Shepherd Rubenstein

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**BY EMAIL and RESS**

December 14, 2023
Our File: EB20220157

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

Dear Ms. Marconi:

**Re: EB-2022-0157 – Enbridge Inc – PREP LTC – SEC Final Argument**

We are counsel to the School Energy Coalition ("SEC"). Pursuant to Procedural Order No. 8, attached please find SEC's interrogatories in this matter.

Yours very truly,
**Shepherd Rubenstein P.C.**

Mark Rubenstein 2023.12.14 10:53: 14-05'00'

Mark Rubenstein

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

**EB-2022-0157**

**ONTARIO ENERGY BOARD**

**IN THE MATTER OF** the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, Schedule B; and in particular section 90(1) and section 97 thereof;

**AND IN THE MATTER OF** an application by Enbridge Gas Inc. for an order granting leave to construct natural gas pipelines in the Municipality of Chatham Kent and Essex County

**FINAL ARGUMENT OF THE**

**SCHOOL ENERGY COALITION**

## A. Overview

1. Enbridge Gas Inc. ("Enbridge" or the company) seeks approval from the Ontario Energy Board (“OEB”) for leave to construct the Panhandle Regional Expansion Project ("PREP" or the "project"), a 19 km NPS 36 natural gas pipeline, along with certain ancillary facilities. This project would expand the capacity of the Panhandle transmission system at a forecast cost of $358M.

2. The need for the project is driven almost exclusively by a discrete number of large new or expanding contract customers, specifically greenhouses and gas-fired generators, who require significant incremental capacity in the near-term. This demand cannot be accommodated without increasing the capacity of the Panhandle transmission system.

3. This is the Final Argument of the School Energy Coalition (“SEC”).

4. The application raises two important interrelated issues:

   i. How should the OEB evaluate a gas facilities project that, while technically a transmission project, is designed to serve the growth needs of specific customers in the same manner as a distribution project? Does the E.B.O. 134 economic feasibility test as traditionally applied produce a reasonable result, particularly if the E.B.O. 188 test would produce a different result?

   ii. What approach should the OEB take to ensure that the impacts of the energy transition on the economic feasibility and broader cost/benefit analysis are properly taken into account? In particular, which customers, if any, should bear the risk for assets becoming underutilized or stranded?

5. Even if the OEB accepts that PREP is needed and is the most cost-effective alternative, as proposed, it does not meet the economic feasibility assessment. Applying an interpretation of the existing economic feasibility test, E.B.O. 134 demonstrates a revenue shortfall that leads to an undue burden on existing customers, that can only be eliminated by requiring capital contributions to eliminate the cross-subsidy.

6. This is also the first leave to construct application for a transmission project where the OEB has been confronted directly with the question of how best to balance an immediate capacity shortfall with the longer-term impact of the energy transition, which will almost certainly reduce overall system demand. The energy transition requires that the OEB evolve its economic feasibility test for transmission expansion projects to reduce the risk on existing customers that the pipeline will become underutilized or stranded. This can be done by only assessing the forecast project revenues and costs alone, similar to what is done for distribution expansion projects.

7. SEC accepts that the incremental capacity is needed in the near term. The question then is who should pay for it. In this case, there is no sensible basis for existing customers to provide a large cross-subsidy, and take on a substantial financial risk, for the new and expanding customers that seek the additional capacity. It is those customer who should pay for PREP.

**B. The Project**

8. In June 2022, Enbridge filed its application for leave to construct a project that consisted of, a) a 19 km NPS 36 pipeline starting at its existing Dover Transmission Station (the "Panhandle Loop"), b) a 12 km NPS 16 pipeline between its existing Kingsville East Line and Leamington North Line (the "Panhandle Interconnect"), and c) various ancillary services.[1] The total cost for the project was approximately $314M[2], with an in-service date of 2023 for the Panhandle Loop and 2024 for the Panhandle Interconnect.[3] The need for the project was the forecast capacity shortfall driven by growth along the Panhandle transmission system, almost entirely due to growth in the greenhouse sector and natural gas-fired power generation.[4]

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[1] D-1-1 (2022-06-10)
[2] E-1-2, p.1 (2022-06-10)
[3] A-3-1, p.4
[4] A-2-1, p.2; B-1-1, p.4

9. Just as the argument stage of the proceeding was to begin in December 2022, Enbridge requested that the OEB place the application in abeyance due to material cost increases. The company advised that it required time to assess the implications.[5]

