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

BY EMAIL

March 16, 2023

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Marconi:

Re: Ontario Energy Board (OEB) Staff Submission
EPCOR Electricity Distribution Ontario Inc.
Cost of Service
OEB File Number: EB-2022-0028

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to Procedural Order No. 7.

Yours truly,

Katherine Wang
Digitally signed by Katherine Wang
Date: 2023.03.16 15:56:59 -04'00'

Katherine Wang
Advisor, Incentive Rate-Setting & Regulatory Accounting

Encl.

cc: All parties in EB-2022-0028

ONTARIO ENERGY BOARD

OEB Staff Submission

EPCOR Electricity Distribution Ontario Inc.

Cost of Service Application

EB-2022-0028

March 16, 2023

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Introduction

EPCOR Electricity Distribution Ontario Inc. (EEDO) filed a cost of service application with the Ontario Energy Board (OEB) on May 27, 2022, under section 78 of the *Ontario Energy Board Act, 1998* seeking approval for the rates that EEDO charges for electricity distribution, effective October 1, 2023. The estimated distribution bill impact for a typical residential customer is 21% as most recently revised by EEDO.[1]

The OEB issued an approved issues list for this proceeding on July 28, 2022. A settlement conference took place on November 7-9, 2022. EEDO filed a Settlement Proposal setting out an agreement among all the parties to a partial settlement on December 9, 2022. EEDO, School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC) and Environmental Defence (ED) participated in the settlement conference. The Small Business Utility Alliance (SBUA) and ED, both intervenors in this proceeding, took no position on the issues that were settled or partially settled. However, neither SBUA nor ED opposed the position reached by the remaining parties and both advised that they would focus their attention on issues still outstanding.

The Settlement Proposal represented a partial settlement. Full settlement was reached on the following issues.

- Issue 3.2 – Cost Allocation
- Issue 3.4 – Retail Transmission Service Rates and Low Voltage
- Issue 3.5 – Specific Service Charges, Retail Service Charges, and Pole Attachment Charge

Partial settlement was reached on the following issues.

- Issue 3.3 – Rate Design, including Fixed/Variable Splits
- Issue 4.2 – Deferral and Variance Accounts

No settlement was reached on the remaining issues.

- Issue 1.1 – Capital
- Issue 1.2 – Operating, Maintenance and Administration (OM&A)
- Issue 2.0 – Revenue Requirement (Issues 2.1 and 2.2)
- Issue 3.1 – Load Forecast

[1] 2023 Tariff Schedule & Bill Impact Model, 6. Bill Impacts, filed with the Settlement Proposal on December 9, 2022

- Issue 4.1 – Impacts of Changes in Accounting Standards, Policies, Estimates and Adjustments
- Issue 5.1 – Effective Date

The OEB issued Procedural Order No. 5 on December 20, 2022, in which it accepted the settlement reached on the issues identified in the Settlement Proposal and made provisions for an oral hearing on the remaining issues, followed by written argument.

The transcribed oral hearing took place in a virtual format on February 14-15, 2023.

EEDO filed responses to undertakings in the oral hearing and its Argument-in-Chief on March 3, 2023.

This submission sets out OEB staff's review of this proceeding's record and is intended to assist the OEB in deciding upon the unsettled and partially settled issues.

OEB Staff Submission

Issue 1.1 Capital

OEB staff submits that EEDO's capital budget for 2023 should be reduced by $1.3 million resulting in a net capital budget of $3.0 million. The capital budget should be reduced based on the following:

a) In developing its current budget, EEDO did not sufficiently consider the 2023 and 2024 forecasts from its Mergers, Acquisitions, Amalgamations and Divestitures proceeding[2] (MAADs Proceeding)
b) EEDO did not sufficiently validate its pole replacement assessment methodology ($700k reduction)
c) EEDO has not justified the spike in 2023 system service spending or adequately explained why the ArcGIS Pro and Utility Network Migration project must be completed in 2023 ($509k reduction)
d) EEDO's historical system access spending and latest road authority information do not support its forecasted 2023 system access expenditures ($100k reduction)

EEDO did not consider its MAADs application in its current capital budget

In the MAADs Proceeding, the OEB approved the EPCOR Utilities Inc. (EUI) acquisition of Collus PowerStream Corporation (Collus PowerStream) with the formal closing date of October 1, 2018.[3]

OEB staff submits that EEDO did not adequately consider the rate impacts to customers after EEDO's latest rebasing deferral period. EEDO also did not take into consideration the budget from the MAADs application when developing its current capital plan, which was one of the premises for the MAADs approval.

EEDO's MAADs application included a capital plan spanning 2019 to 2024. The OEB evaluated the capital plan against its "no harm" test in that proceeding. Objective 1 of the "no harm" test is to protect consumers with respect to price and adequacy, reliability, and quality of electricity service.[4] EEDO projected a capital requirement of $3.3 million in 2023, which forecasted no capital savings from the purchase of Collus PowerStream. The capital plan from EEDO's MAADs application is recreated below:[5]

[2] EB-2017-0373/0374
[3] EB-2017-0373/0374, Decision and Order, August 30, 2018
[4] Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, page 6
[5] EB-2017-0373/EB-2017-0374, December 21, 2017, page 31

Table 1.1-1 2019-2024 Capital Budget and Projected Savings (EB-2017-0373/EB-2017-0374) ($000)

	2019	2020	2021	2022	2023	2024
Status Quo Forecast	3,256	3,312	3,303	3,246	3,303	3,361
EPCOR Forecast	3,256	3,312	3,303	3,246	3,303	3,361
Projected Savings	0	0	0	0	0	0

In the MAADs Decision, the OEB stated that the decision was premised on the evidence submitted by the applicant in that case. The OEB further stated that it placed importance on understanding how, post-rebasing deferral period, EEDO's costs or rates are impacted by the MAADs.[6]

As part of its 2023 cost of service application, EEDO is now projecting a $4.3 million budget for its 2023 test year. A $4.3 million capital budget represents a $1 million (30%) increase from the forecast at the time of the purchase. EEDO's current capital plan is produced in the table below:[7]

Table 1.1-2 2023-2027 Capital Budget (EB-2022-0028) ($000)

	2023	2024	2025	2026	2027
Net Capital Budget	4,296	4,469	3,813	3,768	3,862

Relevance of the MAADs application

In its argument-in-chief, EEDO stated that the evidence from the MAADs case has no relevance to the determination of just and reasonable rates for the cost of service term.[8] EEDO is also of the view that the forecasted revenue requirements and service quality levels from the MAADs application are not binding commitments.[9] EEDO also noted that in at least two other MAADs proceedings (but not in the EUI MAADs case), the OEB imposed conditions on future revenue requirements as part of its approval of the proposed MAADs transactions.[10] In each of the two proceedings referred to by EEDO, the OEB made its approval subject to a condition (among others) that if the fully allocated revenue requirement for the rate classes for the acquired utility is higher than

[6] EB-2017-0373/EB-2017-0374, Decision and Order, August 30, 2018, page 9
[7] Chapter 2 Appendices, App.2-AB_Capital Expenditures, December 9, 2022
[8] Argument-in-Chief, March 3, 2023, page 5
[9] Argument-in-Chief, March 3, 2023, page 4
[10] EB-2018-0242 – Hydro One acquisition of Peterborough Distribution Inc.; and EB-2018-0270 – Hydro One acquisition of Orillia Power Distribution Corporation

the year 11 status quo forecast as set out in the evidence and the decision, the excess costs will be borne by the shareholder and not the ratepayers.

OEB staff acknowledges that the OEB did not impose a similar condition in its decision in the EUI MAADs case. However, as noted above, the MAADs decision was premised on the evidence submitted by the applicants in that case, and the applicants stated “that the economies and efficiencies introduced by the consolidation are expected to result in lower revenue requirements in the future….”[11] A proposed EEDO revenue requirement that does not match the forecast in the MAADs case should not necessarily be rejected here, but OEB staff submits that in determining just and reasonable rates for EEDO, the significant increase in capital spending beyond the forecast in the MAADs Proceeding is relevant, and must be considered. As EEDO is aware, the OEB has already found that questions around the previous forecasts and the actual results are relevant to, and within the scope of, this proceeding.[12]

OEB staff is also concerned that the implication of EEDO’s suggestion that the MAADs forecasts are irrelevant to the post-MAADs rate case is that a MAADs applicant will be incented to make whatever representation is necessary to obtain OEB approval, including providing unrealistic forecasts of future revenue requirements, as any forecasts given in that case will be ignored in the rates case. That is not a reasonable approach to the MAADs application process, nor is it an appropriate approach to a rates case.

During the oral hearing, OEB staff asked EEDO if the MAADs application was used in the guidance of capital budgeting. EEDO did not directly address how it took into consideration the MAADs capital forecast in its current Distribution System Plan. Instead, EEDO stated that it used the Distribution System Plan as a starting point and incorporated EEDO’s capital governance program, which includes improving the asset inspection data and asset condition assessment program to identify capital investment needs.[13] EEDO believes that its increased investment since the purchase of Collus PowerStream, including its 2023 forecasted projects, has been required to ensure the safe and reliable operation of the utility.

