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

BY EMAIL and RESS

March 16, 2023
Our File: EB20220028

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

Attn: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: EB-2022-0028 – EPCOR Electricity Distribution Ontario Inc. – Final Argument

We are counsel to the School Energy Coalition ("SEC"). Enclosed, please find SEC's Final Argument in the above-captioned matter.

Yours very truly,
Shepherd Rubenstein P.C.

Mark
Rubenstein
2023.03.16 14:
39:37-04'00'

Mark Rubenstein

cc: Brian McKay, SEC (by email)
Applicant & Intervenors (by email)

EB-2022-0028

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by EPCOR Electricity Distribution Ontario Inc. for an order approving just and reasonable rates and other charges for electricity distribution beginning October 1, 2023.

FINAL ARGUMENT OF THE SCHOOL ENERGY COALITION

March 16, 2023

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

Mark Rubenstein
Tel: 416-483-3300
Fax: 416-483-3305

Counsel for the School Energy Coalition

TABLE OF CONTENTS

1 OVERVIEW

1.1 *Introduction*

1.1.1 EPCOR Electricity Distribution Ontario Inc. ("EDDO" or the "Applicant") filed an application with the Ontario Energy Board ("OEB" or the "Board") under section 78 of the *Ontario Energy Board Act, 1998,* for approval of distribution rates, initially effective for January 1, 2023, now October 1, 2023.

1.1.2 A partial Settlement Proposal was filed with the OEB, on behalf of all parties, in which they reached an agreement on several issues related to cost allocation, rate design, and the disposition of certain deferral and variance accounts. No settlement was reached related to, among other issues, the revenue requirement, which includes rate base, load forecast, Operating, Maintenance & Administration ("OM&A") expenses, and cost of capital.

1.1.3 This is the Final Argument of the School Energy Coalition ("SEC").

1.1.4 The unsettled issues in this proceeding have numerous sub-issues and components. SEC's argument focuses on the major outstanding matters. Silence on the others should not be taken as agreement with the Applicant or any other party.

1.2 *Summary*

1.2.1 EEDO is seeking approval for a revenue requirement of approximately $10.32M for 2023.[1] This reflects an overall increase in revenue over forecast revenue at current rates of 14.5%.[2]

1.2.2 When Group 2 DVA balances are included, the distribution bill impacts for customers are even higher. For a representative customer in each rate class, the bill impacts provided by EEDO range from a low of a 20.7% increase for residential customers, to a high of a 41.1% increase for GS>50 customers, as shown in the table below.[3]

[1] Settlement Proposal, December 9, 2022, Appendix A, p.8 (K1.3, p.5)
[2] Settlement Proposal, December 9, 2022, Appendix A, p.7 (K1.3, p.4)
[3] Settlement Proposal, December 9, 2022, Appendix B, p.2 (K1.3, p.7)

Table 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.58	20.7%	$ 8.58	25.6%	$ 8.54	19.0%	$ 8.61	7.2%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 11.72	21.8%	$ 18.72	26.7%	$ 18.66	19.3%	$ 18.79	6.3%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 415.34	41.1%	$ 753.94	66.0%	$ 763.24	31.7%	$ 748.27	5.3%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - Non-RPP (Other)	kWh	$ 1.29	50.8%	$ 1.56	40.4%	$ 1.55	26.5%	$ 1.56	6.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (1,927.27)	-33.7%	$ (1,792.89)	-31.2%	$ (1,790.06)	-29.2%	$ (2,042.68)	-22.9%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 5.58	20.7%	$ 7.29	21.4%	$ 7.26	15.9%	$ 7.31	5.7%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 5.58	20.7%	$ 6.60	22.4%	$ 6.59	19.7%	$ 6.66	11.2%
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kWh	$ 11.72	21.8%	$ 15.28	21.3%	$ 15.22	15.5%	$ 15.31	4.8%

1.2.3 These proposed and the resulting bill impacts are plainly neither just nor reasonable.[4]

1.2.4 This is highlighted when the test year costs are compared against what was presented as part of the application, and accepted by the Board in its approval, by EPCOR Utilities Inc ("EUI"), to purchase Collus PowerStream ("Collus"), now renamed EEDO.

1.2.5 The detailed submissions of SEC in this Final Argument can be summarized as follows:

(a) ***Rate Base and Capital Expenditures***. SEC submits the OEB should require EEDO to update the 2023 opening rate base to reflect the material underspending that occurred in 2022. With respect to the 2023 capital expenditures and in-service additions, at a minimum, it should be reduced by $647K to reflect historic overspending, and the need for greater pacing of capital work over the Distribution System Plan ("DSP") period.

(b) ***OM&A.*** EEDO proposed test year OM&A budget is unreasonable. Its costs have increased substantially since the approval of the MAADs Application, and no savings have been achieved. The main driver of the cost increase appears to be the substantial amount paid for affiliated shared and corporate services. SEC has proposed a reduction in the test year OM&A amount of $719K.

(c) ***Cost of Capital – Long-Term Debt.*** SEC submits that the long-term debt rate should be reduced from 3.98% to 3.71%. The difference reflects the application of the OEB's cost of capital policy to affiliate debt, as well as recognition that it was imprudent for the company to have retired early 10-year third-party debt, for a more expensive 30-year affiliate debt.

(d) ***DVA.*** SEC has provided detailed submissions on each of the three unsettled deferral and variance accounts.

(e) ***Effective Date.*** EEDO's effective date and rate-setting schedule proposal should be rejected. The effective date for EEDO's rate should be January 1, 2024. Even if the OEB accepts EEDO's proposal for an October 1, 2023 effective date, its first IRM adjustment should be no earlier than October 1, 2024. Additionally, EEDO should not be eligible to rebase until January 1, 2028.

[4] Settlement Proposal, December 9, 2022, Appendix B, p.2 (K1.3, p.7)

(f) ***Other Issues - Load Forecast.*** SEC has reviewed a draft of VECC's final argument and agrees with its submission related to the load forecast.

1.3 *MAAD Application Context*

1.3.1 The background to this application is important as it sets part of the context for the problem with EEDO's request.

1.3.2 In 2018, EUI signed a Share Purchase Agreement to purchase Collus from the Town of Collingwood ("The Town").[5] EUI is a large utility headquartered in Edmonton, Alberta, with a number of subsidiaries in Canada and the United States, including those who undertake electricity distribution activities.[6]

1.3.3 EUI and the Town filed the required application under section 86 of the *Ontario Energy Board Act* ("MAADs Application") for the necessary regulatory approvals.[7] As part of the application, EUI provided evidence for the purpose of demonstrating that the transaction would meet the OEB's "no harm test". The evidence included forecast capital expenditures and OM&A spending for each year through to the end of its proposed 5-year deferred rebasing period.[8] EUI's evidence was not just that Collus customers would not be harmed, but that it would benefit from EUI's purchase, by reducing costs that would otherwise have had to be incurred. EUI forecasted OM&A savings as a result of the transaction beginning in year 2020 through 2024.

1.3.4 Based on that evidence, in August 2018, the OEB issued a decision and approved the purchase, finding that the proposed transaction met its "no-harm test" ("MAADs Decision").[9] As part of the OEB's decision, it required the utility to file a DSP within a year and approved the proposed 5-year deferred rebasing period.[10] The transaction closed on October 1, 2018, and the utility

---

[5] The full transaction involved the Town of Collingwood purchasing the outstanding 50% interest in Collus' holding company from Alectra Utilities, and then selling the full amount to EPCOR Collingwood Distribution Corporation, a wholly owned subsidiary of EPCOR Utilities Inc. (See *Decision and Order* (EB-2017-0373/374), August 30, 2018, p.1-2 (K1.3, p.118-119)

[6] EB-2017-0373/374 Application, p.20 (K1.3, p.26)

[7] EB-2017-0373/374 Application

[8] EB-2017-0373/374 Application, p.31 (K1.3, p.28)

[9] *Decision and Order* (EB-2017-0373/374), August 30, 2018, p.9 (K1.3, p.126)

[10] *Decision and Order* (EB-2017-0373/374), August 30, 2018, p.16 (K1.3, p.33)

was renamed EEDO.