10. In June 2023, Enbridge filed an updated application. As part of the update, Enbridge's revised cost estimate for the project was $358M, with a significantly narrowed scope.[6] It was no longer seeking leave to construct the Panhandle Interconnect portion of the project. Enbridge's costs for the remaining portion of the project, the Panhandle Loop and ancillary facilities, had increased by 45.2%.[7] The Leamington Interconnect portion has not been cancelled, but simply delayed.[8]

11. The $358M forecast cost for the project is based on a cost estimate primarily driven by an RFP Enbridge undertook more than a year ago, in late 2022.[9] As of the oral hearing, Enbridge had not selected a contractor to undertake the construction of the project, and contractors who bid into the RFP over a year ago cannot be held to their bid prices.[10] The implication is that the cost estimate is highly uncertain, and the actual costs could very well end up being materially higher.

### C. Project Need

12. Enbridge justifies the need for the project based on increased demand required to serve new (and expanding) greenhouses and gas-fired power generators in the Leamington and Windsor area.[11] The current Panhandle system cannot accommodate the increased demand sought by these existing and new customers.[12] These large-volume contract customers are forecast to account for approximately 94% of the increased demand on the Panhandle system, necessitating the need for the project.[13] Atura Power's Brighton Breach Generation Station alone represents almost 40% of the total incremental capacity.[14]

13. ***Capacity Needed in the Short-Term***. SEC accepts that these identified customers require natural gas. For the greenhouses, there is insufficient electricity capacity to meet their needs, and the carbon dioxide from burning natural gas is itself required in their operations as part of the growing

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[5] Letter from Enbridge, December 5, 2022
[6] Tr.2, p.173
[7] Interrogatory Response I.SEC.2, Table 1; Tr.2, p.175
[8] Tr.2, p.176
[9] Tr.2, p.183
[10] Tr.2, p.185; Interrogatory Response I.SEC.1(c)
[11] Tr.1, p.8
[12] B-1-1, p.13
[13] Tr.2, p.154
[14] Tr.1, p.17

process. The IESO has identified the need for new natural gas generation, and has entered into a contract with Brighton Beach Generation Station to increase its generation capacity.[15]

14. The increased demands cannot, in the short-term, be offset by increased conservation or fuel switching by other customers in a sufficient quantity to offset the forecast incremental demand driven by contract customers.[16] The evidence is that there would need to be a 21% decrease in forecast general service demand by winter 24/25, and substantial additional declines would be required in each subsequent year.[17] Even assuming that demand can be reduced in the short-term, not just from general service, but also existing contract customers, it is unlikely that it would be sufficient to offset the increased demand from the new or expanding contract customers.

15. Similarly, SEC is not aware of any supply-side or other IRP solution that would allow for the incremental capacity to be acquired in some other more cost-effective fashion in the short-term.

16. ***Impact of Energy Transition.*** The short-term need for the project, while real, is not sufficient for Enbridge to meet its burden of demonstrating need. This is especially true in the context of the energy transition, where the OEB needs to consider the risks of future underutilization of the project in assessing whether its construction is in the public interest as required for leave to be granted.[18] Enbridge must justify the longer-term expected utilization of the Panhandle system. It must demonstrate that it needs the additional capacity, not just in the short-term from the identified growth, but in the longer term as well. This is important as the project, based on existing depreciation rates for transmission pipelines, has an expected service life of 55 years.[19]

17. Long before 2079, let alone 2040 or 2050, natural gas consumption on Enbridge's system, including the Panhandle system, will dramatically decline due to the energy transition. In contrast, the company's position is that there is no risk. Enbridge's evidence suggests there is "no basis" to believe the pipeline will be underutilized or stranded.[20] Enbridge has come to that conclusion not through analysis, but solely because it has not considered that risk. It is simply looking at forecast demand during its planning period, which only extends to 2033.[21]

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[15] Tr.1, p.16-17
[16] Response to OEB Additional Request, p.2-3
[17] See Response to OEB Additional Request, p.3, Table 2
[18] *Ontario Energy Board Act,* section 96(1)
[19] Tr.3, p.21
[20] Tr.3, p.36; I.ED.12(d)
[21] B-1-1-1, Attachment 1; Interrogatory Response I. Staff.4

18. The question then is what the OEB should do about, the short-term need for incremental capacity that can only be met by physical facilities, in the context of a longer-term outlook that will almost certainly consist of declining system demand.

