elexicon ENERGY

July 27, 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: Elexicon Energy Inc.
2023 IRM Distribution Rate Application
OEB File No: EB-2022-0024

Elexicon Energy Inc. ("Elexicon") submits its 2023 IRM Distribution Rate Application for the Veridian Rate Zone ("VRZ") and the Whitby Rate Zone ("WRZ"). This application includes an Incremental Capital Module request to support two projects that will provide benefits to both of its rate zones. The application includes an electronic filing through the Board's web portal ("RESS") and is comprised of:

- Complete copy of the application in PDF form
- Excel version of the IRM Checklist
- Excel version of the 2021 IRM Rate Generator model (VRZ & WRZ)
- Excel version of the GA Analysis Work Form (VRZ & WRZ)
- Excel version of the LRAMVA Work Form
- Excel version of the ICM models (one VRZ & two WRZ)
- Excel version of the Regulatory Accounting Guidance analysis in support of Accounts 1588 and 1589
    i. VRZ: 2020 (full year)
    ii. WRZ: 2020 (full year) & 2021 (full year)
- For demonstration purposes

i. alternate version of the VRZ 2021 IRM Rate Generator model
ii. alternate version of the GA Analysis Work form
iii. excel spreadsheet comparison of the two versions of the IRM Rate Generator model

This application is respectfully submitted in accordance with the prescribed filing guidelines as outlined by the Board. Please contact me if you have any questions.

Sincerely,

Cynthia Chan, CPA, CA
Chief Financial Officer
Elexicon Energy Inc.

cc: John Vellone

Elexicon Energy Inc.

2022

IRM Rate Application

EB-2022-0024 | July 27, 2022

Elexicon Energy Inc.

2023 Incentive Rate-Making Application

elexiconenergy.com

Office T (905) 427-9870 T 1 (888) 445-2881 F (905) 619-0210

Customer Care T (905) 420-8440 T 1 (888) 420-0070 F (905) 837-7861

55 Taunton Rd. E.
Ajax, ON L1T 3V3

Table of Contents

3.1 Application Introduction

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Elexicon Energy Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity for Elexicon Energy Inc. as of January 1, 2023.

Title of Proceeding:	An application by Elexicon Energy Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges for Elexicon Energy Inc., effective January 1, 2023.
Applicant's Name:	Elexicon Energy Inc.
Applicant's Address for Service:	100 Taunton Road East Whitby, Ontario L1N 5R8 Attention: Cynthia Chan Telephone: (289) 356-3123 E-mail: cchan@elexiconenergy.com

1. Introduction

(a) In the Decision and Order in Elexicon Energy Inc.'s Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") Application (EB-2018-0236), dated December 20, 2018, the Ontario Energy Board ("OEB" or the "Board") granted approval for Whitby Hydro Electric Corporation and Veridian Connections Inc. to amalgamate and continue operations as a single electricity distribution company. The merger was effective April 1, 2019. The amended licence ED-2019-0128 was issued April 2, 2019. As described in that application, Elexicon Energy Inc. ("Elexicon") was granted a 10-year deferred rebasing period. This will be accomplished by maintaining two separate rate zones, Elexicon Energy Inc. – Whitby Rate Zone ("WRZ") and Elexicon Energy Inc. – Veridian Rate Zone ("VRZ") until rates are rebased.

(b) Elexicon hereby applies to the OEB pursuant to Section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective January 1, 2023, pursuant to the Board's Price Cap Incentive Rate Index rate-setting methodology ("Price Cap IR").

2. Proposed Distribution Rates and Other Charges

The Schedule of 2023 Rates and Charges proposed in this Application is identified in Appendix D.

3. Proposed Effective Date of Rate Order

Elexicon requests that the OEB make its Rate Order effective January 1, 2023.

Elexicon requests that the existing rates be made interim commencing January 1, 2023, in the event that there is insufficient time for the Board to issue a final Decision and Order in this application for the implementation of the proposed rates and charges as of January 1, 2023.

Elexicon also requests to be permitted to recover the incremental revenue from the effective date to the implementation date if the dates are not aligned.

4. Form of Hearing Requested

Elexicon respectfully requests that this application be decided by way of a written hearing.

5. Relief Sought

Elexicon hereby applies for an Order or Orders approving the proposed distribution rates for all Elexicon rate classes updated and adjusted in accordance with Chapter 3 of the Filing Requirements dated May 24, 2022 including the following:

(a) An adjustment to the approved Retail Transmission Service Rates ("RTSRs") as provided in the *Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates* (dated October 22, 2008) and subsequent revisions and updates to the Uniform Transmission Rates ("UTRs") and as supported by the completion of the related sections of the Board issued 2023 Rate Generator Model.

(b) The continuation of currently approved rates for:

- Smart Metering Entity Charge until December 31, 2027;
- Low Voltage Service Rates

(c) Shared Tax Savings - VRZ is requesting the transfer of a credit amount of $2,849 to subaccount 1595. This amount is associated with the 50/50 sharing of the impact of currently known legislated tax changes as per the Filing Requirements and as calculated in the 2023 Rate Generator Model. WRZ is requesting disposition of the shared tax savings as calculated in the 2023 Rate Generator Model

(d) Rate riders to address the disposition of LRAMVA account 1568 for $3,787,229 for VRZ ($2,637,190) and WRZ ($1,150,039). As per the *Conservation and Demand Management Guidelines for Electricity Distributors* issued December 20, 2021 (EB-2021-0106), Elexicon is also seeking disposition of all outstanding LRAMVA balances on a prospective basis to address amounts that would otherwise be recorded in the LRAMVA for each year until the next rebasing application currently scheduled for 2029. See Appendix A.

(e) Rate riders associated with the final disposition of the following deferral and variance accounts:

- Group 1 accounts as identified by the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* dated July 31, 2009 (the "EDDVAR Report") and any subsequent additions to the listing of accounts identified by the Board in the Filing Requirements.

The disposition requested relates to principal balances as at December 31, 2021, plus any adjustments identified in this application along with the carrying charges projected to December 31, 2022

VRZ is also requesting disposition on a final basis of the 2020 Balances approved as interim in its 2022 Electricity Distribution Rate Application (EB-2021-0015).

In addition, Elexicon requests the following:

(f) Incremental Capital Module ("ICM") – Elexicon has capital investment needs that are not funded through existing distribution rates and hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act,1998*, as amended (the "OEB Act") for approval of proposed incremental revenue requirement recovery as follows:

- ICM funding for the Whitby Smart Grid Project, including a proportionate share of the Advanced Distribution Management System ("ADMS") costs in the WRZ;

- ICM funding for a proportionate share of the ADMS costs in the VRZ; and

- ICM funding for the Sustainable Brooklin Project in the WRZ, together with an exemption for the Brooklin Line from Section 3.2 of the Distribution System Code;

See Appendix B.

Table 1: 2023 Elexicon Rate Application Summary of Request

		2023 Elexicon Rate Application Summary of Request	
		VRZ	WRZ
	Distribution Rates	Updated Rates	Updated Rates
a	RTSRs	Updated Rates	Updated Rates
b	LV, SMEC	Continuation of Existing Rates	Continuation of Existing Rates
c	STS	Transfer to Account 1595	New Rate Riders
d	LRAMVA	New Rate Riders	New Rate Riders
e	Group 1 Disposition	New Rate Riders & Approval of 2020 Balances on a Final Basis	New Rate Riders
f	ICM	ICM Approval and new Rate Riders (2025)	ICM Approval and New Rate Riders (2023 & 2025) & Exemption from Section 3.2 of the DSC for the Brooklin Line

6. Bill Impact

The total bill impacts by customer class are:

Table 2: Bill Impacts by Rate Class -VRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill	
Customer Class	kWh	kW	RPP? Non?	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	750		RPP	0.78	2.6%	0.85	2.3%	2.03	4.2%	1.95	1.6%
Seasonal	645		RPP	1.56	2.8%	1.62	2.6%	2.71	3.8%	2.60	1.9%
GS<50 kW	2,000		RPP	4.95	8.3%	4.95	6.4%	7.68	7.4%	7.37	2.4%
GS 50 to 2,999 kW	432,160	1,480	Non	804.80	13.3%	- 689.26	-7.6%	267.12	1.5%	301.84	0.4%
GS 3,000 to 4,999 kW	1,752,000	4,000	Non	1,127.53	6.8%	- 4,410.47	-17.0%	- 1,564.07	-3.0%	- 1,767.40	-0.7%
Large User	4,219,400	6,800	Non	5,395.71	15.5%	4,317.91	8.5%	9,156.79	9.5%	10,347.17	1.7%
USL	500		RPP	0.53	3.0%	0.53	2.4%	1.21	4.2%	1.16	1.5%
Sentinel Lights	180	1	RPP	0.60	2.8%	0.56	2.4%	0.96	3.5%	0.92	2.1%
Street Lighting	424,881	988	Non	6,660.59	44.7%	5,254.23	31.4%	5,673.58	27.4%	6,411.15	8.3%

Table 3: Bill Impacts by Rate Class -WRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill	
Customer Class	kWh	kW	RPP? Non?	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	750		RPP	$ 3.85	11.5%	$ 5.80	15.2%	$ 7.29	14.2%	$ 7.00	5.5%
GS<50 kW	2,000		RPP	$ 8.23	11.6%	$ 13.63	16.6%	$ 17.18	15.0%	$ 16.50	5.2%
GS>50 kW	40,000	100	Non	$ 80.72	12.2%	$ 105.97	15.3%	$ 173.82	13.4%	$ 196.42	3.2%
USL	500		RPP	$ 3.10	11.5%	$ 4.50	15.2%	$ 5.39	14.3%	$ 5.17	5.9%
Sentinel Lights	150	1	Non	$ 3.05	13.9%	$ 4.19	18.4%	$ 4.70	17.2%	$ 4.52	10.8%
Street Lighting	283,400	736	Non	$ 3,569.43	10.3%	$ 2,829.88	8.2%	$ 3,208.77	8.4%	$ 3,625.91	4.5%

DATED at Whitby, Ontario, this 27th day of July, 2022

All of which is respectfully submitted,

Cynthia Chan
Chief Financial Officer
Elexicon Energy Inc.

Manager's Summary

3.1.2 Components of the Application Filing

On May 24, 2022, the OEB issued a letter to all electricity distributors outlining the filing requirements for incentive regulation distribution rate adjustments and provided an update to Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications (the "Filing Requirements").

Accordingly, Elexicon submits its 2023 Distribution Rate Application is consistent with the filing guidelines issued by the Board under the Price Cap IR rate setting option. WRZ was previously on the Annual IR Index but is moving to the Price Cap IR based on the December 1, 2021 letter from the OEB to Rate-regulated Electricity Distributors which stated*: "To provide a further incentive for distributors considering consolidation, the OEB will allow distributors that are on the Annual IR Index rate-setting plan and in a current deferral period arising out of a consolidation to move to the Price Cap IR plan effective with 2023 rates."*

Elexicon has outlined any additional elements that have been included in this application for the OEB's consideration.

The following details of Elexicon's rate application are noted below:

Contact Information

The primary contact for the application is

Cynthia Chan
Chief Financial Officer
Elexicon Energy Inc.
289-356-3123
cchan@elexiconenergy.com

John Vellone
Legal Counsel
Borden Ladner Gervais
416-367-6730
jvellone@blg.com

Models

A completed Rate Generator Model and supplementary workforms will be submitted in Excel format.

2022 Current Tariff Sheet

Appendix C contains the approved 2022 Tariff Sheet issued December 16, 2021 and updated January 13, 2022 (EB-2021-0015). The rates and charges within the tariff sheet provide the basis for the starting point from which the 2023 rates and charges are calculated using the Board's 2023 Rate Generator model.

Copies of the current and proposed tariff sheets and customer bill impacts are included in this Application (Appendices C, D and E respectively).

Supporting Documentation Cited within Application

Elexicon has committed to citing the supporting documentation throughout the Application, as applicable.

Who is affected by the Application

Elexicon distributes electricity to approximately 173,000 residential and commercial customers (including general service, unmetered scattered loads, sentinel light and street light customer classes) within its regulated service area of Ajax, Pickering, Whitby, Belleville, Brock, Uxbridge, Scugog, Clarington, Port Hope, Gravenhurst, Village of Brooklin, hamlets of Ashburn and Myrtle

Internet Address

Elexicon's application and related documents will be made available on the website: www.elexiconenergy.com

Accuracy of the Billing Determinants

Elexicon confirms the accuracy of the pre-populated data in the 2023 Rate Generator Model.

2023 IRM Checklist

The 2023 IRM Checklist has been included with this application as Appendix G.

Certifications

Certification by a senior officer has been included with this application as Appendix F.

3.1.3 Application and Electronic Models

Rate Generator Model & Supplementary Workforms

Elexicon has used the most recent versions of the following Board issued models:

- 2023 IRM Rate Generator Model
- GA Analysis Workform
- LRAMVA Workform
- Capital Module Applicable to ACM and ICM

3.2 Elements of the Price Cap IR Plan

3.2.1 Annual Adjustment Mechanism

The annual adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains (Price Cap adjustment). Elexicon has reviewed the Filing Requirements which indicate that the 2023

Rate Model will be populated with the 2022 rate-setting parameters as a placeholder until the inflation factor for 2023 is issued by the OEB.

3.2.1.1 Application of the Annual Adjustment Mechanism

The annual adjustment mechanism applies to distribution rates (fixed and variable charges) uniformly across customer rate classes. The annual adjustment mechanism will not be applied to other components of delivery rates.

3.2.2 Revenue-to-Cost Ratio Adjustment

There are no previous Board approved adjustments to Elexicon's revenue-to-cost ratios required within this application.

3.2.3 Rate Design for Residential Electricity Customers

Elexicon incorporated the final phase of the transition to a fully fixed monthly distribution service charge for VRZ in its 2020 rate application EB-2019-0252 and WRZ in its 2019 rate application EB-2018-0079. As a result, there are no further transition adjustments in the 2023 rate application for rate design.

3.2.4 Electricity Distribution Retail Transmission Service Rates

The Board's last Revision to *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates (the "RTSR Guideline")* was issued on June 28, 2012. The RTSR Guideline requires distributors to adjust their proposed RTSRs based on a comparison of historical transmission costs adjusted for the new Ontario Uniform Transmission Rates ("UTR") and revenue generated under existing RTSRs. Board Staff has included RTSR worksheets within the 2023 Rate Generator Model and included the most current rates. The most recent RTSR Guideline indicates that once new UTRs or Hydro One Networks Inc ("Hydro One") sub-transmission rates are determined, Board Staff will adjust each distributor's IRM rate application to incorporate any change.

Elexicon has populated the model with the required historical data and requests that the Board update Elexicon's 2023 rate application to incorporate approved 2023 UTRs and sub-transmission rates if they become available (or the most current draft data available/requested for 2023 should they not be approved at the time of the Decision).

3.2.5 Review and Disposition of Group 1 Deferral and Variance Account Balances

Elexicon has completed the continuity schedule in the 2023 Rate Generator Model related to Group 1 Deferral and Variance Accounts ("DVA") and confirms the accuracy of the pre-populated billing determinants.

VRZ - The last disposition of Group 1 account balances for VRZ was in the 2022 IRM application (EB-2021-0015), which was based on 2020 balances and approved on an interim basis.

Adjustments to Deferral and Variance Accounts

During our preparation of the 2023 rate application, specifically the disposition of 1595 (2019) Elexicon discovered an error.

In EB-2018-0072 the VRZ GA amount approved for disposition was as follows:

Proposed Amounts	Proposed Method for Recovery
$1,244,587 recovered from customers who were Class B for the entire period from January 2017 to December 2017	per kWh rate rider
$220,827 from customers formerly in Class B during the period January 2017 to June 2017 who were reclassified to Class A	12 equal installments[14]

The $220,827 was recovered from Class A/B transitioning customers. Upon review, it was discovered that the $220,827 was incorrectly posted to a GA revenue account rather than 1595(2019). In order to correct this, a principal adjustment of $220,827 between GA and 1595 (2019) in Tab 3 of the continuity schedule is required.

The 2019 GA account was approved for disposition on an interim basis in Elexicon's 2022 Rate Application (EB-2021-0015). The 1595 (2019) is being requested for disposition in this 2023 Rate Application (EB-2022-0024).

The IRM Rate Generator Model's instructions are as follows:

b) If the accounts were last approved on an interim basis, and

> **i) there are no changes to the previously approved interim balances, select the year of the year-end balances that were last approved for diposition on an interim basis.**
>
> **ii) If there are changes to the previously approved interim balances, select the year of the year-end balances that were last approved for disposition on a final basis.**

Based on this, Elexicon should be selecting ii). When doing this, Elexicon discovered two problems:

1) In the 2022 rate application a GA amount was apportioned to the 16 transitioning customers. This amount has since been recovered from those customers. The IRM model is not set up to account for the amounts already recovered; and

2) Due to year-over-year variability in the GA amount for disposition, the results are very different when 4 years of transitioning information is populated in Tab 6. See Column I vs Column O in file "*EE_VRZ_2023 Rate Generator_Compare i_ii*" which has been submitted with the application.

Since the $220,827 is below the GA materiality threshold[1], Elexicon is selecting i) and putting a Principal adjustment of $220,827 between GA and 1595 (2019) in Tab 3 of the continuity schedule for 2021 (column BF). See "*EE_VRZ_2023_IRM-Rate-Generator_Model_i_20220727*". A version of the Rate Generator Model under scenario ii) has also been submitted with the application for demonstration purposes only (see "*EE_VRZ_2023_IRM-Rat-Generator-Model_ii_Demonstration ONLY*"). A version of the GA Analysis Work form which includes 2019 has also been submitted with the application to demonstrate that the 2019 GA Analysis is still within the threshold limit (see "*EE_VRZ_2023_GA_Analysis_Workform_Demonstration ONLY*").

Scenario i) will alleviate the concerns noted above. However, Elexicon acknowledges the following (both of which are noted in "*EE_VRZ_2023 Rate Generator_Compare i_ii*")

- In the 2022 Rate Application, the 16 transitioning customers were undercharged by $8,897 (columns O, P and Q); and
- In the 2023 Rate Application, the 10 transitioning customers will be under credited by $5,914 (columns K, L and M)

While the amount is immaterial, Elexicon proposes that it will conduct a manual adjustment (outside the model) to refund the 10 transitioning customers the $5,914 if the OEB so orders.

WRZ - The last disposition of Group 1 account balances for WRZ was in its 2021 IRM application (EB-2020-0012), which was based on 2019 balances and approved on a final basis. In keeping with the model instructions, the continuity starts with the balances as per the date for which approval was last received (ie. 2019 closing balances). No

[1] **As per the GA Analysis Workform, materiality is assessed on an annual basis based on a threshold of +/- 1% of the annual calculated IESO GA charges. For 2019 this would be $796,100**

adjustments have been made to any deferral and variance account balances previously approved by the OEB on an interim or final basis.

The account balances in Tab 3 of the Continuity Schedule of the Rate Generator Model differ from the account balances in the trial balance as reported through RRR. The variance in column BW is reconciled as follows:

Table 4: RRR Reconciliation VRZ

		Note 1		Note 2		Note 3	Column BW
Account Descriptions	Account	Unbilled to Actual billed revenue differences	CT142 True Up	GL correction	Misc Rounding	LRAMVA adjustment	Variance RRR vs. 2021 Balance *(Principal + Interest)*
LV Variance Account	1550						0
Smart Metering Entity Chg	1551				(2)		(2)
RSVA - Wholesale Market Service Charge	1580						0
Variance WMS – Sub-account CBR Class A	1580						0
Variance WMS – Sub-account CBR Class B	1580						0
RSVA - Retail Transmission Network Chg	1584				(1)		(1)
RSVA - Retail Transmission Connection Chg	1586						0
RSVA - Power	1588	1,126,252	(653,670)		0		472,582
RSVA - Global Adjustment	1589	319,630		(220,827)			98,803
Disposition and Recovery/Refund (2017)	1595				(1)		(1)
Disposition and Recovery/Refund (2018)	1595						0
Disposition and Recovery/Refund (2019)	1595			220,827			220,827
Disposition and Recovery/Refund (2020)	1595						0
Disposition and Recovery/Refund (2021)	1595						0
RSVA - Global Adjustment	**1589**	319,630	0	(220,827)	0	0	98,803
Total Group 1 Balance excl 1589 - GA		1,126,252	(653,670)	220,827	(4)	0	693,405
Total Group 1 Balance		1,445,882	(653,670)	0	(4)	0	792,208
LRAM Variance Account	**1568**	0	0	0	0	(846,608)	(846,608)
Total including Account 1568		1,445,882	(653,670)	0	(4)	(846,608)	(54,400)

Note 1: See GA Analysis Workform, Tab "Principal Adjustments"
Note 2: See Manager Summary explanation of 1595 (2019)
Note 3: See Appendix A, LRAMVA claim includes 2022 disposition request

Table 5: RRR Reconciliation WRZ

		Note 1				Note 2	Column BW
Account Descriptions	Account	Unbilled to Actual billed revenue differences	CT 148 True Up	CT142 True Up	Misc Rounding	LRAMVA adjustment	Variance RRR vs. 2021 Balance *(Principal + Interest)*
LV Variance Account	1550						0
Smart Metering Entity Chg	1551						0
RSVA - Wholesale Market Service Charge	1580						0
Variance WMS – Sub-account CBR Class A	1580						0
Variance WMS – Sub-account CBR Class B	1580						0
RSVA - Retail Transmission Network Chg	1584						0
RSVA - Retail Transmission Connection Chg	1586						0
RSVA - Power	1588	(221,035)	(74,761)	5,453	(1)		(290,344)
RSVA - Global Adjustment	1589	(45,181)	74,761		3		29,583
Disposition and Recovery/Refund (2018)	1595						0
Disposition and Recovery/Refund (2019)	1595						0
Disposition and Recovery/Refund (2020)	1595						0
Disposition and Recovery/Refund (2021)	1595						0
RSVA - Global Adjustment	**1589**	(45,181)	74,761	0	3	0	29,583
Total Group 1 Balance excl 1589 - GA		(221,035)	(74,761)	5,453	(1)	0	(290,344)
Total Group 1 Balance		(266,216)	0	5,453	2	0	(260,761)
LRAM Variance Account	**1568**	0	0	0	0	(247,612)	(247,612)
Total including Account 1568		(266,216)	0	5,453		(247,612)	(508,373)

Note 1: See GA Analysis Workform, Tab "Principal Adjustments"
Note 2: See Appendix A, LRAMVA claim includes 2022 disposition request

VRZ & WRZ - the Group 1 Total Claim (2021 ending balances plus any identified adjustments and projected interest) exceeds the threshold test. As a result, this application includes a VRZ & WRZ Final disposition request for the Total Group 1 DVA balance. The disposition period requested to clear the Group 1 account balances by means of a rate rider is one year.

3.2.5.1 Wholesale Market Participants

Elexicon has followed the approach identified in the Filing Requirements to address wholesale market participants ("WMP"). Since WMP customers settle commodity and market-related charges with the IESO, Elexicon has not allocated any balances to these customers related to the Wholesale Market Service Charge, WMS Sub-Account CBR Class B, Power or Global Adjustment. The rate riders have been appropriately calculated for the remaining charges that the WMP settles with Elexicon.

3.2.5.2 Class A and Class B Customers

Elexicon settles GA and CBR costs with some Class A customers based on actual GA and CBR prices. Elexicon does not allocated GA and CBR variances to these customers for the period that the customer were designated Class A.

3.2.5.3 Commodity Accounts 1588 and 1589

Accounting Guidance

On February 21, 2019, the OEB issued its letter entitled *Accounting Guidance related to Accounts 1588 Power and 1589 Global Adjustment* as well as the related accounting guidance ("accounting guidance"). The accounting guidance was effective January 1, 2019 and was to be implemented by August 31, 2019.

The following table summarizes a status of Elexicon's rate zones with respect to the accounting guidance and Group 1 Dispositions. Below is a summary of what has transpired in the most recent applications.

Table 6: Summary of Accounting Guidance and Group 1 Dispositions

	VRZ	***WRZ***
Accounting Guidance • ***Aligned Outcomes*** • ***Aligned Timing of True-ups***	 ***Yes*** ***Yes***	 ***Yes*** ***No - timing differences are addressed through DVA Continuity (Principal Adjustments)***
Group 1 Disposition Request	***Yes*** ***$6,596,499***	***Yes*** ***$1,870,967***
Last Approved Group 1 Disposition • ***Rate Application*** • ***Balances as of*** • ***Final/Interim***	 ***2022 (EB-2021-0015)*** ***2020*** ***Interim***	 ***2021 (EB-2020-0012)*** ***2019*** ***Final***

Veridian Rate Zone:

2021 Electricity Distribution Rate ("EDR") Application (EB-2020-0013)

- For the VRZ, Elexicon stated that it completed the modifications necessary to ensure compliance with the accounting guidance, highlighting some changes made in calendar 2019 and 2020.
- Elexicon indicated that it is now completely aligned with the OEB Accounting Guidance for the VRZ.
- Elexicon also considered the Accounting Guidance in the context of pre-2019 balances.
- The OEB noted in its findings that account balances (2018 and 2019) appeared reasonable.

2022 EDR Application (EB-2021-0015)

- VRZ filed a request to clear 2018, 2019 and 2020 Group 1 DVA balances on an interim basis
- During the IR process, Elexicon identified an issue related to the levels of unaccounted for energy ("UFE") used for VRZ settlement in 2020.

- The issue related to UFE required corrections to the 2020 settlement calculations and related accounting entries.
- In order to review and address the issue, Elexicon was able to re-run metering data used in the 2020 settlement process (January to December) and re-calculate settlement and the resulting accounting entries.
- Revised settlement information related to 2020 was included in the Group 1 DVA balances requested for interim disposition.
- All revisions (including true-ups) were included as principal adjustments in 2020. This ensured that the balances reviewed for VRZ's Group 1 interim disposition request were as accurate and up-to-date as possible.
- Elexicon advised that the UFE issue occurred subsequent to a system modification that took effect in December 2019. The modification was designed to automate certain portions of the meter data extraction process used for settlement. This has since been updated to correct the identified issue.
- Elexicon committed to doing a final review of the Accounting Guidance prior to requesting a final disposition for VRZ's Group 1 balances.
- The issue identified which relates to the UFE did not materially impact the 2019 principal adjustment amounts for Account 1588 and 1589.
    - The original UFE for December 2019 was 1,173,186 compared to a revised amount of 786,038 (difference 387,148 kWh). The impact on the analysis is $25,860 for Energy and $11,460 for GA.
- Elexicon confirms that the 2018 principal adjustments are not affected by the UFE matter and its impact on the VRZ settlements and accounting.
- Elexicon did not believe there are any other errors or discrepancies that would result in a material impact to the ending Group 1 balances for VRZ.
- In its findings, the OEB approved the disposition on an interim basis.

2023 EDR Application (EB-2022-0024)

- Elexicon undertook a final review of the settlement and accounting for Accounts 1588 and 1589 prior to requesting a final disposition of 2018-2021 balances.
- Elexicon has reviewed these balances in the context of the Accounting Guidance
- In addition to the items identified in the 2021 EDR Application (EB-2020-0013) and the UFE correction discussed above, Elexicon has made one further refinement. As of August 2021, Elexicon is now receiving revised SM Tiered & TOU reports from Elexicon's Operational Data Store provider on the 10th business day. This allows for any missing data (due to communication issues/edits/estimates/etc.) at the time of initial preparation to be updated.
- Elexicon will continuously review other data extracts to ensure accuracy and completeness of data.
- Elexicon does not believe that there are material systemic issues that have not been identified.
- In order to support the review of the Account 1588 and 1589 balances, the GA Workform has been completed and the 2021 transactions have been reviewed for reasonability and comparability against the regulatory accounting guidance (see excel file "*EE_VRZ_2023_Acctg Guidance_2021 Analysis_20220727*" accompanying this application).
- Final review of 2021 data show differences which are not material:

Table 7: VRZ Difference between Accounting Guidance and DVA Continuity Schedule[2]

	Account 1588			Account 1589			1588 & 1589
	Transactions	Principal Adjustments	Total	Transactions	Principal Adjustments	Total	Total
Accounting Guidance 2021 Analysis			$(662,414)			$(1,570,444)	
DVA Continuity Schedule (sum of 2021 tranactions and principal adjustments	$ (649,531)	$ (42,608)	$(692,139)	$ (1,524,917)	$ 57,963	$(1,466,954)	
Difference			$ 29,725			$ (103,490)	$ (73,765)

- Differences in Table 7 are immaterial. Small differences may be explained by transactions (such as billing adjustments) or differences due to methodology (i.e. proration of consumption in the billing system). The regulatory accounting guidance analysis has been consolidated and reviewed on an annualized basis. The review demonstrates that these types of differences are not considered material enough to review at a more detailed level. Elexicon confirms that the row “Accounting Guidance 2021 Analysis” in Table 7 is not intended to reflect the balances in the DVA Continuity Schedule but is an analysis of the OEB accounting guidance for Accounts 1588 and 1589 and demonstrates alignment with the General Ledger.
- Elexicon is confident that there are no systemic issues with its RPP settlement and related accounting processes
- Elexicon requests final disposition of these amount previously approved on an interim balance AND the 2021 balances which meet the threshold

Whitby Rate Zone:

2020 EDR Application (EB-2019-0130)

- Elexicon conducted a fulsome review of its existing processes against the accounting guidance for both 2019 year-to-date and historical year (2018) for the

[2] Account 1589 Principal Adjustment amount of 57,963 does not include the 2019 GL correction of $220,827

WRZ, with a specific objective to assess and compare the final outcome of WRZ's method with the OEB's guidance to determine whether there were any material differences.

- The Group 1 balances did not meet the threshold and as a result, WRZ did not request to dispose of balances in Accounts 1588 and 1589.
- The OEB Decision dated December 12, 2019 stated the following regarding the Accounting Guidance:

> *"The OEB finds that the account balances, are reasonable and confirms that the threshold calculation is correct. No disposition is required at this time, as the disposition threshold has not been exceeded and the utility did not request disposition.*
>
> *OEB finds that the implementation of the February 21, 2019 accounting guidance is mandatory. However, given the special circumstances of integrating the operations of the two merged distributors' rate zones, OEB will approve an extension for the implementation of the accounting guidance to align with the implementation date of the new integrated CIS system."*

2021 EDR Application (EB-2020-0012)

- In its application, Elexicon confirmed that the approach (with the modifications as outlined in its 2020 rate application) continued to be used for the WRZ. This approach ensured that the outcomes were fully aligned with the OEB's regulatory accounting guidance.
- Elexicon requested final disposition of Group 1 account balances for the WRZ including Accounts 1588 and 1589 for the year ended December 31, 2019 (plus projected interest) and received approval.

The OEB Decision dated December 10, 2020 stated the following regarding the Accounting Guidance: *"The OEB also approves the disposition of a credit balance of $1,843,826 as of December 31, 2019, including interest projected to December 31, 2020 for Group 1 accounts on a final basis."*

2022 EDR Application (EB-2021-0015)

- Elexicon confirmed that the approach (with the modifications as outlined in its 2020 and 2021 rate applications) for the WRZ had been further augmented to improve alignment with several process elements of the accounting guidance. Specifically, the posting of transactions in the general ledger in 2020 were adjusted to flow in a manner consistent with the accounting guidance. Elexicon reconfirms that this change continues to ensure that the outcomes (balances in Account 1588/1589) are fully aligned with the OEB's accounting guidance.
- The Group 1 balances are below the threshold and as a result, disposition is not requested in this application.
- Elexicon requested an extension with respect to the implementation of the OEB's Accounting Guidance related to Accounts 1588 and 1589. Elexicon stated that the extension will support additional process changes delayed by the COVID-19 emergency and unexpected upgrades related to the recently merged CIS.
- Elexicon noted that additional planning is in place to support the continued transition to a consistent settlement process and tool for the WRZ which mirrors the VRZ. Elexicon further stated that while this transition will not have a material effect on the outcome of the settlement amounts, it will assist to align to the timing expectations for settlement and true-ups as outlined in the OEB's

regulatory accounting guidance. Elexicon also noted that it will also provide for greater consistency between both of the rate zones' processes.

- As part of transition planning, Elexicon identified the importance of stabilizing a number of key elements prior to the transition. The transition is planned in 2022 with an expectation of completion by the end of June. Elexicon requested the OEB approve an extension until June 2022.
- Elexicon Energy confirmed that the granting of an extension request regarding the implementation of the OEB's Accounting Guidance for Accounts 1588 and 1589 for the WRZ would not have a material impact on the WRZ's Group 1 DVA balances (2020 and forward). Elexicon confirms that it does not expect any further adjustments to any of the DVAs for the WRZ upon implementation of the new integrated CIS system.
- In its December 16, 2021 decision the OEB stated:

  "The OEB finds that the account balances for the Whitby RZ are reasonable, and the threshold calculation is correct. No disposition is required at this time, as the disposition threshold has not been exceeded and the distributor did not request disposition.

  The OEB also approves Elexicon Energy's extension request regarding implementation of the OEB's Accounting Guidance, for the Whitby RZ, to June 2022 to enable process improvements and CIS upgrades."

- In June 2022, Elexicon requested an extension regarding the implementation of the OEB's Accounting Guidance in the WRZ to December 31, 2022, due to a high turnover in its finance, regulatory and settlement groups, following the closing of the record in the 2022 EDR Application proceeding.

2023 EDR Application (EB-2022-0024)

- In order to support the review of the Account 1588 and 1589 balances, the GA Workform has been completed and the 2021 transactions have been reviewed for reasonability and comparability against the regulatory accounting guidance (see excel file "*EE_WRZ_2023_Acctg Guidance_2021 Analysis_20220727*" accompanying this application). Elexicon is also re-submitting the review of the 2020 transactions (see "*EE_WRZ_2023 Acctg Guidance_2020 Analysis_20220727*"). This file was included in last year's application and is being included again to complete the record.
- Final review of 2021 data show differences that are not material

Table 8: WRZ Difference between Accounting Guidance and DVA Continuity Schedule

2021	Account 1588			Account 1589			1588 & 1589
	Transactions	Principal Adjustments	Total	Transactions	Principal Adjustments	Total	Total
Accounting Guidance 2021 Analysis			$(146,605)			$(532,512)	
DVA Continuity Schedule (sum of 2021 tranactions and principal adjustments	$ (856,064)	$ 779,752	$ (76,312)	$ (407,288)	$ (149,908)	$(557,196)	
Difference			$ (70,293)			$ 24,684	$(45,609)

2020	Account 1588			Account 1589			1588 & 1589
	Transactions	Principal Adjustments	Total	Transactions	Principal Adjustments	Total	Total
Accounting Guidance 2020 Analysis			$(268,794)			$ 20,715	
DVA Continuity Schedule (sum of 2020 tranactions and principal adjustments	$ (103,312)	$ (137,108)	$(240,420)	$ (306,810)	$ 327,104	$ 20,294	
Difference			$ (28,374)			$ 421	$(27,953)

- Differences in Table 8 are immaterial. Small differences may be explained by transactions (such as billing adjustments) or differences due to methodology (i.e. proration of consumption in the billing system). The regulatory accounting guidance analysis has been consolidated and reviewed on an annualized basis. The review demonstrates that these types of differences are not considered material enough to review at a more detailed level. Elexicon confirms that the row "Accounting Guidance 2021 Analysis" in Table 8 is not intended to reflect the balances in the DVA Continuity Schedule but is an analysis of the OEB accounting guidance for Accounts 1588 and 1589 and demonstrates alignment with the General Ledger.

- Elexicon requests final disposition of the 2021 balances that meet the threshold

<u>WRZ Extension request regarding implementation of the 1588/1589 Accounting Guidance</u>

Elexicon confirms that the limited extension previously requested regarding implementation of the 1588/1589 Accounting Guidance for the WRZ will not impact customers, nor the outcome of account balances reviewed for disposition. As such, it is strictly a process-driven change mandated by the OEB Decision (EB-2019-0130) resulting in a standardized process with some accelerated timing.

The transition was challenged by:

- Loss of four involved staff members, two of which were key resources with unique subject matter expertise.
- Resource replacement challenges.
- The delay in the completion of a major CIS upgrades (from late 2021 to early 2022)
- COVID-19 effects that continued to produce challenges including the flat rate RPP pricing from Jan 18 2022 to Feb 8 2022 which challenged both the billing department and the settlement group

Elexicon has work plans to complete this by the end of 2022 in order to allow for implementation of the new process beginning of January 1, 2023. It is confident that it can meet this revised timeline.

While the additional modifications to support the new process have been reviewed, these changes will require the dedication of key resources in multiple departments (Metering, Wholesale Settlements, Billing and Regulatory) to complete. This is required to ensure a clean cut-over between metering and billing data flowing through using the old and new processes. Such a transition is better conducted at a year-end, rather than mid-year, as the finalization of true-ups under the old process must be completed and new processes established, in order to support the updated processes going forward.

Elexicon has taken a number of steps to facilitate the changes required to more fully align the process required by the OEB's regulatory accounting guidance. These include:

- Modifications to the CIS system setup related to billing transactions, in order to align with regulatory accounting guidance. This included mapping of accounts, testing, as well as significant process changes for regulatory finance. *Status: Completed in 2020*.

- Review of 2020 true-ups under the modified CIS setup to align with regulatory accounting guidance outcomes.
  Status: *Completed in 2021.*

- Setup of Whitby RZ metering information integration into the Elexicon in-house retail settlement database and tools

  - Wholesale meters and GS 50-200kW accounts
    Status: Completed in 2020.

    - GS 200-4,999 kW accounts.
      Status: Completed October 2021.

- CIS Integration. *Status: Completed February 2021.*

- Two new major upgrades to the CIS that must be completed in 2021
  Status: Completed January 2022.

- Whitby RZ queries created in Settlement systems

  Status: Completed January 2022

- Whitby settlement/metering data brought in-house

  Status: Completed March 2022.

- Whitby RZ compilation template created.

  Status: Completed March 2022.

- Whitby RZ query listings created in CIS

  Status: Completed March 2022.

Additional work is planned to support the continued transition to a consistent settlement process and tool for WRZ that mirrors the VRZ. While this transition will not have a material effect on the outcome of the settlement amounts, it will assist with aligning the timing expectations for settlement and true-ups as outlined in the OEB's regulatory accounting guidance. It will also provide for greater consistency between both of the rate zones' processes.

Planned for the balance of 2022:

- Create WRZ CIS extract listings. *Status: Scheduled completion August 2022*

- Acceptance testing of new WRZ compilation template/method.
  Status: WIP August, September & October 2022

Elexicon has made considerable progress and is close to completing the transition. Elexicon has been diligent in its efforts and believes that the additional amount of time would ensure the transition is done correctly and presents no harm to rate payers.

Similar to prior years, in the 2024 EDR Application, Elexicon will review the 2022 transactions for reasonability and comparability against the regulatory accounting guidance.

<u>GA Analysis Workform</u>

As stated in the Filing Requirements all distributors are required to complete and submit the GA Analysis Workform for each year that has not previously been approved by the OEB for disposition. As such, Elexicon has completed the GA Analysis Workform in order to assist in assessing the reasonability of balances in accounts 1589 and 1588.

The analysis tab provides a reconciliation which demonstrates that any unresolved differences are extremely small and well within a range of reasonability (+/- 1%). The summary from the Information Sheet of the GA Workform is below:

Table 9: GA Analysis Workform – VRZ

Account 1589 Reconciliation Summary

Year	Annual Net Change in Expected GA Balance from GA Analysis	Net Change in Principal Balance in the GL	Reconciling Items	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	$ Consumption at Actual Rate Paid	Unresolved Difference as % of Expected GA Payments to
2021	$ (1,726,395)	$(1,524,917)	$ 57,963	$(1,466,954)	$ 259,441	$ 52,775,164	0.5%

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2021	-0.4%

The reconciliation amounts in Note 5 are consistent with the principal adjustments in Tab 3 of the 2023 Rate Generator Model columns BF (2021). The applicable explanation sections of the workform have been completed.

Table 10: GA Analysis Workform – WRZ

Account 1589 Reconciliation Summary

Year	Annual Net Change in Expected GA Balance from GA Analysis	Net Change in Principal Balance in the GL	Reconciling Items	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	$ Consumption at Actual Rate Paid	Unresolved Difference as % of Expected GA Payments to
2020	$ (60,949)	$ (306,810)	$ 295,246	$ (11,564)	$ 49,386	$ 25,317,011	0.2%
2021	$ (606,019)	$ (407,288)	$ (149,908)	$ (557,196)	$ 48,823	$ 18,281,634	0.3%
Cumulative Balance	**$ (666,968)**	**$ (714,098)**	**$ 145,338**	**$ (568,760)**	**$ 98,209**	**$ 43,598,644**	**N/A**

Account 1588 Reconciliation Summary

Year	Account 1588 as a % of Account 4705
2020	-0.3%
2021	-0.1%
Cumulative Balance	-0.2%

The reconciliation amounts in Note 5 are consistent with the principal adjustments in Tab 3 of the 2023 Rate Generator Model column AV (2020) and column BF (2021). The applicable explanation sections of the workform have been completed.

Account 1589 Balance Allocation and Disposition

Elexicon's 2023 Rate Generator model has established a separate rate rider that would apply prospectively to non-RPP Class B customers. The billing determinant and all the rate riders for the GA are calculated on an energy basis (kWh) regardless of the billing determinant used for distribution rates for a particular class.

The Rate Generator model has allocated the portion of Account 1589 GA to customers that transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged the general GA rate rider. Customers will be charged in a consistent manner for the entire rate rider period until the sunset date.

3.2.5.4 Capacity Based Recovery ("CBR")

Elexicon has followed the approach identified in the Filing Requirements to address the disposition of CBR variances. A separate rate rider has been calculated in Tab 6.2.CBR B in the Rate Generator model to dispose the balance over the default period of one year. The Rate Generator model allocated the portion of Account 1580, Sub-account CBR Class B to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be refunded the general CBR Class B rider. Customers will be charged in a consistent manner for the entire rate rider period until the sunset date.

3.2.5.5 Disposition of Account 1595

Elexicon is requesting disposition of 1595 (2019) for the VRZ. Elexicon is requesting disposition of 1595 (2018) and 1595 (2019) for the WRZ. Elexicon confirms that the disposition of residual balances for vintage Account 1595 have only been done once.

As noted in 3.2.5 above, there is a residual balance in VRZ 1595 (2019) outside the normal forecasted vs. actual billing determinants that Elexicon is proposing to correct in this application

3.2.6 LRAM Variance Account ("LRAMVA")

Elexicon is applying for partial disposition of Account 1568 – LRAMVA to recover lost revenues in the amount of $3,787,229. The claim for VRZ which includes results from 2020-2022 CDM programs and the persistence of 2012-2019 programs in 2020-2022 is

$2,637,190. This includes carrying charges on the principal LRAMVA balance accumulated to December 2022 of $44,275. The claim for WRZ which includes results from 2020-2022 CDM programs and the persistence of 2011- 2019 programs in 2020-2022 is $1,150,039. This includes carrying charges on the principal LRAMVA balance accumulated to December 31, 2022 of $19,098.

Elexicon has already submitted claims for lost revenues from CDM programs and persistence through 2019 for both VRZ and WRZ in its 2022 EDR Application (EB-2021-0015).

A summary of the LRAMVA disposition request by customer class including projected carrying charges is as follows:

Table 11: LRAMVA Disposition – VRZ

	2020-2022 LRAMVA		
Customer Class	Principal	Carrying Charges	Total
Residential	-	-	-
GS<50 kW	579,034	9,973	589,008
GS 50 to 2,999 kW	1,287,034	21,846	1,308,880
GS 3,000 to 4,999 kW	56,457	961	57,417
Large Use	412,665	7,132	419,797
Unmetered Scattered Load	204	3	208
Street Lighting	257,521	4,360	261,881
Total	**$ 2,592,915**	**$ 44,275**	**$ 2,637,190**

Table 12: LRAMVA Disposition – WRZ

	2020-2022 LRAMVA		
Customer Class	Principal	Carrying Charges	Total
Residential	-	-	-
GS<50 kW	160,740	2,749	163,490
GS>50 kW	726,774	12,205	738,979
Street Lighting	243,427	4,143	247,570
Total	**$ 1,130,941**	**$ 19,098**	**$ 1,150,039**

The LRAMVA is intended to capture the variance between the level of CDM program activities included in the LDC's Board-approved load forecast and the results of actual, verified impacts of CDM activities undertaken by the LDC. In Veridian's last cost of service rate application (EB-2013-0174), the approved load forecast was established for a 2014 single forward test year. It included the impacts of CDM in 2012 and prior years. There was no CDM adjustment in the approved load forecast in Whitby Hydro's last cost of service application (EB-2009-0274)

Elexicon retained IndEco Strategic Consulting Inc. ("IndEco") to develop its LRAMVA claim including both rate zones. Their full report is available in Appendix A. IndEco used the most recent input assumptions available at the time of the program evaluation, including IESO Final Verified CDM savings report for 2011-14, IESO Final Verified CDM savings report for 2015-2017, and April 2019 IESO Participation and Cost Report for both rate zones; all of which have been filed in support of previous LRAMVA applications.

Elexicon proposes to recover the LRAMVA amount of $3,787,229 of which $2,637,190 is to be recovered from VRZ customers and $1,150,039 is to be recovered from WRZ customers, through class-specific volumetric rate riders that would be in effect for a period of 1 year (January 1, 2023 to December 31, 2023) for VRZ and 3 years (January 1, 2023 to December 31, 2025) for WRZ. The class-specific rate riders were determined by totaling the class-specific LRAMVA amount by program and dividing by the amount of volume or demand billed in 2021.

In addition, Elexicon is applying for approval of 2023 to 2028 LRAM-eligible amounts shown in the table below. Approval of these amounts would mean that they are accepted as final, and subject only to the annual mechanistic adjustment to be completed in later years. This treatment is consistent with the December 20, 2021

Conservation and Demand Management Guidelines for Electricity Distributors (the "Guidelines").

