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October 22, 2024

Sent by EMAIL, RESS e-filing

Ms. Nancy Marconi
Registrar
Ontario Energy Board
27-2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi,

Re: EB-2024-0238: EPCOR Natural Gas Limited Partnership's ("ENGLP") 2025 Custom Incentive Rate Adjustment Application – Southern Bruce

In accordance with Procedural Order #1, please find enclosed responses to the Ontario Energy Board (OEB) Staff interrogatories in the above proceeding.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Digitally signed by Hesselink, Tim
Date: 10/22/24 1:30:09 PM

Tim Hesselink, CPA
Senior Manager, Regulatory Affairs
EPCOR Natural Gas Limited Partnership
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Encl.

EPCOR Natural Gas Limited Partnership
Responses to OEB Staff Interrogatories
EB-2024-0238

OEB Staff.1 – Municipal Tax Variance Account (MTVA)

Ref: 2025 Incentive Rate Adjustment Application, pg 16-17
Appendix D- Auditor's Report, pg. 73

The MTVA records 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. ENGLP has requested the disposition of its 2023 MTVA balance of a debit of $ 77,670 (including interest).

OEB staff notes that the previous MTVA balances approved for disposition are as follows:

Proceeding #	Description	MTVA Balance Approved for Disposition (not including interest)
EB-2023-0161	2022 MTVA year-end balances	$(336,285)
EB-2022-0184	2021 MTVA year-end balances	$(280,946)

The following was taken from Appendix D- Auditor report

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

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
Billed Distribution revenue												5,034,240	
Distribution Revenue per CIP												6,645,722	
Municipal taxes per CIP												581,587	
Ratio												8.8%	
Property taxes collected through revenues												440,561	
Other													
Property taxes paid	118	293			202,644	43,027	209	256,669	50				
Difference	118	293	-	-	202,644	43,027	209	256,669	50	-	-	(440,561)	-
Cumulative	118	411	411	411	203,055	246,082	246,292	502,961	503,011	503,011	503,011	62,450	62,450
Opening Interest	-	-	0	2	4	6	848	1,869	2,892	4,979	7,280	9,581	11,883
Interest calculation on disposal balance	-	0	2	2	2	843	1,021	1,022	2,087	2,301	2,301	2,301	3,341
Closing Interest	-	0	2	4	6	848	1,869	2,892	4,979	7,280	9,581	11,883	15,224
OEB Prescribed Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	5.35%

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year
Billed Distribution revenue												3,469,603	
Distribution Revenue per CIP												5,818,265	
Municipal taxes per CIP												565,324	
Ratio												9.7%	
Property taxes collected through revenues												337,120	
Property taxes paid	-	106	260	-	-	-	-	439	30	-	-	-	
Difference	-	106	260	-	-	-	-	439	30	-	-	(337,120)	-
Cumulative	-	106	366	366	366	366	366	805	835	835	835	(336,285)	(336,285) (2)
Opening Interest	-	-	-	0	0	1	1	2	2	4	6	9	12
Interest calculation on disposal balance	-	-	0	0	0	0	1	1	1	3	3	3	(16,537)
Closing Interest	-	-	0	0	1	1	2	2	4	6	9	12	(16,525) (2)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	4.92%

	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) (1)
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)	(4,207)
Closing Interest	(27)	(54)	(81)	(108)	(135)	(162)	(189)	(216)	(243)	(270)	(297)	(323)	(4,531) (1)
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%	1.50%

Questions:

a) Please explain why in the previous two years (2021 and 2022) there were substantial credit balances in the MTVA account and now there is a debit balance in 2023.

ENGLP Response:

ENGLP experienced a lag in receiving all the relative property tax assessments and corresponding tax billing in 2021 and 2022. Without all the assessments completed, ENGLP would not have been billed for the entirety of property taxes owed in those years, but was earning revenue to remit taxes, resulting in a credit to customers.

These assessments are now being finalized as the Southern Bruce project is complete and ENGLP expects a better balance between revenue collected to pay taxes and taxes paid, resulting in smaller fluctuations in the MTVA balance in future years related to this timing issue.

b) Please explain what occurred in May 2023 and August 2023 that incurred debit balances of $202,644 and $256,669, respectively.

ENGLP Response:

ENGLP paid actual property taxes in these periods.