19. SEC submits that one way to address the issue is by reducing the risk of future underutilization, through requiring those customers who are driving the need for those facilities to pay for them. This is how a distribution project would be assessed.

20. This is different from the OEB's historic treatment of transmission projects, whose costs have rarely been supported by the additional revenue attributable to the new demands. Those projects, from an economic feasibility perspective, have largely been justified on the basis of energy savings and broader macro-economic impacts. That is what Enbridge is doing to justify for the proposed project.[22]

21. The OEB should revisit this approach, starting with this application.

22. ***Need For Project in Context of Enbridge Capital Budget.*** In Enbridge's 2024-2028 rebasing application, SEC argues that in the face of the energy transition, the company's rate base needs to begin to decline over this rate period, not significantly increase, as Enbridge had proposed.

23. As customers start reducing and eliminating their use of natural gas to meet greenhouse gas reduction commitments and goals, natural gas consumption will decline.[23] The company needs to focus on the immediate risks that capital expenditures it constructs today will be stranded, underutilized, or become uneconomic for the remaining customers over time. To reduce the risk by requiring a decline in Enbridge's rate base, SEC argues the company needs to make significant reductions to its proposed capital expenditure.

24. SEC did not propose which specific projects should be canceled, deferred, or if a need should be accomplished through a different approach to be considered by Enbridge to meet the required capital budget. It would be up to the company to determine how to manage its spending through the (reduced) approved capital budget, and to explicitly consider energy transition risk in its project-by-project planning. As of the date of this final argument, the EB-2022-0200 Phase I decision is pending.

[22] E-1-1, p.3-8

[23] See SEC Final Argument in EB-2022-0200, p.40-49

25. The implication of SEC's proposed approach in the rebasing proceeding on PREP is that if the OEB were to approve PREP, it would be up to Enbridge to determine how to manage the project's costs within the reduced capital budget approved for 2024.

**D. Economic Feasibility**

26. Enbridge is required to demonstrate not just that the project is needed and that it is the most cost-effective option, but that it is economic.[24] PREP's Profitability Index ("PI") is significantly below 1.0, which means that the forecast incremental revenues from the additional demand will not cover the costs of the project, and the difference will be funded by existing customers. There is no balancing benefit to existing customers. This is just a subsidy.

27. Based on Enbridge's own calculations, the project has a P.I. of only 0.48, requiring a net present value ("NPV") cross-subsidy from existing customers of $150M.[25] As discussed below, SEC believes the actual PI is lower, and the subsidy is significantly higher. Enbridge justifies the significant subsidy on the basis that, after consideration of benefits as calculated in Stage 2 and 3 of the E.B.O. 134 economic feasibility test, the project is in the public interest.[26]

28. Leaving aside the Stage 2 and 3 benefits, the cross-subsidy under Stage 1 represents an undue burden on existing customers that is not in the public interest.

29. Furthermore, the application demonstrates that E.B.O. 134 should not be applied as Enbridge proposes. If the OEB is considering approving the project, then it should require contract customers to pay a capital contribution sufficient to raise the project P.I. to 1.0.

30. ***E.B.O. 134***. What is known as E.B.O. 134 is a report of the OEB, issued more than 35 years ago, that reviewed the economic feasibility framework to be used to assess natural gas expansion.[27] The report set out a system expansion framework more broadly, and was not exclusive to transmission pipeline expansion. In fact, the underlying proceeding was initiated to consider system expansion to smaller communities following the discontinuation of federal funding programs at the time for gas system expansion.[28] It was in that context that the OEB developed the three-stage economic feasibility

[24] Natural Gas Facilities Handbook (EB-2022-0081), p.25
[25] Tr. 2, p.177; E-1-5, p.1
[26] E-1-1, p.7-8
[27] Report of the Ontario Energy Board: Natural Gas System Expansion (E.B.O. 134), June 1 1987
[28] Tr.1, p.166

test that considered not only the cross-subsidy between customers (Stage 1), but also other public interest factors (Stage 2 and 3).[29]

31. It is important to understand that E.B.O. 134 was developed during a period in which the prevailing policy imperative was very different regarding natural gas. Natural gas was considered economically beneficial option and there was almost no discussion about negative environmental impacts as they are today. The economic feasibility test for natural gas system expansion was designed to facilitate gas expansion for these reasons.

