January 24, 2023

via RESS

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto, ON M4P 1E4
Email: Boardsec@oeb.ca

Dear Ms. Marconi:

Re: EB-2022-0024 – Elexicon Energy Inc. ("Elexicon") ICM Application (the "Application"): Phase 2 Technical Conference Undertakings

Elexicon is filing its responses to Undertakings taken during the Technical Conference held on January 17 and 18, 2023. Elexicon highlights that this filing includes responses to all Undertakings except for JT1-18 which will be filed via separate cover letter under the OEB's Confidentiality provisions.

All Undertakings have been filed through the OEB's web portal ("RESS") and include the following files:

EE_JT1-21_Whitby Smart Grid NPV – Elexicon Updates 20230124
EE_VRZ_2023_ACM_ICM_Model_JT_1.15_20230124
EE_VRZ_2023_ACM_ICM_Model_JT_1.17_20230124
EE_WRZ SB_2023_ACM_ICM_Model_JT_1.15_20230124
EE_WRZ WSG_2023_ACM_ICM_Model_JT_1.15_20230124
EE_WRZ WSG_2023_ACM_ICM_Model_JT_1.17_20230124

Stephen Vetsis
Vice President Regulatory Affairs and Stakeholder Relations
Elexicon Energy Inc.

cc: John Vellone

Elexicon Energy Inc.

Answer to Undertaking from

Power Workers' Union

Undertaking JT1.1:

TO QUANTIFY ANY ADDITIONAL SAVINGS ARISING FROM THE SAVED COST OF THE TRUCK IN THIS SCENARIO.

Response:

Elexicon has updated Table 1 of interrogatory response VECC-02 to include the average cost of the truck to the Estimated OM&A Savings section of the O&M Costs and Benefits calculation. Elexicon has determined the average cost of a truck to be $58.07 per hour.

As shown in the updated table below, the addition of the average cost of a truck per hour increases the Estimated OM&A Savings to $47,744 from $40,950. The resulting Net O&M Impact is a reduction to $275,943 from $282,737 in the original Table 1 of VECC-02.

Updated VECC-02 Table 1 – O&M Costs and Benefits

O&M Costs & Benefits

Estimated Additional FTEs	Hourly Rate	Cost Loading	Total Hourly	Annual Hours	Annual Cost	Qty	Cost
Supervisor	$ 55.00	25%	$ 68.75	2080	$ 143,000	1	$ 143,000
Hourly Staff (e.g. operator, electrician)	$ 46.33	25%	$ 57.91	2080	$ 120,458	1.5	$ 180,687
						Total	$ 323,687

Estimated OM&A Savings	
Average Annual Outages	117
Average Reduction to Response Time	1.00
Total Annual Outage Response Time Reduction	117
Hourly Cost of Truck Roll (2 Tech & OH & Truck @ $58.07/hr)	$ 408.07
O&M Savings	**$ 47,744**
Net O&M Impacts	**$ 275,943**

Elexicon Energy Inc.

Answer to Undertaking from

Power Workers' Union

Undertaking JT1.2:

TO RESTATE TABLE 3 WITH THE PROPER UNITS AND SHOW DECIMALS WHERE APPROPRIATE. ALSO TO REVIEW THE ESCALATION FACTOR AND CONFIRM WHETHER THE COST FIGURES IN TABLE 3 REQUIRE ADJUSTMENT.

Response:

Please find an updated Table 3 Reliability Benefit for interrogatory response VECC-02 that corrects the units for the Customers and SAIDI Reductions columns from dollars to number of customers. All other columns remain the same as filed in VECC-02.

Elexicon did not find a material change to the reliability benefit calculation if the GDP-IPI escalation factor used a start date of Q1 2015 instead of Q1 2016.

Updated Table 3 Reliability Benefit – VECC-02

	Cost/Customer per 1hr outage	GDP-IPI Escalation: Q1 2016 to Q1 2022	SAIDI Reductions	Cost/Customer per 0.58 hr outage	Customers	Reliability Benefit
Residential	$ 6.5	$ 7.3	0.58	$ 4.2	43,441	$ 183,970.0
GS <1 MW	$ 826.0	$ 927.9	0.58	$ 538.2	2,737	$ 1,472,951.9
GS >1MW	$ 22,737.0	$ 25,541.1	0.58	$ 14,813.8	11	$ 162,952.0
					Total Benefit	**$ 1,819,874**

Elexicon Energy Inc.

Answer to Undertaking from

Power Workers Union

Undertaking JT1.3:

TO ADVISE WHETHER THE VALUE OF THE LOST LOAD ACCOUNTS FOR THE VALUE OF THE LOWER SAIFI. IF THE ANSWER IS THAT THERE IS SOME ADDITIONAL ECONOMIC VALUE TO BE QUANTIFIED, TO MAKE BEST EFFORTS TO PROVIDE SOME QUANTIFICATION OF THAT ADDITIONAL VALUE.

Response:

With respect to the potential benefit of a SAIFI improvement, there is no load associated with the frequency of outages, (i.e. an outage can be nearly instantaneous) and therefore the calculation correctly refers to SAIDI improvement only.

While it would be reasonable to include the impact of frequency in the calculation, and it would improve the business case in favour of the project, the previously approved methodology focuses on “Cost per Customer per 60 minutes of Outage” and has been applied for consistency with previous applications. Elexicon is not in possession of any methodology to quantify the economic benefits associated with reduced frequency of outages as opposed to solely quantifying the total duration of outages.

Elexicon Energy Inc.

Answer to Undertaking from

Power Workers' Union

Undertaking JT1.4:

TO RESPOND TO THE HYPOTHETICAL POSED IN PWU-8 PART B: IF THE SUSTAINABLE BROOKLIN COST MORE THAN THE BROOKLIN TS BUT THE CUSTOMER CONTRIBUTION WAS GREATER THAN THE DIFFERENCE WOULD ELEXICON BE INCENTIVIZED TO SELECT THE LESS ECONOMIC OPTION AS IT WOULD RESULT IN A LOWER REVENUE REQUIREMENT?

Response:

Elexicon does not make system planning decisions based solely on the revenue requirement impact of assets placed into rate base. Rather, Elexicon performs its options analyses to determine the most cost-effective option that provides the most favourable net present value when comparing both the costs and benefits; including some benefits which are not immediately quantifiable in dollars (as shown below). In the example presented above, this analysis would include but not be limited to:

- The ongoing operations and maintenance costs of each option
- The system capacity benefits afforded by each option
- The reliability/redundancy benefits afforded by each option
- Other potential benefits afforded by each option
- The implementation timeline for each option and its effect on cash flows

Based upon this analysis of both the costs and benefits, Elexicon would select the most economically efficient and cost-effective option in the posed hypothetical.

Whereas the question poses a hypothetical, it is unlikely that the cost of a distribution system expansion would exceed the cost of constructing a new Transmission Station ("TS"). Indeed, in the case of Sustainable Brooklin, the cost of expanding the 27.6-kV feeders is less than the cost of constructing a new TS. However, for the purpose of responding to the question posed, the situation posed will be assumed; that there is a solution to construct a new TS with a gross cost less than the cost of expanding the distribution system.

What Elexicon is effectively being asked to do is perform a prudence analysis on a hypothetical situation that is not likely to occur. In accordance with the OEB's September 18, 2014 report on the *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, prudence means that the distributor's decision to incur the amounts must represent the most cost effective option (not necessarily least initial cost) for ratepayers.

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.5:

TO RECALCULATE THE NPV OF THE WHITBY SMART GRID PROJECT BASED ON A TIME PERIOD THAT IS EQUAL TO THE AVERAGE LIFETIME OF THE EQUIPMENT; TO INCLUDE WHATEVER CAVEATS OR ASSUMPTIONS NECESSARY

Response:

Elexicon has calculated the weighted average useful life for the Whitby Smart Grid assets to be 27.28 years ("Useful Life"). Table 2 below provides this calculation.

As per the Undertaking, Table 1 below updates the originally filed Interrogatory ED-01 Table 1 20 Year Net Present Value ("NPV") of the benefits from the Whitby Smart Grid to use the weighted average useful life period of 27 years. No other adjustments aside from the period of time assessed for NPV have been made to this Table.

For clarity, Table 1 below is comparable to the interrogatory ED-01 Table 1. The updated NPV of net benefits using the Useful Life is $39.8 MM which is an increase in benefit of $11.8 MM when compared to the original ED-01 Table 1[1] $27.9 MM.

[1] The NPV of Net Benefits amount of $27.9 MM in interrogatory response ED-01 Table 1 was calculated using a time period of 20 years.

Table 1 – Net Present Value Benefit Summary from Whitby Smart Grid using Weighted Average Useful Life value of 27 Years

Customer 27yr NPV Benefit Summary (5% Discount)		
(All Dollars Listed in Thousands CAD)		
Total Purchased Power Savings from WSG	$	58,910
ICM Additional Revenue	$	46,937
Additional OM&A Expenses	$	5,857
Operating Efficiencies from WSG	$	741
Sub-Total of Savings	$	6,857
Projected VoLL Benefit from Reliability	$	32,928
NPV of Net Benefits (27 years) to WSG Customers	$	39,785

Table 2 below provides the calculation of the 27.28 years as the weighted average useful life of the Whitby Smart Grid assets.

Table 2 – Calculation of Weighted Average Useful Life of Whitby Smart Grid Assets

Useful Life (Years)	Asset Category	OEB USoA	Whitby Smart Grid Cost per Asset Category	Asset Cost % of Total Whitby Smart Grid Cost	Weighted Average Useful Life (Years)
60	Wood Poles	1830-001	6,630,000	14%	8.43
20	OH Load Inter Switch	1835-002	17,570,000	37%	7.44
40	Tx Polemount	1850-002	10,170,000	22%	8.62
15	SCADA	1980-001	4,760,000	10%	1.51
5	Computer Sw Internal	1611-002	616,090	1%	0.07
5	Computer Equip-other	1920-001	3,398,245	7%	0.36
10	Communication Equipt	1955-001	4,067,665	9%	0.86
Totals			**47,212,000**	**100%**	**27.28**

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.6:

TO PROVIDE AN UNDERTAKING RESPONSE EXPLORING AN ALTERNATIVE OPTION OF MEETING THE GOALS OF THE SUSTAINABILITY PROJECT THAT INVOLVE, INSTEAD OF AN EXEMPTION FROM SECTION 3.2, AN EXTENSION OF THE CUSTOMER CONNECTION HORIZON AND THE CUSTOMER REVENUE HORIZON UNDER APPENDIX B OF THE DSC.

Background:

The following background context for this undertaking can be found in the Day 1 Transcript page 33, line 25 to page 34 line 7:

"..would you be able to come back to the parties and the Board in an undertaking response with what I will describe as a Plan B if the Board doesn't support a full exemption from section 3.2 and instead allow for a customer connection horizon beyond five years and a customer revenue horizon beyond 25 years, which are beyond the sort of defaults in Appendix B of the Distribution System Code? And whether that would meet the needs and goals of this project? And specifically whether there might be other issues with that relating to deposits and so on and so forth?."

Response:

Elexicon evaluated three alternative options to its preferred option[1] for the Sustainable Brooklin project. One of the alternative options[2] evaluated the extension of the connection horizon window from 5 years to 15 years, and no exemption for the Brooklin Landowners Group ("BLGI") from paying the capital contribution.

Elexicon dismissed this option because it could result in BLGI not constructing Distributed Energy Resources ("DER") and electric vehicle ("EV") roughed in homes without the exemption. This observation has been confirmed by BLGI in its supplementary interrogatory responses[3]. It is also Elexicon's perspective that the extension of the connection horizon window beyond 5 years, to 15 or 20 years, introduces significant administrative complexities with the process of managing

[1] Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this Distribution System Code exemption, ICM application request, and with the Whitby Smart Grid project enabling DER integration capability

[2] Option 2 as noted in Appendix B-2 Sustainable Brooklin Business Case, Pages 18 to 26

[3] STAFF-17 part d) last paragraph

capital contributions from unforecasted customers that are tied to the Brooklin Line. By extending the connection horizon to 15 or 20 years, Elexicon would be obligated to recompute the capital contributions on a periodic basis to accommodate the connection of each unforecasted customer. Each time the computation results in a capital contribution, Elexicon would need to collect the monies from the new customer and reimburse the appropriate customer who would have previously paid a capital contribution. Over the course of 15 or 20 years, with the expectation of dozens of additional customers connecting to the Brooklin Line, the efforts to manage this process would be onerous, administratively complex, and substantively increases the chances for error. The associated complexity is not supported by Elexicon as a reasonable alternative.

In addition, Elexicon collaborated with BLGI to understand the capital costs to separately connect the North Brooklin homes to the Sustainable Brooklin project[4]. BLGI provided an estimate of the capital costs to connect 700 homes, and Elexicon produced five Economic Evaluation models to calculate the capital contribution associated with the construction of the Brooklin Line for each of the five years from 2021 to 2025. Please refer to the response to Undertaking JT1-19 for the empirical results from the set of Economic Evaluation models.

The output from these Economic Evaluation models confirms that the revenues from the connection of homes in North Brooklin will not offset the total capital costs of the Sustainable Brooklin project and annual costs to connect 700 homes.

For clarity, the revenues from the 700 homes are not sufficient to offset the capital costs of connecting the homes to the end point of the Sustainable Brooklin project. Therefore, the Economic Evaluation model identified that the revenues from the North Brooklin homes would not offset the total cost of the Sustainable Brooklin project and connection of 700 home per year for twenty years.

With that context, Elexicon submits that it cannot identify a “Plan B” as requested by Environmental Defence that supports the goals of the Sustainable Brooklin project.

[4] This is the effort to take electricity from the end of the Sustainable Brooklin project (i.e. Brooklin Line) and install infrastructure that brings electricity to each of the 700 homes per year. This is separate from the effort to bring electricity to North Brooklin which is the Sustainable Brooklin project (i.e Brooklin line).

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.7:

TO PROVIDE A TABLE COMPARING THE NATURAL GAS EXPANSION RULES FOR ENBRIDGE AS BASICALLY PHASE 1, PHASE 2, ET CETERA, WITH THE ELECTRIC CONTEXT FOR PARTICULARLY THE RULES APPLYING TO ELECTRICITY DISTRIBUTORS EXPANDING, JUST THE ECONOMIC ANALYSIS, NOT THE TEST, SO AN APPENDIX OF EBO 188 AND THE APPENDIX B OF THE DSC.

Background:

From Day 1 Transcript page 36 lines 23 to 26:

"Elexicon provide a table comparing the rules in the gas context and in the electricity context, both in terms of customer contribution and deposits."

Response:

Please see Table 1 below.

Table 1 – Listing of Natural Gas and Electricity Expansion Economic Analysis Rules

Economic Analysis Area	Electricity Distribution Expansion Guidance	Natural Gas Expansion Guidance
Revenue Forecasting	The common elements for any project will be as follows: (a) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below; (b) Customer Revenue Horizon as specified below; (c) Estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added - for various classes of customers, this should be carried out by class; (d) Customer additions, as reflected in the model for each year of the Customer Connection Horizon; and (e) Rates from the approved rate schedules for the particular distributor reflecting the distribution (wires only) rates.	For revenue forecasting, the common elements will be as follows: (a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project; (b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year; (c) an estimate of average use per added customer which reflects the mix of customers to be added; (d) a factor which reflects the timing of forecasted customer additions; and (e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component.

<table>
<tr><th>Economic Analysis Area</th><th>Electricity Distribution Expansion Guidance</th><th>Natural Gas Expansion Guidance</th></tr>
<tr><td>Capital Costs</td><td>Common elements will be as follows:

(a) An estimate of all capital costs directly associated with the expansion to allow forecast customer additions.

(b) For expansions to the distribution system, costs of the following elements, where applicable, should be included:
- distribution stations;
- distribution lines;
- distribution transformers;
- secondary busses;
- services; and
- land and land rights.
Note that the “Ownership Demarcation Point” as specified in the distributor’s Condition of Service would define the point of separation between a customers’ facilities and distributor’s facilities.

(c) Estimate of incremental overheads applicable to distribution system expansion.

(d) A per kilowatt enhancement cost estimate – the per kilowatt enhancement cost estimate shall be set annually and shall be based on a historical three to five year rolling average of actual enhancement costs incurred in system expansions.
(d.1) paragraph (d) shall cease to apply to a distributor as of the date on which the distributor’s rates are set based on a cost of service application for the first time following the 2010 rate year.

(e) For residential customers, the amount the cost of the basic connection referred to in section 3.1.4 of the Code.

(f) For non-residential customers, if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 of the Code that have been factored into the economic evaluation.</td><td>The common elements will be as follows:

(a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights;

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and

(c) an estimate of the normalized system reinforcement costs.</td></tr>
</table>

Economic Analysis Area	Electricity Distribution Expansion Guidance	Natural Gas Expansion Guidance
Expense Forecasting	Common elements will be as follows: (a) Attributable incremental operating and maintenance expenditures - any incremental attributable costs directly associated with the addition of new customers to the system would be included in the operating and maintenance expenditures. (b) Income and capital taxes based on tax rates underpinning the existing rate schedules. (c) Municipal property taxes based on projected levels.	The common elements will be as follows: (a) gas costs as used in revenue forecasts (excluding commodity costs); (b) incremental operating and maintenance costs; (c) income and capital taxes based on tax rates underpinning the existing rate schedules; and (d) municipal property taxes based on projected levels.

Economic Analysis Area	Electricity Distribution Expansion Guidance	Natural Gas Expansion Guidance
Specific Parameters/ Assumptions	Specific parameters of the common elements include the following: (a) A maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities[1]. (b) A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers[2]. (c) A discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity. (d) Discounting to reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted. The same approach to discounting will be used for revenues and operating and maintenance expenditures[3].	Specific parameters of the common elements include the following: (a) a 10 year customer attachment horizon;. (b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers); (c) a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity; (d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and (e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs.

[1] For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board
[2] For example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.
[3] For certain projects Capital Expenditures may be staged and can occur in any year of the five year Connection Horizon.

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.8:

UNDERTAKING NO. JT1.8: TO PROVIDE AN ESTIMATE OF PER HOME AVOIDED RETROFIT COST.

Response:

As noted by Environmental Defence on page 38 of the Day 1 technical conference transcript, Brooklin Landowners Group has identified the incremental cost as 300% or more. In response to Environmental Defence's request to rectify these figures, Elexicon has confirmed the 300% increase in the cost of DER and EV rough-ins with the Brooklin Landowners Group. Applying the 300% increase to the estimated $2,260 per home cost to rough-in of a DER and EV ready home results in an estimate of $6,780 per home avoided retrofit cost.

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.9:

TO CALCULATE THE NPV OR THE NET PRESENT VALUE OF THE AVOIDED COSTS BASED ON CERTAIN ADOPTION RATES OF DERs AND EVS IN NORTH BROOKLIN.

Response:

Elexicon used the value of $6,780 provided in Undertaking JT1.8 as the per home amount of retrofit cost avoided, assumed a DER and EV adoption rate of 50% per year of the annual 700 homes planned to be constructed in North Brooklin, a twenty-year time period, inflation rate of 2% and discount rate of 3% as the basis for the following Net Present Value ("NPV") calculation of avoided costs.

The result is a positive NPV of $45.28 Million as shown in Table 1 below:

Table 1 – Net Present Value Calculation of Avoided Retrofit Costs with 350 DER and EV homes being constructed per year from 2023 to 2043

Discount Rate		3%
Inflation		2%
Number of Homes Adopting DERs and EVs Per Year		350
DER/EV per home	$	2,260
DER/EV Avoided Retrofit Cost per home	$	6,780

		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
DER/EV Avoided Retrofit Cost ($ Millions)		$ 2.37	$ 2.42	$ 2.47	$ 2.52	$ 2.57	$ 2.62	$ 2.67	$ 2.73	$ 2.78	$ 2.84	$ 2.89	$ 2.95	$ 3.01	$ 3.07	$ 3.13	$ 3.19	$ 3.26	$ 3.32	$ 3.39	$ 3.46	$ 3.53
DER/EV NPV Avoided Retrofit Cost ($ Millions)	**$ 45.28**	$ 2.37	$ 2.35	$ 2.33	$ 2.30	$ 2.28	$ 2.26	$ 2.24	$ 2.22	$ 2.19	$ 2.17	$ 2.15	$ 2.13	$ 2.11	$ 2.09	$ 2.07	$ 2.05	$ 2.03	$ 2.01	$ 1.99	$ 1.97	$ 1.95

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.10:

UNDERTAKING NO. JT1.10: ELEXICON TO COMMUNICATE WITH HYDRO OTTAWA ON A BEST-EFFORTS BASIS TO GATHER INFORMATION ON LESSONS LEARNED OR ANY PUBLIC INFORMATION THAT WITH RESPECT TO METRICS OR OUTCOMES ON THEIR PROJECT THAT WAS AGREED TO IN THEIR SETTLEMENT AGREEMENT, LAST SETTLEMENT AGREEMENT THAT PERTAINS TO GRID EDGE VOLT-VAR CONTROL TECHNOLOGY.

Response:

Elexicon has communicated with Hydro Ottawa and been provided a joint paper[1] on the study regarding their Grid Edge Volt/Var study, and a report produced by Sentient Energy on its ENGO+GEMS project. The joint paper is included with this response as Attachment 1, and the Sentient Energy report is included as Attachment 2.

With respect to the joint paper, Elexicon observes that the experience of the Hydro Ottawa project supports the Elexicon proposal three manners. First, the Hydro Ottawa is an application of CVR/VVO technology to defer capital expenses. This is supportive of the Elexicon proposal in the context of the technology maturity. Second, the Hydro Ottawa proposal predicts a 6V drop at the station. This is supportive of the Elexicon intent to achieve 6V voltage reduction. Third, in the last paragraph it states that Hydro Ottawa expects to enjoy a 2.4% reduction PEAK LOAD, from a 5V reduction in station voltage.

Extending this concept to Elexicon's expectation of 6V or more of reduction on most feeders, and connecting it to research by the IEEE referenced in Appendix B-5, is supportive of the 3% energy consumption savings.

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[1]https://urldefense.com/v3/__https:/static1.squarespace.com/static/59cbc56fedaed8aca77fd167/t/5fc663744e98326c02ec71a2/1606837109111/EDIST*2021*Abstract*-*Hydro*Ottawa*and*Varentec.pdf__;KysrKysrKw!!DhSOP0m-jrCHTSU!6I9Md5JewN1ReQYINtmHYcj6mel72y2VMOcmv9WAbn_4ALkIPb_MZlyVvk4x1FvweyHby3b8RRLjwB5Z3PCqk7njFmeo6Tw$

With respect to the Sentient Energy report, Elexicon observed that the application for Hydro Ottawa was a little different from its Whitby Smart Grid proposal. The Hydro Ottawa solution was not always on, and the study was limited to discrete time periods to test specific features.

JT 1-10

Attachment 1

Hydro Ottawa Study

CVR and Grid Edge Technology as a Non-Wires Alternative for Capacity Reduction

Authors:

Hydro Ottawa Kevin Ainsworth, Steve Hawthorne

Varentec Inc. Umang Deora, Rohit Moghe, Damien Tholomier

Short Abstract:

By combining CVR (Conservation Voltage Reduction) with grid-edge power-electronic technology, Hydro Ottawa is targeting a demand reduction of 1.2 MW or 2.4% of substation peak load at Kanata MTS substation. The project currently includes 43 pole mount ENGO® devices, manufactured by Varentec, to support up to 6% voltage reduction at the station LTC. The ENGO™ devices boost low-voltage outliers above CSA minimums, enabling demand reduction, energy savings and improved power quality without customer impact or participation. Project cost and complexity make CVR attractive compared to other non-wires alternatives to offset demand and reduce or defer capital investments on lines and stations.

Learning Objectives:

1. **Understand CVR and how it can be leveraged by LDCs as a tool energy savings and demand reduction.**
2. **Learn how grid edge devices (in this project, Varentec's ENGO™ + GEMS™ solution) can boost the technical and economic performance of CVR by supporting low-voltage outliers.**
3. **Hydro Ottawa will share project experience and lessons learned.**

Long Abstract:

The objective of Non-Wires Alternatives is to offset distribution investment by deferring or replacing the need for specific equipment upgrades such as T&D lines or power transformers by reducing load / demand at a substation or circuit level. CVR (Conservation Voltage Reduction) empowers electric distribution utilities to achieve a significant reduction in energy and peak demand, without impacting customers through load shedding or major equipment investments.

New power electronics-based grid-edge technology combined with CVR offers promise to manage and mitigate load/demand and can be classified as a Non-Wires Alternative (NWA) to conventional upgrades. Deployment of utility owned assets called Dynamic VAr Controllers (DVCs) provide visibility to low voltage nodes and enable real-time Volt-VAr Optimization (VVO)/CVR at the grid edge; hence achieving a fast and dynamic response to varying load and enabling increased demand reduction and energy saving through CVR. This grid edge technology can be used by the utilities as a cost-effective NWA to achieve deterministic flexible control over their system without the need for consumer participation.

Hydro Ottawa deployed the Varentec's solution comprised of hardware components called Edge of Network Grid Optimization (ENGO®) and a cloud-based software component called Grid-Edge Management Solution (GEMS®). ENGOs are fast-acting power-electronics devices that are installed on the secondary side of a distribution grid, to autonomously sense and regulate voltage with a ± 0.5% within control range by injecting sub-cycle VArs between 0 to 10 kVArs. GEMS acts as a supervisory control and provides a data analytics and visualization engine.

Hydro Ottawa's Kanata substation has 43 pole mount ENGO units deployed at the low voltage outliers to ensure the tight regulation of voltage at a local and feeder wide level and prevent a dip below the minimum CSA standard (110V at customer location) during periods of CVR or peak loading conditions. These DVCs allow Hydro Ottawa to reap multiple benefits of peak demand reduction, voltage stability, grid visibility and dynamic VAr management, all with deterministic control within the hands of the distribution operators.

This paper highlights the use of this grid edge technology as a new resource in every utility's toolkit. Prior to implementing CVR, the lowest recorded voltage (at the AMI location) without the ENGO devices deployed was below the CSA limit and did not permit any reduction in voltage at the substation. Comparing the voltages on a similar loading day with one transformer upgrade and the ENGO devices turned ON showed a healthy improvement of 12.3% (14.8V) resolving all CSA violations and creating an additional voltage margin for planned reductions.

Kanata being a heavily commercial and industrial circuit, the CVR factor for power used was calculated to be 0.47. CVR tests were conducted through the peak load month of July/August 2020 with a 3% and 5% reduction in voltage at the LTC. Stepping down the voltage (during the peak load hours) provided a load reduction of 1,2MW or ~2.4% of the substation load (50 MW) by reducing the voltage by 5% at the LTC. The ENGO devices were primarily responsible for facilitating this risk-free reduction in voltage as well as identifying the worst voltage outliers that did require service transformer upgrade to maximize the voltage reduction at the Kanata substation.

JT 1-10

Attachment 2

Hydro Ottawa Report on GEMS

Hydro Ottawa
ENGO®+GEMS® Project Report

Report on Evaluation, Measurement & Verification Analysis and Economic Use Case for Kanata MTS

Version 2.3

9/10/2021
Sentient Energy
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RECORD OF REVISION

Issue	Date	Authors	Comments
Rev1.0	October 10, 2020	Umang Deora	Version creation with EM&V performed with field-based estimates
Rev2.1	November 9, 2020	Umang Deora, Damien Tholomier	EM&V computed using June 2018 – May 2019 to June 2019 – May 2020 data and associated Economic Use Cases (Capacity Reduction, Energy Savings, Technical Loss Reduction)
Rev2.2	December 1, 2020	Umang Deora, Damien Tholomier	Integration of comments from Hydro Ottawa into final report
Rev2.3	September 22, 2021	Damien Tholomier	Addition of an abbreviation / definition section Integration of the Winter testing period Integration of the final economic analysis Update of all numbers using measured CVR factor for Power and Energy Update of the section 6.3 Sentient Energy's formatting of the document

APPROVAL

Name	Function
Damien M. Tholomier	EVP Product Management & Project Delivery

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1. Abbreviations and definitions

All capitalized terms not defined herein will have the meanings set forth in the document.

a) **AMI: Advanced metering infrastructure** is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

b) **CSA**: the **Canadian Standards Association** is a standards organization which develops standards in 57 areas.

c) **CVR: Conservation voltage reduction** enables electric distribution utilities to achieve a significant reduction in energy and peak demand at little or no cost, and without impacting customers through load shedding or equipment investments. Advantages of CVR include peak shaving, energy conservation, potential lowering of greenhouse gases and mitigation of distributed generation (DG) voltage impacts.

d) **LCOC: Levelized Cost of Capacity** refers to the annual fixed revenue requirements in nominal dollars for each resource that are summed and levelized over the assumed economic life and are presented in terms of dollars per kW of nameplate capacity per month/year.

e) **LCOE: Levelized cost of electricity** refers to the estimates of the revenue required to build and operate a generator over a specified cost recovery period. The LCOE is also referred to as the levelized cost of electricity or the levelized energy cost, is a measurement used to assess and compare alternative methods of energy production. The LCOE of an energy-generating asset can be thought of as the average total cost of building and operating the asset per unit of total electricity generated over an assumed lifetime.

f) **LTC or OLTC: on-load tap changers** regulate the turns ratio and thus the voltage ratio of an electrical transformer. Unlike its no-load counterpart, on-load tap changers do this without interrupting the load current.

g) **VVC: Volt-VAr Control is the capability** to control the voltage level and reactive power (VArs) level at different points of the distribution grid by using a combination of LTCs, LVRs and Capacitor Bank controllers. Without a proper coordination, control actions may affect voltages, VArs flow, power factor and finally raise energy loss, load demand, etc.

h) **VVO: Volt-VAr Optimization** is the capability to optimize the vars & voltage in the system in order to achieve a certain objective by controlling capacitor banks and voltage regulators. VVO usually is accomplished by a ADMS system and requires communication to field devices (for measurement reading and issuing controls).

2. Executive Summary

The purpose of this document is to present and assess results from the Kanata Municipal Transmission Substation (MTS) deployment of Sentient Energy's GEMS®+ENGO® solution. High level benefits measured by the project include Voltage Support/Visibility and Peak Demand / Capacity Reduction as primary objectives, and Energy Savings and Technical Loss Reduction as secondary benefits.

Hydro Ottawa's Kanata MTS has five (**5**) distribution circuits and forty-three (**43)** pole-mount ENGO units deployed at the low voltage outliers to ensure the tight regulation of voltage at a local and feeder wide level and prevent a dip below the minimum **CSA-CAN3-C235-83** standard (Normal and Extreme Voltage Operating Limits) during periods of normal or peak loading conditions.

The Sentient Energy's GEMS+ENGO solution allows Hydro Ottawa to reap multiple benefits of peak demand / capacity reduction, voltage stability, grid visibility and dynamic VAr management, all with deterministic control within the hands of the distribution operators.

Voltage Optimization (VO) is defined as a combination of VVO and CVR. VVO regulates distribution voltages by coordinating medium voltage (MV) assets such as LTC and switched capacitor banks (SCB) to reduce distribution losses and improve power factors. As provinces continue to advance ratepayer-funded EE initiatives and establish increasingly aggressive energy conservation goals, it is vitally important to consider VVO/CVR programs as a cost-effective tool. Conventional VVO/CVR, traditionally managed from centralized software platforms, initiates a systematic reduction of consumer voltages to reduce energy consumption or demand with performance in the range of 0.8% to 2% efficiency.

Using its patented advanced technology, Sentient Energy has developed a Grid Edge VVO/CVR technology, which delivers greatly improved VVO/CVR performance, in the range of 4 to 6% energy savings and peak demand reduction (e.g., CVR factor equal to 1), as demonstrated by the voltage control range of ~5% created by Sentient Energy's technology on multiple pilot projects in the USA and Canada.

CVR is traditionally used as a "Supply-Side" energy conservation and peak demand reduction from the grid side, as opposed to "demand-side management (DSM)". CVR can be used to achieve regulatory or legislative EE objectives without requiring the engagement of consumers (no change of consumer behavioral), the financial contribution of EE participants or the distribution utility costs to administer the EE program. From a utility perspective, it reduces the amount of power utilities need to generate or purchase from a generation and transmission utility (G&T) and it lowers operating costs, among many other benefits such as building of new generation power plant and transmission & distribution assets e.g., reconducting feeders, adding voltage regulators and capacitors, and balancing feeders) and reducing technical losses.

CVR is beneficial to all consumers, even low-income participants who might not be able to invest in EE programs and is well adapted to all residential and commercial customers, and partially adapted to larger C&I customers. The supply-side benefits of VVO/CVR are additive and cumulative to any existing or new DSM benefits.

Prior to implementing CVR, the lowest recorded voltage (at the AMI location) without the ENGO devices deployed was below the CSA limits (i.e., service entrance between 110V and 125V during normal conditions) and did not permit any reduction in voltage at the substation without CSA violations. Comparing the voltages on a similar loading day with one transformer upgrade (X07487) and the ENGO devices turned ON showed a healthy improvement of **12.3%** (**14.8V)** resolving all CSA violations and creating an additional voltage margin for planned voltage reductions.

The Kanata MTS being a heavily commercial and industrial substation (C&I customers represent 83% of the billed kWh in August 2019), the CVR factor for power was measured to be **0.52** during summertime and **0.76** during wintertime. **Section 6.3** of this report elaborates on how the customer class was determined as well as the CVR factor for Power and Energy. CVR tests were conducted through the peak load month of July/September 2020 and November/February 2020 with a **2.5%** and **5%** reduction in voltage at the LTC. Stepping down the voltage during the summer peak load hours provided a load reduction of **1.31 MW** or **~2.60%** of the substation load **(50.53 MW**) by reducing the voltage by **5%** at the LTC. Stepping down the voltage during the winter peak load hours provide a load reduction of **1.52 MW** or **~3.95%** of the substation load **(36.80 MW**) by reducing the voltage by **5%** at the LTC

Simulations were run on the CYME model along with an AMI data-based analysis to determine the voltage outliers and select suitable locations for ENGO deployment. A combination of the two methodologies helped reconcile the differences between the model and the field and decide on an optimal set of transformers for implementation.

The ENGO devices were primarily responsible for facilitating a risk-free reduction in voltage as well as identifying the worst voltage outliers (visibility in field) that did require service transformer upgrade/tap change to maximize the conservation voltage reduction at the Kanata MTS.

This report presents the EM&V test results as well as the economics of the project. VVO/CVR is a significant opportunity to increase ambitious Energy Savings and Demand Reduction objectives at a competitive cost. A summary of the results captured during testing and the field based annual estimates are provided below.

3. Varentec Solution Overview

One of the promising methods to enhance system's efficiency by increasing Demand/Capacity Reduction and Energy Savings is through the deployment of utility owned assets called Dynamic VAr Controllers (DVCs). Each device is connected to the secondary side of a pole- or pad-mounted service transformer and tightly regulates the voltage at local and feeder wide level. For the Kanata MTS project, only pole units have been deployed. Sentient Energy is a pioneer in the development and deployment of these DVCs.

Sentient Energy's solution comprises hardware components called Edge of Network Grid Optimization (ENGO®) and a cloud-based software component called Grid-Edge Management Solution (GEMS®). ENGOs are fast-acting power-electronics devices that are installed on the secondary side of a distribution transformer, to autonomously sense and regulate voltage with a ± 0.5% within control range by injecting sub-cycle VArs between **0 to 10 kVArs**.

DVCs are well designed to mitigate in real-time Distributed Generation (DG) voltage impacts such as residential PVs. This results in the flattening of the primary and secondary feeder voltage. GEMS acts as a supervisory control and provides a data analytics and visualization engine. A recommended solution by Sentient Energy provides visibility to low voltage locations/nodes; enables real-time VVO system at the grid edge to achieve a fast and dynamic response to load; and enables CVR for either Energy Savings and/or Demand Reduction.

CVR enables electric distribution utilities to achieve a significant reduction in energy and peak demand, and without impacting customers through load shedding or major equipment investments. With the deployment of ENGO units at the low voltage outliers, this will ensure that the voltage will not temporarily dip below the minimum CSA standard level during heavy load conditions when the maximum drops occur and during out-of-normal conditions when voltage sags — caused by short circuits that occur on the grid.

GEMS+ENGO facilitates CVR by using power electronics devices installed on feeders, close to consumers, to flatten and equalize voltages. Utilities can then reduce the voltage on the feeder lines that run from substations to homes and businesses. This capability enables distribution utilities to operate their distribution grids at the low end of the acceptable supply voltage level without exposing consumers to undervoltage conditions.

CVR could be used as a **Non-Wires Alternatives** solution to offset distribution investment by deferring or replacing the need for specific equipment upgrades such as T&D lines or power transformers by reducing load / demand at a substation or circuit level (CAPEX Deferral).

The Sentient Energy solution benefits society and the environment because less energy is used to meet the same load, which helps reduce CO_2 and other harmful emissions. Consumers also benefit because they receive lower energy bills without any change in the quality of their services.

4. Field Testing Results

4.1. Executive Summary

In the project, **43** ENGO devices were installed in the Kanata MTS with a peak loading of:

- **66,129 kW** in **July 2018**
- **52,807 kW** in **July 2019**
- **50,530 kW** in **July 2020**

and an average loading of:

- **35,710 kW** measured over the period of **June 2018 – May 2019**
- **31,690 kW** measured over the period of **June 2019 – May 2020**

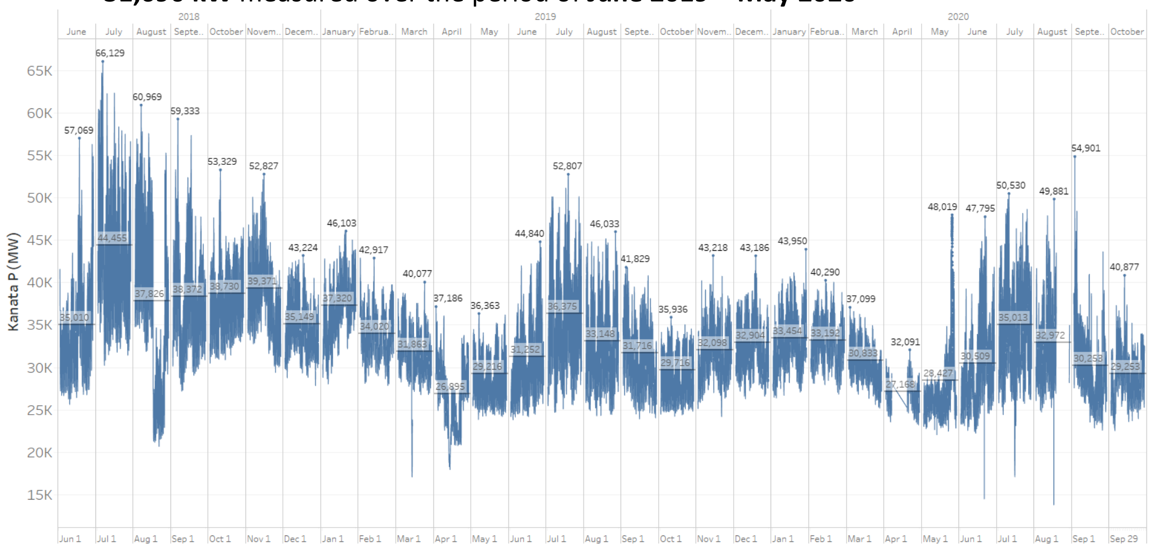

Figure 1: Substation Load from June 2018 through Sep 2020

<u>Note 1:</u> The first test period (peak demand reduction) was conducted over the period of **June 2020** through **September 2020** and the second test period (energy savings) over the period of **November 2020** through **February 2021**.

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The results using field-based estimates computed over the period of **June 2018 to May 2019** data are shown in the Table 1.

Table 1: Field-based Annual Estimates Computed using the %VM versus MW Model developed in Section 8.2.3 – Time Period over the period of June 2018 to May 2019

Month		Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Total / Maximum / Average
Measured Substation Loading	Sub Peak kW	57,069	66,129	60,969	59,333	53,329	52,827	43,224	46,103	42,917	40,077	37,186	36,363	66,129 kW (Max.)
	Sub Avg kW	35,010	44,455	37,826	38,372	38,730	39371	35,149	37,320	34,020	32,155	26,895	29,216	35,733 kW (Avg.)
	MWh Energy	25,207	33,075	28,143	27,628	28,815	28,347	26,151	27,766	22,861	23,923	19,364	21,737	313,017 MWh (Total)
Without ENGO + No System Upgrades	Min Voltage	0.930	0.919	0.925	0.927	0.935	0.936	0.948	0.944	0.948	0.952	0.956	0.957	0.940 p.u. (Avg.)
	Voltage Margin	-0.31%	-1.46%	-0.80%	-0.59%	0.17%	0.23%	1.45%	1.09%	1.49%	1.85%	2.22%	2.33%	0.64% (Avg.)
With ENGO + System Upgrades	Min Voltage	0.986	0.974	0.981	0.983	0.991	0.992	1.005	1.001	1.006	1.009	1.013	1.015	0.996 p.u. (Avg.)
	Voltage Margin	5.30%	4.06%	4.77%	4.99%	5.81%	5.87%	7.18%	6.79%	7.23%	7.61%	8.01%	8.12%	6.31% (Avg.)
	Incremental Voltage Margin	5.60%	5.52%	5.57%	5.58%	5.64%	5.64%	5.73%	5.70%	5.73%	5.76%	5.78%	5.79%	5.67% (Avg.)
	MWh Saved	668	671	671	869	1055	1048	1352	1357	1190	1147	977	1112	12,117.6 MWh Saved (Total)
	kW Shaved	1,573	1,396	1,511	1,954	2,045	2,047	2,359	2,379	2,358	2,013	1,966	1,949	Up to 2,379 kW Shaved (Max)
	tonnes CO2e/MWh saved	107	107	107	139	169	168	216	217	190	184	156	178	1,939 Tonnes CO2 Avoided (Total)
	tonnes CO2e/MW saved	1,565	1,389	1,503	1,944	2,035	2,037	2,347	2,367	2,346	2,003	1,956	1,939	2,367 Tonnes CO2 Avoided (Max)

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The results using field-based estimates computed over the period of **June 2019 to May 2020** data are shown in the Table 2: Field-based Annual Estimates Computed using the %VM versus MW Model developed in Section 8.2.3 – Time Period over the period of June 2019 to May 2020

Table 2: Field-based Annual Estimates Computed using the %VM versus MW Model developed in Section 8.2.3 – Time Period over the period of June 2019 to May 2020

Month		Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Total / Maximum / Average
Measured Substation Loading	Sub Peak kW	44,840	52,807	46,033	41,829	35,936	43,218	43,186	43,950	40,290	37,099	32,091	48,019	52,807 kW (Max)
	Sub Avg kW	31,252	36,375	33,148	31,716	29,716	32098	32,904	33,454	33,192	30,833	27,168	28,427	31,690 kW (Avg.)
	MWh Energy	22,501	27,063	24,662	22,836	22,109	23,111	24,481	24,890	23,102	22,940	19,561	21,150	278,404 MWh (Total)
Without ENGO + No System Upgrades	Min Voltage	0.946	0.936	0.944	0.950	0.957	0.948	0.948	0.947	0.952	0.956	0.962	0.942	0.949 p.u. (Avg.)
	Voltage Margin	1.25%	0.24%	1.10%	1.63%	2.38%	1.46%	1.46%	1.36%	1.83%	2.23%	2.87%	0.84%	1.55% (Avg.)
With ENGO + System Upgrades	Min Voltage	1.003	0.992	1.001	1.007	1.015	1.005	1.005	1.004	1.009	1.014	1.020	0.999	1.006 p.u. (Avg.)
	Voltage Margin	6.96%	5.88%	6.80%	7.37%	8.18%	7.18%	7.19%	7.08%	7.58%	8.02%	8.70%	6.53%	7.29% (Avg.)
	Incremental Voltage Margin	5.71%	5.64%	5.70%	5.74%	5.79%	5.73%	5.73%	5.72%	5.76%	5.78%	5.83%	5.69%	5.74% (Avg.)
	MWh Saved	783.0	795.7	838.5	1060.3	1139.4	1045.4	1267.3	1268.8	1260.8	1159.1	1072.1	870.1	12,560.6 MWh Saved (Total)
	kW Shaved	1623	1615	1628	2035	1940	2048	2360	2365	2321	1964	1843	2070	Up to 2,365 kW Shaved (Max)
	tonnes CO2e/MWh saved	125	127	134	170	182	167	203	203	202	185	172	139	2,010 Tonnes CO2 Avoided (Total)

	tonnes CO_2e/MW saved	1,615	1607	1620	2024	1930	2038	2348	2353	2309	1954	1833	2059	2,353 Tonnes CO2 Avoided (Max)

Note 2: The above voltage margin has been calculated from 112V or 0.933 p.u. considering a 2V voltage drop on the secondary line (or 110V at the meter)

Note 3: We did not use Aug 2020 data and subsequent months (Sep and Oct 2020) as the Kanata MTS Wholesale meter connection at the Kanata MTS had malfunctioned and stopped sending U/I/P/Q reads for the last 10 days of the month.