EEDO’s Rate of Return since the MAADs approval

OEB staff submits that EEDO’s current capital governance program alleviates the financial risk EEDO took in its purchase by further increasing rate base, thereby increasing rates to customers. Conversely, EEDO believes that it has taken on the financial risk of its purchase by accepting a rate of return five basis points lower than its

[11] EB-2017-0373/EB-2017-0374, Decision and Order, August 30, 2018, page 11
[12] Decision on Issues List, July 28, 2022, page 3
[13] Oral Hearing Transcript, Volume 1, pages 129-131

deemed rate since 2019.[14] EEDO's rate of return has been low since 2019 due to EEDO investing in its system far beyond what its predecessor had invested prior to the purchase. OEB staff notes that the underearning may not be purely due to over-investing in capital during the deferral period but could also be due to higher OM&A costs than those incorporated into Collus PowerStream's OEB-approved 2013 rates (average OM&A increase per year is 6.5%, which is higher than inflation less stretch factor).

OEB staff submits that EEDO's lower rate of return since 2019 is a short-term loss to EEDO as its investments since the acquisition will now be embedded in the 2023 rate base which carries forward. As part of its overall capital plan, EEDO has invested heavily in the replacement of its wood poles since 2019. Wood poles have a typical useful life of 45 years, and EEDO will be recovering a return on these assets for the next 40 years. Because EEDO will benefit from these investments for the next 40 years, OEB staff does not believe historical underearning should have any bearing on the appropriate level of capital spending from 2023 onward. Rather, in considering an appropriate capital expenditure amount for 2023, the OEB should consider that EEDO has already invested a significant amount of capital from 2019 to 2022 and whether this level of spending should continue from 2023 onward. A significant component of this increased spending was on poles.

EEDO did not sufficiently support its pole replacement prioritization methodology ($700k reduction)

EEDO proposes to replace a total of 548 wood poles from 2023 to 2027. In the 2023 test year, EEDO budgeted $1.3 million of its $4.3 million capital plan for the replacement of 78 wood poles.

EEDO's 2023-2027 wood pole replacement strategy was developed in response to an asset condition assessment conducted by METSCO Energy Solutions Inc. on EEDO's wood poles in 2021. METSCO estimated that there would be 463 poles in poor or very poor condition after the five-year period[15], far fewer than the 891 wood poles identified to be in poor or very poor condition currently. EEDO noted that its long-term goal is to eventually address all poles in poor or very poor condition.[16]

OEB staff submits that the OEB should reduce EEDO's 2023 capital budget by $700k related to the replacement of wood poles, as calculated below. OEB staff questions EEDO's annual pole replacement assessment methodology for several reasons:

[14] Argument-in-Chief, March 3, 2023, page 5
[15] 2-Staff-21d
[16] Settlement Proposal, Appendix D, 2-Staff-96

- limited strength data on its wood pole population
- a lack of correlation between reliability metrics and pole-related outages
- minimal consideration of the risk between pole-related outages versus replacement cost

Limited strength data on EEDO's wood pole population

OEB staff submits that the asset condition assessment was completed based on limited pole-related data as EEDO only has strength data on 20% of its wood poles.[17] EEDO has not demonstrated that its available pole strength data was a statistical sampling or used to create a representative model of the total population. Most of the data available on EEDO's wood poles is related to pole age, followed by pole treatment and visual inspections. Due to the lack of strength data, OEB staff believes that it would be difficult to accurately assess the number of poles to replace. OEB staff also notes that EEDO believes in the importance of strength data as it continues to improve its inspection process through resistograph testing.[18]

OEB staff's capital reduction proposal of $700k is based on METSCO classifying 891 (16%) wood poles as being in poor or very poor condition at the time of the asset condition assessment and 463 (8%) wood poles in that state after the five-year period. Although OEB staff does not believe EEDO has enough pole strength data to accurately assess its pole population, OEB staff submits that a reasonable estimate for the number of poles to replace lies between the current state of the poles and the state of the poles at the end of the five-year period. Based on EEDO's methodology, If EEDO were to reduce its estimated number of pole replacements across the five-year period to 340, EEDO should have 12% of its wood poles in poor or very poor condition. Such a reduction would aid with cost control while also allowing EEDO to improve its distribution system condition from its current state. EEDO should use the next five-year period to improve its collection of pole strength data to better support the number of poles EEDO should replace going forward. The pole replacement cost reduction calculations are shown in the table below. These are estimates provided only to support the OEB staff recommended test year reduction:

[17] Exhibit 2 – Rate Base, Asset Condition Assessment Report 2021, August 20, 2021, page 9
[18] Oral Hearing, Volume 1, February 14, 2023, page 3

Table 1.1-3 Proposed Pole Replacement Strategy

	2023	2024	2025	2026	2027
EEDO number of poles to be replaced	78	132	103	129	106
EEDO total pole replacement program costs ($000)	$1,858	$2,012	$1,849	$2,101	$2,036
Staff proposed number of poles to be replaced	48	82	64	80	66
Staff proposed total pole replacement program costs ($000)[19]	$1,153	$1,249	$1,148	$1,304	$1,263
Staff proposed reduction in total pole replacement program costs ($000)	$705[20]	$764	$702	$797	$773

A lack of correlation between reliability metrics and pole-related outages

OEB staff submits EEDO's reliability data does not justify the amount of spending being attributed to pole replacements. According to EEDO, pole failures would typically be categorized as storm-related outages or due to fallen trees. OEB staff assumes storms and fallen tree outages are categorized in reliability metrics under 'adverse weather' as EEDO does not have reliability data specifically for storms or fallen trees.[21]

EEDO's overall reliability and adverse weather hours, measured using the System Average Interruption Frequency Index (SAIDI), are shown in the table below.[22]

Table 1.1-4 Overall SAIDI and SAIDI – Adverse Weather (2014-2021) (hours)

	2017	2018	2019	2020	2021
Overall SAIDI (hours)	4.52	1.93	3.56	3.75	4.47
SAIDI – Adverse Weather (hours)	0.06	0.08	0.03	0.38	1.13

Adverse weather outages account for only a small portion of all outages from 2017 to 2019. Once EEDO began increasing its investments, especially in pole replacements in 2019, adverse weather outage hours increased and are reflected in the 2020 and 2021 reliability metrics. EEDO's overall reliability has also declined over the same period.

[19] The proposed reduction in pole replacements and the associated costs are calculated using the ratio of the total number of poles to be replaced based on OEB staff's recommendation from 2023-2027 (340) compared to that of the original application (548).
[20] For the purposes of simplicity, OEB staff's capital reduction proposal has been rounded down to $700,000.
[21] Settlement Proposal, Appendix D, 2-Staff-97a
[22] Exhibit 2 – Rate Base, Distribution System Plan, May 27, 2022, page 20

Given that both overall reliability and adverse weather outages have trended negatively since the purchase of Collus PowerStream, it appears that EEDO has spent on pole replacements with no measurable improvement in reliability. EEDO has not offered sufficient evidence of its expected reliability improvements even if EEDO were to be allowed the requested 2023 capital expenditure amount.

OEB staff asked EEDO how it related its reliability metrics to the number of poles being replaced given that EEDO does not directly track pole-related outages. EEDO responded by stating that it did not have a correlation between its outages due to pole failures, but that it could not take the risk of pole failures.[23] Without any correlation between pole-related outages and reliability metrics, it is unclear how EEDO prioritized how many poles to replace each year. METSCO did not include an action plan to aid EEDO in its pole replacement pacing process and the pole selection process was solely that of EEDO.

Minimal consideration of the risk between pole-related outages versus replacement cost

OEB staff submits that EEDO has not sufficiently weighed the impact on safety and reliability versus cost when developing its long-term goal of addressing all poles in poor or very poor condition. According to EEDO, customers almost equally value reliability and affordability[24], yet EEDO is increasing overall capital expenditures in the test year with a significant emphasis on pole replacements. Without a risk assessment detailing the safety/reliability risk compared to the cost of replacement, OEB staff does not believe EEDO has provided sufficient evidence to support its pole replacement methodology.

EEDO has not adequately shown why the ArcGIS Pro and Utility Network Migration project must be completed in 2023 ($509k reduction)

EEDO has budgeted $509k in the system service category for the ArcGIS Pro and Utility Network Migration project. The project involves replacing existing software, with the next-generation alternative, ArcGIS Pro, as well as replacing the underlying data model with Utility Network. ArcGIS Pro is used to support operational and business needs including system mapping and asset database recording. EEDO believes the project requires completion in 2023 as the existing software will no longer be supported with software updates, including security patches in 2024, with a complete phase-out by 2026.[25]

[23] Oral Hearing, Volume 1, February 14, 2023, page 135
[24] Exhibit 2 - Rate Base, Community Consultation Survey, November 2021
[25] Exhibit 2 - Rate Base, Distribution System Plan, May 27, 2022, page 91

OEB staff submits that the project should be deferred to a 2024 completion date and that the OEB should reduce EEDO's 2023 capital budget by $509k. OEB staff believes the project can be deferred given that software updates do not cease until 2024.

The project should be deferred since EEDO did not pace its system service budget over the 5-year period (2023-2027). The average system service forecast across the five years is $802k, while the 2023 test year system service budget is $1,373k, a difference of $570k. Rates for the next five years are determined based on the 2023 test year budget along with annual inflationary increases. By including this project as part of the 2023 budget, EEDO would over-recover from 2024 to 2027 given that EEDO's system service budget in those years is lower. Deferring the project would ensure the test year system service budget is more in line with the five-year average forecast.

