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April 3, 2023

Sent by EMAIL, RESS e-filing

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

Dear Ms. Marconi:

Re: EB-2022-0028: EPCOR Electricity Distribution Ontario Inc. ("EEDO")
2023 Cost of Service Filing – Reply Submission

In accordance with Procedural Order Number 7, please find enclosed EEDO's reply submission and final argument in response to the submissions received from OEB Staff and Intervenors in this preceding.

Please contact me if you require any additional information.

Sincerely,

Hesselink, Tim

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Encl.

EB-2022-0028

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by EPCOR Electricity Distribution Ontario Inc. for an order or orders approving electricity distribution rates and other charges commencing as of October 1, 2023.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.
COST OF SERVICE APPLICATION
FINAL ARGUMENT

April 3, 2023

A. INTRODUCTION

1. On March 3, 2023 EPCOR Electricity Distribution Ontario Inc. ("EEDO") filed its argument-in-chief ("Argument-in-Chief") summarizing its proposals and evidence in respect of the unsettled items in this proceeding. EEDO's Argument-in-Chief explains why its proposals are reasonable and appropriate and should be accepted by the Ontario Energy Board (the "OEB" or the "Board").

2. Five parties filed arguments (the "Arguments") in response to EEDO – OEB Staff and each of the Intervenors in this proceeding: School Energy Coalition ("SEC"), Vulnerable Energy Consumers Coalition ("VECC"), Small Business Utility Alliance and Environmental Defence Canada Inc. ("Environmental Defence") (collectively, the "Intervenors").

3. This reply argument ("Reply Argument") sets out EEDO's response to the arguments advanced by the other parties in this proceeding. In addition to the items set out in this Reply Argument, EEDO re-iterates and relies on the arguments set out in its Argument-in-Chief.

4. In advance of the direct rebuttals on the unsettled items in this proceeding, EEDO believes it is important to respond to the argument that EEDO is prioritizing the interests of its shareholder, EPCOR Utilities Inc. ("EUI"), over ratepayers.[1] EEDO's mission is not to maximize the profit to its shareholder; this is evidenced by the low ROE taken by EEDO since EUI's acquisition (actual ROE in 2019 = 2.77%; 2020 = -1.77%; 2021 = 3.47%).[2] Rather, since completion of the transaction, EEDO's mission has been and continues to be achieving safe, reliable and cost-effective service for its ratepayers. The utility industry has shifted significantly since this LDC's last cost of service; equipment and labour costs more, regulatory and operational requirements are more onerous and accordingly, the proposed rates are higher. The application put forward by EEDO has always been, and continues to be, about providing safe, reliable and cost-effective electric distribution service to ratepayers. The costs requested by EEDO in the Application are the necessary

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[1] VECC Argument at para. 40.
[2] EB-2022-0028 Interrogatory Response to 1-SEC-4.

and appropriate costs required to provide this service. The resultant rates being proposed are fair and reasonable.

5. Overall, EEDO submits that an examination of the benchmarking data provided in EEDO's Argument-in-Chief and in this Reply Argument clearly demonstrates that the proposed costs in this Application are reasonable. EEDO has put forward an application that is focused on delivering operational effectiveness by investing in capital to improve performance, implementing projects in response to the priorities of EEDO's customers, and positioning the utility for the changing energy market in the coming years.

6. This Reply Argument is organized to address each of the unsettled issues as set out below. Under each subheading, EEDO responds to the arguments made by the other parties on each of the unsettled issues:

A. Introduction
B. MAADs Proceeding
C. Capital
D. OM&A
E. Revenue Requirement
F. Load Forecast, Cost Allocation and Rate Design
G. Accounting
H. Other

7. EEDO requests approval of its proposal for each of the unsettled items as filed in the Application in order to continue to provide safe, reliable, cost-effective service to its customers.

B. MAADs PROCEEDING

8. Before specifically addressing the unsettled issues, EEDO will respond to issues raised in the Arguments about the significance of the MAADs proceeding that approved EUI's acquisition of Collus PowerStream Corporation ("Collus") (the "MAADs Proceeding").[3]

9. In their submissions, OEB Staff and certain Intervenors in this proceeding have emphatically argued that the capital and OM&A cost forecasts made by EUI in the MAADs Proceeding are of the utmost importance in setting EEDO's 2023 Test Year revenue requirement. It is clear from the submissions that OEB Staff, SEC and VECC view the capital and OM&A forecasts made by EUI in the 2017 MAADs Proceeding as either binding on EEDO (and the Board) in this proceeding or the yardstick used to determine EEDO's Test Year costs.

10. For example, in arriving at its proposal to reduce EEDO's OM&A costs, SEC suggests making an adjustment "to reflect the expected and forecasted savings that customers were promised in the MAADs Application."[4] Even OEB Staff, in its submissions on EEDO's proposed capital costs, spends three full pages discussing the MAADs Proceeding and how important it should be to the Board's determination of EEDO's Test Year capital costs. It takes the same position on OM&A.

11. There are two problems with this: First, the effect of this approach is to ignore or largely overlook far more relevant factors to cost-based rate-setting, most notably recent actual costs of running the utility, management's judgment based on recent operational experience, and the utility's applied-for costs in comparison to its peers. The task of the Board is to establish just and reasonable rates based on the best evidence before it. Instead, Board Staff and Intervenors are encouraging the Board to disregard the most relevant, current information, and rely instead on EUI's OM&A and capital cost estimates from 2017, made without any experience operating the utility.

[3] EB-2017-0373/0374 (August 30, 2018).
[4] SEC Final Argument, para 3.4.7 (emphasis added).

12. Second, treating the estimates in the MAADs proceeding as *de facto* binding on EEDO in the Test Year is both wrong at law and inconsistent with past OEB practice. EEDO made this point in its Argument-in-Chief – pointing to two proceedings where rate-related commitments were made binding on a subsequent rate-setting OEB panel.[5] OEB Staff acknowledges these two cases and the fact that the OEB in the MAADs Proceeding "did not impose a similar condition in its decision in the EUI MAADs case." Notwithstanding that, OEB Staff then goes on to state that cost savings from consolidations "are expected" – and reverts to relying on the forecasts in the MAADs Proceeding to frame their submissions. In doing so, they diminish to the point of completely dismissing the critical distinction between a binding commitment and a non-binding forecast.

13. This is wrong at law. There are two ways in which an OEB panel setting rates can be bound by a previous OEB panel's determination, and have its rate-setting discretion constrained: (a) by a utility applicant voluntarily committing to (or providing an undertaking to) a future rate or rate mechanism; or (b) a previous OEB panel setting out binding rate-setting rules governing a future rate determination.

14. There is precedent for both of these approaches at the OEB:

(i) Voluntary Commitment: In early 2018, the OEB denied Hydro One's MAAD application to acquire Orillia Power,[6] primarily because the OEB was not convinced that Hydro One's forecasted cost savings would materialize. Hydro One subsequently filed a second MAAD application to acquire Orillia Power, but in this second application committed to capping its Year 11 revenue requirement (i.e., at the end of the rebasing deferral period) at the Status Quo Forecast. On that basis, the OEB approved Hydro One's second MAADs application.[7] The Year 11 revenue requirement cap will bind Hydro One when it brings its first post-acquisition rebasing application. Hydro One voluntarily proposed this cap and the OEB accepted it in its ruling. Hydro One gave the exact same commitment in its MAAD application to acquire Peterborough Distribution, and again it was accepted by the

[5] Argument-in-Chief at page 4.
[6] EB-2018-0276 (April 12, 2018).
[7] EB-2018-0270 (April 30, 2020).

OEB – allowing the acquisition to proceed. EUI gave no such voluntary undertaking or commitment in its MAAD Proceeding to acquire Collus.

(ii) Binding Rules: In 2017, the OEB initiated a process to select a gas utility to expand Ontario's natural gas distribution system into South Bruce (i.e., a competition for the franchise rights). EPCOR South Bruce Gas Inc.[8] and Union Gas Limited were the two competing utilities. In order to select the preferred distributor, the OEB asked the two utilities to each submit a cumulative 10-year revenue requirement, based on a common infrastructure plan. In other words, the utilities were asked to provide a binding revenue requirement forecast associated with the development, construction and operation of a "common" distribution system. EPCOR SBG was ultimately selected by the OEB, and granted the South Bruce franchises (the "Selection Decision").[9] At its first rate case, EPCOR SBG had to ensure that its rate application was filed in accordance with the Selection Decision. In other words, EPCOR SBG had to take the risks associated with its binding revenue requirement forecast. That is appropriate because that is the process the OEB established for that proceeding. EPCOR SBG understood that its cost forecasts would be binding – and EPCOR SBG accepted that risk. That was not the basis upon which EUI filed its application to acquire Collus in the MAADs Proceeding.

15. In addition to not being bound to EUI's capital and OM&A cost forecasts in the 2017 MAADs Proceeding, it is also contrary to past OEB practice to treat utility cost estimates provided in non-rates proceedings as binding or significantly relevant in later rate proceedings. This has been true of other MAAD applications, as well as a recent transmission build:

(i) In 2012, the OEB established a competitive process to select a transmitter to build the East-West Tie Line. A significant number of very sophisticated utility companies participated (TransCanada, Enbridge, Hydro One, Florida Power & Light, Fortis, RES, AltaLink). One of the competitive evaluation criteria was construction costs to build the approximately 400 km transmission line.

[8] EPCOR South Bruce Gas Inc. ("**EPCOR SBG**") is a subsidiary of EUI.
[9] EB-2016-0137/0138/0139, April 12, 2018.

Construction cost estimates by the six eventual bidders ranged from $378 million to $527 million. Upper Canada Transmission Inc. ("UCT") was ultimately selected as the transmitter.[10] In its first rate case, UCT was permitted to include $737 million in construction costs in its Test Year rate base, which was well in excess of all bidders' forecasted costs, but the real costs to construct the line.[11] Unlike the South Bruce natural gas proceedings, this competitive process established by the OEB did not require binding construction cost estimates, and there was no consideration given to holding UCT to its initial construction cost bid of $378 to $409 million.

16. For these reasons, EEDO submits that EUI's forecasts in the MAADs Proceeding are not binding on EEDO or this OEB panel. Moreover, they should not serve as the anchor or primary principle around which EEDO's Test Year cost forecasts in this proceeding are evaluated.

17. As noted above, the OEB's focus in this (and any) rate proceeding must be establishing just and reasonable cost-based rates – following careful consideration of more relevant factors such as recent actual costs of running the utility, management's judgment based on recent operational experience, and the utility's applied-for costs in comparison to its peers. OEB Staff criticized the capital costs applied for in this proceeding on the basis, *inter alia*, that EEDO did not take into consideration the capital budget from the MAADs Proceeding. That is, at best, misguided – the basis for EEDO's Test Year capital budget is its Distribution System Plan, recent capital expenditures, and management's judgment of how best to approach capital planning in the near-term. It should not be estimates of EEDO's parent based on information gleaned in a due diligence data room several years ago (without any operational insight).

18. The pre-occupation with the MAADs Proceeding in this proceeding has been largely – if not entirely – irrelevant.

19. Although not expressed with any precision, what OEB Staff, SEC and VECC seem to be suggesting is that the MAADs Proceeding evidence should be given precedence because

[10] EB-2011-0140 (August 7, 2013).
[11] EB-2020-0150 (June 17, 2021).

it created customer expectations about distribution rates in 2023. But not only were the forecasts in the MAADs Proceeding never intended to be binding, but customer expectations are not a basis for just and reasonable rate-setting. The OEB establishes rates on a cost-to-serve basis – ensuring utilities recover their prudently incurred costs and earn a fair return.

