**ONTARIO ENERGY BOARD**

**Enbridge Gas Inc.**

**Application for leave to construct natural gas pipelines in the Municipality of Chatham Kent and Essex County**

**ARGUMENT**

**Industrial Gas Users Association (IGUA)**

## IGUA's POSITION

1. The proposed Panhandle Regional Expansion Project (PREP) would provide 168 TJ/day of incremental capacity on Enbridge Gas Inc.'s (EGI) Panhandle Transmission System.

2. EGI has identified 34 greenhouses[1] and 2 power generators who are forecast to take up all of that capacity by the winter commencing November, 2028, save for the 6% of the PREP capacity that is forecast to be taken up by general service demand growth between now and then.[2]

3. The forecast cost of the project, excluding indirect overheads, is $289.2 million. The incremental revenues forecast from the 36 customers driving the project and expected to consume the capacity thereby made available are expected to fall short of this cost by $150 million (52%) on a net present value (NPV) basis.

4. It is EGI's position that this shortfall should be subsidized by all existing and future EGI customers in classes to which Panhandle System costs are allocated.

5. It is IGUA's position that this shortfall should be recovered from the contract customers who will take up, and benefit from, the capacity created by the project. If these customers

[1] Tr1-154, line 18 to Tr1-155, line 3.
[2] JT1.23, page 2.

want firm gas delivery service, and are prepared to commit to the capacity required to provide it, then they should have it, and they should pay for it.

**<u>EGI's POSITION</u>**

6. EGI has chosen not to address the topic of contributions in aid of construction (CIAC's) in its Argument in Chief (AIC). This despite the topic;

   (a) having been expressly and specifically highlighted by the OEB in Procedural Order No. 4;

   (b) having consequently been addressed by EGI in its June, 2023 evidence update;

   (c) having been the subject of a number of interrogatories responded to by EGI;

   (d) having been specifically addressed by EGI's witnesses in their opening presentation at the oral hearing; and

   (e) having been addressed by EGI's witnesses repeatedly during oral examinations.

7. It is clear that the topic of CIAC's has been a major one for the OEB and a number of the parties to this proceeding, and EGI is obviously aware of this, but has chosen to remain silent on the topic in its AIC.

8. In this argument we have addressed what we understand from all of the foregoing to be EGI's positions on the CIAC topic and its arguments in support of those positions. Should EGI raise in its reply submission arguments or materials that we have not addressed, we reserve the right to provide response to those should we determine it necessary to do so.

9. We understand EGI's basic positions on CIAC's to be as follows:

   (a) As a transmission project, PREP falls under the OEB's EBO-134 policy for evaluation of capital investment and EBO-134 does not contemplate CIAC's, save in limited circumstances which don't apply in the case of PREP.

   (b) It would be unfair for the OEB to direct CIAC's in support of PREP when the customers who responded to EGI's February, 2023 Expression of Interest (EOI) with intention to commit to the incremental capacity to be created by the project have made their incremental investment plans based on the OEB's past decisions to the effect that CIAC's do not apply to transmission projects. Directing CIAC's in these circumstances would be contrary to the expectations of these customers, and potentially anti-competitive *vis a vis* previous similarly situated customers in the area who obtained incremental gas delivery service without having to make CIACs.

(c) Imposition of CIACs on the customers anticipated to be served by way of the incremental capacity created by PREP would cause those customers to take their investment to other jurisdictions, precluding the spinoff economic benefits thereby promised for Ontario. (We note, however, that the evidence and EGI's position on this point is unclear, as EGI's witnesses ultimately seemed to assert that what would preclude these customers from making incremental capital investments in Ontario would be the lack of incremental gas service *per se*; see AIC paragraph 51, and a more complete discussion of the point at Tr2-21, line 12, through Tr2-25, line 3.)

(d) Because PREP is a transmission project it benefits the entire Panhandle system and all of the customers thereby served, and it would be inappropriate for specific customers seeking incremental service to bear the costs of the project.

(e) If customers connect at different locations and/or present incremental demands which are different from those reflected in response to EGI's EOI, actual capacity created by the project would end up being higher or lower than the planned 168 TJ/d, and either;

(i) CIAC's established at the outset would result in over or under collection from customers subject to them; or

(ii) CIAC calculation would have to be redone as each new customer comes along which would be complex and/or unfair as between connecting customers.

10. We address each of these positions in turn, following which we discuss application to PREP of the Hourly Allocation Factor (HAF) mechanism previously advanced by EGI, endorsed by the OEB and already utilized in analogous circumstances.

**<u>SALIENT FACTS</u>**

11. PREP is the 6th Panhandle system expansion project since 2013.[3] All six of these projects have been driven by incremental Kingsville-Leamington area greenhouse growth.

12. EGI's witnesses confirmed[4] that in the present case all 34 greenhouse customers seeking incremental gas supply;

(a) are located in the Kingsville-Leamington area; and

[3] See K1.9, IGUA *Compendium for Examination*, pages 36-105, which contains excerpts from the following proceedings: EB-2012-0431; EB-2013-0420; EB-2016-0013; EB-2016-0186; EB-2018-0013; EB-2018-0188.
[4] Tr3-82, line 17 through Tr3-83, line 13.

(b) are existing EGI customers seeking to increase their firm contracted gas delivery capacity.

