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EPCOR Electricity Distribution Ontario Inc.

2023 Cost of Service Application
EB-2022-0028

Submission of the
Vulnerable Energy Consumers Coalition
(VECC)

March 16, 2023

Vulnerable Energy Consumers Coalition

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Summary and Overview

1. This is an unusual case. The determination of "just and reasonable" requires the Board consider a prior MAADs transaction. If it concludes, as we submit it should, that EPCOR minimized its transaction risk (whether with intend or by ineptitude is of no consequence) then the Board should factor this into its decision as to what constitutes just and reasonable rates. Fundamentally, the rate case is about credibility -both EPCOR's and the Board's. It is about whether representation made to the Board have a meaning or not?

2. In 2018 EPCOR made this representation to the Board.[1]

Table 3: Year over year comparative cost structure ($ thousands)

$000's CAD		Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023	Year 6 2024
OM&A							
	Status Quo Forecast	5,331	5,425	5,520	5,616	5,752	5,814
	EPCOR Forecast*	5,872	5,191	5,110	5,189	5,306	5,350
	Projected Savings	-541	234	409	427	446	464
Capital							
	Status Quo Forecast**	3,256	3,312	3,303	3,246	3,303	3,361
	EPCOR Forecast	3,256	3,312	3,303	3,246	3,303	3,361
	Projected Savings	0	0	0	0	0	0

** includes transaction and integration costs in 2019 only*

*** CollusLDC Distribution System Plan 2017 – 2022. Years 5 and 6 of the forecast is prior year plus 1.75% inflation*

"*For the period after the five year deferred rebasing EPCOR will file a cost of service rate application to support the revenue requirement of the utility. When this rebasing application is filed EPCOR forecasts that rate payers will see a net benefit as the cost structure, and therefore revenue requirement, post-transaction is less than that of the status quo by$464,000/year.*"

3. In response the Board said the following in approving that transaction:

"*Based on the Applicants' statement that the economies and efficiencies introduced by the consolidation are expected to result in lower revenue requirements in the future, the*

[1] EB-2017-0373/374, page 31-32

Applicants have demonstrated reasonable consideration for the long-term impacts of the transaction on customers.

The OEB has examined the impact that the proposed transaction will have on the economic efficiency and cost effectiveness of CollusLDC, and has determined that the "no harm" test has been met."

4. The Board went on in that Decision to state it would not require EPCOR to file evidence to demonstrate how the efficiencies expected from the transaction have produced savings in its first Cost of Service Application, but also made the point:

   "*The evidence of projected savings in this application support a finding that there is a reasonable expectation that customers will not be harmed in the immediate and long term.* ***The evidence filed in this application will be available to interested parties in a future cost of service application if it is relevant to the rates proposed at that time.***" (emphasis added)

5. That time is now and the evidence of the past case is clearly relevant to this proceeding. This proponent has not only failed to show no harm it has shown quite the opposite. Customers under the Applicant's rate proposal will be harmed.

6. This case is also uniquely about the credibility of the regulator who must grapple with the fact that representations made in one proceeding and which affect this proceeding are now shown to be - not slightly or even modestly wrong – but patently inaccurate. There has been no evidence presented which suggest EPCOR unknowingly purchased a small Ontario utility in dire need of resuscitation. While the pandemic occurred during this period there is no link between that event and the extraordinary increase in cost sought. There is evidence of financial extraction as between corporate parent and utility. In our view that evidence is compelling enough so as to give little weight to the poor returns of this Utility since its acquisition.

7. EPCOR's response to criticism that it has failed to produce results even remotely close to those presented in the MAAD's proceeding is to argue that it made no binding agreement and the Board embedded in its order no binding requirements[2]. It is indeed weak argument - not denying what was said but denying it had any meaning.

8. In this argument we make the following submissions:

   - A revision of the 2023 opening rate base to reflect as yet to be filed final asset continuity and depreciation schedules;
   - A reduction in the 2023 capital in-service amount of $600,000.

[2] Argument-in-Chief, March 3, 2023, pages 4-

- A reduction in the 2023 OM&A costs of between $713,000 and $929,000.
- A recalculation of the long-term debt costs to reflect the Board approved affiliated debt rates at the time of debt acquisition.
- A recalculation of the long-term debt costs to reflect to premature retirement of lower cost commercial debt.
- Removal of the impact of the COVID variable from the Residential and GS<50 consumption (kWh) forecasts for 2023.
- Denial of the establishment of the Recovery of Income Taxes Deferral Account.
- Denial of the establishment of the Non-Utility Bill Variance Account.
- Setting of new cost of service rates to begin January 1, 2024.

1.1 CAPITAL

9. The reasonability of capital additions should be considered in light of both the reasonability of the current distribution system plan (DSP) and the execution of prior plans. This is important because it allows the regulator to assess whether the utility is gaming the rate making process by deferring needed capital investments in the "out years" and then accelerating investments in the bridge and test years. Pacing of the capital budget should, in our submission be a key element since there is a natural motivation for regulated utilities to ramp up investments to embed those costs just before resetting rates. For example, we would invite the Board to consider the inordinately large number of Ontario electricity distributors who's need for an expensive bucket truck coincides with the bridge or test year of the rate application -as is the case for this Utility.

