Shepherd Rubenstein

Mark Rubenstein
mark@shepherdrubenstein.com
Dir. 647-483-0113

BY EMAIL and RESS

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

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Our File: EB20180264

Attn: Christine Long, Registrar & Board Secretary

Dear Ms. Long:

Re: EB-2018-0264 – EPCOR South Bruce Rates – SEC Submissions

We are counsel to the School Energy Coalition ("SEC"). Pursuant to the *Decision on the Settlement Proposal and Procedural Order No. 6*, these are SEC's submissions on the unsettled issues in the application brought by EPCOR South Bruce ("EPCOR") for approval of a Custom Incentive Rate-making plan beginning January 1, 2019.

As the Board is aware, this is a unique rate application for two major reasons. First, EPCOR is seeking approval for rates and a rate-framework, for a greenfield utility and distribution system, and so some of the usual features and concerns regarding monopoly regulations are not yet present as currently no customers are connected to the distribution system. Second, EPCOR was selected to service the distribution territory by way of a competitive Common Infrastructure Plan ("CIP") process. Most of the issues in this proceeding were about ensuring that EPCOR's application is consistent with the CIP process and the commitments it made throughout, and if they were not included as part of CIP, their appropriateness.

Recovery of revenue deficiency of $1.764 million (Issues 5a, 10a, and 10b)

EPCOR is seeking recovery of an additional $1.764M by rate-rider related to a claimed revenue deficiency "driven by the transition from the common assumption on the timeline for OEB decisions to the revised timeline that reflects the current timeline for OEB decisions."[1] The $1.764M amount represents the NPV of the shortfall over the 10-year rate stability period.[2]

The deficiency is a number of interrelated changes. It involves an amount representing forgone revenue caused by the delay in connecting customers in 2019, and because of that the recovery of certain upstream charges, offset slightly by the delay in the capital expenditure spending profile, and related property taxes that result from the construction delay.[3]

[1] Ex.1-2-1, p.17
[2] *Ibid*
[3] Ex. 6-1-1, p.3

Table 6-2 Summary of Revenue Deficiency

	Description	Col. 1 NPV of Revenue Deficiency
Row 1	Change in Customer Connection Profile - Forgone Revenue	2,324
Row 2	Delay in Property Taxes - Forgone Cost	(224)
Row 3	Change in Capital Expenditure Profile - Forgone Cost	(460)
Row 4	Deferred Recovery of Upstream Charges	124
Row 5	Sum	**1,764**

EPCOR's argument is that there was a delay in getting leave to construct approval, as compared to what was assumed by both itself and Union Gas in the CIP process.[4] The delay for receiving leave to construct approval has led to a delay in construction. Since the delay in leave to construct approval was outside of its control, it should be allowed to collect its calculated foregone revenue.

The delay in receiving leave to construct approval was caused not by the Board, but at least in part by EPCOR. In its leave to construct application, EPCOR noted that it was underpinned by the then Ministry of Infrastructure's Natural Gas Grant Program.[5] After filing its application, EPCOR wrote to the Board to inform them that the program had been cancelled and that it expected to receive funding by the replacement Natural Gas Expansion Support Program created under Bill 32. The Board determined that it would hold the application in abeyance until "such time as [the application] is either withdrawn or amended to enable issuance of a Notice of Hearing that accurately reflected the underpinnings of the application."[6] It was not until March of 2019 that EPCOR filed an updated application to account for the funding it would receive under the Natural Gas Expansion Support Program.[7]

SEC's view is that customers should not have to pay *more* because of a delay that was predicated on EPCOR's management's decision. The CIP process and both EPCOR and Union's proposals were not predicated on receiving *any* grant money from the Ontario government.[8] The after the fact decision by EPCOR to decide that it could not proceed with the project without grant funding was entirely a decision within its control. While the available grant funding changed after the filing of the leave to construct application, that should be a risk that is borne not by new ratepayers, but by the company. The Board will never know if Union Gas had been selected as part of the CIP process, whether it would have similarly made the project conditional on receiving grant funding. It may have very well decided it did not need the funding, or more likely, it was a risk it was willing to take to move the project forward.

