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Oshawa PUC Networks Inc. (OPUCN)

EB-2025-0014

Application for electricity distribution rates and other charges beginning January 1, 2026

Submission of the
Vulnerable Energy Consumers Coalition
(VECC)

November 28, 2025

Vulnerable Energy Consumers Coalition

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Overview

1. Our arguments begin with a response to Oshawa PUC Networks Inc.'s (OPUCN) argument-in-chief (AIC). We have little to comment on its first section –"Legal Framework." The Board is well aware of the law and does not need to be lectured its responsibilities to both shareholders and ratepayers. We do take umbrage to hyperbolic statements of "financial cliffs" to which this Utility (or any other) might be headed. The only financial cliff in this case is the one Utility management is pushing its ratepayers over. The Board, in our submission should also not be overly impressed by what the regulated utility's advocate - the Electricity Distributor Association - has to say about the state of electricity distributors in Ontario[1].

2. Nor are OPUCN's musings of politicians and unsubstantiated claims as to "maintenance backlogs" of any relevance[2]. They are not evidence in this proceeding. And this is not a case about maintenance backlogs. In fact, the evidence shows that the largest source of labour cost increases does not originate from unionized outside workers diligently addressing purported backlogs. The fact is that in 2021 the Board approved costs for 62 unionized (largely outside) workers. The Utility never employed more than 48. The fact is the proposal for 2026 calls for only 39 unionized workers. Hardly evidence of maintenance and operations backlogs. Where OPCUN has grown large is not with boots on the ground but rather with shoes – some of them highly polished - in the office. Executives and non-unionized labour costs have skyrocketed as the Utility increased its executive and management staff from 13 in 2021 to a proposed 24 in 2026[3]. Ratepayers are being asked to fund more people with pencils not people with tools.

3. Nor, as implied in their argument in chief, is this the story of a 'poor' utility consistently underearning and struggling to survive. Again, the facts belie the proposition. In 2022 and 2023 OPUCN over earned. In 2024 it did indeed under earned and significantly so, but for because in that year it began its prolific spending – and without approval of its regulator – it took a risk. In 2024 OPUCN increased its O&M costs from \$15.8 million to \$18.8 million – a 19% increase in one year. What is more it that between 2023 and 2024 there was a jump in executive and management salary costs of 37.7%! Predicably returns plummeted taking the Utility from a position of overearning to one of underearning. And belying the story now told about the dire investment needs, the operations and maintenance spending of the Utility actually <u>declined</u> between 2023 and 2024.[4]

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[1] AIC, page 3. We observe that OPCUN paid over $128,000 to the EDA over the past 5 years – see 4-VECC-156 (check)

[2] Ibid

[3] OPUCN_Partial SettlementP_Appendix 2K Breakdown_20250923.XLSX

[4] See Appendix 2-JA

4. No this is not the story about a distribution utility in dire need of investment. Something else happened since the last cost of service application. Starting in 2023 the entire senior management team at Oshawa Power changed[5]. This is a story that the Board has seen before[6]. With regime change come new, financially prolific and in this case, grandiose plans. This new management finds itself unrestrained by the discipline of competition. They need only find a way to convince the regulator that money should be no object because after all the future is all electric. At VECC we do not think that those forced to make real trade-offs to pay their utility bill or something else would agree with this change in direction.

5. The Board may wish to revisit its decision in North Bay EB-2020-0043. Similar to this case, North Bay Hydro, under a new management also with a sought what we characterized at the time as a "massive" OM&A increase – 33% above its last Board approved. Compare that to the equivalent figure in this proceeding which is over 60%! We are at a loss for a new adjective to describe this ask – perhaps audacious?

6. Audacity might also best describe what is layered on top of an unprecedented OM&A request. A new facility to house all those new hires. An expensive new home of over $61 million from this Utility with an average gross capital spending between 2021 and 2024 was just over $13 million[7] per annum.

7. OPUCN has taken considerable effort to exclude consideration of the new facilities from this proceeding. The estimated costs of this building are multitudes higher than any such facility built in the last 15 years by a comparable sized utility[8]. One might charitably characterize the efforts to side step the most significant event occurring <u>during</u> the proposed rate plan as, the very least, disingenuous.

8. VECC is somewhat at a disadvantage when it comes to the details of the planned facilities and the details on the compensation studies done to bolster OPUCN's generous compensation plan. We are not a party to any confidential filings in this proceeding. We have seen only what ratepayers are able to see. We make our arguments as they would – on the evidence that is transparently put before them from this regulated monopoly. And we remain sceptical about arguments that are go beyond personal information as to what should remain confidential when a monopoly seeks to have ratepayers fund it. In our submission decisions of the Board must be fully explained to ratepayers - those who seek the Board's protection against from the worst of monopoly behaviour. It is difficult to explain decision based on secret evidence.

[5] Exhibit 1, page 8

[6] In the case of North Bay Hydro EB-2020-0043 a similar overhaul of the Utility's management occurred prior to a request for significant increases in spending. That case was also not settled and heard by the Board.

[7] See Appendix 2-AB

[8] Exhibit K1.5

9. We argue in this submission that there should be significant reductions to operating and capital costs for the purpose of establishing short-term base rates. Not a five year plan but a one year plan with four to come. These rates would only be in place until the Utility files an addendum to this application with complete information on the new facilities. That addendum would also provide OPUCN's proposal to mitigate costs (capital and OM&A) in order to accommodate the proposed costs of these new facilities. That would be fair to ratepayers.

1.1 Capital and In-Service Additions

2026 Opening Rate Base - Reduction of $1.67 million

10. We have reviewed the draft submissions of the Consumer Council of Canada (CCC). They make cogent arguments for a reduction of the 2026 opening rate. We agree with the tenor of their argument and especially that it is unlikely that the current forecast of 2025 projects will all be completed and in-service by December 31, 2024. We do think their recommended reductions, though sound, are on the conservative side. We will not repeat their arguments as we adopt them with the following modifications.

11. CCC makes the submission that the Board should reduce the in-service amounts for the MS2 switchgear by $0.41 million. We think the reduction should be higher at $480,000. Reproduced below is OPCUN' s table showing the various overbudget items.[9]

IRR Table 2-9: 2023 Municipal Substation Switchgear Replacement Program Variance Analysis

		MS2 (2023)			
Items	Description	Amount (per Switchgear)	Revised Amount	Difference	Explanation
1	As filed	$ 1,800,000.00			
2	Post settlement	$ 1,800,000.00	$ 2,125,000.00	$ 325,000.00	Acknowledging that the amount set was preliminary and additional scope changes were necessary prior to RFP, Oshawa Power revised the value of each switchgear revised to $2.125M. This is the amount that the variance analysis is based on.
3	RFP Finalization / Base Bid	$ 2,125,000.00	$ 2,230,750.00	$ 105,750.00	Final Base bid was more expensive than the initially anticipated amount of $2.125M
4	Change orders	$ 2,230,750.00	$ 2,658,053.00	$ 427,303.00	The approved additional costs along with descriptions can be seen in final MS2 invoice 42-1624293 that released holdback
5	Internal costs	$ 2,658,053.00	$ 3,111,322.00	$ 453,269.00	Since the egress cables were being upgraded in order to prepare for future demand growth from 500MCM to 1000MCM cable, pole calculations needed to remodelled in order to meet Ontario Reg 22/04 and the decision was made to replace riser poles as per industry best practice and prudent system planning. This work was performed internally. Internal costs also included supply of material such as insulation boots, station transformer, base, duct, and cable along with inspection of work performed by the third-party contractor.

[9] Exhibit 2, page 34

12. As can be seen from the Table there are four categories of cost overrun. The first and last (325k and 454.3k) relate to change of scope in the project. The middle two ($105.7k and 427.3k) are unexplained variations. In our submission the Board could reasonably reduce the in-service costs for both of these latter adjustments. The law puts the onus on the Applicant to explain the reasonability of the increase and they have not done so. However, we think it fair to make a lower reduction than the resulting 533k. The "change order" explanation is clearly inadequate as it simply references some invoices – that is not an explanation of prudence. We accept that the final bid amount is what it was but, we submit that given the known cost overruns at the time effort should have been made to change to scope of the project to stay within the new increased budget. Therefore, a sum of half of this might reasonably be disallowed (52.85k) for a total sum of $480,150 or 480k.