Table 13: 2023-2028 LRAM-Eligible Amounts – VRZ

Customer Class	2023	2024	2025	2026	2027	2028
Residential	-	-	-	-	-	-
GS<50 kW	157,356	132,054	106,834	75,579	49,473	26,987
GS 50 to 2,999 kW	412,442	362,236	330,030	313,415	288,588	256,711
GS 3,000 to 4,999 kW	18,484	18,323	18,002	17,876	16,956	15,057
Large Use	124,821	114,220	105,914	102,641	88,887	74,751
Unmetered Scattered Load	70	67	60	59	44	22
Street Lighting	88,475	88,475	88,475	86,100	84,912	84,912
Total	**$ 801,649**	**$ 715,376**	**$ 649,316**	**$ 595,670**	**$ 528,860**	**$ 458,440**

Table 14: 2023-2028 LRAM-Eligible Amounts – WRZ

Customer Class	2023	2024	2025	2026	2027	2028
Residential	-	-	-	-	-	-
GS<50 kW	51,356	48,011	34,248	28,830	23,846	21,066
GS>50 kW	238,487	219,913	205,307	196,540	186,337	172,914
Street Lighting	82,714	82,714	82,714	82,714	76,202	43,100
Total	**$ 372,558**	**$ 350,638**	**$ 322,269**	**$ 308,084**	**$ 286,385**	**$ 237,081**

Methodology for Calculating LRAMVA

The Guidelines provide the basis and methodology required to file an application for LRAMVA disposition.

Between 2011 and 2020, Elexicon administered only IESO-Contracted Province-Wide CDM programs and did not have any Board-Approved programs.

The 2011-2014 IESO Final Savings Report, 2015-2017 IESO Final Savings Report and April 2019 IESO Participation and Cost Report ("P&C Report") are the sources of the CDM savings used to calculate LRAMVA amounts related to IESO programs. Some projects in 2018 and 2019 were completed subsequent to the P&C Report. Gross savings for these were captured in the Elexicon CDM database. These were converted to net values using the most recent verified net-to-gross ("NTG") and Realization Rate ("RR") factors for Elexicon which are included in the 2017 final results reports.

The lost revenue amounts to be recovered have been adjusted for free riders as defined in the Guidelines. Lost revenues are based on net kWh or kW after deducting for free riders. The amount of free riders varies depending on the CDM program.

LRAMVA Calculation

The LRAMVA amount was calculated by deducting the LRAMVA threshold from the net energy savings (kW or kWh) for each program, and then multiplying by the Board approved volumetric distribution charge for the applicable rate class, on a year-by-year basis.

In accordance with the Filing Requirements, Elexicon has included the OEB LRAMVA Workform with the Application.

CDM Adjustment to Load Forecast - VRZ

In the OEB's April 10th, 2014 Decision and Order on Veridian's 2014 EDR application (EB-2013-0174), the Board approved Veridian's Settlement Proposal, which included the CDM adjustment to Veridian's test year load forecast.

The table below provides the CDM adjustment to the load forecast by rate class in VRZ. Note there are no demand savings built in to the load forecast for street lights.

Table 15: CDM Load Forecast Adjustment - VRZ

	CDM Load Forecast Adjustment	
Rate Class	**kWh**	**kW**
Residential	6,117,617	
Residential - Seasonal	94,223	
GS<50	5,350,400	
GS>50	19,546,777	19,267
Intermediate	62,993	54
Large Use	461,286	450
Street Lights	-	
Sentinel Lights	-	
USL	-	
Total	**31,633,297**	**19,771**

From these values and the Chapter 2 Appendix I filed with the Cost of Service, IndEco was able to calculate the LRAMVA Threshold that considers the above manual adjustment, 2012 partial results captured through the regression analysis, and an adjustment to 2014 estimated results to make them comparable to IESO reports that are based on first-year savings, not calendar year savings. The table below shows the LRAMVA threshold (based on estimated results in 2012-2014). The difference between the amounts stated below and the actual verified final program results form the basis of the LRAMVA amount available for recovery from customers:

Table 16: LRAMVA Threshold-VRZ

	LRAMVA Threshold	
Rate Class	**kWh**	**kW**
Residential	8,597,676	
Residential - Seasonal	132,421	
GS<50	7,519,432	
GS>50	27,470,967	27,078
Intermediate	88,530	6
Large Use	648,290	632
Street Lights	-	
Sentinel Lights	-	
USL	-	
Total	**44,457,315**	**27,716**

CDM Adjustment to Load Forecast - WRZ

WRZ prepared its last cost of service application for rates effective January 1st, 2011. This was prior to the issuance of the CDM Guidelines that were issued April 26th, 2012 and the introduction of LRAMVA (for which the CDM Code applied to the four-year period from January 1, 2011 to December 31, 2014). Prior to the LRAMVA, there was no specific requirement to address a CDM adjustment in the load forecast. As a result, WRZ's Settlement Agreement, upon which the 2011 rates were based, was not determinative on the point of whether CDM was or was not included in the accepted load forecast for 2011. In order to provide clarity and regulatory certainty, in its 2012 and 2013 EDR applications, Whitby Hydro requested that the Board consider providing a decision on the matter of whether its load forecast for 2011 included a CDM adjustment and if an adjustment did exist, the value or process to determine the value by customer class. Whitby Hydro took the position that its load forecast did not include a CDM adjustment. With regards to the matter of CDM impacts on its 2011 load forecast, in its 2013 EDR Decision (EB-2012-0177), the OEB stated:

> *"The Board finds that the 2011 forecast did not include CDM impacts related to Whitby's 2011-2014 CDM programs and therefore, Whitby Hydro is eligible to apply for a disposition of a LRAM Variance account for 2011."*

The 2013 EDR application decision provided certainty on this issue in the absence of being specifically addressed in the last cost of service application and settlement agreement. On this basis, the full amount of the LRAM associated with the 2011-2022 IESO CDM program impacts on 2020-2022 has been included in the disposition request. Therefore, Tab 2 has been left blank in the WRZ LRAMVA Workform.

Street Lighting

Several municipalities in Elexicon's service area have completed LED streetlight retrofits with IESO funding based on SaveOnEnergy Retrofit incentives. The energy savings associated with these projects are included in Elexicon's results. However, streetlights are not used during peak periods and are unmetered. Consequently, the IESO report is not appropriate for estimated lost revenue for this rate class. Instead, the kW reductions have been calculated based on the number and types of fixtures changed.

Prior to calculating the lost revenues for its streetlight accounts, Elexicon removed the associated net kW and kWh savings assigned by the IESO to Elexicon's street lighting retrofit projects from the total retrofit savings.

Carrying Charges

In accordance with Section 13.3 of the 2012 Guidelines, Elexicon is seeking recovery of carrying charges up to December 31st, 2022 in the amount of $63,373 for VRZ ($44,275) and WRZ ($19,098).

Elexicon used the Board's prescribed interest rates through Q3-2022. Elexicon assumes that the Board's prescribed rate for Q4-2022 to be the same as Q3-2021. Elexicon will update Elexicon's 2023 rate application to incorporate updated Q4-2022 prescribed rates if they become available.

Rate Rider Calculation

Elexicon proposes to recover the LRAMVA amounts, including associated carrying costs, through class-specific volumetric rate riders. These rate riders were determined by dividing the class- specific LRAMVA amount by the total billed kWh or kW for each rate class in 2021

Elexicon proposes a one year recovery from January 1, 2023 to December 31, 2023 for VRZ. The proposed rate riders are shown in the table, below.

Table 17: LRAMVA Rate Riders – VRZ

LRAMVA Rate Riders

1 year

Customer Class	Annual Recovery	Volume	Rate Rider	per
Residential	0	1,029,321,566	$ -	kWh
GS<50 kW	589,008	278,876,540	$ 0.0021	kWh
GS 50-2,999 kW	1,308,880	2,251,119	$ 0.5814	kW
GS 3,000-4,999 kW	57,417	233,934	$ 0.2454	kW
Large User	419,797	481,567	$ 0.8717	kW
USL	208	4,578,173	$ -	kWh
Streetlighting	261,881	31,140	$ 8.4098	kW
	2,637,191			

For rate mitigation, Elexicon proposes a three year recovery from January 1, 2023 to December 31, 2025 for WRZ. The proposed rate riders are shown in the table below.

Table 18: LRAMVA Rate Riders-WRZ

LRAMVA Rate Riders

3 year

Customer Class	Annual Recovery	Volume	Rate Rider	per
GS<50 kW	163,490	83,266,323	$ 0.0007	kWh
GS 50-4,999 kW	738,979	915,640	$ 0.2690	kW
Streetlighting	247,570	9,363	$ 8.8138	kW
	1,150,039			

3.2.7 Tax Changes

<u>Shared Tax Savings</u>

As stated in the Filing Requirements (Section 3.2.7), OEB policy, as described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "Supplemental Report"),* prescribes a 50/50 sharing of the impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. Elexicon has completed the appropriate sheets in the 2023 Rate Generator Model.

VRZ - The impact of legislated tax changes results in a $2,849 Shared Tax Savings adjustment charge to customers. As stated in section 3.2.7 of the Filing Requirements, "A rate rider to four decimal places must be generated for all applicable customer classes in order to dispose of the amounts. If one or more customer classes do not generate a rate rider to the fourth decimal place, the entire 50/50 sharing amount will be transferred to Account 1595 for disposition at a future date." Since none of the customer classes generated a rate rider, Elexicon is proposing to transfer the balance to 1595 for future disposition. This approach is consistent with Elexicon's recommendations and the Board's approvals in previous rate applications.

WRZ – Elexicon is requesting disposition of the calculated shared tax savings as calculated in the 2023 IRM Rate Generator Model for the WRZ.

<u>Bill C-97 CCA Rule Change</u>

As per the OEB's July 25, 2019 letter, Elexicon has recorded the impacts of CCA rule changes in Account 1592 - PILs and Tax Variances – CCA Changes effective November 21, 2018. Elexicon will bring forward the amounts tracked in this account for review and disposition in a future rate application.

3.2.8 Z-factor Claims

Elexicon has not included a Z-Factor claim in this application. A Z-factor claim will be filed later in 2022 for the May 21st storm that affected many regions in Ontario.

3.2.9 Off-ramps

Elexicon does not have an OEB approved return on equity ("ROE"). However, a weighted average has been used to derive an OEB-approved ROE proxy of 9.43%. Elexicon's 2021 ROE of 6.87% is not in excess of the dead band of +/- 300 basis points from the OEB-approved ROE proxy.

3.3 Elements Specific only to the Price Cap IR Plan

3.3.1 Advanced Capital Module

Elexicon has not requested rate relief through an ACM in this application.

3.3.2 Incremental Capital Module ("ICM")

Elexicon is applying to secure incremental capital funding for a pair of ICM projects and seeks the following relief:

1. ICM funding of $36,739,433 for the Whitby Smart Grid Project ("WSG Project"), including a proportionate share of Advanced Distribution Management System ("ADMS") and SCADA costs, in the WRZ;

2. ICM funding of $6,431,567 for a proportionate share of the ADMS and SCADA costs of the WSG Project, in the Veridian Rate Zone ("VRZ"); and

3. ICM funding of $26,657,000 for the Sustainable Brooklin Project in the Whitby Rate Zone ("WRZ") and an exemption for the Brooklin Line (as more fully described in Appendix B) from Section 3.2 of the Distribution System Code ("DSC") (the "DSC Exemption"). For clarity, approvals for the Sustainable Brooklin Project and DSC Exemption request are inextricably linked and one should not be approved without the other.

The WSG Project involves the deployment of a combination of well understood and proven smart grid technologies across Elexicon's distribution system in the WRZ and VRZ. The Sustainable Brooklin Project involves Elexicon providing capacity to a group of residential developers represented by the Brooklin Landowners Group Inc. (the "Developers"), who will in turn construct new homes in Brooklin, ON with DER enabling features such as rough-ins for solar panels, battery storage and EVs.

Elexicon submits that both the WSG Project and the Sustainable Brooklin Project meet the OEB's well-established eligibility criteria of materiality, need and prudence as outlined in the ACM Report. Please see Appendix B.

3.3.3 Treatment of Costs for 'eligible investments'

When Veridian rebased in 2014 (EB-2013-0174), the OEB approved provincial rate protection payments under O.Reg 330/09 for two Renewable Enabling Improvement Projects and a Renewable Expansion Project for the period of 2014 to 2018.

In Elexicon's 2021 EDR Application decision (EB-2020-0013), the OEB approved the funding for the Micro-Grid and the Index Energy Projects as well as their proposed funding schedule up to 2028. The OEB accepted the withdrawal of the request for the funding of the Communications Platform project until more up-to-date information is provided to the OEB. No further evidence is being provided in this application.

3.4 Specific Exclusions from Applications

Elexicon has not included any specific issues identified for exclusion from an IRM Application.

Bill Impacts

A summary of the Bill Impacts are as follows:

Table 19: Bill Impacts by Rate Class - VRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill	
Customer Class	kWh	kW	RPP? Non?	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	750		RPP	0.78	2.6%	0.85	2.3%	2.03	4.2%	1.95	1.6%
Seasonal	645		RPP	1.56	2.8%	1.62	2.6%	2.71	3.8%	2.60	1.9%
GS<50 kW	2,000		RPP	4.95	8.3%	4.95	6.4%	7.68	7.4%	7.37	2.4%
GS 50 to 2,999 kW	432,160	1,480	Non	804.80	13.3%	- 689.26	-7.6%	267.12	1.5%	301.84	0.4%
GS 3,000 to 4,999 kW	1,752,000	4,000	Non	1,127.53	6.8%	- 4,410.47	-17.0%	- 1,564.07	-3.0%	- 1,767.40	-0.7%
Large User	4,219,400	6,800	Non	5,395.71	15.5%	4,317.91	8.5%	9,156.79	9.5%	10,347.17	1.7%
USL	500		RPP	0.53	3.0%	0.53	2.4%	1.21	4.2%	1.16	1.5%
Sentinel Lights	180	1	RPP	0.60	2.8%	0.56	2.4%	0.96	3.5%	0.92	2.1%
Street Lighting	424,881	988	Non	6,660.59	44.7%	5,254.23	31.4%	5,673.58	27.4%	6,411.15	8.3%

Total bill impacts proposed range from -0.7% to 8.3% for average customers in each class.

Key impacts to the overall bill are summarized as:

- Distribution charges reflect an inflationary increase for the annual price cap index of 3%
- Network Transmission Rates increased ~15% and Connection Rate increased ~4% for all classes based on Forecast Wholesale Billing at the most recently approved IESO UTRs and HONI sub-transmission rates
- Increase in LRAM rate riders based on three year disposition request
- Increases are offset by a newly proposed Rate Rider credit for GA recovery

Table 20: Bill Impacts by Rate Class - WRZ

				A Distribution Charges (excluding pass through)		B Distribution Charges (including pass through)		C Delivery (including Sub-Total B)		Total Bill	
Customer Class	kWh	kW	RPP? Non?	$ Change	% Change	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	750		RPP	$ 3.85	11.5%	$ 5.80	15.2%	$ 7.29	14.2%	$ 7.00	5.5%
GS<50 kW	2,000		RPP	$ 8.23	11.6%	$ 13.63	16.6%	$ 17.18	15.0%	$ 16.50	5.2%
GS>50 kW	40,000	100	Non	$ 80.72	12.2%	$ 105.97	15.3%	$ 173.82	13.4%	$ 196.42	3.2%
USL	500		RPP	$ 3.10	11.5%	$ 4.50	15.2%	$ 5.39	14.3%	$ 5.17	5.9%
Sentinel Lights	150	1	Non	$ 3.05	13.9%	$ 4.19	18.4%	$ 4.70	17.2%	$ 4.52	10.8%
Street Lighting	283,400	736	Non	$ 3,569.43	10.3%	$ 2,829.88	8.2%	$ 3,208.77	8.4%	$ 3,625.91	4.5%

Total bill impacts proposed range from 3.2% to 10.8% for average customers in each class.

Key impacts to the overall bill are summarized as:

- Distribution charges reflect an inflationary increase for the annual price cap index of 3%
- Network Transmission Rates increased ~15% and Connection Rate increased ~6% for all classes based on Forecast Wholesale Billing at the most recently approved IESO UTRs and HONI sub-transmission rates
- Newly proposed rate riders for Group 1 disposition and Recovery of Incremental Capital

Copies of the current and proposed tariff sheets and Elexicon's calculated customer bill impacts are included in this Application (Appendices C, D and E respectively).

elexicon ENERGY

List of Appendices

Appendix A	LRAM Indeco Report
Appendix B	Incremental Capital Module: Whitby Smart Grid & Sustainable Brooklin
Appendix B-1	Whitby Smart Grid Business Case
Appendix B-2	Sustainable Brooklin Business Case
Appendix B-3	DER Enabling Program and Local Capacity Market
Appendix B-4	METSCO Elexicon Energy 2022-2041 Peak Load Forecast
Appendix B-5	METSCO Feasibility Study Whitby SmartGrid VVO and DA
Appendix B-6	Letters of Support for ICM Application
Appendix B-7	Customer Engagement Report
Appendix C-1	2022 Tariff Sheet - VRZ
Appendix C-2	2022 Tariff Sheet - WRZ
Appendix D-1	2023 Proposed Tariff Sheet - VRZ
Appendix D-2	2023 Proposed Tariff Sheet - WRZ
Appendix E-1	Bill Impacts - VRZ
Appendix E-2	Bill Impacts - WRZ
Appendix F	Certificate of Evidence
Appendix G	Check List

APPENDIX A:

LOST REVENUE ADJUSTMENT MECHANISM VARIANCE ACCOUNT (LRAMVA) DISPOSITION

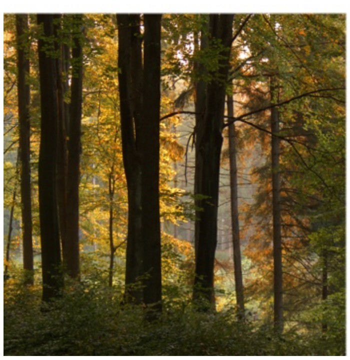
INDECO REPORT

Strategic Solutions for a Changing World™

Elexicon Energy Inc.
2020-2028 LRAMVA





Elexicon Energy Inc.

Lost revenue related to Conservation and Demand Management

2020-2028

IndEco

This document was prepared for Elexicon Energy Inc. by IndEco Strategic Consulting Inc.

For additional information about this document, please contact:

IndEco Strategic Consulting Inc.
300 -192 Spadina Avenue
Toronto, ON, Canada
M5T 2C2

Tel: 888 463-3261
E-mail: **info@indeco.com**

IndEco report C2195

25 July 2022

Table of Contents

Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of the LDC. These savings and reductions directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts on the LDC included in the LDC's load forecast.[1]

On April 1, 2019, Veridian Connections Inc. merged with Whitby Hydro Electric Corporation to form Elexicon Energy Inc. The rate zones of the two utilities, hereinafter referred to as VRZ for the original Veridian service territory, and WRZ for what was the service area of Whitby Hydro, have different rate structures and therefore LRAMVA is calculated separately for each rate class and for each rate zone.

The former Veridian Connections Inc. and the former Whitby Hydro Electric Corporation contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period.

LRAMVA for both VRZ and WRZ has already been claimed for results through 2019. Lost revenue variances being claimed in the 2023 rate application are summarized on Figure 1 and Figure *2* for the VRZ and WRZ, respectively.

---

[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

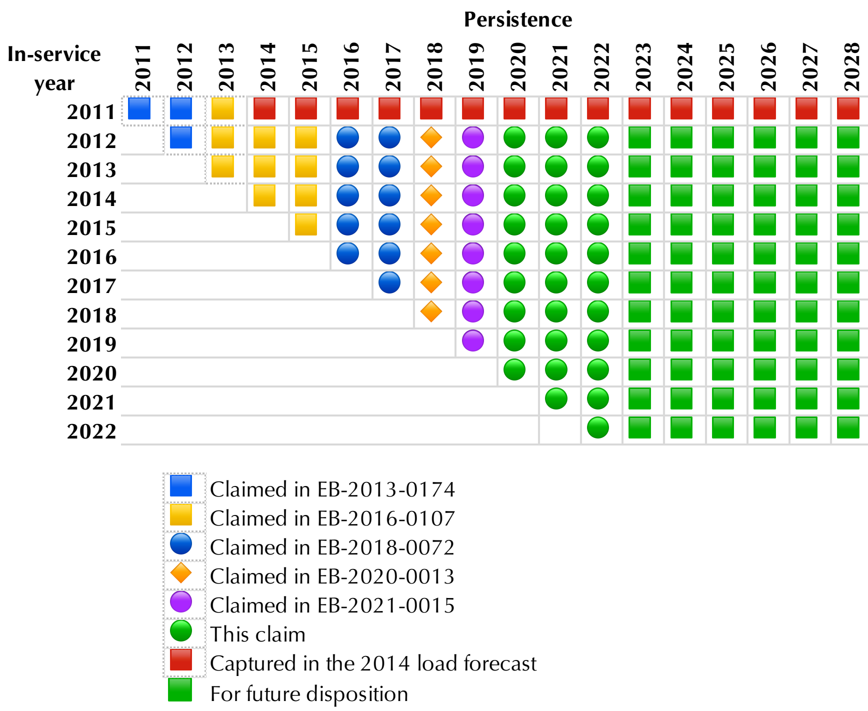


Figure 1 LRAMVA claims for VRZ

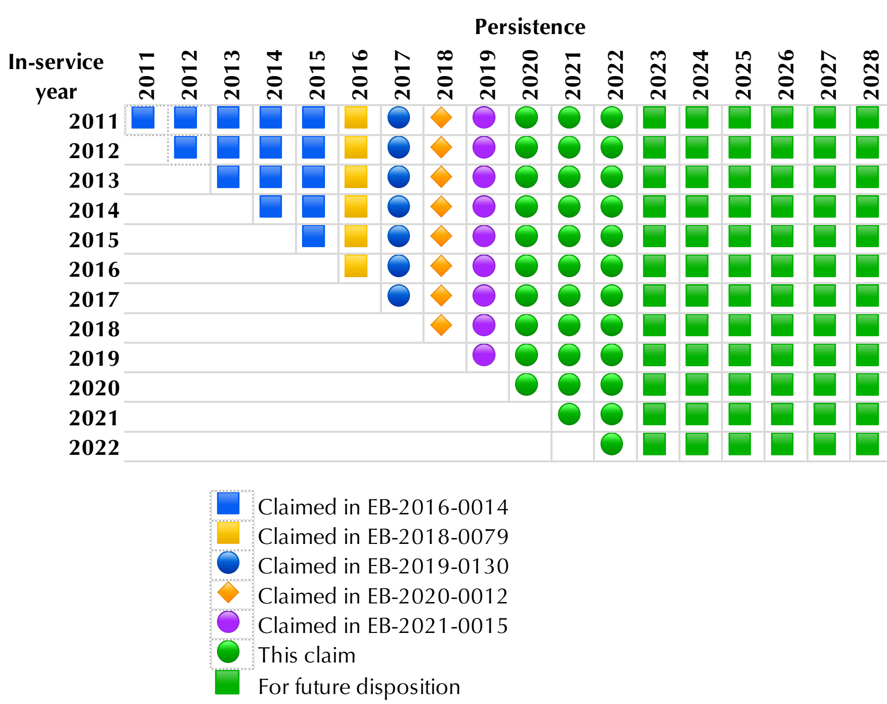


Figure 2 LRAMVA claims for WRZ

Elexicon is requesting disposition of the LRAMVA balance that will remain at the end of 2022, including specifically:

- Savings in 2020 and 2021 of projects approved before April 1, 2019 as part of the Conservation First Framework, but completed in 2020 or later
- Persistence of those savings through 2022
- Persistence of programs offered in VRZ in 2012 through 2019 that persist in 2020 and through 2022
- Persistence of programs offered in WRZ in 2011 through 2019 that persist in 2020 and through 2022.

The persistence of these CDM savings through 2028 is also provided for future disposition. Elexicon plans to file its next cost of service rate application for the 2029 rate year. That application will include a new load forecast that will capture any savings from the Conservation First Framework or the earlier framework that persist beyond 2028. Given that Elexicon is no longer offering customers new CDM programs, the LRAMVA balances that will remain through December 31, 2028 from Elexicon's initiatives under the Conservation First Framework (CFF) can be determined at this time.

In preparing this claim, the methodology prescribed by the OEB filing requirements has been followed:

"The OEB will rely on the Participation and Cost Reports and detailed project level savings files as supporting documentation when assessing applications for lost revenues in relation to energy and demand savings from programs delivered under the CFF where final verified results from the IESO are not available."[2]

[2] Ontario Energy Board, 2021. *Filing Requirements for Electricity Distribution Rate Applications - 2021 Edition for 2022 Rate Applications*. Chapter 2 Cost of Service

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the use of different volumetric units for billing in different rate classes and the need to determine carrying charges on the lost revenues.

The information sources for the LRAMVA analysis are summarized on Table 1.

Table 1 Information sources for LRAMVA analysis

CDM program years	Sources	Information used in this analysis	Used for
2011-2014	2014 final verified results report for Veridian and Whitby (OPA)	Net first year energy savings by program	Savings
		Net first year demand reductions by program	Savings
	2011-2015 persistence reports for Veridian and Whitby (IESO)	Persistence of net results by program through 2028	Savings
	CDM databases (Veridian and Whitby)	First year savings by project	Allocation to rate classes
2015-2017	2017 final verified results reports for Veridian and Whitby (IESO)	Net first year energy savings by program	Savings
		Net first year demand reductions by program	Savings
		Persistence of results through 2028 by program	Savings
	2015, 2016 and 2017 final verified results by project (IESO)	Net first year energy savings by project	Allocation to rate classes
		Net first year demand reductions by project	Allocation to rate classes
2018 - March 2019	April 2019 Participation & Cost Report for Veridian and Whitby (IESO)	Unverified first year net savings for 2018, Jan-Apr 2019, and adjustments for 2016 and 2017 by program	Savings
		Unverified persistence in 2020 by program	Savings in 2020
	CDM databases (Elexicon)	Reported gross energy and demand savings	Calculating net savings
	2017 final verified results reports for Veridian and Whitby (IESO)	Net-to-Gross and Realization Rates	Calculating net demand savings in the P&C reports
		Rate of loss of persistence	Persistence in 2020-2028
2018-2022	CDM databases (Elexicon)	Reported gross first year energy savings by project	Gross savings and allocation by program
		Reported gross first year demand savings by project	Gross savings and allocation by program
	2017 final verified results reports for Veridian and Whitby (IESO)	Net-to-Gross and Realization Rates	Calculating net energy and demand savings by program
		Rate of loss of persistence	Persistence through 2028 where IESO persistence is not available.
2023-2028	2017 final verified results reports for Veridian and Whitby (IESO)	Rate of loss of persistence	Persistence through 2028 where IESO persistence is not available.

CDM RESULTS

For programs offered through 2017, the IESO performed evaluations which examined reported gross energy savings from the programs, and the Realization Rate (RR) and the net-to-gross ratio (NTGR), and then from those calculated net energy savings for each initiative or program. Peak load reductions were also calculated and reported in the same way. For some programs the IESO calculated gross and net energy at the project level.

Provincial results were allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reported energy savings and peak demand reductions by program in the current year, adjustments to previous years based on updated validation, and contribution to total savings or reductions for the 2011 to 2014 and the 2015 to 2017 periods. The savings and demand reductions for a particular year for most programs persist for several years. The savings and demand reductions for demand response programs do not persist beyond the year in which those savings and demand reductions occur. The IESO provided the persistence into future years of savings and reductions for each program in each year.

Before final evaluation results were available, the IESO published monthly Participation and Cost (P&C) reports that showed both verified and preliminary unverified savings. With the ending of the Conservation First Framework by the Ontario government on April 1, 2019, the IESO stopped producing reports of verified results. Unverified net energy savings for 2018, Q1 2019 and adjustments to program results for earlier years that came in after the 2017 final verified results report are in the April 2019 Participation and Cost reports. Results after the April 2019 Participation and Cost reports are from Elexicon databases which record gross values, as reported to the IESO.

The results included projects for streetlighting in both VRZ and WRZ. Energy and demand savings are calculated based on the number and type of fixtures that were retrofitted.

These are the best and most definitive and defensible estimates of savings associated with these programs and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Determining net demand savings for projects completed after the 2017 final results

Only reported demand savings are available for projects completed after the 2017 final results report. That includes both projects captured in the P&C report, and post-P&C projects captured in Elexicon CDM databases. These reported values were converted to net values using the net-to-gross values and realization rates in the 2017 final verified results report.

Allocating results to rate classes

The IESO reports results by program or initiative. These only partially map onto rate classes. The IESO provided net results by project for projects in programs that span multiple rate classes in 2015, 2016 and 2017 and Elexicon identified the rate classes for these projects to calculate the allocation across rate classes. For 2018 through 2021, Elexicon reported information on projects to the IESO and again the rate classes were identified for individual projects to calculate the allocation. The allocation was calculated according to the billing unit of the relevant rate class. That is, for GS<50 projects, the allocation to GS<50 is the percentage of total kWh for projects in that rate class; for GS>50, their allocation is the percentage of total kW for projects in that rate class.

In most cases, the allocation is straightforward. In some years, the Retrofit Program, its predecessor the Energy Efficiency Retrofit Initiative (EERI), the Energy Manager Program, the Business Refrigeration Program, and the High Performance New Construction program spanned more than one rate class in any given year. For these, allocations were done using the process described in Figure 3.

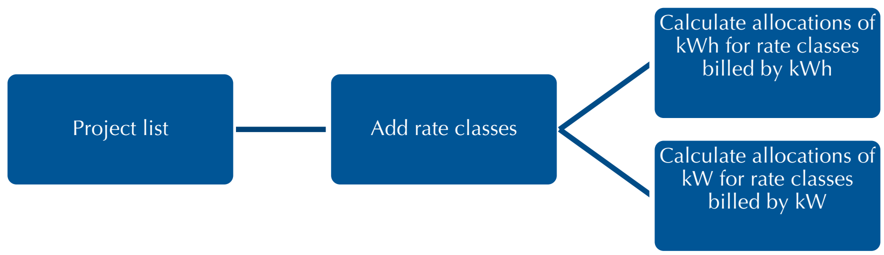


Figure 3 Allocation of savings to rate classes

Rate classes were identified for all projects in the program, the percentage of total energy use in each rate class billed by kWh was calculated, and the percentage of total demand reductions in each rate class billed by kW was calculated.

Elexicon bills customers in different rate classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for both rate zones of Elexicon are:

- Residential (kWh)
- GS <50 kW (kWh)
- Unmetered Scattered Load (kWh)
- Sentinel Lighting (kW)
- Street Lighting (kW).

WRZ has one rate class for GS>50 kW (kW), whereas in VRZ, these customers are divided into three rate classes, based on their demand: GS 50-2999 kW, GS 3,000-4,999 and Large Use, all billed by monthly peak kilowatts.

In both rate zones, customers undertook projects under the Retrofit program to retrofit streetlights to more energy efficient LED bulbs. Savings from these projects persist for 12 years. Elexicon has tracked the type and wattage of retrofitted fixtures, and details of these are shown on Tab 8-a and Tab 8-b of the LRAMVA work form for VRZ and WRZ respectively.

Tables 5-a through 5-h of the OEB LRAMVA work form show the percentage allocation by rate class for 2011 through 2022 results respectively. In each year the rate class allocation percentage totals for each program may not add up to exactly 100% in cases where kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW. The details of the allocation calculation are on Tab 3-a and Tab 3-b of the work form for VRZ and WRZ respectively.

Application of reported results

The IESO reported both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported net energy savings are used to calculate lost revenues related to CDM results. For rate classes where the LDC charges for distribution are based on the customer's peak monthly demand (kW), the IESO reported net peak demand reductions are used to calculate lost revenues related to CDM results.[3] The demand reductions in the IESO reports are multiplied by the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year."[4]

No lost revenues are claimed for demand response programs, consistent with OEB policy.[5]

For 2018 and 2019 and adjustments to earlier years made after the 2017 final results were available, the IESO did not report demand reductions. Demand reductions were estimated based on the reported post-completion gross demand savings by project and the 2017 NTG and RR factors.

Persistence

Persistence of 2011 to 2022 results through 2028 is shown at the bottom of Table 4-a to Table 4-d and 5-a to Table 5-n of the workform.

IESO provided persistence of 2011-2014 programs over 40 years. Persistence of programs in 2015 to 2017 is included in the 2017 final verified results report.

The April 2019 Participation and Cost report provided estimated net energy persistence in 2020 for all verified and unverified results.

---

[3] The exception is streetlighting retrofit projects. Streetlighting is billed by kW, but streetlighting retrofit projects have no peak demand reductions associated with conservation measures. A special calculation is done for these, as described below.

[4] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2016-0182, May 19, 2016, p. 4.

[5] Ibid. p. 7.

Where persistence data were not provided, persistence is estimated using the following methods:

- For unverified program results in 2016 to 2019 in the April 2019 Participation and Cost Report, the annual persistence of the unverified results to 2020 was estimated using linear interpolation between the program year and 2020
- For unverified results, persistence in 2021 to 2028 was estimated using the same rate of persistence seen in the verified results for that program and that year, if available, or for 2017.

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs. In VRZ, the last load forecast was in 2014, and a threshold for 2014 and later was determined. In WRZ, there has not been a forecast since 2010, and there was no accounting for CDM in the load forecast.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally, the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

Overall lost revenues in 2020-2022 are shown on Table 5-f to 5-h of the workform.

DISTRIBUTION RATES

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues when energy efficiency measures are adopted by customers. An exception is for certain rate riders related to taxes or where rate implementation was delayed, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

Beginning in 2021, distribution rates in both zones were based on the calendar year and no adjustment to these is required.

CARRYING CHARGES

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. So, 1/12 of the annual results are allocated to each month of the year.

Carrying charges for results realized in 2020 to 2022 accrue from the time of the results. Carrying charges on persistent savings from earlier projects accrue from January 1, 2020. Carrying charges on savings through December 31, 2019 have already been claimed.

Results

Following the methodology described above, lost revenues were calculated for Elexicon. The discussion of results refers to tables provided in the completed LRAMVA work form for the two rate zones. The work form uses the OEB's template.

LOST REVENUES

The lost revenues for each year by rate class for Elexicon calculated from final CDM program results are shown on Table 1-b of the OEB LRAMVA work form. The lost revenue for 2020, 2021 and 2022 is based on the load impact for each rate class multiplied by the rate for that rate class in that year. The load impact includes only the impact of CDM programs offered through the Conservation First Framework.

Table 1-b of the OEB LRAMVA work form also shows the anticipated lost revenue in each year due to CDM activities accounted for in Elexicon's 2014 Cost of Service application for VRZ. The impact on Elexicon's revenue is the variance between what is calculated from final CDM program results and estimated CDM activities.

CARRYING CHARGES

The monthly carrying charges by rate class on Elexicon's lost revenue variance are shown on Table 6 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues accrue.

TOTAL LRAMVA CLAIM

The LRAMVA balance on December 31, 2022 for Elexicon that includes persistence of results from 2012-2022 CDM programs in the VRZ, and 2011-2022 CDM programs in WRZ is $3,723,856. The total carrying charges on this LRAMVA balance accumulated to December 31, 2022 are $63,373. The balances by rate zone and individual rate class are shown on Table 2.

The claim for most classes is material, though there were no savings to claim in either rate zone for sentinel lighting. There is a small LRAMVA balance for unmetered scattered load in VRZ but nothing in WRZ. Savings in none of these rate classes will increase over time, and there is thus no reason to delay a claim because of the nil or immaterial amounts in these rate classes.

In addition to the savings through 2022 being claimed now, persistence of these savings through December 2028 using 2022 rates are calculated as an input to future deposition claims. These values are shown on Table 3.

Table 2 Summary of LRAMVA claim by rate class and rate zone

Customer class	Principal	Carrying charges	Total LRAMVA claim
VRZ - Residential	$0	$0	$0
VRZ - GS<50 kW	$579,034	$9,973	$589,008
VRZ - GS 50 to 2,999 kW	$1,287,034	$21,846	$1,308,880
VRZ - GS 3,000 to 4,999 kW	$56,457	$961	$57,417
VRZ - Large Use	$412,665	$7,132	$419,797
VRZ - USL	$204	$3	$208
VRZ – Sentinel Lighting	$0	$0	$0
VRZ - Street Lighting	$257,521	$4,360	$261,881
VRZ - Subtotal	**$2,592,915**	**$44,275**	**$2,637,190**
WRZ - Residential	$0	$0	$0
WRZ - GS<50 kW	$160,740	$2,749	$163,490
WRZ - GS>50 kW	$726,774	$12,205	$738,979
WRZ - Streetlighting	$243,427	$4,143	$247,570
WRZ - Sub-total	**$1,130,941**	**$19,098**	**$1,150,039**
Total	**$3,723,856**	**$63,373**	**$3,787,229**

Table 3 LRAM-eligible amounts for prospective disposition

Customer class	2023	2024	2025	2026	2027	2028
Residential - VRZ	$0	$0	$0	$0	$0	$0
GS<50 kW - VRZ	$157,356	$132,054	$106,834	$75,579	$49,473	$26,987
GS 50 to 2,999 kW - VRZ	$412,442	$362,236	$330,030	$313,415	$288,588	$256,711
GS 3,000 to 4,999 kW - VRZ	$18,484	$18,323	$18,002	$17,876	$16,956	$15,057
Large Use - VRZ	$124,821	$114,220	$105,914	$102,641	$88,887	$74,751
Unmetered Scattered Load - VRZ	$70	$67	$60	$59	$44	$22
Sentinel Lighting - VRZ	$0	$0	$0	$0	$0	$0
Street Lighting - VRZ	$88,475	$88,475	$88,475	$86,100	$84,912	$84,912
VRZ - Subtotal	**$801,649**	**$715,376**	**$649,315**	**$595,670**	**$528,860**	**$458,440**
Residential - WRZ	$0	$0	$0	$0	$0	$0
GS<50 kW - WRZ	$51,356	$48,011	$34,248	$28,830	$23,846	$21,066
GS>50 kw - WRZ	$238,487	$219,913	$205,307	$196,540	$186,337	$172,914
Street Lighting - WRZ	$82,714	$82,714	$82,714	$82,714	$76,202	$43,100
WRZ - Sub-total	**$372,558**	**$350,638**	**$322,269**	**$308,084**	**$286,385**	**$237,081**
Total	**$1,174,207**	**$1,066,014**	**$971,584**	**$903,754**	**$815,246**	**$695,521**

Appendix B

Incremental Capital Module:

Whitby Smart Grid & Sustainable Brooklin

Table of Contents

List of Figures

List of Tables

List of Appendices

Glossary

ACM Report	Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014
ADMS	Advanced Distribution Management System
Brooklin TS	Has the meaning ascribed in section 4.3.1
CDM Guidelines	Conservation Demand Management Guidelines
DER	Distributed Energy Resources
DER Enabling Programs	Has the meaning ascribed in section 1.2
Developers	Brooklin Landowners Group Inc.
DSC	Distribution System Code
DSC Exemption	Has the meaning ascribed in section 1.1
DSO	Distribution System Operator
DSP	Distribution System Plan
EVs	Electric Vehicles
FEIWG	Framework for Energy Innovation Working Group
Filing Requirements	Filing Requirements for Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications
FLISR	Fault Location Isolation and Service Restoration
GHG	Greenhouse Gas
ICM	Incremental Capital Module
ICM Projects	Has the meaning ascribed in section 1.1
IESO	Independent Electricity System Operator
LDC	Local Distribution Company
MAADs	Mergers, Amalgamations, Acquisitions and Divestitures
METSCO	METSCO Energy Solutions Inc.
New TS	Has the meaning ascribed in section 5.2
NWAs	Non-Wire Alternatives
OEB	Ontario Energy Board

ROE	Return on Equity
RPPAG	Regional Planning Process Advisory Group
RRR	Reporting and Record Keeping Requirements
TS	Transformer Station
TSC	Transmission System Code
VRZ	Veridian Rate Zone
VVO	Volt/VAR Optimization
WRZ	Whitby Rate Zone
WSG	Whitby Smart Grid Project

1. Executive Summary

1.1. Application Overview

Elexicon Energy Inc. ("**Elexicon**") is applying to the Ontario Energy Board ("**OEB**") under section 78 of the *Ontario Energy Board Act, 1998* seeking approval for changes to its electricity distribution rates to be effective January 1, 2023, and January 1, 2025. This application has been prepared in accordance with the requirements set out in the *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (the "**ACM Report**") to secure incremental capital funding for two Incremental Capital Module ("**ICM**") projects.[1] Elexicon is seeking the following relief:

1. ICM funding of $43.171MMfor the Whitby Smart Grid Project (the "**WSG**"), including a proportionate share of Advanced Distribution Management System ("**ADMS**") and Supervisory Control and Data Acquisition ("**SCADA**") costs, in the Whitby Rate Zone ("**WRZ**");
2. ICM funding of $6.431MM for a proportionate share of the ADMS and SCADA costs of the WSG, in the Veridian Rate Zone ("**VRZ**");[2] and
3. ICM funding of $26.657MM for the Sustainable Brooklin Project in the WRZ and an exemption for the Brooklin Line (as more fully described in Appendix B-2) from Section 3.2 of the Distribution System Code ("**DSC**") (the "**DSC Exemption**"), which would otherwise require Elexicon to collect a capital contribution from the local developers towards the cost of constructing and operating the Brooklin Line. For clarity, approvals for the Sustainable Brooklin Project and DSC Exemption

[1] Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219) dated September 18, 2014.
[2] The Sustainable Brooklin Project is specific only to the WRZ, and as such all capital expenditures have been allocated to the WRZ. The WSG is made up of investments in VVO, FLISR and ADMS, as well as support costs to enable these items. While the VVO and FLISR investments are only applicable to the WRZ, the ADMS component of the Project will apply to both the WRZ and VRZ and will be allocated accordingly.

request are inextricably linked and one should not be approved without the other. (together, the "**ICM Projects**")

The WSG involves the installation of a suite of proven smart grid technologies on Elexicon's distribution system in the WRZ and VRZ, further described below in section 2.3.1. In the Sustainable Brooklin Project, Elexicon will provide capacity to a group of residential developers represented by the Brooklin Landowners Group Inc. (the "**Developers**"). The Developers will in turn construct new homes in Brooklin, Ontario with Distributed Energy Resource ("**DER**") enabling features including rough-ins for solar panels, battery storage and electric vehicles ("**EVs**"). Please see section 2.3.2 for further detail.

Both the WSG and the Sustainable Brooklin Project meet the OEB's well-established eligibility criteria of materiality, need and prudence as provided in the ACM Report. Elexicon addresses these criteria in Sections 3 and 4, below.

Finally, Elexicon is seeking the DSC Exemption in respect of the Brooklin Line. The estimated total capital cost of the Booklin Line component of the Sustainable Brooklin Project is $26.657MM. The OEB should grant the DSC Exemption for the reasons set out below:

1. It will facilitate innovation, specifically the creation of a DER and EV ready community in Brooklin, ON (on both the customer and utility sides of the connection point) and a DER and EV ready grid in the balance of the WRZ as more fully outlined in section 5.1;

2. It will allow Elexicon to credibly pursue opportunities to potentially defer or avoid material capital investments in the future. This has the potential to create ratepayer benefits as more fully outlined in section 5.2;
3. Issues of fairness with respect to the Brooklin Line as more fully explained in section 5.3;
4. It supports Federal, Provincial, and Regional goals to reduce greenhouse gas ("**GHG**") emissions and mitigate climate change as more fully explained in section 5.4.

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.[3] 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.

Elexicon addresses the DSC Exemption request at Section 5, below.

1.2. Summary of Anticipated Benefits

The ICM Projects, when implemented, will deliver real and tangible long-term benefits to WRZ ratepayers. Moreover, the ICM Projects address the expectations of the government of Ontario and the OEB that electricity transmitters and distributors will seek ways to adopt

[3] Source Brooklin Landowners Group Inc.

innovative and cost-saving energy technologies, including DER and EV technologies, as alternatives to investment in traditional wires technologies ("**Non-Wires Alternatives**" or "**NWAs**"). Finally, the ICM Projects respond to the desire of local communities to have a say in the kinds of investments in electricity infrastructure that are made in their service area, to serve their needs. In this regard it is noteworthy that on July 11, 2022, the Whitby Town Council unanimously endorsed the WSG and Sustainable Brooklin Projects. This endorsement and expression of support is consistent with recent messaging by the OEB to the effect that distributors take steps to recognize the investment preferences of local communities.