Note 4: The estimated energy savings and peak demand reduction are based on the measurement and computation of the CVR factor for Power and Energy

As per the testing conducted and results obtained, the detailed EM&V analysis provides the following key findings for both periods (**June 2018 – May 2019** and **June 2019 – May 2020**).

4.2. CSA Standard – Voltage Guidelines

Hydro Ottawa's Power Quality Standard (ECG0008- Distribution System Voltage and Power Quality https://static.hydroottawa.com/documents/specifications/ECG0008.pdf) is shown in Table 3: Steady State Operating Voltage Ranges Under Normal Conditions (Adapted from CSA CAN-3-C235-83 and Table 4:

Table 3: Steady State Operating Voltage Ranges Under Normal Conditions (Adapted from CSA CAN-3-C235-83)

Nominal Voltage (RMS V)	Allowable Deviation from Nominal (%)	Normal Minimum Voltage (RMS V)	Normal Maximum Voltage (RMS V)	Reference
120V / 240V	+4.17% ; -8.33%	110V / 220V	125V / 250V	At Service Entrance per CSA CAN3-C235-83 Table 3.0
120V / 208Y	+4.17% ; -6.67%	112V / 194Y	125V / 216Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
347V / 600Y	+3.75% ; -8.33%	318V / 550Y	360V / 625Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
2400V / 4160Y	+6.00% ; -6.00%	2256V / 3910Y	2544V / 4410Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
4800V / 8320Y*	+6.00% ; -6.00%	4512V / 7821Y	5088V / 8819Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7200V / 12470Y	+6.00% ; -6.00%	6768V / 11722Y	7632V / 13218Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7600V / 13200Y*	+6.00% ; -6.00%	7144V / 12408Y	8056V / 13992Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
15930V / 27600Y*	+6.00% ; -6.00%	14974V / 25944Y	16886V / 29256Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
44000V*	+6.00% ; -6.00%	41360V	46640V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
46000V	+6.00% ; -6.00%	43240V	48760V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1

Table 4: Steady State Operating Voltage Ranges Under Extreme Conditions (Adapted from CSA CAN-3-C235-83)

Nominal Voltage (RMS V)	Allowable Deviation from Nominal (%)	Extreme Min. Voltage (RMS V)	Extreme Max. Voltage (RMS V)	Reference
120V / 240V	+5.83% ; -11.67%	106V / 212V	127V / 254V	At Service Entrance per CSA CAN3-C235-83 Table 3.0
120V / 208Y	+5.83% ; -8.65%	110V / 190Y	127V / 220Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
347V / 600Y	+5.76% ; -11.82%	306V / 530Y	367V / 635Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
2400V / 4160Y	+6.00% ; -6.00%	2256V / 3910Y	2544V / 4410Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
4800V / 8320Y*	+6.00% ; -6.00%	4512V / 7821Y	5088V / 8819Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7200V / 12470Y	+6.00% ; -6.00%	6768V / 11722Y	7632V / 13218Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
7600V / 13200Y*	+6.00% ; -6.00%	7144V / 12408Y	8056V / 13992Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
15930V / 27600Y*	+6.00% ; -6.00%	14974V / 25944Y	16886V / 29256Y	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
44000V*	+6.00% ; -6.00%	41360V	46640V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1
46000V	+6.00% ; -6.00%	43240V	48760V	At Point of Sale per CSA CAN3-C235-83 Clause 6.1

4.3. Voltage Visibility/Support and CSA Compliance

As per Sentient Energy's recommendation based on AMI-data analysis and in coordination with HOL, a few transformer upgrades were performed as well as tap changes that led to a MV voltage improvement. Further, the ENGOs deployed in the system provided an incremental LV voltage improvement in addition to the real-time voltage visibility provided by ENGOs (the ENGO device is a **0.5%** voltage accuracy sensor). Based on ENGO-DAY ON/OFF testing, the combined MV and LV solution demonstrated ability to maximize voltage reduction and achieve significant demand reduction and energy savings.

Results:

- In **2019**, the minimum AMI voltage observed on **July 4th** was **101.8V**. Based on this measurement, it is clear that there is no existing voltage margin for performing a safe peak demand reduction (no customer voltage below CSA threshold of 110V during normal operating conditions or 106V during extreme operating conditions) and therefore system upgrades and ENGO deployment are required

4.4. ENGO ON/OFF Test

Based on ENGO-DAY ON/OFF testing during nominal operation, the GEMS+ENGO solution demonstrated ability to provide improvement in voltage margin.

Results:

- ENGOs provided in May 2020 an incremental improvement in voltage margin by **3.10V** (**2.58%**) prior to MV System Upgrade/Change
- This paired with the system upgrades as showed in Table 5: MV System Upgrades/Changes (transformer upgrades and tap changes) allowed us to comfortably proceed with CVR reduction of **5%** for the peak demand reduction testing

- ENGOs Improve lightly the substation Power Factor PF from **0.9478** to **0.9503**, which reduces line losses by **0.53%**

Table 5: MV System Upgrades/Changes

Xfmer	Phase	ENGO Unit	Min. ENGO V (15min Avg) Before System Upgrades and ENGO OFF May 26th, 2020 / 43.93MW	MV Upgrade	Min. ENGO V (15min Avg) After System Upgrades and ENGO ON October 12th, 2020 / 40.88MW
X07484	B	2112692	107.9V	Xfmer Replaced (August 26th, 2020)	120.3V
X50916	A	2106377	108.7V	Xfmer Replaced (August 26th, 2020)	120.8V
X07508	B	2122829	108.7V	Xfmer Replaced (August 26th, 2020)	123.7V
X07487	B	2100193	104.6V before Xfmer Upgrade 108.9V after Xfmer Upgrade	Xfmer Replaced (May 7th, 2020) and then Taps increased by 5% (July 30th, 2020)	123.4V
X07491	B	2125813	108.8V	Taps increased by 5% (July 30th, 2020)	123.8V

4.5. Voltage Support

Based on ENGO-DAY ON/OFF and CVR-DAY ON/OFF testing, the combined MV and LV solution demonstrated ability to maximize voltage reduction and achieve significant demand reduction and energy savings.

Results:

- In 2020, after performing system upgrade and deployment of ENGO units, the minimum voltage recorded on July 2nd is **116.6V**. If we compare this result to July 4th, 2019 (**101.4V**), we observed a voltage improvement of nearly **14.8V** (**12.34%**). This allows the voltage to be reduced at the LTC without causing any CSA violations
- Estimated average voltage reduction of ~**6.31%** with an average incremental of **~5.67%** over the period of June 2018 to May 2019 (or ~**90%** contribution coming from combined MV System Upgrade and GEMS-ENGO solution). The incremental of the GEMS+ENGO is ~**2.80%** (or ~**44%** contribution coming from GEMS-ENGO solution)
- Estimated average voltage reduction of ~**7.29%** with an average incremental of ~**5.74%** over the period June 2019 to May 2020 (or ~**79%** contribution coming from GEMS+ENGO solution). The incremental of the GEMS+ENGO is ~**2.25%** (or ~**31%** contribution coming from GEMS-ENGO solution)

4.6. System Error Computation

As there is bound to be differences in voltage margin obtained from CYME analysis and that obtained from the field data, it was decided to add the concept of a system error in the contract. The system error essentially aligns the results from CYME with the field results and allows a fair comparison between the two results.

Using the methodology outlined in the contract, the average system error was found to be **2.39%** and the average percentage voltage margin was **3.53%**.

So, the adjusted voltage margin for comparison purposes was found to be **5.92%**, which shows that the ENGOs exceed performance. Essentially, ENGOs deliver a minimum voltage improvement of what was promised during the analysis phase now validated from the field results.

4.7. Capacity/Peak Demand Reduction Testing

Capacity/Peak Demand reduction tests have been conducted in three consecutive months (July, August, September 2020) with 54 LTC events or 108 LTC transitions (step down and step up/return to nominal). Tests were initially conducted at 2.5% CVR followed by 5% CVR after system upgrades (transformer tap and rating changes). Additional Capacity/Peak Demand reduction tests have been conducted from November 2020 through February 2021 with 36 LTC events or 72 LTC transitions.

Results:

- A **5% CVR reduction** was performed, and the minimum voltage recorded on September 24th was **114.3V** which is again above the CSA lower limit.
- A **5% CVR** was proved to be safe and feasible unlocking a potential of **1.31 MW** of reduction during peak load month of July 2020 (**50.53 MW**) with no CSA violations (CVR_{factor} for Power = **0.52** in summertime)
- Based on the analysis of “voltage drop on secondary lines” and AMI data assessment – an additional margin of **2.3V (>1.92%)** is available unlocking a potential CVR reduction up to **6%** (or **1.58 MW**) while keeping CSA compliance at customer location (110V at customer location and 112V at transformer location considering a 2V voltage drop on the secondary run)
- Based on historical **July** Peak Month and estimated voltage margin, a potential of **1.40 MW** (July 2018 Peak @ 66.1MW) **– 1.63 MW** (July 2019 Peak @ 52.8MW) of reduction is feasible as showed in

- Table 6: Voltage Margin during July Peak Month.

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Table 6: Voltage Margin during July Peak Month

Year	System Upgrades	Month	Voltage Margin (Without ENGO)	Lowest Voltage (Without ENGO)	Peak Shaving (Without ENGO)	Voltage Margin (With ENGO)	Lowest Voltage (With ENGO)	Peak Shaving
2018-2019	No	**July 2018 (66.13 MW)**	**-1.46%**	**110.25**	**NOT POSSIBLE**	**0.62%**	**112.74**	**0.21 MW**
2018-2019	Yes	**July 2018 (66.13 MW)**	**2.29%**	**114.75**	**0.79 MW**	**4.06%**	**116.87**	**1.40 MW**
2019-2020	No	**July 2019 (52.81 MW)**	**0.24%**	**112.29**	**0.07 MW**	**2.51%**	**115.01**	**0.69 MW**
2019-2020	Yes	**July 2019 (52.81 MW)**	**3.96%**	**116.75**	**1.09 MW**	**5.88%**	**119.06**	**1.61 MW**
2020-2021	No	**July 2020 (50.53 MW)**	**0.53%**	**112.64**	**0.14 MW**	**2.83%**	**115.40**	**0.74 MW**
2020-2021	Yes	**July 2020 (50.53 MW)**	**4.25%**	**117.1**	**1.12 MW**	**6.19%**	**119.43**	**1.63 MW**

- Annual demand reduction using June 2018 to May 2019 data ranges between **~1.40 MW** (July 2018 Peak) to **~2.38 MW** (Jan 2019 Peak) shaved
  - ✓ ~**2.11%** (Summer Peak: **July 2018 / 66.13 MW**) or ~**5.16%** (Winter Peak: **January 2019 / 46.10 MW**) Demand Reduction with an incremental of **~2.87%** or **~4.33% (~5.52%** or **~5.70%** Voltage Incremental x 0.52 (summer) or 0.76 (winter) $CVR_{f\ Power}$) (or >**~100%** or **~84%** contribution coming from GEMS+ENGO solution)
- Similar peak shaving performance has been estimated using June 2019 to May 2020 data
  - ✓ Annual demand reduction between **~1.61 MW** (July 2019 Peak) to **~2.37 MW** (January 2020 Peak) shaved
  - ✓ ~**3.06%** (Summer Peak: **July 2019 / 52.81 MW**) or ~**5.38%** (Winter Peak: **January 2020 / 43.95 MW**) Demand Reduction with an incremental of **~2.93%** or **~4.35% (~5.64%** or **~5.72%** Voltage Incremental x 0.52 (summer) or 0.76 (winter) $CVR_{f\ Power}$) (or **~96%** to **~81%** contribution coming from GEMS+ENGO solution)

4.8. Energy Savings

Energy Savings tests have been conducted from November 2020 through February 2021 with 144 CVR events (LTC operation, daily CVR ON/OFF @ 5%).

Energy Savings = Consumer Consumption Reduction + Technical Loss Reduction (Line + Transformer Losses)

Results:

- Annual avoided energy due to Visibility and MV System Upgrade/ENGOs of **~12,117.6 MWh** saved or **3.87%** Energy Savings with an incremental of **~3.49%** estimated over the period of **June 2018 to May 2019** (or **~90%** contribution coming from MV System Upgrades/ENGOs solution)
- Annual avoided energy due to Visibility and MV System Upgrade/ENGOs of **~12,560.5 MWh** saved or **~4.51%** Energy Savings with an incremental of **~3.55%** estimated over the period of **June 2019 to May 2020** (or **~79%** contribution coming from MV System Upgrades/ENGOs solution)

Note 5: For the calculation of Energy Savings, we assume a CVR factor for Energy ($CVR_{f\ Energy}$) equal to 0.62.

4.9. CVR Factor Test

Based on CVR-DAY ON/OFF testing, CVR factor for Power was measured and computed during the first test period (peak demand reduction) **June 2020** through **September 2020.** During the second test period (energy savings) over the period of **November 2020** through **February 2021,** CVR factor for Power and Energy were measured and computed.

Results:

- CVR Factor for Power and Energy:

Peak Demand Reduction Test (Summer 2020)	**July – Sept 2020**
LTC Reduction in Voltage	2.5% - 5%
Number of CVR Events	54
Error Band (95% confidence)	0.06
CVR Factor for Power	**0.52 ± 0.03**
CVR Factor for Energy	**No Test**

Energy Savings Test (Winter 2020)	Nov 2020 – Feb 2021
LTC Reduction in Voltage	4,1%
Number of CVR Events	36
Error Band (95% confidence)	0.026
CVR Factor for Power	**0.76 ± 0.013**
LTC Reduction in Voltage	4,56%
Number of CVR Events	144
Error Band (95% confidence)	0.46
CVR Factor for Energy	**0.72 ± 0.23**

- Considering the period of **June 2018 to May 2019**, MV System Upgrade and ENGO deployment allow the system to perform an annual average voltage reduction of **~6.24%** (Energy Savings) and **~4.06%** during **July 2018** peak month
- Considering the period of **June 2019 to May 2020**, MV System Upgrade and ENGO deployment allow the system to perform an annual average voltage reduction of **~7.28%** (Energy Savings) and **~5.88%** during **July 2019** peak month

Based on the billing data of August 2019 (see **Section 6.3**) shared by Hydro Ottawa, CVR factors of each season were estimated to analyze the effect of voltage reduction by season. The data measured/estimated at Kanata substation can be classified by season and customer class as follows:

Table 7: Seasonal CVR factors for Energy and Power

	Summer	Falls	Winter	Spring	Average
CVR factor for Power	0.52*	0.66	0.76*	0.66	0.65
CVR factor for Energy	0.50	0.63	0.72*	0.63	0.62

*Measured and computed CVR

Table 8: CVR factors for Energy and Power per Customer Class

	CVR factor for Power (July 2019)	CVR factor for Power (average)	CVR factor for Energy (average)
Residential	0.80	0.85	0.81
Small & Medium < 50 kW	0.82	0.92	0.89
Small & Medium > 100 kW	0.44	0.56	0.55
Average CVR factor	0.52*	065	0.62

When analyzing data by season, CVR factors (Energy and Power) of Winter were found to be higher than those of Summer.

4.10. Technical Loss Reduction

Results:

Considering **3.27%** technical losses (Line Loss **1.12%**, Transformer Load Loss **1.11%** and Transformer Non-Load Loss **1.04%**) or **~10,234.1** MWh total losses out of **313,017.1 MWh** computed over the period of **June 2018 to May 2019** and **~9,102.4 MWh** total losses out of **278,403.7 MWh** computed over the period of **June 2019 to May 2020**:

- Annual reduction of overall technical losses:
  - ✓ **~372.2 MWh** (**-3.64%** of overall technical loss reduction or **3.07%** of the overall Energy Savings) estimated over the period of **June 2018 to May 2019**
  - ✓ **~413.4 MWh** (**-4.54%** of overall technical loss reduction or **3.87%** of the overall Energy Savings) estimated over the period of **Sep 2018** to **Aug 2019**
- Annual reduction of line losses due to PF improvement thanks to ENGO units (copper loss reduction):
  - ✓ Technical Loss Reduction of **~20.0 MWh (-0.20%** of overall technical loss reduction) estimated over the period of **June 2018 to May 2019**

  Or

  - ✓ Technical Loss Reduction of **~17.6 MWh** (**-0.17%** of overall technical loss reduction) estimated over the period of **June 2019 to May 2020**
- Annual reduction of technical losses due to CVR 24/7/365 (copper and core loss reduction)
  - ✓ Technical Loss Reduction of **~352.2 MWh** saved **(-3.44%** of overall technical loss) over the period of **June 2018 to May 2019**

  or

  - ✓ Technical Loss Reduction of **~395.7 MWh** saved (**-4.35%** of overall technical loss) estimated over the period of **June 2019 to May 2020**

4.11. Consumer Benefits:

Results:

- Annual Consumption Reduction due to Visibility and MV System Upgrade/ENGOs of **~11,745.6 MWh** (**96.93%** of overall Energy Savings) estimated over the period of **June 2018 to May 2019**
- Annual Consumption Reduction due to Visibility and MV System Upgrade/ENGOs of **~12,147.29 MWh** (**96.71**% of overall Energy Savings) estimated over the period of **June 2019 to May 2020**

4.12. Environmental Benefits:

Results:

- Annual CO2 reduction due to visibility and MV System Upgrade/ENGOs of **~1,938.8** Tonnes (**~12,117.6 MWh**) or **~2,367.1** Tonnes (average **1,962kW**) estimated over the period of **June 2018 to May 2019**
- Annual CO2 reduction due to visibility and MV System Upgrade/ENGOs of **~2,009.7** Tonnes (**12,560.5 MWh**) or **~2,353.0** Tonnes (average **1,984kW**) estimated over the period of **June 2019 to May 2020**

Note 6: "There are two components to the calculation of GHG reductions due to reductions in electricity usage resulting from CVR. These are computed based on the metrics for tonnes CO2e/MWh saved (0.160) and tonnes CO2e/MW saved (995), calculated by Ontario's Independent Electricity System Operator (IESO) for 2015 as reported in the Conservation Framework Mid-Term Review – Climate Change - Discussion Draft Discussion Slides prepared by Navigant (document CF-2017020-Climate-Change-Summary), Slide 27"

4.13. Project Results Summary Data:

Note 7: All costs and benefits showed in the report are in CAD.

Table 9: Field Test Results using June 2018 to May 2019 data

Engineering Calcs		
Annual Technical Loss Reduction	372.2	MWh
Avoided Wholesale Energy Purchases	12,117.7	MWh
Avoided Retail Electricity Sales	11,745.5	MWh
Customer peak capacity reduction	2.379	MW
Average System Peak reduction	1.397	MW
Annual Substation Energy Consumption Billed	302,783.1	MWh
Asset Life Extension Benefit	2,345.6	$
Power Quality Benefit	800.0	$
Annual CO2 reduction	1,938.83	tonnes
Annual NOx reduction	0.36	tonnes
Annual SOx reduction	0.61	tonnes
NPV Feeder Revenue Requirement	38,400,695,896	$

Table 10: Field Test Results using June 2019 to May 2020 data

Engineering Calcs		
Annual Technical Loss Reduction	413.4	MWh
Avoided Wholesale Energy Purchases	12,560.7	MWh
Avoided Retail Electricity Sales	12,147.3	MWh
Customer peak capacity reduction	2.366	MW
Average System Peak reduction	1.614	MW
Annual Substation Energy Consumption Billed	269,301.3	MWh
Asset Life Extension Benefit	2,345.6	$
Power Quality Benefit	800.0	$
Annual CO2 reduction	2,009.71	tonnes
Annual NOx reduction	0.38	tonnes
Annual SOx reduction	0.63	tonnes
NPV Feeder Revenue Requirement	34,154,348,389	$

5. Economic Use Case

5.1. Economic Evaluation Approach

Following financial information were considered for the Economic Use Case:

- Energy cost inflation rate of **2.0%** per year
- After-tax discount rate of **6.02%** per year (WACC)
- Utility return on equity of **8.98%** per year
- Effective Tax Rate of **26.50%**
- 2021 average retail rate before HST with Ontario electricity rebate is around **$12.74** cts/kWh considering the customer distribution at the Kanata substation
- 2021 marginal purchase energy rate (total cost of power before HST with Ontario electricity rebate) is around **$10.82** cts/kWh considering the customer distribution at the Kanata substation

5.2. Project Costs

An overall cost of **$497,802** (asset deployment and 15-year O&M costs) was considered for the medium voltage (replacement of 4 service transformers and tap changes) and the low voltage (GEMS+ENGO solution) Volt VAr control assets. No O&M expenses were considered for the ENGO devices as it does not require any preventive maintenance (no moving parts). The annual GEMS hosted subscription and GEMS apps/ENGO cellular comm are considered over 15 years ($194,532).

Table 11: Deployment and O&M Costs at Kanata MTS

Cost Calculations		
GEMS Software	$	194,532
ENGO Hardware	$	161,410
GEMS + ENGO Professional Service Costs	$	43,426
ENGO Install + Prof Service Costs (HOL)	$	78,747
MV Hardware + Install Costs (HOL)	$	19,687

An overall Hydro Ottawa project costs of **$78,747** for the ENGO deployment as well as **$19,687** for the MV System Upgrades has been considered (**$98,433**). An overall GEMS+ENGO cost of $399,368 is considered.

<u>**Note 9**</u>: We assume a GEMS Hosted Solution (above costs of $194,532 are for a 15-year operation) for the EUC calculation. However***, a GEMS on-premise solution might be more cost effective when Hydro Ottawa decides to go full-scale***. It will reduce the overall cost of the solution meaning it will reduce the LCOE and LCOC numbers presented in the following sections.

Sentient ENERGY

5.3. Energy Savings and Capacity Reduction Economics Using June 2018-May 2019

Considering all costs of the project (ENGOs and MV System Upgrades) and all benefits (Net Present Value NPV avoided energy of **$12,843k**, NPV technical (transformer and line) loss reduction of **$394k** and NPV O&M of **$32k** over **15** years), the Ratepayer Impact Measure (RIM) Test BCR is **0.86** (discounted) or **0.87** (undiscounted).

The deployed MV System Upgrade/ENGOs solution delivers a Levelized Cost of Energy (LCOE) Saved of **$3.65**/MWh or **$0.365** cts/kWh (to be compared with the 2021 marginal purchase energy rate of **$10.82** cts/kWh).

The Total Resource & Utility Cost (TRC/UCT) Tests BCR is **30.92** (discounted) and the IRR Internal Rate of Return is **434%** (to be compared to **6.02%** WACC or **8.98%** ROE).

Table 12: Energy Cost Effectiveness Tests of Kanata MTS Project (considering all costs)

Project Summary	
12,117.6	Annual MWh Saved
1.396	Annual MW Saved (considering July 2018 only)
$3.65	LCOE (Levelized Cost of Energy) $/MWh
$30.21	LCOC (levelized Cost of Capacity) $/kW-Yr
-3.87%	Change in Usage
-3.33%	Minimum change in Electrical Bills

Lifetime Costs and Benefits	*Discounted*				*Undiscounted*	
Cost Tests	Net Benefit	BC Ratio	IRR	Payback Yrs	Net Benefit	BC Ratio
RIM (RATEPAYER IMPACT MEASURE)	$(2,119,425)	0.86	N/A	N/A	$(3,125,598)	0.87
TRC/UCT (TOTAL RESOURCE & UTILITY COST TEST)	$12,839,446	30.92	434%	1	$20,132,180	41.44
SCT (SOCIETAL COST TEST)	$13,287,217	31.97	449%	1	$20,828,377	42.84

Note 10: The societal benefits are just shown for information and only considered in the SCT (Societal Cost Test) BCR Calculation. The federal system prices pollution at a rate of **$20** per tonne of CO2 equivalent emissions in **2019** and considering that this amount will gradually rise to **$50** per tonne by 2022, the discounted BCR will increase from **31.97** (TRC/UCT) to **33.32** (SCT) including NOx and SOx reduction.

The Table 13: RIM, TRC/UCT and SCT Test (considering all costs)shows the detail costs and benefits of the RIM, TRC/UCT and SCT tests (discounted and undiscounted over 15-years):

Table 13: RIM, TRC/UCT and SCT Test (considering all costs)

RIM Test (WACC 6.02%)

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV	Undiscounted
Costs	GEMS Software	$ -	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$125,792	$ 194,532
	ENGO Hardware	$ 161,410	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$161,410	$ 161,410
	ENGO Install + Prof Service Costs (HOL)	$ 78,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$78,747	$ 78,747
	GEMS + ENGO Professional Service Cost	$ 43,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$43,426	$ 43,426
	MV Hardware + Install Costs (HOL)	$ 19,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$19,687	$ 19,687
	Bill Savings (if sales decrease)	$ -	$1,496,995	$1,504,480	$1,512,003	$1,519,563	$1,527,160	$1,534,796	$1,542,470	$1,550,183	$1,557,934	$1,565,723	$1,573,552	$1,581,420	$1,589,327	$1,597,273	$1,605,260	$14,958,872	###########
Benefits	Avoided Energy Retail	$ -	$1,285,209	$1,291,635	$1,298,094	$1,304,584	$1,311,107	$1,317,662	$1,324,251	$1,330,872	$1,337,526	$1,344,214	$1,350,935	$1,357,690	$1,364,478	$1,371,301	$1,378,157	$12,842,580	###########
	Line & Xfmer Loss Reduction	$ -	$ 39,471	$ 39,669	$ 39,867	$ 40,066	$ 40,267	$ 40,468	$ 40,670	$ 40,874	$ 41,078	$ 41,283	$ 41,490	$ 41,697	$ 41,906	$ 42,115	$ 42,326	$394,421	$ 613,248
	Avoided Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	O&M (VLR, ALE, PQ)	$ -	$ 3,146	$ 3,162	$ 3,178	$ 3,195	$ 3,212	$ 3,229	$ 3,247	$ 3,265	$ 3,283	$ 3,302	$ 3,321	$ 3,340	$ 3,360	$ 3,380	$ 3,401	$31,507	$ 49,018
	CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Bill Savings (if sales increase)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Net Cash Flow	$ (303,270)	$ (182,138)	$ (182,983)	$ (183,833)	$ (184,687)	$ (185,544)	$ (186,406)	$ (187,271)	$ (188,141)	$ (189,015)	$ (189,893)	$ (190,775)	$ (191,661)	$ (192,551)	$ (193,446)	$ (194,344)	$(2,119,425)	$(3,125,958)
	Payback	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	N/A	Yrs to Payback
																		N/A	IRR

UCT/TRC Tests (WACC 6.02%)

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV	d
Costs	GEMS Software	$ -	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$125,792	$ 194,532
	ENGO Hardware	$ 161,410	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$161,410	$ 161,410
	ENGO Install + Prof Service Costs (HOL)	$ 78,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$78,747	$ 78,747
	GEMS + ENGO Professional Service Cost	$ 43,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$43,426	$ 43,426
	MV Hardware + Install Costs (HOL)	$ 19,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$19,687	$ 19,687
Benefits	Avoided Energy Retail	$ -	$1,285,209	$1,291,635	$1,298,094	$1,304,584	$1,311,107	$1,317,662	$1,324,251	$1,330,872	$1,337,526	$1,344,214	$1,350,935	$1,357,690	$1,364,478	$1,371,301	$1,378,157	$12,842,580	###########
	Line & Xfmer Loss Reduction	$ -	$ 39,471	$ 39,669	$ 39,867	$ 40,066	$ 40,267	$ 40,468	$ 40,670	$ 40,874	$ 41,078	$ 41,283	$ 41,490	$ 41,697	$ 41,906	$ 42,115	$ 42,326	$394,421	$ 613,248
	Avoided Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	O&M (VLR, ALE, PQ)	$ -	$ 3,146	$ 3,162	$ 3,178	$ 3,195	$ 3,212	$ 3,229	$ 3,247	$ 3,265	$ 3,283	$ 3,302	$ 3,321	$ 3,340	$ 3,360	$ 3,380	$ 3,401	$31,507	$ 49,018
	CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Net Cash Flow	$ (303,270)	$1,314,857	$1,321,497	$1,328,170	$1,334,876	$1,341,616	$1,348,390	$1,355,199	$1,362,041	$1,368,919	$1,375,830	$1,382,777	$1,389,759	$1,396,775	$1,403,828	$1,410,915	###########	###########
	Payback	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	Yrs to Payback
																		434%	IRR

SCT Test (WACC 6.02%)

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV	d
Costs	GEMS Software	$ -	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$ 12,969	$125,792	$ 194,532
	ENGO Hardware	$ 161,410	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$161,410	$ 161,410
	ENGO Install	$ 78,747	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$78,747	$ 78,747
	ENGO Hardware	$ 43,426	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$43,426	$ 43,426
	Services	$ 19,687	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$19,687	$ 19,687
Benefits	Avoided Energy Retail	$ -	$1,285,209	$1,291,635	$1,298,094	$1,304,584	$1,311,107	$1,317,662	$1,324,251	$1,330,872	$1,337,526	$1,344,214	$1,350,935	$1,357,690	$1,364,478	$1,371,301	$1,378,157	$12,842,580	###########
	Line & Xfmer Loss Reduction	$ -	$ 39,471	$ 39,669	$ 39,867	$ 40,066	$ 40,267	$ 40,468	$ 40,670	$ 40,874	$ 41,078	$ 41,283	$ 41,490	$ 41,697	$ 41,906	$ 42,115	$ 42,326	$394,421	$ 613,248
	Avoided Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	O&M (VLR, ALE, PQ)	$ -	$ 3,146	$ 3,162	$ 3,178	$ 3,195	$ 3,212	$ 3,229	$ 3,247	$ 3,265	$ 3,283	$ 3,302	$ 3,321	$ 3,340	$ 3,360	$ 3,380	$ 3,401	$31,507	$ 49,018
	CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
	Societal CO2	$ -	$ 96,942	$ 97,426	$ 97,913	$ 98,403	$ 98,895	$ 99,389	$ 99,886	$ 100,386	$ 100,888	$ 101,392	$ 101,899	$ 102,409	$ 102,921	$ 103,435	$ 103,952	$968,698	$ 1,506,137
	Societal NOx	$ -	$ 3,093	$ 3,109	$ 3,124	$ 3,140	$ 3,156	$ 3,171	$ 3,187	$ 3,203	$ 3,219	$ 3,235	$ 3,251	$ 3,268	$ 3,284	$ 3,300	$ 3,317	$30,910	$ 48,059
	Societal SOx	$ -	$ 2,940	$ 2,955	$ 2,970	$ 2,985	$ 3,000	$ 3,015	$ 3,030	$ 3,045	$ 3,060	$ 3,075	$ 3,091	$ 3,106	$ 3,122	$ 3,137	$ 3,153	$29,382	$ 45,683
	Net Cash Flow	$ (303,270)	$1,417,833	$1,424,987	$1,432,177	$1,439,404	$1,446,666	$1,453,966	$1,461,302	$1,468,675	$1,476,086	$1,483,533	$1,491,018	$1,498,541	$1,506,102	$1,513,701	$1,521,338	###########	###########
	Payback	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	Yrs to Payback
																		468%	IRR

As expected, the LCOE is in line in comparison with a recent study made in June 2018 by **Navigant Consulting** “**Volt/VAr Optimization and Conservation Voltage Reduction: Market Potential Assessment & Economic Metrics for the province of Ontario**”.

As reported by **Navigant**, the LCOE of energy saved via Secondary Volt-VAr optimization (VVO) technologies such as Sentient Energy’s offering is around **$1.13 cts/kWh vs. $4.71 cts/kWh** for Primary VVO only deployments. The addition of Secondary VVO reduces the overall LCOE to **$3.41** cts/kWh (to be compared with **$0.365** cts/kWh at Kanata MTS as mentioned previously).

In 2017, Navigant Consulting performed an analysis of the potential for VVO technologies to contribute to Energy Efficiency goals in Ontario (“**Considerations for Deploying In-Front-of-the-Meter Conservation Technologies in Ontario**”). The study includes an in-depth analysis of the BCR by class of feeder across Ontario. It concluded that approximately **30%** of the feeders in the province are good candidates for VVO as showed in Table 14: Ranking for Prototypical Feeders by Cost-Benefit Ration - VVO.

Table 14: Ranking for Prototypical Feeders by Cost-Benefit Ration - VVO

Rank	Ranked Feeders by Cost-Benefit Ratio	Feeders per Cluster	Benefit-Cost Ratio	Cluster Peak Reduction (MW)	Cluster Electricity Reduction (GWh)	Cluster Line Loss Reduction (GWh)
1	12.47 kV - Heavy Suburban	305	1.45	15	106	6
2	27.6 kV - Moderate Suburban	508	1.35	34	246	5
3	27.6 kV - Moderate Urban	508	1.34	33	244	6
4	12.47 kV - Moderate Urban	1,016	1.29	44	325	8
5	12.47 kV - Moderate Suburban	711	1.17	28	207	4
6	12.47 kV - Light Suburban	508	0.80	14	104	1
7	4.16 kV - Heavy Urban	102	0.72	1	10	1
8	4.16 kV - Heavy Suburban	102	0.65	1	9	0
9	44.4 kV - Light Rural	508	0.59	39	292	3
10	4.16 kV - Moderate Urban	1,524	0.58	17	122	3
11	27.6 kV - Light Rural	508	0.53	13	97	1
12	4.16 kV - Moderate Suburban	1,524	0.52	15	111	2
13	4.16 kV - Light Suburban	1,321	0.48	12	90	1
14	12.47 kV - Light Rural	508	0.38	7	49	1
15	4.16 kV - Light Rural	508	0.17	2	12	0

Source: Navigant analysis

The lowest performing feeders are all the 4.16 kV feeders and some of the lightly loaded 12.47 kV feeders as shown above in Table 14: Ranking for Prototypical Feeders by Cost-Benefit Ration - VVO. These feeders have a negative NPV and are not cost-effective largely because the line loss savings achieved through phase balancing are relatively small (in proportion to the feeder load) and do not justify the costs required. Recent deployments in Ontario have shown that by deploying ENGO devices at targeted location (low voltage outliers) and optimizing the MV assets, it was demonstrated that 4.16kV – light rural feeder could be turned to become eligible for VVO deployment.

Considering the Kanata MTS (27.6kV Heavy Suburban), a TRC BCR of **1.45** would have been expected as reported by Navigant study (to be compared with **30.92 (!)** achieved at the Kanata MTS).

Overall, the LCOE and IRR of the Kanata MTS project are in line with LDC's financial (Utility Return on Equity of **8.98%** vs. **434%** IRR and 2021 marginal purchase energy rate of **$10.82** cts/kWh vs. LCOE of **$0.365** cts/kWh saved) as well as the LCOE reported in 2017 Navigant's study (e.g., **$5.20** cts/kWh saved).

As shown in

Table 15: LCoE / LCoC by Feeder for VVO, the LUEC for Energy (Levelized Unit Electricity Cost) or LCOE for IFMC deployment across 15-feeders (from 4.16kV to 27.6kV, from light rural to heavy urban) ranges from **$5.20** cts/kWh and **$19.8** cts/kWh saved. An LCOE of **$5.20** cts/kWh saved is reported for a 12.47kV – Heavy Suburban feeder (to be compared to **$3.65** cts/kWh saved achieved at the Kanata MTS).

As shown in

Table 15: LCoE / LCoC by Feeder for VVO, the LUEC for Demand or LCOC ranges from **$422** and **$3,352/kW-Yr** shaved. An LCOC of **$710/kW-Yr** is reported for a 12.47kW – Heavy Suburban

feeder (to be compared to **$30.21/kW-Yr** shaved achieved at the Kanata MTS or **$120.85/kW**-Summer Time).

Table 15: LCoE / LCoC by Feeder for VVO

Prototypical Feeder	LUEC ($/kWh)	LUEC ($/kW)
4.16kV - Heavy Urban	$0.105	$777
4.16 kV - Moderate Urban	$0.131	$984
4.16 kV - Heavy Suburban	$0.117	$866
4.16 kV - Moderate Suburban	$0.144	$1,087
4.16 kV - Light Suburban	$0.157	$1,188
4.16 kV - Light Rural	$0.443	$3,352
12.47 kV - Moderate Urban	$0.059	$441
12.47 kV - Heavy Suburban	$0.052	$388
12.47 kV - Moderate Suburban	$0.065	$487
12.47 kV - Light Suburban	$0.094	$710
12.47 kV - Light Rural	$0.198	$1,502
27.6 kV - Moderate Urban	$0.056	$424
27.6 kV - Moderate Suburban	$0.056	$422
27.6 kV - Light Rural	$0.143	$1,084
44.4 kV - Light Rural	$0.128	$970

Source: Navigant analysis

Considering the Rate Payer Impact (RIM) test, a BCR of **0.87** (discounted) is shown below:

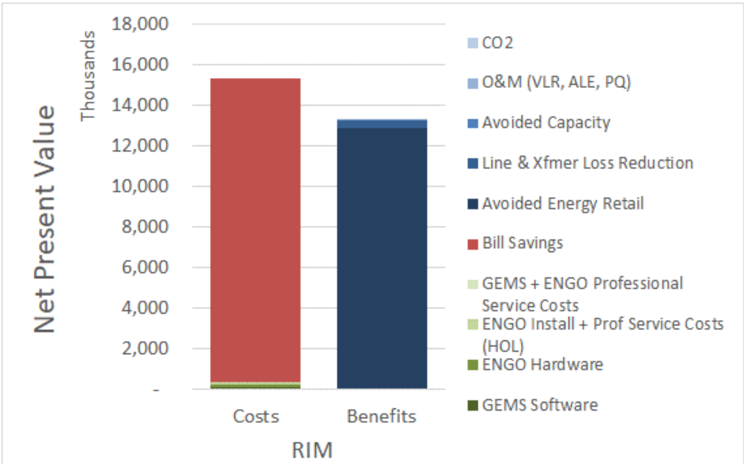

Figure 2: RIM Test Results

Based on the project measured results and financial provided by Hydro Ottawa, a reduction in energy usage of **3.87%** at Kanata MTS corresponds in a change in consumer electrical bill of **3.33%**

Considering the Total Resource Cost/Utility Cost Test TRC/UCT test, a BCR of **30.92** (discounted) is shown, which implies a decrease of the total energy expenditures (BCR>1).

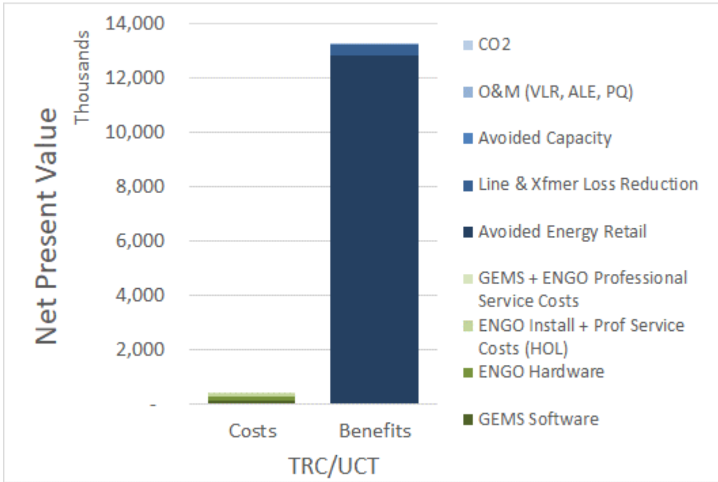

Figure 3: TRC/UCT Test Results

5.4. Energy Savings and Capacity Reduction Economics Using June 2019-May 2020

The Economics are summarized in Table 16: Economics Summary Using June 2019-May 2020.