13. In aggregate these greenhouse customers are expected to contract for ~38.5% of the PREP demand.[5]

14. The other major driver for PREP is incremental gas demand from Atura Power and East Windsor Cogeneration; two gas fired power generation (GFG) facilities, located close to each other near Windsor. Together these two power generators are forecast to consume just over 57% of the PREP capacity.[6]

15. Atura Power itself represents ~40% of the PREP demand, and has already entered into its contract with EGI for this capacity. Atura Power has also renegotiated its power purchase agreement with Ontario's Independent Electricity System Operator (IESO) to the effect that if Atura is required to pay a CIAC in respect of its PREP enabled capacity, 50% of that payment will be passed through to the IESO.[7]

16. The residual ~5.5% of the forecast PREP demand arises from EGI's forecast general service load growth of 2% per year.[8]

17. This data is summarized in the following table:

| Customer Category | % PREP Capacity |
|---|---|
| Greenhouses | 38.5% |
| GFGs | 57% |
| General Service | 5.5% |

18. While EGI's witnesses testified that the they can't actually predict which customers will ultimately come along and contract for the PREP created capacity, there appears to be sufficient certainty in EGI's view regarding the level and location of demand for incremental capacity to have designed the PREP project to meet the 5 year demand forecast and to justify the PREP Project on that basis. EGI's witnesses testified that they neither

[5] JT1.23, updated 2023-10-03.
[6] JT1.23, updated 2023-10-03.
[7] K2.5, SEC Compendium, pages 57-58.
[8] JT1.23, updated 2023-10-03. We note that while there are two large commercial-industrial customers included in EGI's forecast, there is no incremental large commercial-industrial contract customer load in EGI's forecast from and after November, 2024, the planned in service date for PREP.

discounted nor supplemented their EOI derived forecast of needed new capacity in designing and advancing this project.[9]

19. The Panhandle transmission system is a "stand alone" system, distinct from; i) the Sarnia Industrial Transmission Line (SIL); and ii) the Dawn-Parkway Transmission System (DP System) and the balance of EGI's system east of Parkway. Customers served by the SIL and the DP System and east receive no benefit from the Panhandle System, and will receive no benefit from PREP.[10]

20. Despite the fact of the independence of the EGI's transmission systems, under EGI's current cost allocation mechanisms[11] costs of the Panhandle System and the SIL are combined for the purpose of allocation, and the aggregate costs of the two discrete systems are allocated to rate classes on the basis of design day demand by each rate class on either of these two systems.[12] That means that the Sarnia area chemical complex companies, who are members of IGUA, will be allocated significant PREP costs though they will receive no benefit from the project at all.

21. The rate base values of each of the Panhandle System & the SIL, as of the forecast PREP in-service date and the addition to this combined rate base of the $358 million of PREP costs (inclusive of indirect overheads), are forecast to be as follows[13]:

| | | |
|---|---|---|
| Panhandle | $422.2 + $358 = $780.2 million | 99.53% |
| St. Clair | $3.7 million | 0.47% |
| Total | $783.9 million | |

22. The largest allocation of PREP costs will go to Rate T2 (Firm) customers, which is the rate class into which many of IGUA's members, including IGUA's members who take service on the SIL, fall. Once PREP goes into service, under EGI's proposal all Rate T2 customers would subsidize Atura Power, East Windsor Cogeneration, and 34 Leamington area

[9] Tr1-162.
[10] Tr1-153, lines 6-24.
[11] We acknowledge that these cost allocation mechanisms, including in particular the mechanism for allocation of Panhandle system costs, will be subject to review in Phase 3 of EGI's rate rebasing application, expected to take place in 2024, with any resulting cost allocation changes likely to be implemented in 2026.
[12] I.IGUA.1, part (b).
[13] I.IGUA.1.

greenhouses to the tune of ~$3.7 million annually, resulting in almost a 5.5% percent annual gas delivery bill impact to the largest subsidizing T2 customers.[14]

23. IGUA's Sarnia area large industrial trade exposed members who cannot possibly receive any benefit from PREP would, under EGI's proposal, be subsidizing Atura and the Leamington greenhouse expansions to the tune of several hundred thousand dollars a year.

## BASIC REGULATED RATE MAKING PRINCIPLES

24. The OEB has held that CIACs are a "rate" which is within its jurisdiction to set.

25. It is a fundamental principle of rate making that rates should reflect costs to serve. Put differently, costs should follow benefits.[15]

26. It is also true, of course, that absent setting a unique rate for each individual customer, rates can never perfectly achieve this fundamental principle. Thus there are additional rate making principles the effect of which is to allow for practicality and administrative efficiency in rate setting.[16] These additional principles recognize that subsidies as between individual utility customers and rate classes are unavoidable, but also that they should not be "undue"[17], as recognized by Chair Moran in discussion with EGI's Mr. Szymanski.[18]

27. This balance between cost reflectivity and reasonable (or not unreasonable) cross-subsidy is recognized in the Ontario Energy Board's (OEB) natural gas expansion economic analysis frameworks; both EBO-134 and EBO-188.

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[14] I.IGUA2, Attachment 1, page 1, line 30 and page 2, line 16.

[15] *Principles of Public Utility Rates*, Bonbright, Danielsen, Kamerschen, page 109; *"… the golden rule of socially optimal ratemaking is that, whenever possible, prices should track all the identifiable (marginal private and social) costs occasioned by a service's provision."*

[16] *Principles of Public Utility Rates*, Bonbright, Danielsen, Kamerschen, page 384; *"The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application."*

[17] *Principles of Public Utility Rates*, Bonbright, Danielsen, Kamerschen, page 385; *"… the principle that the burden of meeting total revenue requirements must be distributed fairly and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service so as, if possible, to avoid undue discrimination."*

[18] Tr3-97, lines 22-27.

28. The proposed $150 million subsidy from EGI's customers at large to the few dozen contract customers expected to take up all of the PREP created capacity would be undue and is unnecessary.

29. The OEB approved HAF mechanism provides a means to effectively and equitably preclude such undue subsidy.

**EBO-134 and EBO-188**

30. We understand it to be EGI's position that, as a transmission project, PREP falls under the OEB's EBO-134 policy for evaluation of capital investment[19] and EBO-134 does not contemplate CIAC's, save in limited circumstances which don't apply in the case of PREP.

31. EBO-134 does not in fact contemplate a project like PREP; reinforcement of an existing system to provide gas delivery capacity to a particular set of forecast customers.