The five-year system service forecast is shown in the table below:[26]

Table 1.1-5 System Service Forecast (2023-2027) ($000)

Year	2023	2024	2025	2026	2027
System Service	1,373	959	682	479	519

EEDO has overbudgeted its road authority budget considering EEDO's historical trends ($100k reduction)

OEB staff submits that EEDO's road authority[27] budget for the test year should be $87.7k instead of $187.7k, reducing EEDO's 2023 net capital budget by $100k. The road authority budget is for EEDO to work with surrounding public work departments to relocate assets for road maintenance or improvement projects.

OEB staff submits that EEDO's 2023 road authority budget of $187.7k is not indicative of what EEDO would expect for road authority over the next five years. Rates for the next five years are established using the 2023 test year budget with an annual inflationary increase. As such, OEB staff believes that approving the abnormally high road authority budget in 2023 would result in over-recovery in 2024-2027.

One reason EEDO has estimated a higher-than-usual road authority budget in 2023 is due to deferred work from 2022.[28] When only analyzing 2022 and 2023, a better

[26] Chapter 2 Appendices, App.2-AB_Capital Expenditures, December 9, 2022
[27] *Public Service Works on Highways Act*: "road authority" means the Ministry of Transportation, a municipal corporation, board, commission, or other body having control of the construction, improvement, alteration, maintenance and repair of a highway and responsible therefor.
[28] Settlement Proposal, Appendix D, 2-Staff-92a

approximation of what EEDO could expect annually over the five-year period would be $94k, an average of the 2022 and 2023 road authority budgets.

OEB staff also considered EEDO’s historical net road authority spending, which has been on average $25k between 2013 to 2021 and includes no road authority projects from 2016 to 2021. Given the low historical road authority spending and the deferred road authority needs from 2022 to 2023, OEB staff believes a further reduction from $94k to $87.7k would be a better approximation of road authority over the next five years.

EEDO’s historical road authority spending and 2023 forecast are presented in the table below:[29]

Table 1.1-6 Net Road Authority Spending (2013-2023) ($000)[30]

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 forecast
Road Authority Spending	6.9	81.7	138.1	0	0	0	0	0	0	-0.6	187.7

[29] Chapter 2 Appendices, App.2-AA_Capital Projects, December 9, 2022
[30] Road authority spending is negative in 2022 due to EEDO receiving contributions for work that has been deferred to 2023.

Issue 1.2 OM&A

EEDO requested a test year OM&A budget of $6.53 million, which represents an increase of $1.95 million (42.4%) over its 2013 OEB approved OM&A. For the following reasons, OEB staff submits that a reduction of $0.65 million to the test year OM&A budget is appropriate.

MAADs

As noted in the Decision and Order in the MAADs Proceeding,[31] the applicant expected to generate targeted economies and efficiencies as a result of the proposed acquisition. OM&A cost savings arising from the proposed transaction of approximately $185k were forecasted for 2020, with cost savings expected to rise to $464k by 2024 – relative to the forecasted OM&A costs under the status quo (i.e. in the absence of the transaction). EUI provided the following table[32] for the forecasted savings in the MAADs Proceeding. In considering economic efficiency and cost effectiveness in the MAADs Proceeding, the OEB made the following findings:

> Based on the Applicants' statement that the economies and efficiencies introduced by the consolidation are expected to result in lower revenue requirements in the future, the Applicants have demonstrated reasonable consideration for the long-term impacts of the transaction on customers.
>
> The OEB has examined the impact that the proposed transaction will have on the economic efficiency and cost effectiveness of CollusLDC, and has determined that the "no harm" test has been met.[33]

[31] EB-2017-0373/0374, Decision and Order, August 30, 2018, page 10
[32] EB-2017-0373/0374, 1-Staff-1b
[33] EB-2017-0373/0374, Decision and Order, August 30, 2018, page 11

Table 1.2-1 MAADs Proceeding: Breakdown of Net Efficiencies by Business Area ($000)

	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024
Leadership	-149	-151	-154	-157	-159	-162
Operations & HR	-117	-119	-320	-325	-331	-337
Finance & Regulatory	-125	-127	-129	-132	-134	-136
IT	-142	-145	-147	-150	-152	-155
Shared Services Provided by Affiliates	314	308	341	336	331	326
Transaction Costs	760	0	0	0	0	0
Total	541	-234	-409	-427	-446	-464
Cost of 1% Rate Rider	48	49	51	52	54	0
Total	**589**	**-185**	**-358**	**-375**	**-392**	**-464**

Based on the information on record of the MAADs Proceeding and the current proceeding, OEB staff produced the following table for its compendium in the oral hearing. Looking at the variances calculated for the five-year period 2019-2023 in the table, EEDO's actual and estimated OM&A expenditures for four of the five years are not only significantly higher than the "EPCOR Forecast" (with acquisition) figures from the MAADs Proceeding, but also higher than the "Status Quo" (without acquisition) figures. In particular, EEDO's requested 2023 Test Year OM&A budget of $6.53 million is $0.78 million higher than the status quo estimate for 2023.

Table 1.2-2 Status Quo, Forecast, and Actual OM&A[34]

Reference	OM&A ($000)	2019	2020	2021	2022	2023	2024	Total
4-SEC-32	Status Quo Forecast	5,331	5,425	5,520	5,616	5,752	5,814	
4-SEC-32	EPCOR Forecast	5,872	5,191	5,110	5,189	5,306	5,350	
EB-2017-0373/0374 1-Staff-1b)	Projected Savings	(541)	234	410	427	446	464	
EB-2017-0373/0374 1-Staff-1b)	Cost of 1% Rate Rider	48	49	51	52	54	0	
EB-2017-0373/0374 1-Staff-1b)	Projected Savings adjusted by 1% Rate Rider	(589)	185	359	375	392	464	
Appendix 2-JA (IRR dated Aug 25/22)	Appendix 2-JA Actual	5,594	6,111	5,512	6,185	6,530		
Calculated	Variance Actual to EPCOR Forecast	(278)	920	402	996	1,224		3,264
Calculated	Variance Actual to Status Quo	263	686	(8)	569	778		2,288
Calculated	Variance Actual to Status Quo (adjusted by 1% Rate Rider)	215	637	(59)	517	724		2,034

The OEB assessed the transaction in the MAADs application based on the “no harm” test. The “no harm” test assesses whether the proposed transaction will have an adverse effect on the attainment of the OEB’s statutory objectives. If the proposed transaction has a positive or neutral effect, the OEB will approve the application.[35] In the MAADs Proceeding, EUI forecasted significant OM&A savings which helped demonstrate that the customers would not be worse off with acquisition and formed the basis for the OEB’s approval of the MAADs transaction.

In EEDO’s case, OEB staff submits that the total variance of $2.28 million between actual and status quo OM&A figures for 2019-2023 (as shown in table above) is a significant difference from the evidence upon which the acquisition was approved in 2018. EEDO reiterated multiple times in the oral hearing that the MAADs Proceeding forecast was based on the best information it had at the time prior to taking over operations of the utility. However, OEB staff submits that it is EEDO’s responsibility to justify the increased costs while considering customer service levels, customer

[34] OEB Staff Compendium for Oral Hearing, page 45
[35] Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, pages 6 and 4

preferences and what costs should be borne by its customers. Staff submits that EEDO has not adequately justified this level of increase.

Projected 2023 Test Year OM&A

With respect to the approach to assess the trending of OM&A costs, EEDO argues that looking at only inflationary increases since 2013 would be far too simplistic and assumes that the base business of the utility would have to be exactly the same in 2023 as in 2013.[36] OEB staff does not disagree, but notes that it is not inappropriate to at least partly inform the analysis in this manner and has thus provided that assessment below.

OEB staff performed an analysis to project the 2023 Test Year OM&A based on different starting years' OM&A costs[37] taking into consideration both inflationary increases (adjusted by stretch factor)[38] and customer growth:[39]

- With 2013 approved OM&A as a base starting point, the projected 2023 OM&A will be approximately $5.96 million suggesting a reduction of $0.58 million from the proposed 2023 OM&A.
- With 2013 actual OM&A as a base starting point, the projected 2023 OM&A will be approximately $5.73 million suggesting a reduction of $0.80 million from the proposed 2023 OM&A.
- With 2018 (the planned rebasing year in the absence of acquisition) actual OM&A as the base starting point, the projected 2023 OM&A will be approximately $5.63 million suggesting a reduction of $0.91 million from the proposed 2023 OM&A.

Review of Areas with Material Additional Costs

As noted in the current application, as of the October 1, 2018 acquisition date and for subsequent periods, EEDO has been receiving shared services from its affiliate companies EPCOR Water Services Inc. (EWSI), EPCOR Distribution and Transmission

[36] Argument-in-Chief, March 3, 2023, page 14
[37] Each year's OM&A data is from Appendix 2-JA, filed with the Settlement Proposal on December 9, 2022
[38] The analysis employed the Price Cap Adjustment (the OEB-approved inflation minus X-factor formula) for each year.
[39] For each 1% change in number of customers, cost was estimated to change by 0.44%. This estimation is in line with Report to the OEB: Empirical Research in Support of Incentive Rate-Setting: 2021 Benchmarking Update, dated July 2022. The customer count data (excluding connections) is from Appendix 2-IB, filed with the Settlement Proposal on December 9, 2022.