20. EEDO understands that Intervenors are displeased with the cost forecast in this proceeding as compared to those in the MAADs Proceeding. EEDO is also frustrated that the cost savings forecasts in the MAADs Proceeding have not borne out. EEDO has, nevertheless, done what any responsible utility would do – spent the necessary capital and operating funds to ensure the utility could operate reliably and safely. In some cases, this has meant correcting deficiencies that came to light once EEDO began operating the distribution system in Collingwood. It should not be faulted or punished for doing so, and it should not have going-forward rates set on a basis that ignores these most recent spending levels. If anything, spending in the most recent years (when EEDO was not recovering those expenditures) lends credence to the presumption that EEDO management was making necessary, prudent spending decisions since 2019.

21. EEDO believes that the pre-occupation with the MAADs Proceeding in this case is actually part of the Intervenors (and OEB Staff's) dissatisfaction with cost forecasting in MAADs applications more generally. If true, that is a broader issue for the Board to address – the answer is not to re-interpret the 2017 MAADs proceeding here or retroactively turn the OEB's MAADs process into something it wasn't in 2017. It also raises broader policy questions regarding utility consolidations and – as EEDO has made very clear in this proceeding – the difficulty in cost forecast on the basis of typical, inherently limited transactional diligence.[12]

[12] We note that EUI's purchase of Collus was not a very large utility absorbing a very small one (where cost variances from forecast might be easily absorbed) but a utility without any Ontario presence in the electricity distribution sector buying a distributor.

C. CAPITAL

22. EEDO submits that it has proposed an essential capital investment plan that addresses both the historic undercapitalization of the utility that has resulted in an increased risk to safety and reliability, while also investing in grid modernization that will create the opportunity for EEDO's customers to participate in the benefits of electrification.

23. EEDO has worked to resolve the issues associated with historic capital underspending that pre-dated the sale of the utility in 2018, including addressing staff retention issues, strengthening relationships with contractors, and ensuring internal resources are in place for planned projects.[13] EEDO is confident in its ability to deliver the capital program that it has brought forward. EEDO submits that the costs are reasonable, justified and required for this LDC.

24. The reasonableness is demonstrated by EEDO's net PPE per customer, which has been historically low as compared to other LDCs.[14] Using the OEB's 2021 Open Data for Electricity Distributors, EEDO ranked as the 16th lowest for net PPE per customer out of 57 LDCs for the 2021 year.[15] [16] For this same metric, EEDO ranked 12th lowest in 2017 and 15th lowest in 2020.[17] The proposed EEDO PPE per customer for 2023 of $2,173 is consistent with the all-LDC average PPE per customer of $2,139 from six years ago.[18] The EEDO PPE per customer proposed in this Application is very much in-line with EEDO's customer growth since its last rebasing and still remains low when compared to other LDCs.

25. The capital plan program both improves performance and addresses risk. The system renewal program is primarily focused on addressing pole line distribution infrastructure. This investment is critical to ensure ongoing reliability and resilience. It is arguably the

[13] EB-2022-0028, Oral Hearing Transcript, February 14 and 15, 2023, [Transcript] Volume 1 page 13 lines 3 to 20 and page 163 lines 1 to 16.
[14] Transcript, Volume 1 page 121 lines 13 to 19 and Volume 2, page 117 lines 1 to 14.
[15] OEB 2021 Open Data for Electricity Distributors, Unitized Statistics and Other, Tab Unitized & Other Statistics [2021 Unitized Data]
[16] Lower rank means lower PPE investment.
[17] OEB 2017 Annual Yearbook for Electricity Distributors; OEB 2020 Annual Yearbook for Electricity Distributors. 2021 Unitized Data at Tab Unitized & Other Statistics.
[18] OEB 2017 Annual Yearbook for Electricity Distributors.

most important program that EEDO undertakes each year addressing both public safety and reliability risk with the most exposed and uncontrolled assets. The system service program addresses the performance of the system through investments in municipal stations and grid modernization. Without these investments EEDO would be trading off the ability to support growing electrification. General Plant investments ensure EEDO's employees have the essential tools and facilities necessary to support the grid. Reducing any of these programs trades off the ability to ensure non-discretionary system access investments (connecting customers) meet the long term objectives of our stakeholders.

26. The following sections provide EEDO's rebuttal of arguments made by OEB Staff, SEC and VECC in response to their short term goal to reduce EEDO's 2023-2027 planned capital investment.

<u>OEB Staff Capital</u>

27. **Reference: OEB Staff Page 5**

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.

28. EEDO's response to OEB Staff's line of questioning was meant to stress that the process was iterative. EEDO's 2023-27 DSP used the 2019-2023 DSP as its starting point. The 2019-2023 DSP used the 2017 MAAD application process and learnings as an input. The MAAD Proceeding capital forecasts were made with the best information available and with limited time available to EUI in performing its analysis. When the 2019 DSP was submitted in August of 2019, EEDO had 10 months of operating experience to be able to better assess the state of the assets and the areas in need of investment. This assessment would have been informed by conversations with employees and contractors, and more time with the asset data reviewing performance.

29. **Reference: OEB Staff Page 5**

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.

30. **Reference: OEB Staff Page 6**

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.

31. **Reference: OEB Staff Page 6**

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.

32. To clarify, EEDO has not tried to correlate future capital spending to historical under earning as inferred in the three references provided above. EEDO's reference to under earning between the years 2019 to 2022 were to explain that EEDO and its shareholder assumed the risk to any errors in the MAAD forecasts during this period.[19] The customers benefited by having a utility that was willing to assume this risk, under earn, yet continue to make the investments required to mitigate future risk and improve system performance for years to come. EEDO has not been making capital decisions in an attempt to make up for these years of under earning. EEDO's capital plan has been developed based on its asset management process as outlined within the DSP and further explained through IR responses, the oral hearing, and its Argument-in-Chief.

33. **Reference: OEB Staff Page 6**

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:

[19] Argument-in-Chief, paragraphs 17, 18 and 19.

- *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*

34. Raising the issue of the lack of strength data on the wood pole population actually supports EEDO's assertion that there had been limited historical or condition-based asset data available to make highly accurate forecasts in the MAADs Proceeding.

35. EEDO does not disagree that the Data Availability Index (DAI) for wood poles is low and should improve. EEDO has only been able to implement this program for one third of its total population to date. As the METSCO asset condition assessment points out, 16% of EEDO's over 5600 wood poles (~900) have no known manufacture data or installation date. METSCO had to develop a predictive algorithm to determine the age factor for these poles using pole coordinates, pole type, pole class and pole height to run the K-Nearest Neighbor predictive analytics algorithm. EEDO's service area is estimated to have over 1,200 wood poles that are 50 years old or greater. EUI could not have conducted this analysis during the due diligence process to acquire Collus. It is not unexpected that EEDO has found that there are more wood poles in need of replacement than the status quo forecast in the MAAD application given the age of these assets.

36. As noted in evidence, there are several factors used when evaluating the prioritization of capital projects. The risk ranking matrix utilized by EEDO considers safety, reliability, customer impact, financial viability, effect or ease of integration, the environment and the impact on conservation[20]. This was submitted to demonstrate that a project's business case is driven by many factors beyond asset condition. This is true for our applied-for pole line rebuild projects, the scope of which may include poles, conductors, transformers and insulator replacement in often complicated settings.

37. To further illustrate, as discussed during the oral hearing, rear back lot pole replacement projects are driven by public safety and are in hazardous environments[21]. The poles

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[20] EB-2022-0028, Application, Exhibit 2 – Distribution System Plan, page 28 of 134 & EB-2022-0028 IR Response 2-Staff-33 DSP Risk Ranking Matrix 20220825

[21] Transcript, Volume 1 page 147 lines 12 to 26 and page 140 -141.

themselves may be in good condition, but it is no longer acceptable to carry primary copper conductor through neighborhood backyards. In other cases, while addressing a poorly conditioned pole or bringing one up to code, this often means replacing a 35 foot pole with a 45 foot pole to ensure proper clearances are met. The cascading effect is that the adjacent four to five poles which may be in good condition, also now need to be replaced to meet safety codes and standards. Further, pole line rebuild projects may be driven by a direct reliability need. An example is the applied-for Osler Bluff Road pole line rebuild where the driver is to connect feeders for the purpose of achieving a looped back feed to ensure steady delivery of power in the event of mechanical failure or other outages.

38. Pole strength data is important but not the only criteria used for the replacement or addition of poles. EEDO (and any other distributor) must also consider safety and reliability, conductor size, clearances, current standards, radial feeds, future loads, etc. There will be a number of poles replaced during this DSP period that are driven by other factors beyond just condition, and to reduce capital spending in this area due to low pole strength data would be misunderstanding the driver for those projects.

39. EEDO disagrees with OEB Staff's statement that wood pole replacement should be lessened because there is not a strong correlation between reliability metrics and pole related outages. To support this view, EEDO offers the following comparison: LDCs do not experience a large number of station related outages. The reason for this is that there is a regular preventative capital and operating maintenance program executed on stations to reduce the risk of an outage occurring. This is the same concept LDCs use on pole replacements. If poorly conditioned wood poles are not proactively replaced or pole lines are not continually updated to meet code (clearances) or improve capacity (conductor type), LDCs would be putting reliability and public safety at risk. If there were a strong correlation between reliability metrics and pole related outages, the LDC is not doing its job.

40. EEDO disputes that there has been minimal consideration between pole related outages and replacement costs. EEDO has submitted in its written and oral evidence that it has invested in the necessary equipment to be able to make pole line replacement projects more efficient and effective. For example, EEDO acquired tension stringing machines so

that it could replace poles and conductors at the same time, leading to a lower cost outcome by not having to revisit that same pole line in future to replace the conductor and not having to use expensive contractors to do this work.

41. If the Board chose to reduce capital spending in this area by $700K, EEDO would be forced to prioritize safety related pole line rebuild projects over reliability driven projects. The impact to this would be a less resilient system further set back from being able to respond to the growing needs of electrification.

42. **Reference: OEB Staff Page 10**

OEB staff submits that the (ArcGIS Pro and Utility Network) 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.

43. EEDO disputes this argument for two reasons. First, waiting until 2024 to complete the project increases cyber security and software stability risk given the vendor has indicated that software updates will cease in March 2024. The prudent preventative maintenance action for a LDC is to update its software prior to support being ended by the vendor.

44. This IT software investment is subject to a 20% annual level of depreciation and deferring this project until after the Test Year would result in a $0 net book value over six years (when taking into account the ½ year rule). Due to the short useful life of the asset (5 years in comparison of 40 years for poles), the impacts of pushing the investment out of the Test Year would result in the LDC paying for the asset with no possibility to recover not only the annual depreciation, but also any return on equity over the next rate cycle. A Test Year investment is already a compromise and provides an additional $200k of value to customers as the NBV will be $0 before the next rebasing.

2023 INVESTMENT	2023T	2024	2025	2026	2027	2028	Total
Cost	500,000						500,000
Depreciation	(50,000)	(100,000)	(100,000)	(100,000)	(100,000)	(50,000)	(500,000)
NBV	450,000	350,000	250,000	150,000	50,000	-	-
Depreciation in Rates	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(300,000)

45. If EEDO waits until 2024 to complete this investment, it would only be able to earn a return on 10% of the asset value. This is unreasonable, and does not support the overall financial viability of the LDC given the unique nature of this asset.

46. The Utility Network (UN) Project is vital to the forward movement of EEDO's business over the next decade and beyond. The current geometric database model has been used since 2007 and is now at end of life (currently in mature support through Vendor). This model does not provide for the future of electrification, advance network modelling, visualization/analysis, as well as the ability to work with modern IT architecture and security. The new UN model will allow for a more realistic representation of utility assets, which will result in greater accuracy for planning, better integration and streamlined workflows. The new UN model will provide EEDO with an environment to work smarter with its resource allocation, benefiting both the EEDO and its customers in the long run.