10. EEDO indicates that for the 2022 Bridge Year capital tracked closely to planned expenditures. In fact, the amount currently forecast is significantly under what was projected as shown in the table below.[3]

The decrease is explained in the following table:

Description	**Capital expenditure ($ millions)**
2022 Forecast capital expenditure	$3.70
Lower General Plant spend primarily due to supply chain delays for a bucket truck	(0.51)
Lower System Renewal spending due to project carrying over into 2023, partially offset by higher than forecast project costs	(0.08)
Lower general plant spending due to leasehold improvement construction delays	(0.08)

[3] Undertaking J1.1. Revised March 8, 2023

Lower system access spending due to lower customer demanded work and higher ratio of contributions relative to capital costs	(0.10)
Lower system access spending due to lower meters capital costs	(0.07)
Other miscellaneous variances	(0.01)
2022 Actual capital expenditure	**$2.85**

(highlighting shows Applicant's revision to original response)

11. Under the revised Procedural Order No.7 the Utility's reply submissions are due on April 3, 2023. This is sufficient time for EEDO to complete updated Appendices 2_BA (Fixed Asset Continuity) and 2-C (Depreciation and Amortization Expense) for the 2022 Bridge Year. In our submission the Board should require these be updated (whether audited or not) and to be used for the Opening 2023 Rate Base Calculations.

12. On a net basis at the time of the MAADs acquisition the overall capital spending was estimated at just under $3.3 million per year. The first distribution plan covering the 2019-2023 period undertaken by EEDO was completed in August of 2019 and produced the following estimates.[4]

	2019	2020	2021	2022	2023
System Access	$ 311,957	$ 517,226	$ 353,820	$ 361,475	$ 390,582
System Renewal	$ 2,117,880	$ 2,449,813	$ 2,374,029	$ 2,881,046	$ 2,865,186
System Services	$ 300,000	$ 75,000	$ 76,875	$ 79,181	$ 81,161
General Plant	$ 569,210	$ 657,757	$ 585,755	$ 263,809	$ 567,904
Total	$ 3,299,047	$ 3,699,796	$ 3,390,479	$ 3,585,511	$ 3,904,833

13. Up until 2022 the 2019 DSP capital spending are roughly analogous to what was presented in the MAADs proceeding. For these four years the MAADs forecast was $13,117,000. The 2019 DSP raised this slightly to $13,974,833. However, by the year 2021 EPCOR was apparently no longer following the 2019 DSP as demonstrated by the difference between what is labelled "Plan" in Appendix 2-AB of this proceeding and what is shown for those capital categories in the 2019 DSP[5]. In the current DSP 2023 net spending has risen by 10% to $4,295,838. It is noteworthy that the overall process of asset management has not changed significantly between the two DSP periods[6].

14. The System Access category is largely reactive and subject to customer contributions which are also subject to variation as between in-service of project and booking of contribution. To study investment trends, it is more useful to focus on the other three categories of spending where management has more control over timing. The actual spending in these categories for the 2019 to 2022 period is $11,928,758 or just under $3 million per year. The 2023 DSP gross spending in these three categories is just under

[4] EPCOR Electricity Distribution Ontario Inc. 2019-2023 Distribution System Plan, August 26, 2019 Ver. 3.3
[5] As explained in response to 2.0-VECC-2
[6] 2.0-VECC-3

$3.7 million. Even after considering an inflation adjustment to the prior period average of $3 million a more reasonably paced capital spending program would reduce 2023 spending by between $500-$600k.

15. Another way to look at the reasonableness of the 2023 capital budget is to consider individual projects. The largest areas of increase in the capital budget are in Pole Line Rebuilds and Replacements. This category of projects has increased from just over $600k in 2013 and to an average of about $1.9 million since 2019. 2023 also has two large projects: MS1/ MS2 substation upgrades ($689k) and the IT programs ArcPRo and Un Migration ($508k). With respect to the former project EEDO states: "*EPCOR has drafted the RFP for these two transformers, but hasn't committed to a purchase **yet until the end of this proceeding**. EPCOR will look to put the existing 5MVA transformers back into inventory as spares if possible, or look to salvage for any value*" (emphasis added).[7]

16. It has been our experience in recent cost of service proceedings that post covid supply chain difficulties are resulting in significant delays in receiving transformers. EEDO itself states in its business plan for this project: "[E]*quipment procumbent availability could pose a critical challenge for timely project implementation, given labor and manufactory* [sic] *shortages resulting in extensively lengthy lead times*.[8]" 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 it is unlikely that this project will meet a 2023 in-service date.