The WSG and Sustainable Brooklin Projects are anticipated to provide an annual benefit to WRZ customers of $0.673MM[4], which is primarily comprised of the following benefits:

1) **Energy Savings:** Implementation of the WSG will enable Elexicon to pursue conservation voltage reduction across its system, reducing electricity consumption across the WRZ by as much as 3%, resulting in forecast aggregate customer bill reductions of $3.26MM annually;[5]

2) **Customer Reliability Improvements:** The WSG will implement fault location and distribution automation that will improve customer reliability. In the WRZ, SAIFI is expected to improve from 0.87 to 0.28 and SAIDI is expected to improve from 1.03 to 0.45. The estimated annual customer reliability benefits are approximately $1.828MM[6];

[4] Table 1 page 12
[5] Appendix B-1, page 8

3) **Leveraging Private Capital:** The commitment by the Developers to invest approximately $30.4 million over a 20-year period in DER and EV-enabling infrastructure in newly constructed homes in North Brooklin will lower barriers to entry for customers wishing to install DER and EV infrastructure in their newly purchased homes. ICM funding for the Sustainable Brooklin Project will guarantee this investment of private sector capital;

4) **Customer-Specific Benefits**: Greater access to DERs and EVs will create customer-specific benefits including opportunities for rate arbitrage, reduced electricity consumption at the meter, provision of back-up power and a buffer against the volatility of gasoline prices; and,

5) **GHG Reductions:** Reduced electricity consumption will decrease the use of natural gas fired generation for marginal electricity generation, resulting in GHG reductions of approximately [202,977] T CO2e over the next twenty years.[7]

The ICM Projects will also enable and facilitate concentrated uptake of DERs in the WRZ generally, and more particularly in the new community of North Brooklin. As set out in Appendix B-4, to defer upstream capital investments needed for distribution system capacity, approximately 12% of all new customers in the North Brooklin area need to install rooftop solar with battery storage to defer a material capital investment by one year, 39% for a three-year deferral and 53% for a five-year deferral.[8]

The ICM Projects establish the necessary capital infrastructure to allow Elexicon to further explore the creation of two potential programs to incent new DER capacity, as further

[7] Appendix B-1 page 9
[8] Appendix B-4, page 30

discussed in Section 2.3.3 below (the “**DER Enabling Programs**”). The first program would involve traditional marketing, communications and the exploration of the potential for on-bill financing of new DERs. The second program would involve the creation of a local capacity and energy market (modelled on the IESO’s York Region Non-Wires Alternatives Demonstration Project) to financially incent technology-agnostic DER capacity through market-based mechanisms. By facilitating the DER capacity now, it allows Elexicon acting as a distribution system operator (“**DSO**”) to gain sufficient experience with different DER resources to make informed decisions about the viability of these resources as future NWA solutions.

The following table summarizes the net benefits to customers anticipated as a result of the WSG.

Table 1: WSG Net Benefits

Customer Annual Benefit Summary		
(All Dollars Listed in Thousands CAD)		
Cost of Power (WRZ)	$	108,526
Projected % Energy Savings from WSG		3.00%
Total Purchased Power Savings from WSG (A)	$	3,256
ICM Additional Revenue (B)	$	4,120
Additional OM&A Expenses (C)	$	324
Operating Efficiencies from WSG (D)	$	41
Sub-Total of Savings (E = A-B-C+D)	$	(1,147)
Projected VoLL Benefit from Reliability (F)	$	1,820
Annual Net Benefit to WSG Customers (G = E+F)	$	673

Finally, the Sustainable Brooklin Project will lower barriers and costs for customers in North Brooklin to install DERs and EVs through private capital developer investments of up to $30MM over 20 years to construct DER-and-EV-Ready homes[9]. Greater penetration of DERs and EVs has the potential to create system benefits as well as customer-specific benefits. As a first-of-its-kind project, Sustainable Brooklin may also inform future amendments to the Ontario Building Code – potentially making DER and EV ready homes standard for all new housing into the future. Sustainable Brooklin may also address the issue of housing affordability set out in Table 1.

2. Introduction

2.1. Background

Recent developments in government policy, accelerated regional growth forecasts, and maturing innovative technologies present an opportunity for Elexicon to implement an innovative pair of projects that will facilitate grid modernization primarily in the WRZ. The proposed ICM Projects will serve to modernize Elexicon's distribution system to better accommodate DERs and other new technology and deliver important learnings to benefit other utilities in Ontario, particularly other suburban and high growth utilities.

Elexicon's proposal to implement the ICM Projects is made in response to, and consistent with the expectation of the OEB and the government of Ontario that distributors will consider opportunities to invest in NWAs, specifically DER and EV technologies, as alternatives to investments in traditional wires technologies. This expectation has been expressed in various OEB's guidelines, filing requirements, and correspondence with stakeholders and in a renewed Mandate Letter from the Minister of Energy to the OEB, as further discussed below.

2.1.1. Ministry of Energy Mandate Letter

[9] Source Brooklin Landowners Group Inc.

Elexicon considered the Minister of Energy's November 15, 2021 mandate letter to the OEB that articulated the prioritization of innovation and NWAs.[10] The ICM Projects identify Elexicon's efforts to be responsive to the following priorities highlighted in the mandate letter (emphasis added in bold):

- "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."
- "Increased adoption of 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 ("LDC") on system investments to prepare for EV adoption**."
- "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."

[10] Minister of Energy Todd Smith, Renewed Mandate Letter to the Ontario Energy Board, November 15, 2021

2.1.2. OEB's 2023 Filing Requirements for Electricity Distribution Rate Applications

The OEB released the *Filing Requirements for Electricity Distribution Rate Applications-2022 Edition for 2023 Rate Applications* ("**Filing Requirements**"), on May 24, 2022. Section 2.1.7 of the Filing Requirements directs distributors to include a description of the ways in which innovation has shaped their cost-based applications specifically suggesting, "*an explanation of [the distributor's] approach to innovation in its business more generally, or related to specific projects or technologies, including enabling characteristics or constraints in its ability to undertake innovative solutions, for enhancing the provision of distribution services in a way that benefits customers, or facilitating its customer's ability to innovate in how it receives electricity services*."[11]

These ICM Projects, together with the DER Enabling Programs, constitute Elexicon's proposed approach to pursue an innovative suite of solutions in a portion of its service area (i.e., WRZ), with a view to learning from these efforts to adapt the lessons learned to the benefit of customers in its entire service area over time.

2.1.3. OEB's Guidance in Response to the Regional Planning Process Advisory Group ("RPPAG") Report

In the OEB's April 28, 2022 letter to RPPAG titled "OEB Response to RPPAG Recommendations to Improve the Regional Planning Process", the OEB identified plans for a:[12]

[11] Filing Requirements, Section 2.1.7, page 12
[12] EB-2020-0176, OEB Response to RPPAG Recommendations to Improve the Regional Planning Process, April 28, 2022, (LINK >

"New Bulletin to inform communities that they have a choice to opt for a "premium" solution (e.g. DER, rather than wires) to reflect "local preferences" and the cost responsibility for the premium option."

On July 11, 2022, the Whitby Town Council unanimously endorsed the ICM Projects,[13] consistent with the OEB's planned guidance empowering local communities to elect electricity investments which reflect local preferences.

2.1.4. Conservation and Demand Management Guidelines

On December 20, 2021, the OEB issued its Conservation and Demand Management Guidelines for Electricity Distributors (EB-2021-0106) ("**CDM Guidelines**").[14] Under the CDM Guidelines, Elexicon must make reasonable efforts to incorporate consideration of CDM activities into its distribution system planning process to avoid or defer spending on traditional infrastructure.[15]

In the CDM Guidelines, distributors are encouraged to take three key steps to meet this objective:

1) When assessing system needs, provide sufficient lead time to enable consideration of CDM activities.
2) Identify and define the types of system needs where CDM activities have the greatest potential to meet the system need; and

[13] Town of Whitby, Special Council Minutes, July 11, 2022, Council Chambers, (LINK)
[14] EB-2021-0106, Conservation and Demand Management Guidelines for Electricity Distributors, December 20, 2021, (LINK) >
[15] CDM Guidelines at page 6.

3) Ensure a process is in place to consider CDM as a potential solution for these types of system needs and to compare CDM to traditional wires solutions.

Each of these are discussed in turn, below.

2.1.4.1. Assessing System Needs

Significant customer and load growth is expected in Elexicon's service territory. The Durham Region is forecasted to grow from 699,460 people in 2022 to 1.3 million people in 2051 (in addition to businesses providing over 460,000 jobs in the region).[16]

On April 1, 2019, Elexicon was formed. It filed its first consolidated Distribution System Plan ("**DSP**") with the OEB on April 1, 2021 in connection with its 2022 IRM rate application.[17] The DSP was prepared by METSCO Energy Solutions Inc. ("**METSCO**") and included a load forecast covering the period 2020-2030 at Appendix H of the DSP.

For this application, Elexicon asked METSCO to generate an updated load forecast over a longer time horizon (i.e., 2021-2040) than that which was included in its DSP, in order to consider future system needs that may arise over the medium and long-term. METSCO's updated load forecast is attached as Appendix B-4 to this Application. METSCO's analysis concludes that Elexicon is expected to exceed available capacity on its 44 kV system as early as 2030, and to exceed available capacity on both its 44 kV and 27.6 kV system as early as 2036.

With the Sustainable Brooklin Project forecasted to be used and useful in 2023 and the WSG forecasted to be used and useful in 2025, the timing of these investments provides

[16] Durham Region, The Regional Municipality of Durham is one of the fastest growing regions in the world, (LINK)
>
[17] See EB-2021-0015, "Application and Evidence" at Appendix N and O, (LINK)

sufficient lead time for Elexicon to design and implement the DER Enabling Programs and to gain experience managing a significantly increased number of DERs. With the experience gained through the implementation of these projects, Elexicon can make a subsequent evaluation of whether spending on traditional infrastructure can be avoided or deferred in advance of anticipated system needs in the 2030s.

2.1.4.2. Defining the System Needs with the Greatest Potential for CDM Opportunities

In response to the promise of the lower cost and increased capabilities of DERs as alternatives to traditional distribution infrastructure, the Independent Electricity System Operator ("**IESO**") released a white paper exploring models to deploy DERs in a targeted area, sited close to load centres in order to provide local energy and capacity.[18]

The Projects are expected to significantly increase the penetration of DERs in the WRZ. Elexicon retained METSCO to analyze the DER penetration rates that would be required in the North Brooklin area, in order to defer future capacity upgrades (see Appendix B-4 of this Application). METSCO concluded that, in the best case scenario, i.e., one that assumes a DER consists of a 10kWh rooftop solar installation with battery storage, a 12% DER penetration rate is required to achieve a 1-year deferral; 39% for a 3-year deferral; and 53% for a 5-year deferral.

Importantly, as the number of DERs increases in the WRZ, the WSG suite of technologies will help to prevent islanding.[19] The Institute of Electrical and Electronics Engineers

[18] IESO Innovation and Sector Evolution White Paper Series titled *Non-Wires Alternatives Using Energy and Capacity Markets* issued May 2020.
[19] Islanding is where a customer is cut off from the main grid but still getting power from their DER. While the main grid can usually absorb and mitigate any fluctuations in reliability or stability present in DERs, in an islanding situation, there's risk of out-of-range voltages and frequencies. This can lead to poor-quality power for customers, damage customer equipment and, most importantly, put the safety of maintenance crews at risk

("IEEE") code number 1547-2018 recommends that detailed engineering should take place if the total DER presence on a feeder exceeds 33% of minimum load. In general, Elexicon's distribution system can currently only accommodate a maximum of 7.5% DER penetration on any given feeder in the absence of detailed engineering.

2.1.4.3. Ensuring a Process is in Place to Compare DERs to Traditional Wires Solutions

The ICM Projects are intended to increase the suite of tools that Elexicon, as the DSO, has available to manage and allow for DER penetration levels that are sufficient enough to meaningfully avoid or defer future capacity investments. Ensuring a Process is in Place to Compare DERs to Traditional Wires Solutions

The OEB's *Framework for Energy Innovation Working Group*'s ("**FEIWG**") has recently published a series of reports[20] that articulate the need for a process to value the benefits and compare DERs to traditional wires solutions. The first FEIWG work stream sought to "*investigate and support utilities' use of DERs they do not own as alternatives to traditional solutions to meet distribution needs*."

Concurrently, the IESO has released a series of white papers, the Innovation and Sector Evolution White Paper Series, that explore the opportunities of utilizing market-based mechanisms at the distribution level in order to incent technology-neutral cost effective DERs, while also facilitating efficient coordination between distribution and transmission system operators.

One of the planned DER Enabling Programs will be modelled on the successful York Region Non-Wires Alternatives Demonstration Project. Through the NWA project, 15,000

[20] OEB Framework for Energy Innovation Reports July 6, 2022 (Link)

kW of local capacity was procured for the 2022 summer commitment period. This represents 50% more capacity than the previous year and at a price that was 37.5% lower, comparatively.[21] With the most cost effective DER resources being enabled through competitive market-based mechanisms, Elexicon can then compare the efficacy of these DERs resources to replace or defer traditional wires solutions based on actual experience.

2.2. Project Drivers

This is an ideal time for Elexicon to invest in grid modernization and facilitate a future with significantly higher uptake of DERs and EVs, given: i) the timing of load growth from new construction; ii) the willing participation by the Developers; and iii) the need for future electricity supply. As identified above, Elexicon has developed the ICM Projects in response to OEB guidance and direction regarding innovation and the pursuit of NWAs as an alternative to traditional infrastructure. Additionally, the WSG and Sustainable Brooklin Project are responsive to other drivers. The table below describes the drivers for the WSG and Sustainable Brooklin Project, as well as how the Projects are responsive to each of the identified drivers.

[21] IESO York Region Non-Wires Alternatives Demonstration Project, "Post-Auction Report", October 27, 2021(LINK)
IESO York Region Non-Wires Alternatives Demonstration Project, "Post-Auction Report", November 25, 2021 (LINK)

Table 2: Drivers for the Projects

	Project Drivers	Description of Driver	Responsiveness of the Projects to Driver
1	**Ensuring Sufficient Lead Time**	Among other OEB and government guidance, the OEB's CDM Guidelines require distributors "to make reasonable efforts to incorporate consideration of CDM activities into its distribution system planning process to avoid or defer spending on traditional infrastructure."[22]	Elexicon is proposing to significantly modernize its distribution system in the WRZ by 2025 so as to facilitate the integration of high-levels of DERs with sufficient lead time to enable consideration of these resources to defer or avoid a future material upstream capacity investment that could be needed as early as 2030
2	**Facilitating DER Adoption**	As per the IESO, "The cost and capabilities of DERs are improving, making it more technically feasible and economically attractive to procure electricity services from them. One key emerging opportunity is the deployment of DERs as NWAs to traditional transmission and distribution network infrastructure, especially as identified in integrated planning processes."[23]	Both ICM Projects are intended to facilitate DER adoption in the WRZ. As further described in Appendix B-2, in consultation with the Developers, Elexicon has an opportunity to facilitate the creation of a new residential community with elevated levels of DER and EV penetration through the construction of DER and EV ready homes. Facilitating this outcome will require regulatory innovation and the approval of an exemption to section 3.2 of the DSC, as well as the deployment of technologies included within the WSG.

[22] Conservation and Demand Management Guidelines for Electricity Distributors (EB-2021-0106) issued December 20, 2021 at page 8.
[23] IESO *Non-Wires Alternatives Using Energy and Capacity Markets* White Paper issued May 2020.

	Project Drivers	Description of Driver	Responsiveness of the Projects to Driver
3	**Storm Hardening and Ensuring WRZ's Reliability**	Ontario's communities are experiencing a significant increase in volatile or severe weather. In the spring of 2022, Elexicon's customers experienced a derecho as well as an EF2 tornado which touched down in their service territory, causing significant damage to infrastructure and a long duration power outage. Ontario's communities and electricity sector have been asked to put in place, asset management strategies that harden their infrastructure to minimize customer outages.	As a step-change to its storm-hardening, Elexicon's WSG will deploy technologies to the WRZ that will monitor for faults within its grid, and when a fault or loss of power signal is received, isolate the segment in fault and restore power to the segments that are not in fault.
4	**Significant Regional Growth**	Elexicon's service territory and the WRZ have experienced, and are anticipated to continue experiencing, significant customer and load growth. Today, Durham Region is home to 699,460 people. By the year 2051, the population is expected to grow to 1.3 million people, with over 460,000 jobs in the region.[24] At the same time, the lack of affordability of housing in Ontario is one of the most pressing issues facing the province. The Report of the Ontario Housing Affordability Task Force states that the province must set an ambitious and bold goal to build 1.5 million homes over the next 10 years.[25]	Elexicon has retained METSCO to model the implications of this significant growth on its electrical distribution system – the results of this modelling is set out in Appendix B-4. In summary, and as more fully set out in Appendix B-4, based on regional growth forecasts Elexicon's 44-kV-system is expected to exceed capacity by 2030, and if load can be balanced between the 27.6-kV and 44-kV systems, then the whole system is forecast to exceed capacity in 2036. The Projects facilitate greater uptake of DERs, with the potential to defer material capital investments anticipated in the 2030's

[24] Durham Region, The Regional Municipality of Durham is one of the fastest growing regions in the world, (LINK)
[25] Report of the Ontario Housing Affordability Task Force, February 8, 2022 at page 8, (LINK)

	Project Drivers	Description of Driver	Responsiveness of the Projects to Driver
5	**NRCan Funding for Advanced Distribution Management System (ADMS)**	As described in Appendix B-1, over the course of late 2021 and early 2022 Elexicon secured approximately $4 million in NRCan funding to deploy an ADMS. The ADMS serves as the backbone of the WSG; incrementally facilitating a variety of technologies such as VVO, FLISR, Advanced Metering Infrastructure (AMI), and Distributed Energy Resource Management Systems (DERMS).	Elexicon submits that an ADMS investment can be maximized where it is paired with complimentary technologies bearing additional and immediate customer benefits, such as VVO (conservation benefits) and FLISR/DA (reliability benefits). The Projects maximize the benefits of funding secured from NRCan and ensure that grid modernization takes place within the timeline required for funding by NRCan. In addition, Elexicon will continue to pursue opportunities for further funding for the ICM Projects.
6	**OEB's Framework for Energy Innovation Working Group's**	The working group's first workstream sought to "investigate and support utilities' use of DERs they do not own as alternatives to traditional solutions to meet distribution needs."	The Projects are responsive to this objective, and are also responsive to the FEIWG's Report to the Ontario Energy Board.

In order to cohesively and comprehensively address the drivers listed above in a manner consistent with OEB guidance, Elexicon requires approval of the WSG and Sustainable Brooklin Projects. Beyond responding to the near-term drivers listed above, the Projects will begin Elexicon's transition toward the "Grid of the Future".

Figure 1 below, depicts the investments in distribution assets (as currently identified) that are required in order to facilitate implementation of the "Grid of the Future." All distributors are striving to achieve this end state. The Projects proposed in this Application, once implemented, will establish the trunk of Elexicon's Grid of the Future and capture the low-hanging fruit of energy savings, reliability improvements, and GHG reductions, all for the benefit of customers. These initial steps will position Elexicon for measured and effective grid modernization in the coming decade and, ultimately, lead to the creation of a dynamic, flexible, affordable, and reliable Grid of the Future.

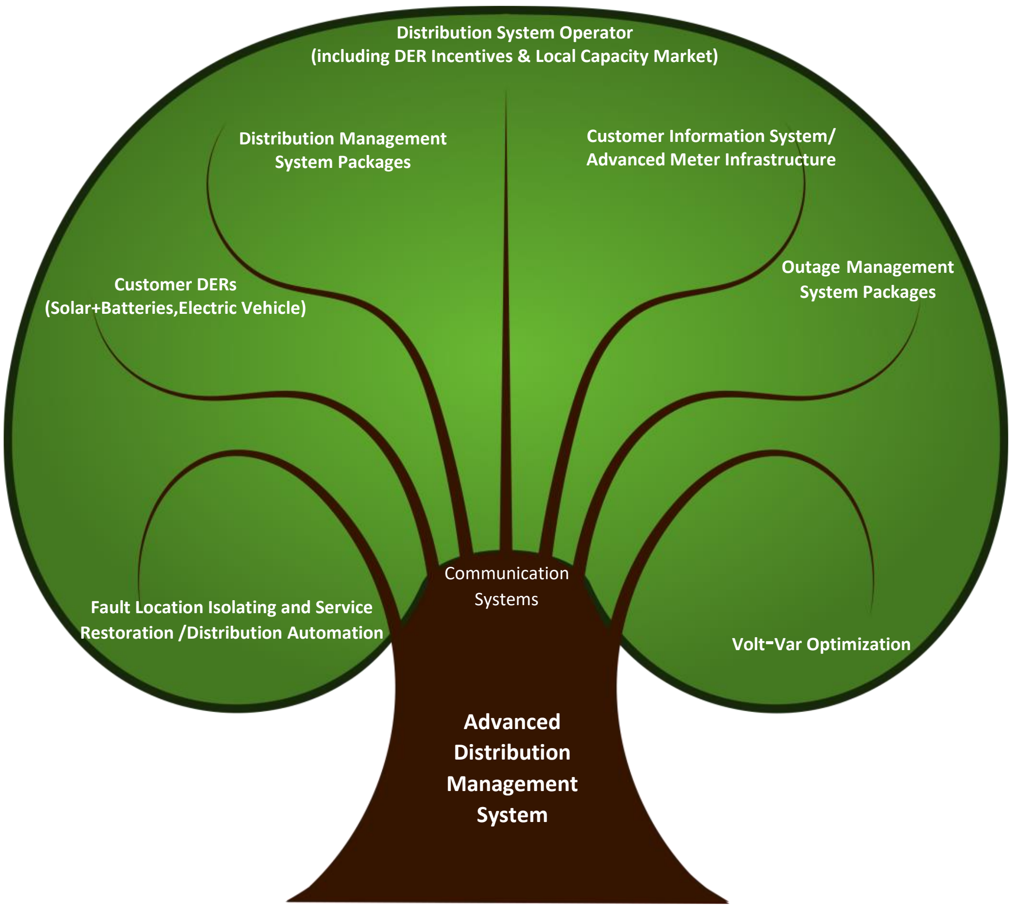


Figure 1: Grid of the Future Tree

2.3. Project Descriptions

2.3.1. WSG Project

The WSG represents the critical first step towards the modernization of Elexicon's distribution system to facilitate innovative and new technology, such as DERs, to service a portion of the electricity demand in the WRZ and VRZ. The components that comprise the WSG include the ADMS, Volt-Var Optimization ("**VVO**"), and Fault Location and Isolation Service Restoration ("**FLISR**").

Elexicon chose to focus the WSG in the WRZ at this time given the advantage of the geographical continuity of the service area in the WRZ relative to the geographical discontinuity of the service area in the VRZ.

However, Elexicon does not intend to limit the use of the ADMS to the WRZ only, but rather it intends to maximize the benefits of this technology across both rate zones.

Accordingly, the ICM funding request pairs the costs of deploying these technologies with the ratepayers that will obtain the benefits of such improvements. The WSG will be placed into service in Q4 of 2025. The estimated total capital cost of the WSG, less NRCan funding, is $43.172MM.

Please see Appendix B-1: WSG Business Case for additional detail.

2.3.2. Sustainable Brooklin

Sustainable Brooklin provides an opportunity to facilitate the creation of a new construction community with the potential for significantly higher penetration levels of DERs and EVs relative to existing or proposed residential neighbourhoods. The Sustainable Brooklin community is forecasting 700+ DER and EV ready homes per year starting in Q4, 2023[26].

[26] Source Brooklin Landowners Group Inc.

The Sustainable Brooklin Project leverages the technologies embedded within the WSG to facilitate residential DER adoption and includes the following core elements:

a. **The Brooklin Line:** In order to proceed with the Sustainable Brooklin Project and secure the commitment of the Developers to construct DER-enabling and EV charging elements as part of their basic, new-build offering, Elexicon will construct two new 27.6 kV feeders connecting the new load at North Brooklin to the available capacity at Whitby TS DESN 1. Initially, each of the pole lines will be strung with a single circuit, but will have the capacity to accommodate three circuits each, in anticipation of planned future growth.
b. **DER-and-EV-Ready Homes:** The Developers commit (secured by binding agreement or conditions in related regulatory approvals) to constructing all new residential homes as "DER-and-EV-Ready" homes including rough-ins and conduit within walls, electrical panels, garages, and elsewhere needed to accommodate roof-mounted solar photovoltaic installations, battery storage and EV charging. Even if the homeowner does not elect to incorporate DERs into a new home, such measures will incent homeowners to install DERs in the future, as the rough-ins will allow for the installation of solar, battery storage and EV equipment without expensive home retrofits usually required for running new electrical wires in the home. Over the course of the entire development, the Developers estimate construction of 10,000 to 11,200 homes to this standard, translating into an investment by the Developers and other developers of between $20 to $30MM over the course of 20 years[27].

[27] IBID.

Sustainable Brooklin is currently scheduled to become used and useful in Q3 of 2023, to be ready in time for the energization of the first new homes. The estimated total capital cost of the Sustainable Brooklin Project is $26.6MM.

Please see Appendix B-2: Sustainable Brooklin Business Case for additional detail.

2.3.3. DER Enabling Program & Local Capacity Market

As discussed above, Elexicon is currently considering two DER Enabling Programs to incent incremental DER capacity. The first would be modelled on a typical CDM marketing program, with a focus on promoting the benefits of new DERs, and may include the exploration of potential on-bill financing opportunities. The second would explore the creation of local capacity and energy markets modelled on the successful York Region Non-Wires Alternatives Demonstration Project.

The underlying objective of these two programs will be to facilitate technology-agnostic DER capacity through market-based mechanisms, in order to gain sufficient experience with these DER resources. Through the programs, Elexicon will better understand their reliability, will be able to report on observed customer benefits, and will be positioned to make an informed decisions about future NWA solutions.

Elexicon's ability to meaningfully pursue the DER Enabling Programs will be determined in part by whether or not the OEB approves the ICM Projects in this Application. Together, the above-described measures will enhance and increase the long-term benefits accruing to Elexicon ratepayers, and to Ontario's electricity sector, more generally.

Please see Appendix B-3: DER Enabling Program & Local Capacity Market for additional detail. Elexicon notes that it is still considering whether to file an application with the OEB under the *Conservation and Demand Management Guidelines for Electricity Distributors* for one or both of these DER Enabling Programs. The final details of these programs have not yet been determined and the discussion in Appendix B-3 is provided on a preliminary basis.

2.4. Customer Engagement

2.4.1. 2021 Distribution System Planning Customer Engagement

In connection with its 2022 IRM rate application, Elexicon filed a Customer Engagement Report on April 28, 2021. Elexicon has leveraged this recent engagement effort to identify customer needs and preferences to inform the development of the ICM Projects and this Application. The Customer Engagement Report can be found in Appendix B-7.

In the Customer Engagement Report, Elexicon presented customers with eight potential objectives; asking customers to identify how Elexicon should focus its investments. The results of this engagement are shown below:[28]

[28] DSP, PDF page 1046

Table 3: Customer Engagement Survey Results

Q15. Please select two potential objectives from the following list that you think Elexicon should focus its efforts on in addition to keeping the system safe and accommodating new growth in the coming years.

Q15. FIRST CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	192	32.0
Preparing the grid for new types of uses, like electric vehicles and renewable generation	133	22.2
Investing now in things that will help reduce rate increases after 2029	73	12.2
Helping customers manage their electricity use	65	10.8
Reducing the environmental impact of Elexicon's operations	63	10.5
Minimizing the impact of power outages	37	6.2
Improving power quality	24	4.0
Addressing customer requests faster and more efficiently	13	2.2
Total	600	100.0

Q15. SECOND CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	182	30.3
Minimizing the impact of power outages	121	20.2
Investing now in things that will help reduce rate increases after 2029	120	20.0
Preparing the grid for new types of uses, like electric vehicles and renewable generation	69	11.5
Helping customers manage their electricity use	51	8.5
Reducing the environmental impact of Elexicon's operations	30	5.0
Improving power quality	20	3.3
Addressing customer requests faster and more efficiently	7	1.2
Total	600	100.0

The results above indicate that the primary concern of customers is "improving the grid's resilience to major weather events" and placed some emphasis on "minimizing the impact of power outages." The technologies embedded within the WSG address these customer concerns by helping Elexicon manage outages, however caused, to minimize the number of affected customers and minimize restoration time for affected customers.

At the same time, investment in Sustainable Brooklin and the enabling WSG will facilitate greater uptake of DERs including renewables, storage and EV chargers. Elexicon expects customers' sensitivity to weather driven outages increased since completion of this customer engagement as a result of the derecho and EF2 tornado that touched down in Elexicon's service area.

Customer engagement also indicated that there was strong support for Elexicon *“investing now in things that will help reduce rate increases after 2029”*, and *“preparing the grid for new types of uses such as EVs and renewable generation*”. The WSG creates a unique opportunity to implement conservation-based voltage reductions to facilitate a 3% decrease in energy bills that would persist past 2029. In addition, the ICM Projects, together with the planned DER Enabling Programs, are intended to create a credible opportunity for Elexicon to potentially defer material capital investments that are otherwise expected to be needed in the 2030’s. Finally, the ICM Projects are directly responsive to the preferences of customers; enabling greater EV and DER uptake which may not be efficiently managed by Elexicon’s current distribution system.

Other results from the Customer Engagement Report show that 76% of customers were highly supportive or somewhat supportive of Elexicon “investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage.”[29] Further, 47% of customers responded that they were very likely or somewhat likely to purchase an EV.[30]

2.4.2. Direct Customer Engagement

On July 11, 2022, Elexicon presented the ICM Projects to Whitby Town Council. In that meeting Elexicon provided the scope, drivers, needs, benefits, costs, and anticipated bill impacts to customers. Whitby Town Council voted and unanimously supported this application to the OEB for the ICM Projects. A discussion occurred between Members of Council regarding:[31]

[29] DSP, PDF 1046
[30] DSP, PDF 1019
[31] Supra note 13.

- the importance of ensuring a responsible, innovative and robust electrical distribution system to support the needs of the community, including the ability to address future storm events; and,
- the benefits of Whitby Smart Grid and Sustainable Brooklin to community members, including the ability to support green initiatives, new housing development, and the growing number of electric vehicles in Whitby.

Subsequently, on July 19, 2022 the Regional Municipality of Durham filed a letter **to the registrar@oeb.ca** in support of this application.

Elexicon puts significant stock on the decision of elected officials to endorse the WSG and Sustainable Brooklin Projects. Elexicon notes this aligns with the OEB's pending Bulletin, referred to in section 2.1.3, that communities have an opportunity to endorse system investments which may be 'premium' relative to traditional investments, but reflect the needs, values, and priorities of those communities.

Please see Appendix B-6: Letters of Support for ICM Application for additional detail.

3. ICM Eligibility

On July 30, 2018 Veridian Connections Inc. and Whitby Hydro Electric Corporation filed a Mergers, Amalgamations, Acquisitions and Divestitures **("MAADs**") application with the OEB seeking approval to amalgamate and form a single electricity distributor.[32] In Decision EB-2018-0236, the OEB found that consistent with the *Handbook to Electricity*

[32] OEB Decision EB-2018-0236, Application for approval to amalgamate Veridian Connections Inc. and Whitby Hydro Electric Corporation and continue operations as a single electricity distribution company. December 20, 2018, (LINK)

Distributor and Transmitter Consolidations,[33] the newly amalgamated LDC would be able to apply for an ICM during the deferred rate rebasing period. On April 1, 2021, Elexicon filed its first consolidated DSP considering the entirety of the amalgamated entity's service territory, in accordance with the OEB Decision EB-2018-0236.

On December 16, 2021, the WRZ 2022 rates were set based on the Annual IR option and the VRZ rates were set based on the Price Cap Incentive Rate-setting option, which represents two of three incentive rate-setting mechanisms approved by the OEB.[34] Distributers are eligible to apply for ICMs if they are on a Price Cap Incentive Rate-setting plan or an Annual Incentive Rate-setting plan provided they are also in a MAADs deferred rebasing period.[35] Accordingly, Elexicon is eligible to apply for ICM funding within the WRZ and VRZ.

In preparing this application, Elexicon has followed the instructions provided in:

- the Appendix of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* dated July 14, 2008;
- Appendix B of the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-0673) dated September 17, 2008;
- Addendum to the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-0673) dated January 28, 2009;
- the ACM Report;

[33] OEB Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, (LINK)
[34] EB-2021-0015
[35] OEB, Incremental Capital Modules During Extended Deferred Rebasing Periods, February 10, 2022, (LINK)

- the *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219) dated January 22, 2016;
- Chapter 3 of the Filing Requirements; and
- OEB Letter on *Incremental Capital Modules During Extended Deferred Rebasing Periods* issued February 10, 2022.

In order to be eligible for incremental capital, an ICM claim must be incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates. It must also satisfy the eligibility criteria of materiality, need and prudence set out in section 4.1.5 of the ACM Report. These criteria are discussed in detail below for the ICM Projects.

Elexicon has completed the OEB's Capital Module applicable to ACM and ICM, with respect to the Sustainable Brooklin Project; a live excel model has also been filed with this application. With respect to the WSG, Elexicon has utilized the 2023 ICM model to complete preliminary, illustrative analyses regarding rate riders and bill impacts as presented in this Application. As further described in section 4.1.1, Elexicon will place the WSG into service in 2025. Elexicon proposes to update and finalize 2025 rate riders and bill impacts relating to the WSG within its 2025 IRM application.

3.1. Materiality

The ACM Report sets out two materiality tests:

Materiality Threshold

A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.

Project-Specific Materiality Test

Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.

3.1.1. Materiality Threshold & Maximum Eligible Incremental Capital

The first step requires that the ICM capital exceeds the ICM "materiality threshold formula", which serves to define the level of capital expenditures that a distributor should be able to manage within current rates. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operations of the distributor:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

Where;

RB = rate base from distributor's last cost of service application

d = deprecation expense from distributions last cost of service application

g = calculated based on the percentage difference in distribution revenues between the distribution revenues from the most recent complete year and the distribution revenues from the most recent approved test year

PCI = Price Cap Index from the distributors most recent Price Cap IR application as a placeholder for the initial application filing and will updated if new parameters become available during the course of the proceeding

n= number of years since the last rebasing

X = dead band set at 10%

For the period of 2023 to 2025, the following materiality thresholds have been calculated for the WRZ and VRZ utilizing the OEB's 2023 Capital Module Applicable for ACM and ICM – Version 1.0, issued May 27, 2022.

Table 4: Materiality Thresholds for WRZ and VRZ (2023 – 2025)

Year	Materiality Threshold) ($ Thousands)	
	WRZ	VRZ
2023	$ 10,182	$ 23,452
2024	$ 10,385	$ 23,844
2025	$ 10,596	$ 24,249

The costs of the Sustainable Brooklin Project are to be allocated entirely to the WRZ with an in-service date in Q3 of 2023. The majority of the WSG costs are also to be allocated to the WRZ, however the costs of the ADMS and SCADA will be proportionately allocated to both the WRZ and VRZ. The WSG has an in-service date in Q4 of 2025. As such, Elexicon has calculated the following Maximum Eligible Incremental Capital amounts for the WRZ and VRZ, in 2023 and 2025 as applicable:

Table 5: Maximum Eligible Incremental Capital for WRZ in 2023

Item	Amount ($ Thousands)
2023 Capital Forecast (WRZ)	$ 39,712
Less: Materiality Threshold	$ 10,182
Maximum Eligible Incremental Capital (WRZ 2023)	$ 29,530

Table 6: Maximum Eligible Incremental Capital for WRZ in 2025

Item	Amount ($ Thousands)
2025 Capital Forecast (WRZ)	$ 48,582
Less: Materiality Threshold	$ 10,596
Maximum Eligible Incremental Capital (WRZ 2025)	$ 37,985

Table 7: Maximum Eligible Incremental Capital for VRZ in 2025

Item	Amount ($ Thousands)
2025 Capital Forecast (VRZ)	$ 37,330
Less: Materiality Threshold	$ 24,249
Maximum Eligible Incremental Capital (VRZ 2025)	$ 13,080

With respect to the VRZ, Elexicon's forecast capital expenditures in 2025, absent the ADMS and SCADA component of the WSG, already exceeds the materiality threshold for the VRZ by over $3MM. Elexicon's VRZ ICM request relates only to the ADMS and SCADA portion of the WSG at a cost of $6.431MM, and as such Elexicon is not seeking the maximum eligible incremental capital for the VRZ in 2025. With respect to the WRZ in both 2023 and 2025, Elexicon is seeking the maximum eligible incremental capital for recovery.

3.1.2. Project-Specific Materiality Threshold

The second step requires application of a project-specific materiality test which provides that minor expenditures, in comparison to the overall capital budget, should be considered ineligible for ICM treatment. Moreover, a certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.

Whether looking at the WSG or Sustainable Brooklin Project individually, or the ICM Projects as a whole, it is clear that Elexicon's proposed Projects are eligible for ICM treatment.

As noted, the costs of the Sustainable Brooklin and WSG to the WRZ and VRZ in 2023 and 2025 respectively are as follows:

Table 8: Eligible Capital Projects (WRZ & VRZ: 2023 & 2025)

Project & Year	Net Capital Additions (WRZ) ($ Thousands)	Net Capital Additions (VRZ) ($ Thousands)	Total Net Capital Additions ($ Thousands)
Sustainable Brooklin (2023)	$26,657	N/A	$26,657
WSG (2025)	$36,739	$6,431	$43,171

When comparing the Projects to the net capital expenditures of either rate zone or Elexicon as a whole, the amounts in question meet the materiality criterion.

3.2. Need

In order to qualify for ICM funding for a particular project, a distributor must demonstrate that there is a need for the incremental funding. The OEB's ACM Report requires a three-fold test to demonstrate need:

- The distributor must pass the Means Test.
- Amounts must be based on discrete projects and should be directly related to the claimed driver.
- The amounts must be clearly outside of the base upon which rates were derived.[36]

3.2.1. Means Test (Part 1)

If a distributor's most recently available regulated return on equity ("**ROE**") exceeds 300 basis points above the deemed ROE embedded in the distributor's rates, then funding for any incremental capital project would not be allowed.

Elexicon's 2021 ROE was as follows:

Achieved: 6.87%
Deemed: 9.43%
Difference -2.56%

Elexicon's 2021 ROE was calculated on a consolidated basis using the weighted average of the OEB-approved deemed equity ratio amount for each rate zone, from the most recent OEB–approved rebasing application for both Veridian and Whitby Hydro. As Elexicon's regulated return does not exceed 300 basis points above the deemed ROE, Elexicon meets the Means Test.

[36] ACM Report, page 17

3.2.2. Discrete Project and Unfunded Through Base Rates (Parts 2 and 3)

The drivers for the ICM Projects are set out in sections 2.1, 2.2, and 2.4.1 above.

3.2.2.1. WSG

The WSG is outside of the base upon which current rates were derived and the incremental capital amount being requested in this Application is directly related to the cost of deploying the WSG. It is a novel project and therefore not part of an ongoing capital program. The WSG is a discrete project, which directly relates to the claimed drivers, and the amount requested is unfunded through base rates.

3.2.2.2. Sustainable Brooklin

The Sustainable Brooklin Project is outside of the base upon which current rates were derived and the incremental capital amount being requested in this application is directly related to the cost of deploying the Sustainable Brooklin Project. It is a novel project and therefore not part of an ongoing capital program. The Sustainable Brooklin Project is a discrete project, directly relates to the claimed drivers and the amount requested is unfunded through base rates.

4. Prudence

A distributor needs to establish that the incremental capital amount it proposes to incur is prudent. In order to satisfy the prudence test, a distributor must demonstrate that its decision to incur the incremental capital represents the most cost-effective option for its customers (though, not necessarily the least initial cost option).

Prudency requires that Elexicon not only plan and grow its system to accommodate the forecasted load growth, but also take steps to maximize the capabilities of its current assets and to explore opportunities to defer traditional distribution investments. For the reasons that follow, Elexicon selected ICM Projects that are the most prudent options.

4.1. Assessment of Alternatives

Appendices B-1and B-2 provide a comprehensive assessment of the alternatives evaluated for the WSG and Sustainable Brooklin Project, respectively. What follows are brief summaries of the outcomes of those assessments.

4.1.1. WSG

Elexicon identified 3 alternatives with respect to the WSG:

1. Deployment of WSG by 2025, with funding through this ICM application (**preferred**);
2. Deployment of WSG by the end of 2028, using Elexicon's existing capital expenditure allocation; and,
3. Do nothing and do not pursue the WSG.

Elexicon determined that the prudent option is to implement the WSG with an in-service date in Q4 of 2025, facilitated by this ICM application.

Option 1 is the preferred option for the WSG. It has the dual benefit of immediately providing energy consumption reductions (up to 3%) and improved reliability (estimated reliability benefits of $ 1,819MM) for WRZ customers, while also facilitating greater uptake of EVs and DERs in the future. The public policy guidance outlined in section 2.1, as well as customer preferences identified in section 2.4, suggest that a transition in consumer energy patterns, volumes, and fuel-choice is already beginning, and is set to accelerate over the course of the next decade. Failing to invest in required system upgrades now to facilitate this transition will result in either Elexicon's system standing in the way of customer and policy driven market changes, or Elexicon being required to make suboptimal investments at a later date to 'catch-up' to the market, at a greater cost to ratepayers. Market and policy forces are driving changes within the energy system that will modify customer behaviour such as electricity consumption, energy use patterns, and types of facilities connected to Elexicon's distribution system.

Option 2 was rejected for several reasons. First, Elexicon secured approximately $4MM in funding from NRCan relating to the WSG under an agreement which expires in 2025. As a result, elongating the deployment of the WSG puts at risk Elexicon's access to these funds, which would significantly increase the cost of the Project to ratepayers. Second, the WSG as an investment is simply too large for Elexicon to accommodate within its existing capital envelope. Attempts to fund the Project out of existing rates would have unacceptable impacts to the slate of other necessary capital investments required up to 2028. Absent incremental funding, Elexicon would be unable to implement the WSG.

Option 3 was also rejected. This option fails to follow good utility practice and properly manage known capacity constraints on the distribution system that are expected to arise in the early 2030's. It also fails to meet the OEB's expectation that distributors "make reasonable efforts to incorporate consideration of CDM activities into its distribution system planning process to avoid or defer spending on traditional infrastructure."[37] Absent the WSG, Elexicon would encounter difficulty managing operational challenges resulting from increasing DER and EV uptake. Finally, this option was dismissed because it fails to respond to anticipated changes in customers' energy use and interaction with the grid, and fails to respond to customer feedback that was received as part of the Customer Engagement Report.

[37] Conservation and Demand Management Guidelines for Electricity Distributors (EB-2021-0106) issued December 20, 2021 at page 8.

4.1.2. Sustainable Brooklin

Elexicon identified 4 alternatives with respect to the Sustainable Brooklin Project:

1. Extend feeders from Whitby TS DESN 1 to serve the North Brooklin area, with funding through this ICM, and with the WSG enabling DER integration capability (**preferred**);
2. Proceed with system enhancement by extending the feeders from Whitby TS DESN 1 to serve the North Brooklin area with developers paying a capital contribution as per the DSC, with the extension of the duration of capital contribution period from 5 years to 15 years;
3. Build a new TS to serve the North Brooklin area, funded by Elexicon's existing rates; and,
4. Utilize existing 44kV feeders to the North Brooklin area, funded by Elexicon's existing rates.

Elexicon determined that the prudent option is to proceed with the proposed Brooklin Line from Whitby TS to North Brooklin, funded via this ICM application, while the WSG enables DER integration capabilities for anticipated DER uptake in North Brooklin.

Option 1 is the preferred option for Sustainable Brooklin. Participation by the Developers in the design of Elexicon's distribution system to facilitate the development of a DER-and-EV-Ready community is a highly innovative and unique opportunity. Electing this option would result in over 10,000 concentrated residential units which could have been future-proofed for DERs and EVs, being constructed status quo; meaning future uptake of these technologies would require costly retrofits paid for by customers.

Option 2 was rejected as suboptimal for two reasons. First, absent the DSC section 3.2 exemption, the Developers would otherwise be required to pay a capital contribution for construction of the Brooklin Line and the developers would no longer be willing to commit to invest in building DER and EV ready homes across all of North Brooklin. This will likely result in lower DER and EV penetration rates, and may be a lost opportunity for Elexicon, the OEB and other LDCs to observe and gather information about the ICM Projects to defer or avoid future material capital expenditures through greater uptake of DERs.

Option 3 was rejected for two reasons. First, development and construction of a TS takes considerable time (measured in years), especially given the supply chain issues that have resulted from COVID-19, and would not bring capacity in time to serve the immediate need for power to facilitate the construction of new homes and businesses in the Brooklin area. Second, a new TS is not the most cost-effective option for ratepayers when compared with the Brooklin Line. Elexicon has capacity available at Whitby TS DESN 1 that can be brought to the Brooklin area via the Brooklin Line, which is approximately half the cost of a new TS.

Option 4 was also rejected. Naturally, one of the immediate options evaluated by Elexicon was to provide capacity from existing assets proximate to North Brooklin; namely existing 44kV feeders in the area. Typically, Elexicon reserves 44kV feeder capacity for commercial and industrial customers that do not require a substation step-down to 13.8kV as residential customers do. In this case, while capacity does exist on local 44kV feeders today, this capacity has already been reserved for known commercial and industrial load under development south of the 407 highway. This option was dismissed and not subject to detailed costing as it is not technically feasible.

5. Distribution System Code Exemption Request

Section 3.2 of the DSC contains principles that distributors must consider when connecting customers. If a distributor connects new customer facilities, the DSC requires the distributor to perform an economic evaluation of the project (in accordance with Appendix B of the DSC) to determine whether the future revenue from the customer will pay for the capital cost and ongoing maintenance costs of the expansion project. If a revenue shortfall is calculated in the difference between the (a) present value of the projected capital costs and ongoing maintenance costs for the equipment; and (b) the present value of the projected revenue for distribution services provided by those facilities, the distributor may propose to collect all or a portion of that amount from the customer by way of a capital contribution.

The Developers anticipate that the construction of new homes in North Brooklin area will occur in several phases over the next 20 years. Elexicon forecasts that the cost for the first phase of the Brooklin Line is approximately $26.6MM and subsequent phases will be substantially cheaper as Elexicon would only need to string additional circuits on the existing poles. Appendix B of the DSC limits the customer connection horizon to five years and the customer revenue horizon to twenty-five years when forecasting revenue for determining the quantum of capital contribution paid. Given that many of the customers to be served by the Brooklin Line will connect beyond the customer connection horizon of five years, a standard capital contribution calculation results in the Developers paying the majority of costs for the Brooklin Line through a capital contribution.

While the Developers have previously paid capital contributions for the connection of new neighbourhoods in other areas of Ontario, the magnitude of the capital contribution required for the Brooklin Line is not common.[38] Absent the DSC Exemption, the Developers are concerned that construction of both the Brooklin Line and new homes in North Brooklin area will be delayed by several years while the Developers raise financing for the capital contribution.