OEB Staff.2- Customer Volume Variance Account (CVVA)

Ref: 2025 Incentive Rate Adjustment Application, page 20-22
Excel file: ENGLP_APPL_2025 Custom IR_SB_CVVA_20240815 (CVVA Workbook)
EB-2022-0184, ENGLP_Addl EVD_CVVA_20221114.PD, November 14, 2022 (CVVA Process)

ENGLP utilized the services of Power Advisory Inc. to complete the weather normalization calculation as part of the balance determination.

ENGLP included a workbook with the calculations of the CVVA (CVVA Workbook).

In ENGLP's 2023 Custom IR update proceeding, ENGLP provided a document describing how the CVVA is calculated (CVVA Process). In the CVVA Process, ENGLP stated that due to the timing of year-end close and delays in data availability, amounts consumed in November/December would not be fully billed until the following calendar year. For this reason, ENGLP intended to book an accrual in the CVVA using the available regression results based on actual data and apply to the weather normal heating degree day, providing a weather normalized average consumption that can be used to reasonably estimate year end results.

ENGLP's regulated net income was ($2.484M) loss in 2023, resulting in a calculated ROE of (7.34%).

ENGLP proposes to recover the CVVA balances through the implementation of a twelve-month fixed rate rider commencing on January 1, 2025. ENGLP noted that a fixed rate rider was chosen as it appears to be more equitable, as a variable rate rider would be punitive to customers who are using more gas, which is counter-intuitive to the purpose of the CVVA.

Questions:

a) Please provide rational to why Power Advisory was chosen to complete the weather normalization calculation.
    i. Please provide credentials.

ENGLP Response:

ENGLP felt it was appropriate to have a qualified third party complete the weather normalization calculation given that this was the initial disposition of the CVVA.

Power Advisory has performed services for ENGLP in 2023 and 2024 both the Gas Supply Plan and the ENGLP-Aylmer cost of service filing. The weather normalization calculation was prepared by Andrew Blair, who moved from Elenchus to Power Advisory in July 2023. With Elenchus, Mr. Blair prepared ENGLP's throughput forecasts in its 2020-2024 rates application and each gas supply plan filing since that application. Additionally, he regularly prepares load forecasts for electricity LDC cost of service applications that have been approved by the OEB or accepted in settlement agreements.

Mr. Blair's credentials have been included with this submission as Appendix A

b) Please confirm that the CVVA Accounting Order was followed when calculating the balances in CVVA.

ENGLP Response: Confirmed

c) Please confirm that the CVVA Process was followed when calculating the CVVA balances.

ENGLP Response: Confirmed

d) OEB staff notes that in the CVVA Process, the amounts consumed in November/December would not be fully billed and ENGLP intends to book an accrual. Please confirm if the October 2023 numbers are actuals or accruals.

    i. If the October 2023 numbers are accruals please explain why there is a deviation from the CVVA Process.

ENGLP Response: There are no accruals included in the calculation for the October values. The calculations were not completed until actuals were available.

e) In the CVVA Workbook, under Tab “2023 R1_RES”, and “2023 R1_AG”, in cells K14, L14 and M14, each cell’s formula refer to the Tab “2021 R1_COM”. In the CVVA Process, Step 3, states: “take the most recent average annual consumption for each rate class and category of customers, then remove the baseload consumption from these values.” Please explain why when calculating the actual average (with CIP Heat Value) the Rate 1 commercial numbers are referred in the residential and agricultural calculations cells.

   i. If required, please correct any errors.

ENGLP Response:

The calculations/values in the cells noted above had not been updated with actuals as the original model contemplated accruals for Q4 of the year being calculated. ENGLP has updated the cells in the accompanying CVVA model (cells highlighted in yellow on each respective tab). Note the adjustment of these cells do not change the resulting calculation of the CVVA balance.

f) Please provide a step-by-step example to show how “NAC w/ actual connections” are calculated (i.e. Tab “2023 R1_RES”, cell B23)

ENGLP Response:

NAC w/ actual connections is calculated using the weather-normalization methodology used in ENGLP’s 2020-2024 cost of service application for its Aylmer service area (EB-2018-0336), which it is also used in its 2025-2029 cost of service application (EB-2024-0130).

Actual monthly consumption from January 2021 to December 2023 is predicted using a base load and excess consumption method. Average monthly consumption per customer is first calculated for each class. The amounts are then reduced by the base load consumption, which is considered the average consumption in the summer months of July and August. The remaining consumption is considered the weather-sensitive load (or “excess” load).