17. As we understand it the ArcGIS is an update and replacement for the existing ArcMap software. EEDO states in its business plan for that project that the "*GIS team has leveraged Esri's ArcMap software for utility asset database recording, system mapping, analysis, and other geospatial functions to support operational and business needs. Software updates, including security patches for ArcMap, will cease in 2024 and support of ArcMap will be completely phased out by 2026.*[9]" In other words a delay in this project to an implementation date of early 2024 is plausible.

18. Elimination of either of these projects would reduce 2023 in-service by the capital investment by between $500-$700k. This is congruent with our macro analysis of a reasonable reduction in 2023 investments.

19. If this were not enough, we invite the Board to consider the Pole Line Rebuild/Replacement Program. These programs have escalated from $614k in 2013 to $1,858k in 2023. And on what basis? The asset management data for poles is largely age not condition based. EEDO itself suggests that over time it will improve its assessment of the need for pole replacement stating*: Indeed, the accuracy of the*

[7] 2-Staff-31

[8] Exhibit 2, Tab 2, Appendix A, Distribution System Plan, page 99

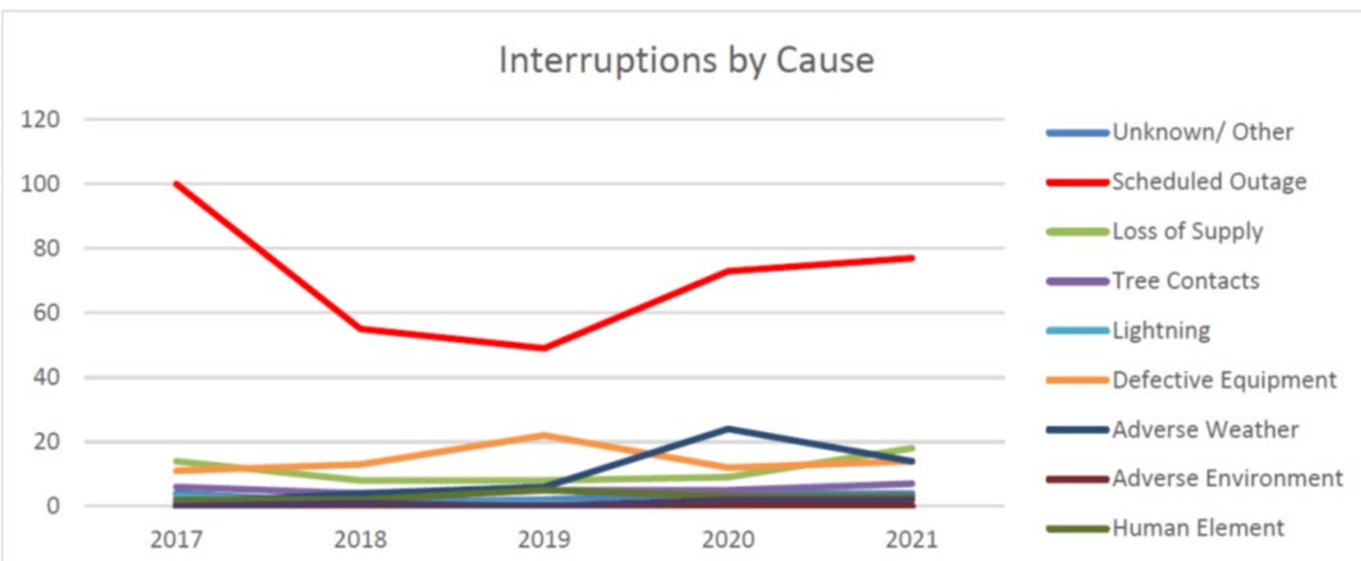
[9] Ibid, Page 59

Health Index calculation will increase as EEDO digitizes more pole testing and inspection results. As these data are collected, EEDO will be able to continuously rerun the calculation and verify which poles have the greatest need for replacement each year."[10] It belies belief that a program that has increased three-fold since 2013 and is subject ongoing data review could not be adjusted to provide better pacing and a more reasonable rate impact to ratepayers.

20. In making its decision the Board might ask itself how has reliability faired since the MAADs transaction. Unfortunately, as shown below it has in fact gotten worse not better:[11]

	Average 2014-2018	Target 2019-2023	Average 2017-2021	Target 2023-2027
SAIDI	1.24	1.24	1.55	1.24
SAIFI	0.68	0.68	0.83	0.68

21. 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.



10 2-Staff-23

11 2-SEC-22

22. Outside of weather the largest contributor to outages are scheduled outages. These have increased in each year since acquisition. Which means that while customers might or might not be getting reliability benefits in the future, they are certainly paying for them in terms of reliability now. We suggest rather than more capital spending EEDO might look to how it can minimize scheduled outages.

23. For the purpose of 2023 rate determination the Board may wish to understand better the how this Utility is minimizing outages due to its investment plan before it provides rate monies for an inordinately large 2023 capital budget. In this regard we note that speed of response and service to outages represents the 3rd largest ranking of priorities of customers in EEDOs Sonte-Olafson survey. The Board might wish to understand better the ability of this Utility to effectively minimize scheduled outages and scheduled outage durations before it provides EEDO capital spending carte blanche.

