actual average use to be lower or higher than forecasted.

657. Neither the AUTUVA nor the NAC Account included the revenue variance due to weather. Including this revenue variance in the proposed VOLUVAR reduces volumetric risk in a symmetric and revenue-neutral manner for both customers and Enbridge Gas. In a year where actual weather occurs colder than the OEB-approved normal, customers receive the benefit of being refunded higher delivery charges resulting from weather in the proposed account. In a year where actual weather is reported warmer than the OEB-approved normal, the Company is able to recover the majority of its delivery costs, including recovery of fixed costs that do not vary with the level of customers' volumetric consumption.[780]

658. As explained by Mr. Bashualdo-Hilario in testimony, the risk from over- and under-recovery due to weather is roughly symmetrical in recent years.[781] That being said, the variances on a yearly basis can be meaningful, so the VOLUVAR provides smoothing and certainty for ratepayers and the Company alike.

659. The proposed VOLUVAR provides a similar de-risking of fixed cost recovery to that resulting from the proposed SFVD rate design for general service customers.[782]

660. As has been the case with the AUTUVA and NAC Account, the revenue impact of forecast variances related to changes in the customer forecast are not included in the proposed VOLUVAR. As explained in response to questions from Commissioner Moran, where the customer count changes as could be the case if customer attachments are lower than forecast or customer departures are higher than

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[780] Exhibit 9, Tab 1, Schedule 2, page 27.
[781] See 15 Tr.13-14, as well as Exhibit JT3.27 which was discussed by Mr. Bashualdo-Hilario and shows the annual revenue variances due to weather in recent years. See also 15 Tr. 20.
[782] Exhibit 9, Tab 1, Schedule 2, page 27. Please see Exhibit 8, Tab 2, Schedule 3 for the rate design proposal for general service customers.

forecast, that will not necessarily impact average use per customer.[783] If customers leave the system, and those are "average" customers, then there would be no impact on average use and no related revenue impacts reflected in the VOLUVAR.

661. The Guidehouse report titled "Natural Gas Volume Forecasting Benchmark Study" sets out a review of what ten comparator utilities in North America do in relation to a variety of forecasting methodologies and variance accounts.[784] Section 3.7 of the report indicates the following:

> Revenue stability mechanisms are common in all regulated utilities. The scope of such mechanisms varies but these are generally applied to better align utility incentives with societal benefits (e.g., by protecting utilities from revenue short-falls due to DSM), and to provide bilateral protection to customers and utilities for random shocks and deviations from trend (e.g., volatility in weather and macro-economic drivers of volume demand). Both EGD and Union rate zones are equipped with deferral accounts intended to stabilize revenues to fluctuations in weather-normalized AU [Average Use].[785]

662. It can be seen in the Guidehouse report that half of the peer utilities have explicit weather adjustment mechanisms and most of the rest of the peer utilities have implicit weather adjustment mechanisms.[786]

663. According to Guidehouse, the VOLUVAR proposal made by Enbridge Gas is broadly consistent with the approach taken by comparator utilities:

> All of the comparators reviewed in this report employ some form of revenue stabilization. Bilateral protection of consumers and the utility from the effects of weather volatility are explicitly addressed by the mechanism in place for four of the comparator utilities and is implicit in the mechanism of five comparator utilities (e.g., Utility E's revenue decoupling mechanism). Generally speaking, no explicit weather stabilization mechanism is necessary where rates are structured such that utility revenues are insensitive to normal and expected fluctuations in temperature around seasonal norms.[787]

[783] 15 Tr.104-108.
[784] 15 Tr.104-108.
[785] Exhibit 3, Tab 2, Schedule 2, page 23.
[786] Ibid, page 24-26. See also 15 Tr.24-28.
[787] Ibid, page 32.

664. The proposed VOLUVAR will remain in effect until the implementation of the SFVD rate design, if approved by the OEB in this Application. If, alternatively, the OEB approves another rate design approach, the proposed VOLUVAR will continue to be required to capture average use and weather variances.[788]

Panhandle Regional Expansion Project Variance Account

665. Enbridge Gas has proposed a levelized rate treatment for PREP. This would treat PREP in a similar manner to an ICM project.

666. Similar to the treatment of prior ICM projects (and the proposed prospective treatment of future ICM projects), Enbridge Gas proposes to establish an associated variance account, the PREPVA, that would capture any variance between the project's actual net revenue requirement and the actual revenues collected through the average unit rate that would be in place over the IR term. The variance account would ensure ratepayers do not over or under pay for the project, and that Enbridge Gas does not over or under recover over the IR term.[789]

667. The clearance of any cumulative balance in the account is proposed to occur at the end of the IR term, as during the IR term the account will be expected to capture the temporary differences between the average annual revenue requirement and the actual annual revenue requirement. Establishing an average unit rate at the outset of the IR term will be administratively efficient, as the project costs will not need to be reviewed annually as part of the rate adjustment applications.[790]

668. A draft accounting order for the PREPVA is included in evidence.[791]

[788] Exhibit 9, Tab 1, Schedule 2, page 27. See also 15 Tr.14.
[789] Exhibit 2, Tab 5, Schedule 4, page 31.
[790] Ibid, page 31.
[791] Exhibit 2, Tab 5, Schedule 4, Attachment 2.

669. In the event that the Company's proposed levelized rate treatment for PREP is approved, the Company is not aware of specific concerns with the proposed PREPVA.

Short-term Storage and Other Balancing Services Deferral Account

670. The Short-term Storage and Other Balancing Services Deferral Account has been in place for the Union rate zones before and during the deferred rebasing term. This account records the utility portion of actual net revenues for Short-term Storage and Other Balancing Services, less a 10% shareholder incentive to provide these services, and less the net revenue forecast for these services as approved by the OEB for rate-making purposes.[792]

671. As part of the Settlement Proposal, parties agreed that certain harmonized gas supply accounts will not be established before gas supply related issues are determined in later phases of the proceeding. Enbridge Gas provided a list of gas supply accounts that would continue on an interim basis until such time as a different approach is approved. Enbridge Gas inadvertently failed to include the need to continue with the Short-term Storage and Other Balancing Services Account for the Union rate zones.[793]

672. The Settlement Proposal indicates that matters related to gas storage will be determined in Phase 2 of this proceeding, and that Enbridge Gas will maintain its current levels of market-based storage. The Settlement Proposal also indicates that parties agree with Enbridge Gas's proposal to implement the 2024 Gas Supply Plan after the OEB's decision on relevant matters is issued. For these reasons, Enbridge Gas will not be implementing the 2024 Gas Supply Plan for the 2023/2024 gas year and therefore expects that there will continue to be excess utility storage space in

[792] Exhibit 9, Tab 1, Schedule 1, Attachment 1, page 11.
[793] Exhibit I.9.1-SEC-220, updated August 1, 2023. See also 15 Tr.7-8.

the Union rate zones until at least the implementation of outcomes of the OEB's decision on Phase 2 of this proceeding.[794]

673. Maintaining the Short-term Storage and Other Balancing Services Account allows for tracking and sharing of revenues from the sale of the Union rate zones excess utility storage space for the benefit of ratepayers.[795] Enbridge Gas does not expect that there will be any opposition to the continuation of this account.

Proposed Deferral and Variance Accounts Clearances

674. There are two accounts requested for clearance where there is no agreement. The Company's submissions on each are below.

675. As the final balances are not known at this time for these accounts (and the other deferral and variance accounts agreed for clearance in the Settlement Proposal[796]), Enbridge Gas is proposing disposition on an interim basis. Enbridge Gas will seek final disposition of the respective balances, calculated as the difference between actual balances as of December 31, 2023, and balances approved for disposition as part of this Application, within the Company's 2023 annual earnings sharing and D&VA disposition proceeding.[797]

Accounting Policy Changes Account (APCDA)

676. Enbridge Gas is proposing to clear the cumulative forecast debit balance in the APCDA deferral account, originally forecast at $142.2 million, plus interest to December 31, 2023, for a total of $142.2 million.[798] However, as a result of updated forecasts provided during the course of the proceeding, the forecast balance

[794] Exhibit I.9.1-SEC-220, updated August 1, 2023. See also 15 Tr.8.
[795] Ibid. See also 15 Tr.8 and 83-84.
[796] Exhibit O2, Tab 1, Schedule 1, page 58 (Issue 33).
[797] Exhibit 9, Tab 2, Schedule 1, pages 1-2.
[798] Ibid, page 4. Details are set out in Attachments 1 to 4 of that evidence.

proposed for disposition, including interest to December 31, 2023, is $140.2 million (see below).

677. As part of the MAADs Decision, the OEB established the APCDA to record the impact of any accounting changes required as a result of amalgamation that affect the revenue requirement.[799] The OEB approved the wording of the Accounting Order for the APCDA effective January 1, 2019, in its Decision and Order on Enbridge Gas's 2019 Rates Application.[800]

678. As per the 2019 Disposition of Deferral and Variance Account Balances Decision on Settlement Proposal, parties agreed to defer the review, allocation, and disposition of all balances in the APCDA until the end of Enbridge Gas's deferred rebasing term (December 31, 2023).[801]

679. Enbridge Gas has continued to track the annual revenue requirement impact of accounting policy changes made as of the amalgamation date of January 1, 2019, as well as any further accounting policy changes adopted since that time. The cumulative net balance in the APCDA is driven by the revenue requirement impact of six accounting policy changes arising from (and since) amalgamation, which are detailed in the Table 8 below, which categorizes the cumulative account balances by policy change.[802] The details of each accounting policy change are described further in the evidence.[803]

[799] EB-2017-0306 and EB 2017-0307, OEB Decision and Order, August 30, 2018, page 47.
[800] Exhibit 9, Tab 2, Schedule 1, page 5.
[801] Ibid.
[802] The table includes information from the pre-filed evidence at Exhibit 9, Tab 2, Schedule 1, pages 5-6, with updates where applicable. References are shown at each line.
[803] Exhibit 9, Tab 2, Schedule 1, pages 6-23.

Table 8
Net Forecasted APCDA

Balance	$ millions
Pension and OPEB Expense – Unamortized Pre-2017 Actuarial Losses and Prior Service Costs	156.0[804]
Amortized Gas Supply Storage and Transportation costs	62.1[805]
Interest during construction	1.5[806]
Capitalization vs Expense	(11.7)[807]
Depreciation expense	(31.2)[808]
Overhead capitalization	(36.5)[809]
Net forecasted APCDA	140.2

680. The only part of the APCDA that received attention at the Oral Hearing was the Pension & OPEB line expense. Accordingly, Enbridge Gas will focus its submissions on that item. If other items are discussed in intervenor argument, Enbridge Gas will respond in Reply Argument.

681. The Pension & OPEB line balance represents the remaining unamortized Union rate zones pre-2017 pension and OPEB actuarial gains and losses and past service costs. The balance represents costs incurred that the ratepayers of Enbridge Gas have not yet paid. While the balance includes both pension and OPEB costs, to simplify matters the amounts will be referred to in this submission as pension costs.

