EPCOR Natural Gas Limited Partnership

Southern Bruce

2023 Customer Incentive Rate Adjustment Application

EB-2022-0184

Rates Effective: January 1, 2023

Filed: July 18, 2022

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CERTIFICATION OF EVIDENCE

The undersigned, being EPCOR Ontario Utilities Inc.'s Vice President, Ontario Region, Susannah Robinson hereby certifies for and on behalf of EPCOR Natural Gas Limited Partnership (ENGLP), as general partner of ENGLP that:

1. I am a senior officer of EPCOR Ontario Utilities Inc., which is the general partner of ENGLP;

2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's (the "**Board**") Filing Requirements for Natural Gas Rate Applications dated February 16, 2017; and

3. The evidence submitted in support of ENGLP's 2023 Incentive Rate Adjustment Application for its South Bruce operations, filed with the Board on July 18, 2022 is accurate, consistent and complete to the best of my knowledge.

4. The evidence filed in support of this application does not include any personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

DATED this 18th day of July, 2022

Susannah Robinson
Vice President, Ontario Region
EPCOR Ontario Utilities Inc.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Sched. B), as amended (the "**OEB Act**");

AND IN THE MATTER OF an application by EPCOR Natural Gas Limited Partnership pursuant to section 36(1) of the OEB Act for an order or orders approving or fixing just and reasonable rates and other charges for the sale and distribution of gas to be effective January 1, 2023 for the EPCOR Natural Gas Limited Partnership gas distribution system to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss.

APPLICATION

1. The Applicant, EPCOR Natural Gas Limited Partnership ("EPCOR"), is a wholly-owned indirect subsidiary of EPCOR Utilities Inc. ("EUI"). The general partner of EPCOR is EPCOR Ontario Utilities Inc. an Ontario corporation, and the sole limited partner is EPCOR Commercial Services Inc., an Alberta corporation (formerly EPCOR Power Development Corporation), which are both subsidiaries of EUI. EPCOR was formed pursuant to a limited partnership agreement, which provides that EPCOR Ontario Utilities Inc., as general partner, will control and have the full and exclusive power, authority and responsibility for the management and day-to-day operations of EPCOR. In accordance with the limited partnership agreement, EPCOR Commercial Services Inc., as limited partner, has an economic interest in the partnership but does not control or otherwise play a role in the day-to-day operations and management of EPCOR.

2. EPCOR has offices in the Town of Aylmer and Kincardine and carries on the business of selling and distributing natural gas within the Province of Ontario. EPCOR has operations in the Aylmer and Southern Bruce communities.

3. EPCOR filed a Custom Incentive Rate setting plan ("**Custom IR**") Application (EB-2018-0264) with the Ontario Energy Board ("**Board**") on October 2, 2018 (updated April 11, 2019) for South Bruce to seek approval for a tariff and other matters under which it would provide service to the South Bruce Municipalities. The Application sought approval for distribution rates based on a ten-year Custom IR effective January 1, 2019, establishment of certain deferral and variance accounts, approval of the proposed performance score card, and as well as further orders in all other respects to give effect

to the proposals described in that Application and Evidence.

4. The parties to EB-2018-0264 submitted a settlement proposal in which settlement on a number of issues was proposed. On October 3, 2019 the Board issued a Decision on Settlement Proposal and Procedural Order No. 6 in which it approved the settlement proposal. On November 28, 2019 the Board issued its Decision and Order in which it addressed outstanding issues that were not addressed in the approved settlement proposal and approved Southern Bruce's rates to be effective January 1, 2019. A final Rate Order was issued on January 9, 2020.

5. Consistent with EB-2019-0264, per the terms of the settlement proposal, and the rates application, EPCOR will file an annual Incentive Rate Adjustment ("**IR**"). This IR is to be applied to the Monthly Fixed Charge and Delivery Charge in each rate class and the Authorized Overrun and Unauthorized Overrun charges for Rates 11 & 16. The agreed to formula for determining the IR is as follows:

Incentive Rate Adjustment (IR) = [(1.0 – 0.314) x 0.0127] + [0.314 x Inflation (I)]

6. The Inflation factor ("I") will equal the inflation value the Board determines each year in its annual generic inflation amount. As of the filing date of this Application, the Board has not yet confirmed the 2-factor Input Price Index ("**IPI**") for use in 2023 rates. For the purposes of this Application, EPCOR has used an inflation factor of 3.3%, which is the IPI issued by the Board for electricity transmitters and electricity and natural gas distributors for the year 2022 (EB-2021-0212). Should this value change for 2023, EPCOR will file a revised submission accordingly.

7. Specifically in this application, EPCOR is applying for:

   a) An order or orders granting that distribution rates be updated effective January 1, 2023 and adjusted in accordance with the EB-2018-0264 Decision and Order, including adjusting the Monthly Fixed Charge and Delivery Charge for each rate class and the Authorized Overrun and Unauthorized Overrun charges for Rates 11 & 16 by the IR factor as calculated below.

   b) Approval to dispose of three approved deferral and variance accounts as part of this application (balances as of December 31, 2021):

- Energy Content Variance Account (“ECVA”)
- Contribution in Aid of Construction Variance Account (“CIACVA”)
- Municipal Taxes Variance Account (“MTVA”)

c) An Order or Orders allowing EPCOR to establish a new variance account called the Customer Volume Variance Account (“CVVA”), effective as of the date of this application, to enable the utility to track the variance in revenue resulting from the difference between forecasted customer volume and the actual customer volume for Rate 1 and 6 customers in its Southern Bruce operations. With respect to recording carrying charges on the balance in the Variance Account, simple interest will be calculated monthly on the opening balance in accordance with the methodology approved by the Board in EB-2016-0117.

d) An interim order establishing the Variance Account effective the date of this application to enable EPCOR to record costs in the proposed account in advance of the final decision of the Board.

e) Notwithstanding the effective date that is established for the Variance Account, an order permitting EPCOR to begin recording costs in this account from January 1, 2020 until December 31, 2028, which corresponds with the end of the utility’s approved rate stability period.

8. EPCOR has prepared an Excel workbook based on the 2023 Annual Incentive Rate Adjustment Model to support the calculation of rates in the Application. A live working version of this model has been filed as supporting material. A hard copy of the model is provided in Appendix A.

9. EPCOR seeks issuance of a Decision and Order by December 1, 2022, to ensure the implementation of 2023 rates by January 1, 2023. In the event that the Board does not issue a rate order by December 1, 2022 EPCOR requests that the Board issue an Interim Rate Order declaring the current distribution rates as interim until the decided implementation date of the approved 2023 distribution rates.

10. In the event that the Board’s implementation date for 2023 distribution rates is later than

the effective date, EPCOR requests permission to recover the incremental revenue from the effective date of January 1, 2023 to the implementation date through the implementation of a fixed-term rate rider.

11. EPCOR requests that, pursuant to Section 34.01 of the OEB's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

12. The persons affected by this Application are the ratepayers of EPCOR's Southern Bruce's service territory. Specifically for the CVVA, Rate 1 and Rate 6 customers will be affected.

13. EPCOR confirms that the Application and related documents will be published on its website (EPCOR.com).

Application Contact Information

EPCOR requests that copies of all documents filed with the Board in connection with this proceeding be served as follows:

Tim Hesselink
Senior Manager, Regulatory Affairs, Ontario
EPCOR Utilities Inc.

Address for personal service and mailing address:

43 Stewart Road
Collingwood, ON, L9Y 4M7

Telephone: (705) 445-1800 ext. 2274
E-Mail: Thesselink@epcor.com

Daniela O'Callaghan
Legal Counsel
EPCOR Utilities Inc.

Address for personal service and mailing address:

2000 – 10423 101 Street NW
Edmonton, Alberta T5H 0E8

Telephone: (780) 412-4081
E-Mail: DOCallaghan@epcor.com

Dated at Collingwood, Ontario this 18th day of July, 2022.

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Tim Hesselink
Senior Manager, Regulatory Affairs

MANAGER'S SUMMARY

Annual Incentive Rate Adjustment

The IR formula is as follows:

Incentive Rate Adjustment (IR) = [(1.0 – 0.314) x 0.0127] + [0.314 x Inflation (I)]

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

In the Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, the Board adopted a 2-factor Input Price Index ("IPI") methodology. The Board uses the year-over-year change in the GDP-IPI ("FDD"), and the Average Weekly Earnings ("AWE") All Employees-Ontario, to calculate the IPI. The percentage change is calculated as the weighted sum of 70% of the annual percentage change in the FDD for the prior year relative to the index value for two years prior and 30% of the annual percentage change in the AWE for the prior year relative to the data for years prior. For the purposes of this Application, EPCOR has used an inflation factor of 3.3%, which is the IPI issued by the Board for electricity transmitters and electricity and natural gas distributors for the year 2022 (EB-2021-0212). Should this value change, EPCOR will file a revised submission accordingly.

The calculation of the IR is as follows: I**R = [(1.0 – 0.314) x 0.0127] + [0.314 x 0.0330] = 0.0191**

The IR of 1.91% has been used in the 2023 Annual Incentive Rate Adjustment model to determine the proposed distribution rates. The IR has been applied to the Monthly Fixed Charge and Delivery Charge in each rate class. It has also been applied to the Authorized and Unauthorized Overrun Charges for Rate 11 and 16 Customers. EPCOR continues to connect customers as part of the Southern Bruce project and forecast values for customer connections and volumes are consistent with the projections included in the 2022 Annual Update to the Gas Supply Plan (EB-2021-0146).

For comparison purposes, Tables 1 and 2 following, provide the current and proposed distribution rates:

Table 1 - Current Distribution Rates

Rate Class		Fixed Monthly Base	Bill 32 Rate	Delivery Charge Tier 1	Delivery Charge Tier 2	Delivery Charge Tier 3	Delivery Charge Contract Demand	Gas Supply	Upstream Recovery Charge	Transportation & Storage Charge	Transportation Charge From Dawn	Transportation Charge From Kirkwall	Transportation Charge From Parkway	Federal Carbon Charge
		$/month	$/month	¢ / m3	¢ / m3	¢ / m3	¢ /contracted m3	¢ / m3	(A)	¢ / m3	¢ /contracted m3	¢ /contracted m3	¢ /contracted m3	¢ / m3
Rate 1	General Firm Service	26.27	1.00	28.1486	27.5941	26.7790		30.3706	1.4740	2.6982				9.79
Rate 6	Large Volume General Firm Service	107.16	1.00	25.9678	23.3710	22.2023		30.3706	2.9200	5.6413				9.79
Rate 11	Large Volume Seasonal Service	214.31	1.00	16.1303	16.1303	16.1303		30.3706	0.0352	1.8166				9.79
Rate 16	Contracted Firm Service	1,575.78	1.00				107.4831		14.2434		18.2999	11.8480	11.8480	9.79

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

Table 2 - Proposed Distribution Rates

Rate Class		Fixed Monthly Base	Bill 32 Rate	Delivery Charge Tier 1	Delivery Charge Tier 2	Delivery Charge Tier 3	Delivery Charge Contract Demand	Gas Supply	Upstream Recovery Charge	Transportation & Storage Charge	Transportation Charge From Dawn	Transportation Charge From Kirkwall	Transportation Charge From Parkway	Federal Carbon Charge
		$/month	$/month	¢ / m3	¢ / m3	¢ / m3	¢ /contracted m3	¢ /m3	(A)	¢ / m3	¢ /contracted m3	¢ /contracted m3	¢ /contracted m3	¢ / m3
Rate 1	General Firm Service	26.77	1.00	28.6862	28.1211	27.2905		30.3706	1.4740	2.6982				9.79
Rate 6	Large Volume General Firm Service	109.21	1.00	26.4638	23.8174	22.6264		30.3706	2.9200	5.6413				9.79
Rate 11	Large Volume Seasonal Service	218.40	1.00	16.4384	16.4384	16.4384		30.3706	0.0352	1.8166				9.79
Rate 16	Contracted Firm Service	1,605.88	1.00				109.5360		14.2434		18.2999	11.8480	11.8480	9.79

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

Deferral and Variance Accounts

In Rate Order EB-2018-0264[1], EPCOR was granted approval to establish the following deferral and variance accounts:

a) Purchased Gas Commodity Variance Account
b) Gas Purchase Rebalancing Account
c) Storage and Transportation Variance Account for Rates 1, 6 and 11
d) Transportation Variance Account for Rate 16
e) Unaccounted for Gas Variance Account
f) Greenhouse Gas Emissions Administration Deferral Account
g) Federal Carbon Charge – Customer Variance Account
h) Federal Carbon Charge – Facility Deferral/Variance Account
i) Municipal Tax Variance Account
j) Energy Content Variance Account
k) Contribution in Aid of Construction Variance Account
l) External Funding Variance Account

In Rate Order EB-2021-0216[2], EPCOR was granted approval to establish the following deferral and variance accounts:

m) Approved Deferral/Variance Disposal Account
n) Other Revenues Deferral Account

In addition, EPCOR received approval to modify the wording of the Municipal Tax Variance Account to align with the intent of the original CIP decision.[3]

[1] EB-2018-0264 Rate Order, January 9, 2020, Schedule B
[2] EB-2021-0216 Decision & Order, December 9, 2021, Page 9/EB-2021-0216 Rate Order, February 17, 2022 Page 5
[3] EB-2021-0216 Rate Order, February 17, 2022 Page 9

As part of this application, EPCOR is seeking disposition to approve of the December 31, 2021 audited balances of:

a) Energy Content Variance Account ("ECVA")
b) Contribution in Aid of Construction Variance Account ("CIACVA")
c) Municipal Tax Variance Account ("MTVA")

The auditor's report on the December 31, 2021 balances for each of the three accounts above has been included as part of this Application in Appendix D.

A summary of the account balances can be seen below in Table 3:

Table 3 – Deferral Accounts Requested for Disposition

Account	Balance Dec 31, 2021	2021 Carrying Charges	2022 Carrying Charges	Balance Dec 31, 2022
CIACVA	$ 304,568	$ -	$ 4,561	**$ 309,129**
ECVA	$ 26,734	$ -	$ 400	**$ 27,134**
MTVA	$ (280,946)	$ (323)	$(4,207)	**$ (285,477)**
Total	**$ 50,356**	**$ (323)**	**$ 754**	**$ 50,786**

2022 carrying charges have been calculated using the OEB's prescribed rates for Q1-Q3 and projected using the Q3 rate for Q4 2021.

Q1	0.57%
Q2	1.02%
Q3	2.20%
Q4	2.20%
Annual	**1.50%**

Note that this rate is a variance from the Auditor's report in Appendix D, as the report was in preparation before the Q3 rate was published.

Energy Content Variance Account

The Energy Content Variance Account ("ECVA") records differences in variable revenues resulting from differences in the energy content of the gas actually delivered and the assumed energy content of 38.89MJ/M3 used in determining EPCOR Southern Bruce's revenue requirement and delivery rates as approved in EB-2018-0264. Differences in the energy content of the gas delivered from the assumed energy content would impact the actual volumes delivered thereby impacting the amount of revenue collected over EPCOR's 10-year rate stability period.

As per the ECVA accounting order[4]: the audited balance in this account, together with carrying charges, will be brought forward for approval for disposition on an annual basis. The balance in this account will be apportioned to Rates 1, 6 and 11 based on forecasted volumes underpinning CIP revenues for each rate class.

The calculation of the projected total amount proposed for disposal is summarized in Table 4 below and further details of the specific items making up these balances are provided in the continuity schedule in Appendix D.

Table 4 - Projected Total ECVA Amount for Disposal

ECVA	Balance 31-Dec-21	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Balance 31-Dec-22
		0.57%	1.02%	2.20%	2.20%	
Principal	$26,734					$26,734
Carrying Charges		$38	$68	$147	$147	$400
Total	$26,734	$38	$68	$147	$147	**$27,134**

Balance Allocation:

EPCOR is proposing to allocate the balance in this account will be apportioned to Rates 1, 6 and 11 based on forecasted volumes underpinning CIP revenues for each rate class, Consistent with the approved account order.

As per EB-2018-0264, Exhibit 3, Tab 1, Schedule 2, pg. 3, the CIP volumes for 2023 are:

[4] EB-2018-0264 Rate Order, January 9, 2020, page 30 of 34

Table 5 – CIP Forecasted Volumes

Rate Class	2023 Volumes	% of Total
Rate 1	10,497,651	69.7%
Rate 6	3,209,649	21.3%
Rate 11	1,353,326	9.0%
Total	15,060,626	100.0%

Balance Recovery

EPCOR proposes to recover the costs as allocated above from customers in rates 1, 6 and 11 based on revised forecast volumes. The ECVA balances are proposed to be recovered through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2023. The calculation of the proposed rate rider is shown in Table 6 below.

Table 6 - Calculation of Proposed ECVA Rate Rider

		A Unit	B Row Sum	C Rate 1	D Rate 6	E Rate 11
1	Volume	m3	8,897,276	5,502,795	2,081,332	1,313,149
2	Allocation	%	100%	69.7%	21.3%	9.0%
3	Sum	$	$27,134	$18,913	$5,783	$2,438
4	**Rate Rider**	**¢/m3**		**0.3437**	**0.2778**	**0.1857**

Rate 16 2022 Adjustment

During the preparation of this application, EPCOR staff noted an error in the approved rate schedule for Rate 16 customers regarding the Energy Content Variance Account (ECVA) rate rider effective January 1, 2023 and requested a correction as part of ENGLP Southern Bruce July 2022 QRAM application (EB-2022-0173)[5].

Due to a clerical error, the 2022 ECVA rate rider was incorrectly added to the draft rate order and approved in EB-2021-0216 Decision and Order, December 6, 2021, page 20 of 27.

[5] ENGLP_EB-2022-0174_RateOrder_QRAM_JUL2022_20220623

As this was an approved rate rider, EPCOR had billed this rate rider to four Rate 16 accounts since its commencement date of January 1, 2022 until June 27, 2022.

In the June 27, 2022 EB-2022-0173 decision and order, EPCOR was approved to remove the error and rebate the amounts as soon as feasible. EPCOR was also instructed to report back to the OEB on details of the correction, which is provided in the section below.

Correction and Customer Recovery

Three accounts were impacted by this error, totalling $676.68.

	Amount Billed
Customer 1	$63.52
Customer 2	$452.14
Customer 3	$161.02
Total	**$676.68**

Once approval was received in EB-2022-0173, EPCOR immediately credited the amounts owing to customers, which was included on bills issued July 2022.

Contribution in Aid of Construction Variance Account

The Contribution in Aid of Construction Variance Account ("CIACVA") records the revenue requirement impact of any differences between the actual capital contributions that EPCOR Southern Bruce pays to Enbridge Gas/Union Gas related to Enbridge's Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the capital contribution included for these projects for the purposes of determining EPCOR's approved rates

As per the CIACVA accounting order[6]: the balance in this account, together with carrying charges, will be brought forward for disposition on an annual basis at which time EPCOR will propose a methodology and timing for disposition of the balance that aligns with customers' use of the capacity and EPCOR's rate smoothing objectives.

The calculation of the projected total amount proposed for disposal is summarized in Table 7 below and further details of the specific items making up these balances are provided in the continuity schedule in Appendix D.

Table 7 - Projected Total CIACVA Amount for Disposal

CIACVA	Balance 31-Dec-21	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Balance 31-Dec-22
		0.57%	1.02%	2.20%	2.20%	
Principal	$304,568					$304,568
Carrying Charges	$0	$434	$777	$1,675	$1,675	$4,561
Total	$304,568	$434	$777	$1,675	$1,675	**$309,129**

Balance Allocation:

Consistent with the final decision of EPCOR's 2022 rate application[7], EPCOR proposes to allocate the CIACVA balance based on the CIP distribution and non-distribution rate base for all rate classes.

[6] EB-2018-0264 Rate Order, January 9, 2020, page 30 of 34
[7] EB-2021-0216 Decision & Order, December 9, 2021, page 6

Referencing: EB-2018-0624, Exhibit 7, Tab 1, Schedule 2, Table 7-25:

Table 8 – CIP Rate Base

	Unit	Sum	Rate 1	Rate 6	Rate 11	Rate 16
Rate Base	$000's	54,946	32,657	11,611	1,418	9,261
Allocation	%	100%	59%	21%	3%	17%

Balance Recovery

EPCOR proposes to recover costs from customers in rates 1, 6, 11 and 16 (all rate classes) based on revised forecast volumes allocated by rate base referenced in Table 8 above. The CIACVA balances are proposed to be recovered through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2023. The calculation of the proposed rate rider is shown in Table 9 below. Rate riders for rates 1,6 & 11 are projected based on m3 volumes and rate 16 is based on monthly contract demand (CD).

Table 9 - Calculation of Proposed CIACVA Rate Rider

		A	B	C	D	E	F	G
		Unit	**Row Sum**	**Rate 1**	**Rate 6**	**Rate 11**	**Unit**	**Rate 16**
1	Volume	m3	8,897,276	5,502,795	2,081,332	1,313,149	CD	95,824
2	Allocation	%	100%	59%	21%	3%	%	17%
3	Sum	$	$309,129	$183,729	$65,322	$7,976	$	$52,102
4	**Rate Rider**	**¢/m3**		**3.3388**	**3.1385**	**0.6074**	**¢/CD/month**	**4.5311**

Municipal Tax Variance Account

The establishment of the MTVA was approved by the OEB in EPCOR's Custom IR application for 2019 to 2028 rate application and modified as part of the Decision and Order of Phase 2 of ENGLP's 2022 rate application[8].

As per the approved accounting order, the Municipal Tax Variance Account (”MTVA”) is to record the difference between the actual annual municipal taxes paid, net of municipal contributions related to municipal taxes, and the net municipal taxes billed to customers by ENGLP. The effective date of this account is January 1, 2019.

Net municipal taxes billed to customers by EPCOR is calculated by multiplying the annual distribution revenues billed to customers and accrued for the year by the proportion of annual municipal taxes included in the annual revenue requirement for EPCOR's Southern Bruce operations as approved in EB- 2018-0264 for each year of the rate stability period.

The calculation of the projected total amount proposed for disposal is summarized in Table 10 below and further details of the specific items making up these balances are provided in the continuity schedule in Appendix D.

Table 10 - Projected Total MTVA Amount for Disposal

MTVA	**Balance 31-Dec-21**	**Q1 2022** 0.57%	**Q2 2022** 1.02%	**Q3 2022** 2.20%	**Q4 2022** 2.20%	**Balance 31-Dec-22**
Principal	($280,946)					($280,946)
Carrying Charges	($323)	($400)	($716)	($1,545)	($1,545)	($4,531)
Total	($281,269)	($400)	($716)	($1,545)	($1,545)	**($285,477)**

Balance Allocation:

EPCOR proposes to allocate the MTVA balance based on the total CIP distribution and non-distribution rate base for all rate classes (consistent with the CIACVA).

[8] EB-2021-0216, Decision and Order (Phase 1 and Phase 2), February 17, 2022, page 11 of 15

Table 11 – CIP Rate Base

	Unit	Sum	Rate 1	Rate 6	Rate 11	Rate 16
Rate Base	$000's	54,946	32,657	11,611	1,418	9,261
Allocation	%	100%	59%	21%	3%	17%

Balance Recovery

EPCOR proposes to recover costs from customers in rates 1, 6, 11 and 16 (all rate classes) based on revised forecast volumes allocated by rate base referenced in Table 10 above. The MTVA balances are proposed to be recovered through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2023. The calculation of the proposed rate rider is shown in Table 9 below. Rate riders for rates 1,6 & 11 are projected based on m3 volumes and rate 16 is based on monthly contract demand (CD).

Table 12 - Calculation of Proposed MTVA Rate Rider

		A **Unit**	B **Row Sum**	C **Rate 1**	D **Rate 6**	E **Rate 11**	F **Unit**	G **Rate 16**
1	Volume	m3	8,897,276	5,502,795	2,081,332	1,313,149	CD	95,824
2	Allocation	%	100%	59%	21%	3%	%	17%
3	Sum	$	-$285,477	-$169,672	-$60,324	-$7,366	$	-$48,116
4	**Rate Rider**	**¢/m3**		**-3.0834**	**-2.8983**	**-0.5609**	**¢/CD/month**	**-4.1844**

Bill Impacts

The following table provides a summary of bill impacts for each rate class assuming the average consumption level of the rate class based on the forecasted 2023 customer connections and volumes. The bill impact provided assumes a full 12 months of distribution service and consumption. Further details on the bill impacts as summarized below are provided in the 2023 Incentive Rate Adjustment Model.

Table 13 – Illustrative Bill Impact Summary

Rate Class	Description	Fixed Change ($/year)	Volumetric Change ($/year)	Rate Riders ($/year)	Total Change ($/year)	Total Change %
Rate 1	Existing Residential	6.02	11.43	(12.98)	4.47	0.23%
Rate 1	New Residential	6.02	10.99	(12.48)	4.53	0.24%
Rate 1	Small Commercial	6.02	24.70	(28.36)	2.37	0.06%
Rate 1	Small Agricultural	6.02	24.84	(28.52)	2.34	0.06%
Rate 6	Medium Commercial	24.56	125.10	(268.42)	(118.76)	(0.55%)
Rate 6	Large Commercial	24.56	338.48	(754.30)	(391.26)	(0.68%)
Rate 11	Sample Dryer 1	49.12	312.71	188.14	549.97	0.88%
Rate 11	Sample Dryer 2	49.12	1,042.36	627.14	1,718.62	0.94%
Rate 16	Contracted Demand	361.17	12,317.56	(8,460.09)	4,218.64	0.45%

[1] Existing Residential and New Residential are standard categories that were included in EPCOR's Common Infrastructure Plan ("CIP") (EB-2016-0137 / 0138 / 0139). A New Residential is considered a newly constructed building whereas an Existing Residential is considered a building that was existing as of the time that the CIP was submitted. EPCOR has maintained these categories in this application to ensure consistency with the CIP.

Customer Volume Variance Account Application

Background

EPCOR is developing a greenfield natural gas distribution utility ("Southern Bruce") to service the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss (collectively the "South Bruce Municipalities"). The Southern Bruce operations connected its first customer in the third quarter of 2019 and has continued to build out the system and connect new customers.

The Southern Bruce operations are the outcome of a generic proceeding commenced by the Ontario Energy Board (the "Board") to review opportunities for natural gas expansion in the province (EB-2016-0004). The Board held a competitive process to determine which utility would receive Certificates of Public Convenience and Necessity ("CPCN") for the Southern Bruce Municipalities[9]. EPCOR was the successful proponent of that competitive process and received the necessary CPCNs on April 12, 2018.

A key element of the competitive process was the development of Common Infrastructure Plan Applications ("CIP") by EPCOR and Union Energy (now Enbridge) ("the proponents"). The CIP submissions detailed the proponents' revenue requirement to serve the Southern Bruce Municipalities. The Board relied on these submissions in making its determination as to which proposal was most favorable to customers. In deriving their respective revenue requirements, the proponents incorporated certain common assumptions as well as competitive parameters.

Generally, proponents did not accept the risk associated with variances in their common assumptions, which includes forecast volume consumed by mass market customers. In contrast, the Board determined that proponents would take the risk on achieving certain competitive parameters, which included elements such as the capital cost to build out the distribution system and the number and timing of connecting customers to the system.

EPCOR has recorded consumption volumes since connecting its first Southern Bruce customer

[9] EB-2016-0137 / EB-2016-0138 / EB-2016-0139 Southern Bruce Expansion Applications

and determined that for some classes of mass market customers, their actual consumption is less than the forecasted value included as a common assumption in the CIP. This variance has resulted in a material under-generation of revenue for EPCOR.

The Variance Account would address this revenue shortfall and track variances between the forecasted and actual volumes consumed by Rate 1 and 6 customers, as such forecasts were part of the CIP common assumptions and therefore not a category of risk accepted by the utility.. Volume variances related to seasonal Rate 11 and large commercial or industrial Rate 16 customers would not be tracked in the Variance Account as their volumes were not forecast using common assumptions.

EPCOR requests that the Variance Account be established as of the date of this filing.

EPCOR proposes to bring the balance in the Variance Account, 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 Board may order.

As it relates to the Variance Account, EPCOR submits that it meets the eligibility criteria of causation, materiality and prudence, as set out in the Board's Filing Requirements for Natural Gas Rate Applications. A detailed analysis is set out in EPCOR's written evidence, below.

<u>Southern Bruce Expansion Applications – The Competitive Process</u>

EPCOR Southern Bruce Gas Inc., EPCOR's predecessor, filed applications[10] with the Board 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 CPCN's for the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss ("the EPCOR Applications").

[10] EB-2016-0137 / EB-2016-0138 / EB-2016-0139 Applications for Approval of Franchise Agreements and Issuance of Certificates of Public Convenience regarding Municipality of Arran-Elderslie, Municipality of Kincardine and the Township of Huron-Kinloss

The Board had announced on January 20, 2016, that it would be holding a generic proceeding to review opportunities for natural gas expansion in the province (EB-2016-0004). As the EPCOR Applications related to expanding gas service to new areas, they were placed on hold pending the outcome of the generic proceeding. The Board issued its decision on natural gas expansion on November 17, 2016 ("expansion decision").

The Board determined it should confirm whether there were other parties interested in serving the areas covered by the EPCOR Applications. Union Gas (now Enbridge) notified the OEB it was interested in servicing the areas covered by the EPCOR Applications on January 19, 2017.

The Board continued with the processing of EPCOR's Applications seeking approval for its franchise agreements and CPCNs on March 3, 2017. As a first stage, the Board published a list of six issues for comment by the parties[11]. In a partial decision on issues, on issue #4 regarding whether there was a need for a common format for applications for the Board to be able to appropriately assess and compare the value propositions of different proponents, it was determined that:

> The OEB will establish a Common Infrastructure Plan (CIP) as the basis for the proponents to determine their respective revenue requirements. Full consensus between the proponents on the plan's "fit for purpose" design attributes is not required as the CIP will act as a relative proxy or sample plan to allow the OEB to undertake a comparison of the stated revenue requirements on a set of common parameters. The CIP will be used as the basis for the revenue requirement submissions.[12]

The Board undertook a process to determine the common parameters for the CIP. The process included a joint session with Board staff, EPCOR and Union representatives on July 13, 2017 and an oral hearing on August 2, 2017. The common parameters that the parties could agree to were confirmed in an OEB Staff Progress Update on July 20, 2017[13]. The Board confirmed the agreed to parameters and determined the unresolved areas after the oral hearing[14].

In alignment with the intended risk allocation underlying the competitive process, there were two categories of CIP parameters and the treatment of each is different. The first category included

[11] EB-2016-0137 / EB-2016-0138 / EB-2016-0139, Procedural Order No. 5, April 20, 2017.
[12] Partial Decision on the Issues List and Procedural Order No. 6 June 27, 2017, page 4
[13] EB-2016-0137 / EB-2016-0138 / EB-2016-0139, OEB Staff Progress Update: South Bruce Expansion Applications, July 20, 2017
[14] EB-2016-0137 / EB-2016-0138 / EB-2016-0139, Procedural Order No. 8, August 22, 2017

parameters that were set as common assumptions in order “to allow the proponents to file an application based on the CIP that will facilitate a meaningful comparison of the proposals and embody the policy objectives pertaining to positive outcomes for customers previously described”.[15] This category included certain costs for which a definitive value could be confirmed, costs for which a common forecast was agreed to and those costs that would be excluded from the CIP and addressed in the rate case stage of the process. These simplifying, or common, assumptions included elements that the parties agreed they would not compete on and enabled the OEB to focus on the agreed to competitive parameters.

Generally, the forecasted values for common assumptions represented industry averages. Therefore, the successful proponent did not accept any risk for achieving them. Accordingly, those forecasted common assumption values were used in EPCOR’s Southern Bruce rate case as the Board directed that “the OEB will require EPCOR to demonstrate that forthcoming leave to construct and rates applications are consistent with its CIP proposal[16]”. We note that in recognition of the shared nature of common assumptions, the Board has typically approved variance accounts to allow for a true up between actuals versus the value of the common assumption. These approvals protect the ratepayer and the shareholder, ensuring that neither are disadvantaged as a result of a common assumption.

The second category of CIP parameters included those that were competitive in nature and for which the successful proponent would take the risk on achieving and will be held to its forecast for rate-making purposes. These parameters generally covered the capital cost to construct the system, the operation and maintenance costs to operate the network and the timing and number of customer connections.

Table 1.1 below summarizes the common assumptions included as parameters in the CIP and how they were treated.

[15] Partial Decision on the Issues List and Procedural Order No. 6 June 27, 2017, page 5
[16] EB-2016-0137 / EB-2016-0138 / EB-2016-0139, Decision and Order, April 12, 2018, Section 4.2 Assessment of CIP Proposals, page 11

Table 1.1

CIP Common Assumptions

Common Assumption	Description	Implementation
Definitive Value Used in CIP		
Communities Serviced	Listed the 10 communities to be served by the distribution system	System constructed to the 10 listed communities
Comparison Criteria	Three criteria were agree to be used by OEB in determining successful proponent	The three criteria were calculated in the CIP using approved methodology. The OEB used these criteria to select the successful proponent.
Forecast Horizon	The CIP would incorporate a 10 year forecast horizon	Incorporated into CIP application and subsequent rate case
Depreciation Rates	Use Union's OEB-approved depreciation rates	Approved rates incorporated into CIP and subsequent rate case.
Capital Structure	Use Union's approved deemed debt/equity ratio of 64/36.	Deemed capital structure incorporated in CIP and subsequent rate case
Service Levels	Meet service levels identified in Gas Distribution Access Rules	Cost of service levels included in O&M costs as filed in rate case
Interest During Construction (IDC)	IDC used would be at the OEB's prescribed rate.	Approved rate used in CIP and subsequent rate case.
Forecast Value Used in CIP		
Customer Consumption	Annual consumption for each mass market segment, except large commercial or industrial customers	Incorporated into CIP and subsequent rate application as a common assumption.[17] Energy Content Variance Account approved to address changes in energy content versus underlying common assumption.
Taxes	Use common tax rates	Incorporated into CIP and subsequent rate application as a common assumption. Municipal Tax Variance Account approved to address variance between forecast and actual rates.
Construction Schedule	Common forecast for timeline of OEB decisions	Incorporated into CIP and subsequent rate application as a common assumption. Rate rider approved to address impact of delayed decisions[18]
Inflation Costs	Common inflation rate applied to capital and O&M costs	Incorporated into CIP and subsequent rate application as common assumption. Custom IR

[17] EB-2018-0264 EPCOR Natural Gas Limited Partnership Southern Bruce Rate Application, April 11, 2019, Exhibit 1, Tab 2, Schedule 1 page 11 of 64, row 4, row 18
[18] EB-2018-0264 Decision and Order, November 28, 2019, pages 9 - 13

Common Assumption	Description	Implementation
		application filed annually allows for a true up of rates with actual inflation.
Excluded From CIP		
Government Grants and Municipal Contributions and Aid to Construct	Excluded from CIP. Forecast of amount and timing of grants to be included in rate case	Incorporated into rate application. External Funding Variance Account approved to address variance between forecast and actual value of government grants received
Demand Side Management (DSM) Costs	Excluded from CIP. No DSM requested in rate case	OEB approved not incorporating DSM plan for utility.
Cap and Trade Costs	Excluded from CIP.	Two Federal Carbon Charge variance accounts approved in rate case to address carbon charge.
Gas Commodity Costs	Excluded from CIP. Forecast to be included in rate case.	Incorporated into rate application. Cost of Commodity recovered through commodity charge. Four variance and one rebalancing account approved to address variances.
Upstream Reinforcement	Excluded from CIP. Forecast to be included in rate case.	Incorporated into rate application. Contribution in Aid of Construction Variance Account approved to address final cost of upstream reinforcement.

Table 1.2 below summarizes the competitive parameters and how they were treated.

Table 1.2

CIP Competitive Parameters

Competitive Parameter	Description	Implementation
Infrastructure Specifications	Infrastructure specifications, including routing and size of pipe left to competition	Competitive details provided in CIP and were the basis for construction of system.
Customer Attachments	Number and timing of customer attachments left to competition	Competitive details provided in CIP and used in buildup of revenue requirement. Subsequently incorporated into rate application
Capital Structure	Cost of debt and return on equity left to competition	Competitive values included in buildup of revenue requirement in CIP. Subsequently incorporated into rate application.
Customer Consumption	Consumption for large commercial or industrial customers was left to competition	Competitive values included in buildup of revenue requirement in CIP. Subsequently incorporated into rate application.

Based on the proponents' CIP applications, on April 12, 2018 the Board issued a Decision and Order[19] finding that EPCOR's CIP was most favourable to customers and granted CPCN's for the Southern Bruce Municipalities.

As a result, EPCOR filed a Custom Incentive Rate setting plan ("Custom IR") application (EB-2018-0264) ("the Application") on October 2, 2018 (updated April 11, 2019) for Southern Bruce to seek approval for a tariff and other matters under which it would provide service to the Southern Bruce Municipalities. The Application sought approval for distribution rates based on a ten-year Custom IR effective January 1, 2019, establishment of certain deferral and variance accounts, approval of the proposed performance score card, and as well as further orders in all other respects to give effect to the proposals described in that Application and associated evidence. A final Rate Order for this proceeding was issued on January 9, 2020.

In the CIP, there were three common assumptions for which forecasts were used: taxes; construction schedule; and customer consumption. For taxes, the rate payer and shareholder are protected against low forecasts or windfall profits through the use of the Municipal Tax Variance Account. The impact of the difference between actuals and the common assumption for the construction schedule was addressed in EPCOR's Customer IR, Exhibit 6 Revenue Deficiency. In that Exhibit, the financial impact of the delays caused by changes to the timing of OEB decisions related to the competitive process was detailed. As EPCOR stated:

> *As noted in the above table, there are material changes between the assumed timelines for OEB decisions included as a common assumption in the CIP versus the actual / forecast dates. … This has pushed the ability of EPCOR to connect customers by up to a year, reshaping the customer connection profile as system availability is delayed.*[20]

In its decision, the Board accepted EPCOR's statement that revenue lost as a result of the delay in connection of customers, which was a competitive assumption, due to the change in approval of the leave to construct application, which was a common assumption, could be recovered through a rate rider:

[19] EB-2016-0137 / EB-2016-0138 / EB-2016-0139, Decision and Order, April 12, 2018, page 1
[20] EB-2018-0264, Exhibit 6, Tab 1, Schedule 1 Page 2 of 12, para 4.

> *The OEB will approve the recovery of $1.32 million through a rate rider as proposed by EPCOR Southern Bruce….*[21]

For customer consumption, the Board confirmed the principle that customer consumption was an assumption that the proponents were not taking the risk on when it approved the Energy Content Variance Account[22]. The energy content of natural gas is a factor in determining the customer consumption as it inversely impacts the volume that a customer uses (as energy content per m^3 increases, volume used decreases and vice versa). In that Decision the Board stated:

> *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.*

Therefore, if Enbridge (then known as Union Gas) had been the successful proponent, consistent with the principle of not taking the risk on common assumptions regarding customer consumption, they had existing variance accounts[23] that capture variances in consumption volume versus those approved in rates. While EPCOR has an approved variance account relating to the energy content of the natural gas consumed, there is no variance account that addresses changes in consumption volume (increase or decrease) due to other reasons.

<u>The Proposed Variance Account</u>

EPCOR is requesting the Variance Account to track the variance in revenue resulting from the difference between customer volume forecast based on common assumptions and the actual customer volume. This includes all mass market customers billed as one of two rate classes including Rate 1 and Rate 6. Volume variances related to seasonal Rate 11 and large commercial

[21] EB-2018-0264, Decision and Order, November 28, 2019, page 13
[22] EB-2018-0264, Decision and Order, November 28, 2019, pages 20 - 22
[23] Deferral Account No. 179-133, Normalized Average Consumption (NAC) Account and Deferral Account No. 179-106, South Purchase Gas Variance Account

or industrial Rate 16 customers would not be tracked in this account as their volumes were not forecast using common assumptions.

EPCOR requests that the Variance Account be established effective as of the date of this filing.

Notwithstanding the effective date that is established for the Variance Account, EPCOR requests that variances be recorded back to January 1, 2020, the year that the first mass market customer was connected to the Southern Bruce system and with an end date corresponding to the end of the approved rate stability period (i.e. December 31, 2028).

The EPCOR is seeking a start date for recording variances of January 1, 2020 as that is the year that EPCOR began relying on the revenue generated from a common assumption related to the forecasted volume consumed by mass market customers. As a greenfield utility, EPCOR did not have access to any historical customer usage data for the Southern Bruce region for use in setting rates in its Application. A customer base that has been steadily increasing from zero, and lack of data covering an annual usage cycle combined such that EPCOR was unable to complete any meaningful analysis to confirm the existence of a material usage shortfall until recently. In the interim, EPCOR has continued in good faith to build out the distribution system according to the commitments made in its CIP, which are based on the revenue requirement determined using the common assumption related to customer volume.

EPCOR understands that there is Board precedent for establishing the effective date of a deferral account prior to the application date for such an account. EPCOR submits that the Board's approval of a January 1, 2020 effective date for the proposed Variance Account would be appropriate and consistent with prior decisions.

In particular, in EB-2016-0262, the Board agreed that the greenfield utility Wataynikaneyap Power LP ("WPLP"), could establish a deferral account to record developmental costs for the WPLP Transmission Project. WPLP's deferral account application was filed on August 26, 2016, whereas the effective date of the approved variance account was six years earlier on November 23, 2010, which coincided with the date on which WPLP incurred certain developmental costs. The Board acknowledged that WPLP had incurred development costs that contributed to the Province formally recognizing the project as a priority and that the development costs were fundamental and of benefit to ratepayers.

EPCOR is seeking an end date for recording amounts in the Variance Account of December 31, 2028 as that is the end date of its current 10-year Custom Incentive Rate plan. EPCOR is not expecting that the concept of a common assumption will be relevant for its future rate applications. This end date is consistent with the end date of its existing Energy Content Variance Account, which also records the difference between a common assumption relied on by EPCOR that directly impacts customer volume related to the energy content of natural gas and the actual energy content of natural gas distributed to its customers.

EPCOR intends to bring the balance recorded in the Variance Account 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 Board may order. With respect to recording carrying charges on the balance in the Variance Account, simple interest will be calculated monthly on the opening balance.

Customer Consumption – EPCOR's Experience to Date

To assist the Board in understanding the materiality of the amounts forecasted to potentially be recorded in the Variance Account, the following includes detail as to of the potential revenue shortfall.

The common assumptions regarding annual customer volume for mass market customers were based on Union Gas' (now Enbridge) then current normalized average consumption ("NAC") per customer for its adjustment markets. For EPCOR's rate classes, mass market are covered by rate classes Rate 1 and Rate 6[24].

Table 1.3 summarizes the common assumption volume forecasts that were used in the CIP[25]

Table 1.3
CIP Common Assumption Volume Forecasts

Segment / Sub-segment		**Average Annual Consumption (M^3/year)**
Residential	Pre-existing Homes	2,149
	Future Construction	2,066

[24] EB-2018-0264 Rate Order, January 9, 2020 pages 23 - 27
[25] EB-2018-0264 Southern Bruce Rate Application, April 11, 2019, Exhibit 3, Tab 1, Schedule 1, page 5 of 16 Table 3-3; Customer Consumption Common Parameter

Segment / Sub-segment		Average Annual Consumption (M^3/year)
Commercial	Small (0-15,000 m^3/year)	4,693
	Medium (15,001- 50,000 m^3/year)	26,933
	Large (>50,000 m^3/year)	75,685
Agricultural	Cash Crop Farm (excl. large grain dryers)	4,720
	Other Agri-Business	4,720

EPCOR's experience to date is that the customer consumption for residential customers is below that which was forecast as a common assumption. Due to the greenfield nature of the utility, EPCOR does not have long term consumption data for its customers, however, for the approximately 1,000 residential customers with gas flowing for at least 12 months as of April 2022, EPCOR is estimating an annual consumption of approximately 1,453 m^3. This is a shortfall of approximately 696 m^3 or 32% per year versus the common assumption of 2,149. For medium commercial (3 customers currently) and large commercial and agricultural (1 customer currently) EPCOR has developed a forecast for the purposes of this application (see Table 1.7) which suggests that customer consumption could be greater than the respective common assumption. However, given the limited customer base and history it is unclear at this time what, if any, variance from the common assumptions there might be.

While it is unclear what all the underlying drivers for the consumption shortfall for residential customers are, a material factor appears to be that a low number of customers have been connecting multiple gas appliances. In particular, EPCOR estimates that only 13% of customers have converted to gas water heaters, which are estimated to use an average of 400 - 500m^3 annually.

While the current experience of lower consumption versus the common assumption may reverse itself over time as existing customers potentially change out their water heaters, and a wider range of customers connect to the system, including those with multiple gas appliances, the negative impact on the utility if consumption does not reach the common assumption values is material. The summary table below details the actual (2019 – 2021) and forecasted (2023 – 2028) annual revenue impact on the utility.

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)

The actual / forecast differences in revenue are broken out by rate class in Table 1.5.

Table 1.5

Actual / Forecast Revenue Difference by Rate Class ($)

Description	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
Existing Residential	(7,369,927)	0	(51,134)	(369,973)	(542,066)	(848,792)	(1,065,576)	(1,088,082)	(1,111,084)	(1,134,595)	(1,158,625)
New Residential	(549,546)	0	(3,900)	(27,958)	(40,456)	(63,267)	(79,366)	(81,042)	(82,755)	(84,506)	(86,296)
Small Commercial	78,058	0	(699)	(4,054)	275	(3,989)	16,590	16,940	17,297	17,663	18,036
Small Agricultural	5	0	0	0	(265)	270	0	0	0	0	0
Rate 1	(7,841,410)	0	(55,733)	(401,985)	(582,512)	(915,778)	(1,128,352)	(1,152,184)	(1,176,542)	(1,201,438)	(1,226,885)
Medium Commercial	(31,094)	0	0	(16,311)	(5,761)	(8,628)	(75)	(77)	(79)	(81)	(83)
Large Commercial	125,478	0	0	9,006	34,138	7,385	14,389	14,683	14,983	15,290	15,604
Rate 6	94,384	0	0	(7,305)	28,376	(1,243)	14,314	14,606	14,905	15,210	15,521
Rate 1 & Rate 6 Summary	(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)

As highlighted in Table 1.5, for a number of customer classes, including Small Commercial, Medium Commercial and Large Commercial, the forecast suggests that revenues will be higher than that based on the common volume assumption. However, for residential customers, there is a significant revenue shortfall. As a result, on a net basis, the utility is experiencing material shortfalls in revenues.

For clarity, EPCOR acknowledges that it should retain risk related to customer attachments, as that was a CIP competitive parameter. As a result, in calculating any actual / forecast revenue shortfalls, Tables 1.4 and 1.5 above were calculated using the actual customer connections for years 2020 and 2021 and a forecast of actual customer connections for future years, rather than the customer connection counts as included in the CIP. The actual / forecast customer connection count used by rate class is as detailed in Table 1.6 below.

Table 1.6

Actual / Forecast Connection Count (Annual Average)

	Description	Col. 1 Actual 2019	Col. 2 Actual 2020	Col. 3 Actual 2021	Col. 4 Forecast 2022	Col. 5 Forecast 2023	Col. 6 Forecast 2024	Col. 7 Forecast 2025	Col. 8 Forecast 2026	Col. 9 Forecast 2027	Col. 10 Forecast 2028
Row 1	Existing Residential	0	81	928	2,262	3,627	4,858	4,894	4,931	4,968	5,005
Row 2	New Residential	0	6	74	179	288	385	388	391	394	397
Row 3	Small Commercial	0	1	10	31	71	107	107	108	109	110
Row 4	Small Agricultural	0	0	0	2	5	5	5	5	5	5
Row 5	Rate 1	0	88	1,011	2,474	3,990	5,355	5,395	5,436	5,476	5,517
Row 6											
Row 7	Medium Commercial	0	0	3	11	20	25	25	25	25	25
Row 8	Large Commercial	0	0	1	7	15	17	17	17	17	18
Row 9	Rate 6	0	0	4	18	35	42	42	42	42	43

Using the actual / forecast connection count as summarized in Table 1.6, the forecast volumes, using CIP assumptions and actual / forecast values are summarized by rate class in Table 1.7 (using CIP volumes) and Table 1.8 (using actual / forecast volumes) below.

Table 1.7

Volume Using CIP Common Assumptions By Rate Class (M^3)

	Description	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	Existing Residential	67,809,726	0	173,219	1,994,010	4,860,088	7,793,861	10,439,932	10,518,231	10,597,118	10,676,596	10,756,671
Row 2	New Residential	5,172,519	0	13,213	152,103	370,727	594,515	796,357	802,330	808,347	814,410	820,518
Row 3	Small Commercial	3,060,060	0	2,347	44,584	143,137	333,203	499,805	503,553	507,330	511,135	514,968
Row 4	Small Agricultural	150,463	0	0	0	9,440	21,240	23,600	23,777	23,955	24,135	24,316
Row 5	Rate 1	76,192,768	0	188,779	2,190,696	5,383,392	8,742,819	11,759,693	11,847,891	11,936,750	12,026,275	12,116,473
Row 6												
Row 7	Medium Commercial	4,237,943	0	0	67,333	282,797	538,660	659,859	664,807	669,793	674,817	679,878
Row 8	Large Commercial	8,233,362	0	0	75,685	529,795	1,097,433	1,286,645	1,296,295	1,306,017	1,315,812	1,325,681
Row 9	Rate 6	12,471,306	0	0	143,018	812,592	1,636,093	1,946,504	1,961,102	1,975,811	1,990,629	2,005,559

Table 1.8

Actual / Forecast Volume By Rate Class (M^3)

	Description	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	Existing Residential	44,838,752	0	2,850	776,191	3,100,210	5,073,997	7,070,249	7,123,275	7,176,700	7,230,525	7,284,754
Row 2	New Residential	3,459,894	0	224	60,104	239,410	391,822	545,424	549,514	553,636	557,788	561,971
Row 3	Small Commercial	3,304,584	0	0	31,268	144,079	320,660	553,353	557,503	561,684	565,897	570,141
Row 4	Small Agricultural	150,421	0	0	0	8,544	22,094	23,600	23,777	23,955	24,135	24,316
Row 5	Rate 1	51,753,650	0	3,074	867,563	3,492,243	5,808,573	8,192,625	8,254,070	8,315,975	8,378,345	8,441,183
Row 6												
Row 7	Medium Commercial	4,130,774	0	0	8,199	262,578	508,858	660,250	665,201	670,190	675,217	680,281
Row 8	Large Commercial	8,701,540	0	0	110,631	658,118	1,127,346	1,340,825	1,350,882	1,361,013	1,371,221	1,381,505
Row 9	Rate 6	12,832,313	0	0	118,830	920,695	1,636,204	2,001,075	2,016,083	2,031,204	2,046,438	2,061,786

The volume differences between CIP common assumptions and actual / forecast volumes, by rate class, are summarized in Table 1.9.

Table 1.9

Volume Difference by Rate Class (M^3)

	Description	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	Existing Residential	(22,970,974)	0	(170,369)	(1,217,819)	(1,759,878)	(2,719,865)	(3,369,683)	(3,394,955)	(3,420,418)	(3,446,071)	(3,471,916)
Row 2	New Residential	(1,712,625)	0	(12,989)	(91,999)	(131,317)	(202,693)	(250,933)	(252,815)	(254,711)	(256,622)	(258,546)
Row 3	Small Commercial	244,524	0	(2,347)	(13,316)	943	(12,543)	53,548	53,950	54,354	54,762	55,173
Row 4	Small Agricultural	(42)	0	0	0	(896)	854	0	0	0	0	0
Row 5	Rate 1	(24,439,117)	0	(185,705)	(1,323,133)	(1,891,149)	(2,934,246)	(3,567,068)	(3,593,821)	(3,620,775)	(3,647,930)	(3,675,290)
Row 6												
Row 7	Medium Commercial	(107,170)	0	0	(59,134)	(20,219)	(29,802)	391	394	397	400	403
Row 8	Large Commercial	468,177	0	0	34,946	128,323	29,913	54,180	54,587	54,996	55,409	55,824
Row 9	Rate 6	361,008	0	0	(24,188)	108,104	111	54,571	54,981	55,393	55,808	56,227

As highlighted in Table 1.9, for a number of customer classes, including Small Commercial, Medium Commercial and Large Commercial, the forecast suggests that actual volumes will be higher than the common assumption. However, for residential customers, there is a significant shortfall in usage. As a result, on a net basis, the utility is experiencing material shortfalls in volumes.

A Draft Accounting Order, which includes a description of the mechanics of the Variance Account and examples of general ledger entries is provided in Appendix E.

Eligibility Criteria for Establishment of the Deferral Account

EPCOR's request meets the Board's criteria for establishment of a new variance account, as set out in the Board's Filing Requirements for Natural Gas Rate Applications. These criteria are causation, materiality, and prudence.

a) Causation

The eligibility criteria for a deferral account requires that the forecasted expense must be clearly outside the base upon which rates were derived. The forecasted consumption of mass market customers was agreed on by the proponents and the Board to be a common assumption and therefore its achievement was not a risk the proponents were expected to take. This common assumption was subsequently used by EPCOR as a basis on which its rates were derived;[26] and therefore any deviation of actuals from this assumption is outside of the base on which EPCOR's rates have been derived. The common volume assumption used was equal to Union's normalized average consumption for a particular customer class. Enbridge / Union has an existing variance account to record the differences between forecast and actual values and would therefore not have been taking the risk of achieving those consumption values if they had been the successful proponent.

b) Materiality

The eligibility criteria for a deferral account further requires that forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements. EPCOR's materiality threshold is $50,000 as its revenue requirement is less than $10 million. EPCOR estimates that the annual revenue impact during the period of its Custom IR was approximately $55,733 in 2020 and is forecast to be $1,211,364 in 2028. As a greenfield utility that has a built out system, is growing its customers base and therefore revenue collected, EPCOR has O&M expenses that reflect the requirement to safety operate a mature gas distribution utility. For the year ended 2020, EPCOR incurred a loss of $2,114,240[27] and does not have the capability of absorbing the revenue losses due to the variances in volumes consumed versus forecast by mass market customers. In addition, the risk

[26] EB-2018-0264, Southern Bruce Rate Application, Updated April 11, 2019, Exhibit 3, Tab 1, Schedule 1, Section 3.2.1, pages 5 – 6 of 16
[27] Ontario Energy Board Yearbook of Natural Gas Distributors 2020/21, page 7 of 19

of gains or losses as the result of differences in volume of natural gas consumed is generally not a variance that utilities are exposed to.

c) Prudence

The eligibility criteria for a deferral account also requires that the nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers. The common assumptions related to mass market customer consumption were prudent and reasonable at the time they were agreed to by the proponents and the Board. As there was no existing gas utility servicing the Southern Bruce Municipalities it was reasonable to accept as a common assumption the normalized average consumption that Union was experiencing in its adjacent territory.

Appendix A - 2023 Annual Incentive Rate Adjustment Model

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Distributor Information

Distributor Name	EPCOR Natural Gas Limited Partnership
OEB Application Number	EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

A1.1 Distributor Information

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Current Distribution Tariff Sheet Rates

Rate Class		Fixed Monthly Base $/month	Bill 32 Rate $ / month	Delivery Charge Tier 1 ¢ / m3	Tier 2 ¢ / m3	Tier 3 ¢ / m3	Delivery Charge Contract Demand ¢ /contracted m3	Gas Supply ¢ / m3	Upstream Recovery Charge (A)	Transportation & Storage Charge ¢ / m3	Transportation Charge From Dawn ¢ /contracted m3	Transportation Charge From Kirkwall ¢ /contracted m3	Transportation Charge From Parkway ¢ /contracted m3	Federal Carbon Charge ¢ / m3
Rate 1	General Firm Service	26.27	1.00	28.1486	27.5941	26.7790		30.3706	1.4740	2.6982				9.7900
Rate 6	Large Volume General Firm Service	107.16	1.00	25.9678	23.3710	22.2023		30.3706	2.9200	5.6413				9.7900
Rate 11	Large Volume Seasonal Service	214.31	1.00	16.1303	16.1303	16.1303		30.3706	0.0352	1.8166				9.7900
Rate 16	Contracted Firm Service	1,575.78	1.00				107.4831		14.2434		18.2999	11.8480	11.8480	9.7900

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

Name for $1 (Bill 32 Rate

Name of LDC: **EPCOR Natural Gas Limited Partnership**
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Billing Determinants

Rate Class		Fixed Monthly Base	Delivery Charge Tier 1	Tier 2	Tier 3	Delivery Charge Contract Demand	Gas Supply
Rate 1	General Firm Service	4,887	3,391,849	1,847,677	263,269		5,502,795
Rate 6	Large Volume General Firm Service	35	287,896	903,329	890,107		2,081,331
Rate 11	Large Volume Seasonal Service	7			1,313,149		1,313,149
Rate 16	Contracted Firm Service	3				95,824	0

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Forecasted Revenue from Current Rates

Months / Year	12

Rate Class		Fixed Monthly		Delivery Charge			Delivery Charge					
		Base	Bill 32 Rate	Tier 1	Tier 2	Tier 3	Contract Demand	Gas Supply	Upstream Recovery Charge	Transportation & Storage Charge (A)	Federal Carbon Charge	Total
Rate 1	General Firm Service	1,540,719	58,644	954,757	509,849	70,501	0	1,671,232	81,111	148,476	538,724	5,574,012
Rate 6	Large Volume General Firm Service	45,007	420	74,760	211,117	197,624	0	632,113	60,775	117,414	203,762	1,542,992
Rate 11	Large Volume Seasonal Service	18,002	84	0	0	211,815	0	398,811	462	23,855	128,557	781,586
Rate 16	Contracted Firm Service	56,728	36	0	0	0	1,235,935	0	163,783	210,428	112,574	1,779,484
Total Revenue		1,660,455	59,184	1,029,517	720,966	479,940	1,235,935	2,702,156	306,131	500,174	983,617	9,678,075

(A) Transportation & Storage for Rates 1, 6, and 11. Transportation only for Rate 16.

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Current Rate Riders

Description: Delay in Revenue Recovery Rate Rider
Effective Until: Dec 31, 2028

Rate 1 | General Firm Service	cents / m3 volume	1.6330	Cents/m3
Rate 6 | Large Volume General Firm Service	cents / m3 volume	0.9090	Cents/m3
Rate 11 | Large Volume Seasonal Service	cents / m3 volume	0.5524	Cents/m3
Rate 16 | Contracted Firm Service	cents / contracted demand / month	0.0601	$/contracted demand m3

Energy Content Variance Account (ECVA)

	ECVA Rate Rider	
Rate 1 | General Firm Service	0.1403	Cents/m3
Rate 6 | Large Volume General Firm Service	0.1403	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.1403	Cents/m3
Rate 16 | Contracted Firm Service	0.0000	Cents/contracted demand m3

Contribution in Aid of Construction Variance Account (CIACVA)

	CIACVA Rate Rider	
Rate 1 | General Firm Service	0.5434	Cents/m3
Rate 6 | Large Volume General Firm Service	0.7135	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.0992	Cents/m3
Rate 16 | Contracted Firm Service	0.9603	Cents/contracted demand m3

External Funding Variance Account (EFVA)

	EFVA Rate Rider	
Rate 1 | General Firm Service	0.5197	Cents/m3
Rate 6 | Large Volume General Firm Service	0.6608	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.1075	Cents/m3
Rate 16 | Contracted Firm Service	0.7964	Cents/contracted demand m3

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 1 Incentive Rate Adjustment

D1.1 Rate 1 Adjustment

Rate 1

GDP-IPI	
Less Productivity	
Less Stretch Factor	
Incentive Rate Adjustment	1.91%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	26.27	1.91%	26.77	4,887	1,570,146
Bill 32 Rate	$/month	1.00	0.00%	1.00	4,887	58,644
Tier 1	cents / m3	28.1486	1.91%	28.6862	3,391,849	972,993
Tier 2	cents / m3	27.5941	1.91%	28.1211	1,847,677	519,587
Tier 3	cents / m3	26.7790	1.91%	27.2905	263,269	71,847
Contract Demand	cents / m3	0.0000	1.91%	0.0000	0	0
Gas Supply	cents / m3	30.3706	0.00%	30.3706	5,502,795	1,671,232
Upstream Recovery Charge	cents / m3	1.4740	0.00%	1.4740	5,502,795	81,111
Transportation & Storage Charge	cents / m3	2.6982	0.00%	2.6982	5,502,795	148,476
Federal Carbon Charge	cents / m3	9.7900	0.00%	9.7900	5,502,795	538,724
						5,632,761

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 6 Incentive Rate Adjustment

D1.2 Rate 6 Adjustment

Rate 6

GDP-IPI	
Less Productivity	
Less Stretch Factor	
Incentive Rate Adjustment	1.91%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	107.16	1.91%	109.21	35	45,866
Bill 32 Rate	$/month	1.00	0.00%	1.00	35	420
Tier 1	cents / m3	25.9678	1.91%	26.4638	287,896	76,188
Tier 2	cents / m3	23.3710	1.91%	23.8174	903,329	215,150
Tier 3	cents / m3	22.2023	1.91%	22.6264	890,107	201,399
Contract Demand	cents / m3	0.0000	1.91%	0.0000	0	0
Gas Supply	cents / m3	30.3706	0.00%	30.3706	2,081,331	632,113
Upstream Recovery Charge	cents / m3	2.9200	0.00%	2.9200	2,081,331	60,775
Transportation & Storage Charge	cents / m3	5.6413	0.00%	5.6413	2,081,331	117,414
Federal Carbon Charge	cents / m3	9.7900	0.00%	9.7900	2,081,331	203,762
						1,553,087

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 11 Incentive Rate Adjustment

D1.3 Rate 11 Adjustment

Rate 11

GDP-IPI	
Less Productivity	
Less Stretch Factor	
Incentive Rate Adjustment	1.91%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	214.31	1.91%	218.40	7	18,346
Bill 32 Rate	$/month	1.00	0.00%	1.00	7	84
Tier 1	cents / m3	16.1303	1.91%	16.4384	0	0
Tier 2	cents / m3	16.1303	1.91%	16.4384	0	0
Tier 3	cents / m3	16.1303	1.91%	16.4384	1,313,149	215,861
Contract Demand	cents / m3	0.0000	1.91%	0.0000	0	0
Gas Supply	cents / m3	30.3706	0.00%	30.3706	1,313,149	398,811
Upstream Recovery Charge	cents / m3	0.0352	0.00%	0.0352	1,313,149	462
Transportation & Storage Charge	cents / m3	1.8166	0.00%	1.8166	1,313,149	23,855
Federal Carbon Charge	cents / m3	9.7900	0.00%	9.7900	1,313,149	128,557
						785,976

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 16 Incentive Rate Adjustment

D1.4 Rate 16 Adjustment

Rate 16

GDP-IPI	
Less Productivity	
Less Stretch Factor	
Incentive Rate Adjustment	1.91%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	1,575.78	1.91%	1,605.88	3	57,812
Bill 32 Rate	$/month	1.00	0.00%	1.00	3	36
Tier 1	cents / m3	0.0000	1.91%	0.0000	0	0
Tier 2	cents / m3	0.0000	1.91%	0.0000	0	0
Tier 3	cents / m3	0.0000	1.91%	0.0000	0	0
Contract Demand	Cents/contracted demand m3	107.4831	1.91%	109.5360	95,824	1,259,541
Gas Supply	cents / m3	0.0000	0.00%	0.0000	0	0
Upstream Recovery Charge	Cents/contracted demand m3	14.2434	0.00%	14.2434	95,824	163,783
Transportation Charge From Dawn	Cents/contracted demand m3	18.2999	0.00%	18.2999	95,824	210,428
Transportation Charge From Kirkwall	Cents/contracted demand m3	11.8480	0.00%	11.8480	0	0
Transportation Charge From Parkway	Cents/contracted demand m3	11.8480	0.00%	11.8480	0	0
Federal Carbon Charge	Cents/contracted demand m3	9.7900	0.00%	9.7900	95,824	112,574
						1,804,174

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Proposed Distribution Tariff Sheet Rates

E1.1 Proposed Dist Rates

Rate Class		Monthly Base	Bill 32 Rate	Tier 1	Tier 2	Tier 3	Contract Demand	Gas Supply	Upstream Recovery Charge	Transportation & Storage Charge	Transportation Charge From Dawn	Transportation Charge From Kirkwall	Transportation Charge From Parkway	Federal Carbon Charge
		$/month	$/month	¢ / m3	¢ / m3	¢ / m3	₵/contracted m3	₵/m3	(A)	¢ / m3	₵ /contracted m3	₵ /contracted m3	₵ /contracted m3	¢ / m3
Rate 1	General Firm Service	26.77	1.00	28.6862	28.1211	27.2905		30.3706	1.4740	2.6982				9.7900
Rate 6	Large Volume General Firm Service	109.21	1.00	26.4638	23.8174	22.6264		30.3706	2.9200	5.6413				9.7900
Rate 11	Large Volume Seasonal Service	218.40	1.00	16.4384	16.4384	16.4384		30.3706	0.0352	1.8166				9.7900
Rate 16	Contracted Firm Service	1,605.88	1.00				109.5360		14.2434		18.2999	11.8480	11.8480	9.7900

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Billing Determinants

E1.2 Billing Determinants

Rate Class	Description	Base cx's	Tier 1 m3	Tier 2 m3	Tier 3 m3	Firm Demand Contracted m3	Gas Supply m3
Rate 1	General Firm Service	4,887	3,391,849	1,847,677	263,269	0	5,502,795
Rate 6	Large Volume General Firm Service	35	287,896	903,329	890,107	0	2,081,331
Rate 11	Large Volume Seasonal Service	7	0	0	1,313,149	0	1,313,149
Rate 16	Contracted Firm Service	3	0	0	0	95,824	0

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Proposed Revenue from Rates

Months / Year: 12

Rate Class		Monthly Base	Bill 32 Rate	Tier 1	Tier 2	Tier 3	Contracted Demand	Gas Supply	Upstream Recovery Charge	Transportation & Storage Charge (A)	Federal Carbon Charge	Total
Rate 1	General Firm Service	1,570,146	58,644	972,993	519,587	71,847	0	1,671,232	81,111	148,476	538,724	5,632,761
Rate 6	Large Volume General Firm Service	45,866	420	76,188	215,150	201,399	0	632,113	60,775	117,414	203,762	1,553,087
Rate 11	Large Volume Seasonal Service	18,346	84	0	0	215,861	0	398,811	462	23,855	128,557	785,976
Rate 16	Contracted Firm Service	57,812	36	0	0	0	1,259,541	0	163,783	210,428	112,574	1,804,174

(A) Transportation & Storage for Rates 1, 6, and 11. Transportation only (no seasonal storage) for Rate 16 from Dawn.

Proposed Revenue	9,775,997
Current Revenue	9,678,075
Change	97,922
% Change	1.01%

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application
F1.3 Rate Riders

Delay in Revenue Recovery Rate Rider

	Delay in Revenue Recovery Rate Rider	
Rate 1 | General Firm Service	1.6330	Cents/m3
Rate 6 | Large Volume General Firm Service	0.9090	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.5524	Cents/m3
Rate 16 | Contracted Firm Service	0.0601	Cents/contracted demand m3/month

Energy Content Variance Account (ECVA)

	ECVA Rate Rider	
Rate 1 | General Firm Service	0.3437	Cents/m3
Rate 6 | Large Volume General Firm Service	0.2778	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.1857	Cents/m3
Rate 16 | Contracted Firm Service	0.0000	Cents/contracted demand m3

Contribution in Aid of Construction Variance Account (CIACVA)

	CIACVA Rate Rider	
Rate 1 | General Firm Service	3.3388	Cents/m3
Rate 6 | Large Volume General Firm Service	3.1385	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.6074	Cents/m3
Rate 16 | Contracted Firm Service	4.5311	Cents/contracted demand m3/month

Municipal Tax Variance Account

	MTVA Rate Rider	
Rate 1 | General Firm Service	-3.0834	Cents/m3
Rate 6 | Large Volume General Firm Service	-2.8983	Cents/m3
Rate 11 | Large Volume Seasonal Service	-0.5609	Cents/m3
Rate 16 | Contracted Firm Service	-4.1844	Cents/contracted demand m3/month

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 1 Delivery Bill Impact

G1.1 Rate 1 Bill Impact

Rate 1

Rate 1 - Existing Residential	Units	Current Rate	Proposed Rate
Customer	$/month	26.27	26.77
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	28.1486	28.6862
Next 400 m3	¢/m3	27.5941	28.1211
GT 500m3	¢/m3	26.7790	27.2905
Contracted Demand	¢ / contracted m3	-	-
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	$/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.1403	0.3437
EFVA Rate Rider	¢/m3	0.5197	-
CIACVA Rate Rider	¢/m3	0.5434	3.3388
MTVA Rate Rider	¢/m3	-	- 3.0834

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	315.27	321.29	6.02	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	1,001	281.86	287.24	5.38	1.91%
Next 400 m3	1,148	316.69	322.74	6.05	1.91%
GT 500m3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	2,149.00	652.66	652.66	0.00	0.00%
Upstream Recovery Charge	2,149.00	31.68	31.68	0.00	0.00%
Transportation & Storage Charge	2,149.00	57.98	57.98	0.00	0.00%
Federal Carbon Charge	2,149.00	210.39	210.39	0.00	0.00%
Total Delivery		1,878.53	1,895.98	17.45	0.93%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	2,149.00	35.09	35.09	0.00	0.00%
ECVA Rate Rider	2,149.00	3.02	7.39	4.37	144.98%
EFVA Rate Rider	2,149.00	11.17	0.00	-11.17	-100.00%
CIACVA Rate Rider	2,149.00	11.68	71.75	60.07	514.43%
MTVA Rate Rider	2,149.00	0.00	-66.26	-66.26	#DIV/0!
Total Rate Riders		60.95	47.97	(12.98)	-21.30%
Total Bill Impact		1,939.48	1,943.95	4.47	0.2%

Rate 1 - New Residential	Units	Current Rate	Proposed Rate
Customer	$/month	26.27	26.77
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	28.1486	28.6862
Next 400 m3	¢/m3	27.5941	28.1211
GT 500m3	¢/m3	26.7790	27.2905
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.1403	0.3437
EFVA Rate Rider	¢/m3	0.5197	0.0000
CIACVA Rate Rider	¢/m3	0.5434	3.3388
MTVA Rate Rider	¢/m3	0.0000	-3.0834

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	315.27	321.29	6.02	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	993	279.55	284.89	5.34	1.91%
Next 400 m3	1,073	296.05	301.70	5.65	1.91%
GT 500m3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	2,066.00	627.46	627.46	0.00	0.00%
Upstream Recovery Charge	2,066.00	30.45	30.45	0.00	0.00%
Transportation & Storage Charge	2,066.00	55.74	55.74	0.00	0.00%
Federal Carbon Charge	2,066.00	202.26	202.26	0.00	0.00%
Total Delivery		1,818.78	1,835.80	17.02	0.94%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	2,066.00	33.74	33.74	0.00	0.00%
ECVA Rate Rider	2,066.00	2.90	7.10	4.20	144.98%
EFVA Rate Rider	2,066.00	10.74	0.00	-10.74	-100.00%
CIACVA Rate Rider	2,066.00	11.23	68.98	57.75	514.43%
MTVA Rate Rider	2,066.00	0.00	-63.70	-63.70	#DIV/0!
Total Rate Riders		58.60	46.12	(12.48)	-21.30%
Total Bill Impact		1,877.38	1,881.92	4.53	0.2%

Rate 1 - Small Commercial	Units	Current Rate	Proposed Rate

Name of LDC: **EPCOR Natural Gas Limited Partnership**
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 1 Delivery Bill Impact

Customer	$/month	26.27	26.77
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	28.1486	28.6862
Next 400 m3	¢/m3	27.5941	28.1211
GT 500m3	¢/m3	26.7790	27.2905
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.1403	0.3437
EFVA Rate Rider	¢/m3	0.5197	0.0000
CIACVA Rate Rider	¢/m3	0.5434	3.3388
MTVA Rate Rider	¢/m3	0.0000	-3.0834

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	315.27	321.29	6.02	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	1,198	337.27	343.71	6.44	1.91%
Next 400 m3	2,475	682.95	696.00	13.04	1.91%
GT 500m3	1,020	273.10	278.32	5.22	1.91%
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	4,693.00	1,425.29	1,425.29	0.00	0.00%
Upstream Recovery Charge	4,693.00	69.17	69.17	0.00	0.00%
Transportation & Storage Charge	4,693.00	126.63	126.63	0.00	0.00%
Federal Carbon Charge	4,693.00	459.44	459.44	0.00	0.00%
Total Delivery		3,701.13	3,731.85	30.72	0.83%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	4,693.00	76.64	76.64	0.00	0.00%
ECVA Rate Rider	4,693.00	6.58	16.13	9.55	144.98%
EFVA Rate Rider	4,693.00	24.39	0.00	-24.39	-100.00%
CIACVA Rate Rider	4,693.00	25.50	156.69	131.19	514.43%
MTVA Rate Rider	4,693.00	0.00	-144.70	-144.70	#DIV/0!
Total Rate Riders		133.11	104.76	(28.36)	-21.30%
Total Bill Impact		3,834.24	3,836.61	2.37	0.1%

Rate 1 - Small Agricultural	**Units**	**Current Rate**	**Proposed Rate**
Customer	$/month	26.27	26.77
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	28.1486	28.6862
Next 400 m3	¢/m3	27.5941	28.1211
GT 500m3	¢/m3	26.7790	27.2905
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.1403	0.3437
EFVA Rate Rider	¢/m3	0.5197	0.0000
CIACVA Rate Rider	¢/m3	0.5434	3.3388
MTVA Rate Rider	¢/m3	0.0000	-3.0834

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	315.27	321.29	6.02	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	1,199	337.43	343.87	6.44	1.91%
Next 400 m3	2,484	685.45	698.55	13.09	1.91%
GT 500m3	1,037	277.75	283.06	5.31	1.91%
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Commodity	4,720.00	1,433.49	1,433.49	0.00	0.00%
Upstream Recovery Charge	4,720.00	69.57	69.57	0.00	0.00%
Transportation & Storage Charge	4,720.00	127.36	127.36	0.00	0.00%
Federal Carbon Charge	4,720.00	462.09	462.09	0.00	0.00%
Total Delivery		3,720.41	3,751.27	30.86	0.83%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	4,720.00	77.08	77.08	0.00	0.00%
ECVA Rate Rider	4,720.00	6.62	16.22	9.60	144.98%
EFVA Rate Rider	4,720.00	24.53	0.00	-24.53	-100.00%
CIACVA Rate Rider	4,720.00	25.65	157.59	131.94	514.43%
MTVA Rate Rider	4,720.00	0.00	-145.54	-145.54	#DIV/0!
Total Rate Riders		133.88	105.36	(28.52)	-21.30%
Total Bill Impact		3,854.29	3,856.63	2.34	0.1%

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 6 Delivery Bill Impact

G1.2 Rate 6 Bill Impact

Rate 6 - Medium Commercial	Units	Current Rate	Proposed Rate
Customer	$/month	107.16	109.21
Bill 32 Rate	$/month	1.00	1.00
First 1000 m3	¢/m3	25.9678	26.4638
Next 6000 m3	¢/m3	23.3710	23.8174
GT 7000m3	¢/m3	22.2023	22.6264
Contracted Demand	¢ / contracted m3	-	-
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	2.9200	2.9200
Transportation & Storage Charge	¢/m3	5.6413	5.6413
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.9090	0.9090
ECVA Rate Rider		0.1403	0.2778
EFVA Rate Rider		0.6608	-
CIACVA Rate Rider		0.7135	3.1385
MTVA Rate Rider		-	- 2.8983

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	1,285.90	1,310.46	24.56	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 1000 m3	9,832	2,553.03	2,601.80	48.76	1.91%
Next 6000 m3	17,101	3,996.78	4,073.12	76.34	1.91%
GT 7000m3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	26,933.00	8,179.71	8,179.71	0.00	0.00%
Upstream Recovery Charge	26,933.00	786.44	786.44	0.00	0.00%
Transportation & Storage Charge	26,933.00	1,519.37	1,519.37	0.00	0.00%
Federal Carbon Charge	26,933.00	2,636.74	2,636.74	0.00	0.00%
Total Delivery		20,969.99	21,119.65	149.66	0.71%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	26,933.00	244.82	244.82	0.00	0.00%
ECVA Rate Rider	26,933.00	37.79	74.83	37.04	98.03%
EFVA Rate Rider	26,933.00	177.97	0.00	-177.97	-100.00%
CIACVA Rate Rider	26,933.00	192.17	845.28	653.11	339.87%
MTVA Rate Rider	26,933.00	0.00	-780.60	-780.60	#DIV/0!
Total Rate Riders		652.75	384.33	- 268.42	-41.12%
Total Bill Impact		21,622.74	21,503.98	- 118.76	-0.55%

Rate 6 - Medium Commercial	Units	Current Rate	Proposed Rate
Customer	$/month	107.16	109.21
Bill 32 Rate	$/month	1.00	1.00
First 1000 m3	¢/m3	25.9678	26.4638
Next 6000 m3	¢/m3	23.3710	23.8174
GT 7000m3	¢/m3	22.2023	22.6264
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	2.9200	2.9200
Transportation & Storage Charge	¢/m3	5.6413	5.6413
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.9090	0.9090
ECVA Rate Rider		0.1403	0.2778
EFVA Rate Rider		0.6608	0.0000
CIACVA Rate Rider		0.7135	3.1385
MTVA Rate Rider		0.0000	-2.8983

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	1,285.90	1,310.46	24.56	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 1000 m3	11,715	3,042.21	3,100.32	58.11	1.91%
Next 6000 m3	40,793	9,533.67	9,715.77	182.09	1.91%
GT 7000m3	23,177	5,145.82	5,244.11	98.29	1.91%
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	75,685.00	22,985.99	22,985.99	0.00	0.00%
Upstream Recovery Charge	75,685.00	2,210.00	2,210.00	0.00	0.00%
Transportation & Storage Charge	75,685.00	4,269.62	4,269.62	0.00	0.00%
Federal Carbon Charge	75,685.00	7,409.56	7,409.56	0.00	0.00%
Total Delivery		55,894.78	56,257.82	363.05	0.65%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	75,685.00	687.98	687.98	0.00	0.00%
ECVA Rate Rider	75,685.00	106.19	210.28	104.09	98.03%
EFVA Rate Rider	75,685.00	500.13	0.00	-500.13	-100.00%
CIACVA Rate Rider	75,685.00	540.01	2,375.34	1,835.32	339.87%
MTVA Rate Rider	75,685.00	0.00	-2,193.59	-2,193.59	#DIV/0!
Total Rate Riders		1,834.30	1,080.00	- 754.30	-41.12%
Total Bill Impact		57,729.08	57,337.82	- 391.26	-0.68%

Name of LDC: **EPCOR Natural Gas Limited Partnership**
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 11 Delivery Bill Impact

G1.3 Rate 11 Bill Impact

Rate 11 - Large Seasonal Service Sample Dryer 1	Units	Current Rate	Proposed Rate
Customer	$/month	214.31	218.40
Bill 32 Rate	$/month	1.00	1.00
All Volumes	¢/m3	16.1303	16.4384
Tier 2	¢/m3	16.1303	16.4384
Tier 3	¢/m3	16.1303	16.4384
Contracted Demand	¢ / contracted m3	-	-
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	0.0352	0.0352
Transportation & Storage Charge	¢/m3	1.8166	1.8166
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.5524	0.5524
ECVA Rate Rider	¢/m3	0.1403	0.1857
EFVA Rate Rider	¢/m3	0.1075	-
CIACVA Rate Rider	¢/m3	0.0992	4.5311
MTVA Rate Rider	¢/m3	-	- 4.1844

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	2,571.68	2,620.80	49.12	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
All Volumes	101,499	16,372.19	16,684.90	312.71	1.91%
Tier 2	-	0.00	0.00	0.00	#DIV/0!
Tier 3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	101,499.49	30,826.00	30,826.00	0.00	0.00%
Upstream Recovery Charge	101,499.49	35.73	35.73	0.00	0.00%
Transportation & Storage Charge	101,499.49	1,843.84	1,843.84	0.00	0.00%
Federal Carbon Charge	101,499.49	9,936.80	9,936.80	0.00	0.00%
Total Delivery		61,598.23	61,960.06	361.83	0.59%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	101,499.49	560.68	560.68	0.00	0.00%
ECVA Rate Rider	101,499.49	142.40	188.46	46.06	32.34%
EFVA Rate Rider	101,499.49	109.11	0.00	-109.11	-100.00%
CIACVA Rate Rider	101,499.49	100.69	4,599.00	4,498.32	4467.60%
MTVA Rate Rider	101,499.49	0.00	-4,247.12	-4,247.12	#DIV/0!
Total Rate Riders		912.89	1,101.03	188.14	20.61%
Total Bill Impact		62,511.12	63,061.09	549.97	0.88%

Rate 11 - Large Seasonal Service Sample Dryer 2	Units	Current Rate	Proposed Rate
Customer	$/month	214.31	218.40
Bill 32 Rate	$/month	1.00	1.00
All Volumes	¢/m3	16.1303	16.4384
Tier 2	¢/m3	16.1303	16.4384
Tier 3	¢/m3	16.1303	16.4384
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	30.3706	30.3706
Upstream Recovery Charge	¢/m3	0.0352	0.0352
Transportation & Storage Charge	¢/m3	1.8166	1.8166
Federal Carbon Charge	¢/m3	3.9100	3.9100
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.5524	0.5524
ECVA Rate Rider	¢/m3	0.1403	0.1857
EFVA Rate Rider	¢/m3	0.1075	0.0000
CIACVA Rate Rider	¢/m3	0.0992	4.5311
MTVA Rate Rider	¢/m3	0.0000	-4.1844

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	2,571.68	2,620.80	49.12	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
All Volumes	338,332	54,573.96	55,616.32	1,042.36	1.91%
Tier 2	-	0.00	0.00	0.00	#DIV/0!
Tier 3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	338,331.62	102,753.34	102,753.34	0.00	0.00%
Upstream Recovery Charge	338,331.62	119.09	119.09	0.00	0.00%
Transportation & Storage Charge	338,331.62	6,146.13	6,146.13	0.00	0.00%
Federal Carbon Charge	338,331.62	13,228.77	13,228.77	0.00	0.00%
Total Delivery		179,404.97	180,496.45	1,091.48	0.61%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	338,331.62	1,868.94	1,868.94	0.00	0.00%
ECVA Rate Rider	338,331.62	474.68	628.21	153.53	32.34%
EFVA Rate Rider	338,331.62	363.71	0.00	-363.71	-100.00%
CIACVA Rate Rider	338,331.62	335.62	15,330.01	14,994.39	4467.60%
MTVA Rate Rider	338,331.62	0.00	-14,157.07	-14,157.07	#DIV/0!
Total Rate Riders		3,042.95	3,670.10	627.14	20.61%
Total Bill Impact		182,447.92	184,166.55	1,718.62	0.94%

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Rate 16 Delivery Bill Impact

G1.4 Rate 16 Bill Impact

Rate 16 - Contracted Demand	Units	Current Rate	Proposed Rate
Customer	$/month	1,575.78	1,605.88
Bill 32 Rate	$/month	1.00	1.00
Tier 1	¢/m3	0.0000	0.0000
Tier 2	¢/m3	0.0000	0.0000
Tier 3	¢/m3	0.0000	0.0000
Contracted Demand	¢ / contracted m3	107.4831	109.5360
Gas Supply	¢/m3	0.0000	0.0000
Upstream Recovery Charge	¢ / contracted m3	14.2434	14.2434
Transportation Charge From Dawn	¢ / contracted m3	18.2999	18.2999
Transportation Charge From Kirkwall	¢ / contracted m3	11.8480	11.8480
Transportation Charge From Parkway	¢ / contracted m3	11.8480	11.8480
Federal Carbon Charge	¢/m3	9.7900	9.7900
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢ / contracted m3	0.0601	0.0601
ECVA Rate Rider	¢ / contracted m3	0.0000	0.0000
EFVA Rate Rider	¢ / contracted m3	0.7964	0.0000
CIACVA Rate Rider	¢ / contracted m3	0.9603	4.5311
MTVA Rate Rider	¢ / contracted m3	0.0000	-4.1844

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	18,909.40	19,270.57	361.17	1.91%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
Tier 1	-	0.00	0.00	0.00	#DIV/0!
Tier 2	-	0.00	0.00	0.00	#DIV/0!
Tier 3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	50,000	644,898.30	657,215.86	12,317.56	1.91%
Gas Supply	0.00	0.00	0.00	0.00	#DIV/0!
Upstream Recovery Charge	50,000.00	85,460.40	85,460.40	0.00	0.00%
Transportation Charge From Dawn	50,000.00	109,799.40	109,799.40	0.00	0.00%
Transportation Charge From Kirkwall	0.00	0.00	0.00	0.00	#DIV/0!
Transportation Charge From Parkway	0.00	0.00	0.00	0.00	#DIV/0!
Federal Carbon Charge	50,000.00	58,740.00	58,740.00	0.00	0.00%
Total Delivery		917,819.50	930,498.23	12,678.73	1.38%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	12.00	360.60	360.60	0.00	0.00%
ECVA Rate Rider	12.00	0.00	0.00	0.00	#DIV/0!
EFVA Rate Rider	12.00	4,778.40	0.00	-4,778.40	-100.00%
CIACVA Rate Rider	12.00	5,761.80	27,186.37	21,424.57	371.84%
MTVA Rate Rider	12.00	0.00	-25,106.26	-25,106.26	#DIV/0!
Total Rate Riders		10,900.80	# 2,440.71	# - 8,460.09	-77.61%
Total Bill Impact		928,720.30	932,938.94	4,218.64	0.45%

Name of LDC: EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2022-0184 Exhibit A - 2023 Custom Incentive Application

Summary of Bill Impacts

G1.7 Summary of Bill Impacts

Rate Class		Fixed Change ($/year)	Volumetric Change ($/year)	Rate Riders ($/year)	Total Change ($/year)	Total Change %
Rate 1	Existing Residential	6.02	11.43	-12.98	4.47	0.23%
Rate 1	New Residential	6.02	10.99	-12.48	4.53	0.24%
Rate 1	Small Commercial	6.02	24.70	-28.36	2.37	0.06%
Rate 1	Small Agricultural	6.02	24.84	-28.52	2.34	0.06%
Rate 6	Medium Commercial	24.56	125.10	-268.42	-118.76	-0.55%
Rate 6	Large Commercial	24.56	338.48	-754.30	-391.26	-0.68%
Rate 11	Sample Dryer 1	49.12	312.71	188.14	549.97	0.88%
Rate 11	Sample Dryer 2	49.12	1,042.36	627.14	1,718.62	0.94%
Rate 16	Contracted Demand	361.17	12,317.56	-8,460.09	4,218.64	0.45%

Appendix B - Proposed Draft Rate Schedules

EB-2022-0184

Effective: January 1, 2023

RATE 1 - General Firm Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are equal to or less than 10,000 m^3 per year.

Rate

Rates per m^3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge [(1)]	$27.77	
Delivery Charge		
First 100 m^3 per month	28.6862	¢ per m^3
Next 400 m^3 per month	28.1211	¢ per m^3
Over 500 m^3 per month	27.2905	¢ per m^3
Upstream Charges		
Upstream Recovery charge	1.4740	¢ per m^3
Transportation and Storage charge	2.6982	¢ per m^3
Rate Rider for Delay in Revenue Recovery - effective for 10 years ending December 31, 2028	1.6330	¢ per m^3
ECVA Rate Rider - effective for 12 months ending December 31, 2023	0.3437	¢ per m^3
CIACVA Rate Rider - effective for 12 months ending December 31, 2023	3.3388	¢ per m^3
MTVA Rate Rider - effective for 12 months ending December 31, 2023	(3.0834)	¢ per m^3
Federal Carbon Charge (if applicable) [(2)]	9.79	¢ per m^3
Gas Supply Charge	30.3706	¢ per m^3

[(1)]Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

[(2)] The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the supplier must qualify as a "gas marketer" under the *Ontario Energy Board Act, 1998*, and must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2023
Implementation: All bills rendered on or after January 1, 2023
EB-2022-0184

RATE 6 – Large Volume General Firm Service

Applicability
Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are greater than 10,000 m^3 per year.