In order to address these concerns, Elexicon and the Developers created the innovative Sustainable Brooklin Project to meet the needs, preferences and goals of customers, the OEB, the Ministry of Energy, Developers and Elexicon. In exchange, the Developers are willing to construct DER-and-EV-Ready homes in the North Brooklin community (as set out in section 2.3.2). The estimated incremental cost per home for the Sustainable Brooklin Project is $2,260; resulting in an expected investment from the Developers of $20 to $30.4MM over the course of 20 years.

[38] By way of example, the recently approved Seaton TS was built in large part to support significant regional new construction. No capital contributions were required to facilitate construction of the Seaton TS

Figure 2: Developers Forecast of Number of Rough-In's and Cost

North Brooklin Community EV and Solar Rough-In Cost Estimate

EV and Solar Rough-In Cost for all Low and Medium density residential units in North Brooklin

Unit Type	Low Units Estimate	High Unit Estimate	Rough In Cost/Unit (incl. HST)	Low Cost	High Cost
Single and Semi Detached	5,984	6,332	$ 2,260	$ 13,523,840	$ 14,310,320
Row	4,097	4,885	$ 2,260	$ 9,259,220	$ 11,040,100
Total	**10,081**	**11,217**	-	**$ 22,783,060**	**$ 25,350,420**
			20% Increase Estimate	**$ 27,339,672**	**$ 30,420,504**

EV and Solar Rough-In Cost BNLG Participating Owners Low and Medium density residential units in North Brooklin

	Low Units Estimate	High Unit Estimate	Rough In Cost/Unit (incl. HST)	Low Cost	High Cost
Single and Semi Detached	5,265	5,447	$ 2,260	$ 11,898,900	$ 12,310,220
Row	3,523	3,839	$ 2,260	$ 7,961,980	$ 8,676,140
Total	**8,788**	**9,286**	-	**$ 19,860,880**	**$ 20,986,360**
			20% Increase Estimate	**$ 23,833,056**	**$ 25,183,632**

Prepared by: MGP Malone Given Parsons

13-Jun-22

The net result of this arrangement is the creation of an innovative new construction community in North Brooklin that will have substantially higher levels of DER and EV uptake than would otherwise be the case. These results would be further improved through the rollout of a DER Enabling Program and Local Markets, as described in Appendix B-3 as the subject of a future Elexicon application. The parameters of DER-and-EV-Ready homes are proposed to be as follows:

1. **All residences will be storage-ready to facilitate DERs including in-home battery storage:** This involves; (i) conduit from the circuit panel to the attic to allow for wiring a solar panel; (ii) two spare breaker slots; and (iii) sufficient space on the wall next to the circuit panel to install solar controls and an inverter. Where the roof size and orientation is suitable, developers will offer customers the option to purchase and install solar panels and related inverter and controls. Developers will offer home-buyers the option to purchase and install a battery storage system (e.g. Tesla, Panasonic or LG);

2. **All residences will be constructed to be EV-ready:** This will involve electrical conduit from the circuit panel to the likely location of an EV charger, with a plate at the point of a future installation, room on the wall for the charger, and appropriate room in the circuit panel for a breaker. Developers will offer customers the option to purchase and install either a unidirectional or a bidirectional 240V EV charger. Both can be used for fast charging of electric vehicles, but the bidirectional charger can be used as additional battery storage for the home or to participate in future grid interoperability initiatives facilitated by Elexicon.

5.1. Facilitating Innovation and DER-EV Uptake

An exemption to Section 3.2 of the DSC and approval of the Sustainable Brooklin Project ICM request will facilitate innovation, specifically the creation of a DER and EV ready community in North Brooklin (on both the customer and utility side of the connection point) and a DER and EV ready grid in the balance of the Whitby rate zone via the WSG.

Absent the DSC Exemption, the Developers would otherwise be required to pay a capital contribution for construction of the Brooklin Line and the Developers would no longer be willing to commit to invest in building DER and EV ready homes across all of North Brooklin. This would be a lost opportunity for WRZ customers to save on electricity costs, for Elexicon's operations and engineering teams to learn from the mass deployment of innovative technologies, and for Ontario's electricity sector to gain from the learnings achieved by the Sustainable Brooklin Project.

Homeowners that are not able to purchase DER-and-EV-Ready homes are forced to undergo expensive retrofits to accommodate the installation of Solar PV, battery storage, or electric vehicle charging infrastructure. This will result in greater costs for customers, and lower uptake of DERs and EVs, resulting in lost opportunities to:

i. Secure the long-term distribution system and rate benefits discussed throughout this application;
ii. Lower GHG emissions;
iii. Empower customers with back-up power facilities;
iv. Empower customers with net-metering and other revenue generating opportunities; and,
v. Protect consumers from the variability of gasoline prices and increasing carbon prices.

Combined with the proposed WSG, the DSC Exemption will facilitate an accelerated penetration of DER's and EVs in North Brooklin by removing barriers to entry on both the customer and Elexicon side of the connection point. Beyond North Brooklin, Elexicon will gain the experience required to facilitate broader deployment of DERs and EVs across its service area and optimize the operation of its distribution system long-term.

5.2. Opportunities to Defer Infrastructure Investments

Approval of the Sustainable Brooklin DSC Exemption and ICM Request will allow Elexicon to credibly pursue opportunities to defer or avoid material capital investments in the future; this has the potential to create significant ratepayer benefits.

As stated in section 2.1.4.1, Elexicon's service territory, including the WRZ, have experienced and are anticipated to continue experiencing, significant customer and load growth. Current growth forecasts suggest the need for a new regional supply point ("**New TS**") in the early-to-mid 2030's; an investment that will incur significant costs for ratepayers in a status quo scenario. To put this in context, Elexicon is nearing completion of its $40MM Seaton TS, which will once completed provide additional capacity for the Seaton area developments and will support additional capacity on the Whitby TS.

In order to avoid or defer investment in a New TS, Elexicon is proposing to make strategic investments now to attempt to achieve conservation outcomes and facilitate DER penetration to try to limit increases to system capacity needs, while also facilitating regional growth. The ICM Projects together with the proposed local market mechanism will create incentives to develop a concentrated DER-laden community, which will have a proven track record of operations before a decision is taken to potentially defer the otherwise required New TS. Deferral of a New TS would yield significant economic benefits to ratepayers.

5.3. Fairness Issues Raised with Respect to the Brooklin Line

5.3.1. Inconsistency between the DSC and the Transmission System Code ("TSC")

Approval of the DSC Exemption and ICM Projects will alleviate issues of fairness raised with respect to the Brooklin Line and its associated capital contributions.

The Developers have raised a concern of inconsistency between the DSC and the TSC. In assessing available alternatives to meet growth needs in the North Brooklin area Elexicon assessed the construction of a potential (hypothetical) new TS ("**Brooklin TS**"). Construction of a Brooklin TS was dismissed on evaluation as an imprudent investment. The costs of a Brooklin TS would be significantly higher than the costs of the Brooklin Line, construction of a Brooklin TS would not meet the timelines required to serve growth in North Brooklin, and the near-term capacity requirements of North Brooklin (while substantial) do not warrant construction of a full TS (i.e. the Whitby TS has adequate capacity available). The Brooklin Line is clearly the prudent investment to meet North Brooklin's growth needs.

The Developers identified that if Elexicon had pursued a Brooklin TS rather than the Brooklin Line, no capital contribution would have been required by the Developer or any other developers under the applicable provisions of the TSC and DSC. The Developers assert that its members will be effectively penalized as a result of Elexicon's choice of upstream solutions to bring additional capacity to North Brooklin; simply because the most prudent investment, while still substantial in cost, requires application of Section 3.2 of the DSC. Of note, the Developers will still be required to pay capital contributions for distribution assets downstream of Brooklin Line regardless of the OEB's Decision on Elexicon's DSC Exemption and ICM Projects.

5.3.2. First-mover pays all the costs of the Brooklin Line and customers connected after 5 years avoid contributions

The size and upstream nature of the Brooklin Line creates further issues of basic fairness. The Developers, being a first-mover, will pay all the costs of the Brooklin Line and unforecasted customers connected after 5 years can avoid any contributions due to the limitations found in Section 3.2.27 of the DSC.

The issue of fairness is exacerbated by the necessity for Elexicon to plan and pace its investments with a long-term view. While the initial build-out of the Brooklin Line will only incorporate a single circuit from the Whitby TS DESN 1 to accommodate the capacity requirements of initial development phases, the poles installed for the Brooklin Line have been designed to accommodate three circuits to serve future phases of growth in North Brooklin. Future customers seeking connection beyond the initial five-year capital contribution period may be required to contribute to the cost of stringing the second or third circuits on the Brooklin Line poles, however these projects will be a fraction of the cost of the initial build-out because no new poles or rights of way will be required.

5.4. Facilitating GHG Emission Reductions

The Sustainable Brooklin Project supports Federal, Provincial, and Regional goals to reduce GHG emissions and mitigate climate change, as discussed in section 2.1.

Approval of the Sustainable Brooklin DSC Exemption and ICM Projects will position the community of North Brooklin for significantly increased uptake of DERs and EVs, which will in turn support climate change and emission reduction goals. Increased DER penetration in North Brooklin, particularly of battery storage, introduces the opportunity for Elexicon to facilitate peak-shaving activities. Not only will this create the potential for economic benefits to ratepayers through potential infrastructure deferral as noted above, but will also reduce GHG emissions given Ontario's reliance on natural gas fired electricity generation for peak system needs. This will be particularly impactful in the near-to-midterm, as the Province's nuclear fleet undergoes planned refurbishment and retirement. Similarly, the reduction of barriers to EV ownership in North Brooklin will facilitate greater EV uptake, and thus lower overall gasoline consumption and associated emissions.

Importantly, the Sustainable Brooklin Project is innovative, and represents an opportunity for the OEB, IESO, other distributors, and municipalities to observe Elexicon and the Developer's experience facilitating a new construction community with deep levels of DER and EV penetration. Elexicon expects approval and implementation of its Sustainable Brooklin requests will be accompanied by appropriate reporting requirements to ensure that lessons learned can be captured and actioned by other industry participants.

6. ICM Financial Implications

6.1. Procedural Treatment of 2025 ICM Funding

While the Sustainable Brooklin Project will come into service in 2023 and can accommodate standard ICM practices with respect to rate riders, the WSG will not enter service until 2025. This issue of timing is a result of:

i. The long lead time required to construct the WSG, including significant lead times for material orders which have been exacerbated by the supply chain constraints of recent years; and,
ii. The need for certainty of cost recovery regarding the WSG prior to significant investments being made.

In a recent Decision,[39] the OEB approved rate riders well in advance of their implementation date for a similar ICM project. In this case, the longer lead time required prior to the in-service date of the WSG warrants finalization of applicable rate riders as part of Elexicon's 2025 IRM application. To facilitate this, Elexicon requests approval of the illustrative 2025 ICM rate riders presented within this application on an interim basis, or such other relief as the OEB deems appropriate to facilitate approval of incremental funding for the WSG with appropriate provisions to finalize cost recovery details. Elexicon will file updated ICM models applicable to the WSG for the WRZ and VRZ in its 2025 IRM application to inform the OEB's final decision at that time.

6.2. Application of the Half-Year Rule

The Half-Year Rule is not applicable in this case as neither the 2023 nor 2025 ICM requests coincide with the final year of Elexicon's IRM plan term.

6.3. Rate Riders

Elexicon is seeking OEB approval of the ICM rate riders identified in the table below to recover the revenue requirement of $2.160MM associated with the Sustainable Brooklin Project within the WRZ effective January 1, 2023. The ICM Model uses Elexicon's most recent allocation of revenues to appropriately allocate the incremental revenue requirement to the appropriate classes. Elexicon proposes that these rate riders remain in effect until its next rebasing.

[39] In its Decision and Order in EB-2020-0249 issued April 29, 2021 the OEB approved final rate riders effective May 1, 2022 applicable to PUC Distribution Inc.'s Sault Smart Grid ICM

Table 9: Sustainable Brooklin ICM Rate Riders (WRZ)

Rate Class	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$ 2.85	$ -	$ -
GENERAL SERVICE LESS THAN 50 kW	$ 2.39	$ 0.0018	$ -
GENERAL SERVICE 50 TO 4,999 KW	$ 18.23	$ -	$ 0.3640
UNMETERED SCATTERED LOAD	$ 0.89	$ 0.0028	$ -
SENTINEL LIGHTING	$ 0.52	$ -	$ 1.4014
STREET LIGHTING	$ 0.16	$ -	$ 0.6132

The WSG will not be placed into service until 2025. As such, Elexicon has not filed an ICM model for the WSG given the lack of an available 2025 ICM model. For illustrative purposes, Elexicon has relied on the 2023 ICM model to produce notional rate riders for the OEB's consideration. As stated above, Elexicon will provide final rate riders for the OEB's consideration in its 2025 IRM application, to be filed in 2024.

Table 10: Illustrative WSG ICM Rate Riders (WRZ)

Rate Class	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$ 5.43	$ -	$ -
GENERAL SERVICE LESS THAN 50 kW	$ 4.56	$ 0.0034	$ -
GENERAL SERVICE 50 TO 4,999 KW	$ 34.76	$ -	$ 0.6942
UNMETERED SCATTERED LOAD	$ 1.69	$ 0.0054	$ -
SENTINEL LIGHTING	$ 0.99	$ -	$ 2.6725
STREET LIGHTING	$ 0.31	$ -	$ 1.1693

Table 11: Illustrative WSG ICM Rate Riders (VRZ)

Rate Class	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
RESIDENTIAL	$ 0.73	$ -	$ -
SEASONAL RESIDENTIAL	$ 1.33	$ -	$ -
GENERAL SERVICE LESS THAN 50 kW	$ 0.47	$ 0.0005	$ -
GENERAL SERVICE 50 TO 2,999 KW	$ 3.01	$ -	$ 0.0929
GENERAL SERVICE 3,000 TO 4,999 KW	$ 158.27	$ -	$ 0.0589
LARGE USE	$ 237.75	$ -	$ 0.0829
UNMETERED SCATTERED LOAD	$ 0.19	$ 0.0005	$ -
SENTINEL LIGHTING	$ 0.13	$ -	$ 0.3828
STREET LIGHTING	$ 0.02	$ -	$ 0.1047

6.4. Deferral and Variance Accounts

Elexicon requests Board approval to record amounts relating to the Projects in the applicable 1508 sub-accounts of the WRZ and VRZ, with the intention of truing up the balance in its next cost of service application. Elexicon will follow the accounting treatment for deferral and variance accounts as described in the Accounting Procedures Handbook and the ACM Report.

6.5. Bill Impacts

The table below provides the estimated monthly impacts resulting from the addition of the 2023 Sustainable Brooklin ICM funding rate riders to the WRZ:

Table 12: Sustainable Brooklin ICM Bill Impacts (WRZ)

[

Rate Classification Whitby Rate Zone	Units	Total Bill Impact: Sustainable Brooklin
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 2.74
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 5.75
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 61.73
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 2.20
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 1.84
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 2,726.96

The following tables provide an illustration of the estimated monthly impacts resulting from addition of the notional 2025 WSG ICM funding rate riders to the WRZ and VRZ. As noted above, Elexicon will provide final estimated bill impacts for the OEB's consideration in its 2025 IRM application. The tables below incorporate forecast reductions to energy consumption resulting from the VVO component of the WSG.

Table 13: Illustrative WSG ICM Bill Impacts (WRZ)

Rate Classification Whitby Rate Zone	Units	Notional Total Bill Impact: Whitby Smart Grid
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 2.98
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 4.95
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ (42.07)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 2.73
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 2.92
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 4,169.28

Table 14: Illustrative WSG ICM Bill Impacts (VRZ)

Rate Classification Veridian Rate Zone	Units	Notional Total Bill Impact: Incl Whitby Smart Grid
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 0.70
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.28
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 1.41
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 158.77
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 445.07
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 905.66
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 0.42
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 0.49
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 357.64

APPENDIX B-1

Whitby Smart Grid Business Case

Table of Contents

List of Tables

List of Figures

1. Executive Summary

Elexicon is at a key juncture to develop a modern, flexible, energy efficient, and resilient high-DER grid that is responsive to signals from the federal, provincial, and local levels of government for an enhanced electricity system that serves an increased portion of customers' overall energy needs.

The changing demands of the distribution system is creating a need for a new type of system operation. The "Grid of the Future" will need to support high penetrations of distributed energy resources ("DERs"), manage electric vehicle ("EVs") charging, and support renewable energy such as roof top solar. Looking ahead, the distribution system is expected to take on a distribution system operator ("DSO") role and handle the dispatch and settlement of locally operated distributed generation, and aggregated customer side storage under distributed energy resource management ("DERMs") scenario.

Many of these concepts are future oriented, however there are mature technologies that will support the "Grid of the Future" that while still considered innovative can be deployed under the umbrella of advanced distribution management systems ("ADMS"). Mature technologies that are ready for deployment include distribution automation ("DA"), fault location isolating and service restoration ("FLISR"), volt-var optimization ("VVO") and the associated conservation voltage reduction ("CVR") , outage management systems ("OMS"), advanced metering infrastructure (AMI), engineering systems and asset management ("GIS", "AMS"), as well as a host of customer interfacing systems ("CIS").

The Whitby rate zone's existing distribution system infrastructure's age, plus the substantive growth forecasts in North Brooklin and elsewhere, make this the prudent time for Elexicon to invest in grid modernization and facilitate a high-DER future.

An increase in future demands is expected on the distribution system imposed by higher penetrations of DERs and EVs which are projected by the IESO under Grid Evolution initiatives, by the Provincial Government with its EV charging program, the Town of Whitby's own EV charging expansion program, and an increase in population growth and therefore demand on the system. In addition, opportunities presented by developing in the Brooklin area will include opportunities to deploy DERs at high levels of penetration. Considering the many phases of the "Grid of the Future" there is a need to get started with the mature technologies that are available today.

To enable the "Grid of the Future" Elexicon is proposing the Whitby Smart Grid project. This will involve:

- The installation of Smart Grid Field Technologies/Hardware
- The implementation of an ADMS Software
- A communication infrastructure that enables the connection of the new software with the hardware
- A feasibility study looking at potential Active Demand Management Programs

The Whitby Smart Grid is a set of technologies that can address risks and opportunities with the increase in DERs being installed in Whitby. The increased penetration of new DERs is expected to include commercial entities (including aggregators) with a high need for reliable access to the system. Recent events have also highlighted the increasing need for system hardening relating to storm events. When the provincial system is relying on DERs for supply, there will be a need to restore connections to all DERs possible quickly and reliably. The application of DA will allow for rapid restoration to all customers outside of the outage zone, in a complex switching situation such as a high DER environment, and situations created by storm events.

In addition, the application of CVR to maximize bill reductions means operating near the low end of the allowable voltage window. This condition comes with an increased risk that voltage violations will occur especially during the rapid variations caused by the increased penetration of DERs. In order to get full value of the voltage reduction program, an automated VVO is needed to manage those variations and monitor feeder tip voltage.

Future oriented benefits of the Whitby SmartGrid project include positioning the LDC for increased reliance on DERs and management of residential based energy storage and EV's by providing:

- linkage to DERMs applications to control and monitor DER and EV.
- visibility into system conditions and improved response time for DERs
- storm hardening and the rapid restoration of grid access (often <1minute) during storm events
- improved availability of DERs to the provincial grid.
- risk reduction relating to voltage variations caused by DERs and a maximization of benefit of CVR
- flexibility in feeder layout in normal and contingency mode,
- centralized system management and worker safety.

2. Project Description

As part of the Elexicon's Grid Modernization roadmap[1], and to make best use of existing assets, reduce losses, improve reliability, accommodate significant DER-uptake, and ultimately deliver value to customers, Elexicon is proposing the Whitby Smart Grid. This project is one of the fundamental projects that will help deliver the "Grid of the Future". The Whitby Smart Grid builds on and integrates solutions which have been previously demonstrated in Ontario, while also accommodating the next phase of grid modernization, as exemplified by the Sustainable Brooklin project. The first tranche of the Whitby Smart Grid project will enable the DER integration of the Sustainable Brooklin project.

Elexicon will deploy several technologies to modernize the distribution system across the Whitby rate zone and beyond. The technologies that shall be deployed are listed below with further details listed in sections 3 and 4:

- **ADMS[2] and associated systems contained within it.**
- **VVO and the associated CVR**
- **DA which is a key component of FLISR and reliability**

These technologies will interact with the relevant operation technology systems that Elexicon is currently installing, thus enabling Elexicon to utilize and achieve the benefits of an integrated smart grid. As Elexicon proceeds towards the "Grid of the Future", there will be a number of inter-related projects that will compliment the Whitby Smart Grid Field Hardware project. Some of these projects are under way at various stages, and others will be activated when the need or technology appears. Systems that will inter-connect

[1] See Figure 1in Exhibit A, Section 2, Page 14 of this ICM application
[2] ADMS installation will be a system-wide installation which will cover all of Elexicon's customer base.

with the Whitby Smart Grid are generally part of the umbrella system known as ADMS, with this project now being brought under the "Whitby Smart Grid Project".

This project will bring about improved reliability, customer savings, and reduced peak and overall load on the transmission system.

The "Grid of the Future" will have many benefits to the customers of the Whitby and the operations of the Elexicon distribution system. The "Grid of the Future" can be expected to provide:

- cost reductions compared to non-automated options for operation,
- reliability improvements and connection flexibility relating to increased complexity of DERs,
- storm hardening and the ability to restore power more quickly in a complex outage,
- reduction in energy consumption and associated Greenhouse gas emissions,
- reduction/deferral of capital expansion programs,
- enhanced communication to customers during events,
- innovative opportunities for non-wires alternatives ("NWAs"),
- aggregated and dispatch of DERs and customer choice in energy transactions, and enhanced asset management

The installation of the proposed smart technologies and systems will bring about improved reliability, customer savings, and reduced peak and overall load on the system. The following table summarizes the high-level expected benefits from the implementation of the proposed assets:

Table 1: Expected Benefits

System	Expected Benefit
ADMS	• Leverage the existing metering, Infrastructure Technology, other system software, and communication systems to effectively regulate voltage, mitigate outages, and Distributed Energy Resources (DER). • Increased safety and operational situational awareness for field crews. • Reduction of restoration time. • Increased efficiency through the reduction of overhead costs. • Advanced real-time load flow calculations and load transfer. • Streamlining of switch order and execution. • Improved asset management of devices through the inherent switch operation logging ability of the ADMS system.
VVO/CVR	The management of Volt-Var allows a reduction of source voltage and a commensurate reduction in Power, Energy and Losses[3]: • 2-3% reduction of energy consumption based on a 5% source voltage reduction • 2-3% reduction in peak energy based on a 5% source voltage reduction • System Losses reduction <0.1% • Reduction in Green House Gas (GHG) emissions due to reduction in energy

[3] Appendix B-5

System	Expected Benefit
FLISR/DA	The rapid isolation of faulted sections and restoration of non-faulted sections improves reliability statistics and converts 75% of sustained feeder customer impact to momentary outages. Reliability Improvement (based on historical period Apr 2020-January 2022)[4] • SAIFI from 0.87 to 0.28 • SAIDI from 1.03 to 0.45 • CAIDI ~ 40 minutes • MAIFI from 0 to 0.59 Operations & Maintenance ("O&M") reduction (i.e., a reduction in truck rolls) due to improved fault location. Reduced O&M costs in locating and isolating faults. Work begins immediately on repairs. This results on average a saving of 1hr per outage.
Peak Shaving (Local Capacity Market)	Capital Deferral of "peak" based investments. Could eliminate one or more feeder or a transformer upgrade in the future.

Future oriented benefits of the Whitby Smart Grid project include positioning the LDC for increased accommodation of DERs and management of residential based energy storage and EV's by providing:

- visibility into system conditions,
- flexibility in feeder layout in normal and contingency mode,

[4] Appendix B-5

- centralized system management and worker safety,
- enhance reputation as an innovative leader in customer energy options.

The implementation of the Whitby Smart Grid will be accompanied by a subsequent application to the OEB proposing efficient participant incentives funded through a Deferral or Variance account, that are expected to be paired with streams of funding from Natural Resources Canada (“NRCan”), the IESO, and potentially other entities. The participant incentive proposal (the “DER Incentive Program”) is intended to accelerate DER adoption in the Whitby Rate Zone to support a DER heavy Local Capacity Market. The Local Capacity Market will adopt a Distribution System Operator (DSO) model similar to the York Region Non-Wires Alternatives Demonstration Project (“YRDemo”). This will be important to ensure DER adoption is accelerated and as such customers can benefit as soon as possible from these technologies. An initial feasibility study on an active demand management program design as part of the ADMS element of this project will be carried out as part of this project. Following this, future proposals shall be brought forward.

The overall proposed cost for the Whitby Smart Grid project is estimated at $47.2 MM[5]. Elexicon has been granted $4.04 MM of NRCan funding that is related to the funding of the ADMS element of this project. Table 2 shows the capital expenditure for this project.

[5] Estimates provided for the VVO and FLISR field hardware herein should be considered Class 4 estimates as defined by AACE and other standard estimate formats. The conditions for a Class 4 estimate presume that 1-15% of Project Definition has been completed. Typical Accuracy ranges of a Class 4 estimate are -30% on the low side and +50% on the high side. All other costs can be considered Class 5 estimates as defined by ACCE.

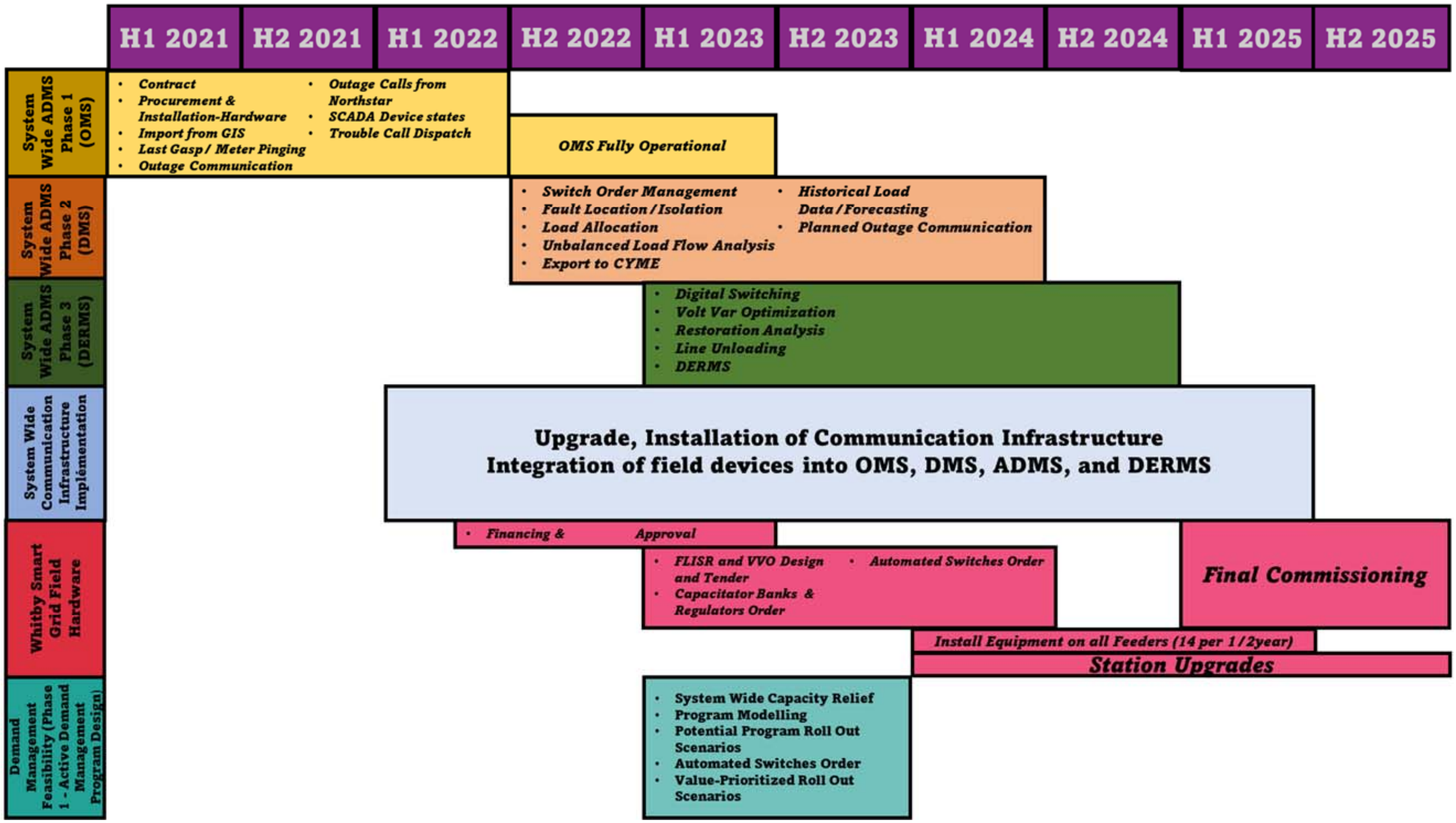
1 *Table 2: Forecast Capital Expenditures ($M)*

	Capital Expenditures ($'000)
ADMS (Software, Communications Infrastructure, Active Demand Management Program Design)	$8,082
VVO and FLISR Field Hardware	$39,130
Total Capital Expenditure	**$47,212**
NRCan Funding	$4,041
Total Capital Expenditure (Excluding NRCan Funding)	**$43,171**

2

The current timeline for the delivery of the project is shown in the table below.

Table 3: Project Timeline



3. Basis for Action

The following section describes both the current state of the Whitby Network and the desired future state. The current state will describe where the current system does not deliver and what will be required in the future. The future state describes what is being proposed and the key benefits the proposed technologies will bring. In addition, any compliance considerations are also described.

3.1. Current State

As of January 2022, the Town of Whitby has a total population of 140,654. Elexicon Energy distributes electricity to 46,643 residential and commercial customers in this area. The Whitby region accounts for approximately 27% of Elexicon's total customer base. Power is delivered at 44kV to the Whitby area through thirteen 44kV feeders. Nine of these feeders come from the Whitby transmission station, and the other four from the Thornton transmission station. There are 12 municipal stations operating at 13.8kV, from which there are 44 distribution feeders which are in service now or will be in-service by the end of 2025. In addition, there are 2 feeders (for a total of 46) that will be supplied directly from the Whitby TS at 27.6kV for the Sustainable Brooklin project. A summary of Elexicon's key asset counts for the Whitby area is given in

Table 4: Existing Asset Counts for the Whitby Area.

Asset Class	Asset Population
Transmission Stations	2
Transmission Feeders (44-kV)	13
Municipal Stations	12
Distribution Feeders (13.8-kV)	44
Overhead Circuit (km)	499
Underground Circuit (km)	576
Pole mount Transformers	1,465
Pad mount Transformers	4,069

Figure 1 illustrates the location of the municipal stations in the Whitby area.

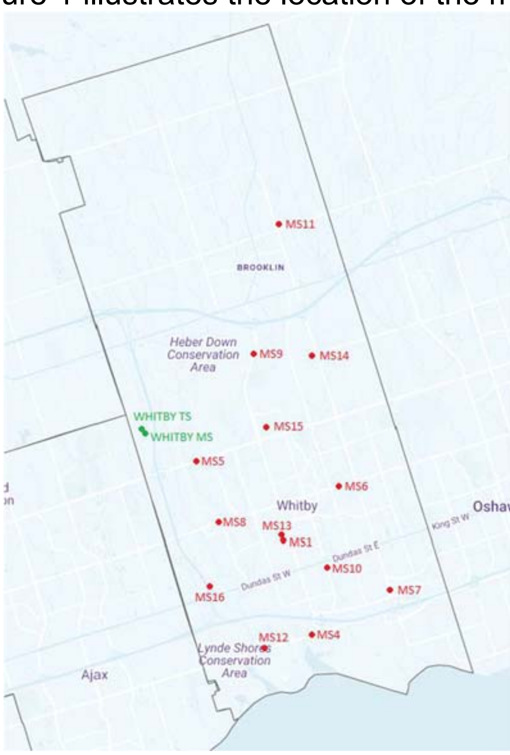


Figure 1 : Municipal Stations Located in the Whitby Area

The historical demand in the Whitby region from 2014 to 2021 is shown in Table 5.

Table 5: Historical Demand Statistics for the Whitby Region

Service Area	Peak Type	2014	2015	2016	2017	2018	2019	2020	2021
Whitby	Winter Peak (kW)	152,191	147,008	140,154	135,964	142,959	142,119	142,119	135,429
	Summer Peak (kW)	171,946	181,742	189,957	175,818	192,937	176,455	204,078	192,668
	Average Peak (kW)	145,580	142,856	148,607	135,186	149,527	138,118	147,899	146,202

Elexicon has retained METSCO Energy Solutions Inc. ("METSCO") to produce a twenty-year load forecasting model that predicts load growth across Elexicon's service area. The model incorporates historical peak load data provided by Elexicon, population and household forecasts for the Town of Ajax, City of Pickering, and the Town of Whitby, census data, updated plans from developers, and other inputs.

This report outlines three scenarios depending on the housing forecast used. The first scenario is based on household estimates originally produced by the Region of Durham but adjusted downwards by METSCO based on 2021 census data. The two other scenarios are based on twenty-year low and high development forecasts provided by a North Brooklin housing developer. The forecasts for Ajax and Pickering are the same in all three scenarios, whereas the forecast for Whitby changes. Full details can be found in Appendix B-4 of this ICM application. The following summarises some of the findings and the potential growth expected in the Whitby Rate Zone. The 2022 load forecast predicted consistent residential customer growth in the Whitby area and includes the expected levels of commercial and industrial growth based on this residential growth.

Table 6: Whitby Forecasted Total Customers and Population Growth for 2022 to 2041

Year	Whitby Total Customers	Whitby Population
2022	48,666	140,654
2023	49,755	142,835
2024	50,868	145,040
2025	52,006	147,273
2026	53,168	149,528
2027	56,437	156,138
2028	59,907	163,038
2029	63,590	170,241
2030	67,500	177,759
2031	71,650	185,608
2032	74,121	192,337
2033	76,602	199,067
2034	79,093	205,796
2035	81,596	212,525
2036	84,108	219,254
2037	86,632	225,984
2038	89,166	232,713
2039	91,712	239,442
2040	94,268	246,171
2041	96,835	252,901

The results of the twenty-year load forecasts for 2041 are shown in **Error! Reference source not found.**. This is a probabilistic forecast. The final peaks produced include the P10 peaks that represent the threshold that 10% of annual peaks will exceed, P50 peaks that represent the peak value threshold that 50% of annual peaks will exceed, and P90 peaks that represent the peak value threshold that 90% of annual peaks will exceed. The P10 value is used for capacity planning.

Table 7: Forecasted Summer and Winter Peak Loads 2041

Summer Peak (MW)	Ajax-Pickering	Whitby (Region of Durham Scenario)	Whitby (Brooklin Low Scenario)	Whitby (Brooklin High Scenario)
P10	443.6	432.0	404.2	409.3
P50	426.2	417.8	389.9	395.1
P90	407.8	401.7	373.9	379.1
Winter Peak (MW)	**Ajax-Pickering**	**Whitby (Region of Durham Scenario)**	**Whitby (Brooklin Low Scenario)**	**Whitby (Brooklin High Scenario)**
P10	357.9	343.1	319.7	324.1
P50	351.6	339.4	316.1	320.4
P90	344.4	335.8	312.5	316.8

Future load growth in the region is expected to be driven by new developments in Brooklin, West Whitby and Port Whitby. The P10 load forecast was divided between the 27.6 kV and 44 kV systems that serve the Whitby rate zone. The breakdown of the load for each area was calculated using both the expected population and household growth.

Currently Whitby receives power at 44 kV from nine feeders egressing from Whitby TS and four feeders egressing from Thornton TS. The new North Brooklin developments will be served via 27.6 kV feeders from Whitby TS. Table 8 summarizes the system capacity constraints at 27.6 kV and 44 kV, as determined from the limited time ratings of the respective TS.

Table 8: Total P10 Load Forecast Breakdown

System	27.6 kV	44 kV
System Capacity Constraint (MW)	282.0	509.0

The tables below show the P10 load breakdown between the 27.6 kV and 44 kV systems. Table 9 shows the P10 load forecast divided into the 27.6 kV and 44 kV systems and the combined 27.6 kV and 44 kV forecasts. Tables 10 and 11 show the divided P10 load forecast for the low and high Brooklin scenario. Highlighted cells show when the individual 27.6 kV or 44 kV systems will begin to exceed capacity. In the Region of Durham scenario, the 44 kV-system is expected to exceed capacity by 2030. If load can be balanced between the 27.6 kV and 44 kV systems, then the whole system is forecast to exceed capacity in 2036 under this scenario. In both Brooklin scenarios, these capacity constraints are forecast to occur one year later.

Table 9: Capacity Analysis – Region of Durham Scenario

Year	Whitby 27.6 kV	Ajax-Pickering 27.6 kV	All 27.6 kV	Whitby 44 kV	Ajax-Pickering 44 kV	All 44 kV	Total
2022	0.0	99.4	**99.4**	236.0	222.2	**458.2**	**557.7**
2023	0.0	104.2	**104.2**	240.4	223.7	**464.2**	**568.4**
2024	5.7	109.0	**114.7**	239.3	225.2	**464.5**	**579.2**
2025	7.6	113.8	**121.5**	241.9	226.7	**468.6**	**590.1**
2026	9.7	118.6	**128.3**	244.7	228.2	**472.8**	**601.1**
2027	15.3	123.2	**138.6**	252.3	229.6	**481.9**	**620.4**
2028	21.4	127.9	**149.2**	260.4	231.0	**491.4**	**640.6**
2029	27.8	132.5	**160.2**	269.0	232.4	**501.4**	**661.7**
2030	34.5	137.1	**171.6**	278.1	233.9	**512.0**	**683.6**
2031	41.7	141.7	**183.5**	287.8	235.3	**523.1**	**706.6**
2032	46.0	147.0	**193.1**	293.5	236.9	**530.5**	**723.5**
2033	50.3	152.3	**202.7**	299.3	238.6	**537.9**	**740.6**
2034	54.7	157.6	**212.3**	305.1	240.2	**545.3**	**757.7**
2035	59.0	162.9	**222.0**	311.0	241.8	**552.8**	**774.8**
2036	63.4	168.3	**231.6**	316.8	243.5	**560.3**	**792.0**
2037	67.8	173.1	**240.9**	322.7	245.0	**567.7**	**808.6**
2038	72.2	178.0	**250.1**	328.6	246.5	**575.1**	**825.3**
2039	76.6	182.8	**259.4**	334.6	248.0	**582.6**	**842.0**
2040	81.0	187.7	**268.7**	340.6	249.5	**590.0**	**858.8**
2041	85.5	192.6	**278.1**	346.5	251.0	**597.5**	**875.6**

Table 10: Capacity Analysis – Brooklin Low Scenario

Year	Whitby 27.6 kV	Ajax-Pickering 27.6 kV	All 27.6 kV	Whitby 44 kV	Ajax-Pickering 44 kV	All 44 kV	Total
2022	0.0	99.4	**99.4**	234.7	222.2	**456.9**	**556.3**
2023	0.0	104.2	**104.2**	238.7	223.7	**462.4**	**566.6**
2024	4.7	109.0	**113.7**	238.0	225.2	**463.2**	**577.0**
2025	6.6	113.8	**120.4**	240.4	226.7	**467.1**	**587.5**
2026	8.5	118.6	**127.1**	243.0	228.2	**471.1**	**598.2**
2027	13.6	123.2	**136.8**	249.8	229.6	**479.4**	**616.2**
2028	18.9	127.9	**146.7**	256.9	231.0	**487.9**	**634.7**
2029	24.5	132.5	**157.0**	264.5	232.4	**496.9**	**653.9**
2030	30.6	137.1	**167.7**	272.5	233.9	**506.4**	**674.0**
2031	37.0	141.7	**178.7**	281.0	235.3	**516.3**	**695.0**
2032	40.6	147.0	**187.6**	285.9	236.9	**522.8**	**710.4**
2033	44.2	152.3	**196.5**	290.7	238.6	**529.2**	**725.7**
2034	47.8	157.6	**205.4**	295.5	240.2	**535.7**	**741.1**
2035	51.4	162.9	**214.4**	300.4	241.8	**542.2**	**756.6**
2036	55.1	168.3	**223.3**	305.3	243.5	**548.7**	**772.1**
2037	58.8	173.1	**231.9**	310.2	245.0	**555.1**	**787.0**
2038	62.4	178.0	**240.4**	315.1	246.5	**561.6**	**802.0**
2039	66.1	182.8	**249.0**	320.0	248.0	**568.0**	**817.0**
2040	69.9	187.7	**257.6**	325.0	249.5	**574.5**	**832.0**
2041	73.6	192.6	**266.2**	330.0	251.0	**581.0**	**847.1**

Table 11: Capacity Analysis – Brooklin High Scenario

Year	Whitby 27.6 kV	Ajax-Pickering 27.6 kV	All 27.6 kV	Whitby 44 kV	Ajax-Pickerin g 44 kV	All 44 kV	Total
2022	0.0	99.4	**99.4**	234.7	222.2	**456.9**	556.3
2023	0.0	104.2	**104.2**	238.8	223.7	**462.5**	566.7
2024	4.8	109.0	**113.8**	238.1	225.2	**463.3**	577.2
2025	6.7	113.8	**120.5**	240.6	226.7	**467.3**	587.8
2026	8.6	118.6	**127.3**	243.2	228.2	**471.4**	598.6
2027	13.9	123.2	**137.1**	250.2	229.6	**479.8**	617.0
2028	19.3	127.9	**147.2**	257.5	231.0	**488.5**	635.7
2029	25.1	132.5	**157.6**	265.3	232.4	**497.7**	655.3
2030	31.3	137.1	**168.4**	273.5	233.9	**507.4**	675.8
2031	37.9	141.7	**179.6**	282.2	235.3	**517.5**	697.1
2032	41.6	147.0	**188.6**	287.2	236.9	**524.1**	712.7
2033	45.3	152.3	**197.6**	292.2	238.6	**530.8**	728.4
2034	49.1	157.6	**206.7**	297.2	240.2	**537.4**	744.1
2035	52.8	162.9	**215.8**	302.3	241.8	**544.1**	759.9
2036	56.6	168.3	**224.9**	307.3	243.5	**550.8**	775.7
2037	60.4	173.1	**233.5**	312.4	245.0	**557.4**	790.9
2038	64.2	178.0	**242.2**	317.5	246.5	**564.0**	**806.2**
2039	68.1	182.8	**250.9**	322.6	248.0	**570.6**	**821.5**
2040	71.9	187.7	**259.6**	327.8	249.5	**577.3**	**836.9**
2041	75.8	192.6	**268.4**	332.9	251.0	**583.9**	**852.3**

Further analysis was undertaken to look at the impact of DER integration. Under the Brooklin Low scenario the estimated DER penetration required to defer future capacity investments for one year, three years, and five years was calculated as a percentage based on the number of DER connections required among new Brooklin development.

The combination of rooftop solar with Battery Energy Storage Systems ("BESS") provides the greatest potential to meet future capacity needs and defer capacity investments. To be able to defer capacity assessments for one year, 12% of new customers in the North Brooklin area need to install rooftop solar with BESS. This percentage is 39% for a three-year deferral and 53% for a five-year deferral. Since these DERs are customer-owned, Elexicon has no control over their implementation and will need to monitor installation trends in the future.

The forecast may also be impacted if other new developments take a similar approach to enabling DERs. Table 12 shows the estimated DER penetration required for deferral based on the number of DER connections required and total expected customers from new Brooklin development for the given time periods. Three options of rooftop solar only, rooftop solar with BESS, and mix of 50% rooftop solar only and 50% rooftop solar with BESS.

Table 12: DER Penetration Required for Excess Load Deferral – Brooklin Low Scenario

	DER Penetration Required (%)		
Deferral Period	**Rooftop Solar**	**50-50 Mixed Infrastructure**	**Rooftop Solar with BESS**
1-Year	36%	18%	12%
3-Year	N/A	58%	39%
5-Year	N/A	79%	53%

The current network:

- o Cannot accommodate a higher penetration of grid connected DERs without significant upgrades,

        - To prevent islanding, IEEE 1547 now recommends detailed engineering take place if the total DER on a feeder exceeds 33% of minimum load[6].
    - Is not enabled for remote monitoring and automated corrections (e.g., fault detection), and
    - Does not have optimized voltage (voltages are within the limits), resulting in a missed opportunity to further conserve energy.

3.2. Future State & Grid Modernization

Elexicon is at a key juncture to develop a modern, flexible, energy efficient, and resilient high-DER grid that is responsive to signals from the federal, provincial, and local levels of government for an enhanced electricity system that serves an increased portion of customers' overall energy needs. As previously stated, Elexicon is developing a Grid Modernization roadmap that will facilitate the "Grid of the Future".

In Elexicon's 2021 Distribution System Plan, Elexicon proposed an early project that involves the purchase and implementation of an ADMS. Being the innovative company Elexicon is, they identified that they didn't have a system capable of satisfying its requirements for the future. This led to Elexicon proposing an initial two-phase project, whilst intimating that further enhancements will be sought in the near future. The initial two phase implementation of this project involved:

1. The first phase involves the implementation of a new enterprise OMS to replace the two legacy systems. This OMS will be part of a larger, established ecosystem of an ADMS and will be incrementally added to as needs arise.

[6] Minimum load is considered to be 25% and therefore Elexicon can currently only accommodate approximately a 7.5% DER penetration.

2. The second phase involves implementing limited ADMS functionality to help streamline or improve current utility processes.