1.3.5 Yet, when EEDO filed this application for rates, not only had savings not materialized, but both historic and test year costs were significantly higher than forecast in the MAADs Application. Both with respect to capital and OM&A costs, EEDO's actual costs since the transaction closed, and forecast for the test year, look nothing like what EUI told the customers of Collus to expect when it sought approval for the purchase.

1.3.6 In the MAADs Application, EUI also committed to maintaining or even improving reliability.[11] This was another important factor in the OEB's decision to grant MAADs approval.[12] However, reliability has not improved; in fact, it has declined since EUI purchased the utility. Both the 5-year SAIDI and SAIFI have declined, as shown below. This is despite the fact that EEDO has not only spent more on both capital and OM&A than it had previously, but also significantly more than it had forecast it would spend.[13]

Reliability (excluding MED and LOS)		
	2014-2018	**2017-2021**
SAIFI	0.68	0.83
SAIDI	1.24	1.55
Source: Ex.2, DSP, p.20; 2019-2023 DSP, p.36 (K1.3, p.43,47)		

1.3.7 Customers of EEDO, are clearly worse off because of the transaction. They are paying more than they would if EUI had not purchased the utility and are receiving worse service. They have been harmed.

1.3.8 EPCOR repeats the argument that the OEB already explicitly rejected in the *Decision on Issues List*[14], that the MAADs evidence "has no relevance" to the setting of rates in this application.[15] While the forecasts provided in the MAADs Application, including those in the test year, are not binding on the OEB in setting rates in this application, they are indicative of a problematic situation that has occurred and should act as the de facto starting point for what costs are just

[11] Tr.1, p.71; EB-2017-0373, Application, p.31 (K1.3, p.29)
[12] *Decision and Order* (EB-2017-0373/374), August 30, 2018, p.12 (K1.3, p.129)
[13] *Decision on the Issues List*, July 28, 2022, p.3
[14] Argument-in-Chief, para 20
[15] Argument-in-Chief, para 14

and reasonable rates. It cannot simply be the case, as EEDO argues[16], that it can say one thing to the OEB regarding costs to get MAADs approval, and then once it received approval, set those representations aside. This only encourages a "bait and switch" approach by utilities.

1.3.9 The Auditor General of Ontario's most recent Annual Report commented on the need for the OEB to monitor post-MAADs approvals, and that the projected benefits are realized through the deferred rebasing period.[17]

1.3.10 SEC does not dispute that once EUI purchased the utility it may have discovered some new requirements that arose and needed to be addressed, which required it to depart from the forecast budget it provided in the application. But that is not what the evidence shows. EUI is a sophisticated entity and undertook due diligence activities before purchasing the utility.[18] The bulk of new spending, at least in relation to OM&A, relates to efficiencies that it thought it would be able to achieve by way of its corporate structure that did not materialize, as well as additional costs from allocation of corporate costs.

1.3.11 In its Argument-in-Chief, EEDO seems to suggest that all of the extra spending during the deferred rebasing was entirely beneficial to customers and detrimental to its shareholder, as evidenced by its Return on Equity ("ROE") being materially below the deemed rate over part of the deferred rebasing period.[19] SEC submits that the increased spending's impact on its shareholder is significantly overstated and misleading.

1.3.12 First, as discussed later in this argument, much of the increased spending from forecast, that lowered EEDO's ROE, related to amounts paid to affiliates and EUI through shared and corporate services, as well as interest expenses on affiliate debt. These are costs that lowered EEDO's ROE but acted as a transfer or revenue to the shareholder.

1.3.13 Second, considering the long-term nature of much of the capital assets that are being installed, the impact of foregoing recovery of those amounts during the deferred rebasing period is

[16] Argument-in-Chief, para 14

[17] Auditor General of Ontario, *2022 Annual Report Ontario Energy Board: Electricity Oversight and Consumer Protection* (November 2022), p.41

[18] Tr.1, p.33; Tr.2, p.97

[19] Argument-in-Chief, p.17-18

limited, as compared to the return it will achieve over the full life of the asset.

1.4 ***Post-MAAD Spending***

1.4.1 The significant bill impact for customers as a result of the proposed revenue requirement in the application is a direct result in the significant increase in spending by EEDO since the purchase by EUI.

1.4.2 With respect to capital related costs, EEDO's net fixed assets, a measure of the asset component of rate base, have doubled since its last rebasing application in 2013. Approximately 74.5% of that increase has occurred since 2018.[20] Similarly, the annual depreciation expense has almost doubled since 2013, with almost 90% of that increase has occurred since 2018.[21] With respect to OM&A, EEDO's costs increased by 16.6% in the year after the EUI's purchase.[22] The 2023 request represents a 36.1%, or 6.35% average annual increase since 2018. This compares to a relatively flat OM&A spending between 2013 and 2018.[23]

1.4.3 All of this compares to forecasts filed by EUI in the MAAD's Application showing that capital expenditures and OM&A would not increase nearly at the rate that it actually did. Based on the rate proposals in this application, while the company may have met the "no harm test" as a result of its forecasts at the time provided in its MAADs Application, it is evident that customers have been harmed by the transaction and are worse off to date as a result.

[20] Exhibit 2, Tab 1, Schedule 1, p.7 (K1.3, p.22)
[21] Exhibit 2, Tab 1, Schedule 1, p.8 (K1.3, p.23)
[22] Appendix J-AA
[23] Appendix J-AA

2 RATE BASE, CAPITAL EXPENDITURES & IN-SERVICE ADDITIONS

2.1 *Overview*

2.1.1 EEDO seeks approval of average net fixed assets of $31,105M for the 2023 test year. The amount represents additions to the rate base since its last rebasing year, based on actual capital additions and forecast additions for each of the 2022 bridge year and the 2023 test year. It proposes approval for in-service additions of $4.3M in the 2023 test year.

2.1.2 The OEB should require EEDO to use actual 2022 in-service additions in determining the opening 2023 rate base. For 2023 in-service additions, the OEB should at a minimum, reduce the test year in-service additions by $647K, which reflects a levelized pacing of capital spending during the DSP period, as well as a reduction to reflect the greater than previously forecast work that had been done since 2019.

2.2 *Rate Base*

2.2.1 In response to Undertaking J1.1, EEDO revealed that it underspent in 2022, as its actual capital expenditures were $850K less than it had forecast as part of its application.[24] The lower spending was a result of a number of issues, predominantly the delayed delivery of a $510K bucket truck, and reduced system access spending.[25]

2.2.2 SEC submits that EEDO should be required to update its opening 2023 rate base to reflect the lower year-end 2022 capital spending. Customers should not be required to pay for amounts that are not actually in-service at the beginning of 2023. Even if the capital work is delayed until 2023, such as delivery of the bucket truck, there is a material revenue requirement impact, of having the assets included in the opening 2023 rate base as compared to being added to the closing 2022 rate base as a result of the half-year rule.

