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VIA EMAIL and RESS

January 29, 2024

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Nancy Marconi:

**Re: Enbridge Gas Inc. ("Enbridge Gas")
Ontario Energy Board ("OEB") File No. EB-2022-0157
Panhandle Regional Expansion Project
Reply Argument**

In accordance with the OEB's correspondence dated January 17, 2024, enclosed please find the Reply Argument from Enbridge Gas in the above noted proceeding.

If you have any questions, please contact the undersigned.

Sincerely,

Haris Ginis
Digitally signed by Haris Ginis
Date: 2024.01.29 19:40:15 -05'00'

Haris Ginis
Technical Manager, Leave to Construct Applications

c.c. Charles Keizer (Torys)
Zora Crnojacki (OEB Staff)
Intervenors (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, sections 90 (1) and 97 thereof;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order or Orders granting leave to construct natural gas pipelines in the Municipality of Chatham-Kent and Essex County;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order or Orders approving the proposed forms of pipeline easement and temporary land use agreements.

ENBRIDGE GAS INC.

REPLY SUBMISSIONS

EB-2022-0157

January 29, 2024

TABLE OF CONTENTS

A. Introduction 4

B. Enbridge Gas Appropriately Accounted for Energy Transition 7

(i) The Nature of the Panhandle System 7

(ii) The Dependency on Natural Gas by Contract Rate Customers in the Panhandle Market 8

(iii) The Pace of Electrification of General Service Rate Customers in the Panhandle Market 10

(iv) The Extensive Electricity System Investments, Not Yet Planned, Required to Accommodate the Level of Electrification Needed to Strand the Project 13

C. Enbridge Gas Correctly Applied EBO 134 16

(i) The Project is Exclusively a Transmission Facility 16

(ii) The Project is Not Distribution or Dual Function 18

(iii) EBO 134 and EBO 188 Have Been Misinterpreted and Can Be Reconciled 29

(iv) A CIAC is Not Part of the EBO 134 Evaluation 33

D. Enbridge Gas Correctly Applied the EBO 134 Three-Stage Test 35

(i) Stage 1: No Basis That the Project Will Be Underutilized or Stranded 36

(ii) Stage 2: ED/Dr. McDiarmid's Approach Should Not Be Accepted 37

(iii) Stage 3: The Calculated Benefits Are Appropriate 40

E. There is No Undue Burden 43

F. EBO 134 Should Not Be Amended 44

G. A CIAC Should Not Be Imposed 47

(i) Transmission System Dynamics Do Not Permit a CIAC 47

(ii) Capacity and Cost Responsibility Are Misaligned 49

H. Impacts of Imposing a CIAC 52

I. The Project Costs Are Reasonable 54

(i) Requiring Enbridge Gas to Estimate Project Costs Based on the Lowest Priced Proposal is Not the Prudent Approach 54

(ii) Project Costs Were Estimated Following a Comprehensive Process with Built-In Contingencies and Other Measures 58

(iii) The Estimated Indirect Overheads are Appropriate....60

J. The Project Is the Optimal Solution to Meet the System Need 61

(i) Enbridge Gas's Evaluation of IRP Alternatives Was Appropriate 61

(ii) Enbridge Gas's Evaluation of an IRP Alternative at Ojibway Was Appropriate ..65

K. Enbridge Gas's Approach to Subsequent Phases of Panhandle System Expansion is Appropriate 71

(i) IRP Alternatives Could Be Viable For a Future Project (i.e At Least 5 years In the Future)....72

(ii) Enbridge Gas Applies an "Assess and Adapt" Approach (Not a "Wait and See" Approach) 74

(iii) A Direction to Assess Whether Enbridge Gas Recommends a Proactive IRP Plan is Not Required 76

L. Enbridge Gas Undertook Meaningful Indigenous Consultation....77

M. Enbridge Gas's Environmental Mitigation Measures are Appropriate....80

N. Relief Requested 83

A. Introduction

1. These are the reply submissions of Enbridge Gas Inc. ("Enbridge Gas" or the "Company") in its leave to construct application in respect of the Panhandle Regional Expansion Project (the "Project") (the "Application"). Enbridge Gas refers the Ontario Energy Board (the "OEB") to its Argument in Chief in respect of the Application filed on November 30, 2023.

2. Submissions were received from OEB Staff, the Association of Power Producers of Ontario ("APPrO"), Atura Power ("Atura"), and Ontario Greenhouse and Vegetable Growers ("OGVG"), all of which submitted that the Project is in the public interest and leave to construct should be granted. Environmental Defence ("ED"), Energy Probe ("EP"), Federation of Rental-Housing Providers of Ontario ("FRPO"), Industrial Gas Users Association ("IGUA"), Kitchener Utilities, Pollution Probe ("PP"), School Energy Coalition ("SEC"), and Three Fires Group Inc. ("TFG") all either opposed the granting of leave to construct or sought a contribution in aid to construct ("CIAC") in the event the Project is granted leave (the "Opposing Intervenors"). Enbridge Gas addresses the salient issues raised by the Opposing Intervenors below.

3. Central to the Opposing Intervenors' submissions is that Enbridge Gas failed to take into account energy transition and that there is an unacceptable level of risk that the Project will become underutilized or obsolete, uniquely justifying the imposition of a CIAC payable by contract customers acquiring the incremental capacity of the Panhandle System created by the Project. As indicated in Part B below, there is no evidentiary basis to deny the Project or to impose a CIAC on the grounds that the Project will become stranded or underutilized because of energy transition. Nor is there evidentiary basis to require Enbridge Gas to charge a CIAC and depart from the established practice of evaluating the Project's economics and public interest under EBO 134 as stipulated in the OEB's Natural Gas Facilities Handbook (the "Facilities Handbook"). Enbridge Gas has appropriately considered the potential impacts of energy transition together with critical facts regarding the Project, including (i) the nature of the Panhandle System, (ii) the

dependency on natural gas by contract rate customers in the Panhandle Market[1], (iii) the pace of electrification of general service rate customers in the Panhandle Market, and (iv) the extensive electricity system investments, not yet planned, required to accommodate the level of electrification needed to strand the Project.

4. Fundamentally, the Project is of critical importance to economic development, food security, and electricity generation in Ontario. The Project will address the Panhandle Market's natural gas transmission capacity shortfall of 66 TJ/d projected for Winter 2024/2025, which increases to 156 TJ/d by Winter 2028/2029.[2]

5. At a cost of $358 million,[3] the Project will create natural gas transmission capacity that will enable approximately $4.5 billion in direct customer capital investment in the province (over 12 times the cost of the Project) and create 6,900 jobs.[4] Additionally,

a. construction of the Project itself will generate approximately $257 million of direct and indirect benefits to the province, along with an estimated 1,093 jobs;[5]

b. the Project will support economic growth opportunities across various sectors within the Panhandle Market, which are expected to exceed billions of dollars in local and foreign investments as indicated by Invest WindsorEssex[6] and the Windsor Star[7];

c. the Project will enable growth within Ontario's vegetable greenhouse sector, a sector which is expected to both double its contribution to GDP by 2030 (with farmgate sales alone projected to exceed $2 billion)[8] and play an important role in promoting domestic food security[9]; and,

d. as discussed in APPrO's submissions,[10] the Project is essential to meeting increased electricity demand in the Panhandle Market and across Ontario. Notably, the electricity demand in the Windsor-Essex and Chatham region is

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1 Exhibit A, Tab 1, Schedule 2, p. 2: "The municipalities of Dawn-Euphemia, St. Clair, Chatham-Kent, Windsor, Lakeshore, Leamington, Kingsville, Essex, Amherstburg, LaSalle, and Tecumseh."

2 Exhibit B, Tab 2, Schedule 1, p. 11, Table 3.

3 Exhibit E, Tab 1, Schedule 2.

4 Exhibit B, Tab 1, Schedule 1, p. 16.

5 Exhibit E, Tab 1, Schedule 1, p. 6.

6 Invest WindsorEssex Letter of Support (November 9, 2023).

7 Exhibit I.STAFF.25, pp. 4-5.

8 Exhibit K3.2 (November 6, 2023), p. 1.

9 Exhibit J3.8, p. i.

10 APPrO Submissions, paras. 69-73.

expected to grow from 500 MW in 2022 to 2,100 MW in 2035 (over 4 times in size in the next 13 years), equivalent to adding cities the size of Ottawa and London to the grid.

6. If the Project is not granted leave to construct, or if the Project is granted leave to construct subject to a CIAC, the economic development and food security benefits described above would be lost and the electricity generation needs of Ontario would be negatively impacted. Enbridge Gas submits that rejecting the Project or imposing a CIAC is not in the public interest. The consequences of rejecting the Project or imposing a CIAC are discussed further in these submissions in Part H below.

7. The Project is in the public interest on the basis of having satisfied the requirements of EBO 134's three-stage test. No CIAC should be imposed since it is not appropriate to do so under the requirements of EBO 134 and, in any event, there is no undue burden arising from the Project. Contrary to the position of the Opposing Intervenors, the evidence on the record in respect of the Project – including with respect to its purpose, physical characteristics, design, and end-use – entirely support that it is exclusively a transmission project. As such, Enbridge Gas's application of the three-stage test is consistent with EBO 134, the Facilities Handbook and past OEB Decisions. Furthermore, it is incorrect to conclude (as submitted by some Opposing Intervenors) that EBO 134 cannot be reconciled with the application of EBO 188 (applicable to distribution pipelines) or that EBO 134 contemplates the application of a CIAC as part of the evaluation process. The Opposing Intervenors' objective of abruptly eliminating or fundamentally modifying the established EBO 134 framework should not be accepted. EBO 134 is a test of general application which should not be selectively modified in a singular circumstance and without participation from all impacted stakeholders (including existing and prospective customer groups and provincial and municipal economic development groups), many of whom are not before the OEB in this proceeding. Enbridge Gas's submissions in this regard are set out in Parts C to G below.

8. Submissions related to Project Costs are set out in Part I below. Submissions related to Integrated Resource Planning ("IRP") are set out in Parts J and K. Submissions related to

Indigenous Consultation are set out in Part L. Submissions related to Environmental Matters are set out in Part M.

B. Enbridge Gas Appropriately Accounted for Energy Transition

9. The Opposing Intervenors assert that Enbridge Gas has failed to adequately account for energy transition and its impact on natural gas peak demand to the Panhandle System. They raise this issue primarily in the context of Enbridge Gas's Stage 1 calculation under the EBO 134 test by asserting that the impacts of energy transition are not compatible with the forecasted natural gas revenues for the Project.[11]

10. There is no basis to assert that the Project will be underutilized or stranded due to energy transition.[12] Enbridge Gas has appropriately considered the potential impacts of energy transition together with critical facts regarding the Project, including (i) the nature of the Panhandle System, (ii) the dependency on natural gas by contract rate customers in the Panhandle Market, (iii) the pace of electrification of general service rate customers in the Panhandle Market, and (iv) the extensive electricity system investments, not yet planned, required to accommodate the level of electrification needed to strand the Project.

(i) The Nature of the Panhandle System

11. The Panhandle System is a natural gas transmission system that serves a broad geographic region comprised of multiple distribution systems with thousands of customers representing various customer types.[13] The natural gas molecules flowing through the Panhandle System cannot be differentiated and can flow to any customer attached to the downstream distribution networks that connect to the transmission system. Furthermore, the Panhandle System has the same characteristics as Enbridge Gas's other major transmission pipeline systems that connect to Dawn.[14]

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[11] ED Submissions, pp. 4-5; TFG Submissions, p. 15.
[12] Hybrid Hearing Transcript Vol. 3, p. 36.
[13] Exhibit A, Tab 3, Schedule 1, pp. 1-2.
[14] Exhibit K1.1, p. 2.

12. Because the Project loops part of the existing Panhandle System transmission pipeline, the Project will form part of the Panhandle System as a whole. As a result, any discussion regarding the potential for energy transition to strand the Project must consider the Panhandle System as a whole – not just the Project. The energy transition impact on all customers of the Panhandle System must be considered and not just those customers that contract for the incremental capacity on the Panhandle System that is created by the Project.

13. In this context, it is also important to note that the Panhandle System has undergone several reinforcements, which have been staged over many years.[15] The nature of the Panhandle System as a transmission system and its staged reinforcements provides resource planning flexibility in the face of long-term energy transition uncertainty.

14. It is also important to consider that 10% (60 TJ/d) of Panhandle System demand is satisfied through contracted upstream supply deliveries from the Panhandle Eastern Pipeline ("PEPL") at Ojibway.[16] To the extent that there is a variance in the forecasted demand on the Panhandle System, Enbridge Gas can de-contract this third-party transportation capacity over time and utilize the capacity on the Panhandle System from Dawn to meet Panhandle Market demand.[17] This further defers any forecast or energy transition risk related to stranded assets.

(ii) The Dependency on Natural Gas by Contract Rate Customers in the Panhandle Market

15. The Panhandle System has a customer demand mix of 44% general service and 56% contract rate customers.[18] These contract rate customers consist of greenhouses, power generators, automotive and other large commercial and industrial customers. Contract

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[15] Exhibit B, Tab 1, Schedule 1, p. 2.
[16] Exhibit B, Tab 2, Schedule 1, p. 6.
[17] Hybrid Hearing Transcript Vol. 3, p. 51.
[18] Exhibit B, Tab 2, Schedule 1, p. 9.

rate customers have energy-driven processes and uses that require access to natural gas[19] and have limited electric alternatives, economically or practically.

16. For the greenhouse sector specifically, natural gas is an important input for the growing process and there are limited viable energy alternatives available for heating and back-up electricity generation. Furthermore, natural gas is used to supply the carbon dioxide requirements ("CO2") of the growing plants. A common practice within the greenhouse sector is to capture the CO2 that would normally be emitted into the atmosphere upon combustion of natural gas and use it within the greenhouse where it is consumed by the growing plants, resulting in faster growth and increased production.[20] There is no basis to believe that energy transition's broader impact on greenhouses will make the Project underutilized or stranded. Enbridge Gas's Argument in Chief sets out in detail why natural gas is a uniquely suitable fuel type for the greenhouse sector.[21] These submissions, which Enbridge Gas continues to rely on, address how the evidence, including the testimony from Dr. McDiarmid and Dr. Petro, supports that demand from greenhouses cannot be satisfied with lower emitting alternative energy sources, and describes how Dr. McDiarmid's testimony is theoretical in nature by failing to consider the economic and technical feasibility of the proposed alternative energy sources.

17. ED's submissions acknowledge that there are challenges with decarbonizing greenhouses and clarified that its position (that there is opportunity to reduce demand and emissions from greenhouses by using biomass and efficiency measures) should not be construed as ED attacking the Project need.[22] Given that ED is not attacking the Project need, Enbridge Gas notes that there is no credible argument advanced by the Opposing Intervenors that energy transition will result in the substantial replacement of natural gas with electricity in the greenhouse sector.

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[19] APPrO Submissions, paras. 69-73; Exhibit I.STAFF.25, pp. 4-5; Invest WindsorEssex Letter of Support (November 9, 2023).

[20] Exhibit B, Tab 1, Schedule 1, p. 15.

[21] Argument-in-Chief, pp. 8-12.

[22] ED Submissions, p. 13.

18. Furthermore, contrary to the assertions made by TFG,[23] the greenhouse sector does not pose a departure risk once the Project is in-service and contracts are executed. In entering into natural gas contracts, these customers are expected to invest billions of dollars into their facilities, which provides a long-term commitment to the area and natural gas usage. Also contrary to the assertions of TFG, the contractual terms incentivize the continued taking of service since Enbridge Gas will hold sufficient security to guarantee the payment of that contract and will continue to do so throughout the term of the contract.[24]

(iii) The Pace of Electrification of General Service Rate Customers in the Panhandle Market

19. Opposing Intervenors assume that general service customers (residential and small commercial/industrial) will choose to reduce their emissions via disconnecting from the natural gas system, converting all natural gas burning equipment to new electrical equipment and placing no value on energy resilience. Opposing Intervenors assume this could happen at a pace and level that risks stranding the Project.

20. In its consideration of energy transition, Enbridge Gas contemplated the pace of electrification of general service customers in the Panhandle Market. As indicated in Enbridge Gas's testimony[25] and in response to the OEB's additional request[26], a reduction of 52% in general service natural gas peak demand would be required by Winter 2029/2030 to offset the forecast growth in contract market natural gas demand that is underpinning the Project need. This reflects a cumulative decline in general service demand of 160 TJ/d by Winter 2029/2030, relative to Winter 2023/2024 levels.[27] Given the total Panhandle System general service customer count of approximately 198,000 customers (182,000 residential and 16,000 commercial/industrial), approximately

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[23] TFG Submissions, pp. 20-21.
[24] Hybrid Hearing Transcript Vol. 3, p. 34.
[25] Hybrid Hearing Transcript Vol. 3, pp. 51-52.
[26] Enbridge Gas Response to OEB Additional Request (November 30, 2023), p. 2.
[27] Enbridge Gas Response to OEB Additional Request (November 30, 2023), p. 3.

103,000 general service customers would need to terminate their natural gas service by Winter 2029/2030 to accommodate the incremental contract demand.[28]

21. Recognizing that small commercial/industrial general service customers have a variety of energy needs for which electric heat pumps may not be viable or commercially available, Enbridge Gas also considered the departure of residential general service customers only. All of the 182,000 residential customers currently attached to the Panhandle System would need to terminate their natural gas service by Winter 2029/2030 to accommodate the incremental contract demand.[29]

22. Under the first scenario, 52% of general service customers attached to the Panhandle System would need to fully convert from natural gas to electricity by Winter 2029/2030. Under the second scenario, every residential customer would need to fully convert from natural gas to electricity by Winter 2029/2030 to accommodate the incremental contract demand and avoid the need for the Project. Neither of these circumstances will happen between Winter 2023/2024 and Winter 2029/2030, as was acknowledged by OEB Staff.[30] Importantly, as described in the following section, there are no plans to build electrical infrastructure to meet this increased amount of electric winter heating load in the above noted timeframe or in the longer term.[31]

23. Furthermore, even though an electric heat pump is installed in a home it does not mean that it will be the singular heating source. As indicated in Exhibit J3.6, of the 532 natural gas heated homes that installed an electric heat pump through NRCan's Canada Greener Homes Grant in Ontario in 2023, only 21 (4%) completely switched off natural gas while 511 (96%) maintained natural gas as their primary fuel type.[32]

24. Notwithstanding the unrealistic level of general service customers that would need to fully disconnect from the natural gas system to offset the growth in contract market

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28 Enbridge Gas Response to OEB Additional Request (November 30, 2023), pp. 5-6.
29 Enbridge Gas Response to OEB Additional Request (November 30, 2023), pp. 6-7.
30 OEB Staff Submissions, p. 31.
31 Hybrid Hearing Transcript Vol. 3, p. 107.
32 Exhibit J3.6.

natural gas demands, and the lack of electricity infrastructure to accommodate those conversions as discussed in the following section, Opposing Intervenors also ignore several other aspects related to their assumptions about residential electrification.