Inc. (EDTI), EPCOR Ontario Operations Management Inc. (EOOMI) and EPCOR Ontario Utilities Inc. (EOUI) (collectively affiliate shared services), as well as from its parent EUI (corporate shared services).[40]

EEDO was asked to provide a summary (through an undertaking) for each year of 2019 to 2023 to show in which areas of OM&A there have been savings relative to status quo and in which areas there have been additional costs relative to status quo, with the associated net saving/cost dollar amounts. For each area where material additional costs were incurred, EEDO was asked to explain why the incremental portion of the cost was necessary and what benefit or value that incremental cost provided to customers. The following table was provided by EEDO in its response to Undertaking J1.6.[41]

[40] Exhibit 4, Tab 1, Schedule 1, May 27, 2022, page 60
[41] Responses to Undertakings, page 4, Table J1.6 – Savings and Additional Costs versus Status Quo

Table 1.2-3 Saving and Additional Costs versus Status Quo ($000)

OM&A	Item Ref.	2019	2020	2021	2022	2023
Difference in inflation relative to Status Quo	1	(7)	5	30	117	228
Savings versus Status Quo:						
Higher labour and vehicle costs capitalized	2	(70)	98	(248)	(159)	(201)
Decrease in rent expense	3	(195)	(196)	(202)	(206)	(209)
Restructuring Operations management	4	-	-	(153)	(180)	(180)
Various Cost Savings Initiatives	5	(30)	(10)	(85)	(55)	(91)
Decrease in smart meter billing costs	6	(37)	(38)	(39)	(41)	(42)
Accounting error correction relating to 2018	7	(78)	-	-	-	-
Bad debt expense	8	(6)	4	(53)	18	5
Additional Costs versus Status Quo:						
Information Technology	9	218	184	179	179	164
Regulatory and Customer Service	10	(29)	(39)	(3)	125	141
Engineering and Operational Technology	11	-	21	22	89	138
Net new operating position	12	34	106	107	108	111
Supply Chain Management	13	199	97	65	77	107
Finance/Treasury/Internal Audit	14	98	93	94	109	105
Health, Safety & Environment	15	89	97	88	109	102
Various miscellaneous other	16	(26)	(91)	(69)	11	55
Human Resources	17	147	116	67	62	73
Amortization of Cost of Service application costs	18	-	-	-	-	72
Management Oversight	19	(66)	(27)	(52)	60	52
System Controls	20	-	24	25	40	41
Internal audit finding remediation	21	-	150	103	62	-
Public & Government Affairs	22	12	4	19	11	36
Short-term incentive pay for EEDO employees	23	-	34	102	29	29
Legal	25	10	(2)	(5)	2	3
COVID incremental OM&A	26	-	54	-	-	-
Maintenance Programs	27					40
Net Costs/(Savings) versus Status Quo		**263**	**686**	**(8)**	**569**	**778**
1% Rate Rider Adjustment		**(48)**	**(49)**	**(51)**	**(52)**	**(54)**
Variance Actual to Status Quo (adj by 1% Rate Rider)		**215**	**637**	**(59)**	**517**	**724**

Item 1 of the table indicates that the difference in actual to expected inflation rates explains over $200k of the total variance of $778k between the proposed OM&A and status quo figure. Total savings versus status quo (Items 2 to 8) are $718k and total additional cost over status quo (Items 9-27) are $1,269k.

In the current application, EEDO provided a narrative in its evidence of cost savings, efficiencies and economies of scale and scope resulting from leveraging the shared service model and the new organizational structure since the acquisition. A few examples of EEDO's narrative are listed below. However, as shown in Table 1.2-3, in the majority of service areas, EEDO actually incurred additional costs instead of savings.

Ex 1 Tab 1 Schedule 1 page 19 - Section 1.2.10 Business Planning Assumptions & Business Plan:

> *EEDO has pursued a business plan to achieve this objective [cost synergies] by realizing synergies between our natural gas and electricity LDCs in Ontario. This has both resulted in cost savings for our customers and the ability to implement operational solutions driving innovation, efficiencies and safety through collaboration and shared services.*

Ex 1 Tab 1 Schedule 1 page 33 - 1.3.12 Organizational Structure:

> *As a member of the EPCOR group of corporations, one of the advantages for EEDO is that it can take access and leverage expertise across EPCOR's entities through a shared services model. EEDO has structured its business operations to reasonably and prudently take advantage of economies of scale and scope through the appropriate use of corporate and affiliate services.*

Ex 4 Tab 1 Schedule 1 page 10 - 4.1.3 Business Environment Changes:

> *In October 2018, EPCOR acquired Collus PowerStream and has worked to create efficiencies by implementing a shared service model that maximizes the value of services being provided.*

OEB staff submits that most of the cost increases summarized in Table 1.2-3 are not adequately justified by EEDO. OEB staff identifies the following issues.

1. Are the additional services, functionalities and/or FTEs necessary?

In responses related to Information Technology (IT), Regulatory and Customer Service and Human Resources (HR), EEDO explained that the majority of the cost increase is driven by the additional services, initiatives and/or FTEs included in the 2023 costs when compared to the status quo. EEDO noted that the additional services and/or FTEs provide the utility with greater capacity and access to a broader, better set of expertise and resources. OEB staff does not disagree that additional services and the affiliate and corporate shared services resources can bring additional benefits to EEDO. However, OEB staff's concern is focused on whether these additional services and greater capacity are necessary considering the scale of the utility, its customers' needs and preferences, and bill impacts.

In service areas such as Supply Chain Management (SCM), Finance/Treasury/Internal Audit, HR and Management Oversight, EEDO provided a description of the services, functions or positions. However, the need for the incremental work and costs has not been discussed. OEB staff submits that the description of the services/positions does not justify the increase in cost. It is also not clear to OEB staff whether, before the share acquisition in 2018, the services provided in these areas had less functionality and/or fewer responsibilities, and if so, whether there had been any major impact on the utility's operation.

OEB staff also notes that for Item 16 – Various Miscellaneous Other (variance of $55k), EEDO did not provide any detail or example in the explanation. For a few other items, such as Item 27 – Maintenance Program, EEDO did not provide clear and complete information to justify the specific incremental cost.

Based on its review of the evidence, OEB staff submits that the need for most of the additional services, functionalities and/or FTEs has not been adequately demonstrated.

2. Consistency and Accuracy of Information

In areas of Engineering and Operational Technology, IT, HR and Management Oversight, OEB staff notes that some of the material in the undertaking responses does not reconcile with other evidence. Therefore, OEB staff is of the view that there could be issues related to the consistency and accuracy of information presented in these areas.

OEB Staff's Recommended OM&A Reductions

Based on the above, OEB staff's overall recommendation is for an envelope reduction to EEDO's 2023 Test Year OM&A in the amount of $0.65 million or 10% of the proposed total spending. With the recommended reduction, the 2023 OM&A of $5.88 million still results in an increase of $1.30 million (28.25%, or a 2.52% compounded annually) above what was approved in the previous (2013) cost of service proceeding. OEB staff submits that its recommended reductions represent a more appropriate level of spending that still allows EEDO to address its growing needs (having also considered rising inflation rates over recent years) while maintaining rates at a level reasonable for its customers.

In the following sub-section, OEB staff raises a number of potential issues related to EEDO's corporate and affiliate shared services. OEB staff submits that these issues provide further justification for OEB staff's proposed reductions.

Other Potential Issues

1. Bundled Set of Corporate Services and Costs Allocated to EEDO

Table 4.4.2-9 in Exhibit 4 of the application[42] lists about 34 items of different types of services and corporate asset usage fees that EUI allocates to EEDO. In the oral hearing, EEDO confirmed that these corporate services and fees are a bundled set that EUI allocates to all subsidiaries in Canada and US based on cost allocators, and that EEDO is not in a position to select from the set of services based on its own review of its needs. Although EEDO noted some advantages in receiving the corporate shared services, OEB staff has a concern with EEDO being required to receive the same bundled set of services as other EUI affiliates without its own control over the selection of services. EEDO is an electricity distribution company serving about 18,500 customers. It has operational and customer needs based on its own conditions and factors. OEB staff does not believe that the bundle of services that EUI provides to all subsidiaries necessarily meets EEDO's needs. OEB staff submits that with this current practice, there is no way of confirming that EEDO is not being allocated excessive corporate shared services with associated additional costs and customer bill impacts.

2. Corporate Cost Allocation Method

In EEDO's response to SEC's Pre-settlement Clarification Question 5, EEDO provided a table showing the additional costs for corporate services compared to those forecasted in the MAADs Proceeding. The table is reproduced below.

Table 1.2-4 Additional Corporate Services and Higher Allocation Percentages[43]

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

This evidence shows that the higher allocation percentages have contributed to the bulk of the increases (about 88% on average) in actual corporate costs compared to forecasted. OEB staff submits that this raises questions about the reasonableness of

[42] Exhibit 4, Tab 1, Schedule 1, filed May 27, 2022, page 77
[43] Settlement Proposal, Appendix D, SEC's Pre-settlement Clarification Question 5

the allocation percentages - whether they are reflecting the real amount of work performed for and required by EEDO.