2.2.3 In Undertaking J1.1, EEDO also notes that its year-end 2022 CWIP balance is $462K lower than included in its application.[26] This would suggest that its 2023 in-service additions, all else equal, are likely lower than what was forecast in the application. With that said, it is not clear what the impact of any CWIP balance is on EEDO's in-service additions. This is because its

[24] Undertaking J1.1
[25] Undertaking J1.1
[26] See Appendix 2-AA (EEDO_20223 Chapter 2 Appendices_Settlement_20221209)

forecast capital expenditure for 2022 and 2023[27] are the same as its in-service additions for those years, as shown in its continuity schedule (Appendix 2-BA).[28] In its reply argument, EEDO should clarify the relationship between its capital expenditures and in-service additions for 2022 and 2023 and what impact the reduced 2022 CWIP has on forecast 2023 in-service additions.

2.3 *Historic Over-Spending.*

2.3.1 EEDO capital expenditures during the deferred rebasing years, are significantly higher than what was forecast at the time of the MAADs Application as well as in the DSP filed for 2019 to 2023.

2.3.2 Between 2019 and 2023, EEDO spent approximately $2.76M (16.8%) more than it had told the OEB it would spend in that application. For the 2023 test year, EEDO plans to spend $993K or 30% more.

Capital Expenditures ($000)	2019	2020	2021	2022	2023	*2019-2023*
EB-2017-0373 - Status Quo (1)	$3,256	$3,312	$3,303	$3,246	$3,303	$16,420
EB-2017-0373 - EEDO Forecast (1)	$3,256	$3,312	$3,303	$3,246	$3,303	$16,420
2019-2023 DSP (2)	$3,299	$3,700	$3,391	$3,586	$3,905	$17,881
Actual/Forecast (EEDO Request)	$4,134	$3,277	$3,775	$3,697	$4,296	$19,179
Actual/Forecast (Update) (3)	$4,134	$3,277	$3,775	$2,845	$4,296	$18,327
Actual/Forecast v. Status Quo/EEDO Forecast	$878	-$35	$472	$451	$993	$2,759
Actual/Forecast v. 2019-2023 DSP	$835	-$423	$384	$111	$391	$1,298
Actual/Forecast (EEDO Request) v. Status Quo/EEDO Forecast	26.97%	-1.06%	14.29%	13.89%	30.06%	16.80%
Actual/Forecast (EEDO Request) v. 2019-2023 DSP	25.31%	-11.43%	11.32%	3.10%	10.01%	7.26%
Source (1); EB-2017-0373, Application, p.3 (K1.3, p.28) (2) EB-2018-0025, DSP, p.12 (K1.3, p.40) (3) Undertaking J1.1						

2.3.3 A year after the MAADs Application, as required, EEDO filed a DSP for 2019 to 2023. The 2019-2023 DSP proposed an additional $1.4M in capital spending over the 5-year period than had been forecast by the EEDO just a year earlier.[29] No explanation was included regarding why its forecast had changed so significantly since the MAADs Application. Even with the revised forecast, EEDO capital spending over the 5-year period was even higher. Its 2023 test

[27] Undertaking J1.1
[28] Appendix 2-AA (EEDO_20223 Chapter 2 Appendicitis _Settlement_20221209)
[29] EB-2018-0025, DSP, p.12 (K1.3, p.40)

year spending alone, is 10% higher than what was forecast as part of that DSP.

Capital Expenditures ($000)	2019	2020	2021	2022	2023	*2019-2023*
EB-2017-0373 - Status Quo (1)	$3,256	$3,312	$3,303	$3,246	$3,303	$16,420
EB-2017-0373 - EEDO Forecast (1)	$3,256	$3,312	$3,303	$3,246	$3,303	$16,420
2019-2023 DSP (2)	$3,299	$3,700	$3,391	$3,586	$3,905	$17,881
Actual/Forecast (EEDO Request)	$4,134	$3,277	$3,775	$3,697	$4,296	$19,179
Actual/Forecast (Update) (3)	$4,134	$3,277	$3,775	$2,845	$4,296	$18,327
Actual/Forecast v. Status Quo/EEDO Forecast	$878	-$35	$472	$451	$993	$2,759
Actual/Forecast v. 2019-2023 DSP	$835	-$423	$384	$111	$391	$1,298
Actual/Forecast (EEDO Request) v. Status Quo/EEDO Forecast	26.97%	-1.06%	14.29%	13.89%	30.06%	16.80%
Actual/Forecast (EEDO Request) v. 2019-2023 DSP	25.31%	-11.43%	11.32%	3.10%	10.01%	7.26%
Source (1); EB-2017-0373, Application, p.3 (K1.3, p.28) (2) EB-2018-0025, DSP, p.12 (K1.3, p.40) (3) Undertaking J1.1						

2.3.4 As a result of the higher than forecast capital work and spending undertaken since 2019, as compared to both the MAADs Application and 2019-2023 DSP, customers should expect that going forward, a reduction in overall spending over the DSP period is appropriate. A lot of the needed work has been undertaken and could be deferred to reduce the overall bill impacts.

2.3.5 SEC submits that over the upcoming 5-year DSP period, EEDO capital expenditures should be reduced by at least $2M, which represents a 10% reduction over the 2023-2027 DSP period of $20.24M[30], representing an annual reduction of $400K.

2.4 *Capital Expenditures and Pacing*

2.4.1 In assessing the reasonableness of test year capital expenditures, the OEB considers if an Applicant has paced its capital spending throughout the 2023-2027 DSP period.[31] A review of its annual planned capital expenditures shows that EEDO has done very little to pace them over the 5-year period. Appropriate pacing would see a gradual increase over the DSP period, which would match the rate increase that it receives as a result of the annual IRM adjustment, as well as increased revenue from additional customers over-time.

2.4.2 EEDO net capital expenditures are materially highest in the first two years of the DSP period.

[30] Appendix 2-AB

[31] See Issue 1.1: "Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:"[emphasis added]; See also *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 18, 2012), p.4, 36-37

	2023	2024	2025	2026	2027		2023-2027
Net Capital Expenditures	$4,295,838	$4,490,774	$3,826,255	$3,768,443	$3,862,012		$20,243,321
DSP Average							***$4,048,664***
Source: Appendix 2-AB							

2.4.3 SEC submits that OEB should reduce EPCOR's 2023 test year capital expenditures by, at a minimum, $247K, which reflects the difference between its planned spending and the DSP average.

2.4.4 When asked about why it was not doing more to pace its capital expenditures, EEDO said that there were some lumpy projects that needed to be done early in the DSP period.[32] Having lumpy capital expenditures is not unique to EEDO and is inherent in distribution capital work. What a prudent utility would do in such a case, is to defer other work to balance out the spending over the period.

2.4.5 For example, EEDO has not explained why it needs to spend $2M of pole line rebuild/replacement projects each year[33], and cannot defer a portion of the 2023 (and likely 2024) work to 2025 to 2027, to better pace its capital spending. If anything, the evidence points the deferring some of the work is the prudence course of action as it would allow it time to undertaken needed preparatory work to determine the optimal size of its pole line rebuild/replacement project ($1.28M in 2023) and an annual pole replacement program ($583K in 2023).[34] The Asset Condition assessment that was undertaken by METSO revealed that EEDO has very limited information regarding wood pole condition. Its data availability index score for the two condition measures, remaining pole strength and visual inspections, were 20% and 60% respectively.[35] The health index score is then primarily based on age (year of installation) and if previous work had been done on the pole (pole treatment).[36] This is insufficient information to properly assess the size of a pole line rebuild project.