While new ratepayers should not have to bear the additional $1.764M, this does not mean that the Board is without options to balance the interests of EPCOR and its customers. While the common assumptions for the CIP process included a schedule, what was central to the entire process and the framework the Board set out was the 10-year rate stability period. The schedule was simply a way

[4] Ex. 6-SEC-14(a)
[5] Letter from Rudra Mukherji (Acting Manager, Registrar) to Bruce Brandell (EPCOR), November 29 2018, p.2 (Ex.6-1-2, p.2)
[6] *Ibid*
[7] *Ibid*
[8] EB-2016-0137/138/139, Decision on Preliminary Issues and Procedural Order No. 8, p.6

for the Board to be able to compare both proponents' submissions. Without it, the two proponents would have made different assumptions regarding when the 10-years began and when it was allowed to construct facilities and attach customers.

SEC submits that a way to ensure that EPCOR is able to recover most of its revenue requirement is by simply shifting the effective date and start of stability period from January 1 2019, to the date it expects to connect its first customer. Since the trajectory of its 10-year rate stability period is that it under-collects its costs in the early years and over-collects in the later years, moving the starting date will allow it to collect increased revenues. The benefit of this approach is that there are no "catch-up" amounts borne by customers, while keeping within the Board's required 10-year stability period framework.

Cost Allocation (Issues 6a,b,c)

SEC understands the primary dispute between parties to be regarding EPCOR's proposed revenue-to-cost ratios.[9] EPCOR developed the revenue-to-cost ratios for rate making purposes based on the costs at the end of the proposed 2028 rate stability period. Instead of setting the revenue-to-cost ratios at 1.0 for each class, they range from 0.78 to 1.37. [10] Cost allocation and rate design was not part of the CIP process.[11]

At first glance, one would have expected the revenue-to-cost ratios for a greenfield utility to be set at 1.0, or at least within the Board's policy range for each rate class.[12] This would ensure that as much as possible, there are no cross-subsidies between customer classes, a principle that is at the heart of rate making.

EPCOR has taken a different approach, which is equally compelling. Its view is that many of the considerations regarding normal cost allocation principles are not present for a greenfield utility. At present, EPCOR has no customers, and no potential customer is required to attach to this new distribution system. Each customer will have the opportunity to make their own calculation to determine if converting to natural gas and attaching to the EPCOR's system is in their best interest, based on the Board-approved rates during the rate stability period. If they do not feel the rates are appropriate, they do not need to connect. Nobody is captive to the monopoly distribution system until they make a decision to attach.

As EPCOR puts it, the "outcome it is targeting with its proposed rates for Southern Bruce is to attract customers in all rate classes in sufficient numbers to ensure the long term economic viability of the utility."[13] The more potential customers who attach to the system, the better all customers are in the long run. Different customer classes will require different rates, to find connecting to the natural gas system attractive.

While the proposed revenue-to-cost ratios benefit SEC member schools in the present case, it may be in another proposed greenfield utility, the situation will be reversed. SEC agrees with EPCOR that there is room for greater management judgment in the setting of the revenue-to-cost ratios in the context of a greenfield utility as compared to a more mature utility. However, the Board is still required under the *Ontario Energy Board Act* to approve just and reasonable rates. It cannot delegate what "just and reasonable" is to EPCOR.

SEC proposes that two principles need to be considered. First, there must be an appropriate balance between avoiding cross-subsidy between rate classes, and ensuring the long-term viability

[9] Letter for the Industrial Gas Users Association, dated May 17 2019, p.2
[10] Ex.7-1-1, p.15
[11] EB-2016-0137/8/9, Procedural Order No.6, p.4
[12] 7-Staff-22(a); The Board's policy range has been set in the context of electricity distributors rates. See *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219), dated March 31 2011, p.36
[13] *Ibid*

of the utility by attracting customers through the setting of revenue-to-cost ratios using a more market-based approach. Second, the Board should ensure that customers are not going to see a rate shock upon rebasing at the end of the 10-year stability period when utility transitions from being greenfield, and its customers become captive. If the expectation is that in the rebasing application after the rate stability period, the revenue-to-cost ratios are expected to be within the Board's ranges, customers who are below that, based on the more market driven approach, may face significant rate-shock at that time.

With respect to the first principle, EPCOR has not filed evidence explaining why the specific revenue-to-cost ratios are the most appropriate as compared to any others. It has not presented any evidence that the rates that flow from the proposed revenue-to-cost ratios are what is required to attract certain customers to meet its customer attachment forecast. At the same time, presumably, it would have considered these revenue-to-cost ratios when it considered the customer attachment forecast contained in its CIP. Regarding the second principle, since the lowest revenue-to-cost ratio is 0.78 based on 2028 costs, and the Board's policy floor is 0.80%, at rebasing in 2029, SEC does not expect customers will see any rate shock.