Table 16: Economics Summary Using June 2019-May 2020

Project Summary	
12,561	Annual MWh Saved
1.615	Annual MW Saved (considering July 2019 only)
$3.52	LCOE (Levelized Cost of Energy) $/MWh
$26.16	LCOC (levelized Cost of Capacity) $/kW-Yr
-4.51%	Change in Usage
-3.89%	Minimum Change in Electrical Bills

Lifetime Costs and Benefits	*Discounted*				*Undiscounted*	
Cost Tests	Net Benefit	BC Ratio	IRR	Payback Yrs	Net Benefit	BC Ratio
RIM (RATEPAYER IMPACT MEASURE)	$(2,117,950)	0.87	N/A	N/A	$(3,123,664)	0.88
TRC/UCT (TOTAL RESOURCE & UTILITY COST TEST)	$13,352,586	32.12	451 %	1	$20,930,011	43.04
SCT (SOCIETAL COST TEST)	$14,419,190	34.61	486 %	1	$22,588,374	46.38

Using the billing data of August 2019 shared by Hydro Ottawa (see section 6.3) and June 2019-May 2020 SCADA-data, Sentient Energy estimated the electrical bill reduction based on customer class:

- **Residential Customers:**
  - Prior to CVR implementation, the monthly consumption is **786** kWh per customer or **9,430** kWh annually
  - CVR implementation has a negligeable impacts on LDC revenue (Fixed Monthly Service Charge + kWh-based LV Charges) that corresponds to $(170.56) over 12-months for **5,926** customers
  - For an average **7.29%** voltage reduction (**0.81** CVR factor for Energy), residential customers will see a reduction of their electrical bill by **4.56% ($71.69** annually before HST & Rebate or **$65.82** annually with HST & Rebate) while their energy usage will reduce by **5.90%**

Residential	Rates Effective January 1, 2021					
	Consumption @ 55880027 kWh			Consumption @ 52580377 kWh (5% Voltage Reduction)		
Charge Description	kWh	Rates	Customer Charge	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$40,533.84		$0.57	$40,533.84
Monthly Service Charge		$29.32	$2,085,003.84		$29.32	$2,085,003.84
Distribution Volumetric Rate	55,880,027	$0.0000	$0.00	52,580,377	$0.0000	$0.00
Low Voltage Charges	57,768,772	$0.00005	$2,888.44	54,357,594	$0.00005	$2,717.88
Adjusted Consumption	1,888,745			1,777,217		
Off-Peak	1,208,797	$0.085	$102,747.72	1,137,419	$0.085	$96,680.59
Mid-Peak	339,974	$0.119	$40,456.92	319,899	$0.119	$38,067.98
On-Peak	339,974	$0.176	$59,835.44	319,899	$0.176	$56,302.23
Network Charge	57,768,772	$0.0081	$467,927.05	54,357,594	$0.0081	$440,296.51
Connection Charge	57,768,772	$0.0050	$288,843.86	54,357,594	$0.0050	$271,787.97
Electricity Charge	55,880,027			52,580,377		
Off-Peak	35,763,217	$0.085	$3,039,873.47	33,651,441	$0.085	$2,860,372.50
Mid-Peak	10,058,405	$0.119	$1,196,950.18	9,464,468	$0.119	$1,126,271.67
On-Peak	10,058,405	$0.176	$1,770,279.25	9,464,468	$0.176	$1,665,746.34
Wholesale Market Service Rate	57,768,772	$0.0030	$173,306.32	54,357,594	$0.0030	$163,072.78
Capacity Based Recovery	57,768,772	$0.0004	$23,107.51	54,357,594	$0.0004	$21,743.04
Rural Rate Protection Charge	57,768,772	$0.0005	$28,884.39	54,357,594	$0.0005	$27,178.80
Standard Supply Service Charge		$0.25	$3.00		$0.25	$3.00
Total Loss Factor		1.0338			1.0338	
Total before HST & Rebate			**$9,320,641.22**			**$8,895,778.97**
Ontario Electricity Rebate		21.2%	$1,975,975.94		21.2%	$1,885,905.14
Total before HST with Rebate			**$7,344,665.28**			**$7,009,873.82**
HST 13%		13%	$1,211,683.36		13%	$1,156,451.27
Total with HST/Rebate			**$8,556,348.64**			**$8,166,325.09**

- **Small Commercial Customers (<50kW):**
  - Prior to CVR implementation, the monthly consumption is **3,494** kWh per customer or **41,933** kWh annually
  - With the CVR implementation, LDC revenue will see a decrease by **5.31%** of its revenue if no rate adjustment is made (Fixed Monthly Service Charge + kWh-based Distribution Volumetric Rate) = $(20,128.31) over 12-months for **289** customers
  - For an average **7.29%** voltage reduction (**0.89** CVR factor for Energy), small commercial customers will see a reduction of their electrical bill by **6.25% ($417.99** annually before HST & Rebate or **$383.71** annually with HST & Rebate) while their energy usage will reduce by **6.49%**

Small and Medium General Service < 50 kW	Rates Effective January 1, 2021					
	Consumption @ 12118560.069646 kWh Demand (on peak): 6 kW or 6.7 kVA			Consumption @ 11332298 kWh (5% Voltage Reduction) Demand (on peak): 6 kW or 6.7 kVA		
	Voltage < 5 kV			Voltage < 5 kV		
Charge Description	kWh	Rates	Customer Charge	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$1,976.76		$0.57	$1,976.76
Monthly Service Charge		$19.7600	$68,527.68		$19.7600	$68,527.68
Distribution Volumetric Rate	12,118,560	$0.02560	$310,235.14	11,332,298	$0.02560	$290,106.83
Low Voltage Charges	12,528,167	$0.00005	$626.41	11,715,330	$0.00005	$585.77
Adjusted Consumption	409,607			383,032		
Off-Peak	262,149	$0.085	$22,282.64	245,140	$0.085	$20,836.92
Mid-Peak	73,729	$0.119	$8,773.79	68,946	$0.119	$8,204.54
On-Peak	73,729	$0.1760	$12,976.36	68,946	$0.1760	$12,134.44
Network Charge	12,528,167	$0.0076	$95,214.07	11,715,330	$0.0076	$89,036.51
Connection Charge	12,528,167	$0.00480	$60,135.20	11,715,330	$0.00480	$56,233.58
Electricity Charge	12,118,560			11,332,298		
Off-Peak	7,755,878	$0.085	$659,249.67	7,252,671	$0.085	$616,477.01
Mid-Peak	2,181,341	$0.119	$259,579.56	2,039,814	$0.119	$242,737.82
On-Peak	2,181,341	$0.1760	$383,915.98	2,039,814	$0.1760	$359,007.20
Wholesale Market Service Rate	12,528,167	$0.0030	$37,584.50	11,715,330	$0.0030	$35,145.99
Capacity Based Recovery	12,528,167	$0.0004	$5,011.27	11,715,330	$0.0004	$4,686.13
Rural Rate Protection Charge	12,528,167	$0.00	$6,264.08	11,715,330	$0.00	$5,857.66
Standard Supply Service Charge		0.2500	$3.00		0.2500	$3.00
Total Loss Factor		1.0338			1.0338	
Total before HST & Rebate			**$1,932,356.11**			**$1,811,557.86**
Ontario Electricity Rebate*		21%	$409,659.50		21%	$384,050.27
Total before HST with Rebate			**$1,522,696.61**			**$1,427,507.59**
HST 13%		13%	$251,206.29		13%	$235,502.52
Total with HST			**$1,773,902.91**			**$1,663,010.11**

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- **Small & Large C&I Customers (General Services >50kW to 1,599kW):**
    - Prior to CVR implementation, the monthly consumption is **184,343** kWh per customer or **2,212,118** kWh annually
    - With the CVR implementation, LDC revenue will see a decrease by **7.29%** of its revenue if no rate adjustment is made (Fixed Monthly Service Charge + kWh-based Distribution Volumetric Rate) = $(93,712.48) over 12-months for **91** customers
    - For an average **7.29%** voltage reduction (**0.55** CVR factor for Energy), small & large C&I customers will see a reduction of their electrical bill by **4.07% ($14,377.05** annually before HST & Rebate or **$13,198.14** annually with HST & Rebate) while their energy usage will reduce by **4.01%**

	Rates Effective January 1, 2021					
Small and Medium General Service 50 to 1,499 kW	Consumption @ kWh			Consumption @ 0 kWh (5% Voltage Reduction)		
	Demand (on peak): 100 kW or 111 kVA			Demand (on peak): 100 kW or 111 kVA		
	Voltage < 5 kV			Voltage < 5 kV		
Charge Description	Usage	Rates	Customer Charge	Usage	Rates	Customer Charge
Monthly Service Charge		$200.00	$218,400.00		$200.00	$218,400.00
Distribution Volumetric Rate	30,982	$5.2905	$1,966,941.98	29,506	$5.2905	$1,873,229.56
Low Voltage Charges	30,982	$0.0196	$7,301.91	29,506	$0.01964	$6,954.02
Network Charge	30,982	$3.1059	$1,154,734.92	29,506	$3.1059	$1,099,719.06
Connection Charge	30,982	$1.9644	$730,339.44	29,506	$1.9644	$695,543.36
Electricity Charge	208,106,781	$0.01825	$3,797,948.75	199,762,764	$0.01825	$3,645,670.44
Global Adjustment	208,106,781	$0.11261	$23,434,904.57	199,762,764	$0.11261	$22,495,284.81
Wholesale Market Service Rate	208,106,781	$0.0030	$624,320.34	199,762,764	$0.0030	$599,288.29
Capacity Based Recovery	208,106,781	$0.0004	$83,242.71	199,762,764	$0.0004	$79,905.11
Rural Rate Protection Charge	208,106,781	$0.0005	$104,053.39	199,762,764	$0.0005	$99,881.38
Standard Supply Service Charge		$0.25	$3.00		$0.25	$3.00
Total Loss Factor		1.0338			1.0338	
Total before HST & Rebate		0.0000	**$32,122,191.02**			**$30,813,879.02**
Ontario Electricity Rebate*		21.2%	$6,809,904.50		21.2%	$6,532,542.35
Total before HST with Rebate			**$25,312,286.52**			**$24,281,336.67**
HST 13%		13%	$4,175,884.83		13%	$4,005,804.27
Total with HST			**$29,488,171.36**			**$28,287,140.94**

5.5. Economics Conclusion

Benefits of CVR accrue primarily to the utility and customers. The CVR benefit with the largest and clearest payback, and hence of most interest to Hydro Ottawa, was Capacity Reduction and Energy Savings and loss reduction are other benefits.

CVR enables Hydro Ottawa to either achieve a significant reduction:

- in energy (**3.87%** in **June 2018-May 2019 or 4.51%** in **June 2019 – May 2020**)
    - The Kanata MTS project demonstrated a potential annual consumer bill reduction (CVR 7/24/365) in the range of **$71.69** to **$14,377** (before HST & Ontario electricity rebate) per consumer class without requiring any change in consumer behavior nor participant costs in comparison with traditional demand-side management program

- VVO/CVR is beneficial to all consumers (low, mid, or high-income) and is considered as In-Front-of-the-Meter Conservation technology or also named supply-side management
- Levelized Cost of Energy Saved is in the range of **$0.365** and **$0.352** cts per kWh saved
- Considering the marginal purchase energy rate (total cost of power before HST with Ontario electricity rebate) of **$10.82** cts/kWh, the project demonstrated that energy savings is cheaper than making and transmitting energy
- 2021 marginal purchase energy rate (total cost of power before HST with Ontario electricity rebate) is around **$10.82**

and/or

- in capacity (**~1.40 MW** - July 2018 Peak - to **~2.38 MW** - January 2019 Peak- shaved from **June 2018** through **May 2019**) **or** (**~1.61 MW** - July 2019 Peak- to **~2.37 MW** - January 2020 Peak - shaved from **June 2019** through **May 2020**)
  - The Kanata MTS project demonstrated a potential Voltage Reduction by 5%-6% without impacting customers through load shedding or major equipment investments
  - The proposed MV upgrades/ENGO deployment as a Non-Wires Alternatives solution can offset distribution investment by deferring or replacing the need for specific equipment upgrades such as T&D lines or power transformers by reducing load / demand at a substation or circuit level (CAPEX Deferral).
  - CVR is a cheap solution to reduce demand or increase substation/line capacity with a Levelized of Capacity Cost (LCOC) shaved in the range of **$26.15** and **$30.21** per kW-Yr

The deployed technology at Kanata MTS enables greater savings without compromising power quality and grid reliability and demonstrates cost-effectiveness thresholds higher than initially reported by Navigant considering only medium voltage or primary VVC equipment (i.e., Line Voltage Regulator, Switched Cap Banks etc.). The addition of Low Voltage or secondary VVC equipment such as ENGO devices reduces the overall LCOE and LCOC and increases the BCR and the number of eligible VVO feeders versus primary VVC only.

As mentioned earlier, the quantified benefit of reduced greenhouse gas (GHG) emissions was not considered in RIM or TRC/UCT BCR calculation. Any monetized benefits related to the reduction of GHG would be added to the annual consumer bill reduction.

6. Kanata MTS Overview

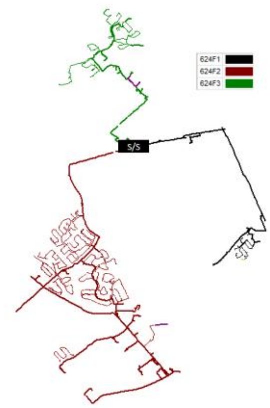
6.1. One Line Diagram and Circuit Information

The Kanata MTS is in Kanata, Ontario, Canada. The Kanata MTS has two transformer banks T1 and T2 feeding a total of five (5) feeders. Figure 4 shows the one-line diagram for the feeders connected to transformer T1 and transformer T2 obtained from the CYME model.

The circuit operates at 27.6 kV (L-L) and it is controlled by a single LTC or AVR (Automatic Voltage Regulator). The two transformer T1 and T2 are connected using a tie-switch under normal operation. However, under emergency peak conditions when the total real power flow through both the transformer banks exceeds 60.5 MW, the tie-switch is opened, and the two banks are manually controlled while the LTC is offline.

Model Specs of Kanata Substation Transformer T1:

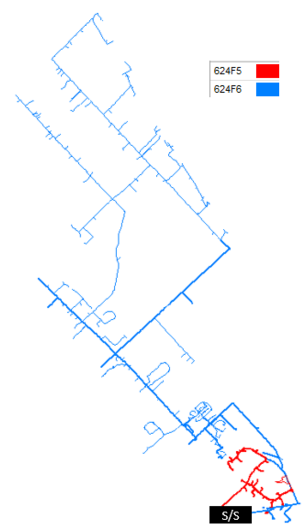
- Nominal: 27.6 kV (L-L), 15.9 kV (L-N)
- LTC SP: CB = 122V, BW = 4V
- 3 Feeders: 624F1, 624F2, 624F3
- Total 28 MW, 11.9 MVAr, PF = 91%
  - F1: 12.89 MW, 5.48 MVAr
  - F2: 13.8 MW, 5.87 MVAr
  - F3: 1.34 MW, 0.57 MVAr
- 0 Line Cap banks and 0 LVRs
- Maximum length from substations ≈ 8.96 km
- 389 service transformers



T1 Bank

Model Specs of Kanata Substation Transformer T2:

- Nominal: 27.6 kV (L-L), 15.9 kV (L-N)
- Two Step Down Transformers: 27.6 kV (L-L) / 12.43 kV (L-L)
- LTC SP: CB = 122V, BW = 4V
- 2 Feeders: 624F5, 624F6
- Total 20.3 MW, 8.75 MVAr, PF = 91.8%
  - F5: 12.6 MW, 5.46 MVAr
  - F6: 7.78 MW, 3.29 MVAr
- 0 Line Cap banks and 0 LVRs
- Maximum length from substations ≈ 22.3 km
- 486 service transformers

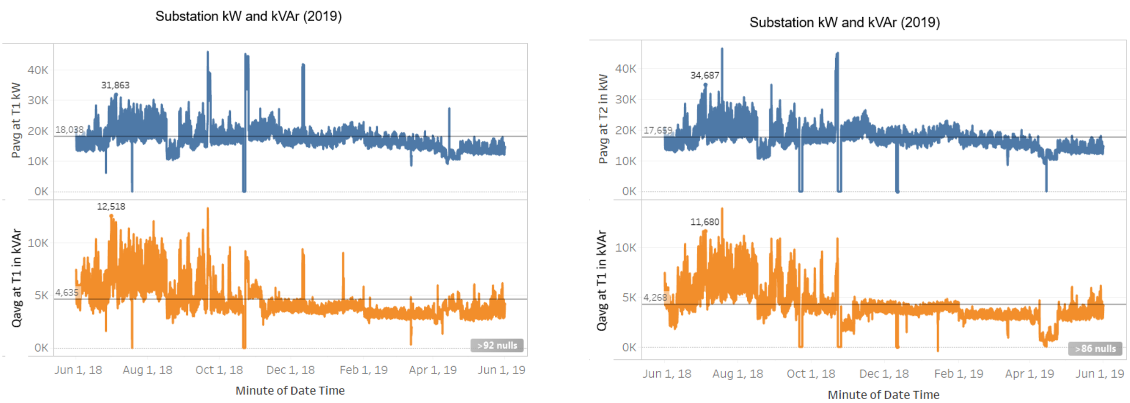


T2 Bank

Figure 4: Kanata MTS Circuit One-line Diagram for all Feeders Connected to Transformer Banks T1 and T2

6.2. Historical Kanata MTS Power Flow

Figure 5 shows the Kanata MTS load (real power P and reactive power Q) at the two transformer banks T1 and T2 between June 2018 and May 2019. The summer peak of 31.9 MW on T1 and 34.7 on T2 happens around July. In comparison, the CYME model for the two transformers has peaks of 28MW and 20.3MW, respectively.



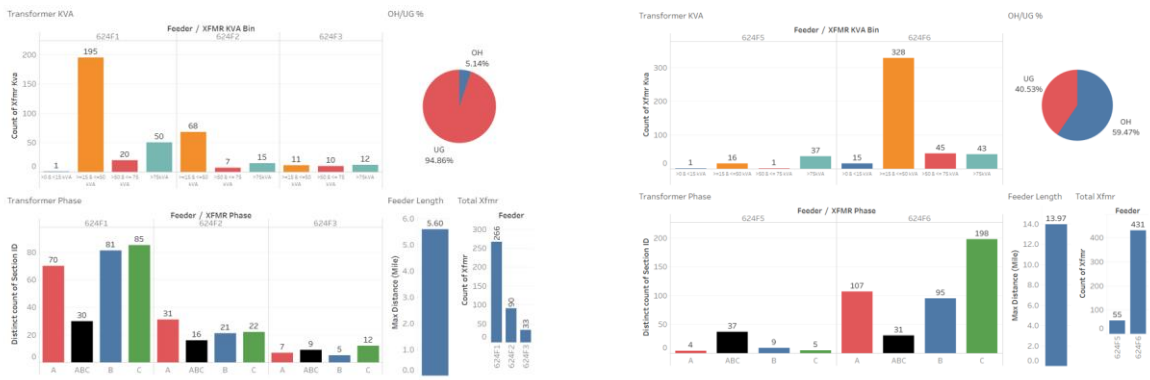
T1 Bank T2 Bank

Figure 5: Kanata MTS MW and MVAr Flow in 2018-2019

6.3. Load Type / Mix and Customer Class

Figure 6 depicts the metrics for service transformers on banks T1 and T2 on the Kanata MTS. The first plot shows the distribution of service transformers by kVA ratings across the different feeders. The second plot shows the percentage of overhead and underground sections.

The third plot shows the distribution of service transformers by phase (A, B, C, ABC) and the final plot shows the feeder length and the number of service transformers per feeder. It is seen that for T1 most sections are underground (~95%) while for T2 the majority is overhead (~60%). Further, a load report is run in CYME to obtain the type (residential, commercial, industrial etc.) and the combined connected kVA ratings of the service transformers is used to calculate the ratio of commercial and industrial load to residential load. Kanata MTS is found to have a high ratio of C&I customers as compared to Residential customers (Ratio C&I: Residential 2.22 for T1 and 2.48 for T2).



T1 Bank T2 Bank

Figure 6: Kanata's Service Transformer Metrics

Hydro Ottawa shared with Sentient Energy the billing data of August 2019 to give a rough snapshot of the consumption/demand in the Kanata MTS area. The account match represents **87%** of residential customers, **88%** of small commercial customers (<50kW) and **90% of** small & large customers (General Service >50 to 1,599kW).

- Number of customers serviced in Kanata:
  - ✓ Residential - **5,330**
  - ✓ Small Commercial <50kW - **263**
  - ✓ Commercial - **85**
- Total kWh consumed per rate class based on the accounts match (see above):
  - ✓ Residential - **3,904,088** kWh (**17**%)
  - ✓ Small Commercial <50kW - **915,915** kWh (**4**%)
  - ✓ Commercial - **17,819,987** kWh (**79**%)
- Total kW when applicable per rate class
  - ✓ Commercial Demand - **31,183 kW** (Represents **43** Commercial Customers)

Based on the above data, **22,639,990** kWh have been billed to those customers. Considering a technical loss of **3.27%**, **23,405,222** kWh have been purchased by Hydro Ottawa (to be compared with **24,662,112** kWh reported by the SCADA system).

Therefore, Sentient Energy scaled the billing data of August 2019 per customer class to match 1-year of SCADA data (from June 2019 to May 2020 = **278,404** MWh) and 100% of the customer consumption/demand:

- Residential Customers
  - ✓ **5,926** customers (vs. 5,330)
  - ✓ **4,340,287** kWh in Aug 2019 (vs. 3,904,088 kWh)
  - ✓ Average monthly load of **786** kWh over 12-months (**732** kWh considering Aug 2019)
  - ✓ Average monthly electrical bill of $**120.32** over 12-months with Ontario Electricity Rebate and HST ($**114.01** considering Aug 2019)

Table 17: Monthly Electrical Bill of Residential Customers

	Consumption @ 4340287 kWh		
Charge Description	**kWh**	**Rates**	**Customer Charge**
Smart Metering Entity Charge		$0.57	$3,377.82
Monthly Service Charge		$29.32	$173,750.32
Distribution Volumetric Rate	4,340,287	$0.0000	$0.00
Low Voltage Charges	4,486,989	$0.00005	$224.35
Adjusted Consumption	146,702		
Off-Peak	93,889	$0.085	$7,980.57
Mid-Peak	26,406	$0.119	$3,142.35
On-Peak	26,406	$0.176	$4,647.51
Network Charge	4,486,989	$0.0081	$36,344.61
Connection Charge	4,486,989	$0.0050	$22,434.94
Electricity Charge	4,340,287		
Off-Peak	2,777,784	$0.085	$236,111.60
Mid-Peak	781,252	$0.119	$92,968.94
On-Peak	781,252	$0.176	$137,500.29
Wholesale Market Service Rate	4,486,989	$0.0030	$13,460.97
Capacity Based Recovery	4,486,989	$0.0004	$1,794.80
Rural Rate Protection Charge	4,486,989	$0.0005	$2,243.49
Standard Supply Service Charge		$0.25	$0.25
Total Loss Factor		1.0338	
Total before HST & Rebate			**$735,982.81**
Ontario Electricity Rebate		21.2%	$156,028.36
Total before HST with Rebate			**$579,954.45**
HST 13%		13%	$95,677.77
Total with HST			**$675,632.22**

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Table 18: Annual Electrical Bill of Residential Customers

	Consumption @ 55880027 kWh		
Charge Description	**kWh**	**Rates**	**Customer Charge**
Smart Metering Entity Charge		$0.57	$40,533.84
Monthly Service Charge		$29.32	$2,085,003.84
Distribution Volumetric Rate	55,880,027	$0.0000	$0.00
Low Voltage Charges	57,768,772	$0.00005	$2,888.44
Adjusted Consumption	1,888,745		
Off-Peak	1,208,797	$0.085	$102,747.72
Mid-Peak	339,974	$0.119	$40,456.92
On-Peak	339,974	$0.176	$59,835.44
Network Charge	57,768,772	$0.0081	$467,927.05
Connection Charge	57,768,772	$0.0050	$288,843.86
Electricity Charge	55,880,027		
Off-Peak	35,763,217	$0.085	$3,039,873.47
Mid-Peak	10,058,405	$0.119	$1,196,950.18
On-Peak	10,058,405	$0.176	$1,770,279.25
Wholesale Market Service Rate	57,768,772	$0.0030	$173,306.32
Capacity Based Recovery	57,768,772	$0.0004	$23,107.51
Rural Rate Protection Charge	57,768,772	$0.0005	$28,884.39
Standard Supply Service Charge		$0.25	$3.00
Total Loss Factor		1.0338	
Total before HST & Rebate			**$9,320,641.22**
Ontario Electricity Rebate		21.2%	$1,975,975.94
Total before HST with Rebate			**$7,344,665.28**
HST 13%		13%	$1,211,683.36
Total with HST/Rebate			**$8,556,348.64**

- ✓ Annual Purchased Energy: **57,768,772** kWh
- ✓ Annual Billed Energy: **55,880,027** kWh
- ✓ Peak Load: **9,380** kW (July 2019)
- ✓ CVR factor for Energy: **0.81 (average) + 0.74 (July 2019)**
- ✓ CVR factor for Power: **0.85 (average) + 0.80 (July 2019)**

▪ Small and Medium General Service < 50 kW

- ✓ **289** customers (vs. 263)
- ✓ **1,005,395** kWh in Aug 2019 (vs. 915,915 kWh)
- ✓ Average monthly load of **3,165** kWh over 12-months (**3,479** kWh considering Aug 2019)
- ✓ Average monthly electrical bill of $**499.65** over 12-months with Ontario Electricity Rebate and HST ($**509.32** considering Aug 2019)

Table 19: Monthly Electrical Bill of Small Commercial Customers (<50kW)

Small and Medium General Service < 50 kW	Consumption @ 1005395.1701427 kWh Demand (on peak): 6 kW or 6.7 kVA		
	Voltage < 5 kV		
Charge Description	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$164.73
Monthly Service Charge		$19.7600	$5,710.64
Distribution Volumetric Rate	1,005,395	$0.02560	$25,738.12
Low Voltage Charges	1,039,378	$0.00005	$51.97
Adjusted Consumption	33,982		
Off-Peak	21,749	$0.085	$1,848.64
Mid-Peak	6,117	$0.119	$727.90
On-Peak	6,117	$0.1760	$1,076.56
Network Charge	1,039,378	$0.0076	$7,899.27
Connection Charge	1,039,378	$0.00480	$4,989.01
Electricity Charge	1,005,395		
Off-Peak	643,453	$0.085	$54,693.50
Mid-Peak	180,971	$0.119	$21,535.56
On-Peak	180,971	$0.1760	$31,850.92
Wholesale Market Service Rate	1,039,378	$0.0030	$3,118.13
Capacity Based Recovery	1,039,378	$0.0004	$415.75
Rural Rate Protection Charge	1,039,378	$0.00	$519.69
Standard Supply Service Charge		0.2500	$0.25
Total Loss Factor		1.0338	
Total before HST & Rebate			**$160,340.64**
Ontario Electricity Rebate*		21%	$33,992.22
Total before HST with Rebate			**$126,348.43**
HST 13%		$0.1300	$20,844.28
Total with HST			**$147,192.71**

Table 20: Annual Electrical Bill of Small Commercial Customers (<50kW)

Small and Medium General Service < 50 kW	Consumption @ 12118560.069646 kWh Demand (on peak): 6 kW or 6.7 kVA		
	Voltage < 5 kV		
Charge Description	kWh	Rates	Customer Charge
Smart Metering Entity Charge		$0.57	$1,976.76
Monthly Service Charge		$19.7600	$68,527.68
Distribution Volumetric Rate	12,118,560	$0.02560	$310,235.14
Low Voltage Charges	12,528,167	$0.00005	$626.41
Adjusted Consumption	409,607		
Off-Peak	262,149	$0.085	$22,282.64
Mid-Peak	73,729	$0.119	$8,773.79
On-Peak	73,729	$0.1760	$12,976.36
Network Charge	12,528,167	$0.0076	$95,214.07
Connection Charge	12,528,167	$0.00480	$60,135.20
Electricity Charge	12,118,560		
Off-Peak	7,755,878	$0.085	$659,249.67
Mid-Peak	2,181,341	$0.119	$259,579.56
On-Peak	2,181,341	$0.1760	$383,915.98
Wholesale Market Service Rate	12,528,167	$0.0030	$37,584.50
Capacity Based Recovery	12,528,167	$0.0004	$5,011.27
Rural Rate Protection Charge	12,528,167	$0.00	$6,264.08
Standard Supply Service Charge		0.2500	$3.00
Total Loss Factor		1.0338	
Total before HST & Rebate			**$1,932,356.11**
Ontario Electricity Rebate*		21%	$409,659.50
Total before HST with Rebate			**$1,522,696.61**
HST 13%		13%	$251,206.29
Total with HST			**$1,773,902.91**

- ✓ Annual Purchased Energy: **12,528,167** kWh
- ✓ Annual Billed Energy: **12,118,560** kWh
- ✓ Peak Load: **2,154** kW (July 2019)
- ✓ CVR factor for Energy: **0.89 (average) + 0.76 (July 2019)**
- ✓ CVR factor for Power: **0.92 (average) + 0.82 (July 2019)**

- Small and Medium General Service > 100 kW
  - ✓ **91** customers (vs. 85)
  - ✓ **19,819,583** kWh in Aug 2019 (vs. 17,819,987 kWh)
  - ✓ Average monthly load of **3,191,695** kWh over 12-months (**210,677** kWh considering Aug 2019)
  - ✓ Average monthly electrical bill of $**29,022.20** over 12-months with Ontario Electricity Rebate and HST ($**30,895.31** considering Aug 2019)

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Table 21: Monthly Electrical Bill of Small & Large Commercial Customers (>50kW to 1,599kW)

Small and Medium General Service 50 to 1,499 kW	Consumption @ 19171583.6471221 kWh		
	Demand (on peak): 100 kW or 111 kVA		
	Voltage < 5 kV		
Charge Description	**Usage**	**Rates**	**Customer Charge**
Monthly Service Charge		$200.00	$18,200.00
Distribution Volumetric Rate	35,983	$5.2905	$190,368.06
Low Voltage Charges	35,983	$0.01964	$706.71
Network Charge	35,983	$3.1059	$111,759.60
Connection Charge	35,983	$1.9644	$70,685.01
Electricity Charge	19,819,583	$0.01825	$361,707.39
Global Adjustment	19,819,583	$0.11261	$2,231,883.26
Wholesale Market Service Rate	19,819,583	$0.0030	$59,458.75
Capacity Based Recovery	19,819,583	$0.0004	$7,927.83
Rural Rate Protection Charge	19,819,583	$0.0005	$9,909.79
Standard Supply Service Charge		$0.25	$0.25
Total Loss Factor		1.0338	
Total before HST & Rebate			**$3,062,606.65**
Ontario Electricity Rebate*		21.2%	$649,272.61
Total before HST with Rebate			**$2,413,334.04**
HST 13%		13%	$398,138.86
Total with HST			**$2,811,472.91**

Table 22: Annual Electrical Bill of Small & Large Commercial Customers (>50kW to 1,599kW)

Small and Medium General Service 50 to 1,499 kW	Consumption @ 201302747.823564 kWh		
	Demand (on peak): 100 kW or 111 kVA		
	Voltage < 5 kV		
Charge Description	**Usage**	**Rates**	**Customer Charge**
Monthly Service Charge		$200.00	$218,400.00
Distribution Volumetric Rate	41,278	$5.2905	$2,620,580.77
Low Voltage Charges	41,278	$0.01964	$9,728.42
Network Charge	41,278	$3.1059	$1,538,467.41
Connection Charge	41,278	$1.9644	$973,040.14
Electricity Charge	208,106,781	$0.01825	$3,797,948.75
Global Adjustment	208,106,781	$0.11261	$23,434,904.57
Wholesale Market Service Rate	208,106,781	$0.0030	$624,320.34
Capacity Based Recovery	208,106,781	$0.0004	$83,242.71
Rural Rate Protection Charge	208,106,781	$0.0005	$104,053.39
Standard Supply Service Charge		$0.25	$3.00
Total Loss Factor		1.0338	
Total before HST & Rebate			**$33,404,689.51**
Ontario Electricity Rebate*		21.2%	$7,081,794.18
Total before HST with Rebate			**$26,322,895.33**
HST 13%		13%	$4,342,609.64
Total with HST			**$30,665,504.97**

- ✓ Annual Purchased Energy: **208,106,781** kWh
- ✓ Annual Billed Energy: **208,106,781** kWh
- ✓ Peak Load: **41,278** kW (July 2019)
- ✓ Average Peak Load: **30,982** kW

- ✓ CVR factor for Energy: **0.55 (average) + 0.43 (July 2019)**
- ✓ CVR factor for Power: **0.56 (Summer) + 0.44 (July 2019)**

6.4. GEMS+ENGO Deployment

An initial analysis was performed by Sentient Energy based on the CYME models provided for both T1 and T2. The results of this analysis for T1 showed that a deployment of 3 Pole-ENGO units for visibility was sufficient. While, for T2 there was a need to deploy 40 Pole-ENGO units to achieve maximum incremental voltage improvement.

A plot Figure 7 shows the voltage profile at the secondary side of the service transformer comparing voltages without and with ENGO deployment on Kanata T2 under peak load. The voltage improvement achieved with 40 Pole-ENGO devices at the optimal locations is 5.4V (4.5%). The final list of ENGO deployment is shown in Appendix. Also, the deployment map of ENGO devices on the CYME model is shown in Figure 8.

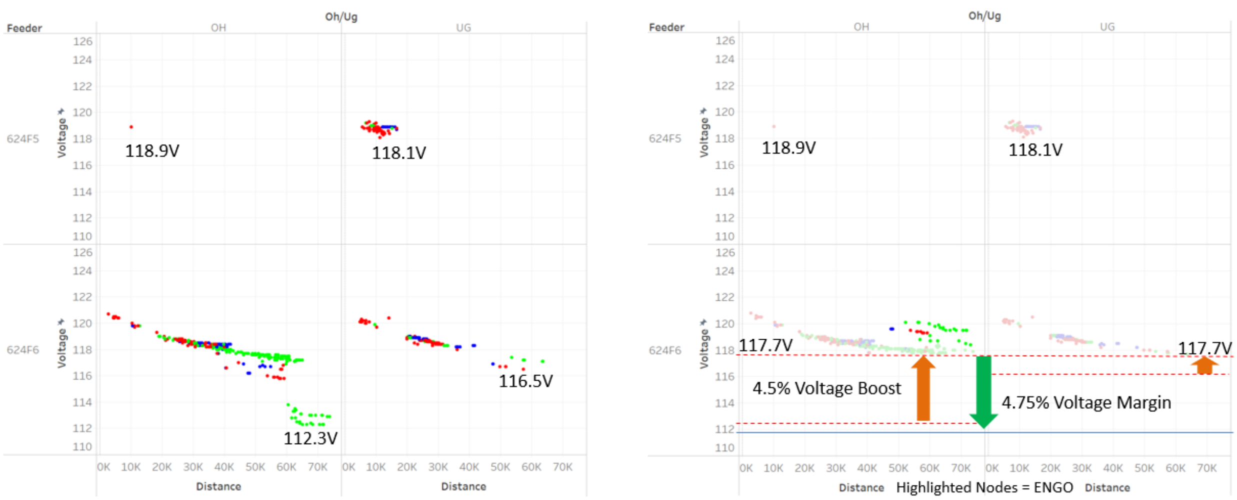


Figure 7: Initial analysis performed prior to contract signature to find the estimated number of ENGO devices and their locations in Kanata MTS

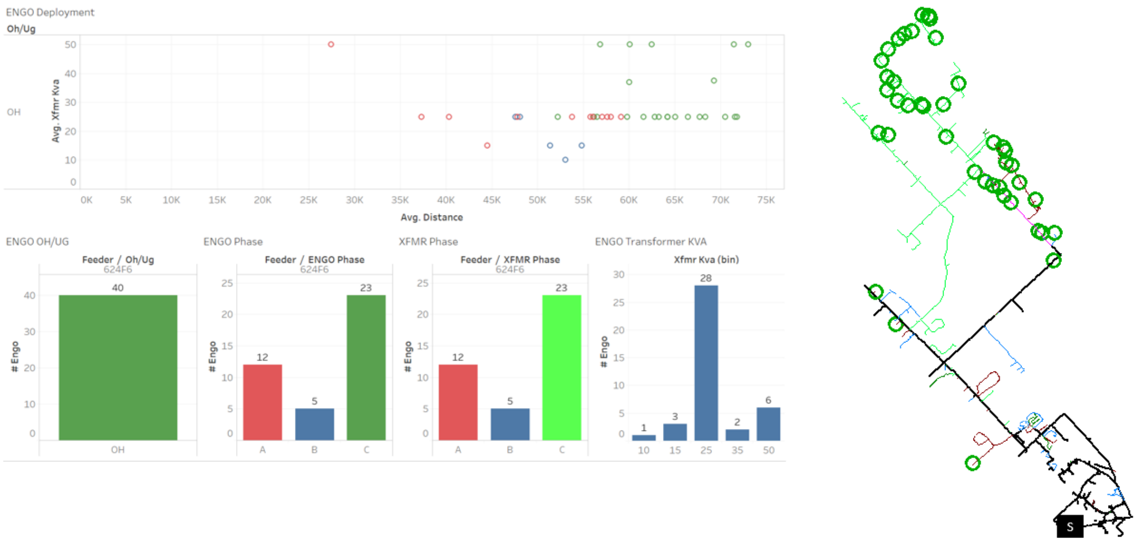


Figure 8: The final ENGO locations on a one-line diagram of feeders connected to bank T2 as per the initial analysis performed

However, due to practical constraints several pole locations identified in the initial study were not feasible for deployment. Therefore, a re-analysis was performed where Sentient Energy provided a priority list of alternative ENGO locations with the assumption that the overall voltage improvement would reduce. For this analysis, Sentient Energy relied on AMI data that was shared post the first analysis. A priority list of units based on the AMI analysis is shown in the Appendix. Hydro Ottawa chose the alternative locations from this list based on feasible pole locations. Sentient Energy also recommended some transformer upgrades that would help boost the system performance.

The final voltage profile with the alternative locations is shown in Figure 9. The voltage improvement without and with ENGO deployment as per CYME model analysis is also provided. As expected, the voltage improvement reduces due to the locations chosen as alternatives and the fact that not all are at the optimal locations. However, a healthy 3.1V (2.6%) improvement is still achieved with the 40 Pole-ENGO devices. The ENGO deployment locations on the CYME model is shown in Figure 10.

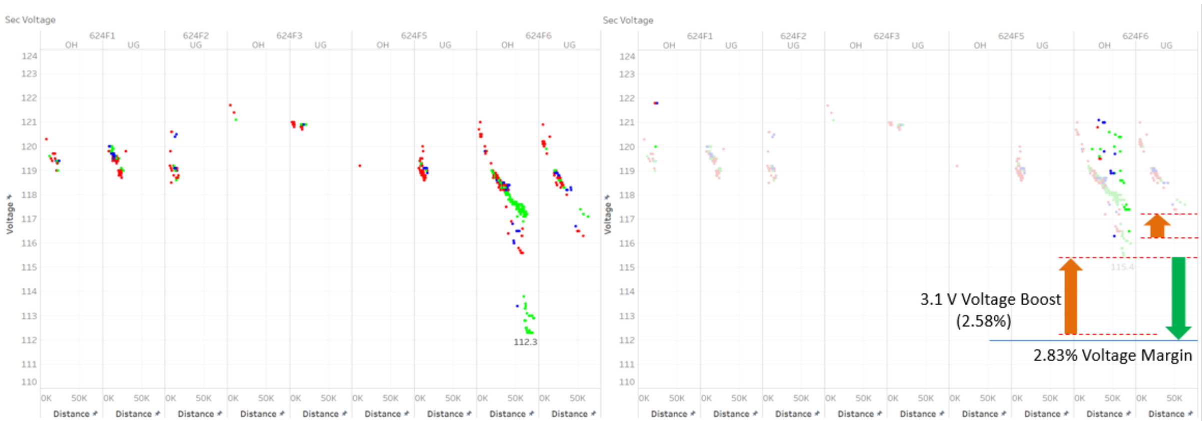


Figure 9: Analysis performed after Hydro Ottawa completed the pole survey. As several locations from the initial analysis were infeasible for deployment, a list of alternative locations was generated using AMI data. The voltage improvement estimates were found using CYME for the final locations.

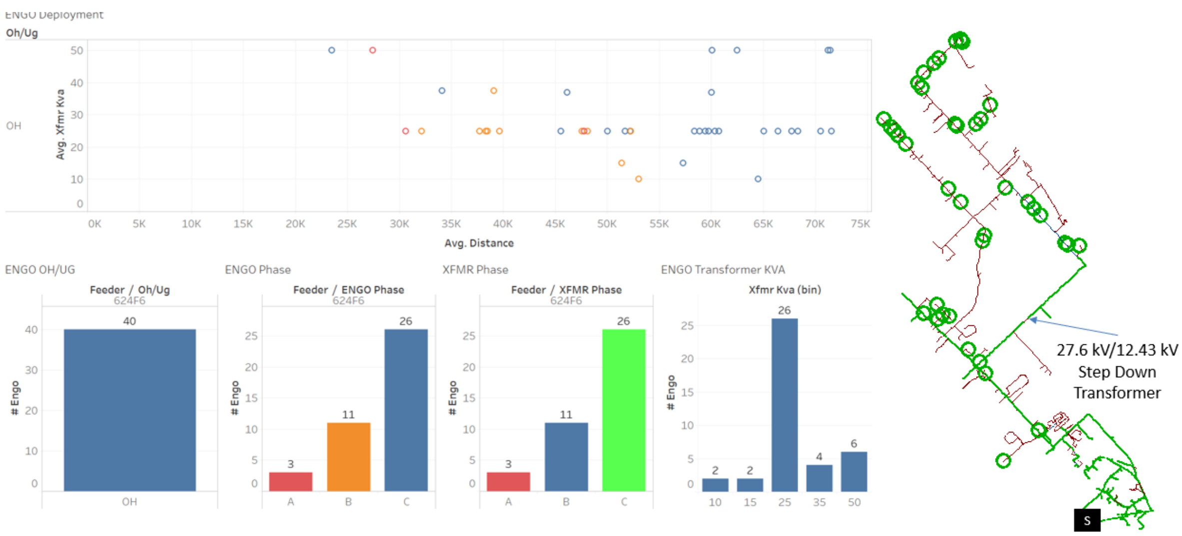


Figure 10: The final ENGO locations on a one-line diagram of feeders connected to bank T2 as per the final analysis performed

The installation of 43 ENGO units was completed on 4th May 2020 and the GEMS software was also commissioned and operational since 10th February 2020.

Table 23 below summarizes ENGO unit deployment by phase:

Table 23: Summary of Kanata ENGO Unit Deployment

	Kanata T1			Kanata T2		Total by Phase
Feeder	**624F1**	**624F2**	**624F3**	**624F5**	**624F6**	
Phase A	1	0	0	0	3	**4**
Phase B	1	0	0	0	11	**12**
Phase C	1	0	0	0	26	**27**
Feeder Total	3	0	0	0	40	**43**

7. ENGO EM&V Test Plan

The test plan and the project timeline are shown in Table 24. It is followed by brief definitions of each type of testing.

Table 24: Testing Schedule

Project Segment	Objectives	Duration	Date Range
Kanata MTS Testing			
• ENGO Install & Monitoring	Baseline Monitoring	6 Weeks	April/May 2020
• ENGO On/Off Testing	Core Metrics	2 Weeks	May/June 2020
• CVR Capacity Reduction Testing	Capacity Reduction (2.5%)	6 Weeks	July/Aug 2020
• CVR Capacity Reduction Testing	Capacity Reduction (5%)	2 Weeks	Sept 2020
• Energy Savings Testing	Energy Saving	6 Weeks	Nov/Dec 2020

7.1. Test Procedure 1 – ENGO DAY ON/OFF Test:

In this test procedure, all ENGO devices are turned ON and OFF on alternate days. During the DAY ON/OFF test, the FHR Set-Point is fixed. The Day ON/OFF testing demonstrates the benefits to improve voltage margin and grid edge voltage support provided by ENGO units. In general, 20 days daily toggling of ENGO unit VAR injection helps us measure:

- **Voltage Control Margin**: Percentage voltage control available without and with ENGO
- **Voltage Improvement**: Percentage voltage boost that is provided by ENGO devices at the weakest location on the system

7.2. Test Procedure 2 – Peak Demand Reduction Testing

In this test, the LTC setpoint is switched between nominal setpoint and CVR setpoint during the peak load hours on alternate days. The ENGO setpoint is adjusted to match the LTC setpoint. This test measures:

- **Maximum Voltage Reduction**: maximum voltage reduction with ENGO without causing any CSA violations
- **CVR Factor for Power**: Based on the voltage transitions measured whenever the LTC setpoint is toggled from nominal to CVR setpoint, the CVR factor for power can be measured.
- **Demand Reduction**: Using the measured CVR factor and the voltage reduction measured in the field, the demand reduction can be computed for the test duration.
- **Technical Loss Reduction**: As a result of reducing the voltage across the entire feeder, the transformers are energized with lower voltage which tends to reduce the core losses on the transformer. This reduction in core losses can be estimated during this test. Further, there is a general power factor improvement that leads to lower line and transformer copper losses.

7.3. Test Procedure 3 – Energy Savings Testing

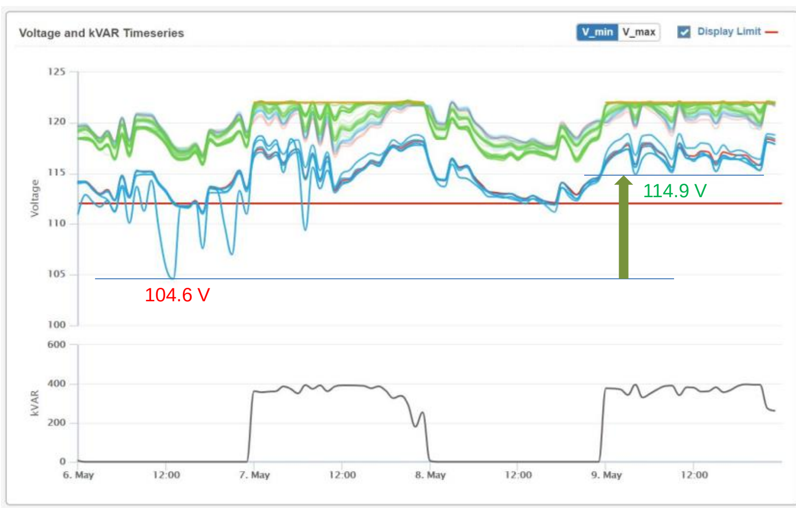
In this test, the LTC setpoint is switched between nominal setpoint and CVR setpoint (24-hour intervals) on alternate days. The ENGO setpoint is adjusted to match the LTC setpoint. This test measures:

- **Maximum Voltage Reduction**: maximum voltage reduction with ENGO without causing any CSA violations
- **CVR Factor for Energy**: Based on the voltage transitions measured whenever the LTC setpoint is toggled from nominal to CVR setpoint, the CVR factor for energy can be measured.
- **Reduction in Energy Consumption**: Using the measured CVR factor and the voltage reduction measured in the field, the energy savings can be computed for the test duration.
- **Technical Loss Reduction**: As a result of reducing the voltage across the entire feeder, the transformers are energized with lower voltage which tends to reduce the core losses on the transformer. Further, there is a general power factor improvement that leads to lower line and transformer copper losses.
- **Environmental Benefits**: Annual CO_2 emission reduction can be estimated using the energy saved metrics.
- The Energy Savings Test will continue over the months of November and December 2020 and the $CVR_{f\ Energy}$ will be calculated. This report contains the MWh Energy Saving and Environmental Benefit metrics using the CVR factor for power which was calculated as part of the capacity reduction test.