3. Lack of Study on Shared Service

In EEDO's response to Interrogatory 4-Staff-48, EEDO confirmed that no cost-benefit study has been conducted on the affiliate/corporate shared services. In response to SEC's questions at the oral hearing, EEDO confirmed again that there have been no formal analyses or cost studies conducted with respect to corporate shared services.[44] Considering the complexity of the shared service structure of EEDO, OEB staff submits that a cost-benefit study will help EEDO resolve issues that exist in its shared service model, ensure the cost causation principle is met in the allocation methods, and make necessary adjustments to the current shared service structure to better reflect customers' needs at appropriate costs. OEB staff submits that the OEB should direct EEDO to file a cost-benefit study on the affiliate/corporate shared services in EEDO's next rebasing application.

[44] Transcript, Vol. 1, page 52/l. 27 to page 54/l. 1

Issue 2.0 Revenue Requirement

2.1 Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

2.2 Has the revenue requirement been accurately determined based on these elements?

The parties did not reach a settlement on Issues 2.1 and 2.2. OEB staff makes the following submission on the unsettled matters related to Issues 2.1 and 2.2.

2.1.1 Cost of Capital

EEDO is proposing the following capitalization, debt and equity rates for its cost of capital.[45]

Table 2.1.1-1 2023 Cost of Capital

Particulars	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00	19,071,039	3.98	759,027
Short-term Debt	4.00	1,362,217	4.79	65,250
Total Debt	60.00	20,433,256	4.03	824,278
Equity				
Common Equity	40.00	13,622,170	9.36	1,275,035
Preferred Shares				
Total Equity	40.00	13,6922,170	9.36	1,275,035
Total	100.00	34,055.426	6.16	2,099,313

For long-term debt, OEB staff submits for the reasons discussed below, EEDO's weighted average cost of long-term debt for the 2023 test year should be 3.88%, rather than the 3.98% as proposed by EEDO.

45 Chapter 2 Filing Requirements, Appendix 2-OA for the 2023 Test Year, as filed with the Settlement Proposal on December 9, 2022

EEDO's Long-term Debt

EEDO and its parent, EUI, have altered the approach to debt financing for EEDO since the acquisition. The changes were tested through interrogatories and through cross-examination during the oral hearing.

Since the completion of the share purchase on October 1, 2018, EEDO has obtained all of its long-term debt through its parent, EUI.[46] EEDO's debt costs have been determined by EUI using an internally estimated credit spread over long-term government of Canada bond yields. The following shows an example of the calculation of the affiliated debt between EUI (as the lender) and EEDO (as the borrower) issued on December 3, 2018.[47]

Table 2.1.1-1 Long-term Cost of Debt – Promissory Note from Affiliate

		Dated	Value
1	GOC [Govt. of Canada] 30 Year Rate	3-Dec-03	1.57%
2	EEDO Credit Spread		1.84%
3	Transaction Fee		0.05%
4	**Total Rate [1 + 2 + 3]**		**4.30%**

EUI and EEDO have used this approach for new debt issuances since 2018 and for forecasted debt for the 2023 test year. This affiliated debt is executed in December of each year and has a 30-year maturity.

OEB staff submits that EUI's and EEDO's formula for determining the debt rate on loans between EEDO with EUI (or any affiliated subsidiary of EEDO) should not be adopted for rate-setting purposes.

EUI's methodology produces results higher than the OEB's deemed debt rate in four out of the five years. Since restructuring on April 1, 1999, the OEB's cost of capital policy has been established through rigorous public processes, and has been tested and upheld in the many rate applications by utilities in all sectors to the present. The current cost of capital policy was established through the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (Cost of Capital Report) in the fall of 2009.[48]

As is noted in the Cost of Capital Report, it is a policy, and a panel can decide to diverge from the policy, but with reasons and based on the circumstances in an application. However, the onus is on the party seeking different treatment to justify and

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[46] 5-Staff-56a
[47] Exhibit 5, Tab 1, Schedule 1, page 9, Table 5.2.1
[48] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009

support its request from a deviation from established policy.[49] In OEB staff's submission, EEDO has not justified any different treatment compared to other rate-regulated utilities in Ontario, including EEDO's predecessors, Collus Power Corporation and, subsequently, Collus PowerStream.

Aligning Loan Maturity Dates to Lives of Invested Assets

EEDO's witness testified that the adoption of 30-year loans between EUI and EEDO was to align the maturity of the debt financing with the useful lives of EEDO's assets.[50]

OEB staff agrees with the concept of aligning maturity more closely to the lives of assets. OEB staff also agrees that the majority of EEDO's assets are long-lived, with typical useful lives of 25 years or longer. However, there are also investments in many types of capital assets with useful lives of 15 years or less, including computer hardware and software, meters and smart meters, system supervisor equipment, communications, rolling stock, office furniture and equipment. OEB staff also considers the capital expenditures or capital additions of these shorter-lived assets as being informative.

In OEB staff's view, some mixture or portfolio of debt instruments of different maturities would better align with the mix of assets with different lives being funded by this debt.

Updating of the Interest Rate for the December 31, 2022 Loan

In the Application, EEDO documented a proposed rate of 5.25% for a 30-year promissory note between EUI and EEDO with a planned issuance date of December 31, 2022 and a principal amount of $1.2 million.[51] EEDO's witness stated that the loan was executed, but at a rate lower than the OEB's deemed long-term debt rate for 2023, which is 4.88%.[52] During the Oral Hearing, EEDO's witness stated that the 2022 debt was executed with a rate of 4.80%.[53] However, EEDO was not proposing to update the rate from what is proposed in the application.[54]

OEB staff submits that the rate that should apply to this debt is the lower of the actual rate of 4.80% or the OEB's deemed long-term debt rate of 4.88%, as announced in the

[49] Cost of Capital Report, page 13
[50] Transcript, Vol. 1, page 79/ll. 1-8, Vol. 2, page 84/l. 3 to page 85/l. 16; See also Argument-in-Chief, page 18, para. 56
[51] Exhibit 5, Tab 1, Schedule 1, pages 3 and 8; Chapter 2 Appendices, Appendix 2-OB for 2022 and 2023, December 5, 2022
[52] Transcript, Vol. 1, page 84/l. 19 to page 85/l. 6
[53] Undertaking J1.3, responded to orally during the hearing. Transcript, Vol, 2, page 2/ll. 17-20
[54] Transcript, Vol. 1, page 85/l. 19 to page 86/l. 14

October 20, 2022 letter, rather than EEDO's proposed 5.25% rate.[55] OEB staff submits that there is no basis for allowing a recovery of 5.25% on this debt instrument. The rate is now known, and it is less than the OEB's deemed rate. OEB staff submits that the applicable rate for the December 31, 2022 loan from EUI to EEDO should be 4.80% for rate-setting purposes.

Applicable Rates for Other Affiliated Loans

For the same reasons noted above, OEB Staff submits that historical long-term debt used to determine the weighted average cost of debt for the 2023 test year should comply with the OEB's Cost of Capital policy. Long-term debt rates for affiliated debt should be the lower of the actual rate or the deemed rate determined each year. On that basis, OEB staff has prepared the following updated table from 5-Staff-101 to document OEB staff's proposed treatment.

Table 2.1.1-2 OEB Staff's Proposed Treatment of Affiliated Debt

Date of Issuance		Term (years)	Principal	Rate EEDO Applied in Application	OEB Deemed LT Debt Rate (most current at the time of issuance of debt)	OEB staff proposal, lower of deemed long-term debt rate and actual/ proposed for affiliated debt
3-Dec-18	Actual	30	$8,100,000	4.30%	4.13%	4.13%
1-Dec-20	Actual	30	$2,020,000	2.88%	2.85%	2.85%
15-Dec-21	Actual	30	$2,000,000	3.41%	3.49%	3.41%
31-Dec-22	Actual[1]	30	$1,200,000	4.80%[1]	4.88%	4.80%
31-Dec-23	Forecast	30	$1,200,000	5.03%	4.88%	4.88%

1. Per Undertaking J1.3

As proposed and documented in Appendix 2-OB for the 2023 test year, EEDO is proposing a weighted average long-term debt rate of 3.98%. Under OEB staff's

[55] While the loan was executed in the 2022 calendar year, the OEB's approved forecast for the cost of capital parameters was already known at the time that the 2022 loan was completed, and so EUI and EEDO knew the updated parameters, and should have taken this into account in completing the rate for this loan. There is precedent for this; in the *Report of the Board on the 2006 Electricity Distribution Rate Handbook* and the associated *2006 Electricity Distribution Rate Handbook*, establishing the electricity distribution rate-setting framework for rates to be effective May 1, 2006. Despite the lead time. the OEB established that new or renewed affiliated and variable rate loans issued after May 12, 2005, two days after the of issuance of the report of the Board and the associated handbook, would be governed by the new deemed debt rate and not that of the previous RP-1999-0034 decision and First Generation Rate Handbook. See RP-2004-0188, *Report of the Board on the 2006 Electricity Distribution Rate Handbook*, and, in particular, the *2006 Electricity Distribution Rate Handbook,* page 32. Both the report of the board and the handbook were issued on May 11, 2005.

proposal from the above table, the weighted average cost of long-term debt would be 3.88%. The derivation of this is shown in Attachment.