**EBO-134**

32. The EBO-134 report was released more than 36 years ago, in June, 1987. The policy was developed in response to the discontinuation of federal government programs which provided funds to Ontario gas utilities in the form of contributions in aid of construction to assist in expansion of their distribution systems to previously unserved communities where such projects were otherwise not financially viable and through which projects the use of oil would be displaced by natural gas.[20]

33. The EBO-134 inquiry addressed, *inter alia*, the following questions[21];

- *with [the federal funding programs] discontinued, what are the means whereby marginally uneconomic areas of Ontario are to be served, it at all;*
- *what is the role of the Board in light of the removal of [the federal funding programs] and to what extent should it be encouraging gas service to marginally uneconomic areas;*

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[19] AIC paragraph 4.
[20] EBO-134 paragraphs 2.7-2.10.
[21] EBO-134 paragraph 2.13.

- *with Ontario utilities facing mature markets, is expansion into uneconomic areas appropriate;*

- *should the shareholders or customers of utilities subsidize uneconomic expansion into smaller communities;*

*…*

34. The EBO-134 report focussed on a framework for determination of whether such new community uneconomic natural gas system expansions were in overall public interest[22];

> *The Board considers that system expansion should not be unlimited and that it is required to continue to determine whether the expansion of gas service is in the public interest.*

35. To this end, EBO-134 established a 3 stage test for evaluation of otherwise uneconomic gas system expansions. The first stage is a test of the stand alone economics of the proposed expansion; i.e. do the revenues to be derived from the project cover its costs. The second and third stages seek, respectively, to evaluate: i) the interests of the customers to be served by the project (by evaluating their energy savings as a result of the project); and ii) broader quantifiable and unquantifiable public interest benefits from the project. This project evaluation framework was developed and was to be applied to determine whether the proposed uneconomic expansion was, despite not being internally cost effective, in the broader public interest. Under the EBO-134 framework, the Board would consider[23];

> *… if the welfare of the public is enhanced without imposing an undue burden on any individual, group or class. The Board will continue to be guided by this general principle in determining the extent to which gas service should be extended into other areas of the province.*

36. Under EBO-134, determination of whether a natural gas expansion project is in the overall public interest is a separate determination from that of whether a burden on other customers resulting from the project would be *"undue"*. The EBO-134 three stage analysis addresses the overall public interest in a project proceeding, <u>not</u> allocation and recovery

[22] EBO-134 paragraphs 5.17 through 5.19.
[23] EBO-134 paragraph 5.16.

of the associated costs. EGI's Mr. MacPherson acknowledged that this is correct, and that the latter is a matter of rate making and cost allocation.[24]

37. Chair Moran explored this point in the following exchange with EGI's witnesses[25];

> *MR. MORAN: All right. So, clearly, there's a subsidy, and the Board has recognized in the past that these subsidies exist, and the question becomes whether it's an acceptable subsidy that doesn't require any contribution from the people benefitting directly from the project. And, as I understand it, the Stages 2 and 3 analyses are intended to consider other benefits that result from the creation of the project in order to make sure that, at the end of the day, there is no net loss to the economy as well. Right?*
>
> *MR. MacPHERSON: Generally, that's correct.*
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> *MR. MORAN: Okay. But, to the extent that those benefits have been quantified, none of those benefits changes the fact that the ratepayers are going to end up paying more than they were already paying. Right? The Stage 2 and Stage 3 analysis doesn't change the subsidy and it doesn't get rid of the subsidy.*
>
> *MR. SZYMANSKI: Yes, I would agree with that.*

38. Nothing in EBO-134 precludes the imposition of CIAC's in support of an uneconomic gas expansion project, and to preclude an *"undue"* resulting burden thereof on non-benefitting customers. Indeed, the emphasis in the policy on precluding an *"undue burden"* on existing customers would suggest the opposite; that CIAC's are appropriately considered in an EBO-134 evaluation.

39. EBO-134 specifically directs that[26];

> *… a contribution-in-aid of construction should be required for those projects where the sole purpose is to supply gas into a new area and where the evaluation process demonstrates an undue burden on existing customers.*

In light of the stated purpose of the EBO-134 review to examine the OEB's role in respect of continued expansion of the Ontario natural gas system into new communities otherwise uneconomic to serve, this formulation is not surprising. It is also not expressed as being exhaustive, or as in any way derogating from the fundamental principle expressly retained

[24] Tr1-173, lines 21-27.
[25] Tr3-100, lines 17 *et seq.*
[26] EBO-135 paragraph 7.29.

in the EBO-134 framework that any *"burden"* on existing customers resulting from such an expansion not be *"undue"*.

40. EGI has in fact required CIACs from customers directly connecting to transmission projects, though conceding that this is not specifically provided for in EBO-134.[27]

41. Further, as matters have evolved, the circumstances initially the subject of EBO-134 – uneconomic gas system expansions to new areas or communities – are now addressed by legislation and updated OEB policies[28] which provide for system expansion surcharges for customers in communities expansion to which is otherwise uneconomic. These surcharges are specifically designed to ensure that existing customers not bear an *"undue burden"* of subsidy for new gas expansions.

**EBO-188**

42. In January, 1998, a decade following the release of EBO-134, the OEB released its Final Report in EBO-188.

43. EBO-188 was convened by the OEB *"to inquire into, hear and determine certain matters relating to the expansion of the natural gas systems of The Consumers' Gas Company Ltd. ("Consumers Gas"), Union Gas Limited ("Union") and Centra Gas Ontario Inc. ("Centra")*.[29] The proceeding advanced by way of two phases of negotiations among engaged stakeholders with an intervening interim OEB report, and culminated in the aforementioned Final Report.