25. First, Dr. McDiarmid's evidence regarding the cost-effectiveness of electric heat pumps versus natural gas did not include a sensitivity analysis related to electricity prices, notwithstanding her acknowledgement that the probability that current electricity prices remain unchanged throughout the term of her analysis is "low".[33] A cost-effectiveness calculation regarding electric heat pumps cannot be entirely based on a current snapshot in time. It must consider potential longer-term energy prices that reflect policy changes, transmission and distribution infrastructure build-outs, grid modernization and renewal, build out of supply, technological change, and economic cycles. These important factors could change the economic relationship between electric heat pumps and natural gas in the future.[34]

26. Second, any analysis regarding residential energy transition must consider the political and public policy risk associated with the Federal Carbon Charge. Effective November 9, 2023, the federal government paused the Federal Carbon Charge on deliveries of home heating oil in all provinces and territories where it currently applies.[35] Following this change, the Premiers of five provinces (including Ontario) requested that the federal government remove the Federal Carbon Charge for all forms of home heating fuels (including natural gas).[36] Furthermore, effective January 1, 2024, the Province of Saskatchewan removed the Federal Carbon Charge from all home heating fuels (including natural gas).[37] Most notably, the Federal Carbon Charge is expected to be a

33 Hybrid Hearing Transcript Vol. 1, p. 104.

34 EB-2022-0156, OEB Decision and Order (September 21, 2023), p. 20; EB-2022-0248, OEB Decision and Order (September 21, 2023), p. 20; EB-2022-0249, OEB Decision and Order (September 21, 2023), p. 19.

35 https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcn15/temporary-relief-fuel-charge.html

36 https://x.com/PremierScottMoe/status/1723087693528064465

37 https://www.saskatchewan.ca/government/news-and-media/2023/december/28/saskatchewan-to-provide-families-with-relief-from-federal-carbon-tax-in-new-year

key issue with respect to the next federal election, which will occur on or before October 20, 2025.[38]

27. The political and public policy risk associated with the current Federal Carbon Charge is critically relevant to residential energy transition because of the impact it could have on the cost-effectiveness of electric heat pumps versus natural gas. While Dr. McDiarmid's analysis did not consider a sensitivity analysis related to the Federal Carbon Charge, Dr. McDiarmid confirmed at the hearing that the removal of the current Federal Carbon Charge would result in natural gas being more cost-effective than electric heat pumps for the average residential energy consumer, based on her analysis.[39] More specifically:[40]

a. Using the current Federal Carbon Charge (including annual escalations to 2030), Dr. McDiarmid's analysis results in a customer NPV for electric heat pumps of **+$4,012** (i.e., electric heat pumps are more cost effective than natural gas, on average).

b. Using a Federal Carbon Charge of zero, Dr. McDiarmid's analysis results in a customer NPV for electric heat pumps of **-$3,516** (i.e., electric heat pumps are less cost effective than natural gas, on average).

c. Using a Federal Carbon Charge frozen at the 2023 level, Dr. McDiarmid's analysis results in a customer NPV for electric heat pumps of **-$128** (i.e., electric heat pumps are less cost effective than natural gas, on average).

(iv) The Extensive Electricity System Investments, Not Yet Planned, Required to Accommodate the Level of Electrification Needed to Strand the Project

28. Opposing Intervenors criticized Enbridge Gas for not taking into account energy transition.[41] TFG does so when it readily admits that no one can predict the future with certainty.[42] However, Opposing Intervenors fail to acknowledge the extensive electricity system investments that would be required, both within the region's electric distribution system, but also at the provincial transmission and capacity level, to accommodate the

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38 https://www.canada.ca/en/public-service-commission/services/political-activities/election-calendar.html

39 Hybrid Hearing Transcript Vol. 1, pp. 100-101.

40 Exhibit K1.6, p. 2.

41 ED Submissions, pp. 4-5; PP Submissions, p. 14; SEC Submissions, p. 9; TFG Submissions, para. 48.

42 TFG Submissions, para. 47.

amount of electrification needed to strand the Project. The associated transmission and capacity build out requirements are critical to consider as the speed at which they could occur, their costs, and their operational reliability would be impacted by the level of electrification occurring in Ontario beyond the Panhandle Market.

29. In this regard, it is important to consider the Independent Electric System Operator's ("IESO") Pathways to Decarbonization Report ("P2D")[43], as it provides insight into the level of transmission and capacity related investment that would be required to deliver such levels of electrification. The P2D articulates that to enable decarbonization (including full general service electrification) by 2050:

a. In addition to 20,000 MW of today's supply that will still be in operation, an additional 69,000 MW of installed capacity would be required, including 17,800 MW of nuclear supply, 17,600 MW of wind (as most of Ontario's existing wind facilities will have reached their end of life), and 650 MW of new hydroelectric.[44]

b. 4,000 MW of imports from Hydro-Québec would be required, requiring incremental new infrastructure including: new interties, reinforcements to deliver the capacity to load centers in the Greater Toronto Area, reinforcements in Québec, and new hydroelectric and new wind facilities in Québec.[45]

c. $375 billion to $425 billion in new transmission and supply infrastructure investment would be required, resulting in an annual total system cost of approximately $60 billion by 2050.[46] This includes:

    i. 150 to 280 new load supply stations[47] at a cost ranging between $5 billion and $10 billion. This results in five to ten new stations a year, on average, which amounts to "a yearly pace potentially outstripping the number of new stations that have been developed across the province in the last decade".[48]

    ii. Building out the bulk 500 kV and 230 kV system, at a cost estimated to be between $20 billion and $50 billion.[49]

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[43] IESO *Pathways to Decarbonization* (December 15, 2022).

[44] IESO *Pathways to Decarbonization* (December 15, 2022), p. 29.

[45] IESO *Pathways to Decarbonization* (December 15, 2022), p. 30.

[46] IESO *Pathways to Decarbonization* (December 15, 2022), p. 32.

[47] Taking into account existing load supply stations and assuming that a new station would supply approximately 250 MW of winter load.

[48] IESO *Pathways to Decarbonization* (December 15, 2022), p. 31.

[49] IESO *Pathways to Decarbonization* (December 15, 2022), p. 31.

d. Building challenges related to new energy infrastructure (taking four to five years for new wind and solar generation, 10 years for transmission networks and longer for large, capital-intensive infrastructure) will need to be addressed.[50]

e. A six-fold increase to the estimated 14,000-strong labour force currently working on electricity infrastructure projects in Ontario, expected to last for decades.[51]

f. An operability assessment on the decarbonization scenario would need to be performed by IESO, which has not been completed, to ensure that the electricity system will remain reliable.[52]

30. These are formidable challenges and there exist no current plans or budgets to meet them. Further, Enbridge Gas notes that in the IESO's recent response to the draft Clean Electricity Regulations, which is addressed to the Federal Minister of Environment and Climate Change Canada, the IESO characterized the Clean Electricity Regulations merely as a "starting point for a discussion," and noted the following concern:

> [T]he CER as drafted is unachievable in Ontario by 2035 without putting at risk the reliability of the electricity system, electrification of the broader economy and economic growth. Further, the CER could also jeopardize Ontario's ability to meet the electricity needs associated with the province's expected significant population growth.[53]

31. Notwithstanding the good intentions of government policy, there is no clear certainty that the objectives intended by that government policy will be met, leaving any impact on the Project demand uncertain. This uncertainty was recently echoed by the Electrification and Energy Transition Panel's *Ontario's Clean Energy Opportunity* report:

> Finally, it is not possible to predict the precise trajectory of a transition of this scale and complexity. It will be shaped by the decisions of countless consumers and other market actors. It will be affected by global economic, social and geopolitical forces that we are unable to anticipate. It will be influenced by the evolving views of citizens and communities within and beyond Ontario. And it will be shaped by an unprecedented pace of technological change. This uncertainty calls for ongoing research, collaboration, innovation, experimentation learning and adaptability. The core

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50 IESO *Pathways to Decarbonization* (December 15, 2022), pp. 35-36.

51 IESO *Pathways to Decarbonization* (December 15, 2022), p. 36.

52 IESO *Pathways to Decarbonization* (December 15, 2022), p. 30.

53 IESO *Submission on the Proposed Clean Electricity Regulations* (November 2, 2023), p. 2.

> focus of our collective efforts should be to approach transformation of our energy system and broader economy with an open mind.[54]

32. Furthermore, for natural gas generation, the draft Clean Electricity Regulations provide for various compliance methods which the natural gas generation facilities forming part of the Project demand would adopt. Given the formidable challenges, there is also an emergency element being proposed to enable natural gas generators to come online, which could still reflect their peak demand for capacity.[55] Also, as noted in the P2D:

    a. It is assumed that hydrogen is a cost-effective resource for reducing peak demand, although considerable uncertainty remains around cost assumptions for various fuels over the P2D time period.[56]

    b. The new demand profile has up to three ramps per day of 6,000 MW to 10,000 MW, representing a significant operability challenge for the IESO.[57]

    c. It is assumed that there would exist a heavy reliance on low-carbon fuels for intermediate, peaking and flexibility needs, for which there are currently no like-for-like replacement for the operating characteristics of natural gas, since low-carbon fuels do not yet exist at scale and there are many barriers to commercialization.[58]

33. As a result of the forgoing, Enbridge Gas has appropriately considered energy transition from the perspective of the Project and the Panhandle System.

C. Enbridge Gas Correctly Applied EBO 134

(i) The Project is Exclusively a Transmission Facility

34. Enbridge Gas submits that EBO 134 as constituted is the appropriate economic test to apply to the Project, as the Project consists entirely of transmission pipeline infrastructure to which distribution customers do not directly connect.[59]

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54 *Ontario's Clean Energy Opportunity: Report of the Electrification and Energy Transition Panel*, "Final Reflections", (January 19, 2024).

55 Hybrid Hearing Transcript Vol. 2, p. 179.

56 IESO *Pathways to Decarbonization* (December 15, 2022), p. 29.

57 IESO *Pathways to Decarbonization* (December 15, 2022), p. 27.

58 IESO *Pathways to Decarbonization* (December 15, 2022), p. 32.

59 Exhibit I.STAFF.25(b).

35. This is consistent with the definition set out within the Facilities Handbook[60] (which was last updated by the OEB in March 2022, less than 2 years ago) and, in turn, from a regulatory perspective, Enbridge Gas generally defines transmission pipelines as those pipelines where no distribution customers are directly connected.[61] As a transmission project, the Project will increase capacity on the Panhandle System to meet forecast demand throughout the Panhandle Market.[62] While the demand underpinning the need for the proposed Project is informed by customer demand throughout the area of benefit, there will be no customers directly connecting to the proposed Project.[63] The proposed Project will enable the transportation of natural gas for the benefit of all natural gas customers within the Panhandle Market.[64]

36. In contrast, distribution pipelines benefit a very specific customer or set of customers. Distribution projects, in comparison, generally provide customer premises with direct access to natural gas through pipelines that convey natural gas to individual (customer) service lines or other distribution lines.[65]

37. As aptly described during the hearing:[66]

> *MR. GILLETT: That's right. And so, I think there's a key, key thing that we need to understand, though, is a difference between transmission lines and distribution systems and distribution lines. If you picture the natural gas network, picture it like a tree you got the trunk, the very thick trunk of the tree and it branches off into ever smaller branches that's essentially the natural gas system.*
>
> *The trunk of the system, something like the Panhandle transmission lines, they feed all those branches. Every time you branch off it becomes easier and easier to determine the hydraulic impact that a customer will have. So, the [HAF] specifically that you raised is a mechanism where we can allocate costs for one of those branches because we are able to actually isolate geographically the impact that that customer will have and what*

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60 EB-2022-0081, OEB Natural Gas Facilities Handbook, pp. 27-28.
61 Exhibit JT1.2.
62 Exhibit JT1.3.
63 Exhibit JT1.3.
64 Exhibit I.STAFF.25.
65 Exhibit JT1.2; Exhibit JT1.3.
66 Hybrid Hearing Transcript Vol. 2, p. 8.

> *facilities it will actually use. But the closer you get to the trunk of the tree you can't really do that.*

38. FRPO asserted that Enbridge Gas adjusted definitions to "suit its purposes", as it did for the definition of hydraulics.[67] It proceeded to state that "just because Enbridge Gas defines something, that does not make it so" and its alleged cherry-picking of definitions should not form the basis of the OEB rejecting the requirement for CIAC.[68] Although this is not explicit, Enbridge Gas assumes that FRPO's allegations are predicated on Mr. Gillett's testimony that the Company's adopted definitions for transmission and distribution in a regulatory context may not always align with how these terms are defined in other contexts, such as in an engineering or modelling context.[69] Enbridge Gas rejects that it adopted any definition – particularly for transmission – for self-serving means. Rather, as set out above, Enbridge Gas has classified the Project as a transmission project in accordance with the relevant definition provided in the Facilities Handbook. Further, as set out below, this approach is consistent with Enbridge Gas's OEB-approved approach in other leave to construct applications. In Enbridge Gas's view, in a leave to construct proceeding before the OEB, adopting the definition endorsed by the OEB in the Facilities Handbook – i.e., a regulatory policy and guidance document – is appropriate. The Facilities Handbook sets out that "[t]he OEB expects applicants to file these applications in a manner that is consistent with this Handbook, unless they can demonstrate a cogent rationale for departing from it."[70] Enbridge Gas notes in spite of FRPO's allegations, FRPO fails to explain why any alternative definition would be more appropriate in the circumstances.

(ii) The Project is Not Distribution or Dual Function

39. Opposing intervenors and OEB Staff assert that the Project benefits an identifiable set of contract customers and on this basis the Project should be considered a dual

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[67] FRPO Submissions, pp. 15-16.
[68] FRPO Submissions, pp. 15-16.
[69] Hybrid Hearing Transcript Vol. 2, p. 16.
[70] EB-2002-00821, Natural Gas Facilities Handbook (March 31, 2022), p. 4.

transmission/distribution line or a distribution line[71]. These submissions are incorrect as they fail to consider the fundamental nature of a transmission pipeline in that it serves a transmission system as a whole and the capacity will invariably serve and impact all downstream distribution customers supported by the transmission system. The Opposing Intervenors also incorrectly apply the OEB's Kingsville Decision (EB-2018-0013) to the current facts before the OEB in an effort to argue that the Project is dual function.

40. All transmission pipelines ultimately support distribution systems. If they did not, the natural gas they transport would have no ultimate destination and no one would have natural gas service. This does not make a transmission facility dual function (distribution and transmission). The very nature of a transmission pipeline is that it provides natural gas to a broad geographic region comprised of multiple distribution systems through which a large number of both contract and general service customers are served.[72]

41. All customers, both incumbent and incremental, benefit from transmission pipelines that make up Enbridge Gas's system overall. It is because of this that the costs of transmission pipelines are allocated to all customers and not to specific customers. This is also the case for transmission projects that increase the capacity of a transmission system serving a broad geographic area, like the Panhandle System.

42. The Project partially alleviates the largest Panhandle System bottleneck.[73] Partial alleviation of the transmission bottleneck improves the reliability of natural gas service for existing customers and will allow for growth among both existing and new customers on the Panhandle System. By partially looping the existing transmission system, the Project facilities will also provide operational flexibility to maintain service to customers should that portion of the existing transmission system experience operational or integrity issues in the future.[74]

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[71] OEB Staff Submissions, p. 40; EP Submissions, p. 4 ; PP Submissions, p. 19.
[72] Exhibit JT 1.3.
[73] Exhibit B, Tab 2, Schedule 1, pp. 13-14.
[74] Exhibit I.STAFF.25.

43. Transmission system capacity is available on a "first come first served" basis. Existing contract and general service customers already attached to the system will benefit from the capacity created by the Project since they will have the ability to leverage the capacity that is available after the Project is placed into service. This could occur because of an existing commercial/industrial customer's economic growth or a decision to convert interruptible service to firm. That customer may not have participated in the EOI, but it will benefit no less than those new and existing customers that participated in the EOI. The proposed Project will serve all existing and future customers whether or not they participated in the EOI, including general service customers.

44. In this regard, intervenors and OEB Staff have elevated the EOI's purpose beyond what was originally intended. Although the demand forecast is based on contract customers who responded to the EOI, these are not the only customers that will benefit from the capacity created. Customers that did not respond to the EOI will have the ability to connect to the system using any capacity that is available at the time of their request. The timing of when commercial, industrial, and power generation customers are in a position to express their needs for natural gas service do not always align with the timing of Enbridge Gas's EOI process. As a result, the EOI results are only a point-in-time snapshot of customer demand.[75] As has been demonstrated over the last decade, both expected and unexpected growth in the Panhandle Market has continued to materialize as new customers attach to the natural gas system. As these new customers request natural gas service, it is important that Enbridge Gas has the ability to accommodate them in a timely and economic manner.[76]

45. The EOI was intended simply as a way to gather market intelligence to form the basis of a demand forecast on which Enbridge Gas could rely on to conservatively plan the Panhandle System over the next 5 years. The results of the EOI represent the participating customers' forecasts of their future needs at a point in time, while the actual volume, location and timing of their requirements may differ from their EOI submissions.

[75] Exhibit I.STAFF.25.
[76] Exhibit I.STAFF.25.

Furthermore, customer demand that was not submitted in the EOI can and will materialize. For example, Stellantis did not participate in the EOI initiated in 2021 despite having since attached to the natural gas system.[77] This potential occurs because the Project creates capacity on a "first come first serve" basis across a broad geographic area. It is not contained to particular distribution laterals, service areas, or customers locations.

46. The EOI is an appropriate tool to evaluate future demand as part of fulfilling Enbridge Gas's obligation to serve and to rationally plan to fulfill that obligation in a timely and efficient manner. Instead of recognizing the EOI as an appropriate planning tool, the Opposing Intervenors and OEB Staff have used the EOI results to conclude that the respondents are a definitive and specific group of customers that will enter into contracts and drive demand.[78] This is a mischaracterization. These are respondents that are indicative of future demand by contract customers as a group. However, whether it is those specific customers that ultimately contract for the incremental capacity is uncertain.

47. It is reasonable to state that the EOI provides a sufficient indication of interest to reasonably conclude that contract demand customers will require the Project. However, it remains to be seen whether those EOI customers will be the actual contracting parties for the incremental capacity and, given the scope of the Panhandle System and the basis on which capacity can be taken, it is an oversimplification and inappropriate characterization of a transmission system to assert that the beneficiaries of the incremental capacity are readily identifiable.

48. IGUA, EP and OEB Staff incorrectly attempt to draw a parallel between the Project and the OEB's Kingsville Decision (EB-2018-0013) in an attempt to assert that the Project is a dual transmission and distribution pipeline. In particular, these Intervenors and OEB Staff ignore the fact that the OEB ruled in that proceeding that EBO 134 was appropriately applied. Instead, they rely on the OEB's finding that the pipeline in question was dual function since in the OEB's view the pipeline in question had ancillary

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[77] Exhibit B, Tab 1, Schedule 1, p. 5.
[78] IGUA Submissions, para. 86.

distribution benefits in addition to the transmission functions and had firm and negotiated customer contracts reliant on the approval of the Project.

49. However, key important facts, which the OEB had before it in the Kingsville Application, need to be understood as the Kingsville Application is distinguishable from the current proceeding. It is unreasonable to draw a comparison between the Kingsville Project and the Project and to conclude that the Project is both transmission and distribution.