32. In 1998, the OEB reviewed the economic feasibility test that would apply to distribution expansion projects, a subset of those included in E.B.O. 134, and issued E.B.O. 188 that, among other things, only included the Stage 1 Discounted Cash Flow ("DCF") analysis.[30] Projects would be required to have a P.I. of 0.8, and in any given year the aggregate PI of all expansion projects must be 1.0.[31] If the revenues from the proposed new customers are not sufficient to reach the minimum project PI, a gas distributor has the option of requiring new customers to pay contributions-in-aid of construction ("CIAC") to raise the project P.I. to the required threshold if it wanted to construct it.[32] The intent was to ensure there is no overall subsidy from existing customers to new customers.[33]

33. In Enbridge's current rebasing application, at issue is E.B.O. 188, where parties have argued that the DCF calculation needs to be changed to strengthen the protection against the risk of cross-subsidy from existing customers in light of the energy transition.[34] As the OEB is considering the context of the rebasing proceeding, it should reconsider the economic feasibility test for transmission projects which currently allows cross-subsidies between new (or expanding) and existing customers.

34. E.B.O. 134 does not bind the OEB. It is a guideline that the OEB requires the company to meet as a filing requirement, but it is not part of any rule or regulation.[35] In this way, it is different from E.B.O. 188, which is incorporated by reference in the Gas Distribution Access Rule, and is binding on

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[29] Report of the Ontario Energy Board: Natural Gas System Expansion (E.B.O. 134), June 1 1987

[30] Final Report of the Board (E.B.O. 188), January 30 1998

[31] Final Report of the Board (E.B.O. 188), January 30 1998, p.19

[32] Final Report of the Board (E.B.O. 188), January 30 1998, p.19

[33] Final Report of the Board (E.B.O. 188), January 30 1998, p.18-19

[34] See Procedural Order No. 6 (EB-2022-0200), p.5 where the OEB identified "as a matter of particular interest" for the oral hearing, "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."

[35] Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), p.1

Enbridge.[36] The OEB has the ability to depart, in whole or in part, from E.B.O. 134 if it believes the circumstances warrant it based on the evidence and argument.

35. Enbridge itself has not uniformly applied E.B.O. 134, and has departed from it when circumstances warrant. For example, Enbridge used E.B.O. 188 to assess its Chatham-Kent Rural Project (EB-2018-0188), even though it was a transmission pipeline.[37] While this was a requirement of the provincial grant that was part of the project funding[38], it demonstrates that neither Enbridge nor the OEB was required to strictly apply E.B.O. 134 to every transmission project.

36. ***Stage 1 Analysis Requires Adjustments.*** Enbridge has not undertaken the Stage 1 DCF calculation properly, and so has significantly underestimated both the shortfall in revenue from new customers, and the cross-subsidy required from existing customers.

37. Enbridge has used a 40-year revenue horizon for all customers, even though in all other contexts, it considers a 20-year revenue horizon appropriate for contract customers. This has the effect of underestimating the cross-subsidy paid by existing customers. Under E.B.O. 188, Enbridge applies a maximum 20-year revenue horizon for contract rate customers, as those customers and system demands are riskier compared to general service customers.[39] SEC submits that the same approach should be applied to the Stage 1 assessment under E.B.O. 134, and a maximum 20-year revenue horizon should be used for contract rate customers. When applied, the project PI decreases from 0.48 to 0.39, and the cross-subsidy increases from $150M to $174M.[40]

38. The actual revenue horizon that Enbridge uses should be specific to each contract rate customer underpinning the need for the project, based on the length of the distribution contract. The distribution contract represents the period that those customers have financially committed to remaining on Enbridge's system and can be less than 20 years.[41] The evidence shows that Enbridge has either completed or is currently negotiating contracts with the relevant customers who require service in 2024 and 2025.[42] The impact of a customer-specific revenue horizon would almost certainly lead to a lower

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36 Gas Distribution Access Rule, section 2.2.2
37 *Decision and Order* (EB-2018-0188), July 11, 2019 (Revised November 19, 2019), p.6
38 Tr.2, p.30
39 Tr.3, p.102
40 Interrogatory Response I.EP.15(b)
41 Tr.3, p.30-31; Tr.3, p.29
42 Interrogatory Response I.Staff.24(a),(b)

project P.I. as a result of customers having distribution contracts shorter than 20 years.[43]