Conclusions

OEB staff concludes the following with respect to EEDO's cost of capital:

1. EUI's methodology for determining the long-term debt rate that EUI charges to EEDO should not be adopted for rate-setting purposes.

2. EEDO has not provided any substantive evidence on why the OEB's cost of capital policy should not apply to it as it applies to all other rate-regulated utilities in Ontario, and as it did to EEDO's predecessors.

3. The interest rate on the December 31, 2022 loan between EUI to EEDO should be updated with the actual rate of 4.80% (per Undertaking J1.3) in place of the proposed rate of 5.25%.

4. For affiliated debt between EUI and EEDO from 2018 to 2023 (forecast), the allowed long-term debt rate should be the lower of the actual rate (forecasted rate for the 2023 test year) and the OEB's issued deemed long-term debt rate known at the time. Since EUI and EEDO have, since the acquisition, issued debt in December of the year, OEB staff submits that the OEB-issued deemed long-term debt rate for the next calendar rate year, issued earlier in October/November should be used, as this provides the most recent information.

5. Under OEB staff's proposed treatment of the affiliated debt between EUI and EEDO, the weighted average cost of long-term debt for setting EEDO's rates for 2023 would be 3.88%, in contrast with the 3.98% proposed by EEDO in its Application.

2.1.2 PILs Expense

OEB staff reviewed the proposed PILs methodology and has no concerns. OEB staff notes that EEDO used the OEB's PILs Workform to calculate test year PILs of $0. EEDO forecasted a regulatory tax loss carry-forward of $2.9 million[56] as at December 31, 2022 and proposed to apply the 2022 tax loss carry-forward to 2023 regulatory

[56] 6-Staff-58c

taxable income, resulting in $0 PILs in the test year.[57] EEDO's regulatory tax loss carry forward was calculated as follows:[58]

Table 2.1.2-1 Regulatory Tax Loss Carry-Forward

	Amount ($)
Loss carry-forward per 2020 tax return	3,017,883
Add 2021 tax loss generated	332,610
Add 2022 tax loss generated	806,407
Reduce by judicial inquiry costs incurred from 2018 to 2021	(1,266,169)
Regulatory loss carry-forward available for use in 2023	2,890,731

As seen in the table above, EEDO reduced the total tax loss carry-forward by the loss generated from judicial inquiry costs. EEDO stated that as a result of the summons for the Town of Collingwood Judicial Inquiry concerning the 50% share sale of Collingwood Utility Services Corp. to PowerStream Inc., EEDO incurred legal and other expenses from 2018 to 2021, totaling $1.3 million.[59] EEDO considered these costs non-distribution related as these are not costs which customers would be responsible for.[60] Therefore, EEDO recorded these as non-utility costs in the OEB's *Reporting and Record Keeping Requirements* (RRR).[61] OEB staff does not have any concerns with excluding the losses due to judicial inquiry costs from the tax loss carry-forward for regulatory purposes. OEB staff submits that this follows the regulatory principle of benefits following costs. EEDO incurred the judicial inquiry costs at the expense of the shareholder since EEDO did not recover these costs from ratepayers. Therefore, EEDO's shareholder should receive the benefits from this cost, the benefit being the resulting tax loss that can be used to offset taxable income in the future. As EEDO has excluded the tax loss due to judicial inquiry costs from the regulatory tax loss carry-forward, this benefit will be retained by EEDO's shareholder and not ratepayers. OEB staff also submits that the PILs calculation should be updated to reflect the OEB's decision in the current proceeding.

OEB staff discusses further issues related to tax loss carry-forwards in Issue 4.0 below.

[57] Ibid.
[58] Ibid.
[59] Exhibit 4, Tab 1, Schedule 1, June 8, 2022, page 9
[60] Exhibit 6, Tab 1, Schedule 1, June 8, 2022, page 10 and 9-SEC-48
[61] 9-SEC-48b

Issue 3.0 Load Forecast, Cost Allocation and Rate Design

3.1 Are the proposed load and customer forecast including the application of Conservation and Demand Management savings, loss factors, and resulting billing determinants appropriate, and to the extent applicable, are they an appropriate reflection of the energy and demand requirements of EPCOR Electricity Distribution Ontario Inc.'s customers?

OEB staff submits that the load forecast as updated for 2022 historical usage would generally produce a more accurate forecast as compared to the forecast proposed by EEDO,[62] which relies on older data. However, as outlined below, the forecast using most recent data would result in slightly higher proposed rates, all else being equal, than those proposed by EEDO.

During the hearing, OEB staff requested an update to EEDO's filed load forecast to reflect current data as of year-end 2022.[63] This update reflects:

- 2022 energy usage information
- 2022 actual customer connections
- An updated 10-year period (2013-2022) for weather normalization
- An updated economic forecast for 2023.

The load forecast scenario updated for 2022 actual data results in a slightly lower customer connection count forecast, a lower energy forecast, and a lower billing demand forecast, as indicated in the tables below. OEB staff estimates that these combined would result in an increased deficiency of approximately $61,000.

[62] Argument-in-Chief, page 20
[63] EEDO's response to Undertaking J2.8

Table 3.1-1 Impact of Connection Count Update

	Proposed Forecast[64]	Updated Forecast Scenario[65]	Difference	2022 Approved Fixed Charge	Revenue Impact[66]
Residential	17,012	16,938	(74)	27.24	(24,189)
GS < 50 kW	1,833	1,830	(3)	23.07	(831)
GS > 50 kW	127	126	(1)	110.21	(1,323)
Street Light	3,318	3,288	(30)	4.03	(1,451)
USL	30	30	-	0.56	-
Total	22,319	22,211	(108)		(27,793)

Table 3.1-2 Impact of Energy Usage Update

	Proposed Forecast	Updated Forecast Scenario	Difference	2022 Approved Volumetric Charge	Revenue Impact
Residential	137,612,684	136,610,629	(1,002,055)	-	-
GS < 50 kW	44,847,586	45,150,636	303,050	0.0153	4,637
GS > 50 kW	131,569,449	126,943,940	(4,625,509)	-	-
Street Light	1,242,766	1,231,783	(10,983)	-	-
USL	396,233	395,161	(1,072)	0.0132	(14)
Total	315,668,719	310,332,149	(5,336,570)		4,622

Table 3.1-3 Impact of Billing Demand Update

	Proposed Forecast	Updated Forecast Scenario	Difference	2022 Approved Volumetric Charge	Revenue Impact
GS > 50 kW	324,247	313,762	(10,485)	3.6042	(37,790)
Street Light	3,496	3,467	(29)	16.8079	(487)
Total	327,743	317,229	(10,514)		(38,277)

EEDO continues to support use of its older forecast. It submits that the forecast is an appropriate reflection of its customers' energy and demand requirements, and that the methodology used is consistent with the OEB's expectations. OEB staff has no concerns with the methodology used. However, OEB staff submits that using the latest information produces a more accurate forecast, and that the latest information is

64 3-Staff-41
65 EEDO's response to Undertaking J2.8
66 Change in customer count, multiplied by the monthly charge and 12 months per year

typically used in cost of service proceedings. However, the OEB may consider accepting EEDO's load and customer forecast in the interest of mitigating in small part the proposed rate impact arising from this proceeding.

3.3 Are EPCOR Electricity Distribution Ontario Inc.'s proposals, including the proposed fixed/variable splits for rate design appropriate?

The parties partially settled on issue 3.3 subject to updates required to implement the OEB's decision on the unsettled or partially settled issues and the potential for rate mitigation when the rate impacts are known. OEB staff agrees with this approach and anticipates that any further review can be done at the draft rate order stage.

Issue 4.0 Accounting

4.1 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

4.2 Are EPCOR Electricity Distribution Ontario Inc.'s proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?

The parties did not reach a settlement on Issue 4.1 and reached a partial settlement on Issue 4.2. Parties did not reach an agreement with respect to

- the appropriate disposition period for the proposed deferral and variance accounts
- their applicable interest calculation, which is contingent on the OEB's approved effective dates for new rates.
- the continuation or discontinuation of the deferral and variance accounts
- the proposed disposition of Account 1508 – Other Regulatory Assets, Sub-account OEB Cost Assessment Variance Account.
- the proposed establishment of the Non-Utility Billing Variance Account
- the proposed establishment of the Recovery of Income Taxes Deferral Account

OEB staff makes the following submissions on the unsettled issues:

4.2.1 Disposition Period

OEB staff does not take issue with the proposed two-year disposition period for deferral and variance accounts. OEB staff notes that the OEB's default disposition period for deferral and variance accounts is one year, but a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.[67] OEB staff does not take issue with a two-year disposition period as a two-year disposition period will mitigate bill impacts, if the bill impact resulting from the OEB's decision is high.[68]

[67] Report of the OEB on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR), July 31, 2009, page 24
[68] In the 2023 Tariff Schedule & Bill Impact Model filed with the December 9, 2022 settlement proposal, OEB staff notes that the total bill impact for residential customers with consumption of 750 kWh and 256

4.2.2 Interest

OEB staff supports the disposition of interest calculated to the effective date of EEDO's rates. As discussed under Issue 5.1, EEDO proposed an effective date of October 1, 2023. OEB staff notes that in the Deferral and Variance Account Continuity Schedule filed as part of the settlement proposal in December 2022, EEDO has included forecasted interest using the OEB's prescribed Q3 2022 rate of 2.2% up to September 30, 2023. OEB staff notes that the Q4 2022, Q1 2023 and Q2 2023 rates are 3.87%, 4.73% and 4.98%, respectively.[69] OEB staff does not have any concerns with using the Q3 2022 rate in the calculation of forecasted interest because the updates to the Q4 2022, Q1 2023 and Q2 2023 rates would not likely be material, however, OEB staff would not object if EEDO proposes to update carrying charges in the draft rate order stage.[70]

4.2.3 Continuation and Discontinuation of Accounts

OEB staff has no concerns with the proposed continuation and discontinuation of deferral and variance accounts.[71] OEB staff submits that the proposal is in line with OEB guidance for the accounts, where applicable.