24. In our submission it is reasonable that the Board reduce EEDO's 2023 capital investment (on an in-service basis) by 600k.

1.2 OM&A

	2013 Last Rebasing Year OEB Approved	2013 Last Rebasing Year Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Operations[4]	582,100	657,706	706,743	721,686	754,396	886,046	885,794	866,849	1,149,538	1,060,428	1,056,073	977,066
Maintenance[5]	1,490,900	1,395,752	1,462,370	1,667,027	1,727,736	1,303,848	1,424,249	1,391,638	1,636,327	1,391,926	1,382,679	1,640,206
Billing and Collecting[6]	993,862	839,380	809,917	823,062	895,356	974,046	949,464	975,000	1,010,748	985,537	1,087,165	1,109,304
Community Relations[7]	138,000	153,000	161,767	210,766	158,939	225,346	227,791	241,736	239,793	176,984	160,108	188,552
Administrative and General[8]	1,380,298	1,369,268	1,423,503	1,282,167	1,380,719	1,228,690	1,311,958	2,118,937	2,075,033	1,897,222	2,498,636	2,615,186
Total	**4,585,160**	**4,415,105**	**4,564,301**	**4,704,707**	**4,917,146**	**4,617,976**	**4,799,257**	**5,594,161**	**6,111,438**	**5,512,097**	**6,184,661**	**6,530,315**
%Change (year over year)		-3.7%			4.5%	-6.1%	3.9%	16.6%	9.2%	-9.8%	12.2%	5.6%

25. There are several ways to look at the Utility's O<&A proposal. One is to simply compare the last Board approved amount in 2013 and adjusts these for inflation, customer growth, productivity and stretch factors and any truly incremental requirements (like new cyber security costs). We call this a "historical analysis."

26. Our historical" analysis uses the Bank of Canada's inflation calculator (CPI[12]). CPI is an appropriate way to view costs from the perspective of ordinary customers who see inflation in relation to a basket of goods which includes electricity. Most people, including we suggest , ratepayers are generally uninterested in complicated inflation methodologies which do not reflect what see experience in everyday purchases. If one were to apply a CPI inflation factor to the 2013 Board approved OM&A amount then the Utility would today require $5,817,445. This is a reduction of $712,870 from what EEDO proposes.

27. However, the Utility did not actually spend the totality of its approved OM&A in either 2013 or 2014. If we were to instead use the actual 2013 spending and inflate that number it would result in a reduction of $928,628 from the sought amount of $6,530,315.

[12] https://www.bankofcanada.ca/rates/related/inflation-calculator/

28. EEDO was in the stretch factor cohort 2 prior to 2016 and in cohort 3 thereafter. The stretch factors between 2014 and 2016 was 0.30%. Between 2017 and 2022 it was 0.15%.[13] Residential customer growth between 2013 and 2022 was roughly 20% (14,009 vs 16,714 forecast[14]). The Board has generally used a conversion rate approximately 0.45% as the translation of the cost of customer growth. The result is an approximate increase of 7% in expected in OM&A costs. The resulting incremental additional cost would be between 321K and 309k depending on whether one uses Board approved or 2013 actual OM&A costs.

29. These estimates suggest a reduction in OM&A spending of somewhere between 400k and 620k. We encourage the Board to try and makes its exercise of determining an appropriate OM&A an exact mathematical science. We clearly do not follow this concept. Instead, we suggest the Board consider all factors and impute them into a more general number. The law does not require a formula it expects the panel exercise its discretion based on its inherent knowledge as an expert tribunal.

30. For example, we think the Board should consider the evidence on 5h3 increase in affiliate and corporate transfers. Such transactions should be closely scrutinized by regulators since they are text book way companies manipulate cost between regulated and non-regulated entities to the benefit of shareholders. The Table below shows the trend of such costs since 2013.[15]

$000	2013 appr.	2013 actual	2014 actual	2015 actual	2016 actual	2017 actual	2018 actual	2019 actual	2020 actual	2021 actual	2022 bridge	2023 test year
Collus PowerStream Solutions	1,071	975	1,144	1,068	694	-	-					
Service Fee	132	132	132	-	-	-	-					
Town of Collingwood	59	22	5	8	19	39	17					
Collingwood PUC	367	310	287	276	238	216	180					
Alectra	-	182	239	160	221	181	115					
Affiliate Shared Services								365	557	511	758	790
Corporate Shared Services							186	740	682	660	792	875
Total	**1,629**	**1,621**	**1,807**	**1,512**	**1,172**	**436**	**498**	**1,105**	**1,239**	**1,171**	**1,550**	**1,665**

31. This presentation is, we believe, may be a bit misleading of the comparable costs over time. For example, as we understand it the costs in the row labelled “Alectra” relate CDM service which have no analogous function since CDM activities are no longer carried out by the Utility. And we also understand that the row noted as “Collus PowerStream Solutions” relate to billing services which are now internalized at EEDO. If

[13] Exhibit 1, Tab 1, Schedule 1, Table 1.6-1, page 50
[14] Exhibit 3, Tab 1, Schedule 1, Table 3.1-7, page 13
[15] 4-SEC34

we are even partially correct this would mean that the comparable post MAADs EPCOR related affiliate/corporate costs have increased in real terms significantly since 2013.