8. EM&V Test Metrics

8.1. Impact of System Upgrades and ENGO Voltage Improvement

Hydro Ottawa upgraded the rating of an overloaded transformer (X07487) recommended by Sentient Energy. This led to a significant voltage improvement in the system. Further, ENGOs provided a voltage improvement on top of the improvement obtained from the system upgrade. The proof of this improvement is shown in Figure 11: GEMS plot shows voltage improvement as a result of the transformer upgrade and ENGO devices deployed in the field from an initial low voltage of 104.6V to a final minimum voltage of 114.9V. It can be seen that prior to May 6th, 2020, the minimum voltage recorded by ENGOs is 104.6V. Around May 7th the limiting transformer was replaced with an upgraded bank and the ENGO units were in the auto-toggle ON/OFF schedule, therefore on May 9th, 2020, the minimum voltage recorded a jump up to 114.9V. Therefore, the overall effect of Sentient Energy recommended system upgrades and ENGO devices in the system allowed an effective voltage increase from 104.6V to 114.6V (8.3%) – demonstrating no CSA violations.



Unit	Phase	V_min
2100193	B	104.6
2122829	B	111
2125813	B	111.2
2112692	B	111.2
2106377	A	111.2
2010366	C	115.8
13496871	C	115.9
13496498	C	116
2010352	C	116
2100730	C	116
2100729	C	116.1
13496610	C	116.1
13496536	C	116.1
2123642	C	116.5
2120826	C	116.5

Figure 11: GEMS plot shows voltage improvement as a result of the transformer upgrade and ENGO devices deployed in the field from an initial low voltage of 104.6V to a final minimum voltage of 114.9V

Based off the success of system upgrades combined with ENGO voltage support, a study was conducted to identify outliers that would enable performing a 5% reduction at the LTC. Five transformers are selected for tap setting changes (X07491, X07487) and connected kVA rating upgrades (X07484, X50916, X07508). These enhancements were incorporated over the months of July and August boosting the available voltage margin for load reduction and energy savings. The minimum voltage recorded jumps up to 118V+ providing a 6V-7V margin for CVR (CSA voltage threshold of 111V-112V at the distribution transformer).

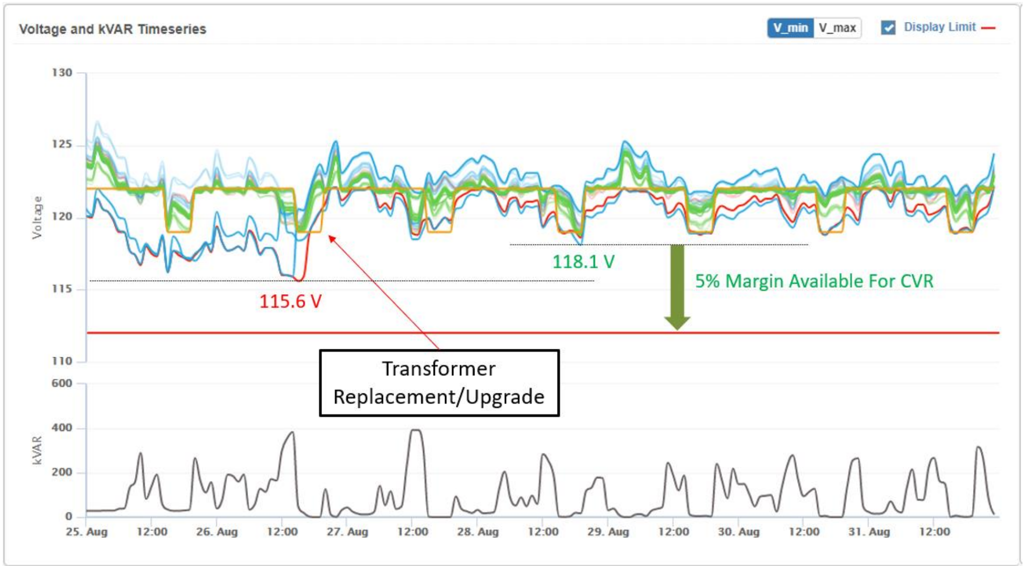


Figure 12: GEMS plot shows voltage improvement as a result of the transformer upgrade and ENGO devices deployed in the field boosting voltage to a final minimum of 118.1V

8.2. ENGO ON/OFF Testing Result

8.2.1. Substation Loading and Voltage Profile

The loading at Kanata MTS for both the transformer banks T1 and T2 is shown in Figure 13. It can be seen that the AVR was fixed around June 5th, 2020 and bank T2 was brought online and the load was shared between T1 and T2. Further, if we look at Figure 14 which shows the voltage per phase at the substation, it is seen that prior to June 5th in the absence of regulation the swing in substation voltage was large (~117V to ~126V) and the average substation voltage was around 122V. After the AVR fix, the voltage is much more controlled and swings within the bandwidth of the AVR. Also, the average voltage is around 124V after the AVR fix.

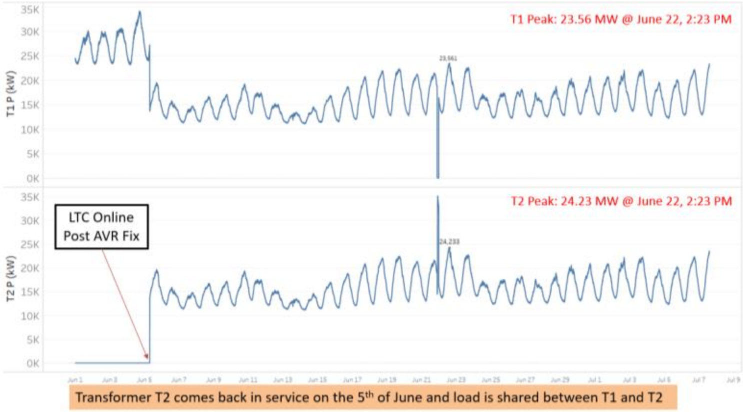


Figure 13: Substation MW loading on both banks T1 and T2 shows that the AVR was fixed around June 5th consequently the power is shared between the two banks

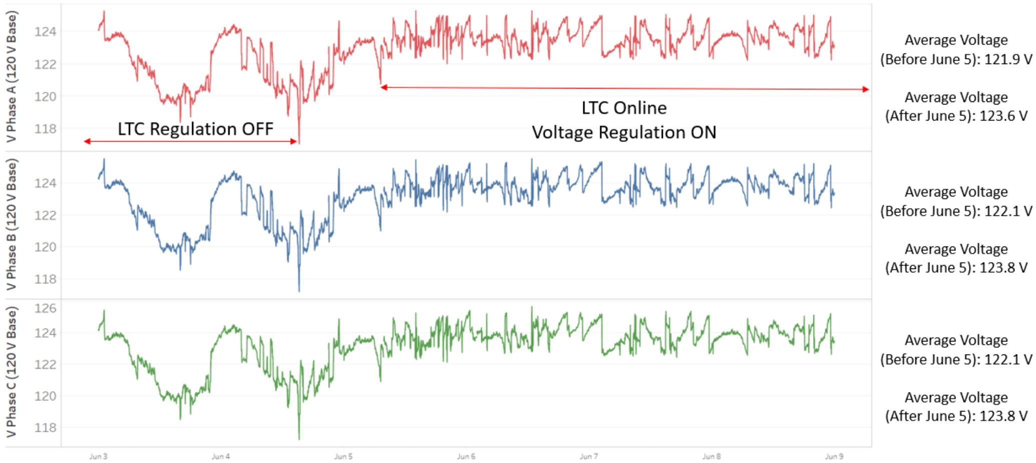


Figure 14: Data per phase voltage indicates that after the AVR fix the voltage are well regulated with an average voltage of ~124V

8.2.2. Voltage Improvement Due to ENGO Units

The ENGO ON/OFF test was conducted for 20 days (from 6/8/2020 to 7/3/2020) the ENGO units were deployed. Subsequently, voltage measurement and analysis of installed ENGO nodes was completed. The minimum voltage recorded when ENGO devices are OFF is 110.6V at a peak load of 22.8 MW (T2), while the minimum voltage recorded when ENGO devices are ON is 113.7V at 24.2MW (T2). The overall voltage improvement is ***3.1V during peak load of 24.2MW***. *Please note that this is a minimum voltage improvement as if the loading on ENGO OFF days was the same as ENGO ON days (which was not the case as the peak load during ENGO OFF days was 22.8MW while during ENGO ON days was 24.2MW), then the voltage on ENGO OFF days would have been even lower giving us a higher voltage improvement value.*

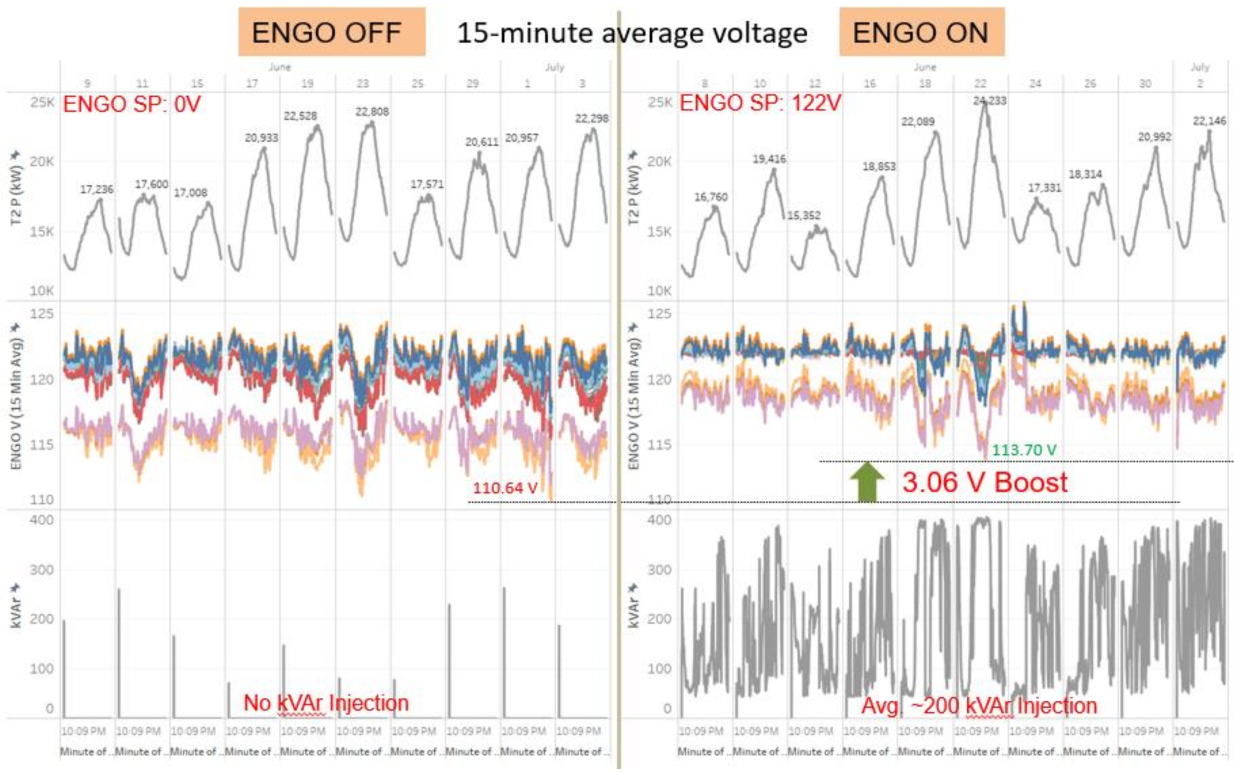


Figure 15: ENGO voltage time series data during ON/OFF testing along with circuit loading condition

Deployed ENGOs help improve the power factor at the substation from 0.9478 to 0.9503 and help reduce the line losses by 0.53%.

Another way of representing the time series plot comparison between ENGO OFF and ENGO ON days is through a voltage versus distance profile where the voltage is the minimum voltage observed over the entire duration. This voltage profile is shown in Figure 16. If we take a 2V drop (conservative value) along the secondary line from the service transformer to the service entrance, then during ENGO OFF days under peak load, the CSA limit is violated. However, with ENGOs ON, no CSA violations are seen and in fact a voltage margin for voltage reduction is observed. ***This shows that voltage reduction on Kanata MTS is not possible without ENGO***.

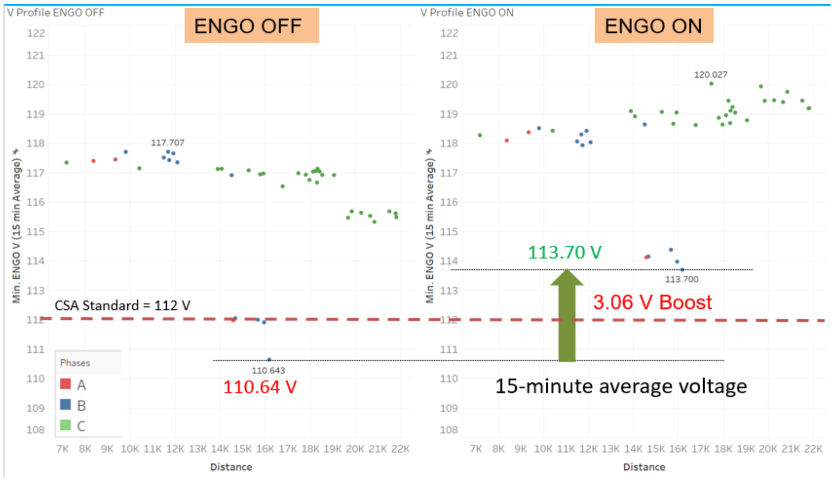


Figure 16: ENGO voltage profile as a function of distance during ON/OFF testing

The values computed for voltage improvement from ENGO is nearly the same as that obtained from the final CYME analysis. But please note that as per initial CYME analysis, the lowest recorded voltage at peak of 20.4 MW (T2) was supposed to be 115.7V while that obtained from the field at a peak of 24.2MW is 113.7V. Hence, there is a gap or error between the analysis performed in CYME and that obtained from field that needs to be accounted for and has been performed in the section on *System Error Calculation.*

8.2.3. Voltage Margin Curve

In order to estimate voltage margin, demand reduction and system error calculation at Kanata, a curve between %Voltage Margin and substation MW was created using field measurements collected during the ON/OFF testing. This curve was created for ENGO ON days to compare with the CYME based curve. Please note that to compute the voltage margin, a difference of minimum voltage and 112V was computed and converted to a percentage value.

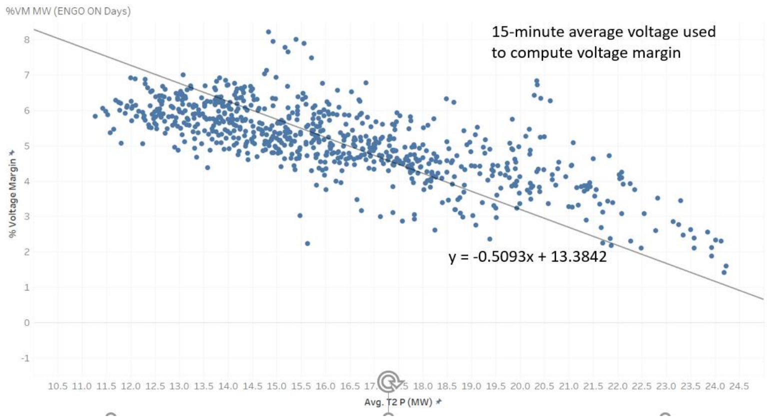


Figure 17: A Curve between Voltage Margin and Substation MW with ENGO ON

9. System Error Calculation as per Contract

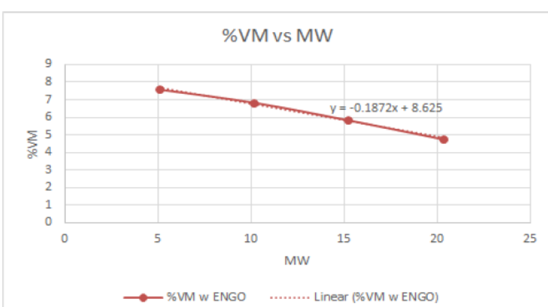
Generally, engineering analysis performed using software such as CYME may have errors and the results obtained may differ from what is observed in reality in the field. These errors arise as the model may not accurately represent the field data.

A performance-based incentive/penalty structure has been proposed as part of the contract which is based on the voltage reductions achieved at the ENGO locations at Kanata T2. Due to the existing healthy voltage margin, no penalty/incentive structure for Kanata T1 was proposed.

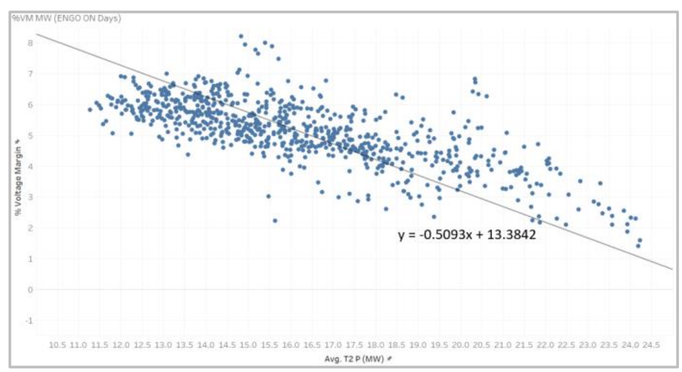
System error calculation for Kanata T2 feeders (F5, F6) was proposed as part of the contract to ensure that when we compare results between CYME and field data, both are aligned together and we are able to account for the incremental value provided by the ENGO units alone.

In this section, we provide the methodology used for computing system error as per the contract. Data considered for computing the system error for the T2 circuits, is over the period of June during which ENGO ON/OFF testing took place.

The first step to finding the system error is to compare the regression model between %Voltage Margin and MW loading obtained from CYME with the same regression model obtained from the field results. These two plots are shown in Figure 18. These plots are obtained for the ENGO ON periods as ultimately, we want to analyze the impact of ENGO units alone without the system error impact.



CYME



Field Data

Figure 18: A comparison between regression model obtained from CYME and field data. Regression model is between %Voltage margin and MW loading (Kanata T2)

The corresponding linear regression model obtained from CYME is

$$\%VM = -0.1872MW + 8.625$$

While the linear regression model obtained from field data captured over the period of June is

$$\%VM = -0.5093MW + 13.3842$$

The difference between these two linear regression models provide us with the system error as a function of MW loading. Doing this gives us the following equation for system error

$$\%SystemError = 0.3221MW - 4.7592$$

As an example of how to use this system error, consider the peak day in June that was recorded on June 22nd (ENGO ON day) with a peak of 22.4MW, the system error can be calculated for this one day as follows

$$\%SystemError = 0.3221(22.4MW) - 4.7592 = 3.05\%$$

The above calculation tells us that for June 22nd there was a system error between the CYME model-based analysis and the field data-based measurements of 3.05% and this system error needs to be considered before we can compare results from the CYME model with field results.

As per the contract, we need to consider the top 10 peak MW values recorded over the ON/OFF test duration. Considering the top 10 peak MW values, we get the results shown in Figure 19.

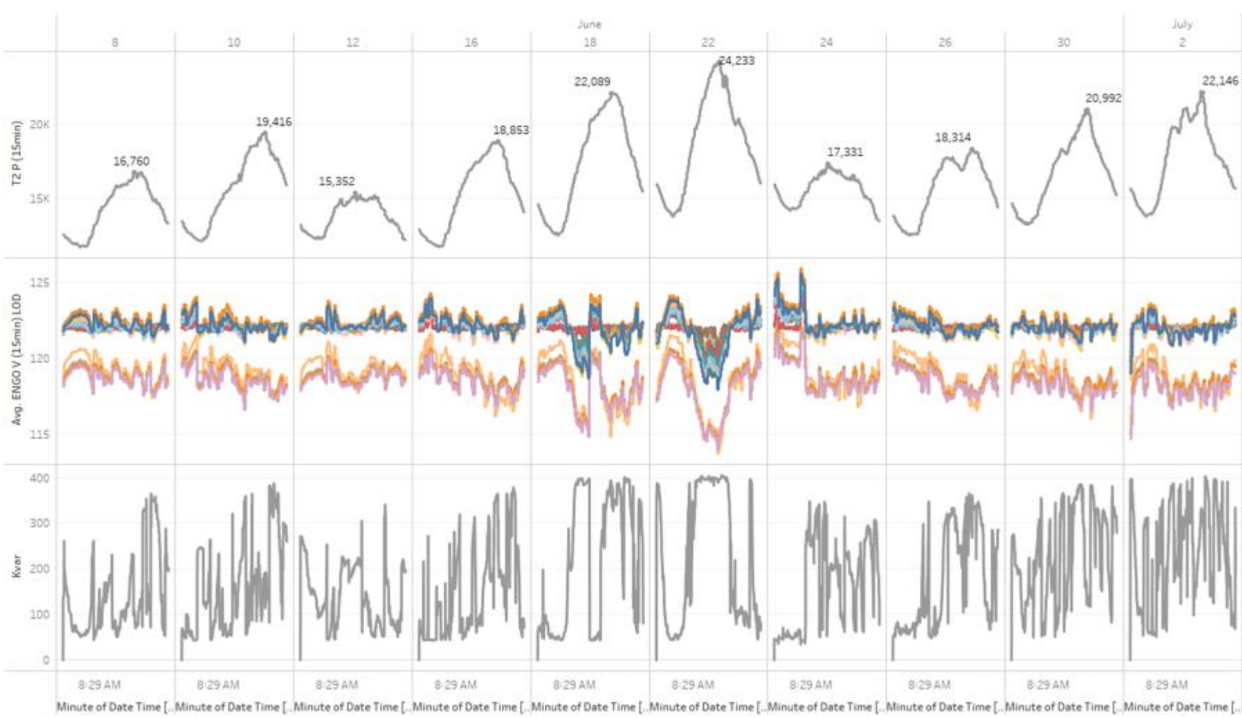


Figure 19: Ten instances of peak in June with ENGO ON captured to compute system error metrics

The Figure 19: Ten instances of peak in June with ENGO ON captured to compute system error metrics shows MW loading at the transformer bank T2 on top, the ENGO voltages in the middle and the kVArs injected by the ENGO to support the voltage at the bottom. Using this plot, we created a table that shows the peak MW and the lowest voltage measured by the ENGO at that point in time which allowed us to then compute the corresponding system error for each sample. A total of 10 samples are collected and at the end an average of the system error and the minimum voltage measured by ENGO is computed.

Table 25: Ten instants of peak MW captured during June with ENGO ON used to compute system error metrics

Peak MW Time Stamp	Peak MW Load (T2 Only)	System Error %	Min Voltage Recorded
6/22/2020 14:30	24.233	3.05	113.92
6/22/2020 15:45	23.296	2.74	116.14
6/22/2020 16:00	23.126	2.69	116.22
7/2/2020 16:00	22.261	2.41	116.70
6/18/2020 17:00	22.117	2.36	116.69
6/18/2020 17:45	22.047	2.34	116.88
6/18/2020 18:00	21.904	2.30	116.06
6/18/2020 18:30	21.534	2.18	116.29
6/18/2020 19:00	21.237	2.08	117.14
6/18/2020 19:30	20.401	1.81	116.43
Average		**2.39%**	**116.24V**

To compute the final metrics that can then be used for comparison with the Penalty structure table provided in the contract and shown below in Table 26, we do the following:

- *Using the average minimum voltage recorded on ENGO ON Days, the %VM computed = 3.53% (116.24V – 112V)*
- *Adjusting for sys_error = 3.53% + 2.39% =* ***5.92%***
- *Voltage reduction for penalty/bonus table =* ***5.92%****. This corresponds to highest bonus based on performance exceeding 110%.*

These calculations simply prove that after accounting for system error, the ENGO units perform as promised during the CYME analysis phase.

Please note that this 5.92% voltage margin is not the actual voltage margin by which the LTC can be reduced under peak. It is a metric that is used to compare results with the penalty/bonus table for convenience.

No penalty/incentive structure was proposed for Kanata Transformer T1 since we have a healthy margin available for voltage reduction and 3 pole mount ENGO devices were placed for visibility only.

Table 26: Penalty/Bonus computation reference table obtained from the contract document. Based on the calculation for system error we provide the highest performance and get the maximum bonus

Min 15-min Voltage Measured by ENGO	Voltage Reduction due to ENGO (min 112V, VM% 120V base)	Weighted Achieved Performance	Total $ Due
Less than 114.4V	Less than 2%	Performance less than 50%	$138,835 - $17,544 = $121,291
114.9V - 117.1V	2.38% - 4.28%	=50% up to 90%	$138,835 - $11,696 = $127,139
117.1V - 117.4V	4.28% - 4.51%	=90% up to 95%	$138,835 - $5,848 = $132,987
117.4V - 118V	4.51% - 4.99%	=95% up to 105%	$138,835 + 11,640 = $150,475
118V - 118.3V	4.99% - 5.23%	=105% up to 110%	$138,835 + $17,460 = $156,295
Greater than 118.3V	5.23%	Performance greater than 110%	$138,835 + $23,280 = $162,115

10. Peak Demand Reduction Testing Results

In order to estimate the load reduction capacity, it is imperative to compute the CVR factor for Power. The System Entropy Method (SEM) developed by Sentient Energy uses natural variation in the substation voltage due to the LTC change and a method of aggregation that reduces the error in calculation of the CVR factor.

- SEM works as follows:
  - We compute the voltage transitions and capture the corresponding changes in power
  - In order to estimate the error present in our computation due to natural variation in power, we create a distribution of the natural variation in Power
  - Using this natural variation in Power we estimate the distribution of error in CVRf-power
  - Using an aggregation of events captured, we reduce the variance of the error distribution around the CVRf-power
  - The mean of valid events captured through all the single transitions provide the final estimate of CVRf-power and the standard deviation of the natural variation helps us compute the error band around this CVRf-power

$$Single\ Event\ CVR_{f-Power} = \frac{\left(\frac{P[i]-P[i-1]}{P[i-1]}\right)}{\left(\frac{V[i]-V[i-1]}{V[i-1]}\right)} \qquad Estimated\ CVR_{f-power} = \frac{1}{N}\sum_{Valid} Single\ Event\ CVR_{f-Power}$$

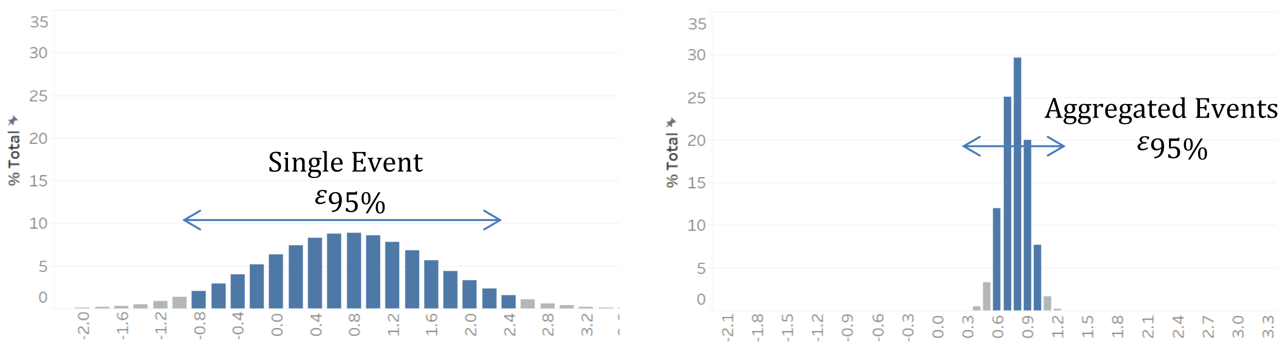


Figure 20: CVR Factor Computation for Power

Peak demand reduction tests are run over three months July (2.5% CVR), August (2.5% CVR) and September (5% CVR) and 27 events (54 transitions) are recorded to calculate an average **CVRfp of 0.52+/- 0.03** (95% confidence). Being a majority C&I customer feeder, the CVRfp is expected to be in the 0.3-0.6 range. **No CSA violations are observed (GEMS) or reported (AMI/Customer Call) during the tests.**

Applying this metric to calculate the total peak shaving on September 23rd (5% CVR Day), a 900kW reduction in load is observed.

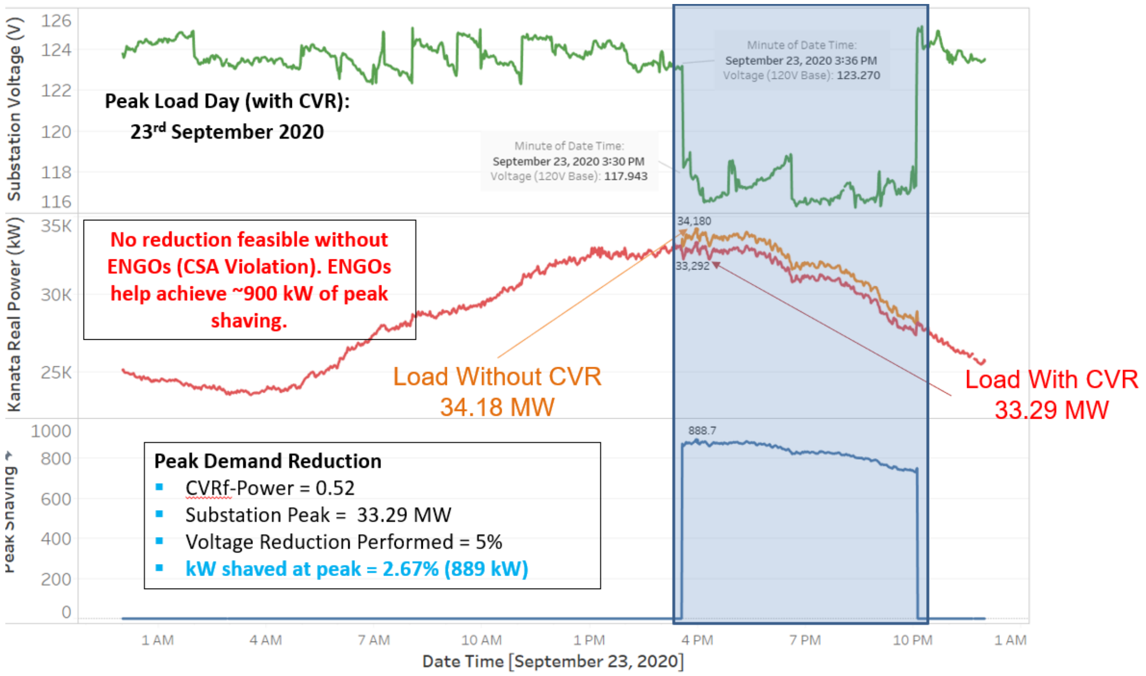


Figure 21: Peak Shaving on September 23rd, 2020 (5% CVR Day)

Similarly, applying the calculated CVRfp to the yearly peak of 50.53 MW (July 2020) a potential reduction of 1.3 MW – 1.6 MW is deemed possible.

Peak Demand Reduction

- CVRf-Power = 0.52
- Substation Peak (Without Reduction) = 50.53 MW
- Load Reduction Possible with **5% CVR** (if CVR was performed): 50530*0.05*0.52 = ***1314 kW (2.60%)***
- Load Reduction Possible with **6% CVR** (if CVR was performed): 50530*0.06*0.52 = ***1577 kW (3.12%)***

Figure 22: Peak Reduction Estimate by 5% and 6% CVR Day

The expected 2.6% - 3.1% peak demand reduction is a promising metric in line with the expected results from the CYME simulation proving the efficacy of Sentient Energy's ENGO solution.

11. Voltage Improvement Story (Voltage Visibility)

Sentient Energy performed analysis using CYME model and AMI data to provide locations for ENGO devices. While performing this analysis, Sentient Energy also recommended some transformer upgrades to ensure that the overall voltage profile of the system improves and maximum incremental voltage benefits can be obtained from the deployment. Figure 23 through Figure 28: 5% CVR – Energy Savings Test – AMI Voltage Profile shows a storyline using AMI and GEMS voltage profile of transformer nodes with ENGOs deployed and engaged in ON mode (injecting reactive VAr for voltage support; essentially a historical trend of voltage improvement as the recommended steps were followed by Hydro Ottawa. Ultimately, as a result of these upgrade and ENGO voltage regulation, CVR reduction is made possible without any CSA violations.

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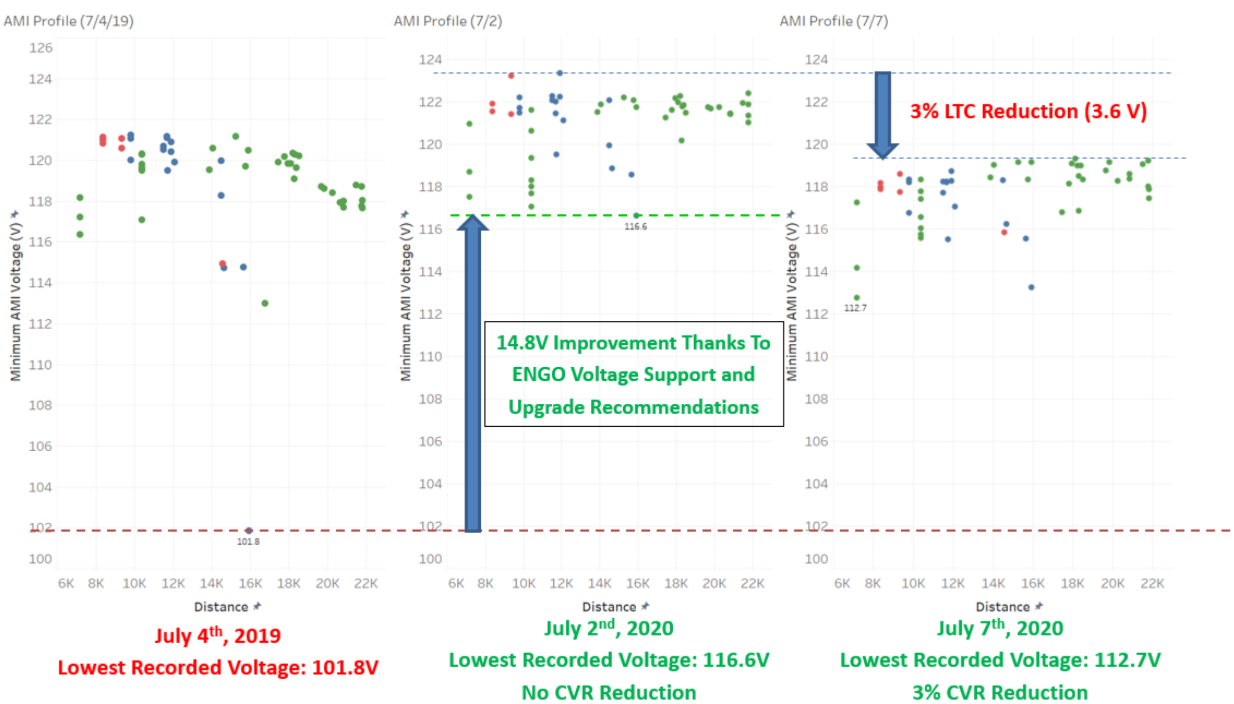

Figure 23: X07487 Transformer Replacement and ENGO ON (May-July 2020)

AMI voltage profile shown over an extended period from last year peak time to this year peak time. It is clear from this plot that after making the upgrades and adding ENGO units to the system, a CVR reduction is possible without any CSA violation which was not the case before.

Note 11:

Meter [redacted] connected to Transformer X36610 is excluded for abnormal secondary voltage drop

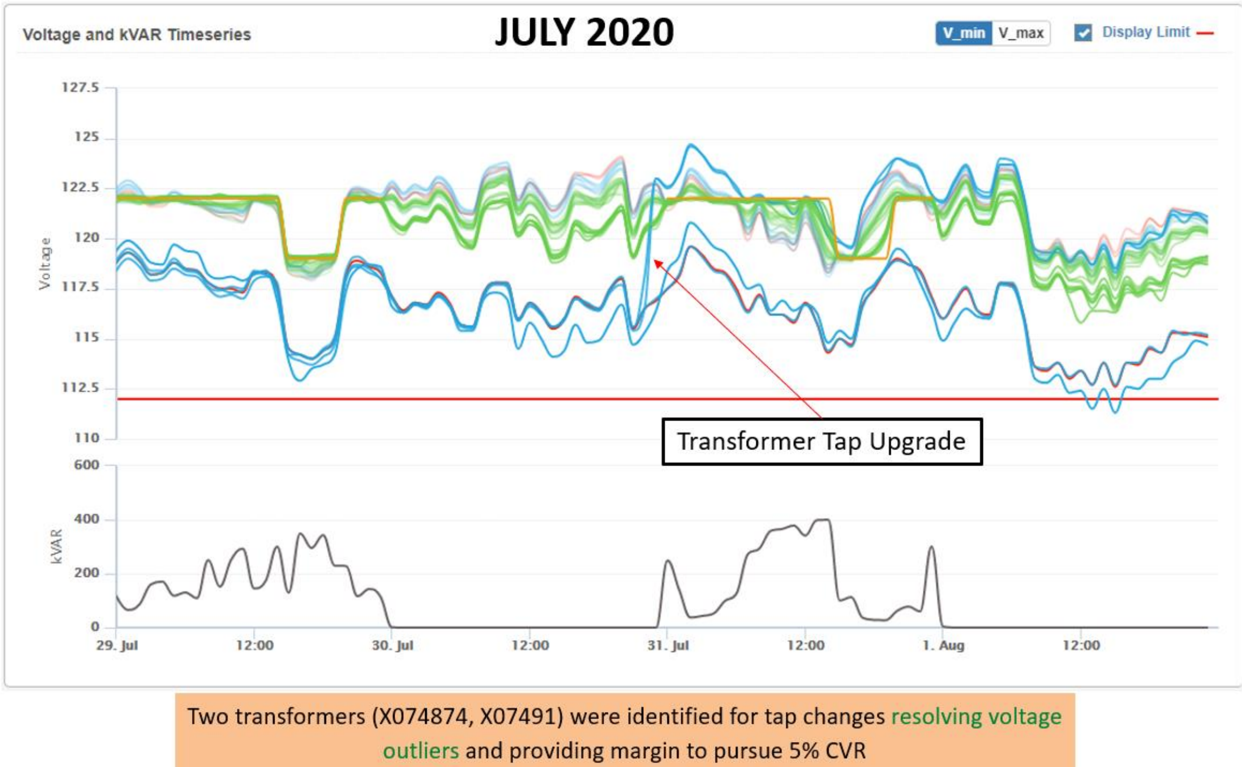

Figure 24: Limiting Voltage Transformer Upgrade (July 2020)

Figure 24**: Limiting Voltage Transformer Upgrade (July 2020)** shows a GEMS view of ENGO time series voltage from July 30th, 2020. Two transformers (X07487, X07491) were identified for tap upgrades resolving voltage outliers and providing margin to pursue 5% CVR. GEMS provides near real time visibility into operation of assets in the field at high data granularity.

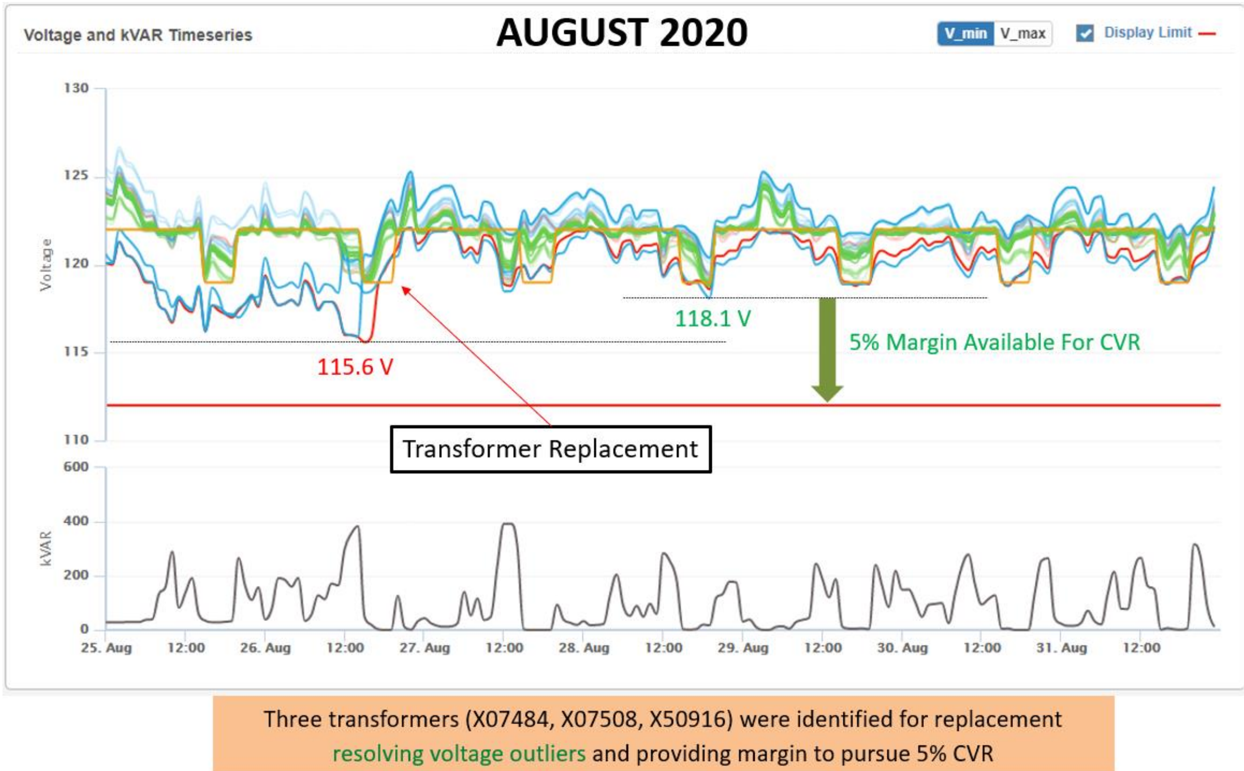

Figure 25: Limiting Voltage Transformer Replacement (August 2020)

Figure 25: **Limiting Voltage Transformer Replacement (August 2020)** shows a GEMS view of ENGO time series voltage from August 26th, 2020. Three transformers (X07484, X07508, X50916) were identified for replacement (kVA rating upgrade) resolving voltage outliers and providing margin to pursue 5% CVR. GEMS provides near real time visibility into operation of assets in the field at high data granularity.

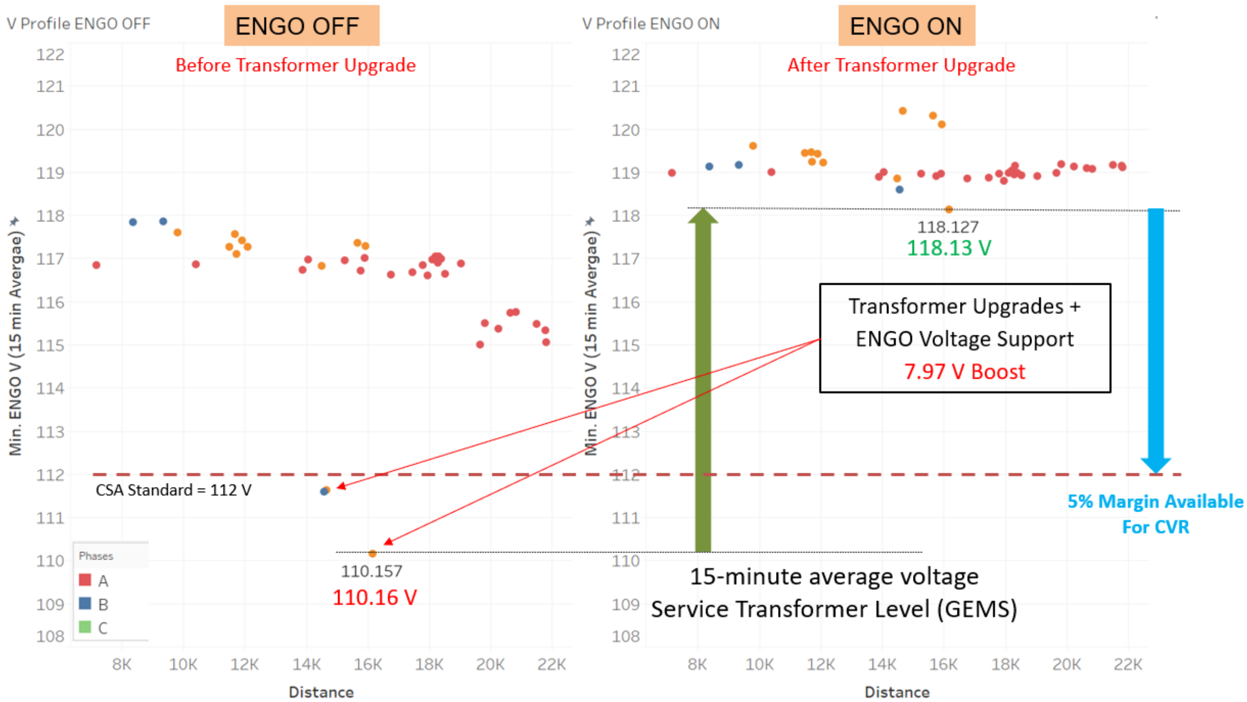

Figure 26: ENGO ON/OFF Voltage Profile (No CVR Day – August 2020)

Figure 26: ENGO ON/OFF Voltage Profile (No CVR Day – August 2020) shows the Voltage Profile (Minimum Voltage vs Distance) measured by ENGO devices before and after the transformer upgrades conducted on August 26th, 2020. With ENGOs turned OFF, there is a CSA violation and no voltage margin present for CVR (prior to system upgrades). Transformer replacement + ENGO ON provides dramatic incremental voltage improvement creating a margin for 5% (and more) CVR.

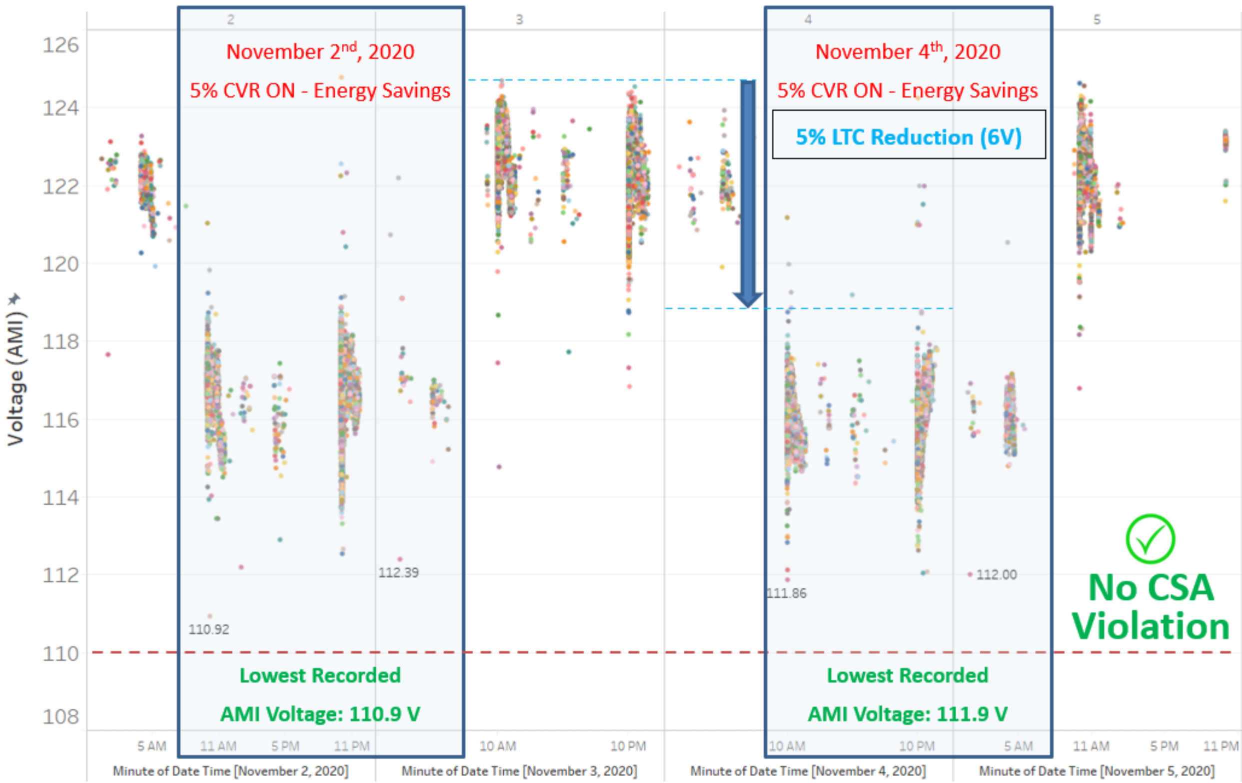

Figure 27: 5% CVR – Energy Savings Test – AMI Voltage Time Series

Figure 27: **5% CVR – Energy Savings Test – AMI Voltage Time Series** shows the system-wide AMI voltage recorded during week 1 of energy savings test. 5% reduction in LTC is performed on alternate days in 24-hour intervals. No CSA violation or customer complaint detected. Lowest recorded voltage shows presence of margin for higher CVR.

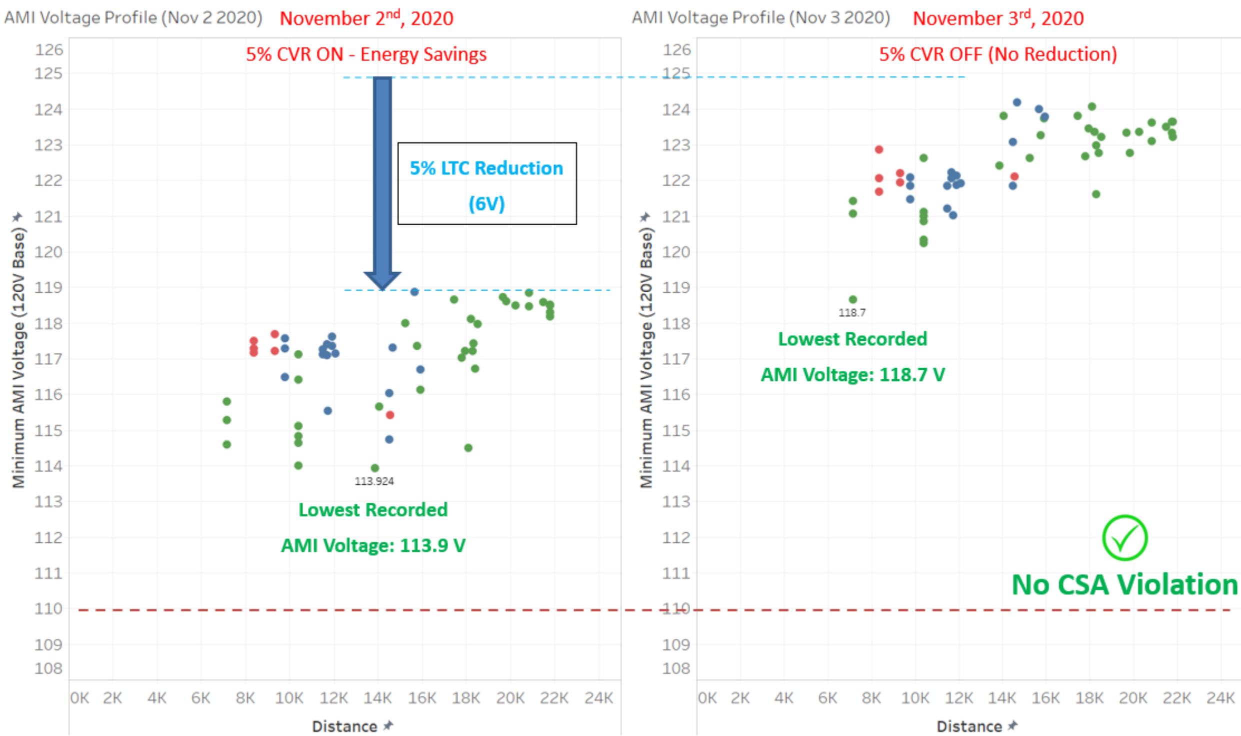

Figure 28: 5% CVR – Energy Savings Test – AMI Voltage Profile

Figure 28: 5% CVR – Energy Savings Test – AMI Voltage Profile shows the AMI Voltage (vs Distance) profile for meters connected to transformers with ENGO deployment during week 1 of energy savings test. 5% reduction in LTC is performed on alternate days in 24-hour intervals. No CSA violation or customer complaint detected.

12. Appendix A: List of ENGO Units as per First Analysis

ENGO ID	[redacted]	XFMR KVA	XFMR Phase	ENGO Phase	OH/UG	# ENGO	Distance
ENGO100	[redacted]	50	C	C	OH	1	22341.5
ENGO101	[redacted]	25	C	C	OH	1	68360.3
ENGO102	[redacted]	25	C	C	OH	1	65062
ENGO103	[redacted]	25	C	C	OH	1	71557.3
ENGO104	[redacted]	25	C	C	OH	1	70545.5
ENGO105	[redacted]	25	C	C	OH	1	66439.7
ENGO106	[redacted]	25	C	C	OH	1	67744.2
ENGO107	[redacted]	50	C	C	OH	1	71459.2
ENGO108	[redacted]	25	A	A	OH	1	47802.3
ENGO109	[redacted]	25	B	B	OH	1	48099.1
ENGO110	[redacted]	25	C	C	OH	1	59782.3
ENGO111	[redacted]	25	C	C	OH	1	52204.5
ENGO112	[redacted]	50	C	C	OH	1	62485.8
ENGO113	[redacted]	37	C	C	OH	1	60019.6
ENGO114	[redacted]	50	C	C	OH	1	60085.7
ENGO115	[redacted]	10	B	B	OH	1	53050.9
ENGO116	[redacted]	15	B	B	OH	1	51395.9
ENGO117	[redacted]	25	C	C	OH	1	58376.1
ENGO118	[redacted]	25	C	C	OH	1	60371.4
ENGO119	[redacted]	25	C	C	OH	1	58912.4
ENGO120	[redacted]	25	A	A	OH	1	30638.7
ENGO121	[redacted]	25	A	A	OH	1	21389
ENGO122	[redacted]	25	B	B	OH	1	52297.2
ENGO123	[redacted]	25	B	B	OH	1	32157.2
ENGO124	[redacted]	25	B	B	OH	1	38490.5
ENGO125	[redacted]	25	B	B	OH	1	37706.5
ENGO126	[redacted]	50	C	C	OH	1	23529.4
ENGO127	[redacted]	50	C	C	OH	1	71274.6
ENGO128	[redacted]	37.5	C	C	OH	1	34133.6
ENGO129	[redacted]	10	C	C	OH	1	64531.4
ENGO130	[redacted]	25	C	C	OH	1	45552.8
ENGO131	[redacted]	25	B	B	OH	1	38329.4
ENGO132	[redacted]	25	B	B	OH	1	39671.9
ENGO133	[redacted]	37.5	B	B	OH	1	39082.8
ENGO134	[redacted]	25	B	B	OH	1	39174.7
ENGO135	[redacted]	50	C	C	OH	1	52793.4
ENGO136	[redacted]	50	C	C	OH	1	34341.2
ENGO137	[redacted]	25	C	C	OH	1	53442
ENGO138	[redacted]	50	A	A	OH	1	33077.9
ENGO139	[redacted]	50	C	C	OH	1	32930.3
ENGO140	[redacted]	50	A	A	OH	1	34285.6
ENGO_M1	[redacted]	25	B	B	OH	1	47577.9
ENGO_M2	[redacted]	25	B	B	OH	1	24049

13. Appendix B: List of ENGO Units as per Final Analysis

ENGO ID	[redacted]	XFMR KVA	XFMR Phase	ENGO Phase	OH/UG	# ENGO	Distance
ENGO100	[redacted]	25	C	C	OH	1	68360.3
ENGO101	[redacted]	25	C	C	OH	1	65062
ENGO102	[redacted]	25	C	C	OH	1	71557.3
ENGO103	[redacted]	25	C	C	OH	1	70545.5
ENGO104	[redacted]	25	C	C	OH	1	66439.7
ENGO105	[redacted]	25	C	C	OH	1	67744.2
ENGO106	[redacted]	50	C	C	OH	1	71459.2
ENGO107	[redacted]	25	A	A	OH	1	47802.3
ENGO108	[redacted]	25	B	B	OH	1	48099.1
ENGO109	[redacted]	25	C	C	OH	1	59782.3
ENGO110	[redacted]	25	C	C	OH	1	52204.5
ENGO111	[redacted]	50	C	C	OH	1	62485.8
ENGO112	[redacted]	37	C	C	OH	1	60019.6
ENGO113	[redacted]	50	C	C	OH	1	60085.7
ENGO114	[redacted]	10	B	B	OH	1	53050.9
ENGO115	[redacted]	15	B	B	OH	1	51395.9
ENGO116	[redacted]	50	A	A	OH	1	27458.2
ENGO117	[redacted]	15	C	C	OH	1	57297.4
ENGO118	[redacted]	37	C	C	OH	1	46135.1
ENGO119	[redacted]	25	C	C	OH	1	60767.8
ENGO120	[redacted]	25	C	C	OH	1	59435.2
ENGO121	[redacted]	25	C	C	OH	1	58376.1
ENGO122	[redacted]	25	C	C	OH	1	60371.4
ENGO123	[redacted]	25	C	C	OH	1	58912.4
ENGO124	[redacted]	25	C	C	OH	1	51738.3
ENGO125	[redacted]	25	A	A	OH	1	30638.7
ENGO126	[redacted]	25	C	C	OH	1	50062.4
ENGO127	[redacted]	25	B	B	OH	1	52297.2
ENGO128	[redacted]	25	B	B	OH	1	32157.2
ENGO129	[redacted]	25	B	B	OH	1	38490.5
ENGO130	[redacted]	25	B	B	OH	1	37706.5
ENGO131	[redacted]	50	C	C	OH	1	23529.4
ENGO132	[redacted]	50	C	C	OH	1	71274.6
ENGO133	[redacted]	37.5	C	C	OH	1	34133.6
ENGO134	[redacted]	10	C	C	OH	1	64531.4
ENGO135	[redacted]	25	C	C	OH	1	45552.8
ENGO136	[redacted]	25	B	B	OH	1	38329.4
ENGO137	[redacted]	25	B	B	OH	1	39671.9
ENGO138	[redacted]	37.5	B	B	OH	1	39082.8
ENGO_M1	[redacted]	25	B	B	OH	1	47577.9
ENGO_T1_1	[redacted]	25	A	A	OH	1	18754.8
ENGO_T1_2	[redacted]	25	B	B	OH	1	24049
ENGO_T1_3	[redacted]	50	C	C	OH	1	22341.5

14. Appendix C: Lessons learned during ENGO Placement

The initial ENGO placement analysis was conducted using CYME simulations to identify voltage outlier nodes and iteratively deploy ENGO devices in the model. Phase I of the field installation gave us several insights in the process:

1. **Identified constraints during field survey of proposed locations:**

    - Customer owned poles were removed from the list
    - Poles with accessibility issues were removed from the list
    - Poles with 120V service were preferred for placement and 240V poles were removed from the list

    The lessons learnt from this exercise include:

    - Ensuring pole locations criteria is identified before analysis is completed for the final pole list
    - Pole inspections should be completed earlier in the project to confirm any pre-work or to identify the pole as not being ENGO compatible.

2. **The initial phase of ENGO deployment gave us some much-needed visibility (high granularity of recorded data in GEMS) in the field:**

    - It was observed that the voltage profile from the CYME analysis did not correlate well with the field data. This was confirmed on analyzing the AMI data which was limited by the small number of reads (two) recorded on a daily basis.
    - A fresh analysis was conducted using an AMI data-driven approach to revise the list of potential locations for ENGO placement. Performance metrics were re-evaluated and multiple options were considered for deployment and relocation.

    The lessons learnt from this exercise include using field data to verify the accuracy of the CYME model and use a hybrid model + data approach while generating the list of potential ENGO locations.

3. **Consider system topography and operating conditions while conducting analysis:**

    Kanata MTS has two transformer regions T1 (feeding circuits 624F1, 624F2 and 624F3) and T2 (feeding circuits 624F4 and 624F5) which are connected by a closed bus tie and regulated through a single LTC controller under normal operating condition. Initially the analysis was conducted on the two transformer areas as independent systems with separate improvement metrics. This was later rectified to conduct combined studies for the normal operating condition and separate analysis for the abnormal operating condition with the bus tie open.

The main takeaway from this effort was communication and clarification of all assumptions made during the study and aligning the Sentient Energy analysis to correctly reflect the HOL system state.

4. **Evaluating primary asset modifications prior to ENGO installation and ensure availability of inventory and construction material:**

   During the project, five (5) transformers were identified for connected kVA rating upgrades and tap changes to rectify voltage issues. These primary asset modifications greatly helped improve the overall voltage profile and provided margin to pursue an additional reduction in voltage.

   The lesson learned from this aspect of the project is to address primary asset issues before the ENGO analysis and be prepared with materials like mounting hardware for construction.

Elexicon Energy Inc.

Answer to Undertaking from

Environmental Defence

Undertaking JT1.11:

UNDERTAKING NO. JT1.11:TO PROVIDE A SPREADSHEET SHOWING THE OPERATING COSTS OF THIS LINE PER YEAR, WITH EXPLANATIONS.

Response:

Elexicon's estimate of operating costs for the Sustainable Brooklin project (i.e. Brooklin Line) is primarily driven by its costs to service the wood poles, line clearing (i.e. vegetation management), and system patrols. Elexicon does not include depreciation as an OM&A expense given it is a non-cash item, or include property taxes where the project uses easements in its routing of the project.

Elexicon Energy adopted an inspection and maintenance cycle of three (3) years for most programs.

To calculate the operating and maintenance costs, Elexicon's estimate uses the following assumptions:

- The useful life of a wood pole is 60 years.
- The Sustainable Brooklin pole line will consist of approximately 332 wood poles.

Table 1: Maintenance cost per cycle (3 years) for the useful life of the poles.

Year	3	6	9	12	15	18	21	24	27	30
Pole inspection	$6,640	$6,972	$7,321	$7,687	$8,071	$8,475	$8,898	$9,343	$9,810	$10,301
Line clearing	$10,567	$11,095	$11,650	$12,233	$12,844	$13,486	$14,161	$14,869	$15,612	$16,393
System Patrol	$145	$152	$160	$168	$176	$185	$194	$204	$214	$225
Total	$10,712	$11,248	$11,810	$20,087	$21,091	$22,146	$23,253	$24,416	$25,637	$26,919

Year	33	36	39	42	45	48	51	54	57	60
Pole inspection	$10,816	$11,357	$11,924	$12,521	$13,147	$13,804	$14,494	$15,219	$15,980	$16,779
Line clearing	$17,213	$18,073	$18,977	$19,926	$20,922	$21,968	$23,066	$24,220	$25,431	$26,702
System Patrol	$236	$248	$260	$273	$287	$301	$317	$332	$349	$366
Total	$28,265	$29,678	$31,162	$32,720	$34,356	$36,074	$37,877	$39,771	$41,760	$43,848

Elexicon Energy Inc.

Answer to Undertaking from

CCMBC

Undertaking JT1.12:

TO RUN THE ECONOMIC EVALUATION MODEL FOR A NON-RESIDENTIAL CUSTOMER, POTENTIALLY BY ILLUSTRATION A SMALL COMMERCIAL CUSTOMER, BASE CONSUMPTION; TO LIST OUT ALL OF THE ASSUMPTIONS AND PARAMETERS THAT LEAD TO THE ECONOMIC EVALUATION MODEL; OUTPUT IS THE CAPITAL CONTRIBUTION, IF ANY.

Response:

As noted in the response to Undertaking JT2.4, Elexicon's proposal is to calculate the capital contribution associated with connecting a non-residential customer to the Sustainable Brooklin project ("Brooklin Line") and including an apportioned amount of the cost of the Brooklin Line as per section 3.2.27 of the Distribution System Code. Also noted in JT2.4, Elexicon is open to alternative approaches to calculate the capital contribution to connect a non-residential customer to the Brooklin Line. To assist parties, Elexicon has run two economic evaluation models and provided the output of both models in its response to this undertaking.

In Model 1, Elexicon has run the economic evaluation model as per its proposal in this Application. Model 1 **includes** both the apportioned cost of connecting the customer to the Brooklin Line and the construction costs to connect the customers meter to the most cost effective point on the Brooklin Line. In Model 2, Elexicon has run the economic evaluation model to **not include** the apportioned amount of the cost of the Brooklin Line. [emphasis added in bold to distinguish the two models provided in this Undertaking response]

The assumptions and results from running Model 1 and Model 2 are described below:

Model 1 – Economic Evaluation Model Including Apportioned Brooklin Line Cost Plus Construction Cost to Connect Meter to Brooklin Line

An economical evaluation was produced of which the calculation results and assumptions are listed below, and a copy of the model is provided as Attachment 1 to this Undertaking.

In the illustrative example of this undertaking, for a school consuming 150kW, and total cost of the expansion estimated at $0.413 MM, the OEB's Economic Evaluation model calculated that the school would be asked to pay a capital contribution of approximately $0.286 MM.

Table 1 – Example Economic Evaluation Model Using Model 1 Assumptions

Calculation Results		
Expressed in relation to internal construction costs only…..		
Total Cost of Project	$	412,500.00
Capital Contribution by Customer	$	286,479.60
Elexicon's Contribution	$	126,020.40
Capital Contribution Recovery Rate (CCRR) (% of Project Total)		69%

Economic Evaluation Calculation Results		
Expressed in relation to internal construction costs only…..		
Total Cost of Project	$	412,500.00
Capital Contribution by Customer	$	286,479.60
Elexicon's Contribution	$	126,020.40
Capital Contribution Recovery Rate (CCRR) (% of Project Total)		**69%**

List of Assumptions Used in the Economic Evaluation Model

- A new General Service load (e.g. a school) will be connected
- The new school will have a load of 150kW in year 3.
- The total cost of the expansion is $412,500.
    - Apportioned cost of Brooklin Line is estimated as $142,500[1]
    - Construction Cost to Connect Meter to Brooklin Line is $270,000[2]

Model 2 – Economic Evaluation Model Including Construction Cost to Connect Meter to Brooklin Line

An economical evaluation was produced of which the calculation results and assumptions are listed below, and a copy of the model is provided as Attachment 2 to this undertaking.

For clarity Elexicon's calculation of construction costs for a non-residential customer attaching to the Sustainable Brooklin project ("Brooklin Line") will not include any of the Brooklin Line costs.

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[1] The assumptions are that 150kW is the school's non-coincident peak, the Brooklin Line non-coincident peak is 28,000kW, and the cost of the Brooklin Line is $26.6 MM. (Calculation is (150kWh / 28,000 kWh) x $26.6 MM = $142,500)

[2] The assumption is the connection of a non-residential customer to the Brooklin Line would require 8 spans or 9 poles away from Ashburn & Columbus (i.e. the end of the Sustainable Brooklin project's Brooklin line) or a distance of 450m.

The construction costs used in the economic evaluation will only include an estimate of the costs of expansion from the customer meter to the most cost effective point of the Brooklin Line.

In the illustrative example shown in Model 2, for a school consuming 150kW, and cost of the expansion estimated at $0.270 MM, the OEB's Economic Evaluation model calculated that the school would be asked to pay a capital contribution of approximately $0.148 MM.

Table 2 – Example Economic Evaluation Model Using Model 2 Assumptions

Calculation Results		
Expressed in relation to internal construction costs only…..		
Total Cost of Project	$	270,000.00
Capital Contribution by Customer	$	147,570.34
Elexicon's Contribution	$	122,429.66
Capital Contribution Recovery Rate (CCRR) (% of Project Total)		55%

Economic Evaluation Calculation Results		
Expressed in relation to internal construction costs only…..		
Total Cost of Project	$	270,000.00
Capital Contribution by Customer	$	147,570.34
Elexicon's Contribution	$	122,429.66
Capital Contribution Recovery Rate (CCRR) (% of Project Total)		55%

<u>List of Assumptions Used in the Economic Evaluation Model</u>

- A new General Service load (e.g. a school) will be connected
- The new school will have a load of 150kW in year 3.
- The total cost of the expansion is $270,000[3].

---

[3] IBID

JT 1-12

Model 1

Economic Evaluation Model Including Apportioned Brooklin Line Cost Plus Construction Cost to Connect Meter to Brooklin Line

Summary of Customer Data and Economic Analysis Results

Project Name	Model 1 - 27.6kV Brooklin N Dev-ICM - (no line cost)
Project Number	
Developer	TBA
Municipality	Whitby

Technician: | **Date Run:** 22-Jan-23 | **Version:**

EE Template : **Whitby Only**

New Customers and Input Data

Customers, Type	kWh per Unit	Year 1- 2023	Year 2- 2024	Year 3-2025	Year 4-2026	Year 5-2027	Total
		Number of Units or GS load (kW) Added in Each Year					
General Service Load			0	150	0	0	150
							0
							0
Residential	750		-	-	-	-	0
							0
							0
Total Residential		0	0	0	0	0	0
Average energy added per Res. customer		0	0	0	0	0	0

Data

Annual O,M, & A

Incremental OM&A, $/Customer $ 148.32 $ 148.32

Distribution Rates in effect

Monthly, fixed customer charge		
	Residential	$ 33.41
	General Service < 50kW	$ 28.08
	General Service 50 to 2,999 kW	$ 213.88
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -
Monthly, variable		
	Residential, per kWh	$ -
	General Service < 50kW, per kWh	$ 0.0208
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	$ 4.2717
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -

Elexicon Energy Use Only

NOTE: Option 2 - EE Different from OTC

N/A

Summary

Statement of Costs

Cost Breakdown:	Project Total Costs (Data Inputs)
Eng & Admin	$ -
Connecting (Section A)	$ -
Material (Section A)	$ -
Other	$ 270,000.00
Installation (Section B)	
Inspection	$ -
Total	**$ 270,000.00**

Calculation Results

Expressed in relation to internal construction costs only.....

Total Cost of Project	$ 270,000.00
Capital Contribution by Customer	$ 147,570.35
Elexicon's Contribution	$ 122,429.65
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**55%**

Expansion Deposit

Elexicon's Contribution	$ 122,429.65
NPV of Revenue	$ 133,472.18
Expansion Deposit (the lesser of the 2 above)	**$ 122,429.65**

JT 1-12

Model 2

Economic Evaluation Model Including Construction Cost to Connect Meter to Brooklin Line

Summary of Customer Data and Economic Analysis Results

Project Name	Model 2 - 27.6kV Brooklin N Dev-ICM - (proportional line cost added)
Project Number	
Developer	TBA
Municipality	Whitby

Technician: | **Date Run:** 22-Jan-23 | **Version:**

EE Template : **Whitby Only**

New Customers and Input Data

Customers, Type	kWh per Unit	Year 1- 2023	Year 2- 2024	Year 3-2025	Year 4-2026	Year 5-2027	Total
General Service Load			0	150	0	0	150
							0
							0
Residential	750		-	-	-	-	0
							0
							0
Total Residential		0	0	0	0	0	0
Average energy added per Res. customer		0	0	0	0	0	0

Number of Units or GS load (kW) Added in Each Year

Data

Annual O,M, & A

Incremental OM&A, $/Customer	$ 148.32	$ 148.32

Distribution Rates in effect		
Monthly, fixed customer charge		
	Residential	$ 33.41
	General Service < 50kW	$ 28.08
	General Service 50 to 2,999 kW	$ 213.88
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -
Monthly, variable		
	Residential, per kWh	$ -
	General Service < 50kW, per kWh	$ 0.0208
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	$ 4.2717
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -

Elexicon Energy Use Only

NOTE: Option 2 - EE Different from OTC

N/A

Summary

Statement of Costs

Cost Breakdown:	Project Total Costs (Data Inputs)
Eng & Admin	$ -
Connecting (Section A)	$ -
Material (Section A)	$ -
Other	$ 412,500.00
Installation (Section B)	
Inspection	$ -
Total	$ 412,500.00

Calculation Results

Expressed in relation to internal construction costs only…..

Total Cost of Project	$ 412,500.00
Capital Contribution by Customer	$ 286,479.60
Elexicon's Contribution	$ 126,020.40
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	69%

Expansion Deposit

Elexicon's Contribution	$ 126,020.40
NPV of Revenue	$ 133,472.18
Expansion Deposit (the lesser of the 2 above)	**$ 126,020.40**

Elexicon Energy Inc.

Answer to Undertaking from

Coalition of Concerned Manufacturers and Businesses of Canada

Undertaking JT1.13:

TO SET OUT A DRAFT RATE ORDER FROM ELEXICON'S PERSPECTIVE FOR THE SUSTAINABLE BROOKLIN PROJECT SPECIFIC TO THE EXEMPTIONS BEING REQUESTED.

Response:

IMPLEMENTATION AND ORDER

This Decision is accompanied by Rate Generator Models, applicable supporting models, and Tariffs of Rates and Charges (Schedule A). The Rate Generator Models incorporate the rates set out in the following table:

[NTD: Insert table]

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Subject to the conditions set out below, the Ontario Energy Board approves the three Incremental Capital Module (ICM) applications filed by Elexicon Energy Inc. (Elexicon) for new rates:
    a. effective January 1, 2025 for ICM funding for the Whitby Smart Grid Project, including a proportionate share of the Advanced Distribution Management System (ADMS) costs in the Whitby Rate Zone (WRZ);
    b. effective January 1, 2025 for ICM funding for a proportionate share of the ADMS costs in the Veridian Rate Zone (VRZ); and
    c. effective January 1, 2023 for ICM funding for the Sustainable Brooklin Project in the WRZ.
2. The Tariffs of Rates and Charges set out in Schedule A of this Decision and Order is approved.
3. The Ontario Energy Board approves an exemption for the Brooklin Line from Sections 3.2.1, 3.2.2, 3.2.3, 3.2.4, 3.2.6, 3.2.7, 3.2.8, 3.2.12, 3.2.14, 3.2.16, 3.2.18, 3.2.20, 3.2.21, 3.2.22, 3.2.23, 3.2.24, 3.2.25, 3.2.26, 3.2.27 and 3.2.30 of the Distribution System Code, which would otherwise require Elexicon to collect a capital contribution from the local developers towards the cost of constructing and operating the Brooklin Line.

4. As a condition of the approved exemption for the Brooklin Line, Elexicon shall ensure in its contractual arrangements that all current and future residential developers that may stand to benefit from the Brooklin Line shall construct DER and EV ready homes or buildings.
    a. Should a residential developer fail to deliver on the construction of DER-and-EV-Ready homes or buildings, as determined by Elexicon, Elexicon shall require that developer or property owner to pay an appropriate capital contribution to Elexicon in support of the Brooklin Line prior to energizing the property. For residential customers, the amount of the capital contribution, as of January 1, 2023, shall be $2,260 per home or building before Elexicon supplies power.
    b. With respect to non-residential customers, Elexicon would apply the standard requirements of Section 3.2.24 of the DSC to calculate a capital contribution for a 5-year customer connection horizon.
5. Cost eligible intervenors shall submit to the OEB and copy Elexicon cost claims no later than [NTD].
6. Elexicon shall file with the OEB and forward to all cost eligible intervenors any objections to the claimed costs no later than [NTD].
7. Cost eligible intervenors shall file with the OEB and forward to Elexicon any responses to any objections for cost claims no later than [NTD].
8. Elexicon shall pay the OEB’s costs incidental to this proceeding upon receipt of the OEB’s invoice no later than [NTD].

Elexicon Energy Inc.

Answer to Undertaking from

Coalition of Concerned Manufacturers and Businesses of Canada

Undertaking JT1.14:

ELEXICON TO FILE THE NOVEMBER 15TH, 2021 MINISTER OF ENERGY MANDATE LETTER TO THE OEB.

Response:

Attachment 1 to this Undertaking is the November 15, 2021 mandate letter from the Ontario Ministry of Energy to the OEB.

Attachment 2 to this Undertaking is the October 21, 2022 Letter of Direction from the Ontario Ministry of Energy to the OEB.

JT 1-14

Attachment 1

Mandate Letter from the Minister of Energy

Ministry of Energy

Office of the Minister

77 Grenville Street, 10th Floor
Toronto ON M7A 2C1
Tel.: 416-327-6758

Ministère de l'Énergie

Bureau du ministre

77, rue Grenville, 10e étage
Toronto ON M7A 2C1
Tél. : 416-327-6758

Ontario

MC-994-2021-723

November 15, 2021

Mr. Richard Dicerni
Chair
Ontario Energy Board
2300 Yonge Street, 27th floor
PO Box 2319
Toronto ON M4P 1E4

Dear Mr. Dicerni:

Thank you for your letter dated July 27, 2021 presenting the Ministry of Energy (ENERGY) with the Ontario Energy Board's (OEB) 2021 Annual Report for the fiscal year ending March 31, 2021. I have accepted the Annual Report and tabled it with the Legislative Assembly of Ontario on September 28, 2021. The report should now be made available on the OEB's website (as required by our Memorandum of Understanding).

The 2020/2021 Annual Report captures the progress the OEB made toward modernization in the year that it transitioned to its new governance structure. The OEB's commitment to modernization is further reflected in the report card on the Mandate Letter that you submitted to me on September 20, 2021.

The Mandate Letter provided to the OEB on October 1, 2020 showed an ambitious multi-year agenda for a modernized OEB. I am pleased that the OEB has taken such significant steps to promote regulatory excellence within the organization. This work was accomplished while facing the challenges associated with the COVID-19 pandemic. This period saw the OEB adapt to a remote work environment while also moving quickly to support consumers experiencing difficulties with their energy bills and industry as it responded to the crisis. I want to thank you along with the OEB's leadership team, Commissioners and dedicated staff for the incredible work done in support of Ontarians over the past year.

As you begin planning for your next Business Plan, it is my responsibility as Minister to provide you with a renewed Mandate Letter to update you on the government's priorities for the energy sector and my expectations for the OEB for the upcoming three-year planning period. It is essential that the OEB continues to make progress in implementing the priorities of the 2020 Mandate Letter, including robust performance measurement, transparent engagement with stakeholders and red tape reduction.

…/cont'd

The OEB has incorporated these priorities into the Strategic Themes of its 2021/22 – 2025/26 Strategic Plan – evolving to become a top quartile regulator, driving energy sector performance, protecting the public and facilitating innovation. These themes remain both relevant and necessary as the OEB updates its Business Plan to reflect the priorities set out below.

The government's priorities for the energy sector are about promoting reliability, affordability, sustainability and consumer choice. I know that the OEB has begun grappling with important questions related to these priorities, such as how to consider greenhouse gas emissions and decarbonization within the energy sector activity that the OEB regulates. I have confidence in the OEB, its commitment to modernization and that it will set its priorities and undertake its work with an eye to addressing the challenges and opportunities facing Ontario's energy sector. Within that context, I would like to highlight some initiatives where the OEB's role in delivering these priorities will be critical over the next three years:

- The OEB should continue to prioritize its work facilitating and enabling innovation and adoption of new technologies where it makes sense for customers, including implementation of the government's Green Button and Community Net Metering initiatives. Developing policies that support the adoption of non-wires and non-pipeline alternatives to traditional forms of capital investment, where cost-effective, will be essential in maintaining an effective regulatory environment amidst the increasing adoption of Distributed Energy Resources. Work that is already underway, like the Framework for Energy Innovation, should continue. I am pleased with the increased co-ordination and collaboration with stakeholders, especially the Independent Electricity System Operator (IESO). This ongoing collaboration is critical to ensure that initiatives are evaluated and decisions are made with both cost and reliability in mind.

- Increased adoption of electric vehicles (EVs) is expected to impact Ontario's electricity system in the coming years and the OEB must take steps to facilitate their efficient integration into the provincial electricity system, including providing guidance to Local Distribution Companies (LDCs) on system investments to prepare for EV adoption. I am pleased that the OEB is participating in the government's Transportation Electrification Council. I will write to you in the near future on this matter, as it relates to the OEB's Regulated Price Plan (RPP) Roadmap to improve system efficiency and give customers greater control.

- The OEB has done extensive work studying dynamic pricing plans for Class B customers. As Ontario recovers from COVID-19-related economic hardships, we must find ways to support small businesses and give businesses the tools to keep energy prices low so as to not pass on those costs to consumers. I ask that the OEB work with the IESO to develop a plan to design and implement a dynamic pricing pilot to assess the benefits for non-RPP Class B customers.

…/cont'd

- I expect to see the establishment of multi-year natural gas Demand Side Management (DSM) programming and the implementation of the OEB's Integrated Resource Planning framework for assessing demand-side and supply-side alternatives to pipeline infrastructure in meeting natural gas system needs. I would like to express my strong interest in a framework that delivers increased natural gas conservation savings and reduces greenhouse gas emissions. Conservation is a strong driver for cost savings for ratepayers, and with the introduction of carbon pricing, conservation can also transform homes and help protect ratepayers from the impact of the carbon tax. Natural gas conservation programs have delivered continued value for money for ratepayers – based on OEB-verified results for 2019, every dollar spent on natural gas DSM has resulted in up to $3 in participant and social benefits.

- With regard to the next multi-year DSM programming period, it is important that the regulatory processes are optimized to increase efficiency so that they do not hinder Ontarians' access to the real savings that result from these programs. It is also important that the DSM Framework be implemented in a way that enables customers to lower energy bills in the most cost-effective way possible, and help customers make the right choices regardless of whether that is through more efficient gas or electric equipment. I also wish to stress the continued need to foster integration and alignment between natural gas and electricity conservation programs to find efficiencies and to facilitate a streamlined customer experience, where feasible. That said, I am pleased to see the continued collaboration between the IESO Conservation and Demand Management (CDM) and DSM programs in the low-income space and encourage further collaboration, as appropriate. Likewise, as communicated in a recent letter from the Ministry to the federal government encouraging collaboration between DSM and the new Canada Greener Homes Program, it is important that the OEB considers how to use Ontario's DSM programs to leverage these federal funds to benefit Ontario ratepayers.

- The *Supporting Broadband and Infrastructure Expansion Act, 2021* (Bill 257) received Royal Assent on April 12, 2021. This Act contains amendments to the *Ontario Energy Board Act, 1998* that, when proclaimed into force, would establish new authorities in support of the use of and access to electricity infrastructure for non-electricity purposes. As ENERGY considers how these authorities can support the government's objectives for rural broadband expansion, continued consultation and collaboration with the OEB will be essential.

- Modernizing and streamlining processes to reduce regulatory burden is vitally important to the work of an efficient and effective regulator. I am pleased that the OEB has taken steps in this direction in response to the 2020 Mandate Letter, including reviewing how filing requirements can be tailored to LDC size, releasing the Chief Commissioner's Plan with initiatives to enhance adjudicative processes and launching a review of the Reporting & Record-keeping Requirements.

…/cont'd

These plans should continue, ensuring they reflect the feedback of stakeholders and deliver results in the coming fiscal year. The OEB should also continue its work reviewing intervenor processes to identify opportunities to improve the efficiency and effectiveness.

- The OEB should continue to ensure that the structure and operations of the distribution sector constantly evolve towards optimal efficiency. To that end, the OEB should explore opportunities to enable proactive investment in energy infrastructure, such as protection and refurbishment, where utilities can prove there are long-term economic and reliability benefits to ratepayers. In previous years, these efficiencies have been found both through utility mergers/ acquisitions and with the formation of innovative partnerships between utilities. Considering this, I also ask that the OEB require LDCs with fewer than 30,000 customers to file information within their cost-of-service applications on the extent to which they have investigated potential opportunities from consolidation or collaboration/partnerships with other distributors.

- Over the coming year, the government will continue its review of Ontario's long-term energy planning framework to increase the effectiveness, certainty, transparency and accountability of energy decision-making in Ontario while protecting the interests of ratepayers. I want to thank OEB staff and leadership for their contribution to the process so far and look forward to continued collaboration as we consider an appropriate role for the OEB in long-term planning.

Through these priorities we can ensure that the OEB is continuing to deliver value for Ontario's energy consumers. We are confident that as we recover from the COVID-19 pandemic, the people of Ontario are going to unleash the economic growth that is necessary for job creation, prosperity and a stronger province.

This Mandate Letter is also my opportunity to provide you with the government's broad priorities for board-governed agencies. As part of the Government of Ontario, agencies are expected to act in the best interests of Ontarians by being efficient, effective and providing value-for-money to the people of Ontario. Our government's primary focus is to protect every life and every job we possibly can. Without healthy people, we cannot have a healthy economy. As you implement your modernization plan for the OEB, I ask that you do so in a manner consistent with Ontario's priorities for board-governed agencies that are appended to this Letter.

Finally, in the coming months, my staff will continue to work with the OEB to prepare for the conclusion of the two-year transition period related to the establishment of the new governance structure. I am confident that the OEB will emerge from the transition period in October 2022 in a strong position to fully deliver on its statutory responsibilities.

…/cont'd

I thank you and your fellow board members for your continued support and for your valuable contributions. Should you have any questions/concerns regarding this Mandate Letter, please feel free to contact Karen Moore, Assistant Deputy Minister – Strategic, Network and Agency Policy Division at karen.moore@ontario.ca.

Sincerely,

Todd Smith
Minister

c: David Donovan, Chief of Staff to the Minister of Energy
Dominic Roszak, Deputy Chief of Staff to the Minister of Energy
Stephen Rhodes, Deputy Minister of Energy
Susanna Zagar, CEO, Ontario Energy Board

APPENDIX: Government of Ontario Priorities for Board-Governed Agencies

1. **Competitiveness, Sustainability and Expenditure Management**
    - Operating within your agency's financial allocations;
    - Complying with applicable direction related to supply chain centralization and Realty Interim Measures for agency office space;
    - Leveraging and meeting benchmarked outcomes for compensation strategies and directives; and
    - Working with the ministry, where appropriate, to advance the *Ontario Onwards Action Plan.*

2. **Transparency and Accountability**
    - Abiding by applicable government directives and policies and ensuring transparency and accountability in reporting;
    - Adhering to requirements of the Agencies and Appointments Directive, accounting standards and practices, and the *Public Service of Ontario Act* ethical framework and responding to audit findings, where applicable; and
    - Identifying appropriate skills, knowledge and experience needed to effectively support the board's role in agency governance and accountability.

3. **Risk Management**
    - Developing and implementing an effective process for the identification, assessment and mitigation of risks, including planning for and responding to health and other emergency situations, including but not limited to COVID-19; and
    - Developing a continuity of operations plan that identifies time critical/essential services and personnel.

4. **Workforce Management**
    - Optimizing your organizational capacity to support the best possible public service delivery; and
    - Modernizing and redeploying resources to priority areas when or where they are needed.

5. **Data Collection**
    - Improving how the agency uses data in decision-making, information-sharing and reporting, including by leveraging available or new data solutions to inform outcome-based reporting and improve service delivery; and
    - Supporting transparency and privacy requirements of data work and data sharing with the ministry, as appropriate.

6. **Digital Delivery and Customer Service**
    - Exploring and implementing digitization or digital modernization strategies for online service delivery and continuing to meet and exceed customer service standards through transition; and
    - Adopting digital approaches, such as user research, agile development and product management.

7. **Diversity and Inclusion**
    - Developing and encouraging diversity and inclusion initiatives promoting an equitable, inclusive, accessible, anti-racist and diverse workplace;
    - Demonstrating leadership of an inclusive environment free of harassment; and
    - Adopting an inclusion engagement process to ensure all voices are heard to inform policies and decision-making.