44. The focus of EBO-188 was on a framework for grouping utility new community expansion projects into "portfolios" so as to limit rate increases to existing customers resulting from such expansions while allowing *"more marginal customers"* to be served:[30]

> *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a*

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[27] Tr1-175, lines 18-26.
[28] EB-2020-0094, Enbridge Gas Inc. *Application for approval of System Expansion Surcharge, a Temporary Connection Surcharge and an Hourly Allocation Factor*.
[29] EBO-188, paragraph 1.1.1.
[30] EBO-188, paragraph 2.1.1.

*group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.*

45. The EBO-188 portfolio framework was specifically designed to limit long-term subsidies, as reflected in the following paragraph from the EBO-188 Final Report [emphasis in original]:[31]

> *The Board recognizes that subsidization can be measured at both the project and portfolio level. 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. The board is therefore of the view than an overall portfolio P.I. of 1.0 <u>or better</u> is in the public interest. Using this approach will obviate the need for the intense scrutiny of the financial viability of each project; will ensure that existing ratepayers are not negatively impacted by new projects (given the Board's proviso above on the sharing of risks); and assist communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.*

46. The EBO-188 Report specifically addresses CIAC's as follows[32] [our emphasis]:

> *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.*

[31] EBO-188, paragraph 2.1.5.
[32] EBO-188, paragraph 4.3,3.

**Reconciling EBO-134 and EBO-188**

47. The EBO-134 framework concerned itself with uneconomic "system expansions" to previously unserved communities, though in the case of that framework no distinction between, or mention of, distribution expansions versus transmission expansions is made.

48. The EBO-188 framework similarly concerned itself with "system expansions", and also does not expressly distinguish between transmission and distribution expansions, though it does consistently refer to the latter.

49. During examination Mr. MacPherson for EGI explained that EGI's predecessor utilities applied EBO-134 to both transmission and distribution expansions until EBO-188 was released, and since the release of EBO-188 the application of the 3 stage "public interest" test in EBO-134 has been reserved for "transmission projects", and the more recent EBO-188 framework which entails only a one stage economic feasibility test (the same as the first stage of the EBO-134 framework) has been applied to economic justification of "distribution projects".[33]

50. EGI maintains that CIACs apply in the case of "distribution projects", but not in the case of "transmission projects". As PREP is a reinforcement of a transmission line, EGI's position is that CIACs do not apply.

51. As outlined above, both EBO-134 and EBO-188 were developed to be applied to gas system expansions to new communities. PREP is not such an expansion. Rather it is a project to increase capacity in order to supply 36 particular large volume contract customers.

52. Even if EBO-134 were to be applied to PREP, however, as discussed above EBO-134 does <u>not</u> preclude CIACs. To the contrary, it expressly precludes *"undue"* subsidies from existing to new customers.

53. EGI has focussed on an asserted distinction between "transmission" and "distribution" facilities in support of applying EBO-134 to the former and EBO-188 to the latter. However, there is no bright line indicating where "transmission" ends and "distribution" begins, and

[33] Tr1-177, line 10 through Tr1-178, line 3.

the demarcation is defined in different ways for different purposes, as explained by Mr. Gillett during examination:[34]

> *… there are different ways to classify what a transmission or distribution line is. There's regulatory ways where the Board has talked about, I think there's a couple different ones, whether customers are directly connected. I believe in the handbook it also talks about whether it carries gas, transmits gas on behalf of other shippers.*
>
> *There's also engineering ways of looking at it. So there's a concept of 30 percent SMYS, which is a way of looking at the maximum operating pressure of the pipeline and whether it's – whether we classify as distribution or transmission.*
>
> *There's also how we model it, whether it's steady state or transient.*
>
> *So these are all different – my point is that there's different ways of classifying it. For the purposes of EBO-188 and EBO-134, though, which I think is what we are talking about here and specifically your question around the [HAF], it's about the behaviour of the system, it's about the location of the customers, the location of the pipelines, and hydraulically how the system behaves.*
>
> *And on a case-by-case basis we can figure out whether or not we can create a half based on the behaviour of that system.*

54. At another point Mr. Gillett described a "transmission" project as *"a pipeline.. that provides capacity to a broad geographic region where a number of customers will benefit"*, as opposed to *"a distribution project, specifically one that would be evaluated under 188, is where the facilities are more clearly identified for that customer"*. [35] The PREP project arguably fits both of these scenarios, the first from a technical engineering perspective and the second from a practical customer perspective.

55. Neither of the two legacy system expansion reports expressly addresses a *"transmission"/"distribution"* distinction, and, in any event, as Mr. MacPherson conceded in examination, matters have evolved since then.[36]

56. We canvassed this evolution through our examination with EGI's witnesses of 5 Panhandle System expansions since 2013[37]:

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[34] Tr1-16, lines 4 *et seq.* See also Tr.1-45, lines 19 *et seq.*
[35] Tr1-137, lines 2-8.
[36] Tr1-179, lines 15-28. Mr. MacPherson when on to assert that *"the application of EBO-134 has been consistently applied by Enbridge and by the Board"* but, as canvassed here, we don't believe that to be the case.
[37] Tr2-10, line 22, *et seq.* and K1.9, pages 36-104.

(a) In March, 2013 the OEB issued leave to construct a Leamington Expansion (EB-2012-0431). While a looping of a Panhandle transmission line into Leamington, and physically and hydraulically connected to that main transmission line, this project was characterized by Mr. Gillett in testimony in this case as a *"high pressure distribution expansion"*, and also as *"a transmission lateral, which then branches off into distribution systems"*. Mr. Gillette further recalled this project as the first time that EGI applied a HAF like mechanism, based on an area of benefit that the project created.

(b) In June, 2016 the OEB issued leave to construct another Leamington Expansion (EB-2016-0013). Mr. Gillett explained that, like the 2013 Leamington Expansion, this was another loop down the same transmission lateral, which he characterized as a "distribution" project. On the basis of the resulting capacity being *"sold out almost immediately"* as a result of (then) Union Gas' expression of interest process, Union was able to derive and apply a HAF to this project as well.