47. **Reference: OEB Staff Page 10**

OEB staff submits that EEDO's road authority budget for the Test Year should be $87.7k instead of $187.7k, reducing EEDO's 2023 net capital budget by $100k.

48. EEDO does not believe a reduction should be made because the level of investment in this area was lower in the past. The inclusion of the road authority work is our 2023 capital expenditures is based on the communications we received from local municipalities. Potential municipally driven projects include a road rebuild in Thornbury, new roundabouts in Collingwood, and a street beautification project in Creemore. EEDO notes that the net system access forecasted in the 2023 Test Year is in line with historical spending levels for this category.

SEC Capital

49. **Reference: SEC Page 6**

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.

50. EEDO strongly refutes the assertion that reliability is a measure of EEDO's operating or capital investment performance. As stated in oral evidence, near term reliability performance is dominated by longer term historical investment into asset management or system design[22]. The primary driver of unplanned outages experienced by EEDO since acquisition have been related to weather events or catastrophic tree failures. These outages could only have been prevented by designing the system to be more resilient to these events, designing the system to be more flexible through automated switches, or going underground. The increase in scheduled outages (as referenced in VECC submission page 7) is indicative of EEDO taking action to make the system more resilient to increased weather events in the future. EEDO believes that future reliability performance metrics (SAIDI and SAIFI) will be more reflective of the impacts of the actions taken since EEDO assumed operation of the LDC so long as EEDO continues to implement its capital plan.

51. If the utility is properly capitalized, it follows that reliability will increase. EEDO believes that this utility has been historically underfunded and that the majority of issues with reliability today, including major weather events that have tested system resilience, are traceable to historic undercapitalization. The benefits on reliability from the already placed and proposed capital investments will be realized over time as a safer, more reliable and more resilient distribution system is built and maintained.

52. **Reference: SEC Page 9**

The OEB should require EEDO to use actual 2022 in-service additions in determining the opening 2023 rate base.

53. SEC's points to the delayed delivery of a $510K bucket truck as an example of an expected 2022 in-service addition that did not transpire. Given that this truck will be received in early 2023, and delivery was delayed due to circumstances out of EEDO's control, EEDO argues that it should form part of the Testy Year opening rate base, or in the alternative, should be added to the 2023 capital spend.

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[22] Transcript, Volume 2 page 55, lines 2-7.

54. **Reference: SEC Page 9**

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.

55. EEDO's 2023 in-service additions were forecasted based on the assumptions that the 2023 capital expenditures would be put into service and that the dollar value of WIP being carried forward into 2023 would be equal to the WIP that would be carried forward into 2024.[23] The forecasted CWIP balance represents a general amount of work that would be carried forward from year to year and is not related to the work of any specific project that is expected to be carried forward. These assumptions have not changed in light of the actual 2022 closing CWIP balance being lower than forecast. EEDO believes there is no reason to expect that the 2023 closing CWIP balance will be any different from the 2022 actual closing balance.

56. **Reference: SEC Page 10**

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.

57. SEC argues that EEDO's capital expenditures should be reduced because of an over spend during the last DSP period in comparison to the MAAD forecast and the submitted 2019 DSP. As noted above, EEDO adjusted its spend between 2019 to 2022 to reflect the true condition of the assets after assuming operational control of the distribution system in Collingwood. Additional information was gained through operation which required action to be taken. As SEC and VECC point out, reliability metrics have worsened in the years since EEDO's acquisition. EEDO argues this reflects the historic undercapitalization of the system. Rather than continue to see reliability metrics degrade in future periods, EEDO has increased the investments to build a more reliable and resilient system[24].

[23] EB-2022-0028 Interrogatory Response 2-SEC-16.
[24] Transcript, Volume 2 page 55, lines 2-7.

58. **Reference: SEC Page 11**

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.

59. SEC argues that EEDO's capital expenditures should be reduced because of an over spend during the last DSP period in comparison to the MAAD forecast and the submitted 2019 DSP. As noted above, EEDO adjusted its spend between 2019 to 2022 to reflect the true condition of the assets after assuming operational control of the distribution system in Collingwood. Additional information was gained through operation which required action to be taken. As SEC and VECC point out, reliability metrics have worsened in the years since EEDO's acquisition. EEDO argues this reflects the historic undercapitalization of the system. Rather than continue to see reliability metrics degrade in future periods, EEDO has increased the investments to build a more reliable and resilient system.

60. **Reference: SEC Page 12**

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.

61. SEC argues that EEDO has not paced its expenditures. EEDO disputes this assertion that it has not paced its investments. During the development of the DSP, EEDO placed considerable thought to pacing out these expenditures[25]. It is important to note that for 2023 and 2024, there are priority system service and general plant projects that push the costs for those years above the average of the remaining years. In 2023 and 2024, it is critical to address the capacity needs of a growing Stayner community with an increasing peak load. This will be done through the MS station upgrades. It is also critical to upgrade the ArcGIS system prior to vendor support expiring in March 2024. In determining when to complete these projects and how to best pace capital expenditures throughout the life

[25] Transcript, Volume 1 page 15 lines 7-25.

of the DSP, EEDO determined that these projects needed to be completed early in the DSP period. EEDO submits that even with the inclusion of these critical projects early in the term, it has still achieved a balanced approach to capital expenditures over the DSP period.

62. For example, EEDO has planned to spread out the upgrade of the Stayner station transformer over two years[26]. EEDO has also planned to upgrade the Thornbury stations over a two period[27]. These are examples of projects that could have been completed in the same year. EEDO has previously explained above why the ArcPro GIS and Utility Network Project is required to be completed in 2023. The system renewal pole line replacement projects have been paced to be roughly equal each year. This was evenly paced so that the addition of expensive contractors are not required in a heavy capital year versus a lighter capital year if EEDO were to defer to later years as suggested by SEC.

63. The pole line rebuild program can also be viewed as a paced program when considering the number of poles EEDO is planning to replace. The condition assessment indicated that approximately 891 poles are in poor to very poor condition. The analysis also projected that EEDO has over 1200 poles that are 50 years or greater in life. EEDO plans to replace less than 550 poles in this DSP period instead of trying to remedy every poorly conditioned pole as means to pace the program.

<u>VECC Capital</u>

64. **Reference: VECC Page 4**

For example, we would invite the Board to consider the inordinately large number of Ontario electricity distributors whose need for an expensive bucket truck coincides with the bridge or Test Year of the rate application – as is the case with this Utility.

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[26] EB-2022-0028, Application [Application], Exhibit 2 – Distribution System Plan, page 97 of 134.
[27] Application, Exhibit 2 – Distribution System Plan, pages 101 & 104 of 134.

65. EEDO cannot speak to other LDCs and, other than a bald assertion, VECC has offered no evidence about such a trend/practice. However, EEDO utilizes a condition assessment to evaluate when vehicles need to be replaced – and filed this condition assessment along with its DSP evidence[28]. EEDO's current bucket truck was to be replaced in 2021 (non-bridge year) due to its assessed condition. Due to supply chain conditions outside of EEDO's control delivery of the bucket truck was first delayed until 2022, and then to 2023.

66. **Reference: VECC Page 5**

It is noteworthy that the overall process of asset management has not changed significantly between the two DSP periods.

67. VECC is questioning why (if EEDO's asset management process has not changed) is EEDO's current capital plan so much greater than historical spend. EEDO disputes that the asset management process has not changed. EEDO has put a greater emphasis on the asset management of its municipal substations in the 2023 DSP which is reflective of the increased planned expenditures into system service with the modernization of Stayner MS1 and MS2, Thornbury MS1 and MS2, and Collingwood MS7[29]. This change in asset management of critical station assets is one of the primary drivers behind the increased capital profile in this next DSP. Collus under-invested in these assets. Equipment issues at municipal stations pose major reliability impacts due to the number of customers served and the duration in replacing critical spares. Functioning relay protection is critical to public and employee safety.

68. **Reference: VECC Page 6**

The current schedule makes it likely a Board decision will not be rendered before May or perhaps June of 2023. Based on EEDO's decision to wait until that time before ordering equipment (Stayner MS transformers) it is unlikely that this project will meet a 2023 in-service date.

69. EEDO views this project as essential to the ability to service Stayner under an N-1 contingency scenario given the increased loading in this service area. Given the

[28] Application, Exhibit 2 – Distribution System Plan, page 124 of 134.
[29] Application, Exhibit 2 – Distribution System Plan, pages 97-109 of 134.

importance of this investment, EEDO has elected not to wait until the OEB decision to move forward on this essential station upgrade in 2023.

70. **Reference: VECC Page 7**

A more insightful indicator to the relationship between capital investment (and operating maintenance costs) and reliability is to look at the root cause of outages and those aspects of reliability most directly impacted by capital investment. Outages due to defective equipment is key in this regard. The table below shows that since acquisition there has been little change in the outages due to defective equipment.

71. **Reference: VECC Page 8**

In this regard we note that speed of response and service to outages represents the 3rd largest ranking of priorities of customers in EEDO's Stone-Olafson (sic) survey.

72. EEDO agrees that these are major priorities of our customers. This is why EEDO's capital plan includes investments into grid modernization through fault line indicators and remotely operable switches which will allow EEDO to fault locate, isolate and restore customers faster than the current system permits. As Environmental Defence's argument rightly points out,[30] these investments would be at risk if EEDO is forced to reduce its planned capital program as EEDO must always serve safety and reliability risk as a priority.

[30] Environmental Defence Argument, page 2.

D. OM&A

73. The 2023 Test Year OM&A budget is $6,530,315, which represents a 42.4% increase or an annualized increase of 3.6% over 10 years.[31] The proposed OM&A costs for the 2023 Test Year are aligned with EEDO's expectations for annual costs going forward. EEDO submits these are reasonable and reflect the minimum cost required to operate the utility in a manner that provides the level of service expected by customers while maintaining safe, reliable and efficient operations.

74. As stated in its Argument-in-Chief, EEDO understands this is a significant increase from the 2013 OEB-approved amount, but there are several important reasons as to why the OM&A increase is necessary. First, the electricity distribution business, and the regulatory and technological environment in which it operates has changed substantially over the past decade. In EEDO's view, it is becoming increasingly complex to deliver electricity – which results in greater costs. Second, since the last rebasing, there was a reduction in services being provided by Collus shared service affiliates in 2016 which caused a fundamental shift in EEDO's cost structure, as employee costs previously split with the Town of Collingwood had to be fully borne by EEDO. Additionally, inflation has occurred at unanticipated levels and customer counts have grown significantly (18% increase in customers since 2013) requiring significantly more resources to address the associated increase in capital and operating demands.[32]

75. A focus throughout this entire proceeding has been on the corporate cost allocation model, with a particular emphasis on the costs from EUI. For the equivalent of approximately three to four FTEs,[33] EEDO receives the diverse set of services it needs to run the utility without embedding additional headcounts. EEDO submits that embedding the many required FTEs to provide these services would result in additional incremental costs and does not make sense for our size of utility.

76. The corporate and shared services evidence filed in the original evidence was extensive (over 30 pages). Board Staff and Intervenors have had the opportunity to test the evidence

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[31] Application, Exhibit 4 – Operating Expenses at page 15 lines 8-9.
[32] Chapter 2 Appendixes_Settlement_20221209_App 2-IB.
[33] Argument-in-Chief at paragraph 53.

through interrogatory responses and questioning in oral hearing. EEDO has done its best to explain the nature of the corporate and shared services, and the benefits and efficiencies provided to EEDO.

77. It is alleged throughout OEB Staff and Intervenor Arguments that EEDO has not offered enough evidence to justify the costs resulting from the EUI shared services[34] or is using the corporate cost allocation model for nefarious purposes.[35] EUI does not manipulate this model. The reality is that shared service costs are provided to EEDO at cost with no profit margin built in by the service provider. EUI recovers its costs and nothing more. As discussed in detail in EEDO's direct rebuttals below, these are the needed and necessary services to run the utility.

