ONTARIO ENERGY BOARD

EPCOR Natural Gas Limited Partnership (EPCOR)

Application for gas distribution rates and other charges for the period from January 1, 2019 to December 31, 2028

Industrial Gas Users Association (IGUA)

Final Argument

Summary of Position

1. IGUA addresses two issues in this Final Argument:

   (a) *Issue 6: Cost Allocation and Rate Design*.

   (b) *Issue 5: Revenue Deficiency/Sufficiency*.

2. In respect of *Issue 6: Cost Allocation and Rate Design*:

   (a) EPCOR's proposal to use a *"market based approach"* to set rates[1] in order to maximize customer connections (and thus minimize EPCOR's 10 year rate stability plan risk);

      (i) is novel for Ontario;

      (ii) would be a significant departure from conventional utility rate making principles anchored in cost causality and user pay;

      (iii) has been advanced without any legal or regulatory precedent or justification; and

[1] IRR Staff.22, part a)

(iv) inappropriately offloads risk assumed by EPCOR as part of its competitive Common Infrastructure Plan (CIP) proposal to the two South Bruce Rate 16 customers and five forecasted Rate 11 customers;

and should be rejected.

(b) EPCOR should be directed to file a rate order which calculates rates for all of its approved rate classes to achieve forecast revenue to cost ratios of 1.0.[2]

(c) In calculating such rates, EPCOR should be directed remove from Rate 16 allocations costs of assets located downstream of its Bruce Energy Center pressure regulation and metering station[3], which downstream assets are not used in the provision of distribution service to the two Rate 16 customers forecast to be served by EPCOR during the 10 year rate stability period[4].

3. In respect of *Issue 5: Revenue Deficiency/Sufficiency*;

(a) EPCOR should be held to its CIP revenue requirement, and should not be permitted to increase its revenue requirement to compensate for revenue "lost" as a result of a construction start or end date later than that assumed when its CIP was submitted; but

(b) EPCOR should be afforded the full benefit of "the deal" resulting from its successful competitive South Bruce expansion designation by being permitted to maintain its rate stability plan rates for a period of 10 years from the date on which it provides service to its first customers (currently anticipated for December, 2019).

4. IGUA requests that the Hearing Panel, in assessing IGUA's positions, bear in mind that EPCOR is seeking a 10 year rate approval. IGUA has no objection to a 10 year rate approval (as contemplated in the approval of EPCOR's South Bruce expansion proposal), but this extended length of the rate stability period has two implications particularly salient to IGUA's positions on EPCOR's application:

(a) If the Board were to approve EPCOR's proposed cross-subsidy from Rate 16 and Rate 11 customers, that cross-subsidy would be in place for a decade.

(b) EPCOR has the entire 10 year rate stability period within which to regularize the status of its new gas distribution system and manage the risks which it agreed to assume.

[2] IRR IGUA.4, part (b)
[3] See Map; Ex2/T2/S1/p.10
[4] IRR IGUA.9, part (a).

5. IGUA also wishes to note that it requested an oral hearing of these two unsettled issues, and EPCOR resisted that request. In the result, IGUA and other parties will be arguing based on the record as it currently stands. IGUA expects EPCOR to do the same. IGUA would object were EPCOR to attempt to introduce by way of responding argument additional evidence which would not subject to proper testing.

Issue 6: Cost Allocation and Rate Design

6. It is common ground that the decision awarding the South Bruce franchise to EPCOR (CIP Decision) on the basis of EPCOR's competitive Common Infrastructure Plan proposal (CIP) approved a 10 year revenue requirement, but was silent on the setting of rates to recover that revenue requirement.[5]

7. It is also common ground that while the CIP forecast revenue requirement was approved, it was not guaranteed. EPCOR willingly assumed risk for controllable costs, as well as for customer connections and thus for revenue. Assumption of that risk was an essential element of the competitive CIP process and for the Board's selection of EPCOR as the successful applicant in that process.[6]

8. Now, however, EPCOR is proposing to offload a portion of its customer connection (and thus revenue) risk to its two largest (Rate 16) customers and to 5 additional forecast Rate 11 customers. That should not be permitted.