[32] Tr.1, p.15
[33] Tr.1, p.15
[34] Appendix 2-AA
[35] Exhibit 2, DSP, Appendix, p.9
[36] Exhibit 2, DSP, Appendix, p.9

3 OM&A

3.1 *Overview and Summary*

3.1.1 EEDO is seeking approval for the 2023 test year OM&A of $6.530M. This represents a 5.3% increase from its 2022 year-end actuals, and an 18.5% increase from its last year of audited actuals (2021).[37] The OM&A increases are not reasonable.

3.1.2 SEC submits that while any individual item may be reasonable in isolation, it is the total sum of those costs that must also be reasonable. Most costs can be justified on their own, but a utility, like any business, must consider each cost in the context of the overall amounts sought and the impact on customers. A utility must make trade-offs between cost pressures and the total impact on customers. In light of the bill impacts, and the substantial increase in OM&A, it is clear that EEDO has not done so, as seen in the table below. In addition, as discussed further below, much of the increase is not even related to providing new services to customers, but as a result of increased costs that are being paid to affiliate and shared services.

OM&A	2013A	2014A	2015A	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023F
Operations	$657,706	$706,743	$721,686	$754,396	$886,046	$885,794	$866,849	$1,149,538	$1,060,428	$1,124,815	$977,066
Maintenance	$1,395,752	$1,462,370	$1,667,027	$1,727,736	$1,303,848	$1,424,249	$1,391,638	$1,636,327	$1,391,926	$1,326,799	$1,640,206
Sub-total O&M	***$2,053,457***	***$2,169,113***	***$2,388,712***	***$2,482,131***	***$2,189,894***	***$2,310,043***	***$2,258,487***	***$2,785,865***	***$2,452,353***	***$2,451,614***	***$2,617,273***
Billing and Collecting	$839,380	$809,917	$823,062	$895,356	$974,046	$949,464	$975,000	$1,010,748	$985,537	$1,148,333	$1,109,304
Community Relations	$153,000	$161,767	$210,766	$158,939	$225,346	$227,791	$241,736	$239,793	$176,984	$174,079	$188,552
Administrative and General	$1,369,268	$1,423,503	$1,282,167	$1,380,719	$1,228,690	$1,311,958	$2,118,937	$2,075,033	$1,897,222	$2,427,842	$2,615,186
Sub-total Admin	***$2,361,648***	***$2,395,188***	***$2,315,994***	***$2,435,015***	***$2,428,082***	***$2,489,214***	***$3,335,673***	***$3,325,573***	***$3,059,743***	***$3,750,253***	***$3,913,043***
Total	**$4,415,105**	**$4,564,301**	**$4,704,707**	**$4,917,146**	**$4,617,976**	**$4,799,257**	**$5,594,161**	**$6,111,438**	**$5,512,097**	**$6,201,867**	**$6,530,315**
Source: Undertaking J1.1, Appendix 2-JA											

3.1.3 SEC submits the OEB should reduce the OM&A by $719K.

3.2 *Higher Costs After EUI Purchased the Utility.*

3.2.1 EEDO's OM&A costs significantly increased after the purchase of Collus by EUI. EEDO's cost increased 16.6% between 2018 and 2019. The 2023 request represents a 36.1%, or 6.35% average annual increase, since 2018.

3.2.2 The unreasonableness of the OM&A request is highlighted when compared to what was forecast in the MAADs Application. At that time, EUI's forecast of its 2023 OM&A costs was $1.1M, or 23%, below the requested amount that it now seeks. The status quo forecast, that is, what EUI forecast Collus would have spent if there was no transaction, was expected to be

[37] Undertaking J1.1, Appendix 2-JA

$778K (13.5%) below the requested amount, as shown below.

OM&A Comparison ($000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Collus PowerStream (1)	$4,415	$4,564	$4,705	$4,917	$4,618	$4,799					
EB-2017-0373 - Status Quo (2)							$5,331	$5,425	$5,520	$5,616	$5,752
EB-2017-0373 - EEDO Forecast (2)							$5,872	$5,191	$5,110	$5,189	$5,306
EB-2017-0373 - EEDO Forecast (Risk) (3)							$6,341	$5,265	$5,249	$5,330	$5,449
Application Actual/Forecast (1)							$5,594	$6,111	$5,512	$6,202	$6,530
Application Actual/Forecast v. EB-2017-0373 Status Quo							4.94%	12.65%	-0.14%	10.43%	13.53%
Application Actual/Forecast Actual/Forecast v. EB-2017-0373 EEDO Forecast							-4.73%	17.73%	7.87%	19.52%	23.07%
Application Actual/Forecast Actual/Forecast v. EB-2017-0373 EEDO Forecast (Risk)							-11.78%	16.08%	5.01%	16.36%	19.84%
Source: (1) Undertaking J1.1, Appendix 2-JA, (2) EB-2017-0373, Application, p.31 (K1.3, p.28) (3) EB-2017-0373 1-Staff-1 (K1.3, p.28)											

3.2.3 While the amounts were simply a forecast and some new cost pressures have emerged since the MAADs Application, it is the scale of the difference which reveals the unreasonableness of its proposed 2023 OM&A amount.

3.2.4 As part of the OEB's consideration of the MAADs application, EUI provided an analysis of the risks it faced in achieving the forecast savings and provided an alternative savings scenario where each of the various risks materialized.[38] This resulted in a revised 2023 savings of $303K as compared to $446K, resulting in a revised forecast OM&A amount of $5.35M. [39] But in doing so it told the Board that it "considers this to be the worst case scenario and to be an extremely unlikely outcome" because "[t]he potential of any one of the scenarios underlying each risk taking place is considered modest. Incurring the costs of all of the risks is significantly less likely."[40] It would appear that all the risks, and more, have materialized, since there are not only no longer any savings, but the 2023 costs are 13.5% higher than the status quo forecast for 2023.

3.2.5 EEDO's explanation for the variance in the 2023 OM&A budget in this application, as compared to what was forecast in its MAADs Application, demonstrates the cost increases have little to do with new requirements, but more to do with higher costs payable for shared and corporate services to its affiliates and EUI.

3.2.6 EEDO claims that its assumptions regarding IT/GIS and finance/regulatory costs savings did

[38] EB-2017-0373, 1-Staff-1(d) (K1.3, p.36-38)
[39] EB-2017-0373, 1-Staff-1(d) (K1.3, p.36-38)
[40] EB-2017-0373, 1-Staff-1(d) (K1.3, p.38)

not materialize.[41] But when asked specifically to provide a breakdown of costs for each of the categories it had referenced, not only does it reveal savings did not materialize, but costs dramatically increased right after the acquisition, and then again between 2022 and the 2023 test year.[42]

	2017	2018	2019	2020	2021	2022	2023
IT/GIS	222,175	235,440	419,121	395,117	425,528	463,293	512,112
Finance and Regulatory	444,728	554,347	611,989	619,090	607,988	652,652	684,337

3.2.7 In response to Undertaking J2.2 requested by OEB Staff, EUI compares pre-acquisition and 2023 costs in certain categories, including IT, and attempts to demonstrate that in certain cost categories, there is no increase.[43]

3.2.8 As a preliminary matter, SEC submits the OEB should give little weight to this evidence, as it involves a significant number of assumptions, and was not subject to any cross-examination.

3.2.9 More importantly, the undertaking is fundamentally flawed as its comparison takes a selected number of categories of costs and makes adjustments so that they are no longer an "apples-to-apples" comparison and raise more questions than it answers.