13. OPUCN's CIS software and enhancements were budgeted at $1.4 million. As of June 30th, total spend on the project was $1,471,926 with final testing expected in the third quarter of 2025.[10] At the hearing OPCUN explained that the project was approved in the previous cost of service application. We went back and looked at that and found this interrogatory and response (reproduced in part):

    Reference 2, page 190 states that currently, Oshawa PUC Networks does not own the CIS software in use, and that the acquisition will remove risk from its current operating model and will allow Oshawa PUC Networks to operationalize and advance customer service improvements.

    Response

    The "outsourced" line item reference has been retained in the description to maintain easy comparability for the CIS related expense pre-, during and post-acquisition. Completion of the project to acquire and host in-house the CIS is expected close to the end of Q4 2021, with the 'outsourced' label being redundant from 2022.

14. At the time the project was to cost $736[11] and was based on a plan to bring CIS in-house. The filing in EB-2020-0048 includes this amount as in-service in the test year 2021.

15. In the event, none of this occurred. Instead, we are told that in the revised project is in-service as of October 2025[12]. New budgeted cost in 2024 is either $1,471,926 (2-Staff/CCMBC-70) or $1.5 million (Chapter 2 Appendices filed with the Settlement Agreement) or $2,297,300 (filed in undertaking J2.4 Appendix 2-AA). In all cases significantly above the $736K that ratepayers have been paying for as part of the last rate plan. At a weighted cost of capital of 5.31% (from EB-2020-0048) and a half

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[10] 2-Staff/CCMBC-70 EB-2020-0048
[11] 2-VECC-17 EB-2020-0048
[12] TR Vol 1, October 28, page 92

year impact the result would be approximately $20k a year loss for ratepayers or $100k over the 5 year plan. Ratepayers should be compensated for this double dipping on its CIS plan.

16. A more material concern is with the updates provided in undertaking J2.4 Appendix 2-AA which apparently show the CIS project ballooning from $1.4 million, prior to the hearing to $2.3 million after and without explanation. Perhaps this is an error. If not it would have major implications and not just for rate base in 2026 but also for the calculation of the appropriate tax in rates given the tax shield CRA provides to computer related investments. We invite OPUCN to address this change in their reply argument.

17. In our submission 2026 rate base should be reduced by the $1.4 million calculated by CCC with additional 170k as we have calculated for MS2 switchgear and the inclusion of a new CIS in the last cost of service application (100k). We also submit that OPCUN should explain the adjustment shown in undertaking J2.4 with respect to the CIS investment in 2026. If there has been a material change parties should be provided with the opportunity to examine these and make additional submissions in called for.

2026 Capital Plan and DSP – 2026 Capital Budget Reduction of $6.3 million +

18. The biggest issue in the 2026 capital plan isn't in the 2026 capital plan. OPCUN's 2026 and DSP of the proposed rate plan present a quandary for the Board. It is clear that the new facilities filed with this cost of service was not included as part of the distribution system plan although, it is quickly pointed out to us, it is part of the Utility's business plan.[13]

19. Our response to the doublespeak of "*It's in the plan – just not that one*" is that there can only be one plan that ratepayers are required to pay for in rates. The schism of the purposeful avoidance of the most significant investment that will occur over the term of this rate plan cannot be papered over. It is an affront to the fairness of how rates are set because it turns a blind eye to an imminent project, one that has already begun with the purchase of the land and will continue in 2026 as contracts are awarded for its construction. Occupancy is set for 2027. The existing facility lease expires at the end of 2027[14]. OPUCN cannot deny that the facilities project is actively ongoing.[15]

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[13] TR , Vol 2, October 29, page 84

[14] TR Vol.2 October 28,2025, page 115. Assuming a 6-12 month physical construction period and the requirement of a complex move in the months before lease expiry OPCUN would need to begin physical construction no later than the fall of 2026.

[15] TR. Vol 1, October 28, 2025, page 5

We are -- the client is actively, through 25 their construction manager, engaged in these procurements live right now. At best, they are done by the end of the year, early Q1 next year.

20. The Utility aims to be at its new facilities in 2027. Even before the Board issues a decision on this application ground may be turned and structures begun. Yet it is not part of the DSP, not an ACM of the application – how can that be a thing? Oh yes, it's because we can't know about the costs because if the secret were out the costs will go up. Its hard to see how they can go higher than what we know now.

21. That the Board would allow months from now an ICM later, after all the costly decision have been made, after it has just set rates , would be a travesty. The Applicant would like you to believe the question of the prudence of the building and its cost is a separate matter to be determined later – after things are done. Maybe = we disagree, but in any event that does not answer the question that should be in the minds of this Panel.

22. How did OPCUN adjust its capital and operating budget for the <u>term of the rate plan</u> in order to accommodate what is clearly going to be extraordinarily large investment made in new facilities?

23. The answer - they didn't. That building is another thing - in another plan. As if the monies paid for the extraordinary rate increase of this proceeding are a different colour than the dollars ratepayer will be asked pay for the building in 18 months from now. Don't look – nothing happening over there. In our submission if the Board does not address the fundamental question raised about the impact of this building on a five year rate plan then it cannot reasonably approve a five year rate plan. Unless we are missing some explanation to ratepayers who have no idea of what is about to transpire.

24. The exploitation of the Board's ICM policy does not constitute an explanation of how this upcoming investment fits into the sought five year rate plan. If it does then the Board must also be able to explain why it heard this application at this time. Why did it not defer the application? The Board grants cost of service rate review deferrals to utilities all the time when they ask and it suits their needs (and we are never notified or provided an opportunity to comment on their requests). Is there no time in the service of ratepayers the Board should order the same – defer hearing the application or make an interim decision until the matter is clarified?

25. By mid 2026 most if not all the matters so secret today would see light. What exactly is the urgency – the Board's application metrics? And what is the purpose of an ACM if not to address a project that is occurring not just in the test year but that started in the bridge year? The only answer to this today is that we cannot address matters until what the utility knows is no longer a secret. And in any event was the

ICM policy developed to allow utilities to make capital investments in the order of five times that of an entire annual capital budget during some time of the rate term? Whose interest are being served and who is being "manipulated or managed" by this application of the ICM policy?

26. We submit that the Board should turn its mind to these questions. With respect, slavish adherence to policies when those policies do not suite the circumstance does not constitute rate regulation. Arguing that the Board is tied by a general policy and not the evidence before it may be a convenient and may allow the avoidance of making hard decisions but that does make it right or defensible.

27. In our submission the Board has three choices:

- Cede to the Utility's strategy. Two large increases in two or so years with the cost and implication of the new facility made in isolation of the actual distribution system plan and the rates set today.
- It may defer making a decision on the application until sometime in 2026 and have the Applicant file an update with the new facility information.
- It may approve a shorter rate term of 1 or 2 years and have the Applicant file an addendum to this application showing cost of the new facilities <u>and</u> (under Board direction) allow it to show in a modified proposal how it is adjusting the proposal before the Board in this application to accommodate the new facilities and to manage rate impacts.

VECC holds that the last of these options provides the fairest processes for both the Utility's shareholders and its ratepayers. It allows OPUCN to both justify its new facility and to show how it is managing that extraordinary investment within the operational plans (both OM&A and Capital) over the duration of the rate plan it is seeking. It might even consider asking to extend its rate plan term to accommodate its modified plan. All of which would allow the Board to put before and have answered the question – what changes need be made to accommodate the large investment in these new facilities?

28. The forecast cost of the new facility ($61 million) will be nearly equal to the entire net capital expenditures of the last 5 year Distribution Plan ($69.7). This assumes the facility project comes in on budget and that the costs of leaving the old building are too high– something we think unlikely.

29. OPUCN has made no accommodation for the building in its 2026 budget. In order to set 2026 rates, the Board should therefore make the adjustment to the capital plan for them. If our rate plan proposal is adopted the Board will be able to revisit the 2027 and onward budget when the Utility files its application addendum in 2026.