A multivariate regression analysis is done to estimate excess load, using actual heating degree days in each month to determine the impact of cold weather on average consumption. Heating degree days are a measure of heating load, equal to 18ºC less the actual temperature for each day in which the average daily temperature is below 18ºC. Heating degree days values used in the regression analysis are the sum of daily heating degree days in the month. The time-series regression uses the natural logarithm of excess load as the dependent variable and the natural logarithm of heating degree days in each month as the independent variables. This regression determines the coefficient of heating degree days in each month, which indicates the impact of each heating degree day on gas consumption.

To estimate weather-normal consumption, actual heating degree days are subtracted from "normal weather" heating degree days and the difference is multiplied by the coefficients from the regression analysis. Normal weather heating degree days are the 10-year average of heating degree days from 2014 to 2023. The product of the heating degree difference multiplied by the heating degree day coefficient is then added to actual excess consumption and baseload consumption to produce weather-normal consumption per customer. This is multiplied by the number of customers to provide the total class weather-normal consumption.

A step-by-step example calculation for the January 2023 NAC with actual connections is provided below.

	Class Consumption	Customers	Consumption Per Customer	Baseload	Excess	Ln (Excess)
	A	B	C = A / B	D	E = C - D	F = ln (E)
Jan 23	813,901 m^3	3,299	246.7 m^3	24.5 m^3	222.2 m^3	5.4036

	January 2023 HDD	Ln (January 2023 HDD)	Avg. January HDD	Ln (Avg. January HDD)	Ln HDD Difference
	G	H = ln(G)	I	J = ln(I)	K = J - H
Jan 23	578.8	6.361	690.87	6.538	0.1772

	January ln HDD Coefficient	Ln HDD Impact	Ln (Actual plus HDD Impact)	Actual plus HDD Impact	Actual with HDD Impact plus Baseload	Total Weather-Normal Class Consumption
	L	M = K * L	N = F + M	O = e^N	P = D + O	Q = P * B
Jan 23	0.8193	0.1469	5.5506	257.4 m^3	281.9 m^3	929,923 m^3

g) Please provide detailed calculations on the ROE.

ENGLP Response:

The -7.34% value was calculated using ENGLP's Southern Bruce annual RRR filing contributed values*:

2023 Regulatory Net Income	($2,483,796)
Regulated Equity	
Opening Rate base	$92,781,799
Closing Rate base	$95,165,484
Mid-Year Rate base	$93,973,642
Equity Component	36%
	$33,830,511
ROE	**(7.34%)**

*Note for the purposes of the RRR, ENGLP Aylmer and Southern Bruce are required to be submitted as a combined entity.

h) ENGLP stated that a fixed rate rider is more equitable, please provide further discussion on the equity considerations in selecting a fixed rate vs variable rate.
   i. Provide the annual cost impact for a variable rate under the following scenarios for residential:
      i. Customers in the bottom 10% of gas usage.
      ii. Customers that average usage.
      iii. Customers in the top 10% of gas usage.
   ii. Compare the annual bill impacts of the fixed rate to the three scenarios above.

ENGLP Response:

The need for the CVVA was driven by lower customer consumption, or conversely, a higher load forecast than what is actually being experienced. Because average customers have consumed less gas than expected, there is a revenue shortfall.

ENGLP consider both a fixed and variable rate rider before ultimately proposing a recommendation of a fixed rate for the recovery of the CVVA. As per the accounting order[1], *"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 Normalized Average Customer Volume ("NACV")"*

A variable rate rider would result in a higher overall cost to customers who are consuming more gas, when it could be argued that high consumption customers contributed less to the need for the CVVA as their consumption patterns contributed less to the revenue shortfall. As a result, a variable rate rider could be considered punitive to those customers.

A fixed rate rider results in a more balanced recovery of the revenue shortfall collected through the CVVA as it is not based on consumption. This reduces the impact on high usage customers and allocates a targeted share of the revenue shortfall to customers making lower contributions to supporting the network. As

[1] EB-2022-0184 Accounting Order, October 26, 2023, Page 10 of 14.

a result, ENGLP believes a fixed rate rider is more equitable given the nature of the CVVA.