39. ***Enbridge Does Not Assess Costs As Part of Stage 2 and 3 As Required.*** Even as it purports to apply E.B.O. 134, Enbridge does not properly follow the approach set out in the report. Under E.B.O. 134, Stage 2 is "designed to quantify other public interest factors not considered at Stage 1", and it states that "[a]ll quantifiable other public interest information as to costs and benefits should be provided at this stage."[emphasis added][44]

40. Confusingly, Enbridge assesses these quantifiable benefits as part of both Stage 2 and Stage 3. In Stage 2, it estimated cost savings to in-franchise customers as a result of using natural gas[45], and as part of Stage 3, it includes a forecast of the macro-economic impacts from the construction of the pipeline.[46]

41. Yet, Enbridge has not tried to quantify any of the public interest costs of the project not included in Stage 1, as it was required to do. It has only provided a quantification of the benefits. This includes costs borne by either new or existing customers, and the province.

42. Those costs include includes the risks on existing customers of future underutilization of the pipeline as a result of the energy transition, costs of the increased GHG emissions, the broader macro-economic harms caused by increased natural gas rates as a result of the project.[47] Higher rates for existing customers come at a cost, as they now have less money to spend and invest. Even where those costs cannot be quantified, they are supposed to be considered as part of assessment of "all other relevant public interest factors" in Stage 3.[48] Enbridge does not even discuss any public interest costs or assess them, even on a qualitative basis.

43. Enbridge's application of E.B.O. 134 is one-sided. It is unfair and provides a distorted picture of the public interest factors that must be considered by the OEB.

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[43] In EB-2022-0200, SEC has argued Enbridge should be required to reduce the 40-year revenue horizon under E.B.O. 188 for general service customers. If the OEB agrees and makes changes, those should similarly be applied to the calculation for transmission pipelines.

[44] Report of the Ontario Energy Board: Natural Gas System Expansion (E.B.O. 134), June 1 1987, section 6.74-6.75; Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), p.2

[45] E-1-1, p.4; E-1-6

[46] E-1-1, p.5; E-1-7

[47] See for example, Tr.2, p.183

[48] Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), p.2

44. ***Phase 2 Benefits Overstated.*** Enbridge has dramatically overstated the benefits of the project. In Stage 2, Enbridge claims the project will generate $226M-$353M of benefits (on a NPV basis).[49] This is illusory. The calculation is based on an estimate of energy cost savings for general service in-franchise customers that would be served by the incremental capacity created by the project by using natural gas.[50]

45. Environmental Defense filed expert evidence from Dr. McDiarmid that challenged Enbridge's calculations. Dr. McDiarmid showed that these customers would in fact be financially worse off by approximately $48M to $78M if they were to use natural gas as opposed to solely electricity.[51] Dr. McDiarmid's evidence demonstrates that gas heating is not as cost-effective as electric heat pumps over the life of the relevant equipment.[52]

46. Enbridge and several other parties challenged Dr. McDiarmid's findings, most significantly because she did not include the incremental electricity infrastructure that would be required to serve these customers if they used electric heat pumps as their heating supply, given electricity system constraints in the area.[53]

47. SEC agrees that a comprehensive cost and benefit financial analysis would need to include any incremental electricity bill impacts because of any new additional infrastructure that would be needed. However, just as Dr. McDiarmid did not include all possible considerations in her analysis, neither did Enbridge. In fact, Enbridge's analysis did not include readily known and available information regarding equipment efficiency and the type of electricity-based heat customers would be likely to use.[54] Enbridge's analysis is premised on an alternative scenario where customers use electric resistance heating, as opposed to the more likely electric heat pumps.[55] This is simply not credible.

48. Regardless, the analysis must be symmetrical. If the bill impacts of incremental electricity costs should be included in the alternative scenario, then so must the bill impacts of the incremental natural gas infrastructure (i.e. the project, and all required distribution and storage assets to connect those

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[49] E-1-1, p.5
[50] E-1-1, p.5; Tr.1, p.120
[51] McDiarmid Climate Consulting, Evidence Regarding Stage 2 Analysis and Gas Alternatives for Greenhouses, October 18 2023, p.3
[52] McDiarmid Climate Consulting, Evidence Regarding Stage 2 Analysis and Gas Alternatives for Greenhouses, October 18 2023, p.3; Tr.1, p.50-52
[53] Enbridge Argument-in-Chief, para. 85; Tr.1, p.14, 84-85
[54] Tr.1, p.51
[55] Tr.1, p.51

customers) in Enbridge's analysis.