30. In their submission CCC makes a proposal for the type of adjustment we are advocating by considering the 2024 capital year which was clearly reduced in order to accommodate the land purchase for the new facility. They calculate a 37% reduction of $6.3 million for that adjustment. We agree this is a reasonable approach. Another approach would be to consider capital spending trends during the 2021 to 2024 period (which has actual data). We have produced a table showing the differences:

Category	2021-2024 Average ‘000	2026 Proposal ‘00	Difference ‘000
System Access	5,464	9,186	3,722
System Renewal	7,425	8,045	620
System Service	1,720	1,336	-414
General Plant	1,154	1,680	526
Capital Contributions	2,672	3,228	556

31. We make these further observations and adjustments. The first is that in making adjustments to the 2026 capital plan the Board should consider that the amounts should be <u>lower</u> than past averages since the point is to “fit in” the greater spending of the new facilities. As such we would “zero out” the negative value for system service. The total amount with this adjustment would be a reduction of approximately $4.9 million. We also note that OPUCN’s value for capital contributions – tied almost exclusively to system access spending is significantly different for 2026 than suggested by past activity. In the 21-24 period contributions were 49% of system access spending. For 2026 OPUCN has estimated that they will only be 35%. Meaning that 14%, or $1,378 million of the 2026 access budget estimated to go into rate base is not likely to actually form part of rate base. The resulting total of $6.3 million is the same as that estimated by CCC but using a completely different methodology.

32. However, we submit a further adjustment should be made on the basis that the reduction in 2026 spending should accommodate the greater spending on the new facilities. Some this adjustment will be accounted for by the fact that we have not made any inflationary adjustment to our calculations. Nevertheless, the Board would be within reason to make further downward adjustments. If our proposal is adopted this change would only be for 2026 and would also serve to motivate the Utility to find sustaining capital reductions for the term of the rate plan and while the costs of the new building are being absorbed into rate base.

33. Finally, it might be that the Board is concerned that making reductions to the capital plan could jeopardize system reliability. In this regard we considered reliability as it pertains to equipment failures. This category of outages is more highly coordinated others which are either “acts of god” (lightening) or issues that are otherwise beyond OPUCN’s control. Below we have highlighted the past performance of OPUCN with regard to outages related to equipment failure. As can be seen there is an encouraging pattern showing that over the past plan, with significant less resources than being sought in this plan, OPUCN was able to decrease outages due to equipment failure. We can only imagine what more could be done if more monies were being directed to outside workers and less on inside paper shufflers. In any event, the evidence gives confidence that the Utility can manage and maintain reliable service with a reduced capital budget.

IRR Table 2-5: Updated Table 8 from DSP – Historical Interruptions 2019-2024

Interruptions	2019	2020	2021	2022	2023	2024	Total of Row	% of Tot
Number of Interruptions								
0 - Unknown/Other	17	9	11	7	11	0	55	1.72%
1 - Scheduled Outage	485	427	731	378	470	313	2491	78.06%
2 - Loss of Supply	0	0	1	1	1	0	3	0.09%
3 - Tree Contacts	9	7	11	6	15	9	48	1.50%
4 - Lightning	1	5	1	2	6	0	15	0.47%
5 - Defective Equipmen	56	71	42	57	58	40	284	8.90%
6 - Adverse Weather	2	19	5	3	5	6	34	1.07%
7 - Adverse Environmer	6	0	0	0	0	0	6	0.19%
8 - Human Element	4	9	2	0	2	3	17	0.53%
9 - Foreign Interference	59	58	47	33	41	24	238	7.46%
							3191	100%
Number of Customer Interruptions								
0 - Unknown/Other	1316	8492	6523	2044	3066	0	21441	6.49%
1 - Scheduled Outage	4586	8187	7603	3338	5452	2432	29166	8.83%
2 - Loss of Supply	0	0	10554	5	13514	0	24073	7.29%
3 - Tree Contacts	3365	670	1146	1895	8439	5210	15515	4.70%
4 - Lightning	172	5232	8	2409	12121	0	19942	6.04%
5 - Defective Equipmen	22052	17280	3263	26541	8793	4331	77929	23.58%
6 - Adverse Weather	99	2500	922	17530	671	123	21722	6.57%
7 - Adverse Environmer	2314	0	0	0	0	0	2314	0.70%
8 - Human Element	14695	14559	6887	0	26	62	36167	10.95%
9 - Foreign Interference	15906	32597	13213	9425	11028	23868	82169	24.87%
							330438	100%
Number of Customer Hours of Interruption								
0 - Unknown/Other	568	3317	4982	1562	2354	0	12784	3.91%
1 - Scheduled Outage	5212	8784	5494	3433	6391	1992	29315	8.97%
2 - Loss of Supply	0	0	9079	0	968	0	10047	3.08%
3 - Tree Contacts	7174	473	1449	2543	8589	10160	20227	6.19%
4 - Lightning	487	1975	9	1325	11914	0	15711	4.81%
5 - Defective Equipmen	17773	23882	5010	10167	9269	3410	66102	20.24%
6 - Adverse Weather	225	11741	1774	62908	130	306	76778	23.50%
7 - Adverse Environmer	3079	0	0	0	0	0	3079	0.94%
8 - Human Element	4682	10688	793	0	12	16	16175	4.95%
9 - Foreign Interference	19046	26001	14564	6835	9987	24084	76433	23.40%
							326649	100%

2.1 OM&A – reduction $5 million +

	2021 Last Rebasing Year OEB Approved	2021 Last Rebasing Year Actuals	2022 Actuals	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year
Operations	2,891,000	2,427,693	2,613,290	3,143,980	2,833,190	3,381,252	4,003,063
Maintenance	1,349,949	996,991	1,103,692	1,175,488	1,442,317	1,375,222	1,349,796
Billing and Collecting	3,500,467	2,862,727	3,254,066	3,949,857	4,899,646	5,025,619	5,247,373
Community Relations	239,216	230,409	297,797	422,398	270,588	282,786	394,033
Administrative and General	5,885,460	6,782,354	7,110,887	7,072,385	9,354,202	9,811,940	11,277,725
Total	**13,866,092**	**13,300,173**	**14,379,731**	**15,764,108**	**18,799,942**	**19,876,820**	**22,271,990**

34. As we said at the start of our argument the 84% increase in OM&A since the last Board approved is simply audacious. Using the Bank of Canada's inflation calculator, we found that using the 2021 Board approved amount as a starting point and applying CPI would result today in a figure of $15,928,179.[16] It would be $650,000 less than that if one started from what the Utility actually spent in 2021. Based on these figures the Board would be well within its ambit to reduce the OM&A budget for 2026 by $7 million. And this is not making any adjustment, as we have argued for the exceptional building costs that are putting pressure on rates. We however are arguing for something less than that.

35. The most significant factors of the extra ordinary increase in OM&A are:

- Increase in FTEs;
- Increase in compensation per FTE;
- Unrealistic assumptions about vacancy or churn rates; and
- Higher costs driven by transferring tasks to affiliates.

36. The table below filed in response to interrogatories and as part of the Appendices in the Settlement Agreement provides the most detailed picture of the change in FTEs[17]

[16] https://www.bankofcanada.ca/rates/related/inflation-calculator/
[17] Undertaking J3.1 and 4-CCC/VECC-142