As an alternative to simplify matters, the Board could require the revenue-to-cost ratios to must be set within the Board's existing policy range. This still gives EPCOR flexibility in determining the exact levels, but ensures they stay within a range the Board has already deemed to be reasonable.

Availability of Incremental Capital Module (Issue 8e)

EPCOR proposes as part of its rate making framework during the rate stability period that it have available to it the Incremental Capital Module ("ICM"). This is proposed even though it does not actually forecast needing to use it.[14]

SEC submits that allowing EPCOR to have available to it the ICM is entirely inconsistent with the CIP process. The central part of the CIP process required proponents to forecast its revenue requirement, which included amounts related to capital expenditures, for the entire 10-year stability period. The CIP process was clear that the risk of cost overruns during the stability period would be entirely borne by the utility:

> In the context of this competition, the "rate stability period" is the period of time that the proponent can expect to have its stated revenue requirement available from ratepayers to furnish all the capital and operating requirements that the identified service requires. During this period customers can expect relative rate stability as the proponent's revenues related to its controllable costs will be capped at its proposed level. The rate stability period may include an allowance for consideration of externally driven, unforeseen events as well as annual financial allowance updates typically allowed by the OEB.[15]

Allowing EPCOR to have access to a mechanism for additional capital funding through an ICM would be antithetical to the competitive process which resulted in its selection. With respect to exceptional externally driven unforeseen events, the now approved Settlement Proposal provides that EPCOR has access to the Z-Factor mechanism.

The Board should deny EPCOR's request for access to the ICM.

Deferral and Variance Accounts (Issues 7a,b)

EPCOR has sought approval for several Deferral and Variance accounts. As set out in the Settlement Proposal, there was agreement between the Parties with respect to all but three

[14] 10-SEC-19(a)
[15] EB-2016-0137/138/1399, Procedural Order No.6, p.4

accounts. SEC submits that EPCOR should not be granted two of these disputed accounts, as they are inconsistent with the CIP and thus not appropriate. As discussed below, each involve cost or revenue variances that were properly required to be forecast as part of the CIP process.

i. ***Regulatory Expense Deferral Account ("REDA").*** EPCOR seeks approval for the REDA to track costs it incurs associated with participating in generic and other Board hearings that impact the utility, including Union Gas proceedings.[16] There was no carve out for regulatory costs as part of the CIP process. These costs should have been forecast as part of EPCOR's submission as Union Gas presumably did. It would be unfair to that competitive process to allow EPCOR to be allowed to recover these incremental costs. While EPCOR may argue that this account is for participation in proceeding other than those it initiates is no different than any other utility who as part of its forecast of costs includes regulatory expenses that do not involve its own applications.

ii. ***Municipal Tax Variance Account ("MTVA").*** EPCOR seeks approval for the MTVA to track variances in municipal tax rates or levies as compared to what was built into the revenue requirement.[17] As these amounts were included with its revenue requirement as part of the CIP process, these are costs of which EPCOR has taken the risk. Both EPCOR and Union included as part of their forecast OM&A, municipal taxes.[18] Both had to have made a number of assumptions about how they may or may not change over the 10-year rate stability period. It would be unfair to the competitive process that, after EPCOR has been selected, it would be able to shift the risk to ratepayers.

    Furthermore, the proposed account does not meet the requirement for materiality. EPCOR has reached specific municipal tax funding agreements with the three municipalities within which it will provide natural gas service, Kincardine, Arran-Elderslie and Huron-Kinloss. The only municipal taxes that could change would be school taxes, or county taxes, as well as those related to municipalities in which it does not serve, but its distribution pipe passes through.[19] The increase would have to be very significant in the aggregate to meet EPCOR's $50,000 a year materiality threshold.[20] EPCOR provided information that this would occur if all taxes across <u>all</u> municipalities, school boards, and counties increase by 10%.[21] This is not very realistic.

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally (by email)
Applicant and intervenors (by email)

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[16] Ex.9-1-1, p.5
[17] Ex.9-1-1, p.5
[18] 9-Staff-36
[19] *Ibid*
[20] 9-Staff-36(b)
[21] *Ibid*