8. **COVID-19 Recovery**
    - Identifying and pursuing service delivery methods (digital or other) that have evolved since the start of COVID-19; and
    - Supporting the recovery efforts from COVID-19.

JT 1-14

Attachment 2

Letter of Direction from the Minister of Energy

Ministry of Energy

Office of the Minister

77 Grenville Street, 10th Floor
Toronto ON M7A 2C1
Tel.: 416-327-6758

Ministère de l'Énergie

Bureau du ministre

77, rue Grenville, 10e étage
Toronto ON M7A 2C1
Tél. : 416-327-6758

Ontario

MC-994-2022-850

October 21, 2022

Mr. Richard Dicerni
Chair
Ontario Energy Board
2300 Yonge Street, 27th floor
PO Box 2319
Toronto ON M4P 1E4

Dear Mr. Dicerni:

Congratulations on your reappointment as Chair of the Ontario Energy Board (OEB). In keeping with my responsibilities as Minister of Energy, I am writing to provide you with a renewed Letter of Direction, including updates on the government's priorities for the energy sector and my expectations for the OEB in the upcoming three-year business planning period.

It has been two years since the OEB's modernized governance structure came into effect on October 1, 2020. This marks the end of the modernization transition period. Effective October 1, 2022, the OEB's board of directors began exercising its full authorities under the *Ontario Energy Board Act, 1998* (OEBA), including the authority to appoint the team of Commissioners. I am pleased with the transformational work the OEB undertook during the transition period, including the advancement of the Chief Commissioner's Plan, and that Cabinet has approved your reappointment as Chair and the reappointments of your fellow Board of Directors members. I know as the Board of Directors exercises its new authorities it will ensure the independence of the persons hearing and determining matters within the OEB's jurisdiction.

The transition period is ending at a time when the OEB's role as energy regulator has never been more important: the push for further electrification and the transition to cleaner energy sources will require innovation and leadership from the OEB. The government has a vision for the energy system in which Ontario leverages its clean energy grid to promote electrification and job creation while continually enhancing reliability, resiliency and customer choice. In my previous mandate letter, I noted specific initiatives that I viewed as critical to the health of Ontario's energy sector and necessary for the OEB to prioritize. This work remains both relevant and necessary to the OEB's overall modernization agenda and should continue. I appreciate the OEB's efforts to incorporate these initiatives into its ongoing work via previous business plans.

…/cont'd

Priorities to Advance in the Near-Term

At this time, I wish to highlight areas where I will be expecting significant progress over the coming year. While previous mandate letters have referred to these priorities, there is urgent need to advance them in the next 12 months and thus I am providing the OEB with my timing expectations:

- **Supporting the Electrification and Energy Transition Panel:** Over the next 12 months, I will receive advice on how to support the transformation of the energy sector from the Energy Transition and Electrification Panel (Panel) chaired by David Collie. Ontario must take action to accelerate this transformation to secure the associated environmental and economic development benefits, while ensuring investments across the energy system are made in the interest of ratepayers. I know that the OEB has begun considering its role in this transformation, particularly through the work of its Innovation Task Force. **I am counting on the OEB, informed by the work of its Innovation Task Force, to provide the Panel with its best advice on potential changes to the OEB's mandate and operations, including any necessary legislative amendments.** This advice should include, but need not be limited to, opportunities to incorporate environmental and economic development benefits into the OEB's regulation of the sector, approaches to integrating the regulation of the electricity and natural gas systems, and enhancements to how the OEB and the Market Surveillance Panel oversee the acquisition of energy resources, regulate the Independent Electricity System Operator (IESO) and review long-term planning efforts.

- **Regulatory Framework:** The government's vision for a clean energy grid that promotes electrification, attracts investment and creates jobs while continually enhancing reliability, resiliency and customer choice will require utilities to make new investments. I recognize that the OEB cannot make substantive changes to its regulatory approach without a legislative amendment; however it is critical that the OEB not wait until it has been provided with additional legislative authority before it begins to consider these reforms so that its work can proceed expeditiously. **Therefore, I ask that the OEB launch workshops in 2023 that explore how the OEB could enable electrification related investments while protecting consumers' interests to deliver on the government's vision.**

- **Distribution Sector Resiliency, Responsiveness, and Cost Efficiency:** Ontario's electricity distribution sector will have a critical role in Ontario's electrification transition. As the pace of the electrification of the economy increases and extreme weather events as a result of climate change impact our businesses and communities, there will be pressure on local distribution companies (LDCs) to continue to provide high levels of reliability and resiliency to their customers, be responsive to changing consumer expectations and new government mandates, and to do it all at an affordable price. This year, Ontario experienced two extreme weather events, which affected LDC infrastructure across Eastern Ontario.

…/cont'd

As our climate changes, the OEB will have an important role to play in ensuring LDCs are preparing their distribution infrastructure for these kinds of events. LDCs will need greater capacity to meet these expectations – capacity that can be enabled by aggressively pursuing efficiencies through consolidation or enhanced shared services, adoption of innovative technologies and processes, collaboration on responsibilities like cybersecurity, and changes to the utility remuneration and incentive structure that ensure LDCs make the right investments for their customers. The time to reconsider the structure and regulation of the distribution sector is now. **I ask that the OEB provide me with advice and proposals to improve distribution sector resiliency, responsiveness, and cost efficiency by June 30, 2023.** Please work with the Ministry of Energy and other partners as needed to ensure proposals reflect current and anticipated future extreme weather impacts and best practices in climate change resilience, including insights from the Ministry of Environment, Conservation and Parks' Provincial Climate Change Impact Assessment. This report may also, as possible, reflect input from the workshops being held on the future of the OEB's approach to sector regulation.

- **Electric Vehicles (EVs):** Within the context of the OEB's ongoing work to facilitate innovation in the energy sector, the previous mandate letter requested that the OEB "issue guidance to [LDCs] on system investments to prepare for EV adoption." I understand the OEB has developed its plan to enable system readiness for EV adoption, consider distribution rates for EV charging (including demand charges), and examine connection processes for EV charging stations. This includes studying barriers to EV charger connections through the Distributed Energy Resources Connection Review Working Group, updating filing requirements in December 2022 to underscore that distribution planning activities must include consideration of EV adoption, and being ready to consult with the sector on the EV charging analysis in 2023. **This work has my full endorsement and should proceed as quickly as possible.**

- **Strengthening the Performance Measurement Framework:** In my letter of April 1, 2022 approving the 2022-2025 Business Plan, I noted my expectation that future business plans include increased specificity in the performance measurement framework to demonstrate how outcomes will be measured and how they advance the OEB's strategic goals. As the OEB continues in its journey to become a top quartile regulator, it is critical that the OEB hold itself to a high standard, including setting performance measures that clearly define the OEB's impact in the sector and establishing stretch goals that contain the possibility of failure. I am accountable to the Legislative Assembly for the OEB's performance – including, at some point in the coming years, requiring an effectiveness review of the OEB as specified in s. 128.1 of the OEBA – and thus I expect that I and the Board of Directors will be aligned on what constitutes fair and aggressive performance targets. **I ask that this refined performance measurement framework be submitted to me for refinement and approval in the upcoming business plan submission due on December 31, 2022.** Note that as I review the draft plan, I may request changes to be reflected in the final submission.

…/cont'd

- **Red Tape Reduction:** Reducing the cost of regulation on businesses and consumers remains a government-wide priority. In the 2021 Burden Reduction Report, the government reported a 6.5 per cent reduction in regulatory compliance costs between 2018 and 2021 and we continue to find ways to cut red tape. While the OEB has made some progress in this area, including its ongoing review of utility filing requirements and intervenor processes, I continue to hear from stakeholders who are concerned with onerous and costly regulatory requirements without clear justification. **In the performance measurement framework that will be submitted to me in the next business plan, I ask that the OEB propose aggressive targets for continuing to reduce the number and cost of regulatory burdens by the end of the current business planning period (i.e., March 30, 2026), with regular updates to me on progress toward those targets throughout the current business planning period.**

Work Continuing over the Business Planning Period

The OEB continues to execute on a significant volume of critical work that aligns both with my expectations for the evolution of the energy sector and its own Strategic Plan. I wish to recognize the ongoing importance of that work:

- **Facilitating Innovation:** The release of the Framework for Energy Innovation's (FEI) Working Group Report marks a significant milestone in the evolution of the OEB's approach to utility regulation. The OEB must maintain momentum in this space by making use of stakeholder feedback to propose meaningful changes to how utilities can make use of Distributed Energy Resources to cost-effectively meet emerging local and broader system needs and how non-wires and non-pipeline alternatives are considered, given their significant potential to replace or defer the need for more costly traditional infrastructure; this work is connected to my request in this letter for proposals to reform the distribution sector and to advise on enhancements to the OEB's mandate. I also wish to commend the OEB and the IESO for its collaboration and joint work to promote innovation in the sector, including through the Grid Innovation Fund's joint targeted call. I encourage both parties to find additional opportunities for collaboration.

- **Ultra-Low Overnight Price Plan:** As you are aware, I am pleased with the OEB's March 31, 2022 report on the design of an ultra-low overnight electricity price plan. I know the OEB is undertaking considerable effort to support LDCs in meeting the May 1, 2023 implementation target, including through stakeholder consultations and the development of new codes and manuals. Please keep my Ministry apprised on the progress of this work.

- **Dynamic Pricing Pilot for Class B Customers:** Over the past year the OEB has advanced the development of a new dynamic pricing pilot for Class B customers not on the Regulated Price Plan (RPP). Following stakeholder consultation, the application process will begin before the end of 2022. I look forward to updates on this important initiative.

…/cont'd

- **Green Button:** I am pleased that the OEB is continuing its work to facilitate the implementation of the government's Green Button initiative. I acknowledge that over the coming year, the OEB will consider stakeholder input on how to support LDC implementation and will consider appropriate compliance steps for LDCs that have not made reasonable progress on the November 1, 2023 implementation deadline.

- **Supporting Broadband Expansion:** Delivering high speed broadband to all Ontarians by 2025 remains a top priority for the government. I appreciate the OEB's efforts to meaningfully engage with my Ministry, the Ministry of Infrastructure and Infrastructure Ontario to help clarify roles and responsibilities with regard to enforcing the new legislative and regulatory instruments that promote broadband expansion. I ask that you continue this work, to ensure the OEB's dispute resolution process can provide clear and timely outcomes.

- **Conservation and Demand Management/Demand-Side Management (CDM/DSM):** I am pleased to see the continued collaboration between the IESO and Enbridge Gas Inc. related to CDM and DSM programs in the low-income space and encourage further collaboration, as appropriate. I request that the OEB work with the IESO to reduce barriers, to the extent practicable, for LDCs that wish to deliver CDM activities through distribution rates to address local distribution level electricity needs. This will help guide the co-ordination of LDCs' CDM activities with IESO-led CDM programs in the cases where the distribution level benefits coincide with province-wide system benefits. With the nation-wide launch in 2021 of the Canada Greener Homes Program and Enbridge's efforts to co-ordinate with their residential DSM program in Ontario, I am looking to the OEB to ensure Ontario natural gas ratepayer interests are protected and that Ontario takes every opportunity to generate deeper retrofits, more natural gas savings and greater emissions reductions.

- **Net Metering Regulatory Changes:** I thank the OEB for its collaboration with the Ministry on the new Community Net Metering (CNM) regulation and regulatory amendments to clarify eligible third-party ownership (TPO) net metering arrangements, including its work to implement these regulatory changes through release of regulatory code amendments and consumer protection information documents. I ask the OEB to continue with its work to provide regulatory oversight and guidance for the implementation of the CNM demonstration project authorized under the CNM regulation and to monitor market activities and regulatory compliance of TPO net metering arrangements.

Next Steps and Broad Government Priorities for Agencies

Please continue to provide quarterly updates on the OEB's progress against these expectations. If, in executing any of these priorities, the OEB identifies that legislative or regulatory barriers are preventing the OEB from delivering on expectations, please engage my Ministry with analysis and potential solutions to resolve the barriers. As I've made clear throughout this letter, the Ministry is prepared to take action to ensure the OEB has the tools, authority and resources it needs to advance the government's vision for the energy sector.

…/cont'd

Appended to this letter you will find the government-wide priorities for Board-governed agencies for 2023-24. All provincial agencies are expected to act in the best interests of the people of Ontario and ensure that they provide value for money. I am confident that the OEB will reflect these priorities in its work ahead.

My thanks to you, the Board of Directors, and all OEB executives and staff for the work they do in support of Ontarians. I look forward to receiving the forthcoming business plan and continuing to work together in support of a clean, reliable and affordable electricity system.

Sincerely,

Todd Smith
Minister

c: David Donovan, Chief of Staff to the Minister of Energy
Tyler Lively, Deputy Chief of Staff to the Minister of Energy
Jason Fitzsimmons, Deputy Minister of Energy
Susanna Zagar, Chief Executive Officer, OEB

APPENDIX: Government of Ontario Priorities for Board-Governed Agencies

1. **Competitiveness, Sustainability and Expenditure Management**
   - Identifying and pursuing opportunities for revenue generation through partnerships, where appropriate.
   - Identifying efficiencies and savings through innovative practices, and/or improved program sustainability.
   - Operate within the agency's financial allocations.
   - Complying with applicable direction related to supply chain centralization, including contract harmonization for planned and pending procurements, accounting practices and realty interim measures for agency office space.
   - Leveraging and meeting benchmarked outcomes for compensation strategies and directives.

2. **Transparency and Accountability**
   - Abiding by applicable government directives and policies and ensuring transparency and accountability in reporting.
   - Adhering to accounting standards and practices, and responding to audit findings, where applicable.
   - Identifying appropriate skills, knowledge and experience needed to effectively support the board's role in agency governance and accountability.

3. **Risk Management**
   - Developing and implementing an effective process for the identification, assessment, and mitigation of agency risks, including COVID-19 impacts and any future emergency risks.

4. **Workforce Management**
   - Optimizing your organizational capacity to support the best possible public service delivery, including redeploying resources to priority areas, where needed.
   - Supporting the implementation of the Community Jobs Initiative (CJI) by identifying opportunities to relocate new or existing agencies to lower cost communities.

5. **Diversity and Inclusion**
   - Developing and encouraging diversity and inclusion initiatives by promoting an equitable, inclusive, accessible, anti-racist and diverse workplace.
   - Adopting an inclusion engagement process to ensure all voices are heard to inform policies and decision-making.

6. **Data Collection**
   - Improving how the agency uses data in decision-making, information sharing and reporting, to inform outcome-based reporting and improve service delivery.
   - Increasing data sharing with Supply Ontario when applicable regarding procurement spending and planning, contract arrangements and vendor relations to support data-driven decision-making.

7. **Digital Delivery and Customer Service**
   - Exploring and implementing digitization for online service delivery to ensure customer service standards are met.
   - Using a variety of approaches or tools to ensure service delivery in all situations, including pursuing delivery methods that have evolved since Covid-19.

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.15:

TO REFILE THE ICM MODELS UPDATED FOR THE INFLATION FACTOR, UPDATED FOR ACTUAL DEMAND DATA FOR 2022 AND TO INCLUDE THE 2025 RATE YEAR.

Response:

Updated excel versions of the following files will accompany the submission and be uploaded through RESS:

1) ICM/ACM Model – Whitby Rate Zone Whitby Smart Grid (see: EE_WRZ_WSG_2023_ACM_ICM_Model_JT_1.15_20230124)
2) ICM/ACM Model – Veridian Rate Zone Whitby Smart Grid (see: EE_VRZ_2023_ACM_ICM_Model_JT_1.15_20230124)
3) ICM/ACM Model – Whitby Rate Zone Sustainable Brooklin (see: EE_WRZ_SB_2023_ACM_ICM_Model_JT_1.15_20230124)

Updates to the ICM/ACM Models provided include:

- Use of latest inflation factor applicable to 2023;
- Application of Whitby Smart Grid capital amounts to the 2025 rate year; and,
- Updated tab 3 with 2022 Actual Distribution Demand data and the Current Approved Distribution Rates

The models do not incorporate updated 2023 Cost of Capital parameters, as requested in JT1.22. The ICM policy framework requires distributors to establish the cost of capital based on their most recently approved rebasing cost of capital parameters.

In the case of Whitby Rate Zone, these values remain 2.43% for short-term interest, 5.48% for long-term interest, and 9.66% for return on equity. For the Veridian Rate Zone these values remain 2.11% for short-term interest, 4.94% for long-term interest, and 9.36% for return on equity

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.16:

TO PROVIDE FOR WHITBY RATE ZONE, FOR THE WHITBY SMART GRID PROJECT, AN UPDATED FORECAST, UPDATE THE ICM MODELS WITH THE DEMAND DATA FROM AN UPDATED LOAD FORECAST.

Background:

Excerpt from Technical Conference Day 1 Transcript Page 120, Lines 15 to 28

> "MR. MARTIN-STURMEY: Yes, so to clarify from your request, Ms. Armstrong, so when you are referring to forecasted load, so the load forecast that was submitted in evidence only covers peak demand in kilowatts, and so at this time Elexicon does not have a consumption forecast in kilowatt-hours based on, say, an econometric model, for example, that I think you are referencing.
>
> MS. ARMSTRONG: Well, I basically -- since you are applying for an ICM and the ICM model requires actual demand data, and you are asking for 2025, there needs to be -- I just wanted a scenario that shows what your expectations are over the next -- **because I cannot determine a materiality threshold right now, based on what I have on the record.**"[Emphasis added in bold to highlight reference]

Response:

Elexicon re-affirms what it stated during the Technical Conference. It is not able to produce a detailed forecast of charge determinants by rate-class for 2025 to support this undertaking. Elexicon notes that its application proposes to file an updated ICM model reflecting the latest parameters in order to finalize the ICM rate riders in Elexicon's IRM application for 2025 rates. All parties will be able to review the ICM/ACM Excel models for the most up to date demand, usage, inflation factors and materiality threshold at that time. Elexicon's response to undertaking JT2.2 provides an explanation on what details will be updated in Elexicon's 2025 WSG Rate Rider Update application.

Elexicon notes that its proposed approach to file updated ICM/ACM Excel models addresses OEB Staff's concern about the 2025 value of Elexicon's Whitby Rate Zone ("WRZ") and Veridian Rate Zone ("VRZ") ICM materiality threshold, as well as the ICM/ACM models using the most up to date demand and usage data.

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.17:

TO RUN THE MODELS AS ACM MODELS, USING THE EXISTING PARAMETERS FOR EACH RATE ZONE.

Response:

As set out in the response to Staff-3(a), Elexicon confirms that it is not seeking "ACM-like" treatment of the Whitby Smart Grid in this application.

Rather, Elexicon is seeking ICM treatment of the Whitby Smart Grid ("WSG") in a manner consistent with the OEB's treatment of the Sault Ste. Marie Smart Grid proposal. Specifically, and similar to the Sault Smart Grid, given the scale and innovative nature of the project, Elexicon requires regulatory approval in 2023 in order to place the WSG into service by 2025.

In this context, as a hypothetical scenario only, Elexicon has completed the OEB's Advanced Capital Module ("ACM") excel Model with the Whitby Smart Grid project details to produce models for the Whitby Rate Zone and Veridian Rate Zone. The following two live Excel models have been filed as attachments to this undertaking.

EE_VRZ_2023_ACM_ICM_Model_JT 1.17_20230124

EE_WRZ_WSG_2023_ACM_ICM_Model_JT 1.17_20230124

Elexicon observes that the OEB's ACM/ICM policy [1] states that utilities can use the ACM module for approval of incremental capital expenditures as part of their cost of service application. Elexicon's current application is not a rebasing application and therefore not suitable for ACM treatment. Elexicon further identifies that the model outputs (e.g,. ICM rate riders, materiality threshold calculations) are identical under both the ACM and ICM mechanisms. Additionally, Elexicon's request for Incremental Capital Module treatment of the Whitby Smart Grid is in

[1] EB-2014-0219 Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report

compliance with the MAADs Decision[2] where the OEB found that its policies outlined in the Handbook[3] apply to the amalgamation.

[2] EB-2018-0236, Decision and Order, Page 17
[3] Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, p. 17

Elexicon Energy Inc.

Answer to Undertaking from

OEB STAFF

Undertaking JT1.18:

TO PROVIDE A TABLE OF FORECASTS UP TO 2025.

Response:

Elexicon has filed its response to this Undertaking under the OEB's Confidentiality provisions.

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.19:

ELEXICON TO FILE ITS ECONOMIC EVALUATION MODEL AS NOTED IN THE EXCHANGE OF LETTERS FILED BY BLGI AS SUPPLEMENTARY RESPONSES TO STAFF-17

Response:

Please see the six attached files to this Undertaking which provide the summary page for each of the six economic evaluation models that Elexicon produced for the expansion infrastructure to North Brooklin on behalf of the Brooklin Landowners Group ("BLGI"). Elexicon produced an economic model for the Brooklin Line (i.e. Sustainable Brooklin project)[1], and individual economic evaluations for the connection of 700 homes in each of the years 2021 through to 2025[2].

The following assumptions were used to determine the capital contribution for the Brooklin Line summarized in attachment 1:

1. Customer Connection Horizon of 5 years and Revenue Horizon of 25 years
2. Estimate of Brooklin Line construction costs of $35 MM
3. Whitby Rate Zone ("WRZ") last cost of capital parameters:
    a. Borrowing Rate of 2.55%
    b. Rate of Return of 9.66%
    c. Total Debt of 57.87%
    d. Total Equity of 42.13%
    e. Tax Rate of 26.5%
    f. Capital Cost Allowance Rate of 8%
4. Annual per customer incremental OM&A expense of $152.39 per customer
5. Monthly fixed charge for residential customer of $32.02 per month

The following assumptions were used to determine the capital contribution for the annual connection of 700 homes in North Brooklin for each of the years 2021 to 2025 in attachments 2 to 6:

1. Customer Connection Horizon of 5 years and Revenue Horizon of 25 years

[1] Attachment 1 of this undertaking
[2] Attachments 2 to 6 of this undertaking

2. Customer additions of 700 homes in year 1
3. Average energy added per customer of 750 kWh for each of years 1 to 5
4. Estimate of construction costs to connect 700 homes of $3.5 MM
5. Whitby Rate Zone ("WRZ") last cost of capital parameters:
   a. Borrowing Rate of 2.55%
   b. Rate of Return of 9.66%
   c. Total Debt of 57.87%
   d. Total Equity of 42.13%
   e. Tax Rate of 26.5%
   f. Capital Cost Allowance Rate of 8%
6. Annual per customer incremental OM&A expense of $152.39 per customer
7. Monthly fixed charge for residential customer of $32.02 per month

JT 1-19

Attachment 1

North Brooklin Whitby

$35M 2021

Summary of Customer Data and Economic Analysis Results

Project Name	**Blank**
Project Number	**TBA**
Developer	**TBA**
Municipality	

Technician: TBA **Date Run:** 16-Dec-20 **Version:**

EE Template : Whitby

New Customers and Input Data

Customers, Type	kWh per Unit	Year 1- 2021	Year 2- 2022	Year 3-2023	Year 4-2024	Year 5-2025	Total
							Number of Units or GS load (kW) Added in Each Year
General Service Load			**0**	**0**	**0**	**0**	0
							0
							0
Residential	750	**0**	**0**	**0**	**0**	**0**	0
							0
							0
Total Residential		0	0	0	0	0	0
Average energy added per Res. customer		0	0	0	0	0	0

Data

Annual O,M, & A

Incremental OM&A, $/Customer	$ 152.39	$ 152.39

Distribution Rates in effect

Monthly, fixed customer charge		
	Residential	$ 32.02
	General Service < 50kW	$ -
	General Service 50 to 2,999 kW	$ -
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -
Monthly, variable		
	Residential, per kWh	$ -
	General Service < 50kW, per kWh	$ -
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	$ -
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -

Summary

Statement of Costs

Cost Breakdown:	Project Total Costs (Data Inputs)
Eng & Admin	$ -
Connecting (Section A)	$ -
Material (Section A)	$ -
Other	$ 35,000,000.00
Installation (Section B)	$ -
Inspection	$ -
Total	$ 35,000,000.00

Calculation Results

Expressed in relation to internal construction costs only…..

Total Actual Cost of Project (Paid by Owner)	$ 35,000,000.00
Capital Contribution by Customer	$ 35,000,000.00
Expansion Deposit	$ -
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**100%**

JT 1-19

Attachment 2

North Brooklin Whitby

700 Units 2021

Summary of Customer Data and Economic Analysis Results

Project Name	**Blank**
Project Number	**TBA**
Developer	**TBA**
Municipality	

Technician: TBA **Date Run:** 16-Dec-20 **Version:**

EE Template : Whitby

New Customers and Input Data

Customers, Type	**kWh per Unit**	*Year 1- 2021*	*Year 2- 2022*	*Year 3-2023*	*Year 4-2024*	*Year 5-2025*	*Total*
		Number of Units or GS load (kW) Added in Each Year					
General Service Load			**0**	**0**	**0**	**0**	0
							0
							0
Residential	750	**700**	**0**	**0**	**0**	**0**	700
							0
							0
Total Residential		700	0	0	0	0	700
Average energy added per Res. customer		750	750	750	750	750	750

Data

Annual O,M, & A

Incremental OM&A, $/Customer	**$ 152.39**	**$ 152.39**

Distribution Rates in effect

Monthly, fixed customer charge		
	Residential	**$ 32.02**
	General Service < 50kW	**$ -**
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**
Monthly, variable		
	Residential, per kWh	**$ -**
	General Service < 50kW, per kWh	**$ -**
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**

Summary

Statement of Costs

Cost Breakdown:	**Project Total Costs (Data Inputs)**
Eng & Admin	**$ -**
Connecting (Section A)	**$ -**
Material (Section A)	**$ -**
Other	**$ 3,500,000.00**
Installation (Section B)	**$ -**
Inspection	**$ -**
Total	**$ 3,500,000.00**

Calculation Results

Expressed in relation to internal construction costs only…..

Total Actual Cost of Project (Paid by Owner)	$ 3,500,000.00
Capital Contribution by Customer	$ 1,557,104.14
Expansion Deposit	$ 1,942,895.86
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**44%**

JT 1-19

Attachment 3

North Brooklin Whitby

700 Units 2022

Summary of Customer Data and Economic Analysis Results

Project Name	**Blank**
Project Number	**TBA**
Developer	**TBA**
Municipality	

Technician:	**TBA**	**Date Run:**	**16-Dec-20**	**Version:**	

EE Template : **Whitby**

New Customers and Input Data

Customers, Type	**kWh per Unit**	*Year 1- 2022*	*Year 2- 2023*	*Year 3-2024*	*Year 4-2025*	*Year 5-2026*	*Total*
General Service Load			**0**	**0**	**0**	**0**	0
							0
							0
Residential	750	**700**	**0**	**0**	**0**	**0**	700
							0
							0
Total Residential		700	0	0	0	0	700
Average energy added per Res. customer		750	750	750	750	750	750

Number of Units or GS load (kW) Added in Each Year

Data

Annual O,M, & A

Incremental OM&A, $/Customer	**$ 152.39**	**$ 152.39**

Distribution Rates in effect

Monthly, fixed customer charge		
	Residential	**$ 32.02**
	General Service < 50kW	**$ -**
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**
Monthly, variable		
	Residential, per kWh	**$ -**
	General Service < 50kW, per kWh	**$ -**
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**

Summary

Statement of Costs

Cost Breakdown:	**Project Total Costs (Data Inputs)**
Eng & Admin	**$ -**
Connecting (Section A)	**$ -**
Material (Section A)	**$ -**
Other	**$ 3,500,000.00**
Installation (Section B)	**$ -**
Inspection	**$ -**
Total	**$ 3,500,000.00**

Calculation Results

Expressed in relation to internal construction costs only…..

Total Actual Cost of Project (Paid by Owner)	$ 3,500,000.00
Capital Contribution by Customer	$ 1,557,104.14
Expansion Deposit	$ 1,942,895.86
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**44%**

JT 1-19

Attachment 4

North Brooklin Whitby

700 Units 2023

Summary of Customer Data and Economic Analysis Results

Project Name	**Blank**
Project Number	**TBA**
Developer	**TBA**
Municipality	

Technician: TBA **Date Run:** 16-Dec-20 **Version:**

EE Template : Whitby

New Customers and Input Data

Customers, Type	kWh per Unit	Year 1- 2023	Year 2- 2024	Year 3-2025	Year 4-2026	Year 5-2027	Total
		Number of Units or GS load (kW) Added in Each Year					
General Service Load			**0**	**0**	**0**	**0**	0
							0
							0
Residential	750	**700**	**0**	**0**	**0**	**0**	700
							0
							0
Total Residential		700	0	0	0	0	700
Average energy added per Res. customer		750	750	750	750	750	750

Data

Annual O,M, & A

Incremental OM&A, $/Customer **$ 152.39 $ 152.39**

Distribution Rates in effect		
Monthly, fixed customer charge		
	Residential	**$ 32.02**
	General Service < 50kW	**$ -**
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**
Monthly, variable		
	Residential, per kWh	**$ -**
	General Service < 50kW, per kWh	**$ -**
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**

Summary

Statement of Costs

Cost Breakdown:	Project Total Costs (Data Inputs)
Eng & Admin	$ -
Connecting (Section A)	$ -
Material (Section A)	$ -
Other	$ 3,500,000.00
Installation (Section B)	$ -
Inspection	$ -
Total	**$ 3,500,000.00**

Calculation Results

Expressed in relation to internal construction costs only…..

Total Actual Cost of Project (Paid by Owner)	$ 3,500,000.00
Capital Contribution by Customer	$ 1,557,104.14
Expansion Deposit	$ 1,942,895.86
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**44%**

JT 1-19

Attachment 5

North Brooklin Whitby

700 Units 2024

Summary of Customer Data and Economic Analysis Results					
Project Name	Blank				
Project Number	TBA				
Developer	TBA				
Municipality					
Technician:	**TBA**	**Date Run:**	**16-Dec-20**	**Version:**	
EE Template :	**Whitby**				

New Customers and Input Data

Customers, Type	**kWh per Unit**	Year 1- 2024	Year 2- 2025	Year 3-2026	Year 4-2027	Year 5-2028	Total
		Number of Units or GS load (kW) Added in Each Year					
General Service Load			**0**	**0**	**0**	**0**	0
							0
							0
Residential	750	**700**	**0**	**0**	**0**	**0**	700
							0
							0
	Total Residential	700	0	0	0	0	700
	Average energy added per Res. customer	750	750	750	750	750	750

Data

Annual O,M, & A

Incremental OM&A, $/Customer	**$ 152.39**	**$ 152.39**

Distribution Rates in effect		
Monthly, fixed customer charge		
	Residential	**$ 32.02**
	General Service < 50kW	**$ -**
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**
Monthly, variable		
	Residential, per kWh	**$ -**
	General Service < 50kW, per kWh	**$ -**
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	**$ -**
	General Service 3,000 to 4,999 kW	**$ -**
	Large User	**$ -**

Summary

Statement of Costs

Cost Breakdown:	**Project Total Costs (Data Inputs)**
Eng & Admin	**$ -**
Connecting (Section A)	**$ -**
Material (Section A)	**$ -**
Other	**$ 3,500,000.00**
Installation (Section B)	**$ -**
Inspection	**$ -**
Total	**$ 3,500,000.00**

Calculation Results	
Expressed in relation to internal construction costs only…..	
Total Actual Cost of Project (Paid by Owner)	$ 3,500,000.00
Capital Contribution by Customer	$ 1,557,104.14
Expansion Deposit	$ 1,942,895.86
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**44%**

JT 1-19

Attachment 6

North Brooklin Whitby

700 Units 2025

Summary of Customer Data and Economic Analysis Results

Project Name	**Blank**
Project Number	**TBA**
Developer	**TBA**
Municipality	

Technician: TBA **Date Run:** 16-Dec-20 **Version:**

EE Template : Whitby

New Customers and Input Data

Customers, Type	kWh per Unit	Year 1- 2025	Year 2- 2026	Year 3-2027	Year 4-2028	Year 5-2029	Total
		Number of Units or GS load (kW) Added in Each Year					
General Service Load			**0**	**0**	**0**	**0**	0
							0
							0
Residential	750	**700**	**0**	**0**	**0**	**0**	700
							0
							0
Total Residential		700	0	0	0	0	700
Average energy added per Res. customer		750	750	750	750	750	750

Data

Annual O,M, & A

Incremental OM&A, $/Customer	$ 152.39	$ 152.39

Distribution Rates in effect		
Monthly, fixed customer charge		
	Residential	$ 32.02
	General Service < 50kW	$ -
	General Service 50 to 2,999 kW	$ -
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -
Monthly, variable		
	Residential, per kWh	$ -
	General Service < 50kW, per kWh	$ -
Monthly Variable, per kW		
	General Service 50 to 2,999 kW	$ -
	General Service 3,000 to 4,999 kW	$ -
	Large User	$ -

Summary

Statement of Costs

Cost Breakdown:	Project Total Costs (Data Inputs)
Eng & Admin	$ -
Connecting (Section A)	$ -
Material (Section A)	$ -
Other	$ 3,500,000.00
Installation (Section B)	$ -
Inspection	$ -
Total	**$ 3,500,000.00**

Calculation Results

Expressed in relation to internal construction costs only…..

Total Actual Cost of Project (Paid by Owner)	$ 3,500,000.00
Capital Contribution by Customer	$ 1,557,104.14
Expansion Deposit	$ 1,942,895.86
Capital Contribution Recovery Rate (CCRR) (% of Project Total)	**44%**

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.20:

TO PROVIDE DATA FOR THE WHITBY RATE ZONE.

Background:

Technical Conference Day 1 Transcript Page 140, Lines 12 and 13:

"Is it possible for Elexicon to provide the actual residential growth in the past five historical years…"

Response:

The following table provides the total number of residential customers in Elexicon's Whitby Rate Zone over the period of 2017 to 2022.

Elexicon notes that the customer count for 2022 included in Table 1 is an estimate currently being finalized for Elexicon's 2022 RRR submission.

Table 1 – 2018 to 2022 Residential Customer Count

	2018	2019	2020	2021	2022	**Growth 5 years (2018 to 2022)**	**% Increase 5 years (2018 to 2022)**
Residential	40,272	41,437	42,256	43,441	44,498	4,226	10.49%

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.21:

AS DESCRIBED ON PAGES 165-168

Background:

Technical Conference Day 1 Transcript Page 167, Lines 10 and 18:

"Elexicon to review and update the, including reliability, sheet pertaining to Staff, Whitby smart grid, Excel workbook, and updated to reflect -- well you have options 1, 2 and 3. Options 1 and 2 are equivalent to what Elexicon has proposed in its alternative -- in its project evaluations. But option 3 is Staff's option. You are asking us to review the sheet for all three. And the NPV net calculations."

Response:

Elexicon has reviewed the OEB's Whitby Smart Grid Excel workbook and identified one item of correction as well as changes to both values and assumptions to reflect a more appropriate and accurate estimation of the Net Present Value of net benefits from the Whitby Smart Grid ("WSG") project. An updated live Excel workbook has been filed with this Undertaking with a new worksheet labelled EE- Including Reliability Worksheet reflecting Elexicon's changes ("EE- Including Reliability Worksheet"). The EE- Including Reliability Worksheet is also included below as Table 1 in this response.

As noted in the Technical Conference discussion and Undertaking, Elexicon agreed to provide its assessment of the OEB – Including Reliability worksheet. Elexicon observed the following item of error which has been updated in its EE- Including Reliability Worksheet:

1. Ongoing OM&A cost has been changed to reflect inclusion of efficiencies. This was not performed in the original worksheet. This results in the update of the OM&A cost from $0.38 MM to $0.28 MM throughout the worksheet[1].

Elexicon has made the following changes to values and assumptions in the EE – Including Reliability worksheet:

---

[1] On the cost line, the additional ongoing OM&A costs should be the OM&A cost (C) from Table 1 in Appendix B of the ICM Application minus the Efficiency Benefits (D) highlighted in Table 1.

1. Updated Energy Savings to $3.37MM as per undertaking JT1.5
2. Updated the Ongoing OM&A cost to $0.28MM, and only incurred this after the in-service year of the project.
3. Updated time period of NPV to 27years (average lifetime of assets installed) once the project is in-service.
4. Elexicon has removed the partial savings in both the original OEB Option 2 and Option 3 NPV models.

With respect to Elexicon's removal of partial savings that were inserted in both Option 2 and Option 3, Elexicon's rationale is the following:

VVO savings are linear, so once the assets are installed and commissioned, then the benefits can be realized only once ADMS is fully installed. Reliability savings are not as straightforward. Elexicon's calculation of reliability savings is a value achieved based on historical outage events across its the entire Whitby Rate Zone service. Therefore, the estimated additional savings can only be achieved when the entire FLISR and ADMS system is put in-service. It is unknown, how many and where outages that are prevented by the FLISR and ADMS implementation will occur. Additionally, Elexicon's current schedule per its NRCan Agreement, is for the ADMS component of the WSG to be placed in-service on June 30, 2024.

It is therefore imprudent to allocate a percentage of future benefits during the implementation phase of the WSG project. For the purposes of this NPV, Elexicon has assumed that 100% of the energy and reliability savings for the installed assets in any given year is achieved after the assets are placed in-service.

- For option 1, the Benefits of the installed assets, will not be realized until ADMS is fully functional and the whole project is in-service. So 100% of benefits will be achieved from 2026 onwards.
- For option 2, the Benefits of the installed assets, will not be realized until ADMS is fully functional and the whole project is in-service. So 100% of benefits will be achieved from 2029 onwards.
- For Option 3,the Benefits of the installed assets, will not be realized until ADMS is fully functional and the whole project is in-service. So 100% of benefits will be achieved from 2029 onwards.

Table 1 – Elexicon Update and Correction of OEB – Including Reliability Worksheet

Elexicon Updated OEB-Including Reliability Worksheet

Discount Rate	3%
Savings Scenario	100%
Reliability Savings ($M)	$ 1.82
Reliability Savings Percentage	100%
Ongoing OM&A Cost ($M)	$0.32
Efficiency ($M)	$0.05
Net OM&A ($M)	$0.28

		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Option 1		**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**
Cost		$ (15.74)	$ (16.21)	$ (16.53)	$ (0.28)	$ (0.28)	$ (0.29)	$ (0.29)	$ (0.30)	$ (0.30)	$ (0.31)	$ (0.32)	$ (0.32)	$ (0.33)	$ (0.34)	$ (0.34)	$ (0.35)	$ (0.36)	$ (0.36)	$ (0.37)	$ (0.38)	$ (0.39)	$ (0.39)	$ (0.40)	$ (0.41)	$ (0.42)	$ (0.43)	$ (0.44)	$ (0.44)	$ (0.45)	$ (0.46)			
Savings					$ 3.37	$ 3.44	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.87	$ 3.95	$ 4.03	$ 4.11	$ 4.19	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42	$ 5.53	$ 5.64			
Adjusted Savings					$ 3.37	$ 3.44	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.87	$ 3.95	$ 4.03	$ 4.11	$ 4.19	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42	$ 5.53	$ 5.64			
Reliability Savings					$ 1.82	$ 1.86	$ 1.89	$ 1.93	$ 1.97	$ 2.01	$ 2.05	$ 2.09	$ 2.13	$ 2.18	$ 2.22	$ 2.26	$ 2.31	$ 2.35	$ 2.40	$ 2.45	$ 2.50	$ 2.55	$ 2.60	$ 2.65	$ 2.70	$ 2.76	$ 2.81	$ 2.87	$ 2.93	$ 2.99	$ 3.05			
Total Savings					$ 5.19	$ 5.29	$ 5.40	$ 5.51	$ 5.62	$ 5.73	$ 5.84	$ 5.96	$ 6.08	$ 6.20	$ 6.33	$ 6.45	$ 6.58	$ 6.71	$ 6.85	$ 6.99	$ 7.12	$ 7.27	$ 7.41	$ 7.56	$ 7.71	$ 7.87	$ 8.02	$ 8.18	$ 8.35	$ 8.51	$ 8.69			
NPV Cost	$ (52.69)	$ (15.74)	$ (15.74)	$ (15.58)	$ (0.25)	$ (0.25)	$ (0.25)	$ (0.25)	$ (0.24)	$ (0.24)	$ (0.24)	$ (0.24)	$ (0.23)	$ (0.23)	$ (0.23)	$ (0.23)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.20)			
NPV savings	$ 113.29				$ 4.75	$ 4.70	$ 4.66	$ 4.61	$ 4.57	$ 4.52	$ 4.48	$ 4.44	$ 4.39	$ 4.35	$ 4.31	$ 4.27	$ 4.22	$ 4.18	$ 4.14	$ 4.10	$ 4.06	$ 4.02	$ 3.98	$ 3.95	$ 3.91	$ 3.87	$ 3.83	$ 3.79	$ 3.76	$ 3.72	$ 3.69			
NPV Net	$ 60.60																																	
Option 2																																		
Cost		$ (7.87)	$ (8.11)	$ (8.27)	$ (8.43)	$ (8.60)	$ (8.77)	$ (0.28)	$ (0.28)	$ (0.29)	$ (0.29)	$ (0.30)	$ (0.30)	$ (0.31)	$ (0.32)	$ (0.32)	$ (0.33)	$ (0.34)	$ (0.34)	$ (0.35)	$ (0.36)	$ (0.36)	$ (0.37)	$ (0.38)	$ (0.39)	$ (0.39)	$ (0.40)	$ (0.41)	$ (0.42)	$ (0.43)	$ (0.44)	$ (0.44)	$ (0.45)	$ (0.46)
Savings								$ 3.37	$ 3.44	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.87	$ 3.95	$ 4.03	$ 4.11	$ 4.19	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42	$ 5.53	$ 5.64
Adjusted Savings								$ 3.37	$ 3.44	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.87	$ 3.95	$ 4.03	$ 4.11	$ 4.19	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42	$ 5.53	$ 5.64
Reliability Savings								$ 1.82	$ 1.86	$ 1.89	$ 1.93	$ 1.97	$ 2.01	$ 2.05	$ 2.09	$ 2.13	$ 2.18	$ 2.22	$ 2.26	$ 2.31	$ 2.35	$ 2.40	$ 2.45	$ 2.50	$ 2.55	$ 2.60	$ 2.65	$ 2.70	$ 2.76	$ 2.81	$ 2.87	$ 2.93	$ 2.99	$ 3.05
Total Savings								$ 5.19	$ 5.29	$ 5.40	$ 5.51	$ 5.62	$ 5.73	$ 5.84	$ 5.96	$ 6.08	$ 6.20	$ 6.33	$ 6.45	$ 6.58	$ 6.71	$ 6.85	$ 6.99	$ 7.12	$ 7.27	$ 7.41	$ 7.56	$ 7.71	$ 7.87	$ 8.02	$ 8.18	$ 8.35	$ 8.51	$ 8.69
NPV Cost	$ (51.06)	$ (7.87)	$ (7.87)	$ (7.79)	$ (7.72)	$ (7.64)	$ (7.57)	$ (0.23)	$ (0.23)	$ (0.23)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.19)	$ (0.19)	$ (0.19)	$ (0.19)	$ (0.19)	$ (0.18)	$ (0.18)	$ (0.18)	$ (0.18)
NPV savings	$ 103.68							$ 4.35	$ 4.30	$ 4.26	$ 4.22	$ 4.18	$ 4.14	$ 4.10	$ 4.06	$ 4.02	$ 3.98	$ 3.94	$ 3.90	$ 3.87	$ 3.83	$ 3.79	$ 3.75	$ 3.72	$ 3.68	$ 3.65	$ 3.61	$ 3.58	$ 3.54	$ 3.51	$ 3.47	$ 3.44	$ 3.41	$ 3.37
NPV Net	$ 52.62																																	
Option 3																																		
Cost		$ (7.87)	$ (8.11)	$ (8.27)	$ (8.43)	$ (8.60)	$ (8.77)	$ (0.28)	$ (0.28)	$ (0.29)	$ (0.29)	$ (0.30)	$ (0.30)	$ (0.31)	$ (0.32)	$ (0.32)	$ (0.33)	$ (0.34)	$ (0.34)	$ (0.35)	$ (0.36)	$ (0.36)	$ (0.37)	$ (0.38)	$ (0.39)	$ (0.39)	$ (0.40)	$ (0.41)	$ (0.42)	$ (0.43)	$ (0.44)	$ (0.44)	$ (0.45)	$ (0.46)
Savings								$ 3.37	$ 3.44	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.87	$ 3.95	$ 4.03	$ 4.11	$ 4.19	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42	$ 5.53	$ 5.64
Adjusted Savings								$ 3.37	$ 3.44	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.87	$ 3.95	$ 4.03	$ 4.11	$ 4.19	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42	$ 5.53	$ 5.64
Reliability Savings								$ 1.82	$ 1.86	$ 1.89	$ 1.93	$ 1.97	$ 2.01	$ 2.05	$ 2.09	$ 2.13	$ 2.18	$ 2.22	$ 2.26	$ 2.31	$ 2.35	$ 2.40	$ 2.45	$ 2.50	$ 2.55	$ 2.60	$ 2.65	$ 2.70	$ 2.76	$ 2.81	$ 2.87	$ 2.93	$ 2.99	$ 3.05
Total Savings								$ 5.19	$ 5.29	$ 5.40	$ 5.51	$ 5.62	$ 5.73	$ 5.84	$ 5.96	$ 6.08	$ 6.20	$ 6.33	$ 6.45	$ 6.58	$ 6.71	$ 6.85	$ 6.99	$ 7.12	$ 7.27	$ 7.41	$ 7.56	$ 7.71	$ 7.87	$ 8.02	$ 8.18	$ 8.35	$ 8.51	$ 8.69
NPV Cost	$ (51.06)	$ (7.87)	$ (7.87)	$ (7.79)	$ (7.72)	$ (7.64)	$ (7.57)	$ (0.23)	$ (0.23)	$ (0.23)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.22)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.21)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.20)	$ (0.19)	$ (0.19)	$ (0.19)	$ (0.19)	$ (0.19)	$ (0.18)	$ (0.18)	$ (0.18)	$ (0.18)
NPV savings	$ 103.68							$ 4.35	$ 4.30	$ 4.26	$ 4.22	$ 4.18	$ 4.14	$ 4.10	$ 4.06	$ 4.02	$ 3.98	$ 3.94	$ 3.90	$ 3.87	$ 3.83	$ 3.79	$ 3.75	$ 3.72	$ 3.68	$ 3.65	$ 3.61	$ 3.58	$ 3.54	$ 3.51	$ 3.47	$ 3.44	$ 3.41	$ 3.37
NPV Net	$ 52.62																																	

Elexicon Energy Inc.