(c) In February, 2017 the OEB issued leave to construct a Panhandle System Expansion (EB-2016-0186). Mr. Gillett indicated that this was a transmission project. It was a replacement of the existing 16" pipe running from Dawn to Dover Transmission Station with a new 36" pipe, which expanded the size of the "trunk" of the Panhandle transmission system, as Mr. Gillett explained. In this instance no CIACs were required, though the majority of the requests that drove the project were for firm contracts from greenhouse customers in the Leamington-Kingsville area.

(d) In September, 2018 the OEB issued leave to construct a Kingsville Reinforcement (EB-2018-0013). Mr. Gillett agreed this was a "transmission" project. In approving this project the OEB expressed concerns[38] to the effect that given the customer contracts executed and under negotiation in support of the project, the project met both distribution and transmission needs, yet there was no ready mechanism to have these parties make a contribution to the costs of the project despite the substantial benefits that they would realize. Mr. MacPherson acknowledged the similarities of the circumstances of concern to the OEB in the Kingsville Reinforcement Project to the circumstances presented in this case for PREP; i.e. the *"specific contracts being negotiated and commitments being made by large-volume customers for 94 percent of your capacity over the forecast period which rely on the PREP project"*[39], and that these customers who are investing billions of dollars in expansion will benefit from the gas supply that PREP is intended to provide[40].

(e) In July, 2019 the OEB issued leave to construct the Chatham-Kent Rural Reinforcement Project (EB-2018-0188). In that case, EGI advanced what was a transmission pipeline project under EBO-188, to accommodate Ontario government Natural Gas Grant Program and Municipality of Chatham-Kent funding, <u>and</u> individual customer CIACs.[41] As Mr. Gillett explained it, *"it was a bit of a hybrid approach"*. Importantly, this project was described by EGI, and

[38] EB-2018-0013 *Decision and Order*, September 20, 2018, pages 5-6.
[39] Tr2-27, lines 8-12 and Tr2-29, line 4.
[40] Tr2-28, line 25 through Tr2-29, line 4.
[41] Tr2-29, line 10 throughTr2- 30, line 20.

accepted by the OEB, as *"a reinforcement of the Chatham transmission system which operates as a primary feed to several other downstream systems"*[42], which Mr. Gillett acknowledged as a *"transmission function"*[43], though one isolated enough to admit calculation of a HAF.

57. While not a Panhandle System Expansion, we note that in March, 2020 the OEB issued leave to construct a project to increase the capacity of EGI's SIL transmission system (EB-2019-0218). The project was in response to a request for incremental demand from Nova Chemicals (Canada) Ltd., and was sized to accommodate EGI's forecast of a further 12.2 Tj/d of capacity beyond Nova's requirements to serve future growth in the Sarnia market. That transmission line reinforcement project proceeded under E.B.O. 188, and included a proposal from EGI to apply a HAF for recovery of cost of the incremental capacity from Nova and future contract customers.

58. Consideration of this history of the Panhandle System expansions, and of the recent SIL leave to construct, indicates a number of exceptions to the EBO-134 "transmission"/EBO-188 "distribution" distinction relied on by EGI in eschewing a requirement for CIACs from the 36 specifically identified PREP customers.

59. It is submitted that a better way to consider the evolution of system expansion policies from EBO-134 through EBO-188 and continuing to more recent legislative and OEB policy determinations regarding community expansions and associated customer contribution charges is not to attempt to define where "transmission" becomes "distribution" (which neither EBO-134 nor EBO-188 do), but rather to consider;

(a) the focus found throughout this evolution on finding ways to preclude *"undue"* rate increases for existing customers; and

(b) the directions that where the use of a proposed facility will be dominated by one or more large volume customers (EBO-188), contributions in aid of construction are appropriate to preclude *"undue"* subsidies from existing to new customers (EBO-134, paragraph 7.29).

60. As Mr. MacPherson put it (albeit in discussion of the application of EBO-188)[44];

> *… if there was shared infrastructure where there's some upstream segment and there was several downstream customers connecting distribution customers, then*

[42] EB-2018-0188, *Decision and Order*, July 11, 2019 (Revised November 19, 2019), page 1, 2nd paragraph.
[43] Tr2-30, line 21 through Tr2-32, line 15.
[44] Tr2-5, lines 9-16.

> *we would be looking potentially to apply something like the hourly allocation factor to apportion those costs to those connecting customers.*

61. Since EBO-134 and EBO-188, a methodology for achieving a rate making result that is fair to all concerned - new customers, existing customers and the utility - has been defined through the OEB's EB-2020-0094 *Decision and Order* directing appropriate expansion surcharges, including a HAF.

62. EGI has expressed concern for application of a HAF mechanism in instances where system hydraulics do not admit of isolation, from an engineering perspective, of a constrained "area of benefit" resulting from a capacity expansion project. We disagree with that concern, and come back to consideration of application of the HAF mechanism to PREP later in this argument.

## CUSTOMER EXPECTATIONS

63. We understand it to be EGI's position that it would be unfair for the OEB to direct CIAC's in this case when the customers who responded to EGI's EOI with intention to commit to the incremental capacity thereby created have made their incremental investment plans based on the OEB's past decisions to the effect that CIAC's do not apply to transmission projects, and that directing CIAC's in these circumstances would be contrary to the expectations of these customers, and potentially anti-competitive *vis a vis* previous similarly situated customers in the area who obtained incremental delivery service without having to make CIACs.

64. First to note is that these customers who are seeking incremental capacity are all existing customers.[45] There can be no anti-competitive impact. They are not competing against themselves, and they have all obtained capacity from the Panhandle system already. As the history of Panhandle System leave to construct decisions summarized above illustrates, in some instances CIACs have been required, and in some instances they have not. From a Panhandle System customer perspective whether CIACs have been required for incremental firm capacity has been a rather random matter to date.

[45] Tr3-83.