682. Specifically, the pension balance in the APCDA reflects the forecast December 31, 2023, balance of unamortized accumulated actuarial gains/losses and past service costs incurred by Union. The amortization of accumulated actuarial gains/losses and

804 Exhibit JT3.37 and Exhibit I.4.4-STAFF-133
805 Exhibit I.ADR.44
806 Exhibit 9, Tab 2, Schedule 1, pages 4-5.
807 Ibid.
808 Ibid.
809 Ibid.

past service costs, and corresponding drawdown of the APCDA asset over the deferred rebasing term, has been recognized as a component of accrual-based pension expenses included in operating and maintenance expenses and recovered in rates.[810] Through 2021, Enbridge Gas amortized $41.8 million of the $211.2 million pre-2017 balance originally transferred to the APCDA. Enbridge Gas forecasts additional amortization of $13.5 million over the 2022 Estimate to 2023 Bridge Year, resulting in a residual unamortized balance of $156 million.[811]

683. The facts underlying this issue are complex, relating to the initial February 27, 2017, merger of Spectra and Enbridge (referred to as the Merger), adjustments to EI financial statements, the MAADs decision, the January 1, 2019 amalgamation between EGD and Union (referred to as the Amalgamation) and the drawdown of the unamortized Union pension balance during the deferred rebasing term. The Deferral and Variance Account witnesses (Panel 13) provided an overview of the relevant facts and circumstances in their Examination in Chief, with reference to a two-page annotated timeline and spreadsheet filed as Exhibit K15.1. The paragraphs below summarize the key items.

684. Prior to the Merger of Spectra and Enbridge, both EGD and Union incurred pension actuarial gains and losses in a similar manner. The disposition or recovery of these amounts occurs over time, through annual accrual-based pension expense. Amortizing or drawing down these amounts annually in accordance with U.S. GAAP results in a natural smoothing mechanism that is intended to mitigate annual volatility. The residual balances that have existed at any point in time on EGD's or

[810] Exhibit JT3.37.
[811] Exhibit 9, Tab 2, Schedule 1, pages 17-18. The annual forecast amortization amounts are derived by Mercer in accordance with U.S. GAAP and are provided at Exhibit 9, Tab 2, Schedule 1, Attachment 8 along with the forecasted ending December 31, 2023, residual balance. Updated amounts are set out at Exhibit JT3.37.

Union's balance sheets represent incurred costs or credits that have not yet been reflected in rates.[812]

685. Over time, the accrual-based pension costs that ratepayers have paid for theoretically should equal the cash basis for which the utility has funded the plans on.[813] This is recognized in evidence filed by Mercer in this case.[814] It is also recognized in the KPMG Report on Pension and Other Post-Employment Benefit Costs (May 2016) to the OEB, which states as follows:

> … despite these periodic differences in P&OPEB costs, in the fullness of time, the cumulative cash (or funding) costs for a plan (or arrangement) is generally expected to equal that plan's cumulative accrual accounting costs. This is true regardless of the accounting framework that is used by a regulated utility. As such, over time, a regulated utility would recover all its P&OPEB costs irrespective of the method that is used to include these costs in rates.[815]

686. At the time of the February 2017 Merger of Spectra and Enbridge, the amount of the Union rate zones' pension actuarial gains and losses was $250.9 million.[816] As a result of the Merger, at the EI level, Union's cumulative actuarial gains/losses were reset to nil by way of a purchase price adjustment, which resulted in a new pension expense basis that excluded the draw down of Union's unamortized pre-Merger actuarial gains/losses.[817] At the time of the Merger, the pension adjustment was only required at EI. This accounting change had no impact on Enbridge Gas's (or the predecessor utility) pension funding requirements. Union continued to operate as stand-alone entity and continued to amortize the pre-February 2017 gains/losses (along with post February 2017 gains and losses), through accrual-based pension expense, which were reset at EI.[818]

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[812] 15 Tr.9-10.
[813] Ibid.
[814] Exhibit 9, Tab 2, Schedule 1, Attachment 9, page 1.
[815] KPMG Report to the Ontario Energy Board, Report on Pension and Other Post-Employment Benefit Costs, May 2, 2016, filed in EB-2015-0040. This same concept and phrasing are repeated three times in the report – at pages 21, 25 and 57.
[816] Exhibit 9, Tab 2, Schedule 1, page 17.
[817] Exhibit K15.1 and 15 Tr.10. See also 15 Tr.35-40.
[818] Exhibit K15.1 and 15 Tr.10.

687. As explained in testimony from Mr. Vinagre, the recognition by EI of Union's net assets acquired in the Merger initially failed to include the regulatory and recoverable nature of the cumulative actuarial gains/losses. Subsequently, the fair value of acquired Union net assets was updated, resulting in a lower purchase price excess attributed to goodwill.[819] This reassessment and the impacts to EI's financial statements was accepted by the Company's external auditors[820] and reflected in EI's December 31, 2018, financial statements. This was appropriate as it reflected the ongoing regulatory and recoverable nature of the balances.[821] In the result, the Union pension receivable amount was recognized on the EI balance sheet consistent with the Union balance sheet.

688. Between the time of the Merger (February 2017) and the time of Amalgamation (January 1, 2019), Union continued to draw down its pension receivable amount as had been the case prior to the Merger. As explained by Mr. Small, "following the merger of Enbridge and Spectra, there was no impact at the utility level. We just continued on as we were, as independent entities, and then we entered into the amalgamation or the MAADs proceeding."[822] This was confirmed by Mr. Vinagre in response to a question from Commissioner Duff: "…. the merger of Spectra and Enbridge Inc. on February 27, 2017, had no impact on Union as a standalone entity and did not have an impact on Union until the approval for amalgamation in the amalgamation itself, and then the required push-down".[823]

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[819] See also Exhibit JT3.30.
[820] As Mr. Rutitis indicated in testimony, "PwC was providing an opinion that we had analyzed U.S. GAAP and reflected the balance correctly with regards to the accounting criteria" – 15 Tr.113. The PwC audit opinion is provided at Exhibit J15.2.
[821] 15 Tr.10-11. See also 15 Tr.44-49.
[822] 15 Tr.92.
[823] 15 Tr.101.

689. From 2017 to 2018, Union had amortized $39.7 million of this balance in its own results, resulting in an unamortized balance of $211.3 million as at December 31, 2018.[824]

690. At the time of the Amalgamation, Enbridge Gas was required under U.S. GAAP to adopt and reflect the accounting policy change that had previously been recognized by its parent, EI. As explained, Enbridge Gas was required to "push down" the treatment on the EI balance sheet of the Union unamortized pre-Merger actuarial gains/losses.[825] There was no impact on EGD pension balances, since it was treated as the acquirer and no "push down" was required.[826]

691. Enbridge Gas recognized the residual pre-Merger unamortized net losses of Union within the APCDA as a result of this accounting policy change. Inclusion of this $211.3 million balance in the APCDA and subsequent annual amortization or drawdown nullified the revenue requirement impact that would have existed absent the amortization within the new pension expense basis. Absent the Amalgamation, Union would have continued to collect this receivable over time. At that time, U.S. GAAP accounting rules allowed that the pension receivable be placed in a regulatory account for future recovery. Enbridge Gas included the pension receivable amount in the APCDA and drew it down between 2019 and 2023, in order to bring the balance forward at rebasing and allow for the revenue requirement impacts to be mitigated during the deferred rebasing term.[827]

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[824] Exhibit 9, Tab 2, Schedule 1, pages 16-17. See also Exhibit K15.1, page 2.
[825] Ibid, page 17. As explained in the pre-filed evidence (footnote 11). "Pushdown accounting refers to establishing a new basis of accounting in the separate financial statements of the acquired entity (or acquiree) after it is acquired. The acquisition adjustments recorded by the acquirer in a business combination under ASC Topic 805 are pushed down to the acquiree's separate financial statements." The pushdown accounting requirement was discussed in response to questions from VECC - see 15 Tr.88-89 and 93-96.
[826] Exhibit K15.1 and 15 Tr.11.
[827] Ibid.

692. Beginning in 2019, Enbridge Gas amortized the APCDA balance pertaining to Union's pre-Merger losses in a manner identical to the pre-Amalgamation pension accounting basis, thereby mitigating any revenue requirement impact in accordance with the APCDA. This treatment continued throughout the deferred rebasing term, with the balance in the APCDA being drawn down to the forecast balance as brought forward in this proceeding ($156.0 million). The draw down during the deferred rebasing term mitigated the revenue requirement impact that occurred as the amortization was separate from pension expense under the new basis.[828]

693. Enbridge Gas has brought forward for approval the proposal to dispose of the remaining forecast December 31, 2023, balance in the APCDA. Beginning in 2024, Enbridge Gas's forecast for accrual-based pension costs excludes the drawdown of Union's gains/losses which accumulated prior to the Merger, and therefore separate regulatory approval is required to continue to recover the remainder of the balance either as a one-time adjustment or over a period of time.[829]

694. In the absence of an amalgamation, both EGD and Union would have continued to separately account for the balances and amortization in a manner that would have resulted in the same financial impacts. As such, the balance reflected in the APCDA is consistent with what Union's outstanding unamortized pre-Merger actuarial gains/losses would have been, to be drawn down through future accrual-based pension expenses recovered in rates, absent the Amalgamation.[830]

695. Neither the Merger, nor the Amalgamation, should impact the recoverable nature of the costs incurred and ratepayers are not harmed in any way as they would have been accountable to pay for the costs had the Merger and Amalgamation not occurred. The Amalgamation has not absolved ratepayers from this obligation, just

[828] Exhibit K15.1 and 15 Tr.11. See also Exhibit 9, Tab 2, Schedule 1, page 18.
[829] 15 Tr.12.
[830] Exhibit 9, Tab 2, Schedule 1, pages 18-19.

as Enbridge Gas would not have absolved itself of the obligation had the balance been a net gain or payable back to ratepayers before the Merger. Recovery is appropriate to ensure that over the life of the pension plan, the costs recovered on an accrual basis will equate to the required cash funding.

696. Enbridge Gas has brought forward an EGD rate zone pension transition payable balance of $255 million in this proceeding for refund to customers, recognizing that it is required to extinguish this liability.[831] That payable amount is based upon the same accrual-based pension cost approach being applied for EGD pension costs. Parties have agreed that it is appropriate for ratepayers to receive the benefit of this payable amount.[832]

697. Based upon the questions asked at the Oral Hearing, Enbridge Gas anticipates that there are at least two bases upon which intervenors may object to the recovery of the pre-Merger unamortized net pension losses of Union within the APCDA. In the paragraphs below, Enbridge Gas provides its preliminary responses.

698. First, Enbridge Gas anticipates that parties may argue that no amount is recoverable because the Union pension losses were initially written down to goodwill.[833]

699. The treatment of this balance by Union's parent EI at the time of the Merger did not alter the recoverable nature of these losses. At all times, the amounts were included as receivables in the Union balance sheet. Importantly, EI, prior to the Amalgamation, reassessed its purchase price allocation and correctly recognized the losses as an asset.

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[831] Exhibit 9, Tab 2, Schedule 2, pages 7-8.
[832] Settlement Agreement, Issue 33 – see Exhibit O1, Tab 1, Schedule 1, page 58.
[833] See, for example, questions from SEC (15 Tr.41-42).