32. Even if we are wrong in our analysis as to the comparability of past and current related party costs the EPCOR driven shared service costs have increase significantly between 2019 and 2023. Certainly, more than what would be expected from just inflation. Incorporating inflation would result in an expected cost today of $1,272 (again using BoC calculator) or about 392k lower than estimated in the test year.

33. We also understand a significant portion of that increase is the result of changes in the cost allocation attribution of costs as shown in the table below.[16]

Table 4.4.2-6

EOOMI/EOUI Shared Services Costs Allocated to EEDO

($)

	Shared Service	A **2019A**	B **2020A**	C **2021A**	D **2022 Bridge Year**	E **2023 Test Year**
1	Management Oversight	25%	25%	20%	38%	37%
2	Regulatory	10%	10%	N/A	33%	33%
3	Human Resources	55%	70%	55%	48%	48%
4	HSE	33%	33%	33%	38%	37%
5	Customer Service	N/A	18%	25%	59%	56%
6	OT and SCADA Support	N/A	N/A	N/A	38%	37%
7	Operational Support	N/A	40%	40%	38%	37%
8	Ontario Facilities	23%	26%	22%	29%	26%
9	HOCA	23%	26%	22%	29%	26%

34. The changes in affiliate cost allocation methodology were also done internally. As far we understand no outside expert has reviewed either the affiliate or corporate cost allocation or services to ensure that EEDO is getting value for money. Given the

[16] Exhbit 4, Tab 1, Schedule 1, page 70

significant sums involved we find this surprising. In any event we submit that the Applicant has not met its burden of proof to merit such a large increase in shared service-related costs.

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 is considers it peer utilities.[17]

Table 4.1.1-2

Distribution revenue and OM&A per customer[2]

	Electricity Distributor	Distribution Revenue per Customer $	OM&A per customer $	Number of Customers #
1	E.L.K. Energy Inc.	271	196	12,611
2	Wasaga Distribution Inc.	317	248	14,238
3	**EPCOR Electricity Distribution Ontario Inc.**	**409**	**339**	**18,203**
4	Welland Hydro-Electric System Corp.	421	284	24,054
5	Orangeville Hydro Limited	437	255	12,697
6	Westario Power Inc.	456	254	23,953
7	Halton Hills Hydro Inc.	492	298	11,684
8	Grimsby Power Incorporated	498	307	22,564
9	North Bay Hydro Distribution Limited	507	284	24,290
10	Festival Hydro Inc.	536	285	13,936
11	Lakeland Power Distribution Ltd.	548	390	23,547
12	ERTH Power Corporation	558	315	21,654
13	Orillia Power Distribution Corporation	588	430	14,552
14	Innpower Corporation	602	332	19,281
15	Algoma Power Inc.	2,071	1,113	12,124

36. The elephant in this proceedings are the representations about future OM&A made during the MAADs proceeding. We do not think the Board should let the Applicant resile from its commitments to ratepayers. Under even the “status quo” EPCOR was estimating OM&A costs to be $5,752,00 in 2023. Incorporating MAADs related savings customers were promised to paying only $5,306,000. Instead, we are now being told to pay $1,224,315 more than that amount! There is no evidence in this proceeding which would justify missing the target by such a large margin.

37. The Board’s decision must now speak to ratepayers who might reasonably believe they have been sold a bill of goods. Because of that we submit that in considering VECC’s suggestion of a reduction in OM&A of between $713k and $929k that it lean toward the higher end of the spectrum. We also encourage the Board to consider what we see as a

[17] Exhibit 4, Tab 1, Schedule 1, page 7

pattern of self serving affiliated transactions (including debt rates as described below). At best the evidence points to a certain indifference to the extraction of funds from this small utility.

2.0 Revenue Requirement

Cost of Long-term Debt

38. In our submission the Board should adjust the long-term debt rate to be applied to (1) reflect the OEB's cost of capital policies and (2) make an adjustment for EPCOR's premature replacement of lower cost commercial debt with higher cost affiliate debt.

39. If one aspect of this Application denotes EPCOR's disregard for the provenance of Ontario regulation it must certainly be in its proposal for determining the long-term debt rate for the cost of service formula. The Board has a long-standing set of policies on how to determine the cost of affiliate debt the purpose of which is to guard against inappropriate intercorporate transfers and to eliminate the lengthy (and costly) individual debates that might otherwise be had setting affiliated debt rates for the 50 or so LDCs regulated by the Board.