Answer to Undertaking from

OEB Staff

Undertaking JT1.22:

TO UPDATE TABLE 1,PAGE 11 OF APPENDIX B TO REFLECT THE 2022 TOTAL COST OF POWER IN THE SAME MANNER AS WAS DONE WITH THE CURRENT TABLE 1, INCLUDING THE COST-OF-CAPITAL PARAMETERS FOR THE ICM, TO UPDATE THAT WITH THE 2023 COST-OF-CAPITAL PARAMETERS, THE FINALIZED OEB COST-OF-CAPITAL PARAMETERS, AND, TO THE EXTENT POSSIBLE, ALSO DO THAT WITH THE EXCEL FILE THAT WAS PROVIDED. AND ALSO TO LOOK AT THE RELIABILITY WORKSHEET WITHIN THE STAFF WHITBY SMART GRID WORKBOOK AND SEE IT CAN BE APPLIED TO THE UPDATED TABLE 1.

Response:

The updated Table 1, page 11 of Appendix B, included below reflects the following updated values which are highlighted in yellow:

1. Elexicon's unaudited total Cost of Power for the Whitby Rate Zone as of December 31, 2022 of approximately $112 MM.
2. Whitby Smart Grid ("WSG") Additional ICM Revenue from the OEB ICM Excel model provided in undertaking JT1.15 of $4.477 MM, and
3. Updated Operating Efficiencies from WSG to include the cost of truck assets provided in undertaking JT1.1 of $0.05 MM.

As a result of the above updates, the net benefit of the WSG to Whitby Rate Zone ("WRZ") customers has been reduced from $0.673 MM to $0.433 MM per year. Elexicon did not include an update to the Cost of Capital parameters for the purpose of this response as requested. The OEB's ICM policy requires the use of a distributors most recently approved cost of capital parameters; updating of these parameters to match the OEB's 2023 Cost of Capital parameters would be inconsistent with OEB policy.

In addition to the updated Table 1 requested in this undertaking, Elexicon has included the following additional tables related to benefit calculations that were produced during the interrogatory and technical conference proceeding steps:

1. Updated Interrogatory ED-01 Table 1 – 20 Year NPV Whitby Smart Grid Benefit Calculation
2. Updated Interrogatory ED-01 Table 4 – 20 Year NPV Benefits From Sustainable Brooklin and Whitby Smart Grid
3. Updated Undertaking JT1.5 - NPV Whitby Smart Grid Based on Time Period Equal to Average Lifetime of the Equipment

Updated Table 1 – Annual Net Benefit of WSG to WRZ Customers

Table 1 – Annual Net Benefit of WSG to WRZ Customers

Customer Annual Benefit Summary		
(All Dollars Listed in Thousands CAD)		
2022 Cost of Power (WRZ)	$	112,198
Projected % Energy Savings from WSG		3.00%
Total Purchased Power Savings from WSG (A)	$	3,366
ICM Additional Revenue (B)	$	4,477
Additional OM&A Expenses (C)	$	324
Operating Efficiencies from WSG (D)	$	48
Sub-Total of Savings (E = A-B-C+D)	$	(1,387)
Projected VoLL Benefit from Reliability (F)	$	1,820
Annual Net Benefit to WSG Customers (G = E+F)	$	433

Updated Interrogatory ED-01 Table 1 – 20 Year NPV Whitby Smart Grid Benefit Calculation

Table 2 – 20 Year NPV Whitby Smart Grid Benefit Calculation

Customer 20yr NPV Benefit Summary (5% Discount)		
(All Dollars Listed in Thousands CAD)		
Total Purchased Power Savings from WSG	$	49,363
ICM Additional Revenue	$	45,739
Additional OM&A Expenses	$	4,747
Operating Efficiencies from WSG	$	700
Sub-Total of Savings	-$	423
Projected VoLL Benefit from Reliability	$	26,689
NPV of Net Benefits (20 years) to WSG Customers	$	26,266

Updated Undertaking JT1.5 - NPV Whitby Smart Grid Based on Time Period Equal to Average Lifetime of the Equipment

Table 3 - NPV Benefit Calculation of Whitby Smart Grid Based Using Time Period Equal to Average Lifetime of the Equipment of 27 Years

Customer 27yr NPV Benefit Summary (5% Discount)		
(All Dollars Listed in Thousands CAD)		
Total Purchased Power Savings from WSG	$	60,903
ICM Additional Revenue	$	50,425
Additional OM&A Expenses	$	5,857
Operating Efficiencies from WSG	$	864
Sub-Total of Savings	$	5,485
Projected VoLL Benefit from Reliability	$	32,928
NPV of Net Benefits (27 years) to WSG Customers	$	38,413

Elexicon Energy Inc.

Answer to Undertaking from

Consumers Council of Canada

Undertaking JT2.1:

ON A BEST-EFFORTS BASIS, TO TAKE STAFF 5'S TABLE IN RESPONSE A WHICH SHOWS TWO TABLES, ONE WITH VERIDIAN RATE ZONE, ONE FOR WHITBY RATE ZONE; ACTUALS; AND THEN INCLUDE FORECAST 2023-2026 AND ALSO INCLUDE THE ICMS.

Response:

Please see Table 1, 2 and 3 below where Elexicon has updated the capital tables from interrogatory Staff-05 to include the forecasted capital for years 2023 to 2026.

Table 1 – Whitby Rate Zone Capital Expenditures Including ICM

Whitby Rate Zone																			
Category	2018	2018	2019	2019	2020	2020	2021	2021	Sept 2021 YTD	2022	Sept 2022 YTD	2023	2023	2024	2024	2025	2025	2026	2026
Plan	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
System Access (WRZ)	$ 6,930	$ 2,132	$ 14,276	$ 14,794	$ 10,087	$ 10,694	$ 11,380	$ 8,857	$ 617	$ 13,929	$ 735	$ 2,037	$ -	$ 2,605	$ -	$ 2,955	$ -	$ 2,354	$ -
System Renewal (WRZ)	$ 7,347	$ 7,032	$ 3,275	$ 9,189	$ 4,865	$ 3,249	$ 8,264	$ 5,669	$ 1,343	$ 2,998	$ 483	$ 2,441	$ -	$ 3,321	$ -	$ 6,040	$ -	$ 4,338	$ -
System Service (WRZ)	$ 2,840	$ 476	$ 152	$ 1,035	$ 784	$ 199	$ 227	$ 3,740	$ -	$ 3,916	$ 611	$ 6,087	$ -	$ 1,089	$ -	$ 1,724	$ -	$ 374	$ -
General Plant (WRZ)	$ 3,124	$ 1,309	$ 1,309	$ 205	$ 1,849	$ 1,809	$ 1,597	$ 1,844	$ 359	$ 2,379	$ 215	$ 2,490	$ -	$ 1,310	$ -	$ 1,124	$ -	$ 1,364	$ -
Total Gross (WRZ)	$ 20,241	$ 10,949	$ 19,012	$ 25,223	$ 17,585	$ 15,951	$ 21,468	$ 20,110	$ 2,319	$ 23,222	$ 2,044	$ 13,055	$ -	$ 8,325	$ -	$ 11,843	$ -	$ 8,430	$ -
Contributed Capital (WRZ)	$ 3,671	$ 1,786	$ 5,853	$ 11,438	$ 4,051	$ 3,486	$ 7,417	$ 5,049	$ 578	$ 13,265	$ 648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net (WRZ)	$ 16,570	$ 9,163	$ 13,159	$ 13,785	$ 13,534	$ 12,465	$ 14,051	$ 15,061	$ 1,741	$ 9,957	$ 1,396	$ 13,055	$ -	$ 8,325	$ -	$ 11,843	$ -	$ 8,430	$ -
ICM (WRZ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,657	$ -	$ -	$ -	$ 36,739	$ -	$ -	$ -
ICM Contribution (WRZ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 825	$ -	$ -	$ -
Total Including ICM (WRZ)	$ 16,570	$ 9,163	$ 13,159	$ 13,785	$ 13,534	$ 12,465	$ 14,051	$ 15,061	$ 1,741	$ 9,957	$ 1,396	$ 39,712	$ -	$ 8,325	$ -	$ 47,757	$ -	$ 8,430	$ -

Table 2 – Veridian Rate Zone Capital Expenditures Including ICM

Veridian Rate Zone																			
Category	2018	2018	2019	2019	2020	2020	2021	2021	Sept 2021 YTD	2022	Sept 2022 YTD	2023	2023	2024	2024	2025	2025	2026	2026
Plan	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
System Access (VRZ)	$ 34,018	$ 13,223	$ 28,891	$ 11,586	$ 11,860	$ 13,595	$ 33,301	$ 17,156	$ 1,623	$ 44,914	$ 2,303	$ 7,334	$ -	$ 6,078	$ -	$ 7,244	$ -	$ 8,784	$ -
System Renewal (VRZ)	$ 10,117	$ 10,846	$ 9,885	$ 17,810	$ 8,298	$ 9,917	$ 11,404	$ 14,912	$ 1,523	$ 11,418	$ 1,689	$ 12,286	$ -	$ 13,499	$ -	$ 24,154	$ -	$ 15,136	$ -
System Service (VRZ)	$ -	$ 21	$ 354	$ 63	$ 536	$ 2,972	$ 1,191	$ 5,383	$ 225	$ 2,000	$ 1,043	$ 1,721	$ -	$ 8,067	$ -	$ 3,309	$ -	$ 10,349	$ -
General Plant (VRZ)	$ 2,650	$ 4,857	$ 3,051	$ 5,611	$ 4,315	$ 4,221	$ 10,467	$ 4,830	$ 839	$ 10,752	$ 733	$ 6,171	$ -	$ 3,056	$ -	$ 2,623	$ -	$ 3,182	$ -
Total Gross (VRZ)	$ 46,785	$ 28,947	$ 42,181	$ 35,070	$ 25,009	$ 30,705	$ 56,363	$ 42,281	$ 4,210	$ 69,084	$ 5,768	$ 27,512	$ -	$ 30,700	$ -	$ 37,330	$ -	$ 37,451	$ -
Contributed Capital (VRZ)	$ 4,053	$ 6,345	$ 13,657	$ 5,369	$ 9,451	$ 12,855	$ 25,059	$ 10,616	$ 1,039	$ 33,241	$ 1,550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net (VRZ)	$ 42,732	$ 22,602	$ 28,524	$ 29,701	$ 15,558	$ 17,850	$ 31,304	$ 31,665	$ 3,171	$ 35,843	$ 4,218	$ 27,512	$ -	$ 30,700	$ -	$ 37,330	$ -	$ 37,451	$ -
ICM (VRZ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,667	$ -	$ -	$ -	$ -	$ -	$ 6,432	$ -	$ -	$ -
ICM Contribution (VRZ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 3,216	$ -	$ -	$ -
Total Including ICM (VRZ)	$ 42,732	$ 22,602	$ 28,524	$ 29,701	$ 15,558	$ 17,850	$ 31,304	$ 31,665	$ 3,171	$ 82,510	$ 4,218	$ 27,512	$ -	$ 30,700	$ -	$ 40,546	$ -	$ 37,451	$ -

Table 3 – Elexicon Total Capital Expenditures Including ICM

ELEXICON																			
Category	2018	2018	2019	2019	2020	2020	2021	2021	Sept 2021 YTD	2022	Sept 2022 YTD	2023	2023	2024	2024	2025	2025	2026	2026
Plan	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
System Access (Elexicon)	$ 40,948	$ 15,355	$ 43,167	$ 26,380	$ 21,947	$ 24,289	$ 44,681	$ 26,013	$ 2,240	$ 58,843	$ 3,038	$ 9,371	$ -	$ 8,683	$ -	$ 10,199	$ -	$ 11,138	$ -
System Renewal (Elexicon)	$ 17,464	$ 17,878	$ 13,160	$ 26,999	$ 13,163	$ 13,166	$ 19,668	$ 20,581	$ 2,866	$ 14,416	$ 2,172	$ 14,727	$ -	$ 16,820	$ -	$ 30,194	$ -	$ 19,474	$ -
System Service (Elexicon)	$ 2,840	$ 497	$ 506	$ 1,098	$ 1,320	$ 3,171	$ 1,418	$ 9,123	$ 225	$ 5,916	$ 1,654	$ 7,808	$ -	$ 9,156	$ -	$ 5,033	$ -	$ 10,723	$ -
General Plant (Elexicon)	$ 5,774	$ 6,166	$ 4,360	$ 5,816	$ 6,164	$ 6,030	$ 12,064	$ 6,674	$ 1,198	$ 13,131	$ 948	$ 8,661	$ -	$ 4,366	$ -	$ 3,747	$ -	$ 4,546	$ -
Total Gross (Elexicon)	$ 67,026	$ 39,896	$ 61,193	$ 60,293	$ 42,594	$ 46,656	$ 77,831	$ 62,391	$ 6,529	$ 92,306	$ 7,812	$ 40,567	$ -	$ 39,025	$ -	$ 49,173	$ -	$ 45,881	$ -
Contributed Capital (Elexicon)	$ 7,724	$ 8,131	$ 19,510	$ 16,807	$ 13,502	$ 16,341	$ 32,476	$ 15,665	$ 1,617	$ 46,506	$ 2,198	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net (Elexicon)	$ 59,302	$ 31,765	$ 41,683	$ 43,486	$ 29,092	$ 30,315	$ 45,355	$ 46,726	$ 4,912	$ 45,800	$ 5,614	$ 40,567	$ -	$ 39,025	$ -	$ 49,173	$ -	$ 45,881	$ -
ICM (VRZ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,667	$ -	$ -	$ -	$ -	$ -	$ 6,432	$ -	$ -	$ -
ICM (WRZ)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,657	$ -	$ -	$ -	$ 36,739	$ -	$ -	$ -
ICM Contribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 4,041	$ -	$ -	$ -
Total Including ICM (Elexicon)	$ 59,302	$ 31,765	$ 41,683	$ 43,486	$ 29,092	$ 30,315	$ 45,355	$ 46,726	$ 4,912	$ 92,467	$ 5,614	$ 67,224	$ -	$ 39,025	$ -	$ 88,303	$ -	$ 45,881	$ -

Elexicon Energy Inc.

Answer to Undertaking from

Consumers Council of Canada

Undertaking JT2.2:

TO PROVIDE DETAILS OF WHAT WILL BE UPDATED IN ELEXICON'S 2025 WHITBY SMART GRID ICM RATE RIDER UPDATE APPLICATION.

Response:

Elexicon Energy ("Elexicon") has identified in its application and evidence[1] that it proposes to file updated Whitby Smart Grid ("WSG") OEB ICM Excel models for the Veridian Rate Zone ("VRZ") and Whitby Rate Zone ("WRZ") (collectively called "ICM Models") with its 2025 Incentive Rate Mechanism ("IRM") application. The 2025 IRM application is expected to be filed in the summer of 2024.

Elexicon proposes to only update the ICM Models with the most up to date inflation factor, approved 2024 Rates, and 2023 billing determinants (the "Proposed Updated Parameters"). Elexicon does not propose to update the ICM Models for the WSG capital costs as proposed in its application and evidence[2] or any other parameters.

Elexicon has been guided by the OEB's ICM Policy[3] (the "Policy") which would normally have as inputs the Proposed Updated Parameters. While Elexicon requires early ICM approval for the reasons specified in the Application, Elexicon is of the view the ICM models should still be run as contemplated in the Policy prior to setting a final rate rider for 2025 rates. As shown in Figure 1 below which is an excerpt of Appendix A from the Policy, a review of the project actuals will be performed at Elexicon's next Cost of Service application, and any true-up approved by the OEB.

Figure 1 – Appendix A of OEB's ACM/ICM Policy[4]

[1] Appendix B – Incremental Capital Module Whitby Smart Grid & Sustainable Brooklin, Page 32 of 56
[2] The Whitby Smart Grid budget is $43.1 MM after including the $4.0 MM of NRCan funding.
[3] EB-2014-0219 Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report
[4] IBID

Appendix A
The Capital Module Policy [Unchanged from the ACM Report]

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the OEB may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Elexicon Energy Inc.

Answer to Undertaking from

Consumers Council of Canada

Undertaking JT2.3:

TO PROVIDE EXAMPLES OF SPECIFIC TECHNOLOGIES APPROVED BY THE BOARD

Response:

The project that is specifically OEB approved relating to this application is PUC Distribution's Sault Smart Grid Incremental Capital Module ("ICM") application; as referenced at several points throughout evidence. Additionally, Hydro Ottawa has undertaken a similar project of "VR & Grid Edge Technology as a Non-Wires Alternative for Capacity Reduction & Energy Savings" (Listed on the "EDA Blog" dated August 2021).

As additional examples of Distribution Automation ("DA") and Volt-Var Optimization ("VVO") technology projects, Elexicon has conducted a best efforts basis search of the OEB Regulatory Document Service and included a list of electricity distributors who have implemented DA, VVO and FLISR projects.

Elexicon would also point to archived documents available at the Smart Grid Fund[1] for a list of projects funded by the Ontario Smart Grid Fund and in particular these projects:

- #2 Grid Monitoring and Automation in Oshawa (DA and VVO)
- #3 Comprehensive Voltage Management in Thamesville (VVO/CVR Entegrus)
- #4 dTechs Oakville (wireless sensors)
- #11 Distributed Dynamic Voltage/VAR Control and Monitoring of Distribution Feeders (VVO/CVR London Hydro, Entegrus, and Enwin Utilies)
- #16 Loss reduction pilot at Chapleau (VVO Chapleau PUC)

Also as listed in the CV of Mr. Thompson attached to Appendix B-5 the following is a summarised list of Distribution Automation projects that are within his professional experience:

- Festival Hydro
- Entegrus Powerlines Inc.
- Toronto Hydro
- Brant County, Ontario,

[1] https://www.ontario.ca/document/projects-funded-smart-grid-fund/grid-automation

- Niagara on the Lake
- Manitoba Hydro, WaverlyWest Automation System.
- Kitimat Rio Tinto, Campus Grid and Automation.
- Fortis – IntelliTeamII Installation 30 intelligent devices,
- ENMAX – IntelliTeamII Installation 25 intelligent devices, Studies

The projects listed above and many others are installed and operating within the systems of utilities in Canada, and presumably within capital plans generally approved by their relevant regulators.

In the context of the significant sub-components, a Distribution Automation system is made up of automated line switches from manufactures such as S&C and G&W in Ontario, and a VVO system is made up of voltage regulators and capacitors made by manufactures such as GE, ABB and Eaton to name a few. All of these components have been in use for decades in Ontario.

Table 1 below is a list of electricity distributors who have implemented VVO, Fault Location Isolation Service Restoration ("FLISR"), Advanced Distribution Management System ("ADMS") and Distribution Automation. Elexicon has provided the OEB docket number and taken best efforts to list out the technology component that was implemented under the OEB's approval of the docket.

Table 1 – List of Ontario Electricity Distributors Implementing VVO, ADMS/Distribution Automation, FLISR, and AMI

Utility	Case	ADMS / DA	VVO	FLISR	AMI	Project Name
Hydro Ottawa	EB-2019-0261 EB-2015-0004	Y	Y	Y	N	Volt/var mangement & system automation (Exhibit 2, Tab 4, Schedule 3, Attachment E, Page 397 of 534)
PUC Distributio	EB-2018-0219 EB-2020-0249	Y	Y	N	Y	Sault Smart Grid - DA / VVO / AMI
Canadian Niagara Power Inc.	EB-2021-0011	Y	N	N	N	"Distribution Automation" (s.5.4.3 of DSP)
Bluewater Power Distribution Corporation	EB-2022-0016 EB-2012-0107	Y	N	Y	N	"Smart grid" and " Supervisory Control and Data Acquisition (SCADA)" (s.5.2.1.8 of DSP and s.6.2 & 6.3 Asset Management Strategy)
Milton Hydro	EB-2022-0049	Y	N	Y	N	"Smart Grid" or "SCADA" (IR responses 2-Staff-48, Exhibit 1 s.1.7.6)
London Hydro	EB-2021-0041 EB-2012-0187	Y	N	Y	N	"SCADA Enhancement Project" See 2-SEC-29
Oakville Hydro	EB-2021-0048	Y	N	Y	N	SCADA - ADMS FLISR System
Brantford Powe	EB-2021-0009	Y	N	Y	N	"Automated reclosers"
Grimsby Power	EB-2021-0027	Y	N	Y	N	"Smart grid" & "Automate Primary 3-Phase Switches"
Waterloo North Hydro	EB-2020-0059	Y	N	Y	N	See Exhibit 2, Appendix K, Distribution System Reliability Report or 1-SEC-6
Oshawa Power	EB-2020-0048	Y	N	Y	N	"Automation Controller, Smart Fault Indicators, Lateral Reclosers & IEDs" (see page 101, Exhibit 2 – DSP Appendix A)
Enwin Utilities	EB-2019-0032	Y	Y	Y	N	"SCADA FCI Project", "Distribution System Loss Reduction" and "SCADA Distribution Management System – FLISR " (Exhibit 2, ATTACHMENT 2 – A, pages 27, 28 and 227)
Toronto Hydro	EB-2018-0165 EB-2012-0064	Y	N	Y	N	"Feeder Automation" (Exhibit 2B, Section E7.1, E7.1.3.1)
Power Stream	EB-2012-0161	Y	N	Y	N	"Distribution Automation" (application at PDF page 440 - 6.3.1.4)
Innisfil	EB-2012-0139	Y	N	Y	N	"Smart Grid" or "Mechanized SCADA Controlled Load Interruptors" (Application PDF page 419)
Greater Sudbury Hydro	EB-2012-0126	Y	N	Y	N	"Distribution Automation" (Exhibit 2, Tab 4, Schedule 3, s.9.2)
Lakefront Utilities	EB-2021-0039	Y	N	Y	N	"Distribution Automation" (DSP page 73)
Festival Hydro	EB-2012-0124	Y	N	Y	N	"Distribution Automation" (Application, Appendix I, Capital Budget, page 13)

Elexicon Energy Inc.

Answer to Undertaking from

School Energy Coalition

Undertaking JT2.4:

TO EXPLAIN THE PROCESS FOR CUSTOMER CONNECTION OF A COMMERCIAL CUSTOMER TO THE SUSTAINABLE BROOKLIN LINE OUTSIDE OF NORTH BROOKLIN AFTER THE BROOKLIN LINE IS CONSTRUCTED AND IN-SERVICE.

Background:

Elexicon included the following detail in its application and evidence with respect to the connection of a non-residential customer to the Sustainable Brooklin line[1]:

> "Elexicon requests that a condition of the OEB's approval of the DSC Exemption be that all developers that may stand to benefit from the Brooklin Line will construct DER and EV ready homes or buildings as specified in Appendix B-2 of this Application. Should a developer fail to deliver on the construction of DER-and-EV-Ready homes or buildings, that developer or property owner will be required to pay an appropriate capital contribution to Elexicon in support of the Brooklin Line. The amount of the capital contribution would be approximately $2,260 per home or building before Elexicon supplies power[2]. **With respect to non-residential customers, Elexicon would apply the standard requirements of the DSC to calculate a capital contribution commensurate with the capacity required for the customer in question.**" [emphasis added in bold]

Response:

For non-residential customers that are not part of the *quid-pro-quo*, Elexicon Energy's ("Elexicon") proposal is to calculate the contribution associated with the Brooklin Line in accordance with Section 3.2.27 of the Distribution System Code ("DSC") by collecting a capital contribution to the benefit of ratepayers funding the Brooklin Line, over a five year period. The benefit of the Brooklin Line would be apportioned by assessing the relative non-coincident peak demand of the load customer and the relative line length in proportion to the line length being shared, as applicable.

[1] Appendix B – Incremental Capital Module Whitby Smart Grid & Sustainable Brooklin, Page 8 of 56, Lines 10 to 19
[2] Source Brooklin Landowners Group Inc.

For clarity, Elexicon would use the OEB's standard Economic Evaluation model[3] ("EE Model"), to determine if a capital contribution is required to connect any non-residential customer seeking to connect to the Sustainable Brooklin project ("Brooklin Line"). For the capital cost component of the EE Model, Elexicon would include an apportionment of costs associated with the Brooklin Line as described above plus the costs for the assets to distribute electricity from the location of the customer meter to the Brooklin Line. The customer revenue component of the EE Model would be determined using the proposed load forecasting information gathered by Elexicon in collaboration with the customer.

Elexicon understands the question and concern raised by certain parties during the Technical Conference, and is open to alternative approaches to apportioning the value of the Brooklin Line to non-residential customers that are not part of the quid-pro-quo should the OEB order otherwise.

[3] Appendix B of the Distribution System Code ("DSC")

Elexicon Energy Inc.

Answer to Undertaking from

School Energy Coalition

Undertaking JT2.5:

TO FILE THE Z-FACTOR APPLICATION THAT ISN'T CURRENTLY ON THE RECORD, INCLUDING THE TABLE OF RATE RIDERS.

Response:

Elexicon's Z-Factor Application is provided as attachment 1 to this Undertaking. Please review pages 14 to 20 of the main application for Elexicon's methodology to allocate operating and capital expenditures and the resulting tables of Rate Riders.

JT 2-5

Z Factor Application

elexicon ENERGY

December 9, 2022

via RESS

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto, ON M4P 1E4
Email: Boardsec@oeb.ca

Dear Ms. Marconi:

Re: 2023 IRM Application for Electricity Distribution Rates (EB-2022-0317)
Z-Factor Event Application

Elexicon Energy Inc. ("Elexicon") is submitting the following evidence supporting its Z-Factor Application. Elexicon experienced a Z-factor event on May 21, 2022, specifically a powerful derecho storm. It notified the Ontario Energy Board ("OEB") on September 6, 2022 that it would be filing a Z-factor application. In its Z-Factor Application, Elexicon is seeking implementation of Rates effective July 1, 2023.

The derecho event was outside Elexicon's control, and significantly impacted operations which resulted in Elexicon incurring a material level of prudently incurred incremental costs.

Yours truly,

Cynthia Chan
Chief Financial Officer
Elexicon Energy Inc.

CC: John Vellone

elexicon ENERGY

Z-Factor Application

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Table of Contents

1. Overview

On May 21, 2022, Elexicon Energy Inc. (“Elexicon”) experienced a Z-factor event as a result of a *derecho* storm (the “Derecho Storm Event”) that swept through the province of Ontario, including large portions of Elexicon’s service territory. This widespread and fast-moving storm caused extensive damage to Elexicon’s infrastructure, leading to prolonged power outages for the majority of Elexicon’s customers. The Derecho Storm Event was: outside Elexicon’s control; significantly impacted operations; and resulted in Elexicon incurring material, prudently incurred costs. As identified in greater detail below, this event meets the Z-factor eligibility criteria as set out in Section 2.6 of the Ontario Energy Board’s (“OEB” or the “Board”) Report on *3rd Generation Incentive Regulation for Ontario’s Electricity Distributors* dated July 14, 2008 (the “Z-Factor Guidelines”) and Section 3.2.8 of the Board’s *Chapter 3 Filing Requirements for Electricity Distribution Rate Applications*, dated May 24, 2022 (“the Chapter 3 Filing Requirements”).

Elexicon is seeking recovery of a total of $ 4,602,788 in expenditures associated with the restoration of electricity service to its customers following this event and proposes to recover this amount from rate payers via two rate riders effective July 1, 2023.

Background

On May 21, 2022, parts of Southern Ontario experienced a powerful *derecho*[1] storm. Within this storm, an EF-2 tornado touched down in Elexicon's service territory in Uxbridge, ON, as confirmed by Environment Canada.[2]

Elexicon had very limited prior warning based on reports of high winds advancing into its service territory. Environment Canada's Severe Thunderstorm Warnings for Uxbridge and the broader Durham Region were not issued until after Elexicon had issued its own Pre-Event Readiness warning internally on May 21,2022. The readiness warning alerts staff to the possible need for their assistance should conditions require it.

In the aftermath, over 95,000 customers were without power in the communities of Ajax, Belleville, Bowmanville, Pickering, Uxbridge and Whitby. Uxbridge was the most severely impacted service area with its main transformer station requiring a full rebuild as part of the Derecho Storm Event restoration operation. The Crisis Management Team immediately activated the organization's Power Restoration Plan and declared a Level 3 outage situation, which involves any power interruption event affecting more than 25,000 customers with an expected restoration time exceeding 24 hours.

Elexicon restored service to approximately 90% of customers by May 23, 2022 at approximately 10:30 am. This restoration took nearly 70 hours; by Friday May 27th power was restored to approximately 98.7% of customers, at which point and Elexicon declared its Level 3 Outage over. Major reconstruction work continued in Uxbridge and

[1] A widespread, long-lived, straight-line wind storm that is associated with a fast-moving group of severe thunderstorms.
[2] https://uwo.ca/ntp/blog/2022/uxbridge_on_ef2_tornado.html, and https://www.theweathernetwork.com/ca/news/article/tornado-confirmed-in-ontario-after-destructive-long-weekend-storm

along Westney Road in North Pickering on Saturday May 28th. Uxbridge was fully restored on Sunday, May 29th.

The Derecho Storm Event was one of the most severe storms in Elexicon or its predecessor utilities' history, with its impact spread over a wide portion of Elexicon's service territory. The harm caused by this extraordinary event was beyond Elexicon's experience and expectations. For additional details supporting the magnitude of the Derecho Storm Event, please see Appendix A-1 *Elexicon May 2022 Derecho Storm Event - Additional Information*.

Elexicon tracked the costs associated with restoration efforts associated with the Derecho Storm Events over the subsequent weeks. Once Elexicon understood the materiality of those costs, it promptly notified the OEB of its intention to file this Z-factor application, by letter dated September 6, 2022. A copy of this letter is attached as Appendix A-2 *Notice of Intent to file Z-Factor Application*.

While Elexicon had originally intended to make this Z-factor filing in October, the organization was working with the OEB through the process of the adjudication of its 2023 electricity distribution rate application which included two incremental capital module ("ICM") projects. This resulted in a re-prioritization of resources and this filing, dated, December 9, 2022.

2. Eligibility Criteria

Z-factor eligibility is defined as unforeseen events that are outside the control of a distributor's ability to manage.[3] The cost to a distributor must be material and its causation clear for a Z-factor claim to be justified. The OEB has set out the eligibility criteria for applications to recover amounts via the Z-factor in its Incentive Regulation Report and its guidelines discussed in section 2.6 of the Z-Factor Guidelines[4]. The OEB's Z-Factor Guidelines state that a distributor must submit evidence that the costs incurred meet the following three eligibility criteria of causation, materiality, and prudence:

Causation: Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.

Materiality: The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.

Prudence: The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

[3] OEB's Filing Requirements For 2023 Rate Applications Chapter 3 Incentive Rate-Setting Applications (https://www.oeb.ca/sites/default/files/OEB-Filing-Reqs-Chapter-3-2023-20220524.pdf)
[4] https://www.oeb.ca/oeb/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf

Additionally, the OEB's 2023 Incentive Rate-setting Applications Filing Requirements state[5]:

> *To be eligible for a Z-factor claim, a distributor must demonstrate that its achieved regulatory return on equity (ROE), during its most recently completed fiscal year, does not exceed 300 basis points above its deemed ROE embedded in its base rates.*

Elexicon confirms that its achieved Regulatory Return on Equity (ROE) in the most recently completed fiscal year does not exceed 300 basis points above the deemed ROE embedded in its base. The achieved regulatory ROE for 2021 was 6.97%, which is 2.56% less than the 9.43% OEB approved ROE[6]. Elexicon's forecast for its regulated 2022 ROE at this time is expected to be below the OEB Deemed ROE, and fall within the OEB's 300 basis points ROE deadband[7].

The following sections provide the details as to how Elexicon's Z-Factor claim satisfies each of the OEB's three eligibility criteria.

3. Causation

The costs included in this Z-factor recovery claim were directly related to the restoration of service in the wake of the May 21, 2022 Derecho Storm Event, and have been incurred within a 12-month period[8]. Had the *derecho* storm not occurred, Elexicon would not have incurred any of the costs requested for recovery. Elexicon has verified

[5] Chapter 3 Incentive Rate-Setting Applications May 24, 2022, Page 21
[6] Elexicon's Interrogatory Response to SEC-05 in its 2023 Incentive Rate-Making Application, EB-2022-0024
[7] IBID
[8] Elexicon's filing date of its Z-factor application (i.e. December 9, 2022) is well within the 12-month period from May 21, 2022.

that the amounts sought for recovery are outside of the base upon which Elexicon's rates were derived.

As noted above, and further provided in Appendix A – 1a *Elexicon's May 21 2022 Outage Summary*[9], Elexicon had very limited prior warning based on reports of high winds advancing into its service territory. Management enacted a Readiness Alert to the Core Power Restoration Team to stand-by in the Virtual Incident Command Centre prior to Environment Canada issuing a Severe Thunderstorm Warning on May 21, 2022.

In the normal course of business, Elexicon employs several strategies, in two broad methods, to reduce the impact of extreme weather events on its distribution system: proactively through asset hardening, and reactively through the safe and efficient restoration of power following a major event as outlined in its Power Restoration Plan.

The following is a high level listing of how Elexicon Energy employs asset hardening measures to reduce the risk of asset failure as a result of extreme weather such as high winds, ice storms, etc.:

- Assessing and replacing poles proactively to be able to withstand windspeeds to their design standard;
- Reinforcing key infrastructure with steel guy wires to make them more secure;
- Undergrounding around key infrastructure such as hospitals, fire stations, etc.;
- Vegetation management to reduce the likelihood of tree contacts during high winds or from snow/ice accumulation; and
- Investing in smart grids / micro grids.

[9] Appendix A – 1a Elexicon's May 21 2022 Outage Summary, page 3

With respect to restoring power as quickly and as safely as possible following a major event, Elexicon Energy has a robust Power Restoration Plan ("PRP") that outlines the processes and procedures to be followed for any power disruption events that are considered to be outside of the normal course of business.

The PRP executes readiness procedures that include continuous weather monitoring, and the issuance of readiness alerts to the key members of the Power Restoration Team, to ensure the proactive assembly of key staff and other resources

The PRP is a standalone plan under Elexicon Energy's overarching Business Continuity Plan ("BCP"), which contemplates a number of different types of emergencies. These include emergencies such as fires, cybersecurity incidents, ice storms, all of which have the potential to threaten the distribution system.

In such events, Elexicon activates its PRP and declares the appropriate outage level. The PRP is tested annually through a hybrid drill/ tabletop exercise that tests the various areas of the plan and trains the key members of the Power Restoration team, to ensure an efficient response to a real event. The last training event prior to the May 21, 2022 derecho event was held on December 2, 2021 using an ice storm scenario that disrupted >25,000 customers for >24 hours (i.e., a Level 3 outage).

These strategies help mitigate the impact of a Z-factor event. However, Elexicon and other affected electricity distributors could not have foreseen the *derecho* storm, nor could they have planned or budgeted for damage caused by a storm of this magnitude and severity. Therefore, the costs resulting from this extreme weather event were not included in Elexicon's rates.

4. Materiality

The materiality threshold applicable to Elexicon is 0.5% of distribution revenue requirement, which is the threshold applicable to distributors with a revenue requirement greater than $10M and less than or equal to $200M. As such, Elexicon's materiality threshold is $346,352; equal to 0.5% of its distribution revenue requirement of $69,126,603[10]. This amount is the sum of revenue requirement approved in Veridian and Whitby Hydro's last cost of service applications[11]. The relief requested of $677,031[12] as a result of expenditures incurred during the May 21 derecho storm exceeds the materiality threshold of $346,352[13].

5. Prudence

The amounts associated with restoring service to customers following the Derecho Storm Event were incurred prudently. The derecho storm hit on Saturday, May 21st, and caused extensive damage to Elexicon's distribution system.

Elexicon's operational systems and processes set out the plans for addressing events such as the Derecho Storm Event of May 21, 2022. In the aftermath, 95,000 customers were without power in the communities of Ajax, Belleville, Bowmanville, Pickering,

[10] Elexicon's distribution revenue requirement is the sum of Veridian and Whitby Hydro's Distribution Revenue Requirement as decided by the OEB in their last cost of service applications. Veridian's Distribution Revenue Requirement is $49,930,177 from its Draft Rate Order in its last cost of service application in 2014 (EB-2013-0174). Whitby Hydro's Distribution Revenue Requirement is $19,196,426 from its Draft Rate Order in its last cost of service application in 2010 (EB-2009-0274). The sum of the legacy utility Distribution Revenue Requirement is $69,126,603.

[11] EB-2020-0008 - CNPI 2021 IRM and Z-Factor Claim Decision and Order page15,16 approved the use of revenue requirement from the last approved cost of service application(s).

[12] The sum of VRZ and WRZ operating expenses and capital revenue requirements is $677,031. (Sum of $246,725 + $298,156 + $58,384 + $73,766)

[13] Materiality threshold calculated by multiplying $69,126,603 by 0.005 or 0.5%/100.

Uxbridge and Whitby. The Crisis Management Team immediately activated the organization's Power Restoration Plan and declared a Level 3 outage situation, which involves any power interruption event affecting more than 25,000 customers with an expected restoration time exceeding 24 hours.

Power restoration efforts proceeded non-stop in the immediate aftermath of the storm, with crews and system operators working around the clock to restore power as quickly and as safely as possible. The damage was severe and widespread, particularly in Ajax, south Pickering, northwest Pickering, and Uxbridge. Environment Canada confirmed that an EF2 tornado directly struck the urban area of Uxbridge, including Elexicon's substation, which required a rebuild as a result.

The storm, and the impact it had on Elexicon's distribution system, was more destructive than the 2013 ice storm. While restoration was challenging and the team encountered many obstacles all power was restored within just over a week.

During the course of this event Elexicon issued several communications to the public to keep customers informed. These included:

- Outage map on website displaying information regarding outage locations and estimated restoration times ("ERTs").
- Website banner display that contained information regarding power restoration efforts, the number of customers affected, restoration time as a whole, contact information for customers to utilize should they see a downed power line or tree or to report an outage, a new storm email inbox, and Electrical Safety Association ("ESA") information for customer-owned infrastructure and connections. During the event, Elexicon had 689,539 page views on its website.

- Updated news releases posted to public facing website, twitter and sent to all local and major GTA media outlets to provide information regarding Elexicon's power restoration efforts, including critical information to ensure public safety.
- Media interviews to continue to update customers through traditional media, that was carried on Global and CTV News locally (Durham) and provincially.
- Social media updates including real-time posts from system control that aligned with the outage map and ETRs, supplemental posts regarding restoration efforts/images of damage and crews conducting restoration efforts, safety messages, conservation messaging to ensure ongoing reliability in areas where load needed to be transferred and shared with another substation, information regarding local community relief locations, power outage survival checklists, emergency management for those who require electricity for critical life support, and review/triaging of all messages from customers to ensure follow up by distribution operations and crews.
- Direct communications as well as regular updates to Mayors, City and Town Councilors and CAOs of all affected regions to ensure most up-to-date local information was provided to the public through municipal communication channels.
- Direct communications to customers and the public through Elexicon's call centre and specialized storm communication email address was actively monitored throughout the event.

In addition to executing its communications plan, Elexicon conducted its power restoration efforts in a prudent manner as per the Power Restoration Plan. Some of the steps it undertook included:

- With regards to the capital additions, Elexicon pulled primarily from its existing inventory/stores for replacements. Due to the magnitude of damage to the distribution grid, Elexicon did purchase additional material to assist the restoration efforts. These purchases did not incur incremental costs over the current pricing that was negotiated for Elexicon's regular day-to-day purchases.

- Elexicon utilized all available internal labour, as well as several outside contractors to complete its restoration efforts. Elexicon labour costs are set in its collective agreement with the Power Workers Union (PWU), and for non-union staff, Elexicon has established its Overtime Policy with which it complied. Elexicon procured the services of its pre-approved contractors on a single source basis given the emergency situation. These pre-approved contractors charges used pre-established rates.
- Elexicon requested support from Alectra Utilities, Toronto Hydro and Oshawa PUC, however none of these LDCs were able to provide the support requested during the timeframes needed.
- Elexicon issued a Pre-Event Readiness Alert internally on May 21, 2022 and key members of the Power Restoration team immediately began assembling virtually via its Microsoft Teams Virtual Incident Command Centre to respond to the impending weather event.

Elexicon's decision to incur these amounts represented the most cost-effective option for rate payers. Labour and contractor costs were incurred according to previously negotiated agreements. Repairs were made where appropriate, and the portions of the system that were rebuilt were constructed on a 'like for like' basis. Elexicon also used materials available in its inventory and minimized the costs to procure materials on an emergency basis. Ultimately, Elexicon prioritized and coordinated work to ensure restoration was completed efficiently, and power was restored to customers as quickly as possible

6. Recoverability of Z-Factor Costs

Elexicon proposes to recover the Z-Factor costs for each of the rate zones through two separate fixed rate riders commencing July 1, 2023. One of the rate riders will be for the operating costs (effective for 1 year) and the other rate rider will be for the Revenue Requirement of the capital costs (effective until re-basing[14]) ("Z-Factor Capital Costs"). The proposed recovery is set out in Tables 7 through 10 below.

With respect to the recovery of Z-Factor capital costs, Elexicon evaluated the following two approaches:

1. A fixed rate rider recovering all of the Z-Factor Capital Costs in 1-year, similar to Elexicon's proposal for recovery of its Operating Costs
2. A fixed rate rider that recovers the Z-Factor Capital Costs annually until re-basing.