9. EPCOR has, in its evidence in this application, sought to qualify its assumption of connection (and thus revenue) risk, stating;

> *As noted by the OEB, "Proponents were expected to include details on their forecast attachments as part of the [CIP] proposals, with the successful proponent to be held to its forecast for rate-making purposes." EPCOR accepts this risk of attracting customers to connect, however, this connection forecast is based on being able to offer rates that all classes find compelling.*[7]

10. EPCOR did not, during the CIP process, so qualify its assumption of risk. It did not condition its CIP Proposal on *"being able to offer rates that all classes find compelling"* by

[5] Ex7/T1/S1/p2, paragraph 6.
[6] IRR Staff.40, page 2, first full paragraph.
[7] IRR Staff.22, page 2, end of 2nd paragraph.

being allowed to set "market based rates" divorced from standard utility rate making principles of cost causality and user pay in order to be able to extract cross-subsidies from some customer classes and thus reduce rates for other customer classes below costs to serve them.

11. Yet that is precisely what it now proposes to do. While accepting connection risk (and associated revenue risk) to win the CIP process, EPCOR now seeks to shield itself from that risk by charging Rate 16 customers 137% of what it will cost EPCOR to serve them, and charging Rate 11 customers 135% of what it will cost EPCOR to serve them, in order to subsidize Rate 6 (Large Volume General Service) customers to the tune of a 22% reduction in rates relative to costs incurred to serve them.[8]

12. Eschewing accepted utility rate making principles, EPCOR proposes to set its "market based rates" based on savings to consumers relative to their costs of alternative fuels.[9] That is, EPCOR effectively says that it will recapture some portion of savings from switching to natural gas that would otherwise be enjoyed by Rate 16 and Rate 11 customers from those customers, and use those recaptured savings to enhance savings for Rate 6 customers.

13. The actual calculations and sensitivities that led to the proposed rate levels, both subsidizing and subsidized, have not been put in evidence, and the sensitivities related to such calculations and resulting proposed rates and connection forecasts have not been tested. We simply have EPCOR's general statements on these matters.

14. EPCOR justifies its departure from accepted rate making principles and practices as being in support of *"the economic viability of the utility"*;

> *Reliance on a rate design that focuses specifically on cost of service principles will impact the rates EPCOR is proposing and could therefore materially influence customer savings and connection rates, thereby <u>impacting the economic viability of the utility</u>.*[10]

This assertion of potentially compromised *"economic viability"* from EPCOR's IRRs has also not been tested.

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[8] Ex7/T1/S1/p4, Table 7-2.
[9] Ex7/T1/S4/p2, paragraph 6.
[10] IRR Staff.22, page 2, paragraph 2.

15. The evidence that we do have indicates that EPCOR proposes to offload as much of its own customer connections (and thus revenue) risk to its two Rate 16 and five Rate 11 customers as it can by charging them as much as they can bear without deciding not to switch from their current fuel supply arrangements to EPCOR's new gas service.[11]

16. In contrast, EPCOR's Rate 6 (large volume general service) customers will pay rates set on a completely different methodology; essentially rates as low as they can be set, well below the cost to serve these customers, while permitting EPCOR to recover its full revenue requirement, inclusive of its return of and on investment.

17. Rate 1 (General Firm Service) customers will be charged essentially what it costs to serve them.

18. This "market based" rate subsidy approach is novel for Ontario.

19. EPCOR has acknowledged that this approach is in departure from "typical cost of service" utility rate making principles[12], principles which have been used for decades across North America, and generally considered "desirable"[13].

20. EPCOR's approach is also a departure from this Board's long-applied policy, which would have reasonably been assumed at the time of the CIP Decision deliberations to apply. Yet there was no indication from EPCOR at that time of the CIP process that, in securing its franchise, it would seek to secure its revenue requirement (and thus de-risk its competitively bid investment) by engineering rates to secure cross-subsidies from a particular customer class in favour of another customer class. Such a departure from conventional rate making should not now be permitted, after the fact.