700. The Amalgamation has not absolved ratepayers from this obligation, just as Enbridge Gas would not have absolved itself of the obligation had the balance been a net gain or payable back to ratepayers before the Merger. As noted, Enbridge Gas has similarly brought forward an EGD rate zone pension transition payable balance of $255 million in this proceeding for refund to customers, and that benefit is being credited to ratepayers.

701. Second, Enbridge Gas anticipates that parties may argue that the Company has already effectively recovered the amount of the Union pension losses.[834]

702. Enbridge Gas does not agree. Enbridge Gas has followed the OEB-approved approach for accrual-based pension costs and applied the appropriate adjustment to the Union pre-Merger unamortized net pension losses each year. Just because there was a specific amount included in Union's 2013 base rates related to pension costs does not mean that the corresponding amount is or should notionally be applied to accrual-based pension costs each year.

703. There are two reasons for Enbridge Gas's position on this item.

704. First, the suggestion that a fixed amount should be applied against pension liabilities each year is not how Enbridge Gas's accrual-based pension accounting (which follows U.S. GAAP[835]) works. This was explained by Mercer in response to an interrogatory[836] (and repeated by Mr. Ukonga from Mercer in testimony[837]):

> The basis upon which Enbridge Gas has been amortizing amounts to drawdown the APCDA asset since 2017 are calculated by Mercer with the amortization amount updated annually by Mercer based on changes to Enbridge Gas's actuarial valuation. Please see Exhibit 9, Tab 2, Schedule 1,

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[834] See, for example, questions from SEC (15 Tr.57 – 64) and from OGVG (15 Tr.71-77, and Exhibit K15.3).
[835] 15 Tr.63.
[836] Exhibit I.9.2-OGVG-11, part b).
[837] 15 Tr.109-111.

> Attachment 8 for the letter from Mercer that describes how the balance came to be and how they have forecast the balance at December 31, 2023.
>
> The following response was provided by Mercer:
>
> The reason the amortization amount changes each year is that there is no fixed amount of gains and losses being recognized over a fixed term. Rather, in accordance with the accounting standard, cumulative unrecognized gains and losses are charged to the income statement each year through the net periodic benefit cost, based on Enbridge's gain and loss recognition policy. Enbridge's policy is to recognize, for a given fiscal year, the amount of cumulative unrecognized actuarial gains or losses which exceed 10% of the greater of the benefit obligation and market value of assets, over the expected average remaining service lifetime of members. The amount recognized each year changes, since the cumulative unrecognized gains and losses, the amortization period, and the amount that is subject to recognition for that fiscal year, all change each year.
>
> We note that the cumulative unrecognized gains and losses include both the net cumulative pre-2017 actuarial gains and losses from Union Gas along with gains and losses that have occurred since 2017 less any amounts that have been recognized.

705. Second, and in any event, revenues and costs are decoupled during an incentive ratemaking term. As Mr. Small explained in testimony, the amount included in base rates for a particular item is not directly applied towards that item every subsequent year. Instead, the approved revenue requirement (as adjusted each year under an IRM) is used to fund all of the utility's costs in subsequent years. There will be new costs that were not included when base rates were set, and changes in other costs that did exist when base rates were set. The utility's overall revenues are expected to fund these items, without reference to how the revenue requirement was initially determined.[838]

706. Enbridge Gas expects that parties will raise additional items in their submissions (and may have more to say on the items discussed in the preceding paragraphs). The Company will provide its response in Reply Argument.

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[838] 15 Tr.60-62 and 72. See also 15 Tr.102.

Tax Variance Deferral Account (TVDA)

707. A description of the purpose and history of the TVDA, including the treatment of Accelerated CCA, is set out in evidence.[839] Enbridge Gas is proposing to clear the forecast credit balance in the TVDA of $6.8 million plus interest costs of $0.5 million, for a total of $7.3 million.[840] The balance represents 100% of the accelerated CCA impacts resulting from integration capital additions which occurred from 2020 to 2023.[841]

708. As the credit balance in the TVDA relates to the integration capital projects completed during the deferred rebasing term, Enbridge Gas submits that the benefit of this credit balance should accrue to the party (ratepayers or utility) who will be paying for the undepreciated cost of the integration capital projects on a go-forward basis.

709. Enbridge Gas has already set out the reasons why it is appropriate for the undepreciated cost of the integration capital projects to be included in 2024 rate base. If Enbridge Gas's position is accepted, then ratepayers will pay depreciation expense on those assets and should also receive the benefit of the associated TVDA credit balance. This fits with the OEB's benefits follow costs principle.[842]

710. Should the OEB decide that the undepreciated cost of the integration capital projects must be borne by Enbridge Gas, then the Company submits that it should receive the credit balance in the TVDA.

[839] Exhibit 9, Tab 2, Schedule 1, pages 20-21.
[840] The updated TVDA balance is set out at Exhibit J15.1.
[841] Exhibit 9, Tab 2, Schedule 1, page 19. The details of the TVDA entries are set out at Exhibit 9, Tab 2, Schedule 1, Attachment 5. The updated balance in the TVDA, inclusive of the Capital Update, is set out at Exhibit J15.1.
[842] 15 Tr.24-25. The "benefits follow costs" principle is explained, for example, in EB-2016-0160 Decision and Order for Hydro One Transmission, September 28, 2017, at page 11.

J. Other

Treatment of Property Dispositions

711. Issue 10 – Is the 2024 other revenue forecast appropriate?

Consequences Of Settlement Proposal

712. For the purposes of setting rates for 2024, the parties to the Settlement Proposal agreed to Enbridge Gas's as-filed other revenue forecast, subject to two exceptions:

1. There is no agreement as to whether and/or how amounts related to proceeds from Enbridge Gas dispositions of property in 2024 and subsequent years should be included in other revenue forecast or otherwise credited to ratepayers; and
2. There is no agreement on appropriate treatment of the NGV Program (Issue 34), and if different treatment of the NGV Program is ordered than proposed by Enbridge Gas, then corresponding changes may be necessary to the other revenue forecast.

713. This section addresses the first exception regarding proceeds from Enbridge Gas property dispositions. As noted in the exception wording, the OEB's determination of this matter may impact Enbridge Gas's other revenue forecast or some other component of rates related to allocation of property disposition proceeds for 2024.

Outstanding Approvals Required

714. Enbridge Gas is requesting OEB approval of its proposed forecast of other revenue to exclude any forecast of property disposition gains or losses.[843] Stated another way, Enbridge Gas has forecast property disposition proceeds as equal to the net book value of these capital assets for 2024 for the reasons outlined below.

[843] Exhibit 3, Tab 5, Schedule 1, page 3.

Revenue Requirement Implications for 2024

715. As noted above, there is no impact on the proposed Enbridge Gas 2024 revenue requirement if the OEB accepts the manner in which Enbridge Gas has proposed to account for property dispositions.

Evidence in Support

716. Enbridge Gas provided the required evidence at Exhibit 3, Tab 5, Schedule 1. Evidence about the Company's property plan is set out at Exhibit 2, Tab 6, Schedule 2.

717. The issue has not received very much attention in the discovery and hearing process, but there are a few interrogatories[844] and undertakings[845] that are relevant. No other parties in this proceeding have proposed an alternate rate treatment or filed evidence on this issue.

Overview

718. Land is a non-depreciable capital asset for which ratepayers have not, by definition, borne a depreciation expense, so sharing of disposition proceeds is not required by regulatory or legal principles. Despite this, Enbridge Gas is proposing that any gains or losses on land dispositions be shared with ratepayers in accordance with any sharing mechanism approved by the OEB as part of an earnings sharing mechanism (ESM) beyond 2024. For 2024, Enbridge Gas has forecast disposition of any properties at net book value, as described below.

719. Enbridge Gas's proposed rate treatment for property disposition is appropriate because there is significant uncertainty around timing, amount of proceeds and allocation of proceeds for any such transactions. Further, it would not be appropriate

[844] Exhibit I.2.6-STAFF-68, Exhibit I.2.6-SEC-137 and Exhibit I.2.6-VECC-18.
[845] Exhibit JT5.8 (there was brief discussion about property dispositions at 5 TC Tr.26-29) and Exhibit J15.1 (there was brief discussion about the property plan at 15 Tr.13-18).

to include a one-time gain or loss from net proceeds in base rates that will underpin rates for the incentive regulation term as any forecast future dispositions may not occur as anticipated or may not occur at all.

720. In the event that the OEB determines that proceeds from gains on land disposed of in 2024 should be shared with ratepayers, Enbridge Gas proposes that this be done by way of a deferral account. This is more appropriate than an adjustment to “other revenue” because it properly recognizes that any such gain is a one-time event rather than part of the Company’s base costs and revenues that would be expected to repeat each year of the IR term.

Submissions

721. Enbridge Gas provided detailed information about its asset management plans related to its REWS asset class in the AMP.[846] The potential for several facility dispositions are noted, based on Enbridge Gas’s Facility Assessment Results.[847] Enbridge Gas also provided its more detailed plans for property dispositions and the forecast proceeds and timing, to the best of its knowledge.[848]

722. Enbridge Gas did not forecast any gain or loss on disposition of property in 2024. Rather, as Ms. Dreveny explained in the Technical Conference, because of market volatility, the Company forecasts the disposition of properties based on the book value and any gain or loss on disposition would flow through the annual ESM on an actual basis.[849]

723. This is a reasonable position for Enbridge Gas to take because property dispositions are not part of the regular course of business for Enbridge Gas, unlike the revenues

[846] Exhibit 2, Tab 6, Schedule 2, pages 210-225.
[847] Ibid, pages 215-218.
[848] Exhibit I.2.6-SEC-137 part b).
[849] 5 Tr.27.

associated with the typical categories of “other revenue” such as miscellaneous service charges, ancillary business charges and mid-market transactions.[850] In other words, property dispositions are not expected to re-occur on a regular basis, either monthly, annually or on any other consistent timeline. It is therefore not appropriate to forecast potential gains or losses related to property dispositions as a component of base rates, especially in a cost-of-service year that underpins an incentive regulation cycle. The effect would be to “bake in” one-time gains as if they repeated each year of the IR term.

724. Further, the OEB does not have a consistent approach to allocating capital asset proceeds for rate-making purposes. The OEB has accepted in some past decisions that ratepayers are not entitled to share in the gains or losses on non-depreciable capital asset dispositions because ratepayers have not borne the depreciation expense on such assets. This is explained in a 2020 Decision related to Brantford Power and Energy+:

> The OEB has no definitive policy with respect to the sharing of gains on the sale of property. While the 2006 Rate Handbook established that gains and losses on the sale of property would be shared on a 50/50 basis, the 2006 Rate Handbook was issued solely for the purpose of setting 2006 electricity distribution rates. No subsequent policy has been established and the OEB has adopted various approaches depending on the specific circumstance, including no sharing, 50/50 sharing, 75/25 sharing, and 100% sharing.[851]

725. Land (but not buildings) associated with property dispositions are non-depreciable assets, so there should be no expectation that any gains (or losses) should be shared with ratepayers. Many of the OEB proceedings in which land-related proceeds have been shared with ratepayers have been determined by way of settlement rather than the OEB’s direct determination.