Since the submission of the DSP, Elexicon has been engaged with NRCan to seek further funding to support a wider project called Project Veritas. This project incorporates the existing proposed ADMS two-phase implementation. It also includes the implementation of further ADMS functionality, including the DERMS package, which allows Elexicon to integrate DERs onto the grid. Additionally, to be able to integrate filed hardware into the new ADMS, an upgrade to the telecommunications network infrastructure will be required. It will allow Elexicon to properly support its operations and customers as the grid evolves and smart grid and distributed energy resources place greater reliance on communications. Finally Project Veritas also includes the commissioning of an active demand management program design. Another key element for the 'Grid of the Future', will be having a robust model for enabling the uptake and management of DERs. Elexicon is proposing to undertake an initial feasibility study on active demand management program designs.

Taking this a step further and with the implementation of the smart grid field hardware in the Whitby Rate Zone, Project Veritas and the Whitby Smart Grid Field Hardware have been combined to form the Whitby Smart Grid Project. This project is the beginning of Elexicon's Grid Modernization journey in facilitating the 'Grid of the Future".

The Whitby rate zone's existing distribution system infrastructure's age, plus the substantive growth forecasts in North Brooklin and elsewhere, make this the prudent time for Elexicon to invest in grid modernization and facilitate a high-DER future.

Elexicon has retained METSCO to undertake an initial engineering analysis of the Smart Grid field hardware technologies required. The engineering report is included in Appendix

B-5 of this ICM application. It details the methodology and information used to design a solution that meets the future needs. Table 13 below indicates the type and number of field hardware assets that will be installed as part of the Whitby Smart Grid project. In addition to the physical assets there are costs associated with the Project Management, Engineering, and IT support, there is also all the software and associated assets that need to be installed as part of the ADMS element of this project. Appendix A1 of this business case contains example schematics that illustrate the location of the assets/devices that will be installed on a typical feeder.

Table 13: Estimated Assets Required for Whitby Smart Grid Field Technology Upgrades

Asset Type	Units
Automated Switches	144
Capacitors	46
Voltage Regulators	46
Major Equip Field Commissioning	236
Communicating Faulted Circuit Interrupters	138
Voltages Sensor	138
Radio HeadEnd	8
Routers and Leased Line	8
Minor Equip Field Commissioning	292

ADMS is required to enable the integration and functionality of these new technologies and systems. Elexicon will be able to utilize the new ADMS platform to operate with increased system performance data and grid intelligence. Such operational intelligence will be critical in meeting new demands on system grid such as the continued growth in DER and emerging electric vehicle requirements. The system and Class data available will also support Elexicon's decision making to make better long term asset management decisions and forecasting capital requirements with the continuing operating and financial challenges of aging infrastructure renewal. Elexicon is currently installing this as part of Project Veritas. The first phase involves an implementation of a new enterprise OMS to replace the two legacy systems. This approach will help Elexicon to set up an operationally correct network model to be in anticipation of a DMS implementation in Phase 2 and 3. Underpinning the implementation of these systems is the need for a robust communications infrastructure. Throughout the implementation of the ADMS software, an upgrade and installation of the communications infrastructure will be made to allow for the integration of field devices into OMS, DMS, and DERMS. Another key element for the 'Grid of the Future', will be having a robust model for enabling the uptake and management of DERs. Elexicon is proposing to undertake an initial feasibility study on active demand management program designs. Table 14 list the key components of the Project Veritas element of the Whitby Smart Grid project and Figure 2 illustrates the implementation approach.

Table 14: Breakdown of Project Veritas Components to be carried out as part of the Whitby Smart Grid Project[7]

	Hardware	Software
1. ADMS/OMS Implementation	8 Servers	Hitachi OMS (Outage Management System)
	4 Ajax Production Servers	Hitachi DMS (Advanced Distribution Management System)
	18 Virtual Machines	
	4 Pickering Production Servers (Backup for Ajax)	
	16 Virtual Machines	
	Ajax Development Server (part of the 4 servers listed above under 1.)	
	Virtual Machines	
2. DERMS Implementation		DERMS
3. Active Demand Management Program Design		Survalent Platform
		EV Detection Platform (AI Software)
		Power Consumers Platform
4. Communication Infrastructure Implementation	Fiber links	
	Radios	

[7] Note: As previously mentioned these components are for the whole of Elexicon's rate base.

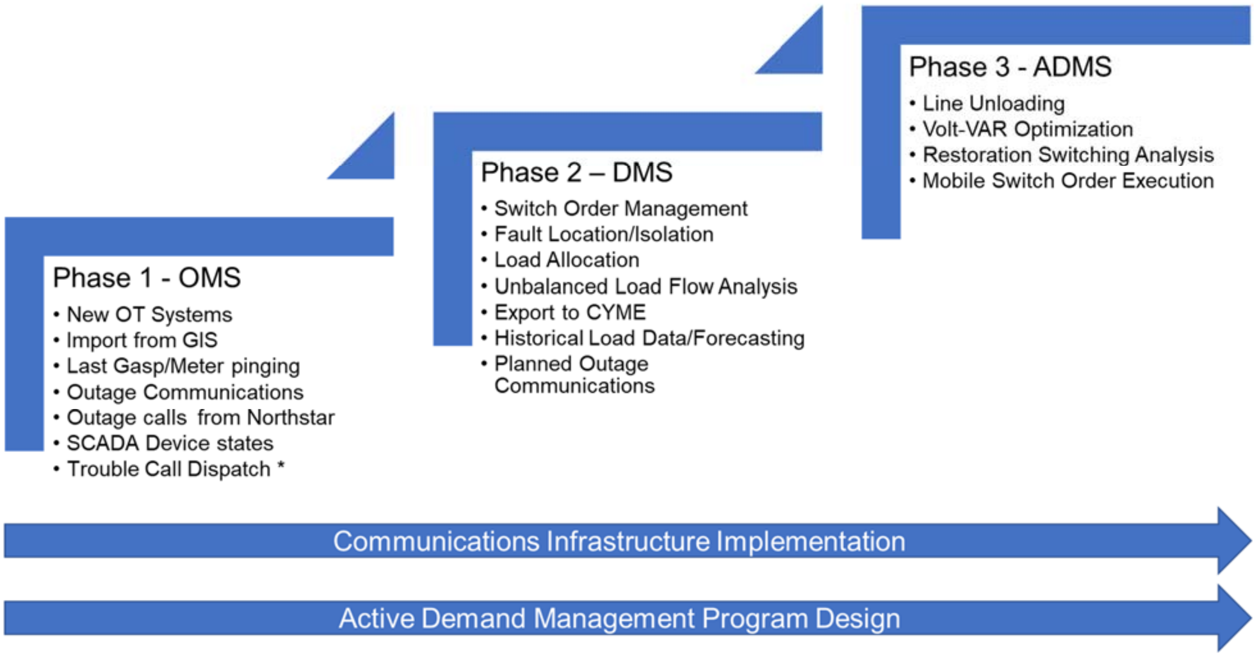


Figure 2: Project Veritas Implementation Approach

The following sections describes the key technology upgrades that will be implemented as part of these projects and the benefits of these technologies and systems.

a) Advanced Distribution Management System

Advanced Distribution Management System (ADMS) uses software to leverage the existing metering, Infrastructure Technology, other system software, and communication systems to effectively regulate voltage, mitigate outages, and Distributed Energy Resources (DER). ADMS also improves customer and internal key performance indicators.

ADMS integrates operations across the numerous systems and applications that are typically isolated or, at best, loosely coupled. These systems and applications include, but are not limited to: Energy Management Systems ("EMS"), Distributed Energy

Resource Management System ("DERMS"), Supervisory Control and Data Acquisition ("SCADA"), Outage Management Systems ("OMS"), Graphical Information Management Systems ("GIS"), Advanced Metering Infrastructure (AMI) and Meter Data Management Systems ("MDMS"), Customer Information Systems ("CIS"), OMS/ADMS Purchase and Implementation Fault Location Isolation and Service Restoration ("FLISR"), mobile workforce tools, feeder load balancing and optimization, voltage optimization control, and distribution state estimation. By integrating operations across all of these systems and applications, ADMS technologies provide utilities with greater ability to observe and control distribution systems so as to address rising operational complexities while ensuring reliable and resilient operations.

Expected Benefits

ADMS integrates all systems, efficiently managing the operation of the distribution system. The following benefits can be achieved with ADMS and the integration of associated systems within it:

- Increased safety for field crews as operational situational awareness, especially in crisis situations, is greatly improved by providing crew management, incident management, SCADA management, work order and tagging management, and awareness of distributed generation into plain focus.
- Reduction of error and restoration time due to automatic loading calculations and automatic generation of switching orders using current, historical, and projected system loading, profiling down to the customer.
- Increased efficiency through the reduction of overhead costs.
- Advanced real-time load flow calculations and load transfer, reducing overall infrastructure requirements. This will become increasingly important as electric vehicles and distributed generation and storage increase.

- Streamlining of switch order creation and execution through digitization of currently paper-based process.
- Improved asset management of devices through the inherent switch operation logging ability of the ADMS system. This will allow us to keep track of the number of operations of devices and to proactively maintain them as per specification. Additionally, if devices have not been operated for an extended period, such systems can provide warnings to add extra steps in order to operate before execution of switching steps, avoiding device failure.

Assets/Devices Involved

The following Table 15 shows the existing system software that will be leveraged by ADMS:

Table 15: *Elexicon* Existing Software Leveraged by ADMS

Asset/Device	**Implementation Assumptions**
Distributed Energy Resources Management Systems (DERMS)	To control distributed energy resources.
Advanced Metering Infrastructure (AMI)	AMI System for Generation 3[8] meters will be leveraged to report voltages to VVO system and outage information to DA/FLISR.
Outage Management Systems (OMS)	OMS to integrate FLISR with ADMS and Customer Outage Reporting.
Communication Systems	Radio/Fibre, routers and data concentrators required for real-time data management.

[8] Elexicon is planning on upgrading its meters post 2025.

b) Volt-VAR Optimization

The requirement of the distribution system is to deliver power to the customer within the voltage range established in CSA 235-83-2015. Traditional system planning recommends setting the source voltage at the level that is near the top of the voltage window when the feeders are lightly loaded, and then examining the feeder tips for voltage violation in normal and contingency modes. The normal operating range for a 120/240V residential customers is 108/220V to 125/250V and in extreme operating conditions can be as much as 104/212V to 127/225V.

VVO combined with CVR, is an advanced application that optimally manages voltage levels and reactive power to achieve more efficient grid operation. The application of a VVO algorithm will switch capacitors, regulators and station on-load tap changes ("LTCs") to optimize the lines. VVO/CVR reduces system losses, peak demand, energy consumption, or a combination of all three with its two-way communication infrastructure and remote-control capability for capacitator banks and voltage regulating transformers. VVO typically involves the installation of switched capacitor banks at strategic locations throughout the system to improve voltage profile and reduce system losses. Remote operations can then manage reactive power by VAR management using real-time data. VVO is versatile and designed to work in various system design and operating conditions.

Expected Benefits

Implementing VVO provides for a more efficient distribution system. VVO/CVR would allow the distribution system to operate at the lower end of acceptable voltage ranges and to reduce reactive power in the distribution system, resulting in lower system losses, and overall reduction in system energy and demand.

In addition, for a high-DER future, VVO will be required to help manage voltage levels. Research studies have projected that a 1.5-3% of demand reduction is typically expected by implementing VVM tool. In the Whitby case, the lines are short, and the voltage profile is flat so the slightly more optimistic range of 2-3% is viable. This is a savings on the Customer Bill and a commensurate reduction in the LDC Cost of Power.

The following list provides a summary of the typical industry expected benefits of VVO implementation[9]:

- Energy Reduction: 2-3% based on a 5% source voltage reduction
- Peak Reduction: 2-3% based on a 5% source voltage reduction
- System Losses Reduction: <0.1%
- Greenhouse Gas Reduction

Taking the potential energy reduction of 3%, the below table highlights the potential equivalent greenhouse gas emissions reductions. The analysis has taken the total energy usage for 2021 for the Whitby Rate Zone, and then for each year increased this by the same ratio as indicated in the load forecast to calculate each years Total Energy Usage (kWH) for the 2022-2041 period. A report[10] published by The Atmospheric Fund (TAF) in 2021 developed energy savings emission factors from IESO published data and their own methodology suggested use of a Marginal Emissions Factor (MEF) to quantify GHG savings from energy efficiency savings. This enables the calculation of the TCO2e GHG savings. Using the MEF the calculated GHG savings, over the 20 year forecast period and based on a 3% annual energy usage savings, is 202,977 TCO2e. The below table 16 shows the annual GHG savings from 2022-2041:

[9] Appendix B-5
[10] 20211116_TAF_Emissions-Factors-Guidelines

Table 16: *GHG* Savings 2022 to 2041

Year	GHG Saved (TCO2e)
2022[11]	-
2023	7,053
2024	6,936
2025	9,559
2026	9,303
2027	8,942
2028	9,803
2029	9,272
2030	10,006
2031	11,128
2032	10,443
2033	10,378
2034	10,865
2035	10,655
2036	11,232
2037	12,606
2038	12,858
2039	13,963
2040	13,849
2041	14,126
20-Year Total	**202,977**

Further analysis has been carried out to quantify the loss reduction and energy savings due to the addition of a capacitor. Full details of this analysis is captured in Appendix B-VVO Impact Preliminary Loss Study of Appendix B-5 of this ICM application. Four typical 13.8 kV feeders are considered for comparison. The terms used below for long, short, lightly, and heavily loaded are not defined but reflect a preference to review a variety of

[11] Project does not start until 2023 so no GHG emission savings can be accounted for in 2022.

scenarios. These four scenarios reflect the extremes of heavily and lightly loaded feeders and the extremes of short and long feeders.

- Short Feeder/Lightly Loaded
- Long Feeder/Lightly Loaded
- Short Feeder/Heavily Loaded
- Long Feeder/Heavily Loaded

A 3-phase capacitor of 1500 KVAR, with a nominal voltage of 15 kV is going to be added to the feeders for the comparison assessment of voltage profile from the furthest node of the feeder from station to determine the voltage rise at the furthest node. Then a cost estimate evaluation has been conducted to determine the cost saving due to the loss reduction caused by adding the capacitor. Table 17 illustrates the maximum potential energy savings per type of 13.8kV feeder. As can be seen energy savings per feeder can vary from 5,000kWh/year to 38,544kWh/year.

Table 17: Potential Energy Savings Per Type of 13.8kV Feeder

	Short Feeder		**Long Feeder**	
	Lightly Loaded	Heavily Loaded	Lightly Loaded	Heavily Loaded
Maximum Energy Savings per Feeder (kWh/year)	5,256	not modelled	6,132	38,544

Assets/Devices Involved

The following table 18 lists the assets that will be involved in the VVO upgrade:

Table 18: List of Assets Involved in VVO Upgrade

Asset/Device	Implementation Assumptions
Feeder Voltage Regulator	One 3-phase controllable Voltage regulator per feeder unless the stations are fitted with LTCs that met the purpose.
Capacitor Bank	On average, 1 Capacitor Bank per feeder. *Note: Smaller feeders may not need capacitors; larger ones may need two sets.*
Voltage Sensors	Voltage sensors at the tips of feeders capable of communicating to the station. *Note: The latest generation of AMI metering would be capable of such communication but are not expected to be deployed within this project window. This will be investigated for delivery post 2025.*
Make Ready Poles	Make ready poles are required to support the Capacitors and Regulators.

c) **Fault Location Isolation and Service Restoration**

Fault Locating is part of the FLISR system which provides better monitoring of the distribution system by providing real time data, as well as the capabilities to remotely locate faults. This allows crews to restore power faster during outages by spending less time trouble shooting faults. Fault Locating software integrates with remote sensing devices such as CFCIs and AMI technology and relays to algorithmically locate faults and communicate with operations staff.

Isolation and Service Restoration is part of the FLISR systems, also known as a self-healing grid or DA.The DA component of FLISR is a mature technology and has been adopted in many jurisdictions. DA typically comprises several sectionalizing devices (normally closed) per feeder (optimally 3), a tie switch (normally open) and control of the feeder breaker. Excluding the breaker control, which is inherent in station operations, this is called 3.5 devices per feeder with the tie switch being counted as half a device on both feeders.

The Whitby Smart Grid project includes an extension of previous distribution automation activities to encompass the entire Whitby rate zone. Previous efforts to modernize the distribution system in the Whitby rate zone, have included the installation of automation-ready distribution switches in 17 locations on 6 feeders generally following the 3.5 devices per feeder concept as proposed in this project. Automation-ready devices are located at:

- Feeder 8F4 – 4 devices
- Feeder 10F1 – 3 devices
- Feeder 10F6 – 3 devices
- Feeder 12F2 – 2 devices
- Feeder 14F2 – 1 device
- Feeder 15F3 – 4 devices

FLISR software integrates with remote switches and instruments to restore power during major feeder level outages. If the restoration can occur within 1 minute, affected customers are said to have experienced a “momentary fault” rather than a “permanent fault”. From the context of reliability statistics, a momentary event is preferable and counts towards the Momentary Average Interruption Frequency Index (MAIFI) index, whereas the permanent fault counts against System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index CAIDI.

Expected Benefits

FLISR system reduces the duration, customer impact, and frequency of outages and identifies faults that need repairs in the distribution system. High penetrations of DERs, increases the needs for distribution system reliability. Thus, to quickly locate faults, maintain system reliability, and minimize outages, CFCIs will be added to the DA system. DERs increase distribution system complexity and traditional methods of fault locating may be too cumbersome, resulting in extended outages in a high-DER future. Incorporating FLISR systems will help improve system reliability

Additionally, DA reduces full feeder lockout faults to something that affects only a quarter of the feeder for a permanent fault while the rest of the feeder sees a momentary outage. CFCI, a component of DA also provides better information to the control center about the location of faults.

DA does not usually return a direct financial benefit but rather is often the most economical way to achieve some other system goal (usually reliability improvement). Part of the automation benefit is a reduction in fault locating time, which in some reports can reduce driving and isolating time from 100 minutes to 20 minutes, but this ranges greatly depending on the area size, location of emergency crews and dispatch arrangements. With the reduction in truck rolls this can result in the reduction of O&M costs but these costs can vary depending on the location of emergency crews and any dispatch arrangements. It is therefore hard to quantify these potential financial benefits.

Table 19 below describes the impact of DA on the number of customers affected and the duration of outages that is experienced.

Table 19: Reliability Impact With and Without DA

Traditional System	With DA
Unaffected Customers (approx. 75% of feeder) out for 1 hour	Unaffected customers (75%) out for <1min (Momentary)
Affected Customer (25%) out for full repair duration plus 1 hour.	Affected customers (25%) out for full duration of repair.

The following provides a summary of system reliability improvements through FLISR/DA systems implementation based on a historical example. These results are based on looking at a historical period (April 2020 – January 2022). The following assumptions were incorporated in the outage data example review:

- Only full feeder outages were examined (fused laterals and services are not automated)
- Where an outage was reported to have multiple durations, the assumption is that the longest restoration time is where the permanent fault is located, and the shorter times are restoration procedures. This is not universally true in complex outages, but it is reasonable.
- Sections are assumed to be divided exactly in quarters for restoration.
- 75% of the feeder is assumed to be restored instantly, and 25% is assumed to experience the full duration of the repairs.
- Station level outages and those on the 44kV system are assumed to be not switchable, however it is likely that some improvement could be made with feeders that are backed up from alternate supplies.

Table 20 shows the analysis of these historical outage with and without DA. Further detail on the analysis of DA impact is provided in the Appendix C of the Appendix B-5 of this ICM application.

Table 20: Reliability Analysis of Historical Outages With and Without DA

Study Data			
Study Period (Apr 2020->Jan 2022)	33 (months)		
Approx. Customer Count	46,189		
Total Feeder Lockout Events	69		
	As Reported	**After DA**	**Improvement w/ DA**
Total Customer Outages	110,155	35,622	- 74,500 Customer Outages
Total Customer Momentary	-	74,533	+ 74,500 Momentary Outages
Total Customer Hours Interrupted	131,112.89	57,341.34	- 73,700 Customer Hours Interrupted
Contribution to SAIFI	0.87	0.28	More than ½ outage / customer.
Contribution to MAIFI	-	0.59	Not typically a concern
Contribution to SAIDI	1.03	0.45	More than ½ hour saved /customer.

Notre: The similarities in the reduction of Customer Outages and Customer Hours is driven by the fact that the target for CAIDI is about 1hr.

Assets/Devices Involved

The following table 21 lists the devices and elements are assumed to be involved in FLISR/DA systems upgrade:

Table 21: Devices and Elements to be Involved in FLISR/DA Upgrade

Asset/Device	Implementation Assumptions
Station Recloser	All existing Breaker/Reclosures are suitable for DA.
DA Switch	Most DA switches will be installed where there are existing load break switches. Some of the switches will be pad mounted, but for feasibility estimating, all devices are assumed to be on poles. Approximately 17 DA switches exist within the Whitby Area.
Relays	Existing Relays in each station will be able to support DA.
Make Ready Poles	One pole per feeder will need make-ready work.
CFCIs	Required to better monitor the system by providing real-time fault location data.
Communication Systems	Station level communications exist in each DS/TS.

DER Incentives and Total Distribution System Operator Model

To enable further grid modernization and the acceleration of DER adoption and integration in the grid, Elexicon is looking into potential DER Enabling Program and the implementation of an enhanced local capacity market. As part of the ADMS element of this project and partially funded through the NRCan, Elexicon will carry out an initial feasibility study on active demand management program designs. Future proposals will be brought forward as part of a separate application in the future that will further explore the solutions for a future DER and DSO model. The active demand management program design will include:

- The modeling of high impact program(s) that would enable system-wide capacity relief and identifying target areas to potentially trial programs within Elexicon's service area.
- Providing suggested programs by customer type, controllable assets, and outcomes.
- Determining potential program roll-out scenarios including customer engagement methods, incentives, and suggested program administration/management methods.

The following is a very high-level summary of Elexicon's directional thinking on these items.

Elexicon believes the York Region Demo can be built upon to create a Local Capacity Market which continues to enable commercial and aggregator participants, while also engaging general service customers directly to install DER technologies and connect with commercial partners to participate in serving local capacity needs. Larger participants and aggregators would participate in the Local Capacity Market in much the same manner as they have in the YRDemo.

Elexicon is considering a targeted DER Enabling Program that an end-use customer can access to reduce their capital cost of installing DER systems. Elexicon is considering various funding sources for the DER Incentive Program, including NRCan, other government sources, and the potential of a Conservation and Demand Management

("CDM") program under the OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (CDM Guidelines[12]) to fund upfront customer incentives. The DER Enabling Program will incent technology-agnostic end-use customers to install battery storage, in agreement for access to these resources for the purpose of managing local demand as needed.

While an important piece of enabling the success and benefits of the project, Elexicon will not bring forward detailed relief requests for its CDM proposal or Local Capacity Market proposal within its ICM application. As noted, the in-service date for the Whitby Smart Grid is such that Elexicon anticipates ample time will be available to bring forward its CDM proposal and Local Capacity Market proposal once certainty of the Whitby Smart Grid's implementation is in place. Further details on a potential DER Enabling Program and Local Capacity Market can be found in Appendix B-3 of this ICM application.

3.3. Compliance Considerations

The following section lists key compliance considerations by Elexicon in the implementation of this project.

Distribution System Code – A distributor must document in its Conditions of Service the operating practices and connections policies of the distributor as stated in Section 2.4 of the Distribution System Code. Elexicon's Conditions of Service is compliant with the Distribution System Code.

Performance Measures - As stated earlier it is expected that with the implementation of smart grid technology there will be reliability improvements. The following provides a

[12] OEB- 2021 Conservation and Demand Management Guidelines for Electricity Distributors.

summary of an example of system reliability improvements through FLISR systems implementation based on historical period of April 2020 to January 2022:

- SAIFI improving from 0.87 to 0.28
- SAIDI improving from 1.03 to 0.45
- CAIDI ~ 40 minutes improvement per complex outage.
- MAIFI going from 0 to 0.59

Leave to Construct - Leave to Construct approval is not required for these investments.

Ontario Cyber Security Framework - Elexicon is required to comply with the Ontario Cyber Security Framework and new smart grid investments will leverage advanced technology while complying with standards for interoperability and cybersecurity.

ESA 22/04 regulation – When constructing or updating new electrical distribution infrastructure, Elexicon must follow O. Reg. 22/04 (Electrical Distribution Safety). In compliance with O. Reg. 22/04, Elexicon ensures its distribution system is safe and poses no undue hazard to the public. These requirements apply to customer connections.

4. Project Alternatives

4.1. Alternative Descriptions and Comparative Analysis

Table 22: Summary Comparison of Alternatives

Option	**1**	**2**	**3**
Scenario Description	Deployment of Whitby Smart Grid by 2025, with funding through this ICM application	Deployment of Whitby Smart Grid by the end of 2028, using Elexicon's existing capital expenditure allocation.	Do nothing and do not pursue the Whitby Smart Grid project
Project Scope	This entails to implementation of the proposed technologies across the Whitby rate zone by 2025.	This entails to elongated implementation of the proposed technologies across the Whitby rate zone by extending the delivery period to the end of 2028.	This entails Elexicon not modernizing its grid.
Total Capex	$47.2MM[13]	$56.6MM[14]	N/A
Project Pros	The following key benefits will be realized through the Whitby Smart Grid a. The implementation of ADMS:	The same benefits as Option 1 will be realized, albeit in a delayed manner due to the extended timeline.	Ratepayers will incur no incremental costs under this option.

[13] $4,041,000 of this is NRCan approved funding.
[14] This cost accounts for an increase in costs due to the extension of the timeline for the project.

Option	1	2	3
	i. Enables an integrated system approach to electric power system operations and control that spans transmission, distribution, and local energy networks such as buildings and microgrids. ii. Enables the utilization of real-time, spatial data of all connected devices to manage and optimize grid operations iii. Achieves interoperable and integrated operations between legacy and new and emerging systems		

Option	1	2	3
	b. Improved system reliability and operations efficiency through Distribution Automation and Fault Location Isolation and Service Restoration reducing costs for customers. c. Once a local capacity market is developed, there could be avoided or deferred distribution capital investments enabled through DER capacity, reducing future costs to customers. d. Reduced system losses and overall consumption reduction through Volt-VAR Optimization including the reduction of Greenhouse Gases (GHG),		

Option	1	2	3
	reducing costs to customers; and e. Reduced energy commodity costs from the IESO markets by enabling local DER resources when more cost effective to do so. f. Overall enhanced ability to better manage future load growth whilst reducing minimizing system losses and improving system reliability. While a more elongated deployment is an option, Elexicon has produced a compressed timeline for the following reasons: a. The rapid deployment of the Whitby Smart Grid ensures that the customers bearing the costs of		

Option	**1**	**2**	**3**
	investment will also reap the benefits at approximately the same time; and, b. Elexicon strongly believes the Whitby Smart Grid should not only be enabled in time to facilitate Sustainable Brooklin but should also be in a stable state such that integration of a new DER-laden community will be seamless.		
Project Cons		Whilst this option is technically possible, there are wider impacts from this option. The first is that to the current NRCan funding has a delivery date tied to	The “do nothing” option, is not recommended because it prevents Elexicon from modernizing its grid and keeping up with the technological advances facing all

Option	1	2	3
		it, which is March 31, 2025. Should Elexicon not meet this date, the NRCan funding would be withdrawn. This would have a detrimental impact on the overall Whitby Smart Grid project. Furthermore, Elexicon would be spending year on year and average of approximately \$9 MM. As this option would have to be funded through the existing rate base this would have a significant impact on what other projects Elexicon could deliver. Elexicon would have to delay and or cancel \$9 MM a year worth of projects elsewhere. For context, using the discretionary expenditure categories, \$9 MM a year of	utilities. This is contrary to good utility practice. Additionally, if Elexicon pursues Option "3", the NRCan Funding would be forfeited as the timeframe for funding is four years, starting February 1, 2022 to March 31, 2025. Although ratepayers will incur no incremental costs under this option, ratepayers would not receive any of the benefits associated with the Whitby Smart Grid Project. In addition, to enable the integration of DER and realize the benefits of the Sustainable Brooklin project, it is critical that the first tranche of the Whitby Smart Grid project is carried out. If it is not

Option	1	2	3
		expenditure is the equivalent of: • 70% increase on the average yearly General Plant expenditure • 58% of the average annual System Renewal expenditure • At least double the average expenditure of System Service expenditure. Breaking this down further, the current average forecast capital expenditure in the Whitby Rate Zone is $10 MM a year. Therefore when comparing to just the average Whitby capital expenditure, this would require Elexicon to defer 90% of its current projects and spend. Again this would not be feasible as the current identified projects are	carried out, then no DER integration will be possible for Sustainable Brooklin. This means customers will not be able to realize the benefits previously stated. Further, if Elexicon does not make its system Smart Grid ready, there could be a future decline in reliability performance in years to come as the DER penetration growth would make it more difficult for Elexicon to operate the grid under two way power flow and thus maintaining status quo level of reliability.

Option	1	2	3
		required to be carried out to maintain the system. This demonstrates that it would be not feasible economically to be able to defer all this potential capital. By deferring this amount of capital expenditure from discretionary projects would have a detrimental impact on Elexicon's ability to continue to deliver a safe, reliable, and efficient service for its customers.	
Project Economics	From the NPV analysis in two out of the three cases show the NPV for Option 2 is greater than the net Whitby Smart Grid costs for Option 1. See section 4.1.1 for more detailed NPV analysis.	This option extends the timeline of the project and therefore inherently the overall cost of the project will be incrementally more due to increase in costs each year both from supply chain costs and inflation. From the NPV analysis in two out	Whilst ratepayers incur no costs, they will also not realize any of the benefits being proposed.

Option	**1**	**2**	**3**
		of the three cases show the NPV for Option 2 is greater than the net Whitby Smart Grid costs for Option 1. See section 4.1.1 below for more detailed NPV analysis. In addition, as this option would entail Elexicon to use its existing approved capital funding allocation, this would have a severe impact on other projects. See section 4.1.1 for details.	
Customer Feedback	Overall, Elexicon has had positive feedback and support for the project. This includes from the developers of the Sustainable Brooklin, who see the 1st tranche of this project being a key enabler of their overall project. Appendix B-6 contains a full list of the letters of support Elexicon has received. Elexicon conducted a customer engagement survey from October to December 2020. A key outcome that supports the proposed project was that *"Customer's support "investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage" and felt Elexicon should focus on "Preparing the grid for new types of uses, like EV's & renewable generation."*		
Other Constraining Factors	The first tranche of the Whitby Smart Grid is critical in	This option would put at risk the approved NRCan	This option would put at risk the approved NRCan

Option	1	2	3
	enabling the DER integration and functionality of the Sustainable Brooklin Project.	funding which has an eligible expenditure period from February 1, 2022 to March 31, 2025. In addition, the overall cost of delivering this solution will be higher than option 1 due to the additional inflation and increased material costs that will need to be accounted for in the additional years.	funding which has an eligible expenditure period from February 1, 2022 to March 31, 2025.
Preferred Alternative	X		

4.1.1. Economic Analysis

Table 23 shows the overall estimate capital cost, associated NRCan funding and the net capital cost for Option 1 with the project being delivered by March 31, 2025.

Table 23: Option 1 Capital Costs $'000

	Capital Costs ($'000)
Estimated Capital Cost	$47,212
Approved NRCan Funding	$4,041
Net Project Cost	$43,171

Table 24 shows the annual cash profile for Option 2, adjusted for Consumer Price Index (CPI) of 7.2%[15]. An NPV has been performed using three different discount rates: 3%, 5%, and 8%. Elexicon's current discount rate is 3.2%. The results of the NPV are shown in Table 25.

Table 24: Option 2 Capital Cash Profile

Elexicon Cash Profile ($'000)							
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
CPI Adjusted	7,869	8,435	9,043	9,694	10,392	11,140	56,571

Table 25: Option 2 NPV ($'000)

	Total Cost	**NPV (3% Discount Rate)**	**NPV (5% Discount Rate)**	**NPV (8% Discount Rate)**
CPI Adjusted	$ 56,571	$ 50,772	$ 47,386	$ 42,913

Completing the project by the end of 2028 would cause Elexicon to forfeit the NRCan Funding, since a 2028 in-service date for the Smart Grid Project exceeds the required completion date of March 31, 2025 under the NRCan Funding. Absent of the NRCan Funding, the ratepayer will be liable to cover the full cost of $56.6 MM (CPI adjusted) to implement the Whitby Smart Grid project. Table 24 provides the NPV, calculated for different discount rates (3%, 5%, and 8%). For a 3% and 5% discount rate, the NPV exceeds $43.1 MM which is the net Whitby Smart Grid project cost after deducting NRCan Funding. Whilst the NPV at a discount rate of 8% does not exceed the net cost, this scenario is an unlikely one to unfold. For example, the current discount rate Elexicon used is 3.2%. At this rate (3.2%) the NPV would exceed the net Whitby Smart Grid project costs.

[15] Statcan.gc.ca – Consumer Price Index May 2022

In addition, Option 2 requires Elexicon to use its existing capital funding allocation. In order to deliver the Whitby Smart Grid Project this would have an impact on other project spending. Table 25 shows the current forecasted capital allocation by OEB category for 2023- 2028. Table 26 shows the percentage of spend that the Whitby Smart Grid would account for in each OEB category, as well as the percentage against the overall capital allocation. As can be seen this would have a significant impact on the amount of spending and therefore projects that Elexicon would have to defer or cancel in order to deliver the Whitby Smart Grid under Option 2. On average, Elexicon would need to defer or cancel 25% of its current capital spending to accommodate the Whitby Smart Grid project under current capital allowances.

Table 26: Current Forecast Capital Expenditure 2022-2028 by OEB Category

OEB Category	$'000					
	2023	2024	2025	2026	2027	2028
GENERAL PLANT	8,662	4,365	3,747	4,546	8,000	6,000
SYSTEM ACCESS	9,370	8,683	10,198	11,138	13,000	13,000
SYSTEM RENEWAL	14,727	13,821	18,195	16,474	16,000	18,000
SYSTEM SERVICE	7,808	9,156	5,033	3,103	3,000	2,000
Total	40,568	36,025	37,173	35,262	39,000	39,000

Table 27: Whitby Smart Grid Percentage of Current Forecast Capital Expenditure by OEB Category

OEB Category	Percentage of current approved capital spend						
CPI Adjusted	2023	2024	2025	2026	2027	2028	Average
GENERAL PLANT	87%	211%	226%	194%	130%	186%	172%
SYSTEM ACCESS	87%	94%	90%	88%	80%	86%	88%
SYSTEM RENEWAL	52%	60%	50%	61%	65%	62%	58%
SYSTEM SERVICE	98%	94%	181%	323%	346%	557%	267%
Total	19%	23%	24%	28%	27%	29%	25%

4.2. Rationale for Preferred Alternative & Consequences of Inaction

Table 28: Rationale for Preferred Alternative

Preferred Alternative: Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.		
Benefits	**Rationale**	**Consequences of Inaction**
Customer Benefits	The rapid deployment of the Whitby Smart Grid ensures that the customers bearing the costs of investment will also reap the benefits at approximately the same time. Customers will see direct savings in their bills due to	If the Smart Grid project is not carried out, this will affect the delivery of the Sustainable Brooklin project and as such reduce the likelihood of an uptake in DER and EV's, and therefore

<table>
<tr><th colspan="3"><u>Preferred Alternative:</u> Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.</th></tr>
<tr><th>Benefits</th><th>Rationale</th><th>Consequences of Inaction</th></tr>
<tr><td></td><td>voltage and thus power reduction. The improved reliability and resilience of the new system will allow Elexicon to consider defer or eliminate certain capital expenditure, subject to certain level of DER penetration.</td><td>any of the expected benefits would not materialize.
In addition, the overall benefits summarized in section 3.2 will not be realized.</td></tr>
<tr><td>Grid Resiliency</td><td>Through the installation the smart grid technologies, this allows Elexicon to automatically monitor and manage the distribution system. This includes improvements to reliability and minimize energy loss:

<u>Reliability</u>
• Reduction of Permanent faults to a quarter.
• Truck rolls avoided, locating time reduced.
• Reduction of SAIDI, SAIFI and CAIDI

<u>Loss Reduction</u>

Small, but positive, primary line losses on a distribution system is in the range of 5-10% of load[16]. The</td><td>With the forecasted increase of the load demand over the next 20 years, Elexicon needs to ensure it can continue to deliver safe and reliable energy supply. One way of doing this is by installing these proposed smart devices that will enable Elexicon to automatically monitor and manage the distribution system. If this ICM funding is not approved, it will put at risk future reliability and will impact Elexicon's ability to maintain a resilient grid and accommodate future growth.</td></tr>
</table>

[16] Appendix B-5

<u>Preferred Alternative:</u> Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.		
Benefits	**Rationale**	**Consequences of Inaction**
	application of CVR reduces these losses by 2-3%. The installation of the proposed software and hardware will allow Elexicon to be able to accommodate the future demand and uptake and integration of a high-DER community.	
Operational Efficiency and Cost Effectiveness	The installation the smart grid technologies will enable improvements in system losses, which leads to energy savings. Through the installation of capacitor banks at strategic locations energy savings can vary from 5,000kwh/year to 38,544kwh/year per feeder. These potential savings are described in more detail in section 3.2 of this document and Appendix B-5 of the ICM application. The deployment of DERs and the technology required to support them creates long-term opportunities for distributors to defer or avoid traditional capital investments as learnings accumulate from	If the Whitby Smart Grid project is not carried out, this will have a negative impact on the effectiveness of the operation of the grid, especially considering the growing capacity demands and the future potential high DER-uptake.

<u>Preferred Alternative:</u> Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.		
Benefits	**Rationale**	**Consequences of Inaction**
	early operation of a Smart Grid with high DER uptake. Elexicon conducted an analysis of the potential for deferred capital specific to the Sustainable Brooklin project. This illustrative case was based on a review of load on the Whitby TS T1/T2 utilizing a 20-year load forecast set against the 90MW LTR of Whitby TS T1/T2. In this illustrative case, battery-plus-solar DER penetration would need to reach 3% to defer upgrades 1 year, 19% to defer upgrades 5 years, and 30% to defer upgrades 10 years. Elexicon also sees options for capital deferral or alternative asset designs which would be enabled by the Whitby Smart Grid project. Depending on the pace of construction within the Whitby area, a high DER-uptake level creates the opportunity for deferrals in the build-out of localized capacity to serve new homes. This will create savings across the Whitby rate zone.	
Safety	Safety is top priority for Elexicon, and these	Safety is top priority for Elexicon, and these investments will meet

Preferred Alternative: Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.		
Benefits	**Rationale**	**Consequences of Inaction**
	investments will meet all the latest safety standards.	all the latest safety standards.
Cyber Security/Privacy	New communications systems deployed will include the latest in security and data safety features	Existing technology is at risk of becoming exposed to new cyber-attacks.
Environmental Benefits	The enablement and use of DER's is one of the key solutions to facilitating the energy transition and delivering on net-zero commitments by the Town of Whitby and Region of Durham, and ultimately the provincial and federal governments net-zero plans. Reduced system losses and overall consumption reduction, resulting in the reduction of Greenhouse Gases (GHG). Taking an average energy savings of 16,644 kwh/year per feeder and applying this across all 44 13kV feeders, this is the equivalent of energy consumed by:[17] • 55 passenger vehicles • 75,326 liters of gasoline or, • 64 homes electricity use for one year or,	Net-zero targets and reductions in greenhouse gas emissions would not be enabled if this project were not completed as technologies will not be in place to manage increased loads efficiently and effectively to minimize system losses and manage energy consumption. It is also less likely customers will install DER solutions that would further facilitate net zero objectives.

[17] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/calculator/ghg-calculator.cfm

<u>Preferred Alternative:</u> Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.		
Benefits	**Rationale**	**Consequences of Inaction**
	• 420 barrels of oil.	
Coordination/Interoperability	The ADMS system is the core of Elexicon's ability to coordinate and "interoperate" with distributed energy resources, including renewables, storage and Non-wires alternatives. Elexicon works closely with all its stakeholders and customers to understand their needs and plans. Elexicon has identified the requirements of the Sustainable Brooklin project and the importance of this project in enabling it. Elexicon and the developers have been in constant communication on the best solution to deliver the most optimal customer benefits within the desired timelines. Elexicon continues to collaborate with the developer as the details of the project is developed. Letters of support from its stakeholders are attached in Appendix B-6 of the ICM application.	
Conservation Demand Management		

<u>Preferred Alternative:</u> Deployment of Whitby Smart Grid by 2025, with funding through this ICM application.		
Benefits	**Rationale**	**Consequences of Inaction**
	CVR can be considered as conservation demand management. Elexicon is considering a targeted DER Incentive Program that an end-use customer can access to reduce their capital cost of installing DER systems. Elexicon is considering various funding sources for the DER Incentive Program, including the potential of a Conservation and Demand Management (“CDM”) program under the OEB’s 2021 Conservation and Demand Management Guidelines for Electricity Distributors (CDM Guidelines) to fund upfront customer incentives. Following the certainty of the Sustainable Brooklin project and Whitby Smart Grid, Elexicon will bring forward its CDM proposal.	Without the installation of the smart grid technologies through the Whitby Smart Grid, Elexicon cannot put in place the relevant mechanisms to encourage and manage DERs. Part of the Whitby Smart Grid project is to undertake an initial feasibility into the different active demand management program designs. Without this funding for this feasibility study, Elexicon cannot bring forward concrete and detailed CDM proposals.

4.3. Risk Mitigation

Risk Category	Description	Mitigation
Budget risk	The current cost estimates are class 4.	These costs will be refined further, as the project progresses.
Timeline risk	To accomplish the objectives of the Sustainable Brooklin project, the 1st tranche of this project needs to be completed. To fully utilize NRCan funding, the project is required to be completed by March 31, 2025. There are supply chain risks with several long-lead items.	Elexicon has put forward a timeline that will deliver the Whitby Smart Grid by March 31, 2025. This will enable both the Sustainable Brooklin project as well as allow Elexicon to fully utilize the NRCan funding. Elexicon is in regular contact with suppliers of long-lead items and has factored in the timings for the procurement of these items.
Savings risk	There is a risk that the proposed potential savings/benefits are not realized.	The first step in realizing the benefits is to ensure the full installation of all the devices across the entire Whitby system. Secondly, as mentioned in section 3.2, Elexicon is investigating proposals to incentivize DER adoption and introduce an enhanced local capacity market. Further proposals on these are being developed and will be brought forward in the near future (as early as 2023).

Technology Obsolescence	There is a risk that the technologies installed will become obsolete.	Whilst obsolescence is always a risk, it should not stop the implementation of these devices, as they are required to enable the needs and objectives outlined. Elexicon stays abreast of technology changes and will ensure it is installing devices that meet the latest technology standards.
Operational Technology Integration	The new field hardware that is being installed as part of the Whitby Smart Grid project requires integration into Elexicon's operating system.	Field Integration costs have been estimated at a Class 4 level. Other systems integration such as within the ADMS and communications systems are generally part of the ADMS project. These costs are estimated at a Class 5 level. Elexicon is installing an ADMS which is critical in integrating and enabling the functionality of the new technologies that will be installed. Elexicon has ensured that any additional integration costs have been captured in this project to ensure the full functionality and benefits are realized from the overall project.

1

5. Appendix A1– Example Future-State Schematics

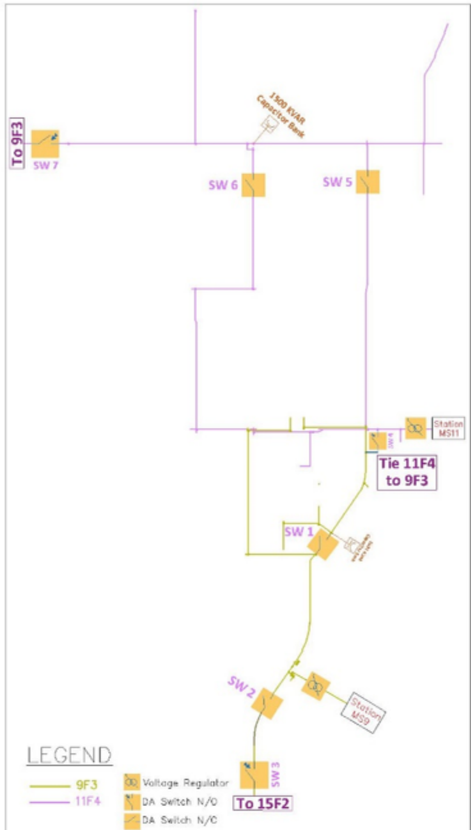


Figure 3: Whitby Smart Grid Typical Layout 9F3 and 11F4

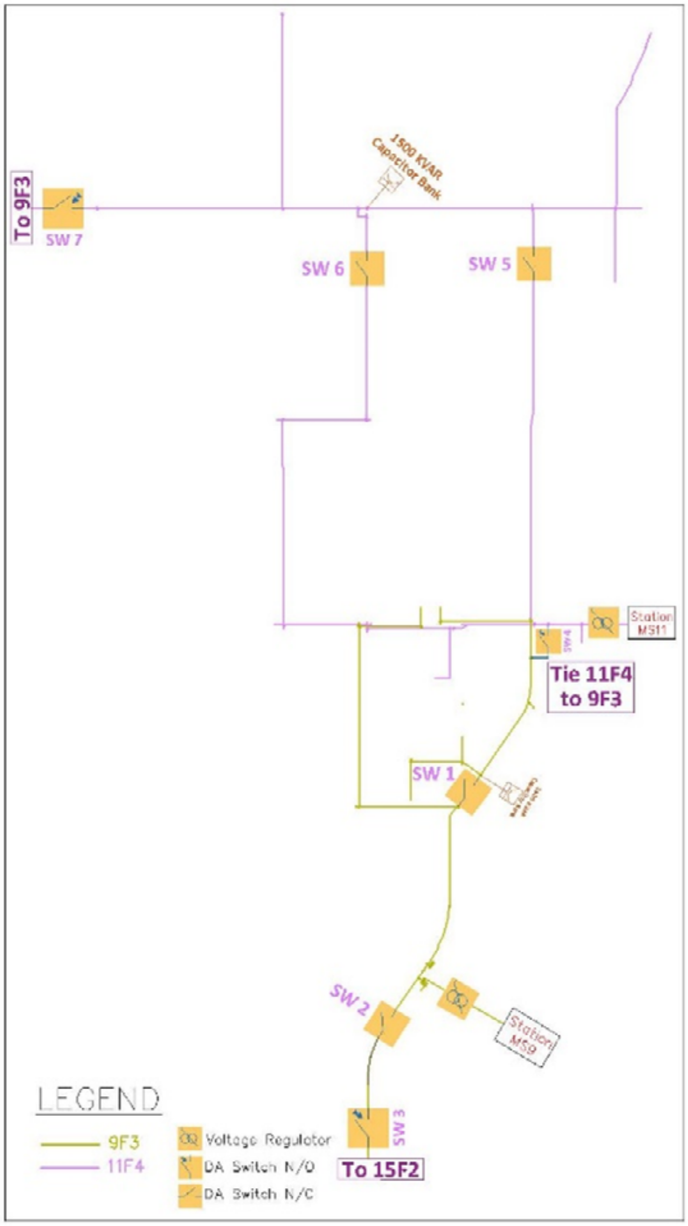


Figure 4: Whitby Smart Grid Typical Layout 9F3 and 11F4

elexicon ENERGY

APPENDIX B-2

Sustainable Brooklin

Business Case

Table of Contents

List of Tables

List of Figures

1. Executive Summary

Elexicon is at a key juncture to develop a modern, flexible, energy efficient, and resilient high-DER grid that is the first tranche DER site for the Whitby Smart Grid, responsive to the federal, provincial, and local levels of government climate change policies, and connect south Whitby to the emerging North Brooklin community.