21. EPCOR has provided no regulatory precedent or regulatory policy justification for its proposal to engineer rates to de-risk its competitively secured franchise investment.

22. EPCOR has stated that because it's new system is a "greenfield system expansion";

[11] Ex7/T1/S1/p.2, paragraph 6.
[12] IRR Staff.22, page 1, part a).
[13] IRR Staff.22, page 1, part a).

there are no existing customers that would be negatively impacted by the proposed rates. Rather the intent of EPCOR's proposed rates is to attract sufficient new customers onto the system such that the utility's economic viability is assured.[14]

23. There are, however, new customers that would be *"negatively impacted"*. This Board should not be an agent of social policy, approving rates engineered to require one or more customer classes to subsidize other customer classes, all to the ultimate protection of the shareholder of the regulated utility from its expressly assumed risk.

24. ***The Board should direct EPCOR to file draft rates calculated on the basis of revenue to cost ratios for all of its rate classes set to 1.0.***[15]

25. In addition to the express 37% cross-subsidy which EPCOR has proposed to collect from Rate 16 customers, there is a further, less obvious, level of cross subsidy from Rate 16 customers as a result of the cost allocation judgements that EPCOR has made in the cost to serve analysis that it has provided.

26. Review of the evidence provided by EPCOR on its *"reasonableness check"*[16] cost allocation analysis indicates that EPCOR has pooled the costs of its steel distribution mains into one asset group.[17] This asset group is actually comprised of two distinct pipelines[18];

    (a) a 60 km NPS 8 pipeline from the Dornoch connection with Enbridge Gas to the Bruce Energy Centre; and

    (b) a smaller, lower pressure NPS 6 pipeline running from the Bruce Energy Centre to Kincardine.

27. In its interrogatory responses EPCOR indicates that costs for both of these pipelines are allocated, *inter alia*, to the 2 Rate 16 customers.[19]

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[14] Staff.22, page 1, last paragraph.
[15] IRR IGUA.4, part b).
[16] Ex7/T1/S1/p3, paragraph 2.
[17] Ex2/T2/S1/p7, Table 2, Row 3.
[18] Ex2/T2/S1/p7, Table 1.
[19] IRR IGUA.8, Table 1.

28. EPCOR's prefiled evidence further indicates that of its 7 pressure regulating and metering stations[20], 3 are located downstream of the Bruce Energy Centre, yet costs of all of the 7 are allocated, *inter alia,* to the 2 Rate 16 customers.[21]

29. The 2 Rate 16 customers to be attached to the EPCOR system during the 10 year rate stability period are both located upstream of the Bruce Energy Centre pressure and regulating station, and the Bruce Energy Centre to Kincardine NPS 6 steel pipeline.[22]

30. It is thus apparent that, beyond the express 37% over-collection (relative to costs to serve) proposed to be extracted from the Rate 16 customers, the cost allocation analysis which indicates the 37% over-collection is premised on allocation to these customers of costs of facilities which will be downstream of them and will <u>not</u> be engaged in the provision to them of service.

31. EPCOR has justified the allocation to Rate 16 customers connected directly to the Dornoch to Bruce Energy Centre NPS 8 pipeline[23] of costs of pipelines and metering and regulating stations downstream of the Bruce Energy Centre on the basis of benefit to all customers of *"the cost minimization strategy of a shared system"*, and the integrated design of the EPCOR system.[24] This explanation, provided in response to an interrogatory, has not further explained (beyond the interrogatory response) or tested.

32. For example, the basis for including in Rate 16 cost allocations costs of the NPS 6 inch pipeline from Bruce Energy Centre to Kincardine but not of any further downstream pipeline has not been explained. Nor, as another example, has the judgement to not include the downstream plastic distribution main but to include costs from <u>all</u> downstream regulating and metering stations.