78. One of the challenges of a smaller utility is that the services required for it are the same as for a large utility. The need for these services does not simply disappear because there are less ratepayers. Instead fewer ratepayers have to bear the totality of these costs. Despite allegations otherwise,[36] EEDO feels quite strongly about what ratepayers in Collingwood should receive. EEDO's customers do not (and should not) receive fewer or inferior services because they are served by a small utility located outside of a large urban centre. . By utilizing the corporate cost allocation model, EEDO has been able to close the operational gaps that existed under Collus and EEDO is able to receive all of the services required to operate a utility in 2023 at a lower cost for ratepayers.

79. Instead of this model of savings being viewed as a benefit to the customer, it has been characterized as a simple downloading of costs for EUI's ultimate benefit or as self-serving affiliated transactions. EEDO disagrees with this characterization; the Application put forward has always been and continues to be about providing safe, reliable and cost-effective electric distribution service to ratepayers. The costs requested by EEDO in the Application are the just and reasonable costs required to provide this service.

80. The point that seems to be lost in much of the discussion around the corporate cost allocation model is that EUI's largest subsidiaries, EPCOR Water Services Inc. and

[34] OEB Staff Argument at page 18.
[35] VECC Argument at paragraphs 6, 30 and 37.
[37] Application, Exhibit 4, pages 78 and 79.

EPCOR Distribution & Transmission Inc., both operate under performance based regulatory regimes ("PBR"). To put it colloquially, the services provided are not bells and whistles, these are the basic and essential services required to operate utilities in 2023. Examples include:

- Health, Safety & Environment as a critical cornerstone of utility operations to ensure compliance with legislative and industry standards, assisting with investigation and reporting of safety incidents, and most importantly to help ensure the safety and well-being of staff and customers. The majority of the HSE costs included in OM&A are to have an on the ground resource to provide that support to the utility.

- Human Resources to manage the employee life cycle from hiring to retiring, providing payroll services, assisting with employee performance management, administering employee-benefit programs, and assisting with collective bargaining agreements.

- Public & Government Affairs to develop and oversee our customer and community communications and be involved in discussions at various levels of government to understand the continuing changes to the electrical grid and to help anticipate impacts on the needs of our customers.

- Information Services/Technologies to manage our IT applications and IT infrastructure so the utility can address the increasing reliance on computer systems for utility system monitoring and operations, the increase in cyber security requirements and risk mitigation requirements to protect the electrical distribution grid, and customer information.

- Management oversight to ensure the utility is well-equipped to provide electric distribution service, ready to adapt to new requirements and to captain the utility in the face of an ever changing industry and society.

81. The Alberta-based regulatory utilities which bear the vast majority of the corporate costs are facing rate pressures as well and do not have the luxury of adding unnecessary

personnel or services to their folds. It is also important to highlight that the corporate costs allocated to EEDO through the corporate cost allocation model constitute a statistically small percentage (0.7%)[37] of EUI's total costs.

82. Short of providing the Board and Intervenors with shared employee diarized docket sheets, EEDO believes it will be always be a difficult task to provide enough evidence to Intervenors to convince them that costs resulting from this model have been sufficiently justified.

83. As stated in EEDO's Argument-in-Chief,[38] the benchmarking data demonstrates that EEDO is very much in line with other LDCs. It bears repeating in this Reply Argument as much of the focus of Intervenors and Board Staff has been on the MAADs forecasts and the corporate cost allocation model rather than the reasonableness of EEDO's proposed OM&A costs themselves.

84. In order to determine the reasonableness of EEDO's proposed costs, EEDO submits that the metrics should not be viewed in isolation and rather a variety of metrics need to be examined together in order for the most accurate view of a utility to be gained, which include revenue, capital and OM&A components.

85. For distribution revenue per customer, utilizing the OEB's Open Data for 2021, for EEDO's 2023 Test Year, EEDO ranks as the 20th lowest[39] out of 57 LDCs on distribution revenue per customer.[40] Amongst LDCs with a similar customer count based on information from the OEB's 2020 Yearbook of Electricity Distributors, EEDO's 2023 Test Year distribution revenue per customer in this Application would be $496 which would still place EEDO amongst the lowest of similar sized utilities, even with taking into account the numbers in the comparison are from 2020.[41]

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[37] Application, Exhibit 4, pages 78 and 79.
[38] Argument-in-Chief, paragraphs 46, 47 and 48.
[39] For Distribution Revenue per Customer, lower rank means lower revenue.
[40]Transcript Volume 2, page 20, lines 7 to 28 and page 117 lines 1 to 10; 2021 Unitized Data at Tab Unitized & Other Statistics.
[41] Application, Exhibit 4 -- Operating Expenses at page 7, Table 4.1.1-2 and lines 1 to 5; OEB 2020 Yearbook of Electricity Distributors.

86. EEDO's 2023 Test Year proposed OM&A cost per customer is $344 which is lower than the escalated 2020 industry average OM&A expenses per customer of $353.[42] Based on the 2023 Test Year expenses, EEDO ranks 33rd lowest out of 57 LDCs on OM&A cost per customer.[43]

87. Based on the OEB's 2021 Open Data for Electricity Distributors, 35 FTEs is average for EEDO's cohort.[44] EEDO currently has 28 FTEs directly embedded in the utility.[45] Following the inclusion of headcounts for EUI corporate shared services and affiliate shared services, based on assuming total compensation amounts of $150,000 for the shared service FTEs as these services would be at approximately a manager level, EEDO's number is approximately 35 FTEs, which is in line with its peers.

<u>OEB Staff OM&A</u>

<u>Starting Point</u>

88. OEB Staff's Argument included analysis on projecting OM&A to at least partly inform what a reasonable Test Year OM&A amount would be. The analysis was based on different starting years (2013T, 2013A, and 2018A) and took into account inflationary increases and customer growth to project 2023 Test Year OM&A. EEDO would like to highlight why it does not believe those starting points are appropriate data points for the costs required to operate the utility today:

- 2013T and 2013A – The cost structure of the utility was much different in 2013 when greater opportunities to reduce employee costs by providing non-utility services to the Town of Collingwood existed. When these opportunities were significantly reduced in 2016, the utility was left in a position where they had higher labour costs. In response, the utility chose not to backfill some position vacancies when they arose but that was not enough to mitigate all of the labour cost increase.

[42] EB-2022-0028, Application, Exhibit 4 – Operating Expenses at page 6 Table 4.1.1-1.
[43] Lower ranking means lower cost per customer. This ranking is derived from the figures in the 2021 Unitized Data escalated with the OEB's annual inflationary factor for 2022 and 2023.
[44] Transcript, Volume 2, page 21, lines 5 to 28 and page 117 lines 1 to 10; 2021 Unitized Data at Tab Unitized & Other Statistics.
[45] Application, Exhibit 4, page 7 lines 13 to 14.

- 2018A – Although 2018 actual costs take into account the impacts of the increased employee costs from 2016, the costs from 2018 reflect vacant or eliminated positions (CEO and Controller) that would not be sustainable to continue to operate without additional resources.

Test Year Adjustments

89. In their reply argument, SEC proposed that the Test Year OM&A should make one further adjustment to reflect expected and forecasted savings that customers were promised in the MAADs Application.[46] As discussed in the MAAD section of this Reply Argument, EEDO does not believe it is reasonable to be held to forecast assumptions which were determined to be incorrect once EEDO took over and began operating the utility. Since taking over in 2018, EEDO has provided customers a 1% reduction in rates and has not been compensated for its investments into the utility since that time; EEDO believes it is disingenuous to argue that customers are harmed unless they receive the forecasted savings relative to the status quo forecast.

90. EEDO believes that the escalated 2023 status quo OM&A of $6,114,000 from SEC's Argument analysis (paragraph 3.4.6) represents the level of OM&A that would be a reasonable starting point to determine 2023 Test Year OM&A; however, additional costs for services which were not being provided, resulting in operational gaps, in the starting point would need to be included to calculate comparable 2023 Test Year OM&A. EEDO argues that its 2023 Test Year OM&A of $6,530,315 represents additional costs to the customer but provides commensurate benefits for the required services that were not being provided under the status quo operation of the utility.

91. As explained in EEDO's response to Undertaking J1.6,[47] there are additional costs over and above the status quo EEDO argues are essential to the safe and reliable operation of the utility:

[46] SEC Final Argument at paragraph 3.4.7.
[47] Undertaking J1.6, Table J1.6 – Savings and Additional Costs versus Status Quo, page 4 of 21

- Having a boots on the ground Health, Safety, and Environment (HSE) resource supported by a supervisor which allows for the establishment and monitoring of appropriate HSE policies and procedures. ($102k)
- Employing an increased maintenance program to address sub-station condition and reliability issues. ($40k)
- Having an additional inspector/locator position ($111k) and operational technology/ engineering support ($138k) which have been necessary for EEDO to meet its operational and capital demands. In recent years the significant growth in the Collingwood community has left EEDO struggling to keep up with customer demands for electricity distribution infrastructure.

Based on SEC's calculated 2023 status quo OM&A forecast of $6,114,000, and with the adjustments noted above, a comparable Test Year OM&A budget envelope is $6,505,000 which is reasonable given the significant changes that the utility has seen over the past 10 years. This calculation captures not only the impacts of inflation and customer growth but increases in built-in efficiency gains expected due to the inclusion of the OEB's stretch factor in the calculation.

92. **Reference OEB Staff, page 18**

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

93. EEDO disagrees with the characterization of the services and affiliate and corporate shared services resources as simply bringing additional benefits to EEDO. EEDO submits

that these are not just benefits, these are required services. As pointed out above, small utilities require the same suite of services as a large utility because they are subject to the same legal and operational requirements as those large utilities. For example, EEDO must: (a) comply with all provincial health, safety and environmental laws; (b) comply with all OEB regulatory codes; (c) file robust rate applications and participate in rate proceedings; (d) coordinate and implement changes to support customer choice, grid resiliency and modernization; (e) understand and comply with IESO Market Rules and settlement processes; (f) remain abreast of regulatory developments and changes (e.g., distributed energy resources and EV charging); and (g) comply with federal PCB regulations.

94. The size of the utility does not markedly shift the scope of services required to operate safely and reliably – it only changes the quantum of services needed (e.g., fewer FTEs). In fact, EEDO contends that it is more difficult for smaller utilities to efficiently secure the broad suite of services required to operate an electricity distributor in Ontario today. Smaller utilities have fewer ratepayers to absorb the costs, so every spending decision can have a more significant rate implication. EEDO understands this and, as demonstrated above, makes cost trade-offs with that front of mind.

95. Because small utilities are subject to the same legal and operational requirements as large utilities, failing to procure (or eliminating) services exposes the utility to risk – risk of not being able to attract and retain employees in a tight labour market, risk of not being able to adequately comply with complex regulatory requirements, risk of not being able to meet provincial and federal initiatives in the rapidly changing electricity industry, and risk of not being able to accommodate customer growth.

96. EEDO believes the additional services and affiliate and corporate shared services being provided are needed to run the utility and through the sharing of these essential services with other regulated utilities, the overall cost to the ratepayer is reduced without sacrificing quality.

97. **Reference OEB Staff, page 19**

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.

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.

98. EEDO disagrees that the need for incremental work and costs has not been discussed. Throughout the Application, Interrogatory Responses, Oral Hearing, Argument-in-Chief and Undertakings the need for these costs has been discussed in extensive detail.