	2021 OEB Approved	2021	2022	2023	2024	2025	2026
Salary and Wages							
Executive	**514,838**	**714,796**	**543,241**	**897,620**	**1,407,952**	**1,797,078**	**1,949,041**
Salary	468,034	584,620	443,301	724,954	1,160,858	1,466,430	1,511,473
Incentive	46,803	130,176	99,939	172,666	247,095	330,649	437,568
Management	**2,772,187**	**1,488,280**	**1,271,652**	**1,349,489**	**1,634,921**	**2,147,740**	**2,624,615**
Salary	2,563,224	1,268,791	1,103,146	1,223,183	1,483,295	1,894,945	2,299,861
Incentive	208,963	219,489	168,507	126,306	151,626	252,795	324,754
Non-Union	**158,003**	**1,192,050**	**1,256,881**	**2,102,708**	**2,644,332**	**2,682,005**	**3,116,970**
Salary	158,003	1,035,052	1,136,351	1,971,350	2,481,474	2,391,554	2,769,924
Incentive	-	156,997	120,530	131,358	162,858	290,451	347,046
Union	**5,755,478**	**4,610,382**	**4,626,075**	**4,978,732**	**5,017,177**	**5,035,313**	**5,933,111**
Wages	4,956,039	3,951,072	3,806,366	4,208,632	4,312,934	4,370,937	5,252,126
Overtime	799,439	659,311	819,709	770,100	704,243	664,376	680,985
Total Salary and Wages	**9,200,506**	**8,005,508**	**7,697,849**	**9,328,548**	**10,704,382**	**11,662,136**	**13,623,737**
Benefits							
Executive	147,236	237,082	187,757	354,761	478,084	525,802	554,261
Management	797,734	386,993	419,308	386,857	513,117	748,050	932,491
Non-Union	711,974	471,671	459,008	626,605	844,144	946,309	1,079,197
Union	1,109,291	1,324,188	1,335,661	1,339,827	1,408,653	1,586,209	1,839,507
Total Benefits	**2,766,235**	**2,419,934**	**2,401,734**	**2,708,050**	**3,243,998**	**3,806,370**	**4,405,456**
Compensation							
Executive	662,074	951,878	730,997	1,252,381	1,886,036	2,322,881	2,503,301
Management	3,569,921	1,875,273	1,690,961	1,736,346	2,148,038	2,895,790	3,557,106
Non-Union	869,977	1,663,721	1,715,889	2,729,313	3,488,476	3,628,314	4,196,168
Union	6,864,769	5,934,571	5,961,736	6,318,559	6,425,830	6,621,522	7,772,618
Total Compensation	11,966,740	10,425,442	10,099,583	12,036,598	13,948,381	15,468,506	18,029,194
Employees Eligible for Incentive	14	14	24	37	40	45	52
Total Employees	91	72	74	90	85	86	105

37. This table shows clearly the increase human resource costs occur in the non-unionized sector. The number of employees eligible to receive incentive pay demonstrative of the large increase in executive and management positions.

IRR Table 4-48: 2021 to 2026 Mid-Year FTE values by Program (Application)

Program Mid-Year FTEs	2021 OEB-approved	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year
Operations & Maintenance							
Distribution	29.0	25.5	22.0	23.8	24.4	23.7	27.0
Metering Service - Technicians	3.0	2.5	2.0	2.2	2.5	2.8	3.0
System Control - Operators	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Engineering	4.0	3.0	1.5	2.5	4.2	4.2	4.5
Technical Services	5.0	5.5	6.0	6.0	6.8	7.8	8.3
Operations Management	7.0	5.5	3.5	2.5	2.0	2.0	2.5
Sub-Total	**50.0**	**44.0**	**37.0**	**38.9**	**41.9**	**42.5**	**47.3**
Customer Service							
Communications	1.0	0.5	1.0	1.8	1.3	1.5	2.2
Customer Service	15.5	11.8	8.8	8.5	5.3	3.1	3.5
Metering / Reading	3.3	2.2	1.0	1.5	2.3	2.8	3.5
Sub-Total	**19.8**	**14.4**	**10.8**	**11.8**	**8.8**	**7.3**	**9.2**
Administrative & General							
Corporate	4.0	5.5	5.5	5.6	7.9	8.7	8.9
Finance & Regulatory	7.3	7.6	8.7	11.9	14.0	13.6	14.6
Supply Chain	3.3	2.7	2.5	3.0	3.1	3.1	3.7
IT Operations	3.0	2.7	3.2	4.8	6.5	7.8	9.2
Human Resources	2.0	2.0	2.3	2.4	2.1	1.8	1.8
Health & Safety	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Facilities	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sub-Total	**21.6**	**22.4**	**24.1**	**29.6**	**35.6**	**36.9**	**40.0**
Total	**91.4**	**80.8**	**71.9**	**80.2**	**86.4**	**86.8**	**96.5**

38. From this chart we can see that operations and maintenance account for a declining share of the FTEs and that white collar positions account for the cost increases.

39. OPUCN also did not include a vacancy rate in its proposal. In our experience this is unusual. Most companies with any significant staff complement realize that at any given times some positions are vacant. OPUCN provide these actual vacancy rates:[18]

IRR Table 4-59: Vacancies & Vacancy Rate (2021-2024)

Year	Vacancies	Rate
2021	8	11%
2022	6	8%
2023	4	5%
2024	11	13%

[18] 4-CCC/CCMBC/VECC/AMPCO-144

40. Because VECC did not sign non-disclosure documents we are not privy to the confidential information in the Korn Ferry Study. We therefore rely on our partner intervenors and especially CCC for submissions with respect to comparability of compensation. We have however considered the MEARIE Management Survey and agree with CCC's conclusion that OPUCN is an outlier in respect to the number of staff eligible for incentive compensation. Again, this goes to the top heavy management style of this Utility.

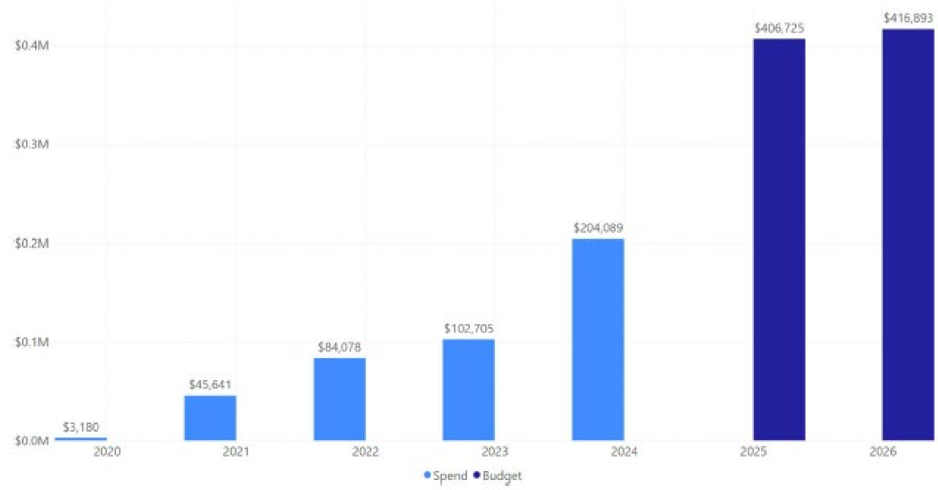
41. The Board should also consider that in considering FTE growth these tables understate the situation. This is because 12.5 FTES were displaced when the call centre was outsourced in 2024[19]. In other words, the OM&A overall request contains the financial equivalent of these FTEs.

42. The only "expert" evidence put forward to support this extraordinary request for human resource funding is a "Resource Optimization Review." There is no a report per se but rather a set of slides produced by Ms. Lise Galli on behalf of an organization known as Marjorie Richards & Associates. A simple search does not show this firm to have prominence in the field of resource assessment. The information presented by Ms. Galli is largely derivative of an organization known as "Electricity Human Resource Canada". This organization is governed largely by representatives of regulated utilities and the labour unions representing employees at regulated utilities. Ms. Galli's material is mostly hearsay of this organization's work. Therefore, the basis for conclusions remains untested. Ms. Galli herself does not appear to have any particular academic qualifications or experience that would lend credence to the presentation. This slide presentation is at best opinion and certainly not expert evidence. It is not the type of evidence one might expect to support such a massive change in human resource planning and costs. We submit the Board should give this presentation no weight.

43. With respect to other OM&A costs we would draw the Board's attention to the shifting of collection activities that occurred in 2023. Below is a chart showing the growing collection costs[20].

[19] 4-Staff/CCC/VECC/AMPCO-108, Table 4-26
[20] 4-CCC/VECC-130

IRR Figure 4-1: Collections Costs



44. The budget for collection costs rose from $84,078 in 2022 to a forecasted $416,893 for 2026. For the same period the Bad Debt Expense increased from $419,859 to a forecast $1.2 million in 2026.[21] In other words while OPUCN is paying its affiliate more to do its collection work it is actually getting worse results.

45. There are various other detailed aspects of OM&A spending that might be used as examples of the excess OM&A spending of this Utility. Other intervenors have shared with us their concerns and in the interest of efficiency (and acting together as the Board has asked to do with interrogatories in this case) we rely upon and support their arguments.

46. We submit the way for the Board to find a reasonable reduction to OM&A is to consider the matter as a whole – an envelope approach. This means considering cost pressures due to inflation, customer growth and other non controllable costs like rising cyber security and the Board's own assessments costs.

47. We start from the Board's last approved OM&A for this Utility of $13,866,092. We then apply the inflation rate that applies to customers, CPI as calculated by the Bank of Canada's on-line tool. As noted in our opening remarks this provides a starting point for 2026 of $15,928,179. To this we add an amount for customer growth. Customer growth between 2021 and 2026 (as per OPOCUN's forecast) was 6%, or just over 1% per year.[22] Using the PEG conclusion that for each 1% change in

[21] Appendix 2-JC Partial Settlement Version
[22] Exhibit 1, page 21

number of customers cost are estimated to change by 0.44%[23] would result in an upward adjustment of approximately 2.65% to OM&A for customer growth. This adds an additional $422,100 to this amount. To this we add $1 million for such things as new cyber security and regulatory costs (our source is this is not an exact science and we err to be generous to the Applicant). This provides an expected 2025 OM&A amount of $16,350,279. We then inflate this figure for 2026 by an amount slightly higher than the Board's 3.5% (and Bank of Canada's) to 4%. The result is just over $17 million. The Applicant is seeking $22.3 million. In our submission a $5 million reduction is therefore is reasonable.

48. Our proposal is below what the Utility estimates it will spend in 2025. We have seen this a number of times. An applicant comes before the Board in a cost of service application and in the test year and year prior we find large OM&A increases as compared to the years before. The big jump to get to a new plateau and erase any efficiencies gained in the last term. As long as one stays in one's productivity cohort - the argument goes – all is well.

49. In this case examine the difference between 2023, $15.8 million in OM&A expenses and 2024, $18.8 million. The Applicant can be expected to expresses horror at the thought that the Board might have the audacity to refer back in time to the more reasonable figure. "People will have to be fired - the sky will fall".. the reply is easily guessed. So be it. This Utility took a risk. It risked putting itself in a difficult position by increasing spending in a very significant way and before it had put its plans before the regulator. OPUCN is counting on the OEB not being able to stomach the hard decision that results if it concludes that what has occurred is neither just or reasonable to the ratepayers of Oshawa.

50. If the Board accepts our proposal of a shorter initial rate term and a new application addendum to consider the new facilities then OPUCN can be invited to adjust its OM&A to meet the challenge. OPUCN will get another day and need not dismiss staff or make other drastic measures other than to work hard to find efficiencies over the next few months – like non-monopoly businesses do all the time. Or it can just stand idly by and accept it's the results of its imprudent actions -lower returns.

[23] PEG, Empirical Research in Support of Incentive Rate-Setting 2022 Benchmarking Update, Report to the Ontario Energy Board, July 2023, pages 9-10

4.1 Load Forecast

51. OPUCN is seeking approval of the updated load forecast for the 2026 Test Year included with the Partial Settlement Proposal[24]. The load forecast consists of forecasts for 2026 customer/devices counts, energy (kWhs) and, where applicable, billing demand (kWs) for each customer class.

2026 Customer/Devices Forecast

52. The methodology for forecasting 2026 customer/devices counts is described in OPUCN's Application[25]. However, the updated load forecast included with the Partial Settlement Proposal reflects corrections to the historical data used[26] and the use of actual data up to June 2025 (as compared to December 2024 in the original Application). OPUCN's 2026 customer/devices forecast is set out in the following table[27]. For each customer class, the value shown is the mid-year average for 2026[28].

Summary

2026	Customers / Devices
Residential	59,464
GS < 50	4,545
GS 50-999	530
GS 1,000-4,999	12
Large Use	1
Street Light	14,755
Sentinel Lights	19
USL	296
Total	79,622

2026 Residential Customer Forecast

53. The geometric mean of the annual growth from 2017 to 2024 is used to forecast the Residential growth rate from June 2025 to the end of 2026[29]. However, the January 2026 forecast count is adjusted so that the increase in the average annual customer count between 2025 and 2026 equals the historic geomean[30].

[24] OPUCN AIC, page 25
[25] Exhibit 3, pages 31, 33, 35, 38, 41 and 42
[26] Partial Settlement Proposal, Appendix F, VECC CQ #2
[27] Partial Settlement Proposal, Load Forecast Model, Summary Tables Tab
[28] Exhibit 3, page 29
[29] Partial Settlement Proposal, Load Forecast Model, Customer Count Tab
[30] Partial Settlement Proposal, Appendix F, VECC CQ #1

54. VECC submits that OPUCN's Residential customer count forecast for 2026 is too low for the following two reasons. First, OPUCN's forecast 2026 Residential customer count does not align with OPUCN's expectations as to the number of additional housing developments OPUCN expects to connect over the remaining months of 2025 and 2026. In response to 3-Staff/VECC 98 OPUCN states:

> "*As of June 2025, there are 725 remaining residential lots yet to be connected in subdivisions where distribution assets on the right of way are already installed and energized. There are also 4 more subdivisions that are approaching energization of distribution assets (constructed by the developer – Alternative bid) - Approximately 720 lots. Several other subdivisions are under construction by the developer under the Alternative bid that Oshawa power has not been given definitive energization dates for*."

55. In VECC's submission it is reasonable to assume that all of these residential lots will be connected by the end of 2026. Adding these 1,445 additional housing units to OPUCN's actual June 2025 residential customer count of 58,609 would result in OPUCN having 60,054 Residential customers as of December 2026. This compares with OPUCN's December 2026 forecast of 59,823.5[31].

56. Second, in its Distribution System Plan OPUCN is planning for the additions of 932 and 947 new Residential customers for 2025 and 2026 respectively arising just from the connection of new residential subdivisions and associated customers to Oshawa Power's distribution system that do not lie along the existing distribution system (i.e. System Access-Expansions)[32]. Adding these 1,879 additional Residential customers to the December 2024 Residential customer count of 58,330[33] would result in OPUCN having 60,209 Residential customers as of December 2026, again higher than OPUCN's December 2026 forecast.

57. Furthermore, VECC notes that both of these values (i.e., 60,054 or 60,209) understate the total number of Residential customers as of December 2026 as the first value excludes subdivisions under construction by developers using the Alternative bid approach while the second value excludes new Residential customers who lie along Oshawa Power's existing distribution system. VECC calculates that using the higher of the two values and assuming a constant monthly growth rate (0.15%) for the period June 2025 to December 2026 so as to achieve a December 2026 Residential customer count of 60,209 yields an average Residential customer count of 58,729 for 2025 and 59,716 for 2026 (as compared to OPUCN's forecasts of

[31] Partial Settlement Proposal, Load Forecast Model, Customer Count Tab
[32] Exhibit 2, Distribution System Plan, Appendix B, page 12
[33] Partial Settlement Proposal, Load Forecast Model, Customer Count Tab

58,688 and 59,464 respectively). VECC submits that 59,716 is the minimum 2026 average Residential customer that should be approved by the Board.

2026 GS<50, GS 50-499 and GS 500-4,999 Customer Forecasts

58. For each of these customer classes the geometric mean of the annual growth from 2015 to 2024 is used to forecast the Residential growth rate from June 2025 to the end of 2026[34]. Again, the January 2026 forecast count s adjusted so that the increase in the average annual customer count between 2025 and 2026 equals the historic geomean[35].

59. VECC accepts OPUCN's forecast 2026 customer counts for these classes for purposes of setting 2026 rates.

Large Use Customer and Sentinel Lights Devices 2026 Forecast

60. The historical customer/device counts for both of these classes have remained constant in recent years. For the Large Use class the customer count has been one since 2015 and for the Sentinel Lights class the device count has been 19 since 2019[36]. For both these classes OPUCN forecasts the counts will remain the same for 2025 and 2026.

61. VECC accepts OPUCN's forecast 2026 customer/device counts for these classes for purposes of setting 2026 rates.

Street Lights and USL Devices 2026 Forecast

62. For each of these customer classes the geometric mean of the annual growth from 2016 to 2024 is used to forecast the class' growth rate from June 2025 to the end of 2026[37]. Again, the January 2026 forecast count is adjusted so that the increase in the average annual customer count between 2025 and 2026 would equal the historic geomean[38].

63. VECC accepts OPUCN's forecast 2026 device counts for these classes for purposes of setting 2026 rates.

[34] Partial Settlement Proposal, Load Forecast Model, Customer Count Tab
[35] Partial Settlement Proposal, Appendix F, VECC CQ #1
[36] Partial Settlement Proposal, Load Forecast Model, Customer Count Tab
[37] Partial Settlement Proposal, Load Forecast Model, Customer Count Tab
[38] Partial Settlement Proposal, Appendix F, VECC CQ #1

2026 Energy Forecast

64. For the Residential, GS<50, GS 50-999, GS 1,000-4,999 and Large Use classes, the 2026 energy use is forecasted in four stages:
- First, a base forecast for 2026 is developed using regression equations specific to each customer class that seek to explain historic (2015-2024) energy use levels based on relevant explanatory variables. For purposes of these regression equations, persisting CDM is added back to rate class consumption to simulate the rate class consumption had there been no CDM program delivery. For the period up to 2020 the CDM values are based on OPUCN results as reported by the IESO. For the period 2021-2023 the CDM values are based on an estimate of Oshawa Power's share of actual provincial energy savings, while for 2024 the CDM values are based on an estimate of Oshawa Power's share of planned provincial savings. [39]
- Adjustments are then made to the 2026 forecast for each customer class to account for an anticipated increase in the adoption of electric vehicles (EVs)[40].
- Further adjustments are made to the Residential and GS<50 classes to account for additional anticipated loads from electric heating[41].
- Finally, adjustments are made to account for the impact of 2024[42] to 2026 CDM/eDSM programs[43].

65. For the Street Lights, Sentinel Lights and USL classes, the 2026 energy forecasts are based on the forecast devices count for 2026 and the historic average use per device over the 2022-2024 period[44].

OPUCN's proposed load forecast for 2026 is as follows[45]:

kWh	2026 Weather Normal Forecast	CDM Adjustment	2026 CDM Adjusted Forecast	Additional EV & Heating Loads	2026 Forecast Excluding Additional Loads
Residential	557,049,836	6,631,014	550,418,823	7,179,995	543,238,828
GS < 50	135,002,433	4,594,252	130,408,181	1,644,739	128,763,442
GS 50-999	339,053,014	6,850,142	332,202,872	474,538	331,728,333
GS 1,000-4,999	81,580,592	7,183,442	74,397,150	313,547	74,083,603
Large Use	35,878,079	912,579	34,965,500	36,185	34,929,315
Street Light	4,602,783		4,602,783		4,602,783
Sentinel Lights	25,474		25,474		25,474
USL	2,874,357		2,874,357		2,874,357
Total	**1,156,066,568**	**26,171,429**	**1,129,895,139**	**9,649,004**	**1,120,246,135**

[39] Exhibit 3, pages 5-8 and 3-VECC 107
[40] Exhibit 3, pages 49-53
[41] Exhibit 3, pages 54-56
[42] To account for the ½ year rule used for the 2024 forecast
[43] Exhibit 3, pages 57-61
[44] Exhibit 3, pages 43-49
[45] Partial Settlement Proposal, Load Forecast Model, Summary Tables Tab

Base Forecasts

Residential, GS<50, GS 50-999, GS 1,000-4,999 & Large Use

66. The following table summarizes the explanatory variables used for each customer class along with the Adjusted R^2 values indicating the equations overall "goodness of fit". All of the explanatory variables used are statistically significant and have an intuitively correct sign.

Variables Used in Regression Equations				
Residential	GS<50	GS 50-999	GS 1,000-4,999	Large Use
-HDD14 -CDD10 -CWFHCDD12 -Trend	-HDD16 -CDD14 -COVIDAM -Days in Month -#GS<50 Cust.	-HDD18 -CDD12 -COVIDAM -OEA_GDP -Days in Month	-CDD16 -COVIDAM -Osh_FTE_adj -Days in Month	-HDD8 -CDD14 -COVIDAM -Spring/Fall Var -OEA_GDP chg
Adj R^2 =0.848	Adj R^2 =0.887	Adj^2 R =0.784	Adj R^2 =0.773	Adj R^2 =0.839
Notes: a) HDD and CDD are weather variables b) CWFCDD12 and COVIDAM are COVID-related variables c) Variables and Adj R^2 values per Partial Settlement Proposal, Load Forecast Model				

67. While the variables used for each customer class' model are the same as those in the initial application, for the load forecast included with the Partial Settlement the models have changed (i.e. re-estimated using data up to June 2025), the forecast GS<50 customer count has been revised[46] and economic forecast used for the GS 50-999, GS 1,000-4,999 and Large Use classes has been updated[47].

68. The forecasts produced by the models are then reduced to remove the 2026 persisting CDM impacts from programs implemented in 2015-2024. Finally, as the historical loads used to develop the GS 50-999 class forecast do not include Wholesale Market Participants (WMP), the actual 2024 WMP kWh volumes are added to the GS 50-999 class[48].

[46] See discussion in previous section
[47] Partial Settlement Proposal, Load Forecast Model, Economic Tab
[48] 3-VECC 108

69. VECC has no issues with the models used by OPUCN to forecast 2026 energy use by customer class or the resulting forecasts which are set out below[49].

	Residential kWh			GS<50 kWh			GS 50-999 kW kWh				
Year	Normal Predicted No CDM	Cumulative Persisting CDM	Normalized	Normal No CDM	Cumulative Persisting CDM	Normalized	Normal Predicted No CDM	Cumulative Persisting CDM	Normalized	Wholesale Market Participant	Normalized with WMP
	D	E = B	F = D - E	D	E = B	F = D - E	D	E = B	F = D - E	I	J - H + I
2024	560,569,549	30,767,232	529,802,317	140,050,574	9,978,627	130,071,947	344,809,693	14,195,316	330,614,377	6,210,990	336,825,366
2025	570,814,012	30,423,648	540,390,363	140,984,580	9,298,052	131,686,529	344,832,125	13,577,001	331,255,124	6,210,990	337,466,114
2026	579,983,047	30,113,205	549,869,842	142,111,204	8,753,509	133,357,694	345,578,631	13,211,145	332,367,486	6,210,990	338,578,476

	GS 1,000-4,999 kW kWh				Large Use kWh		
Year	Actual	Normal Predicted No CDM	Cumulative Persisting CDM	Normalized	Normal Predicted No CDM	Cumulative Persisting CDM	Normalized
	A	D	E = B	F = D - E	D	E = B	F = D - E
2024	81,507,757	93,199,639	12,646,208	80,553,430	37,407,610	661,569	36,746,041
2025		93,156,099	12,169,724	80,986,374	36,908,492	660,905	36,247,587
2026		93,359,379	12,092,334	81,267,045	36,494,516	652,622	35,841,894

Street Lights, Sentinel Lights and USL

70. As noted above, the 2026 energy forecasts for these classes are based on the forecast device count for 2026 and the historic average use per device over the 2022-2024 period[50].

Street Light				
Year	Actual	Connections	Average per Connection	Normal Forecast
	A	B	C = A / B	D = B * C
2022	4,432,743	14,204	312	4,432,743
2023	4,495,190	14,384	313	4,495,190
2024	4,498,710	14,452	311	4,498,710
2025		14,554	312	4,540,300
2026		14,755	312	4,602,783

Sentinel Light				
Year	Actual	Connections	Average per Connection	Normal Forecast
	A	B	C = A / B	D = B * C
2022	26,915	19	1,417	26,915
2023	26,915	19	1,417	26,915
2024	22,593	19	1,189	22,593
2025		19	1,341	25,474
2026		19	1,341	25,474

USL				
Year	Actual	Connections	Average per Connection	Normal Forecast
	A	B	C = A / B	D = B * C
2022	2,750,057	285	9,661	2,750,057
2023	2,811,443	292	9,620	2,811,443
2024	2,859,026	291	9,842	2,859,026
2025		294	9,707	2,853,754
2026		296	9,707	2,874,357

71. VECC has no issues with OPUCN's proposed 2026 energy forecasts for these classes.

[49] Note: The tables show the load forecasts prior to any adjustment for EVs, additional heating load or post-2024 CDM/eDSM impacts.
[50] Partial Settlement Proposal, Load Forecast Model, Normalized Annual Summary Tab

Adjustment for Electric Vehicles (EVs)

72. In order to reflect the Government of Canada's zero-emission vehicle sales target of 20% by 2026, OPUCN adjusts its load forecast for 2026 to account for the anticipated increase in EVs in Oshawa between 2024 and 2026. The total number of EVs in Oshawa in the Test Year is forecast based on the number of vehicles sold in Ontario, the share of Ontario EVs sold in Oshawa, and the target number of EVs sold in Canada. However, as actual EV sales in Ontario have lagged behind a trajectory to 20% EV sales in Ontario by 2026, this target is pushed by two years to 2028 for purposes of the forecast.[51] The resulting incremental kWh forecast is set out below[52].

		kWh	
		2025	2026
	Residential	1,704,530	3,893,488
EVs	GS<50	321,255	721,132
	GS 50-999	214,296	474,538
	GS 1,000-4,9	139,146	313,547
	Large Use	17,171	36,185
	Total	**2,396,398**	**5,438,889**

73. The forecast involves considerable judgement, particularly in terms of the total annual vehicle sales in Oshawa, the annual increase in the EVs proportions of these total sales between 2024 and 2026 and the assignment of the electricity usage for these EVs to OPUCN's customer classes[53]. However, VECC considers OPUCN's forecast of incremental energy use due to the increased EV penetration to be reasonable for purposes of setting 2026 rates.

Adjustment for Additional Heating Loads

74. OPUCN also adjusted the 2026 load forecast to incorporate additional loads from electric heating based on assumptions of regarding the heating loads of new customers and customer conversions for the Residential and GS<50 kW classes[54]. For both customer classes OPUCN assumed that 0.2% of existing customers will convert from natural gas to electricity heating each year and that 17.5% of new customers will have electric heating. The resulting incremental heating loads are set out below[55].

[51] Exhibit 3, pages 49-50

[52] Partial Settlement Proposal, Load Forecast Model, Total Additional-Lost Loads Tab

[53] 3-VECC-104

[54] Exhibit 3, page 54

[55] Partial Settlement Proposal, Load Forecast Model, Total Additional-Lost Loads Tab

			kWh	
			2025	2026
		Residential	1,691,359	3,286,507
Additiona	Heating	GS<50	455,425	923,607
		GS 50-999		
		GS 1,000-4,999		
		Large Use		
		Total	**2,146,784**	**4,210,114**

75. VECC submits that the calculation of the Additional Heating Load for the Residential class should be updated to reflect the higher Residential customer counts for 2025 and 2026 as recommended in the preceding section. Revising the 2025 and 2026 Residential customer counts accordingly in the Heating Tab of the Load Forecast model results in the following incremental heating load adjustments.

			kWh	
			2025	2026
		Residential	1,708,268	3,420,962
Additiona	Heating	GS<50	455,425	923,607
		GS 50-999		
		GS 1,000-4,999		
		Large Use		
		Total	**2,163,693**	**4,344,569**

76. VECC submits that these are the values that should be used for purposes of setting OPUCN's 2026 rates.

Adjustment for New CDM/eDSM

77. As noted above the 2026 energy forecasts developed for the Residential, General Service and Large Use classes using the base models include the impacts of CDM programs implemented in 2024 and prior years. As a result, further adjustments are made to account for the estimated impacts of eDSM[56] programs implemented in 2025 and 2026. For the Load Forecast included in the Partial Settlement these impacts are based on an estimate of OPUCN's share of the IESO's targeted provincial savings for 2025 and 2026[57]. OPUCN's proposed 2026 CDM/eDSM adjustments are set out in the following table.

[56] New term used by the IESO in lieu of CDM
[57] 3-VECC-107

kWh	CDM Adjustment
Residential	6,631,014
GS < 50	4,594,252
GS 50-999	6,850,142
GS 1,000-4,999	7,183,442
Large Use	912,579
Street Light	
Sentinel Lights	
USL	
Total	26,171,429

78. VECC has three issues with OPUCN's 2026 CDM/eDSM adjustments. First, in calculating the saving from 2026 CDM/eDSM programs for the GS 1000-4999 and Large Use classes OPUCN did not apply a ½ year adjustment similar to that used for the other customer classes. Rather the weightings used were 1.5 and 2.5 respectively as seen the following extract from the Load Forecast model[58].

2024-2026 Forecasted kWh Savings by Rate Class									
Rate Class	2024			2025			2026		
	kWh	CDM Adj Weight	Amount	kWh	CDM Adj Weight	Amount	kWh	CDM Adj Weight	Amount
	D	E	F = D * E	G	H	I = G * H	J	K	L = J * K
Residential	2,120,751	0.500	1,060,375	3,610,036	0.5	1,805,018	3,921,205	0.5	1,960,602
GS < 50	2,238,481	0.500	1,119,240	2,219,390	0.5	1,109,695	2,511,243	0.5	1,255,622
GS 50-999	3,104,497	0.500	1,552,248	3,376,147	0.5	1,688,073	3,843,495	0.5	1,921,747
GS 1,000-4,999	2,114,648	0.500	1,057,324	2,260,921	0.5	1,130,461	2,576,798	1.5	3,865,197
Large Use	224,257	0.500	112,128	206,479	0.5	103,239	237,589	2.5	593,972
Street Light									
Sentinel									
USL									
TOTAL	9,802,633		4,901,317	11,672,972	0.5	5,836,486	13,090,329	0.5	6,545,165

79. Correcting the values for these two weights to 0.5 reduces the total 2026 CDM/eDSM adjustment to the following values.

[58] Partial Settlement Proposal, Load Forecast Model, CDM Adjustment Tab

kWh	CDM Adjustment
Residential	6,631,014
GS < 50	4,594,252
GS 50-999	6,850,142
GS 1,000-4,999	4,606,644
Large Use	437,401
Street Light	
Sentinel Lights	
USL	
Total	**23,119,454**

80. Second, in accordance with the Government's Directive[59], the IESO's suite of planned 2025-2027 eDSM programs includes funding for local initiatives to be delivered by LDCs[60]. In its initial Application OPUCN did not include any savings in associated with local initiatives stating[61]:

"*Oshawa Power is not aware of any Local Initiatives programs so no share of that program is attributed to Oshawa Power.*"

VECC notes that this exclusion of eDSM energy savings attributable to local initiatives is also consistent with OPUCN's DSP which states[62]:

"*After reviewing the system needs to be addressed in Oshawa Power's 2026-2030 DSP, Oshawa Power does not currently have any system needs in this 2026-2030 DSP that would be feasible for a NWS*[63]."

81. However, in the Load Forecast included with the Partial Settlement Proposal OPUCN has included, as part of the 2026 CDM/eDSM adjustment, 7,853,216 kWh attributable to local initiatives. This consists of 5,097,632 kWh associated with local initiatives assumed to be implemented in 2025 and 2,755,584 kWh associated with 2026 local initiatives[64]. VECC notes the savings attributed to 2025 and 2026 local initiatives are not based on known or planned activities but rather on OPUCN's share

59 OC 1448/2024

60 https://www.ieso.ca/-/media/Files/IESO/Document-Library/eDSM/2025-2027-DSM-Plan-with-Beneficial-Electrification.pdf

61 Exhibit 3, page 59

62 Exhibit 2, Attachment 2-1 (DSP), page 90

63 The OEB's definition of Non-Wires Solutions (NWS) includes energy efficiency and demand response programs - Non-Wires Solutions Guidelines for Electricity Distributors (EB-2024-0118), page 6

64 Partial Settlement Proposal, Load Forecast Model, CDM Framework Tab. Note: The ½ year rule is applied to the 2026 savings per the Partial Settlement Proposal, Load Forecast Model, CDM Adjustment Tab

of total provincial energy[65] and the IESO planned provincial savings from local initiatives in 2025 and 2026.

82. In its July 30, 2025 interrogatory responses[66] OPUCN states:

"*The organization signed a copy of the IESO's contribution agreement on May 22, 2025 and is currently developing its eDSM plan for approval. Once the plan is approved, Oshawa Power intends to execute a multichannel, diverse and ongoing marketing, education and outreach campaign for 2025, 2026 and 2027*."

83. This response suggests that as of mid-2025 OPUCN had not initiated any new Local Initiatives under the IESO's 2025-2027 Framework and considerable work remained before any plans were completed and submitted to the IESO for approval. In addition, VECC notes that during the recent stakeholder meeting held as part of the OEB's Consultation on the Regulatory Treatment of Local Electricity Demand-side Management (Stream 2) Programs (EB-2025-0156) representatives from the Working Group indicated that[67] "*the earliest we would start to see programs progress in field would be in 2027*".