49. SEC submits that what can be drawn from the competing evidence is that Enbridge's Stage 2 benefits are, at best, significantly overstated. Just adopting Ms. McDiarmid's alternative energy mix and efficiency assumptions over 20 years reduces the net benefits from $226M to $79M.[56]

50. ***Phase 3 Benefits Flawed.*** SEC also has concerns with the proposed Phase 3 benefits. Enbridge has calculated $223M in Stage 3 benefits, which reflects an estimate of the macroeconomic impact of the project construction, specifically, the GDP and provincial taxes paid. [57]

51. Enbridge's approach to estimating the GDP impact of the construction of the project is partially based on a 2017 report prepared for a number of Ontario government departments.[58] The approach applies a GDP factor of 91% to every dollar of capital expenditures spent within Ontario ($232M).[59]

52. The counterintuitive basis of the Enbridge approach is that the higher the cost of the project, the greater the GDP impact.[60] If the company overspends, even imprudently, that additional amount would represent a GDP benefit worth 73% (91% x 80% of the incremental cost).[61] Such an outcome calls into question the methodology. When pressed at the oral hearing regarding this, all Enbridge could say is "[t]hat's how the math would work".[62]

53. This clearly cannot be the case, Ratepayers – who are responsible for the costs – would generally not agree as a principle that spending is good, and higher spending is better still. This is one of the reasons why Phase 3 benefits cannot be valued on the same basis as the outcomes of Phase 1, or even Phase 2 (i.e. a dollar of cross-subsidy is the same as a dollar of macro-economic benefit).

54. ***Even if OEB Applies E.B.O. 134 as Enbridge Proposes, the Cross-Subsidy is An Undue Burden.*** Under E.B.O. 134, even if a project has a net positive benefit after consideration of Stages 2 and 3, the OEB must still look back at the Stage 1 DCF analysis to ensure that the "subsidy does not cause an undue burden on any individual, group, or class." [63] The OEB stated that it would "continue

[56] Enbridge Reply Evidence, p.5-6
[57] E-1-7, p.1
[58] E-1-7, p.1
[59] Tr.2, p.181; E-1-7, p.1
[60] Tr.2, p.182
[61] Tr.2, p.182
[62] Tr.2, p.182
[63] Report of the Ontario Energy Board: Natural Gas System Expansion (E.B.O. 134), June 1 1987, section 5.16; Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), p.3

to be guided by this general principle in determining the extent to which gas service should be extended into other areas of the province."[64]

55. A subsidy of $150M, as calculated by Enbridge, $174M if corrected, or an even higher amount if the expected cost escalation materializes, is a clear undue burden on existing customers. With a P.I. of 0.48 or 0.37, it represents less than 50% of the costs of the project being recovered by those who want it.

56. Adding to that, the DCF methodology assumes that the incremental demands stay on the system throughout the entire revenue horizon, and that the projects come in on budget, even though the forecast is now more than a year old. The risk that the actual P.I. is overstated, and the subsidy is even higher, is very significant. E.B.O. 134 was never intended to support the economic feasibility of projects like this.

57. ***E.B.O. 134 Should Be Modified.*** Stage 2 and 3 of E.B.O. 134 should be eliminated from the assessment of the economic feasibility of a transmission pipeline of this kind, and the test should mirror that applied to distribution pipeline expansion under E.B.O. 188. There is no principled reason for different approaches for different classes of pipelines where the need is driven by discrete growth. From a customer's perspective, both types of pipelines are required to serve them, and their natural gas use will necessitate their construction.

58. The consideration of broader benefits as part of the feasibility assessment, as opposed to project need, is outdated in this context, especially in light of the energy transition. The need to protect customers against the risk of underutilized and stranded assets is important. The inclusion of Stage 2 and 3 costs and benefits allows Enbridge to transfer the risk from customers driving the need for a given project to all other customers without justification.