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[850] Exhibit 3, Tab 5, Schedule 1.
[851] EB-2019-0022/EB-2019-0031 Decision and Rate Order, January 23, 2000, at pages 17-18.

726. Nevertheless, Enbridge Gas believes it is 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. This can be done on an “actuals” basis once all facts are known.

727. Accounting rules require that in the event that there is a gain or loss on property dispositions in a particular year, Enbridge Gas is to calculate a separate gain (or loss) for the land and building by apportioning the sale proceeds between the land and building in accordance with U.S. GAAP. As prescribed in the OEB’s *Uniform System of Accounts for Class A Gas Utilities*, the gain (or loss) on the sale of non-depreciable plant, such as land, is recorded in income. The gain (or loss) on the building sale is captured in accumulated depreciation and is recovered through depreciation expense over the remaining life of the assets left within the asset group, based on subsequent depreciation studies.[852]

728. Beyond 2024, Enbridge Gas is proposing an ESM which would provide for sharing a portion of any property disposition proceeds (related to land) with ratepayers (subject to any deadband), to be treated like any other forecast variance.

729. There are many uncertainties related to property dispositions and they generally can be categorized as follows:
   a) Timing of dispositions;
   b) Amount of proceeds; and
   c) Allocation of proceeds between land and building(s).

730. Each of these uncertainties underlines why it is not appropriate to embed a credit for future property disposition proceeds on a forecast basis.

[852] Exhibit I.2.6-VECC-18, part b).

a) Timing of dispositions

731. The timing of property dispositions is subject to unpredictable changes and timelines that may be outside of the Company's control, as evidenced by the original and updated list of property dispositions Enbridge Gas provided in the interrogatory responses summarized in Table 9 and described in the Capital Update evidence:[853]

Table 9
Forecast Timing of Property Dispositions

	Exhibit I.2.6-SEC-137 (Original response, filed March 8)	Exhibit I.2.6-SEC-137 (Capital Update, filed July 6)
2024	4 dispositions; $30-31 million proceeds	1 disposition; $6.3 million proceeds
2025-2026	3 dispositions; $38.5-42.1 million proceeds	no change
2027	2 dispositions; proceeds dependent on market conditions at future time of sale	no change

732. Actual timing of property dispositions can fluctuate from forecast timing due to dependencies such as availability of replacement facilities or accommodations. As noted above, Enbridge Gas's forecast dispositions for 2024 decreased from 4 to 1 within the four months between filing the original interrogatory response and the Capital Update and the estimated capital proceeds show a similarly dramatic decline from $31 million to $6.3 million.

733. Timeframes are influenced by various factors ranging from project specific factors to broader economic and regulatory considerations. For instance, the following factors can affect timelines:

1. Zoning and permitting – the time to obtain necessary zoning approvals, permits and other required clearances can significantly impact timeframes;
2. Site acquisitions – finding and acquiring a suitable site for the replacement development can take time, negotiations, due diligence, and title issues can contribute to extended timeframes;

[853] Exhibit 2, Tab 5, Schedule 4, page 8, updated June 18, 2023.

3. Construction – actual construction execution can be subject to various delays including weather, material shortages, labor availability and unexpected site conditions;
4. Market conditions – in a robust market, development may face resource competition leading to longer lead times; and
5. Environmental factors – regulation and contamination issues may require additional time for remediation.

734. Property dispositions are infrequent transactions that are not in the normal course of business for Enbridge Gas. Therefore, they should not be built into a 2024 base year other revenue forecast because these proceeds would be escalated during the incentive rate term, in years when there may be no dispositions.

b) Amount of proceeds

735. Property values can fluctuate significantly from forecasted proceeds due to many factors that impact supply and demand dynamics in the commercial real estate market. Each property and its transaction elements are unique. Factors that may affect property and building values include, but are not limited to:

- Economic conditions and consumer confidence; the overall health of the economy – During economic booms, property values tend to rise. Conversely, during downturns, values may decline due to economic uncertainty;
- Supply and Demand – When demand for properties exceeds supply, prices tend to rise. Conversely, an oversupply can lead to declining values;
- Government Policies – Changes in government policies such as evolving zoning regulations can require investment to comply and affect existing value. Favourable tax policies may encourage ownership, boosting demand and prices;

- Location – This is a critical factor affecting value/desirability, access to amenities, transportation hubs and crime rates. Properties in less desirable areas can have slower appreciation or a decrease in value;
- Speculation – Investor speculation can create volatility. If investors believe values will rise, they may drive prices up artificially. Conversely, if speculators expect a downturn, they may sell in large numbers causing a downturn; and
- Natural disasters and climate change – Properties that are located in areas prone to hurricanes, earthquakes, flooding or other severe storm activity may experience fluctuations in value based on perceived risk.

736. Real estate markets can be affected by multiple factors simultaneously creating a complex and unpredictable dynamic subject to change over time. It is therefore difficult for Enbridge Gas to estimate forecast proceeds with precision unless it already has a firm transaction agreement in place.

c) Allocation of proceeds between land and buildings

737. It is important to emphasize that not all proceeds from a property disposition constitute income. Only the gains or losses on land are recorded as income and gains or losses on building dispositions are captured in accumulated depreciation. Also, such gains or losses, including the allocation between land and buildings, are only determined at the time of sale.[854]

738. For the gains or losses on buildings, the full benefit (or loss) will accrue to ratepayers through a future credit (or debit) to depreciation expense. Therefore, the only potential portion of proceeds that may be available to be shared with ratepayers through the ESM will be those related to land gains (or losses). As noted, Enbridge Gas is not able to estimate those amounts with precision at this time and any such amounts are expected to be immaterial in 2024. Enbridge Gas is currently planning

[854] Exhibit I.2.6-VECC-18.

only one disposition, with total potential proceeds estimated to be $6.3 million (total, not net, proceeds for both land and building). As explained in Exhibit J12.1, Enbridge Gas forecasts disposition at net book value, as gains or losses on disposition are uncertain until the time of sale after final details of the sale are known including an allocation of proceeds (net of selling and other costs) between land and building.[855]

Regulated Treatment of NGV

739. Issue 34 – Is the proposed regulatory treatment of the Natural Gas Vehicle Program appropriate?

Consequences Of Settlement Proposal

740. In the Settlement Proposal, parties agreed that if the OEB orders different treatment of the NGV Program than proposed by Enbridge Gas, then corresponding changes may be necessary to Rate Base (Issue 6), the other revenue forecast (Issue 10), and O&M (Issue 12). The relevant amounts included for the NGV Program in Enbridge Gas's application are:

[855] Exhibit J12.1, part c).

Table 10
Impacts of the NGV Program

Line No.		($ millions)
1	Rate Base (1)(2)	21.4
2	Other Revenue	4.3
3	O&M	0.9

Notes:
(1) This will include corresponding impacts on depreciation, cost of capital and income tax.
(2) The rate base impact is shown in the Capital Update evidence at Exhibit 2, Tab 2, Schedule 1, Attachment 8, page 4 – NGV-related rate base includes most of the amounts at lines 1, 6 and 9, and the amount shown in the table above takes into account the accumulated depreciation on the same lines at Exhibit 2, Tab 2, Schedule 1, Attachment 8, page 9.

741. Enbridge Gas submits that no adjustments to these amounts are warranted.

Outstanding Approvals Required

742. Enbridge Gas proposes the following regulatory treatment for the NGV Program:[856]

1. Continue the NGV Program as an ancillary activity for the utility;
2. Expand the NGV Program to all Enbridge Gas franchise areas; and
3. Modify the current regulatory treatment to remove the requirement to impute revenue when the achieved annual rate of return (RoR) does not meet or exceed the required RoR, such that the NGV Program is funded solely by the monthly service fees charged to participating customers.

Revenue Requirement Implications for 2024

743. There are no 2024 revenue requirement implications if Enbridge Gas receives approval to continue the NGV Program. If the NGV Program is moved out of regulation, there will be a modest increase to revenue requirement, because the NGV Program is currently forecast to produce a revenue sufficiency.

[856] Exhibit 1, Tab 14, Schedule 2, page 1.

Evidence in Support

744. Enbridge Gas provided the required evidence at Exhibit 1, Tab 14, Schedule 2, and answered follow-up questions in associated interrogatories.[857]

745. It was not discussed during the Technical Conference or Oral Hearing and there is no intervenor evidence on this issue.

Overview

746. The long-standing NGV Program has an even greater significance today than in prior years given the heightened focus on GHG emission reduction and energy transition. OEB approval of continuation of the NGV Program in the manner summarized above will support continued growth and development of natural gas as a transportation fuel, benefiting ratepayers, NGV Program customers, energy transition objectives and the environment.

747. The manner in which Enbridge Gas is proposing to operate the NGV Program, including the proposed regulatory treatment, is appropriate because it:

a) Is a long-standing ancillary business activity that is an important component of the Enbridge Gas Energy Transition Plan and is one of the “safe bets” that benefits ratepayers, the province, and the transportation sector economically and environmentally both through the NGV Program itself and in support of Integrated Resource Planning and the Low-Carbon Voluntary Program
b) Is managed in a manner that provides ratepayers with financial benefits and has safeguards that protect ratepayers from negative financial impacts
c) Is facilitated by Enbridge Gas to continue stimulating and growing the market, as there is still no fully functioning competitive market for turnkey NGV solutions

[857] See Exhibit I.1.14.

d) Enhances energy security and diversification in Ontario by displacing gasoline and diesel with cleaner burning natural gas and increasing distribution volumes.

History and Evolution of NGV Program

748. The NGV Program is not a new business activity for Enbridge Gas. Both EGD and Union first embarked on an NGV Program in the mid-1980s. However, Union exited the NGV line of business in 2000 and only a few years pre-amalgamation began to work with the City of Hamilton to install a refueling station for city transit vehicles and reintroduced NGVs into its fleet of utility service vehicles in 2019.[858]

749. Consistent with the OEB's Decision in E.B.R.O 495 (EGD 1997 rates), Enbridge Gas has been operating the NGV Program as an unregulated ancillary business that is complementary to the core utility business. The Program is subject to fully allocated costing for rate treatment purposes.[859]

750. The NGV Program has evolved in response to changes in the vehicle fuel marketplace and currently consists of three components: Compressed Natural Gas (CNG) refueling facilities; NGV fuel cylinders and vehicle refueling appliances; and CNG tube trailers, as described in detail in the evidence.[860]

751. There is significant growth potential for the market and customers rely on the Program benefits as NGVs present an opportunity to reduce GHG emissions from transportation.[861] The NGV Program continues to be relevant and important for the purposes of maintaining the market and continues to have proven benefits for the gas industry, customers, the environment and the broader energy transition.

[858] Exhibit 1, Tab 14, Schedule 2, pages 1 and 3.
[859] Exhibit I.1.14-STAFF-43 part b).
[860] Exhibit 1, Tab 14, Schedule 2, pages 2-3.
[861] Ibid, pages 3-4.