99. Where helpful, EEDO has tried to explain these benefits in very tangible terms by providing examples:

- For example, the last rate filing done by the utility was 2013 and significant support has been required from Finance and Treasury to complete this filing as well as annual regulatory filings.
- Supply Chain Management provides expert advice on procurement and contracting best practices. They have assisted in developing and employing sourcing strategies for EEDO such as competitive bidding to ensure EEDO receives the most value for their purchases. They negotiate contracts including multi-year Master Supply Agreements with key contractors and they also provide supplier relationship management. Through the impacts of COVID the Supply Chain group were essential in ensuring that EEDO had the safety and sanitizing supplies needed to operate and by assisting in navigating supply chain shortages

for critical purchases like meters. These services were not being provided previously at EEDO.

- Internal Audit provides comprehensive integrated audits such as the one done post-acquisition as well as ensures a sound internal control framework is implemented and followed by EUI operating entities. Internal audit plays a key governance role in managing not just financial risk but operational and safety risks for the utility.

- HR services has been instrumental in managing the life cycle of the employee and has participated in labour negotiations and provides ongoing support for union issues. Under Collus, the utility had a real HR issue. There was one FTE that could not cover the entire utility properly (i.e. ensuring required policies and procedures are in place; carrying out compensation/performance reviews; implementing policies to attract and retain employees). Now, EEDO is provided with more robust, broader HR service through the corporate shared services model. Prior to EUI's ownership, employee turnover was a significant issue for the utility; without putting a lens on the human resources required to operate the utility, EEDO runs the risk of again losing these resources and then dealing with the risks of employee turnover and competing for labour in a tight market.

- As noted in EEDO's response to Undertaking J2.3, the 2023 Test Year OM&A relating to Management Oversight is $355k which EEDO feels is reasonable relative to what it would cost for stand-alone CEO and sub-board costs.

100. **Reference OEB Staff, page 19**

OEB Staff also note 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.

101. The balance represented in Item 16 was comprised of numerous immaterial variances which is why EEDO did not provide additional detail in the explanation.

102. In its undertaking response, EEDO stated that the "test year related to an increased maintenance program on the municipal substation. Additional maintenance scope includes infrared of transformer and breaker connect points, and the testing for partial discharge (PD) points. The infrared is on the distribution side, while the PD is on the sub-transmission side."[48] As shown, the $40k of incremental costs in the 2023 Test Year relates to an increased maintenance program on the municipal substation and associated feeders. Additional maintenance scope includes infrared testing on the distribution system connections on the load side of the transformers, connections on the line and load side of our switches at the riser poles and connections on the line and load side of our feeder switches and paralleling devices. In addition, this includes testing for partial discharge on the sub transmission system. While infrared testing has always been a reliable way of finding hot spots, equipment that is tracking, or poor connections on the distribution system, EEDO feels that completing the partial discharge testing provides a better view of what is actually happening in the sub transmission system allowing insulation degradation to be detected and corrected before an incident/outage occurs.

103. **Reference OEB Staff, page 20**

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.

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[48] EEDO Undertakings at paragraph 27.

104. With respect to the bundling, these are not services being provided by a parent in an adjacent or alternate industry – EUI and its affiliates are in the utility industry and operating under similar regimes with the same goal of delivering safe, reliable and efficient water and energy to communities. To suggest that EEDO should be able to select its particular services, does not make sense as what EEDO is obtaining are already the required services for the utility. EEDO does not see any value in a selection approach. EEDO submits the services that it obtains from EUI and its affiliates are the needed and necessary services required to operate the utility.

105. EEDO's management believes that a portfolio approach provides more appropriate tools in order to anticipate current business needs and also to adapt to increasing uncertainties due to a rapidly changing industry and current economic volatility. EEDO believes in the necessity of the shared services and does not believe forecasting what particular services it will require in a given year would provide any value. In EEDO's view, if it was forced to select certain services from a menu of items, it would be left vulnerable to not having the services it needs when it counts. To EEDO this feels akin to the risk of leaving a vacant headcount open even though the position is required for the utility. This would expose the utility to more risk and uncertainty and potentially leave EEDO scrambling to obtain more costly services from third parties.

106. EEDO does not view the services it obtains as excessive. After acquiring this utility in 2018, did EUI believe that the utility already had the requisite personnel required to allow the utility to operate safely, efficiently and reliably? The answer is no. As discussed throughout the Application, Oral Hearing, Undertakings and Argument-in-Chief, EUI invested in EEDO to allow it to meet this goal. EEDO now has the services and personnel needed for utility operations in 2023. With a tight labour market, expectation of instant customer communication, supply chain issues, new provincial, federal and municipal initiatives and a generational shift for the electricity grid, it follows that the resources required to deliver electricity become more costly and complex. The ability to share the resources required for the delivery of electricity with other regulated utilities allows EEDO to obtain the personnel it needs to achieve its mission statement at a lower cost.

107. **Reference OEB Staff, page 20 and 21**

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

108. The original corporate allocation percentages were only estimates made at the time of the MAADs Proceeding, without the benefit of being able to operate and fully understand the utility's needs. The process of forecasting corporate allocations requires an estimate of the cost allocators49) such as headcount, assets and Information System Infrastructure costs. The corporate allocation estimates in the MAADs Proceeding, particularly the Information System Infrastructure cost allocator, were lower than the actual cost allocators when EEDO began operating the utility. This resulted in the allocation percentages to be higher and therefore higher costs than forecasted in the MAAD application. The higher allocation percentage was not the result of an arbitrary decision or a change in methodology.

<u>SEC OM&A</u>

109. **Reference SEC page 13, paragraph 3.1.2**

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 . . .

110. EEDO strongly disagrees with the assertion that it has not evaluated trade-offs between cost pressures and impacts on customers. Cost trade-offs are judgment calls. Since taking over the utility, EEDO has made a number of decisions to increase spending in certain areas (where Collus was clearly underspending) and decreasing costs in other areas (where efficiencies could be achieved). All of these decisions are driven by an effort to improve the reliability, safety, and operational efficiency of the distributor. For instance:

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[49] Application, Exhibit 4, Schedule 1, Tab 1, page 77.

- EEDO decided to materially increase spending on Health, Safety and Environment (HSE) – an area of focus that was significantly underfunded by Collus. In 2016 HSE spending was $9k vs $109k in 2022.
- EEDO's HR Manager and IT/OT Manager position was moved to its shared service affiliate to reduce costs in these areas.
- EEDO has made its employees available to provide services to affiliates in instances where the employee had excess capacity – which enabled EEDO to reduce the labour cost of embedded employees.
- EEDO has reduced its headcount and not backfilled certain vacancies where it was considered operationally feasible, partly due to affiliate shared services being provided (e.g., Hydro Manager, Controller).
- EEDO has reduced costs spent on certain outside services, such as Cornerstone Hydro Electric Concepts and other outside service providers.

111. All of these decisions/trade-offs are made for not only cost reasons, but other reasons as well – e.g., improving services received by being able to access more senior HR expertise at a lower cost; bolstering a deficient HSE program, etc. To suggest that EEDO has no made the effort to make trade-offs to improve the utility is easily said in argument, but completely ignores the evidence in the proceeding. If anything, the scale of decisions made involving cost and service trade-offs since acquiring Collus have been substantial.

112. These decisions were made by management in good faith, with a view to improving utility operations. The fact that certain Intervenors suggest that these decisions were made in bad faith – solely to enrich EEDO's shareholder – is not only discouraging to those that have worked hard to improve the utility in these past few years, but completely unsupported by the evidence, which: (a) explains in detail the rationale for the trade-offs (cost increases and decreases); and (b) shows significant under-earning since 2018 (i.e., a utility that has elected to make the necessary OM&A expenditures since taking over the utility without the ability to recoup those expenditures in rate revenues). As stated earlier, shared service costs are provided to EEDO at cost with no profit margin built in by the service provider. EUI recovers its costs and nothing extra.

113. **Reference SEC page 13, paragraph 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 . . .

114. EEDO strongly disagrees with the assertion that it has not evaluated trade-offs between cost pressures and impacts on customers. EEDO has made significant efforts to reduce costs by making trade-offs and implementing measures, including the examples listed a few paragraphs above. Some of the cost increases relate to areas that EEDO deems as essential to running a utility like Health, Safety and Environment; taking safety risks is counter to EEDO's philosophy in running a utility and not an area where EEDO will compromise on if it sees deficiencies or unacceptable risks.

115. EEDO restates that it believes the requested OM&A costs are required for the safe and efficient running of this LDC.

116. **Reference SEC page 13, paragraph 3.1.2/3.2.5**

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… 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.

117. **Reference SEC page 17, paragraph 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, changed its cost allocation methodology that was previously based on time spent, to a set of composite cost allocators that differ based on the category of shared services. 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.*

118. There a several reasons for the increase in allocation costs from 2021A to 2022B, with the change in methodology being only one reason for the change.

119. EEDO disagrees with the assertion that the additional costs do not come with a commensurate benefit. As described in the Application,[50] a portion of the increase in EOOMI/EOUI costs from 2021A to 2022B are the result of adding positions and related services for Regulatory[51] and Operational Technology/SCADA support.[52] In addition, additional costs are allocated related to Customer Service as the Customer Service Manager had to spend additional time in 2021A setting up the billing and customer service activities for one of EUI's new regulated utilities and the 2022B represents a more steady-state for this service now that those set-up activities are completed.[53] These changes account for approximately $111,312 of increase in costs from 2021A to 2022B.[54]

120. Another significant component of the increase from 2021A to 2022B was an inadvertent accounting error ($99,307) related to IS infrastructure costs which were not included in the 2021A costs and should have been, as discussed in table 4.4.2-14 of Exhibit 4 in the Application.[55] If this item had been correctly recorded then the 2021A actual shared services costs would have been $99,307 higher, and would reduce the change in costs from 2021A to 2022B.[56] Factoring in this inadvertent error, Corporate Shared Services

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[50] Application, Exhibit 4 – Operating Expenses at pages 60 to 90.
[51] Application, Exhibit 4 – Operating Expenses at page 72.
[52] Application, Exhibit 4 – Operating Expenses at page pages 71-73.
[53] Transcript, Volume 1 at page 185; Application, Exhibit 4 – Operating Expenses at page 73.
[54] *Ibid.*
[55] Application, Exhibit 4 – Operating Expenses at page 88 and 86.
[56] *Ibid.*

only actually increased from 2021A to 2022B approximately $32,700 or approximately 4%.[57]

121. We disagree with SEC's comment that the change in allocation methodology for EOOMI affiliate costs was to a set of composite allocators; the majority of allocators for the new methodology were functional cost causation allocators, as fully discussed in Table 4.4.2-5 of Exhibit 4 of the Application.[58]

122. The rationale for the change in allocation methodologies for EOOMI was fully discussed in EEDO's interrogatory responses to OEB Staff.[59] Prior to 2022, the shared service support model was being set up for all of EUI's Ontario operations. With more operations being added and with additional services moving towards a more cost effective shared service model, it was determined that it would be increasingly difficult and administratively burdensome for EOOMI staff to adequately and accurately track and record time spent on the various Ontario operations; instead of spending time tracking and coding time to the various operations, employees of EOOMI can spend this time providing services to EEDO and the other Ontario operations. And using specific allocators, or drivers, also allows for efficient apportionment of costs when the services being provided benefit all of the entities receiving the services, as opposed to when working on a work task for a specific operation. Finally, most of the services being provided by EEDO lend themselves well to functional cost causation allocators and the allocators chosen align very logically to the services being provided – for example the Headcount allocator used for Human Resources as Human Resources would highly correlate to effort expended by the position providing these services.

123. A comparison of the cost allocation for EOOMI, under the new methodology as compared to estimates using the former time spent methodology for the 2023 Test Year, were also provided in the interrogatory responses to OEB Staff.[60] As noted in the responses, the new methodology resulted in lower costs allocations to EEDO for Human Resources, HSE, OT and SCADA Support and Operational Support. The new methodology results in

[57] *Ibid.*
[58] Application, Exhibit 4 – Operating Expenses at page 69.
[59] EEDO Interrogatory Responses to OEB Staff, Response to 4-Staff-53(a).
[60] EEDO Interrogatory Responses to OEB Staff, Response to 4-Staff-53(b)

slightly higher Customer Service allocations and higher allocations for Management Oversight. The overall impact of the new methodology on the 2023 Test Year was allocations being slightly lower.