40. There is no reason for us to discuss the merits of the "EPCOR model" for setting affiliated debt rates. As we raised at the hearing, Mr. Koski who led this evidence is not an expert in finance or economics. He was not a party to the original policies' establishment and therefore has no understanding of whether the merits of his proposal have been considered and already dismissed by the Board. His formula does however result in more monies being transferred from this affiliate to its parent. We also respectfully submit that Mr. Koski is conflicted in his fiduciary duties to the two entities whose interests are diametrically opposed in this matter. EPCOR has a duty to maximize its returns whereas EEDO has a duty to minimize its debt costs.

41. The other means of extracting monies from this affiliate has been to replace lower cost commercial debt with long-term affiliate debt. In 2017 EPCOR replaced three commercial ten-year loans with a principal of just over $6 million and rates of 3.59% and 3.65% with an affiliated debt instrument of $8 million priced at 4.30%.

42. The explanation for replacing low-cost debt with higher cost debt is to match the life of the asset with the life of the debt to the extent possible[18]. EEDO's annual capital spending of $2 to $4 million belies the thesis that 30-year debt matches all asset age. In any event it is common finance strategy to create portfolios in order to diversity risk and

[18] Vol. 2 February 15, 2023, page 28

in light of annual capital investments needs. Nor is it clear to us why it was in EEDO's interest to incur a $70k penalty to prematurely retire cheaper commercial debt. This course of action was defended by a clearly conflicted employee of EPCOR. EEDO itself does not have a Chief Financial Officer and its CEO choose not to appear to explain why these financial transactions are in the Utility's best interest.[19]

43. The Board's policy is clear that affiliated debt should be priced at the lower of the actual rate or the Board's annually proclaimed debt rate. In our submission $6 million of the affiliated debt should be priced at 3.62% which is our calculation of the retired commercial debt weighted cost.

3.0 Load Forecast, Cost Allocation and Rate Design

Issue 3.1

44. EEDO's 2023 Rate Application included[20] a forecast of the number of customers/connections and usage (kWh and kW where applicable) for 2023 for each rate class. This forecast is used in the Application to determine: i) revenue at existing rates, ii) the allocation factors used for purposes of cost allocation and iii) the billing determinants used in the derivation of the proposed rates for 2023. The load forecasts for each of the three main customer classes (Residential, GS<50 and GS>50) are based on regression analyses that use 2012-2021 consumption (kWh) adjusted for CDM as the dependent variable and various independent explanatory variables including weather, economic indicators, calendar indicators, number of customers, COVID indicators and binary variables as appropriate[21].

45. During the interrogatory process the regression models for the Residential, GS<50 and GS>50 classes were revised to include 2021 CDM program savings and the load forecast was updated accordingly[22]. In evidence given during the oral hearing EEDO's witnesses confirmed that it was this revised load forecast that EEDO is proposing should be used for purposes of setting its 2023 rates[23]. The load forecast is summarized below[24].

19

20 EEDO_2023 Load Forecast Model_20220527, Summary Tables Tab

21 Exhibit 3, Tab 1, Schedule 1, pages 1-2

22 3-VECC-16 a) and 3-Staff-41

23 Transcript Vol. 2, pages 107-108

24 EEDO_2023 Load Forecast Model_20220825, Summary Tables Tab

Customers / Devices	
Customers	**2023 Forecast**
Residential	17,012
GS < 50	1,833
GS > 50	127
Street Light	3,318
USL	30
Total	22,319

CDM Adjusted

kWh	2023 Weather Normal Forecast	CDM Adjustment	2023 CDM Adjusted Forecast
Residential	137,753,321	140,637	137,612,684
GS < 50	45,416,700	569,114	44,847,586
GS > 50	133,307,696	1,738,246	131,569,449
Street Light	1,242,766		1,242,766
USL	396,233		396,233
Total	318,116,716	2,447,998	315,668,719

CDM Adjusted

kW	2023 Weather Normal Forecast	CDM Adjustment	2023 CDM Adjusted Forecast
GS > 50	327,660	3,413	324,247
Street Light	3,496		3,496
Total	331,156	3,413	327,743

46. Included in the derivation of the regression models for each of the three of the main customer classes is a variable intended to capture the impact of the COVID-19 pandemic on electricity consumption as follows[25]:
    - For the Residential class, “COVID HDD” and “COVID CDD” variables equal to the relevant HDD and CDD variables from March 2020 to December 2021 and equal to 0 in all other months are used.
    - For the GS<50 class, a “COVID_AM” variable equal to 0 in all months prior to March 2020, equal to 1 in April and May 2020, and 0.5 in each month from June 2020 to December 2021 is used.
    - For the GS>50 class, a “COVID2020” variable equal to 0.5 in March 2020, 1 in April and May 2020, 0.5 in June 2020, and 0 each month thereafter is used.