59. Enbridge witnesses testified that it was unfair to change the economic feasibility test for transmission projects, as it would result in unequal treatment between customers impacted by PREP and those who were previously attached to the system under a different approach, which did not require the payment of any capital contributions.[65] This is undoubtedly correct, but is an inherent feature of regulation. The OEB has the obligation to change standards, policies, and tests as circumstances warrant, even if it will impact new customers differently from existing ones. OEB principles, rules and

[64] Report of the Ontario Energy Board: Natural Gas System Expansion (E.B.O. 134), June 1 1987, section 5.16
[65] Tr.2, p.194

decisions must ensure that they remain in the public interest, and evolve when required to achieve that mandate. E.B.O. 134 itself recognizes that the "public interest is dynamic and it must change according to the circumstances".[66]

**F. CIAC Payments Should Be Required**

60. SEC submits that if the OEB believes the project is needed and the costs are reasonable, it should only grant leave to construct if contract customers are required to pay a Contribution-In-Aid of Construction (CIAC) to bring the project P.I. up to 1.0, thereby reducing the cross-subsidy between existing and new (or expanding) customers. This would promote fairness among customers and mirror what Enbridge does with respect to distribution expansions, including for new distribution assets required to serve the same customers.

61. Requiring CIACs is simply an application of the OEB's long-standing benefits follow costs (or more aptly here, costs follow benefits) principle.[67]

62. For distribution assets, Enbridge applies the OEB-approved Hourly Allocation Factor ("HAF") methodology to determine CIAC payments for new and expanding large-volume customers when required as a result of the economic feasibility test.[68]

63. The HAF methodology splits the project capital costs into small and large volume components based on peak hourly demands.[69] It then calculates a specific HAF by taking the forecast capital costs of the large volume component of the project and dividing it by the forecast firm hourly large volume demand in an area served by the project.[70] The HAF methodology ensures that connecting customers, regardless of when they attach, contribute to the capital that is being built to serve them.

64. Enbridge witnesses during the oral hearing argued that a CIAC could not be properly calculated in a way that treats similarly situated customers fairly or predictably over time.[71] This is a result of two interrelated factors.

65. First, based on what Enbridge called system hydraulics, depending on where customers connect to the Panhandle system, the overall system capacity may be different, which may cause a cost

[66] Report of the Ontario Energy Board: Natural Gas System Expansion (E.B.O. 134), June 1 1987, section 5.14
[67] *Decision with Reasons* (EB-2016-0004), November 17 2016, p.3-4
[68] *Decision and Order* (EB-2020-0094), November 5 2020, p.15
[69] *Decision and Order* (EB-2020-0094), November 5 2020, p.15
[70] *Decision and Order* (EB-2020-0094), November 5 2020, p.19
[71] Tr.1, p.10

allocation problem.[72] Since the Expressions of Interest ("EOI") do not bind these new or expanding customers, and the connection is first-come, first-served, any forecast allocation factor to determine the CIAC payment may not reflect actuals.[73]

66. Second, as customers connect to the system, the forecast allocation factor would change, resulting in customers being charged different CIACs for the same capacity.[74] This would result in either an over or under-collection.[75]

67. The fact that no perfect methodology can be developed is not a valid argument for why there should be no methodology. Enbridge's identified issues can be overcome by developing a CIAC methodology that balances fairness and cost certainty for new and expanding customers.

68. It is no wonder that Enbridge seeks to avoid CIACs for the project. CIACs are treated as an offset to its rate base.[76] If the OEB ordered the company to collect CIACs, it would reduce the net in-service additions of the project added to the rate base, which would reduce its return on equity.

69. In Procedural Order No. 4, the OEB approved Enbridge's request to place the application in abeyance. It also confirmed that the issue of requiring CIAC payments is within the scope, and that Enbridge may wish to consider whether additional evidence should be filed in any updated application. It also suggested the company may "wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required."[77] Enbridge did so and sought feedback from potential customers who participated in the EOI process.

70. The feedback from those potential customers was generally that they do not favor paying any CIAC.[78] This is unsurprising.[79] Asked if they would like to pay more for a service, like any other person, they would prefer not to.

71. The feedback is also not useful for the purpose of the OEB's decision. What Enbridge did not ask, and what would have been useful, would be to understand the implications for forecast demand,

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[72] Tr.2, p.13
[73] Tr.2, p.9
[74] Tr.1, p.10
[75] Tr.2, p.193-194
[76] Interrogatory Response I.EP.10(f)
[77] Procedural Order No. 4, December 14 2022, p.3
[78] Tr.2, p.189
[79] Tr.2, p.189; Interrogatory Response I.Staff.25, Attachment 1

if any, of being required to pay a CIAC.[80] Enbridge did not provide these potential customers with any information regarding the magnitude of the CIAC so that meaningful feedback could be provided to the OEB.