124. EEDO believes that the revised methodology is more efficient and less administratively burdensome, with appropriate cost allocators and results in cost allocations which are comparable to costs which would have been allocated to EEDO under the former methodology.

125. **Reference SEC page 18, paragraph 3.4**

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.

126. EEDO does not disagree that evaluating utility forecasted costs on an envelope approach basis can be informative – but EEDO submits that it should not be determinative given the limited scope of the analysis. Relying wholly or significantly on such an approach risks shifting the focus of the Board away from the actual facts and evidence about a utility's operations and cost decisions, and turning rate-setting into a mathematical exercise.

VECC OM&A

127. **Reference: VECC page 10, paragraph 28**

EEDO was in the stretch factor cohort 2 prior to 2016 and in cohort 3 thereafter.

128. This is incorrect. To clarify, EEDO was in stretch factor cohort 3 prior to 2016 and improved to cohort 2 thereafter, where it currently remains. EEDO has also calculated that it will remain in this cohort after rebasing using the Pacific Economics Group (PEG) forecasting excel model.[61]

[61] Application, Exhibit 1 – Table 1.6-2 Summary of Cost Benchmarking Results.

129. **Reference: VECC page 12, paragraph 35**

We also point out that EEDO is among the highest cost utilities among its peers on an OM&A per customer basis. Leaving aside the obvious outlier, Algoma Power Inc., EEDO is second highest among what it [sic] considers its [sic] peer utilities.

130. EEDO welcomes the opportunity to discuss benchmarking data as EEDO believes that despite the geographical and economic variances that may occur between service territories, it is an objective way to test the reasonability of its proposed 2023 Test Year OM&A costs. As stated earlier in this Reply Argument, the benchmarking data demonstrates the reasonableness of EEDO's proposed costs as EEDO is very much in line with other LDCs.

131. To correct an error made by VECC , EEDO notes that in 2020 its ranking was third highest (not second as noted above) when removing Algoma Power and only 2% away from the fourth highest LDC out of a total of eight LDCs (with the exclusion of Algoma Power) which places EEDO in the middle of its cohort.

132. **Reference VECC page 10, paragraph 30**

For example, we think the Board should consider the evidence on the [sic] increase in affiliate and corporate transfers. Such transactions should be closely scrutinized by regulators since they are text book ways [sic] companies manipulate costs [sic] between regulated and non-regulated entities to the benefit of shareholders.

133. EEDO disagrees with the assertion that affiliate and corporate transfers are a textbook way to manipulate costs. As explained above, the affiliate and corporate shared services model has been utilized to maximize value for EEDO – it can not only fill in operational gaps that existed under Collus, but has allowed EEDO to access better quality operational resources and shared resources where embedding FTEs in a small utility would not make sense.

134. EEDO understands that arrangements between affiliates attract more scrutiny, but the insinuations in the oral hearing and Intervenor submissions that EEDO's management are acting in bad faith or manipulating the utility cost structure to benefit EEDO's shareholder

is insulting. The EEDO witnesses were forthright and honest, and clearly articulated how and why operations and spending has changed since taking over Collus. Nothing in the evidentiary record suggests that increased OM&A spending has been done to enrich the shareholder – it suggests the exact opposite to date. Everything in the evidentiary record suggests that EEDO management is committed to improving the utility – and that the utility today is in fact, operationally improved compared to when EEDO took ownership. At the end of the day, EEDO requires services to operate the utility. The customer count has increased significantly since the last rebasing, regulatory requirements are more complex, and the costs for labour, materials and equipment have increased substantially. Intervenors seem to suggest these services can either disappear or be embedded in EEDO. If EEDO had elected to embed these services in the utility, the OM&A costs in this proceeding would have been consumed with arguments about increased head counts. The corporate cost allocation model has been a value-add for much needed services.

135. It is also important to highlight again that the corporate costs allocated to EEDO through the corporate cost allocation model constitute a statistically small percentage (0.7%)[62] of EUI's total costs. EEDO is not an extraction tool for corporate costs as has been alleged. Rather, the corporate cost allocation model reduces costs to EEDO because FTEs do not have to be embedded in a small utility (which would result in higher head counts and a less robust suite of required services.)

[62] Application, Exhibit 4, pages 78 and 79.

E. 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?

136. EEDO maintains an actual capital structure closely aligned with the OEB's deemed capital structure, and as a result EEDO is required to issue long-term debt from time-to-time in order to fund the utility's long-term fixed assets and maintain an appropriate capital structure.

137. Throughout the Application, and all of the various steps, EEDO has not commented or asserted that the OEB's cost of capital policy or the related long-term debt calculations are not appropriate. In fact, EEDO believes that the long-term debt methodology is a very rationale and reasonable approach to forecasting rates at a point-in-time, assuming that a LDC is an A-rated debt issuer.

138. The issue at hand for this Application is whether using the OEB's annual cost of capital calculations, and specifically the long-term debt forecast calculations acting as a ceiling for affiliate debt, is appropriate for setting actual debt rates of the utility.

139. EEDO understands that if a utility were to obtain third-party debt then the long-term debt forecast calculations in the OEB's annual cost of capital calculation would not put a ceiling on such debt. EEDO also understands that a panel can diverge from the cost of capital policy in an application, but with reasons and based on circumstances in the application.

140. EEDO believes that in circumstances where affiliate debt is issued using a reasonable approach, using market-based information, which would align or be more cost effective than what EEDO could obtain from a third-party, then it would be appropriate to allow that debt to be included in rates at the rate obtained on the date that debt was issued, and not be capped by the OEB's forecast long-term debt calculations.

141. There are several reasons why EEDO believes that capping affiliate long-term debt issuances at the OEB's annual cost of capital long-term debt calculation would not be fair or reasonable:

a. The OEB's annual calculations are point-in-time forecasts and may have little in common with the actual cost of debt when EEDO actual issues debts. Both underlying government of Canada ("GoC") rates and credit spreads (the two components which make up an all-in debt rate) fluctuate daily and capping borrowing rates with a point-in-time estimate could result in significant differences between allowed interest rates and actual interest rates. These differences would be allowed for third-party debt and should be allowed for affiliate debt where the affiliate debt is reasonably determined.

b. The methodology used to calculate the debt rates to EEDO are fair and reasonable and use available market data. In this methodology, the rate quoted to EEDO by the lender is based on GoC underlying interest rates on the date that the debt is requested by EEDO and the credit spread used is based on a credit-rating determined by EEDO's lender (currently BBB) using credit metrics and calculations in-line with S&P methodologies.

142. Given that EEDO has demonstrated that its long-term borrowing rates are based off of market data and inputs, EEDO believes that its actual debt rates should be included when setting rates for the utility and should not be capped by the OEB's annual forecast long-term debt calculations.[63]

__Cost of Debt Arguments__

143. **Reference: SEC 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

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[63] EEDO Interrogatory Responses to OEB Staff, Response to 5-Staff-56, pages 80 to 86; Transcript, Volume 2, page 26, lines 3 to 18; EB-2022-0028; Application, Exhibit 5 – Cost of Capital, pages 9-10.

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. EEDO did not seek an independent credit rating, nor did EUI undertake any third-party review of its assessment of EEDO's methodology. 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.

144. The methodology used to determine EEDO's credit spreads is not an assumption, it is based on a review of the credit worthiness of the utility using S&P metrics and calculations. EEDO cannot obtain debt from lenders based on assumed, deemed rate calculations; lenders will lend to EEDO based on the credit worthiness of the entity at the time the debt is raised.

145. There is no more clear evidence that EEDO is not an A- utility than the 10-year debt which EEDO issued prior to be being acquired by EUI, which was third-party debt. The last of these loans was on March 10, 2017 and this debt was for 10 years and had an all-in rate of 3.59%. As noted during the oral hearing, the combined underlying and credit spread for 10 year debt for an A-rated entity on or around March 10, 2017 would have been approximately 2.87%.[64] So if EEDO were able to raise debt at an A-rated level, the cost of such debt should have been in the 2.87% range for this 10-year debt, while EEDO actually issued 10 year debt at 3.59%. EEDO clearly could not (and currently still cannot, as if anything the creditworthiness of the entity has gone down with the utility currently earning much less than its allowed ROE) issue debt at an A-level. EEDO believes, based on historical discussions it had with banks when third-party debt was issued, and current knowledge of the debt markets, that the rates obtained for its issuances since 2018 are at or below what it could have obtained from third-party lenders.

146. Capping EEDO borrowing rates at the OEB's long-term debt rate calculations may limit EEDO's ability to take advantage of issuing 30 year debt. While other utilities may use a mixture of different tenures/terms of debt, EEDO believes that matching the useful life of the majority of its assets to the term of its long-term debt is beneficial for customers, as

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[64] Transcript, Volume 1 page 90 line 15.

locking in long-term rates provides rate certainty and does not subject customers to refinancing risk when shorter-lived debt matures well before the useful life of the asset being financed. Based on pro-rating Appendix 2-BA Fixed Asset Continuity 2023 net book value amounts with Appendix 2-BB Service Life for each type of asset, EEDO's average useful life for utility infrastructure assets is approximately 34 years, and 30 year debt terms are appropriate to finance assets with this average useful life profile.

147. **Reference: OEB staff Page 24**

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."

148. **Reference: SEC 4.2.7:**

…and have the same ability to access debt as the EEDO did before the purchase by EUI.

149. This is not accurate. EEDO is not able to issue third-party 30 year debt due to its size and the size of any debt issuances it would have. Prior to EUI's acquisition of EEDO, Collus clearly preferred to issue longer term debt than 10 year debt, as evidenced by the utility issuing the majority of its debt at 20 to 30 years until 2015,[65] at which time it could no longer access OSIFA/OILC and was forced to take out shorter term debt in 2015 and 2017 from other third-party lenders. EEDO historically, and currently, prefers to take out longer term debt. If EEDO is capped at the OEB's longer-term debt calculations, then EEDO could lose the ability to issue 30 year debt, which it feels provides customer several benefits as noted above.

150. OEB staff and the Intervenors all argued that EEDO could issue shorter-term long-term debt,[66] and EEDO assumes this was with a view to EEDO's affiliate debt rate coming in below the OEB's annual long-term debt forecast and ensuring that affiliate debt would not exceed this ceiling. However, none of these parties offered any concrete argument that taking a portfolio type approach was actually a better option for the utility and its

[65] EB-2022-0028, App.2-OEB_Debt Instruments
[66] EB-2022-0028, OEB Staff Final Argument, page 24/EB-2022-0028, SEC Final Argument, paragraph 4.3.3/ EB-2022-0028, VECC Final Argument, paragraph 41

customers. In fact, the one example provided by SEC of using a mix of different term debts as a hedge for market conditions[67] is not at all an example of a hedge for market conditions; it is an example of a utility issuing a mix of 10 year and 30 year debt to help ensure there is not investor fatigue in any of the utility's debt offerings and to help ensure that the utility's offerings to the market were priced as competitively as possible.

151. EEDO is fortunate in this respect as its lender is willing to provide debt to EEDO based on its needs and what EEDO believes is best for its customers and does not charge a premium if EEDO decides to issue one term of debt over another. EEDO has the full decision-making authority to take out whatever term of debt it chooses (i.e. EEDO's lender does not dictate what term of debt EEDO has to issue). While EEDO cannot comment on the specific factors that other LDCs have encountered which have lead them to issue shorter-term long-term debt, EEDO believes there is strong merit in issuing long-term debt to match the majority of its asset base and this is consistent with EEDO's past practice when longer-term debt has been available to the utility.