NGV Program Energy Transition and Environmental Benefits

752. There are many clear benefits that support Enbridge Gas continuing to operate the NGV Program as it does today as an ancillary activity and as an important “safe bet” component of the Company’s Energy Transition Plan, summarized below:

a) Compared to gasoline or diesel as a transportation fuel, natural gas offers both fuel savings and GHG reductions. It is one of the few or perhaps only GHG emission reduction initiatives available to the medium and heavy-duty transportation sector based on proven existing technology and not requiring subsidies from any level of government to be economically feasible.[862] Technological improvements have greatly improved the operating characteristics of NGVs for this market segment[863] and there is no practical alternative for the reduction of GHG emissions in heavy trucking market segments.[864]

b) The environmental benefits associated with moving from diesel fuel to natural gas as a transportation fuel for heavy trucks, smaller return to base fleet vehicles and public transit include a 20% lower emission factor, up to 90% less NOx levels and less particulate matter in emissions compared to current US Environmental Protection Agency standards. On a “well to wheel basis[865]”, NGVs with an RNG fuel supply have the opportunity to fully decarbonize the vehicle fuel supply, compared even to electric vehicle charging.[866]

c) Both natural gas and RNG have a price advantage over diesel fuel (60% and 50%, respectively, and even greater when factoring in the federal fuel

[862] Exhibit 1, Tab 14, Schedule 2, pages 3-4.
[863] Ibid, page 8.
[864] Exhibit I.1.10-GEC-51.
[865] The term “well-to-wheel emissions” considers all the emissions associated with the complete lifecycle of a fuel, from its production (the “well”) to its use (the “wheel”).
[866] Exhibit I.1.10-GEC-51.

charge). For instance, this reduces operating costs for municipal waste collection and public transit, as the City of Hamilton is experiencing.[867]

d) The NGV Program is consistent with and complementary to the federal government's Green Freight Program[868] and Clean Fuel Regulation (CFR) as owners and operators of CNG refuelling facilities can generate, trade, and sell credits under the CFR.

e) The NGV Program includes the use of CNG tube trailers as one of its components. In the context of IRP, CNG trailers can play a role in addressing peak demand and supply constraints by providing a flexible and mobile solution for transporting natural gas to areas with limited pipeline capacity or during periods of high demand. While any particular IRP alternative would be subject to specific OEB approval, Enbridge Gas gaining experience with this market aligns with IRP objectives of ensuring a reliable, cost-effective, and sustainable energy supply for the future.[869]

f) The NGV Program also supports the objectives of the proposed Low-Carbon Voluntary Program (LCVP) by encouraging the adoption of natural gas vehicles and the development of CNG refueling facilities. CNG refueling facility owners are excellent candidates for the LCVP as diesel fuel is one of the most expensive and highest carbon conventional fuels. The expansion of CNG refueling facilities can drive RNG volume, further enhancing the environmental benefits of the program.

Role of Enbridge Gas and Ratepayer Benefits

753. Enbridge Gas continues to play the unique role of a facilitator in the niche NGV market. This bolsters the need for the NGV Program to be conducted as an activity

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[867] Exhibit 1, Tab 14, Schedule 2, pages 5-7.
[868] Government of Canada. (2023 August 8). Green Freight Program. https://natural-resources.canada.ca/energy-efficiency/transportation-alternative-fuels/greening-freight-programs/green-freight-program/20893
[869] Ibid, page 11.

by the regulated utility, especially considering its increasing importance due to energy transition, GHG reduction initiatives, increasing availability of RNG, the CFR, the LCVP, and implementation of the OEB's IRP Framework.[870]

754. The NGV Program differs from other unregulated activities conducted within or outside regulated operations of Enbridge Gas because there is still no fully functioning competitive market for turnkey NGV solutions. Enbridge Gas is concerned that if the OEB were to deny the requested regulatory treatment for the NGV Program, the market would receive this as a negative signal about the importance of Enbridge Gas's role as a facilitator to continue stimulating and growing the market.[871] Further, Enbridge Gas is not aware of any market competitors for the role that Enbridge Gas plays and no parties are participating in this proceeding have expressed any competitive market concerns.[872]

755. Ratepayers not participating in the NGV Program are protected by Enbridge Gas's proposed regulatory treatment, as fully described in the evidence. Enbridge Gas is proposing to continue its current practice to set a customer project specific charge that is levelized and constant for each month of the contract term. This provides the desired certainty to NGV service customers. To ensure there is no ratepayer subsidy, the final service charge will be based on the actual costs of the facilities on a fully allocated basis and all other O&M and related costs will also be included in the DCF analysis to determine the charge, in accordance with the principles in E.B.O. 188. This eliminates any over or under-recovery risk associated with forecast variances. Also, Enbridge Gas will apply credit and security terms consistent with its practices for large volume gas distribution customers.[873]

[870] Exhibit I.1.14-STAFF-43 part b).
[871] Ibid.
[872] Ibid.
[873] Ibid, pages 11-13.

756. Since 2015, Enbridge Gas has earned a RoR on the NGV Program that has consistently exceeded the regulated RoR by a significant margin.[874] That means that non-participating ratepayers have had the opportunity to benefit from and share in the excess revenues in accordance with the Earnings Sharing Mechanism in place for those years.[875] Enbridge Gas is forecasting a revenue sufficiency, net of taxes, resulting from the NGV Program for 2023 and 2024 based on current contractual arrangements already in place.[876] Future business prospects are also very promising for the NGV Program, including a new large-scale customer in the Union rate zone.[877]

757. The fact that Enbridge Gas is required to impute revenue if the NGV Program annual RoR does not meet or exceed the allowed utility RoR, as part of the current regulatory treatment, is asymmetric and unfair to the Company. It is also unnecessary given the manner in which Enbridge Gas is managing the NGV Program service fees and contractual terms. Ratepayers would have strong protections in place to prevent any cross-subsidization since service fees charged will fully cover NGV Program costs and return over the life of the contracts.[878]

758. Enbridge Gas would also support a requirement, as suggested by OEB Staff, to file with the OEB a report in 2026 setting out the annual revenue and costs, including the RoR, of the NGV Program to allow parties to assess the performance of the NGV Program under the proposed framework.[879]

<u>ESM for 2024</u>

759. Issue 37 – Is it appropriate to have an earnings sharing mechanism for 2024?

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874 Exhibit 1, Tab 14, Schedule 2, Attachment 1.
875 Exhibit I.1.14-CCC-34.
876 Exhibit 3, Tab 5, Schedule 1, page 12.
877 Exhibit I.1.14-STAFF-43, part b).
878 Ibid, part a).
879 Ibid, part d).

Consequences Of Settlement Proposal

760. There was no settlement of this issue.

Outstanding Approvals Required

761. Enbridge Gas proposes that there be no ESM for 2024 and that the ESM deferral account (ESMDA) will not apply to the year rates are set based on the cost of service, consistent with current practice.[880]

762. As part of the IRM, which will be determined as part of Phase 2, Enbridge Gas is proposing an asymmetric ESM to share excess utility earnings between Enbridge Gas and ratepayers during the IR term from 2025 to 2028. The ESM is proposed to share efficiencies and to provide protection to ratepayers against excess utility earnings that may occur over an IR term. Enbridge Gas has proposed to share utility earnings in excess of 150 basis points above the OEB-approved ROE on a 50/50 basis with ratepayers.[881]

Revenue Requirement Implications for 2024

763. There is no implication for the 2024 revenue requirement.

Evidence in Support

764. The Phase 2 issue related to ESM is Issue 45, “Is the proposed earnings sharing mechanism appropriate?” There is therefore no Phase 1 evidence on this issue, although Enbridge Gas answered follow-up questions in associated interrogatories that request historical ROE for Enbridge Gas and its predecessors.[882]

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[880] Exhibit 9, Tab 1, Schedule 2, pages 27-28.
[881] Exhibit 10, Tab 1, Schedule 1, page 12.
[882] Exhibit I.5.1-CCC-100, Exhibit I.5.3-IGUA-30 and Exhibit I.9.10-SEC-226.

765. The issue was not discussed during the Technical Conference or Oral Hearing and there is no intervenor evidence on this issue.

Overview

766. Enbridge Gas's proposal is consistent with OEB policy, the regulatory process associated with cost-of-service proceedings and past practice for both EGD and Union. The ESM is not required for the test year 2024 as there is already protection for ratepayers from excessive earnings through the extensive reviews of the test year forecast that have taken place in this cost-of-service proceeding.

Enbridge Gas Proposal

767. The ESM has formed part of the IRM for the past multi-year IR terms for both EGD and Union. Most recently, both EGD and Union had an ESM in place during their last two IR terms, from 2008 to 2012 and 2014 to 2018. Enbridge Gas also maintained an ESM during the deferred rebasing term from 2019 to 2023. Neither EGD nor Union had an ESM in 2007 and 2013, when base rates were last set through a cost-of-service process.

768. The ESM as proposed provides protection to ratepayers should there be substantial returns on equity over the OEB-approved ROE during the IR term. The cost-of-service process for setting rates for 2024 already affords sufficient protection for ratepayers because it involves an extensive review of all elements of the Company's test year forecast by more than 30 interested parties that will have extended for more than a year by the time the OEB issues a decision on Phase 1 for 2024 rates. This process includes a lengthy settlement conference extending over two weeks that resulted in a partial settlement proposal in which the settlement parties agreed to a substantial number of elements related to 2024 rates for Enbridge Gas, including much of volumes and revenues, operating costs, and deferral and variance accounts.

769. For any issues that the parties were not able to settle, the OEB held a lengthy hearing of more than four weeks, involving 17 witness panels, including several independent expert witnesses, to further examine certain rate elements in detail, such as energy transition, capital expenditures, equity thickness and depreciation. It seems unnecessary and counter-intuitive to now impose an ESM on top of the extensive review that has already occurred to determine just and reasonable rates for 2024.

770. While there are some OEB decisions and policy documents that identify the ESM as a mechanism to protect customers during an IR or performance-based regulation term,[883] there is no OEB policy that requires, recommends, or contemplates application of an ESM in a year for which rates are set on a cost-of-service basis for gas or electric utilities. This makes sense given the nature of a cost-of-service proceeding. Enbridge Gas is aware that some electricity distributors regulated by the OEB agreed to application of an ESM in a cost-of-service rate year (leading into a multi-year IR term), typically as part of settlement agreements.[884] That appears to be the exception, not the rule. Enbridge Gas submits that such settlements should not serve as precedents for this case given the nature of the many compromises that settlement agreements may involve.

Dawn Parkway Turnback Risk

771. Issue 38 – How should Dawn Parkway capacity turnback risk be dealt with?

Consequences Of Settlement Proposal

772. There was no settlement of this issue. Note, though, that as part of the Settlement Proposal, parties accepted the establishment of the Dawn Parkway System Surplus

[883] For instance, see Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008, Section 2.8; RP-2000-0069 Decision, paragraph 3.1.2; RP-1999-0034 Decision, paragraphs 2.1.1, 4.3.13, 4.3.18; Handbook to Utility Rate Applications, October 13, 2016, page 28, Filing Requirements For Natural Gas Rate Applications, February 16, 2017, page 41.
[884] For example, see EB-2019-0261, EB-2018-0275, EB-2015-0083, EB-2015-0004 and EB-2014-0002.