4.2.4 Disposition of Account 1508, OEB Cost Assessment Variance Account

OEB staff accepts the proposed disposition of Account 1508 – Other Regulatory Assets, Sub-account OEB Cost Assessment Variance Account. The principal balance in the sub-account from 2016 to 2022 is as follows:[72,73]

kWh is 7.2% and 11.2%, respectively, reflecting a two-year deferral and variance account disposition period. Total bill impact using a one-year disposition period would result in higher bill impacts.

[69] https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/prescribed-interest-rates

[70] OEB staff estimates if Group 1 and 2 account carrying charges were updated for Q4 2022 and Q1 to Q3 2023 using the OEB's prescribed rates, carrying charges would increase by approximately a debit amount of $50k.

[71] Exhibit 9, Tab 1, Schedule 1, June 8, 2022, pages 3 and 9, and updated in 9-Staff-75

[72] Exhibit 9, Tab 1, Schedule 1, June 8, 2022, page 14

[73] 2022 amount is forecasted.

Table 4.2.4-1 Account 1508, Sub-account OEB Cost Assessment Variance Account Balance

	2016	2017	2018	2019	2020	2021	2022	Total
Included in 2013 CoS ($)	27,632	36,496	36,496	36,496	36,496	36,496	36,496	173,616
Actual Invoice ($)	55,325	74,206	70,550	71,990	72,457	69,016	69,016	344,528
Variance $	**27,693**	**37,710**	**34,054**	**35,494**	**35.961**	**32,520**	**32,520**	**235,952**

In the OEB's February 9, 2016 letter regarding Revisions to the OEB Cost Assessment Model that established the 1508 sub-account states that:

> …any disposition of deferral and variance account balances must meet any OEB default or company-specific materiality thresholds.

In its argument-in-chief, EEDO stated that the accumulated balance in the sub-account is beyond the $50,000 deferral and variance account materiality. While the annual amounts in the sub-account are not material, OEB staff does not oppose the recovery of the cumulative amount given the length of time it has been since EEDO has had an opportunity to update its cost assessment forecast for rate-setting purposes. OEB staff also notes that this account will close upon its disposition.

4.2.5 Non-Utility Billing Variance Account

OEB staff does not take issue with the proposed establishment of the Non-Utility Billing Variance Account. The sub-account is to record the difference between the amount of fixed non-electricity billing costs (i.e., water billing), net of actual recoveries from the Town of Collingwood in the event the agreement to provide these services to the Town is terminated by the Town.[74]

EEDO has included revenue offsets of $115k in its test year revenue requirement relating to billing services. The breakdown of the revenues and costs is shown in the table below.

[74] Exhibit 9, Tab 2, Appendix E Proposed NBDA Accounting Order, June 8, 2022

Table 4.2.5-1 Revenue Offsets for Billing Services

Account 4375 - Revenues from Non Rate-Regulated Utility Operations		**Account 4380 - Expenses of Non Rate-Regulated Utility Operations**	
Water/Wastewater billing	(675,000)	Water/Wastewater labour	350,000
Water/Wastewater service charge	(20,000)	Water/Wastewater system fixed	200,000
Water/Wastewater interest	(45,000)	Water/Wastewater system variable	50,000
Total	**(715,000)**	**Total**	**600,000**

In the event that the Town terminates its agreement with EEDO, EEDO will no longer receive the forecasted revenues included in Account 4375 – Revenues from Non-Rate Regulated Utility Operations. However, EEDO will continue to incur forecasted costs as shown in Account 4380 – Expenses of Non-Rate Regulated Utility Operations (excluding the $50k of variable costs) to provide billing services to its electricity customers even if water billing is no longer part of the bill. In particular, EEDO will continue to incur fixed costs for the customer information system and an allocated portion of meter communication network.[75] EEDO is requesting that the sub-account record these fixed costs, forecasted to be $200k. EEDO stated that it would need to take drastic measures to absorb this cost.[76]

As documented in the OEB's Filing Requirements, a distributor seeking an accounting order to establish a new deferral and variance account must demonstrate how the eligibility criteria of causation, materiality and prudence are met.[77] In its argument-in-chief, EEDO addressed the OEB's criteria of causation, materiality, and prudence for establishing the proposed sub-account. OEB staff does not take issue with EEDO's assessment of the criteria. In OEB staff's view, it is reasonable for EEDO to recover the fixed costs as those costs would generally be incurred for electricity billing services regardless of if EEDO provided water billing services to the Town. EEDO intends to request the disposition of the sub-account annually, as noted in the draft accounting order.[78] OEB staff submits that disposition of the balance in the sub-account should be requested in EEDO's next rebasing application. The sub-account would be a Group 2 account, and typically, Group 2 accounts are not brought forth for disposition annually as they require a prudence review, and this prudence review would not be consistent with the mechanistic nature of a distributor's annual incentive rate setting application.

The draft accounting order states that the purpose of the sub-account is "to record the difference between the amount of fixed billing costs attributable to non-electricity billing

[75] Argument-in-Chief, page 23
[76] Ibid.
[77] Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications pages 64-65
[78] Exhibit 9, Tab 2, Appendix E Proposed NBDA Accounting Order, June 8, 2022

and any actual recoveries of these costs from the non-electricity billing service recipient, if any". OEB staff understands that the "fixed billing costs" are charged to EEDO based on the number of accounts billed – they are therefore variable costs. For clarity, OEB staff suggests that the draft accounting order be rephrased as "to record the amount of unavoidable external billing costs attributable to non-electricity billing, net of any revenues received from the Town of Collingwood. The unavoidable external billing costs are CIS costs and a portion of meter communication costs that will be paid to external vendors regardless of whether water billing services are provided to the Town." Any subsequent references to "fixed costs" in the draft accounting order should also be revised to "unavoidable costs".

OEB staff notes that there appears to be an error in the draft accounting order, where it states, under Accounting Entries, "To record the difference between the annual actual income taxes payable and the Board approved deemed income taxes". OEB submits that this should be corrected to "To record the difference between the amount of unavoidable external billing costs attributable to non-electricity billing and any revenues received from the Town of Collingwood." if the OEB approves the establishment of this sub-account.

Furthermore, OEB staff notes that the proposed journal entry for this sub-account is:

Debit/Credit	Account 1508, Sub-account Non-Electricity Billing Deferral Account
Debit/Credit	Account 5310/5315 - Meter Reading Expense/Customer Billing

OEB staff is unclear why Account 5310 or Account 5315, which are OM&A accounts, would be affected. EEDO stated that the related expenses are currently recorded in Account 4380, which is an Other Revenues account. OEB staff invites EEDO to clarify and confirm that the recording of the journal entry to Account 4380 would be more appropriate.

4.2.6 Recovery of Income Taxes Deferral Account

OEB staff submits that the proposed establishment of the Recovery of Income Taxes Deferral Account should be denied as it does not meet the OEB's criteria of materiality and prudence for establishing new accounts.[79]

EEDO's proposed sub-account would record the annual difference between the $0 in PILs included in the revenue requirement of this application and the actual PILs paid (as recalculated at the 26.5% tax rate in place at the time of this application) during the IRM

[79] Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications pages 64-65

term.[80] As noted under Issue 2.1, under PILs, EEDO forecasted $2.9 million of regulatory tax loss carry-forward as at December 31, 2022.[81] It proposed to apply the 2022 regulatory tax loss carry-forward to 2023 regulatory taxable income so that there would be $0 PILs in the test year.[82]

In its pre-filed application, EEDO stated that it expected income taxes payable will exceed the materiality threshold during the IRM term.[83] Subsequently, in response to interrogatories and confirmed in the oral hearing, EEDO currently only forecasts $2.5 million of regulatory tax loss carry-forward to be used by the end of 2027, resulting in no taxes paid during the IRM term and no balance to be recorded in the sub-account.[84] In its argument-in-chief, EEDO argued that establishing the requested deferral account will enable the recording and fair recovery of incurred income tax expenditures over the IRM term once the loss carry-forward balance for regulatory purposes is fully utilized.[85] OEB staff notes one of the key factors in this statement is that the regulatory tax loss carry-forward is fully utilized, which in the current case, is not expected to occur. Therefore, OEB staff submits that the materiality criterion is not met.