50. First, the Kingsville Reinforcement Project consisted of a new high pressure NPS 20 lateral pipeline extending from the NPS 20 Panhandle pipeline towards the Kingsville area whereas the Project is intended to reduce the pressure drop along the existing NPS 20 Panhandle pipeline using an NPS 36 pipeline loop. As stated during the hybrid hearing:

> *MR. LADANYI: Well certainly the Board saw it that in the project, the Kingsville project was both transmission and distribution. I am putting to you that Panhandle project that we are currently discussing is also transmission and distribution. It's both.*
>
> *MR. GILLETT: No it's not. This project is purely a transmission project. <u>The Kingsville reinforcement project had to do with a high pressure lateral off the system, so back to my tree analogy from this morning it was one of these branches off of the trunk.</u> This one [the Project] is reinforcing the trunk of the system. So, there are no distribution facilities as part of this project at all.[79] [Emphasis added]*

51. Furthermore, a key aspect of the Kingsville Reinforcement Project was that it was advanced from 2020 to 2019. Moving the Kingsville Reinforcement Project from 2020 to 2019 alleviated a distribution constraint and offset the installation of significant distribution system facilities that would no longer be required. By advancing the Kingsville Reinforcement Project from 2020 to 2019, $10.4 million of distribution reinforcement costs were avoided.[80] This is a key part of the ancillary distribution

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[79] Hybrid Hearing Transcript Vol. 2, pp. 113-114, lns 19-28, lns 1-2.
[80] EB-2018-0013, Enbridge Gas Response to Board Panel Question 3 (July 9, 2018).

benefits referenced by the OEB in that proceeding. No similar circumstances exist for the Project.

52. Failing to consider the Kingsville Reinforcement Project in a comprehensive manner, the Intervenors and OEB Staff focus only on and draw a comparison between the customers contracting for increased capacity for the Kingsville Reinforcement Project and the respondents to the EOI for the Project. This is the only basis that they assert the Project has a distribution function and is thereby dual function. However, this again is a mischaracterization of a distribution function. Just because the end-use customer receives a distribution service does not mean that the Project, to which no customer directly connects, is operating in any functional manner as distribution. The Opposing Intervenors are incorrectly conflating a form of regulated service for in-franchise distribution customers (distribution service) with the functioning of the Panhandle System (a transmission system) of which the Project is a part. As stated:

> *MR. LADANYI: But you're offering a distribution function on it. We just saw that from your reverse open season document.*
>
> *MR. GILLETT: To be clear, the way that customers receive service in our system, in-franchise customers, is through distribution services. Ultimately the capacity that feeds those distribution systems comes from a transmission system.*
>
> *So this project is purely a transmission reinforcement to provide more capacity to the broader Panhandle system. <u>That capacity in that broad system will ultimately be used by customers under provision of a distribution service. So I don't think we should be mixing how the rates are regulated and services are regulated with the OEB versus what this project is, which is a transmission facility. Our in-franchise customers, the only way they get service from us is through distribution contracts.</u>*[81] *[Emphasis added]*

53. While use of the OEB's Kingsville Decision as an example of a dual function pipeline is not appropriate with respect to the Project, Enbridge Gas does note that the key finding of the OEB's Kingsville Decision is that EBO 134 was properly applied since no customers

[81] Hybrid Hearing Transcript Vol. 2, p. 115, lns 1-14.

were connected to the pipe in question. This is the one aspect that is appropriate to consider with respect to the Project.

54. The most appropriate comparison to the Project are the facilities approved in EB-2016-0186 Panhandle Reinforcement Project ("Panhandle Reinforcement Project"). That Application was for leave to construct of approximately 40 kilometers of NPS 36 pipeline from Union's Dawn Compressor Station in the Township of Dawn-Euphemia to its Dover Transmission Station in the Municipality of Chatham-Kent. The NPS 36 pipeline was a replacement of the previous NPS 16 Panhandle pipeline within the Panhandle System. Customers were not connected to the pipe in question, but the Panhandle Reinforcement Project was needed to satisfy the majority of the requests for firm contracts from greenhouse customers in the Leamington-Kingsville area.

> *MR. MONDROW: Okay. Could we go to your opening day presentation just to orient this, if we could. So, this was maybe it was even -- it was replacement of an existing line with a new NPS 36 line, as I recall, from Dawn compressor station down to Dover transmission station?*
>
> *MR. GILLETT: Yes, that's correct. So, in my analogy earlier this was basically expanding the size of the tree trunk by doing what we call a lift and lay where we pulled out the existing 16-inch and put in a new 36-inch which created capacity all along the Panhandle system, very similar to what we are looking at doing today.*
>
> *MR. MONDROW: And, again, this was driven primarily by continued growth in the Leamington-Kingsville greenhouse market?*
>
> *MR. MACPHERSON: In this application the forecast demands were for greenhouses and other mass market forecast demand in the Panhandle region.*
>
> *MR. MONDROW: The majority of the requests that drove the project were for firm contracts from greenhouse customers from Leamington-Kingsville; is that correct?*
>
> *MR. MACPHERSON: Subject to check, I believe that's correct that they were predominant.*[82] *[Emphasis added]*

[82] Hybrid Hearing Transcript Vol. 2, p. 20, lns 3-24.

55. Like the Project, the Panhandle Reinforcement Project had no operational distribution functions and customers taking capacity were all in-franchise customers and received OEB-approved distribution services according to their need and classification. As a result, EBO 134 was appropriately applied by the OEB and the same should occur with respect to the Project.

56. In submissions, IGUA referred to various leave to construct applications and the application of either EBO 134 or EBO 188 and because of various factual circumstances asserted that Enbridge Gas was using various exemptions in an effort to avoid charging the "36 specifically identified" customers a CIAC. As noted above, there are not "36 specifically identified" customers since those identified are EOI participants and the actual customers taking capacity are to be identified over time on a "first come first served" basis throughout the Panhandle Market. IGUA is incorrect in this regard. IGUA is also incorrect in asserting that Enbridge Gas is somehow construing EBO 134 in a manner to avoid the charging of a CIAC. Instead, Enbridge Gas has taken a consistent approach to match the function with the appropriate test in applying EBO 134 and EBO 188.

> *MR. MACPHERSON: I would say the beginning point of our evaluation of what economic test to apply begins with that initial determination of what type of project it is. Is it a transmission project or is it a distribution project? And then we follow through…*[83]
>
> ***
>
> *MR. MONDROW: You say EBO 134 applies only to transmission. Right?*
>
> *MR. MACPHERSON: That is our interpretation.*
>
> *MR. MONDROW: So you first determine whether you have a transmission project or a distribution project, and then, if it's a transmission project, you then turn to EBO 134. Right?*
>
> *MR. MACPHERSON: Not necessarily.*
>
> *MR. MONDROW: Okay. When don't you?*

[83] Hybrid Hearing Transcript Vol. 1, p. 171, ln. 9.

> *MR. MACPHERSON: We wouldn't turn to 134 if the purpose of the transmission project was for a community expansion project. We wouldn't turn to 134 if the purpose of the project was for a single customer on a dedicated lateral connecting and driving the project. We wouldn't use 134 if specifically exempted from application based on funding of the provincial government, as is the case in the community expansion funding in some cases. <u>We would look at the particulars of the case before we would go further in that determination.</u>[84][Emphasis added]*

57. As is reflected in the testimony summarized in Table 1 below, for more than a decade Enbridge Gas has maintained a consistent approach to the application of EBO 134 and EBO 188 and the OEB has subsequently affirmed the correctness of that approach in a consistent manner in each of the decisions referenced by IGUA.[85]

<u>Table 1: Enbridge Gas Leave to Construct Summary</u>

Case	Facility Type	Policy Applied	Enbridge Gas Testimony Summary
EB-2012-0431 (Leamington Expansion 1)	Distribution (NPS 12 high pressure distribution loop)	EBO 188	The project was not a transmission expansion. It was a high-pressure distribution expansion.[86] It is part of the overall system, but it is a transmission lateral, which is one of the main branches that then branches off into distribution systems.[87] Because the project was a high-pressure distribution loop, Enbridge Gas was able to develop an Hourly Allocation Factor ("HAF").[88]
EB-2016-0013 (Leamington Expansion 2)	Distribution (NPS 12 transmission lateral loop)	EBO 188	This was an NPS 12 looping a transmission lateral[89] and was a distribution project.[90] Enbridge Gas used the HAF because the hydraulic impact was stable. The level of interest was such that there was more interest than capacity which was prorated between customers with capacity sold out almost immediately.[91]
EB-2016-0186 (Dawn to Dover)	Transmission (NPS 36)	EBO 134	This project replaced an existing NPS 16 transmission line with a new NPS 36 line. It was expanding the size of the "tree trunk" by conducting

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[84] Hybrid Hearing Transcript, Vol. 1, pp. 171, ln 20 – p. 172, ln 10.
[85] IGUA Submissions, para. 56.
[86] Hybrid Hearing Transcript Vol. 2, p. 11, lns 14-15.
[87] Hybrid Hearing Transcript Vol. 2, p. 11, ln 28 – p.12, ln 23.
[88] Hybrid Hearing Transcript Vol. 2, p. 14, ln 21 – p.15, ln 19; p. 16, ln 28 – p.17, ln 3.
[89] Hybrid Hearing Transcript Vol. 2, p. 19, lns 15-20.
[90] Hybrid Hearing Transcript Vol. 2, p. 19, lns 12-14.
[91] Hybrid Hearing Transcript, Vol. 2, p. 19, lns 1-14.

			a lift and lay, creating capacity all along the Panhandle System.[92]
EB-2018-0013 (Kingsville Reinforcement)	Transmission (NPS 20 transmission lateral)	EBO 134	This was a transmission project filed under EBO 134.[93] See further submission above. [94]
EB-2018-0188 (Chatham-Kent Rural)	Distribution (NPS 12 and NPS 8 transmission pipeline)	EBO 188	This was classified as a distribution project under unique circumstances[95] related to the Ministry of Infrastructures Natural Gas Grant Program ("NGGP") as part of the community expansion initiative requiring that the application be filed under EBO 188 to receive public funding.[96] Although it served a transmission function,[97] it is not comparable to the Panhandle transmission lines in terms of size and length and impact. It has an isolated area of benefit that is very rural and is not high density and based on the hydraulics Enbridge Gas was able to develop a HAF based on the area of benefit.[98]

58. Notwithstanding the foregoing, IGUA has proposed that the OEB abandon any alignment between the functional aspects of distribution and transmission and the application of EBO 134 and in so doing abandon entirely the use of the EBO 134 three-part test. Instead, IGUA suggests that the OEB should focus only on (i) precluding "*undue*" rate increases for existing customers, and (ii) whether the use of a proposed facility will be dominated by one or more large volume customers and CIAC will preclude "*undue*" subsidies from existing to new customers.

59. IGUA incorrectly abandons the alignment between the functional aspects of distribution and transmission solely on the basis that the original decisions relating to EBO 134 and EBO 188 do not reference transmission or distribution. However, IGUA has taken a very restrictive reading of the OEB's policies in this regard and ignores the many OEB

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[92] Hybrid Hearing Transcript, Vol. 2, p. 19, ln 28 – p. 20, ln 13.
[93] Hybrid Hearing Transcript, Vol. 2, p. 25, lns 1-4; p. 26, lns 7-9.
[94] See paras. 48-53 of these submissions for a discussion on the Kingsville Reinforcement Project.
[95] Hybrid Hearing Transcript, Vol. 2, p. 29, lns 17-18; p. 29, ln 27 – p. 30, ln 2.
[96] Hybrid Hearing Transcript, Vol. 2, p. 29, ln 19 – p. 30, ln 18.
[97] Hybrid Hearing Transcript, Vol. 2, p. 30, ln 22 – p. 31, ln 2.
[98] Hybrid Hearing Transcript, Vol. 2, p. 29, ln 19 – p. 31, 14; p.32, lns 14-20.

decisions applying the respective policies and the clear statements made in the Facilities Handbook. The OEB has clearly aligned the functional aspects to a pipeline in question with the applicable policy basis and consistent with that Enbridge Gas applies the case-by-case approach set out above.

60. IGUA justifies its position of abandoning the functional aspect for purpose of EBO 134 and EBO 188 by parsing the statements of Mr. Macpherson in testimony. IGUA relies on the following statement of Mr. Macpherson:

> *… if there was shared infrastructure where there's some upstream segment and there was several downstream customers connecting distribution customers, then we would be looking potentially to apply something like the hourly allocation factor to apportion those costs to those connecting customers.*[99]

61. However, this statement must be considered in its full context. The statement was actually a clarification of a question asked by Mr. Mondrow and was not a statement of fact. The full statement is as follows:

> *MR. MACPHERSON: <u>To be clear, I mean, I am trying to parse out the example of what you're asking of us</u>, which is if there was shared infrastructure where there's some upstream segment and there was several downstream customers connecting distribution customers, then we would be looking potentially to apply something like the hourly allocation factor to apportion those costs to those connecting customers. <u>If that's what you're asking?.</u>*[100]

62. In any event, IGUA fails to consider the entire context of the clarification sought by the witness and by subsequent testimony. As articulated later in Mr. Mondrow's examination by Mr. Gillett.

> *MR. GILLETT: …. The trunk of the system, something like the Panhandle transmission lines, they feed all those branches. Every time you branch off it becomes easier and easier to determine the hydraulic impact that a customer will have. So, the [HAF] specifically that you raised is a mechanism where we can allocate costs for one of those branches because*

[99] Hybrid Hearing Transcript Vol. 2, p. 5, lns 11-16.
[100] Hybrid Hearing Transcript Vol. 2, p. 5, lns 9-16.

> *we are able to actually isolate geographically the impact that that customer will have and what facilities it will actually use. But the closer you get to the trunk of the tree you can't really do that.*
>
> *And so what we are talking about here is a project that, essentially, is reinforcing the trunk of that tree, it can serve any customer within that network. And so, it becomes virtually impossible to actually calculate a CIAC and figure out how much of the capacity they are going to be using on a forecast basis. So, hopefully that made sense.*[101]

63. IGUA's restrictive interpretation of the application of EBO 134 to abandon the functional aspect of transmission or distribution should not be accepted by the OEB.

(iii)EBO 134 and EBO 188 Have Been Misinterpreted and Can Be Reconciled

64. Based on IGUA's restrictive interpretation of EBO 134, IGUA has asserted the proposition that EBO 134 does not apply to the Project as EBO 134 and EBO 188 were developed to apply to system expansion to new communities and the Project is not such an expansion.[102]

65. With respect to IGUA's first proposition, IGUA ignores the key parts of EBO 134 to conclude that EBO 134 and EBO 188 cannot be reconciled and that both only apply to community expansion such that EBO 134 does not apply to the Project.[103] In doing so, IGUA (and other Opposing Intervenors) parses the wording of EBO 134 and EBO 188 decisions and ignores the evolution of OEB policy from EBO 134 to EBO 188 and the various leave to construct decisions made by the OEB, together with the relevant parts of the Facilities Handbook. The latter states explicitly that EBO 134 applies to transmission where no customers are connecting to the pipe in question. In doing so, IGUA fails to recognize that EBO 134 and EBO 188 together with the Facilities Handbook are entirely reconcilable.

[101] Hybrid Hearing Transcript Vol. 2, p. 8, ln 15 – p. 9, ln 3.
[102] IGUA Submissions, paras. 31 and 51.
[103] IGUA Submissions, para. 47.

66. To appropriately reconcile the policy elements, both EBO 134 and EBO 188 must be seen within the broader basis from which they arose.

67. The EBO 134 Decision resulted in two separate but related aspects: (i) the test for economic feasibility under Part 6 of the Decision; and (ii) the issue of any subsidy under Part 7 of the Decision.

68. Regarding economic feasibility, the OEB found at:

- Paragraph 6.72 that the three-stage test should apply – in particular: "*The Board finds that Union's three-stage test has considerable merit.*"
- Paragraph 6.76 that the three-stage test is cumulative in its application; "*If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, <u>then stages two and three must be completed before the project can be said to be fully evaluated.</u>*" *[Emphasis added]*
- Paragraph 6.79 that it is appropriate that existing customers subsidize through higher rates, if not undue – "*The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, <u>financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.</u>*" *[Emphasis added]*

69. Under Part 6, there is no reference to imposing a CIAC to avoid such subsidization.

70. Quite separate from the OEB's determination of economic feasibility in establishing the public interest, Part 7 of the EBO 134 Decision dealt with the issue of the subsidy but not in a general sense, rather in a limited and specific manner. At paragraph 7.1, the OEB stated: "*This section considers the potential expansion available and who should be required to make the contribution or provide the subsidy should it be required.*"

71. Regarding potential expansion, paragraphs 7.3 to 7.5 of the Decision speak specifically of the various communities to which expansion was possible.

72. At paragraph 7.29, *"The Board finds that a contribution-in-aid of construction should be required for those projects where the sole purpose is to supply natural gas into a new area and where the evaluation process demonstrates an undue burden on existing customers."*

73. Paragraph 7.29 is the paragraph that is relied on by Opposing Intervenors to argue that a contribution is possible under EBO 134.[104] However, the Opposing Intervenors have taken this paragraph out of context and as noted below it is intended for a limited purpose of community expansion and not for general application.

74. Further clarifying the contribution and its application to community expansion, the OEB stated at paragraph 7.30 "*The Board would expect an agreement to be reached* <u>*between the utility and the community regarding the contribution*</u> *before an application is made to the Board.*" *[Emphasis added]*

75. EBO 134, therefore, as originally proposed established two key aspects. First, in general, ratepayers would subsidize projects through rates with the application of the three-stage test. Second, a recovery of a contribution was possible if the project was an expansion to a new community.

76. This latter aspect was further refined and supplemented by EBO 188. A focus of EBO 188 was the OEB's *Interim Report of the Board*. In particular, EBO 188 made the following reference: "*An Interim Report of the Board ("Interim Report") was issued on August 15, 1996. In that Interim Report the Board made a determination of the issues and set out the principles that would apply to system expansion projects.*" (paragraph 1.1.8) Included within the Interim Report's conclusions was the following:

> "*The Board recognizes that subsidization can be measured at both the project and portfolio level.* <u>*An overall rolling portfolio P.I. of 1.0 means that existing customers will not suffer a rate increase over the long term as a result of distribution system expansion.*</u> *The Board is therefore of the view that an overall portfolio P.I. of 1.0 or better (emphasis added) is in the public interest.*" *[Emphasis added]* (paragraph 2.1.1)

77. Contrary to the assertion of IGUA, based on the foregoing one could conclude that the focus of EBO 188 was the expansion of distribution pipelines.

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[104] IGUA Submissions, paras. 39 and 59.