Rate
Rates per m^3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge (1)	$110.21	
Delivery Charge		
First 1000 m^3 per month	26.4638	¢ per m^3
Next 6000 m^3 per month	23.8174	¢ per m^3
Over 7000 m^3 per month	22.6264	¢ per m^3
Upstream Charges		
Upstream Recovery charge	2.9200	¢ per m^3
Transportation and Storage charge	5.6413	¢ per m^3
Rate Rider for Delay in Revenue Recovery - effective for 10 years ending December 31, 2028	0.9090	¢ per m^3
ECVA Rate Rider - effective for 12 months ending December 31, 2023	0.2778	¢ per m^3
CIACVA Rate Rider - effective for 12 months ending December 31, 2023	3.1385	¢ per m^3
MTVA Rate Rider - effective for 12 months ending December 31, 2023	(2.8983)	¢ per m^3
Federal Carbon Charge (if applicable) (2)	9.79	¢ per m^3
Gas Supply Charge	30.3706	¢ per m^3

(1) Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

(2) The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2023
Implementation: All bills rendered on or after January 1, 2023
EB-2022-0184

RATE 11 - Large Volume Seasonal Service

Applicability
Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose gas requirements are only during the period of May 1 through Dec 15 inclusive and are greater than 10,000 m^3.

Rate

Rates per m^3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge [(1)]	$219.40	
Delivery Charge		
All volumes delivered	16.4384	¢ per m^3
Upstream Charges		
Upstream Recovery charge	0.0352	¢ per m^3
Transportation and Storage charge	1.8166	¢ per m^3
Rate Rider for Delay in Revenue Recovery	0.5524	¢ per m^3
- effective for 10 years ending December 31, 2028		
ECVA Rate Rider	0.1857	¢ per m^3
- effective for 12 months ending December 31, 2023		
CIACVA Rate Rider	0.6074	¢ per m^3
- effective for 12 months ending December 31, 2023		
MTVA Rate Rider	(0.5609)	¢ per m^3
- effective for 12 months ending December 31, 2023		
Federal Carbon Charge (if applicable) [(2)]	9.79	¢ per m^3
Gas Supply Charge	30.3706	¢ per m^3

[(1)]Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

[(2)] The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Unaccounted for Gas (UFG):
Forecasted UFG is applied to all volumes of gas delivered to the customer.

Forecasted Unaccounted for Gas Percentage	0.00	%

Overrun Charges:

Any volume of gas taken during the period of December 16 through April 30 inclusive shall constitute "Overrun Gas" and must be authorized in advance by EPCOR. Delivery of these volumes is available at the Authorized Overrun Charge in addition to applicable Upstream Charges and Gas Supply Charges. EPCOR will not unreasonably withhold authorization.

Authorized Overrun Charge	17.1298 ¢ per m^3

Any volume of gas taken during the period of December 16 through April 30 inclusive without EPCOR's approval in advance shall constitute "Unauthorized Overrun Gas". Delivery of these volumes will be paid for at the Unauthorized Overrun Charge in addition to applicable Upstream Charges and Gas Supply Charges.

Unauthorized Overrun Charge	410.1987 ¢ per m^3

For any volume of Unauthorized Overrun Gas taken, the customer shall, in addition, indemnify EPCOR in respect of any penalties or additional costs imposed on EPCOR by its suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

Nominations:

Union Gas Limited will be the "Upstream Service Provider" to facilitate delivery and balancing of gas supplies to the EPCOR Southern Bruce Natural Gas System. For service under this Rate Schedule, the customer shall nominate for transportation of gas volumes for ultimate delivery to the customer. The customer agrees to nominate its daily gas volumetric requirement to EPCOR, or its designated agent, consistent with industry nomination standards including those nomination requirements of the Upstream Service Provider.

The customer shall nominate gas delivery daily based on its daily gas requirements plus the Forecasted UFG rate as set out in this Rate Schedule.

The nomination calculation shall equal:

[(Daily volume of gas to be delivered) * (1 + Forecasted UFG)]

Customers may change daily nominations based on the nomination windows within a day as defined by EPCOR's agreement with the Upstream Service Provider.

In the event nominations under this Rate Schedule do not match upstream nominations, the nomination will be confirmed at the upstream value.

Customers with multiple connections under this Rate Schedule may combine nominations at the sole discretion of EPCOR. For combined nominations the customer shall specify the quantity of gas to each meter installation ("Terminal Location") and the order in which the gas is to be delivered to each Terminal Location.

Load Balancing:

Daily nominations provided by the customer shall be used for the purposes of day-to-day balancing as required under EPCOR's arrangement with the Upstream Service Provider.

When a customer's metered consumption on any day is different than the gas nominated for consumption by the customer on any day, this constitutes a "Daily Load Imbalance". A "Cumulative Load Imbalance" occurs when the ongoing absolute value of Daily Load Imbalances are greater than zero.

To the extent that EPCOR incurs daily or cumulative load balancing charges, the customer will be responsible for its proportionate share of such charges. Charges related to these imbalances are as defined in EPCOR's agreement with the Upstream Service Provider.

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

1. In any year, during the period of May 1 through December 15 inclusive, the customers shall receive continuous ("**Firm**") service from EPCOR, except where impacted by events as specified in EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service including force majeure. During the period of December 16 through April 30 inclusive, any authorized overrun service shall be interruptible at the sole discretion of EPCOR. All service during the period December 16 through April 30 inclusive shall be subject to EPCOR's prior authorization under the daily nomination procedures outlined in this Rate Schedule and shall constitute Overrun Gas.

2. To the extent that EPCOR's Upstream Service Provider provides any seasonal or day-to-day balancing rights for EPCOR, the customer shall be entitled to a reasonable proportion of such balancing rights as determined by EPCOR from time to time. If the customer utilizes any of EPCOR's seasonal or day-to-day balancing services or any other services available from the Upstream Service Provider, the customer agrees to comply with all balancing requirements imposed by the Upstream Service Provider. The customer also agrees to be liable for its share of any such usage limitations or restrictions, fees, costs or penalties associated with the usage of such services, including but not limited to any associated storage fees, daily or cumulative balancing fees or penalties, and gas commodity costs as determined by EPCOR, acting reasonably.

3. EPCOR receives upstream services under the Union Gas Limited M17 Rate Schedule. Details of this upstream arrangement and associated nomination standards and Load Balancing Arrangement are available at www.uniongas.com.

4. The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2023
Implementation: All bills rendered on or after January 1, 2023
EB-2022-0184

RATE 16 – Contracted Firm Service

Applicability

Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m^3.

Rate

Rates per m^3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge (1)	$1,606.88	
Delivery Charge		
Per m^3 of Contract Demand	109.5360	¢ per m^3
Upstream Charges		
Upstream Recovery charge per m^3 of Contract Demand	14.2434	¢ per m^3
Transportation charge per m^3 of Contract Demand		
Transportation from Dawn	18.2999	¢ per m^3
Transportation from Kirkwall	11.8480	¢ per m^3
Transportation from Parkway	11.8480	¢ per m^3
Rate Rider for Delay in Revenue Recovery	0.0601	¢ per m^3
- effective for 10 years ending December 31, 2028		
CIACVA Rate Rider	4.5311	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2023		
EFVA Rate Rider	(4.1844)	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2023		
Federal Carbon Charge (if applicable) (2)	9.79	¢ per m^3

(1) Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

(2) The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Unaccounted for Gas:
Forecasted Unaccounted for Gas (UFG) is applied to all volumes of gas delivered to the customer.

Forecasted Unaccounted for Gas Percentage	0.00	%

Overrun Charges:
Any volume of gas taken in excess of the daily Contract Demand or Peak Hourly Volume EPCOR is obligated to transport as per the contract with the customer shall constitute "Overrun Gas" and must be authorized in advance by EPCOR. Delivery of these volumes is available at the Authorized Overrun Charge in addition to applicable Upstream Charges. EPCOR will not unreasonably withhold authorization.

Authorized Overrun Charge	5.3529	¢ per m^3

Any volume of gas taken in excess of the daily Contract Demand or Peak Hourly Volume EPCOR is obligated to transport as per the contract with the customer without EPCOR's approval in advance shall constitute "Unauthorized Overrun Gas". Delivery of these volumes will be paid for at the Unauthorized Overrun Charge in addition to applicable Upstream Charges.

Unauthorized Overrun Charge	410.3041	¢ per m^3

For any volume of Unauthorized Overrun Gas taken, the customer shall, in addition, indemnify EPCOR in respect of any penalties or additional costs imposed on EPCOR by its suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

Nominations:
Union Gas Limited will be the "Upstream Service Provider" to facilitate delivery and balancing of gas supplies to the EPCOR Southern Bruce Natural Gas System. For service under this Rate Schedule, the customer shall nominate for transportation of gas volumes for ultimate delivery to the customer. The customer agrees to nominate its daily gas volumetric requirement to EPCOR, or its designated agent, consistent with industry nomination standards including those nomination requirements of the Upstream Service Provider.

The customer shall nominate gas delivery daily based on its daily gas requirements plus the Forecasted UFG rate and Fuel Ratio. The Forecasted UFG rate is as set out in this Rate Schedule. The Fuel Ratio is the Shipper Supplied Fuel rates applicable to the receipt point of gas defined in the "Gas Supply" section of this Rate Schedule.

The nomination calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Customers may change daily nominations based on the nomination windows within a day as defined by EPCOR's agreement with the Upstream Service Provider.

In the event nominations under this Rate Schedule do not match upstream nominations, the nomination will be confirmed at the upstream value.

Customers with multiple connections under this Rate Schedule may combine nominations at the sole discretion of EPCOR. For combined nominations the customer shall specify the quantity of gas to each meter installation ("Terminal Location") and the order in which the gas is to be delivered to each Terminal Location.

Load Balancing:
Daily nominations provided by the customer shall be used for the purposes of day-to-day balancing as required under EPCOR's arrangement with the Upstream Service Provider.

When a customer's metered consumption on any day is different than the gas nominated for consumption by the customer on any day, this constitutes a "Daily Load Imbalance". A "Cumulative Load Imbalance" occurs when the ongoing absolute value of Daily Load Imbalances are greater than zero.

To the extent that EPCOR incurs daily or cumulative load balancing charges, the customer will be responsible for its proportionate share of such charges. Charges related to these imbalances are as defined in EPCOR's agreement with the Upstream Service Provider.

Gas Supply:
Unless otherwise authorized by EPCOR, customers under this Rate Schedule must deliver firm gas at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). The customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. T-Service Receipt Contract rates are described in Rate Schedule T1.

The customer must deliver to EPCOR on a daily basis the volume of gas to be delivered to the customer's Terminal Location plus the Forecasted UFG rate and Fuel Ratio. Transportation charges vary depending on the Ontario Delivery Point at the rates provided in this Rate Schedule. The Forecasted UFG rate is as set out in this Rate Schedule, and the Fuel Ratio is the Shipper Supplied Fuel rates of the Ontario Delivery Point related to necessary compressor or other fuel requirements of the Upstream Service Provider.

The Gas Supply calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Terms and Conditions of Service

1. EPCOR receives upstream services under the Union Gas Limited M17 Rate Schedule. Details of this upstream arrangement and associated nomination standards, applicable Fuel Ratio, and Load Balancing Arrangement are available at www.uniongas.com.

2. The provisions in the "EPCOR Natural Gas Limited Partnership General Terms and Conditions for Rate 16 Customers" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2023
Implementation: All bills rendered on or after January 1, 2023
EB-2022-0184

RATE T1 – Direct Purchase Contract Rate

Availability
Rate T1 is available to all customers or their agent who enter into a T-Service Receipt Contract for delivery of gas to EPCOR. The availability of this option is subject to EPCOR obtaining a satisfactory agreement or arrangement with EPCOR's Upstream Service Provider for direct purchase volume.

Eligibility
All customers who must, or elect to, purchase gas directly from a supplier other than EPCOR. These customers must enter into a T-Service Receipt Contract with EPCOR either directly or through their agent, for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**").

Rate
All charges in the customer's appropriate Rate Schedule excluding Gas Supply Charge shall apply. Applicable Transportation and Storage charges are determined based on the Ontario Delivery Point.

In addition, administration fees apply to customers who elect to enter into a T-Service Receipt Contract with EPCOR and are detailed in the Direct Purchase Contract with the customer or its agent.

For gas delivered to EPCOR at any point other than the Ontario Delivery Point, EPCOR will charge the customer or their agent all approved tolls and charges incurred by EPCOR to transport the gas to the Ontario Delivery Point.

Unaccounted for Gas:
Forecasted Unaccounted for Gas (UFG) is applied to all volumes of gas supplied:

Forecasted Unaccounted for Gas Percentage	0.00	%

Gas Supply:
Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must deliver firm gas at a daily volume acceptable to EPCOR, to an Ontario Delivery Point, and, where applicable, must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

The customer or its agent must deliver to EPCOR on a daily basis, at the Ontario Delivery Point, the volume of gas to be delivered to the customer's Terminal Location plus the Forecasted UFG rate and Fuel Ratio. Where the Forecasted UFG rate is as set out in this Rate Schedule, and the Fuel Ratio is the Shipper Supplied Fuel rates of the Ontario Delivery Point related to necessary compressor or other fuel requirements of the Upstream Service Provider.

The Gas Supply calculation shall equal:
[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Terms and Conditions of Service
The provisions in the "T-Service Receipt Contract General Terms and Conditions" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2023
Implementation: All bills rendered on or after January 1, 2023
EB-2022-0184

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Schedule of Miscellaneous and Service Charges

	A Service	B Fee
1	Service Work	
2	During normal working hours	
3	Minimum charge (up to 60 minutes)	$100.00
4	Each additional hour (or part thereof)	$100.00
5	Outside normal working hours	
6	Minimum charge (up to 60 minutes)	$130.00
7	Each additional hour (or part thereof)	$105.00
8		
9	Miscellaneous Charges	
10	Returned Cheque / Payment	$20.00
11	Replies to a request for account information	$25.00
12	Bill Reprint / Statement Print Requests	$20.00
13	Consumption Summary Requests	$20.00
14	Customer Transfer / Connection Charge	$35.00
15		
16	Reconnection Charge	$85.00
17		
18	Inactive Account Charge	ENGLP's cost to install service
19		
20	Late Payment Charge	1.5% / month, 19.56% / year (effective rate of 0.04896% compounded daily)
21		
22		
23	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs
24	Installation of Service Lateral [3]	No charge for the first 30 meters

Note: Applicable taxes will be added to the above charges

[3] No Charge for initial connection

Appendix C - Proposed Customer Notice

IMPORTANT INFORMATION ABOUT YOUR NATURAL GAS BILL

The rates EPCOR Natural Gas Limited (EPCOR) charges its customers are set out in EPCOR's Rate Schedules, which are approved by the Ontario Energy Board (OEB) from time to time. When EPCOR's Rate Schedules are amended by the OEB, the amended rate(s) and/or term(s) will apply to customers on the effective date established by the OEB.