The changing demands of the distribution system is creating a need for a new type of system operation. The "Grid of the Future" will need to support high penetrations of distributed energy resources ("DERs"), manage electric vehicle ("EVs") charging, and support renewable energy such as roof top solar. Looking ahead, the distribution system may take on a distribution system operator ("DSO") role and handle the dispatch and settlement of locally operated distributed generation, and aggregated customer side storage under distributed energy resource management ("DERMs") scenario.

Elexicon has been engaging with a group of developers (known as the Brooklin Developers), who are looking to build DER and EV-ready homes in the North Brooklin area of the Whitby region. In 2015, the Town of Whitby undertook a comprehensive study[1] to guide and manage growth in the Brooklin area. The plan estimates Brooklin to reach a population capacity of about 80,000 at full development. Over the next twenty years, the Brooklin Developers have plans to provide 10,081 to 11,217[2] affordable and energy-efficient homes in a new residential community in the North Brooklin area to serve some of the 80,000 population. Other developers will likely supply homes for the remaining population that the Brooklin Developers proposal currently does not.

[1] "Brooklin Study Secondary Plan and Transportation Master Plan," Town of Whitby, Jan 2015

[2] This is the number of homes that the Brooklin Developers are proposing with the expectation that other developers will come along in future years and add to the population of homes.

In light of the significant growth in this area, Elexicon, in close consultation with the Brooklin Developers, is proposing the Sustainable Brooklin project. The core feature of the Sustainable Brooklin project is an approach through which new construction homes will be built DER-and-EV-ready, with standard rough-ins for rooftop solar, battery storage, and EV charging ("Standard Rough-In"). The estimated cost to the Brooklin Developers to install the Standard Rough-In is approximately $23M. As a result of the Brooklin Developers incurring incremental costs to build Standard Rough-In's, Elexicon is requesting an exemption from Section 3.2 of the Distribution System Code ("DSC"). As discussed throughout the ICM application, Elexicon believes the fairness principle justifies this quid-pro-quo treatment to exempt the Brooklin Developers from paying a capital contribution to construct the Sustainable Brooklin project.

To accommodate near term and long term forecasted demand within North Brooklin, the first phase of development requires Elexicon to construct two new 27.6 kV feeders connecting the North Brooklin development to Whitby TS DESN 1.

Elexicon has already outlined its plan for the 'Grid of the Future" with the Whitby Smart Grid being one of the key projects that will enable this through the installation of Smart Grid hardware and software. The Sustainable Brooklin project is also another key project that further enables this 'Grid of the Future" by supporting the development of a DER and EV-ready community. Along with the assets being installed as part of the Whitby Smart Grid, the connection of these homes will allow Elexicon and its customers to reap the benefits of a more sustainable and smarter grid and community.

2. Project Description

The Region of Durham and Elexicon's Whitby rate zone are forecast to experience significant customer growth in the coming decades, including in the community of Brooklin. Over the next twenty years, the Brooklin Developers have plans to provide affordable and energy-efficient homes to approximately 10,000 homes in a new residential community in the North Brooklin area. The Brooklin Developers anticipate that residential construction will occur in three phases, with electricity demand increasing as: (i) Brooklin constructs new homes; and (ii) other real estate developers build residential and commercial properties in the North Brooklin area. There are also plans by other developers (herby referred to as "Developers") that have plans to build additional future homes.

In 2015, the Town of Whitby undertook a comprehensive study[3] to guide and manage growth in the Brooklin area. The growth plan estimates a declining average household size in the Region of Durham, from 3.02 persons per unit in 2006 to 2.45 persons per unit in 2056. The plan also estimates Brooklin to reach a capacity of about 80,000 people at full development.

In light of the significant growth in this area, Elexicon, in close consultation with the Brooklin Developers, is proposing the Sustainable Brooklin project. The core feature of the Sustainable Brooklin project is an approach through which new construction homes will be built DER-and-EV-ready, with standard rough-ins for rooftop solar, battery storage, and EV charging. The project would also facilitate optional upgrades for buyers to purchase homes that include fully functional DER and EV systems. The Brooklin Developers accounts for 87% of total household construction in Brooklin. The Brooklin

[3] "Brooklin Study Secondary Plan and Transportation Master Plan," Town of Whitby, Jan 2015

Developers estimates 10,081 to 11,217 new homes will be built by 2041. The Brooklin Developers is proposing to build approximately 700 DER/EV-ready homes a year for the next 20 years.

To accommodate near term and long term forecasted demand within North Brooklin, the first phase of development requires Elexicon to construct two new 27.6 kV feeders connecting the North Brooklin development to Whitby TS DESN 1 as shown below in Figure 1:

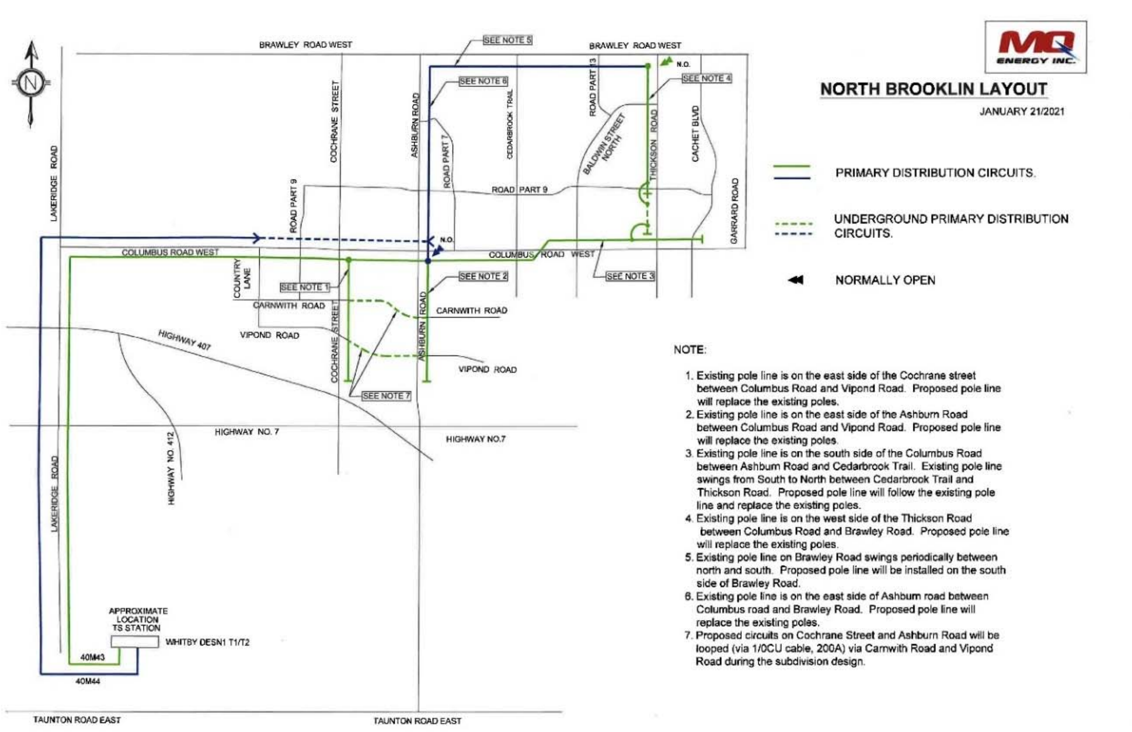


Figure 1: Distribution Infrastructure Layout to Connect North Brooklin

Initially, each of the pole lines will be strung with a single circuit but will have the capacity to accommodate three circuits each, in anticipation of future growth. Consistent with broader plans for the Whitby Smart Grid, Elexicon intends to build the new distribution assets servicing Sustainable Brooklin to incorporate innovative functions and features such as Volt-Var Optimization ("VVO") which leads to conservation voltage reduction ("CVR"), Fault Location Isolation and Service Restoration ("FLISR"), Communicating Faulted Circuit Indicators ("CFCI"), Distribution Automation ("DA") and a supporting Advance Distribution Management Systems ("ADMS"). On the back of these technologies, Elexicon's assets in North Brooklin will be capable of automatically monitoring and managing the distribution system, with the foundation set for future capability of the integration of DERs. The installation of the VVO, FLISR/DA, and CFCI functionality is part of the first tranche of the Whitby Smart Grid project. The ADMS will ensure that the relevant systems being put in place integrate the VVO, FLISR/DA and CFCI functionality. Details on these installations and the benefits are described in further detail in Appendix B of this ICM application.

The current estimated cost for this project is $26.6 MM[4]. To be clear, the costs in this business case only cover the construction of the two new 27.6kV line and associated equipment. The installation of the smart grid technologies, including ADMS, will be conducted through the Whitby Smart Grid project. Elexicon's best information at this time, and guidance from the Brooklin Developers is the first tranche of the DER and EV-ready homes are to be energized by Q3, 2023.

[4] This is a Class 4 estimate.

3. Basis for Action

The following section describes both the current state of the Brooklin service area within the Whitby region and the desired future state. The current state will describe where the current system does not deliver and what will be required in the future. The future state describes what is being proposed and the key benefits the proposed technologies will bring. In addition, any compliance considerations are also described.

3.1. Current State

Currently, the town of Brooklin is served from a 13.8kV system which is stepped down from the 44kV system. Elexicon's existing Whitby TS and distribution system (to be clear the TS has capacity but there are no feeders available to supply North Brooklin) on Lakeridge Road cannot accommodate the additional demand required by the residential development in North Brooklin. The station and the existing associated 44kV feeders are expected to service the industrial growth in the North Whitby region. No existing 27.6kV feeders currently exist to be able to supply the new North Brooklin residential development at the 27.6kV voltage level required. Figure 2 depicts the Brooklin development area.

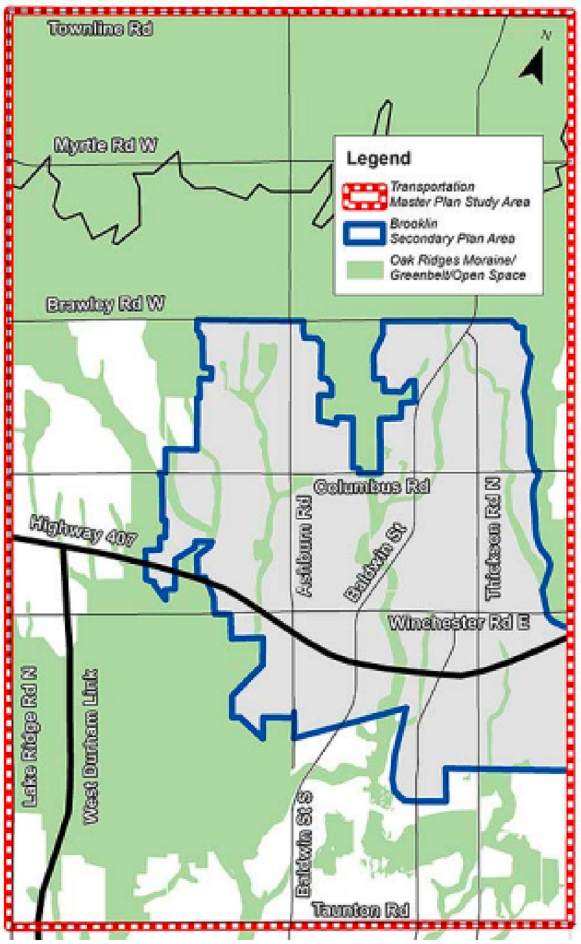


Figure 2: Brooklin Development Area

When building new homes, developers typically build homes with traditional electrical requirements. However, there is a push for more homes to be DER and EV ready to enable and push customers to take up these technologies. Amongst this, the town of Whitby, in which Brooklin is located, is committed to reduce emissions by 80% by 2045 in their corporate service and across the community by 80% by 2050[5]. However, current customers would have to engage in costly retrofits post construction. Typically for solar panel installation, this could cost approximately $20K and up to $30K for energy storage solutions[6], depending on the scope of works. However, this cost can vary, and most retailers will not provide a firm quote until visiting your property. The Brooklin Developers are ensuring that the new homes built will be ready to fit a new solar panel and battery storage, as well as offer additional packages to do the installation at the same time.

As previously stated, North Brooklin is set to experience significant greenfield growth, with a significant increase in number of homes and customers needing to connect to Elexicon's grid. The Brooklin Developers, which account for 60% of the landowners in the area and 87% of the housing, are planning on building between 10,081 to 11,217 homes over the next 20 years. This requires Elexicon to invest in new assets to facilitate this growth and enable safe and reliable supply of electricity supply. In the normal course of business, this would require capital contributions from the builders as per 3.2 of the DSC and would result in new construction homes that cannot (without retrofit and significant cost) accommodate DER or EV system. The current network:

- Cannot accommodate a higher penetration of grid-connected DERs without significant upgrades,
    - To prevent islanding, IEEE 1547 now recommends detailed engineering take place if the total DER on a feeder exceeds 33% of minimum load[7].

[5] https://www.whitby.ca/en/live/climate-change-and-extreme-weather.aspx#:~:text=The%20Zero%20Carbon%20Whitby%20Plan,increase%20to%201.5%C2%B0C.
[6] Note: The costs are estimates based on previous experience and have not been verified through any quotes.
[7] Minimum load is considered to be 25% and therefore Elexicon can currently only accommodate approximately a 7.5% DER penetration.

- Is not enabled for remote monitoring and automated corrections (e.g., fault detection), and
- Does not have optimized voltage (please note voltages are currently within the limits), resulting in a missed opportunity to further conserve energy. For example, the benefit of conservation voltage reduction (CVR) is primarily a reduction in the demand and energy which proportional to the amount the voltage is lowered at the source,

In addition, the Brooklin Developers have indicated as they are investing a significant amount of capital in creating these DER and EV-ready homes, if they had to pay the capital contribution, they would not be able to do this and would instead just build conventional homes. These homes would then, at the cost of homeowners, have to be retrofitted for DER and EV enablement. It is expected that the Brooklin Developers will incur a capital expenditure of around $23 MM to install standard rough-ins to make the homes DER and EV-ready. If a capital contribution is required, this would be the equivalent of the proposed capital expenditure requested in this ICM ($26.6 MM).

3.2. Future State

Over the next twenty years, the Brooklin Developers have plans to provide 10,081 to 11,217 affordable and energy-efficient homes. The Brooklin Developers anticipate that residential construction will occur in three phases, with electricity demand increasing as: (i) Brooklin constructs new homes; and (ii) other real estate developers build residential and commercial properties in the North Brooklin area.

To accommodate near-term and long-term forecasted demand within North Brooklin, the first phase of development requires Elexicon to construct two new 27.6 kV overhead pole lines connecting the North Brooklin development to Whitby TS DESN 1. The distribution pole lines will be routed along either side of Lakeridge Road and Columbus Road and terminate at various locations, as shown in the diagram below. Initially, each of the pole lines will be strung with a single circuit but will have the capacity to accommodate three circuits each. The new distribution lines will cross both Highway No. 7 and Highway 407. Figure 1 above illustrates the service route to connect North Brooklin to Whitby DESN 1.

Table 1 shows the location and costs associated with the Overhead and Underground assets that Elexicon will install as part of the Sustainable Brooklin project. As previously stated, the smart grid technologies associated with these two new lines will be implemented as part of the Whitby Smart Grid project.

Table 1: Proposed Locations and Cost for the Installation of Assets to Connect North Brooklin

Underground	
Location	**Cost ($'000)**
Whitby TS to Egress of HONI ROW - UG	$1,950
Lakeridge- under tower line 1- UG	$1,425
Lakeridge- under tower line 2- UG	$882
Columbus (Country Lane to Ashburn)- UG	$6,000
Underground Total	**$10,257**
Overhead	

Location	Cost
Lakeridge - Between two Tower line- OH	$1,875
Lakeridge - North of HONI ROW to South of HWY407- OH	$5,975
Lakeridge - South of HWY 407 crossing to Columbus - OH	$3,575
Columbus(from Lakeridge to Country Lane)- OH	$4,975
Overhead Total	**$16,400**
Overall Project Total	**$26,657**

As stated earlier, Elexicon is proposing to fund the new feeders and associated smart grid technologies through the ICM. Instead of the Brooklin Developers making capital contributions as Section 3.2 of the DSC, they have committed to construct new homes that have DER and EV ready functionality such that the benefits of these technologies can be realized by both customers and Elexicon. This requires Elexicon to apply for an exemption from section 3.2 of the DSC[8]. However, with this exemption in place, the Brooklin Developers will commit to building DER and EV-ready homes, which in turn will increase EV and DER uptake on a more cost-effective basis. Should there not be approval of the exemption to the DSC, it is certain that the developer would construct homes with

[8] Rationale for a DSC exemption is included in Section 5 of this ICM application.

traditional functionality, and therefore customers would have to undertake costly retrofits if they wanted DER and EV capabilities.

The Brooklin Developers will invest their own capital in the creation of a new, innovative community wherein DER and EV uptake can significantly exceed business-as-usual; with resulting benefits for both the residents of North Brooklin and the broader Whitby rate zone customer base. Based on initial quotes the Brooklin Developers has received, it is estimating a cost of around $23M install the standard rough-in. The Brooklin Developers will undertake the following:

With respect to solar generation, all residences will be built to be solar-ready. This would involve the following key elements: (i) conduit from the circuit panel to the attic to allow for wiring a solar panel; (ii) two spare breaker slots; and (iii) sufficient space on the wall next to the circuit panel to install solar controls and an inverter. Where the roof size and orientation are suitable, the Brooklin Developers will offer customers the option to purchase and install solar panels and related inverter and controls. The Brooklin Developers will offer this alone or in a package with battery storage.

With respect to in-home battery storage, all residences will be built to be have the ability to store a battery in the homes premises. The Brooklin Developers will offer customers the option to purchase and install a battery storage system (e.g., Tesla, Panasonic, or LG) either in conjunction with solar or for peak-shaving, reliability needs. This will also allow for the eventual participation in a local capacity market when this is formed. Battery storage would allow customers the added benefit of outage protection.

With respect to EV charging, all residences will be built to be EV charging ready. The Brooklin Developers will install electrical conduit from the circuit panel to the location of an EV charger, with a plate at the point of a future installation, room on the wall for the charger, and appropriate room in the circuit panel for a breaker. The Brooklin Developers will offer customers the option to purchase and install either a unidirectional or a bidirectional 240V EV charger. Both can be used for fast charging of electric vehicles, but the bidirectional charger can also be used as additional battery storage for the home or to feed power into the grid. An electric vehicle can be programmed to charge using ultra low overnight rates, and then discharge back to the home during the day when the vehicle is not in use to offset peak electricity.

Investments made by the Brooklin Developers to create a DER and EV-ready community will incur capital costs on their part, for which recovery at the time of home sale is highly uncertain. Given the high and increasing cost of residential development and construction, the Brooklin Developers would be otherwise unlikely to assume the business risk of constructing DER and EV-ready homes in North Brooklin. This outcome is highly sub-optimal, as the costs and challenges of DER and EV retrofits are significantly greater than inclusion of these technologies at the design and construction phases. All else equal, failing to incorporate these technologies into front-end development will result in a community of North Brooklin that has low or average levels of DER and EV uptake.

Smart Grid Functionality

Consistent with broader plans for the Whitby Smart Grid, Elexicon intends to build the new distribution assets servicing Sustainable Brooklin to incorporate innovative functions and features such as VVO, FLISR/DA, and a supporting ADMS. On the back of these technologies, Elexicon's assets in North Brooklin will be capable of automatically monitoring and managing the distribution system. The end-state will be the promotion and wide adoption of DERs while maintaining the service and reliability of the distribution system expected by customers. For Sustainable Brooklin, this will entail the installation of

- VVO and FLISR/DA including CFCI on the two new 27.6kV feeders, and
- Integration of these new devices into the new ADMS system to allow the automated monitoring and management of the system.

3.3. Compliance Considerations

Distribution System Code – Elexicon and the developers are seeking a temporary exemption from Section 3.2 of the DSC. Rationale for the DSC exemption can be found in section 5 of this ICM application.

A distributor must document in its Conditions of Service the operating practices and connections policies of the distributor as stated in Section 2.4 of the Distribution System Code. Elexicon's Conditions of Service is compliant with the Distribution System Code.

Performance Measures - As stated earlier it is expected that with the implementation of smart grid technology there will be reliability improvements. The following provides a summary of an example of system reliability improvements for the Whitby Rate Zone through FLISR systems implementation based on historical period of April 2020 to January 2022:

- SAIFI improving from 0.87 to 0.28
- SAIDI improving from 1.03 to 0.45
- CAIDI ~ 40 minutes' improvement per complex outage.
- MAIFI going from 0 to 0.59

Leave to Construct - Leave to Construct approval is not required for these investments.

Ontario Cyber Security Framework - Elexicon is required to comply with the Ontario Cyber Security Framework and new smart grid investments will leverage advanced technology while complying with standards for interoperability and cybersecurity.

ESA 22/04 regulation – When constructing or updating new electrical distribution infrastructure, Elexicon must follow O. Reg. 22/04 (Electrical Distribution Safety). In compliance with O. Reg. 22/04, Elexicon ensures its distribution system is safe and poses no undue hazard to the public. These requirements apply to customer connections.

4. Project Alternatives

4.1. Alternative Descriptions and Comparative Analysis

Option	1	2	3	4
Scenario Description	Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability	Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area with the developer paying a capital contribution as per the DSC, with the extension of the duration of Capital Contribution period from 5	Build a new TS to serve the North Brooklin area using Elexicon's existing rate base	Utilize existing 44kV feeders to the North Brooklin area using Elexicon's existing rate base.

Option	1	2	3	4
		years to 15 years.		
Project Scope	Elexicon will install two new 27.6kV feeders and the associated assets that will connect the Brooklin development to the Whitby TS.	This is the same as Option 1 with the difference that the developer would provide a capital contribution but rather than the normal 5-year contribution period, it would be extended to 15 years.	A brand new TS would be built to serve the additional capacity from the Brooklin development. This would be funded through the existing rate base.	Utilize existing capacity on the two 44kV feeders at Whitby TS that are typically used for commercial and industrial loads and step down the 13.8kV to serve the residential load. This would be funded through the existing rate base.

Option	**1**	**2**	**3**	**4**
Total Gross Capex	$26.6 MM	$35.5 MM[9]	~$50 MM	N/A
Project Pros	This solution provides a connection that meets the developer's timeline. The two new 27.6kV feeders can directly supply the development, when compared to option 4 where the voltage would have to be stepped down from 44kV to 13.8kV. In addition, the two 27.6kV feeders have a combined	Developer must pay a capital contribution, therefore reducing the impact of the cost on the rates.	N/A	N/A

[9] It would be expected that the Capital Contribution would be cover the full amount.

Option	1	2	3	4
	capacity that matches the anticipated capacity from the North Brooklin development. Through the project, Elexicon can maximize DER and EV uptake in an expanding community, avoiding costly DER or EV retrofits post-construction. This solution and the associated funding will allow developers to			

Option	1	2	3	4
	fund and construct DER ready homes, thus reducing costs for customers.			
Project Cons	An exemption from DSC 3.2 requirements is needed to allow the developers to be exempt from paying a capital contribution. The rationale and justification for this is included in section 5 of this ICM application.	If the developer must make a capital contribution, even extended out to 15 years, it is likely they will not build DER and EV ready homes. Given the high and increasing cost of residential development and construction, the developers	This is not the preferred option as building a new TS station is a costly and timely undertaking. A new TS typically take a minimum of 5 years to build. To meet the timings of the Brooklin developers, the TS would need be	This is not the preferred option. Though the two feeders currently have capacity, they are planned for a known commercial and industrial load south of the 407 highway. Elexicon's planning

Option	1	2	3	4
		would be otherwise unlikely to assume the business risk of constructing DER-and-EV-ready homes in North Brooklin. This outcome is highly sub-optimal, as the costs and challenges of DER and EV retrofits are significantly greater than inclusion of these technologies at the design and construction phases.	completed by the end of 2023 which is not possible in the current market. In addition, the cost of the delivering a new TS station is the equivalent of Elexicon typical annual capital budget. If existing rate base were to be used, this would mean Elexicon would have to defer and cancel a considerable number of discretionary	practice is to typically reserve the 44kV feeders for commercial and industrial load as no stepdown of the voltage is required. Residential customers are typically fed off either a 13.6kV or 27.6kV system. If a 44kV feeder is used, it would require conversion to 13.8kV which is a costly

Option	**1**	**2**	**3**	**4**
		Failing to incorporate these technologies into front-end development will result in a community of North Brooklin that has low or average levels of DER and EV uptake.	projects to be able to deliver this project. This is unfeasible and would put at risk the safety and reliability of Elexicon's system.	process as a new substation would have to be installed in addition to other associated equipment. Y implementing a 27.6kV feeder, this negates the need to have a substation to step down the voltage further.
Project Economics	The cost is the lowest capital cost and will deliver many benefits for customers now	Whilst the cost of project overall will be similar to the preferred option, this option will not deliver the	The cost of a new substation is around $5MM higher than the preferred option and will	This option has not been costed as it is not a technically feasible option to

Option	1	2	3	4
	and in the future.	objective of building DER ready homes that can be integrated into Elexicon's system. This would therefore have a detrimental impact on enabling a Grid of the Future.	not enable the benefits of the proposed development in the required timelines.	proceed with for costing.
Customer Feedback	Elexicon has engaged with a coordinated group of Developers whose development lands in North Brooklin are largely contiguous. To accomplish the objectives of Sustainable Brooklin, Elexicon must enable a level of project certainty sufficient to secure Developer commitments prior to near-and-mid-term construction of new homes. Appendix B-6 includes the letters of support where the Brooklin Developers and Town of Whitby support for the project can be found.			
Other Constraining Factors	The developer has a timeline of delivering the 1st phase of homes by Q3, 2023, and as	Approval of a change to capital contributions would have to be sought, which	A new TS takes a minimum of five years to build which does not meet	It is Elexicon's planning practice to allocate 44kV feeder

Option	**1**	**2**	**3**	**4**
	such Elexicon needs to install a solution that meets this timeline.	has typically been rejected in the past by the OEB. If the developer must pay a capital contribution, they will not build DER and EV ready properties.	the timeline of the developer.	capacity to commercial and industrial growth. This might lead to capacity constraints in the future and put system contingency at risk if Brooklin residential development is served by the 44kV.
Preferred Alternative	**X**			

4.2. Rationale for Preferred Alternative & Consequences of Inaction

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
Customer Benefits	This project will facilitate the customers' ability to connect DERs to Elexicon's grid. This will enhance a customer's control of their energy usage. As the developer is building DER ready homes this reduces the cost for customers compared with a retrofit. For example, a retrofit could cost in the range of $20-30K per solar installation and integration compared with a much cheaper installation with the functionality already installed (i.e., a customer will only have to purchase a solar panel and battery storage and not all the connection fittings to connect to Elexicon's grid).	If approval for this ICM is not given, then customers will not have DER-ready homes built by the developers. Should they choose to install their own DER solutions post construction, this will result in a costlier solution (typical retrofit costs can range from $20-30K per solution per house). Costs can vary subject to suppliers and the solution the customer is seeking.

Preferred Alternative: Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	The cost of the preferred option is also lowest cost by $5MM compared to option 3.	
Grid Resiliency	To ensure a safe and reliable supply to the new customers in the North Brooklin area, Elexicon needs to build two new feeders. Through the installation the smart grid technologies (being undertaken through the Whitby Smart Grid Project), this allows Elexicon to automatically monitor and manage the distribution system. This includes improvements to reliability and system losses. It should be noted these benefits listed below are for	To connect and serve the new community with North Brooklin, Elexicon must invest in new assets, otherwise it cannot physically supply the electricity required. In addition, if smart grid technologies are not installed on Elexicon's grid at the same time, this would result in a community of North Brooklin that has low or average levels of DER

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	the whole of the Whitby rate zone and not specific to Sustainable Brooklin. <u>Loss Reduction</u> Small, but positive, primary line losses on a distribution system is in the range of 5-10% of load[10]. The application of CVR reduces these losses by 2-3%. <u>Reliability</u> • Reduction of temporary faults to MAIFIs • Reduction of Permanent faults to a quarter.	and EV uptake. This would put it in conflict with the rest of the Whitby Rate Base once the Whitby Smart Grid project is completed.

[10] Appendix B-5

<u>Preferred Alternative:</u> **Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.**		
Benefits	**Rationale**	**Consequences of Inaction**
	• Truck rolls avoided; locating time reduced.	
Operational Efficiency and Cost Effectiveness	Installing two new 27.6kV feeders is the most cost-effective solution to connect the new development in North Brooklin within the timescales required. It uses an existing station and extension feeders from this station to the development. It does not require another station to be built, to step down the voltage, which is costly and timely. In addition, through the installation of the smart grid technologies on Elexicon's	If the new feeders are built too late, then expensive, temporary solutions will be required to serve the new customers.

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	grid, Elexicon's assets in North Brooklin will be capable of automatically monitoring and managing the distribution system and dispatching DERs. The deployment of DERs and the technology required to support them creates long-term opportunities for distributors to defer or avoid traditional capital investments as learnings accumulate from early operation of a Smart Grid with high DER uptake. Elexicon conducted an analysis of the potential for deferred capital specific to the Sustainable Brooklin project. This illustrative case was	

Preferred Alternative: Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	based on a review of load on the Whitby TS T1/T2 utilizing a 20-year load forecast set against the 90MW LTR of Whitby TS T1/T2. In this illustrative case, battery-plus-solar DER penetration would need to reach 3% to defer upgrades 1 year, 19% to defer upgrades 5 years, and 30% to defer upgrades 10 years. Elexicon also sees options for capital deferral or alternative asset designs which would be enabled by the Sustainable Brooklin project as well as the Whitby Smart Grid project. Depending on the pace of construction within the	

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	Sustainable Brooklin community, a high DER-uptake level creates the opportunity for deferrals in the build-out of localized capacity to serve new homes. This will create savings across the Whitby rate zone.	
Safety	Safety is top priority for Elexicon, and these investments will meet all the latest safety standards.	Safety is top priority for Elexicon, and these investments will meet all the latest safety standards.
Cyber Security/Privacy	New communications systems deployed will include the latest in security and data safety features	Existing technology is at risk of becoming exposed to new cyber-attacks.
Environmental Benefits	The enablement and use of DER's is one of the key solutions to facilitating the energy transition and	Net-zero targets and reductions in greenhouse gas emissions would not be

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	delivering on net-zero commitments by the Town of Whitby and Region of Durham, and ultimately the provincial and federal governments net-zero plans.	enabled if this project were not completed as it is less likely customers will install DER solutions that would facilitate this.
Coordination/Interoperability	Elexicon and the developers have been in constant communication on the best solution to deliver the most optimal customer benefits within the desired timelines. Elexicon continues to collaborate with the developer as the details of the project is developed. Letters of support from the developer are attached in Appendix B-6 of the ICM application.	
Conservation Demand Management	Elexicon is considering a targeted DER Incentive	Without the installation of the smart grid

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	Program that an end-use customer can access to reduce their capital cost of installing DER systems. Elexicon is considering various funding sources for the DER Incentive Program, including the potential of a Conservation and Demand Management ("CDM") program under the OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (CDM Guidelines)[11] to fund upfront customer incentives. Following the certainty of the	technologies through the Whitby Smart Grid, Elexicon cannot put in place the relevant mechanisms to encourage and manage DERs.

[11] EB-2021-0106, Conservation and Demand Management Guidelines for Electricity Distributors, December 20, 2021 < https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2021-12/CDM-Guidelines-Elec-Distributors-20211220.pdf >

<u>Preferred Alternative:</u> Proceed with system enhancement by extending the feeders from Whitby TS to serve the North Brooklin area, with funding through this ICM, and with the Whitby Smart Grid project enabling DER integration capability.		
Benefits	**Rationale**	**Consequences of Inaction**
	Sustainable Brooklin project and Whitby Smart Grid, Elexicon will bring forward its CDM proposal.	

4.3. Risk Mitigation

Risk Category	Description	Mitigation
Budget risk	The current cost estimates are class 4.	Upon OEB approval of this ICM funding, Elexicon will go out to tender to establish final budget costs.
Timeline risk	Developers require the connection of a supply in time for the completion of the 1st phase of the development by the end of 2023.	Elexicon has put forward a solution that will meet the developer’s timeline. Elexicon continues to collaborate closely with the developer to keep abreast of any changes.
Development is not built	The homes are not built, and no DER ready	The developer has committed to building these homes.

Risk Category	Description	Mitigation
	homes are available to be integrated in the system.	Should they not proceed, Elexicon would not proceed with the building of the two new feeders.
DER and EV adoption risk	1. To enable DER/EV integration, the 1st tranche of the Whitby Smart Grid requires to be approved. 2. Customers may not install solar panels, battery storage and therefore no DER's will be available for integration into Elexicon network.	1. A separate business case has been included as part for this ICM to approve the Whitby Smart Grid funding. 2. Elexicon is proposing to develop a DER incentive program and an enhanced local capacity market.

1

APPENDIX B-3

DER Enabling Program and Local Capacity Market

Office T (905) 427-9870 T 1 (888) 445-2881 F (905) 619-0210

Customer Care T (905) 420-8440 T 1 (888) 420-0070 F (905) 837-7861

55 Taunton Rd. E.
Ajax, ON L1T 3V3

Table of Contents

DER Enabling Program and Local Capacity Market

Under the Conservation and Demand Management Guidelines for Electricity Distributors ("**Guidelines**"), distributors are required to make reasonable efforts to incorporate consideration of conservation and demand management ("**CDM**") activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure.[1] The Guidelines place a greater emphasis on the use of CDM activities by distributors to address system needs and avoid or defer investments in traditional wires infrastructure than previous iterations of the Guidelines. The Whitby Smart Grid and Sustainable Brooklin Projects (the "Projects") respond to this guidance, as outlined in Exhibit B, by enabling greater distributed energy resource ("DER") uptake while providing immediate benefits to customers via energy savings, greenhouse gas ("GHG") reductions, and improved reliability.

In connection with the Projects, Elexicon is considering two programs to incent DER capacity: (1) CDM marketing, incentives and on-bill financing to encourage customer investments in DERs capable of providing reliable capacity (e.g. batteries, solar-battery combination systems, demand response, or others) ("**DER Enabling Program**");[2] and (2) the creation of a "Total DSO" local capacity and energy market building on the York Region Non-Wires Alternatives Demonstration Project ("**Local Capacity Market**")(collectively, the "**Programs**"). The intent of Programs will be to incent DER capacity through market based mechanisms, to gain sufficient experience with these DER resources and their reliability, enabling Elexicon to make informed decisions with respect to traditional infrastructure in the future.

Elexicon is still considering whether to file an application with the OEB under the Guidelines for the Programs. The final details of these Programs have not yet been determined and the discussion herein is preliminary. The purpose of this Appendix is to set out the programming options Elexicon is considering to promote DER adoption in the Whitby Rate Zone ("WRZ"). Section 3.1 the Guidelines sets out the key steps distributors should take to meet CDM objectives. Each step will be discussed in the context of the Projects.

Step 1: When assessing system needs, provide sufficient lead time to enable consideration of CDM activities.

[1] Conservation and Demand Management Guidelines for Electricity Distributors, EB-2021-0106, December 20, 2021, online: <https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2021-12/CDM-Guidelines-Elec-Distributors-20211220.pdf>

[2] O. Reg 161/99, s.1(2) permits on-bill financing for electricity conservation and load management measures

At Appendix D of this ICM Application METSCO Energy Solutions Inc. ("**METSCO**") produced a twenty-year load forecasting model for Elexicon that predicts load growth across Elexicon's service area. One of the scenarios METSCO considered in their modelling of load growth is the "Region of Durham Scenario" where housing forecasts are based on the data published by the Region of Durham. Under this scenario, METSCO concludes that the 44-kV-system is expected to exceed capacity by 2030. If load can be balanced between the 27.6-kV and 44-kV systems, then the whole system is forecast to exceed capacity in 2036. As noted in Appendix B, the Sustainable Brooklin Project will have an in-service date in Q3 of 2023 and the Whitby Smart Grid will have an in-service date in Q4 of 2025. From an infrastructure perspective, the in-service dates of the Projects provide sufficient lead time for Elexicon to evaluate capacity needs in the early 2030's, and assess non-wires alternatives to traditional wires investments.

Successful deferral of traditional infrastructure will rely both on a grid that can support higher levels of DER connection, as provided by the Projects, and the installation and connections of the DERs themselves. Initiating the Programs in the near-term will help ensure that this second necessary element (i.e. DER uptake) is secured in time to inform critival investment decisions.

Step 2: Define the types of system needs where CDM activities have the greatest potential to meet the system need.

On November 24, 2021, the Independent Electricity System Operator ("**IESO**") published a survey on consumer electricity preferences and behaviors that are likely to impact the supply and demand of electricity in Ontario in the future.[3] There were three key findings from the IESO's study:

- Pricing models are seen as the main way consumers can manage costs, however reliability and predictability is also important.
- Consumers express receptiveness to adopting certain new electricity products and services, particularly those that help to manage costs, and an openness to exploring providers other than their current utility.
- Path to DER uptake relies on increasing knowledge among consumers and shorter timeframes to recoup initial investment.

[3] IESO, Consumer Preferences, Choices and Behaviours Impacting Electricity Supply and Demand, November 24, 2021, online: <https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/Consumer-Electricity-Preferences-and-Behaviours-Survey.ashx>

The Programs will be responsive to all three findings by the IESO identified above. First, the creation of a local capacity and energy market and on-bill financing will allow consumers to manage their electricity costs through the self-generation, storage and/or sale of electricity, or participation in market mechanisms (e.g. aggregator-based demand response).

The Programs can also aid reliability and predictability depending on the DER elected by customers (e.g. battery installations acting as back-up power source). Second, the pairing of the Project and Programs provides customer access to the new and innovative electricity products and services which customers have expressed receptiveness. Third, the marketing campaign for the Programs is expected to include efforts to increase knowledge among consumers and include resources to allow customers to assess investment opportunities in DERs. CDM incentives by their nature would reduce the payback periods of investments by customers.

Substantial work will be required to ensure the public messaging for the Projects and Programs provides customer understanding of the technology and behavioural changes that can facilitate overall reduction in electricity demand and/or consumption; yielding savings for both individual customers and the system as a whole. This could include:

- Identifying the customer type(s) that will be targeted;
- Specifying the number of participants that will be targeted;
- Identifying clear objectives for the educational / marketing (i.e., why there is a need to educate the specified customer type(s) on the specified subject);
- Articulating the educational approaches that will be utilized by the distributor (e.g., brochures, seminars, etc.);
- Considering what existing relationships with customers can be leveraged to promote DER adoption (e.g. key clients and relationship managers);
- Providing estimates of costs of the educational or marketing programs; and
- Describing the anticipated benefits of the educational or marketing programs.

Further, Elexicon's intends to incorporate the following design principles as it develops its DER incentive program:

- All low volume customers in the WRZ will be provided access to the DER incentive program (i.e. new homes, existing homes, small businesses);
- Include DER technologies and suppliers that are commercially viable and industry proven;
- Support DER technology suppliers, DER aggregators, and other participants in the competitive market supporting DERs;
- Create a DER incentive program that is technology-agnostic, provided that the technology supports system benefits in addition to customer-specific benefits; and
- Incorporate or partner with entities that can provide funding beyond that provided by Elexicon's ratepayers (i.e. NRCan, IESO or other not-for-profit agencies) to maximize the funding pool.

While Elexicon requires time and experience to conclude with certainty that the Projects and Programs will result in the avoidance or deferral of investments in traditional wires infrastructure, there is a great potential for the Projects to facilitate this outcome; particularly when augmented by the Programs.

For example, METSCO found that to be able to defer capacity assessments for one year, 12% of new customers in the North Brooklin area need to install rooftop solar with battery storage. This percentage is 39% for a three-year deferral and 53% for a five-year deferral.[4]

Step 3: Ensure a process is in place to consider CDM as a potential solution for these types of system needs and to compare CDM to traditional wires solutions.

The creation of a Total DSO local capacity and energy market will provide the process that customers could use to manage electricity costs while also resulting in an efficient and cost effective solution to address distribution system needs, when compared with traditional wires solutions (e.g. building a new TS).[5]

Elexicon envisions running a capacity market auction to secure DER resources for the following year. In subsequent years, Elexicon would gradually increase the volume of DER capacity secured in each annual auction to reach a level where investments in traditional wires infrastructure after 2030 could be deferred

[4] Please see section 7 of Appendix D in this ICM Application for the present values of TS deferral.
[5] Elexicon is proposing the Total DSO model because it does not require changes to applicable law. For a discussion on the "Total DSO" model please see the IESO paper titled "Development of a Transmission Distribution Interoperability Framework" published in May 2020, online: <https://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/IESO-T-D-Coordination-Framework.ashx>

or avoided. Generally, the local capacity and energy market would operate such that Elexicon would buy energy from DER resources whenever it is more economic than paying the IESO for energy from the transmission grid. DER capacity may also be used to satisfy technical requirements for reliable and efficient distribution system operation, such as alleviating local system constraints.

To formulate a local capacity market, Elexicon would rely on the documents published by, and apply the learnings from, the York Region Non-Wires Alternatives Demonstration Project to explore market-based approaches to secure energy and capacity services from DERs for local needs. For example, the contracts, rules and reports from this demonstration project have been posted publicly online and would serve as the starting point for framing the structure of the capacity and energy market.[6]

The key difference with Elexicon's Total DSO local capacity and energy market from the York Region Non-Wires Alternatives Demonstration Project is that Elexicon intends to operate its market for longer than two years in order to attract more investment. In addition, Elexicon's local capacity market is planned to be paired with the DER incentive program to facilitate greater adoption of DERs amongst small volume consumers, which will in turn allow for their participation in the local market via an aggregator or other arrangements subject to market rules and details.

Depending on the success of the energy and capacity market, Elexicon may expand out into other electricity services in the future as technology or demand evolves.

[6] See here: <https://yrdemo.com/User/login?ReturnUrl=/>

APPENDIX B-4:

METSCO Elexicon Energy 2022-2041 Peak Load Forecast

METSCO

MAKING IT POSSIBLE

Elexicon Energy 2022-2041 Peak Load Forecast

Ajax, Pickering, and Whitby Areas

METSCO Energy Solutions

Toronto Office

2550 Matheson Blvd E,
Mississauga, Ontario
L4W 4Z1
+1 (905) 232-7300

Calgary Office

1206, 20 Ave SE,
Calgary, Alberta
T2G 1M8
+1 (587) 887-0235

Document Information

Title:	Elexicon Energy 2022-2041 Peak Load Forecast: Ajax, Pickering, and Whitby Areas
Project ID:	P-22-153

Revision	Date	Author	Description
IFR	July 10, 2022	Kurtis Martin-Sturmey Charles Austria Nirvaan Bhagwandass	Issued for Review
R0	July 22, 2022	Kurtis Martin-Sturmey Charles Austria Nirvaan Bhagwandass	Revision 0

Table of Contents

List of Figures

List of Tables

Executive Summary

METSCO Energy Solutions Inc. ("METSCO") produced a twenty-year load forecasting model for Elexicon Energy Inc. ("Elexicon") that predicts load growth across Elexicon's service area. The model incorporates historical peak load data provided by Elexicon, population and household forecasts for the Town of Ajax, City of Pickering, and the Town of Whitby, census data, updated plans from developers, and other inputs.

This report outlines three scenarios depending on the housing forecast used. The first scenario is based on household estimates originally produced by the Region of Durham but adjusted downwards by METSCO based on 2021 census data. The two other scenarios are based on twenty-year low and high development forecasts provided by a North Brooklin housing developer group. The forecasts for Ajax and Pickering are the same in all three scenarios, whereas the forecast for Whitby changes.

The methodology used is summarized in the steps shown below.

1. **Weather Normalization** – To remove the effects of the day-to-day weather variation, historical daily peak provided by Elexicon Energy was weather normalized ("WN").
2. **Customer Count** – Given household forecasts and a customer to household ratio established in the previous model, customer counts for the years 2014 to 2041 were calculated for Ajax-Pickering and Whitby.
3. **Average WN Load per customer –** For each region the WN load per customer was found by taking the customer count and dividing it by the historical WN peak load. This was done for both summer and winter for the years 2014-2019. The results were then averaged to produce an average WN load per customer.
4. **Peak Load Forecast** – Peak Loads (2020 – 2041) for summer and winter were estimated using the average WN MW per customer and forecasted customer counts (2020-2041).
5. **Monte Carlo Simulation** – The Monte Carlo simulation from the previous model was extended to produce a base load forecast along with P10, P50, and P90 values, which represent the 10th, 50th, and 90th exceedance values.

The results of the twenty-year load forecast for 2041 are shown in Table 1. This is a probabilistic forecast, where the P50 represents the expected load that would be exceeded every other year. The P10 is the 10% exceedance value, meaning that the peak load would only exceed this value once every ten years. The P10 value is used for capacity planning.

Table 1: Forecasted Summer and Winter Peak Loads 2041

Summer Peak (MW)	Ajax-Pickering	Whitby (Region of Durham Scenario)	Whitby (Brooklin Low Scenario)	Whitby (Brooklin High Scenario)
P10	443.6	432.0	404.2	409.3
P50	426.2	417.8	389.9	395.1
P90	407.8	401.7	373.9	379.1
Winter Peak (MW)	**Ajax-Pickering**	**Whitby (Region of Durham Scenario)**	**Whitby (Brooklin Low Scenario)**	**Whitby (Brooklin High Scenario)**
P10	357.9	343.1	319.7	324.1
P50	351.6	339.4	316.1	320.4
P90	344.4	335.8	312.5	316.8

The P10 load forecast was divided between the 27.6-kV and 44-kV systems that serve the Ajax-Pickering and Whitby areas. P10 values represent the peak value threshold that 10% of annual peaks will exceed and are therefore recommended for use in capacity planning. The breakdown of the load for each area was calculated using both the expected population and household growth. In the Region of Durham scenario, the 44-kV-system is expected to exceed capacity by 2030. If load can be balanced between the 27.6-kV and 44-kV systems, then the whole system is forecast to exceed capacity in 2036 under this scenario. In both Brooklin scenarios, these capacity constraints are forecast to occur one year later.

Under the Brooklin Low scenario the estimated Distributed Energy Resource ("DER") penetration required to defer future capacity investments for one year, three years, and five years was calculated as a percentage based on the number of DER connections required among new Brooklin development. The combination of rooftop solar with BESS provides the greatest potential to meet future capacity needs and defer capacity investments. To be able to defer capacity assessments for one year, 12% of new customers in the North Brooklin area need to install rooftop solar with BESS. This percentage is 39% for a three-year deferral and 53% for a five-year deferral. Since these DERs are customer-owned, Elexicon has no control over their implementation and will need to monitor installation trends in the future. The forecast may also be impacted if other new developments take a similar approach to enabling DERs.

1 Introduction

Elexicon Energy Inc.'s ("Elexicon's") service area is undergoing high residential growth in the City of Pickering, Town of Ajax, and Town of Whitby. As the sole provider of electricity service in these areas, Elexicon has a responsibility to ensure it has the capacity to meet both current and future supply demands within allowable operating limits.

In 2020, METSCO Energy Solutions Inc. ("METSCO") developed a ten-year load forecasting model for Elexicon that was used predict load growth across Elexicon's service area. Current estimates by the Region of Durham predict rapid population growth in the next twenty years, most notably in the City of Pickering. To understand how the projected growth would impact peak load demands, Elexicon tasked METSCO with extending the existing model to produce a twenty-year load forecast.

This document details the updated methodology and summarizes the peak summer load for both the Whitby and Ajax-Pickering areas. A summary of the data inputs used for this forecast are listed below. A more detailed summary can be found in section 2.

1. Population forecasts for Durham, Ajax-Pickering, and Whitby
2. Household forecasts for the Ajax-Pickering and Whitby regions
3. Historical and forecasted average household size in the region of Durham (2006-2056)
4. Low and High 20-year growth projections from a North Brooklin household developer
5. Historical summer and winter peak loads (2014-2019) for the Ajax-Pickering and Whitby regions

The updated methodology can be summarized in 6 steps. A more detailed description of the updated methodology can be found in Section 3.

1. **Weather Normalization** – To remove the effects of the day-to-day weather variation, historical daily peak provided by Elexicon Energy was weather normalized ("WN").
2. **Customer Count** – Given household forecasts and a customer to household ratio established in the previous model, customer counts for the years 2014 to 2041 were calculated for Ajax-Pickering and Whitby.
3. **Average WN Load per customer –** For each region the WN load per customer was found by taking the customer count and dividing it by the historical WN peak load. This was done for both summer and winter for the years 2014-2019. The results were then averaged to produce an average WN load per customer.
4. **Peak Load Forecast** – Peak Loads (2020 – 2041) for summer and winter were estimated using the average WN MW per customer and forecasted customer counts (2020-2041).
5. **Monte Carlo Simulation** – The Monte Carlo simulation from the previous model was extended to produce a base load forecast along with P10, P50, and P90 values, which represent the 10th, 50th, and 90th exceedance values.
6. **Region of Durham vs. North Brooklin Developer Scenarios** – Whereas the forecast of developers in the North Brooklin area do not align with the latest household growth projections from the Region of Durham, two alternative scenarios were defined using low and high 20-year growth projections from North Brooklin household developers.

2 Data Inputs

This Section provides a detailed background the data inputs used for the twenty-year forecast model. This includes a brief description of the source file, description of the values taken, and where they can be found in each file. Source values taken are summarized in Appendix B.

1. **Ontario's "A Place to Grow"**[1] – In August 2020, the Growth Plan for the Greater Golden Horseshoe ("GGH") Office Consolidation was released as Ontario government's initiative plan for growth and development with an applicable time horizon for land use planning up to 2051. "A Place to Grow" estimates a total population of 1,300,000 persons within the Region of Durham by 2051. The distribution of the population in 2051 for the GGH is outlined Section 8 – schedule 3.
2. **Durham Regional Official Plan**[2] – In May 2020, this regional official plan was released for the guidance of growth and development in The Region of Durham. The regional structure plan provided initial population estimates for the Region of Durham in 2021 and 2031, which can be found in Section 7.3.3.
3. **Brooklin Study Secondary Plan**[3] – In 2015, the Town of Whitby undertook a comprehensive study to guide and manage growth in the Brooklin area. One of the key assumptions to the analysis was taken from the Region of Durham's growth plan "Growing Durham". The growth plan estimates a declining average household size in the Region of Durham, from 3.02 persons per unit in 2006 to 2.45 persons per unit in 2056. The plan also estimates a twenty-year population growth of about 50,000 from new housing development in Brooklin, which can be found in Table 9 of that report.
4. **Consolidated Development Charges Background Study**[4] – In July 2021, the Town of Whitby performed a background study to provide the basis and background to update the Town's general and engineered development charges to reflect servicing needs of new development. This report provided 2021 to 2031 forecasts for both population and occupied households within the Whitby area. This information can be found in Appendix A – Table 5 of that report.
5. **Durham Region Profile: Technical Report**[5] – In May 2020, the Regional Municipality of Durham released a report which included a comprehensive collection of demographic and socio-economic data. This report provided population and household forecasts for the Town of Ajax and Region of Durham. Population and housing forecasts can be found in Table 1.16 and Table 3.12 of the Appendix of that report.

[1] "A Place to Grow Growth Plan for the Greater Golden Horseshoe Office Consolidation 2020," Ontario, Aug. 2020

[2] "Durham Region Official Plan," The Regional Municipality of Durham, May 2020

[3] "Brooklin Study Secondary Plan and Transportation Master Plan," Town of Whitby, Jan 2015

[4] "2021 Consolidated Development Charges Background Study," Town of Whitby, Jul 2021

[5] "Durham region Profile: Technical Report," Regional Municipality of Durham, May 2020

6. **Region of Durham**[6] - In July 2022, the region of Durham released an article highlighting the Durham region Profile: Technical Report. A statement given by the Regional Chair mentions that the population of the region of Durham is expected to grow to about 1.2 million by 2041.

7. **City of Pickering: Detailed 20 Year Population Forecast**[7] – In March 2022, the city of Pickering published a detailed twenty-year population forecast. This report provided the population and housing forecasts for the city of Pickering up to 2041. These estimates are listed in the document's introduction.

8. **Statistics Canada Census Data**[8] – Population and household counts for Whitby, Ajax, Pickering, and Durham were taken from census data provided by Statistics Canada in 2011, 2016, and 2021.

9. **Elexicon Historical Loading Data –** Historical daily peak load data for the years 2014 to 2019 was provided by Elexicon Energy. Peak load data was split into summer and winter months. To remove the effects of the day-to-day weather variation the data was weather normalized. Data from 2019 to 2021 were also used to verify the present-day load distribution between the 27.6-kV and 44-kV systems.

10. **North Brooklin Developer Scenario** – Separate scenarios for the Whitby area were defined based on low and high twenty-year growth projections from a North Brooklin household developer who accounts for 87% of total household construction in Brooklin. The Brooklin developers estimate 10,081 to 11,217 new homes to be built by 2041.

[6] "Durham Region Profile highlights the region's growth, development and progressive opportunities," Regional of Durham, July 2022

[7] "City of Pickering: Detailed 20 Year Population Forecast" City of Pickering, March 2022

[8] "Statistics Canada Census", Statistics Canada, 2011-2021

3 Twenty-Year Forecasting Methodology

This Section provides a detailed description of the methodology used in the twenty-year forecast model. This includes key values, formulas, and justification of the approach taken.

1. Using the 2006 and 2056 average household size values that were obtained from the Brooklin Study Secondary Plan, a linear trend of average household size was carried out to obtain the average household size for each year within the forecast's scope (2022-2041). The linear plot of the average household size in the Region of Durham is shown in the figure below.

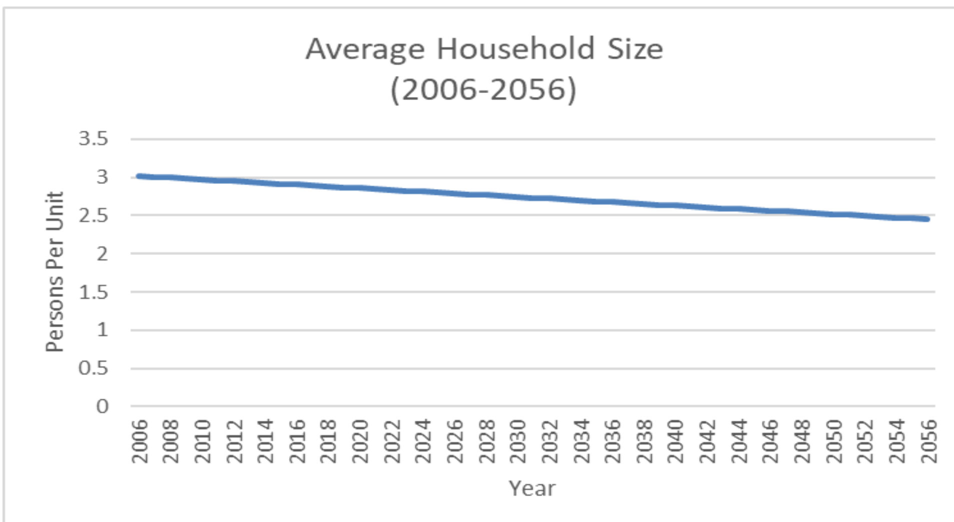


Figure 1: Average Household Size Durham (2006-2056)

2. Population forecasts for the region of Durham were taken from estimates given by the Region of Durham, Ontario's A Place to Grow, and the Durham Region Profile: Technical Profile.

   Current forecasts by the region of Durham project very high growth estimates for the City of Pickering. As an example, the Durham Region Profile: Technical Report forecasted Pickering's 2021 population to be 177,915. However, based on the 2021 Census by Statistics Canada Pickering's 2021 population was only 99,186.

   METSCO balanced this projected growth by subtracting the Region of Durham's projected population growth based on Pickering's contribution. This was done by subtracting 95,000 from current population estimates. This value was determined by considering multiple population forecasts for the City of Pickering and comparing them to Pickering's population counts reported by Statistics Canada Census. The adjusted Region of Durham population are shown below. The 2021 value uses the population count from the 2021 Statistics Canada Census.

Table 2: Adjusted Region of Durham Population

Year	Population
2021	696,992
2031	865,000
2041	1,105,000
2051	1,205,000

3. Population forecasts for Whitby, Ajax, and Pickering were taken from the Consolidated Development Charges Background Study, Durham Region Profile: Technical Report, and City of Pickering: Detailed 20 Year Population Forecast for the years 2021 to 2031.

   The annual population growth shown by each region was then applied to the 2021 population counts to achieve an adjusted population forecast for the years 2022 to 2031.

4. Population estimates from 2032 to 2041 were made by assuming the proportion of the forecasted growth in the region of Durham contributed by each area (Whitby/Ajax/Pickering) in the first ten years (2021-2031) will remain the same in the next ten years (2031-2041).

   The proportion was calculated by dividing the estimated ten-year population growth of a given area by the total estimated ten-year population growth in the Region of Durham. The proportions found for each area are 28%, 3%, and 4% for Whitby, Ajax, and Pickering respectively. By assuming the proportion for each region stays the same for the next ten years (2031-2041) METSCO was able to estimate the population of each area up to 2041.

5. Household estimates up to 2031 for Whitby, Ajax, and Pickering were taken from the Consolidated Development Charges Background Study, Durham Region Profile: Technical Report, and City of Pickering: Detailed 20 Year Population Forecast respectively. Household counts for all areas were taken from the 2011 and 2016 Statistics Canada census. The number of households for the remaining years (2032-2041) were determined by converting the estimated population from steps 2 and 3 using the average household size in Step 1.

6. A customer-to-household ratio established in the existing load forecast model was used to produce a customer forecast from the household forecast. The customer-to-household in Whitby, Ajax, and Pickering were 0.9040, 0.9212, and 0.9260 respectively. Customer forecasts for Ajax and Pickering were subsequently combined.

7. The weather-normalized peak load per household for 2014 to 2019 was calculated by dividing customer forecasts by the historical weather normalized peak load. These results were averaged and used to predict the peak load for years 2022 to 2041. The average weather-normalized peak load per household for Ajax-Pickering was 0.00375 for summer and 0.0033 for winter. The average weather-normalized peak load per household for Whitby was 0.0045 for summer and 0.0039 for winter.

8. Using the Monte-Carlo simulation built on historical weather distributions, probabilistic scenario forecasts (P10, P50, and P90) for the twenty-year period were determined for each region. P10, P50, and P90 values represent the 10^{th}, 50^{th}, and 90^{th} exceedance values.

9. A separate household scenario was defined using a 20-year growth forecast from a North Brooklin housing developer that forecasts a minimum of 10,081 new homes by 2041. Given that the developer accounts for 87% of total household construction in Brooklin, the total twenty-year household growth in Brooklin is 11,587 homes.

10. The Brooklin Study Secondary Plan estimates a twenty-year population growth of about 50,000 from new housing development in Brooklin. METSCO's population forecast estimates a twenty-year population growth of 117,203 in the town of Whitby. Therefore around 43% of the twenty-year population growth in Whitby comes from Brooklyn development.

    Using this percentage and Whitby's adjusted population forecast METSCO was able to find Brooklin's annual population increase. The annual household growth in Brooklin was then determined using the average household size from step 1. METSCO's initial forecast estimates 18,604 households to be built in Brooklin from 2022 to 2041. The percentage of new Brooklin homes constructed annually was then calculated for each year.

11. The annual household growth based on the Brooklin Developer's forecast was found by applying the percentage of new homes constructed each year to the Brooklin developer's low estimate of 10,081 new homes. Given that the developer accounts for 87% of total household construction in Brooklin, the total twenty-year household growth in Brooklin is 11,587 new homes. METSCO assumed that the Brooklin developers would not start construction until 2023 and that construction would ramp up in 2025. To account for this the number of new houses to be built 2022 was divided between 2023 to 2027, where 2025 to 2027 would receive a greater proportion of new houses.

12. The annual household growth based on the Brooklin Developer's forecast was then integrated into the Whitby forecast. Steps 6 to 8 were subsequently repeated to provide an alternate Whitby forecast based on the North Brooklin housing developer's low scenario.

13. Steps 10-13 were repeated using the Brooklin developer's high scenario which estimates a maximum of 11,217 news homes by 2041. Given that the developer accounts for 87% of total household construction in Brooklin, the total twenty-year household growth in Brooklin is 12,893 homes.

4 Results

Results of the twenty-year load forecast for the town of Whitby are shown in the tables below. Table 3 shows the P10, P50, and P90 forecasted summer peaks (MW) from 2022 to 2041. Table 4 show the P10, P50, and P90 forecasted winter peaks (MW) from 2022 to 2041. Tables 5 to 8 show the summer and winter peak load forecasts for the low and high Brooklin Scenarios.

Table 3: Whitby Twenty-Year Summer Load Forecast (MW) (2022-2041) – Region of Durham Scenario

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	236.0	240.4	245.0	249.6	254.3	267.6	281.7	296.7	312.6	329.5
P50	221.8	226.2	230.7	235.3	240.1	253.4	267.5	282.5	298.4	315.3
P90	205.7	210.1	214.7	219.3	224.0	237.3	251.5	266.4	282.4	299.2
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	339.6	349.7	359.8	370.0	380.2	390.5	400.8	411.2	421.6	432.0
P50	325.3	335.4	345.6	355.8	366.0	376.2	386.6	396.9	407.3	417.8
P90	309.3	319.4	329.5	339.7	349.9	360.2	370.5	380.9	391.3	401.7

Table 4: Whitby Twenty-Year Winter Load Forecast (MW) (2022-2041) – Region of Durham Scenario

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	176.4	180.1	184.0	188.0	192.0	199.8	211.6	224.2	237.6	251.7
P50	172.7	176.5	180.4	184.3	188.4	196.1	208.0	220.6	233.9	248.1
P90	169.1	172.9	176.8	180.7	184.8	192.5	204.4	217.0	230.3	244.5
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	263.4	272.1	280.8	289.6	298.4	307.3	316.2	325.1	334.1	343.1
P50	259.7	268.4	277.2	285.9	294.8	303.6	312.5	321.4	330.4	339.4
P90	256.1	264.8	273.6	282.3	291.2	300.0	308.9	317.8	326.8	335.8

Table 5: Whitby Twenty-Year Summer Load Forecast (MW) (2022-2041) – Brooklin Low Scenario

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	234.7	238.7	242.8	247.0	251.5	263.5	275.9	289.2	303.3	318.3
P50	220.4	224.4	228.5	232.8	237.2	249.2	261.7	275.0	289.1	304.1
P90	204.4	208.4	212.5	216.8	221.2	233.2	245.7	258.9	273.0	288.0
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	326.7	335.2	343.7	352.2	360.8	369.4	378.0	386.7	395.4	404.2
P50	312.5	320.9	329.4	338.0	346.5	355.1	363.8	372.5	381.2	389.9
P90	296.4	304.9	313.4	321.9	330.5	339.1	347.7	356.4	365.1	373.9

Table 6: Whitby Twenty-Year Winter Load Forecast (MW) (2022-2041) – Brooklin Low Scenario

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	175.8	178.8	182.3	185.9	189.7	196.8	207.3	218.5	230.3	242.9
P50	172.1	175.2	178.6	182.3	186.0	193.1	203.7	214.8	226.6	239.2
P90	168.5	171.6	175.1	178.7	182.4	189.5	200.1	211.2	223.0	235.6
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	253.0	260.3	267.6	274.9	282.3	289.8	297.2	304.7	312.2	319.7
P50	249.3	256.6	263.9	271.3	278.7	286.1	293.5	301.0	308.5	316.1
P90	245.7	253.0	260.3	267.7	275.1	282.5	289.9	297.4	304.9	312.5

Table 7: Whitby Twenty-Year Summer Load Forecast (MW) (2022-2041) – Brooklin High Scenario

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	234.7	238.8	243.0	247.4	251.9	264.2	277.0	290.6	305.0	320.4
P50	220.4	224.5	228.7	233.1	237.7	250.0	262.8	276.4	290.8	306.1
P90	204.4	208.5	212.7	217.1	221.7	234.0	246.7	260.3	274.8	290.1
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	329.1	337.9	346.7	355.5	364.4	373.3	382.3	391.3	400.3	409.3
P50	314.9	323.6	332.4	341.3	350.1	359.1	368.0	377.0	386.0	395.1
P90	298.8	307.6	316.4	325.2	334.1	343.0	352.0	361.0	370.0	379.1

Table 8: Whitby Twenty-Year Winter Load Forecast (MW) (2022-2041) – Brooklin High Scenario

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	175.8	178.9	182.4	186.2	190.0	197.3	208.1	219.5	231.6	244.5
P50	172.1	175.2	178.8	182.5	186.4	193.7	204.5	215.9	228.0	240.9
P90	168.5	171.6	175.2	178.9	182.8	190.1	200.9	212.3	224.4	237.3
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	254.9	262.5	270.1	277.7	285.3	293.0	300.7	308.5	316.3	324.1
P50	251.3	258.8	266.4	274.0	281.7	289.4	297.1	304.8	312.6	320.4
P90	247.7	255.2	262.8	270.4	278.1	285.8	293.5	301.2	309.0	316.8

Figures 2 and 3 show the predicted peak loads for the Whitby region in summer and winter respectively. Figures 4 and 5 compare the initial Whitby forecast with results from the low and high Brooklin Scenarios for summer only.

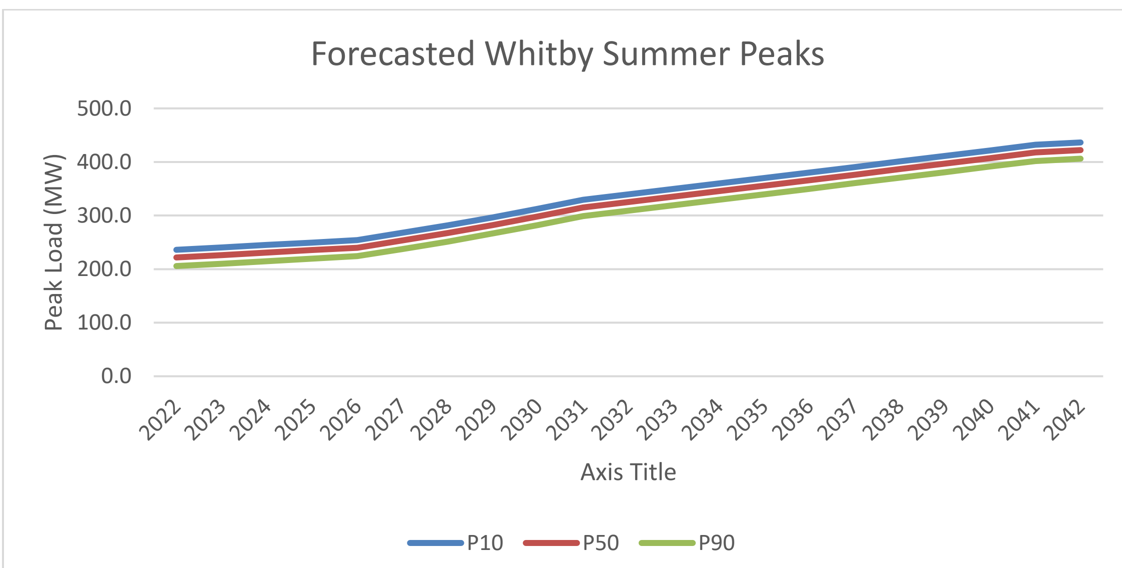


Figure 2: Forecasted Summer Peaks Whitby (Region of Durham Scenario)

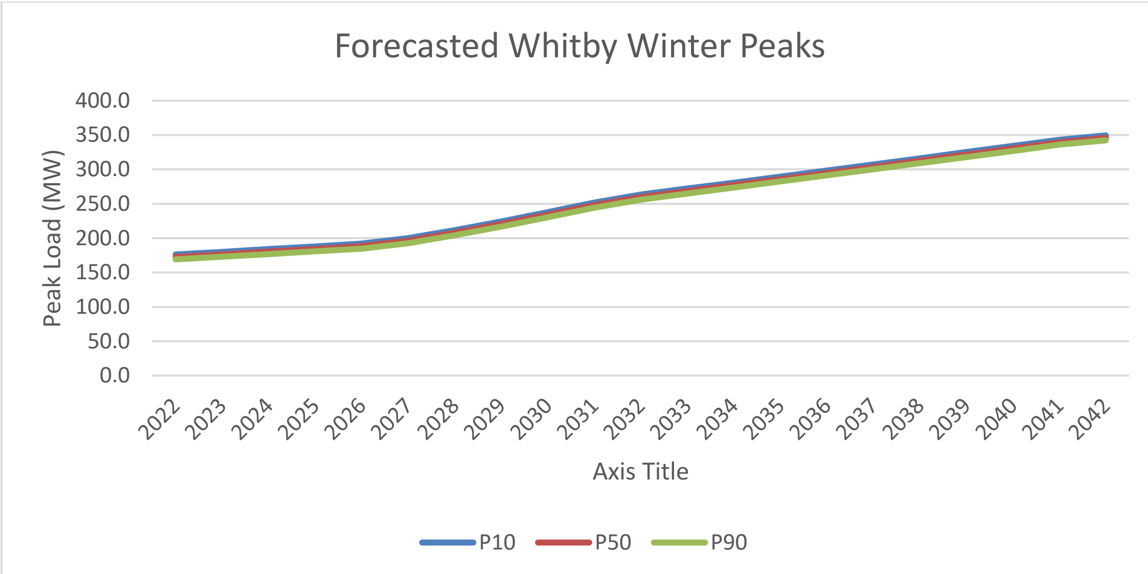


Figure 3: Forecasted Winter Peaks Whitby (Region of Durham Scenario)

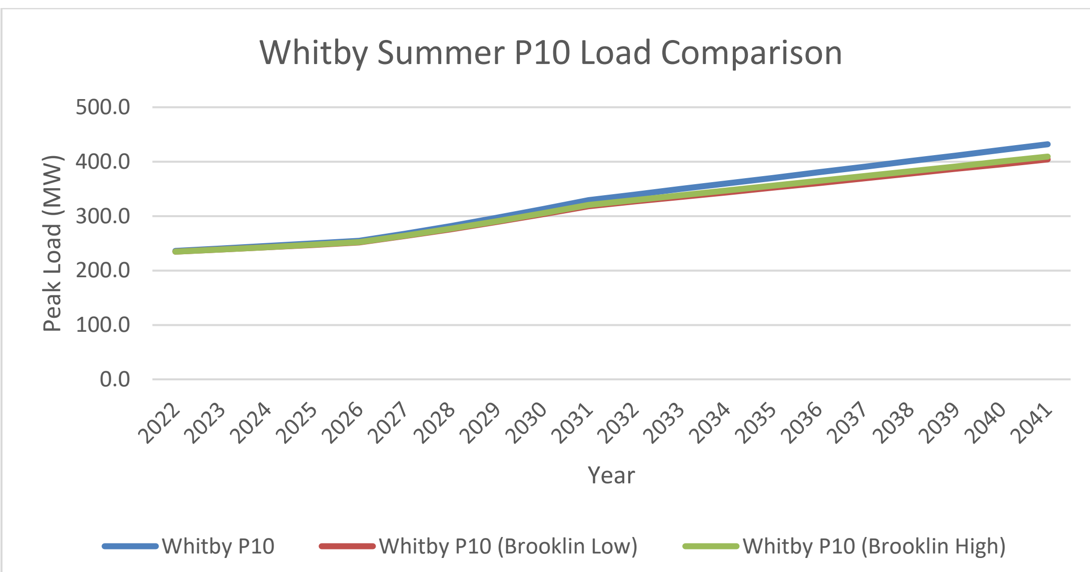


Figure 4: Whitby Summer Peak Load Comparison for Three Scenarios

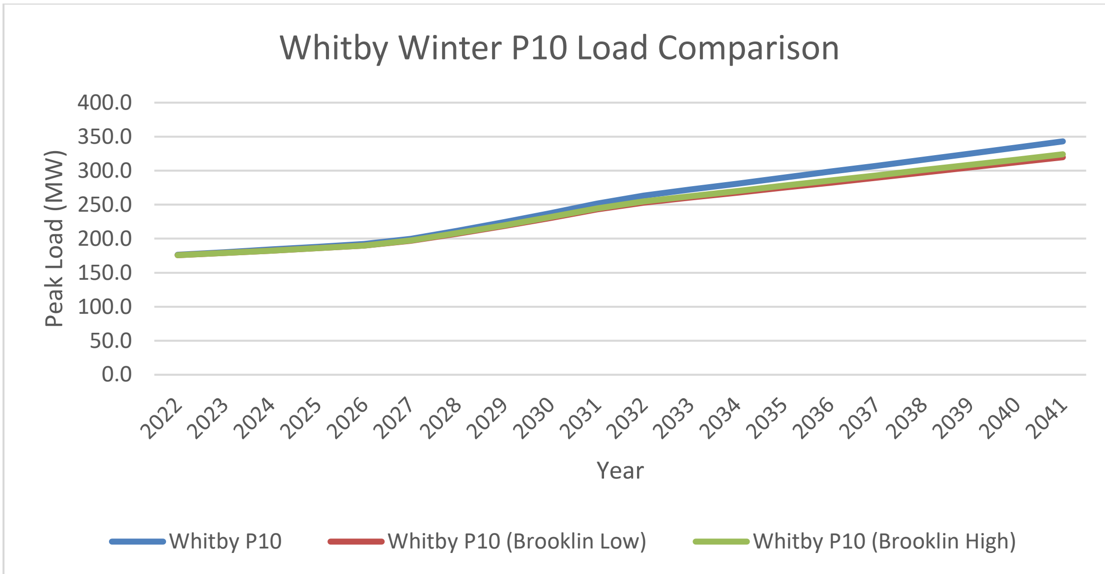


Figure 5: Whitby Winter Peak Load Comparison for Three Scenarios

Results of the twenty-year load forecast for Ajax-Pickering are shown in the tables below. Table 9 shows the P10, P50, and P90 forecasted summer peaks (MW) from 2022 to 2041. Tabled 10 shows the P10, P50, and P90 forecasted winter peaks (MW) from 2022 to 2041.

Table 9: Ajax-Pickering Twenty-Year Summer Load Forecast (2022-2041)

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	321.7	327.9	334.2	340.5	346.8	352.8	358.9	364.9	371.0	377.0
P50	304.3	310.6	316.9	323.1	329.4	335.5	341.5	347.6	353.6	359.7
P90	285.9	292.2	298.5	304.7	311.0	317.1	323.1	329.2	335.2	341.3
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	384.0	390.9	397.8	404.8	411.7	418.1	424.5	430.8	437.2	443.6
P50	366.6	373.5	380.5	387.4	394.4	400.7	407.1	413.4	419.8	426.2
P90	348.2	355.1	362.1	369.0	376.0	382.3	388.7	395.1	401.4	407.8

Table 10: Ajax-Pickering Twenty-Year Winter Load Forecast (MW) (2022-2041)

Peak (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
P10	250.0	255.6	261.2	266.7	272.3	277.7	283.1	288.4	293.8	299.1
P50	243.8	249.3	254.9	260.4	266.0	271.4	276.8	282.2	287.5	292.9
P90	236.5	242.1	247.6	253.2	258.8	264.2	269.6	274.9	280.3	285.6
Peak (MW)	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
P10	304.9	311.0	317.1	323.3	329.4	335.3	341.0	346.6	352.2	357.9
P50	298.6	304.7	310.9	317.0	323.2	329.1	334.7	340.3	345.9	351.6
P90	291.4	297.5	303.6	309.8	315.9	321.8	327.4	333.1	338.7	344.4

The figures below show the results of the twenty-year load forecast for summer and winter. Figures 6 and 7 show the predicted peak loads for the Ajax-Pickering area.

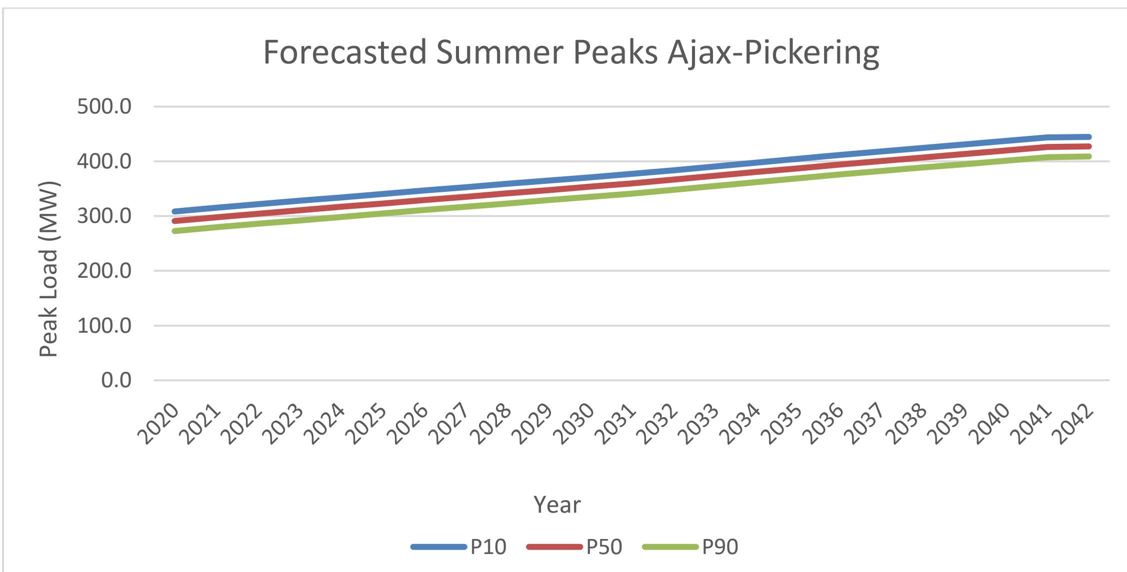


Figure 6: Forecasted Summer Peaks Ajax-Pickering

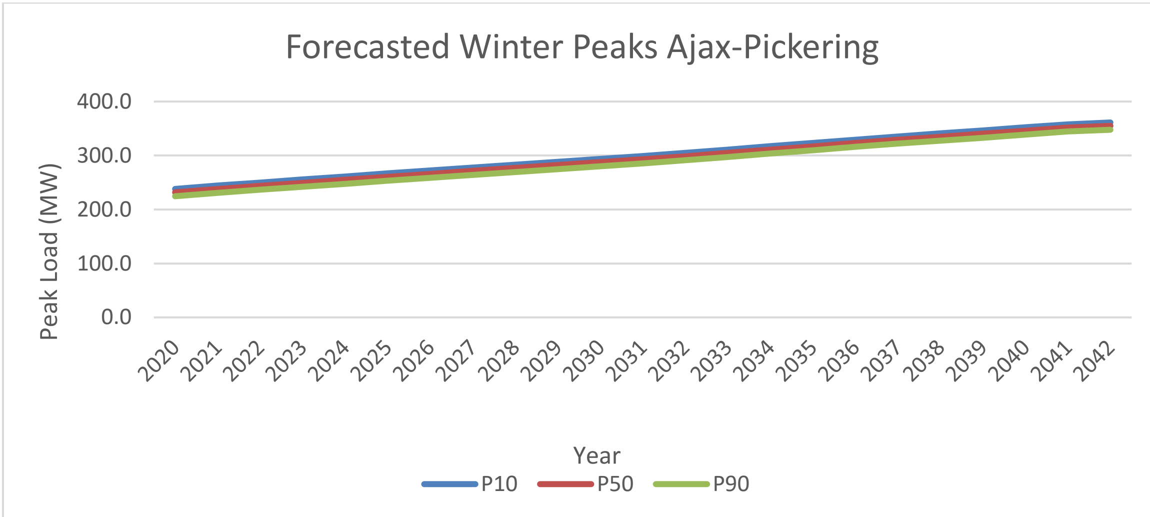


Figure 7: Forecasted Winter Peaks Ajax-Pickering

Comparing P10 summer forecasts, the Ajax-Pickering forecast from METSCO's study two years ago was 390 MW by 2030 compared to the updated forecast of 377 MW by 2030 due to less growth materializing in the Pickering area. Conversely, the previous Whitby forecast was 236 MW and has increased to 313 MW, primarily driven by the Brooklin development.

5 Supply Constraints

Ajax-Pickering receives power at 44 kV and 27.6 kV from transformer stations ("TS") owned by Hydro One. There are eight 44-kV feeders egressing from Cherrywood TS, three 44-kV feeders and six 27.6-kV feeders from Whitby TS, two 27.6-kV feeders egressing from Sheppard TS, and one 27.6-kV feeder egressing from Malvern TS.

Currently Whitby receives power at 44 kV from nine feeders egressing from Whitby TS and four feeders egressing from Thornton TS. The new North Brooklin developments will be served via 27.6 kV feeders from Whitby TS.

Table 11 summarizes the system capacity constraints at 27.6 kV and 44 kV, as determined from the limited time ratings of the respective TS.

Table 11: Total P10 Load Forecast Breakdown

System	27.6 kV	44 kV
System Capacity Constraint (MW)	282.0	509.0

Assumptions applied to the capacity planning process are listed below.

Assumptions:

1. New Brooklin development is assigned to the 27.6-kV system.
2. The 27.6-kV system feeding Brooklin will not be in service until the end of 2023 and will not affect the peaks until 2024.
3. Other developments in Whitby outside of Brooklin are assigned to the 44-kV system.
4. Pickering load growth is assigned to the 27.6-kV system (primarily in the Seaton area).
5. Ajax load growth is assigned to the 44-kV system.

METSCO divided the P10 load forecast between the 27.6-kV and 44-kV systems that serve the Ajax-Pickering and Whitby Regions. Given that the P10 peaks represent the peak value threshold that 10% of annual peaks will exceed, it is therefore used in capacity planning. The breakdown of the load for each region was calculated using both the expected population and household growth.

The tables below show the P10 load breakdown between the 27.6 kV and 44 kV systems. Table 12 shows the P10 load forecast divided into the 27.6-kV and 44-kV systems and the combined 27.6-kV and 44-kV forecasts. Tables 13 and 14 show the divided P10 load forecast for the low and high Brooklin scenario. Highlighted cells show when the individual 27.6-kV or 44-kV systems will begin to exceed capacity.

Given that in certain cases there can be some flexibility between which system is able to pick up the load, the load growth compared to total system capacity is also highlighted.

Table 12: Capacity Analysis – Region of Durham Scenario

Year	Whitby 27.6 kV	Ajax-Pickering 27.6 kV	All 27.6 kV	Whitby 44 kV	Ajax-Pickering 44 kV	All 44 kV		Total
2022	0.0	99.4	**99.4**	236.0	222.2	**458.2**		**557.7**
2023	0.0	104.2	**104.2**	240.4	223.7	**464.2**		**568.4**
2024	5.7	109.0	**114.7**	239.3	225.2	**464.5**		**579.2**
2025	7.6	113.8	**121.5**	241.9	226.7	**468.6**		**590.1**
2026	9.7	118.6	**128.3**	244.7	228.2	**472.8**		**601.1**
2027	15.3	123.2	**138.6**	252.3	229.6	**481.9**		**620.4**
2028	21.4	127.9	**149.2**	260.4	231.0	**491.4**		**640.6**
2029	27.8	132.5	**160.2**	269.0	232.4	**501.4**		**661.7**
2030	34.5	137.1	**171.6**	278.1	233.9	**512.0**		**683.6**
2031	41.7	141.7	**183.5**	287.8	235.3	**523.1**		**706.6**
2032	46.0	147.0	**193.1**	293.5	236.9	**530.5**		**723.5**
2033	50.3	152.3	**202.7**	299.3	238.6	**537.9**		**740.6**
2034	54.7	157.6	**212.3**	305.1	240.2	**545.3**		**757.7**
2035	59.0	162.9	**222.0**	311.0	241.8	**552.8**		**774.8**
2036	63.4	168.3	**231.6**	316.8	243.5	**560.3**		**792.0**
2037	67.8	173.1	**240.9**	322.7	245.0	**567.7**		**808.6**
2038	72.2	178.0	**250.1**	328.6	246.5	**575.1**		**825.3**
2039	76.6	182.8	**259.4**	334.6	248.0	**582.6**		**842.0**
2040	81.0	187.7	**268.7**	340.6	249.5	**590.0**		**858.8**
2041	85.5	192.6	**278.1**	346.5	251.0	**597.5**		**875.6**

Table 13: Capacity Analysis – Brooklin Low Scenario

Year	Whitby 27.6 kV	Ajax-Pickering 27.6 kV	All 27.6 kV	Whitby 44 kV	Ajax-Pickering 44 kV	All 44 kV	Total
2022	0.0	99.4	**99.4**	234.7	222.2	**456.9**	**556.3**
2023	0.0	104.2	**104.2**	238.7	223.7	**462.4**	**566.6**
2024	4.7	109.0	**113.7**	238.0	225.2	**463.2**	**577.0**
2025	6.6	113.8	**120.4**	240.4	226.7	**467.1**	**587.5**
2026	8.5	118.6	**127.1**	243.0	228.2	**471.1**	**598.2**
2027	13.6	123.2	**136.8**	249.8	229.6	**479.4**	**616.2**
2028	18.9	127.9	**146.7**	256.9	231.0	**487.9**	**634.7**
2029	24.5	132.5	**157.0**	264.5	232.4	**496.9**	**653.9**
2030	30.6	137.1	**167.7**	272.5	233.9	**506.4**	**674.0**
2031	37.0	141.7	**178.7**	281.0	235.3	**516.3**	**695.0**
2032	40.6	147.0	**187.6**	285.9	236.9	**522.8**	**710.4**
2033	44.2	152.3	**196.5**	290.7	238.6	**529.2**	**725.7**
2034	47.8	157.6	**205.4**	295.5	240.2	**535.7**	**741.1**
2035	51.4	162.9	**214.4**	300.4	241.8	**542.2**	**756.6**
2036	55.1	168.3	**223.3**	305.3	243.5	**548.7**	**772.1**
2037	58.8	173.1	**231.9**	310.2	245.0	**555.1**	**787.0**
2038	62.4	178.0	**240.4**	315.1	246.5	**561.6**	**802.0**
2039	66.1	182.8	**249.0**	320.0	248.0	**568.0**	**817.0**
2040	69.9	187.7	**257.6**	325.0	249.5	**574.5**	**832.0**
2041	73.6	192.6	**266.2**	330.0	251.0	**581.0**	**847.1**

Table 14: Capacity Analysis – Brooklin High Scenario

Year	Whitby 27.6 kV	Ajax-Pickering 27.6 kV	All 27.6 kV	Whitby 44 kV	Ajax-Pickering 44 kV	All 44 kV		Total
2022	0.0	99.4	**99.4**	234.7	222.2	**456.9**		556.3
2023	0.0	104.2	**104.2**	238.8	223.7	**462.5**		566.7
2024	4.8	109.0	**113.8**	238.1	225.2	**463.3**		577.2
2025	6.7	113.8	**120.5**	240.6	226.7	**467.3**		587.8
2026	8.6	118.6	**127.3**	243.2	228.2	**471.4**		598.6
2027	13.9	123.2	**137.1**	250.2	229.6	**479.8**		617.0
2028	19.3	127.9	**147.2**	257.5	231.0	**488.5**		635.7
2029	25.1	132.5	**157.6**	265.3	232.4	**497.7**		655.3
2030	31.3	137.1	**168.4**	273.5	233.9	**507.4**		675.8
2031	37.9	141.7	**179.6**	282.2	235.3	**517.5**		697.1
2032	41.6	147.0	**188.6**	287.2	236.9	**524.1**		712.7
2033	45.3	152.3	**197.6**	292.2	238.6	**530.8**		728.4
2034	49.1	157.6	**206.7**	297.2	240.2	**537.4**		744.1
2035	52.8	162.9	**215.8**	302.3	241.8	**544.1**		759.9
2036	56.6	168.3	**224.9**	307.3	243.5	**550.8**		775.7
2037	60.4	173.1	**233.5**	312.4	245.0	**557.4**		790.9
2038	64.2	178.0	**242.2**	317.5	246.5	**564.0**		**806.2**
2039	68.1	182.8	**250.9**	322.6	248.0	**570.6**		**821.5**
2040	71.9	187.7	**259.6**	327.8	249.5	**577.3**		**836.9**
2041	75.8	192.6	**268.4**	332.9	251.0	**583.9**		**852.3**

6 Non-Wires Alternatives

Non-wires alternatives for capacity upgrades including customer rooftop solar and the combination of rooftop solar with a battery energy storage system ("BESS"). Specifically, the new developments in North Brooklin will include rough-ins enabling customers to install rooftop solar and BESS if they choose to (and electric vehicles, although vehicle-to-grid capacity relief is not explored in this report). Assumptions made for specifications and performance of the rooftop solar panels and battery storage are listed below.

Assumptions:

1. Nameplate rating of rooftop solar panel: 10 kW.
2. Nameplate rating of battery storage: 10 kWh.
3. Firm capacity of rooftop solar without BESS in summer: 33%.
4. Firm capacity of rooftop solar without BESS in winter: 0%.
5. Firm capacity of rooftop solar with BESS (summer and winter): 100%.

Since the Brooklin Low Scenario is the most conservative of the three, the non-wires alternatives are evaluated based on this scenario to assess feasibility. The total Distributed Energy Resource ("DER") capacity required was calculated for one-year, three-year and five-year periods and used in conjunction with the above assumptions to determine the DER penetration required among the North Brooklin developments to defer the excess load.

Table 15 shows the estimated DER penetration required for deferral based on the number of DER connections required and total expected customers from new Brooklin development for the given time periods. Three options of rooftop solar only, rooftop solar with BESS, and mix of 50% rooftop solar only and 50% rooftop solar with BESS.