72. What we are aware of is that at least one very large customer, Brighton Beach Generation Station, is prepared to pay a CIAC for the project. Its electricity generation contract, entered into with the IESO subsequent to Procedural Order No. 4, specifically includes a set of provisions to deal with the outcome of this proceeding and the potential that the OEB may require CIAC.[81]

73. Insofar as the OEB's decision to require CIAC from contract customers creates uncertainty for those customers and Enbridge, that is squarely the fault of the company. It knew the positions certain parties would be presenting in this proceeding, the OEB told them they should provide notice to those affected customers, and yet they chose not to provide them with useful information.

74. ***SEC CIAC Methodology.*** Even though in EB-2020-0094, Enbridge did not seek, and the OEB did not approve, the HAF methodology for transmission projects, the OEB can still apply some of the principles of the development of a CIAC methodology in this proceeding.[82]

75. SEC proposes the following CIAC methodology that would be applied for transmission projects, such as PREP:

- ***Step 1 – Identification of Revenue Shortfall*** – A Stage 1 DCF calculation is undertaken and any negative NPV (the revenue shortfall) of the project based on forecast costs and revenues is identified.
- ***Step 2 – Allocation of Shortfall Between General Service/Contract Customers*** - The revenue shortfall is split between general service and large volume customers based on their respective forecast firm hourly peak demand and expected location on the Panhandle System. This approach is like the approved HAF, but instead of dividing between small and large volume customers by hourly demand threshold, a general service/contract rate customer distinction is made. This reflects the relative risk profiles of the customer types, relative impact of any given customer on the underlying need for transmission project, and administrative simplicity.
- ***Step 3 – Calculation of CIAC Rate*** - Allocated Contract Customer Shortfall is divided by forecast peak hourly demand of forecast contract customers to determine a cost per peak hourly demand.
- ***Stage 4 – Payment of CIAC*** – The CIACs would be required based on the sum of the CIAC Rate times the customer's contracted peak hourly demand. The rate would be required to be paid by all contract customers who attach to the Panhandle System during the 5-year

[80] Tr.2, p.190-191
[81] Clean Energy Supply Contract Between Brighton Beach Power L.P. and Independent Electricity System Operator, dated April 27, 2023, Exhibit X, Gas Delivery Services Re: Panhandle Project (K2.5, p.57).
[82] *Decision and Order* (EB-2020-0094), November 5 2020, p.19

period, which is the basis for the contract customer demand used for the purposes of the Stage 1 DCF Calculation that underpins the project.

76. The CIAC Rate for the project would not be adjusted based on which customers connect along the Panhandle system or where they connect, nor to reflect actual project costs, even if it results in an over or under-collection. While this could be addressed by way of true-up payments/credits, which are explicitly required when electricity distribution and transmission projects require capital contributions[83], as a preliminary step, SEC can accept Enbridge's view that it would "not [be] a tenable solution...as it introduces even more complexity, uncertainty, and burden to customers."[84]

77. The proposed CIAC methodology will not perfectly reflect the actual costs or a given contract customer's specific impact on system capacity needs, but it will provide a fair proxy of their contribution to costs. Ratemaking never requires each customer to pay rates that reflect their specific contribution to costs. Such an approach is unworkable. What is required is a system that fairly allocates costs, which the proposed methodology does. The risk of over or under-collection is always present in forecast ratemaking. The best way to minimize it is by forecasting costs and revenues as accurately as possible.

**G. Summary**

78. SEC accepts that there is a short-term need for additional capacity to serve the growing greenhouse sector, and natural gas generators. There are no non-pipes alternatives that have been identified which could alleviate all or most of this short-term need.

79. However, in the medium and long-term the Enbridge proposal results in existing customers subsidizing the customers experiencing the growth, taking on material risks of underutilization and stranding, and receiving no benefits, direct or indirect, in return for the subsidy or the risk. In this case, costs should follow benefits, a result that can be achieved by requiring CIACs from the customers to be served by the project. As long as those customers cover a properly calculated Stage 1 shortfall of revenues, the ratepayers will be kept neutral, and this new capacity can be built to serve those growth customers.

[83] See for example, Transmission System Code, section 6.5.3; Distribution System Code, section 3.2.27
[84] Tr.2, p.195

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

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