ENGLP has updated the rate model with additional tabs to provide the information requested. Refer Tab "Staff-2". A summary of the information has been included below:

CVVA Calculations:

CVVA Fixed Rate Rider

		A **Unit**	B **Rate 1**
1	Customer Count	#	5,516
2	Sum	$	$355,612
3	**Rate Rider**	**$/month**	**$5.37**

CVVA Variable Rate Rider

		A **Unit**	B **Rate 1**
1	Consumption	m3	8,270,620
2	Sum	$	$355,612
3	**Rate Rider**	**¢/m3**	**$4.29970**

Customer Bill Impacts:

		A	B	C	D	E	F	G
		Usage	**CVVA**		**Total Bill**			
		m3	Fixed	Variable	Fixed	Variable	Variance $	Variance %
1	Average User	2,149	$64	$92	$1,842	$1,870	$28	1.5%
2	Bottom 10 %	264	$64	$11	$589	$536	($53)	-9.0%
3	Top 10 %	3,100	$64	$133	$2,473	$2,541	$69	2.8%

Note – variances are presented in comparison to the fixed rate rider. The average user would see a $28 annual *increase* (1.5%) in their total annual bill if the rate rider were changed from a fixed to a variable calculation. A bottom 10 percentile would experience a $53 *decrease* in their total annual bill. A top 10 percentile customer would experience a $69 i*ncrease* their total annual bill.

OEB Staff.3 – Bill Impacts

Ref: 2025 Incentive Rate Adjustment Application, page 24
OEB Handbook for Utility Rate Applications (October 13, 2016); see Introduction (page 1) and Rate Mitigation (Appendix 3, page v) (OEB Handbook)

ENGLP provided a table summarizing bill impacts for each rate class assuming the average consumption level of the rate class based on the forecasted 2025 customer connections and volumes.

Table 20 – Illustrative Bill Impact Summary

Rate Class	Description	Fixed Charge ($/year)	Fixed Charge (%)	Volumetric Charge ($/year)	Volumetric Charge (%)	Rate Riders ($/year)	Rate Riders (%)	Total ($/year)	Total (%)
Rate 1 (1)	Existing Residential	$7	2%	$13	2%	$122	322%	$141	8%
Rate 1 (1)	New Residential	$7	2%	$12	2%	$119	329%	$138	8%
Rate 1	Small Commercial	$7	2%	$27	2%	$189	229%	$223	7%
Rate 1	Small Agricultural	$7	2%	$27	2%	$190	229%	$224	7%
Rate 6	Medium Commercial	$27	2%	$137	2%	$747	1677%	$910	5%
Rate 6	Large Commercial	$27	2%	$371	2%	$3,042	2431%	$3,439	7%
Rate 11	Sample Dryer 1	$54	2%	$342	2%	$910	180%	$1,306	3%
Rate 11	Sample Dryer 2	$54	2%	$1,141	2%	$3,032	180%	$4,227	3%
Rate 16	Contracted Demand	$395	2%	$13,484	2%	$40,263	-784%	$54,143	6%

Residential customers are expected to see an 8% increase in their annual bill impact.

In the OEB Handbook, it states:

The OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities. For electricity distributors, the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required when their proposals result in material impacts to customers.

Questions:

a) Even though ENGLP is not an electricity distributor, does ENGLP believe that ENGLP South Bruce should file a mitigation plan when the total bill impact is 10% or more for any rate class?

ENGLP Response:

ENGLP should be required to submit a mitigation plan or provide sufficient rationale as to why mitigation would not be possible.

b) When ENGLP implements the approved 2025 rates and if at that time the total bill impacts for customers are over 10%, will ENGLP propose a mitigation plan?

ENGLP Response:

Refer to Part a above. Note that ENGLP is not proposing increases greater than 10% for any specific rate class.

Appendix A – Power Advisory Credentials

Andrew Blair
Manager, Regulatory

Power Advisory LLC
55 University Avenue
Suite 700, PO Box 32
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ablair@poweradvisoryllc.com

SUMMARY

Andrew Blair is an energy sector professional with eight years of experience in energy regulation. His primary focus is economic price regulation, including cost allocation and rate design. He regularly prepares models, reports, and other written evidence for electricity and natural gas utility application filings and appears in regulatory hearings.

Prior to joining Power Advisory, Andrew was a Senior Consultant with Elenchus Research Associates. Andrew has been engaged in the energy regulatory process with a range of clients including utilities, consumer advocates, an electricity worker union, and industrial customers across multiple jurisdictions. Andrew provides cost of service support to 3 to 5 Ontario distributors annually, primarily in the areas of load forecasting, cost allocation, and rate design. He is also an instructor in MEARIE's Regulatory Specialist Certificate program in these areas.

His experience in economic price regulation extends beyond the energy sector to water utilities and setting quasi-governmental user fees. Andrew holds an MA in Economics from Carleton University and a BA in Economics and Financial Management from Wilfrid Laurier University.

Professional History

Power Advisory LLC, Manager, Regulatory, 2023- Present
Elenchus Research Associates, Senior Consultant, 2016-2023

Education

Carleton University, MA Economics, 2014
Wilfried Laurier University, BA Economics and Financial Management, 2012

PROFESSIONAL EXPERIENCE

Cost of Service and Tariff Design

- New Brunswick Power, prepared cost allocation evidence for annual general rate applications and rate design hearing. Contributed to expert reports on cost allocation issues and proposed methodology changes for NB Power. Appeared before New Brunswick Energy & Utilities Board in GRA and Rate Design hearings as NB Power subject matter expert in area of cost allocation.
- Ontario Energy Board, contributed to *Electric Delivery Rates for Electric Vehicle Charging* report which assessed rate design options for commercial EV fleets and public DC fast chargers.
- Montserrat Utilities Ltd., for an integrated resource plan, cost of service and tariff study led by HATCH, created a cost allocation model to attribute costs to electricity, water, and wastewater services and to rate classes within each service. Proposed changes to tariff structures.

- Burlington Hydro, prepared load forecast, cost allocation, and rate design models and evidence for cost of service application to OEB.
- Grimsby Power Inc., prepared load forecast, cost allocation, and rate design models and evidence for cost of service application to OEB.
- SaskPower, prepared rate design analysis for proposed standby rates in report submitted to the Saskatchewan Rate Review Panel. Prepared cost of service jurisdictional review of best cost allocation and rate design practices.
- EfficiencyOne Nova Scotia, prepared and revised long-term rate and bill impact analysis model for Nova Scotia demand-side management programs. Prepared cost allocation and savings allocation models.
- Bluewater, prepared load forecast, cost allocation, and rate design models and evidence for cost of service application to OEB.
- E.L.K. Energy, prepared load forecast, cost allocation, rate design, and benchmarking models and evidence for cost of service application to OEB.
- EPCOR Electricity Distribution Ontario, prepared load forecast, cost allocation, and rate design models and evidence for cost of service application to OEB.
- Greater Sudbury Hydro, prepared load forecast, cost allocation and rate design models and evidence for cost of service application to OEB.
- Lakeshore Utilities, prepared 40-year cost of service and bill analysis for prospective natural gas utility along the north shore of Lake Superior. Also prepared bill-smoothing and rate mitigation analysis.
- Hydro Ottawa, prepared cost allocation and rate design models and evidence for cost of service application to OEB.
- Hydro One Transmission, prepared report on export transmission service rates based on cost allocation between domestic and export services and appeared on expert panel on export transmission rates.
- Independent Electricity System Operator, prepared annual cost allocation and usage fee design models for revenue requirement submissions.
- Utilities Kingston, prepared electricity load forecast, cost allocation, and rate design models and evidence for Kingston Hydro's cost of service application to OEB. Also prepared water and wastewater cost allocation models and report for setting municipal water rates.
- Milton Hydro, prepared load forecast, cost allocation, rate design, and benchmarking models and evidence for cost of service application to OEB.
- Synergy North, prepared load forecast, cost allocation, and rate design models and evidence for cost of service application to OEB, including rate harmonization and rate mitigation plans for merging Thunder Bay Hydro and Kenora Hydro rate zones.
- Power Worker's Union, act as intervenor on behalf of the Ontario Power Worker's Union in OEB consultations and rate cases of large utilities with PWU-represented employees. Reviewed evidence, prepared interrogatories and submissions on behalf of the PWU in rate cases for Hydro One, Ontario Power Generation, Toronto Hydro, Alectra Utilities, and Elexicon Energy.
- MEARIE Regulatory Specialist Training – conducted training in areas of load forecast, cost allocation, and rate design for cost of service applications to employees of Ontario distribution utilities.