3.2.10 For example, the 2017 actual costs (excluding inflation adjustment) of $353K are significantly higher than the $222K in IT/GIS costs that were provided in response in the Pre-Settlement Clarification Question SEC-5b (shown in the table above). At the same time the 2023 forecast costs of $484K are $27.7K less than what was provided in the same clarification question. Additionally, the 2023 amounts in the undertaking responses do not include GIS related IT costs, which EEDO had previously explained was a reason for the higher spending compared to the MAADs Application forecast.[44]

3.2.11 There are also other issues with the other categories of spending that EEDO has attempted to compare in Undertaking J2.2. EEDO has made several inconsistent adjustments to the 2017

---

[41] Interrogatory Response 4-SEC-32a (K1.3, p.53)
[42] Pre-Settlement Clarification Question SEC-5b (K1.3, p.57)
[43] Undertaking J2.2, p.10
[44] Interrogatory Response 4-SEC-32a (K1.3, p.53)

amounts in certain categories. With respect to management oversight, it attempted to normalize the 2017 amounts by adding the cost of the CEO who had previously retired two years earlier. Yet, for human resources costs, it did not similarly attempt any normalizing adjustments by removing the overlap for training purposes between the new accounting administrator and the retiring payroll/benefits coordinator.[45]

3.3 *Affiliate Shared and Corporate Service Costs*

3.3.1 EEDO's evidence is that the increase in OM&A costs as compared to forecast was also a result of additional corporate services received than what was originally contemplated as part of the MAADs application.[46] But this only reflects a very small portion of the increase in corporate service costs, and the vast majority reflects a higher allocation of EUI costs to EEDO.[47] EEDO customers are simply paying more for the same services than EUI had forecast in the MAADs Application. EUI's higher overall corporate costs, in which EEDO represents a small fraction[48], is being downloaded onto the utility. This is unfair to EEDO customers.

Additional costs	2019	2020	2021	2022	2023
Higher allocation percentages	206,617	130,218	195,032	214,279	287,800
Additional corporate services	16,935	25,067	28,615	32,693	32,790
Difference in corporate shared services	223,012	155,285	223,646	246,973	320,590

3.3.2 Even after the acquisition, affiliate shared and corporate service costs have significantly increased year-over-year, as shown in the table below. The test year forecast of $1.67M represents a 50% increase since 2019.[49]

[45] Undertaking J2.2, p.12
[46] 4-SEC-32a (K1.3, p.53); Tr.1, p.45-46
[47] Pre-Settlement Clarification Question SEC-5b(i) (K1.3, p.58); Tr.2, p.47-48
[48] Tr.1, p.49
[49] Exhibit 4, Tab 1, Schedule 1, p.61 (K1.3, p.69)

Table 4.4.2-1

Shared Services and Corporate Cost Allocated to EEDO

($)

	Expense Category	A **2019A**	B **2020A**	C **2021A**	D **2022 Bridge Year**	E **2023 Test Year**
1	Affiliate Shared Services	365,093	557,435	510,909	757,748	790,070
2	Corporate Shared Services	740,333	681,659	659,924	791,931	875,084
3	**Total Shared Services and Corporate Costs**	**1,105,426**	**1,239,094**	**1,170,833**	**1,549,679**	**1,665,154**

3.3.3 The additional costs do not come with a commensurate benefit, but reflect primarily the increased allocation of costs. As shown in the above table, there was a significant increase in affiliate shared services costs incurred by EEDO beginning in 2022, as compared to 2021. This was a result, not primarily of an increase in services provided to EEDO, but a change in the allocation methodology. Previously, EPCOR Ontario Operations Management Inc. ("EOOMI") and later EPCOR Ontario Utilities Inc. ("EOUI"), who provide most of the shared services to EEDO[50], changed its cost allocation methodology that was previously based on time spent[51], to a set of composite cost allocators that differ based on the category of shared services.[52] No independent review was undertaken to review the revised cost allocation methodology, and so it is difficult to assess the reasonableness of the revised methodology.

3.3.4 Regardless of its decision in this proceeding on the appropriateness of the forecast corporate and shared services costs included in the 2023 OM&A budget, the OEB should require EEDO to undertake an independent third-party expert review of the appropriateness of allocation methodologies to be filled at its next rebasing. The expert should be given full access to both EUI and individual affiliate companies personnel and financial information so that it can properly assess if the amounts allocated to EEDO, and any other Ontario regulated affiliate, are reasonable and follow best practices.

[50] Exhibit 4, Tab 1, Schedule 1, p.62 (K1.3, p.62)
[51] Exhibit 4, Tab 1, Schedule 1, p.71 (K1.3, p.79); Tr.1, p.59
[52] Exhibit 4, Tab 1, Schedule 1, p.69 (K1.3, p.77)

3.4 ***Proposed Reduction***

3.4.1 SEC believes that the most appropriate way to determine an appropriate OM&A test year is by providing EEDO with an envelope budget to operate within. This reflects the fact that it is the utility that needs to make trade-offs between various initiatives while remaining within an overall budgetary framework.

3.4.2 There is no perfect way to determine a reasonable OM&A budget considering the evidence that the proposed amounts are unreasonable, especially for a utility that has not been rebased since 2013. As demonstrated through the hearing and undertaking responses, comparing categories of costs over time is very difficult due to EEDO's substantial use of affiliate and corporate shared services.

3.4.3 The OEB has previously commented that setting an OM&A budget on an envelope basis "assisted by reference to accepted parameters measuring sources of cost increases to utility expenses, including inflation and customer growth, helps provide a yardstick that avoids micromanagement of the regulated utility and helps the regulator cope with any asymmetries of information that may be present." [53]

3.4.4 SEC suggests that the OEB use the methodology adopted by the Board in its decision in EB-2016-0061. In that proceeding, the OEB determined that the level of OM&A for Canadian Niagara Power "should remain, at most, close to the level of inflation reduced by the stretch factor….and should account for customer growth." [54]

3.4.5 SEC submits that the appropriate starting point, in light of the MAADs transaction, is the 2019 status quo scenario. This would be the budget that EUI told the OEB would have been the case without the merger and reflects the proposed 2019 budget without any savings.

3.4.6 Starting from that initial starting point, the OM&A amount is escalated each year to reflect that year's inflation factor and the EEDO's stretch factor.[55] Additionally, it is also escalated to reflect incremental OM&A costs driven by customer growth. SEC proposes that the most

[53] *Decision and Order* (EB-2018-0056) April 11, 2019, p.10
[54] *Decision and Order* (EB-2016-0061), December 9, 2017, p.5
[55] Exhibit 1, Tab 1, Schedule 1, p.50

appropriate method is to multiply the customer growth rate in any year by 0.448%, which is the amount that Pacific Economic Group (PEG), the developer of the OEB's stretch factor methodology, found to be the additional OM&A costs resulting from a 1% increase in the number of customers.[56] The OEB used this method to calculate additional OM&A as a result of customer growth in EB-2018-0056.[57]

3.4.7 One further adjustment that should be made is to reflect the expected and forecasted savings that customers were promised in the MAADs Application. SEC submits that the escalated OM&A discussed above should be reduced accordingly. In recognition that some risks inevitably arise, including additional requirements that could not have been foreseen, a fair approach would be to reduce the 2023 amount by the savings forecast in the risk scenario (a reduction of $303K compared to a $464K in savings).