Capacity Deferral Account (DPSSCDA).[885] The DPSSCDA will record the actual revenue from the sale of all or a portion of the forecast 89 TJ/d Dawn Parkway System surplus capacity, to be credited to ratepayers.[886]

Outstanding Approvals Required

773. Enbridge Gas is not requesting any relief in relation to this issue.

Revenue Requirement Implications for 2024

774. There are no 2024 revenue requirement implications for this issue.

Evidence in Support

775. Enbridge Gas has filed detailed evidence at Exhibit 1, Tab 11, Schedule 1 (Dawn Parkway System Long-Term Utilization), including an associated report from ICF Resources LLC titled "Assessment of the Future Utilization of the Enbridge Gas Dawn to Parkway System".[887] Enbridge Gas answered follow-up questions in associated interrogatories[888], Technical Conference testimony[889], Technical Conference undertakings[890] and filed one ADR response.[891].

776. Enbridge Gas witnesses provided testimony about this issue on Day 7 of the Oral Hearing (Panel 5)[892].

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[885] Exhibit O1, Tab 1, Schedule 1. See discussion of Issue 32 at pages 55-56.
[886] Exhibit 9, Tab 1, Schedule 3, pages 6-8.
[887] The ICF Report is found at Exhibit 1, Tab 11, Schedule 1, Attachment 1. Additional evidence about the operation of the Dawn Parkway System is found at Exhibit 2, Tab 7, Schedule 1. Evidence about the DPSSCDA is found at Exhibit 9, Tab 1, Schedule 3, pages 6-8.
[888] See Exhibit I.1.11.
[889] 6 TC Tr.48-137.
[890] Exhibits JT6.6 and JT6.15.
[891] Exhibit I.ADR.9.
[892] 7 Tr.68-179.

777. John Rosenkranz of North Side Energy, LLC provided a report about this issue[893], and he provided testimony on Day 8 of the Oral Hearing (Panel 6)[894].

Overview

778. In the 2016 Dawn Parkway System Expansion Project proceeding, Union agreed that the issue of Dawn Parkway System capacity turnback risk should be addressed as part of the next cost of service application.[895] Among other things, the Settlement Agreement in that case indicated that intervenors would not be restricted from making any argument before the OEB in that proceeding that it is appropriate that certain cost allocation measures should be put in place to insulate ratepayers from the effect of unutilized and underutilized capacity on the Dawn Parkway System due to potential turnback risk.[896]

779. The Enbridge Gas evidence addresses this commitment. Among other things, Enbridge Gas explains why Dawn Parkway capacity turnback risk is low over the 2024 to 2028 IR term, as well as the ways that ratepayers are protected against the consequences of turnback. Even where there is Dawn Parkway System capacity turnback during the IR term (which is not likely), Enbridge Gas will bear the cost consequences of such turnback because the revenue requirement that recovers Dawn Parkway System costs will not be adjusted. On the other hand, if some of the existing surplus capacity is contracted during the IR term, ratepayers will receive the associated revenues through the DPSSCDA.

780. Mr. Rosenkranz makes two proposals in relation to this issue. The first of these proposals (cost allocation protections) cannot be determined at this time. The second of these proposals (payments to shippers who turnback capacity to reduce

[893] Exhibit M4.
[894] 8 Tr.10-47.
[895] Exhibit 1, Tab 11, Schedule 1, paragraph 1.
[896] EB-2014-0261, Settlement Agreement, February 27, 2015 - see Exhibit 1, Tab 11, Schedule 1, paragraph 1.

needs for future Dawn Parkway builds) does not appear to be in the best interests of ratepayers.

Enbridge Gas has appropriately dealt with Dawn Parkway capacity turnback risk

781. The Dawn Parkway System remains critical for Ontario, Québec, and U.S. Northeast consumers. The liquidity and diversity of competitively priced supply at the Dawn Hub coupled with the flexible storage services available support the continued utilization of the Dawn Parkway System.[897]

782. The Dawn Parkway System connects the Dawn Hub to eastern, downstream pipelines and markets. Utilization of the Dawn Parkway System has increased significantly since 2013, driven by factors such as shale gas supply from eastern United States, shift in contracting from long-haul to short-haul, and continued end-user demand for natural gas.[898]

783. For 2024, Enbridge Gas forecast that there would be 89 TJ/d of surplus capacity on the Dawn Parkway System (from a total system capacity of 7,981 TJ/d).[899] This represents about 1% of system capacity.

784. The full cost of the Dawn Parkway System is included in the 2024 Test Year revenue requirement. The Dawn Parkway System costs are recovered through the proposed rates for 2024 which are derived based on demands that are less than the full Dawn Parkway System capacity by 89 TJ/d.[900] In other words, ratepayers are paying for this amount of surplus capacity.

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[897] Exhibit 1, Tab 11, Schedule 1, page 2, paragraph 3.
[898] Ibid, paragraphs 4-5
[899] Exhibit 2, Tab 7, Schedule 1.
[900] Exhibit 9, Tab 1, Schedule 3, pages 6-8.

785. Enbridge Gas recognizes that the surplus Dawn Parkway System capacity can have value if contracted for during the IR term. Enbridge Gas will refund, through the DPSSCDA, any revenue generated from the sale of the surplus capacity up to 89 TJ/d per year.[901]

786. While ratepayers will benefit where part or all of the surplus Dawn Parkway System capacity is contracted during the IR term, they are not at risk in the event that the surplus grows during the IR term. Revenue requirement is set based on the 89 TJ/d surplus capacity and will not be adjusted if the surplus grows (as would be the case if there is capacity turnback).

787. These concepts were confirmed by Ms. Mikhaila during her testimony:

> Can you explain how ratepayers are or are not at risk for costs associated with Dawn-Parkway turnback during the 2024 to 2028 IR term?
>
> MS. MIKHAILA: Yes, I can. Again, the full costs of the Dawn-Parkway system are included in the cost allocation for recovery from -- from ratepayers. But in addition, the company has proposed and I believe accepted through the settlement process a Dawn-Parkway surplus capacity deferral account, where any surplus capacity that existed as part of the 2024 forecast, which was 89 TJ a day, to the extent the Dawn-Parkway system is in a surplus capacity position of less than 89 TJs a day, meaning there has been a sale of some of that surplus capacity, that would be refunded through -- to customers, through the Dawn-Parkway surplus capacity deferral account.
>
> On the other hand, if there is Dawn-Parkway turnback through the 2024 to 2028 time period and it puts the Dawn-Parkway system in a surplus position of greater than 89 TJ, that risk would be borne by the utility and not sought for recovery through -- to ratepayers, in this IR term.[902]

788. In any event, the evidence is clear that there is limited risk of Dawn Parkway System capacity turnback during the IR term. This is explained in the Enbridge Gas evidence, and in the accompanying ICF report. Among other things, the evidence

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[901] Note that as discussed at Issue 32 of the Settlement Proposal, in the event that Enbridge Gas uses surplus Dawn Parkway capacity to reduce the Parkway Delivery Obligation, then the PDCI costs will be reduced, which will be captured in the Parkway Delivery Obligation Variance Account.
[902] 7 Tr.178-179.

shows that there is currently limited risk of U.S. Northeast customers turning back capacity – these customers rely on the flexibility of the Dawn Hub, and they contract for storage to support their gas supply portfolio, and there is limited access for those customers to replacement storage and transportation options. Additionally, the demand from power generation customers is expected to continue in the coming years both in Ontario and elsewhere.[903]

789. Ultimately Enbridge Gas and Mr. Rosenkranz agree that the risk of turnback during the 2024 to 2028 IR term is "small"[904] or "very low"[905]. The ICF report supports this conclusion. There is no evidence in this case that suggests otherwise.

Response to Proposals from Mr. Rosenkranz

790. FRPO sponsored evidence from John Rosenkranz. This evidence is titled "Report on Dawn Parkway System Capacity Turnback Risk".

791. Mr. Rosenkranz's report concludes by saying "Even if the near-term risk [of turnback] is low, it would be prudent for EGI to implement measures to (1) limit cost shifting between ex-franchise and in-franchise services if turnback occurs, and (2) reduce exposure to capacity turnback by making it less likely that the Dawn Parkway System will become overbuilt". Mr. Rosenkranz then proposes two "measures".[906]

792. Mr. Rosenkranz's first proposal is to add "guardrails" to the proposed cost allocation methodology. Essentially, the proposal is that there would be updates to the methodology that the Company uses to allocate costs at rebasing between in-franchise and ex-franchise customers to reduce the risk of costs being shifted from

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[903] See, for example, Exhibit 1, Tab 11, Schedule 1, pages 5-7 and ICF's "Assessment of the Future Utilization of the Enbridge Gas Dawn to Parkway System", pages 3-13 (found at Exhibit 1, Tab 11, Schedule 1, Attachment 1).
[904] See testimony of Mr. Rosenkranz – 8 Tr.32.
[905] See testimony of Mr. Hagerman – 7 Tr.87-88.
[906] Exhibit M4, page 13.

ex-franchise customers to in-franchise customers.[907] Mr. Rosenkranz confirmed that these changes would not take effect until the next rebasing term (starting in 2029), but that he would be proposing that the current panel of Commissioners would direct what would be in the next cost allocation methodology.[908]

793. In cross-examination, Mr. Rosenkranz confirmed that his proposed changes to cost allocation methodology (to come into effect in the next IR term, staring in 2029) could not be considered at this time, because there has not yet been a determination on the cost allocation methodology that will apply in the immediate upcoming IR term.[909]

794. Mr. Rosenkranz's second proposal relates to the steps that Enbridge Gas should undertake to confirm demand before proceeding with a Dawn Parkway System expansion project. Mr. Rosenkranz suggests that as part of this process, perhaps as an IRP investigation, Enbridge Gas should be required to include a "buyout option" when conducting a reverse open season. Under this approach, Enbridge Gas would solicit bids from existing shippers to accept payments to turnback capacity – the amount of the payments would be capped at the cost of the expansion project.[910] Mr. Rosenkranz confirmed that there would be no incremental revenues from new facilities to fund the turnback payments and that instead existing ratepayers would pay to fund the turnback payments. The notion appears to be there is a benefit from avoiding the cost of a facilities project and it is appropriate for ratepayers to pay for that benefit.[911]

[907] Exhibit M4, pages 13-15. See also 8 Tr.28.
[908] 8 Tr.28.
[909] 8 Tr.30-31.
[910] Exhibit M4, page 15.
[911] 8 Tr.34-36.

795. Mr. Rosenkranz confirmed that the OEB should make this step “mandatory”.[912] Mr. Rosenkranz conceded, however, that he does not have specific details about how this proposal would actually operate.[913] Mr. Rosenkranz did confirm the following:

a) This proposal this could be lucrative for shippers turning back capacity.[914]
b) No shipper would likely turn back capacity in a future reverse open season without requiring payment from Enbridge Gas.[915]
c) There would be nothing to stop a shipper from being paid to exit in one year, and then seeking new capacity the next year.[916]
d) There is no precedent of which he is aware of a similar approved mechanism in other jurisdictions (or even of a proposal for such a mechanism).[917]

796. Enbridge Gas does not support the proposal for a reverse open season with payments to shippers.[918] It is not clear what benefits are obtained, and how value for money is achieved. It is certainly not clear that there is a sufficiently defined evidentiary record for a proposal for the OEB to approve at this time.