[25] Exhibit 3, Tab 1, Schedule 1, page 7

47. For purposes of the 2023 forecast the COVID variables were set as follows:
    - For the Residential class, the "COVID HDD" and "COVID CDD" variables are reduced by 75%.[26]
    - For the GS<50 class, the COVID_AM variable is set equal to 0.125.[27]
    - For the GS>50 class, the COVID2020 variable is set equal to zero.[28]

48. During the oral hearing EEDO's witnesses explained why the load forecast for 2023 included "positive values" for some of the COVID variables when government restrictions on business openings and gatherings were all generally lifted by the summer of 2022 as follows[29]:

> *MR. HARPER: Okay. And I guess, can we agree that, I guess, maybe -- I don't know whether you would agree or not, but my understanding is that the government restrictions on the business openings and sort of gatherings and stuff were generally all lifted by the summer of 2022?*
>
> *MR. BLAIR: Yes.*
>
> *MR. HARPER: So I guess I was just wondering what sort of led you to sort of continue to have Covid variables in there beyond that period of time and extending all the way through to 2023?*
>
> *MR. BLAIR: The load forecast was developed in April and May -- or, sorry, in March, April, and May of 2022, so it was just coming off of the government sort of reopening sort of on the heels of Omicron, sort of as that was subsiding, but it was still sort of in there. It was really a function of when the forecast was developed.*
>
> *MR. HARPER: So you really weren't too sure where the government was going to go at that point in time, I guess, is maybe the honest -- is maybe the way to put it.*
>
> *MR. BLAIR: Right, the government and sort of Covid more generally, the impact that would have.*

49. 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. VECC estimates that this would yield the following load forecast for 2023[30]:

[26] Exhibit 3, Tab 1, Schedule 1, page 11
[27] Transcript Vol. 2, page 112
[28] Exhibit 3, Tab 1, Schedule 1, page 21
[29] Transcript Vol. 2, pages 112-113
[30] Calculated by setting the 2023 Residential and GS<50 COVID variables at zero in EEDO_2023 Load Forecast Model_20220825

CDM Adjusted			
kWh	2023 Weather Normal Forecast	CDM Adjustment	2023 CDM Adjusted Forecast
Residential	135,502,126	140,637	135,361,490
GS < 50	46,114,531	569,114	45,545,416
GS > 50	133,307,696	1,738,246	131,569,449
Street Light	1,242,766		1,242,766
USL	396,233		396,233
Total	316,563,352	2,447,998	314,115,355

50. During the oral proceeding, EEDO was also asked to update its 2023 load forecast to include 2022 actuals in its regression models[31]. As EEDO is not proposing that this updated forecast be used for purposes of setting 2023 rates, VECC has not undertaken a comprehensive review of the load forecast model provided in the undertaking response. 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.

51. Given these initially identified issues and the fact parties have not had the opportunity to fully test the updated load forecast provided with the undertaking responses VECC submits that it would be inappropriate for the OEB to rely on it for purposes of setting 2023 rates.

<u>Issue 3.2</u>

52. VECC notes that the revising the Residential and GS<50 load forecasts (based on "zero" values for the COVID-related variables) will impact the demand allocators used for purposes of cost allocation for both classes. In turn this will likely change both the status quo revenue to cost ratios and the final revenue to cost ratios for all classes based on the application of the adjustment methodology agreed to in the Settlement Proposal[32].

[31] Undertaking J2.8 – J2.8 Load Forecast (with 2022 Actuals)
[32] Page 14

53. The revised GS<50 load forecast will also change the existing fixed/variable split for the GS<50 class. In particular, the increase in the GS<50 forecast usage for 2023 will increase the variable proportion of the split used in the determination of the GS<50 rates.

4.0 Accounting

54. Our arguments with respect to deferral and variance accounts are with respect to the proposed new accounts: the Recovery of Income Taxes Deferral Account (RITDA) and the Non-Utility Bill Variance Account; and the disposition of the OEB Cost Assessment Account.

55. VECC objects to the establishment of the Recovery of Income Taxes Deferral Account. The account appears to be premised on the issue of reconciling actual loss carry-forward benefits used in the calculation of taxes for the purpose of rates[33].

56. It's not clear to us what is special about this calculation to require a regulatory account. No one appears to dispute that the calculation of the losses carried forward. The only way the Utility might find itself in a negative financial position is if were to earn more than expected in the calculated revenue requirement. In that case the Utility would already be benefiting from either greater revenues or its ability to lower costs below what it has presented to the Board for rate making purposes.

57. In our experience it would be unusual in Ontario utility rate regulation to establish what amounts to a tax true up account. In any event if unforeseen events do occur the Utility is free to make an application which presumably would discuss the materiality and other conditions precedent that the Board has set out for the establishment of deferral and variance accounts.

58. We have a similar submission with respect to the Non-Utility Bill Variance Account. This account is proposed to address the possible reduction in benefits which accrue through a shared billing arrangement. That arrangement is being reconsidered by the Town who contracts with EEDO.