84. Based on the current status of local initiative development VECC submits that OPUCN's local initiative savings assumptions for 2025 and 2026 are unrealistic. VECC submits that a more reasonable set of assumptions regarding OPUCN's savings from local initiatives would be:
    - No savings in 2025 – based on the fact that OPUCN's eDSM plan is still in the development stage, will subsequently need approval by the IESO and then require some time to initiate implementation.
    - 50% of OPUCN's assumed 2026 savings – based on the current status of OPUCN's eDSM plan and the fact that no eDSM Stream 2 programs are expected to be in place until 2027. (Note: This 50% is separate from the ½ year adjustment that OPUCN correctly applies to the annualized 2026 program savings)

    Adopting these assumptions would further reduce the 2026 CDM/eDSM adjustment to 16,644,030 kWh with the following customer class breakdown.

[65] Partial Settlement Proposal, Load Forecast Model, CDM Framework Tab
[66] 2-PP-88
[67] Volume 1, page 171, lines 15-17

kWh	CDM Adjustment
Residential	3,711,835
GS < 50	3,647,485
GS 50-999	5,503,298
GS 1,000-4,999	3,406,779
Large Use	374,632
Street Light	
Sentinel Lights	
USL	
Total	**16,644,030**

85. Finally, OPUCN's 2026 CDM/eDSM adjustment includes 4,901,317 kWh in savings related to a ½ year adjustment for the estimated savings from CDM programs implemented in 2024[68]. However, the CDM adjustment included in the base model 2026 forecast for each customer class already includes the full year persisting savings from CDM programs implemented in 2024[69]. As a result, there is no need to include any savings from CDM programs implemented in 2024 in the 2026 CDM/eDSM adjustment. Removing the 2024 savings further reduces the 2026 CDM/eDSM adjustments for the various classes to the following values.

kWh	CDM Adjustment
Residential	2,651,460
GS < 50	2,528,245
GS 50-999	3,951,050
GS 1,000-4,999	2,349,455
Large Use	262,504
Street Light	
Sentinel Lights	
USL	
Total	**11,742,713**

86. VECC submits that these are the CDM/eDSM adjustment values that the OEB should approve for purposes of setting OPUCN's 2026 rates.

[68] Partial Settlement Proposal, Load Forecast Model, CDM Adjustment Tab
[69] Partial Settlement Proposal, Load Forecast Model, CDM Tab, Cells L29-R29

Overall 2026 Energy Forecast

87. Factoring in VECC's recommended changes to the additional heating load and CDM/eDSM adjustments results in the following energy forecast for 2026.

kWh	2026 Weather Normal Forecast	CDM Adjustment	2026 CDM Adjusted Forecast	Additional EV & Heating Loads	2026 Forecast Excluding Additional Loads
Residential	557,184,291	2,651,460	554,532,831	7,314,449	547,218,382
GS < 50	135,002,433	2,528,245	132,474,188	1,644,739	130,829,449
GS 50-999	339,053,014	3,951,050	335,101,964	474,538	334,627,426
GS 1,000-4,999	81,580,592	2,349,455	79,231,137	313,547	78,917,591
Large Use	35,878,079	262,504	35,615,576	36,185	35,579,390
Street Light	4,602,783		4,602,783		4,602,783
Sentinel Lights	25,474		25,474		25,474
USL	2,874,357		2,874,357		2,874,357
Total	1,156,201,023	11,742,713	1,144,458,310	9,783,458	1,134,674,852

2026 Billing Demand Forecast

88. For five of OPUCN's customer classes, the monthly volumetric distribution charges are based on the monthly billing demand (kW).

For each of the GS 50-999, GS 1,000-4,999 and Large Use classes the 2026 billing demand is derive as follows:

- The forecasted energy use per the base model is converted to a billing demand forecast based on the average kW/kWh ratio for 2015-2024[70].
- The billing demand associated with the additional EVs load is added based on the additional EVs kWhs and 20% load factor[71].
- The billing demand reduction associated with the 2026 CDM/eDSM adjustment is calculated by applying the ratio of the 2026 CDM/eDSM energy adjustment/total 2026 class energy base model plus EV energy forecast to the preceding billing demand forecast.
- For the GS 50-999 class the WMP's 2024 actual billing demand is then also added.

89. For the Street Light class the forecasted 2026 energy is converted to a billing demand forecast based on the average kW/kWh ratio for 2015-2024, while for the Sentinel class the average kW/kWh ratio for 2020-2024 is used.

90. OPUCN's proposed 2026 billing demand forecasts for these classes are set out below[72].

[70] Exhibit 3, pages 36, 39 and 42
[71] Exhibit 3, page 53
[72] Partial Settlement Proposal, Load Forecast Model, Summary Tables (Weather Normalized) Tab

kW	2026 CDM Adjusted Forecast
GS 50-999	841,789
GS 1,000-4,999	178,713
Large Use	77,950
Street Light	13,050
Sentinel Lights	78
Total	**1,111,579**

91. VECC has no issues with the methodology used by OPUCN to derive the billing demands for these classes. However, VECC submits that the forecasts for the GS 50-999, GS 1,000-4,999 and Large Use classes need to be revised to reflect VECC's recommended 2026 energy forecasts for these classes. The resulting 2026 billing demands are as follows.

kW	2026 CDM Adjusted Forecast
GS 50-999	849,171
GS 1,000-4,999	190,325
Large Use	79,399
Street Light	13,050
Sentinel Lights	78
Total	**1,132,022**

Summary

92. In the preceding submissions VECC has recommended that the OEB approve to changes to:
- OPUCN's forecast Residential customer count for 2026,
- OPUCN's forecast additional Residential heating load for 2026, and
- OPUCN's CDM/eDSM adjustment for 2026.

93. Based on these recommendations, VECC submits that the OEB should approve the following 2026 load forecast for OPUCN[73].

[73] Accompanying VECC's argument is a revised version of OPUCN's Partial Settlement Proposal, Load Forecast Model that incorporates VECC's recommended changes.

2026	kWh	kW	Customers / Connections
Residential	554,532,831		59,716
GS < 50	132,474,188		4,545
GS 50-999	335,101,964	849,171	530
GS 1,000-4,999	79,231,137	190,325	12
Large Use	35,615,576	79,399	1
Street Light	4,602,783	13,050	14,755
Sentinel Lights	25,474	78	19
USL	2,874,357		296
Total	1,144,458,310	1,132,022	79,874

6.1 Deferral and Variance Accounts

94. Three variance accounts remain unsettled. GOCA DVA which relates to incremental costs of locates and two accounts specifically designed to address the deficiency in this application which is the change in costs that occur when the old facilities are abandoned and the new one occupied. We characterize the latter two proposed accounts as application deficiencies because if VECC's proposal is accepted these accounts are not required. The exist only because of the lack of coordination between the largest single investment in OPCUN history and the timing of this application.

95. With respect to the GOCA DVA proposal we have reviewed and discussed the submissions of CCC. We support and adopt those submissions,

7.1 -7.3 Effective Date, New Building and Concluding Remarks

96. VECC does not support a five year rate plan for this Utility at this time. We submit the Board should set rates for a one year period. In the interim the Applicant should be directed to file an addendum to this application which provides both the proposal for the new facilities and the proposed adjustments to capital and operating budgets to accommodate that investment.

97. The Board can set these shorter term rates in one of two ways. The simplest would be to extent the IRM adjustment for the year 2026. This is the quickest way to ensure a rate adjustment for January 1, 2026. The second method would be to adopt VECC's or other parties adjustments (or some combination of) to the Applicant's proposal. While this would take longer deliberation it would also have the

advantage of allowing the Board to provide direction to OPUCN as to its expectation for an amended application.

98. If the Board considers rejecting our proposal and decides to provide the Applicant with 5 years of relief and a future ICM to increase rates again during the ICM term we think it important to consider two other issues.

99. The customer engagement for this application is flawed. It is clear that when customers were queried about the impact of this proposal they had no idea as to the magnitude of investment for new facilities or the impact it would have on them. The Board requires utilities to engage in costly consumer engagement. If the result is what is before us here then such exercises are not only meaningless but a meaningless waste of consumers time and money.

100. The second issue is the impact of the new facilities on the cost of capital of OPCUN. While the issue of cost of capital is directly settled in this case the Board (and other parties) might wish to consider the consequence of a large amount of debt borrowed at rates that are significantly different than the rate embedded in this agreement. Again, under our proposal this issue could be addressed in a future application addendum.

These are our submissions

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