152. In SEC's Argument, it states that EEDO's lender is able to borrow at lower rates from the debt markets and presumably is suggesting that because EUI can borrow at rates lower than EEDO, then EUI should lend to EEDO at rates equal to or lower than the OEB's annual long-term debt calculated amount.[68] EEDO does not believe this has any relevance at all to appropriate lending rates for EEDO. As noted above, EEDO cannot obtain debt at an A- level, even from third-parties and based on publicly available information EUI can as an A- rated company, so these two entities, not surprisingly, will have different long-term debt rates. Any lender, including EEDO's current lender, will lend to EEDO based on the credit worthiness of EEDO and no other factor. The notion that EUI should somehow be satisfied with the OEB's annual long-term debt rate calculation as a ceiling does not make sense and long-term debt for EEDO has to be priced based on cost of debt on the date and at the time that EEDO requests the debt (which is how a third-party lender would price any debt to EEDO), which is the current practice followed for EEDO's affiliate debt.

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[67] SEC Argument, paragraph 4.3.3.
[68] SEC Argument at paragraph 4.2.6.

<u>2018 Debt Issued</u>

153. With respect to the 2018 debt issued by EEDO, both SEC and VECC have argued that the debt rate on this new debt should be priced at rates of the old debt which was replaced by this new debt issue in 2018.[69] SEC has also argued that replacing this debt was "imprudent"[70] and VECC has argued that this was means of "extracting monies from this affiliate"[71]. These assertions are not correct. Upon acquisition of EEDO by EUI, EEDO was once again able to access longer-life debt (which as discussed above is EEDO's preference for funding its long-term debt requirements) and took the opportunity to replace relatively expensive 10 year debt, with 30 year debt.

154. As noted above, EEDO believes there are various benefits to customers for issuing 30 year debt. And while the new debt did have a somewhat higher rate than the 10 year debt which was replaced, this new debt will be in place for 30 years. The length of this term significantly reduces the refinancing risk to customers from the prior debt which, if not replaced, would have become due in 2025 and 2027, and this is all against the backdrop of a currently rising interest rate environment. The argument by the Intervenors that this action was somehow imprudent or was a mechanism to extract monies from the utility and its customers is inaccurate. In fact EEDO's shareholder was willing to pay the price for settling the former debt early (the $70,000 penalty was not included in rates nor paid for by the customers) and the interest rates on the debt issued in 2018 have not been included in EEDO's rates to date. If EEDO and its lender were as maliciously self-serving, as alleged by the Intervenors, EEDO could have waited to settle this debt until a future date (say in 2023 along with rebasing EEDO's rates) and not incurred the somewhat higher interest costs in the intervening period. However, EEDO believed that having longer lived debt with more appropriate rates for the term of the debt, was beneficial to ratepayers and EEDO's parent was willing to absorb the cost of the conversion and carry the higher interest expense which was not being recovered in rates, to meet EEDO's needs.

[69] SEC Argument at paragraph 4.3.1 to 4.3.5 & VECC Argument at paragraph 41-43.
[70] SEC Argument at paragraph 4.3.4.
[71] VECC Argument at paragraph 41.

2022 Forecast Debt

155. With respect to the 2022 forecast debt, EEDO believes that the forecast debt rate included in the Application was reasonably calculated using market available data to produce the forecast. The debt rate was calculated using the best information available at the time the Application was submitted and EEDO believes the rate applied for should be used to determine its rates. Since EEDO has filed its Application, many items have changed (including things such as inflation being higher than expected, as well as other items) and EEDO has not asked for any changes to its Application for these items.

156. If the OEB decides that the 2022 forecast debt has to use actuals in the long-term debt calculations, then EEDO submits that the calculations need to be updated to not only include the actual debt rate but also the actual principal amount of debt issued which was $2 million versus the $1.2 million which was the forecast amount in the Application.

F. <u>LOAD FORECAST, COST ALLOCATION AND RATE DESIGN</u>

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?

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

158. EEDO submits that the proposed load and customer forecasts are an appropriate reflection of the energy and demand requirements of EEDO's customers. The proposed load and customer forecast was calculated using the OEB's methodology and is based on the most recent historical data. EEDO is also supportive of providing an updated version of the load forecast with 2022 actuals, which takes into account the updates noted below by VECC. This would result in an update to the J2.8 EEDO Load Forecast (with 2022 Actuals) submitted with the Argument-in-Chief to calculate the final rates. This would result in a similar approach as the capital recommendation of using 2022 actual closing rate base in order to calculate 2023 rate base.

159. **Reference: OEB Staff Page 28:**

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, which relies on older data.

160. **Reference: VECC Page 17 (Issue 3.1):**

However, a preliminary review indicates that there are a number of errors:

- *In the CDM Tab of the J2.8 Load Forecast Model (with 2022 Actuals), the program years related to 2022 programs (Column C, Rows 90 & 91) are incorrectly set at 2023 and 2024 as opposed to 2022 and 2023. This means that the impact of 2022*

CDM programs has not been included in the data used to estimate the regression equations.

- *In the CDM Adjustment Tab of the J2.8 Load Forecast Model (with 2022 Actuals), the derivation of the cumulative program (and class) savings for 2022 from the 2021-2024 CDM Framework (Column M, Rows 15-29) only include ½ of the savings from the 2021 programs, while in the CDM Tab (Columns D to F, Row 90) 100% of the 2021 savings are then subtracted from this 2022 cumulative total in order to calculate the 2022 program savings in 2022. The result is that the savings reported in the CDM Tab from 2022 programs are understated.*

161. EEDO agrees with OEB Staff that the updated load forecast more accurately reflects the expected connections and usage in the Test Year as it includes 2022 actual data. EEDO has prepared a revised version of the J2.8 EEDO Load Forecast (with 2022 Actuals) which has taken into account the corrections noted by VECC above.

162. **Reference: VECC Page 18 (Issue 3.1):**
Given that COVID-related restrictions were lifted in 2022, VECC submits that the impact of the COVID variable should be removed from the Residential and GS<50 consumption (kWh) forecasts for 2023.

163. EEDO submits that customer consumption has not returned to an entirely normal state to a level where the impacts of COVID would not have an effect on consumption patterns (even with the cancellation of government safety measures). A number of customers continue to work from home in hybrid or fully remote positions, some business have still not reopened and business meetings continue to take place in a virtual manner (including the oral hearing as part of this proceeding) both as a matter of risk mitigation and cost reduction and convenience, which indicates that a shift in usage may not be temporary in comparison with pre-pandemic levels.

G. 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?

Existing Accounts: Account 1508 Other Regulatory Assets, Sub-account OEB Cost Assessment Variance

164. With one exception, settlement was reached on the treatment and disposition of group 1 and group 2 deferral account balances. In the Application, EEDO has included: Account 1508 Other Regulatory Assets, Sub-account OEB Cost Assessment Variance as a request for disposition. The account has a principal balance of $235,952 accumulated over seven years.

165. **Reference: SEC 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". 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." The same principle applies equally to the disposition of the OEB Cost Assessment Variance Account. Decision and Rate Order (EB-2017-0045), April 26, 2018

166. SEC's submission fundamentally misunderstands the difference between: (a) Z-factor eligibility criteria; and (b) how a variance account operates.

167. The OEB established Z-factor claims to allow distributors under a Price Cap or Annual IR Index rate-setting plan to recover costs associated with one-time unforeseen events that are outside the control of a distributor's ability to manage. In order to not have distributors bring forward as a Z-factor claim every minor unanticipated cost, there are certain thresholds/eligibility criteria – one of which is materiality. In the case cited by SEC, the OEB determined that the Z-factor claim materiality criteria was an annual amount (of $50,000).

168. Variance accounts are different. They are used to track underestimates or overestimates of specific pre-approved costs (or revenues) which are later brought forward for disposition through higher or lower rates. The balance in a variance account can go up or down, sometimes materially sometimes immaterially. That is wholly different than a Z-factor eligibility criteria. In the case of the OEB cost assessment variance account, the OEB established this account in the spring of 2016, directing distributors to make entries in the account on a quarterly basis (when the OEB's cost assessment invoice is received), and dispose of balances in the account when their rates are next rebased (at which time the account will be closed). That is what EEDO is doing.

169. **Reference: VECC 60**

VECC also objects to the disposition of the OEB cost assessment account and for three reasons. First, on an annual basis the amounts booked into this account do not meet the Filing Requirements materiality threshold of 50k. We also object because the balances in the account reflect only the gross variance in costs assessment based on the rates in place at the time of rebasing and in relation to the time when the Board changed its cost assessment methodologies. This means that there is no adjustment being made for the implicit increase in the amount collected for the purpose of covering cost assessments due to IRM rate adjustments. If this were done the balance would be less than currently shown.

170. It is not uncommon to calculate deferral account variances and rate riders based on historical rate base amounts. Both the LRAMVA and Shared Tax Adjustments are calculated using the most recent rebasing data in order to calculate variances. The methodology proposed by EEDO is consistent with this treatment and appropriate.

171. **Reference: VECC 60:**

Finally, we note that this Utility has on its own volition not rebased since 2013. A number of events have occurred both to the benefit and detriment of ratepayers and shareholders during that time. It is not clear why this facet of utility operations should be isolated so that the costs alone are borne by ratepayers. Even if the Board rejects our arguments that none of the balances in this account should be charged to ratepayers it should, in the alternative limit the balance to that in the account as of December 31, 2017. Certainly ratepayers should not have to pay for the carrying costs of an account which is held at the discretion of the shareholder.

172. EEDO submits that the comment above by VECC actually further supports the request for disposition in contrast to the intent in how it was presented. The OEB cost assessment account was established in 2016 and was an existing deferral account at the time of the purchase and EUI agreed for a blanket rebasing deferral/cost stability period. This does not change the fact that EEDO was expected to pay additional regulatory costs that were outside of the construct of historical rates and where the OEB determined that a deferral account was a necessary construct.

<u>New Accounts - Non-Utility Billing Variance Account ("NBDA").</u>

173. OEB Staff and SEC in general did not take issue of the approval of the NBDA. VECC did not support the account. The comments below address specific questions from OEB Staff and SEC.

174. **Reference: OEB Staff 4.6.1 – page 35**

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.

175. EEDO would like to provide clarity on why the OM&A 5310/5315 accounts were used instead of the 4380 account. In the event that the billing services provided by EEDO to the Town of Collingwood are discontinued, what was previously recorded in the 4380 account to account for the portion of billing costs allocable to the Town of Collingwood would now become utility costs which would be recorded in the 5310/5315 account. Therefore EEDO believes the appropriate account for the journal entry would be to credit the OM&A accounts where the corresponding unavoidable external billing cost and CIS costs are recorded.

176. **Reference - SEC – NBDA 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.

177. **Reference - OEB Staff 4.6.1 – page 35**

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".

178. The NBDA accounting order states as follows: EEDO's calculation of 2023 Test Year distribution revenue requirement, approximately $200k of unavoidable billing & collecting costs were excluded from the distribution revenue requirement through revenue offsets for billing services provided by outside vendors for activities such as meter reading, bill preparation, and bill fulfillment. Substantially all of the outside vendor billing costs are fixed and unavoidable in nature and would continue to be incurred if non-electricity billing services were terminated. The costs being charged to third parties result in OM&A savings to EEDO ratepayers that would not otherwise exist.