On **XXX**, 2022, the OEB approved EPCOR's gas distribution rates effective January 1, 2023. For a typical residential customer who consumes about 2,100 cubic meters of gas annually, the rate change will increase the bill by $0.38 per month. Commercial, industrial and seasonal rate customers will also be impacted by the change. Please refer to epcor.com or visit OEB.ca for information on the current approved rates.

The approved rates are reflected in the following line items on your EPCOR natural gas bill:

1. **"Monthly Charge"** – This is an administration charge covering the costs of maintaining gas services and providing billing and customer service. Included in this charge, is the $1 per month required to be billed to all customers as part of the Access to Natural Gas Act (Bill 32), which helps to facilitate the expansion of natural gas into more Ontario communities.
2. **"Delivery and Upstream Charges"** – These charges reflect the costs associated with the distribution, transportation and storage of natural gas from the source to you. This includes all charges EPCOR pays to its upstream service provider in association with transportation and storage of the gas before it is delivered to EPCOR's system. Included in this charge is a rate rider to recover revenue the utility was not able to collect as a result of delays in connecting customers to the system.
3. **"Gas Supply Charge"** – These are gas commodity costs calculated using the cost of gas you use during the period between meter readings (or based on an estimate of the gas used during that period). The commodity rate you are charged on your EPCOR bill depends upon the commodity purchase choice you have made. If you have not signed a contract with an energy retailer you are automatically billed at EPCOR's OEB approved gas commodity rate. If you have signed a contract with an energy retailer you are billed at your contracted energy retailer rate.
4. **"Federal Carbon Charge"** –This charge reflects your monthly consumption and the associated costs to deliver natural gas to your home at the rate set by the government. The money collected from this charge goes to the federal government as part of its carbon pollution pricing program.

When applicable, miscellaneous and/or service charges as set out in EPCOR's Rate Schedules, may appear on your bill in addition to the above charges. Please see the EPCOR's Conditions of Services for more detail on these charges.

Your natural gas bill includes information on the amount of natural gas you consumed in the billing period. Your consumption information is broken out to include length of the billing period, the date of your last meter reading and whether your consumption calculation was based on actual or estimated meter reading or a combination of both.

If you have any questions about the rates or any other items on your bill, please call our office at 1-888-765-2256 or email at gas@epcor.com.

Appendix D - Auditor’s Report

Tel: 519-432-5534
Fax: 519-432-6544
www.bdo.ca

BDO Canada LLP
633 Colborne St., Suite 230
London ON N6B 2V3

Agreed-Upon Procedures Report

To the Management of EPCOR Natural Gas Limited Partnership:

Purpose of this Agreed-Upon Procedures Report

Our report is solely for the purpose of assisting EPCOR Natural Gas Limited Partnership (the "Entity") in assessing the deferral accounts of the Southern Bruce operations in the CIACVA, ECVA and MTVA to comply with the requirements of the Ontario Energy Board (OEB) for the period from January 1, 2021 to December 31, 2021 and may not be suitable for another purpose.

Management's Responsibilities

Management has acknowledged that the agreed-upon procedures are appropriate for the purpose of the engagement. Management is responsible for the subject matter on which the agreed-upon procedures are performed.

Practitioner's Responsibilities

We have conducted the agreed-upon procedures engagement in accordance with the Canadian Standard on Related Services (CSRS) 4400, Agreed-Upon Procedures Engagements. An agreed-upon procedures engagement involves our performing the procedures that have been agreed with the Entity, and reporting the findings, which are the factual results of the agreed-upon procedures performed. We make no representation regarding the appropriateness of the agreed-upon procedures.

This agreed-upon procedures engagement is not an assurance engagement. Accordingly, we do not express an opinion or an assurance conclusion.

Had we performed additional procedures, other matters might have come to our attention that would have been reported.

Professional Ethics

We have complied with the relevant ethical and independence requirements set out in rules of professional conduct / code of ethics in Canada.

Procedures and Findings

We have performed the procedures described in Appendix A, on the deferral accounts as at December 31, 2021, which were agreed upon with the Entity. As a result of performing these procedures, we found no exceptions.

BDO Canada LLP

London, Canada
June 24, 2022

Chartered Professional Accountants
Licensed Public Accountants

APPENDIX A

1. We obtained the schedule of deferral activity for CIACVA, ECVA and MTVA from January 1, 2021 to December 31, 2021 and recalculated the schedule to ensure their mathematical accuracy.

2. For CIACVA, we obtained the back-up calculations spreadsheet for both the CIAC revenue requirement based on the amount paid and based on the filing for the 2021 opening and ending balances. In the calculations spreadsheet, we vouched the capital expenditures during 2021 to the supporting invoices from Enbridge. For the 2021 opening balances, we vouched the capital expenditures in 2019 and 2020 to the agreement with Enbridge dated June 13, 2019 and subsequent CIAC Owen Sound invoices in 2020 and 2021.

3. For the ECVA, we agreed the Actual Energy Content to the unit of measure conversion information effective April 1, 2021 for South and the Benchmark Energy Content to Ontario Energy Board's Exhibit 9 Contents. We also agreed the delivery charges for 2021 to the financial model supporting the EB 2018-0264 application (EPCOR 2019 Financial Model Protected_20190412) and the sum of total delivery charges to the cumulative 10 year data from the rate application (EB 2018-0264).

4. For MTVA, we obtained the annual billed distribution revenue summary and distribution revenue per CIP and vouched samples throughout the year among the billed distribution revenue and property taxes. We also vouched the municipal taxes paid in the year.

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Contribution In Aid of Construction variance account

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year	
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	704,053	-	
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	399,485	-	
Difference	-	-	-	-	-	-	-	-	-	-	-	304,568	-	
Cumulative	-	-	-	-	-	-	-	-	-	-	-	304,568	304,568	
Opening Interest														
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-	2,764	
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-	2,764	
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.91%	(2)

	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2021 Year	
CIAC revenue requirement based on amount paid												511,168	-	
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	406,235	-	
Difference	-	-	-	-	-	-	-	-	-	-	-	104,933	-	
Cumulative	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	61,509	61,509	(1)
Opening Interest	-	-	(79)	(158)	(237)	(316)	(394)	(415)	(436)	(456)	(477)	(498)	(518)	
Interest calculation on disposal balance	-	(79)	(79)	(79)	(79)	(79)	(21)	(21)	(21)	(21)	(21)	(21)	351	
Closing Interest	-	(79)	(158)	(237)	(316)	(394)	(415)	(436)	(456)	(477)	(498)	(518)	(168)	(1)
OEB Prescribed Interest Rate	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	

	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	161,381
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	204,805
Difference	-	-	-	-	-	-	-	-	-	-	-	(43,424)
Cumulative	-	-	-	-	-	-	-	-	-	-	-	(43,424)
Opening Interest												
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate	2.45%	2.45%	2.45%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%

(1) - Variance balances approved for disposition in EB-2020-0234
(2) - 2022 forecast interest rate calculated using a weighted average of Q1'22 rate of 0.57% at 1/4 and Q2'22 rate of 1.02% at 3/4

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Energy Content variance account

		2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year	
Annual CIP Rev R1, 6, 11 (H)	2,444,588														
Actual Energy Content (I)	39.32														
Benchmark Energy Content (J)	38.89														
Difference (H * ((I - J)/I))		-	-	-	-	-	-	-	-	-	-	-	26,734	-	
Cumulative		-	-	-	-	-	-	-	-	-	-	-	26,734	26,734	
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-	243	
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-	243	
OEB Prescribed Interest Rate		0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.91%	(2)

		2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2021 Year	
Annual CIP Rev R1, 6, 11 (E)	1,333,805														
Actual Energy Content (F)	39.28														
Benchmark Energy Content (G)	38.89														
Difference (E * ((F - G)/F))		-	-	-	-	-	-	-	-	-	-	-	13,243	-	
Cumulative		864	864	864	864	864	864	864	864	864	864	864	14,107	14,107	(1)
Opening Interest		-	2	3	5	6	8	9	10	10	11	11	11	12	
Interest calculation on disposal balance		2	2	2	2	2	2	0	0	0	0	0	0	80	
Closing Interest		2	3	5	6	8	9	10	10	11	11	11	12	92	(1)
OEB Prescribed Interest Rate		2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	

		2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
Annual CIP Rev R1, 6, 11 (A)	374,194												
Actual Energy Content (B)	38.98												
Benchmark Energy Content (C)	38.89												
Difference (A * ((B - C)/B))		-	-	-	-	-	-	-	-	-	-	-	864
Cumulative		-	-	-	-	-	-	-	-	-	-	-	864
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate		2.45%	2.45%	2.45%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%

(1) - Variance balances approved for disposition in EB-2020-0234
(2) - 2022 forecast interest rate calculated using a weighted average of Q1'22 rate of 0.57% at 1/4 and Q2'22 rate of 1.02% at 3/4

Appendix E - Draft CVVA Accounting Order

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Municipal Tax variance account

	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
Billed Distribution revenue												0
Distribution Revenue per CIP												589,357
Municipal taxes per CIP												213,867
Ratio	-	-	-	-	-	-	-	-	-	-	-	36.3%
Property taxes collected through revenues	-	-	-	-	-	-	-	-	-	-	-	-
Property taxes paid	-	-	-	-	-	-	-	-	-	-	-	-
Difference	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative	-	-	-	-	-	-	-	-	-	-	-	-
Opening Interest	-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate	2.45%	2.45%	2.45%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%

	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
Billed Distribution revenue												460,454
Distribution Revenue per CIP												3,049,735
Municipal taxes per CIP												376,964
Ratio	-	-	-	-	-	-	-	-	-	-	-	12.4%
Property taxes collected through revenues												56,915
Property taxes paid												0.0%
Difference	-	-	-	-	-	-	-	-	-	-	-	(56,915)
Cumulative	-	-	-	-	-	-	-	-	-	-	-	(56,915)
Opening Interest	-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year
Billed Distribution revenue												1,897,887	
Distribution Revenue per CIP												4,620,572	
Municipal taxes per CIP												546,701	
Ratio												11.8%	
Property taxes collected through revenues												224,556	
Property taxes paid								525					
Difference	-	-	-	-	-	-	-	525	-	-	-	(224,556)	-
Cumulative	(56,915)	(56,915)	(56,915)	(56,915)	(56,915)	(56,915)	(56,915)	(56,390)	(56,390)	(56,390)	(56,390)	(280,946)	(280,946)
Opening Interest	-	(27)	(54)	(81)	(108)	(135)	(162)	(189)	(216)	(243)	(270)	(297)	(323)
Interest calculation on disposal balance	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(2,550)
Closing Interest	(27)	(54)	(81)	(108)	(135)	(162)	(189)	(216)	(243)	(270)	(297)	(323)	(2,873)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.91% (1)

(1) - 2022 forecast interest rate calculated using a weighted average of Q1'22 rate of 0.57% at 1/4 and Q2'22 rate of 1.02% at 3/4

EPCOR NATURAL GAS LIMITED PARTNERSHIP

DRAFT ACCOUNTING ORDER

CUSTOMER VOLUME VARIANCE ACCOUNT ("CVVA")

The Customer Volume Variance Account is to record the variance in revenue by rate class resulting from the difference between customer volume forecast based on common assumptions and the actual customer volume. This account will record such resulting variances in revenue for Rate 1 and Rate 6 since a common assumption related to customer usage volume was used for these rate classes in the development of the Common Infrastructure Plan as submitted by EPCOR in EB-2016-0137 / EB-2016-0138 / EB-2016-0139.

The effective date of this account is June **XX**, 2022. Notwithstanding the effective date of June **XX**, 2022, this account will record revenue variances as a result of variance in customers' usage volume as of January 1, 2020. This account will record such variances until December 31, 2028.

The common assumption volumes per customer by rate class to be used in determining the balances to be recorded in this account are as follows:

Rate Class	**Segment / Sub-segment**		**Average Annual Consumption (M^3/year)**
Rate 1	Residential	Pre-existing Homes	2,149
		Future Construction	2,066
	Commercial	Small (0-15,000 m^3/year)[28]	4,693
Rate 6		Medium (15,001- 50,000 m^3/year)	26,933
		Large (>50,000 m^3/year)	75,685
	Agricultural	Cash Crop Farm (excl. large grain dryers)	4,720
		Other Agri-Business	4,720

In order that EPCOR retain the risk related to customer connection counts, the common assumption volumes per customer outlined in the table above will be applied to the actual customer connections for each corresponding customer segment and rate class to determine the "Common Assumptions Customer Volume".

The balance to be recoded in this account will be calculated as the difference between the Common Assumptions Customer Volume and the actual volume for the same time period multiplied by the relevant tariff for that period. Separate calculations for each customer type[29] within a rate class will be completed and then each subaccount (for Class 1 and Class 6) will record the total resulting from calculations of the customer types in that rate class.

[28] Small commercial customers with a volume greater than 10,000m3/year will be billed as a Rate 6 customer.
[29] As an example, Rate Class 1 includes Residential Pre-existing, Residential Future Construction and Small Commercial Customers.

$$\left(\text{Customer Volume Common Assumption by Customer Type within a Rate Class} - \text{Actual Customer Volume by Customer Type within a Rate Class} \right) \times \text{Tariff for Rate Class}$$

Simple interest is to be calculated monthly on the opening balance in the CVVA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance of this account, together with carrying charges, will be brought forward for approval for disposition an annual basis, unless otherwise directed by the Board. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

<u>Accounting Entries</u>

Subaccount to record the revenue impact of the difference between common volume assumptions and actual volume consumed by Rate Class 1:

Debit / Credit Account No. 179.96 Customer Volume Variance Account – Rate 1 (CVVA)

Credit / Debit Account No. 300 Operating Revenue

To record simple interest on the opening balance of the CVVA for Rate Class 1:

Debit / Credit Account No. 179.97 Interest on Customer Volume Variance Account – Rate 1

Credit / Debit Account No. 323 Other Interest Expense

Subaccount to record the revenue impact of the difference between common volume assumptions and actual volume consumed by Rate Class 6:

Debit / Credit Account No. 179.98 Customer Volume Variance Account – Rate 6 (CVVA)

Credit / Debit Account No. 300 Operating Revenue

To record simple interest on the opening balance of the CVVA for Rate Class 6:

Debit / Credit Account No. 179.99 Interest on Customer Volume Variance Account - Rate 6

Credit / Debit Account No. 323 Other Interest Expense