	Proposed OM&A Reduction (000)	2019	2020	2021	2022	2023	Notes
A	Status Quo Forecast	**$5,331**					
B	Inflation Factor		2.00%	2.20%	3.30%	3.70%	Ex. 1-1-1, p.50, Table 1.6-1
C	Stretch Factor		-0.15%	-0.15%	-0.15%	-0.15%	Ex. 1-1-1, p.50, Table 1.6-1
D	**Base Annual Esculator**		**1.85%**	**2.05%**	**3.15%**	**3.55%**	B-C
E	Customers	17,608	18,070	18,351	18,658	18,971	Appendix 2-IB
F	Customer Growth Rate		2.63%	1.56%	1.67%	1.67%	
G	**Additional Increase From Customer Growth**		**1.17%**	**0.69%**	**0.74%**	**0.74%**	0.448 x F
H	**Total Annual Esculator**		**3.02%**	**2.74%**	**3.89%**	**4.29%**	D+G
I	**Escalated OM&A**		**$5,492**	**$5,643**	**$5,862**	**$6,114**	Previous years OM&A x (1+H)
J	**Forecast MAAD Savings (Risk Scenerio)**					**$303**	EB-2017-0373, 1-Staff-1
K	**Revised Forecast**					**$5,811**	I-J
L	**EEDO Request**					**$6,530**	Appendix 2-JA
M	**Proposed Reduction**					**$719**	L-K

3.4.8 The result is a revised envelope OM&A amount for 2023 of $5.81M, reflecting a reduction of $719K, as shown in the table above. However, this still reflects $504K or 9% more, than what EUI had forecast as part of the MAADs Application, and reflects the maximum reasonable test

[56] *Decision and Order* (EB-2018-0056) April 11, 2019, p.11
[57] *Decision and Order* (EB-2018-0056) April 11, 2019, p.11

year OM&A budget.

4 COST OF CAPITAL – LONG TERM DEBT

4.1 *Long-Term Debt*

4.1.1 EEDO has proposed a weighted average cost of long-term debt at 3.98%. SEC submits that the OEB should reject the proposal and substitute a rate of 3.71%, which reflects the application of the OEB policy and prudent financing actions of the utility.

4.1.2 A summary of the derivation of the proposed rate is shown below:

Revised 2-OB Long-Term Debt Calculation									
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	EEDO Rate (%)	SEC Rate (%)	Comments
Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 300,000	4.67%	4.67%	
Government Agency Loan	OSIFA	Third-Party	Variable Rate	1-Aug-12	25	$4,186,778	3.84%	3.84%	
Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 561,342	4.58%	4.58%	
Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 575,000	2.76%	2.76%	
Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$8,100,000	4.30%	3.75%	Should not have replaced TD Commercial Loan
Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	1-Dec-20	30	$2,020,000	2.88%	2.85%	Complaince with Cost of Capital Policy
Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	15-Dec-21	30	$2,000,000	3.41%	3.41%	Complaince with Cost of Capital Policy
Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-22	30	$1,200,000	5.25%	4.80%	Complaince with Cost of Capital Policy/Actual
Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-23	30	$1,200,000	5.03%	4.80%	Complaince with Cost of Capital Policy/Actual. Proprated for December 31
Weighted Average Long-Term Debt Rate							***3.98%***	***3.71%***	

4.2 *Non-Compliance with OEB's Cost of Capital Policy*

4.2.1 All of EEDO's long-term debt that has been issued since the purchase of the utility by EUI, is affiliate debt through a number of promissory notes with EUI. The debt rate, that EEDO has used for those primary notes for the purpose of setting the weighted average long-term debt rate, are not in compliance with the OEB's cost of capital policy.[58]

4.2.2 The cost of capital policy makes clear that "[t]he deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances." Those circumstances include "affiliate debt with a fixed rate", where the "deemed long-term debt rate at the time of issuances will be used as a ceiling on the rate allowed for the debt".[59]

4.2.3 The rationale for this approach is that affiliate debt, by its very nature, are not negotiated at

[58] See Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.53, K1.3, p.106

[59] See Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, p.53, K1.3, p.106

arm's length. The OEB must rightly ensure that a uniform set of policies, including a ceiling, protect the interests of ratepayers from inter-corporate transactions. In contrast, EEDO has proposed its own methodology that it believes appropriate archives a market equivalent rate.

4.2.4 While EEDO says that EUI is using a fair and transparent process to set the rate it will be charged, this is not entirely correct. For example, for the purpose of calculating credit spreads, EUI assumes that EEDO would be a BBB-rated utility, resulting in a higher interest rate than if it assumed, like the OEB's deemed rate calculation, that it was lending to an A-rated utility. [60] EEDO did not seek an independent credit rating, nor did EUI undertake any third-party review of its assessment of EEDO's methodology.[61] This is precisely the kind of problem that the OEB's cost of capital policy aims to prevent by establishing a maximum rate for affiliate debt.

4.2.5 EEDO acknowledges that it is not adhering to the OEB policy, but argues that the deemed rate is unreasonable for debt issuances in 2022 and 2023, as the debt market has experienced substantial changes since the OEB collected data to calculate the rate.[62] While there has been volatility in debt markets since September, the debt markets have swung in both directions, and EEDO's methodology is simply another point-in-time forecast methodology that is no different from the OEB's approach. Furthermore, the forecast rate for 2022 included in the application (5.25%) is outdated and inaccurate compared to the OEB's 2022 deemed rate. EUI is charging EEDO 4.80% for the 2022 promissory note, which is lower than the OEB's deemed rate based on EUI's methodology at the time of issuance in December 2022. [63] Astonishingly, EEDO is not proposing to update its proposed long-term debt rate despite paying a lower rate to EUI. [64]

4.2.6 The application of the OEB's cost of capital policy still results in a significant financial benefit to EUI. This is because the rate it received on its long-term debt issuances, with the exception of 2020, is well below both OEB's deemed rate and what it subsequently turns around and

[60] Interrogatory Response 5-Staff-57, Tr.2, p.26
[61] Tr.2, p.26
[62] Tr.2, p.26
[63] Undertaking J1.3 Tr.1, p.218
[64] Tr.1, p.86

charges to EEDO.[65]

EUI vs EEDO Debt Rates		
	EUI LT Debt Issuances (30 year) - Weighted Average	***EEDO Promissary Note from EUI (30 year)***
2018	3.95%	4.30%
2020	2.90%	2.88%
2021	2.94%	3.41%
2022	4.57%	5.25% (forecast) 4.80% (actual)
Source: J2.7/2-OB		

4.2.7 EEDO has provided no reason for why it should be granted differential treatment as compared to any other utility in Ontario, most of which have substantial affiliate debt and have the same ability to access debt as the EEDO did before the purchase by EUI. EEDO should be required to apply the OEB's cost of capital policy, and use the lower of the actual/forecast debt rate and the OEB's deemed rate at the time of issuance. Doing so results in the debt rate used for 4 out of 5 EUI promissory notes, being lower than proposed. application.

4.3 *2018 Promissory Note*

4.3.1 SEC has a specific concern with the December 2018 promissory note entered into between EEDO and EUI. After the utility was purchased, it decided to repay and replace three TD commercial loans that had been entered into as recently as the previous year and replace them with a 30-year promissory note with EUI, which had a materially higher interest rate.[66]

4.3.2 The three separate 10-year commercial loans from TD Bank together had a weighted debt rate of 3.62%. This compared much more favorably to the new 4.30% debt rate of the replacement promissory note, as well as a 4.13% OEB deemed rate at the time. EEDO argues that this was reasonable since the long-term of the debt better matched the long-term nature of EUI's assets.[67]

4.3.3 SEC submits that while that may be one financing approach, there are others, including ensuring that a company has a mix of length of debts as a way to hedge against market

[65] See Undertaking J2.7
[66] Tr.1, p.78-79
[67] Tr.1 , p.79

conditions over time.[68] This appears to be the approach used by EUI, who over the five years has issued a mix of 30-year and 3-year debt. [69]

4.3.4 EEDO provided no analysis that the change in financing was expected or has benefited ratepayers. To the contrary, it clearly has not, and the result is EEDO ratepayers are paying more in interest costs than it would have paid otherwise, resulting in a corresponding benefit to EUI.[70] EEDO's actions were imprudent and illustrate the need for vigilant oversight of affiliate transactions.