Option 2 was determined as the most prudent approach of the two options based on it yielding the lowest monthly bill impact. Tables 11 and 12 below, demonstrate the bill impacts from Option 1 and 2 for both the Veridian Rate Zone ("VRZ") and Whitby Rate Zone ("WRZ") customers. For a typical VRZ residential customer the bill impact is $1.48 less per month by selecting Option 2 versus Option 1, and similarly, a WRZ residential customer will experience a bill impact that is $0.94 less per month. Elexicon proposes that its Z-Factor Capital Costs be recovered as a fixed rate rider until re-basing to minimize customer bill impacts.

[14] Elexicon is operating under a deferred rebasing period until December 31, 2028

Elexicon has recorded eligible Z-factor amounts in its Account 1572, "Extraordinary Event Costs", of the Board's Uniform System of Accounts ("USoA"). Elexicon has allocated the Z-factor event costs to all rate classes based on its last Board-approved distribution revenue. The monthly rate rider is calculated using the number of customers as of December 31, 2021 as submitted in its RRR filing.

The total incremental operating costs and capital expenditures associated with the restoration of electricity service to Elexicon's customers following the Derecho Storm Event were $305,110 and $4,297,679 respectively, as shown in Table 1 below.

Table 1 – Total Z-Factor Event Costs

Category	Operating $	Capital $	Total $
Incremental Labour/Material/Vehicle Costs	$ 149,626	$ 2,350,964	$ 2,500,590
3rd Party Contractors	$ 155,483	$ 1,946,715	$ 2,102,198
Total	**$ 305,110**	**$ 4,297,679**	**$ 4,602,788**

Table 2 below shows the total Z-Factor Event Costs allocation between Elexicon Energy's two rate zones.

Table 2 – Allocation of Z-Factor Event Costs by Rate Zone

Category	Operating $	Capital $	Total $
Veridian Rate Zone ("VRZ")	$ 246,725	$ 3,475,295	$ 3,722,021
Whitby Rate Zone ("WRZ")	$ 58,384	$ 822,383	$ 880,767
Total	**$ 305,110**	**$ 4,297,679**	**$ 4,602,788**

Elexicon is seeking recovery of operating costs and the revenue requirement associated with capital expenditures, as identified in Table 3 and Table 4 below. The calculation of revenue requirement associated with capital expenditures is provided in Table 5 and Table 6 below.

Table 3 – Relief Requested Veridian Rate Zone ("VRZ")

Category	Recovery Period	Amount $
Operating Costs	1 Year	$ 246,725
Capital Expenditures (Revenue Requirement)	Until Re-basing	$ 298,156

Table 4 – Relief Requested Whitby Rate Zone ("WRZ")

Category	Recovery Period	Amount $
Operating Costs	1 Year	$ 58,384
Capital Expenditures (Revenue Requirement)	Until Re-basing	$ 73,766

Table 5 – Revenue Requirement Impact of Capital Expenditures VRZ

Description	%	Amount
Incremental Capital		$ 3,475,295
Depreciation Expense		-$ 93,359
Incremental Capital to be included in Rate Base		**$ 3,381,937**
Deemed Short Term Debt (4%)	2.11%	$ 2,854
Deemed Long Term Debt (56%)	4.94%	$ 93,558
Deemed Equity (40%)	9.36%	$ 126,620
Amortization Expense		$ 93,359
Grossed up PILs		-$ 18,235
Revenue Requirement		**$ 298,156**
PILs Calculation		
Deemed Equity		$ 126,620
Add Back Amortization Expense		$ 93,359
Deduct CCA	8%	-$ 270,555
Taxable Income		**-$ 50,576**
PILs Before Gross Up	26.50%	-$ 13,403
Incremental Grossed Up PILs		**-$ 18,235**

Table 6 – Revenue Requirement Impact of Capital Expenditures WRZ

Description	%	Amount
Incremental Capital		$ 822,383
Depreciation Expense		-$ 21,619
Incremental Capital to be included in Rate Base		**$ 800,765**
Deemed Short Term Debt (4%)	2.43%	$ 778
Deemed Long Term Debt (56%)	5.48%	$ 24,574
Deemed Equity (40%)	9.66%	$ 30,942
Amortization Expense		$ 21,619
Grossed up PILs		-$ 4,147
Revenue Requirement		**$ 73,766**
PILs Calculation		
Deemed Equity		$ 30,942
Add Back Amortization Expense		$ 21,619
Deduct CCA	8%	-$ 64,061
Taxable Income		**-$ 11,501**
PILs Before Gross Up	26.50%	-$ 3,048
Incremental Grossed Up PILs		**-$ 4,147**

Table 7 – Determination of Proposed VRZ Z-Factor Operating Costs Rate Riders – **July 1, 2023 to June 30, 2024**

Rate Class	2014 COS (EB-2013-0174) Revenue Requirement	Allocation of Revenue Requirement	# of cust/conn as at Dec 31, 2021	12-Month Fixe Rate Rider
RESIDENTIAL	$31,645,089	$156,371	113,409	0.11
SEASONAL RESIDENTIAL	$867,951	$4,289	1,557	0.23
GENERAL SERVICE LESS THAN 50 kW	$6,553,835	$32,385	9,339	0.29
GENERAL SERVICE 50 TO 2,999 KW	$8,894,814	$43,953	1,060	3.46
GENERAL SERVICE 3,000 TO 4,999 KW	$692,222	$3,421	6	47.51
LARGE USE	$628,721	$3,107	4	64.72
UNMETERED SCATTERED LOAD	$145,696	$720	803	0.07
SENTINEL LIGHTING	$45,387	$224	247	0.08
STREET LIGHTING	$456,462	$2,256	31,736	0.01
Total	**$49,930,177**	**$246,725**		

Table 8 – Determination of Proposed WRZ Z-Factor Operating Costs Rate Riders – **July 1,2023 to June 30, 2024**

Rate Class	2010 COS (EB-2009-0274) Revenue Requirement	Allocation of Revenue Requirement	# of cust/ conn as at Dec 31, 2021	12-Month Fixed Rate Rider
RESIDENTIAL	$12,484,708	$37,971	43,441	0.07
GENERAL SERVICE LESS THAN 50 kW	$1,886,505	$5,738	2,350	0.20
GENERAL SERVICE 50 TO 4,999 KW	$4,386,869	$13,342	398	2.79
UNMETERED SCATTERED LOAD	$118,230	$360	392	0.08
SENTINEL LIGHTING	$3,106	$9	47	0.02
STREET LIGHTING	$317,008	$964	13,214	0.01
Total	**$19,196,426**	**$58,384**		

Table 9 – Determination of Proposed VRZ Z-Factor Capital Rate Riders – **July 1, 2023 to Rebasing**

Rate Class	2014 COS (EB-2013-0174) Revenue Requirement	Allocation of Revenue Requirement	# of cust/ conn as at Dec 31, 2021	Fixed Rate Rider
RESIDENTIAL	$31,645,089	$188,967	113,409	0.14
SEASONAL RESIDENTIAL	$867,951	$5,183	1,557	0.28
GENERAL SERVICE LESS THAN 50 kW	$6,553,835	$39,136	9,339	0.35
GENERAL SERVICE 50 TO 2,999 KW	$8,894,814	$53,115	1,060	4.18
GENERAL SERVICE 3,000 TO 4,999 KW	$692,222	$4,134	6	57.41
LARGE USE	$628,721	$3,754	4	78.22
UNMETERED SCATTERED LOAD	$145,696	$870	803	0.09
SENTINEL LIGHTING	$45,387	$271	247	0.09
STREET LIGHTING	$456,462	$2,726	31,736	0.01
Total	**$49,930,177**	**$298,156**		

Table 10 – Determination of Proposed WRZ Z-Factor Capital Rate Riders – **July 1, 2023 to Rebasing**

Rate Class	2010 COS (EB-2009-0274) Revenue Requirement	Allocation of Revenue Requirement	# of cust/ conn as at Dec 31, 2021	Fixed Rate Rider
RESIDENTIAL	$12,484,708	$47,975	43,441	0.09
GENERAL SERVICE LESS THAN 50 kW	$1,886,505	$7,249	2,350	0.26
GENERAL SERVICE 50 TO 4,999 KW	$4,386,869	$16,857	398	3.53
UNMETERED SCATTERED LOAD	$118,230	$454	392	0.10
SENTINEL LIGHTING	$3,106	$12	47	0.02
STREET LIGHTING	$317,008	$1,218	13,214	0.01
Total	**$19,196,426**	**$73,766**		

Table 11 – VRZ Bill Impact Comparison of Capital Cost Recovered by Option 1 versus Option 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Lights	Veridian Rate Zone		
			Option 1 (A)	Option 2 (B)	Difference (A - B)
			$	$	$
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh		$ 1.73	$ 0.25	$ 1.48
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh		$ 3.46	$ 0.51	$ 2.95
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh		$ 4.36	$ 0.64	$ 3.72
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW		$ 52.13	$ 7.64	$ 44.49
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW		$ 716.69	$ 104.92	$ 611.77
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW		$ 976.41	$ 142.94	$ 833.47
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh		$ 1.13	$ 0.16	$ 0.97
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW		$ 1.14	$ 0.17	$ 0.97
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	10652	$ 958.68	$ 213.04	$ 745.64

Table 12 – WRZ Bill Impact Comparison of Capital Cost Recovered by Option 1 versus Option 2

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Lights	Whitby Rate Zone		
			Option 1 (A)	Option 2 (B)	Difference (A - B)
			$	$	$
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh		$ 1.10	$ 0.16	$ 0.94
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh		$ 3.07	$ 0.46	$ 2.61
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW		$ 42.14	$ 6.32	$ 35.82
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh		$ 1.15	$ 0.18	$ 0.97
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW		$ 0.25	$ 0.04	$ 0.21
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	12262	$1,103.58	$ 245.24	$ 858.34

7. Conclusion

Elexicon respectfully requests recovery of $4,602,788 associated with the restoration of electricity service to its customers in the wake of the May 21 derecho storm. This event meets the Z-factor eligibility criteria as set out in the Incentive Regulation Report and the Chapter 3 Filing Requirements.

Appendix A - 1
Elexicon May 2022 Derecho Storm Event - Additional Information

Overview

Elexicon experienced a Z-factor event on May 21,2022 when a *derecho* storm swept through the province of Ontario and large portions of Elexicon's service territory. This appendix provides supplementary information to Elexicon's Z-factor application, organized in the following subsections:

a. Appendix A-1a - Elexicon's May 21, 2022 Outage Summary
b. Appendix A-1b - CityNews news report from May 24, 2022 coverage of the derecho storm's impact in Uxbridge, where an EF-2 tornado touched down[1].
c. Appendix A-1c - DurhamRegion.com's report from May 25, 2022 on the recovery efforts from the derecho storm.
d. Appendix A-1d - Elexicon's Major Event Response Report submitted to the OEB.

The information in this appendix is being provided to the OEB for its understanding of the magnitude of the Derecho Storm Event, and Elexicon's prudent response in its storm restoration activities.

[1] https://toronto.citynews.ca/2022/05/24/ontario-storm-power-outages-durham-uxbridge/

Appendix A – 1a

Elexicon’s May 21, 2022 Outage

Summary

Contents

Elexicon's May 21, 2022 Outage Summary

Event Summary

The following is a time-based chronology of events running from Environment Canada's issuance of a Severe Thunderstorm Watch to Elexicon having restored electricity to 98.7% of affected customers:

- At 12:55 PM on May 21st, 2022, a Severe Thunderstorm Watch was issued by Environment Canada for Pickering and several of Elexicon's service territories
- At 13:17 A Readiness Alert was sent to the core Power Restoration Team to acknowledge and stand by in the Virtual Incident Command Centre
- At 13:52 Environment Canada issued a Severe Thunderstorm Warning for Uxbridge, Beaverton, Sunderland, Ajax, Port Perry, Whitby, Pickering and Clarington with no separate Tornado Warnings issued.
- Strong winds up to 195 km/hr were seen in many areas leading to tree contacts, broken poles and loss of supply events from Hydro One. The touchdown of an EF-2 tornado in Elexicon's service territory in Uxbridge would later be confirmed by Environment Canada
- Numerous Contractors assisted Elexicon starting on May 21 and continued for the duration of the restoration efforts. Assistance was provided in the areas of Lines crews, Tree Trimming crews, Vac trucks, Civil and Electrical crews.
- At its peak, approximately 64,000 customers were without power, leading Elexicon to declare a Level 3 Outage
- A request for Mutual Aid came from Hydro One at 08:00 on May 22, 2022; Elexicon could not supply any resources

- Lakeland Power managed Gravenhurst trouble calls for Elexicon while crews assisted in Uxbridge at the tornado recovery site
- By Friday May 27th, 98.7% of customers had power restored and the Level 3 Outage was declared over. Major reconstruction work continued in Uxbridge and along Westney Road in North Pickering on Saturday May 28th. Uxbridge was fully restored on Sunday, May 29th

Storm Impact Pictures

The following pictures were taken by Elexicon staff and show the impact of the derecho storm on Elexicon's distribution grid:

Figure 1: Whitby District Mid Town
Location: Ash St and Chestnut St.
Date May 22, 2022

Large tree snapped and pulled down 3 poles

Figure 2: Whitby District Mid Town 2

Location: Maple St. and Center St.

Date: May 22, 2022

Multiple damaged poles and circuits 2 blocks away from Municipal Substation

Figure 3: Central Uxbridge

Location: Albert St. and surrounding streets

Date: May 22, 2022

Large wind impacts that flattened all distribution poles and wires in the general vicinity

Figure 4: Pole line down

Location: Lakeridge Road South of Bayly St.

Date: May 22, 2022

Multiple poles down

Figure 5: Uxbridge TS
Location; Brock St West
Date: May 22, 2022

Municipal Substation damaged by strong winds

Communications and Stakeholder Outreach

Elexicon performed the following stakeholder outreach and media communications during the period of May 21 to May 27 in support of its storm restoration efforts:

Stakeholder Outreach

- 100+ emails and phone calls answered from Mayors and Councillors
- 5 phone calls to MPPs in affected areas
- 22 Official Mayor and Board Briefings
- 18 Official Briefings to CAOs of each municipality affected, 14 to Councillors of all affected areas as well as the Region of Durham
- 1 video conference call briefing with President & CEO and VP Distribution Operations (May 25th)
- 5 interactions with DDSB and DCDSB officials

Media Outreach

- 6 News Releases issued May 21 – May 27
- 7 TV and Radio Media interviews given by the President & CEO
- 96 Media Stories with Elexicon quoted or mentioned (Earned Media) equaling 103 million media impressions - CP24, Global News Toronto, 680 News, Toronto Star, City News, Durham Post

Stakeholder Feedback and Next Steps

Stakeholder Feedback

Elexicon received the following testimonials in appreciation of its rapid storm restoration efforts:

"Thank you to all the #utility workers across Ontario who have been working around the clock after Saturday's storm. To those in Ottawa and other areas of the province still without power, please know that help is on the way." – Premier Doug Ford

"A big thank you to crews from across Ontario, Canada and the US who continue to work around the clock to get power restored to families & businesses. With significant damage to infrastructure, crews have gone above and beyond to speed up restoration and get the light back on." – MPP, Minister of Energy, Todd Smith

"You folks and all the crews have done incredible work. Very grateful to the Elexicon Energy team." – MPP, Minister of Finance, Peter Bethlenfalvy

Positive feedback was also received from Mayors Barton (Uxbridge), Collier (Ajax), Mitchell (Whitby) and numerous Regional and Municipal Councillors

Next Steps:

Management conducted a post storm restoration review of its outage management processes. The following items were identified as opportunities or areas for continuous improvement of Elexicon's outage management processes:

- Changes to how customers report damage (potential self-reporting using map pinning, use of special email address) to expedite the triage process
- Improved information exchange between System Control with Customer Care and Communications to improve messaging
- Further refinement of the damage assessment process

- Changes to social media messaging and process once Level 3 declared, including restoration times
- Rollout of new website before the end of 2022, ADMS and outage map will address many of the complaints with the current outage map functionality

As one can see from the figures provided above, the aftermath of the derecho was apocalyptic and certainly was not within Management's control or planning, notwithstanding investments that continue to be made to ensure the resiliency of the distribution system. However, despite this, the incurred costs are material and Elexicon seeks relief for both operating and capital costs through this Application.

Appendix A – 1b

CityNews news report from May 24, 2022

EF-2 tornado touchdown confirmed in Uxbridge, recovery efforts ongoing

Vehicles remain crushed under trees and power lines in the Ottawa Valley community of Carleton Place, Ont. on Tuesday, May 24, 2022, after a major storm hit parts of Ontario and Quebec on Saturday leaving extensive damage. THE CANADIAN PRESS/Sean Kilpatrick Sean Kilpatrick.

Read More

By News Staff
Posted May 24, 2022, 3:57PM EDT.
Last Updated May 25, 2022, 7:16AM EDT.

Crews are working to restore power to more than 150,000 Ontario customers who are still without hydro after a deadly storm swept through the province on Saturday.

At least ten people died and three communities declared states of emergency after the storm that down trees, brought down power lines and damaged property.

Environment Canada confirmed to CityNews that an EF-2 tornado did touch down in Uxbridge on Saturday, leaving widespread damage.

The Northern Tornadoes Project has said preliminary results showed a long narrow path of enhanced damage was 4.26 km in length and 260 metres wide with a speed of 195 km/h.

It says it's still investigating storm damage from Saturday in Ottawa and London.

Elexicon Energy, which covers Durham region, elaborated on the ongoing efforts to restore power as President and CEO Indrani Butany-DeSouza, says hydro crews have been working 24/7 since Saturday.

"This storm that we saw, for us, was worse than the [1998] ice storm," DeSouza said. "It hit so quickly, and the extensive damage because of downed trees and high winds was enormous."

Butany-DeSouza says that the eastern region of Uxbridge — one of the hardest-hit regions — is getting power back today. The Mayor of Uxbridge declared a state of emergency following the storm on Saturday due to the damage and widespread cleanup.

Butany-DeSouza says it could take several days to restore power in certain areas and Durham region neighbourhoods.

"Saturday's severe storms and heavy winds resulted in substantial damage and power outages across Whitby, Pickering, Ajax, Uxbridge and Port Perry, currently affecting more than 6,600 customers," Elexicon Energy's website reads.

"Our crews are working hard to bring back power and ensure public safety working with emergency services and our municipalities."

Three schools in Durham region remain closed on Wednesday.

More than 98,000 Hydro One customers are still without power. As of early Wednesday morning, Hydro Ottawa said it is working on restoring power to approximately 68,000 customers

Toronto Hydro says there are dozens of scattered outages across the city as crews hope to return power to all by Wednesday afternoon. **Eight schools in Durham** and one in North York had to close down Tuesday due to a lack of power.

The death toll in Ontario climbed to at least 10 on Monday, with Peterborough police confirming that a 61-year-old Lakefield man died during the storm after being struck by a falling tree. One person died in Quebec during Saturday's storm, and nine people died in Ontario as wind gusts up to 151 kilometres uprooted trees and downed power lines.

The storm led to more than 1,400 broken poles, 300 broken cross arms, and nearly 200 damaged transformers in Ontario.

Insurance claims expected to rise after deadly storm hits Ontario and Quebec

Insurance claims are expected to rise following a deadly storm that swept across Ontario and Quebec on Saturday.

Anne Marie Thomas, director of consumer and industry relations with the Insurance Bureau of Canada, says it is too early to project insurance claim tallies, but that home, auto and business insurance will play a key role in the recovery.

She says roofs, fences, cars and food waste will likely make up the bulk of home insurance claims, with additional living expenses such as hotels also covered under some plans should families have to temporarily decamp from damaged properties.

The remains of the roof of a hardware store that lifted off and crashed into neighbouring houses during a major storm is seen spread across residences in the community of Hammond in Clarence-Rockland, Ont., Monday, May 23, 2022. THE CANADIAN PRESS/Justin Tang
Justin Tang.

Thomas says extreme weather continues to highlight the cost of climate change to insurers and taxpayers.

The insurance bureau says severe weather caused $2.1 billion in insured damage last year, stemming in part from November flooding in British Columbia and summer hailstorms in Calgary.

“What a tragedy, what happened over the weekend, with this storm, so widespread,” Progressive Conservative Leader Doug Ford, who is running for re-election as Ontario’s premier, said Tuesday morning at a campaign stop.

“I just want to give my prayers and thoughts to the families that lost loved ones.

With files from The Canadian Press

Appendix A – 1c

DurhamRegion.com’s report from May 25, 2022

WHAT YOU NEED TO KNOW: Recovery efforts continue after devastating storm hits Durham

Power outages, structural damage across region after sustained windstorm

Moya Dillon
DurhamRegion.com
Wednesday, May 25, 2022
Durham residents continue to clean up after a Derecho hit the region Saturday afternoon.

Environment Canada describes a Derecho as “a widespread, long-lived windstorm associated with a line of thunderstorms.” The May 21 storm cell formed near Sarnia and tracked across southwestern Ontario to Ottawa, with winds recorded as high as 132 km/h.

"It was unique because this storm touched all eight municipalities across Durham, so we had challenges everywhere, with Uxbridge being the hardest hit," said Durham Region Chair John Henry.

"We're working with our municipalities to ensure cleanup takes place where needed, disposing of trees that have fallen and just helping them get back to a more normal routine. But this isn't going to be over in just a few days or weeks, this is going to take months."

Henry points to ongoing efforts to restore power, ensure the safety of roads, assess damage not just to buildings but also regional conservation lands and other outdoor facilities, ensure community pumps and sanitation systems have adequate power and more as challenges remaining across the region.

Power remains a number one priority in most areas after the storm left more than 1 million without power across the province. In Durham, Elexicon Energy estimated 6,600 remained without power across

Whitby, Pickering, Uxbridge, Ajax and Port Perry as of Tuesday morning. Reinforcements have been called in from areas that weren't impacted to assist with reconnecting customers as quickly as possible. Residents can visit www.elexiconenergy.com for updates.

Hydro One has called the storm one of the worst weather events crews have seen, with more than 150,000 still without power.

"Our hearts remain with our customers who have been devastated by this storm," said Jason Fitzsimmons, chief customer care and corporate affairs officer from Hydro One. "I've heard from crews on the ground that this is the most destructive storm in recent memory, and you have our commitment that we will not stop until every last customer is restored."

The utility has brought in nearly 500 employees from other utilities, including out-of-province and international partners, as well as contractors, to assist in the hardest hit areas. Damage currently includes more than 1,400 broken poles, 300 broken crossarms, nearly 200 damaged transformers, and countless downed trees and branches. For more information or to report outages visit www.hydroone.com.

To support residents in their cleanup efforts, the Region of Durham is waiving bag limits for curbside collection, waiving fees at waste management facilities for any leaf and yard waste and keeping facilities open from 8 a.m. to 8 p.m. through May 28.

Appendix A – 1d

Elexicon's Major Event Response Report submitted to the OEB

Major Event Response Reporting

Wind Storm
May 21 – May 29, 2022

Prior to the Major Event

1. Did the distributor have any prior warning that the Major Event would occur?

☒ Yes ☐ No

Additional Comments:

Yes, Elexicon Energy Inc. ("Elexicon") had very limited prior warning based on reports of high winds advancing into its service territory. However, Environment Canada's Severe Thunderstorm Warnings for Uxbridge and Northern Regions of Durham, Pickering, Oshawa, Southern Durham Region were not issued until after Elexicon had issued its own Pre-Event Readiness warning internally on May 21, 2022.

2. If the distributor did have prior warning, did the distributor arrange to have extra employees on duty or on standby prior to the Major Event beginning?

☒ Yes ☐ No

Brief description of arrangements, or explain why extra employees were not arranged:

Elexicon issued a Pre-Event Readiness warning internally on May 21, 2022. This Readiness warning alerts staff to the possible need for their assistance should the conditions require it.

3. If the distributor did have prior warning, did the distributor issue any media announcements to the public warning of possible outages resulting from the pending Major Event?

☐ Yes ☒ No

No, Elexicon did not have sufficient advance notice of the storm to issue any media announcements in advance of the event.

4. Did the distributor train its staff on the response plans to prepare for this type of Major Event?

☒ Yes ☐ No

Yes, Elexicon practices its Power Restoration Plan/Business Continuity Plan regularly and a Level 3 Outage training and tabletop exercise was completed on December 2, 2021. A Level 3 outage is a major outage affecting more than 25,000 customers for more than 24 hrs. It is the highest level assigned by Elexicon under its current Power Restoration Plan.

During the Major Event

1. Please identify the main contributing Cause of the Major Event as per the table in section 2.1.4.2.5 of the Electricity Reporting and Record Keeping Requirements.

☐ Loss of Supply
☐ Lightning
☒ Adverse Weather-Wind
☐ Adverse Weather-Snow
☐ Adverse Weather-Freezing rain/Ice storm
☐ Adverse Environment-Fire
☐ Adverse Environment-Flooding
☐ Other

Please provide a brief description of the event (i.e. what happened?). If selected “Other”, please explain:

On May 21, 2022 a derecho storm swept through the province of Ontario and large portions of Elexicon’s service territory. This widespread and fast-moving storm caused extensive damage to Elexicon’s infrastructure thereby leading to prolonged power outages for the majority of Elexicon’s customers.

2. Was the IEEE Standard 1366 used to derive the threshold for the Major Event?

☒ Yes, used IEEE Standard 1366*
☐ No, used IEEE Standard 1366 2-day rolling average
☐ No, used fixed percentage (i.e., 10% of customers affected)

*The OEB preferred option

3. When did the Major Event begin (date and time)?

May 21, 2022, 12:30pm

4. Did the distributor issue any information about this Major Event, such as estimated times of restoration, to the public during the Major Event?

☒ Yes ☐ No

During the course of this Major Event, Elexicon issued several communications to the public to keep them well informed. These included:

- Outage map on website displaying information about outage locations and estimated restoration times (“ETRs”).
- Website banner display that contained information about power restoration efforts, the number of customers affected, restoration time as a whole, contact information about where to call if customers see a downed power line or tree or to report an outage, including new storm email inbox, and Electrical Safety Association (“ESA”) information for customer owned infrastructure and connections. During the Major event, Elexicon had 689,539 page views on its website.
- Updated news releases posted to public facing website, twitter and sent to all local and major GTA media outlets to inform about Elexicon’s power restoration efforts including critical information to ensure public safety.
- News interviews to continue to update and communicate to customers through traditional media that was carried on Global and CTV News locally (Durham) and provincially.
- Social media updates including real-time posts from system control that aligned with outage map on location of outages and ETRs/supplemental posts on restoration efforts/images of damage and crews conducting restoration efforts/safety messages/conservation messaging to ensure ongoing reliability in areas where load needed to be transferred and shared with another substation/information about local community relief locations/power outage survival checklists and emergency management for those who require electricity for critical life support/review and triaging of all messages from customers to ensure follow up by distribution operations and crews.
- Direct communications as well as regular updates to Mayors, City and Town Councilors and CAOs of all affected regions to ensure most up-to-date local information can be provided to the public through their own communication channels as civic leaders.
- Direct communications to customers and the public through our call centre and specialized storm communication email address that was actively monitored throughout the major event.

5. How many customers were interrupted during the Major Event?

126,456

What percentage of the distributor's total customer base did the interrupted customers represent?

72.6%

6. How many hours did it take to restore 90% of the customers who were interrupted?

70 hours, 12 minutes

7. Were there any outages associated with Loss of Supply during the Major Event?

☒ Yes ☐ No

If yes, please report on the duration and frequency of the Loss of Supply outages:

1,195 Customers out for 48.78 hours

8. In responding to the Major Event, did the distributor utilize assistance through a third party mutual assistance agreement with other utilities?

☐ Yes ☒ No

If yes, please provide the name of the utilities who provided the assistance?

N/A

9. Did the distributor run out of any needed equipment or materials during the Major Event?

☒Yes ☐ No

If yes, please describe the shortages:

Elexicon quickly ran out of materials at the onset of the event, but was able to resupply over the next few days with the needed material and equipment (poles, cable, hardware, etc.). The damage caused by the storm exceeded what is planned for in Elexicon's safety stock level. Emergency material was brought in from other distributors and contractors to meet the demand.

After the Major Event

1. What actions, if any, will be taken to be prepared for, or mitigate, such Major Events in the future?

- ☐ No further action is required at this time
- ☒ Additional staff training
- ☒ Process improvements
- ☒ System upgrades
- ☐ Other

Additional Comments:

Elexicon is currently undertaking an organization-wide event postmortem, including Lessons Learned from this event that will inform specific improvements related to staff training, process improvements and potential system upgrades.

Appendix A – 2

Notice of Intent
September 6 2022

elexicon ENERGY

September 6, 2022

Ms. Nancy Marconi
Registrar and Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Elexicon Energy Inc. – Notice of intent to file Z Factor Application EB-2022-0024

Elexicon Energy Inc. ("Elexicon") hereby notifies the Ontario Energy Board ("OEB") of its intent to file a Z Factor Claim for implementation with its May 1, 2023 rates update.

On May 21, 2022, a derecho storm swept through the province of Ontario and large portions of Elexicon's service territory. This widespread and fast-moving storm caused extensive damage to Elexicon's infrastructure thereby leading to prolonged power outages for the majority of Elexicon's customers.

Elexicon was unable to include its Z Factor application in its 2023 IRM application, because of the extended duration of the storm restoration and the event's proximity with the July filing date of the IRM application. Elexicon plans to file the application by October 12, 2022, which is the Tranche 2 filing date set out by the OEB for entities seeking implementation of rates effective May 1, 2023.

If you require any further information, please contact the undersigned at (289) 356-3123 or via email at cchan@elexiconenergy.com.

Sincerely,

Cynthia Chan, CPA, CA
Chief Financial Officer
Elexicon Energy Inc.

cc: John Vellone

Elexicon Energy Inc.

Answer to Undertaking from

School Energy Coalition

Undertaking JT2.6:

TO PROVIDE A SUMMATION OF CUMULATIVE BILL IMPACTS, TO SHOW TOTAL BILL IMPACT FOR THE RESIDENTIAL CLASS.

Response:

Elexicon is providing two Notional Estimated Total Bill Impact tables (each a “Bill Impact Table”) in this Undertaking response. The first is the Bill Impact Table without the 3% energy savings attributed to the Conservation Voltage Reduction (“CVR”) associated with the Volt-Var Optimization (“VVO”) component of the Whitby Smart Grid Project (collectively referred to as “Energy Savings”). The second Bill Impact Table includes Energy Savings.

Elexicon reiterates that including the Whitby Smart Grid (“WSG”) which is to be placed in-service in 2025 results in the Bill Impact Table is, at this time, a notional amount. In practise, the customer bill impacts shown in Table 2 will not all be experienced by the customer in the same year. For the year 2023, no mitigation is required given the WSG Rate Rider is scheduled for 2025. Rather the bill impacts will be felt more gradually over time. Additionally, the magnitude of the increase set out in Table 1 is a notional estimate that can get affected by changes to multiple parameters that are part of the OEB ICM/ACM Excel model.

Table 1 below shows the notional estimated cumulative Total bill Impacts for a typical residential customer in the Whitby Rate Zone ("WRZ") assuming Elexicon's implementation of the following items:

1. OEB's approval of Elexicon's Sustainable Brooklin ICM project with a 2023 in-service
2. OEB's approval of Elexicon's Whitby Smart Grid Project with a 2025 in-service
3. OEB's approval of Elexicon's Z-Factor claim[1] with Rate Riders effective July 1, 2023

Table 1 – Notional Estimated Total Bill Impact Without Energy Savings

Add ICM Rate Riders x 2 and Z Factor Rate Riders x 2

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0454	
Proposed/Approved Loss Factor	1.0454	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.41	1	$ 33.41	$ 34.55	1	$ 34.55	$ 1.14	3.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ (0.06)	1	$ (0.06)	$ 9.35	1	$ 9.35	$ 9.41	-15683.33%
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Sub-Total A (excluding pass through)			$ 33.35			$ 43.90	$ 10.55	31.63%
Line Losses on Cost of Power	$ 0.0929	34	$ 3.16	$ 0.0929	34	$ 3.16	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0028	750	$ 2.10	$ 2.10	
CBR Class B Rate Riders	$ -	750	$ -	-$ 0.0002	750	$ (0.15)	$ (0.15)	
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0010	750	$ 0.75	$ 0.0010	750	$ 0.75	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.42	1	$ 0.42	$ (0.01)	-2.33%
otal B - Distribution (includes Sub-Total A)			$ 37.69			$ 50.18	$ 12.49	33.14%
RTSR - Network	$ 0.0096	784	$ 7.53	$ 0.0114	784	$ 8.94	$ 1.41	18.75%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0072	784	$ 5.65	$ 0.0085	784	$ 6.66	$ 1.02	18.06%
otal C - Delivery (including Sub-Total B)			$ 50.87			$ 65.79	$ 14.92	29.33%
Wholesale Market Service Charge (WMSC)	$ 0.0045	784	$ 3.53	$ 0.0045	784	$ 3.53	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	784	$ 0.55	$ 0.0007	784	$ 0.55	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	480	$ 35.52	$ 0.0740	480	$ 35.52	$ -	0.00%
TOU - Mid Peak	$ 0.1020	135	$ 13.77	$ 0.1020	135	$ 13.77	$ -	0.00%
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	135	$ 20.39	$ -	0.00%
Total Bill on TOU (before Taxes)			$ 124.87			$ 139.79	$ 14.92	11.95%
HST	13%		$ 16.23	13%		$ 18.17	$ 1.94	11.95%
Ontario Electricity Rebate	11.7%		$ (14.61)	11.7%		$ (16.36)	$ (1.75)	
Total Bill on TOU			$ 126.49			$ 141.61	$ 15.11	11.95%

[1] EB-2022-0317

Table 2 below show the notional estimated cumulative Total bill impacts from Table 1, with Energy Savings being added.

Table 2 – Notional Estimated Total Bill Impact with Energy Savings

Add 3 % Energy Savings

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	728	kWh
Demand	-	kW
Current Loss Factor	1.0454	
Proposed/Approved Loss Factor	1.0454	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.41	1	$ 33.41	$ 34.55	1	$ 34.55	$ 1.14	3.41%
Distribution Volumetric Rate	$ -	750	$ -	$ -	728	$ -	$ -	
Fixed Rate Riders	$ (0.06)	1	$ (0.06)	$ 9.35	1	$ 9.35	$ 9.41	-15683.33%
Volumetric Rate Riders	$ -	750	$ -	$ -	728	$ -	$ -	
Sub-Total A (excluding pass through)			$ 33.35			$ 43.90	$ 10.55	31.63%
Line Losses on Cost of Power	$ 0.0929	34	$ 3.16	$ 0.0929	33	$ 3.07	$ (0.09)	-3.00%
Total Deferral/Variance Account Rate Riders	$ -	750	$ -	$ 0.0028	728	$ 2.04	$ 2.04	
CBR Class B Rate Riders	$ -	750	$ -	-$ 0.0002	728	$ (0.15)	$ (0.15)	
GA Rate Riders	$ -	750	$ -	$ -	728	$ -	$ -	
Low Voltage Service Charge	$ 0.0010	750	$ 0.75	$ 0.0010	728	$ 0.73	$ (0.02)	-3.00%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.42	1	$ 0.42	$ (0.01)	-2.33%
Sub-Total B - Distribution (includes Sub-Total A)			$ 37.69			$ 50.01	$ 12.31	32.67%
RTSR - Network	$ 0.0096	784	$ 7.53	$ 0.0114	761	$ 8.67	$ 1.14	15.19%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0072	784	$ 5.65	$ 0.0085	761	$ 6.46	$ 0.82	14.51%
Sub-Total C - Delivery (including Sub-Total B)			$ 50.87			$ 65.14	$ 14.28	28.07%
Wholesale Market Service Charge (WMSC)	$ 0.0045	784	$ 3.53	$ 0.0045	761	$ 3.42	$ (0.11)	-3.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0007	784	$ 0.55	$ 0.0007	761	$ 0.53	$ (0.02)	-3.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0740	480	$ 35.52	$ 0.0740	466	$ 34.45	$ (1.07)	-3.00%
TOU - Mid Peak	$ 0.1020	135	$ 13.77	$ 0.1020	131	$ 13.36	$ (0.41)	-3.00%
TOU - On Peak	$ 0.1510	135	$ 20.39	$ 0.1510	131	$ 19.77	$ (0.61)	-3.00%
Total Bill on TOU (before Taxes)			$ 124.87			$ 136.93	$ 12.06	9.66%
HST	13%		$ 16.23	13%		$ 17.80	$ 1.57	9.66%
Ontario Electricity Rebate	11.7%		$ (14.61)	11.7%		$ (16.02)	$ (1.41)	
Total Bill on TOU			$ 126.49			$ 138.71	$ 12.22	9.66%

Note: The Bill Impact above applies the 3% savings to all volumetric charges

Elexicon Energy Inc.

Answer to Undertaking from

School Energy Coalition

Undertaking JT2.7:

TO INVESTIGATE ON A BEST-EFFORTS BASIS TO SEE ANY BENCHMARKING INFORMATION THAT HAS GONE TO THE BOARD.

Response:

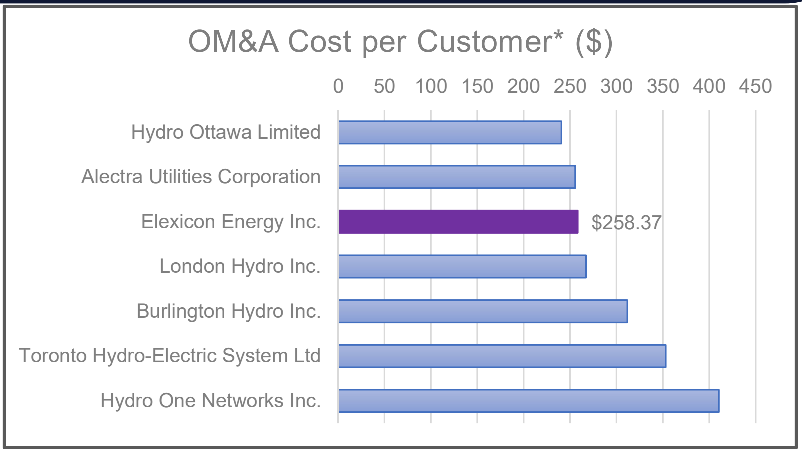
See Attachment 1 to this Undertaking for the most recent sector benchmarking information that was presented to the Board of Directors ("Directors") of Elexicon Energy ("Elexicon") in December of 2022. As noted during the technical conference, Elexicon periodically reviews its performance against peer utilities. In December 2022, management informed its Directors about Elexicon's performance against six specific utilities across several key productivity and financial metrics. The data used by management for benchmarking is from publicly disclosed information found in the 2021 OEB Yearbook of Electricity Distributors.

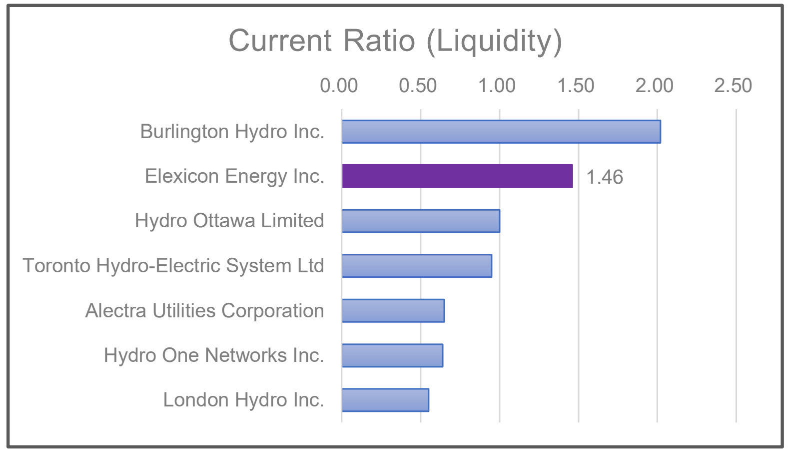
It is important to note that the comparator group that Elexicon uses does not remain static as is being assumed by the questioner. Rather, the comparators are selected based on which grouping is most directly relevant for the comparison in question based on those that would provide the management team with the most directly relevant information.

JT 2-7

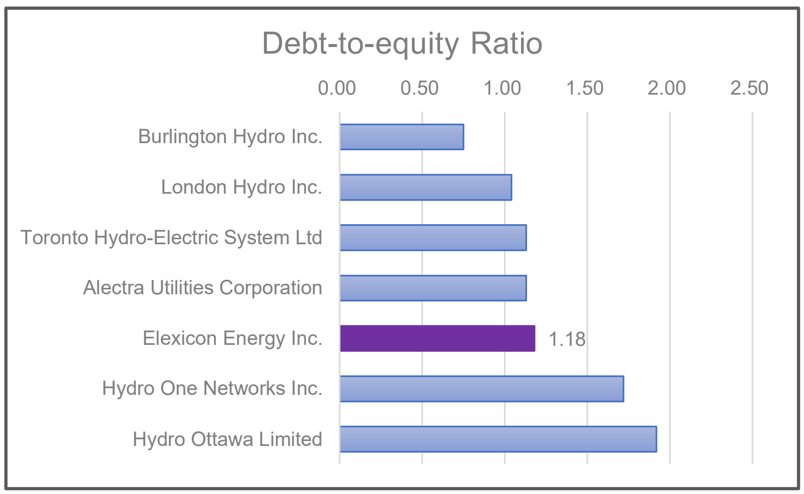
Benchmarking

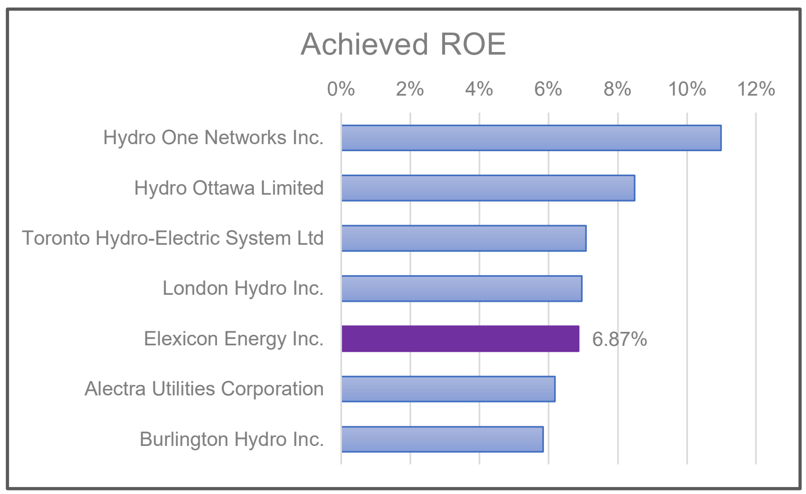
OEB 2021 Performance Benchmarking





*The OM&A Cost per Customer is calculated using data from the OEB yearbook.





- EE performing well within the sector
- Debt to Equity and Achieve ROE are a challenge given EE is far out from rebasing
- Leveraging ICMs to get funding for capital investments and a return on capital, prior to rebasing.

Elexicon Energy Inc.

Answer to Undertaking from

School Energy Coalition

Undertaking JT2.8:

TO EXPLAIN HOW THE IFRS BOOKS AND THE REGULATORY BOOKS WILL DIVERGE AS A RESULT OF THE ACTUAL IN-SERVICE OF THESE WHITBY SMART GRID ASSETS AND HOW YOU PLAN TO ACCOUNT FOR THEM, AND WHAT APPROVALS YOU ARE ASKING FOR FROM THIS BOARD IN THAT REGARD.

Response:

Management will recognize the assets as in-service once the assets are in the location and condition necessary for it to be capable of operating in the manner intended by Management. There will be no divergence between International Financial Reporting Standards ("IFRS") and the OEB's Accounting Procedures Handbook ("APH") regarding the recognition of in-service additions for Whitby Smart Grid assets. Therefore, no approvals will be requested from the OEB in this regard.

The recovery of Whitby Smart Grid Rate riders have been requested and proposed in the Application to commence on January 1, 2025, as this coincides with the Whitby Smart Grid being placed in-service[1]. This is also when all customers within the Whitby Rate Zone will start receiving all the benefits as provided in the pre-filed evidence of this ICM application.

[1] The Whitby Smart Grid will be put in-service in 2025 as required by the OEB's ICM/ACM policy.