797. The Company does not believe that it is necessary in this proceeding for the OEB to add requirements to the steps that Enbridge Gas must take in advance of a LTC application for a Dawn Parkway System expansion. In order to obtain LTC approval, Enbridge Gas will have the burden of establishing the need for any such project, and how all appropriate IRP investigations have been completed. Enbridge Gas has ideas that it can advance in the context of a future potential expansion project about how to keep shippers committed to the pipeline (such as a term-up requirement as described by Mr. Hagerman[919]), but this is not a topic that has been fully canvassed

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[912] 8 Tr.36.
[913] 8 Tr.36-37. This was confirmed again in response to questions from Commissioner Moran at 8 Tr.43-44.
[914] 8 Tr.39-40.
[915] 8 Tr.41.
[916] 8 Tr.40.
[917] 8 Tr.41.
[918] 7 Tr.78 and 159-161.
[919] 7 Tr.76, 78 and 92-93 and 150-152.

or brought into issue in Phase 1 of this rebasing case. Enbridge Gas submits that these items can better and more appropriately be evaluated in the factual context of any LTC application that may be made in the future.

<u>SQRs</u>

798. Issue 40 – Should the OEB grant Enbridge Gas's request for a partial exemption for 2024 from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?

799. In its decision on the Issues List in Procedural Order No. 2, the OEB approved two issues related to the scorecard and performance measurement – Issue 40 (cited above) and Issue 58:

58) Are the proposed scorecard Performance Metrics and Measurement targets for the amalgamated utility appropriate?

800. The OEB approved Issue 40 as a Phase 1 issue and Issue 58 as a Phase 2 issue. Enbridge Gas will therefore only address Issue 40 in these submissions. There was no settlement on Issue 40. Enbridge Gas notes however, as set out in Exhibit I.1.7-STAFF-11, that it filed an application with the OEB on October 27, 2022, for a one year exemption for 2023[920] (2023 Request) identical to the partial exemption requested for 2024 and beyond, except for the 2023 time period. For the 2023 Request, the OEB advised as follows:

> Given this issue is already part of a proceeding, the OEB finds that it would not be efficient or in the public interest to commence a new process in respect of the above-referenced application at this time.[921]

[920] EB-2022-0276, Enbridge Gas Application – Gas Distribution Access Rule Exemption for 2023, October 27, 2022. Filed at Exhibit I.1.7-STAFF-11 Attachment 1.
[921] EB-2022-0276, OEB Letter, December 23, 2022, page 2. OEB_Response Final EGI GDAR Exemption Request_20221223 (1).PDF

801. In its cover letter to interrogatory responses on March 8, 2023, Enbridge Gas reiterated its request for clarity on whether the OEB intends to consider the 2023 Request as part of Issue 40. In the absence of any further guidance, Enbridge Gas assumes the OEB will consider the 2023 Request as part of this Issue 40.

Consequences Of Settlement Proposal

802. There was no settlement of this issue.

Outstanding Approvals Required

803. Enbridge Gas is requesting a partial exemption under Section 1.5.1 of the OEB's GDAR related to three service quality requirement (SQR) performance measures. The requested SQR exemptions are summarized below:

a) GDAR Section 7.3.3 Meter Reading Performance Measurement (MRPM)
   i. *Current:* MRPM represents the number of meters with no read for four consecutive months or more divided by the total number of active meters to be read. The target for the metric is 0.5%.
   ii. *Relief Sought:* approval for MRPM to be a target of no more than 2% of meters with consecutive estimates for four months or more.

b) GDAR Section 7.3.1.1 Call Answer Service Level (CASL)
   i. *Current:* the percentage of calls reaching the general inquiry number, including IVR calls that are answered within 30 seconds. The yearly performance shall be 75% with a minimum monthly standard of 40%.
   ii. *Relief Sought:* approval for CASL to achieve 65% of calls reaching the general inquiry number answered within 30 seconds. This aligns with the DSC.

c) GDAR Section 7.3.4.2 Time to Reschedule a Missed Appointment (TRMA)
   i. *Current:* At minimum, the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time. The TRMA metric is set at 100%.

ii. Relief *Sought:* approval for TRMA to be an attempt to contact customers requiring a rescheduled appointment within one business day of the original appointment window 98% of the time. An attempt within one business day aligns with the DSC.

804. Enbridge Gas is requesting these exemptions to be applicable from January 2023 until the OEB orders otherwise.

Revenue Requirement Implications for 2024

805. There are no 2024 revenue requirement implications for this issue.

Evidence in Support

806. Enbridge Gas has filed detailed evidence at Exhibit 1, Tab 7, Schedule 1, and answered follow-up questions in associated interrogatories[922], Technical Conference testimony[923] and Technical Conference undertakings[924].

807. The issue was not discussed during the Oral Hearing and there is no intervenor evidence on this issue.

Overview

808. In its evidence, Enbridge Gas has provided performance measurement and scorecard information. As explained, Enbridge Gas was not able to achieve four of the GDAR related scorecard targets in certain years. The Company provided an Assurance of Voluntary Compliance (AVC) in September 2022 for CASL, Abandonment Rate (AR), and MRPM. [925]

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922 Exhibit I.1.7.
923 3 TC Tr.185-205.
924 Exhibits JT3.34 and JT3.36.
925 EB-2022-0188, Assurance of Voluntary Compliance, September 12, 2022.
https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf

809. Most of the primary factors (other than system integration) that contributed to Enbridge Gas not meeting the SQR targets were outside the control of Enbridge Gas. These factors are described fully in the evidence. Enbridge Gas has taken and continues to take all reasonable steps to achieve the SQR targets on a consistent basis.

810. Enbridge Gas requests a partial exemption to replace the existing CASL, TRMA and MRPM with the modified measures as noted in the Approvals Requested above.

811. Enbridge Gas is requesting these exemptions to be applicable from January 2023 until the OEB orders otherwise or until such time as the OEB conducts a review of the GDAR SQR metrics to modernize the SQRs to account for the current business environment and customer needs, behaviours and expectations.

812. Enbridge Gas will work towards continuous improvement of metric performance as outlined in its evidence and will monitor and track results of its efforts and report regularly to OEB Staff on progress. Regardless of the current challenges with the SQR metrics, Enbridge Gas remains committed to providing a positive customer experience and continuous improvement related to all of the performance measures on the scorecard.[926]

813. In addition to the specific ongoing challenges with meeting the SQR metrics, as outlined in the evidence and summarized below, Enbridge Gas submits that the OEB ought to grant its request for a partial GDAR exemption for the MRPM, CASL and TRMA because:

   a) The SQRs were added to the GDAR more than 15 years ago, in 2007, and are not reflective of current customer behaviours and expectations. For instance, customer calls are more complex in nature as customers can use

[926] Exhibit 1, Tab 7, Schedule 1, page 22.

web self-service options and the chatbot feature for less complex inquiries. Also as noted, customers are increasingly sensitive to having meter readers on their property[927];

b) There is lack of alignment with the DSC performance standards and no allowance for force majeure relief in the GDAR, without any clear rationale why a different standard for gas may be appropriate. The DSC provides as follows:
   i. The Rescheduling a Missed Appointment measure in section 7.5 is an attempt to contact the customer prior to the appointment and an attempt to reschedule within one business day compared to the TRMA requirement to reschedule within two hours of the end of the original appointment time;
   ii. The Telephone Accessibility performance measure in section 7.6 is to answer 65% of calls in 30 seconds compared to CASL that requires 75% of calls to be answered in 30 seconds; and
   iii. The DSC contains a force majeure provision that allows a utility to be relieved of obligations for events that are beyond its reasonable control and the GDAR is silent on force majeure.[928]

c) The DSC metrics were established in 2009, two years after the GDAR metrics were established, and there is no clear reason why they are different from the related GDAR metrics. Further, the GDAR ought to be interpreted in a manner that relieves a party from an obligation if they are prevented from performing the obligation, in whole or in part, because of a force majeure event, as in the DSC (section 2.3). This force majeure exception should apply to the SQR metrics;

d) There are continuing impacts of external factors that have a particularly notable impact on MRPM and CASL, such as residual pandemic-related

[927] Exhibit 1, Tab 7, Schedule 1, pages 15-16.
[928] Ibid, page 16.

issues, labour market shortages, extreme weather events, global energy and climate change dynamics (including the increasing federal carbon charge) and the economic environment; and

e) Planned activities to align systems and meet industry standards (such as for cyber-security, Green Button and harmonization of rates and services) may impact metric performance. System alignment and enhancement is beneficial to customers and provides a better and more consistent customer experience in the longer run yet may have temporary service impacts.[929]

Background

814. Enbridge Gas provided the required performance measurement and scorecard information in Exhibit 1, Tab 7, Schedule 1.[930] As is set out in its scorecard,[931] Enbridge Gas was not able to achieve four of the GDAR related scorecard targets in certain years. For instance, in 2021 Enbridge Gas missed four SQR metrics and through the OEB's compliance process the Company provided an AVC in September 2022 for CASL, AR, and MRPM; [932] this is despite the fact that Enbridge Gas has taken and continues to take all reasonable steps to achieve the SQR targets on a consistent basis (as detailed in the evidence), by enhancing customer communications, digital channels, staffing (internal and vendor-related), training and systems integration.[933]

815. Most of the primary factors (other than system integration) that contributed to Enbridge Gas not meeting the SQR targets were outside the control of Enbridge Gas. These factors are described fully in the evidence and are summarized below in relation to the specific exemption requests. They include:

a) COVID-19 pandemic

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929 Exhibit 1, Tab 7, Schedule 1, pages 17-18.
930 Filing Requirements for Natural Gas Rate Applications, February 16, 2017, pages 13-14.
931 Exhibit 1, Tab 7, Schedule 1, Attachment 1.
932 EB-2022-0188, Assurance of Voluntary Compliance, September 12, 2022.
https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf
933 Exhibit 1, Tab 7, Schedule 1, pages 4-5.

b) Staffing issues
c) System integration
d) Extreme weather

816. A further summary for each of the SQR metrics for which Enbridge Gas is requesting a partial exemption is set out below. The information summarized provides context as to why the Company's request for an exemption from these metrics (with alternate proposed metrics that will protect ratepayers) is reasonable.

MRPM

817. The MRPM has been especially challenging such that Enbridge Gas was unable to meet the SQR metric in 2019 to 2022 primarily due to the following:[934]

a) COVID-19 impacts as the Company followed public health guidelines, both public and Company safety concerns, closed businesses, customer sensitivities and problems with accessing meters. There were also staffing issues attributable to quarantine/isolation periods and labour resource shortages. If one meter reader misses work for a 14-day period, 8,000 meters could go unread. This makes it difficult for Enbridge Gas to "catch up" on those meter reads;
b) Extreme weather events limiting the ability to travel to properties and access meters safely. There were 27 different events in the 2020 to 2021 period alone;
c) Enbridge Gas lost a key meter reading vendor in 2019, resulting in the unplanned need to hire a new vendor in an already limited market. Meter reading vendors experienced hiring challenges with low applicant interest due to the physically demanding nature of the role, which also contributes to the high attrition rate adding to the challenge of achieving the staffing levels required to meet the MRPM. The attrition rate for meter reading personnel in

[934] Exhibit 1, Tab 7, Schedule 1, pages 6-13.