78. Under Part 4 of EBO 188, the OEB considered customer connection and contribution policies. In this regard, the OEB concluded at paragraph 4.3.3:

> "*The Board directs the utilities to prepare and maintain a common set of Board approved customer connection policies that shall, as a minimum, include:*
>
> *i.* *the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges; and*
>
> ii. *the circumstances where the use of a proposed facility will be dominated by one or more large volume customers for which the utilities will retain the option of collecting contributions in aid of construction. The contribution amounts will be consistent with the cost allocation for such mains and accordingly based on the peak day demand and the cost allocators used by each of the utilities." [Emphasis added]*

79. This finding has been referred to by intervenors, in particular IGUA.[105] However, Intervenors do not refer to the paragraph appearing immediately prior to this finding. At paragraph 4.3.2, the OEB stated that:

> "*The Board recognizes that Union and Centra have been applying a P.I. threshold of 0.8 for the collection of customer contributions for new community attachments. The Board also notes that the utilities proposed this level as the basis for determining the treatment of customers currently paying periodic contributions. In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve a minimum threshold P.I. of 0.8 for inclusion in a utility's Rolling Project Portfolio." [Emphasis added]*

80. Taking paragraphs 4.3.2 and 4.3.3 together, EBO 188 provides for the comprehensive treatment of distribution connections: (i) community expansion (paragraph 4.3.2); (ii) service line connections (paragraph 4.3.3) and (iii) facilities dominated by one or more customers (paragraph 4.3.3). EBO 188 effectively supplants the contribution findings applicable to community expansion in paragraph 7.29 of Part 7 of EBO 134 and

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[105] IGUA Submissions, para. 46.

does so in the distribution context. EBO 134, following the creation of the EBO 188, applies not to community expansions where a contribution could be obtained, but to all transmission expansions that are the subject of Part 6 of EBO 134 which permits the subsidy to be paid by existing ratepayers assuming the three-part test is satisfied. The foregoing is wholly consistent with the Facilities Handbook and as such each of EBO 134, EBO 188 and the Facilities Handbook are reconcilable. Contrary to the assertions of IGUA, EBO 134 is not limited to community expansion. Enbridge Gas's application of the OEB's policies is consistent with the foregoing and Enbridge Gas submits the Project is appropriately classified as a transmission project and EBO 134 applies.

(iv) A CIAC is Not Part of the EBO 134 Evaluation

81. IGUA also asserts the proposition that the determination of the overall public interest is separate from the determination of whether a burden on other customers is undue and whether a CIAC should be imposed, if found to be undue. Enbridge Gas submits that IGUA has mischaracterized EBO 134 and the nature of the burden that would inform the OEB as to whether a subsidy is undue and in so doing, has made the consideration of a CIAC part of the evaluation process under EBO 134. Enbridge Gas submits that based on EBO 134, the consideration of a contribution is not part of the evaluation process. The consideration of a contribution is not a replacement for a full consideration of the public interest or the nature of the burden. This is because it is only after ruling that a project is in the public interest (notwithstanding a subsidy under Stage 1) would the OEB know whether the project in question was economically sustainable and only then in the context of the public interest can the burden be assessed.

82. In this regard, IGUA and PP state that nothing in EBO 134 precludes the imposition of a CIAC in support of an uneconomic expansion project and that CIAC are appropriately considered in an EBO 134 evaluation.[106] IGUA relies on the above noted paragraph 7.29 of EBO 134, which Enbridge Gas submits applied only to community expansion projects

[106] IGUA Submissions, para. 38; PP Submissions, p. 19.

and is now supplanted by EBO 188 and is not part of the evaluation set out in Part 6 of EBO 134. CIAC form no part of the evaluation process under Part 6 of EBO 134. PP relies on Mr. Macpherson's testimony in support of its position that "…Enbridge [Gas] has confirmed that there is nothing in EBO 134 that would exclude consideration of a CIAC."[107] PP is taking Mr. Macpherson's testimony out of context and is mischaracterizing his evidence. Mr. Macpherson testified that section 7.29 of EBO 134 "can be interpreted to be explicit by including what is – where it does imply".[108] His testimony should be interpreted to mean that the explicit availability of CIAC in paragraph 7.29 of EBO 134 can be interpreted to mean that CIAC are not available in other circumstances, where they are not explicitly contemplated. Second, the line of questioning that gave rise to Mr. Macpherson's testimony asked for textual support "in the decision [EBO 134]", in isolation, for Enbridge Gas's position.[109] It is important to note that the questioning was unfairly limited to only the wording of EBO 134 and ignored various OEB applications and interpretations, together with policy statements, that have been made since the EBO 134 Decision.[110] The testimony was limited to that isolated text of the decision without regard to the evolution of OEB policy in other documents, which is described above.

83. Pursuant to EBO 134, the following steps are to be followed by the OEB in the evaluation process:

1. Accept a project by evaluating all three stages of the three-stage test such that (i) if the project passes Stage 1, evaluate if any costs or disadvantages under Stage 2 and 3 disqualify the project, and (ii) if the project fails Stage 1, then Stages 2 and 3 must be completed to fully evaluate the project. (paragraph 6.76)

2. Based on the foregoing, determine if the project is in the public interest.

3. If the project is in the public interest and is financially non-sustaining such that a subsidy is required through higher rates, assess "if the subsidy does not cause an undue burden on any individual, group or class". (paragraph 6.79)

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107 PP Submissions, p. 19.
108 Hybrid Hearing Transcript, Vol. 1, p. 175.
109 Hybrid Hearing Transcript, Vol. 1, p. 175.
110 Hybrid Hearing Transcript, Vol. 1, p. 168.

84. With respect to the latter aspect as to the nature of the burden, an undue burden is in relation to "any individual, group or class" and it is not in relation to the generalization of "any burden" as suggested by IGUA.[111]

85. Only after the determination of whether the project is in the public interest notwithstanding the subsidy and a finding that the subsidy creates an undue burden on any individual, group or class, would the project be non-sustaining since no ratepayer funding would be available. At that time, either the applicant or the OEB at the request of the applicant could consider alternative funding such as a contribution, but this is external to the EBO 134 evaluation process and any determination of the public interest or the nature of the burden.

86. Opposing Intervenors have attempted to skip this process and make the consideration of a contribution a part of the evaluation process which it is not. The consideration of a contribution or the form that a contribution could take is irrelevant to the evaluation process under EBO 134. What is relevant is the full consideration of the public interest and the consideration of any subsidy within that entire context.

D. Enbridge Gas Correctly Applied the EBO 134 Three-Stage Test

87. The Opposing Intervenors challenge Enbridge Gas's application of the three-stage test prescribed by EBO 134 and in so doing, propose changes to the test. OEB Staff accept the results of the three-part test and agrees that the Project is in the public interest. However, OEB Staff also suggest changes, which may impact particular stages but not the overall outcome of the three-stage test. Each stage, together with the Opposing Intervenor and OEB Staff submissions, will be considered in turn below.

[111] IGUA Submissions, para 39.

(i) Stage 1: No Basis That the Project Will Be Underutilized or Stranded

88. The result of Enbridge Gas's Stage 1 calculation is -$150M. The Opposing Intervenors assert that Enbridge Gas has underestimated the Stage 1 result because Enbridge Gas failed to account for the impacts of energy transition on natural gas demand.[112]

89. There is no basis to believe the Project will be underutilized or stranded.[113] To this end, Enbridge Gas relies on its submissions provided Part B above.

90. Also, in respect of the Stage 1 calculation, Opposing Intervenors argue that instead of applying the 40-year revenue horizon applied under EBO 134, Enbridge Gas should apply a 20-year revenue horizon used under EBO 188.[114] These submissions should not be accepted since they fail to recognize a fundamental distinction between the application of EBO 134 for transmission facilities and EBO 188 for distribution facilities. The fundamental difference between EBO 188 and EBO 134 is that EBO 188 applies where there is a matching or a dedication of capacity and facilities made available by the project. This is because the service is for a known customer or discrete group of customers within a local distribution system or connection. In this circumstance, where that customer or set of customers no longer require service, those distribution facilities may remain unused since another party may not connect to that specific area of the system in the future given the discrete and localized nature of the facilities. However, for a transmission pipeline such as the Project, capacity created by the transmission facilities can be reallocated over time on a "first come first served" basis. Since that capacity can be accessed by anyone throughout the entire Panhandle Market it is unlike a particular lateral or connection as in the distribution context under EBO 188. As such, the revenue horizon is not tied to the particular risk of a connection customer as in EBO 188, and instead reflects the flexibility of the transmission system overall and the appropriate life

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[112] TFG Submissions, paras 74-90; SEC Submissions, paras 16-17.
[113] Hybrid Hearing Transcript Vol. 3, p. 36.
[114] SEC Submissions, p. 8

of the pipeline in question and the capacity it represents. As a result, Enbridge Gas submits that 40 years should apply.

91. Even if the 20-year revenue horizon was applied, the Project remains feasible and in the public interest with the application of Stage 2 and Stage 3 under EBO 134.[115]

(ii) Stage 2: ED/Dr. McDiarmid's Approach Should Not Be Accepted

92. With respect to Stage 2, the Opposing Intervenors primarily rely on the evidence of ED's witness Dr. McDiarmid. Enbridge Gas provided extensive submissions on Dr. McDiarmid's evidence in its Argument-in-Chief,[116] in addition to the Company's reply evidence[117] and interrogatory responses regarding its reply evidence.[118] Enbridge Gas does not propose to repeat those submissions here and adopts those submissions for purposes of this reply. However, there are comments which need to be made in response to ED's submissions relating to Enbridge Gas's Argument-in-Chief submissions.

93. ED disagrees with Enbridge Gas's submission that the result of Stage 2 cannot be less than zero,[119] despite Dr. McDiarmid's acknowledgement that Enbridge Gas's position on the matter may be true.[120] OEB Staff agrees with Enbridge Gas and states that it is appropriate to set a floor of zero for Stage 2.[121] Enbridge Gas reiterates its position within its Argument-in-Chief that the result of Stage 2 cannot be less than zero,[122] and that Dr. McDiarmid's knowledge with regards to economic tests for large infrastructure projects (such as EBO 134) must be considered on the very narrow basis of her expertise (Dr. McDiarmid has no financial designation and does not regularly model or evaluate the viability of large infrastructure projects).[123]

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[115] Argument-in-Chief, para. 75.
[116] Argument-in-Chief, paras. 80-87.
[117] Enbridge Gas Reply Evidence (November 3, 2023), paras. 5-22.
[118] Exhibit I.STAFF.EGIReply.2; Exhibit I.ED.EGIReply.19.
[119] ED Submissions, p. 6.
[120] Exhibit ED-IRR, p. 7.
[121] OEB Staff Submissions, p. 44.
[122] Argument-in-Chief, p. 29.
[123] Argument-in-Chief, para. 87.

94. ED argues that the result of Stage 2 is less than zero because new home developers will install natural gas and homebuyers will be stuck with natural gas and will incur negative energy bill savings each year, compared to electric heat pumps, based on Dr. McDiarmid's analysis.[124] However, this is flawed as there is no reason why homeowners would be prohibited from installing electric heat pumps if they choose.

95. Furthermore, Dr. McDiarmid's negative Stage 2 result relies on the assumption that 100% of residential energy consumers would choose electric heat pumps over all other energy options. However, no evidence was provided by Dr. McDiarmid to support this assumption.[125] Enbridge Gas, however, supported its Stage 2 assumptions with reference to the Company's 2021 Residential Single Family End Use Study. The study observed that, without consideration of any energy system limitations or constraints, most customers (77%) prefer natural gas for home heating in a new home.[126] Based on Enbridge Gas's Stage 2 assumptions, and even with the adoption of Dr. McDiarmid's assumption regarding the efficiency of electric heat pumps, the 20-year Stage 2 result would be positive $79 million.[127]

96. Dr. McDiarmid's negative Stage 2 result also relies on the assumption that electric heat pumps are operationally more cost-effective than natural gas in all general service circumstances and for the entire term of her analysis. However, it is important to note the sensitivity in this assumption with respect to both carbon and electricity prices. A sensitivity analysis related to carbon and electricity prices was not included in Dr. McDiarmid's analysis.

97. Regarding carbon prices, real and meaningful political and public policy risks exist (as described in Section B(iii) of these submissions) and Dr. McDiarmid acknowledged that, as an instrument of public policy, carbon tax as an input can change.[128] Dr. McDiarmid agreed that the carbon price scenarios put to her in cross examination were consistent

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[124] ED Submissions, p. 6.
[125] Exhibit ED-IRR, p. 1.
[126] Enbridge Gas Reply Evidence (November 3, 2023), p. 7; Exhibit I.STAFF.EGIReply.1.
[127] Evidence Gas Reply Evidence (November 3, 2023), p. 6, para 12.
[128] Hybrid Hearing Transcript Vol. 1, p. 101.

with the operation of her model[129] and the results of those scenarios was a reduction in NPV for electric heat pumps from +$4,012 to -$3,516 when the carbon tax was set to zero, and to -$128 when the carbon tax was frozen at 2023 levels (i.e., natural gas is more cost-effective than electric heat pumps, on average).[130] ED's submissions ignore the analysis confirmed by Dr. McDiarmid when it argues that changes to the Federal Carbon Charge would not impact Stage 2 results.[131]

98. Regarding electricity prices, Dr. McDiarmid's Stage 2 analysis assumes that electricity prices will remain constant at current rates throughout the term of her analysis, despite her acknowledgement at the hybrid hearing that the probability of this being true is "low"[132] and her agreement that there will be costs of energy transition and electrification that must be borne in the system cost of electricity.[133]

99. ED and Dr. McDiarmid's misuse of EBO 134 is also evident by ED's submission that adding electricity generation, transmission, and distribution infrastructure costs to Dr. McDiarmid's EBO 134 analysis (to account for the electricity infrastructure costs to support electrification, which was ignored by Dr. McDiarmid)[134] would in fact *improve* the cost-effectiveness of electricity versus natural gas.[135] ED appears to make this assertion on the basis that adding the electricity generation, transmission, and distribution infrastructure costs would be less than adding the natural gas distribution infrastructure costs.[136] ED's submission provides no evidence to support this assertion and ignores publicly available information from the IESO (such as the P2D) regarding electricity infrastructure costs (see Section B(iv) of these submissions).

100. Enbridge Gas submits that ED and Dr. McDiarmid's selective modifications and misuse of EBO 134 should not be accepted. EBO 134 is a test of general application which

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[129] Hybrid Hearing Transcript Vol. 1, p. 101.
[130] Exhibit K1.6, p. 2.
[131] ED submissions, p.7.
[132] Hybrid Hearing Transcript Vol. 1, p. 104.
[133] Hybrid Hearing Transcript Vol. 1, p. 102.
[134] Enbridge Gas Reply Evidence (November 3, 2023), para. 15.
[135] ED Submissions, pp. 8-9.
[136] Natural gas transmission infrastructure costs (i.e., the Project) are already included in Stage 1.

should not be selectively modified on a singular circumstance and without participation from all impacted stakeholders (including existing and prospective customer groups and provincial and municipal economic development groups), many of whom are not before the OEB in this proceeding.

(iii)Stage 3: The Calculated Benefits Are Appropriate

101. With respect to Stage 3, the Project's construction will provide direct and indirect economic benefits to Ontario estimated at approximately $257 million and will create approximately 1,093 jobs.[137]

102. The Opposing Intervenors (particularly SEC and ED) argue that the EBO 134 Stage 3 test presents a biased result that does not provide a full representation of costs and benefits of the Project. This is not correct. Through the application of both Stage 2 and Stage 3 there is a proper assessment of the consequences of the Project. In particular, the Stage 2 and 3 analysis deals with each of the negative consequences that SEC[138] and ED[139] suggested were not considered:

- <u>Underutilization</u>: As noted in Section B above, Enbridge appropriately considered the impacts of energy transition in the context of the Project.
- <u>Carbon Emissions</u>: The cost of carbon is included within the Stage 2 analysis.
- <u>Macroeconomic Impacts</u>: SEC argues that higher rates associated with the recovery of the Stage 1 Project shortfall not recovered in current rates will result in a reduction of economic activity.[140] In effect, SEC is arguing that higher rates will reduce disposable income. However, spread over all of Enbridge Gas's customers as established in the OEB-approved EBO 134 process, the rate impacts do not reflect a material impact on disposable incomes[141] and are clearly outweighed by the material economic impacts ($4.5 billion in direct capital investment and the creation of 6,900 jobs)[142] arising from the investments expected from the greenhouse sector due to the availability of incremental natural gas.

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[137] Exhibit E, Tab 1, Schedule 1, p. 6; Exhibit I.STAFF.25.
[138] SEC Submissions, p. 9.
[139] ED Submissions, p. 9-10.
[140] SEC Submissions, p. 9.
[141] Exhibit I.IGUA.2.
[142] Exhibit E, Tab 1, Schedule 1, p. 6; Exhibit I.STAFF.25.

- Fossil Fuel Subsidy: ED asserts that the Project's approval would also subsidize an unsustainable and carbon-intensive greenhouse sector. ED bases this position on reference to an article about carbon emissions from greenhouses relative to field crops in Mexico included in the evidence of Dr. McDiarmid related to greenhouses. As explicitly noted by ED's legal counsel,[143] Dr. McDiarmid is not an expert related to greenhouse agriculture or the energy options available to greenhouses. Dr. McDiarmid's evidence was merely a vehicle by which ED placed unsubstantiated facts on the record and should not be relied upon by the OEB as proper evidence. ED also questioned the sustainability of the jobs arising from the greenhouse sectors investment. This was ably answered by OGVG's witness:

  MR. ELSON: What do you think is the possibility that, in a net zero future, greenhouses just become a non-viable business?

  DR. PETRO: Food security and food sustainability, I would, say really go against that. Because, if we look at earlier this year in the UK, you could go to a Tesco, which is basically their version of Walmart, and a head of lettuce I think was running about 20 British pounds because there was nothing that they could import. They import from Spain, predominantly. There was a supply chain issue, they have limited local production – I think it's under 50 acres, maybe under 100 acres of greenhouse – and, because of that, prices went up and they were rationing tomatoes, cucumbers, and lettuce. Two out of the three commodities are OGVG commodities.[144] *[Emphasis added]*

- Suboptimal Outcomes and Job Losses: ED submits that the application of the OEB-approved EBO 134 approach will blunt the natural incentive for customers to invest in energy efficiency and electrification. This is not the case. Greenhouse farms have an intense commitment to efficiency and sustainability as both are directly reflected in their ability to operate profitably.[145] They are looking for maximum efficiency for all inputs particularly because they are price takers.[146] ED also asserted that job losses will occur because "spending on gas flows out of province" is a loss to the economy.[147] However, it is not clear what this is in reference to given the Project is part of the Panhandle System serving the entire Panhandle Market.

103. In calculating the Stage 3 result, Enbridge Gas applied an accepted economic multiplier of 0.91.[148] SEC did not challenge the multiplier but did challenge the manner which it

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[143] ED Submissions, p. 13.
[144] Hybrid Hearing Transcript Vol. 3, pp. 155-156.
[145] OGVG Evidence (November 6, 2023), p. 3.
[146] Hybrid Hearing Transcript Vol. 3, p. 149.
[147] ED Submissions, p. 10.
[148] Exhibit I.STAFF.15(e)-(f); Footnote at Exhibit E, Tab 1, Schedule 7.

was applied (i.e., applied to the Project cost).[149] An economic multiplier reflects the economic effect arising from each dollar of investment and the derivation of the economic result is, as the name suggests, determined by the multiplication of the investment by the multiplier. SEC sets up a false narrative that implies the multiplication of the multiplier by the investment level is not appropriate. SEC argues that it is counterintuitive for there to be a greater GDP impact from greater amounts of investment.[150] SEC attempts to conflate the concept of an economic measure with the question of whether the construction costs are prudent. Simply put, SEC believes it is not an appropriate economic measure because an increase in costs implies imprudence and any corresponding increase in benefit is not acceptable because that would imply Enbridge Gas is benefiting from imprudence. The estimated construction cost and the basis on which it has been established is irrelevant to the application and method for deriving the multiplier effect of the investment. The level of the construction cost estimate should be considered separate from the method by which the multiplier effect is determined. Enbridge Gas submits that the forecast Project construction costs is reasonable and should be accepted. Enbridge Gas's submissions in this regard are set out in Section I below.