4.3.5 The OEB should impute a debt rate of 3.75% for the EEDO's December 2018 promissory note. As shown below, this reflects what would have been the rate for those amounts if the TD commercial loans were still in place, and the use of the OEB's deemed rate (not the higher actual rate), on the additional principal amounts.

December 2018 EUI Promissary Note - Imputed Debt Rate							
Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%)
Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$1,347,718	3.65%
Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$1,646,305	3.65%
Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	10-Mar-17	10	$3,048,746	3.59%
Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$2,057,231	4.13%
						$8,100,000	**3.75%**

[68] For example, see EB-2022-0200, I.5.2-SEC-202(b): "Enbridge Gas has historically issued dual tranche offerings of medium-term notes, split evenly between 10-year and 30-year tenors with the intent to attract diversified bond investors and maintain price levels, helping reduce interest expense."

[69] Undertaking J2.7

[70] As noted in Undertaking J1.2 (Tr.2, p.2) EEDO paid a pre-payment penalty of $70,000 in 2018 which would have lowered its ROE for that year.

5 DEFERRAL AND VARIANCE ACCOUNTS

5.1 *Recovery of Income Tax Variance Account*

5.1.1 EEDO is seeking approval to establish a new variance account, the Recovery of Income Tax Variance Account ("RITVA"), that would capture the difference between income tax included in rates ($0), and actual income taxes paid during the IRM term. \[71] The reason behind this request is that EEDO had a significant loss carryforward balance at the end of 2022, and as a result, it did not include any income tax in its 2023 revenue requirement.

5.1.2 SEC believes that the OEB should deny approval of the account for two reasons.

5.1.3 First, the proposed account does not meet the materiality threshold required to establish a new account. According to EEDO's own forecasts, it is expected to pay no income taxes throughout the IRM period.[72] The significant loss carryforward that EEDO had by the end of the 2022 tax year will be more than enough to offset its forecasted taxable income until the end of 2027 (and likely a year or two past that).[73] Therefore, the account is not necessary.

5.1.4 Second, approval of the account would allow EEDO to recover more than would otherwise be the case, if there were no loss carryforward, and if it had an income tax expense included in the revenue requirement in base rates. Any income tax paid by EEDO through the IRM would now be recoverable from ratepayers through the account.[74] Since EEDO has forecasted no income taxes payable due to its loss carryforward balance, the only way it will end up paying income taxes is if it over-earns.[75] Income taxes included in the rebasing revenue requirements are set to recover income tax, or PIL amounts, payable when the deemed rate is met. A utility whose ROE is in excess of the deemed rate during the IRM term does not recover the taxes payable on that additional amount from ratepayers. EEDO should not be put in a better position than it would otherwise be because of a large loss carryforward.

5.1.5 SEC submits that the most appropriate way to handle a large loss carryforward that reduces

[71] Tr.1, p.104
[72] Tr.1, p.107
[73] Tr.1, p.104-105
[74] Tr.1, p.105-107
[75] Tr1, p. 106

test year incomes substantially is to amortize the balance over the IRM term. This is similar to how other one-time expenses are treated and ensures that there is no built-in deficiency when there is a large loss carryforward balance. If applied in this case, the loss carryforward applied to 2023 would be $578,146 (the balance of $2,890,371 at the end of 2022 divided by 5)[76], which still more than offsets the test year forecast taxable income of $112,666.[77]

5.2 ***Non-Utility Billing Variance Account***

5.2.1 EEDO is seeking approval to establish a new variance account, the Non-Utility Billing Variance Account ("NUBVA"), which would capture the impacts of what it describes as unavoidable costs resulting from the potential loss of the shared billing arrangement it has with the Town.

5.2.2 As far as SEC understands the evidence, EEDO is currently undertaking certain water and wastewater billing functions on behalf of the Town, and the allocated costs and revenue are included as part of "Other Revenue," resulting in a net benefit to customers. However, the Town has provided notice that it will terminate the agreement and has asked EEDO to rebid for the work. EEDO seeks to use the NUBVA to capture certain costs that it would not be able to avoid if the billing arrangement does not continue.

5.2.3 In the pre-filed evidence, EEDO mentioned capturing "fixed billing and collecting costs that were excluded from the distribution revenue requirement for billing services provided by outside vendors for activities such as meter reading, bill preparation, and bill fulfillment."[78] At the oral hearing, this was clarified to primarily refer to AMI/CIS related costs that EEDO pays to a third-party who actually performs most of the billing functions. EEDO testified that it currently pays a fixed fee per account to that third-party, which is currently allocated between the Town and the utility. The third-party charges the same fee whether the account is for electricity only or for both electricity and water.[79] EEDO seems to suggest that its costs with the third-party for certain billing services would have been the same regardless of the water

[76] Interrogatory Response 6-Staff-58(c)
[77] Interrogatory Response 6-Staff-58(d)
[78] Exhibit 9, Tab 1, Schedule 1, p.25
[79] Tr.1, p.98

and wastewater billing activities that it performs on behalf of the Town.

5.2.4 It is still not entirely clear to SEC which costs would be eligible for inclusion. For the first time in its Argument-in-Chief, EEDO refers to the allocation of communication network costs. Presumably, these are allocated costs of EEDO assets, not those of a third-party. SEC requests that EEDO provide a clarification and a breakdown of the projected $200,000 amount in its reply.[80]

5.2.5 SEC understands the predicament that EEDO finds itself in. At the same time, the estimated annual impact of $200K is significant. The problem with the proposed account is that it assumes that if EEDO ceases to provide billing services to the Town, it should be allowed to recover an additional estimated $200K annually from customers. If the billing arrangement had ended before the filing of the application and EEDO had included these additional costs in its OM&A, this would have resulted in an even higher revenue deficiency and bill impact. The Board would rightly take these additional costs into account when determining the appropriateness of the overall test year OM&A budget.

5.2.6 SEC does not oppose the establishment of the NUBVA on two conditions.

5.2.7 First, EEDO should only be able to record fixed costs that it would have incurred for the purpose of undertaking electricity distribution activities if it had not been for the Town's water billing contract. To put it another way, customers should not be required to pay for any amounts that EEDO may be obliged to pay to a third-party resulting from a contract, or that were already included in its revenue requirement, relating indirectly to water billing activities.

5.2.8 Second, to address the problem of EEDO efficiently avoiding scrutiny of the overall impact of an additional $200K per year in revenue requirements, the OEB should only allow the recording of 50% of the costs. Additionally, if there is a balance to be disposed of, EEDO should be required to demonstrate that it was unable to find any further efficiencies to offset the reduced revenue from the Town.

---

[80] Argument-in-Chief, para. 72

5.3 *OEB Cost Assessment Variance Account*

5.3.1 EEDO is seeking approval for the disposition of the remaining balance of $246,120 ($235,952 in principal debits), contained in the OEB Cost Assessment Variance Account. [81] SEC has submitted that the annual principal entries into the account are each below EEDO's group 2 DVA materiality threshold of $50,000[82], and therefore, no amount should be recovered from ratepayers.

5.3.2 The OEB Cost Assessment account was established on a generic basis by the Board, by a letter dated February 9, 2016, in response to the revision of the methodology used to apportion its costs under section 26 of the *Ontario Energy Board Act*.[83] Since it was the Board's view that the new methodology "may result in material shifts in the allocation of costs", it created a generic variance account to capture the difference between the cost assessment amounts built into rates and the cost assessments that will result from the application of the new model.