2022 was 20% and the level of absenteeism was 17%, the highest that Enbridge Gas has ever experienced;

d) MRPM is cumulative, where the total number of unread meters fluctuates as some meters are read and are deducted from the totals, while other meters remain unread from the previous month, and new meters reach their four-month timeline and are added to the current consecutive estimate results. This means that even though a percentage of meters have successfully been read, Enbridge Gas will continue to have meters that have consecutive estimates. With over 3.8 million customers, if 19,000 meters have consecutive estimates on average each month, the metric is not achieved. Once a meter has a consecutive estimate for four months or more, it will count toward the metric in a minimum of two-meter reading cycles; and

e) Customers not providing access to meters contribute in the range of 1-3% of the total monthly percentage of consecutive estimates. With more people staying at home to work, there is more public sensitivity to in-person meter reading and an increased number of obstacles for meter readers (e.g., locked fences and dogs).

818. While Enbridge Gas has experienced some stabilization of these factors, residual impacts of COVID-19 are continuing to negatively impact the MRPM and appear to have resulted in a notable shift in customer behaviour and labour market conditions that will continue for the foreseeable future. Note that the MRPM for January to June 2023 is 1.7% (1% excluding meters where access is not granted by customers) as Enbridge Gas has reported to the OEB compliance staff and continues to do so on a monthly basis in accordance with the AVC.

819. The evidence outlines the detailed mitigation plans that Enbridge Gas established and that has been reviewed and accepted by OEB compliance staff to address the ongoing challenges with the MRPM.[935]

CASL

820. Enbridge Gas did not achieve the CASL metric in 2021 (achieving 64.3%),[936] however, the Company has been able to achieve the metric in prior and later years (75.4% in 2022[937] and just over 90% to date in 2023). CASL was impacted by COVID-19 as this increased call volumes and Enbridge Gas was administering the Government of Ontario's COVID-19 Energy Assistance Program to support customers through pandemic lockdowns.[938] CASL was also impacted by Enbridge Gas consolidating its customer information systems in July 2021 that introduced 1.6 million customers in the Union rate zones to a new customer-facing website, online billing and IVR systems. While Enbridge Gas prepared for increased call volumes due to integration, with new hires and pre-integration training, COVID-19 resulted in a shortage of staff and it was not practical to hire enough temporary staff to cover all absences, given the lead time required for training.[939]

821. Because the CASL metric requires answering calls within 30 seconds, it incents customer service agents to seek to minimize average call handle time so they can answer a higher volume of calls. This may result in a less positive customer experience for customers seeking assistance with paying bills and other complex issues.[940]

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935 Mitigation plans for 2023 were provided with the 2023 Request (EB-2022-0276) and for 2024 and beyond in Exhibit 1, Tab 7, Schedule 1, Attachments 2-4.
936 Exhibit 1, Tab 7, Schedule 1, Attachment 1.
937 Exhibit I.7.1-VECC-9.
938 Exhibit 1, Tab 7, Schedule 1, page 8.
939 Ibid, pages 6-7.
940 Ibid, page 8.

822. With more customers choosing to have non-complex matters sorted with self-serve options, the majority of calls to the call centre are complex in nature. Call volumes to the Enbridge Gas contact centre did increase between 2019 and 2021, as did average call handling time (from 7 minutes, 7 seconds to 8 minutes, 14 seconds), but would have been even higher if not for Enbridge Gas implementing enhanced web self-serve options (e.g., chatbot in August 2019). From July 2021 (after system integration) to the end of 2021, there were approximately 900,000 customer transactions completed across the Enbridge Gas self-serve digital channels (My Account, IVR and chatbot).[941]

823. Complex call types are most often in the billing category and driven by a heightened interest in understanding and lowering gas use and changes to rates, amplified by broader customer affordability concerns. These calls often include multiple intents within the same interaction and Enbridge Gas trains agents to address customers' questions in an empathetic manner and offer support to customers experiencing hardship.[942]

TRMA

824. Neither Enbridge Gas nor its predecessors have ever met the TRMA metric, despite ongoing efforts towards improving results, including automated emails to dispatch, process changes to drive focus and reporting tools to catch, review and implement corrective actions for missed TRMA incidents. The 100% target is unreasonable and impractical as it does not account for factors like emergency response (redirecting technicians from a non-emergent call to an emergency call), human error (data entry errors and record keeping) or technical error (telecommunications outage across a network could cause issues for communication with customers or other personnel).

[941] Exhibit 1, Tab 7, Schedule 1, page 7.
[942] Ibid, page 8.

825. By meeting and exceeding the GDAR metric for the Appointments Met Within the Designated Time Period, Enbridge Gas is reducing the number of appointments that require a rescheduling. As noted in evidence, the number of appointments that were not rescheduled within two hours in 2021 represent 0.1% of all four-window appointments in 2021, and of those, approximately half were still completed that day, leaving less than 34 appointments not rescheduled within two hours.[943]

K. Rate Implementation

Rate Implementation Proposal

826. Issue 41 – How should the OEB implement the approved 2024 rates relevant to this proceeding if they cannot be implemented on or before January 1, 2024?

Consequences Of Settlement Proposal

827. The Settlement Proposal does not directly address this Issue.

828. Issue 24 of the Settlement Proposal directs that interim rates for 2024 will be set through adjustment of existing rates, by proportionally allocating the impact of any revenue deficiency/sufficiency determined in Phase 1 to each rate zone and rate class.

Outstanding Approvals Required

829. Enbridge Gas is requesting OEB approval for interim 2024 rates based on the OEB's Phase 1 Decision, to be effective January 1, 2024. The 2024 rates are to be interim, because as set out in Procedural Order 2 and in the Settlement Proposal, determinations on Phase 2 issues may require rate adjustments effective January 1, 2024.

[943] Exhibit 1, Tab 7, Schedule 1, pages 9-10.

830. If the approved 2024 rates cannot be implemented on January 1, 2024, Enbridge Gas will implement the rates at the earliest date possible. Enbridge Gas seeks recovery of the full approved interim revenue requirement for 2024. Consistent with current practice, as part of the Draft Rate Order Enbridge Gas would include a revenue adjustment rider for the period between the effective date of January 1, 2024, and the implementation date.

Revenue Requirement Implications for 2024

831. There are no revenue requirement implications from this Issue.

Evidence in Support

832. This Issue was not addressed in any detail in pre-filed evidence or at the Oral Hearing. There are a couple of relevant interrogatory responses.[944]

Submissions

833. To implement rates on January 1, 2024, Enbridge Gas would require that the OEB issue a decision on Phase 1 of this Application by October 30, 2023 (one year after filing), and a decision on a Rate Order by November 30, 2023. This timing depends on the content of the OEB's Decision – where there are complexities to address that may add to the time requirements to develop a Draft Rate Order.

834. Enbridge Gas acknowledges that it is very unlikely that an OEB Decision on Phase 1 will be released by October 30, 2023, given that this date is less than one month after the Company's Reply Argument is to be filed.

835. Enbridge Gas will work as quickly as possible to reflect the OEB's Decision into a Draft Rate Order once it is issued. The next ideal time, after January 1, 2024, to

[944] Exhibit I.9.1-SEC-221 and Exhibit I.4.2-FRPO-115.

implement the new interim rates might be April 1, 2024, in conjunction with the QRAM Application, but an earlier implementation could also be accommodated.

836. Whatever the timing of the implementation date of the Rate Order, Enbridge Gas submits that it is appropriate for the Company to recover the full-year impact of any revenue deficiency/sufficiency approved in Phase 1 effective January 1, 2024.

837. Enbridge Gas filed its application for 2024 rates 14 months before the requested effective date for new rates and met all of the OEB's filing requirements. Enbridge Gas proposed (and the OEB adopted) measures to divide the case into phases to make it more possible to have rates for 2024 approved in a timely manner. This is the biggest case that Enbridge Gas has ever undertaken (and one of the largest cases ever for the OEB). Enbridge Gas has met all deadlines in this case and acted responsibly throughout. Enbridge Gas streamlined the process by having very few confidentiality requests. There have been a couple of minor delays for evidence updates, but these amounted to less than three weeks.

838. Taking all of this into account, Enbridge Gas hopes that no party will take the position that new rates for 2024 should only be effective on a prospective basis from their implementation date. However, should parties make that submission, Enbridge Gas will provide further submissions in Reply Argument.

Summary of Approvals Requested

839. Enbridge Gas has described the approvals requested in the discussions above for each topic covered in this Argument.

840. For ease of reference, Enbridge Gas has collected all of the Approvals Requested into the table set out below. In the first column of the table, the Approvals Requested are summarized and grouped according to the Exhibit in the evidence to which they

relate. In the second column of the table, a cross-reference to the Issues List is indicated, and links are provided to the relevant parts of this Argument.

Approvals Requested	Relevant Issue and Link to Argument
Exhibit 1 - Administration	
• Partial exemption request for certain performance metrics	SQR – Issue 40
• Harmonized customer connection policies	Customer Connection Policy – Issues 3, 6 and 7
• Regulatory treatment of the Natural Gas Vehicle (NGV) Program	NGV Program – Issue 34
Exhibit 2 – Rate Base	
• Harmonized indirect overhead capitalization methodology	Indirect Overhead Capitalization – Issue 8
• 2024 Test Year capitalized overhead amounts	Indirect Overhead Capitalization – Issue 8
• 2024 Test Year capital expenditures and resulting in-service capital additions	2024 Capital – Issue 7
• Levelized rate treatment for PREP	2024 Capital – Issue 7
• 2024 Rate Base (inclusive of 2023 additions and Integration Capital additions)	Rate Base – Issue 6
Exhibit 3: Operating Revenue	
• 2024 Test Year other revenue forecast	Treatment of Property Dispositions – Issue 10
Exhibit 4: Operating Expenses	
• 2024 depreciation rates and expense	Depreciation Expense – Issues 15 and 16

Approvals Requested	Relevant Issue and Link to Argument
Exhibit 5: Cost of Capital and Capital Structure • Increase from 36% to 42% equity thickness • Phase-in the proposed change to equity thickness	Equity Thickness – Issues 20 and 22
Exhibit 8: Rate Design • Approval of ELC	Customer Connection Policy – Issue 29
Exhibit 9: Deferral and Variance Accounts • Establishment of VOLUVAR and PREPVA and continuation of Short-term Storage and Other Balancing Services Account. • Clearance of APCDA • Clearance of TVDA	Deferral and Variance Accounts - Issues 32 and 33 For PREPVA see also 2024 Capital – Issue 7
Rate Implementation (Application) • Interim rates to be implemented as of January 1, 2024, on a full-year basis	Rate Implementation Proposal – Issue 41

All of which is respectfully submitted August 18, 2023.

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