65. Further, we find it hard to believe that these customers, however sophisticated they may be in respect of their own energy (including gas) consumption, parsed the regulatory frameworks set out in EBO-134 and EBO-188 as applied in various permutations over the last decade as outlined above, and concluded, as EGI asserts, that the PREP project is a "transmission" facility and thus falls under EBO-134 and would not attract a CIAC. Even if these customers did study the last 5 Panhandle System decisions, the discussion above illustrates that history is not so simple as to admit of such a conclusion. In any event, any such notion would have been dispelled when EGI provided these customers with notice that CIAC's were under consideration, and asked whether they would want to pay those (which, unsurprisingly, they advised they would rather not).

66. As Mr. Gillett acknowledged in response to questions from Mr. Ladanyi during the oral hearing[46], from a customer perspective these customers are getting a distribution service, plain and simple. Which part of the gas delivery "tree" and its various major and minor branches is to be expanded in order to provide them with that service would be irrelevant to them, even if known and understood from a system hydraulics perspective.

67. These customers have all paid for their own distribution connections. In the case where common upstream infrastructure is shared across more than one customer they may have paid a CIAC in the past in accord with an hourly allocation factor type methodology. Otherwise, they would have previously received incremental capacity without contribution, in which case they were lucky enough to come along at a time when "free" capacity was being made available.

68. That Atura Power, the largest (40% of the PREP capacity) customer to be served through this project, has contemplated a CIAC is evidenced by its renegotiation of its power purchase agreement with the IESO, and express provision through that renegotiation for sharing the risk that a CIAC will be required.[47] Atura has signed a power purchase agreement, and renegotiated it in light of the potential for a CIAC. They are legally obligated to continue with their expansion and provide the contracted power to the IESO, and they accepted that obligation *"with eyes wide open"* and expressly provided for the eventuality that a CIAC will be required.

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[46] Tr2-110, line 23 through Tr2-111, line 10.
[47] Tr3-192 and SEC Compendium ExK2.5, pages 56-58.

69. We take particular note that no concern for fairness, predictability or competitive impact has been taken by EGI for existing customers that EGI asks to subsidize Atura, East Windsor Cogeneration, and the 34 Leamington area greenhouses seeking incremental firm gas delivery capacity. As noted above, under EGI's current cost allocation methodology, T2 customers including IGUA's SIL served members would collectively bear ~$3.7 million a year[48] of PREP costs, with absolutely no concomitant benefit from PREP beyond the 36 customers who responded to the EOI. EGI's calculus takes no consideration of the reasonable expectations for predictable gas delivery service costs of these customers or of the negative economic impact of its proposed allocation of PREP costs to them.[49]

70. EGI has also referred to broader Panhandle System reliability benefits from PREP. Mr. Gillett explained that should the existing NPS 20 pipeline from the Dover to the Comber transmission station need to be taken out of service, at least the portion parallel to the length of the proposed PREP project[50], then the new PREP line could maintain a measure of gas service to the area. That is, PREP provides, along its length, some redundancy.[51] While no doubt true, this would be a salutary, and contingent (on an outage on a particular expanse of pipe) consequence of PREP rather than a stand alone justification for the line. This result would obtain any time there is a redundancy built into the system, purposefully or, as in this case, by happenstance, but clearly would not justify building in redundancy everywhere.

71. Even were redundancy considered a true stand alone benefit, which we don't believe it should be, it would not support in any way T2 customers outside of the Panhandle system, including IGUA's SIL area members, who operate in very competitive, trade exposed industries, incurring tens of thousands of dollars a year in incremental costs to subsidize the 36 Panhandle area businesses who are anticipated to benefit from PREP.

[48] I.IGUA.2, Att. 1.
[49] Tr2-183, lines 2-14.
[50] Illustrated at page 6 of ExK1.1 (EGI's Opening Day presentation).
[51] Tr3-84.

## PUBLIC INTEREST IMPACTS OF CIACs

72. EGI seems to have expressed concern that imposition of CIACs on the customers anticipated to be served by way of the incremental capacity created by PREP could cause those customers to take their investment to other jurisdictions, precluding the spinoff economic benefits thereby promised for Ontario. However, the evidence, and EGI's position on this point, is unclear.

73. EGI's witnesses ultimately conceded that what would preclude these customers from making incremental capital investments in Ontario would be the lack of incremental gas service *per se*, rather than a CIAC, and this is how EGI put it in its AIC.[52]

74. Atura has a contract with the IESO, which addresses allocation of any required CIAC, and Atura is obligated under that contract to proceed with its expansion. Atura was offered an opportunity to lead evidence[53], and if the viability of its expansion were truly at stake one would think they would have taken that opportunity. They did not. There is no evidence in support of Mr. MacPherson's conjecture that a CIAC obligation would be *"very commercially adverse"* to Atura[54], and Atura's silence in this respect indicates otherwise.

75. In respect of the risk of capital flight by the 34 greenhouse customers who responded to the EOI:

(a) They are all existing Leamington area businesses currently taking gas service from EGI.[55]

(b) OGVG's expert, Dr. Petro, testified that there are efficiencies arising from proximal greenhouse expansions.[56]

(c) Dr. Petro also testified that these are large, capital intensive industrial greenhouse operations investing billions of dollars in expansion.[57] One would presume, then, that they are earning profits of millions of dollars, in which context a one time CIAC measured in tens of thousands is unlikely to tank their expansion business cases. When questioned, Dr. Petro, who otherwise provided information on the

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[52] EGI AIC paragraph 51.
[53] Tr1-126, lines 20-24.
[54] Tr3-192, line 26 to Tr3-193, line 8.
[55] Tr3-83.
[56] Tr3-177.
[57] Tr3-141; Tr3-169; ExJ3.8 - OGVG Prosperity Study, page iv.

economics of Ontario greenhouses, was unable to say that CIACs would have such an impact.[58]

(d) In recent history, Panhandle System demand for firm gas delivery service has outstripped capacity to supply that service, including on an number of occasions when CIACs to cover the costs of capacity expansion were required, and EGI expects that circumstance to continue.