104. Most notably, when suggesting that Enbridge Gas's Stage 3 benefits are overstated, neither SEC nor ED refer to the $4.5B of direct capital investment that is estimated to be made by customers, and the creation of 6,900 jobs, as a result of the natural gas transmission capacity created by the Project. These economic benefits were not included by Enbridge Gas in its Stage 3 analysis, and on that basis the Company's Stage 3 analysis is in fact conservative. The denial of the leave to construct application as supported by the Opposing Intervenors will deny these significant economic benefits to Ontario and have a profound negative impact on the province's economic growth.

[149] SEC Submissions, p. 11.
[150] SEC Submissions, para 52.

E. There is No Undue Burden

105. The Opposing Intervenors submit that because there is a PI of less than 1.0 in Stage 1, the subsidy is undue. There is no other basis for the position expressed other than that there is a PI of less than 1.0 after Stage 1 and a PI of less than 1.0 is unacceptable from the Opposing Intervenors perspective.[151]

106. Enbridge Gas submits that, considering the Project is both economically feasible and in the public interest under EBO 134, a PI of less than 1.0 in Stage 1 does not impose an undue burden on any individual, group or class. As has been typically applied, the shortfall should be recovered from ratepayers based on the OEB approved-cost allocation that is appropriately premised on cost causality. The result of such allocation does not unduly allocate costs to any one individual, group or class. More specifically, the rate treatment of the Panhandle System is a general cost allocation issue regarding the apportionment and allocation of the cost of service and not related to the determination of a CIAC. IGUA acknowledges[152] that issues related to cost allocation mechanisms, including the mechanisms for allocation of Panhandle System costs, will be subject to review in Phase 3 of Enbridge Gas's 2024 Rates Application proceeding (EB-2022-0200). IGUA is an approved and active intervenor in that proceeding.

107. Furthermore, the PI level of the Project is in line with other projects that had a PI of less than 1.0 in Stage 1 but overall, based on the three-stage test, were economically feasible and were found by the OEB to be in the public interest without an undue burden. Below are representative projects in this regard:

Table 2: Historical Transmission Project Economic Test Results

Project (Case #)	Stage 1 PI	Stage 1 NPV
Panhandle Regional Expansion Project (EB-2022-0157)	0.48	-$150M

[151] IGUA Submissions, p. 7. SEC Submissions, pp. 11-12. EP Submissions, pp. 14-17.
[152] IGUA Submissions, para. 20.

Panhandle Reinforcement Project (EB-2016-0186)	0.19	-$212M
2017 Dawn Parkway Expansion Project (EB-2015-0200)	0.43	-$343M
Dawn Parkway 2016 Expansion Project (EB-2014-0261)	0.39	-$238M

108. In addition, the consideration of undue burden is not (as expressed by IGUA) divorced from the public interest.[153] Public interest is the standard that must be met under section 96(1) for the granting of a leave to construct. Any consideration of an undue burden is informed by the public interest determination under EBO 134. Therefore, the burden under consideration by the OEB cannot just be any burden as expressed by the Opposing Intervenors. Instead, it must be so material that it outweighs the public interest determination under EBO 134. Clearly, given the application of OEB-approved cost allocation and past precedent and the significant economic impact that the Project will have on the economy and electricity capacity of Ontario, the economic burden arising from Stage 1 is not undue.

F. EBO 134 Should Not Be Amended

109. The submissions of Opposing Intervenors include that (i) EBO 134 should be materially amended in this proceeding, (ii) the Stage 2 and Stage 3 analysis, as previously approved and applied by the OEB, should be dispensed with and (iii) a CIAC, which has never been imposed for transmission pipelines in this context before, should now be applied to any transmission project that has a PI less than 1.0 at Stage 1. Their submissions are tantamount to eliminating the existence of EBO 134 for purposes of evaluating transmission pipelines and adopting EBO 188, which has only applied to distribution pipelines.

[153] IGUA Submissions, pp. 19-20.

110. Enbridge Gas submits that EBO 134 should not be eliminated or altered as suggested by the Opposing Intervenors. This is not only because it is not warranted in the circumstance of the Project, but also because EBO 134 is a test of general application. Especially the current circumstance where (i) the Project is a transmission pipeline that benefits the entire Panhandle Market, (ii) due to the hydraulic nature of the Panhandle System, the physical capacity of the Project depends upon the location of customers that will ultimately take capacity, and (iii) the respondents to the EOI form the basis of the forecast but may or may not be the ultimate customers served given the capacity is not reserved and available on a "first come first served" basis. As set out in Section C above, there are clear differences between a transmission project and a distribution project and the Project exemplifies those differences. And, as stated in Section G below, a CIAC cannot appropriately be calculated from a regulatory and operational perspective for a transmission project such as the Project. As a result, an EBO 188 approach as suggested by the Opposing Intervenors should not be adopted by the OEB.

111. Furthermore, it would be unfair for the OEB to do so. Enbridge Gas has evaluated and considered the Project on the application of EBO 134 as stipulated in the Facilities Handbook (which Enbridge Gas is expected to follow and was last updated by the OEB in March 2022, less than 2 years ago) and more importantly based on the application of EBO 134 as applied and approved by the OEB on numerous occasions. It would be unfair to make the significant policy change proposed by the Opposing Intervenors without appropriate notice to both Enbridge Gas and other impacted parties. Procedural Order No. 4 only indicated that "the applicability of EBO 134 and EBO 188" were in scope for this proceeding and not the elimination or fundamental modification of EBO 134 as contemplated by the Opposing Intervenors. In particular, Enbridge Gas notes that with respect to the order made in Procedural Order No. 4, the OEB ordered that Enbridge Gas's "amended application must comply with the filing requirements set in the *OEB Natural Gas Facilities Handbook*", which Enbridge Gas has done. As noted above, the wording of the Facilities Handbook is wholly inconsistent with the elimination of EBO 134. In this regard, none of the Opposing Intervenor's submissions comply with the Facilities Handbook.

112. In general, an approval of a contribution payable by a customer is the establishment of a rate. A fundamental change in EBO 134 to require a contribution equates to change in a rate making methodology. All existing and prospective customers and provincial and municipal economic development groups seeking to attract business to the province could be impacted.[154] These parties are not before the OEB in this proceeding nor have they had notice of the fundamental rate change proposed by Opposing Intervenors.

113. Furthermore, customers have benefited from EBO 134 with respect to other transmission projects by being able to take advantage of incremental transmission system capacity without incurring a CIAC. It would be unfair to amend EBO 134 and cause customers to incur a CIAC for this Project in particular.

114. Enbridge Gas also agrees with the submissions of APPrO regarding the need for regulatory certainty and predictability.[155] Enbridge Gas notes the decision of the Supreme Court of Canada which held:

> *I recognize that the Board has wide discretion to fix payment amounts that are "just and reasonable" and, subject to certain limitations, to "establish the . . . methodology" used to determine such amounts. That said, once the Board establishes a methodology to determine what is just and reasonable, it is, at the very least, required to faithfully apply that approach. This does not mean that collective agreements "supersede" or "trump" the Board's authority to fix payment amounts; it means that once the Board selects a methodology for itself for the exercise of its discretion, it is required to follow it. Absent methodological clarity and predictability, Ontario Power Generation would be left in the dark about how to determine what expenditures and investments to make and how to present them to the Board for review. Wandering sporadically from approach to approach, or failing to apply the methodology it declares itself to be following, creates uncertainty and leads, inevitably, to needlessly wasting public time and resources in constantly having to anticipate and respond to moving regulatory targets.*[156] *[Emphasis added]*

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[154] Exhibit I.APPrO.9.

[155] APPrO Submissions, paras. 8-10.

[156] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44, para. 159.

G. A CIAC Should Not Be Imposed

(i) Transmission System Dynamics Do Not Permit a CIAC

115. Even if the OEB believes that it is appropriate to consider an amendment to EBO 134 and impose a CIAC, Enbridge Gas submits that the OEB should refrain from doing so with respect to the Project since a contribution cannot be calculated. As previously stated, the nature of a transmission system is dynamic over time. The determination of incremental capacity created by the Project is not limited to the pipeline to be constructed. Instead, the incremental capacity created for the Panhandle System depends on the size and location of the incremental customers' demand over a broad geographic area. Further, this increase in capacity is to the benefit of all Panhandle System customers. As that incremental capacity across the system is acquired, system dynamics means that there is not a one-for-one allocation of the incremental capacity taken and the capacity needed to serve that demand. For the same unit of capacity acquired by each customer, the customers may have consumed very different actual capacity available. In addition, the forecasted potential use of the incremental Panhandle System capacity presented in evidence, while informed by the EOI, is one of many possible future scenarios. There is a temporal component that must be considered given the dynamic nature of the Panhandle System, which depends on where customers ultimately connect. The capacity needed to serve a customer can change over time as others connect across the forecast horizon further changing the relationship between capacity contracted and actual capacity needed to serve that customer.[157]

116. IGUA takes the position that the mismatching of capacity contracted and capacity taken is not relevant since it can occur in both transmission and distribution projects and that, in the case of the Project, there is a high degree of certainty where the demand will be located and what volumes so that Enbridge Gas should have sufficient confidence to design the expansion.[158] Enbridge Gas disagrees with IGUA. IGUA has overgeneralized the facts. First, although some hydraulic impacts can occur with distribution projects, the

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[157] Exhibit I.ED.29.
[158] IGUA Submissions, paras. 92-94.

important fact is that there is a material degree of difference between that impact for a transmission system such as the Panhandle System and a distribution project that is within a discrete area of benefit. As stated:

> *MR. GILLETT: Yes, that is correct. The range of impact changes depending – go back to the tree analogy, the further you branch down these branches, the easier it is to isolate what those impacts are. But you're right, it would – it has an impact even in distribution systems.*[159]

117. In addition, with respect to a distribution area of benefit and the application of the HAF, it was stated:

> *MR. GILLETT: No. I think that that was actually the, one of the primary ways that we designed the [HAF]. The area of benefit is, is very key, it's critical to how the [HAF] is actually calculated, so the idea behind the [HAF] is when we put in a distribution project hydraulically we determine is the area of benefit – so this is the area of the system that benefits from that capacity – is it hydraulically such that we can isolate it to a small – a geographic area where it's predictable, where, as customers come on to that system, we can predict how much impact, and it will be consistent how much impact they will have on that system. And if any customer comes within that area of benefit they get allocated the [HAF]. So, I would actually say that that was critical to the whole proposal.*[160] *[Emphasis added]*

118. This is contrasted with the implications of a transmission system such as the Panhandle System:

> *MR. GILLETT: Yes, absolutely. The idea is that as the gas flows through the system, the faster it flows the more pressure it – there's pressure – or there's friction on the pipeline, and it will have different impacts on the system as it flows through the system. So as gas flows, let's say it branches off down one of those tree branches, it will lower the pressure upstream of it, so we have to continuously keep that line pressurized. As customers take gas off of the system, they impact the pressures as well.*

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[159] Hybrid Hearing Transcript Vol. 2, p. 18.
[160] Hybrid Hearing Transcript Vol. 2, p. 10.

> So when *we talk about hydraulic modelling, what we mean is we are simulating what all those different impacts are as we are compressing gas into the system, as it's being taken off the system.*
>
> *And the important thing to recognize is it's not always intuitive. You can actually expand a piece of pipe in one piece of the system that will actually have a benefit much further down, and that's actually the case in this project.*
>
> *So where we are looping sort of the east part of the system, it provides capacity on the west end of the system as well.*
>
> *So it's about how we simulate the behaviour of the gas as it flows through all of the pipelines.*[161] *[Emphasis added]*

119. In regard to IGUA's view that there is a high degree of certainty of the location of the demand, Enbridge Gas submits that IGUA fails to acknowledge that the incremental capacity in question relates to the entire Panhandle System on a "first come first served" basis and not a discrete area of benefit. As the example of the NextStar battery plant clearly illustrates, significant demand not forming part of the EOI and located far from the area of greenhouse growth can unexpectedly take capacity.[162] Given the level of economic activity in Southwestern Ontario, it is likely such a situation will occur in the case of the current incremental capacity over the next five years.[163] Furthermore, for greenhouse growers, in particular, expansion is related to available land, water and infrastructure and their location could occur throughout the region. As a result, the circumstance related to the Project is far from the static circumstance suggested by IGUA.

(ii) Capacity and Cost Responsibility Are Misaligned

120. The CIAC envisioned by the Opposing Intervenors is to allocate cost responsibility for the incremental capacity causing the subsidy. This is because the Project is intended to increase capacity of the Panhandle System and the customers will acquire that

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[161] Hybrid Hearing Transcript Vol. 2, p. 13.
[162] Hybrid Hearing Transcript Vol. 2, p. 7.
[163] Hybrid Hearing Transcript Vol. 2, p. 34; Invest WindsorEssex Letter of Support (November 9, 2023); Exhibit I.STAFF.25, pp. 4-5.

incremental capacity. Any contribution or any methodology to establish a contribution will need to align cost responsibility with capacity. Otherwise, a methodology will be entirely disconnected from what the Project is intended to do – provide incremental capacity and the acquisition of that incremental capacity by customers potentially throughout the Panhandle System. However, as noted above, because of the transmission system dynamics described, cost responsibility and capacity acquired do not necessarily equate and will change over time. This is the fundamental flaw with the application of the HAF (or something similar to the HAF) as suggested by Opposing Intervenors.[164]

121. IGUA suggests that the HAF mechanism is about matching customer value, not hydraulics, with cost.[165] However, as stated by Enbridge Gas IGUA is not correct:

> *MR. MONDROW: Right. And when you say it's impossible in the case of, for example, the PREP project to calculate an allocation factor, that's true of what you're trying to allocate is hydraulics, but there are other ways to allocate things; right?*
>
> *MR. GILLETT: So, I think the reason <u>why we propose the [HAF] to begin with was it was a way over time that we had figured out how we can allocate costs and the key to the [HAF] is that it is based on hydraulics.</u> Because each customer will have a different – otherwise each customer has a different impact on the system which in theory would incur different costs. <u>The [HAF], the area of benefit for a [HAF] is isolated so that it's consistent and predictable and we can administer it over time.</u>*
>
> *MR. MONDROW: Well, that's interesting because there is nothing in the [HAF] framework that explains that. Actually, there's no condition that – there's no threshold to determine that it's only in the circumstances you just described that the [HAF] will be applied. So, what you're saying is you apply it that way even though that's not one of the criteria?*
>
> *MR. GILLETT: No. <u>I think that that was actually the, one of the primary ways that we designed the [HAF]. The area of benefit is, is very key, it's critical to how the [HAF] is actually calculated</u>, so the idea behind the [HAF] is when we put in a distribution project hydraulically we determine is the area of benefit – <u>so this is the area of the system that benefits from that capacity – is it hydraulically such that we can isolate it to a small – a geographic area where it's predictable, where, as customers come on to that system, we can predict how much impact, and it will be consistent</u>*

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[164] Exhibit I.STAFF.23.

[165] IGUA Submissions, para. 92.

> *how much impact they will have on that system. And if any customer comes within that area of benefit they get allocated the [HAF]. So, I would actually say that that was critical to the whole proposal.*[166] *[Emphasis added]*

122. The HAF is based on cost per peak capacity which is the same as dollar per unit of capacity. The HAF assumes that the unit of capacity taken is reasonably equivalent to the unit of capacity required to serve that customer so that cost responsibility reflects capacity needed. This enables cost responsibility among customers acquiring incremental capacity to be treated fairly and on the same basis relative to each other. For example, customers A and B each take 100 units of capacity and pay the same amount of allocated cost related to the contribution. However, the area of benefit matters. For purposes of EBO 188, the above occurs in a pipeline system where the incremental capacity aligns with the pipeline capacity constructed and there is a reasonable one for one relationship between capacity need and capacity needed to serve. This is the reason EBO 188 is applicable to distribution projects or projects that are predominantly distribution in nature and as noted above, why the HAF has been applied.[167]

123. For the reasons expressed above, the HAF cannot apply to the Project and the Panhandle System. Applying the HAF in the circumstance of the Project means that the rate allocation assumptions will be different from the physical capacity. There will be a misalignment between cost responsibility and capacity needed to serve. For example, the implication is that customer A and B each take 100 units of capacity and pay the same amount but in fact A could be consuming more available capacity than 100 units and B could be consuming much less just because of system dynamics. If another customer is introduced later in the forecast horizon the circumstance can change again. Given the physical dynamics of the Panhandle System, the application of the HAF in effect results in discriminatory treatment between like customers, since customer A would underpay and customer B would overpay.[168]

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[166] Hybrid Hearing Transcript Vol. 2, pp. 9-10
[167] Exhibit I.STAFF.26.
[168] Hybrid Hearing Transcript Vol. 2, p. 41.

124. Opposing Intervenors and OEB Staff argue that a true-up could occur as customers connect.[169] But because the Panhandle System is dynamic, true-ups will occur not just once but potentially multiple times and in either direction. As a rate, it is proper rate making to ensure that customers have rate stability and can have some degree of reliance on that rate to manage their affairs and investments while still being treated fairly and equitably. CIAC approaches proposed by Opposing Intervenors and OEB Staff do not accomplish this goal.

125. Intervenors submit that regulatory treatment is “rough justice” and that it is acceptable to discriminate between customers as part of rate making.[170] But, typically in rate making, it is discrimination between customer classes that is permitted if not undue. Under just and reasonable ratemaking, customers are grouped in classes and costs allocated to those classes using methodologies so that cost responsibility of like customers will be treated similarly and fairly. The alternative approaches proposed by Opposing Intervenors provide for the opposite. Instead of treating like customers similarly, their proposals discriminate between like customers without an appropriate connection between cost causality and cost responsibility or a reasonable degree of rate stability.

H. Impacts of Imposing a CIAC

126. Enbridge Gas submits that imposing a CIAC, as with rejecting the Project altogether, will deprive Ontario of the benefits provided by the Project. CIAC may result in delaying the Project’s commercial operation until after the Winter 2024/2025 forecast shortfall, at best, or, at worst, prompting customers to cease incremental investment in the region. The responses to the EOI are in the absence of a CIAC and the plans of those customers, particularly greenhouse customers, have been formulated without a CIAC. Greenhouse customers are price takers and cost increases related to the investment needing additional pipeline capacity need to be considered.

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[169] OEB Staff Submissions, p. 48.
[170] IGUA Submissions, para. 104. SEC Submissions, pp. 12-14.

