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

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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

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[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.

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[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