(e) As Mr. MacPherson explained during examination by Mr. Daub, these are large, durable investments and once those investments are made these customers don't just up and leave.[59]

(f) Mr. MacPherson acknowledged a host of issues beyond CIACs that would influence such businesses, including labour costs and availability, taxes[60], *"very good conditions in Ontario for greenhouse growers, lots of sunlight, access to water, flat, like level terrain and, potentially access to energy"*[61].

(g) OGVG's *Ontario Growth and Sustainable Prosperity Study 2023* also emphasizes southern Ontario's *"ideal growing conditions that facilitate efficient and productive agriculture operations"*[62], as well as the importance of electricity, water, roads and sanitary sewers.

76. Conversely, there is no evidence that CIAC's for this project would result in the flight of capital from Ontario. Rather EGI's witnesses ultimately asserted that it would be a lack of gas service *per se* that could result in capital flight.[63]

77. Despite all of this evidence, to the extent that there remains a concern that with a requirement for a CIAC a number of these greenhouse expansions would not proceed, then these businesses, who have not been shy about lobbying provincial and municipal governments for support, should do so in respect of gas expansion as well. Funding socio-economic programs is not the role of the OEB, and nothing in EBO-134, even were it to be applied to PREP, suggests otherwise, and in fact the principles emphasized in EBO-134 as discussed above suggest otherwise.

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[58] Tr3-171.
[59] Tr3-32.
[60] Tr3-23.
[61] Tr2-191.
[62] See, for example, ExJ3.8, pages iii and xi. We note that natural gas access is not emphasized in the report.
[63] Tr2-24, line 3 to Tr2-25, line 2.

## AREA OF BENEFIT

78. We understand it to be EGI's position that because PREP is a transmission project it benefits the entire Panhandle system and all the customers thereby served, and it would be inappropriate for specific customers seeking incremental service to bear the costs of the project.

79. While Hydraulically that may be technically true, in fact we know that the incremental capacity to be created by PREP has been driven by, and already spoken for, 36 particular customers.

80. As already discussed, while PREP would result in a degree of redundancy on what looks to be about 2/3rds of the length of the current NPS 20 pipeline running from the Dover Transmission Station to the Comber Transmission Station[64], this is a salutary and contingent benefit to Panhandle System customers at large, and does not justify the $290 million (net of indirect overheads) PREP investment.

81. Rather the justification advanced for the PREP project is the incremental firm gas delivery service to be provided to the 36 identified customers lining up for PREP capacity.

## HYDRAULICS AND THE ABILITY TO DERIVE CIACs (Over or Under Collection)

82. EGI is concerned that if customers connect at different locations and/or present incremental demands which are different from those reflected in the responses to EGI's EOI, actual capacity created by the PREP project would end up being higher or lower than the planned 168 TJ/d, and either;

    (a) CIAC's established at the outset would result in over or under collection from customers subject to them; or

    (b) CIAC calculation would have to be redone as each new customer comes along which would be complex and/or unfair as between connecting customers.

[64] K1.1, EGI's Opening Day Presentation, page 6.

83. Mr. Gillett conceded in testimony that the same variability of resulting capacity would obtain, to some extent, in any instance of common or shared facilities.[65]

84. Given the inevitably imperfect matching of costs to benefits inherent in any practical approach to rate making, the precise matching system hydraulics with allocated costs is beside the point.

85. The 5 historical Panhandle System expansion projects reviewed above presented different engineering solutions and thus hydraulic impacts, but were all largely driven by the imperative to meet the growth in firm demand from greenhouse customers in the Kingsville-Leamington area. In 3 of those instances CIACs were approved, and in a 4th the OEB was concerned that a mechanism for allocating costs in accord with expansion benefits was not proposed.

86. In the case of PREP in particular, there is a relatively high degree of certainty about where customers will consume the incremental capacity to be created, and in what volumes. EGI expects that all of the PREP created capacity will be taken up by customers over the next 5 years, on the basis of the February 2023 EOI and the specific existing customer responses thereto.[66] The resulting forecast, to which EGI neither added nor subtracted relative to the EOI responses[67], has provided sufficient confidence to design an expansion and to justify it in this proceeding.

87. This is the 6th expansion project since 2013 driven specifically by demand growth in the Kingsville-Leamington area where greenhouse growers continue to significantly expand. OGVG's witness Dr. Petro was clear and confident that this is where greenhouses are expanding and requesting incremental gas delivery capacity.[68] Further, there is no uncertainty regarding where Atura and East Windsor Cogeneration will consume their significant (57%) share of the incremental gas delivery capacity to be created by PREP.

88. The OEB approved HAF mechanism is about matching customer value, not hydraulics, with cost. HAF was designed by EGI, and approved by the OEB, precisely to effect advance allocation of shared upstream infrastructure to downstream customers[69] <u>as they</u>

[65] Tr2-17, line 24 through Tr2-18, line 6.
[66] Tr3-21; Tr1-161.
[67] Tr1-162
[68] Tr3-140
[69] Tr2-5, lines 9-16.

come along. In necessarily contemplates some hydraulic imprecision, but to no greater degree than any rate making construct that seeks to be balance cost responsibility with fairness and practicality.

89. It is our understanding that the OEB's HAF policy would apply to PREP as follows:

(a) The total forecast capacity from the project is used as the starting point. For PREP that is 168 TJ/d, on the basis of the customers now identified and where they say they intend to connect. EGI forecasts that 94% of that capacity is to be taken up by contract customers.

(b) The cost of PREP is forecast to be $289.2 million. The proportional contract customer share of this cost (94%) would be $271.84 million.

(c) Dividing the contract customer share of the forecast PREP cost by the 157.9 TJ/d of firm demand indicated by the contract customer EOI responses would result in a HAF unit rate of ~$1.83 million/Tj/d.

(d) The HAF would be allocated and applied as a capital cost to the individual economic analysis of customers as they commit to or contract for incremental PREP created capacity, which analysis then determines whether a CIAC would be required from that customer.

We invite EGI to comment on/correct these calculations as warranted in its reply argument.

90. New connecting contract customers, whether forecast or not, would be subject to the HAF allocation and resulting individual economic analysis as they connect. Once the total incremental PREP capacity has been fully allocated, the HAF would cease to apply to the economic feasibility analysis for new connecting Panhandle System contract customers.

91. EGI is concerned that if customers locate differently than forecast, the capacity remaining on the system will fluctuate, leading to a risk of either over-recovery or under-recovery of the costs of the project.[70] Mr. Gillett explained this clearly at Tr2-160 through Tr2-162.

92. Might there be excess capacity available even after full PREP cost recovery because of hydraulics? Perhaps, but that is no different from other cases of impacts from customer connections on this type of "branching" system and, for example, the timing luck of Stellantis, or the luck of a new customers if an existing customer leaves and frees up

[70] Tr2-41, lines 3-12.

capacity. In this eventuality, additional new connections do get a “capacity windfall” – in the form of capacity without a concomitant CIAC requirement - but existing customers are protected and the forecast customers who drove the project pay its costs and get the “value” and certainty that they bargained for at the outset. There are no surprises.

93. On the other hand, might the PREP capacity be exhausted because of hydraulics before the full cost of the project is recovered from those connecting? Perhaps, but in such event at least the subsidy from existing customers to the connecting customers would be reduced, and a significant degree of user pay in allocation of PREP costs would result. In this event, the connecting customers are actually getting a bargain as they are paying the same amount though effectively using proportionately more of the initially assumed capacity.

94. In all instances the utility is protected. Under the OEB approved HAF framework, the cost of the project that is allocated for recovery from large volume connecting customers as they connect is carried in general rates until those connections occur.

95. The HAF is not a prefect system, in that it will not perfectly allocate capacity costs to capacity consuming customers in many, perhaps any, instances. That is no different from any other approach to rate making. It does, however, better match costs to benefits, in allocating to large customers an equitably and transparently derived share of the revenue shortfall associated with the project which creates the capacity that they have requested.

96. The HAF mechanism is about economics and avoiding, to the extent reasonable and practical, subsidies from existing customers. It is not about matching customers’ costs to constantly shifting hydraulics and resulting system capacity changes, which EGI’s witnesses acknowledged occurs, to some extent, on any pipe at any “level” of the system.

97. In discussion of approaches to deriving capital contributions, Mr. Gillett testified that with the location of the PREP project *“[y]ou cannot isolate what areas benefit more or less until you actually have the customers show up and determine where they’re actually using the capacity”*.[71]

98. In respect of PREP in particular, though, there are specifically identified customers throughout the 5 year period for which the expansion is being undertaken who either have

[71] Tr2-166, lines 5-8.

contracted for incremental gas delivery capacity or are expected to do so. They are all in the Leamington area, save for the 2 power generators who are near Windsor. The PREP situation is analogous to the EB-2016-0013 Leamington expansion, for which a HAF was proposed by EGI and ultimately implemented, in that in that the capacity to be created by PREP is all effectively spoken for now.[72]

99. Mr. Gillett also said:[73]

> *There are situations where there are clearly facilities that are easily attributable to a specific customer, set of customers, in which case they can pay their way on to the system, but there's obviously other cases, such as this, where it's not as clean and it's in the public interest that we provide this capacity in order to allow customers to connect to the system. I understand that there's grey between these two, two extremes, but we are not playing in one of those grey areas in the middle.*
>
> *We are on the very clear end of this is a transmission type project and our view is that the only way to really treat this fairly and ensure that customers are being treated fairly is to do it as proposed.*

100. Mr. Gillett based his conclusion on the characterization of PREP as *"a transmission type project"* rather than focusing on the *"specific…set of customers"* already identified for the PREP capacity. We submit that was the wrong focus.

## CONCLUSION

101. In the case of PREP, as with the 5 Panhandle System expansions which preceded it, there is a very clear set of customers driving the project, and relatively certainty about both their locations and the capacity which they are seeking. In the case of PREP, the already identified customers are forecast to consume the entire PREP created capacity within 5 years.

102. There is a significant revenue shortfall forecast for the project which has been designed and which is being advanced in order to satisfy the capacity demands already identified by these 36 specific customers.

[72] Tr2-19, lines 1-12.
[73] Tr2-164, lines 6-18.

103. To quote from the OEB's EB-2020-0094 expansion charges *Decision and Order*[74];

> *The use of the HAF results in the allocation of the capital costs of a project in a fair and equitable manner as the costs would be allocated over time to* eligible *customers seeking access to the incremental capacity generated by the project.*

104. The HAF is not a perfect system, in that it will not perfectly allocate capacity costs to capacity consuming customers in many, perhaps any, instances. That is no different from any other approach to rate making.

105. The PREP project in particular, for all of the reasons addressed in this argument, is well suited to application of the HAF mechanism. Given the relative certainty of where and when the demand for PREP created capacity is coming from, application of the HAF to this project would result in matching costs to benefits through recovery from large customers an equitably and transparently derived share of the revenue shortfall associated with the project which creates the capacity that they have requested.

106. Application of the HAF is not inconsistent with either EBO-134 or EBO-188.

107. The OEB should direct application of the HAF mechanism to the PREP project as a condition of granting EGI leave to construct the project.

**ALL OF WHICH IS RESPECTFULLY SUBMITTED by:**

**GOWLING WLG (CANADA) LLP,** per:
Ian A. Mondrow
Counsel to IGUA

December 14, 2023

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[74] EB-2020-0094 *Decision and Order*, November 5, 2020.