127. CIAC will also have an adverse competitive impact between customers within the greenhouse industry since customers taking advantage of previous capacity increases did not have to pay a CIAC. Also, given the above-noted problems of calculating a CIAC, this would also mean similarly situated customers will be treated differently from an economic perspective. This unfairness in Enbridge Gas's view gives rise to the prospect that these customers would leave the jurisdiction and expand their businesses in Ohio or Michigan.[171]

128. IGUA disagrees with this by arguing that there is no competition related impacts and that there is no evidence of a flight of capital.[172] The reasons for IGUA's position relate to the size of the investment made by greenhouse growers and the permanency of that investment.[173] However, the issue is not with respect to the investments already made as expressed by IGUA, but rather the incremental investments that rely on the incremental capacity created by the Project. Since greenhouse growers are price takers[174] in a highly competitive marketplace, changes to planned economics could affect industry plans including continued growth in Ontario.

129. SEC criticizes Enbridge Gas for not providing an estimate of a contribution to EOI respondents.[175] This criticism is unjustified since, as noted above, an appropriate contribution cannot be calculated because of transmission system dynamics. Also, as a contribution is a rate, it would not be appropriate to estimate an amount that would pre-judge any determination by the OEB and potentially wrongfully set or affect expectations of customers.

130. The submissions of APPrO and Atura describe the impact a CIAC requirement would have on the power generation sector and Enbridge Gas supports their submissions in this regard.[176]

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[171] Hybrid Hearing Transcript Vol. 3, pp. 31, 178-179
[172] IGUA Submissions, paras. 64 and 76.
[173] IGUA Submissions, para. 75.
[174] Hybrid Hearing Transcript Vol. 3, p. 171.
[175] SEC Submissions, pp. 14-15.
[176] APPrO Submissions, paras. 13-27 and para 80. Atura Submissions, paras. 39-44.

131. Enbridge Gas submits that if the OEB deviates from EBO 134, the Facilities Handbook and past OEB Decisions and requires certain customers to incur a CIAC, the OEB would effectively be denying the Project since no customer expressed that it would be agreeable to incurring a CIAC.[177]

I. The Project Costs Are Reasonable

132. Enbridge Gas maintains that the estimated Project cost of $358.0 million – or $289.2 million excluding indirect overheads – are reasonable.[178]

133. While OEB Staff accept that Enbridge Gas's project cost estimate is reasonable and in line with previous similar projects, OEB Staff submits that the Project cost estimate should be based on the lowest cost qualified proponent, and that any decision in the rebasing proceeding which changes how indirect overheads are capitalized should be applied to the overheads estimated for the Project. EP expresses concern about what it alleges was an unjustified increase in indirect overheads between the original Application and the amended Application and is therefore seeking to reduce the cost estimate by $25.6 million of indirect overheads. SEC alleges that the $358 million Project costs are highly uncertain and might be materially higher since they are based on a 2022 Request for Proposal ("RFP"), and the prime contractor has not been selected. Similarly, PP submits that given the absence of means, including contractual means, to control price increases, coupled with Project cost estimate increases between the original and amended Application, there is a high level of risk that rate payers could incur costs that exceed $358 million.

(i) Requiring Enbridge Gas to Estimate Project Costs Based on the Lowest Priced Proposal is Not the Prudent Approach

134. As mentioned above, OEB Staff takes issue with the fact that Enbridge Gas's Project costs were estimated using an average of the three most competitive proposals responsive to the RFP. OEB Staff submits that because each of the three proponents should possess

[177] Exhibit I.STAFF.25, Attachment 1.
[178] Argument in Chief, paras 70-71; Exhibit C-1-1, pp. 18-19;

the requisite technical ability to carry out the Project, Enbridge Gas's rates should be estimated on the basis of the lowest priced proposal.

135. Enbridge Gas submits that OEB Staff's proposed approach would incentivize Enbridge Gas to select the least expensive proponent without regard to whether the proposal in question results in the most prudent expenditure of ratepayer funds. Similarly, OEB Staff's proposed approach will incentivize Enbridge Gas to select a proponent without regard to whether that decision will ultimately be in the public interest. This is because OEB Staff's submission seems to be predicated on the premise that, in the circumstances, selecting the least expensive bid among the three most competitive proposals is necessarily the methodology that is the most prudent and in the public interest. Enbridge Gas disagrees with this narrow approach.

136. There is no evidence on the record to support OEB Staff's position that equates the view that the lowest priced proposal of the three most competitive proposals is necessarily the most appropriate. Rather, the evidence demonstrates that the RFP process determines the most appropriate proposal based on a holistic assessment consisting of many factors beyond price and technical capability:

> *Enbridge Gas invites proponents to present their technical, commercial, and socio-economic offerings in their proposal. Proposals are evaluated against pre-established evaluation criteria to determine a fair and lawful evaluation outcome that may result in the awarding to one or more proponents. Proposals are complex and the evaluation of proposals requires assessment of many factors, including but not limited to technical, health and safety, environmental matters – in addition to bid price....*[179]

137. Further, Mr. Thomas's testimony suggests that evaluating proposals on the basis of price alone does not necessarily result in the least expensive project, in light of other considerations, including how relevant portions of the contracts are structured**:**

> *MR. THOMAS: [...], I believe Enbridge has looked at different ways of bidding on this. We utilize a competitive supply chain process to make sure we receive value for our ratepayers. It is not necessarily – picking the*

[179] Exhibit I.SEC.1(a).

> *lowest bid may not end up being the lowest in the end, if there are time and materials built into it or if there is a fixed-price component. So that's how we have been evaluating it.*[180]

138. Estimating Project costs based on the average of the three most competitive proposal prices is the most accurate estimation of Project costs because the approach is predicated on the multifaceted holistic assessment involved in determining the most appropriate proposal, which is described above. Conversely, estimating Project costs based on single proposal price alone is incompatible with the reality that Enbridge Gas considers a multitude of factors in determining the proposal that provides the best value for its ratepayers.

139. A problematic consequence of using OEB Staff's proposed approach is that it will provide Enbridge Gas with the financial incentive to select the lowest cost proponent and thereby neglect to undergo the complex assessment of other critical considerations used to determine the proposal that is the most competitive, and therefore the proposal that is most prudent and in the public interest. This is because, in the circumstances, forecasting the Project costs in Enbridge Gas's rates based on the lowest priced proposal would force Enbridge Gas to decide whether to incur an expenditure (i.e., by selecting the proposal) (i) that maximizes the chance of recovering its costs, or (ii) that it believes to be the most prudent and in the public interest, based on a complete assessment of all relevant considerations. As such, Enbridge Gas submits that incentivizing it to incur significant expenditures without regard to the complete and complex set of considerations is contrary to the foundational element of Ontario's rate regulation regime that allows for the recovery of prudently incurred expenses "[i]n view of the nature of th[e] particular costs and the circumstances in which they became committed."[181]

140. Enbridge Gas further submits that, in general, estimating a project's cost based on the lowest proposal price is not a suitable methodology for procurements carried out by way of an RFP. As discussed, the procurement has been carried out, albeit not finalized, as an

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[180] Hybrid Hearing Transcript Vol. 3, p. 94.
[181] Ontario (Energy Board) v. Ontario Power Generation Inc., 2015 SCC 44 (CanLII), [2015] 3 SCR 147, para. 106.

RFP, not an invitation to tender. In the procurement law context, significant differences exist between RFPs and invitation to tender.[182] Notably, because RFPs do not result in the formation of a “Contract A” between proponent and owner at the time of submitting the proposal – to enter into a predetermined contract for the submitted bid price – unlike invitations to tender, RFPs tend to result in a flexible and collaborative negotiation process, in particular with respect to pricing and technical aspects of the project.[183]

141. Mr. Thomas testified that further to the receipt of the “non-binding” proposals, Enbridge Gas is currently engaged in negotiations with proponents,[184] and that “[a]t all times through a project as the project is developed the estimate changes and develops as new information is gained.”[185] While this approach delays achieving contractual certainty with respect to the pricing, which Enbridge Gas addresses below, this approach allows for parties to enter into contractual relations at a more advanced stage after the parties have concluded a collaborative negotiation process. Conversely, in context of an invitation to tender, there is less flexibility, if any, to change the contract (i.e., the “Contract B”) which may result in certain risks associated with premature contracting, including penalties for changes to the project’s scope.

142. Enridge Gas therefore submits that estimating the Project costs based on the lowest priced proposal would be tantamount to treating the procurement process as a request for tenders – not an RFP – whereby the details of the contract are finalized. OEB Staff’s proposed approach is not compatible with the collaborative and iterative process inherent with RFPs. As such, it is not reasonable for OEB Staff to estimate Project costs that are predicated on a procurement process that is not applicable to the Project.

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[182] See Janice Buckingham et al, Tendering and Purchasing Law in Upstream Oil, Gas, and Oilsands: The Competitive Bidding Process and Obligations When Contracting for Work, 2010 47-2 *Alberta Law Review* 497, 2010 CanLIIDocs 316 , pp 506-509.

[183] Ibid, p. 508.

[184] Hybrid Hearing Transcript Vol. 3, p. 103.

[185] Hybrid Hearing Transcript Vol. 2, p. 184.

(ii) Project Costs Were Estimated Following a Comprehensive Process with Built-In Contingencies and Other Measures

143. Enbridge Gas rejects SEC and PP's position that there is any reasonable basis to determine that the Project cost estimate is highly uncertain. As a starting point, Enbridge Gas is "to provide sufficient information to demonstrate that the estimates of the [P]roject costs are reasonable."[186] Enbridge Gas is not expected to predict the Project cost with absolute certainty. The Merriam Webster dictionary defines "estimate" as "a rough or approximate calculation". [187] The degree of latitude that should be afforded to Enbridge Gas is enhanced by the requirement that the estimate be "reasonable," which the Supreme Court of Canada acknowledges "is concerned mostly with the existence of justification, transparency and intelligibility within the decision-making process", as well as "with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law." Enbridge Gas's forecast Project cost reflects a reasonable estimate.

144. As discussed above, RFPs are not binding by design to allow for collaboration and iterative refinement of details at the expense of earlier contractual certainty and to mitigate the risk associated with entering into contracts prematurely, including potential exposure for a party failing to be able to satisfy the originally agreed upon terms (e.g., project scope). Enbridge Gas's procurement approach for the Project was consistent of the "usual process of a design-bid build."[188] Furthermore, the evidence does not demonstrate that there is an unacceptable level of uncertainty in Enbridge Gas's price estimate.

145. The Project cost estimate is the product of a class 3 estimate prepared in Q1 of 2023 and was updated to reflect market conditions based on contractor responses to the RFP in Q4 2022.[189] The Project cost is inclusive of a contingency, in the amount of approximately

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[186] Natural Gas Facilities Handbook, EB-2022-0081 p.26.
[187] "estimate." Merriam-Webster, https://www.merriam-webster.com/dictionary/estimate (January 17, 2024).
[188] Hybrid Hearing Transcript Vol. 3, p. 93.
[189] Exhibit E, Tab 1, Schedule 1, p. 8.

8% of applied direct capital costs, that was established using the American Association of Cost Engineers ("AACE") standards. Enbridge Gas supplemented the AACE formulaic approach for establishing a contingency with a risk analysis that considered the unique risk profile associated with the Project:

> *MR. MURRAY: So is it fair to say the contingency is just like a mathematical – just a certain percentage of the overall project cost? It has nothing do with a specific risk analysis of risks to the project itself; it's more just a back-of-the-envelope calculation based upon project cost, stage. Is that fair?*
>
> *MR. THOMAS: Yes. It's a function of the project class cost estimate.*
>
> *MR. MURRAY: But has Enbridge done any risk analysis of kind of risks, contingencies and likely impacts on the project at this point?*
>
> *MR. THOMAS: <u>The company has evaluated some specific risks and allocated some of the contingencies to some of those risks</u> [emphasis added].[190] [Emphasis added]*

146. Further, the evidence demonstrates that Enbridge Gas's estimation process involves regular assessments to ensure that the estimate reflects the most up-to-date information:

> *MR. RUBENSTEIN: […] [T]he forecast costs – the forecast 358 million are based on the top three responses to an RFP you held in Q4 2022?*
>
> *MR. THOMAS: Yes, that is the current basis of the cost estimate.*
>
> *MR. RUBENSTEIN: So those numbers are from roughly a year ago?*
>
> *MR. THOMAS: Yes, that was the estimate at the time, and the company with the new in-service date is continuing to evaluate executing a contract with a contractor to execute this project.*
>
> *MR. RUBENSTEIN: As I understand, you actually haven't signed the contract. There's no conditional contract if the project is approved; correct?*
>
> *MR. THOMAS: Yes, that is correct. I will just say as well that through the estimate process impacts of the delayed in-service year are reflected through escalation.*

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190 Hybrid Hearing Transcript Vol. 3, p. 70; See Exhibit J3.5.

> *MR. RUBENSTEIN: Well, so I just want to understand, do we know if these costs are still accurate? Or are they going to go up by the time the OEB – if say the OEB approves the project and you go back to your contractors because you haven't signed a contract, are these costs going to be higher?*
>
> *MR. THOMAS: These are the current estimated costs based on the principles used in Enbridge's cost estimating processes. At all times through a project as the project is developed the estimate changes and develops as new information is gained. And that is – and Enbridge also utilizes contingency to account for unknowns in the project.*[191]

147. In addition, recognizing that Enbridge Gas is still in the process of negotiating contracts, the RFP process leading up to these negotiations has prioritized alternative pricing structures that are intended to limit the chance of cost overages for the Project:

> The contract has not yet been executed for the Project and therefore finalized details regarding allocation of cost risk are not available. Alternative contract structures including lump sum and unit price were requested as part of the RFP process.
>
> Enbridge Gas considers lump sum and unit price contract structures to manage the risk of cost overages on construction projects. These contract structures incentivize construction contractor(s) to manage their resources efficiently by allocating the risk of cost overruns due to inefficient use of resources to the construction contractor(s). Other cost risks that are external to Enbridge Gas and the construction contractor(s), such as severe weather conditions, are shared between Enbridge Gas and the construction contractor(s).[192]

148. The potential cost benefit of using these price structures in contracts is reinforced by Mr. Thomas's testimony reproduced above.[193]

(iii) The Estimated Indirect Overheads are Appropriate

149. Regarding indirect overheads, OEB Staff submitted in reference to Enbridge Gas's current rebasing application that "any decision in that proceeding which changes how overheads are capitalized should be applied to the overheads estimate for the project".

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191 Hybrid Hearing Transcript Vol. 2, pp. 183-184.

192 Exhibit I.SEC.1(c); Further details on these pricing structures are provided at Exhibit J2.11.

193 Hybrid Hearing Transcript Vol. 3, p. 94.

The Company agrees with OEB Staff's submission and will update the indirect overhead allocations consistent with the OEB's rebasing decision[194.] The revised impacts to the Project as a result of the changes to indirect overheads will be included in the Draft Rate Order for Phase 1 of 2024 rebasing.

150. EP submits that "the $25.6 million increase in indirect overhead costs allocated to the project is unreasonable and the OEB should reduce indirect overheads from $68.8 million to $43.2 million, the amount that it was in the original application". Enbridge Gas rejects EP's submission because this would be inconsistent with the OEB-approved methodology for indirect overheads and the allocation of indirect overhead costs to projects. As described in Exhibit I.SEC.2, the increase of $25.6 million is a result of an increase to the overall direct capital for the Project and the application of an updated indirect overhead rate due to the shift in timing of the Project from 2023 to 2024. Overhead rates are determined based on the total amount of direct capital spend and the total pool of overheads in a given year.

J. The Project Is the Optimal Solution to Meet the System Need

(i) Enbridge Gas's Evaluation of IRP Alternatives Was Appropriate

151. Regarding the assessment of Project alternatives, PP states "there is a long list of credible IRP alternatives that Enbridge never even considered, despite stakeholders requests for better engagement and discussion".[195] However, PP does not describe a single feasible IRP alternative to the Project that was not considered by Enbridge Gas. PP states that Enbridge Gas did not include a "classic IRP alternative" of reducing delivery pressure to Atura's power generation facility.[196] PP's statement ignores Enbridge Gas's evidence. A reduction in pressure at Atura's power generation facility would shift the constraint to another customer site of similar pressure requirements and would not provide a benefit to the Panhandle System in the form of an IRP alternative.[197] As described at the hybrid

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[194] EB-2022-0200 Decision and Order, December 21, 2023 page 98
[195] PP Submissions, p. 22.
[196] PP Submissions, p. 18.
[197] Exhibit I.FRPO.13, p. 2.

hearing, Atura's power generation facility is one of several customers and stations of similar pressure requirements.[198] PP's suggestion is not a feasible IRP alternative.

152. PP also states that "Enbridge did not conduct any of the OEB required IRP consultation for the Project and refused to do customer outreach as requested by stakeholders."[199] PP's statement ignores Enbridge Gas's evidence. First, Enbridge Gas included IRP as part of the Project's public information sessions.[200] The purpose of the information sessions were to inform and gather feedback from stakeholders about the Project.[201] Second, Enbridge Gas conducted customer outreach as part of its 2023 EOI and Reverse Open Season process as described in Exhibit B, Tab 1, Schedule 1, paras. 23-31 and in the paragraph below.[202] Customer responses to this outreach is summarized at Exhibit I.FRPO.15, Attachment 1. The IRP Framework notes that targeted engagement should be conducted for specific IRP alternatives or IRP Plans that have been identified for a specific need in a specific geographic region.[203] As described in evidence at Exhibit C, Tab 1, Schedule 1, no technically feasible IRP alternatives were identified that could address the Project need, therefore further stakeholder engagement was not required.

153. PP and ED state that Enbridge Gas's IRP assessment ignored contract customers. ED states that Enbridge Gas argued that "contract customers should be ignored" with respect to IRP and energy efficiency. PP and ED's statements are incorrect and are not supported by the evidence:

a. Enbridge Gas administers extensive energy efficiency programs to contract market customers in the Project area. Enbridge Gas provided information regarding its DSM efforts for greenhouse customers at Exhibit I.STAFF.10(c).

b. Contract market customers requesting new/incremental firm service were asked to provide information regarding the viability of interruptible service as an alternative to new firm service. Enbridge Gas reviewed this information to assess whether firm demand reductions could be possible and as a result the

[198] Hybrid Hearing Transcript Vol. 3, pp. 121-123.
[199] PP Submissions, p. 23.
[200] Exhibit JT2.2, Attachment 1, p. 8; Exhibit JT2.2, Attachment 2, p. 10.
[201] Exhibit JT2.2, Attachment 1, p. 3; Exhibit JT2.2, Attachment 2, p. 3.
[202] Exhibit B, Tab 1, Schedule 1, para. 22.
[203] Exhibit EB-2020-0091, Decision and Order, July 22, 2021, Appendix A, p. 15.