33. It appears to us that these allocations of costs from assets downstream of the distribution main to which the Rate 16 customers are directly connected but which do not appear to support service to them is contrary to EPCOR's evidence that its South Bruce cost

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20 Ex2/T2/S1/p7, Table 1.
21 IRR IGUA.8, Table 1.
22 IRR IGUA.9, part (a).
23 Ex8, Tab 1, Schedule 2, p.7, see under *"Applicability"*.
24 IRR IGUA.9.

allocation model takes into account the unique South Bruce distribution system configuration, and in particular *"how each rate class uses the distribution system"*.[25]

34. IGUA has argued above that EPCOR should be required to file draft rates calculated on the basis of revenue to cost ratios for all of its rate classes set to 1.0. In doing so, EPCOR should be further directed to remove from allocation to Rate 16 customers the costs for distribution facilities located downstream of the Bruce Energy Centre pressure regulation and metering station.

<u>Issue 5: Revenue Deficiency/Sufficiency</u>

35. EPCOR has proposed to increase its 10 year rate stability plan revenue requirement by $1.764 million, in order to recover "forgone revenue" resulting from a delay in its construction start, and a consequent delay in its in-service schedule, said to be driven by the timing of its leave to construct approval.[26] The claimed incremental revenue takes into account "mitigating" offsets of delay in property tax liability and an adjustment (deferral, in part) of EPCOR's capital expenditure profile[27]. The claimed incremental revenue also includes a claim for the time value of upstream payments to Enbridge Gas against delayed recovery of such payments from EPCOR customers.[28]

36. First, in respect of the claimed delayed recovery of upstream payments to Enbridge Gas, EPCOR's later interrogatory responses[29] indicate a deferral of upstream charges at least into 2020, if not beyond. Accordingly, the Board should require EPCOR to recalculate the claimed revenue deficiency related to deferred recovery of upstream charges as reflected in Table 6-8 of the prefiled evidence[30] to reflect the most updated information available on when such charges will likely be paid by EPCOR. This should reduce the revenue deficiency claim by at least some, if not all, of the $124,000 reflected on this account in the pre-filed evidence.

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[25] IRR Staff.21, part a), 2nd sub-bullet.
[26] Ex6/T1/S1/p2, paragraph 1.
[27] Ex6/T1/S1/pp. 6-7 and IRR Staff.4, part (d); IRR IGUA6.
[28] Ex6/T1/S1/pp.7-8.
[29] IRR Staff.20, part (b); IRR Staff.18, page 2, first full paragraph.
[30] Ex6/T1/S1/p8.

37. More generally, EPCOR's proposal to be held whole, <u>within its initially planned rate stability period</u>, to its proposed 10 year revenue requirement, is another instance in which EPCOR is seeking to transfer the risks which it assumed in proposing its competitive CIP to its ratepayers.

38. While the CIP proceeding assumed a construction schedule, it did <u>not</u> assume a particular start date. Rather it assumed a construction schedule duration, and approved a proposed 10 year rate stability period.

39. IGUA does not dispute that EPCOR's start date was later than it anticipated, nor that this later start date will push its customer connection profile back.

40. To the extent that EPCOR's customer connection profile in the first years of its decade long rate stability period is different because it had to start construction later in the year than it initially planned to (<u>if</u> that is the case, though there is no clear evidence on this), that is not a risk that ratepayers should bear.

41. The deal was that EPCOR would have a 10 year period over which to recover its approved revenue requirement, with rates would be set for that period based on its committed (and at risk) customer connection profile. EPCOR should be granted that 10 year period for recovery of its CIP approved revenue requirement. It should <u>not</u>, however, be permitted to increase rates (or, as it proposes, add a rate rider) in order to recover its approved CIP revenue requirement over a service period <u>shorter</u> than 10 years (i.e. a revenue requirement period commencing from its <u>initially</u> forecast date of first service, rather than its actual date of first service).

42. **EPCOR should be *granted rates which, based on its <u>CIP</u> forecast customer connection profile, the risk of which it has assumed, will recover its proposed revenue requirement over a period of 10 years, <u>commencing at the date which it connects its first customers</u>*.**

ALL OF WHICH IS RESPECTFULLY SUBMITTED by:

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