5.3.3 The creation of the generic variance account was not intended to ensure that all balances would be recoverable, regardless of the impact on a given regulated entity. The Board's letter was clear that "regulated entities are reminded that, in the normal course, any disposition of deferral and variance account balances must meet any OEB default or company-specific materiality thresholds."[84]

5.3.4 EEDO has failed to meet the materiality threshold for the variance account, since each year the amount debited to the account is below its DVA materiality threshold of $50,000.

5.3.5 As the materiality threshold is calculated based on a utility's annual revenue requirement[85], it is not the aggregate balance that is measured against the materiality threshold, as EEDO suggests, but the annual entries into the account. This makes sense, considering the purpose of

---

[81] Exhibit 9, Tab 1, Schedule 1, p.9, 14

[82] *Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2*, p.6, ft 6: "The previous $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million still applies to other applications of the materiality threshold, e.g., DVAs, Z factor and eligible investments for the connection of qualifying generation facilities."[emphasis added] p.1

[83] OEB Letter, Re: Revisions to the Ontario Energy Board Cost Assessment Model, February 9, 2016, p.1

[84] OEB Letter, Re: Revisions to the Ontario Energy Board Cost Assessment Model, February 9, 2016, p.2

[85] *Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2*, p.6

the materiality requirement for any new DVA is premised on the idea that an account should only be created if the variance would "have a significant influence on the operation of the distributor."[86] Annual amounts below the materiality threshold do not meet this standard and should be "expensed in the normal course and addressed through organizational productivity improvements."[87]

5.3.6 In its *Decision and Rate Order* in EB-2017-0045, the OEB commented that in the context of a Z-Factor requirement, where materiality criteria is *identical,* that "is an annual amount".[88] The OEB also noted that "[w]hile the Z-factor criteria and filing requirements do not expressly address the aggregation of costs, it is inappropriate to use multiple years of costs to justify materiality for a Z-factor event."[89] The same principle applies equally to the disposition of the OEB Cost Assessment Variance Account.

[86] *Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2*, p.6
[87] *Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2*, p.6
[88] *Decision and Rate Order* (EB-2017-0045), April 26, 2018, p.23
[89] *Decision and Rate Order* (EB-2017-0045), April 26, 2018, p.23

6 OTHER ISSUES

6.1 *Effective Date*

6.1.1 In September, EEDO updated its application to seek a new effective date for rates of October 1, 2023.

6.1.2 EEDO's updated request is based on the realization that is not permitted by both the terms of its Share Purchase Agreement with the Town[90], but also terms of the OEB's MAADs decision[91], to rebase until 5 years after the close of the purchase. As the transaction closed on October 1, 2018, the earliest it can rebase is for rates effective October 1, 2023.

6.1.3 EEDO is seeking in addition to an effective date of October 1, 2023, a request that its first IRM adjustment not be the standard, take place just 3 months later, on January 1, 2024.[92] Furthermore, its proposes an IRM term of only 4 years and 3 months, as it plans to file its next rebasing application for rates effective January 1, 2028.[93]

6.1.4 SEC submits that the OEB should reject EEDO's proposed effective date and rate application timing proposals as they are unfair to customers and not consistent with the rate-setting cycle for any other utility.

6.1.5 ***October 1st Effective Date.*** The OEB sets rates for electricity distributors twice a year, on January 1 and May 1. SEC is not aware of any other utility that has proposed an effective date other than the normal January 1 or May 1 rate year, unless they filed late or there were some special circumstances. The date of the closing of the transaction should not be used as an opportunity for the utility to rebase earlier than they would otherwise be able to following the deferred rebasing period, which EUI specifically requested in its MAADs Application.[94]

6.1.6 ***IRM Adjustment.*** SEC submits the more concerning part of EEDO's rate setting proposal is that its first IRM adjustment would be 3 months after the effective date of its new rates. SEC

[90] Letter from EEDO Re: EB-2022-0028: EPCOR Electricity Distribution Ontario Inc. ("EEDO") Interrogatory Responses and Effective Date, August 25, 2022

[91] *Decision and Order* (EB-2017-0373/374), August 30, 2018, p.16 (K1.3, p.133)

[92] Interrogatory Response 1-SEC-50a

[93] Interrogatory Response 1-SEC-50b

[94] *Decision and Order* (EB-2017-0373/374), August 30, 2018, p.16 (K1.3, p.133)

submits that this is entirely inappropriate and inconsistent with the OEB rate-setting process. Regardless of when the effective date is for EEDO rates following its deferred rebasing period, it must wait at least a full year before seeking an IRM adjustment.

6.1.7 At the oral hearing, and again in its Argument-in-Chief, EEDO argues that its proposed rate-setting schedule is appropriate since it has decided to forgo an IRM adjustment for May 1, 2023.[95] However, it is important to note that these two factors are not equivalent.

6.1.8 A rate adjustment occurring just 3 months after the effective date of new rates from a rebasing application, even will result in a much larger increases than a 2023 IRM increase as a result in the difference in base rates (i.e. those currently in place as compared the proposed to be effective October 1, 2023) [96]

6.1.9 Furthermore, SEC expects the 2024 IRM adjustment to be unusually high across the sector. This is due to the OEB's inflation factor methodology, which is based on changes in historic economic indices set in the preceding year. The 2024 inflation factor calculates the annual increases in 2022 compared to the 2021 labour and non-labour indices, and it is well-known that the 2022 inflation was almost historically high compared to the last twenty years.[97] As a result, it is unreasonable for EEDO to impose a substantial rate increase on its customers in October, followed by another major rate increase just three months later. If customers were given an opportunity to voice their opinions on this matter, they would presumably have significant opposition.

6.1.10 EEDO should not be permitted to adjust rates until 12 months after its approved effective date like all other Ontario utilities.

6.1.11 ***Next Rebasing Application.*** The OEB should also reject EEDO's proposal to allow it to rebase again for January 1, 2028. Assuming it is granted an October 1st effective date, this would result in an IRM period of just 4 years and 3 months. The OEB's rate-setting approach is 5 years (cost of service + 4 years of IRM). While occasionally, a utility is allowed to rebase after

---

[95] Tr.1, p.114-15; Argument-in-Chief, para. 79
[96] Tr.1, p.115
[97] Tr.1, p.114

only 4 years and 8 months, if they seek to align their rate year with the calendar year (moving from a May 1 to January 1), there is no basis to allow a utility to have an even shorter cycle, nor has EEDO even suggested one. It is also unfair to customers who will face another cost of service rate increase earlier than any other utility. EEDO has provided no reason why it deserves special treatment.

6.1.12 ***SEC Proposal.*** SEC submits that the effective date for new rates should be January 1, 2024. It should then be eligible to file IRM adjustments each year on January 1, beginning in 2025, and should be scheduled to rebase no earlier than January 1, 2029, with respect to foregoing its May 1, 2023 IRM adjustment. That was a strategic and tactical decision that EEDO took in this proceeding because of its non-compliant proposal. It should not be allowed to use it to justify rate-setting proposals that put customers in a much worse position.

6.2 ***Load Forecast***

6.2.1 SEC has reviewed a draft of VECC's Final Argument and agrees with its submissions on the load forecast.

6.3 ***Costs***

6.3.1 SEC hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that SEC has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible.

ALL OF WHICH IS RESPECFULLY SUBMITTED.

Mark
Rubenstein
2023.03.16
14:39:
22-04'00'

Mark Rubenstein
Counsel for the School Energy Coalition