Company removed two requests for firm demand from the Project area's demand forecast.[204]

c. Contract market customers requesting new/incremental firm service were asked whether they would be more inclined to consider interruptible service over new firm service if the ability to negotiate lower than posted interruptible rates was available. Enbridge Gas reviewed this information to assess whether firm demand reductions could be possible and as a result the Company removed three requests for firm demand from the Project area's demand forecast.[205]

d. Contract market customers requesting to convert existing interruptible service to firm service were asked to identify the driving factors behind their conversion request. Enbridge Gas reviewed this information to assess whether firm demand reductions could be possible however the Company determined it was not.[206]

e. Contract market customers requesting new/incremental firm service were asked to confirm that their volumes were inclusive of all future natural gas conservation activities, including natural gas conservation activities within and outside of Enbridge Gas's Demand Side Management programs, and the use of non-natural gas alternative options. All customers confirmed that to be the case.[207]

f. Contract market customers requesting new/incremental firm service were asked to confirm whether Enbridge Gas had discussed energy conservation program offerings with them. All customers confirmed that to be the case.[208]

g. Contract market customers that attended Enbridge Gas's in-person customer meeting on March 7, 2023, as well as during the March 23, 2023 virtual customer meeting, were reminded of the Company's DSM programs.[209]

h. Existing contract market customers across the Project area were provided an opportunity to de-contract existing firm service.[210] However, no customers requested to de-contract existing firm service.[211]

i. Existing contract market customers across the Project area were provided an opportunity to convert existing firm service to interruptible service.[212] However,

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[204] Exhibit B, Tab 1, Schedule 1, para. 28.
[205] Exhibit B, Tab 1, Schedule 1, para. 29.
[206] Exhibit B, Tab 1, Schedule 1, para. 27.
[207] Exhibit B, Tab 1, Schedule 1, para. 30.
[208] Exhibit B, Tab 1, Schedule 1, para. 30.
[209] Exhibit B, Tab 1, Schedule 1, para. 30.
[210] Exhibit B, Tab 1, Schedule 1, para. 24.
[211] Exhibit B, Tab 1, Schedule 1, para. 31.
[212] Exhibit B, Tab 1, Schedule 1, para. 24.

> no customers requested to convert existing firm service to interruptible service.[213]

154. Further, ED submits that 70 TJ/d of peak savings could be achieved by 2029 from the contract market through Enhanced Targeted Energy Efficiency ("ETEE") programs, based on its extrapolation methodology.[214] By comparison, Enbridge Gas's extrapolation methodology results in 21 TJ/d of peak savings by 2029 for contract market customers.[215] ED's extrapolation methodology applies the peak savings assumption from all general service sectors (residential and small commercial/industrial) to the contract market. In general, general service peak savings assumptions rely on weather sensitive end-uses whereas contract market peak savings rely on non-weather sensitive end-uses (such as process load). Weather sensitive end-uses, as ED's submission states,[216] tend to provide greater peak savings than non-weather sensitive end-uses. By applying the peak savings assumption from all sectors in the general service market to the contract market, ED's extrapolation methodology effectively assumes that the majority of the contract market consists of weather-sensitive end-uses and ignores that much of the contract market in fact consists of non-weather sensitive end-uses. ED's methodology is unreasonable and overstates peak savings from the contract market. ED appears to justify its methodology in part by pointing out that greenhouse envelope improvements are weather-sensitive but ignores that approximately half of the contract market demand in the Panhandle Market is not related to greenhouse customers and is instead related to power generation and large commercial/industrial customers, which is not weather-sensitive.[217]

155. Enbridge Gas's extrapolation methodology is described at Exhibit J2.10 and consists of applying the peak savings assumption from the small industrial sector of the general service market (which includes greenhouses) to the contract market. This is a much more appropriate methodology than that of ED's because by using the small industrial sector specifically (rather than all sectors in the general service market) it more appropriately

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[213] Exhibit B, Tab 1, Schedule 1, para. 31.
[214] ED Submissions, p. 15
[215] Exhibit J2.10.
[216] ED Submissions, p. 15.
[217] Exhibit B, Tab 2, Schedule 1, para. 23.

accounts for weather-sensitive and non-weather sensitive end-uses among contract market customers. In fact, Enbridge Gas's approach is likely conservative because it assumes that contract market industrial customers are similar to small industrial general service customers in terms of energy efficiency sophistication, whereas in practice contract market industrial customers are likely much more sophisticated.

156. Finally, PP states that "[s]o little was done on IRP assessment and options that Enbridge did not even file the May 24, 2023 Posterity Report with its Updated Evidence on June 16, 2023. It was not provided until October 3, 2023 when stakeholders requested it. If Enbridge had done a proper analysis of IRP alternatives, this simply would have been included in the updated application filed June 16, 2023 and highlighted as an attempt at complying with OEB IRP requirements."[218] In making this statement, PP references the attachments provided by Enbridge Gas at Exhibit I.PP.36 (filed October 3, 2023) as consisting of the May 24, 2023 Posterity Report.

157. There is no May 24, 2023 Posterity Report. The attachments at Exhibit I.PP.36 are clearly identified as the scoping document for the Posterity analysis (Attachment 1) and a memo that describes Posterity's modelling approach (Attachment 2). Contrary to the statements made by PP, the Posterity Report is dated June 5, 2023 and was in fact filed with Enbridge Gas's application and pre-filed evidence on June 16, 2023 at Exhibit C, Tab 1, Schedule 1, Attachment 3. PP's submissions regarding the Company's IRP assessment appear to rely on an inadequate review of the evidence, therefore, PP's submissions on the topic should be given little weight.

(ii) Enbridge Gas's Evaluation of an IRP Alternative at Ojibway Was Appropriate

158. FRPO argued that the Project should be denied because Enbridge Gas made insufficient attempts to explore firm natural gas deliveries at Ojibway as an IRP Alternative and that Enbridge Gas sets artificial limits on maximum imports at Ojibway through a methodology where alternatives to increase the import limitation are not considered.[219]

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[218] PP Submissions, p. 23.
[219] FRPO Submissions, p. 1.

There is no basis for FRPO's assertions, as the assertions are based on no established facts. Its submissions should be rejected.

159. Enbridge Gas identified and assessed the following IRP alternatives:[220]

a. Firm exchange between Dawn and Ojibway

b. Firm exchange between Dawn and Ojibway in combination with looping of the NPS 20 Panhandle Line west of Dover Transmission.

160. Enbridge Gas currently contracts 60 TJ/d of upstream transportation capacity for delivery of supply to Ojibway from the PEPL system. This represents an IRP Alternative that is being utilized today. In addition to that capacity, Enbridge Gas considered contracting a third-party firm exchange between Dawn and Ojibway to meet the identified system need underpinning the Project. An exchange would allow more natural gas to be received at Ojibway, from a third party, to be used to serve Enbridge Gas's in-franchise customers, in exchange for natural gas delivered at Dawn to the third party. The exchange would provide natural gas to serve demand on the Panhandle System without the need to physically flow that quantity of natural gas westward from Dawn on the Panhandle System. This would provide an equivalent system benefit to increasing contracted upstream capacity to Ojibway and would reduce the facilities required to serve the forecast demand on the Panhandle System, without impacting the commodity portion of system customers' natural gas costs or the supply mix in the Gas Supply Plan.

161. It is important to note that due to the import limitations at Ojibway there are no third-party commercial services, including both exchanges and upstream transportation services, available that can fully eliminate the forecasted 5-year Panhandle System shortfall. Of the capacity currently held by parties from Ojibway to Dawn, 60 TJ/d is already utilized by Enbridge Gas to serve firm design day demands of the Panhandle Market, and 37 TJ/d is contracted by ROVER with evergreen renewal rights.[221] Enbridge Gas currently estimates that only 21 TJ/d of firm annual capacity is available for

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[220] Exhibit C, Tab 1, Schedule 1, pp. 10-19.
[221] Exhibit C, Tab 1, Schedule 1, pp. 10-11.

deliveries on PEPL to Ojibway, which is further reduced to 11 TJ/d due to the import limitations on Enbridge Gas's system at Ojibway.[222]

162. While Ojibway deliveries can efficiently serve demands directly in the Windsor market (adjacent to the Ojibway supply point), these deliveries do not efficiently serve demands on the remainder of the Panhandle System (i.e., east of Windsor between Sandwich Transmission and Dawn). This was clearly recognized by the OEB in EB-2016-0186 relating to the Panhandle Reinforcement Project, and these facts have not changed. In that proceeding, the OEB stated:

> *"Increasing deliveries at Ojibway will not get the gas to Leamington-Kingsville without an inefficient supply ratio, a significant change in supply mix, the need for additional facilities and the assumption of more risk."*[223]

163. Despite the fact that a supply-side IRP Alternative was not available to offset the entirety of the Project need, Enbridge Gas took the further step of confirming its assessment of the availability of commercial services to deliver incremental firm supply to Ojibway by holding an RFP for a Firm and Obligated Call Option Exchange Service in order to assess alternatives.[224]

164. The RFP was sent to Dawn market area customers, Ojibway to Dawn shippers, and posted on the Enbridge Gas website between September 16, 2021 and October 7, 2021. In addition, Enbridge Gas approached the existing C1 Ojibway to Dawn shipper, ROVER, to determine whether it was interested in participating in the RFP. ROVER holds 37 TJ/d of C1 Ojibway to Dawn capacity on the Panhandle System to facilitate transportation contracts it offers between points on their system and Dawn. ROVER indicated that it was not interested in providing the service, as ROVER is a transmission pipeline operator that transports natural gas on behalf of its shippers and does not hold title to that natural gas. As a result, ROVER did not bid in the RFP. It is also important to note that ROVER

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[222] Exhibit B, Tab 2, Schedule 1; Exhibit B, Tab 3, Schedule 1.
[223] EB-2016-0186 Decision and Order (February 23, 2017), p. 26.
[224] Exhibit C, Tab 1, Schedule 1, Attachment 1.

does not offer Ojibway as a delivery point to its shippers as part of its tariff. ROVER shippers cannot specify the physical delivery path to transport natural gas to Dawn and, as a result, no ROVER shippers bid in the RFP.[225] These underlying facts were discussed extensively during the EB-2016-0186 proceeding and have not changed since that time.[226]

165. Enbridge Gas also notes that on June 1, 2022, the PEPL website indicated that up to 21 TJ/d of delivery capacity was available at Ojibway. This is consistent with the results of the RFP, as the sole counterparty that responded to the RFP limited the availability of the exchange to 19 TJ/d.[227] The results of the RFP confirmed that a firm exchange to Ojibway is not able to defer or eliminate the need for the proposed Project.[228]

166. Given that a firm exchange will not meet the full capacity requirement, Enbridge Gas also considered the potential to utilize the results of the RFP to reduce the pipeline facilities required to meet the 5-year forecast growth. Contrary to FRPO's submission that Enbridge Gas did not consider further options related to the 21 TJ/d[229], Enbridge Gas evaluated two hybrid alternatives:[230]

a. 17.86 km NPS 36 and 21 TJ/d Ojibway to Dawn Exchange; and,

b. 16.20 km NPS 36 and 21 TJ/d Ojibway to Dawn Exchange.

167. Neither option was economically feasible.[231]

168. The evidence clearly shows the limitations of the Ojibway supply point and the fact that it is ineffective in providing the incremental capacity required. Nothing raised by FRPO refutes that evidence.

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[225] Exhibit C, Tab 1, Schedule 1, p. 14.
[226] EB-2016-0186, Union Reply Argument, pp. 36-43.
[227] Exhibit C, Tab 1, Schedule 1, p. 15.
[228] Exhibit C, Tab 1, Schedule 1, pp. 15-16.
[229] FRPO Submissions, p. 9.
[230] Exhibit C, Tab 1, Schedule 1, pp. 16-19.
[231] Exhibit C, Tab 1, Schedule 1, pp. 16-19.

169. With respect to FRPO's first unfounded assertion that Enbridge Gas made insufficient attempts to explore firm natural gas deliveries at Ojibway, FRPO relies on its belief that in 2016 Energy Transfer, the owner of PEPL and ROVER, desired to increase the river crossing capacity at Ojibway. In this regard, FRPO has attempted to relitigate the facts raised in EB-2016-0186 and argue that FRPO's interpretation of those facts support its assertion. However, those facts are not relevant to this proceeding and were fully canvased in EB-2016-0186 (both at a technical conference and oral hearing). The OEB accepted the facts at that time, and this was reiterated by Mr. Gillett in the current proceeding with a clear denial to FRPO's assertion and a full review of the facts.[232]

170. In regard to that testimony, FRPO made the very serious allegation that Enbridge Gas embarked on "revisionist history" and made "erroneous statements". There is no basis whatsoever for this allegation and it is entirely inappropriate and unacceptable that FRPO has made them. The examples, which FRPO points to in this regard, are without merit. One relates to the parsing of the witness statement that Energy Transfer was seeking to "get as much capacity, free capacity, to Dawn as possible through Ojibway." FRPO misconstrues that reference and equates it with misrepresenting the content of various correspondence included in FRPO's compendium. A more comprehensive reading of the transcript indicates clearly that the witness's reference to "free capacity" is a reference to available capacity, not that capacity would come without any payment required.[233] FRPO also relies on parsing various statements from the 2016 document to make conclusions about a desire to increase the capacity of the river crossing. The critical fact that fails to register with FRPO is that Energy Transfer, by contracting the current amount of 37 TJ/d via ROVER, was satisfied with respect to its capacity needs and the Ojibway supply point. Also, given that 21 TJ/d of delivery capacity has been available on PEPL since that time, ROVER has not sought that incremental capacity. If the interest was there, it would have been expressed, especially since an RFP was held to canvas interest directly with

[232] Hybrid Hearing Transcript Vol. 2, pp. 52-55.
[233] Hybrid Hearing Transcript Vol. 2, p. 55.

ROVER. All of which goes to demonstrate the complete irrelevance of FRPO's submissions.

171. FRPO also argues that with respect to the 21 TJ/d, Enbridge Gas could have entered into further supply arrangements with ROVER whereby the natural gas would be purchased through the Gas Supply Plan.[234] What FRPO fails to recognize is that an exchange at Ojibway has the same operational benefits and flexibility for the system as firm supply purchases upstream of Ojibway, but has the benefit of allowing costs to be easily isolated to allow proper comparison of project alternatives.

172. FRPO submitted that Enbridge Gas should negotiate with Energy Transfer to obligate deliveries at Ojibway. However, any "obligated" deliveries would be subject to the same import limitations that exist today and would provide the same benefits to the Panhandle System that have already been explored as a Project alternative. Furthermore, a pipeline operator does not have title of the supply it transports on behalf of its shippers and does not control how those shippers nominate for transportation of that supply. Instead, Energy Transfer provides transportation service to the shippers based on their contractual arrangements and, in turn, will operate its system based on the daily nominations of those shippers. This is the reason that neither PEPL nor ROVER participated in the RFP since they are not in the position to obligate the natural gas it transports on behalf of its shippers.

173. Regarding FRPO's submissions related to the limits on maximum deliveries to Ojibway and FRPO's assertion that they are artificial, Enbridge Gas submits that FRPO's submissions in this regard should be rejected. This issue has been previously considered by the OEB and the OEB accepted Enbridge Gas's method for calculating the applicable import limits in its 2016 Panhandle Reinforcement Project decision[235]. FRPO has established no new evidence in this regard to merit a reconsideration of the methodology.

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[234] FRPO Submissions, p. 9.
[235] EB-2016-0186, OEB Decision, p. 15.

174. The 108 TJ/d import limitation is the combination of the minimum summer market in Windsor (20 TJ/d) and the capability of the Sandwich Compressor Station to transport natural gas easterly towards Dawn (88 TJ/d). This limit dictates the maximum amount of import supply volume that can be contracted on a firm annual basis. Enbridge Gas is not operationally able to guarantee that import volumes greater than this amount can be accepted year-round. As stated in the Panhandle Reinforcement proceeding (EB-2016-0186) and again in the Kingsville Transmission Reinforcement proceeding (EB-2018-0013), this maximum import limit is not artificial as asserted by FRPO. Rather, as noted in response to EB-2016-0186, Exhibit JT1.5 and further reiterated in the Company's Reply Argument in that proceeding, the amount of firm import volume is determined based on available market and system capability. The methodology is sound and is based on historical data over a significant period of time. The available market at Ojibway is calculated based on an average of the lowest demands for 20 days of each month[236]. This average value is compared each month across a rolling 5-year timeframe to determine a reasonably available market and to create a minimum demand profile.[237] FRPO has not provided new evidence that would call this methodology into question, and as such its assertions should be dismissed.

K. Enbridge Gas's Approach to Subsequent Phases of Panhandle System Expansion is Appropriate

175. In the context of OEB Staff's submissions regarding Enbridge Gas's consideration of Project alternatives, OEB Staff raised a number of concerns regarding Enbridge Gas's consideration of IRP alternatives for potential future phases of Panhandle System expansion projects.[238] OEB Staff notes that these concerns, which are further detailed in this section, are primarily based on Enbridge Gas's testimony during Mr. Buonaguro's cross-examination.[239]

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[236] This methodology is not conservative as suggested by FRPO. A conservative approach would be to simply use the lowest consumption experienced in Windsor, which Enbridge Gas does not do.

[237] Exhibit B, Tab 2, Schedule 1, p. 8.

[238] OEB Staff Submissions, pp. 31-32.

[239] Hybrid Hearing Transcript Vol. 1, pp. 146-152.

176. Before addressing the specific concerns raised by OEB Staff, it is important to provide additional context on the circumstances surrounding OEB Staff's concerns.

177. The Project is forecasted to address the Panhandle System capacity shortfall for the next 5 years (i.e., Winter 2024/2025 to Winter 2028/2029, inclusive) and is expected to be fully utilized by Winter 2028/2029.[240] Mr. Thomas testified that this 5-year approach to system planning is rooted in achieving balance and flexibility:

> *The NPS 36 Loop is a size for-size extension of the Panhandle system to support the forecasted growth over the next five years, and is expected to be fully utilized by 2029. Supporting at least five years of growth provides balance between meeting near-term, known demands, cost efficiencies in the planning, development and construction of the project as well as flexibility to adjust the forecast with the most up-to-date inputs, in the future.*[241]

178. Following construction of the Project, a Panhandle System capacity shortfall is expected to reemerge in Winter 2029/2030 at 2 TJ/d and is expected to reach 17 TJ/d by Winter 2030/2031.[242]

179. The submissions made by OEB Staff in this regard relate to project alternatives for a future project (i.e., 5 years in the future) for which Enbridge Gas is not seeking relief as part of the current application.

(i) IRP Alternatives Could Be Viable For a Future Project (i.e At Least 5 years In the Future)

180. OEB Staff expressed concern regarding its understanding that Enbridge Gas carried out an initial assessment of IRP alternatives for a subsequent Panhandle System expansion project and found that no viable IRP alternatives exist for that future project.[243] However,

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240 Exhibit 1.STAFF.6, p. 2.
241 Hybrid Hearing Transcript Vol. 1, pp. 7-8.
242 Exhibit 1.STAFF.6, p. 2.
243 OEB Staff Submissions, p. 31.