179. To provide clarity, the 'communication network costs' refer specifically to the costs related to the Sensus TGB station fixed and variable charges that are incurred in order to gather and transmit meter reads data from meters to the RNI. EEDO pays a fixed monthly cost for the TGB infrastructure (which is currently allocated between electricity and water/wastewater services). EEDO also pays variable fees for each meter read, which are itemized between electricity and water/wastewater services. Should EEDO no longer bill water/wastewater services, the fixed costs would be unavoidable, but the variable charges for water/wastewater reads would no longer be incurred. As part of the NBDA,

EEDO is requesting to include the unavoidable fixed costs currently allocated to the water/waste service. Here is an example assuming a $14,000 invoice:

Current	Electric	Water	Total
TGB Station Costs (Fixed)	$6,000	$4,000	$10,000
Meter Reading (Variable)	$3,000	$1,000	$4,000
Total	$9,000	$5,000	$14,000

No Water	Electric	Water	Total
TGB Station Costs (Fixed)	$10,000	$0	$10,000
Meter Reading (Variable)	$3,000	$0	$3,000
Total	$13,000	$0	$13,000

DVA Inclusion	Electric
TGB Station Costs (Fixed)	$4,000
Meter Reading (Variable)	$0
Total	$4,000

180. To specifically address the question above regarding a breakdown of the projected $200,000 of unavoidable costs, EEDO is projecting the following:

Postage/Fulfillment	$ 82,500
Meter Reading Infrastructure	$ 35,000
CIS System	$ 82,500
Total	$ 200,000

181. To add clarity to the comments of OEB Staff and SEC, EEDO has included a revised accounting order as an appendix to this submission to take into account the wording proposals above. Both a red-line and clean version have been included as appendices A & B.

182. **Reference - SEC – NBDA 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.

183. EEDO submits that the current proposal already takes into account risk sharing and the expectation to find efficiencies should the agreement with the Town be terminated. The use of the term 'fixed costs' may not accurately reflect the costs for EEDO to operate this line of business. Excluded from the deferral account request are approximately $350,000 of labour costs required to provide all aspects of the service agreement as shown in the table below:

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**

184. While EEDO would be able to mitigate a portion of the labour costs, due to the small size of the utility and the additional complexity of the electricity billing, efficiencies of scale would be lost. As an example, EEDO would still require the same number of billing staff and customer service representatives to effectively serve customers even without reducing service levels. This further highlights the mutual benefit of the existing agreement. As such, the majority of those costs would still be incurred. As EEDO has accepted this risk, it is already sharing the risk with customers should the agreement be terminated.

<u>New Accounts - Recovery of Income Taxes Deferral Account</u>

185. EEDO proposes to establish a Recovery of Income Tax Deferral Account ("RITDA") for use during the Price Cap IR Term covered by this Application. The purpose of the RITDA is for EEDO to record the difference between the zero cash income taxes included in the revenue requirement proposed in this Application and the actual cash income taxes for its EEDO operations (as calculated at the tax rate currently in place at the time of this Application) throughout the Price Cap IR Term, commencing in the year 2023.

186. Cost of Service methodology allows for the recovery of taxes in the Test Year. In the Application, taxes included in the revenue requirement are zero in the 2023 Test Year. Whereas the year 2023 sets the base for future years' revenue under Price Cap IR, and whereas income taxes payable in subsequent years of the Price Cap IR Plan are expected to be a material positive amount, embedding such a minimal tax amount in the base revenue requirement does not allow for recovery of taxes in 2023 and beyond. Establishing the requested deferral account will enable the recording and fair recovery of incurred income tax expenditures over the Price Cap IR Term once the loss carry-forward balance for regulatory purposes is fully utilized.

H. **OTHER**

5.1 Is the proposed effective date for 2023 rates appropriate?

187. EEDO submits that the October 1, 2023 effective date and January 1, 2024 IRM filing is permissible and appropriate.

188. Regardless of the hyperbolic language included in the responses to EEDO's Argument-in-Chief regarding EEDO's intentions, EEDO maintains that it has acted responsibly and proactively to ensure compliance with the decision in the MAADs Proceeding. While the benefit of hindsight provides opportunity to review the steps taken by EEDO staff in 2019 to confirm the scheduled rebasing date, EEDO staff did reach out to OEB staff to confirm, while referencing the MAAD application and while EEDO does not blame OEB staff for the communication, it did act on this information.

189. Further, as soon as EEDO was contacted by the Town of Collingwood, EEDO staff reviewed the request and also provided guidance as how to file a letter of comment on the record should it be determined necessary to ensure accountability on the issue. EEDO staff immediately brought the matter up with OEB Staff and Intervenors to address the issue that no parties identified until well into this proceeding.

190. In addition, the Decision and Order from the MAADs Proceeding approves the request to defer the rebasing of CollusLDC for five years from the date of closing of the share acquisition transactions.[72] The decision does not state 'at a minimum of 5 years', it states for five years. Before the share purchase agreement was finalized, EEDO had also requested a cost of service filing deferral in 2018 (which would have been the original expected Test Year), which means the LDC will not have rebased for 10 years and 9 months.

191. While EEDO does not disagree that the deferral was a shareholder decision due to the purchase of the LDC, the length of time and continued deferral period contributes further to increased rate impacts in comparison with the 2013 Test Year. Several deferral

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[72] EB-2017-0373/74, Decision and Order at page 16.

accounts (such as the Deferred IFRS Transition Costs or Renewable Connection Capital Deferral) have been accumulated since the last rebasing period which only compounds rate impacts due to the extensive deferral period.

192. **Reference SEC 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 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.

193. EEDO submits that a January 1, 2024 IRM filing is not inappropriate. Customers have benefitted from EUI's purchase of the LDC since 2018 (before the sale closed) and continued over a 5 years and 10 months before any rebasing impacts have taken effect. Residential customers have also benefitted from the 1% rate reduction during the 5 year deferral rebasing period and all customers will benefit from the lack of a May 2023 IRM filing.

194. While EEDO agrees that the sale of the utility was not the decision of customers, they have benefitted over several years. Costs of capital and operating expenses continue to rise across the province and the LDC is not immune to inflationary pressures in order to maintain service levels. The costs projected in the Application were determined in anticipation of a January 1, 2023 implementation date and reflect the best available information at the time of filing (April 2022). These numbers do not take into account another year of inflation, contributing to the rationale for the January 1, 2024 IRM date.

195. LDCs are provided with the option to align rate setting effective dates with their fiscal years and while this effective date proposal is not typical (as many elements of this Application are not), it is not inappropriate nor is it non-compliant as part of the rate filing process.

196. EEDO submits that in the context of the relatively low level of its current rates, the rate increases being sought in the Application are reasonable and appropriate.

197. For all of the reasons set out in this submission and all aspects of the Application, EEDO respectfully requests that the OEB approve EEDO's proposal for each of the unsettled items in this proceeding as filed for in the Application.

All of which is respectfully submitted this 3rd day of April, 2023.

Hesselink, Tim

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Date: 2023.04.03 17:28:19 -04'00'

Tim Hesselink, CPA
Senior Manager, Regulatory Affairs,
EPCOR Electricity Distribution Ontario Inc.

APPENDIX A – **REVISED** Non-Utility Billing Deferral Account Accounting Order

Red Line Version

EPCOR Electricity Distribution Ontario

Accounting Order

Deferral Account for Non-Electricity Billing

The purpose of the Non-Electricity Billing Deferral Account ("NBDA") is for EPCOR Electricity Distribution Inc. ("EEDO") to record the difference between the amount of ~~fixed~~ of unavoidable external billing costs attributable to non-electricity billing, and any revenues received from the Town of Collingwood relating to the billing services being provided. The unavoidable external billing costs include Customer Information System (CIS) costs, postage and fulfillment 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, ~~billing costs attributable to non-electricity billing and any actual recoveries of these costs from the non-electricity billing service recipient~~, if any.

Amounts would only be recorded in this deferral account in the event the billing service agreement between EEDO and the Town of Collingwood is terminated by the Town of Collingwood. Monthly recording in this account would commence as of the termination date of services.

If the billing service agreement is terminated the amount to be recorded on a monthly basis:

$$\frac{Unavoidable\ external\ \cancel{fixed}\ billing\ costs\ attributable\ to\ non-electricity\ billing}{12\ months} - cost\ recoveries\ from\ the\ Town\ of\ Collingwood\ relating\ to\ unavoidable\ external\ billing\ \cancel{fixed}\ costs$$

Audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis.

Simple interest will be computed monthly on the opening balance in the NBDA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

To record the difference ~~between the annual actual income taxes payable and the Board approved deemed income taxes~~ between the amount of unavoidable external billing costs attributable to non-electricity billing and any revenues received from the Town of Collingwood relating to the billing services being provided:

> Debit/Credit Account No. 1508-11 Other Regulatory Assets sub-account Non-Electricity Billing Deferral Account ("NBDA")
> Credit/Debit Account No. 5310/5315 Meter Reading Expense/Customer Billing

To record simple interest on the opening monthly balance of the NBDA using the Board Approved EB-2006-0117 interest rate methodology:

> Debit/Credit Account No. 1508-11-01 Other Regulatory Assets sub-account Carrying Charges on Non-Electricity Billing Deferral Account
> Credit/Debit Account No. 4405/6035 Interest and Dividend Income/Other Interest Expense

Rationale for Account

In EEDO's calculation of 2023 Test Year distribution revenue requirement, approximately $200k of ~~fixed~~ unavoidable billing & collecting costs were excluded from the distribution revenue requirement through revenue offsets for billing services provided by outside vendors for activities such as meter reading, bill preparation, and bill fulfillment. Substantially all of the outside vendor billing costs are fixed and unavoidable in nature and would continue to be incurred if non-electricity billing services were terminated. The costs being charged to third parties result in OM&A savings to EEDO ratepayers that would not otherwise exist.

APPENDIX B – **REVISED** Non-Utility Billing Deferral Account Accounting Order

Clean Version

EPCOR Electricity Distribution Ontario

Accounting Order

Deferral Account for Non-Electricity Billing

The purpose of the Non-Electricity Billing Deferral Account ("NBDA") is for EPCOR Electricity Distribution Inc. ("EEDO") 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 relating to the billing services being provided. The unavoidable external billing costs include Customer Information System (CIS) costs, postage and fulfillment 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, , if any.

Amounts would only be recorded in this deferral account in the event the billing service agreement between EEDO and the Town of Collingwood is terminated by the Town of Collingwood. Monthly recording in this account would commence as of the termination date of services.

If the billing service agreement is terminated the amount to be recorded on a monthly basis:

$$\frac{Unavoidable\ external\ billing\ costs\ attributable\ to\ non-electricity\ billing}{12\ months}$$
$$-\ cost\ recoveries\ from\ the\ Town\ of\ Collingwood\ relating\ to\ Unavoidable\ extneral\ billing\ costs$$

Audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis.

Simple interest will be computed monthly on the opening balance in the NBDA in accordance with the methodology approved by the Board in EB-2006-0117.

<u>Accounting Entries</u>

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 relating to the billing services being provided:

> Debit/Credit Account No. 1508-11 Other Regulatory Assets sub-account Non-Electricity Billing Deferral Account ("NBDA")
> Credit/Debit Account No. 5310/5315 Meter Reading Expense/Customer Billing

To record simple interest on the opening monthly balance of the NBDA using the Board Approved EB-2006-0117 interest rate methodology:

> Debit/Credit Account No. 1508-11-01 Other Regulatory Assets sub-account Carrying Charges on Non-Electricity Billing Deferral Account
> Credit/Debit Account No. 4405/6035 Interest and Dividend Income/Other Interest Expense

<u>Rationale for Account</u>

In EEDO's calculation of 2023 Test Year distribution revenue requirement, approximately $200k of unavoidable billing & collecting costs were excluded from the distribution revenue requirement through revenue offsets for billing services provided by outside vendors for activities such as meter reading, bill preparation, and bill fulfillment. Substantially all of the outside vendor billing costs are fixed and unavoidable in nature and would continue to be incurred if non-electricity billing services were terminated. The costs being charged to third parties result in OM&A savings to EEDO ratepayers that would not otherwise exist.