In addition, the typical regulatory approach for addressing tax loss carry-forwards would be to take one fifth[86] of the total loss carry-forward available and use this amount to offset the test year regulatory taxable income. This approach amortizes the tax loss carry-forward over the IRM term and would negate the need to establish an account in relation to tax loss carry-forwards. In EEDO's case, if this approach were applied, EEDO would still have PILs of $0 in the test year and no account would be established.[87]

Furthermore, OEB staff submits that the prudence criterion is also not met. It would not be prudent for EEDO to recover the amounts in the sub-account as proposed as it would not be consistent with the OEB's policy for PILs. OEB staff notes that the sub-account as proposed will keep EEDO whole for all fluctuations in its taxes (except for the tax rate, where any change to the tax rate would be captured in the OEB's generic Account 1592 – PILs and Tax Variances). For example, in a simple scenario where EEDO uses all its tax loss carry-forward and makes a business decision to incur lower OM&A than the OM&A approved in the test year revenue requirement, its taxable income will increase, resulting in higher taxes paid, keeping all else equal. EEDO would

80 Argument-in-Chief, page 23
81 6-Staff-58c
82 Ibid.
83 Exhibit 9, Tab 1, Schedule 1, June 8, 2022, page 26
84 6-Staff-58d, 9-Staff-68d, Oral Hearing Transcript Volume 1 Feb. 14, page 107
85 Argument-in-Chief, page 23
86 Representing the number of years between rebasing applications
87 Per 6-Staff-58d, regulatory taxable income for the test year would be $112,666, which would be offset by the tax loss-carryforward.

then record the amount of taxes paid in the sub-account for recovery, while earning a higher net income than forecasted in rates. EEDO confirmed that this is the intent of the proposed sub-account – to keep EEDO whole if income taxes payable are incurred from 2023 to 2027.[88] OEB staff submits that this is not appropriate. The OEB's rate framework does not generally keep utilities whole for the distribution business and, in particular, not for PILs. In the past, the OEB considered and rejected expanding the scope of Account 1592[89] to include a potential true-up of PILs. The OEB's Accounting Procedures Handbook provides:[90]

> Distributors should note that the Board is aware that a difference may exist between the tax or PILs amounts included in rates and the actual amounts paid to tax authorities. However, in its Addendum to Report of the Board dated June 13, 2011, the Board was not prepared, on the basis of the record in the IFRS consultation, to undertake a fundamental reconsideration of long-standing Board practice regarding the true-up of tax or PILs amounts in rates. The scope of Account 1592, PILs and Tax Variance for 2006 and Subsequent Years, was therefore not expanded to allow inclusion of any differences between the PILs provision included in rates and actual taxes paid upon the adoption of IFRS.

In conclusion, OEB staff does not support the establishment of the sub-account as it does not meet the materiality and prudence criteria for establishing new accounts. In addition, OEB staff submits that it is not good regulatory practice to establish an account when it is not expected to be used.

However, if the OEB approves the establishment of the sub-account, OEB staff submits that request for disposition should occur at EEDO's next rebasing, rather than annually, as currently proposed in the draft accounting order.[91] Typically, Group 2 accounts are not brought forth for disposition annually as they require a prudence review, and this prudence review would not be consistent with the mechanistic nature of a distributor's incentive rate setting application.

[88] 6-Staff-58d
[89] Account 1592 records the impact of changes in the tax rates and rules that underpin rates per the Accounting Procedures Handbook, effective January 1, 2012, Article 220, page 38
[90] Accounting Procedures Handbook, effective January 1, 2012, Article 440, page 9
[91] Exhibit 9, Tab 2, Appendix D Proposed RITDA Accounting Order, June 8, 2022

4.2.7 Lost Revenue Adjustment Mechanism Variance Account

In its updated application and evidence filed on September 14, 2022,[92] EEDO proposed a two-year disposition period and projected interest from January 1, 2023, to September 30, 2023, of $3,099.

As noted in Procedural Order No. 5,[93] the OEB accepted the settlement on the disposition of LRAMVA debit balance of $190k proposed by EEDO. However, the parties did not agree to a disposition period or applicable interest for disposition of Group 1 and the updated Group 2 deferral and variance accounts including LRAMVA account 1568 as noted in the OEB staff submission.[94]

Disposition Period

OEB staff does not take issue with the two-year disposition period proposed by EEDO as it is part of the overall proposal for all deferral and variance account dispositions.

Forecasted Interest

OEB staff has no concerns with the forecasted interest calculated to the effective date of EEDO's rates. As discussed under Issue 5.1, OEB staff has no concerns with the proposed effective date of October 1, 2023. Based on the Deferral and Variance Account Continuity Schedule filed as part of the settlement proposal in December 2022, EEDO calculated forecast interest at 75% of the closing LRAMVA principal balance times the OEB's prescribed Q3 2022 interest rate of 2.2%. OEB staff has no concerns with the principal LRAMVA balance or the methodology used by EEDO in calculating the projected interest to September 30, 2023. OEB staff notes that although the Q4 2022 and Q1 2023 rates are 3.87% and 4.73% respectively, using the Q3 2022 rate of 2.2% in the calculation of forecasted interest yields immaterial differences.[95] However, OEB staff would not object if EEDO proposes to update carrying charges in the draft rate order stage.

[92] Application and Evidence, 2023 Deferral and Variance Account Continuity Schedule, September 14, 2022
[93] Procedural Order No. 5, December 20, 2022
[94] OEB Staff Submission, December 15, 2022
[95] https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/prescribed-interest-rates

Issue 5.1 Effective Date

EEDO's original 2023 application requested a January 1, 2023, effective date, consistent with its proposal to aligning the rate year with the calendar fiscal year.

In a letter filed with the OEB on August 25, 2022, EEDO advised the OEB that EEDO's rates could not be changed for the five-year period from the closing of the share purchase agreement between EUI and the Town of Collingwood, other than the "OEB's Price Cap Incentive rate-setting option". As the share purchase was completed on October 1, 2018, EEDO's rebased rates cannot change prior to October 1, 2023.

EEDO's current proposal is for the rebased distribution rates based on the fiscal 2023 year to be effective October 1, 2023. EEDO is proposing to align the rate year with the fiscal calendar year by filing a price cap incentive application for rates effective January 1, 2024.

EEDO did not submit a price cap incentive application for an adjustment on May 1, 2023, because it planned to file a cost-based application for the 2023 rate year. Due to the October 1, 2023 effective date, EEDO has forgone increased revenue for five months (May 1 to October 1).

OEB staff supports EEDO's request to align its fiscal and rate years. As for timing of this alignment, customers have benefitted from EEDO not increasing rates in 2023 until October 1. For this reason, OEB staff does not object to EEDO aligning its rate year to the fiscal year and submitting a price cap incentive application for rates effective January 1, 2024. In addition, a price cap application for January 1, 2024 would not be contrary to the current regulatory framework. OEB staff does however acknowledges that this scenario would result in customers experiencing two rate increases three months apart. Therefore, an alternative approach would be for EEDO to delay the implementation of the alignment and apply for price cap incentive increases effective May 1, 2024, and then again for January 1, 2025. This scenario may be better received by customers.

OEB staff submits that after the draft rate order is issued later in this proceeding, there should be no further updates made to this application before the rate effective date.

~All of which is respectfully submitted~

Attachment: Appendix 2-OB for the 2023 Test Year for EEDO, per OEB Staff's Proposed Treatment of Affiliated Debt between EUI and EEDO

Attachment: Appendix 2-OB for the 2023 Test Year for EEDO, per OEB staff's Proposed Treatment of Affiliated Debt Between EUI and EEDO

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Town of Collingwood	Affiliated	Variable Rate	1-Nov-01	0	$	0.00%		
2	Government Agency Loan	OSIFA	Third-Party	Fixed Rate	15-Apr-10	15	$ 300,000	4.67%	$ 14,010	
3	Government Agency Loan	OSIFA	Third-Party	Variable Rate	1-Aug-12	25	$ 4,186,778	3.84%	$ 160,772	
4	Financing Agreement	OILC	Third-Party	Fixed Rate	26-Jul-12	30	$ 561,342	4.58%	$ 25,709	
5	Financing Agreement	OILC	Third-Party	Fixed Rate	15-Apr-15	20	$ 575,000	2.76%	$ 15,870	
6	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$	3.65%		
7	Commercial Loan	TD Commercial bank	Third-Party	Fixed Rate	24-Dec-15	10	$	3.65%		
8	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	3-Dec-18	30	$ 8,100,000	4.13%	$ 334,530	
9	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	1-Dec-20	30	$ 2,020,000	2.85%	$ 57,570	
10	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	15-Dec-21	30	$ 2,000,000	3.41%	$ 68,200	
11	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-22	30	$ 1,200,000	4.80%	$ 57,600	
12	Promissory Note	EPCOR Utilities Inc.	Affiliated	Fixed Rate	31-Dec-23	30	$ 1,200,000	4.88%	$ 160	End of year issuance
Total							$ 20,143,120	3.65%	$ 734,422	
						Less: pro-rated principal for 2023	(1,196,712)			End of year issuance
						True cost of debt	$ 18,946,408	**3.88%**	$ 734,422	

Notes

1. If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2. Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the OEB.
3. Add more lines above row 12 if necessary.