Enbridge Gas's evidence is that a supply-side IRP alternative is a possible viable option, as explained by Ms. Wade:

> *MS. WADE: So I think I will just go back to what I was noting, that we will continually assess because, as we move closer to the date, for example, there could be a supply side option that would be a feasible option to satisfy the need in 2028/2029. So I think it's important to note that, as I was saying, at this point, we are aware of that project and we are looking at IRP alternatives that we would have to implement in order to avoid that. But, say, the supply side option, we are not going to implement that until we get closer to the date and we have a firm understanding of what the need is.*
>
> *MR. BUONAGURO: So you're saying, then -- and, without judgment, I am asking the question -- you're saying that, in the winter of 2023/2024, looking ahead to the winter of 2029/2030, it's still too early?*
>
> *MS. WADE: No. But I think we have just done our assessment of different IRPA, so we are aware of what alternatives we could use, for example, a supply side option, should that requirement come to fruition.*
>
> *MR. BUONAGURO: I think you are telling me that, right now, the best option is an as-yet-unknown supply option.*
>
> *MS. WADE: It could be one of the options, yes.*
>
> *[…]*
>
> *MS. WADE: And I would note that, based on the analysis that we have done to date, that would likely be the best available option for that next phase of the project, but we wouldn't determine that until the need has been confirmed.*
>
> *MR. BUONAGURO: Right. And is that because, you know, again, assuming the demand is as it is on this page, on JT1.23, a supply side option to service 14 terajoules per day is feasible?*
>
> *MS. WADE: That's correct.*[244]

181. During Mr. Quinn's subsequent cross-examination, Ms. Wade provided additional evidence reaffirming her prior testimony that a supply-side IRP alternative is a potential viable option to address the future capacity shortfall expected to begin in Winter

[244] Hybrid Hearing Transcript Vol. 1, p. 151.

2029/2030.[245] While Enbridge Gas considers a supply-side IRP alternative to be a potentially viable option to address the future shortfall, Ms. Wade testified that it is premature to implement and commit to a future project alternative, as discussed below, until there is greater certainty regarding (i) the timing and nature of the potential future shortfall, and (ii) the availability and price of future project alternatives. [246]

(ii) Enbridge Gas Applies an "Assess and Adapt" Approach (Not a "Wait and See" Approach)

182. OEB Staff "takes issue with Enbridge Gas's statement that it would not make a determination on the best option until closer to the required in-service date when the need has been confirmed" noting that this approach would lead to the potential role of ETEE as an IRP alternative being rejected due to the longer lead time needed for ETEE to deliver results.[247] OEB Staff submits that this "wait and see" approach is inconsistent with the intent of the IRP Framework to identify potential system needs/constraints well in advance to ensure adequate lead time for a detailed consideration of alternatives.

183. Respectfully, Enbridge Gas rejects OEB Staff's characterization that Enbridge Gas has applied what it refers to as a "wait and see" approach, which connotes inaction on the part of Enbridge Gas. Enbridge Gas submits that a more accurate characterization of its approach surrounding IRP determination is "assess and adapt". Enbridge Gas has indeed assessed the viability of IRP alternatives for potential next phases of Panhandle System expansion. As mentioned above, Ms. Wade testified that Enbridge Gas has proactively carried out a full IRP alternative assessment for this potential future project:

> *MS. WADE: Yeah, so what I also noted is that we have completed a full IRP analysis for this project, which would inform the supply-side solution that could be available for that project in the future. And so in looking solutions that we have looked at, the Ojibway could potentially be an option for that 14 TJ...."*[248]

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[245] Hybrid Hearing Transcript Vol. 2, pp. 47-48.
[246] Exhibit C, Tab 1, Schedule 1, pp. 3-4; Hybrid Hearing Transcript Vol, 2, p. 86.
[247] OEB Staff Submissions, pp. 31-32.
[248] Hybrid Hearing Transcript Vol. 2, pp. 47-48.

184. While Enbridge Gas has actively carried out an IRP analysis and continues to view a supply-side IRP alternative as a viable option for a future phase, Enbridge Gas has not implemented an IRP solution because, as Ms. Wade testified, "it's really important to [first] understand what the demand will be and where it will show up in order to understand whether or not that 14 TJ would meet the need."[249] Critical details surrounding a possible subsequent phase are unknown at this time, including certainty about the capacity shortfall and basic physical characteristics of a potential facility solution. Further, before definitively committing to and implementing a specified IRP alternative to meet a need more than 5 years from now, greater certainty is required for factors such as the availability and price of potential non-facility alternatives. In light of this uncertainty, there is ample evidence on the record that in the interim, Enbridge Gas will actively "continue to assess the Panhandle System's capacity position each year and [will] at such time, evaluate if an IRP alternative could feasibly delay the need for further physical capacity."[250]

185. Enbridge Gas agrees with OEB Staff's submission that timelines for making final determinations of any IRP alternative should factor in the longer lead-times associated with ETEE programs. Enbridge Gas has and will continue to factor this longer-lead time into their IRP alternative evaluations. To this end, Enbridge Gas notes that, based on the findings by Posterity, there is the potential to reduce peak natural gas demand on the Panhandle System by 28 TJ/d within 3.5 years at a cost of approximately $230 million via an ETEE IRP alternative.[251] Enbridge Gas's current forecast indicates that a capacity shortfall of 17 TJ/day[252] would come to fruition in Winter 2030/2031, six years from now. As such, this lead time of six years does not result in any lost IRP alternative opportunities at this time. Rather, it affords time to gain greater certainty regarding the

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249 Hybrid Hearing Transcript Vol. 2, p. 48.

250 Exhibit I.STAFF.6; See also Hybrid Hearing Transcript Vol. 1, p. 149, ln 21-28; p. 150, lns 1-2, 25-28; p. 151, ln 1.

251 Extrapolated from Posterity's analysis completed for the Project, data found in Exhibit I.PP.36, Attachment 4.

252 Exhibit I.STAFF.6, p. 2.

timing and nature of the potential future shortfall and the availability and price of the potential alternatives (including the supply-side alternative noted above).

186. Enbridge Gas submits that its "assess and adapt" approach is far more prudent than an approach that prematurely commits to an IRP alternative related to a need that is more than 5 years in the future, given the uncertainties. Further, if Enbridge Gas's current approach was not maintained, there is a risk of binding the Company to incur costs that may not be necessary or helpful to address the future need.

187. Enbridge Gas submits that in the circumstances, its consideration of IRP alternatives strikes a prudent balance between proactive analysis, planning and maintaining the requisite level of flexibility.

(iii)A Direction to Assess Whether Enbridge Gas Recommends a Proactive IRP Plan is Not Required

188. In light of OEB Staff's concerns discussed above, OEB Staff submits that the OEB should direct Enbridge Gas to assess whether it recommends a proactive IRP Plan, including the use of ETEE, to avoid or reduce the scope of future transmission expansions of the Panhandle System. OEB Staff submits that this assessment should be filed as part of a future Enbridge Gas annual IRP report (which already requires Enbridge Gas to report more generally on the results of its IRP Assessment Process), and Enbridge Gas should consider the trade-offs as to the appropriate time to act to address an identified system need.

189. Enbridge Gas submits that, in the circumstances, it is not necessary for the OEB to direct Enbridge Gas to assess whether it recommends a proactive IRP Plan for subsequent phases of Panhandle System expansion because Enbridge Gas is already in the process of completing an IRP assessment using information pertaining to the potential next phase of Panhandle System expansion that is included in the AMP Addendum filed on October 31, 2023. Enbridge Gas notes that this IRP assessment is already considering the "trade-offs

as to the appropriate time to act to address an identified system need"[253] and that any updates to this assessment, and all other IRP assessments, will be included in the IRP annual report. Enbridge Gas further notes that its standard IRP assessment protocol considers the timing of IRP alternatives applicable to each project, including a potential subsequent phase of Panhandle System expansion.

L. Enbridge Gas Undertook Meaningful Indigenous Consultation

190. Enbridge Gas has been delegated the procedural aspects of the duty to consult with potentially impacted Indigenous groups by the Ministry of Energy ("ENERGY").[254] In accordance with the OEB's Guidelines, an Indigenous Consultation Report outlining Enbridge Gas's consultation activities has been prepared and provided to ENERGY and filed with the OEB.[255]

191. While Enbridge Gas has not yet received a letter from ENERGY confirming sufficiency of Indigenous consultation activities on the Project ("Letter of Opinion"), ENERGY has indicated that it will likely be submitting a Letter of Opinion close to the end of record of the OEB proceeding, when Enbridge Gas files its written reply submission.[256] Enbridge Gas has been in contact with ENERGY regarding its activities for the Project and is not aware of any reasons why a Letter of Opinion would not be issued in advance of an OEB decision regarding the Project's leave to construct application. Enbridge Gas would accept the OEB imposing the standard requirement to file the Letter of Opinion as a condition of approval for the Project.

192. OEB Staff's submission confirmed that the OEB Staff is not aware of any outstanding concerns from Indigenous communities regarding any Aboriginal or treaty rights that may be impacted by the Project and acknowledged that Enbridge Gas has committed to ongoing communication and to address concerns raised by the Indigenous communities related to the Project. OEB Staff suggested that the OEB should wait to grant leave to

[253] EB-2020-0091, October 31, 2023, Enbridge Gas Asset Management Plan Addendum -2024.
[254] Exhibit H, Tab 1, Schedule 1, Attachment 2.
[255] Exhibit H, Tab 1, Schedule 1, Attachments 6 and 7; Exhibit I.STAFF.22(a)-(d).
[256] Exhibit I.STAFF.31(e).

construct for the Project until the Letter of Opinion is filed by Enbridge Gas and that in the event that the Letter of Opinion is not received or filed prior to record close, the OEB could place the proceeding in abeyance until such time that the Letter of Opinion is filed.[257] Enbridge Gas submits that placing the proceeding in abeyance is not necessary and instead suggests that the OEB impose the standard requirement to file the Letter of Opinion as a condition of approval for the Project, consistent with the OEB's determinations in past proceedings.

193. TFG's submission expresses concern regarding Enbridge Gas's consultation with respect to the Project and specifically requests that Enbridge Gas be more proactive in incorporating the histories and positions of First Nations into its initial application materials, including environmental reports.

194. Contrary to the suggestions of TFG, and as demonstrated by the evidence on the record, Enbridge Gas undertook early and meaningful Indigenous consultation with potentially affected Indigenous groups in relation to the Project and has committed to continue to engage with those Indigenous groups throughout the lifecycle of the Project. Enbridge Gas undertook this consultation in good faith, with a view of gathering relevant information from the Indigenous groups and addressing their concerns. This consultation involved providing detailed Project information to the Indigenous groups (including an Environmental Report), answering specific questions, making additional commitments, and offering Indigenous groups the opportunity to engage in field work.[258] On a number of occasions, Enbridge Gas requested the input of Indigenous groups in order to better understand how any potential impacts from the Project on Indigenous interests could be avoided or mitigated. Capacity funding was offered to support these activities. Detailed information about this consultation, including any identified Indigenous concerns and Enbridge Gas's responses to those concerns, has been filed on the record of this proceeding, both in the initial Application and through subsequent updates. In addition, Enbridge Gas notes that the OEB's regulatory proceeding, in which TFG was an active

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[257] OEB Staff Submissions, p. 53.
[258] Exhibit H, Tab 1, Schedule 1, Attachments 6 and 7. Exhibit I.STAFF.22(a)–(d).

participant, provided further opportunity for Indigenous groups to ask both written and oral questions regarding the proposed Project, with Enbridge Gas providing detailed responses on the record. In Enbridge Gas's view, its consultation practices were far from deficient, rather its efforts were robust, responsive, and meaningful.

195. In terms of TFG's specific concerns regarding the incorporation of Indigenous history in the Environmental Report for the Project, Enbridge Gas submits the Environmental Report was completed in accordance with the OEB's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (the "Guidelines"). TFG's submission unfairly diminishes the efforts made, both in the context of the Environmental Report and through ongoing consultation with potentially affected Indigenous groups, to understand Indigenous history in the Project area as well as current use and concerns. For example, the Stage 1 Archaeological Assessment (included in Appendix E of the Environmental Report) and the Cultural Heritage Assessment Report (included in Appendix F of the Environmental Report) document land use history and current conditions and were both provided to the potentially affected Indigenous groups for comment. Adding to the analysis outlined in the Environmental Report, Enbridge Gas's consultation activities provided, and continue to provide, the potentially affected Indigenous groups the opportunity to add to the information contained in the Environmental Report and to communicate their perspective. It was through this consultation, for example, that TFG drew Enbridge Gas's attention to the specific Band Council Resolution outlining Chippewas of Kettle and Stony Point First Nation's ("CKSPFN") water rights assertion and its specific concerns regarding potential impacts on water resources. This, along with other comments, lead to Enbridge Gas providing CKSPFN and TFG further explanation of the mitigation measures aimed at protecting water resources.[259]

196. The extensive consultation outlined in the Indigenous Consultation Report, including Enbridge Gas's detailed responses to Indigenous groups' comments on the Environmental Report, demonstrates the importance Enbridge Gas places on

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[259] Exhibit I.STAFF.22, Attachment 4, p. 12.

understanding the perspectives of the potentially affected Indigenous groups and responding to their questions and concerns regarding the Project. Given the significant efforts Enbridge Gas has made to consult with the potentially affected Indigenous groups identified by ENERGY, TFG's requested relief in relation to Indigenous consultation is not necessary.

M. Enbridge Gas's Environmental Mitigation Measures are Appropriate.

197. TFG highlighted certain environmental concerns related to aquatic habitats, monitoring of fugitive emissions, and tree clearing and site restoration, and requested further opportunities to review and provide input into various plans. Enbridge Gas submits that the mitigation measures it has identified and committed to, which were informed by its consultation with Indigenous groups, are appropriate in the circumstances. Enbridge Gas has identified numerous other mitigation measures to address the type of concerns identified in TFG's submission. These mitigation measures are detailed in the Environmental Report as well as in the responses to Indigenous groups' comments on the Project and will be reflected in the project-specific Environmental Protection Plan ("EPP"), a copy of which will be provided to TFG and any other interested Indigenous groups upon request. With the implementation of these mitigation measures, including contingency plans, there are no anticipated significant residual environmental effects. For additional clarity, specific comments on TFG's identified areas of environmental concern are provided in the following paragraphs.

198. **Aquatic Habitats** - With respect to TFG's specific concerns regarding the protection of aquatic habitats, TFG's submission acknowledges the myriad of mitigation measures Enbridge Gas has committed to in order to protect aquatic habitats, including trenchless crossings of certain watercourses and the implementation of sediment and erosion controls. In terms of TFG's specific concern regarding the risk of a "frac-out" and the release of drilling fluid in the surrounding area, Enbridge Gas will implement drilling fluid release contingency measures and any additives used in its horizontal directional drilling ("HDD") operations for the Project will be newly sourced and will comply with applicable environmental regulations and any excess bentonite slurry would be managed

in accordance with O. Reg 406/19- On-site and Excess Soil Regulation. Enbridge Gas has committed to contracting a qualified third-party environmental inspector to monitor aquatic habitats during all watercourse crossings to ensure that the measures in place for environmental protection and regulatory compliance, including drilling fluid release contingency measures, are adhered to throughout construction of the Project. Furthermore, Enbridge Gas will commit to notifying TFG in the event of a reportable spill (i.e., any spills in which an adverse effect has occurred as defined in the Ontario Environmental Protection Act) stemming from the Project, which would encompass inadvertent returns of drilling slurry into watercourses. To the extent that Enbridge Gas alters the planned construction methodology from a trenchless watercourse crossing to another crossing method, the Company commits to notify TFG of this change.

199. **Ongoing Monitoring of Fugitive Emissions** - In terms of TFG's proposal regarding a further plan for monitoring fugitive emissions, Enbridge Gas submits that a further plan is not warranted. As explained in its response to TFG in the course of consultation, Enbridge Gas manages its fugitive emissions in accordance with industry accepted best management practices (CSA Z620.1) and government regulations, including the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*, to reduce emissions from its operations and has implemented a harmonized leak operating standard, which includes increased traceability and tracking of leak repairs, increased monitoring frequencies, harmonized repair timelines for above ground leaks and initiation of a station leak survey program.[260] Pipelines are inspected annually by way of a foot patrol, during which a leak survey is conducted, using a flame ionization gas detector, with the results of the surveys tracked and applied to the appropriate fugitive emission calculations for federal and provincial emissions regulatory reporting. Furthermore, Enbridge Gas has made a commitment as part of the rebasing settlement to investigate ways to accurately measure fugitive emissions, including consideration of top-down measurements.[261] As a result, the Fugitive Emissions Measurement Plan Project has been initiated to deliver a fugitive

[260] Exhibit I.TFG.9.
[261] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, July 12, 2023, p. 37.

investigation plan for inclusion in the 2024 Deferral and Variance Account Clearance proceeding. Given Enbridge Gas's referenced commitments, a further plan for monitoring fugitive emissions is not warranted.

200. **Tree Removal and Restoration** - Throughout the course of Enbridge Gas's consultation with Indigenous groups in relation to the Project, Indigenous groups have provided input in relation to a myriad of issues, including site restoration. As acknowledged in TFG's submission, Enbridge Gas has committed to, where feasible, in consultation with directly impacted landowners, restoring the lands to pre-existing conditions with the exception of woodlands and trees within the permanent easement. In its response to CKSPFN's comments on the Environmental Report,[262] Enbridge Gas further committed to implementing a tree replacement program that replants woodland removed with seedlings of native species that are guaranteed until they reach free to grow status. This program was planned at a ratio of 2:1 for the woodland areas removed and will now be increased to 3:1 (i.e., trees to be replaced on a 3:1 area basis at 1000 tree seedlings per acre). Enbridge Gas has committed to working with Indigenous communities and local conservation authorities to find suitable locations to plant trees in the event directly impacted landowners are not interested in planting trees on their property. In addition, Enbridge Gas has indicated that it would accept the standard conditions requiring the submission of a post construction monitoring report within three months of the in-service date, which will include any impacts and outstanding concerns identified during construction, and a final monitoring report no later than 15 months after the in-service date, which will, among other things, describe the condition of any rehabilitated land and the results of analyses and monitoring programs and any associated recommendations.[263] These monitoring reports will be filed publicly and, consistent with Enbridge Gas's commitment to lifecycle engagement, should the Indigenous groups identified by ENERGY have questions regarding the monitoring reports, Enbridge Gas would be pleased to meet with them to discuss any questions or concerns.

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[262] Exhibit I.STAFF.22, Attachment 4, pp. 14-15.
[263] Exhibit I.STAFF.23.

201. In terms of the relief requested by TFG that would have Enbridge Gas provide additional plans to Indigenous groups for their review and comment prior to implementation, Enbridge Gas submits there is no need to grant the specific relief outlined in TFG's submission. Enbridge Gas has undertaken significant consultation with Indigenous groups, providing them with detailed Project information and making significant efforts to understand and address their concerns, including through additional commitments. Furthermore, Enbridge Gas is committed to continuing to engage with Indigenous groups potentially affected by the Project to address any additional concerns they may have. To the extent that potentially affected Indigenous groups have concerns in relation to this information or any other matter related to the Project, Enbridge Gas would have a standing offer to meet with the Indigenous groups to discuss any concerns. Enbridge Gas submits that, recognizing the consultation on the Project to date and the commitment to ongoing consultation throughout the lifecycle of the Project, as well as the appropriateness of the mitigation measures proposed and committed to, there is no need for additional formal review and comment processes to be completed prior to implementation of plans and procedures.

N. Relief Requested

202. Based on the foregoing, Enbridge Gas respectfully requests that the OEB, pursuant to section 90(1) of the *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Schedule B (the "Act"), issue an Order granting leave to construct the pipelines and pursuant to section 97 of the Act, issue an Order approving the form of pipeline easement agreement found at Exhibit G, Tab 1, Schedule 1, Attachment 3, and the form of temporary land use agreement found at Exhibit G, Tab 1, Schedule 1, Attachment 4.

All of which is respectfully submitted this 29th day of January 2024.

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