59. We are not clear as to how EEDO has derived the amounts to be booked into this account. They are, in the absence of knowing what transpires in the ongoing negotiations simply guesses. Nor is it clear what steps the Utility is taking to mitigate any potential negative impacts of changes to the billing arrangements. Again, it seems to us the better course of action is for the Utility to finalize its negotiations with the Town

[33] Vol 2, page 9

and then, if necessary, apply for the relieve it deems necessary and at that time provide sufficient information for the Board to be able to asses the criteria the Board has articulated before such an account will be granted.

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.

61. 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.

5.0 Other and Response to the Applicant’s Argument-in-Chief

Response to EEDO’s Argument-in-Chief

62. EEDO’s view is that the MAADs Proceeding evidence has no relevance to the determination of “just and reasonable” rates for the cost of service term. They rely on three arguments for that position. First is a legal technicality which purports that had the Board wished to embed its commitments it could have a added them as conditions of a MAADs Order.

63. Leaving aside whether it would have been permissible for the MAADs panel to bind a future panel the “legal” argument is not only without merit it is also without character. Rather than address the question as to whether the Board was misled it simply aims to redirect the issue. In any event we are not asking the Board calculate 2023 rates based on a derivative of the MAADs representations. We are asking the Board to consider the overall reasonableness of what has transpired since that transaction was approved and uses its discretion as an expert panel to make an adjustment to 2023 rates.

64. The second argument raised by EEDO to ignore its prior representation is to plead ignorance. That its due diligence was faulty because *“in an acquisition process is*

inherently limited.[34]" In considering this argument the Board may wish to consider that the transaction was of by some financial neophyte. In fact, it was the second like transaction for the Utility and the buyer and sellers are large sophisticated companies. In fact, EPCOR is not only a sophisticated utility owner it is a seasoned purchaser and owner of multiple utilities in both Canada and the US. Is EPCOR implying it was hoodwinked? Did the seller (PowerStream) fail to disclose critical information in this transaction? Even if that were the case (which we highly doubt) isn't that a matter for the courts and not the Board? We like Commissioner Dodds would like to understand why if there was a faulty assessment of the risks in purchasing this utility that that error should rest with the ratepayers.[35]

65. The last reason given by EPCOR to ignore its prior representations is to plead poverty and threaten disaster should be Board adjust rates to better meet its prior commitments. Dramatic words are used that *"ratepayers would be forced to carry the large risks that threatened the future integrity of the distribution system*.[36]" And we are reminded that since 2019 the actual rate of return has been more than five basis points below its deemed rate. As we have argued elsewhere in there is absolutely no evidence that reducing either capital spending or operating expenses would threaten the viability of EEDO.

Effective date

66. EEDO originally applied for rates to be effective January 1, 2023. This was a change to its existing May 1 rate year that was previously approved by the Board. On August 31, 2022 the Applicant wrote to the Board stating among other things[37]:

    The requirement set out in the Share Purchase Agreement between EEDO and the Town of Collingwood for Collus PowerStream Corporation (CollusLDC), which requires EEDO to maintain existing rates for customers for five years following the closing date (being October 1, 2018), adjusted solely by the OEB's Price Cap Incentive rate-setting option;

67. EEDO subsequently updated its application to seek a new effective date for rates of October 1, 2023.

68. This proceeding has been unusual both in the fact that EPCOR did not substantially meet its representations in the MAADs proceeding, but also somewhat stunningly it **forgot** one of the most critical legal commitments it made. This notwithstanding the Applicant's much vaunted new value-added corporate and affiliate services, included legal assistance.

[34] AIC page 4
[35] Transcript Vol. 2. February 15, 2023, Pages 116-120
[36] AIC page 5
[37] EPCOR EEDO_EffectiveDate_Settlement Conf, August 31, 2022

69. We find it a bit rich for the Applicant to now suggest that they have saved ratepayers from a cost increase by not seeking a May 2023 IRM increase. That was not what happened – what happened was in their desire to extract more money as soon as possible (a reoccurring theme of this Utility and its corporate parent) they got ahead of themselves. Having – in the vernacular – screwed up - EEDO now wants a large increase in rates in October of this year to be followed by another (likely large due to the IRM's incorporation of inflation data) rate increase on January 1, 2024. Is sum rather than rely on a principled approach of either returning to the current approve rate year of May 1 or living with the new proposed rate of year of January 1, we are offered what can only be called an EEDO original (like affiliated debt calculator) which might best described as the "as soon as humanely possible" rate year.

70. A big mistake was made. Not by the Board and not by ratepayers. It was a mistake make by the management of this Utility and its league of ratepayer compensated corporate lawyers providing them advice. The question now is who pays for that mistake. The Board has been keen for the utilities to engage customers to understand what they want. We very much doubt multiple rate increases makes that list.

71. Our submission is that there should be one rate increase and that should be for new cost of service rates beginning January 1, 2024.

VECC submits that it has acted responsibly and efficiently during this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED