EB-2023-0140

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, 3 Schedule B, as amended;

AND IN THE MATTER OF a motion to review and vary EB-2022-0184 Decision and Order (Phase 2) related to the Customer Volume Variance Account.

COMPENDIUM OF THE SCHOOL ENERGY COALITION

Shepherd Rubenstein P.C.
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

Mark Rubenstein
Tel: 647-483-0113
Fax: 416-483-3305

Counsel for the School Energy Coalition

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER (PHASE 2)

EB-2022-0184

EPCOR NATURAL GAS LIMITED PARTNERSHIP (SOUTH BRUCE)

Application for Rates to be Effective January 1, 2023

BEFORE: Emad Elsayed
Presiding Commissioner

Allison Duff
Commissioner

April 6, 2023

1 OVERVIEW

EPCOR Natural Gas Limited Partnership (EPCOR) applied to the Ontario Energy Board (OEB) for changes to its natural gas distribution rates effective January 1, 2023 for its South Bruce service area (Application).

In the Application, EPCOR requested the following approvals:

I. To adjust distribution rates for South Bruce effective January 1, 2023 in accordance with the OEB-approved settlement agreement (Settlement Decision)[1] in EPCOR South Bruce's 2019-2028 Custom IR proceeding
II. To dispose of certain deferral and variance account balances
III. To establish a Customer Volume Variance Account (CVVA)

The OEB bifurcated the proceeding into two phases. The OEB issued a Phase 1 Decision and Order with respect to the proposed price cap adjustment and the request for deferral and variance account disposition on November 3, 2022.[2] This Decision and Order reflects the OEB's findings on EPCOR's request to establish the CVVA (Phase 2).

The OEB approves the establishment of a CVVA, effective January 1, 2023 until December 31, 2028. The approved CVVA is modified compared to the account proposed by EPCOR. Any accumulated balance will be shared on a 50/50 basis between EPCOR's shareholders and its customers. In addition, EPCOR shall only be eligible for the recovery of 50% of the annual balance from its customers in the CVVA until such point that EPCOR's actual earnings reach 300 basis points below its approved ROE. Further, the variance account will apply only to the South Bruce distribution system within the scope of EPCOR's approved 2019-2028 Custom IR framework.[3]

[1] EB-2018-0264, Decision and Order, October 3, 2019
[2] EB-2022-0184, Decision and Order, November 3, 2022
[3] EB-2018-0264

2 THE PROCESS

EPCOR filed the Application on July 18, 2022 under section 36(1) of the *Ontario Energy Board Act, 1998* (OEB Act). On August 5, 2022, the OEB issued a Notice of Hearing. The intervention period ended on August 24, 2022. No persons applied for intervenor status.

Procedural Order No. 1 was issued on August 26, 2022. OEB staff filed written interrogatories on September 7, 2022. EPCOR filed responses to interrogatories on September 19, 2022.

On September 27, 2022, the OEB issued Procedural Order No. 2, which bifurcated the application into two phases: Phase 1 would address the proposed price cap adjustment and request for deferral and variance account disposition and Phase 2 would address the CVVA issue. The OEB also granted intervenor status to all approved intervenors in EPCOR South Bruce's 2019-2028 Custom IR proceeding.[4] The School Energy Coalition (SEC) and Vulnerable Energy Consumers Coalition (VECC) filed letters advising that they intend to participate in Phase 2 of the proceeding. The OEB also provided for interrogatories and a settlement conference. On October 28, 2022, EPCOR filed a letter, supported by intervenors, stating that no settlement was reached.

On November 3, 2022, the OEB issued a Decision and Order with respect to the Phase 1 issues.

On November 7, 2022, the OEB issued Procedural Order No. 3, which provided for additional evidence regarding the CVVA to be filed by EPCOR, interrogatories on the new evidence, a tentative technical conference, argument-in-chief, submissions and reply submission.

OEB staff and intervenors filed written interrogatories, and EPCOR filed interrogatory responses in accordance with Procedural Order No. 3.

On December 8, 2022, the OEB issued Procedural No. 4 cancelling the technical conference due to the lack of sufficient questions to justify a full technical conference.

[4] EB-2018-0264

Instead, the OEB required EPCOR to respond to follow-up questions from OEB staff and intervenors. EPCOR filed responses to OEB staff and intervenor follow-up questions on December 15, 2022.

On January 9, 2023, EPCOR filed its argument-in-chief. OEB staff and intervenors filed submissions on January 27, 2023. On February 13, 2023, EPCOR filed its reply submission.

3 DECISION ON THE ISSUES

3.1 Appropriateness of Establishing the CVVA

EPCOR requested that the CVVA be established to track the variance in revenue resulting from the difference between the average customer volume forecast based on the common assumptions set out in the common infrastructure plan[5] (CIP) and the actual average customer volume from January 1, 2021, until December 31, 2028. EPCOR stated that, for Rate 1 customers, there is a 32% variance between consumption based on the CIP assumptions and actual consumption. EPCOR forecasted that the total balance in the CVVA for the 2021-2028 period to be $7.85 million. EPCOR stated that the CVVA is designed to record only variances associated with volume variances for Rate 1 and Rate 6 customers actually connected to the South Bruce system and EPCOR retains the risk related to customer attachments, as that was a CIP competitive parameter.

In 2018, the OEB selected EPCOR as the successful proponent for the South Bruce community expansion project. The process was competitive and the selection was made on the basis of a cumulative revenue requirement, forecasted attachments and a total volume throughput for a 10-year rate stability period.[6]

EPCOR stated that the CIP submissions detailed the proponents' revenue requirements to serve specific South Bruce communities and consisted of two general parameters: (i) common assumptions; and (ii) competitive parameters. EPCOR submitted that the average customer consumption volumes for Rate 1 and 6 customers were common assumptions in the CIP for which the risk should be borne by ratepayers.

EPCOR further submitted that if Enbridge Gas had been the successful proponent, consistent with the principle of not taking the risk on common assumptions regarding customer consumption, its existing normalized average consumption (NAC) account would have captured variances in actual consumption volume relative to those approved in rates.

[5] EB-2016-0137
[6] EB-2018-0264 Custom IR decision, November 28, 2019, page 1.

OEB staff submitted that the OEB should approve the establishment of the CVVA, with certain modifications. OEB staff agreed with EPCOR that the forecast Rate 1 and Rate 6 customer volumes are common assumptions in the CIP. OEB staff also agreed that had Enbridge Gas been the successful proponent its existing NAC account would have likely captured the same type of volume variances that EPCOR intends to record in the CVVA.

The modifications that OEB staff recommended related to the effective date of the CVVA and risk sharing of the CVVA balance, both of which are discussed later in the decision.

SEC submitted that the OEB should deny the request for the proposed establishment of the CVVA. SEC stated that EPCOR's Custom IR framework with a rate stability period (2019-2028) did not include any adjustments for variances in customers' normalized average consumption.

SEC argued that EPCOR's request is unfair as it undermines the integrity of the partial settlement achieved in its Custom IR proceeding and EPCOR's arguments about under-recovery without the CVVA need to be considered in the proper context. SEC lists three points to consider:

1. The statutory requirements of the OEB Act, in setting just and reasonable rates, only require that over the long-run EPCOR is given an opportunity to earn a fair return on its investment.[7]

2. EPCOR did not file any evidence to support its argument that absent the CVVA it will not be able to expand its distribution system.

3. In the approved partial settlement agreement in the Custom IR proceeding, the parties agreed that EPCOR would not be eligible for the generic +/- 300 basis earnings off-ramp. This is an indication, as part of the package settlement, that EPCOR's financial viability would not be at risk if its ROE was below that level, and so did not require the ability to seek extraordinary relief from the OEB in such a circumstance.

[7] Ontario Energy Board v. Ontario Power Generation Inc., 2015 SCC 44, paras 16-17

VECC also submitted that the OEB should not grant the CVVA. VECC argued that granting the CVVA would violate the terms of the 10-year plan approved by the OEB and effectively change the committed rate from $0.2209/m^3 to $0.2960/m^3 in 2022.

VECC claimed that EPCOR did not do its due diligence in realizing this “obvious risk” when it accepted the CIP consumption assumptions. VECC submitted that only a cursory understanding of Ontario’s gas market was needed to understand the challenges of load building in a greenfield environment. VECC referred to initiatives to convert residential customers to natural gas water heater in the early 2000s.

VECC also disagreed with EPCOR’s claim that the proposed CVVA was similar to Union Gas Limited’s (Union Gas) existing NAC account. VECC submitted that Union Gas’s variance account normalizes for weather, not CIP consumption estimates. Further, the financial risk of consumption variances in South Bruce to EPCOR was unique as a small standalone utility compared to the “de minimis effect” for a large utility like Enbridge Gas (formerly Union Gas).

VECC criticized both EPCOR and OEB staff for presuming the idea of normalizing consumption is an aspect of gas utility regulation. According to VECC, there is no evidence in this case that this practice is applied in any jurisdiction other than Ontario.

In its reply submission, EPCOR stated that the proposed CVVA will (a) restore and fully implement the utility-customer risk allocation framework which was previously approved by the OEB during the competitive process; and (b) enable EPCOR to earn a reasonable return on its investment, consistent with its approved revenue requirement and thereby avoid a scenario of chronic under-earning and ultimately a negative cumulative ROE.

As discussed later in the decision, EPCOR also provided detailed argument with respect to the appropriate effective date for the CVVA, risk sharing and the applicability of the CVVA to any community expansions of the South Bruce utility during the rate stability period in its reply submission.

With respect to VECC’s argument that granting the CVVA will change the rate of $0.2209/m^3 to $0.2960/m^3 in 2022, EPCOR stated that a change to the committed rate would not change the approved revenue requirement for the ten-year term.

Findings

The OEB approves the establishment of the CVVA, which is modified relative to the variance account proposed by EPCOR. The OEB finds that the modified CVVA is consistent with its statutory requirements in setting just and reasonable rates to enable EPCOR to earn a fair return on its capital investments. In its first years as a regulated utility, EPCOR has consistently reported negative ROEs. Its most recently reported ROE in 2021 was negative 14.0%.[8] Table 1 provides EPCOR's forecast returns for the remainder of its 10-year term with and without its proposed CVVA.

Table 1: Forecast Return on Equity[9]

Return on Equity	2022	2023	2024	2025	2026	2027	2028
No CVVA	-9.1%	-2.4%	1.9%	3.2%	3.5%	3.8%	3.4%
Proposed CVVA (i.e. 100% recovery)	-7.2%	1.1%	6.5%	8.3%	8.8%	9.2%	9.0%

EPCOR's forecast ROEs with no CVVA recovery are substantially below the ROE of 8.78% that underpins EPCOR's rates established in the 2019-2028 Custom IR proceeding.[10] The OEB finds it prudent to establish a modified CVVA to provide EPCOR the opportunity to earn a fair rate of return on its investments. To be clear, there is no guarantee for any utility of earning the OEB's approved ROE.

The OEB is not approving the modified CVVA to change the approved 10-year Custom IR framework. The OEB is not persuaded by EPCOR's characterization of the 10-year rate stability period as a regulatory compact that somehow needs to be fixed after the fact to restore and fully implement a prior OEB decision. The OEB finds merit in VECC's suggestion that EPCOR ought to have considered the potential risk of average use variances relative to the CIP volumes as part of EPCOR's due diligence. The OEB notes that EPCOR did not file a motion to review or an appeal of the Custom IR

[8] EPCOR IRR Phase 2, Dec. 5, 2022, Response to SEC 8
[9] EPCOR IRR Phase 2, Dec. 5, 2022, Response to SEC 8
[10] EB-2018-0264, Exhibit 5, Tab 1, p. 1

decision. As a result, the Custom IR decision and the approved partial settlement agreement stand unaltered.[11]

The OEB regards the forecast ROEs with no CVVA recovery in Table 1 as quantifying the challenge for EPCOR for the duration of its Custom IR term.

The OEB finds that the CVVA, as approved by the OEB, will provide EPCOR with the incentives necessary to improve asset utilization and the resulting ROE forecasts from 2023-2028. The proposed CVVA provided little incentive for EPCOR to manage its risks as customers were expected to bear 100% of the revenue risk of average consumption variances.

The modified CVVA compared to the proposed CVVA is explained in detail in the Effective Date, Applicability of the CVVA and Risk Sharing sections of this decision.

3.2 Effective Date

EPCOR amended the originally requested effective date of January 1, 2020 to January 1, 2021, as prior to the revised effective date there was insufficient data to calculate the weather-normalized volumes.[12]

OEB staff, SEC and VECC argued that the approval of an effective date of January 1, 2021 would amount to impermissible retroactive ratemaking.

OEB staff submitted that the CVVA should have an effective date of January 1, 2023, which is the same effective date as the distribution rates requested in the Application. Any effective date prior to this would offend the rule against retroactive ratemaking.

SEC submitted that, should the request for a CVVA be approved, it should have an effective date that is aligned with the OEB's release of its final decision as any earlier date would be impermissible retroactive ratemaking.

[11] EB-2018-0264
[12] EPCOR Interrogatory response, December 5, 2022, OEB Staff Question 4

SEC stated that there are two general exceptions to the rule against retroactive ratemaking. These exceptions are interim rates or the existence of a deferral (or variance) account. SEC stated that neither exception is applicable here.

SEC referred to Halton Hills Hydro Inc.'s (Halton Hills Hydro) 2018 Incentive Rate-setting application.[13] In this application, Halton Hills Hydro requested approval to establish a new deferral account to record an adjustment to its revenue requirement related to an error that it made in its 2016 rebasing application regarding its depreciation expense, effective beginning in 2016.[14] The OEB denied approval of the proposed effective date, noting that the rule against rate retroactivity is not discretionary other than for a narrow set of exceptions. VECC made similar arguments to OEB staff and SEC.

EPCOR submitted that its proposed effective date of January 1, 2021, for the CVVA is both permissible and appropriate when considering retroactive ratemaking principles.

EPCOR stated that the Alberta Court of Appeal noted that "the reason there is no blanket prohibition against retroactive ratemaking is that there are decades of public utility board and judicial decisions variously applying the rule or declining to apply the rule depending on circumstances."[15] The Alberta Court of Appeal further stated that "no court or public utilities board will ever be able to define precisely the circumstances in which retroactive ratemaking is permissible. Nor is it desirable that they should do so. And, presumably, it has been deemed even less desirable to enact a blanket prohibition."[16]

EPCOR submitted that the OEB Act gives the OEB a mandate to "make orders approving or fixing just and reasonable rates"[17] and "adopt any method or technique that it considers appropriate."[18] EPCOR further submitted that Ontario courts have confirmed that "just and reasonable rates" are rates that permit a utility to recover its prudently incurred costs and earn a fair return on invested capital. The Alberta Court of

[13] EB-2017-0045
[14] Halton Hills Hydro Inc., EB-2017-0045, Decision and Order, April 26, 2018
[15] Capital Power Corp. v. Alberta Utilities Commission 2018 ABCA 437 at para 64.
[16] Capital Power Corp. v. Alberta Utilities Commission 2018 ABCA 437 at para 64.
[17] Ontario Energy Board Act, SO 1998, c 15, s 36(2).
[18] Ontario Energy Board Act, SO 1998, c 15, s 36(3).

Appeal decision suggests that regulators should consider whether retroactive ratemaking is in the public interest.[19]

EPCOR argued that the unique circumstances associated with the provision of gas distribution services in South Bruce favour an effective date of January 1, 2021. EPCOR stated that facilitating the maintenance of a financially viable gas industry is a statutory objective of the OEB, and the public interest in EPCOR's ability to realize a fair and reasonable return on its investment and continue to provide safe, reliable utility services should outweigh any assumed presumption of prospective rate making. EPCOR submitted that an OEB finding to the contrary would discourage investment in essential utility services being provided to consumers.

In response to OEB staff, SEC and VECC’s reference to the two exceptions to the rule against retroactive adjustments to rates (i.e., interim rates and deferral and variance accounts), EPCOR stated that several decisions have been critical of an overreliance on the interim rates and deferral and variance account exceptions. EPCOR noted that the Alberta Court of Appeal in *Atco Gas and Pipelines Ltd. v. Alberta (Utilities Commission*) stated that it is not interim rates that are important per se, but the regulators mandate to ensure rates and tariffs are just and reasonable.[20]

EPCOR also submitted that its request for the establishment of the CVVA is distinguishable from the OEB’s decision in Halton Hills Hydro’s 2018 Incentive Rate-setting application.[21] EPCOR stated that in the Halton Hills Hydro decision, the utility requested approval to establish a deferral account to annually record an adjustment to its revenue requirement. The annual amount was related to an error the utility identified in the calculation of depreciation expense in its last cost of service application. The deferral account was unanimously opposed by OEB staff, SEC and VECC on the basis of several concerns, including: (a) Halton Hills Hydro’s control over its own process and the accuracy of information it files; (b) there was no regulatory basis for the request under the OEB’s rate setting policies given its rates were set through a cost of service

[19] Capital Power Corp. v. Alberta Utilities Commission 2018 ABCA 437 at para 66-67.
[20] Atco Gas and Pipelines Ltd. v. Alberta (Utilities Commission), 2014 ABCA 28, 566 A.R. 323 at para 58.
[21] Halton Hills Hydro Inc., EB-2017-0045, Decision and Order, April 26, 2018

application with annual mechanistic adjustments; and (c) Halton Hills Hydro had not demonstrated that its financial viability was at risk.

EPCOR submitted that, in contrast, (a) the CVVA amounts are not the result of any utility error or mistake on the part of the utility (but rather the variance between assumed average customer volumes established in the OEB's competitive process and actual customer volumes to date); (b) there is a clear regulatory basis for EPCOR's request (i.e., the generic proceeding which determined customer annual average volume would be a non-competitive element); (c) EPCOR has established important and significant financial impairment; and (d) EPCOR is not requesting an increase to its approved revenue requirement.

EPCOR concluded that the OEB has authority to approve an effective date of January 1, 2021 for the CVVA, and that a refusal of the request would result in significant financial impairment and prevent EPCOR from earning a fair return on its invested capital.

Findings

The OEB finds that January 1, 2023 is the appropriate effective date for the CVVA. The January 1, 2023 date is the same effective date for the IRM rate increase approved in Phase 1 of the current proceeding. An earlier date would amount to retroactive ratemaking which cannot be justified given the circumstances specific to this case. Exceptional circumstances under which retroactive ratemaking can be considered (i.e., interim rates or a deferral and variance account) do not apply in this case.

The rule against retroactive ratemaking exists to provide customers with rate certainty and to avoid intergenerational inequity, among other objectives. The rule does not exist to reduce utility risk of financial impairment or to enable higher rates of return on invested capital as implied by EPCOR in its reply submission, and the OEB finds that an effective date prior to January 1, 2023 is not appropriate.

3.3 Applicability of the CVVA

EPCOR noted that it was awarded a grant for the Brockton community expansion by the Ontario Government.[22] EPCOR requested that the CVVA be applicable to all Rate 1 and 6 customers who are subject to EPCOR's South Bruce rates. EPCOR stated that it intends to use the South Bruce rate structure for future expansions in order to achieve operational and regulatory efficiencies.[23]

OEB staff, SEC and VECC submitted that the applicability of the CVVA should be limited to the current South Bruce distribution system that underpinned EPCOR's 2019-2028 Custom IR application. OEB staff noted that the rates established for EPCOR's South Bruce distribution system are based on the OEB-approved revenue requirement for only that distribution system.

OEB staff further stated that it is not taking the position that applying the South Bruce rate structure, including the availability of the CVVA to record revenue variances, is necessarily inappropriate. However, OEB staff submitted there is insufficient evidence before the OEB with respect to the appropriateness of applying the South Bruce rate structure to other community expansions, including Brockton.

EPCOR opposed a geographically restricted CVVA. EPCOR submitted that in the context of a typical system expansion, a variance account such as the proposed CVVA applies across the utility. EPCOR also stated that the Ontario government grant for the Brocton community expansion was applied for on the basis of South Bruce rates. EPCOR stated that it was required to use a common assumption for annual customer consumption of 2,200m^3 and without access to the CVVA, this community expansion would become uneconomic.

Finally, EPCOR submitted that the Brockton expansion has a forecasted in-service date of Q3 2024 and all prospective customers for this project would connect to the system well after the establishment of the CVVA. Therefore, EPCOR stated that it should be

[22] EPCOR Interrogatory response, September 19, 2022, OEB Staff Question 3k
[23] Argument-in-chief, pg. 5.

permitted to recover 100% of amounts recorded in the CVVA for all prospective Brockton customers.

Findings

The OEB finds that the CVVA is applicable only to the South Bruce distribution system, and not to any future expansion projects. The South Bruce distribution system was the basis for EPCOR's 2019-2028 Custom IR framework and there is insufficient evidence at this time to apply the South Bruce rate structure to other community expansions.

For future community expansions, EPCOR can seek the necessary rate approvals at the time that it seeks leave to construct approval for the community expansion.

3.4 Risk Sharing

OEB staff submitted that the OEB should approve recovery of 47% of the eventual balance in the CVVA for the 2023-2028 period and no recovery during the 2021-2022 period. The 47% sharing was calculated using the percentage of mass market customers actually connected at the year-end of 2022 relative to the total number of mass market customers that are expected to be connected to ECPOR's South Bruce system at the end of the 10-year Custom IR term (2028). OEB staff stated that using the year-end 2022 customer count as part of this risk sharing calculation is appropriate as these are the customers that did not have all the information necessary to make a fully informed decision regarding taking natural gas service from EPCOR.[24]

SEC submitted that a potential approach for risk sharing would be to apply the OEB's policy regarding recovery of the impacts arising from COVID-19.[25] Applying this approach, the OEB would require a 50/50 split between customers and the utility, for revenue variances below the dead band amounts (300 basis points). There would be no

[24] In its reply argument, EPCOR provided updated calculations of OEB staff's risk sharing proposal based on 3,412 Rate 1 and 6 customers actually connected by 2022 and a total of 6,051 customers forecasted to be connected by the end of 2028. This results in a recovery allocation to EPCOR of 41% compared with 47% set out in OEB staff's submission.

[25] Report of the Ontario Energy Board: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (EB-2020-0133), June 17, 2021, pg.17

recovery of the amounts related to the difference in average use that fall within the dead band, only the amounts that contribute to earnings variance below (or above) 300 basis points.[26]

VECC submitted that a ROE linked sharing mechanism should reflect a floor of 300-500 basis points, meaning EPCOR would not receive any amounts until the ROE has fallen below the floor level. VECC also submitted that 10-20% of EPCOR's recoverable portion of the CVVA should be spent on building load to mitigate the need for the CVVA. VECC also recommended that EPCOR undertake a study to determine the reasons for its low residential volumes and, with its own resources, build load growth in the franchise including facilitating and subsidizing water tanks.

EPCOR submitted that any sharing of the average annual customer volume risk undermines the entire CIP process and the basis upon which EPCOR bid for and undertook the construction of the South Bruce utility. EPCOR stated that it expected that the forecasted average customer volumes established through the CIP were reliable, but the reality was that there was no existing gas utility servicing the South Bruce area and Enbridge Gas's normalized average was deemed an appropriate forecast. Furthermore, there was insufficient data incorporating a 12-month usage cycle to identify the impact of variances between actual and forecasted customer volumes.

EPCOR stated that even if 100% of the balance in the CVVA is approved for recovery, EPCOR would earn an average ROE of 0.9% over the ten-year period, which is only marginally higher than the -2.5% ROE that results if the status quo persists (i.e., no CVVA).[27] EPCOR stated that the recovery of 100% of the balance in the CVVA would still result in EPCOR receiving a near zero rate of return.

EPCOR noted that OEB staff's risk sharing proposal is based on the notion that EPCOR has deprived Rate 1 and 6 customers who connected during the 2019-2022 period of a comprehensive understanding of the changes to the rates that they may experience during the ten-year rate stability period. However, in EPCOR's view OEB staff's rationale regarding customer notice is difficult to reconcile with the reality of customer conversion decision-making. EPCOR stated that OEB staff's risk sharing proposal

[26] Ibid, pg.15
[27] Reply Argument, February 13, 2023, pg. 12

results in a 59% reduction in revenue risk for any customer who connects to the system, regardless of when they connect during the ten-year term.

EPCOR submitted that SEC and VECC have each proposed risk sharing mechanisms that are impractical or lack a principled basis for approval.

EPCOR objected to the concept of risk sharing in respect of average customer volumes as it contradicts the ten-year regulatory compact it signed on to. EPCOR submitted that approval of a risk sharing approach would amount to a review and variance of a prior OEB decision, resulting in a material change to the general parameters. It would also adversely impact EPCOR's financial position, limit its ability to earn a fair return on its investment, and result in an unfair/inequitable outcome. EPCOR stated that South Bruce ratepayers have benefited from the competitive aspects of the OEB's competitive process, and it is only fair for EPCOR to receive the benefit of common assumptions and obtain a result where ratepayers assume the full responsibility of risk associated with annual average consumption.

While EPCOR fundamentally objected to the concept of risk sharing, EPCOR provided an alternative risk sharing proposal in the event that the OEB decides that risk sharing is necessary. EPCOR submitted that the risk sharing mechanism should adequately reflect: (a) recognition that the utility is not at fault for the variances between forecasted and actual average customer volumes; and (b) a fairer compromise that more reasonably reflects the OEB’s prior decision on risk allocation for average customer volume.

EPCOR submitted that the starting point for determining the proportion of the risk borne by EPCOR should be to identify the number of customers consuming gas by the end of August 2022, which is the month after the OEB hearing notification was sent out regarding the Application. The apportionment of risk as between EPCOR and those customers who connected to South Bruce from 2019 (when customers first connected to EPCOR’s South Bruce distribution system) to August 31, 2022 would be shared on a 50/50 split for the duration of the rate term (i.e. until December 31, 2028), consistent with the OEB policy that is used to share the impacts of changes in tax legislation in between filing periods.[28] EPCOR stated that risk sharing would not apply to customers who connected after September 1, 2022. Customers who connect from September 1, 2022-December 31, 2028 would accept 100% of the risk associated with average customer volumes for the remainder of the rate term.

EPCOR stated that under its alternative model, EPCOR would recover 79% of amounts recordable in the CVVA throughout the rate stability period, resulting in an average ROE of 0.2% as opposed to 0.9% if the CVVA is 100% recoverable.

Findings

The OEB finds that a 50/50 sharing mechanism should be applied to the CVVA. The OEB also finds that EPCOR shall only be eligible for the recovery of the annual balance in the CVVA until such point that EPCOR's actual earnings reach 300 basis points below the ROE that underpinned EPCOR's rates established in the 2019-2028 Custom IR proceeding (i.e. 5.78% = 8.78%[29]-3.00%).[30] The balance in the CVVA will be assessed annually as the balance will not be assessed on a cumulative basis. The OEB approves these modifications to the proposed CVVA to incent EPCOR to act to improve capital asset utilization and EPCOR's resulting ROE forecasts from 2023 to 2028.

The OEB finds that 50/50 sharing is appropriate as it balances the risk of consumption variances equally between shareholders and customers as neither should be entirely responsible. The OEB finds that CIP volume risk was not a live issue in the Custom IR proceeding and was not directly addressed in the Custom IR decision.

The OEB does not accept EPCOR's proposal that customers bear 100% of the cost of the CVVA balance as the utility was "not at fault" for the unanticipated variance. If the

---

[28] ECPOR noted that, although the present circumstances are not the outcome of a change in legislation, this 50/50 split approach accounts for an unanticipated variance for which no party is at fault and therefore splits the impacts evenly as between the utility and ratepayer.

[29] EB-2018-0264, Exhibit 5, Tab 1, p. 1

[30] The OEB invites EPCOR, in the draft accounting order process as established later in this decision, to advise whether it believes that the 8.78% ROE figure is the appropriate figure to include in the CVVA accounting order as the starting point for determining the ROE percentage that is 300 basis points below the ROE underpinning rates. As an illustrative example, using the ROE of 5.78%, which is 300 basis points below the 8.78% ROE figure, if the recovery of 50% of the CVVA balance results in a recalculated achieved ROE of 6.00% in any given year, the revenues in the CVVA associated with the 0.22% above the 5.78% ROE would not be recoverable.

OEB were to accept that premise, are customers at fault? The OEB finds that a 50/50 split is appropriate to share the net impact evenly between the shareholder and customer in a case where no party bears all of the fault. While OEB staff suggested a 47/53 sharing based on current and projected customer numbers, the OEB is not convinced that forecast customer numbers is the appropriate basis for sharing revenue variances due to average consumption volumes.

The OEB finds that limiting recovery of CVVA balances to the point that EPCOR's actual earnings reach 300 basis points below the ROE that underpinned EPCOR's rates established in the 2019-2028 Custom IR proceeding is also appropriate. The OEB notes that 300 basis points is used as a means test in the OEB's policy regarding the recovery of the impacts arising from COVID-19.[31] A 300 basis point dead band is also applied as a means test as part of the OEB's ICM/ACM policy[32] and as a criterion for considering the appropriateness of applying IRM increases.[33] The OEB finds that 300 basis points below the approved ROE is a reasonable threshold to limit recovery of balances in the modified CVVA, which should provide EPCOR the opportunity to earn a fair rate of return.

3.5 Bill Impacts

OEB staff submitted that a rate smoothing proposal, as necessary, should be filed in the relevant application if the total annual bill impact, including the recovery of CVVA balances, is greater than 10%. OEB staff noted that the disposition of the balance in the CVVA will likely have material impacts on Rate 1 customers.[34]

---

[31] Report of the Ontario Energy Board: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (EB-2020-0133), June 17, 2021, pg.15. Note that the above-noted means test of less than 300 basis points applies to all costs recorded in the COVID-19 Account, other than the costs necessary to comply with government or OEB-initiated programs recorded in the Exceptional Pool.
[32] EB-2014-0219, Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, issued September 18, 2014
[33] Filing Requirements for Electricity Distribution Rate Applications – Chapter 3, May 24, 2022, p. 23.
[34] OEB staff submission (Phase 2), January 26, 2023, Pg. 10-11

EPCOR supported OEB staff's request that it file a rate smoothing proposal where the total annual bill impacts are greater than 10%.

Findings

As discussed in more detail later in the decision, the OEB finds that EPCOR shall file a rate class allocation and disposition proposal for the CVVA in its first application seeking disposition of CVVA balances. As part of that proposal, if the total annual bill impact for any rate class, inclusive of the recovery of the CVVA balance, is greater than 10%, EPCOR shall include a rate smoothing proposal.

3.6 Customer Communication

OEB staff submitted that future customers should have comprehensive cost information (including the impact of the CVVA) when deciding whether to connect to EPCOR's South Bruce distribution system. EPCOR is expecting approximately 2,700 additional customers to connect to the South Bruce distribution system in the 2023-2025 period and they should be aware of the total cost impact.

SEC stated that, if the CVVA is approved, existing and potential new customers should be made aware of the implication on their costs during the remainder of the rate stability period. Since the impact is through a deferral account disposition as opposed to being included in base rates, those customers cannot accurately take the impact into account when making real-time consumption decisions. SEC requested the OEB require EPCOR to:

1. Notify any existing customers and any potential customers with updated information, and revised bill forecasts, including express notice that past impact information is no longer valid or reliable; and
2. Update all marketing material and other information to explicitly include the impacts of forecast CVVA disposition.

EPCOR agreed with OEB staff that future customers should be provided with the necessary cost information, including impacts of the CVVA.

Findings

EPCOR did not seek approval of the CVVA as part of the 2019-2028 Custom IR proceeding, and therefore its Rate 1 and Rate 6 customers that connected during the 2019-2022 period were not aware of the changes to their rates that may result from disposition of the CVVA.

Similarly, potential customers may rely upon existing rate schedules and bill impact information that do not include the impacts of the approved CVVA.

The OEB directs EPCOR to communicate to existing and potential customers in its South Bruce service area a forecast of bill impacts and delivery costs inclusive of the impact of the CVVA during the remainder of the rate stability period.

3.7 Methodology for Calculating the Balance in the CVVA and the Draft Accounting Order

EPCOR provided additional evidence on November 14, 2022, that set out the methodology that it proposed to apply to calculate the balance in the CVVA.

EPCOR stated that deriving the appropriate volume involves calculating the actual monthly consumption per customer, adjusting it to remove the impact of the Energy Content Variance Account (ECVA), and applying the weather normalization methodology to determine the monthly NAC. The monthly NAC, and approved rate schedules (including volumetric charges, monthly fixed charges and the delay in revenue rate rider) are then used to generate an average customer's monthly revenue. The average customer's monthly revenue is multiplied by the number of actual billable customers in that rate class to calculate the total monthly NAC revenue of that rate class. The total CIP revenue for each month is calculated using the assumed monthly CIP consumption with the approved rate schedule multiplied by the actual billable customers in that rate class. The difference between the total monthly NAC revenue and the total monthly CIP revenue for the corresponding months is calculated and recorded in the CVVA each month.

OEB staff stated that it has no concerns with EPCOR’s proposed CVVA calculation methodology. OEB staff noted that the calculation process ensures there is no double counting of the ECVA, by removing the impact of the energy content, and properly incorporates the proposed weather normalization methodology. OEB staff submitted that the CVVA balance recoverable from ratepayers would be lower if a rate sharing mechanism is applied.

VECC noted that EPCOR’s proposal is to calculate and dispose of the CVVA balances on a rate class basis (i.e., separate calculations for Rate 1 and Rate 6 classes). VECC stated that accepting EPCOR’s proposal would lead to the outcome of having Rate 1 customers pay for both their failure to meet some expected load and provide a benefit to Rate 6 customers because that class exceeded it.

VECC submitted that the balance in the account should be calculated on an all class net basis and that the net balance should be allocated to both of the rate classes (Rate 1 and Rate 6). In this way, any benefits derived from better than expected performance from Rate 6 can be used to mitigate the harm to Rate 1 customers.

SEC submitted that, if the OEB approves the CVVA, it does not oppose the calculation and disposition methodology for the CVVA as detailed in EPCOR’s November 14, 2022 additional evidence subject to its submissions on the effective date, risk sharing and applicability of the account. SEC disagreed with VECC’s rate class allocation proposal and stated that EPCOR's proposed approach is the more appropriate methodology. SEC submitted that if the intent of the CVVA is to capture and dispose of the variance in weather-normalized average customer use compared to what was included the CIP then the disposition methodology should reflect “what would have happened if the actual weather normalized average consumption” was the basis for rate-setting in the first place.

In its reply submission, EPCOR submitted that the proposed CVVA should be approved, including the proposed allocation and disposition methodologies.

OEB staff submitted that the draft accounting order will need to be updated based on the OEB’s findings. OEB staff stated that the OEB should establish a process to address the finalization of the accounting order in its Decision and Order. This process should include the filing of an updated draft accounting order based on the OEB’s findings, an opportunity for comment by OEB staff and intervenors, and reply comments from EPCOR.

Findings

The OEB finds that EPCOR's methodology for calculating the balance in the CVVA is generally appropriate. The OEB approves the proposed methodology for calculating revenue variances to be recorded in the CVVA. As a result, the CVVA will start to track the revenue impact of average volume variances for Rate 1 and Rate 6 customers compared to the CIP assumptions, excluding the energy content variance, effective January 1, 2023.

The modified CVVA will include carrying charges that are calculated using the OEB's prescribed interest rate methodology for deferral and variance accounts. Both the CVVA balance and the associated carrying charges will be subject to 50/50 sharing between EPCOR's shareholders and customers.

The OEB acknowledges the concerns raised regarding the proposed rate class allocation and disposition methodologies for the recovery of the annual CVVA balances and the relative billing impact between Rate 1 and 6 customers. The OEB finds that EPCOR's proposed rate class allocation and disposition proposal requires further consideration. Allocation and disposition options among rate classes of an approved CVVA balance should be considered by a future panel based on actual data when EPCOR applies for CVVA disposition.

With the approved establishment of the CVVA as modified by the OEB, EPCOR's proposed CVVA draft accounting order is required to be updated. The updated draft accounting order shall reflect the findings in this Decision and Order. In addition, the OEB invites EPCOR to advise whether it believes that the 8.78% ROE figure is the appropriate figure to use as the starting point for determining the ROE percentage that is 300 basis points below the ROE underpinning rates. The OEB directs EPCOR to file an updated draft accounting order for review by the OEB.

4 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. EPCOR Natural Gas Limited Partnership shall file with the OEB and forward to OEB staff and intervenors a draft accounting order in accordance with the findings in this decision for the establishment of the Customer Volume Variance Account by **April 20, 2023**.

2. OEB staff and intervenors may file any comments on the draft accounting order with the OEB and forward to EPCOR Natural Gas Limited Partnership by **April 27, 2023**.

3. EPCOR Natural Gas Limited Partnership shall file with the OEB and forward to intervenors responses to any comments on its draft accounting order by **May 4, 2023**.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Please quote file number, EB-2022-0184 for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the File documents online page on the OEB's website.

- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Arturo Lau Arturo.Lau@oeb.ca and OEB Counsel Michael Millar at Michael.Millar@oeb.ca.

Email: registrar@oeb.ca
Tel: 1-877-632-2727 (Toll free)

DATED at Toronto April 6, 2023

ONTARIO ENERGY BOARD

Nancy Marconi
Registrar

EB-2016-0137
EB-2016-0138
EB-2016-0139

South Bruce Expansion Applications

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with natural gas distribution services

DECISION ON PRELIMINARY ISSUES AND PROCEDURAL ORDER NO. 8

August 22, 2017

EPCOR Southern Bruce Gas Inc. (EPCOR) filed applications with the Ontario Energy Board (OEB) on March 24, 2016 under sections 8 and 9 of the *Municipal Franchises Act*, R.S.O. 1990, c. M.55, seeking approval for its franchise agreements with and Certificates of Public Convenience and Necessity for the Municipality of Arran-Elderslie, Municipality of Kincardine and the Township of Huron-Kinloss ("the South Bruce Expansion Applications"). Procedural Order No. 1, which was issued on January 5, 2017, directed other parties interested in serving the areas covered by the South Bruce Expansion Applications to notify the OEB of their interest. Union Gas Limited (Union) filed a letter dated January 19, 2017 notifying the OEB of its interest in serving the areas covered by the South Bruce Expansion Applications.

Through procedural orders, the OEB determined that it would hear the applications to serve the areas in two phases. In the first phase, the OEB would consider submissions on certain preliminary issues, and in the second phase, the OEB would select either EPCOR or Union as the successful proponent.

On June 23, 2017, the OEB issued a Partial Decision and Procedural Order No. 6 (the Partial Decision), which addressed two of the issues on the Preliminary Issues List, and which also required both EPCOR and Union to participate in a joint session with OEB staff on July 13, 2017 to determine the technical parameters of a Common Infrastructure Plan (CIP) for the area covered by the South Bruce Expansion Applications.

On July 20, 2017, OEB staff submitted a progress report (Staff Progress Report) which outlined the CIP parameters discussed in the joint session, areas of agreement and disagreement between proponents, draft permissible rate adjustment criteria and proposal comparison criteria. The proponents requested that the OEB allow for submissions on the areas of disagreement.

On August 2, 2017, pursuant to Procedural Order No. 7, the OEB heard oral submissions from EPCOR and Union regarding each of the areas of disagreement listed in OEB staff's progress report: upstream reinforcements, inflation costs, OM&A costing methodology, treatment of capital costs, other CIP parameters and permissible rate adjustments. The OEB also heard from the proponents on the process for moving forward with this proceeding. During the joint session and as documented in the Staff Progress Report, both Union and EPCOR agreed to a filing date in October 2017.

This decision and order will resolve the CIP-related issues that were the subject of the August 2, 2017 oral hearing. In addition, it will address those other aspects of the Preliminary Issues List that were not determined in the June 23, 2017 Partial Decision. This decision will bring Phase 1 of this proceeding to a close. EPCOR and Union will file proposals in accordance with this decision and order, and the OEB will then select one of them. A cost awards process will be established following the selection of the successful proponent.

Concerns raised by some Intervenors regarding the CIP Hearing

The School Energy Coalition (SEC) filed a letter dated August 4, 2017 expressing concern that some of the submissions at the August 2, 2017 hearing (at which intervenors did not participate) went beyond the CIP, into areas such as rate-setting and the remaining process in the proceeding. SEC referred to the written submissions on process that have already been made by intervenors, and urged the OEB to invite submissions by directly affected ratepayers on the question of permissible rate adjustments during the rate stability period. The Vulnerable Energy Consumers Coalition (VECC) sent a letter dated August 9, 2017 echoing SEC's concerns. Both SEC and VECC reiterated that the OEB should provide for interrogatories on the proposals. On August 16, 2017, Greenfield Global Inc. (Greenfield) filed a letter with the OEB expressing similar views. Greenfield submitted that the competing proposals should contain information that will allow potential customers to make informed submissions, and requesting interrogatories.

The OEB recognizes that submissions were made by the proponents on permissible annual revenue updates at the hearing. The OEB does not consider the setting of rate-making parameters for the purpose of establishing comparable CIP proposals to be determinative of any element of the future rate-making scheme for the successful proponent. How the revenue requirement will be recovered, including the actual permissible annual revenue updates, will be decided later with the full participation of affected ratepayers. All of the following parameters that involve rate making assumptions should be considered in that context.

In respect of the process for examining the competing proposals, the OEB will determine the appropriate process once the CIP proposals have been received.

Decision on CIP Parameters

In its Partial Decision, the OEB decided to establish a CIP as the basis for determining proponents' successful revenue requirements. Both Union and EPCOR agreed on certain CIP parameters in a joint session with OEB staff. The OEB also provided for an oral hearing for areas of disagreement between the proponents on the CIP.

Presentment of the CIP Proposals

The OEB recognizes that both proponents have agreed to certain assumptions regarding CIP parameters. The common assumptions of the CIP should be explicitly included in each proponent's proposal to ensure that proponents are adhering to their agreement. However, the OEB does not expect proponents to disclose those competitively derived elements that build up the revenue requirement.

Agreed Upon Parameters

A full description of the parameters that were agreed upon can be found in the OEB Staff Report filed on July 20, 2017. The OEB has summarized the agreed upon parameters below and finds that they are appropriate:

- Communities

  The CIP will provide service to the following communities: Chesley, Inverhuron, Paisley, Tiverton, Kincardine, Lucknow, Lurgan Beach, Point Clark, Ripley and the Bruce Energy Centre Industrial Park.

  The OEB accepts this portion of the agreement between Union and EPCOR. As discussed later on page 10, the successful proponent will be required to serve these communities. This will ensure that the proponents' proposals are realistic and consistent with what the proponents would do if selected.

- Comparison Criteria

  The proponents agreed to three comparison criteria: $/m^3, number of customer years and cumulative volume. The OEB accepts this aspect of the proponents' CIP agreement. These comparison criteria should be included in proponents' proposals. The successful proponent will be held to the comparative criteria agreed to when filing its rates application.

- Infrastructure Specifications

  The proponents agreed that infrastructure specifications, such as the size of the pipeline to be built, its routing and resulting costs, will be left to competition. The OEB accepts this aspect of the CIP agreement. The OEB does not expect detailed cost information, which builds up to the revenue requirement, to be provided. The OEB does, however, expect proponents to include details of the infrastructure, including the routing and engineering, in their proposals.

- Construction Schedule

  The OEB accepts the construction schedule as agreed to between Union and EPCOR, with the gas mains to all the communities to be served to be constructed within two years from the commencement of construction. The OEB finds that the timing of customer connections each year during the rate stability period will be left to competition. Proponents are expected to include their construction schedule forecast.

- Customer Attachments

  Both proponents agreed that the number of attachments should be competitive, and based on the levels of risk and marketing activities that each proponent would be willing to take on. The OEB accepts this aspect of the CIP agreement and finds that the number of customer attachments will be competitive. The OEB expects proponents to include details on their forecast attachments as part of the proposals. The successful proponent will be held to its forecast for rate-making purposes.

- Forecast Horizon

  The OEB accepts this aspect of the CIP agreement and finds that a 10 year horizon for customer attachment and volume forecasts is appropriate.

- Customer Consumption

  The OEB accepts this aspect of the CIP agreement and finds that using common consumption levels for each mass market segment, except for large commercial or industrial customers, is appropriate. The proponents agreed to work together to develop these values. These values should be included in proponents' proposals. If the proponents are unable to agree on the values to be used, they may seek further directions from the OEB.

- Depreciation Rates

  The OEB accepts this aspect of the CIP agreement and finds that any depreciation rates used should be based on Union's OEB-approved depreciation rates. The proponents should confirm the depreciation rates used in their proposals.

- Capital Structure

  The OEB accepts this aspect of the CIP agreement and finds that the capital structure for both proposals should be based on Union's approved deemed debt/equity ratio of 64% / 36%. The proponents should confirm the depreciation rates used in their proposals.

  However, the OEB finds that the cost of debt and return on equity (ROE) is properly considered competitive. If parties wish to use debt and ROE rates that are different than the OEB-approved rates they can do so. The OEB finds that it will not hold Union to its existing debt rates or return on equity applied to its regulated business, and instead should consider its proposal as coming from a standalone business in the spirit of competition. The OEB does not expect the cost of debt and ROE to be provided in proponents' proposals.

- Government Grants and Municipal Contributions and Aid to Construction

  Both proponents agreed to use a gross revenue requirement excluding any government grants, municipal contributions and Aids to Construction. The OEB accepts this aspect of the CIP agreement and finds that government grants and contributions from municipalities, as well as any Aid to Construction required for customers, should be excluded from the proposals.

- Demand-Side Management (DSM) Costs

  Both proponents agreed to exclude DSM costs in their proposals. The OEB accepts this aspect of the CIP agreement and finds DSM costs should be excluded from the proposals.

- Cap and Trade Costs

  Both proponents agreed to exclude Cap and Trade costs in their proposals. The OEB accepts this aspect of the CIP agreement and finds Cap and Trade costs should be excluded from the proposals.

- Taxes

  Both proponents agreed to use common tax rates and exclude any tax holidays from the municipality from their proposals. The OEB accepts this aspect of the CIP agreement and finds that tax rates should be common and included in each proposal, and that any municipal tax holidays from the municipalities should be excluded from the proposals.

- Service Levels

  Both proponents agreed to plan for operations and maintenance that would meet the service levels identified in the Gas Distribution Access Rules (GDAR). The OEB accepts this aspect of the CIP agreement. The proponents should confirm the service levels that they intend to meet in their proposals.

- Gas Commodity Costs

  In their oral submissions, both proponents agreed to exclude gas commodity costs from the revenue requirement proposal. The OEB accepts this aspect of the CIP agreement and finds that gas commodity costs should be excluded from the proposals.

- Interest During Construction (IDC)

  In their oral submissions, both proponents also agreed to use the OEB-prescribed rate for IDC, so that it will be common between proposals. The OEB accepts this aspect of the CIP agreement and finds that IDC rates for the proposals will be at the OEB's prescribed rate. The proponents should confirm the IDC rate used in their proposals.

- "Other" or "Intangible" Category

  Both proponents agreed to the inclusion of an "Other" or "Intangible" category in their proposals that would include other non-financial issues that the OEB could take into account in its decision. The OEB accepts this aspect of the CIP agreement and finds that an "Other" or "Intangible" category is appropriate.

Areas of Disagreement between the Proponents

The OEB's findings on the unresolved areas of the CIP are set out below:

- Upstream Reinforcement

  Union stated that it had instituted an "ethical wall" between Union representatives working on the competitive proposal and those in the service provision team to ensure an unbiased and objective approach, and that the same methodology for costing upstream reinforcements would be applied to both proponents' proposals. However, EPCOR submitted that it was unable to properly determine upstream costs, or control or test the costs of various supply scenarios on Union's system, which could cause wide variances in capital cost estimates for upstream reinforcements. EPCOR also noted that it would be held to a cost determined by Union through its proposal.

  The OEB will exclude upstream reinforcement costs for the purposes of the CIP proposals. The future recovery of upstream costs by either proponent is based on a common assumption that the lowest cost solution will be chosen and implemented. Where costs are considered to be common to both proponents they need not be included for selection purposes. The OEB will review these costs and their underlying assumptions in the rate case following the selection of the successful proponent.

- Inflation Costs

  For the purposes of establishing the calculation of the 10-year gross revenue requirement, proponents will be allowed to apply the rate of inflation to capital and OM&A costs during the rate stability period. The OEB finds that there should be inflationary adjustments to capital and OM&A costs during the rate stability period and that inflation rates should be the same between the two proposals. The OEB accepts Union's suggested common inflation rate, which should be equivalent to the estimated long term inflation rate based on the most recent four quarter average GDP IPI FDD methodology accepted by the OEB. The GDP IPI FDD is the standard approach towards forecasting inflation. Therefore it is appropriate for these circumstances. How the revenue requirement, including allowed inflation, will be recovered will be decided later with the full participation of affected ratepayers.

  To clarify, the OEB expects proponents to provide their gross revenue requirement, including inflation as noted above, in their proposals. The OEB would be assisted in seeing the revenue requirement on an annual basis, the net present value of the gross revenue requirement, and the cumulative revenue requirement.

- OM&A Costing Methodology

  The OEB reaffirms the principle of fully allocated costs as set out in the Generic Decision, which prevents cross-subsidization of new expansion customers by current ratepayers. Proponents are expected to base their OM&A cost estimates on an allocation that would result from a fully allocated cost study typically filed in a full rates case. To be clear, although the OEB expects this principle will be followed, the OEB does not expect to see a full cost allocation study in proponents' proposals.

- Treatment of Capital Costs

  As determined in the Generic Proceeding, the OEB finds that any capital cost overruns incurred during the first 10 years above the forecasted costs reflected in the proposals will not be permitted into the successful proponent's rate base for year 11 and beyond (following the rate stability period). The treatment will be symmetrical: cost underruns will accrue to the utility's benefit.

- Other CIP Parameters

  The OEB finds that royalty payments to the municipalities will be excluded from the proposals if they are not recovered through the utility's revenue requirement. If the royalty payments are proposed to be collected from the revenue requirement, then the royalty payments must be included in the revenue requirement for the CIP.

In summary, the OEB expects proponents to provide details on the following in their proposals:

- Communities To Be Served
- Comparison Criteria
- Infrastructure Specifications (Routing and Engineering)
- Construction Schedule Forecast
- Customer Attachments Forecast
- Forecast Horizon
- Customer Consumption Levels
- Depreciation Rates
- Capital Structure
- Tax Rates
- Service Levels
- Interest During Construction (IDC)
- "Other" or "Intangible" Category
- Inflation Costs
- Royalty Payments to Municipalities (if collected from the revenue requirement)

The OEB does not expect proponents to provide details regarding the following:

- Infrastructure Costs
- Cost of Debt and Return on Equity
- Government Grants and Municipal Contributions and Aid to Construction

- Demand-Side Management (DSM) Costs
- Cap and Trade Costs
- Tax Holidays
- Gas Commodity Costs
- Upstream Reinforcement
- OM&A Costing Methodology

Decision on Other Preliminary Issues

Issue #1

This issue concerns the appropriate process for selecting a proponent when there are competing proposals for serving a community.

The OEB provided its findings on the issue in the Partial Decision and Procedural Order #6. In accordance with P.O. #6 and #7 the OEB has commenced the selection process and will base it on the parameters described in Procedural Order #6 and in this decision on the outstanding preliminary issues.

The OEB has determined that the selection process set out so far will be limited to this particular proceeding, and that the OEB will be applying the lessons learned from the process to competitive expansion applications in the future.

Issue #2

This issue concerns whether the funding of this process should be treated as a business development cost or as a regulatory expense, recoverable from future ratepayers.

OEB staff, Anwaatin, EPCOR and the Southern Bruce Municipalities supported funding the application proceeding as a business development cost.

Enbridge and Northeast Midstream submitted that an unsuccessful proponent should consider their expenses in the application proceeding as a business development cost, but that the successful proponent should be able to recover the costs from future ratepayers. Northeast Midstream stated that the recoverable amount should be less government grants received. OEB staff submitted that proponents should be able to demonstrate the separation of costs in the proponents’ next cost of service application.

EPCOR submitted that while bidding expenses should be treated as a business development expense, the OEB should take into account the number and level of binding commitments it requires from proponents. EPCOR stated that in Canadian Public-Private Partnerships (P3s), vendors may offer honorariums for P3s that required considerable effort to develop bids for.

CCC supported funding the application proceeding as a business development cost, but submitted that if it were determined to be a regulatory expense, it should be recovered from ratepayers in the relevant communities. Union submitted that the cost of the proceeding should be a business development cost recoverable from future ratepayers. SEC submitted that the successful proponent's reasonable expenses should be treated as a regulatory expense recovered from future ratepayers.

VECC invoked fairness in terms of either allowing the costs of both applicants to be included in the recovery of ratepayers, or allowing neither party to recover these costs. VECC also suggested that the OEB could allow both parties to recover a pre-determined set amount of "business development costs" to be recovered in a regulatory fee adder, which either applicant could waive to make their proposal more attractive.

The Southern Bruce Municipalities referred to their own competitive procurement process, where the preparation of proposals by potential distributors was treated as a business development expense, which they observe did not serve as a disincentive to proponents.

The OEB considers the activities related to determining business interests and participating in a selection process to be business costs incurred for the potential benefit of shareholders and therefore not recoverable in rates.

Issue #3

In the Partial Decision, the OEB determined that a rate stability period of 10 years was appropriate, but did not decide whether proponents should have the opportunity to update costs during the rate stability period.

For the purpose of structuring a common platform for selection purposes, the OEB finds that proponents should price their revenue requirement proposals based on the assumption that there will be no rate adjustments during the 10-year rate stability period, other than the availability of Z-factor relief for certain events that fall within the OEB's policy. Any Z-factor proposals will be reviewed based on the criteria delineated in the OEB's Filing Requirements for Natural Gas Rate Applications:

- Causation – The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside of the base upon which rates were derived
- Materiality –The cost increase or decrease must meet a materiality threshold, in that its effect on the utility's revenue requirement in a fiscal year must be equal to or greater than the established threshold
- Prudence – The cost subject to an increase or decrease must have been prudently incurred
- Management Control – The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence

The OEB’s existing approach to Z-factor updates will be applied on an ongoing basis.

Issue #4

This issue concerns the format for proposals to serve a community, including whether there should be filing requirements. This issue has now been addressed through the OEB’s findings in the Partial Decision and the findings above in respect of the CIP.

Issue #5

This issue concerns how the costs of competing proposals should be compared. As explained above in the section on the CIP parameters, the proponents agreed that the costs should be compared based on three criteria – $/m^3, number of customer years, and cumulative volume – and the OEB agrees. As noted above, the OEB would be assisted in seeing the revenue requirement on an annual basis, the net present value of the gross revenue requirement, and the cumulative revenue requirement.

Issue #6

This issue concerns whether measures should be put in place to ensure completion of the proposed projects, and if so, what those measures should be.

The OEB finds that the winning proponent must serve all the communities identified in the CIP, with the gas mains to all the communities to be served to be constructed within two years from the commencement of construction. The precise measures to be put in place to ensure that this occurs can be determined in due course.

It is necessary to make provision for the following matters related to this proceeding. Further procedural orders may be issued by the OEB.

IT IS THEREFORE ORDERED THAT:

1. EPCOR Southern Bruce Gas Inc. and Union Gas Limited shall submit their proposals for serving the area covered by the South Bruce Expansion Applications on **October 16, 2017**. The format and substance of the proposals shall conform to the directions set out in this decision. To ensure fairness as between the two proponents, the submissions will be received in confidence and will be made publicly available on the next business day.

All filings to the OEB must quote the file numbers, EB-2016-0137 | EB-2016-0138 | EB-2016-0139, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Registrar at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Azalyn Manzano at Azalyn.Manzano@oeb.ca and OEB Counsel, Michael Millar at Michael.Millar@oeb.ca.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Registrar

E-mail: registrar@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, **August 22, 2017**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2016-0137
EB-2016-0138
EB-2016-0139

SOUTH BRUCE EXPANSION APPLICATIONS

Applications to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss with natural gas distribution services

BEFORE: Ken Quesnelle
Presiding Member

Cathy Spoel
Member

Paul Pastirik
Member

April 12, 2018

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

EPCOR Southern Bruce Gas Inc. (EPCOR) filed applications with the Ontario Energy Board (OEB) on March 24, 2016 under sections 8 and 9 of the *Municipal Franchises Act*, seeking approval for its franchise agreements with, and certificate of public convenience and necessity (certificate) for, the Municipality of Arran-Elderslie, Municipality of Kincardine and the Township of Huron-Kinloss.

The OEB had announced previously on January 20, 2016 that it would be holding a generic proceeding to review opportunities for natural gas expansion in the province (Generic Proceeding on Community Expansion).[1] The OEB issued its decision on natural gas expansion on November 17, 2016 (Generic Decision). In that decision, the OEB set out its policy intended to encourage competition in the provision of natural gas distribution service in presently unserved communities. The EPCOR applications are the first set of applications with which the OEB is implementing this policy. Consistent with this policy on competition, the OEB invited other potential providers of natural gas distribution service to notify the OEB of their interest in serving the South Bruce communities. Union Gas Limited (Union Gas) filed a letter dated January 19, 2017, notifying the OEB of its interest. In recognition of the equal status of both utilities as proponents in the competition, the proceeding was renamed the South Bruce Expansion Applications, and the style of cause changed accordingly.

The OEB decided to assess the competing applications through a two-phase process. In the first phase, the OEB would consider submissions on certain preliminary issues, and in the second phase, the OEB would select either EPCOR or Union Gas as the successful proponent.

To facilitate the selection of a successful proponent to serve the South Bruce Municipalities, the OEB established a Common Infrastructure Plan (CIP), which would serve as a relative proxy to allow the OEB to undertake a comparison of the proponents' stated revenue requirements on a set of common parameters.

This decision provides the OEB's findings on the second phase of this proceeding. The OEB has considered the numerous selection criteria submitted in the CIP proposals and determined that the cumulative 10-year revenue requirement per unit of volume ($/m^3) is the criteria that best addresses the OEB-stated objectives regarding the introduction of competition in the natural gas service expansion into new service areas. Given EPCOR's lower cumulative 10-year revenue requirement per m^3 ($0.2209/m^3 versus

[1] EB-2016-0004

0.2444/ m^3 for Union), which EPCOR has committed to maintaining for the duration of the 10-year rate stability period, EPCOR is granted certificates of public convenience and necessity for each of the Municipality of Arran-Elderslie (except for the geographic area of the former Township of Arran and the former Village of Tara), the Municipality of Kincardine and the Township of Huron-Kinloss, conditional on the approval of its subsequent leave to construct application.

2 THE PROCESS

A Notice of Hearing was issued on December 21, 2016 and was served on all parties in EB-2016-0004*.* Procedural Order No. 1, which was issued on January 5, 2017, directed other parties interested in serving the areas covered by the South Bruce Expansion Applications to notify the OEB of their interest. Union Gas filed a letter dated January 19, 2017 notifying the OEB of its interest in serving the areas covered by the South Bruce Expansion Applications.

Through procedural orders, the OEB determined that it would hear the applications to serve the areas in two phases. In the first phase, the OEB would consider submissions on certain preliminary issues, and in the second phase, the OEB would select either EPCOR or Union Gas as the successful proponent.

On June 23, 2017, the OEB issued a Partial Decision and Procedural Order No. 6 (the Partial Decision), which addressed two of the issues on the Preliminary Issues List, and which also required both EPCOR and Union Gas to participate in a joint session with OEB staff on July 13, 2017 to determine the technical parameters of a Common Infrastructure Plan (CIP) for the area covered by the South Bruce Expansion Applications.

On July 20, 2017, OEB staff submitted a progress report which outlined the CIP parameters discussed in the joint session, areas of agreement and disagreement between proponents, draft permissible rate adjustment criteria and proposal comparison criteria. The proponents requested that the OEB allow for submissions on the areas of disagreement.

On August 2, 2017, pursuant to Procedural Order No. 7, the OEB heard oral submissions from EPCOR and Union Gas regarding each of the areas of disagreement listed in OEB staff's progress report and their proposed process for moving forward with this proceeding.

On August 22, the OEB issued a Decision on Preliminary Issues and Procedural Order No. 8 (the Decision and P.O. 8), which resolved the CIP-related issues that were the subject of the August 2, 2017 oral hearing, and addressed those other aspects of the Preliminary Issues List that were not determined in the June 23, 2017 Partial Decision.

In accordance with the Decision and P.O. 8, EPCOR and Union Gas each filed their proposals for serving the area covered by the South Bruce Expansion Applications on October 16, 2017.

In Procedural Order No. 9 (P.O. 9), which was issued on December 7, 2017, the OEB determined that it would be assisted by limited interrogatories to clarify certain aspects of the proposals, and invited parties to submit any other interrogatories that parties believed to be absolutely necessary in assisting the OEB in its deliberations. In P.O. 9, the OEB also made provision for a round of submissions from all parties, to be filed on January 25, 2018. The OEB issued a final list of interrogatories for both EPCOR and Union Gas on December 22, 2017.

On January 19, 2018, the OEB issued a summary table of metrics and CIP criteria based on EPCOR and Union Gas' CIP proposals and interrogatory responses, to ensure that parties had a common understanding of the proposals prior to filing their submissions. On January 22, 2018, EPCOR filed a letter in response to the OEB's table, identifying inaccuracies and proposing several corrections to the summary table.

In Procedural Order No. 10, which was issued on February 22, 2018, after reviewing submissions from all parties, the OEB determined that EPCOR should be allowed to provide explanations for potential anomalies identified by parties in EPCOR's submissions and interrogatory responses.

On March 2, 2018, EPCOR filed its response to the OEB's questions.

3 THE CIP PROPOSALS

This section provides a brief comparison of the two CIP proposals. A comparison summary table can be found below.

3.1 Revenue Requirement

EPCOR's stated cumulative 10-year revenue requirement as calculated over a 120-month period was $75.6 million, with a net present value of $59.1 million. Union Gas' stated cumulative 10-year revenue requirement over the same period was $70.1 million, with a net present value of $55.4 million.

3.2 Customer Attachment and Volume Forecast

Union Gas' total customer years, defined as the cumulative number of customers connected over the 10-year rate stability period multiplied by the number of years each customer is connected, was 54,171. EPCOR's total customer years was 42,569.

In terms of cumulative volume, defined as the cumulative volume of throughput per year, over the ten-year rate stability period, EPCOR's cumulative volume was 342 million m^3. Union Gas' cumulative volume was 287 million m^3. These cumulative volumes take into account the Normalized Annual Consumption (NAC) of each proponent's industrial customers.

Union Gas' cumulative 10-year revenue requirement per m^3 was $0.2444/$m^3$ while EPCOR's was $0.2209/$m^3$.

3.3 Route and Infrastructure Plan

EPCOR proposed a single continuous system to serve the South Bruce municipalities, taking service from Union's Owen Sound Line at Dornoch, while Union Gas' proposal involves two segments, with one supply lateral tied to the Owen Sound Line and the second tied to the Forest-Hensall-Goderich System. EPCOR's total proposed kilometers of pipeline in the first 10 years was 309.9 kilometers, while Union Gas' was 321.7 kilometers.

Both proponents proposed to commence construction in 2019. EPCOR submitted that it expects its Environmental Report process to be completed within six to ten weeks of the certificate award, allowing for an early construction start in the winter of 2019. EPCOR noted that this potential one winter advancement improves the viability of project economics.

Metric / Criteria	EPCOR	Union Gas
Net Present Value (NPV) of 10-year Revenue Requirement	$59.1 million	$55.3 million
Cumulative 10-year Revenue Requirement	$75.6 million	$70.1 million
Cumulative 10-yr revenue requirement per unit of volume[2]	$0.2209 / m^3	$0.2444 / m^3
Customer years[3]	42,569	54,171
Cumulative 10-yr volume[4]	342 million m^3	287 million m^3
Total kilometers of pipeline	309.9 km	321.7 km

[2] The sum of total annual revenue requirement for 10 years divided by the total volumes for 10 years.
[3] Based on the number of customers connected multiplied by the number of years each customer is connected during the initial 10-year service period.
[4] The cumulative volume of throughput per year, over the ten-year rate stability period.

4 OEB DECISION

4.1 Proponent Selection Criteria Determinations in South Bruce Expansion Applications

The Generic Decision established a general framework for competition in the servicing of new communities that do not satisfy the economic tests embodied in the E.B.O. 188 policy.

The framework established in the Generic Decision features:

- ***Stand-alone rates.*** The allowance of stand-alone rates or a system expansion surcharge (not subsidized through rates paid by existing service area customers) that reflect the costs to serve the customers in the newly serviced area. This element facilitates competition by new service provider entrants.

- ***The establishment of a rate stabilization period.*** A rate stabilization period that ensures rates reflect the long-term costs to serve an area as well as ensuring that any risks of revenue deficiency rests with the service provider.

- ***Incentives to lower costs.*** Incentives to build and operate at lowest possible costs in order to attract connections so that stated revenue requirements during the rate stabilization period can be achieved or exceeded.

These features have been put into effect in this case through: 1) a requirement for proponents to base the revenue requirement in their CIP proposals on fully allocated project and OM&A costs, 2) the establishment of a 10-year rate stability period and 3) competition to provide an incentive to lower costs.

The Partial Decision contained the OEB's expressed intention to make a selection determination based on a proponent's commitment to construct and operate a Common Infrastructure Plan for a stated revenue requirement over a 10-year period. Rather than requiring proponents to submit full leave to construct applications which would make it difficult to assess the value of each proponent's proposal, the establishment of the CIP was meant to serve as a proxy to allow the OEB to compare revenue requirements on a set of common parameters.

The Decision and P.O. 8 accepted numerous parameters to be used by the OEB in its consideration of the proposals that the proponents had agreed to in a joint session with OEB staff. The OEB accepted the following agreed-upon parameters:

- **Communities to be Served:** Proponents are required to provide service to the following communities: Chesley, Inverhuron, Paisley, Tiverton, Kincardine, Lucknow, Lurgan Beach, Point Clark, Ripley and the Bruce Energy Centre Industrial Park.
- **Comparison Criteria:** The proponents agreed to three comparison criteria to be included in CIP proposals: $/m^3, number of customer years and cumulative 10-year volume.
- **Infrastructure Specifications:** The proponents agreed that infrastructure specifications, such as the size of the pipeline to be built, its routing and resulting costs, would be left to competition. However, proponents were expected to include details of the infrastructure, including the routing and engineering, in their proposals.
- **Construction Schedule:** Gas mains to all the communities to be served are to be constructed within two years from the commencement of construction. The timing of customer connections each year during the rate stability period, however, would be left to competition. Proponents were expected to include their construction schedule forecast in their proposals.
- **Customer Attachments:** The number of attachments were to remain competitive and based on the levels of risk and marketing activities that each proponent would be willing to take on. Proponents were expected to include details on their forecast attachments as part of the proposals, with the successful proponent to be held to its forecast for rate-making purposes.
- **10-year Forecast Horizon:** Proponents were to use a 10-year horizon for customer attachment and volume forecasts.
- **Customer Consumption:** Proponents were to use common consumption levels for each mass market segment, except for large commercial or industrial customers, which were to be left to competition.

- **Depreciation Rates:** Proponents were to use depreciation rates based on Union's OEB-approved depreciation rates.

- **Capital Structure:** The capital structure for both proposals were to be based on Union's approved deemed debt/equity ratio of 64% / 36%. However, the cost of debt and return on equity (ROE) were considered competitive. The OEB also found that it would not hold Union to its existing debt rates or return on equity applied to its regulated business.

- **Government Grants and Municipal Contributions and Aid to Construction:** Both proponents were to use a gross revenue requirement excluding any government grants, municipal contributions and Aids to Construction.

- **Demand-Side Management (DSM) Costs:** Both proponents were to exclude DSM costs in their proposals.

- **Cap and Trade Costs:** Both proponents were to exclude Cap and Trade costs in their proposals.

- **Taxes:** Both proponents were to use common tax rates and exclude any tax holidays from the municipality from their proposals.

- **Service Levels:** Both proponents were to plan for operations and maintenance that would meet the service levels identified in the Gas Distribution Access Rules (GDAR).

- **Gas Commodity Costs:** Both proponents were to exclude gas commodity costs from the revenue requirement proposal.

- **Interest During Construction (IDC):** Both proponents were to use the OEB-prescribed rate for IDC, so that it will be common between proposals.

- **"Other" or "Intangible" Category:** Both proponents were to include an "Other" or "Intangible" category in their proposals that would include other non-financial issues that the OEB could take into account in its decision.

- **Upstream Reinforcement:** Upstream reinforcement costs were to be excluded from the CIP proposals. The OEB will review these costs and their underlying assumptions in the rate case following the selection of the successful proponent.

- **Inflation Costs:** For the purposes of establishing the calculation of the 10-year gross revenue requirement, proponents were allowed to apply the rate of inflation to capital and OM&A costs during the rate stability period, with the same inflation rate (Union's suggested common inflation rate, which should be equivalent to the estimated long term inflation rate based on the most recent four quarter average GDP IPI FDD methodology accepted by the OEB) applied to both proposals.

- **OM&A Costing Methodology:** The OEB reaffirmed the principle of fully allocated costs as set out in the Generic Decision, which prevents cross-subsidization of new expansion customers by current ratepayers. Proponents were expected to base their OM&A cost estimates on an allocation that would result from a fully allocated cost study typically filed in a full rates case. However, the OEB did not expect a full cost allocation study to be filed in proponents' proposals.

- **Treatment of Capital Costs:** Any capital cost overruns incurred during the first 10 years above the forecasted costs reflected in the proposals will not be permitted into the successful proponent's rate base for year 11 and beyond (following the rate stability period). The treatment will be symmetrical: cost underruns will accrue to the utility's benefit.

- **Other CIP Parameters:** Royalty payments to the municipalities were to be excluded from the proposals if they are not recovered through the utility's revenue requirement. If the royalty payments are proposed to be collected from the revenue requirement, then the royalty payments were to be included in the revenue requirement for the CIP.

4.2 Assessment of CIP Proposals

The OEB has considered all aspects of the proposals, including those features emanating from the Generic Decision, and those that the OEB accepted as part of the proponents' request to have the OEB consider as competitive elements of the CIP proposals.

As described in the process section, after the CIP proposals were filed, two rounds of interrogatories were issued by the OEB to ensure that potential issues and concerns were clarified. The OEB accepts EPCOR's responses to the most recent interrogatories regarding its earlier submissions.

The $\$/m^3$ CIP comparison criterion provides a relatively clear picture of value for money, as it shows on average, what customers could expect to pay on a per unit basis.[5] The emphasis on volume in this metric also encourages the successful proponent to attach as many customers as possible, on the assumption that proponents understand that the goal of community expansion is to facilitate access to natural gas services to many customers, rather than serving only the most profitable customers. The OEB notes that the other two CIP comparison criteria (customer years and cumulative 10-year volume) provides a measure of which proposal most benefits communities in terms of getting service to customers most quickly and customers' potential for fuel savings.[6] All three CIP comparison criteria also provide a potential check against "gaming" of the revenue requirement metrics associated with under-estimated capital and OM&A expenses.

Taking all elements of the CIPs into consideration, the OEB finds that the EPCOR CIP is most favourable to customers, and therefore EPCOR is granted certificates of public convenience and necessity for the South Bruce municipalities, conditional on the approval of its subsequent leave to construct application.

The key determinative factor in the selection of EPCOR as the successful proponent is the $\$/m^3$ of 0.2209, which EPCOR has committed to maintaining for the rate stability period, versus the $\$0.2444/m^3$ submitted by Union Gas. The OEB believes that the $\$/m^3$ measure is most relevant in terms of the cost to serve the customers, and a main concern and focus in terms of the competitive process. Additional measures may be deemed relevant in future competitions.

Given the competitive nature of this process, the OEB will require EPCOR to demonstrate that forthcoming leave to construct and rates applications are consistent with its CIP proposal.

[5] Details of a cost allocation study would determine what costs each rate class would be expected to pay. Depending on how costs are allocated to the rate classes, there could be large differences in, for example, residential rates.
[6] Given that natural gas is less expensive than most competing fuels, volumes consumed are a proxy for fuel cost reduction (the more natural gas consumed the greater the fuel cost reduction).

4.3 Municipal Franchise Agreements

The original applications filed by EPCOR on March 24, 2016 also requested that the OEB approve the terms of their franchise agreements with the South Bruce Municipalities. The form of the franchise agreements filed differs from the 2000 Model Franchise Agreement (MFA) in the following ways:

- The proposed franchise agreements contain termination provisions. If EPCOR fails to meet certain milestones dates at various points throughout the regulatory applications and construction, the municipalities have termination rights. The rationale was to ensure that EPCOR is actively pursuing this undertaking in a timely manner.
- The proposed franchise agreements provide for the payment of an annual fee by EPCOR to the municipalities following the commencement of operation of the gas system. The annual fee is 1% of gross revenue minus gas supply commodity costs.
- The proposed franchise agreements provide for a rebate of the Municipality's portion of any property or similar taxes payable by EPCOR for the first 10 years of operation.
- The proposed franchise agreements provide for the assignment of the agreements to a wholly or majority owned subsidiary of EPCOR.

Given that the scope of this proceeding was modified from its original form and precluded an adequate examination of the additional terms in the franchise agreements proposed by EPCOR, the OEB finds it appropriate to deal with the matter of franchise agreements in a separate proceeding.

4.4 Fitness to Operate

In the Partial Decision, the OEB contemplated subsequent financial and technical acceptance testing if EPCOR, as a new entrant to the Ontario natural gas market, was selected as the successful proponent.

In the OEB's approval of the transfer of Natural Resource Limited's assets to EPCOR's affiliate company (EPCOR Natural Gas Limited Partnership), the OEB noted that EPCOR Natural Gas Limited Partnership has access to EPCOR Utilities Inc. employees with experience in the areas of health and safety, regulatory, communications, engineering, planning and capital project management. The OEB was satisfied that the proposed transaction would not lead to any adverse impact with respect to the reliability and quality of service. The OEB therefore finds that financial and technical acceptance testing will not be necessary for EPCOR Southern Bruce Gas Inc.

5 ORDER

THE BOARD ORDERS THAT:

1. A certificate of public convenience and necessity, attached as Schedule A to this Decision and Order, is granted to EPCOR Southern Bruce Gas Inc. to construct works or supply gas in the Municipality of Arran-Elderslie, excluding the geographic area of the former Township of Arran and the former Village of Tara. A current map of the Municipality of Arran-Elderslie, delineating EPCOR Southern Bruce Gas Inc.'s service territory therein, is attached as Schedule B.

2. A certificate of public convenience and necessity, attached as Schedule C to this Decision and Order, is granted to EPCOR Southern Bruce Gas Inc. to construct works or supply gas in the Municipality of Kincardine. A current map of the Municipality of Kincardine, delineating EPCOR Southern Bruce Gas Inc.'s service territory therein, is attached as Schedule D.

3. A certificate of public convenience and necessity, attached as Schedule E to this Decision and Order, is granted to EPCOR Southern Bruce Gas Inc. to construct works or supply gas in the Township of Huron-Kinloss. A current map of the Township of Huron-Kinloss, delineating EPCOR Southern Bruce Gas Inc.'s service territory therein, is attached as Schedule F.

4. EPCOR shall file a leave to construct application to serve the areas covered by the South Bruce Expansion Applications on or before October 12, 2018.

5. Eligible intervenors shall file with the OEB and forward to EPCOR Southern Bruce Gas Inc. their respective cost claims in accordance with the OEB's Practice Direction on Cost Awards on or before April 27, 2018.

6. EPCOR Southern Bruce Gas Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs of the intervenors on or before May 4, 2018.

7. If EPCOR Southern Bruce Gas Inc. objects to the intervenor costs, intervenors shall file with the OEB and forward to Enbridge any responses to any objections for cost claims on or before May 14, 2018.

8. EPCOR Southern Bruce Gas Inc. shall pay the OEB's costs incidental to this proceeding upon receipt of the OEB's invoice.

DATED at Toronto, April 12, 2018

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

EB-2016-0137 | EB-2016-0138 | EB-2016-0139

DATED: April 12, 2018

Certificate of Public Convenience and Necessity for the Municipality of Arran-Elderslie

EB-2016-0137

Certificate of Public Convenience and Necessity

The Ontario Energy Board grants

EPCOR Southern Bruce Gas Inc.

approval under section 8 of the *Municipal Franchises Act,* R.S.O. 1990, c. M.55, as amended, to construct works to supply gas to the

Municipality of Arran-Elderslie

as it is constituted on the date of this Decision and Order, excluding the geographical areas of the former Township of Arran and the former Village of Tara.

DATED at Toronto, April 12, 2018

ONTARIO ENERGY BOARD

Original Signed By

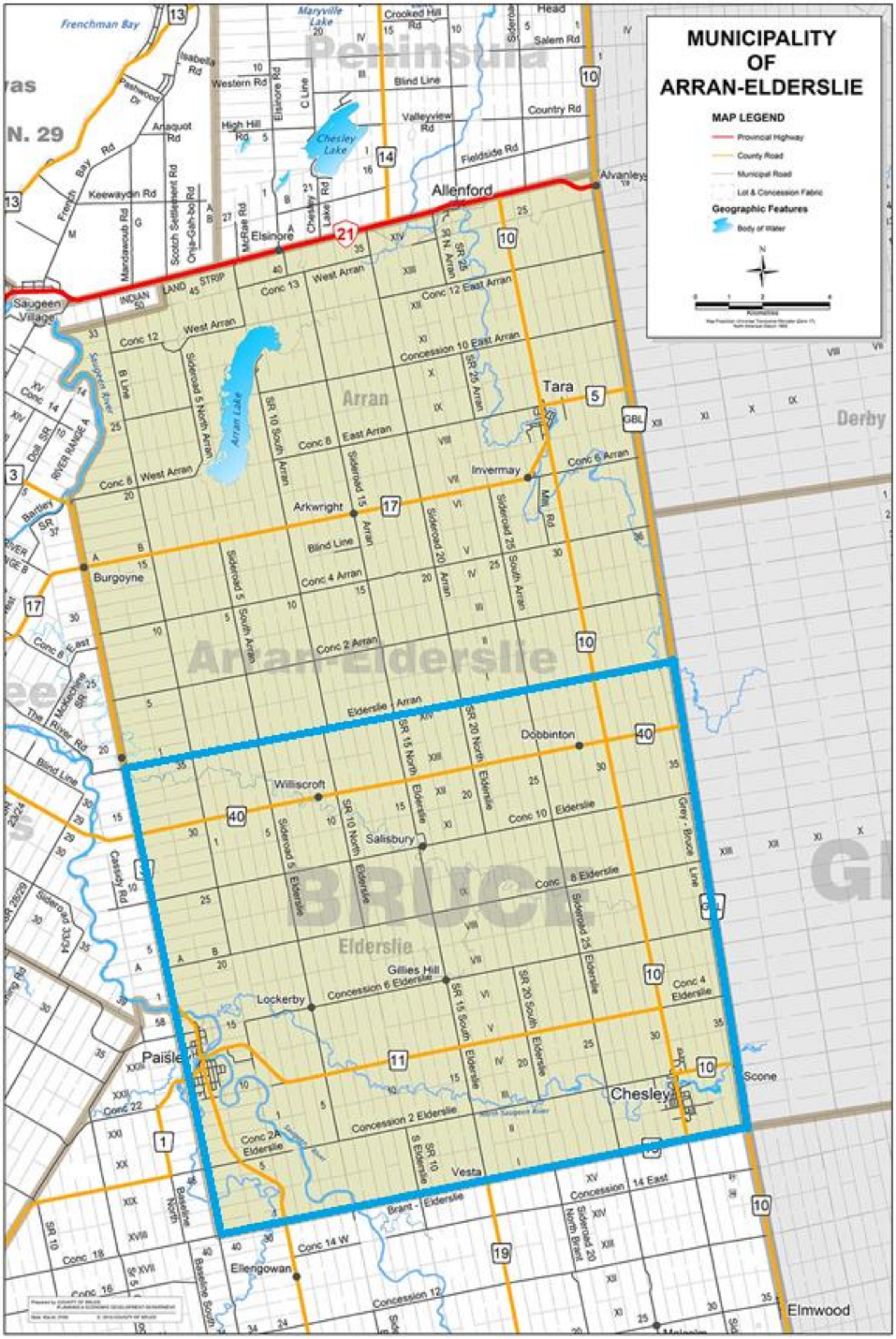
Kirsten Walli
Board Secretary

SCHEDULE B

EB-2016-0137 | EB-2016-0138 | EB-2016-0139

DATED: April 12, 2018

Map of the Municipality of Arran-Elderslie


MUNICIPALITY
OF
ARRAN-ELDERSLIE
MAP LEGEND
Provincial Highway
County Road
Municipal Road
Lot & Concession Fabric
Geographic Features
Body of Water

SCHEDULE C

EB-2016-0137 | EB-2016-0138 | EB-2016-0139

DATED: April 12, 2018

Certificate of Public Convenience and Necessity for the Municipality of Kincardine

EB-2016-0138

Certificate of Public Convenience and Necessity

The Ontario Energy Board grants

EPCOR Southern Bruce Gas Inc.

approval under section 8 of the *Municipal Franchises Act,* R.S.O. 1990, c. M.55, as amended, to construct works to supply gas to the

Municipality of Kincardine

as it is constituted on the date of this Decision and Order.

DATED at Toronto, April 12, 2018

ONTARIO ENERGY BOARD

Original Signed By

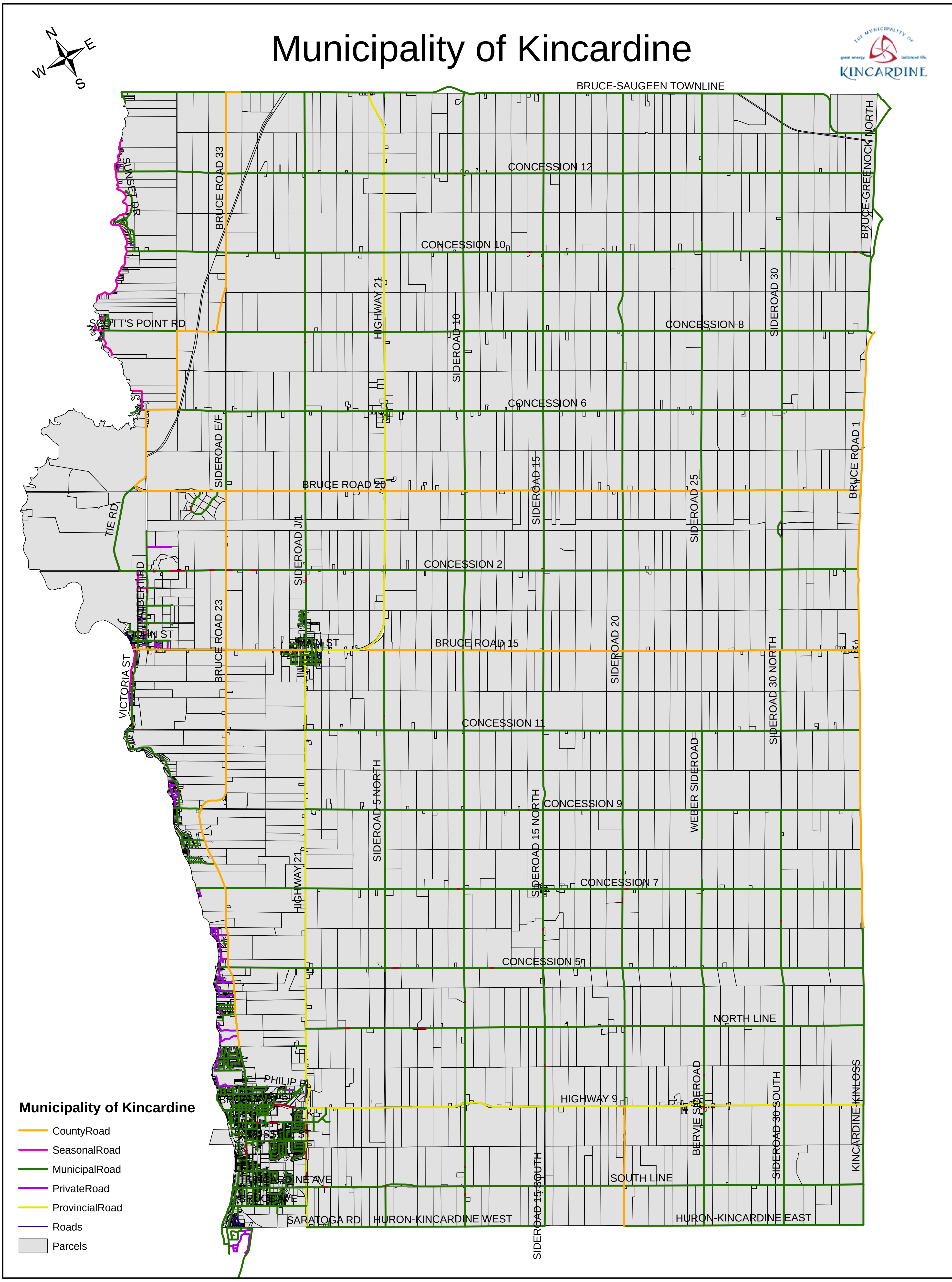
Kirsten Walli
Board Secretary

SCHEDULE D

EB-2016-0137 | EB-2016-0138 | EB-2016-0139

DATED: April 12, 2018

Map of the Municipality of Kincardine


Municipality of Kincardine
N
E
S
W
THE MUNICIPALITY OF
great energy
balanced life
KINCARDINE
BRUCE-SAUGEEN TOWNLINE
CONCESSION 12
CONCESSION 10
CONCESSION 8
CONCESSION 6
BRUCE ROAD 20
CONCESSION 2
BRUCE ROAD 15
CONCESSION 11
CONCESSION 9
CONCESSION 7
CONCESSION 5
NORTH LINE
HIGHWAY 9
SOUTH LINE
SARATOGA RD
HURON-KINCARDINE WEST
HURON-KINCARDINE EAST
SUNSET DR
SCOTT'S POINT RD
BRUCE ROAD 33
HIGHWAY 21
SIDEROAD 10
SIDEROAD 30
BRUCE-GREENOCK NORTH
SIDEROAD E/F
SIDEROAD 15
SIDEROAD 25
BRUCE ROAD 1
TIE RD
SIDEROAD J/1
ALBERT RD
JOHN ST
MAIN ST
BRUCE ROAD 23
SIDEROAD 20
VICTORIA ST
SIDEROAD 30 NORTH
SIDEROAD 5 NORTH
SIDEROAD 15 NORTH
WEBER SIDEROAD
PHILIP PL
BROADWAY ST
RUSSELL ST
QUEEN ST
KINCARDINE AVE
BRUCE AVE
BERVIE SIDEROAD
SIDEROAD 30 SOUTH
KINCARDINE-KINLOSS
SIDEROAD 15 SOUTH
Municipality of Kincardine
CountyRoad
SeasonalRoad
MunicipalRoad
PrivateRoad
ProvincialRoad
Roads
Parcels

SCHEDULE E

EB-2016-0137 | EB-2016-0138 | EB-2016-0139

DATED: April 12, 2018

Certificate of Public Convenience and Necessity for the Township of Huron-Kinloss

EB-2016-0139

Certificate of Public Convenience and Necessity

The Ontario Energy Board grants

EPCOR Southern Bruce Gas Inc.

approval under section 8 of the *Municipal Franchises Act,* R.S.O. 1990, c. M.55, as amended, to construct works to supply gas to the

Township of Huron-Kinloss

as it is constituted on the date of this Decision and Order.

DATED at Toronto, April 12, 2018

ONTARIO ENERGY BOARD

Original Signed By

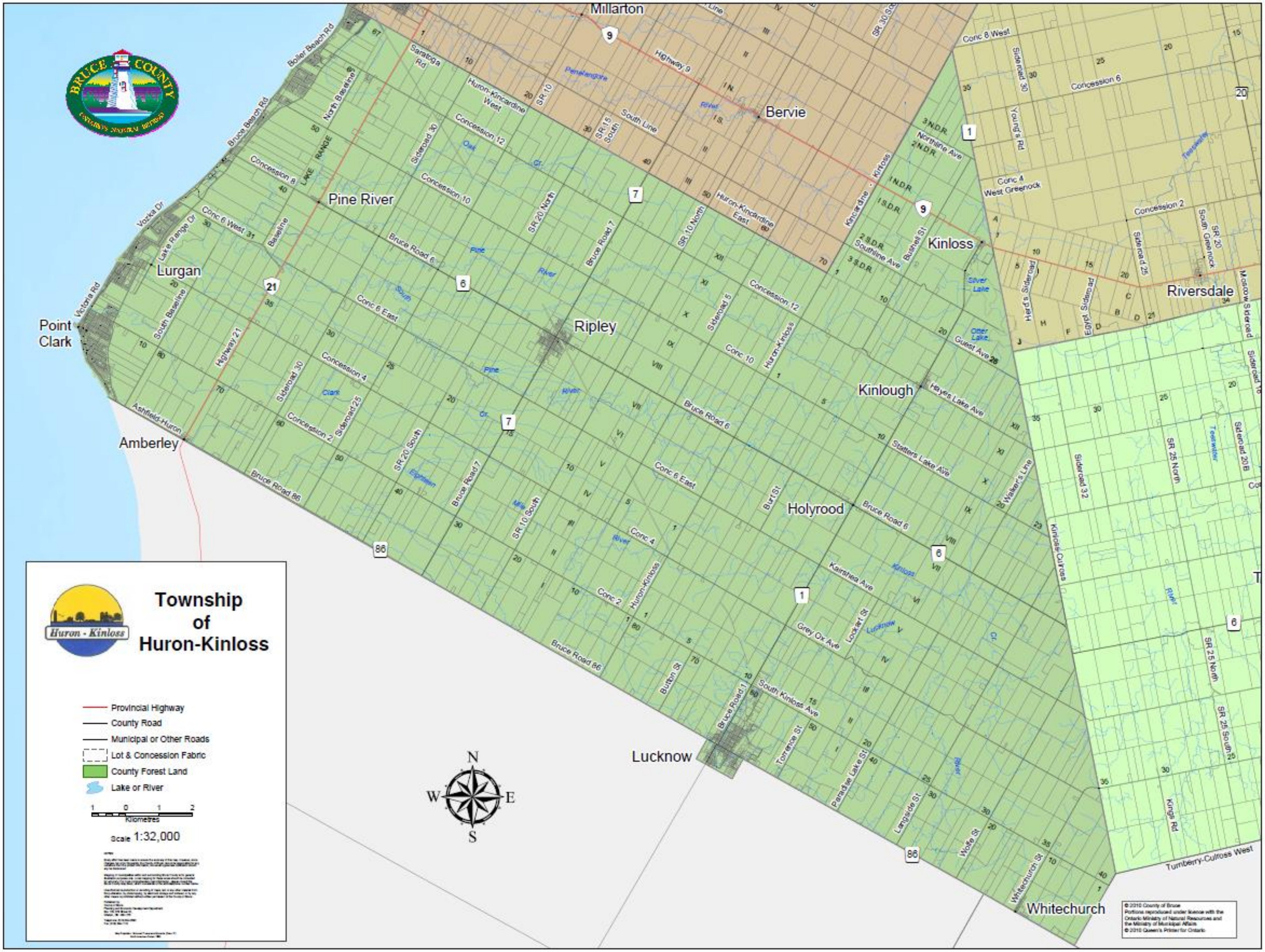
Kirsten Walli
Board Secretary

SCHEDULE F

EB-2016-0137 | EB-2016-0138 | EB-2016-0139

DATED: April 12, 2018

Map of the Township of Huron-Kinloss


Township
of
Huron-Kinloss
Huron - Kinloss
Bruce County
Millarton
Bervie
Pine River
Lurgan
Point Clark
Ripley
Kinloss
Riversdale
Kinlough
Amberley
Holyrood
Lucknow
Whitechurch
Provincial Highway
County Road
Municipal or Other Roads
Lot & Concession Fabric
County Forest Land
Lake or River
Kilometres
Scale 1:32,000
N
S
E
W

DECISION ON SETTLEMENT PROPOSAL AND PROCEDURAL ORDER NO. 6

EB-2018-0264

EPCOR NATURAL GAS LIMITED PARTNERSHIP (SOUTHERN BRUCE)

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

BEFORE: Lynne Anderson
Presiding Member

Robert Dodds
Member & Vice-Chair

Cathy Spoel
Member

October 3, 2019

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

EPCOR Natural Gas Limited Partnership (EPCOR Natural Gas LP) is an Ontario limited partnership with its head office in the Town of Aylmer. EPCOR Natural Gas LP is a wholly owned indirect subsidiary of EPCOR Utilities Inc., based in Edmonton, Alberta. EPCOR Natural Gas LP operates a natural gas distribution business in two service areas in Ontario: the Aylmer franchise area (previously known as Natural Resource Gas Limited) and a new franchise area in South Bruce.

In 2018, the Ontario Energy Board (OEB) selected EPCOR Natural Gas LP (EPCOR Southern Bruce)[1] as the successful proponent for the South Bruce gas distribution project.[2] The process was competitive and the selection was made on the basis of a cumulative revenue requirement, forecasted attachments and a total volume throughput for the 10-year rate stability period.

On April 11, 2019, EPCOR Southern Bruce filed a custom incentive ratemaking application with the OEB under section 36 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for rates that EPCOR Natural Gas can charge for gas distribution effective January 1, 2019.

The OEB provided for a settlement conference between EPCOR Southern Bruce and the interveners with the objective of reaching a settlement on the issues in the proceeding. Parties reached a settlement on some issues and a revised settlement proposal was filed with the OEB on September 16, 2019.

The OEB has reviewed the settlement proposal and accepts it as filed. The OEB finds that the settlement proposal is consistent with the commitments made by EPCOR Southern Bruce as part of the Common Infrastructure Plan (CIP) process in the South Bruce expansion proceeding.[3] With respect to the unsettled issues, the OEB has determined that there is sufficient information on the record to proceed with written arguments. A procedural timeline for written submissions is provided in this decision.

[1] EPCOR Natural Gas LP in this application has been referred to as EPCOR Southern Bruce in order to identify it separately from the Aylmer gas distribution utility.
[2] EB-2016-0137/0138/0139, Decision and Order, April 12, 2018
[3] EB-2016-0137/0138/0139

2 THE PROCESS

A Notice of Hearing was issued on April 18, 2019. Enbridge Gas Inc., Industrial Gas Users Association (IGUA), School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC), Anwaatin Inc. (Anwaatin) and the Municipality of Kincardine, the Municipality of Arran-Elderslie and the Township of Huron-Kinloss (South Bruce Municipalities) applied for and were granted intervenor status in the proceeding. IGUA, SEC, VECC and Anwaatin were found eligible to apply for an award of costs under the OEB's *Practice Direction on Cost Awards*.

The OEB issued Procedural Order No. 1 on May 21, 2019, which set out a schedule for discovery of the evidence and scheduled a settlement conference. By letter dated July 12, 2019, OEB staff advised the OEB that the parties were not able to reach an agreement on the wording of all issues in the proposed issues list. Accordingly, the OEB invited parties to make written submissions on the disputed issues.

In its submission on the issues list, EPCOR Southern Bruce objected to examining the appropriateness of each of the issues that is common in issues lists for other cost of service proceedings before the OEB. EPCOR Southern Bruce argued that its application has largely been predetermined through the CIP process[4] and as a result the same level of regulatory scrutiny applied to conventional rate applications should not apply in this application. It therefore proposed the wording "consistent with EPCOR Southern Bruce's CIP proposal" to replace "appropriate". Intervenors and OEB staff argued that the test of appropriateness should be maintained as it provides the OEB the necessary and legally required flexibility to vary from the CIP, if deemed appropriate.

The OEB in its decision on the issues list noted that a number of cost parameters and rate components were determined in the South Bruce expansion proceeding[5] and it would not be revisiting the overall commitments (with the exception of any proposed adjustments) that were made in the CIP process. The OEB agreed with EPCOR Southern Bruce on a number of issues and included "consistent with EPCOR Southern Bruce's CIP proposal" but omitted "appropriate" in the final issues list. For some of the other issues that were not reviewed or underpin the CIP proposal (cost allocation, rate design, revenue deficiency related to delay, deferral and variance accounts, and gas supply costs) the OEB retained the test of appropriateness.

[4] EB-2016-0137/0138/0139
[5] EB-2016-0137/0138/0139 Decision and Order, April 12, 2018.

In Procedural Order No. 3, the OEB rescheduled the settlement conference. A settlement conference was held on August 21 and 22, 2019. EPCOR Southern Bruce, Anwaatin, IGUA, SEC and VECC participated in the settlement conference. A settlement was reached on a number of issues and EPCOR Southern Bruce filed a settlement proposal on September 13, 2019 with a subsequent revision filed on September 16, 2019.

The following issues were settled:

- OEB Directives from CIP (Issue 1a)
- Rate base, working capital allowance, recovery of upstream costs and customer connection costs (Issues 2 a, b, c and d)
- Adjustment to distribution revenue for external funding and municipal tax holidays (Issue 3a)
- Non-distribution revenues (Issue 3b)
- Gas supply and operating, maintenance and administrative costs (Issues 4a and b)
- Adjusted revenue requirement (Issue 5b), subject to issues 5(a) and 3(c)
- Service charges (Issue 6d)
- Other deferral and variance accounts – Accelerated CCA Income Taxes Variance Account (Issue 7c)
- Addressing Federal carbon charge and related deferral and variance accounts in this application (Issue 7d)
- Incentive rate-setting proposal (Issues 8 a, b, c and d)
- Proposed scorecard (Issue 9a)

The following issues were partially settled:

- Deferral and Variance Accounts (Issues 7 a and b)
  i. Gas supply and greenhouse gas related deferral and variance accounts, Contribution in Aid of Construction Variance Account and External Funding Variance Account were settled.
  ii. Regulatory Expense Deferral Account, Municipal Tax Variance Account and Energy Content Variance Account were not settled.
- Engagement with stakeholders (Issue 11) – no agreement with respect to EPCOR Southern Bruce's engagement with First Nations and Métis communities.

The following issues were not settled:

- Proposed rates consistent with CIP (Issue 1b)
- Other revenues (Issue 3c)
- Recovery of additional revenue deficiency of $1.764 million (Issue 5a)
- Proposed rate classes and rates (Issues 6 a and c)
- Proposed cost allocation, rate design and revenue-to-cost ratios (Issue 6b)
- Availability of Incremental Capital Module (Issue 8e)
- Proposed effective date of January 1, 2019 (Issue 10a)
- Rate riders to recover lost revenues from effective date (Issue 10b)

OEB staff filed a submission on the settlement proposal on September 19, 2019. The submission supported the agreement reached in the settlement proposal. OEB staff noted that the items agreed to in the settlement proposal were essentially accepted as proposed and the agreement had no impact on the revenue requirement.

In its cover letter to the settlement proposal, EPCOR Southern Bruce proposed a written hearing to deal with the unsettled issues. IGUA filed a letter on September 17, 2019 requesting an oral hearing on the unsettled issues. IGUA noted that EPCOR Southern Bruce had based its cost allocation proposal on judgement and that judgement had not been elaborated or tested. IGUA submitted that as a result of EPCOR Southern Bruce's proposal, the customers that it represents would be compelled to subsidize other rate classes. Considering that the rates set in this proceeding will persist for a decade, IGUA submitted that it should fully be able to understand and test EPCOR Southern Bruce's proposals and this can only be achieved through an oral hearing.

With respect to EPCOR Southern Bruce's proposal to recover an additional $1.764 million related to construction delays, IGUA noted that EPCOR Southern Bruce had not provided sufficient explanation for this request. IGUA submitted that parties should be able to understand and challenge the basis for the recovery of the foregone revenue from ratepayers prior to making final arguments on the matter.

OEB staff in its submission noted that there was sufficient information on the record to proceed with written arguments on the unsettled issues. With respect to cost allocation, OEB staff submitted that a limited oral hearing on cost allocation to address the concerns of IGUA would not be an unreasonable path forward.

EPCOR Southern Bruce filed a reply to IGUA's letter on September 25, 2019. In the letter, EPCOR Southern Bruce noted that there was sufficient information on the record to make a determination on all unsettled issues and opposed an oral hearing or a limited oral hearing. With respect to cost allocation, EPCOR Southern Bruce submitted that the written interrogatory process provided sufficient opportunities for parties to seek further evidence or clarification on the issues. EPCOR Southern Bruce clarified that the role of management judgement on cost allocation did not come to light in interrogatory responses but was mentioned in the application.

EPCOR Southern Bruce submitted that there are no customers currently connected to the system and customers have a choice on whether to connect to the system based on the utility's approved rates. EPCOR Southern Bruce further indicated that it was a small utility and had already been subject to multiple OEB proceedings in relation to the South Bruce franchise.

IGUA filed its response to EPCOR Southern Bruce's letter on September 26, 2019. IGUA noted that the role of management judgement in relation to cost allocation was not explained fully in the application but was provided in interrogatory responses. IGUA submitted that its request to test the evidence in an oral hearing was justified in order to understand the basis for, and the impacts of "management judgement" applied by EPCOR Southern Bruce in allocating costs to customer classes.

IGUA further noted that EPCOR Southern Bruce has been given a monopoly franchise to serve the areas of South Bruce and consumers have no choice if they want natural gas service.

With respect to the recovery of the additional revenue deficiency of $1.764 million, IGUA was prepared to proceed directly to written arguments on the issue.

3 DECISION ON THE SETTLEMENT PROPOSAL

The OEB accepts the settlement proposal. The OEB finds that the settled issues are consistent with the CIP proposal and are expected to result in a reasonable outcome for customers.

The settlement reached an agreement on a number of deferral and variance accounts. However, the settlement proposal has included a draft accounting order only for the Accelerated CCA Income Taxes Variance Account. The OEB has determined that it will approve the accounting orders for all deferral and variance accounts as part of the final rate order in this proceeding.

The OEB has considered IGUA’s request for an oral hearing. Having reviewed the interrogatory responses, the OEB concludes that the record is sufficient for parties to make written submissions on the unsettled issues. IGUA’s request for an oral hearing is mainly focused on rate design and cost allocation issues. The OEB has concluded that principles underlying these issues are appropriately a matter of argument. EPCOR Southern Bruce has provided different scenarios for cost allocation as part of interrogatory responses on which parties can make submissions.

While the forecast of customer attachments formed part of the CIP, as this is a greenfield expansion, there is necessarily an even larger element of judgement than usual in cost allocation. Parties can make submissions on the exercise of that judgement and the appropriateness of costs allocated to the various customer classes.

4 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The settlement proposal attached as Schedule A is approved.

2. Intervenors and OEB staff who wish to file final arguments shall file them with the OEB and serve them on other intervenors by **October 11, 2019**.

3. EPCOR Southern Bruce shall file its reply argument with the OEB and serve it on all intervenors by **October 21, 2019**.

All filings to the OEB must quote the file number, EB-2018-0264, be made in searchable/unrestricted PDF format electronically through the OEB's web portal at https://pes.oeb.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.oeb.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a USB memory stick in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Registrar at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Registrar
Email: registrar@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, October 3, 2019

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar

SCHEDULE A

TO

DECISION ON SETTLEMENT PROPOSAL AND

PROCEDURAL ORDER NO. 6

EPCOR NATURAL GAS – SOUTHERN BRUCE

EB-2018-0264

OCTOBER 3, 2019

SETTLEMENT PROPOSAL DATED SEPTEMBER 16, 2019

EB-2018-0264

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by EPCOR Natural Gas Limited Partnership for Natural Gas distribution rates and other charges for the period January 1, 2019 to December 31, 2028.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

(SOUTH BRUCE)

SETTLEMENT PROPOSAL

Filed: September 16, 2019

EPCOR Natural Gas Limited Partnership
EB-2018-0264

Settlement Proposal

TABLE OF CONTENTS

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

EPCOR Natural Gas Limited Partnership
EB-2018-0264
Settlement Proposal

Filed with OEB: September 16, 2019

EPCOR Natural Gas Limited Partnership Southern Bruce ("**EPCOR Southern Bruce**") filed a custom incentive rate making application with the Ontario Energy Board (the "**Board**" or "**OEB**") on January 31, 2019 under section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "**Act**") seeking approval for: (i) rates that EPCOR Southern Bruce will charge for gas distribution through a ten-year custom incentive rate-setting plan (covering the period from January 1, 2019 to December 31, 2028), including a rate adjustment mechanism for annual rate adjustments; and (ii) EPCOR's forecast of upstream charges to be incurred by EPCOR Southern Bruce and the establishment of variance accounts to capture actual upstream costs when determined. This application is based on:

1. EPCOR Southern Bruce's forecasted ten-year distribution revenue requirement of $58.541 million plus a revenue deficiency with an estimated Net Present Value of $1.764 million resulting from a delay in the commencement of construction of the project; and

2. The decision of the Board in EB-2016-0137/0138/0139 whereby the Board selected an affiliate of EPCOR as the successful proponent for the Southern Bruce gas distribution project and approved EPCOR's competitively offered Common Infrastructure Plan (CIP) revenue requirement as filed in that process.

EPCOR Southern Bruce also sought Board approval for, *inter alia*:

1. The establishment of certain new deferral and variance accounts;

2. The classification of customers into various rate classes;

3. Service and Miscellaneous Charges;

4. EPCOR Southern Bruce's initial Utility System Plan;

5. EPCOR Southern Bruce's proposed Scorecard;

6. EPCOR Southern Bruce's Gas Supply Plan; and

7. Certain Accounting Orders

The Board issued a Notice of Hearing on April 18, 2019, which was served and posted as per the direction of the Board. Enbridge Gas Inc. ("**Enbridge Gas**"), Industrial Gas Users Association ("**IGUA**"), School Energy Coalition ("**SEC**"), Vulnerable Energy Consumers Coalition ("**VECC**"), Anwaatin Inc. (**Anwaatin**) and the municipality of Kincardine, the Municipality of Arran-Elderslie and the Township of Huron-Kinloss ("**South Bruce Municipalities**") applied for and were granted Intervenor status. Procedural Order No. 1 was issued on May 21, 2019 which provided for filing of interrogatories, interrogatory responses, a settlement conference and presentation of a Settlement Proposal.

In Procedural Order No. 2, the OEB cancelled the settlement conference pending the resolution of a final issues list. On July 16, 2019, the Board issued a proposed issues list, and invited written submissions on the disputed issues. An Issues List Decision was rendered on August 20, 2019.

Further to the Board's Procedural Orders No. 1 and 2, and its Issues List Decision on August 20, 2019, a settlement conference was convened on August 21, 2019 and continued on August 22, 2019 in accordance with the Board's *Rules of Practice and Procedure* (the "**Rules**") and the Board's *Practice Direction on Settlement Conferences* (the "**Practice Direction**"). Chris Haussmann acted as facilitator for the settlement conference. Settlement discussions among the parties to the Settlement Conference continued following the in-person settlement conference, and have resulted in this Settlement Proposal.

EPCOR Southern Bruce participated in the settlement conference, along with IGUA, SEC, VECC, and Anwaatin (collectively, the "**Intervenors**"). EPCOR Southern Bruce and the Intervenors are collectively referred to below as the "**Parties**".

Ontario Energy Board staff ("**OEB staff**") also participated in the settlement conference. The role adopted by OEB staff is set out in page 5 of the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB staff who did participate in the settlement conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

This Settlement Proposal is filed with the Board in connection with the Application.

This document is called a "**Settlement Proposal**" because it is a proposal by the Parties to the Board to settle the issues in this proceeding. It is termed a proposal as between the Parties and the Board. However, as between the Parties, and subject only to the Board's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. This agreement is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this agreement, the Parties understand and agree that, pursuant to the Act, the Board has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that this settlement proceeding is confidential and privileged in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the Board's *Practice Direction on Confidential Filings*, and the rules of that latter document do not apply. Instead, in this settlement conference, and in this Agreement, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the settlement conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the settlement conference but were (a) any persons or entities that the Parties engage to assist them with the settlement conference, and (b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled issues, together with references to the evidence. The Parties agree that references to the "evidence" (which includes interrogatory and clarification question responses) in this Settlement Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, and (b) the Appendices to this document. The supporting Parties for each settled issue agree that the evidence in respect of that settled issue is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the Board of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by EPCOR Southern Bruce. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties on the settled issues following the settlement conference. For ease of reference, this Settlement Proposal follows the format of the final approved issues list of August 20, 2019.

The Parties are pleased to advise the Board that they have reached a complete agreement with respect to the settlement of three of the issues in this proceeding. Specifically:

"**Complete Settlement**" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the Board, the Parties will not adduce any evidence or argument during the hearing in respect of these issues.	# issues settled: 3
"**Partial Settlement**" means an issue for which there is partial settlement, as EPCOR Southern Bruce and the Intervenors who take a position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the Board, the Parties who take a position on the issue will only adduce evidence and argument during the hearing on those portions of the issue not addressed in this Settlement Proposal.	# issues partially settled: 7
"**No Settlement**" means an issue for which no settlement was reached. EPCOR Southern Bruce and the Intervenors who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	# issues not settled: 1

The Parties have not reached the consensus reflected in this document on the basis of a "package", and accordingly the various resolutions reflected in this Settlement Agreement are considered by the Parties to be severable.

In the event that the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its resubmission to the Board.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not EPCOR Southern Bruce is a party to such proceeding.

Where in this Settlement Proposal, the Parties or any of them "accept" the evidence of, or "agree" to a term or condition, including a budget or forecast, then unless the agreement expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

SUMMARY

In reaching this settlement, the Parties have been guided by the current *Filing Requirements for Natural Gas Distributor Rate Applications* (February 16, 2017) and the Approved Issues List attached as Schedule A to the Board's Issues List Decision of August 20, 2019.

This Settlement Proposal reflects a complete settlement of 3 issues in this proceeding, which are identified below.

Based on the foregoing, and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommends its acceptance by the Board.

1. Administration

(a) Has EPCOR Southern Bruce complied with the OEB directives from the Common Infrastructure Plan (CIP) Process (EB-2016-0137/EB-2016-0138/EB-2016-0139)?

Complete Settlement: The Parties agree that there were no specific directives from the CIP Process. The OEB did require EPCOR to demonstrate that this rate application is consistent with EPCOR's CIP proposal. Parties' positions on the consistency of this application with EPCOR's CIP proposal are addressed on an issue-by-issue basis in the balance of this Settlement Proposal.

Evidence:

Application:
- EB-2016-0137/EB-2016-0138/EB-2016-0139

Supporting Parties: All

(b) Are EPCOR Southern Bruce's proposed rates consistent with its CIP, and where there are departures are such departures appropriate?

No Settlement: The Parties agree that this issue is inextricably tied to issue 6, in respect of which no settlement was reached.

Evidence:

Application:

- Exhibit 1, Tab 3, Schedule 1, pages 1 to 53
- Exhibit 7, Table 1, Schedule 1, Section 7.1

IRRs:

- Staff Interrogatories: OEB 7.Staff.22, OEB 8.Staff.25, OEB 8.Staff.26
- IGUA Interrogatories: IGUA 3, IGUA 4, IGUA 5, IGUA 8, IGUA 9, IGUA 10, IGUA 11, IGUA 14, IGUA 15, IGUA 18, IGUA 19, IGUA 20, IGUA 21
- SEC Interrogatories: 7-SEC-15, 8-SEC-16

2. *Rate Base and Utility System Plan*

(a) Is the level of planned capital expenditures consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: The Parties note that capital expenditures were not detailed in the CIP proposal. The Parties agree that the level of planned capital expenditures over the ten year rate stability period as presented in this application, other than those expenditures identified under issue 5, are consistent in principle with the CIP proposal in that such capital expenditures support the overall revenue requirement which in turn is in accord with the CIP proposal. For this reason, the Parties agree that the proposed rate base for 2028 as filed in this application will be the basis for determining the rate base in EPCOR's subsequent cost of service application for the period beginning on January 1, 2029, subject to adjustment for actual Contributions in Aid of Construction (CIACs) to Enbridge.

The Parties agree that capital expenditures associated with expansion of the system beyond that identified in the CIP[1] as approved would also be eligible for inclusion in EPCOR Southern Bruce's rate base in the subsequent cost of service application.

The estimated CIAC for the Dornoch Meter and Regulator Station ($2.935 million) and Enbridge's Owen Sound Transmission Reinforcement ($2.363 million) are included in the rate base as filed in this application. Enbridge has notified EPCOR Southern Bruce that the estimated CIAC for the Dornoch Meter and Regulator Station has increased from $2.935 million to $4.023 million, and that the estimated CIAC for the Owen Sound Transmission Reinforcement has increased from $2.363 million to $5.191 million. The upstream costs associated with the Owen Sound Transmission Reinforcement are subject to approval by

[1] EB-2016-0137/0138/0139 EPCOR Southern Bruce Gas Inc's Common Infrastructure Proposal, October 16, 2017, Schedule B, Pages 1 - 9

the OEB as part of Enbridge's leave-to-construct application, which was filed on August 29, 2019 (EB-2019-0183). The Parties agree that any difference in the CIAC from the forecast included in this application and the CIAC approved by the Board in Enbridge's Leave to Construct application will be included in the Contribution in Aid of Construction Variance Account ("**CIACVA**").

Evidence:

Application:
- Exhibit 2, Tab 1, Schedule 1, section 2.1 and section 2.8.1.

IRRs:
- Staff Interrogatories: OEB Staff 4(c), (d), OEB 4 Staff 17
- IGUA Interrogatoires: IGUA 8

Supporting Parties: All

(b) Is EPCOR Southern Bruce's proposed working capital allowance during the rate stability period consistent with EPCOR Southern Bruce's CIP proposal and any proposed working capital allowance related to non-distribution costs appropriate?

Complete Settlement: The Parties accept the evidence of EPCOR Southern Bruce that the proposed working capital allowance as summarized in Table 2.5 below is consistent with EPCOR Southern Bruce's CIP proposal.

For the purposes of the settlement of the issues in this proceeding, the Parties accept the evidence of EPCOR Southern Bruce that the proposed working capital allowance related to non-distribution costs (as summarized in Table 2-5 below) is appropriate.

Table 2-5: Projected Working Capital Requirements

(Thousands of Dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
	Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Row 1	Working Capital for Non-distribution Costs	24	95	153	201	232	254	262	266	269	272
Row 2	Working Capital for O&M	66	145	170	178	186	199	205	207	210	232
Row 3	Working Capital Requirement	90	240	323	379	418	454	467	473	479	504
Row 4											
Row 5	Working Capital as % of Rate Base	0.37%	0.44%	0.54%	0.62%	0.69%	0.75%	0.79%	0.82%	0.85%	0.92%

Evidence:

Application:
- Exhibit 2, Tab 1, Schedule 1, section 2.3

Supporting Parties: All

(c) Is EPCOR Southern Bruce's proposal for recovery of the Contribution in Aid of Construction paid to Enbridge Gas for upstream transmission reinforcement appropriate?

Complete Settlement: The Parties agree that EPCOR's proposal for the recovery of the Contribution in Aid of Construction ("CIAC") as included in the application ($2.935 million for the Dornoch Meter and Regulator Station and $2.363 million for Enbridge's Owen Sound Transmission Reinforcement) is appropriate. EPCOR will apply for the disposition of any amounts recorded in the Contribution in Aid of Construction Variance Account. The Parties agree that disposition of these amounts will be consistent with the disposition of the earlier CIAC amounts such that early connecting customers will not be asked to subsidize later connecting customers and that each class of customers will be treated in an equitable manner without regard to time of connection, as EPCOR Southern Bruce has proposed in respect of costs forecast for the CIAC included in this application.

Evidence:

Application:
- Exhibit 3, Tab 1, Schedule 1, Section 3.2.4

IRRs:
- Staff Interrogatories: OEB 4 Staff 17

Supporting Parties: All

(d) Is EPCOR Southern Bruce's proposal to waive new customer connection costs consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: The proposal to waive new customer connection costs was not articulated in the CIP proposal. In this application, EPCOR Southern Bruce proposed to not charge new customers for the first 30 m of service lateral installation costs (see Table 6(d) - 1, row 19, column B). New customers requiring main extensions will be charged in accordance with the principles set out in EBO 188. No party has concerns with this proposal for the purposes of this settlement, on the basis that the costs of customer connections not being charged are included in EPCOR's forecast of capital and operating costs supporting its proposed rates.

3. *Operating Revenue*

(a) Is EPCOR Southern Bruce's proposed Distribution Revenue during the rate stability period consistent with EPCOR Southern Bruce's CIP proposal, giving due consideration to:

(i) **External Funding**

(ii) **Municipal tax holidays**

Complete Settlement: The Parties agree that EPCOR Southern Bruce's proposed Distribution Revenue is consistent with EPCOR Southern Bruce's CIP proposal and the adjustment to reflect external funding is appropriate.

Evidence:

Application:

- Exhibit 3, Tab 1, Schedule 1, section 3.2.3:

Supporting Parties: All

(b) Is EPCOR Southern Bruce's proposed Non-Distribution Revenue (gas supply, storage and transportation) for the rate stability period consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: Non-distribution revenue was explicitly excluded from the CIP distribution revenue. The Parties agree that: (a) the exclusion of such revenues is consistent with EPCOR's CIP proposal; and (b) the forecast values which EPCOR has proposed are appropriate and that the actual values will be determined through Enbridge's Owen Sound Reinforcement Project Leave to Construct and Rate M17 application (EB-2019-0183) and, subject to any required OEB approvals, by any other agreements EPCOR may enter to access gas supply, daily balancing, storage and transportation services or other activities necessary to provide these services.

Evidence:

Application:
- Exhibit 1, Tab 2, Schedule 1, par 13, page 14 of 64
- Exhibit 3, Tab 1, Schedule 1, section 3.2.4

IRRs:
- OEB Staff Interrogatories: 8.Staff.25

Supporting Parties: All

(c) Are EPCOR Southern Bruce's proposed Other Revenues during the rate stability period consistent with EPCOR Southern Bruce's CIP proposal?

No Settlement: The Parties do not agree that EPCOR Southern Bruce's proposed Other Revenues and the treatment of those other revenues during the rate stability period are consistent with EPCOR Southern Bruce's CIP proposal.

Evidence:

Application:
- Exhibit 3, Tab 1, Schedule 1, section 3.5,
- Exhibit 3, Tab 1, Schedule 3, page 3, Table 3-16 and 3-17:

IRRs:
- SEC Interrogatories: 1-SEC-3

4. *Operating Expenses*

(a) Is EPCOR Southern Bruce's forecasted gas supply, transportation and storage costs and proposal for recovery of those costs for the rate stability period appropriate?

Complete Settlement: These costs were specifically excluded from the distribution revenue as detailed in the CIP process. The Parties agree that EPCOR's forecasted costs and proposal for recovery are appropriate. The actual values will be determined through Enbridge's Owen Sound Reinforcement Project Leave to Construct and Rate M17 application (EB-2019-0183) and, subject to any required OEB approvals, any other agreements EPCOR may enter to access gas supply, daily balancing, storage and transportation services or other activities necessary to provide these services.

Evidence:

Application:
- Exhibit 4, Tab 1, Schedule 1, section 4.1

Supporting Parties: All

(b) Are EPCOR Southern Bruce's OM&A costs including shared services costs consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: EPCOR Southern Bruce's OM&A costs were not articulated in the CIP proposal. No Party objects to the OM&A costs filed in this application on the basis that the value and composition of the OM&A costs as included in this application support rates in accord with the CIP approved revenue requirement. Moreover, the Parties agree that the value and composition of the OM&A costs as included in this application does not establish a precedent or baseline for EPCOR's cost-of-service or allocation of shared services costs for the period following the rate stability period.

Evidence:

Application:
- Exhibit 4, Tab 1, Schedule 1, section 4.3

IRRs:
- Staff Interrogatories: OEB 4.Staff.14, OEB 4.Staff.15
- SEC Interrogatories: 4-SEC-10, 4-SEC-11

Supporting Parties: All

5. *Revenue Deficiency/Sufficiency*

(a) Is EPCOR Southern Bruce's proposal to recover an additional $1.764 million due to changes in construction schedule, and the associated rate rider calculation, consistent with EPCOR Southern Bruce's CIP proposal and appropriate?

No Settlement: The Parties could not reach agreement that EPCOR Southern Bruce's proposal to recover the estimated $1.764 million associated with a delayed construction schedule as a revenue deficiency is appropriate.

Evidence:

Application:
- Exhibit 6

IRRs:
- Staff Interrogatories: OEB 6.Staff.20
- Enbridge Interrogatories: Enbridge 5, Enbridge 6
- IGUA Interrogatories: IGUA 16
- SEC Interrogatories: 6-SEC-14

(b) Is the adjusted revenue requirement appropriate?

Complete Settlement: The Parties agree that EPCOR Southern Bruce's proposal for Distribution Revenue is appropriate. The Parties note that this does not include any revenue deficiency addressed under issue 5(a) as proposed by EPCOR Southern Bruce in Exhibit 6 of the application nor any Other Revenues as addressed in issue 3(c).

Evidence:

Application:
- Exhibit 3, Tab 1, Schedule 1, section 3.2.3

IRRs:
- SEC Interrogatories: 1-SEC-3

Supporting Parties: All

6. *Cost Allocation and Rate Design*

(a) Are the proposed rate classes appropriate?

No Settlement: The Parties could not reach agreement that EPCOR Southern Bruce's proposed rate classes are appropriate.

Evidence:

Application:

- Exhibit 8, Tab 1, Schedule 1, section 8.1

IRRs:

- Staff Interrogatories: OEB 8.Staff.23, OEB 8.Staff.24, OEB 8.Staff.26

(b) Are EPCOR Southern Bruce's proposed cost allocation, rate design and revenue to cost ratios appropriate and consistent with EPCOR Southern Bruce's CIP proposal?

No Settlement: The Parties could not reach agreement that EPCOR Southern Bruce's proposed cost allocation, rate design and revenue to cost ratios are appropriate and consistent with EPCOR Southern Bruce's CIP proposal.

Evidence:

Application:

- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design

IRRs:

- Staff Interrogatories: OEB 7.Staff.21, OEB 7.Staff.22
- IGUA Interrogatories: IGUA 3, IGUA 4, IGUA 5, IGUA 8, IGUA 9, IGUA 10, IGUA 11, IGUA 14, IGUA 15, IGUA 18, IGUA 19, IGUA 20, IGUA 21
- SEC Interrogatories: 7-SEC-15, 8-SEC-16

(c) Are EPCOR Southern Bruce's proposed rates appropriate?

No Settlement: The Parties could not reach agreement that EPCOR Southern Bruce's proposed rates are appropriate.

Evidence:

Application:

- Exhibit 8, Tab 1, Schedule 1, sections 8.3, 8.4
- Exhibit 8, Tab 1, Schedule 2, pages 1-12, Rate Schedule

IRRs:

- VECC Interrogatories: 7-VECC-7

(d) Are EPCOR Southern Bruce's proposed service charges appropriate?

Complete Settlement: The Parties agree to the following changes to EPCOR Southern Bruce's Miscellaneous Charges schedule: (1) removal of a disconnection fee; (2) continuation of the NSF (returned cheque) fee at $20; (3) clarification that the service lateral included in the installation of service is 30 metres. These changes are reflected in Table 6(d) - 1 below. With such changes being made, the Parties agree that EPCOR Southern Bruce's proposed service charges are appropriate.

Table 6(d) - 1
Summary of Settled Service and Miscellaneous Charges

		A	B	C
		EPCOR Aylmer	**EPCOR Southern Bruce**	
	Service	**Settled Fee (EB-2018-0336)**	**Proposed Fee (EB-2018-0264)**	**Settled Fee (EB-2018-0264)**
1	Service Work			
2	During Normal working hours			
3	Minimum charge (up to 60 minutes)	$100.00	$100.00	$100.00
4	Each additional hour (or part thereof)	$100.00	$100.00	$100.00
5	Outside normal working hours			
6	Minimum charge (up to 60 minutes)	$130.00	$130.00	$130.00
7	Each additional hour (or part thereof)	$105.00	$105.00	$105.00
8	Miscellaneous Charges			
9	Returned Cheque / Payment	$20.00	$48.00	$20.00
10	Replies to request for account information	$25.00	$25.00	$25.00
11	Bill Reprint / Statement Print Requests	$20.00	$20.00	$20.00
12	Consumption Summary Requests	$20.00	$20.00	$20.00

13	Customer Transfer / Connection Charge	$35.00	$35.00[2]	$35.00[3]
14	Reconnection Charge	$85.00	$85.00	$85.00
15	Disconnection Charge	$0.00	$85.00	$0.00
16	Inactive Account Charge	ENGLP cost to install service	ENGLP cost to install service	ENGLP cost to install service
17	Late Payment Charge	1.5%/month, 19.56%/year (effective rate of 0.04896% compounded daily)	1.5%/month, 19.56%/year (effective rate of 0.04896% compounded daily)	1.5%/month, 19.56%/year (effective rate of 0.04896% compounded daily)
18	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs	Charge based on actual costs	Charge based on actual costs
19	Installation of Service Lateral	$100 first 20 meters. Additional if pipe length exceeds length used to set fee.	No charge for the first 30 meters. Cost if pipe length exceeds 30 meters.	No charge for the first 30 meters. Cost if pipe length exceeds 30 meters.

Evidence:

Application:
- Exhibit 8, Tab 1, Schedule 2, pages 11 and 12

IRRs:
- Staff Interrogatories: OEB 8.Staff.25

Supporting Parties: All

7. *Proposed Deferral and Variance Accounts*

(a) Are the following EPCOR Southern Bruce's proposed deferral and variance accounts appropriate?

(i) **Purchased Gas Commodity Variance Account (PGCVA)**

(ii) **Gas Purchase Rebalancing Account (GPRA)**

(iii) **Storage and Transportation Variance Account Rates 1, 6 & 11 (S&TVA Rates 1, 6 & 11)**

[2] No Charge for initial connection

[3] No Charge for initial connection

(iv) **Transportation Variance Account Rate 16 (TVA Rate 16)**

(v) **Unaccounted for Gas Variance Account (UFGVA)**

(vi) **Greenhouse Gas Emissions Administration Deferral Account (GGEADA)**

(vii) **Federal Carbon Charge - Customer Variance Account (FCCCVA)**

(viii) **Federal Carbon Charge - Facility Deferral/Variance Account (FCCFVA)**

(ix) **Regulatory Expense Deferral Account (REDA)**

Partial Settlement: For the purposes of the settlement of the issues in this proceeding, the Parties agree that EPCOR Southern Bruce's proposals for the PGCVA, GPRA, S&TVA Rates 1, 6 & 11, TVA Rate 16, UFGVA, GGEADA, FCCCVA and FCCFVA are appropriate. EPCOR Southern Bruce agreed to use the language as the Board approved in EB-2019-0101 (EPCOR's Aylmer operation) for GGEADA, FCCCVA and FCCFVA.

The Parties do not agree on EPCOR's proposal for the REDA.

(b) Are the following EPCOR Southern Bruce's proposed deferral and variance accounts consistent with EPCOR Southern Bruce's CIP proposal appropriate?

(i) **Municipal Tax Variance Account (MIYA)**

(ii) **Energy Content Variance Account (ECVA)**

(iii) **Contribution in Aid of Construction Variance Account (CIACVA)**

(iv) **External Funding Variance Account (EFVA)**

Partial Settlement: The Parties agree that EPCOR Southern Bruce's proposal for the CIACVA and EFVA is consistent with EPCOR Southern Bruce's CIP proposal and appropriate.

The agreement on the appropriateness of the CIACVA is on the basis that EPCOR agree to propose a disposition of that account which is consistent with the principle endorsed by agreement of the Parties under Issue 2(c) that early connecting customers will not be asked to subsidize later connecting customers and that each class of customers will be treated in an equitable manner without regard to time of connection, as EPCOR Southern Bruce has proposed in respect of costs forecast for the CIAC included in this application.

The Parties further agree that the base line for determining any value to be captured in the EFVA will be contributions as detailed in Exhibit 2, Tab 1, Schedule 1 section 2.2, Table 2-3, and with the assumption made in that table that such contributions are received by EPCOR on June 30 (i.e. at the mid-point) of each year.

The Parties further agree that the CIACVA will be established according to the Schedule detailed in Exhibit 2, Tab 1, Schedule 1, section 2.8, Table 2-8.

The Parties do not agree on the issue of whether the MTVA and ECVA are consistent with the CIP proposal and appropriate.

Evidence:

Application:
- Exhibit 9
- Exhibit 2, Tab 1, Schedule 1, section 2.2, Table 2-3
- Exhibit 2, Tab 1, Schedule 1, section 2.8, Table 2-8

IRRs:
- Staff Interrogatories: OEB 9.Staff.38

Supporting Parties: All

(c) What other deferral and variance accounts are required?

Complete Settlement: The Parties have agreed that EPCOR will establish an Accelerated CCA Income Taxes Variance Account ("ACITVA") for EPCOR to record the income tax impact from the difference between the capital cost allowance ("CCA") rates used in the income taxes payable calculation included in the 10-year revenue requirement (EB-2018-0264) and the accelerated CCA rates as enacted under Bill C-97, should EPCOR claim accelerated CCA for its Southern Bruce operations during the term of the Custom Incentive Rate Setting Plan. In the calculation of income taxes payable included in the 10-year revenue requirement, EPCOR has not claimed the accelerated CCA on eligible capital property. Therefore, this account is required to record the impact associated with changes to income taxes payable should EPCOR claim accelerated CCA during the term of the Custom Incentive Rate Setting Plan. The draft accounting order for this account is included as **Appendix A** to this Settlement Proposal.

Supporting Parties: All

(d) Should EPCOR Southern Bruce's proposed Federal Carbon Charge and related deferral and variance accounts be addressed in this application or as a separate stand-alone application?

Complete Settlement: The Parties agree that EPCOR Southern Bruce's proposal for the FCCCVA and FCCFVA are appropriately addressed in this application and settled as per Issue 7 (a) above.

The Parties' positions regarding the proposed deferral and variance accounts are summarized in Table 7(d) - 1 below.

Table 7(d) - 1 Treatment of EPCOR Southern Bruce's Proposed Deferral and Variance Accounts

	Account	Settlement Status
1	Purchased Gas Commodity Variance Account ("PGCVA")	Complete Settlement
2	Gas Purchase Rebalancing Account ("GPRA")	Complete Settlement
3	Storage and Transportation Variance Account Rates 1, 6 &11 ("S&TVA 1, 6 & 11")	Complete Settlement
4	Transportation Variance Account Rate 16 ("TVA Rate 16")	Complete Settlement
5	Unaccounted For Gas Variance Account ("UFGVA")	Complete Settlement
6	Greenhouse Gas Emissions Administration Deferral Account ("GGEADA")	Complete Settlement
7	Federal Carbon Charge – Customer Variance Account ("FCCCVA")	Complete Settlement
8	Federal Carbon Charge – Facility Deferral/Variance Account ("FCCFVA")	Complete Settlement
9	Regulatory Expense Deferral Account ("REDA")	No Settlement
10	Municipal Tax Variance Account ("MIYA")	No Settlement
11	Energy Content Variance Account ("EVCA")	No Settlement
12	Contribution in Aid of Construction Variance Account ("CIACVA")	Complete Settlement
13	External Funding Variance Account ("EFVA")	Complete Settlement
14	Accelerated CCA Income Taxes Variance Account ("ACITVA")	Complete Settlement

Evidence:

Application:

- Exhibit 2, Tab 1, Schedule 1 section 2.2, Table 2-2
- Exhibit 9, Tab 1, Schedule 1, pages 1-9
- Exhibit 9, Tab 2, Schedule 1, pages 1 - 17

IRRs:

- Staff Interrogatories: OEB 10.Staff.41, OEB 9.Staff.27, OEB 9 Staff.28, OEB 9.Staff.29, OEB 9.Staff.30, OEB 9.Staff.31, OEB 9.Staff.32, OEB 9.Staff.33, OEB

9.Staff.34, OEB 9.Staff.35, OEB 9.Staff.36, OEB 9.Staff.37, OEB 9.Staff.38, OEB 9.Staff.39
- SEC Interrogatories: 10-SEC-17, 4-SEC-12
- IGUA Interrogatories: IGUA 22
- VECC Interrogatories: 9-VECC-9, 9-VECC-10
- Enbridge Interrogatories: Enbridge 9, Enbridge 13
- IGUA Interrogatories: IGUA 22

Supporting Parties: All

8. ***Incentive Rate Setting Proposal***

(a) Is EPCOR Southern Bruce's proposed Custom Incentive Rate-setting (Custom IR) plan during the rate stability period consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: The Parties agree that EPCOR Southern Bruce's proposed Custom IR plan during the rate stability period is consistent with EPCOR Southern Bruce's CIP proposal.

The details of the Custom IR plan with which parties agree are the following

- Incentive Rate Adjustment (IR) = [(1.0 - 0.314) × 0.0127] + [0.314 × Inflation (I)]

- Adjustments to upstream charges would not be made using the IR adjustment factor, but would be adjusted as necessary to reflect any changes that EPCOR is subject to in contracting for those services from its suppliers, including transmission services.

- There are no productivity or stretch factors included in the adjustment mechanism (See issue 8(d)).

- There is no earnings sharing mechanism (See issue 8(d)).

- There is no earnings dead-band off-ramp (See issue 8(d)).

- The following items are to be treated as Y-factors:

    - Costs related to unaccounted for gas;

LEGAL_1:56655847.1

  - Externally driven costs that are approved in other proceedings (e.g. DSM program costs etc.) for pass-through recovery by gas distributors during then current rate plan terms will be implemented as part of the annual rate application through the Custom IR Term.
  - Gas Supply costs will be treated as a pass-through cost through the use of the PGCVA and will be updated during the Custom IR Term in accordance with the Board's established QRAM process; and
  - Costs related to greenhouse gas emissions programs applicable to the utility will be recorded in the FCCCVA, FCCFVA and GGEADA, or other deferral or variance accounts as established through the specific proceedings regarding greenhouse gas emissions programs.
- A Z-factor mechanism is available. EPCOR Southern Bruce may apply for a Z-factor that meets the all four of the following categories:
  - Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event, and must be clearly outside of the base upon which rates were derived
  - Materiality: The cost increase or decrease must meet a materiality threshold, in that its effect on the utility's revenue requirement in a fiscal year must be equal to or greater than the threshold of $50,000 for an individual event.
  - Prudence: The cost subject to an increase or decrease must have been prudently incurred.
  - Management Control: The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause

that utility management could not reasonably control or prevent through the exercise of due diligence.

There is no agreement with respect to:

- Y-factor treatment for costs associated with participation in generic and other Board proceedings, including Union and Enbridge proceedings (i.e. the REDA account addressed in issue 7(d) in respect of which there is no agreement).
- An incremental capital module (issue 8(e)).

Evidence:

Application:
- Exhibit 10

Supporting Parties: All

(b) Is the proposed 10-year term for the Custom IR plan consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: The Parties have agreed that the proposed 10-year term of the Customer IR plan is consistent with the CIP proposal. The Parties wish to note, however, that this does not constitute agreement on whether the starting date for the 10 years should be January 1, 2019 or should be adjusted in light of the outcome on issue 5(a).

Evidence:

Application:
- Exhibit 10, Tab 1, Schedule 1, page 1 of 7 paragraph 1

Supporting Parties: All

(c) Is EPCOR Southern Bruce's proposed annual adjustment mechanism consistent with EPCOR Southern Bruce's CIP proposal?

Complete Settlement: The Parties agree that EPCOR Southern Bruce's proposal to adjust the OM&A recovery component of its rates (being 31.4% of each of its rates) annually by the Board's annual rate of inflation is consistent with EPCOR Southern Bruce's CIP proposal. The Parties also agree that EPCOR Southern Bruce's plan to annually adjust all other elements of the revenue requirement by 1.27% per annum is consistent with EPCOR Southern Bruce's CIP proposal. In order to apply these two adjustments against existing rates during the annual price adjustment the Parties agree to the use of the Incentive Rate Adjustment formula as follows:

Incentive Rate Adjustment (IR) = $[(1.0 - 0.314) \times 0.0127] + [0.314 \times \text{Inflation (I)}]$

The Inflation factor (I) will equal the inflation value the Board determines each year in its annual generic inflation amount.

Evidence:

Application:
- Exhibit 10, Tab 1, Schedule 1, sections 10.1 and 10.2

IRRs:
- Staff Interrogatories: OEB 10.Staff.41
- SEC Interrogatories: 10-SEC-17

Supporting Parties: All

(d) Is the exclusion of:

(i) **A productivity and stretch factor consistent with EPCOR Southern Bruce's CIP proposal?**

(ii) **An earnings sharing mechanism consistent with EPCOR Southern Bruce's CIP proposal?**

(iii) **An earnings dead-band off-ramp consistent with EPCOR Southern Bruce's CIP proposal?**

Complete Settlement: The Parties agree that the exclusion of a productivity factor, stretch factor, earnings sharing mechanism and an earnings dead-band off-ramp are consistent with EPCOR Southern Bruce's CIP proposal.

Evidence:

Application:

- Exhibit 10, Tab 1, Schedule 1, section 10.2.1, 10.5

IRRs:

- Staff Interrogatories: OEB 10.Staff.40
- Enbridge Interrogatories: Enbridge 11
- IGUA Interrogatories: IGUA 23

Supporting Parties: All

(e) Is EPCOR Southern Bruce's request for availability of an Incremental Capital Module consistent with EPCOR Southern Bruce's CIP proposal?

No Settlement: The Parties do not agree that EPCOR Southern Bruce's request for availability of an Incremental Capital Module is consistent with EPCOR Southern Bruce's CIP proposal.

Evidence:

Application:

- Exhibit 10, Tab 1, Schedule 1, section 10.7

IRRs:

- Staff Interrogatories: OEB 10.Staff.43
- Enbridge Interrogatories: Enbridge 12
- SEC Interrogatories: 10-SEC-19

9. *Score Card*

(a) Is EPCOR Southern Bruce's proposed Score Card appropriate?

Complete Settlement: The Parties agree that the proposed Scorecard is appropriate, subject to adding the following two metrics:

1. Total cost per customer per year; and

2. Total cost per km of distribution pipe per year

The agreed upon Scorecard is provided in **Appendix B** to this Settlement Proposal.

Evidence:

Application:
- Exhibit 1, Tab 2, Schedule 1, section 1.7
- Exhibit 1, Tab 2, Schedule 2, Pages 1 - 2

IRRs:
- Staff Interrogatories: OEB 1.Staff.5
- VECC Interrogatories: 1-VECC-1

Supporting Parties: All

10. *Implementation*

(a) Is EPCOR Southern Bruce's proposal for a January 1, 2019 effective date consistent with EPCOR Southern Bruce's CIP proposal?

No Settlement: The Parties do not agree that EPCOR Southern Bruce's proposal for a January 1, 2019 effective date is consistent with EPCOR Southern Bruce's CIP proposal.

Evidence:

Application:
- Exhibit 1, Tab 2, Schedule 1, page 13 of 64, par 8

IRRs:
- Enbridge Interrogatories: Enbridge 3

(b) Is EPCOR Southern Bruce's proposal for rate riders for recovery from and after the effective date consistent with EPCOR Southern Bruce's CIP proposal and appropriate?

No Settlement: The Parties do not agree that EPCOR Southern Bruce's proposal for rate riders for recovery from and after an effective date of January 1, 2019 is consistent with EPCOR Southern Bruce's CIP proposal and appropriate.

Evidence:

Application:
- Exhibit 3, Tab 1, Schedule 1, section 3.2.4

- Exhibit 6, Tab 1, Schedule 1, section 6.4
- Exhibit 9, Tab 1, Schedule 1, pages 1 - 9

IRRs:

- Staff Interrogatories: OEB 9.Staff.39

11. *Stakeholder Engagement*

(a) Has EPCOR South Bruce effectively engaged with and sought input from key stakeholders and First Nations and Métis communities?

Partial Settlement: The Parties agree that EPCOR South Bruce has effectively engaged with and sought input from key stakeholders. There is no agreement with respect to EPCOR's engagement with First Nations and Métis communities.

Evidence:

Application:

- Exhibit 1, Tab 1, Schedule 1, section 1.6
- Exhibit 1, Tab 2, Schedule 1, page 9
- Exhibit 1, Tab 3, Schedule 1, pages 1-53
- Exhibit 1, Tab 3, Schedule 2, pages 1 - 87

IRRs:

- Staff Interrogatories:
- Anwaatin Interrogatories: Anwaatin 1, Anwaatin 2

Supporting Parties: All, with the exception of Anwaatin.

APPENDIX A

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Accounting Order
Accelerated CCA Income Taxes Variance Account

The Accelerated CCA Income Taxes Variance Account ("ACITVA") is to record the income tax impact from the difference between the capital cost allowance ("CCA") rates used in the income taxes payable calculation included in the annual revenue requirement over the rate stability period for EPCOR's Southern Bruce operations as approved in EB-2018-0264 and the accelerated CCA rates as enacted under Bill C-97, should EPCOR Natural Gas Limited Partnership ("ENGLP") claim accelerated CCA for its Southern Bruce operations during the rate stability period. In the calculation of income taxes payable included in the revenue requirement, ENGLP has not claimed the accelerated CCA on eligible capital property. Therefore, this account is required to record the impact associated with changes to income taxes payable should ENGLP claim accelerated CCA during rate stability period.

In the event that ENGLP claims accelerated CCA, the annual amount recorded in the ACITVA will be the tax impact at the approved income tax rate in EB-2018-0264, on the difference between accelerated CCA calculated on the annual rate base approved in the same proceeding and CCA included in the annual income taxes payable approved in the same proceeding.

The entire audited balance in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis.

Simple interest will be computed monthly on the opening balance in the ACITDA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries[4]

[4] Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the *Ontario Energy Board Act*.

To record the income tax impact on the difference between accelerated CCA (if claimed by ENGLP) and CCA included in income taxes payable of the approved revenue requirement:

> Debit/Credit Account No. 179.72 Accelerated CCA Income Taxes Variance Account ("ACITVA")
> Credit/Debit Account No. 306 Income Tax Expense

To record simple interest on the opening monthly balance of the ACITVA:

> Debit/Credit Account No. 179.73 Interest on Accelerated CCA Income Taxes Variance Account
> Credit/Debit Account No. 323 Other Interest Expense

APPENDIX B

SCORECARD 2020-2024

EPCOR Southern Bruce

Performance Outcomes	Performance Categories	Measures	
Customer Focus	Service Quality	Reconnection response time (# of days to reconnect a customer)	*# of reconnections completed within 2 business days/# of reconnections completed*
		Scheduled appointments met on time (appointments met within designated time period)	*# of appointments met within 4 hrs of the scheduled date / # of appointments scheduled in the month*
		Telephone calls answered on time (call answering service level)	*# of calls answered within 30 seconds / # of calls received*
	Customer Satisfaction	Customer Complaint Written Response (# of days to provide a written response)	*# of complaints requiring response within 10 days / # of complaints requiring a written response*
		Billing accuracy	*Number of manual checks done as per quality assurance program, for excessively high or low usage.*
		Abandon Rate (# of calls abandon rate)	*# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent*
		Time to reschedule missed appointments	*% of rescheduled work within 2 hours of the end of the original appointment time*

Operational Effectiveness	Safety, system reliability and asset management	Meter Reading Performance	*# of meters with no read for 4 consecutive months / # of active meters to be read*
		% of Emergency Calls Responded within One Hour	*# of emergency calls responded within 60 minutes / # of emergency calls*
		Damages	*Third party line breaks per 1,000 locate requests*
Public Policy Responsiveness	Extending natural gas distribution to new communities	New communities that have access to natural gas distribution system	*(# of communities serviced by system/# of communities committed to in CIP)*
		$/m3 cost to deliver natural gas	*Average $/m3 determined in CIP (as adjusted) – Actual average $/m3*
		Customer years	*Average customer years / Customer years as determined in CIP*
		Cumulative volume	*Actual cumulative volume / Cumulative volume as determined in CIP*
Financial Performance	Financial Ratios	Current Ratio	
		Debt Ratio	
		Debt to Equity Ratio	
		Interest Coverage	
		Financial Statement Return on Assets	

		Financial Statement Return on Equity Total Cost per Customer per year Total Cost per km of distribution pipe per year

Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2018-0264

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

EPCOR Natural Gas Limited Partnership (Southern Bruce)

BEFORE: Lynne Anderson
Presiding Member

Robert Dodds
Member and Vice-Chair

Cathy Spoel
Member

November 28, 2019

TABLE OF CONTENTS

1 INTRODUCTION AND SUMMARY

EPCOR Natural Gas Limited Partnership (EPCOR Natural Gas LP) is an Ontario limited partnership with its head office in the Town of Aylmer. EPCOR Natural Gas LP is a wholly owned indirect subsidiary of EPCOR Utilities Inc., based in Edmonton, Alberta. EPCOR Natural Gas LP operates a natural gas distribution business in two service areas in Ontario: the Aylmer franchise area (previously known as Natural Resource Gas Limited) and a new franchise area in South Bruce.

In 2018, the Ontario Energy Board (OEB) selected EPCOR Natural Gas LP (EPCOR Southern Bruce)[1] as the successful proponent for the South Bruce gas distribution project.[2] The process was competitive and the selection was made on the basis of a cumulative revenue requirement, forecasted attachments and a total volume throughput for a 10-year rate stability period.

On April 11, 2019, EPCOR Southern Bruce filed a custom incentive ratemaking application with the OEB under section 36 of the *Ontario Energy Board Act*, *1998*, seeking approval for rates that EPCOR Natural Gas can charge for gas distribution effective January 1, 2019.

The OEB held a settlement conference between EPCOR Southern Bruce and the interveners with the objective of reaching a settlement on the issues in the proceeding. Parties reached a settlement on some issues and a revised settlement proposal was filed with the OEB on September 16, 2019. On October 3, 2019, the OEB accepted the settlement proposal and scheduled a written process to address the unsettled issues.

The unsettled issues included other revenues, cost allocation, incremental revenue deficiency related to delays, the effective date for rates, certain deferral and variance accounts, the availability of an incremental capital module and engagement with First Nations and Métis communities.

OEB staff, Industrial Gas Users Association (IGUA), School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC) and Anwaatin Inc. (Anwaatin) filed submissions on the unsettled issues.

EPCOR Southern Bruce proposed $0 in Other Revenues. OEB staff submitted that EPCOR Southern Bruce would earn additional revenues through service charges and proposed annual Other Revenues of $43,292 based on Other Revenues approved in

[1] EPCOR Natural Gas LP in this application has been referred to as EPCOR Southern Bruce in order to identify it separately from the Aylmer gas distribution utility.
[2] EB-2016-0137/0138/0139, Decision and Order, April 12, 2018

the EPCOR Natural Gas (Aylmer) proceeding or alternatively a deferral account to track actual revenues. EPCOR Southern Bruce did not oppose establishment of a deferral account that would start in 2022 which would also track incremental costs for providing the services.

In its application, EPCOR Southern Bruce claimed that there was a 10-month delay in approval of the leave to construct for the Southern Bruce distribution system as compared to what was assumed in the Common Infrastructure Plan (CIP).[3] As a result of the delay, EPCOR Southern Bruce requested recovery of an incremental revenue deficiency of $1.764 million. In order to address the revenue deficiency, OEB staff, IGUA, SEC and VECC suggested that the start date of the 10-year rate stability period be moved from the proposed date of January 1, 2019 to the date of the first customer connection. EPCOR Southern Bruce disagreed with the proposed approach and noted that delaying the start of the rate stability period would impact revenues and expenses for years 11 and beyond (commencing January 1, 2029) that were taken into account in the preparation of the CIP proposal.

With respect to cost allocation, EPCOR Southern Bruce proposed revenue-to-cost ratios that range from 0.78 to 1.37 for the different rate classes. EPCOR Southern Bruce submitted that in order to create the incentive for customers to convert to natural gas, it must have the flexibility to charge a market-based tariff that is based on savings from conversion as opposed to designing rates on a strict cost allocation basis. While OEB staff and SEC recommended a range 0.8 to 1.2 in recognition of the objectives of EPCOR Southern Bruce, IGUA submitted that the revenue-to-cost ratio should be 1.0 for all rate classes.

OEB staff, VECC and SEC did not support EPCOR Southern Bruce's request for a Regulatory Expense Deferral Account (REDA) and the Municipal Tax Variance Account (MTVA). While VECC supported the request for an Energy Content Variance Account (ECVA), OEB staff opposed the request on the basis that the heat content should have been considered as part of the total throughput volume commitment made in the CIP. EPCOR Southern Bruce in reply argued that the risks to be captured in the deferral and variance accounts were outside the CIP and were therefore appropriate.

Most of the elements of EPCOR Southern Bruce's Custom incentive rate setting (IR) proposal were settled with the exception of the availability of an Incremental Capital Module (ICM). OEB staff, SEC and VECC submitted that EPCOR Southern Bruce's request for access to an ICM should be denied. SEC expressed a concern that EPCOR Southern Bruce could use an ICM to address capital cost overruns as

[3] EB-2016-0137/0138/0139

compared to its commitment in the CIP. OEB staff submitted that the OEB's policy does not permit ICMs or Advanced Capital Modules for Custom IR frameworks. EPCOR Southern Bruce in reply argued that being a greenfield utility, it does not have the operational history necessary to develop a detailed capital expenditure plan as required under Custom IR and therefore access to an ICM may be necessary.

Anwaatin requested the OEB to require indigenous monitoring of archeological work and construction, and enhanced access to applications for low-income rates for indigenous customers. In reply, EPCOR Southern Bruce submitted that the OEB should not impose Anwaatin's proposed conditions as they are outside the scope of this proceeding or relate to generic issues.

For reasons that follow, the OEB has made the following key determinations:

1. The OEB approves $0 in Other Revenues for ratemaking purposes. EPCOR Southern Bruce can bring forward its proposal related to Other Revenues in the 2022 annual rate application.

2. The effective date for rates shall be January 1, 2019. EPCOR Southern Bruce is permitted to recover the revenue deficiency related to the delay in connecting customers. However, the revenue deficiency amount has been adjusted, from $1.764 million to $1.32 million.

3. The OEB approves EPCOR Southern Bruce's cost allocation and rate design proposal including the proposed revenue-to-cost ratios.

4. The OEB denies EPCOR Southern Bruce's request for the REDA but approves the establishment of the MTVA and ECVA.

5. The OEB denies EPCOR Southern Bruce's request for ICM eligibility during the 10-year rate stability period.

6. The OEB will not impose Anwaatin's proposed conditions.

2 THE PROCESS

EPCOR Southern Bruce filed a Custom IR application with the OEB on April 11, 2019 under section 36 of the *Ontario Energy Board Act*, *1998*, seeking approval for gas distribution rates to be effective January 1, 2019 and for each following year through to December 31, 2028.

The OEB issued Procedural Order No. 1 on May 21, 2019, which set out a procedural schedule for the proceeding. Since the parties were unable to agree on all the items in a proposed issues list, the OEB invited parties and OEB staff to make written submissions on the disputed issues. In a decision issued on August 20, 2019, the OEB determined a final issues list for the proceeding.

The OEB held a settlement conference between EPCOR Southern Bruce and the interveners with the objective of reaching a settlement on the issues in the proceeding. Parties reached a settlement on some issues and a revised settlement proposal was filed with the OEB on September 16, 2019. In a decision and procedural order issued on October 3, 2019, the OEB accepted the settlement proposal and scheduled written submissions on the unsettled issues.

OEB staff, IGUA, SEC, VECC and Anwaatin filed written arguments on October 18, 2019. EPCOR Southern Bruce filed its reply on October 29, 2019.

3 THE APPLICATION

The Ontario Energy Board (OEB) awarded EPCOR Southern Bruce Certificates of Public Convenience and Necessity for the Southern Bruce Municipalities in a Common Infrastructure Plan (CIP) competitive process.[4] The OEB in its decision noted that it expected that EPCOR Southern Bruce's rate application would be consistent with its CIP proposal.[5]

The Southern Bruce system is a greenfield project. EPCOR Southern Bruce received leave to construct approval on July 11, 2019, and is expected to connect its first customer in December 2019. The system will serve communities within the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron- Kinloss. Enbridge Gas is expected to provide upstream transportation services to EPCOR Southern Bruce.

This application is made in accordance with the decision of the South Bruce Expansion CIP process.[6] As part of the competitive process, EPCOR Southern Bruce committed to certain metrics that are part of its rate setting process for the 10-year rate stability period, from January 2019 to December 2028. These metrics include:

Table 1: Summary of CIP Criteria

Metric / Criteria	Value
Cumulative 10-yr revenue requirement per unit of volume	$0.2209 / m^3
Customer years	42,569
Cumulative 10-yr throughput volume	342,186,741 m^3

The total gross revenue requirement over the 10-year rate stability period associated with the distribution system is $75.583 million.

[4] EB-2016-0137/38/39
[5] *ibid*
[6] *ibid*

A number of items were excluded from the CIP process. These were included in the current rate application and the gross revenue requirement is subject to certain adjustments. These include:

i. Government grants and capital contributions;
ii. Demand-side management costs;
iii. Cap and trade costs;
iv. Tax holidays from the municipality;
v. Gas commodity costs;
vi. Upstream reinforcement costs; and
vii. Royalty payments if not recovered through revenue requirement.

In 2017, EPCOR Southern Bruce was awarded $22 million under the Province's Natural Gas Grant Program (NGGP) for development of the Southern Bruce natural gas distribution system. On September 26, 2018, EPCOR received notification that the Province would not be providing any funding under the NGGP. As the project was not economically feasible without external funding, the OEB through a letter dated November 29, 2018 placed EPCOR Southern Bruce's original rates application and the leave to construct application in abeyance.

On December 21, 2018, EPCOR Southern Bruce received confirmation that the Southern Bruce expansion project was eligible for rate protection as available through *Bill 32, Access to Natural Gas Act, 2018*, which received Royal Assent on December 6, 2018. In the subsequent Ontario Regulation 24/19, Expansion of Natural Gas Distribution Systems (March 2019) the government confirmed that EPCOR Southern Bruce would receive the $22 million funding. EPCOR Southern Bruce then filed a revised application in April 2019.

EPCOR Southern Bruce requested the following approvals in this application:

1. An adjusted 10-year distribution revenue requirement of $58.5 million (net of external contributions).
2. A 10-year non-distribution revenue requirement of $27.1 million.
3. Recovery of $1.764 million over the 10-year rate stability period resulting from OEB revised timelines.
4. Upstream transportation costs.
5. Four rate classes and the associated fixed monthly charges and distribution rates.

6. Proposed revenue to cost ratios.
7. Several deferral and variance accounts.
8. A Proposed scorecard.
9. Proposed service and miscellaneous charges.
10. Approval of a 10-year custom incentive rate setting plan using an established stabilization factor and forecast inflation[7], and excluding a productivity and stretch factor.

A number of issues were settled between the parties, and EPCOR Southern Bruce filed a revised settlement proposal with the OEB on September 16, 2019. The following section discusses submissions on the unsettled issues and the OEB's findings.

[7] EB-2016-0137/0138/0139

4 UNSETTLED ISSUES AND OEB FINDINGS

The following issues were not settled:

- Proposed rates consistent with CIP (Issue 1b)
- Other revenues (Issue 3c)
- Recovery of additional revenue deficiency of $1.764 million (Issue 5a)
- Proposed rate classes and rates (Issues 6 a and c)
- Proposed cost allocation, rate design and revenue-to-cost ratios (Issue 6b)
- Deferral and Variance Accounts (Issues 7 a and b) – REDA, MTVA and ECVA
- Availability of Incremental Capital Module (Issue 8e)
- Proposed effective date of January 1, 2019 (Issue 10a)
- Rate riders to recover lost revenues from effective date (Issue 10b)
- Engagement with stakeholders (Issue 11) – no agreement with respect to EPCOR Southern Bruce's engagement with First Nations and Métis communities.

Issue 1b – Proposed Rates Consistent with CIP

The proposed rates were not specifically addressed in the submissions of the parties. The issue is dependent on the determination of the other unsettled issues in the proceeding.

Findings

The OEB has made determinations on the other unsettled issues that impact proposed rates. Subject to the matters and adjustments discussed within this Decision, the OEB concludes that EPCOR Southern Bruce's proposed rates are consistent with the CIP.

Issue 3 c – Other Revenues

EPCOR Southern Bruce proposed Other Revenues of $0 in its application. Other Revenues relate to non-recurring items and refer to revenues from other activities or work performed such as account information requests, bill reprint and returned cheque/payments.

OEB staff in its submission argued that since EPCOR Southern Bruce expects Other Revenues to occur during the IR period, Other Revenues of $0 for ratemaking purposes is not appropriate. OEB staff submitted that Other Revenues for EPCOR Southern Bruce should be based on EPCOR Natural Gas' Aylmer operations. OEB staff calculated Other Revenues for EPCOR Southern Bruce to be $43,292 annually or $432,915 for the ten-year period, using the Other Revenues for EPCOR Natural

Gas Aylmer as a proxy.[8] Alternatively, OEB staff recommended a deferral account to record actual Other Revenues.

EPCOR Southern Bruce objected to the amount proposed for Other Revenues by OEB staff. EPCOR Southern Bruce submitted that the Aylmer operations cannot be compared to the greenfield operations in the South Bruce region. EPCOR Southern Bruce further submitted that OEB staff's proposal was not consistent with the CIP. However, EPCOR Southern Bruce did not object to the establishment of a deferral account starting in 2022, provided that such a deferral account also records the incremental costs associated with providing services that attract specific service charges.

Findings

The OEB accepts EPCOR Southern Bruce's submission that it did not include in its CIP either the incremental costs or revenues associated with providing services that generate Other Revenues. The charges that generate Other Revenues should be based on the cost of providing that service therefore the net revenue should not be material. For the years 2019 to 2021, Other Revenues will be set at zero, given the greenfield nature of the utility. Whether a deferral account should be approved for 2022 for incremental net revenues can be determined in the 2022 IRM rate application.

However, the OEB notes that the specific service charges that EPCOR Southern Bruce will charge its customers were approved by the OEB as part of the Settlement Proposal.[9] The OEB considers these specific service charges an integral part of distribution services for gas customers that must be approved by the OEB.

Issue 5 a – Recovery of additional revenue deficiency of $1.764 million
Issue 10 a – Proposed effective date of January 1, 2019
Issue 10 b – Rate riders to recover lost revenues from effective date

These issues are related to each other and parties made submissions that linked the revenue deficiency to the effective date. These issues have therefore been discussed together.

In its application, EPCOR Southern Bruce proposed to true up the $75.6 million revenue requirement to address the delay in the review of its leave to construct

[8] EB-2018-0336
[9] EPCOR Natural Gas Settlement Proposal, EB-2018-0336, June 10, 2019, Table 20, p. 26.

application.[10] The change in timeline on the construction schedule has triggered a revenue deficiency of $1.764 million on a net present value basis compared to that included in EPCOR Southern Bruce's CIP proposal. In other words, the utility is seeking to recover costs caused by the delay and revenues that it will not be able to recover due to the delay in connecting the forecasted number of customers.

OEB staff, IGUA, VECC and SEC suggested delaying the start date of the 10-year rate stability period, from January 1, 2019 to the date of the first connection. If the start date is delayed, parties submitted that EPCOR Southern Bruce would be able to recover the revenue shortfall, as the end of the rate stability period would also be extended. Parties submitted that delaying the start date would eliminate the incremental revenue deficiency. IGUA, SEC and OEB staff argued that the OEB did not approve a specific start date in the competition proceeding and only approved a 10-year rate stability period. The schedule in the CIP was simply a way for the OEB to compare the proposals of both proponents.

SEC submitted that the delay in receiving leave to construct approval was not caused by the OEB but in part by EPCOR Southern Bruce. EPCOR Southern Bruce filed its leave to construct application on September 20, 2018.[11] The provincial government cancelled funding to EPCOR Southern Bruce for expansion of natural gas under the NGGP.[12] On November 29, 2018, the OEB informed EPCOR Southern Bruce that it was placing the application in abeyance as the project was not feasible without external funding. The funding was later restored through *Bill 32,* which received Royal Assent on December 6, 2018, and Ontario Regulation 24/19. EPCOR Southern Bruce filed an updated application on March 8, 2019 and received leave to construct approval on July 11, 2019.

SEC submitted that customers should not have to pay more because of a delay that was predicated on EPCOR Southern Bruce's management decision. The decision of EPCOR Southern Bruce to not proceed with the project without grant funding was entirely a decision within its control according to SEC. Accordingly, SEC submitted that ratepayers should not be at risk for the delay caused by the availability of grant funding.

In reply, EPCOR Southern Bruce referred to the decision on the issues list wherein the OEB determined that the effective date was established as part of the CIP and finalized the language of Issue 10 (a): Is EPCOR Southern Bruce's proposal for a January 1, 2019 effective date consistent with EPCOR Southern Bruce's CIP proposal? EPCOR

---

[10] Exhibit 6, Tab 1, Schedule 1, p.2.
[11] EB-2018-0263
[12] The Natural Gas Grant Program was discontinued and EPCOR Natural Gas LP was informed that there would be no transfer payments in a letter dated September 26, 2018.

Southern Bruce further added that any proposal to change the date would result in the change of a material common assumption on which EPCOR Southern Bruce submitted its CIP. Changing the rules after the fact would be unfair according to EPCOR Southern Bruce.

EPCOR Southern Bruce also disagreed with the suggestion of other parties to shift the start of the 10-year rate stability period to the date of the first customer connection (December 2019). EPCOR Southern Bruce noted that the utility will be a going concern and there will be ongoing revenues past the 10-year rate stability period. EPCOR Southern Bruce submitted that the ongoing expenses and revenues for years 11 and beyond (commencing January 1, 2029) were taken into account in the preparation of the CIP proposal. The proposal by OEB staff and intervenors to shift the start date treats revenues earned in year 11 as revenues during the 10-year rate stability period. EPCOR Southern Bruce stated that this was not the basis of the competitive CIP process.

EPCOR Southern Bruce clarified that the delay in receiving leave to construct approval was not driven by particular inaction on the part of the OEB. However, it noted that the factors were also beyond EPCOR Southern Bruce's control. EPCOR Southern Bruce submitted that it should be permitted to recover the revenue deficiency of $1.764 million through a rate rider over the 10-year rate stability period.

In its evidence, EPCOR Southern Bruce provided the drivers of the $1.764 million revenue deficiency. One of the drivers was delayed upstream charges. IGUA in its submission proposed that EPCOR Southern Bruce should be required to update the upstream charges that will be paid by EPCOR Southern Bruce. In reply, EPCOR Southern Bruce submitted that if it is required to update the upstream charges, then all other cost elements of the revenue deficiency should also be updated.

Findings

The OEB concludes that an effective date of January 1, 2019 was established as part of the CIP and was confirmed in the decision on the issues list. The delay in approval of the leave to construct application was not within EPCOR Southern Bruce's or the OEB's control. EPCOR Southern Bruce in its reply submission updated the schedule for connecting the first customers to December 2019 from November 2019. The OEB concludes that the foregone revenue from January 1, 2019 to December 1, 2019 remains part of the CIP 10-year revenue requirement. The OEB accepts EPCOR Southern Bruce's argument that it is not a matter of simply shifting the effective date because EPCOR Southern Bruce expects to generate revenues past the 10-year rate stability period ending in 2028. The OEB recognizes that EPCOR Southern Bruce considered revenues that would be generated in year 11 in development of its CIP.

However, the OEB notes that EPCOR Southern Bruce did not account for 2019 operating expenses when calculating the revenue deficiency for 2019. The OEB concludes that EPCOR Southern Bruce will only incur a portion of the operating, maintenance and administrative (OM&A) costs in 2019 that it had forecasted, as construction is still ongoing and customers have not been connected. In response to an interrogatory, EPCOR Southern Bruce has indicated that it will employ two gas fitters, two maintenance staff and one foreman for a total of five full-time field staff dedicated to the Southern Bruce operations. With the distribution system still under construction all five full-time field staff will not be required in 2019, especially the maintenance staff.[13] In its evidence, EPCOR Southern Bruce provided forecasted OM&A costs for 2019 at $555,000, which includes an adjustment for costs that have been capitalized ($338,000) for 2019. EPCOR Southern Bruce also noted that it intends to capitalize one full-time equivalent for the entire rate stability period. Other costs such as billing & collection, contractors & emergency services and shared services are also not likely to occur in significant proportion in 2019.[14]

The OEB concludes that a majority of the forecasted 2019 OM&A costs will not be incurred, but EPCOR Southern Bruce has not accounted for the decline in OM&A costs in its summary of revenue deficiency. The OEB has accordingly deducted 80% of the forecasted OM&A costs for 2019 (80% of $555,000) in determining a revenue deficiency number.

The summary of revenue deficiency as outlined in Table 6-2 of the evidence has been adjusted for the OM&A costs as noted above.

Table 2: Summary of Revenue Deficiency[15]

Description	NPV of Revenue Deficiency ($'000)
Change in customer connection profile – Forgone Revenues	2,324
Change in property taxes – Forgone Cost	(224)
Change in capital expenditure profile – Forgone Cost	(460)
Deferred recovery of upstream charges	124
Change in OM&A costs for 2019	(444)
Approved Revenue Deficiency	**1,320**

[13] Response to OEB staff IR#11
[14] Exhibit 4, Tab 1, Schedule 1, p. 7, Table 4-2
[15] Based on Table 6-2, Exhibit 6, Tab 1, Schedule 1, p.3

The OEB will approve the recovery of $1.32 million through a rate rider as proposed by EPCOR Southern Bruce. Contrary to the suggestions of IGUA, the OEB will not require EPCOR Southern Bruce to update any of the drivers of the revenue deficiency. EPCOR Southern Bruce shall re-calculate the rate riders based on the net foregone revenue of $1.32 million as approved by the OEB.

The OEB is approving rates on a final basis. There will therefore be no additional updates to the foregone revenue if there is a further delay to the connection of customers.

Issue 6 (a, b and c) – Cost Allocation and Rate Design

EPCOR Southern Bruce has proposed four rate classes in its application. Parties did not make submissions on the proposed rate classes and OEB staff indicated that it had no concerns with the proposed rate classes or the proposed split between fixed and variable charges. The focus of the submissions was on the proposed cost allocation and revenue-to-cost (RTC) ratios.

EPCOR Southern Bruce proposed the following RTC ratios in its application:

Table 3: Proposed Revenue-to-Cost Ratios

Rate Classes	RTC
Rate 1 – General Service	1.01
Rate 6 – Large Volume Gen. Service	0.78
Rate 11 – Large Volume Seasonal Service	1.35
Rate 16 – Contracted Firm Service	1.37
Overall	1.02

In support of its cost allocation proposal, the utility noted that it has proposed rates that are attractive enough that potential customers in all classes will attach to the system. EPCOR Southern Bruce further indicated that the long-term viability of the system requires that customer conversions reach levels as committed in the CIP. In the absence of these conversions, the system may be unable to generate sufficient revenues to support safe and reliable operations, potentially leading to material rate increases at the end of the rate stability period.[16]

In its submission on the Issues List, EPCOR Southern Bruce argued that in order to create the incentive for customers to convert to natural gas, it must have the flexibility to

[16] Exhibit 7, Tab 1, Schedule 1, p.5.

charge a tariff that is based on its understanding of the difference in cost compared to existing energy sources. This has resulted in a more “market-based” tariff rather than the one that is primarily based on cost allocation and RTC ratios.

OEB staff and SEC submitted that the RTC ratios should be within the OEB’s target range of 0.80 to 1.20. A higher ratio than 1.20 results in an unreasonable subsidy from one rate class to the other. Alternatively, OEB staff submitted that the RTC ratios could be as provided in staff IR#22.[17]

SEC submitted that the OEB should consider two principles in setting the RTC ratios. First, there must be an appropriate balance between the rate classes in terms of cross-subsidy and rates that are attractive to customers. Second, the OEB should ensure that customers will not experience a rate shock upon rebasing at the end of the 10-year rate stability period. Considering that the lowest RTC is 0.78 and the OEB’s policy floor is 0.8, SEC did not expect customers to experience a rate shock at rebasing.

IGUA submitted that EPCOR Southern Bruce had willingly assumed risk for controllable costs in the CIP. This included risks for achieving the required customer connections. IGUA argued that EPCOR Southern Bruce is now proposing to offload a portion of its customer connection risk to its two largest (Rate 16) customers and five Rate 11 customers. IGUA argued that this proposal should not be permitted. IGUA argued that EPCOR Southern Bruce has attempted to shield itself from the risk it has assumed as part of the CIP, by charging Rate 16 customers 137% and Rate 11 customers 135% of what it costs to serve them in order to subsidize Rate 6 customers.

IGUA further noted that EPCOR Southern Bruce had justified its departure from accepted ratemaking principles on the basis of the economic viability of the utility. IGUA submitted that this assertion has not been tested. IGUA argued that EPCOR Southern Bruce’s approach is a departure from the OEB’s long-applied policy which would have been assumed to apply during the CIP process. However, in securing the South Bruce franchise EPCOR Southern Bruce did not indicate at that time that it would seek to engineer rates to secure cross-subsidies from a particular customer class in favour of another customer class. IGUA argued that such a departure from conventional ratemaking should not be permitted after the fact.

IGUA further submitted that EPCOR Southern Bruce had provided no regulatory precedent or regulatory policy justification for its proposal to engineer rates to de-risk its competitively secured franchise investment. Accordingly, IGUA suggested that the OEB

---

[17] In response to Staff IR#22, EPCOR Southern Bruce recalculated the RTC ratios as 1.01 for Rate 1, 0.90 for Rate 6, 1.20 for Rate 11 and 1.22 for Rate 16.

should direct EPCOR Southern Bruce to file draft rates calculated on the basis of RTC ratios for all of its rate classes set to 1.0.

IGUA referred to a further subsidy that is being provided by Rate 16 customers. IGUA noted that EPCOR Southern Bruce has pooled the costs of its steel distribution mains into one asset group and the costs for both of these pipelines are allocated to the two Rate 16 customers. IGUA referred to EPCOR Southern Bruce's evidence that shows that of its seven pressure regulating and metering stations, three are located downstream of the Bruce Energy Centre, yet costs of all of the seven are allocated to the two Rate 16 customers.

IGUA submitted that the two Rate 16 customers that will be attached to the distribution system are both located upstream of the Bruce Energy Centre pressure and regulating station, and the Bruce Energy Centre to Kincardine NPS 6 steel pipeline. IGUA therefore submitted that EPCOR Southern Bruce should be further directed to exclude the costs for distribution facilities located downstream of the Bruce Energy Centre pressure regulation and metering station from allocation to Rate 16 customers.

In reply, EPCOR Southern Bruce reiterated its position that it has designed rates to attract customers to switch to natural gas. EPCOR Southern Bruce submitted that once a customer has connected, they will have the security of the 10-year rate stability period, ensuring that they continue to benefit from the economics that convinced them to connect.

In response to the suggested changes to the RTC ratios by parties and OEB staff, EPCOR Southern Bruce argued that while a RTC ratio of 1.0 for a rate class is assumed desirable, in practice a RTC ratio of 1.0 is rarely achieved and may in fact not be preferable. There may be other rate design objectives (e.g. customer attraction and retention) that could warrant a deviation from a RTC ratio of 1.0.

EPCOR Southern Bruce rejected the suggestions of OEB staff to modify the RTC ratios as per Staff IR#22, noting that the changes would increase the rates of Rate 6 customers by 8.5% to 9.2%, and could materially impact conversion rates as compared to the proposal of EPCOR Southern Bruce.

EPCOR Southern Bruce also disagreed with IGUA's assertion that EPCOR Southern Bruce's proposed rates represent an after-the-fact effort to offload customer connection risk onto certain rate classes. EPCOR Southern Bruce submitted that it presented market research results in the competition proceeding that showed that price was the number one reason for converting to natural gas.[18] EPCOR Southern Bruce noted that it is using the same methodology in proposing rates for all rate classes by targeting an energy savings of greater than 20% for each rate class in order to attract sufficient customers to sustain the new distribution utility.

EPCOR Southern Bruce submitted that as its cost allocation study is based on EPCOR's Aylmer operations with no operating history or customers in South Bruce, the cost allocation study results have to be interpreted with caution. EPCOR Southern Bruce submitted that if the OEB believes that the results of the limited cost allocation study should form the basis for initial rates, then the OEB's typical RTC ratio range should be broadened to not only take into account the uniqueness of the circumstances and in particular the objective of designing rates to maximize customer attachments. Accordingly, EPCOR Southern Bruce submitted that its cost allocation and rate design proposal was appropriate.

With respect to IGUA's argument that certain assets (steel pipelines, pressure regulating and metering stations) are inappropriately allocated to Rate 16 customers, EPCOR Southern Bruce submitted that IGUA was relying on incorrect assertions regarding the high-pressure system. EPCOR Southern Bruce clarified that the six-inch and eight-inch high-pressure lines operate as a single fully integrated high pressure system and the design of each element of the high pressure system is a function of all of the aggregate demands. Rate 16 was designed to address a customer meeting the minimum volume and term requirements, provided the customer is served off any location of the high-pressure system. EPCOR Southern Bruce submitted that the IGUA proposal to only include assets upstream of a customer's location would require the utility to create multiple rate zones based on the location of each Rate 16 customer. EPCOR Southern Bruce further noted that such a change could result in other rate classes advancing a similar argument that includes a combination of assets upstream of their location.

Findings

The OEB approves the cost allocation and rate design proposal of EPCOR Southern Bruce.

EPCOR Southern Bruce has proposed rates that result in the following revenue to cost ratios.

---

[18] EB-2016-0137/38/39, EPCOR CIP, October 16, 2017, Tab 5, p.18.

Rate 1 – General Service	1.01
Rate 6 – Large Volume Gen. Service	0.78
Rate 11 – Large Volume Seasonal Service	1.35
Rate 16 – Contracted Firm Service	1.37
Overall	1.02

When the OEB first adopted a cost allocation policy for electricity distributors in 2007 it determined that a range approach to RTC ratios was appropriate. The initial ranges were as narrow as 0.85 to 1.15 for some classes and as broad as 0.80 to 1.80 and 0.70 to 1.20 for other classes[19]. One of the reasons for the wider ranges initially was concern about data quality. The range approach has been maintained since then, though the ranges were narrowed as greater experience was gained with cost allocation[20].

The OEB's policy recognizes the assumptions and judgement that are inherent in allocating costs between customer classes. These assumptions are even greater for a greenfield utility that does not yet know how many customer connections it will have, the actual gas volumes or the actual costs for serving its new customers.

Furthermore, EPCOR Southern Bruce is held to the 10-year revenue requirement from the CIP. The OEB agrees that it needs the flexibility of a range approach to the RTC ratios to meet its connection forecasts. This can help ensure there is a viable utility to serve the customers of South Bruce into the future. Given the imprecision of the cost allocation exercise for a greenfield utility, the OEB concludes that EPCOR Southern Bruce's proposed RTC ratios are within the range of reasonable approaches.

The OEB will not require EPCOR Southern Bruce to make adjustments for certain assets that are claimed to be inappropriately allocated to Rate 16 customers. The OEB agrees with EPCOR Southern Bruce that pooling of assets in the designing of rates is a common approach. If rates are designed on the basis of assets upstream of a customer's location, multiple rate zones and rate classes would be required. This would lead to a complex and ineffective rate design.

[19] EB-2007-0667, Application of Cost Allocation for Electricity Distributors Report of the Board, November 28, 2007 p.p. 8-10
[20] EB-2010-0219 Report of the Board Review of Electricity Distribution Cost Allocation Policy March 31, 2011 p.34

Issue 7 a and b – Deferral and Variance Accounts

The request for three deferral and variance accounts (DVAs) was not settled as part of the settlement proposal. OEB staff, VECC, SEC and EPCOR Southern Bruce made submissions on the unsettled DVAs.

Regulatory Expense Deferral Account (REDA)

The REDA is intended to record costs associated with EPCOR Southern Bruce's participation in generic and Enbridge Gas Inc. proceedings that impact the utility. EPCOR Southern Bruce indicated that it included regulatory expenses in its OM&A forecast, but only related to its expected routine applications, annual IRM applications and expected Reporting and Recordkeeping Requirements of the OEB. EPCOR Southern Bruce requested the deferral account because a similar deferral account exists for the Aylmer franchise area.

In its submission, OEB staff noted that utilities are normally not granted a deferral account to record costs associated with participating in generic proceedings. This is a cost that should be absorbed by the utility within its OM&A costs. OEB staff referenced the evidence of EPCOR Southern Bruce wherein it noted that it expects REDA related costs to exceed the materiality threshold of $50,000.[21] OEB staff noted that the REDA account for the Aylmer franchise had not exceeded $50,000 in a given year and the costs incurred by Natural Resource Gas Limited (NRG), the predecessor utility to EPCOR Natural Gas (Aylmer), in 2014 and 2015 mainly reflected costs to complete the system integrity study and not to participate in generic proceedings. OEB staff argued that there was no evidence that costs to participate in generic proceedings are expected to exceed the materiality threshold. These costs can be absorbed within the existing OM&A budget and accordingly OEB staff submitted that there was no basis for granting the REDA.

SEC submitted that regulatory costs to participate in generic or Enbridge Gas proceedings should have been forecasted as part of the CIP. Union Gas the other competitive proponent would have included such costs in its proposal and it would be unfair to the competitive process to allow EPCOR Southern Bruce to recover these incremental costs.

In reply, EPCOR Southern Bruce submitted that the proposed REDA is appropriate and should be approved. EPCOR Southern Bruce noted that the OEB had consistently approved a REDA account for EPCOR's Aylmer operations on the grounds that the

[21] Response to OEB Staff IR#35.

costs to participate in generic proceedings are material for a small utility such as EPCOR Aylmer, and in the absence of a REDA, EPCOR Aylmer would refrain from participating in generic proceedings. EPCOR Southern Bruce further noted that it had no intent to utilize the REDA other than to participate in generic proceedings and would accept any clarifications along such lines in the accounting order.

Findings

The OEB will not approve the establishment of a REDA. Regulatory expenses are administration costs and the OEB does not consider administration costs to be outside of the approved CIP revenue requirement.

Municipal Tax Variance Account (MTVA)

The MTVA is meant to capture the difference between the forecasted municipal taxes in EPCOR Southern Bruce's OM&A and actual municipal taxes that are levied by the municipalities in a given year.

OEB staff, VECC and SEC opposed the establishment of the MTVA. OEB staff submitted that municipal taxes are part of OM&A costs and like any other costs, are approved on a forecast basis in all cost of service proceedings. OEB staff noted that there are other external costs similar to municipal taxes (such as insurance, rent, utilities and fuel) that are also beyond the control of management. However, deferral accounts are not granted for all external costs. OEB staff emphasized that ratemaking under cost of service is on a forecast basis and there is some risk for both the ratepayer and the utility. The utility in this case bears certain risks in relation to the forecast but it can also benefit from incurring lower costs from that which it forecast. OEB staff and SEC submitted that EPCOR Southern Bruce assumed the risk of its OM&A costs underpinning the revenue requirement that was approved in the CIP. Approval of the MTVA reduces a portion of the risk that EPCOR Southern Bruce has already assumed as part of the CIP. SEC submitted that it would not be fair to shift the risk to ratepayers after the competitive process.

VECC and SEC further submitted that the proposed account does not meet the requirement for materiality. SEC and OEB staff noted that the three main municipalities[22] have agreed to provide contributions equivalent to the municipal taxes. The only taxes that EPCOR Southern Bruce is liable for are school taxes or county taxes as well as taxes by those municipalities that its infrastructure will pass through, but will not receive service. SEC submitted that the materiality threshold of $50,000 a

[22] Municipalities of Kincardine, Arran-Elderslie and Huron-Kinloss.

year would only occur if all taxes across all municipalities, school boards and counties increased by 10%,[23] which is not realistic.

In reply, EPCOR Southern Bruce argued that the proposed MTVA protects both the ratepayer and the utility if municipal taxes differ from what was forecast in the CIP. EPCOR Southern Bruce noted that unlike a mature utility, the assessment base for EPCOR Southern Bruce has not been completed as the utility does not have assets in the ground. The assessment base as estimated for EPCOR Southern Bruce is subject to confirmation by the Province and the tax bill could be higher or lower than forecast.

EPCOR Southern Bruce further noted that the cost for municipal taxes in this case differs from a standard OM&A cost in that it was required to subtract the value of any municipal tax holidays from the 10-year OEB approved revenue requirement. As a result, EPCOR Southern Bruce subtracted a value of $2.208 million from the approved revenue requirement. However, this value is based on the estimated municipal taxes and the actual value could differ. EPCOR Southern Bruce submitted that the establishment of the MTVA protects both the ratepayer and the utility if municipal taxes differ from the forecast in the CIP. EPCOR Southern Bruce noted that it had no control over the variances in taxes and it was not expected to accept the risk for these variances during the competitive process. Accordingly, the establishment of the MTVA is both consistent with EPCOR Southern Bruce's CIP proposal and appropriate.

Findings

The OEB approves the establishment of the MTVA. Given that EPCOR Southern Bruce is a greenfield utility, the actual municipal tax assessment is still unknown. The costs can therefore be higher or lower than forecast. On this basis, the OEB agrees it is appropriate to record the difference between the forecast and the actual costs in a variance account for future disposition. However, the account will be established with an end date corresponding to the end of the rate stability period (i.e. December 31, 2028).

Energy Content Variance Account (ECVA)

The purpose of the ECVA is to record any variations in revenues and costs resulting from differences in the energy content of the gas actually delivered and the assumed energy content. The assumed energy content is 38.89MJ/M.[3]

OEB staff submitted that EPCOR Southern Bruce has assumed the volume risk as part of the CIP and therefore it should have considered all elements including the heat content in developing its CIP proposal and revenue requirement. By requesting an

[23] Response to OEB staff IR#36.

ECVA, OEB staff argued that EPCOR Southern Bruce is attempting to reduce a portion of the risk that it should have assumed as part of the CIP. OEB staff therefore submitted that the request for the ECVA should be denied.

While SEC did not articulate a specific position on the ECVA, VECC supported EPCOR Southern Bruce's request for the variance account. VECC noted that Enbridge Gas has a similar variance account to record changes in average use for the Enbridge Gas Distribution and Union Gas rate zones. VECC therefore submitted that EPCOR Southern Bruce's request for the ECVA is reasonable.

In reply, EPCOR Southern Bruce noted that during the CIP process, the proponents were required to develop common average use assumptions for each market other than industrial customers. EPCOR Southern Bruce worked with Union Gas (now, Enbridge Gas) to develop these projections. These projections were based directly on Union Gas' then current average use per customer for its adjacent markets. Enbridge Gas currently has a variance account to capture changes in average use for the Union Gas rate zone.

EPCOR Southern Bruce submitted that since it is proposing to sell gas volumetrically to its customers, the energy content of the gas inversely affects the volume of gas sold. Energy content of the gas directly affects the throughput on the system and the resulting distribution revenue. As the energy content was an element of the common assumptions of volume by customer type, EPCOR Southern Bruce indicated that it was not a risk that it accepted in developing its CIP proposal. EPCOR Southern Bruce maintained that the ECVA is required to allow for the recovery/refund of any under/over collection of revenue as a result of differences in the energy content and resulting quantity of gas delivered. EPCOR Southern Bruce further submitted that the account will provide equal protection to the utility and ratepayers, and it is both, consistent with the CIP and appropriate.

Findings

The OEB concludes that a variance in energy content of natural gas is outside of what was considered for the CIP, therefore the OEB approves the account. EPCOR Southern Bruce developed the common average use assumptions for each market with Union Gas (now Enbridge Gas) during the CIP process. These projections were based on Union Gas' average use per customer. The OEB notes that Enbridge Gas has variance accounts to record changes in average use that captures changes in consumption volumes due to among other things changes in the heat content, for both the Enbridge Gas Distribution and Union Gas rate zones.

The account will be established with an end date corresponding to the end of the rate stability period (i.e. December 31, 2028).

While common average use assumptions were used for the CIP, the OEB does expect all gas utilities to supply quality natural gas to their customers. Therefore, the OEB requires EPCOR Southern Bruce to report in its next rate application on the measures it has taken to supply natural gas that meets the energy requirements of its customers.

Issue 8 e – Availability of Incremental Capital Module (ICM)

EPCOR Southern Bruce has requested availability of an ICM as part of its Custom IR plan. This is to facilitate expansion beyond what was outlined in the CIP.

In its submission, OEB staff noted that the ICM and Advanced Capital Module mechanisms were not available for utilities setting rates under Custom IR such as EPCOR Southern Bruce.[24] OEB staff further submitted that if EPCOR Southern Bruce decided to connect additional communities, the OEB would need to address a number of issues under the OEB's existing policies (E.B.O. 188 and the generic community expansion policy) before determining whether funding can be made available. Since EPCOR Southern Bruce did not expect further expansion outside the CIP during the rate stability period, OEB staff was of the view that a determination of an appropriate capital funding mechanism was not required at this time.

VECC in its submission noted that granting of the franchise to EPCOR Southern Bruce was made on the basis of serving the entire franchise area. If EPCOR Southern Bruce wished to serve a new franchise, it would require a new application that would be subject to competition according to VECC. Accordingly, VECC submitted that this issue did not require a finding by the OEB.

SEC in its submission maintained that availability of ICM is inconsistent with the CIP process. SEC submitted that the CIP process required proponents to forecast the revenue requirement and the underpinning capital expenditure for the entire 10-year rate stability period. SEC was concerned that EPCOR Southern Bruce may avail the ICM to address capital cost overruns, a risk that it had assumed as part of the CIP. Accordingly, SEC submitted that the OEB should deny access to ICM. SEC noted that if EPCOR Southern Bruce experienced unforeseen costs, it had access to the Z-factor mechanism as part of its Custom IR.

In reply, EPCOR Southern Bruce noted that normally utilities setting rates under a Custom IR are historically mature utilities that have a long history of operation which allows them to develop detailed capital expenditure plans. Therefore, such utilities do not require access to ICM. Since EPCOR Southern Bruce is a greenfield utility, it does

[24] Handbook for Utility Rate Applications, October 13, 2016, p.27

not have the operational history necessary to develop a detailed capital expenditure plan. EPCOR Southern Bruce therefore submitted that access to an ICM may be necessary under certain circumstances.

Findings

The OEB has determined that an ICM will not be available for any matters related to the CIP during the 10-year rate stability period. EPCOR Southern Bruce did not include ICM eligibility as a criteria during the CIP process. The OEB concludes that any matter that goes beyond the CIP must be dealt with through the OEB's normal rate setting policies. Any expansions beyond what was contemplated in the CIP must be guided by the OEB's E.B.O. 188 guidelines, or whatever expansion policy the OEB has during the rate stability period. EPCOR Southern Bruce may also make use of a Z-factor for extraordinary and material events that are not within its control.

Issue 11 – Engagement with First Nations and Métis communities

This issue was partially settled. There was no agreement with respect to EPCOR Southern Bruce's engagement with First Nations and Métis communities.

Anwaatin's submission focused on EPCOR Southern Bruce's approach to consultation and relationships with Indigenous communities, the adequacy of EPCOR Southern Bruce's services for its Indigenous customers, and a proposal for a rate assistance program for low-income Indigenous customers. Anwaatin requested that its submissions be considered in light of the serious energy poverty issues faced by many Indigenous communities, and within the context of broad Indigenous rights and the duty to consult.

Anwaatin submitted that the OEB should consider and determine whether EPCOR Southern Bruce has adequately consulted with Indigenous communities, including executing the procedural duties delegated to it by the Crown. It further proposed the following conditions:

i. facilitate ongoing (i) communications with Indigenous communities as the archaeological assessment process and line construction continues and (ii) Indigenous monitoring of archaeological work and construction;

ii. establish, in consultation with Indigenous communities and within ninety (90) days of the OEB's Decision and Order in this proceeding, an ongoing utility-wide protocol governing archaeological assessments with Indigenous communities for all future construction, operations, maintenance/integrity programs, and pipeline replacements; and

iii. facilitate one-window, enhanced access to applications for low-income rates for Indigenous customers (both on- and off-reserve, as applicable) through a process coordinated directly by EPCOR Southern Bruce (not by a third-party community organization) that provides rate assistance to all low-income Indigenous customers and is not constrained to emergency financial assistance for customers who are in arrears.

In reply, EPCOR Southern Bruce submitted that Anwaatin had not identified any Aboriginal or treaty rights that could be impacted by the application, which is an application to set distribution rates under section 36 of the OEB Act. It further noted that its currently proposed distribution system will not serve any specific Indigenous community.

EPCOR Southern Bruce submitted that two of Anwaatin's proposed conditions related to construction and archaeological work were appropriately addressed through the leave-to-construct application, which granted EPCOR Southern Bruce authority to build its pipeline network.

Regarding the proposal for low-income rates for Indigenous customers, EPCOR Southern Bruce submitted that, to the extent the OEB is interested in this type of approach, it should be part of a province wide initiative, and not at a utility specific level. EPCOR Southern Bruce further noted that the costs of any such program would presumably have to be borne by other ratepayers, which is not contemplated in the proposed rate structure. Accordingly, EPCOR Southern Bruce submitted that the OEB should not impose any of Anwaatin's proposed conditions.

Findings

Anwaatin's proposed conditions are denied.

The OEB recognizes that the duty to consult is an important constitutional principle, and that in some cases the OEB will have a role in considering the adequacy of consultation efforts. The OEB takes this responsibility seriously, and has considered issues related to the duty to consult in numerous proceedings. However, the duty to consult is triggered where conduct is proposed that may adversely impact an Aboriginal or treaty right. Neither Anwaatin nor any other party have identified what Aboriginal or treaty rights are engaged or are potentially impacted by the current application. Even to the extent that the duty to consult is triggered by this application, no party has argued that consultation efforts have been inadequate.

The application before the OEB is a rates application under section 36 of the OEB Act. An approval under section 36 is not a specific authorization to build anything. The applicant previously obtained permission from the OEB to build its system through a leave to construct approval pursuant to section 90 of the OEB Act.[25] The OEB considered the duty to consult in that decision, and found that the applicant's consultation efforts had been satisfactory. In fact, no party in that case, including Anwaatin, argued that the duty to consult had not been discharged.

The OEB will not direct EPCOR Southern Bruce to "facilitate one-window, enhanced access to applications for low-income rates for Indigenous customers". The OEB is not entirely certain what exactly Anwaatin is proposing, but it appears that it wants to see a separate (and presumably lower) rate that will be available to low-income Indigenous ratepayers in EPCOR Southern Bruce's service territory. The submission provided no information on what the rate would be, how many customers might be eligible, how much revenue the utility would forego through the rate, and how (or even if) that revenue would be made up by the utility. Anwaatin also did not canvass any of these issues with EPCOR Southern Bruce through the interrogatory process.

Although the OEB appreciates that energy poverty is an issue in many Indigenous communities, it is not prepared to consider a utility specific remedy supported by so little evidence or details. The OEB further concludes that this is not a matter than should be addressed in isolation for the EPCOR Southern Bruce franchise area.

[25] EB-2018-0263, Decision and Order, July 11, 2019.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. EPCOR Southern Bruce shall file with the OEB, and forward to all intervenors a draft rate order attaching a proposed Tariff of Rates and Charges and accounting orders reflecting the OEB's findings in this Decision by **December 11, 2019**. The draft rate order shall include customer rate impacts and detailed supporting information showing the calculation of final rates.

2. Intervenors and OEB staff shall file any comments on the draft rate order with the OEB and forward them to EPCOR Southern Bruce on or before **December 18, 2019**.

3. EPCOR Southern Bruce shall file with the OEB and forward to the intervenors responses to any comments on its draft rate order on or before **January 6, 2020.**

4. Cost eligible intervenors shall file cost claims with the OEB and forward them to EPCOR Southern Bruce on or before **January 10, 2020**.

5. EPCOR Southern Bruce shall file with the OEB and forward to the intervenors any objections to the claimed costs by **January 16, 2020**.

6. Intervenors shall file with the OEB and forward to EPCOR Southern Bruce any responses to any objections for cost claims by **January 22, 2020**.

7. EPCOR Southern Bruce shall pay the OEB's costs of and incidental to this proceeding upon receipt of the OEB's invoice.

DATED at Toronto November 28, 2019

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar and Board Secretary

OEB Staff.3- Customer Volume Variance Account (CVVA)

Ref: 2023 Incentive Rate Adjustment Application, pages 21-36 and Appendix E

EPCOR requested approval to establish the CVVA to track the variance in revenue resulting from the difference between customer volume forecast based on common assumptions and the actual customer volume. The CVVA would track the variances for all mass market customers in Rate 1 and Rate 6. Volume variances related to seasonal Rate 11 and large commercial industrial rate customers would not be tracked in this account as their volumes were not forecast using common assumptions.

EPCOR requested that the CVVA be established as of the filing date of its application. Notwithstanding the effective date that is established for the CVVA, EPCOR requested that variances be recorded back to January 1, 2020, which is when the first mass market customer was connected to the Southern Bruce system. EPCOR proposed an end date for the CVVA corresponding to the end of the approved rate stability period (i.e. December 31, 2028).

EPCOR acknowledged that it should retain the risk related to customer attachments, as that was a CIP competitive parameter. EPCOR's draft accounting order for the CVVA stated that for EPCOR to retain the risk related to customer connection counts, the common assumption volumes per customer will be applied to the actual customer connections for each corresponding customer segment and rate class to determine the "Common Assumptions Customer Volume."

EPCOR provided the following methodology to calculate the CVVA balance each year:

$$\left(\begin{array}{c} \text{Customer Volume} \\ \text{Common Assumption by} \\ \text{Customer Type within a} \\ \text{Rate Class} \end{array} - \begin{array}{c} \text{Actual Customer} \\ \text{Volume by Customer} \\ \text{Type within a Rate} \\ \text{Class} \end{array} \right) \text{X} \quad \text{Tariff for Rate Class}$$

EPCOR stated that had Enbridge Gas (then known as Union Gas) been the successful proponent, consistent with the principle of not taking the risk related to common assumptions, it would have used its existing variance accounts (i.e. Normalized Average Consumption Variance Account (NACVA) and South Purchase Gas Variance Account (SPGVA)) to capture variances in consumption volumes.

EPCOR noted that it has an approved variance account relating to the energy content of the natural gas consumed [Energy Content Variance Account (ECVA)], but there is no variance account that addresses changes in consumption volume (increase or decrease) caused by other factors.

EPCOR stated that it intends to bring the balance recorded in the CVVA together with any carrying charges, forward for approval for disposition in its annual Incentive Rate Adjustment Applications once the balance has been audited, or at such other time as EPCOR may request and the OEB may order. EPCOR stated that the manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

EPCOR also provided the following table that highlights the impact on its revenues related to variances in consumption between the common assumptions used to set base rates and expected actual consumption.

Table 1.4

Summary Impact on Revenue ($)

	Forecasted Revenue	Col. 1 Total	Col. 2 Actual 2019	Col. 3 Actual 2020	Col. 4 Actual 2021	Col. 5 Forecast 2022	Col. 6 Forecast 2023	Col. 7 Forecast 2024	Col. 8 Forecast 2025	Col. 9 Forecast 2026	Col. 10 Forecast 2027	Col. 11 Forecast 2028
Row 1	CIP Common Assumptions	28,225,250	0	56,663	705,699	1,890,713	3,199,775	4,289,801	4,380,126	4,472,443	4,566,796	4,663,232
Row 2	Actual / Forecast	20,478,224	0	930	296,409	1,336,578	2,282,755	3,175,763	3,242,548	3,310,805	3,380,567	3,451,868
Row 3	Difference (negative = shortfall)	(7,747,026)	0	(55,733)	(409,290)	(554,135)	(917,020)	(1,114,038)	(1,137,578)	(1,161,638)	(1,186,229)	(1,211,364)

a) Please provide a list of the specific charges (e.g. delivery charges, upstream transportation charges, etc.) that are included in the "Tariff for Rate Class" aspect of the CVVA calculation.

EPCOR Response:

The Delivery Charge is the specific charge included in the Tariff for Rate Class aspect of the CVVA calculation.

b) Please provide a simple example that shows how the CVVA will ensure that EPCOR retains the risk associated with customer attachments. As part of this response, please include calculations for each the "Customer Volume Common Assumption" and "Actual Customer Volume."

EPCOR Response:

The table below illustrates that EPCOR retains the risk associated with customer attachments upon implementation of the CVVA.

Table 3 b. – Illustration of Customer Attachment Risk

		Calculation	Col. 1 Total	Col. 2 Actual 2019	Col. 3 Actual 2020	Col. 4 Actual 2021	Col. 5 Forecast 2022	Col. 6 Forecast 2023	Col. 7 Forecast 2024	Col. 8 Forecast 2025	Col. 9 Forecast 2026	Col. 10 Forecast 2027	Col. 11 Forecast 2028
Row 1	Customer Attachment Committed			0	100	200	300	400	500	600	700	800	900
Row 2	Customer Attachment Realized			0	70	140	210	280	350	420	490	560	630
Row 3	Difference (negative = shortfall)	R2 - R1		0	(30)	(60)	(90)	(120)	(150)	(180)	(210)	(240)	(270)
Row 4													
Row 5	Common Assumption Volume per Cx			2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Row 6	Actual Volume per Cx			1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
Row 7	Difference (negative = shortfall)	R6 - R5		(747)	(747)	(747)	(747)	(747)	(747)	(747)	(747)	(747)	(747)
Row 8													
Row 9	Assumed Volumetric Tariff (cents / m3)			29.2913	29.6841	30.0987	30.6142	31.0266	31.4452	31.8701	32.3013	32.7390	33.1832
Row 10													
Row 11	Tariff Revenue Realized ($)	R2 x R6 x R9 / 100	1,465,587	0	30,192	61,227	93,413	126,229	159,915	194,490	229,975	266,390	303,756
Row 12	Recovery from CVVA ($, excl. carrying cost)	(R2 x R5 X R9 / 100) - R11	753,471	0	15,522	31,477	48,025	64,895	82,213	99,989	118,232	136,954	156,164
Row 13	Total Revenue Realized ($)	R11 + R12	2,219,058	0	45,713	92,704	141,438	191,124	242,128	294,479	348,208	403,344	459,919
Row 14													
Row 15	Tariff Revenue under Committed Attachment ($)	R1 x R5 x R9 / 100	3,170,082	0	65,305	132,434	202,054	273,034	345,897	420,685	497,440	576,206	657,028
Row 16	Customer Attachment Risk ($)	R13 - R15	(951,025)	0	(19,591)	(39,730)	(60,616)	(81,910)	(103,769)	(126,205)	(149,232)	(172,862)	(197,108)

Row 11 above is the revenue that EPCOR would collect if realizing a lower than committed customer attachment. Row 12 is the CVVA disposal related to the consumption shortfall of actual customers attached to the system. Row 13 is the total revenue EPCOR would receive from the actual customers attached. Row 15 is the revenue EPCOR would realize if the customer attachments included in the CIP are realized and they consumed the volume of gas as per the common assumption. Row 16 is the revenue shortfall EPCOR would realize due to lower than committed customer attachment including collection of the CVVA for those customers that did attach. As shown, EPCOR would realize a revenue shortfall with implementation of the CVVA if EPCOR's actual customer attachment is lower than its committed attachment. That revenue shortfall would be equal to the customer shortfall times the common volume consumption assumption times the volumetric tariff (R3 x R5 x R9/100).

c) Please provide a summary table describing how the NACVA and SPGVA operate to true-up consumption variances for the Union Rate Zones and compare the operation of those accounts to EPCOR's proposed CVVA. As part of this response, please discuss if, and how, EPCOR intends to address weather normalization in the CVVA.

EPCOR Response:

Table 3 c) below summaries how Enbridge's NACVA and EPCOR's proposed CVVA would operate to true-up consumption variances.

Enbridge True-up Operation and Values[1]				EPCOR Values	
Line No.	Particulars		Rate 01	Rate 1	Comment for EPCOR Value
	Base Rates				
1	2019 Target NAC: m^3		2,852.7	2,149	CIP Common Consumption Assumption
2	2019 Actual NAC: m^3		2,880.0	1,440	Example of weather normalized NAC Consumption vs 1,453 actual consumption
3	Actual Changes in NAC: m^3 (line 1 – 2)		(27.2)	(709)	
	Y Factor Rates				
4	2019 Target NAC: m^3		2,762.1	N/A	Y Factor Rates not applicable as
5	2019 Actual NAC: m^3		2,880.0	N/A	EPCOR does not have a DSM
6	Actual Changes in NAC: m^3 (line 4 – 5)		(117.9)	N/A	program
7	2013 Board – approved number of Customers at December		323,287.0	2,474	Average forecast customers for 2022
	Base Rates				
8	Annual Volume Impact (10^3m^3)	1	(8,769.9)	(1,754.1)	
9	2019 Net Annual Average Delivery Rate (m^3)	2	0.1	0.28	Using rate for first $100m^3$/month in this simplified example
10	2019 Net Annual Average Storage Rate (m^3)	3	0.0	N/A	Storage costs not addressed in this variance account
11	Delivery Rate Annual Balance Amount ($000)	4	(736.2)	(491.1)	
12	Storage Rate Annual Balance Amount ($000)	4	(374.6)	N/A	Storage costs not addressed in this variance account
	Y Factor Rates				
13	Annual Volume Impact (10^3m^3)	1	(37,753.0)	N/A	
14	2019 Net Annual Average Delivery Rate ($/m^3$)	2	0.0	N/A	
15	2019 Net Annual Average Storage Rate ($/m^3$)	3	0.0	N/A	Y Factor Rates not applicable as EPCOR does not have a DSM
16	Delivery Rate Annual Balance Amount ($000)	4	(170.0)	N/A	program
17	Storage Rate Annual Balance Amount ($000)	4	(0.2)	N/A	
	Total Annual Balance Amounts ($000)				
18	Total Delivery Rate Annual Balance Amount (line 11+16)		(906.1)	(491.1)	
19	Total Storage Rate Annual Balance Amount (line 12+17)		(374.8)	N/A	
20	Storage Cost Annual Balance Amount ($000)		62.7	N/A	
21	Interest ($000)	5	(19.4)	------	Not calculated for this simplified example
22	Total Deferral Account Amounts ($000) (line 18+19+20+21)		(1,237.7)	(491.1)	

[1] EB-2020-0134 Enbridge Gas Inc. 2019 Utility Earnings and Disposition for Deferral & Variance Account Balances Application and Evidence, Exhibit E, Tab 1, Schedule 6, page 1 of 1

Notes (Enbridge)

1 The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.

2 The Net Annual Average Delivery Rate is the volume-weighted average of Board-approved monthly unit rates in effect

3 The Net Annual Average Storage Rate is the volume-weighted average of Board-approved monthly unit rates in effect

4 The annual revenue is obtained from a monthly calculation of volumes (lines 8 and 13) and the monthly unit delivery and storage rates (lines 9, 10, 14 and 15).

5 Interest is calculated to December 31, 2020.

For the CVVA, EPCOR intends to use the weather normalized actual consumption (”NAC”) to compare against the CIP common assumption volume. In calculating the NAC EPCOR intends to adopt the same methodology as EPCOR Aylmer, and use historical average and actual heating degree days specific to the South Bruce region (i.e. Kincardine), to weather normalize consumption. The weather normalized consumption will be captured as the NAC average consumption, which will be used to calculate the variance against the CIP annual volumes. Use of the proposed NAC is illustrated in Line 2 of Table 3 c) as the average customer volume variance in Line 3 will use the difference between the CIP common assumption volume and the NAC to calculate the difference in distribution revenue.

As summarized in the Enbridge notes included in the example, EPCOR proposes to use monthly customer and consumption data and weighted average of Board approved delivery charges to determine the annual value to be recognized in the CVVA. As a result of this, EPCOR proposes a change to the Draft Accounting Order included in Appendix E of the application. The proposed Draft Accounting Order is included in Appendix A of this document.

EPCOR determined that Enbridge’s SPGVA records variances in the per unit cost of gas purchased each month for Union’s Southern operations area and the unit costs of gas included in the approved gas sales rates. As Union’s gas sales rates include a gas energy content that varies according to the source of the gas purchased that quarter this account takes into account variances in energy content. EPCOR understands that this account is cleared through the QRAM for Union Rate Zones (EPCOR South Bruce’s equivalent of the PGCVA) and will not impact its NACVA, the equivalent of EPCOR’s requested CVVA. EPCOR’s PGCVA is the equivalent of Enbridge’s SPGVA and is also cleared quarterly through the QRAM. Like Enbridge, the PGCVA will not impact the CVVA, as the PGCVA captures the variances in gas commodity spend and have no impact on distribution revenue. The ECVA then records the variance between energy content of gas transported from Enbridge’s transmission system to South Bruce, and the Common Assumption made in the CIP. As a result, EPCOR’s ECVA and proposed CVVA do not have the same interaction as Enbridge’s NACVA and SPGVA.

d) Please discuss the operation of the CVVA in the context of the OEB-approved ECVA. Specifically, please discuss how EPCOR will ensure that variances in actual energy content relative to the assumed energy content used in determining EPCOR's revenue requirement are not captured in both the ECVA and the CVVA.

EPCOR Response:

EPCOR would propose to continue to operate the ECVA as is currently the case and to normalize the NAC used in the CVVA for any energy content variance that is recognized in the ECVA. This normalization would be accomplished using a ratio of the actual heat value to the rate setting heat value of 38.89. This will avoid any double counting of changes in consumption due to changes in energy content.

e) Please provide detailed calculations, along with the excel files, supporting Tables 1.4 and 1.5.

EPCOR Response:

Please refer to attachment EPCOR_IRR_OEBStaff3e_20220919.

f) For Table 1.6 Actual/Forecast Connection Count (Annual Average), please describe how the Annual Average is calculated for each rate class.

EPCOR Response:

EPCOR projected connection counts in years 2020 – 2024 based on existing customer additions and currently observed pace of customer unlocks for each rate class. In years 2025 -2028, we applied a general growth rate of 0.75%. Annual Average was taken as the average of the current and previous year's year-end customer count for each rate class.

g) In EPCOR's 2022 Gas Supply Plan update[4] proceeding, in response to OEB staff questions[5], EPCOR provided the following table.

Year	2020 GSP				2021 GSP Update				2022 GSP Update			
	Rate1	Rate6	Rate11	Total	Rate1	Rate 6	Rate 11	Total	Rate1	Rate 6	Rate 11	Total
2020	2,249	34	2	2,285	179	-	1	180	179	-	1	180
2021	3,616	56	5	3,677	2,614	40	3	2,657	1847	7	1	1,858
2022	4,248	78	5	4,331	3,703	56	6	3,765	3,112	21	6	3,139
2023	4,795	87	5	4,887	4,792	71	6	4,869	4,878	34	7	4,919
2024					5,039	91	6	5,136	5,829	34	7	5,870
2025									5,829	34	7	5,870

Please discuss why the customer connection forecast in the table above differs from the forecast in Table 1.6 in the current application.

EPCOR Response:

The customer connection forecast for the Gas Supply Plan is an updated version to the version that was included in the current application. The more recent version reflects an increase in customer applications for gas connections that EPCOR has experienced since the forecast was developed for the current application. As the requested CVVA account is a volume per customer account, changes in the number of customers attached will not impact the calculation of the account.

h) For Table 1.8 Actual/Forecast Volume by Rate Class, the total Actual 2020 Existing Residential only consumed 2,850m^3 with an Annual Average connection count of 81 residential customers. This implies the average customer used 35m^3 in 2020. Likewise, the average existing residential customer in 2021 used 836m^3. Please discuss why these numbers differ from the annual consumption of 1,453m^3 estimated by EPCOR in its application.

EPCOR Response:

For the 1,453 m3/yr estimated average annual volume, EPCOR reviewed Rate 1 residential customers that have at least 12 months of billed consumption history. Since customer connections happen throughout the year, dividing the annual customer consumption by the year-end customer will result in an under-estimate of annual consumption, as the customer count will reflect a number of customers that have less than a full years' worth of consumption.

i) Please comment on the extent to which the backdating of the CVVA to 2020 amounts to impermissible retroactive ratemaking.

EPCOR Response:

Backdating of the CVVA to 2020 does not amount to retroactive ratemaking. Rather doing so is consistent with and upholds the ten year regulatory compact that was central to the competitive process under which EPCOR was awarded a Certificate of Public Convenience and Necessity (CPCN) to construct the South Bruce gas distribution system and the subsequent 10-year custom incentive rate tariff. Certain elements of this regulatory package were meant to be competitive resulting in risk to the utility while other elements were meant to be non-competitive common assumptions which were not a risk. The average volume per customer was a common assumption and its forecasted value was the result of collaboration between EPCOR and Union and accepted by the Board. EPCOR had no reason to believe the actual average volume per customer would be materially different that the common element agreed upon as between EPCOR, Union and the Board. This fact has only recently come to light now that the South Bruce system has been operating for a period of time. In the context of a 10 year regulatory compact, it is only fitting that a discrepancy between a forecasted common assumption and its actual value, needs to be addressed. The requested CVVA restores the underlying risk apportionment of this 10 year deal.

As discussed in this application, the Board and proponents went through a multi-phase process in defining the agreed to competitive and regulatory framework for this community expansion. The process started with the generic proceeding to review gas expansion opportunities in the province and how those opportunities should be awarded if multiple utilities were interested in providing service. In its Community Expansion Decision the Board established the basic regulatory framework confirming that rates would cover a utility's costs, that there would be an extended forecast horizon during which the regulatory compact would hold, and how the risk sharing would work. The Board indicated that "A minimum rate stability period of 10 years (for example) would ensure that rates applied for are representative of the actual underpinning long-term costs." [2] The regulatory framework was further refined and finalized by the Board during the competitive process with the establishment of the Common Infrastructure Plan. Refinements included a more detailed definition of risk sharing between the utility and ratepayer and reaffirmed that this was a long-term 10-year regulatory agreement. There was also agreement as to when the 10-year period would begin "The OEB concludes that an effective date of January 1, 2019 was established as part of the CIP and was

[2] EB-2016-00004 Decision With Reasons, November 17, 2016, Section 6 OEB Findings, Page 20

confirmed in the decision on the issues list."[3] There was agreement that during the 10-year period, the utility would be able to cover the costs that were included in the winning proposal and thereafter confirmed in the subsequent rate case. Approval of this request to backdate the CVVA should therefore not be considered retroactive rate making but recognition that the variance account should be effective starting in 2020 in order to recognize the principle of the risk sharing compact that was agreed to by all parties and that EPCOR has been relying on this agreement as it has continued to buildout the distribution system and connect customers as committed to in that compact.

j) EPCOR has requested an effective date of January 1, 2020 for the CCVA. Please confirm if EPCOR intends to recover carrying charges from January 1, 2020 to the effective date of this decision for any amounts recorded for this period.

EPCOR Response:

EPCOR would intend to recover carrying charges from the effective date of the CCVA to the effective date of this decision.

k) Please discuss the impact on EPCOR Natural Gas Limited Partnership's financial viability in the following two scenarios:

i. The OEB does not approve the CVVA, which EPCOR forecasted to record a total debit balance of $7.48 million by 2028.

EPCOR Response:

The utility does not have the ability to absorb the losses through cost efficiencies or other means and as a result there would be a direct negative impact on the ROE of the utility. As detailed in Table 3 k) below, if the CVVA is not approved, the utility will substantially under earn, with a forecast average reduction of the utility's ROE for 2019 – 2028 of 3.97% with the greatest reduction in 2028 of 6.12%. This extended period of under earning will have a number of impacts on the utility, including its ability to expand. As an example, it will directly impact PI calculations through EBO 188, potentially increasing the requirement for upfront customer contributions, reducing the attractiveness of connecting to the system for certain customers.

In addition, without the CVVA, community expansions would be less likely to take place. As an example, EPCOR has recently been awarded a $22.0 million grant from the

[3] EB-2018-0264 Decision and Order, November 28, 2019, Findings, Page 11

Provincial Government to expand the distribution system into the Brockton area under the Phase 2 of the Natural Gas Expansion program. In applying for the grant EPCOR was required to use a common assumption for annual customer consumption of 2,200m^3. Without access to the CVVA, this community expansion would now become uneconomic. It would also put the utility at a direct disadvantage in competing for future expansion grants given that Enbridge currently has an approved NACVA that would address shortfalls in consumption between common assumptions and actual consumption.

Table 3k – Impact to ROE

		Unit	Col. 1 Weighted Average	Col. 2 Actual 2019	Col. 3 Actual 2020	Col. 4 Actual 2021	Col. 5 Forecast 2022	Col. 6 Forecast 2023	Col. 7 Forecast 2024	Col. 8 Forecast 2025	Col. 9 Forecast 2026	Col. 10 Forecast 2027	Col. 11 Forecast 2028
Row 1	Projected Rate Base in EB-2018-0264	$000s		20,920	50,663	60,186	60,940	60,885	60,319	59,114	57,621	56,320	54,940
Row 2													
Row 3	Deemed Equity	$000s		7,531	18,239	21,667	21,938	21,919	21,715	21,281	20,744	20,275	19,778
Row 4													
Row 5	Revenue Shortfall Related to Customer Volume Variance	$000s		0	(56)	(409)	(554)	(917)	(1,114)	(1,138)	(1,162)	(1,186)	(1,211)
Row 6													
Row 7	Impact to Realized ROE due to Revenue Shortfall	%	(3.97%)	0.00%	(0.31%)	(1.89%)	(2.53%)	(4.18%)	(5.13%)	(5.35%)	(5.60%)	(5.85%)	(6.12%)

ii. The OEB does approve the CVVA, however, the effective date is January 1, 2023 and is not applied retroactively to 2020 (forecasted deficit of $1.02 million).

EPCOR Response:

Approving the CVVA with an effective date of January 1, 2023 would allow the utility to earn an ROE aligned with expectations going forward but would not address the utility's under earning during 2019 – 2023. The $1.02 million shortfall is equal to approximately 8.8% of distribution revenue earned during that period.

l) Please discuss the impact on EPCOR Utilities Inc.'s financial viability in the following two scenarios:

i. The OEB does not approve the CVVA, which EPCOR forecasted to record a total debit balance of $7.48 million by 2028.

EPCOR Response:

EPCOR Utilities Inc. (EUI) would remain financially viable. However, this outcome would materially impact the utility's ROE and therefore EUI's willingness to further invest in the utility.

ii. The OEB does approve the CVVA, however, the effective date is January 1, 2023 and is not applied retroactively to 2020 (forecasted deficit of $1.02 million).

EPCOR Response:

EPCOR Utilities Inc. would remain financially viable.

m) Please provide evidence on EPCOR's proposed allocation and disposition methodologies for the CVVA.

EPCOR Response:

EPCOR is proposing to allocate the CVVA balance to Rate 1 and Rate 6 customers based on the proportion of actual distribution revenue as a percent of the total distribution revenue for Rate 1 and Rate 6 customers during the period of accumulation. This calculation would be completed monthly to account for any connection and volume variances.

i. Please provide a high-level estimate of the bill impact associated with the recovery of a $1 million debit balance from Rate 1 customers in 2024, which is the year when EPCOR expects the majority of Rate 1 customers to be connected.

EPCOR Response:

Refer to the table below:

		Col. 1	Col. 2	Col. 3
		Forecasted Tariff	Bill Determinant	Annual Amount ($)
Row 1	Distribution Charge			
Row 2				
Row 3	Monthly Charge ($ / cx / mth)	28.06	12	337
Row 4				
Row 5	Volumetric Charge			
Row 6	First 100 m3 (cents / m3)	28.9989	903	262
Row 7	Next 400 m3 (cents / m3)	28.4277	606	172
Row 8	Over 500 m3 (cents / m3)	27.5880	21	6
Row 9				
Row 10	Delay Rate Rider (cents / m3)	1.6330	1,530	25
Row 11				
Row 12	Upstream Recovery Charge (cents / m3)	1.4740	1,530	23
Row 13				
Row 14	Commodity (cents / m3)	30.3706	1,530	465
Row 15				
Row 16	Federal Carbon Charge (cents / m3)	14.52	1,530	222
Row 17				
Row 18	Total Billed Amount without CVVA			1,511
Row 19				
Row 20	CVVA Disposal			1,000,000
Row 21	2024 Rate 1 Year End Connection			5,375
Row 22	CVVA Disposal per Connection			186
Row 23				
Row 24	Bill Impact			12.31%

n) Please provide the total forecast CVVA debit (2020-2028) as a percentage of total actual/estimated distribution revenues (2020-2028) and for each year (2020-2028) provide the forecast CVVA debit as a percentage of the actual/estimated distribution revenue.

EPCOR Response:

Forecasted CVVA as a % of Actual / Estimated Distribution Revenue

		Col. 1 Total	Col. 2 Actual 2019	Col. 3 Actual 2020	Col. 4 Actual 2021	Col. 5 Forecast 2022	Col. 6 Forecast 2023	Col. 7 Forecast 2024	Col. 8 Forecast 2025	Col. 9 Forecast 2026	Col. 10 Forecast 2027	Col. 11 Forecast 2028
Row 1	Estimated Distribution Revenue	46,774,426	0	571,987	1,941,707	3,757,098	5,319,335	6,767,921	6,899,607	7,034,047	7,171,299	7,311,425
Row 2	Forecasted CVVA Disposal	7,785,402	0	56,117	410,457	556,650	921,697	1,119,720	1,143,380	1,167,562	1,192,279	1,217,541
Row 3	CVVA as % of Distribution Revenue	16.6%	0.0%	9.8%	21.1%	14.8%	17.3%	16.5%	16.6%	16.6%	16.6%	16.7%

o) Please provide the total forecast CVVA debit (2020-2028) as a percentage of the total OEB-approved Revenue Requirement (2020-2028) and for each year (2020-2028) provide the forecast CVVA debit as a percentage of the OEB-approved Revenue Requirement.

EPCOR Response:

Forecasted CVVA as a % of Actual / OEB Approved Distribution Revenue

		Col. 1 Total	Col. 2 Actual 2019	Col. 3 Actual 2020	Col. 4 Actual 2021	Col. 5 Forecast 2022	Col. 6 Forecast 2023	Col. 7 Forecast 2024	Col. 8 Forecast 2025	Col. 9 Forecast 2026	Col. 10 Forecast 2027	Col. 11 Forecast 2028
Row 1	OEB Approved Distribution Revenue	75,583,261	1,332,492	4,388,984	6,155,922	7,534,172	8,488,867	9,122,050	9,406,087	9,567,338	9,722,807	9,864,542
Row 2	Forecasted CVVA Disposal	7,785,402	0	56,117	410,457	556,650	921,697	1,119,720	1,143,380	1,167,562	1,192,279	1,217,541
Row 3	CVVA as % of Distribution Revenue	10.3%	0.0%	1.3%	6.7%	7.4%	10.9%	12.3%	12.2%	12.2%	12.3%	12.3%

p) Please advise whether EPCOR agrees that the establishment of the CVVA reflects a material change to the rate framework approved by the OEB in EPCOR's 2019-2028 rates proceeding.

EPCOR Response:

EPCOR does not agree that establishment of the CVVA reflects a material change to the rate framework approved by the OEB in EPCOR's 2019-2028 rates proceeding. As detailed in 3 i) above, the rate framework that was approved by the Board is the culmination of a multi-phase process that resulted in a well thought-out and balanced framework whose elements included a detailed risk sharing matrix, approved costs and revenue requirement. Approval of the CVVA is consistent with the OEB's approved risk sharing framework, as the utility has no control over and was never meant to assume risk over average customer consumption.

The 10-year revenue requirement approved by the OEB in EPCOR's 2019-2028 rates proceeding will remain unchanged. The CVVA will allow EPCOR to earn revenue in accordance with the approved revenue requirement. Should the CVVA not be approved, it would immediately place EPCOR in a significant revenue deficiency and result in the utility (a) chronically starting from a position of underearning for the next several years; and (b) not being able to expand the South Bruce gas distribution system. Setting rates on this basis will not allow EPCOR to earn a fair return on its investment. Further, it is contrary to standard ratemaking principles and the statutory objects in the Ontario Energy Board Act, 1998.

EPCOR would have applied for the CVVA in the 2019-2028 proceeding, however, the common customer consumption assumption as approved by all parties was based on historical consumption in adjacent regions and there was no indication that achieving it represented a material risk to the ratepayer or utility and therefore disadvantage either. While at this time there is a shortfall in average per customer consumption, this could potentially reverse itself over time as more customers switch out their water heaters to gas, add other gas appliances and new customers with stronger consumption profiles connect to the system. If that occurs, the CVVA would then serve to safeguard the ratepayers.

q) Please advise whether EPCOR agrees that the proposal to establish the CVVA is not a mechanistic issue that would typically be addressed in an annual update proceeding.

EPCOR Response: Agreed

i. Please advise whether EPCOR agrees that it is appropriate to address the typical issues (i.e. incentive rate adjustment and disposition of existing deferral account balances) as Phase 1 to this proceeding and a Phase 2 process can be established, subject to the OEB Panel's findings on this procedural matter, to address EPCOR's CVVA proposal.

EPCOR Response: Agreed

PART VII - REVIEW

40. Request

40.01 Subject to **Rule 40.02**, any person may bring a motion requesting the OEB to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision.

40.02 A person who was not a party to the proceeding to which the motion relates must first obtain the leave of the OEB by way of a motion before it may bring a motion under **Rule 40.01**.

40.03 The notice of motion for a motion under **Rule 40.01** shall include the information required under **Rule 42**, and shall be filed and served on all parties to the proceeding to which the motion relates within 20 calendar days of the date of the order or decision that is the subject of the motion.

40.04 Subject to **Rule 40.05**, a motion brought under **Rule 40.01** may also include a request to stay the implementation of the order or decision pending the determination of the motion.

40.05 For greater certainty, a request to stay shall not be made where a stay is precluded by statute.

40.06 In respect of a request to stay made in accordance with **Rule 40.04**, the OEB may order that the implementation of the order or decision be delayed, on conditions as it considers appropriate.

41. Powers of the OEB

41.01 The OEB may at any time initiate a review of one of its decisions or orders, and may confirm, vary, suspend or cancel the order or decision.

41.02 The OEB may at any time, without notice or a hearing of any kind, correct a typographical error, error of calculation or similar error made in one of its orders or decisions.

42. Motion to Review

42.01 Every notice of a motion made under **Rule 40.01**, in addition to the requirements under **Rule 8.02**, shall:

(a) set out the grounds for the motion, which grounds must be one or more of the following:

i. the OEB made a material and clearly identifiable error of fact, law or jurisdiction. For this purpose, (1) disagreement as to the weight that the OEB placed on any particular facts does not amount to an error of fact; and (2) disagreement as to how the OEB exercised its discretion does not amount to an error of law or jurisdiction unless the exercise of discretion involves an extricable error of law;

ii. new facts that have arisen since the decision or order was issued that, had they been available at the time of the proceeding to which the motion relates, could if proven reasonably be expected to have resulted in a material change to the decision or order; or

iii. facts which existed prior to the issuance of the decision or order but were unknown during the proceeding and could not have been discovered at the time by exercising reasonable diligence, and could if proven reasonably be expected to result in a material change to the decision or order;

(b) if sought, and subject to **Rule 40**, request a stay of the implementation of the order or decision or any part pending the determination of the motion;

(c) describe how the moving party’s interests are materially harmed by the decision or order;

(d) where the grounds include new facts and the new facts relate to a change in circumstances, explain whether the change in circumstances was within the control of the moving party;

(e) provide a clear explanation of why the motion should pass the threshold described in **Rule 43.01**; and

(f) set out the specific relief requested.

43. The Threshold Question and Determinations

43.01 In addition to its powers under **Rule 18.01**, prior to proceeding to hear a motion under **Rule 40.01** on its merits, the OEB may, with or without a hearing, consider a threshold question of whether the motion raises relevant issues material enough to warrant a review of the decision or order on the merits. Considerations may include:

(a) whether any alleged errors are in fact errors (as opposed to a disagreement regarding the weight the OEB applied to particular facts or how it exercised its discretion);

(b) whether any new facts, if proven, could reasonably have been placed on the record in the proceeding to which the motion relates;

(c) whether any new facts relating to a change in circumstances were within the control of the moving party;

(d) whether any alleged errors, or new facts, if proven, could reasonably be expected to result in a material change to the decision or order;

(e) whether the moving party's interests are materially harmed by the decision and order sufficient to warrant a full review on the merits; and

(f) where the grounds of the motion relate to a question of law or jurisdiction that is subject to appeal to the Divisional Court under section 33 of the *OEB Act*, whether the question of law or jurisdiction that is raised as a ground for the motion was raised in the proceeding to which the motion relates and was considered in that proceeding.

43.02 Where the OEB determines that the threshold in **Rule 43.01** has been passed, or where it has chosen not to consider the threshold, or where it is conducting a review on its own motion, it will hear the motion on its merits and decide whether to confirm, cancel, suspend or vary the decision or order.

43.03 The OEB will only cancel, suspend or vary a decision when it is clear that a material change to the decision or order is warranted based on one or more of the grounds set out in **Rule 42.01(a)**.