Table 15: DER Penetration Required for Excess Load Deferral – Brooklin Low Scenario

	DER Penetration Required (% and # of units)		
Deferral Period	Rooftop Solar	50-50 Mixed Infrastructure	Rooftop Solar with BESS
1-Year	36% - 3294 units	18% - 1647 units	12% -1098 units
3-Year	N/A	58% - 6158 units	39% - 4105 units
5-Year	N/A	79% - 9146 units	53% - 6098 units

Rooftop solar alone cannot reliably defer capacity constraints beyond one year since it is not dispatchable without an associated BESS. The mix of 50% rooftop solar and 50% rooftop solar with BESS can possibly defer investment for three years but the 79% penetration needed for a five-year deferral is not reasonable to expect. Rooftop solar with BESS across the system provides the greatest potential to defer investment across each deferral period.

Since these DERs are customer-owned, Elexicon has no control over their implementation and will need to monitor installation trends in the future. Deferral of future capacity investment needs in the area can be further enhanced if other developments in Brooklin, Whitby, and the surrounding Ajax and Pickering areas promote DER integration.

6.1 Constraints

Upstream of Whitby TS (which has two dual-element spot networks "DESNs") is Hydro One's Cherrywood TS. Elexicon's Renewable Energy Generation Investment Plan[9] has identified constraints on the upstream transmission system that prevent downstream connection of new DERs on certain feeders. Hydro One's Cherrywood TS has reached its short capacity limits and no new downstream generation connections can be added until Hydro One addresses these constraints.

Typical feeder maximum load is set at the level in which the voltage drop from the first customer to the last customer is 10 Volts (+3 V to -7 V or a range preferred by the LDC). By so doing, the utility can set the voltage at the first customer at the highest level allowed by C235:19 (+3 V) and the resulting voltage at the farthest customer will be at the lowest level allowed by CSA (-7 V). The impact of rooftop solar is to create the appearance that there is less load on the system, however when the sun goes behind a cloud, that load still needs to be served by the distribution system or battery storage. Therefore, typically the system is modelled without consideration for rooftop solar.

The impact of DER in general on a feeder is to reduce the load and/or create reverse loads if the DER is larger than the total load. Reverse loads can cause mis-operation of the feeder protection system in the event of a fault. For instance, if a fault occurs at the 1/3rd point of a feeder, the station breaker will operate and clear the fault. However, if significant reverse currents are available from DERs, the fault may be fed from the source side and there may or may not be sufficient protection to open the circuit. In addition, under certain circumstances, the operation of the protection system may result in an "island" of the system where power is maintained, and loads are supplied from the DER. This can create a safety problem as line crews would be unaware that the lines are still energized, it can create a fault current problem if the fault is being supplied from both ends, and unless the system is designed for islanding, such as in a microgrid, it can create a synchronizing problem when the network is reconnected.

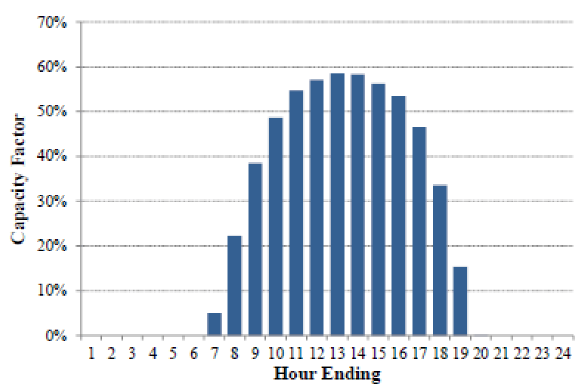
To prevent islanding, IEEE 1547 now recommends detailed engineering take place if the total DER on a feeder exceeds 33% of minimum load. This value is based on simulations and field tests on feeders including synchronous generators so is somewhat conservative in the context of solar photovoltaic ("PV"). When the minimum load on the feeder is not known – as is the case with the Brooklin feeders that are not yet constructed – IEEE 1547 recommends using 7.5% of the feeder's maximum load to limit DER penetration. The 61 MW of DER needed across the three Brookline feeders (to defer a new TS by five years) translates to just over 20 MW per feeder. The predicted peak load in Brooklin is 71 MW by 2040 or 23. 7 MW per feeder, meaning the required DER to defer future capacity investments is close to 90% of the peak load and is much higher than the 7.5% constraint.

Interconnection of DERs to distribution systems might cause issues and violations that could increase the risk of damages to the distribution feeder and station. The following issues are some of the major risks that may rise depending on the location of the interconnection, topology of the feeder, and the size of the DER. LDCs limit the amount and number of DERs that can be added to their feeders based on their

[9] "Renewable Energy Generation Investment Plan," Elexicon Energy, Sep 2020

initial studies, but this is not the whole story. Connection impact assessment studies will show the effect of a specific DER that is going to be added to the distribution feeder under worse case scenarios for the system. Typically, the worst-case scenario for a distribution system is when all DERs are generating at their maximum capacity while the loading of the feeder is at its minimum level. This may cause over-voltages at the interconnection points and along the feeder and damage the distribution system assets. Moreover, other factors should be assessed based on the IEEE 1547-2018 standard to have a reliable system:

- **Steady-state voltages along the feeder and at the station** should not violate the acceptable range defined by C235-83. This point usually causes issues when the feeder is at its minimum loading level and DER generation is maximum. The following picture shows the typical solar generation curve of a summer day. If the weather is clear and we have a sunny day, at 11:00 AM, it is expected that all the solar type DERs generate at their maximum capacity. Whereas based on the load profile for the same day, the loading might be at its minimum value. The mitigation approaches have been introduced by IEEE 1547-2018 depending on the DER type. In this case we consider the solar-type DERs which are connected to the grid through inverters. Fortunately, inverters that are being manufactured and are available in the market meet the requirements of the IEEE 1547-2018 and have the capability to support the distribution system under critical conditions. Advantages such as VVM module integrated in inverters which will help to limit the output generation by solar PVs to keep the voltages in the acceptable range.



Source: Calculated based on 8,760 hourly generation data from NREL's Solar Advisor Model (SAM) version 2011.6.30.

- **Momentary Voltage Fluctuations** should be kept under ± 10%. A good example for this is when the distribution system is working under maximum loading and maximum solar DER. Although system voltages might be in the acceptable range during this operation scenario, however if the sun goes behind the clouds in that specific region, the DER generation will drop down to zero. This scenario can cause voltage drops along the feeder and in the worst-case scenario (if the substation is not designed to meet the full load) station overloading. This overvoltage value should not be passing the ± 10% limit.
- **Feeder Thermal rating and loading** is another crucial factor. The distribution systems are designed for unidirectional power flow from the substation or primary source to the loads. The number and sizes of DERs could be limited by this factor since during off-peak periods, and maximum generation of the solar PVs, the power might flow towards the station and traditional distribution

systems are not designed for bidirectional power flow. This may result in violating the current limits of the conductors. In other words, a non-wire solution might not be the right solution to address the increased loads.

- **Short-Circuit Currents:** The fault current magnitudes during a fault will increase to higher levels than normal operation. In case of interconnecting a DER to a distribution feeder, the fault current contribution of the DER should not cause a situation in which the maximum fault current exceeds the interrupting ratings of feeder equipment. Although, a single DER might not have high contribution to cause issues, multiple DERs interconnected to the distribution system could raise some issues. During a fault at a location between the substation and the DERs, the contribution from the DERs side might increase up to a level that the contribution of the station drops below pick up settings of the protection devices of the feeders and it could cause significant issues and damages to the station. This is also a factor that could affect the level of penetration by DERs.
- **Transfer trip and Anti-Islanding considerations:** An unintentional DER island is formed if a DER facility remains connected to a portion of the distribution system after that portion is separated from the normal supply. Unintentional DER islanding can pose the following threats to the normal operation of a distribution system:
    - Upstream distribution systems may attempt to reconnect into the island unsynchronized with voltage, frequency, and/or phase angle, which can potentially damage switchgear, DER, and customer equipment.
    - Unintentional islands do not have their DERs set up with the required controls to maintain adequate power quality conditions adequate for customer loads, which may result in damages.
    - Unintentional islands might potentially expose the public to unsafe, energized downed conductors.
    - Line crews working on power restoration post-storms or other events may come across unintentional energized islands. This makes their job more hazardous and slows down the power restoration process.

Fortunately, inverter-based DERs such as rooftop solar meet the requirements of the IEEE 1547-2018 to detect the island and cease to energize the grid within two seconds. Furthermore, all the DERs whose aggregate capacity is 1 MW or larger, or when the aggregate generation of the DERs exceeds 50% of the minimum feeder load, a transfer trip signal is required to prevent damages when a severe event occurs in the substation or on the feeder.

- **Harmonics and power quality and DC current injection:** Another factor that might be important when determining the DER penetration is considering the harmonic and DC current injection. These values might be acceptable when considering a single DER; however, for a distribution system with high DER penetration, these injections from all DERs add up and at a certain level of DER penetration, these values might exceed the IEEE 1547-2018 acceptable limits and result in significant saturation of magnetic components, such as cores of distribution transformers.
- **Unbalanced voltages:** Typically, solar DERs connect through three-phase inverters which do not result in unbalanced voltages. In some cases, single-phase DERs connect to the system, and it is

important to distribute the single-phase connections to separate phases equally. Multiple DER connections should be balanced and should not result in the voltage difference between the phases to exceed more than 3%. Phase balancing study could address this issue.

Although non-wire alternatives are attractive in terms of economic aspects, there are always constraints that might limit their effectiveness and their allowable penetration level. Some DER types such as solar systems are not the most reliable sources to meet the significant loads except when combined with sufficient battery storage. Rooftop solar is better at offsetting energy than demand; whereas the combination of solar and battery storage provides the most reliable means of meeting capacity demands.

While DER can be used to offset peak demand and defer investments into new stations and feeders, high DER penetration creates numerous challenges for operating the distribution system. Methods such as VVM, DA, AMI must be used to facilitate the DER.

7 Conclusions

The twenty-year load forecasting model for Elexicon provides probabilistic predictions for load growth in the Ajax-Pickering and Whitby areas. Three separate scenarios were defined for Whitby, the Region of Durham scenario is based on housing estimates provided by the Region of Durham (and adjusted for 2021 census data), whereas the Brooklin Low and High scenarios are based on twenty-year growth estimates provided by the major housing developer in North Brooklin.

The results of the twenty-year peak load forecast show an increasing trend across all scenarios. When comparing summer and winter peak load graphs the P10, P50, and P90 values are much closer in winter when compared to summer. Therefore, more variation in peak load is expected during summer months. When comparing the Region of Durham scenario with both Brooklin Developer scenarios there is a noticeable difference in peak load in Whitby from 2031 onwards. However, there is little difference between the Brooklin Low and Brooklin High scenarios. The lower peak load in both Brooklin scenarios can be attributed to the North Brooklin developer's lower housing estimates when compared to estimates from the Region of Durham.

The P10 load forecast was then divided between the 27.6-kV and 44-kV systems that serve the Ajax-Pickering and Whitby Regions. P10 values were used since they represent the peak value threshold that 10% of annual peaks will exceed. In the Region of Durham scenario, the 44-kV-system is expected to exceed capacity by 2030. If load can be balanced between the 27.6-kV and 44-kV systems, then the whole system is forecast to exceed capacity in 2036 under this scenario. In both Brooklin scenarios, these capacity constraints are forecast to occur one year later. This constraint will necessitate the construction of a new TS, which costs approximately $40 million in present-day dollars. The benefit of deferring the new TS ranges from $0.39 million to $9.94 million depending on the deferral period (one to five years) and discount rate (3% to 8%).

The Brooklin Low scenario was used to determine the minimum amount of DERs required across new Brooklin development to defer over capacity for the one-year, three-year, and five-year periods. The combination of rooftop solar with BESS provides the greatest potential to meet future capacity needs and defer capacity investments. To be able to defer capacity assessments for one year, 12% of new customers in the North Brooklin area need to install rooftop solar with BESS. This percentage is 39% for a three-year deferral and 53% for a five-year deferral. Since these DERs are customer-owned, Elexicon has no control over their implementation and will need to monitor installation trends in the future. The forecast may also be impacted if other new developments take a similar approach to enabling DERs.

8 References

[1] Ontario, "A Place to Grow Growth Plan for the Greater Golden Horseshoe Office Consolidation 2020," Aug. 2020. [Online]. Available: https://files.ontario.ca/mmah-place-to-grow-office-consolidation-en-2020-08-28.pdf [Accessed 2022].

[2] Region of Durham, "Durham Regional Official Plan," 22nd May 2020. [Online]. Available: https://www.durham.ca/en/doing-business/resources/Documents/PlanningandDevelopment/Official-Plan/2020-Durham-Regional-Official-Plan-Consolidation---Revised-1.pdf [Accessed 2022].

[3] Town of Whitby, "Brooklin Study Secondary Plan and Transportation Master Plan," Jan 2015. [Online]. Available: https://www3.whitby.ca/brooklinreports/pl-misc_brooklinpopulationemploymentandhousinganalysis.pdf [Accessed 2022].

[4] Town of Whitby, "2021 Consolidated Development Charges Background Study," Jul 2021. [Online]. Available: https://www.whitby.ca/en/work/resources/Whitby-2021-Consolidated-DC-Background-Study.pdf [Accessed 2022].

[5] City of Durham, " Durham region Profile: Technical Report," May 2020. [Online]. Available: https://www.durham.ca/en/living-here/resources/Documents/DRP-Technical-Report-Appendix_FINAL.pdf [Accessed 2022].

[6] Region of Durham, "Durham Region Profile highlights the region's growth, devlopment and progressive opportunities," 22nd July 2020. [Online].

Available: https://www.durham.ca/en/news/durham-region-profile-highlights-the-region-s-growth-development-and-progressive-opportunities.aspx [Accessed 2022].

[7] City of Pickering, "Detailed 20 Year Population Forecast," 31st December 2019. [Online]. Available: https://www.pickering.ca/en/business/resources/20YearPopulationForecastACC.pdf [Accessed 2022].

[8] Statistics Canada, "2011 Census of Population," 2011. [Online]. Available: https://www12.statcan.gc.ca/census-recensement/2011/dp-pd/index-eng.cfm [Accessed 2022].

[9] Statistics Canada, "2016 Census of Population," 2016. [Online]. Available: https://www12.statcan.gc.ca/census-recensement/2016/dp-pd/index-eng.cfm [Accessed 2022].

[10] Statistics Canada, "2021 Census of Population," 2021. [Online]. Available: https://www12.statcan.gc.ca/census-recensement/2021/dp-pd/prof/index.cfm [Accessed 2022].

Appendix A: Population and Household Estimates (2022-2041)

The tables below show forecasted values that were used as data inputs for the 20-year load forecast model. Table 16 shows population forecasts and Table 17 shows household forecasts.

Table 16: Population Estimates

Year	Whitby	Ajax	Pickering
2022	140,654	126,666	99,186
2023	142,835	127,375	103,031
2024	145,040	128,084	106,877
2025	147,273	128,793	110,722
2026	149,528	129,502	114,568
2027	156,138	130,211	118,413
2028	163,038	130,571	121,976
2029	170,241	130,931	125,538
2030	177,759	131,291	129,101
2031	185,608	131,651	132,663
2032	192,337	132,011	136,226
2033	199,067	132,775	136,792
2034	205,796	133,538	137,358
2035	212,525	134,302	137,924
2036	219,254	135,065	138,490
2037	225,984	135,829	139,055
2038	232,713	136,592	139,621
2039	239,442	137,356	140,187
2040	246,171	138,119	140,753
2041	252,901	138,883	141,319

Table 17: Housing Estimates by Area

Year	Whitby	Whitby (Brooklin Low Scenario)	Whitby (Brooklin High Scenario)	Ajax	Pickering
2022	48,666	48,340	48,340	43,230	35,144
2023	49,755	49,324	49,349	43,575	36,609
2024	50,868	50,330	50,382	43,920	38,073
2025	52,006	51,380	51,460	44,265	39,538
2026	53,168	52,472	52,583	44,610	41,002
2027	56,437	55,416	55,606	44,855	42,500
2028	59,907	58,482	58,747	45,100	43,998
2029	63,590	61,741	62,085	45,345	45,497
2030	67,500	65,207	65,634	45,590	46,995
2031	71,650	68,892	69,405	45,835	48,493
2032	74,121	70,962	71,550	46,115	50,210
2033	76,602	73,041	73,703	46,397	51,928
2034	79,093	75,128	75,866	46,680	53,645
2035	81,596	77,225	78,038	46,963	55,363
2036	84,108	79,330	80,219	47,249	57,080
2037	86,632	81,444	82,409	47,535	58,626
2038	89,166	83,567	84,609	47,822	60,172
2039	91,712	85,700	86,819	48,111	61,717
2040	94,268	87,842	89,037	48,401	63,263
2041	96,835	89,993	91,266	48,693	64,809

Appendix B: Input Data

The tables below show unadjusted data values taken from the sources listed in Section 2. Descriptions of each table are listed below.

1. **Table 18:** Durham population estimates taken from **Ontario's a Place to Grow**, **Durham Regional Official Plan**, and estimates reported by the **Region of Durham**.
2. **Table 19:** Population and household counts for **the Town of Ajax from the Durham Region Profile: Technical Report**.
3. **Table 20:** Population and household counts from the **City of Pickering: Detailed 20 Year Population Forecast**.
4. **Table 21:** Population and household estimates for the Town of Whitby from the **Consolidated Development Charges Background Study.**
5. **Table 22:** Population and household counts form **Statistics Canada Census** 2011, 2016, and 2021.
6. **Table 23:** Peak Load data for summer and winter provided by **Elexicon Energy**

Table 18: Durham Population Estimates

Year	Population
2021	809,990
2031	960,000
2041	1,200,000
2051	1,300,000

Table 19: Ajax Population and Housing Estimates

Year	Population	Households
2018	-	37,550
2016	-	38,360
2021	132,325	42,885
2026	135,870	44,610
2031	137,670	45,835

Table 20: Pickering Population and Housing Estimates

Year	Population	Households
2021	94,568	33,680
2026	113,795	41,002
2031	131,608	48,493
2036	150,678	57,080
2041	168,522	64,809

Table 21: Whitby Population and Housing Estimates

	Whitby	Households
2013	-	42,007
2014	-	43,509
2015	-	43,017
2016	128,377	43,529
2017	130,575	44,134
2018	132,810	44,448
2019	135,084	44,954
2020	136,562	46,201
2021	139,748	47,601
2022	141,901	48,666
2023	144,082	49,755
2024	146,287	50,868
2025	148,520	52,006
2026	150,775	53,168
2027	157,385	56,437
2028	164,285	59,907
2029	171,488	63,590
2030	179,006	67,500
2031	186,855	71,650

Table 22: Statistics Canada Census Data 2011, 2016, 2021

Area	2021 Population Counts	2011 Household Counts	2016 Household Counts
Durham	696,922	213,745	227,905
Whitby	138,501	41,020	43,530
Ajax	126,666	35,040	37,550
Pickering	99,186	29,330	30,920

Table 23: Elexicon Energy Historical Peak Load (MW)

Year	Whitby (Summer)	Ajax-Pickering (Summer)	Whitby (Winter)	Ajax-Pickering (Winter)
2014	161.2	227.5	160.4	225.3
2015	178.0	231.6	158.9	222.0
2016	191.9	246.8	150.2	201.9
2017	170.8	229.3	142.5	197.2
2018	185.1	247.8	153.6	207.8
2019	181.8	256.4	151.8	207.5

APPENDIX B-5:

METSCO Feasibility Study

Whitby SmartGrid VVO and DA

METSCO

MAKING IT POSSIBLE

Feasibility Study

Whitby SmartGrid VVO and DA

Project P-22-153 | Version 2.0

METSCO Energy Solutions | July 20, 2022

METSCO Energy Solutions

Toronto Office

2550 Matheson Blvd E,
Mississauga, Ontario
L4W 4Z1
+1 (905) 232-7300

Calgary Office

1206, 20 Ave SE,
Calgary, Alberta
T2G 1M8
+1 (587) 887-0235

Document Information

Title:	Feasibility Study
Project ID:	P-22-159

Revision	Date	Author	Description
D1	June 30	D.Thompson	Initial draft release
D2	July 8	D.Thompson	Cosmetic and minor language updates
V1	July 15	D.Thompson	Circulated for Review
V2	July 20	D.Thompson	Revised based on Comments

Table of Contents

List of Figures

List of Tables

1 Introduction to Whitby Smart Grid

The changing demands of the distribution system is creating a need for a new type of system operation. The "Grid of the Future" will need to support high penetrations of distributed energy resources ("DERs"), manage electric vehicle ("EVs") charging, and support renewable energy such as roof top solar. Looking farther ahead, the distribution system is expected to take on a distribution system operator ("DSO") role and handle the dispatch and settlement of locally operated distributed generation, and aggregated customer side storage under distributed energy resource management ("DERMs") scenario.

Many of these concepts are future oriented, however there are mature technologies that will support the "Grid of the Future" that, while still considered innovative, can be deployed now under the umbrella of advanced distribution management systems ("ADMS"). Mature technologies that are ready for deployment include distribution automation ("DA"), fault location isolating and service restoration ("FLISR"), volt-var optimization ("VVO"), outage management systems ("OMS"), advanced metering infrastructure ("AMI"), engineering systems and asset management ("GIS, AMS"), as well as a host of customer interfacing systems ("CIS").

This report is a feasibility study relating to two such systems that, as part of the "Whitby SmartGrid", will start to position Elexicon in the Whitby rate zone as an innovative and forward-looking Local Distribution Company ("LDC") that is prepared for the challenges of the future grid. The two systems under study in this report are DA which is a component of FLISR, and VVO which will lead the utility to implement conservation voltage reduction ("CVR").

The pressures on Elexicon to implement these systems include a rapid load growth projection and an expectation that trends in DER penetration will increase the need for rapid service restoration in the event of an outage.

This document summarizes the application of the two proposed sub-systems of the Whitby SmartGrid in the growing Whitby area of Elexicon Energy's ("Elexicon's") service area. The evaluation considers the feasibility of implementation the solutions and benefits expected.

Study Methodology

The output of this study is a feasibility level study including preliminary scope and schedule and an assessment of the project impacts for the Whitby rate zone.

The study modelled 4 typical feeders for impact of VVO and CVR, and the previous 2 years of outage data for the impact of DA. The modelling is a reasonable predictor of real-world results with the caveat that outage experiences are not the same year over year, and that real world distribution systems are not as ideal as a load-flow model would predict. These variances are discussed throughout the study and a reasonable range of results is derived.

Related Systems/Projects

As Elexicon proceeds towards the "Grid of the Future", there will be a number of inter-related projects that will comprise the "Whitby SmartGrid" project. Some of these are under way at various stages, and others will be activated when the need or technology appears.

Systems that will inter-connect with the VVO and DA elements of the Whitby SmartGrid are generally part of the umbrella ADMS and include but are not limited to:

- DERMS, for control of distributed energy resources,
- AMI, and upgrade to latest generation meters,
- SCADA, integration with proposed VVO and FLISR(DA),
- OMS, to integrate FLISR/DA with Customer Outage Reporting and online maps,
- CIS, to manage communications, outages and upgrades,
- AMS and GIS systems for asset management, work order management, and records.
- Control Room Upgrades for additional operational needs,
- Communications Systems (Radio/Fibre) for real-time data management, and
- Operational Data Store ("ODS") for data warehousing and cyber security.

2 Whitby SmartGrid

SmartGrid is not a homogenous term and means different systems to different organizations. In the case of the Whitby SmartGrid project, the technologies proposed are those limited to systems that are mature and ready for deployment and have a technical return on investment at this time. Those systems that address future needs will be subject to future study.

The Whitby SmartGrid project includes VVO and the associated CVR, as well as DA which is a key component of fault locating isolating and service restoration (FLISR) systems. The benefit of the CVR system is to reduce demand and energy by lowering voltage at the source, and the benefit of DA is a reduction in outage impact by reducing the number of customers that experience a sustained outage. Figure 2-1 shows typical hardware of the VVO and DA systems.

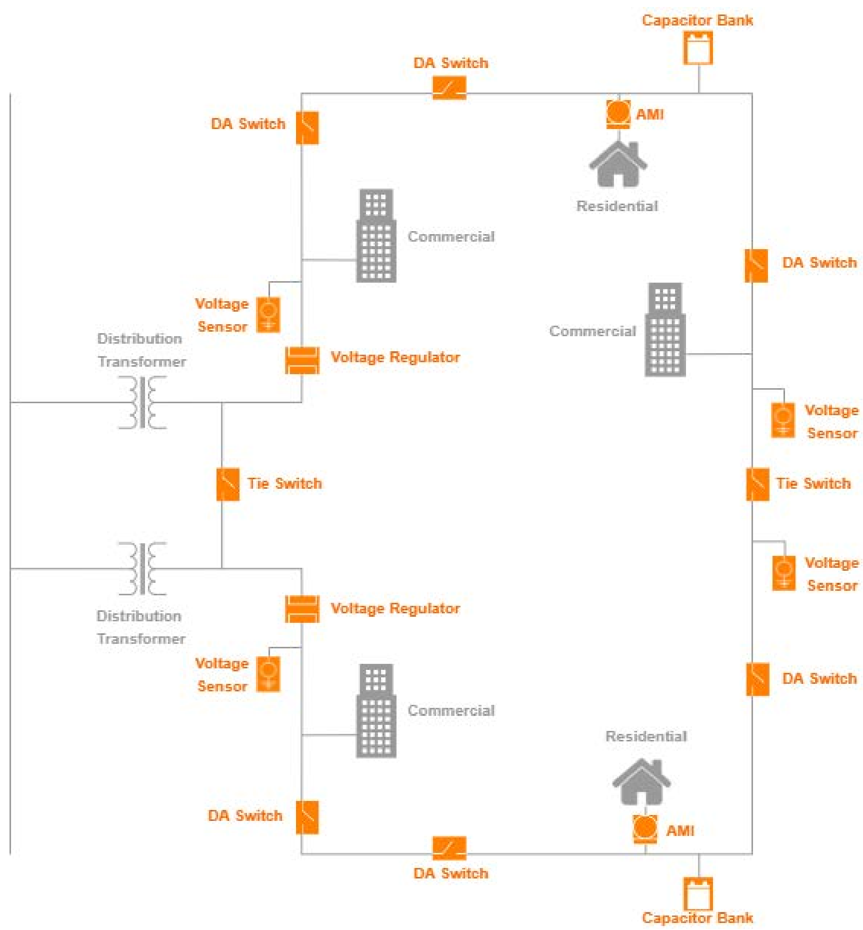


Figure 2-1 -- VVO and DA Systems Diagram

Whitby Smart Grid Project Summary

The plan for this portion of the Whitby SmartGrid plan is to deploy DA and VVO in a common project across the entire distribution network in the Whitby rate zone. Each feeder will be equipped with a regulator, a capacitor bank, an average of 3 sectionalizing automated switches, a tie switch (counted as a half-switch), 3 or 4 voltage sensors and 3 or 4 communicating faulted circuit indicators (CFCIs). Controlling software will be included in an external project for the implementation of ADMS, and the communications will mostly be carried by the existing SCADA system backbone which exists in each sub-station and will be supplemented with local radio links.

The drivers for the Whitby SmartGrid proposal at this time include an expectation of future demands on the distribution system imposed by higher penetrations of DERs and EVs which are projected by the IESO under Grid Evolution initiatives, by the Provincial Government with its EV charging program, and the Town of Whitby's own EV charging expansion program. In addition, opportunities presented by developing in the Brooklin area will include opportunities to deploy DERs at high levels of penetration. Considering the many phases of the "Grid of the Future" there is a need to get started with the mature technologies that are available today.

These portion of the Whitby SmartGrid is presented as a single project however the deployment relates to two distinct and separable systems that are discussed in individual detail in Sections 3 and 4.

Existing Smart Grid Application

The Whitby rate zone has been active in the development of the initial stages of SmartGrid and has piloted DA on 6 feeders and 5 stations and as well has procured centralized controlling software under previous and on-going projects. Some of these systems are in the commissioning stage at this time and will be integrated with the larger Whitby SmartGrid project as it is rolled out.

Expected Benefit

The "Grid of the Future" will have many benefits to the customers of the Whitby rate zone and the operations of the Elexicon distribution system. The "Grid of the Future" can be expected to provide:

- cost reductions compared to non-automated options for operation,
- reliability improvements and connection flexibility relating to increased complexity of DERs,
- storm hardening and the ability to restore power more quickly in a complex outage
- reduction in energy consumption and associated Greenhouse gas emissions,
- reduction/deferral of capital expansion programs,
- enhanced communication to customers during events,
- innovative opportunities for non-wires alternatives (NWAs),
- aggregated and dispatch of DERs and customer choice in energy transactions, and
- enhanced asset management.

At this stage of the development, the Whitby SmartGrid can expect to realize the benefits associated with VVO and CVR, and DA and FLISR which are summarized at a high level in Table 2-1.

Table 2-1: Feasibility Level Benefits of Whitby SmartGrid

System	Projected Benefit
VVO and CVR The management of VARs allows a reduction of source voltage and a commensurate reduction in Power, Energy and Losses	Financial benefit: 5% source voltage reduction delivers 2-3% reduction of energy consumption, and similar reduction in peak energy. Reduction in GHG emissions due to reduction in energy.
FLISR/DA The rapid isolation of faulted sections and restoration of non-faulted sections improves reliability statistics and converts 75% of sustained feeder customer impact to momentary outages. O&M reduction (truck rolls) due to improved fault location.	Reliability benefit: SAIFI from 0.87 to 0.28 SAIDI from 1.03 to 0.45 CAIDI ~ 40 minutes MAIFI from 0 to 0.59 Financial Benefit: Reduced O&M costs in locating and isolating faults. Work begins immediately on repairs. Savings 1hr per outage.

Expected Benefit to DERs

The Whitby Smart Grid is a set of technologies that can address risks and opportunities with the increase in DERs being installed in Whitby. The increased penetration of new DERs is expected to include commercial entities (including aggregators) with a high need for reliable access to the system. Recent events have also highlighted the increasing need for system hardening relating to storm events. When the provincial system is relying on DERs for supply, there will be a need to restore connections to all DERs possible quickly and reliably. The application of DA will allow for rapid restoration to all customers outside of the outage zone, in a complex switching situation such as created by storm events.

In addition, the application of CVR to maximize bill reductions means operating near the low end of the allowable voltage window. This condition comes with an increased risk that voltage violations will occur especially during the rapid variations caused by the increased penetration of DERs. In order to get full value of the voltage reduction program, an automated VVO is needed to manage those variations and monitor feeder tip voltage.

Future oriented benefits of the Whitby SmartGrid project include positioning the LDC for increased reliance on DERs and management of residential based energy storage and EV's by providing:

- linkage to DERMs applications to control and monitor DER and EV.
- visibility into system conditions and improved response time for DERs
- storm hardening and the rapid restoration of grid access (often <1m) during storm events
- improved availability of DERs to the provincial grid.
- risk reduction relating to voltage variations caused by DERs and a maximization of benefit of CVR
- flexibility in feeder layout in normal and contingency mode,
- centralized system management and worker safety,

3 VVO

VVO - Technology Description

The requirement of the distribution system is to deliver power to the customer within the voltage range established in CSA 235-83-2015. Traditional system planning recommends setting the source voltage at the level that is near the top of the voltage window when the feeders are lightly loaded, and then examining the feeder tips for voltage violation in normal and contingency modes.

The normal operating range for a 120/240V residential customers is 108/220V to 125/250V and in extreme operating conditions can be as much as 104/212V to 127/225V.

The shape of the curve that described the voltage drops along the feeder is call the “voltage profile” of the feeder. The longer and more highly loaded and smaller the conductors are, the greater is the difference VVO can make.

If the voltage drops too much between the source and the load the planner usually has two options. The first and most common option is to reduce the reactive power on the line by installed line capacitors at approximately the 66% point along the feeder. The capacitors will support the reactive losses created on the lines and allow the delivery of more real power. Where capacitors are insufficient the planner may explore the use to regulators or line reconductoring.

A complication in the use of capacitors and regulators is when the load on the line drops, such as in shoulder months or at night, the voltage can rise and exceed the allowable voltage causing equipment damage on the customer premise. The application of DERs will look to the system like a reduction in load, and in extreme conditions can cause reverse power flow which in both cases affects the application of capacitors and regulators.

The solution to these variations is the application of a VVO algorithm that will switch capacitors, regulators and station on-load tap changes (LTCs) to optimize the lines.

Once the VVO system is operating, the distribution system operator has an option manage the feeder end voltage rather than the feeder source voltage in a more transparent fashion. To do this, the operator needs visibility to the ends of the feeder which can be accomplished with the latest generation of AMI, or stand-alone voltage sensors connected to a communication system.

With this information the operator no longer needs to operate at the highest (conservative) end of the voltage window but can reduce the source voltage so that the feeder ends are operating at or near the lowest end of the window resulting in an overall reduction in energy, power, and losses. When contingency switching is taking place, the new feeders will be longer and more heavily loaded and the VVO system will adapt to the new conditions and reset the regulators and/or LTCs to optimize the network.

VVO - Expected Benefits

Figure 3-1 below demonstrates the comparison of a feeder voltage profile for a system operating in a traditional configuration and one operating with a VVO and a CVR system in place. The red line shows an end-to-end voltage drop on an uncompensated feeder of about -12 volts which means the first and last home are just barely within the allowable window. The blue line shows a voltage drop of about 5 volts, which means that the voltage can be also dropped by 5 volts at the first customer and the end of feeder customer's voltage is improved by 1 or 2 volts.

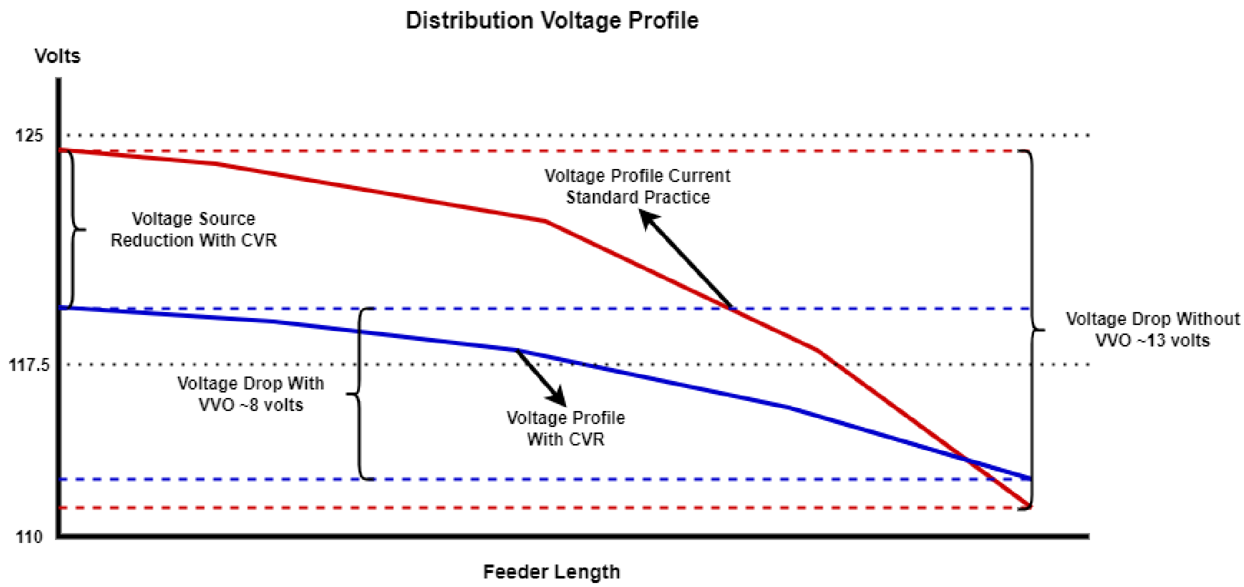


Figure 3-1 – Example Voltage Profile with and without VVO/CVR

Historically, loads on residential feeders were primarily "constant resistance" loads. These are primarily loads such as electric heat, small motors (A/C) and incandescent light bulbs. A 2.5% reduction in voltage resulted in a 2.5% reduction in power (P) since: P (kW) = V^2/R.

Newer electronic controllers found in larger appliances such as EV chargers, A/C units, LED bulbs and some refrigeration units etc. compensate for low voltage by increasing current in a mode that is called "constant power". The impact of voltage reduction to these appliances can be an increase in the current demands which unfortunately neutralizes the consumption benefit and slightly increases the line losses on the distribution system. As a result, VVO systems are considered to provide an effective benefit in the range of 40%-60% of the voltage reduction however this is a moving target and difficult to field test.

There is also a non-linear relationship between the reduction of peak demand and the reduction in energy consumption when devices that "store power" are considered. In an electrically heated home, if the total power output of a heater is reduced it is intuitive that the heater will have to run more time to sustain the warmth in the home. This is also true of battery charging technology such as EVs. So, while a reduction in illumination levels can result in a savings on peak and energy, a reduction in storage and heating/cooling may result only in a lowering of peak and a deferral of energy.

Also, due to variations in load patterns day to day and even hour to hour, it is difficult to verify line losses in the field. Primary line losses occur in the range of 5%-10% of load, and the application of CVR reduces those losses by 2-3% resulting in an improvement that is too small to detect on a variable system. Traditionally, improvement in line loss is calculated using a load-flow modelling program such as CYME or PSS/U, and modelled improvements are taken as representative of real-world results.

Research studies have projected that a 2-4% of demand reduction is typically expected by implementing VVM tool. In the Whitby case, the lines are short, and the voltage profile is flat so the slightly more optimistic range of 3% is viable. This is a savings on the Customer Bill and a commensurate reduction in the LDC Cost of Power.

Whitby Rate Zone Specific Application

The characteristics of the distribution system in the Whitby rate zone are that of an urban center with relatively short but heavily loaded feeders. This compares with other applications before the OEB that are a mix of short urban feeders and some that are quite long and stretching into the rural areas.

The expected result of this uniqueness as compared to other studies is generally summarized as

- impact of capacitors will be smaller as lines are shorted creating less kvar concerns,
- impact of regulators (or LTCs) is larger because the flatter voltage profile allows for more range of adjustment of source voltage.

Other studies before the OEB also considered non-VVO system improvements in the overall loss performance benefit. These include phase balancing and system reconfiguration opportunities that do not have a significant cost impact but can help optimize the voltage profile significantly. This study, being at a feasibility level, has also demonstrated some of the same opportunities (see Appendix B) but considering that the study was conducted over a few representative feeders, the non-VVO range of benefits is can not be included in the overall calculations.

In general, the Whitby system would seem to be consistent with other studies that have projected a range of benefits in the 2-4% range for energy and peak. Considering the short and dense nature of the feeders in this project, an approximation of 3% peak reduction is reasonable.

4 FLISR/DA

FLISR/DA - Technology Description

FLISR is a generic term used to describe a system of DA and sometimes some algorithmic support such as wave-form analysis and fault current monitoring, to isolate a faulted section of feeder and restore service to the unaffected sections and notify the control room of the event and the location of the affected sections. When DA is combined with feedback from CFCIs, field sensors and/or the AMI system to form a full FLISR, the system will provide the location of the common protective device (such as a fuse) and the most likely location of the fault based on fault current characteristics. Full FLISR is still an experimental technology and relies heavily on system data and modelling of conductors and cables to predict locations of faults.

The DA component of FLISR is a mature technology and has been adopted in many jurisdictions. DA typically comprises several sectionalizing devices (normally closed) per feeder (optimally 3), a tie switch (normally open) and control of the feeder breaker. Excluding the breaker control, which is inherent in station operations, this is called 3.5 devices per feeder with the tie switch being counted as half a device on both feeders.

The DA system operates rapidly to isolate and restore power. Those customers that are restored within 1 minute are considered to have experienced a “Momentary” event without a duration, whereas those customers that remain without power experience a “Customer Outage” and “Customer Minutes of Outage”. From the context of reliability statistics, a momentary event is preferrable and counts towards the Momentary Average Interruption Frequency Index (MAIFI) index, whereas the permanent fault counts against System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index CAIDI.

A typical restoration event without a DA system will occur as follows.

- A permanent event occurs the “Fault” location (equipment failure, car hits pole etc.)
- Station Breaker operates to remove power.
- Station Breaker recloses and re-opens a set number of times and locks out.
- Power is off until crews locate the fault and manually open Sw1 and Sw2 to isolate the faulted section, then closing Sw4 and the breaker until only the faulted section between Sw1 and Sw2 remains off.
- Repairs begin after approximately 1 hour,
- The section is repaired (undefined time duration)
- Full Power is restored

The same event under the management of a DA system will occur as follows.

- A permanent event occurs the “Fault” location (equipment failure, car hits pole etc.)
- Station Breaker operates to remove power.
- Sw1 and Sw2 communicate and determine the fault is between them. Sw1 opens, Sw2 opens. Station Breaker recloses and holds, 25% of customers are restored.

- Sw4 detects power on one side and not on the other, communicates with Sw3 and concludes it is safe to close. Sw4 closes, Sw3 may have opened and now closes restoring 50% of affected customers. Only the faulted section between Sw1 and Sw2 remains off affected 25% of the customers.
- Crews arrive on site after a 20-minute trip and repairs begin immediately
- The section is repaired (undefined time duration)
- Full Power is restored

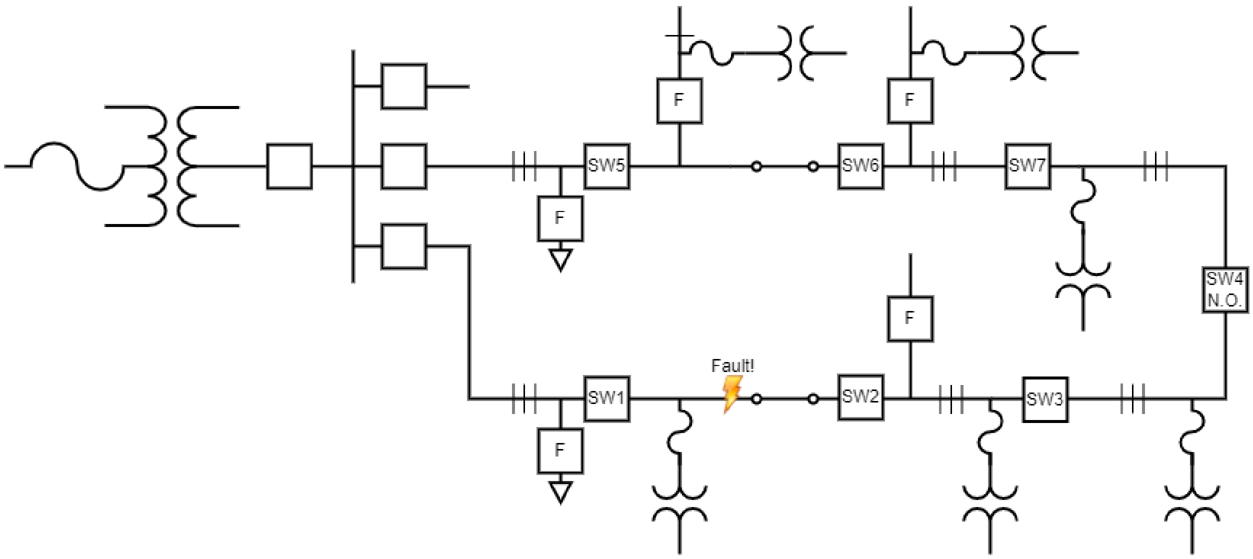


Figure 4-1 – FLISR/DA operational diagram

FLISR/DA - Reliability Benefits

DA does not usually return a financial benefit but rather is often the most economical way to achieve some other system goal (usually reliability improvement). Part of the automation benefit is a reduction in fault locating time, which in some reports can reduce driving and isolating time from 100 minutes to 20 minutes, but this ranges greatly depending on the area size, location of emergency crews and dispatch arrangements. In the example above we assume a general “truck roll” reduction of 1 hour per event.

The primary benefit of DA is that it reduces full feeder lockout faults to something that affects only a quarter of the feeder for a permanent fault while the rest of the feeder sees a momentary outage. There is a small opportunity to reduce capital costs with the application of DA as more complex backup switching becomes possible, removing the need for a 1:1 backup arrangement and permitted 1:2 or 1:3 arrangements. Savings in this area unpredictable and depend greatly on other operational constraints included transformer loading and safety.

As the usage of the system becomes more complex, such as with higher penetrations of DER expected in the mid-term future, the need for system reliability is expected to increase. System stability will rely on distributed generation in ways not currently foreseeable and having the best possible system to retore power will be an asset for future modernization.

Referring to the example given above, Table 4-1 describes the impact of DA on the number of customers affected and the duration of outages that is experienced.

Table 4-1 Impact of DA on outage duration

Traditional System	With DA
Unaffected Customers (approx. 75% of feeder) out for 1 hour	Unaffected customers (75%) out for <1min (Momentary)
Affected Customer (25%) out for full repair duration plus 1 hour.	Affected customers (25%) out for full duration of repair.

At a feasibility level the impact of a DA system can be estimated using past data for outages. The flaw of this method is that outages never happen the same in the future as they did in the past because a) the equipment that failed gets repaired and doesn't fail again and b) random traffic accidents do not repeat in most cases. That said, a mathematical review of outage data can give an informative view of what "would have happened" had a DA system been in place and operating reliably. The full breakdown is shown in Appendix C.

For this study, the following assumptions were incorporated in the outage data review.

- Only full feeder outages were examined (fused laterals and services are not automated)
- Where an outage was reported to have multiple durations, the assumption is that the longest restoration time is where the permanent fault is located, and the shorter times are restoration procedures. This is not universally true in complex outages, but it is reasonable.
- Sections are assumed to be divided exactly in quarters for restoration.
- 75% of the feeder is assumed to be restored instantly, and 25% is assumed to experience the full duration of the repairs.
- Station level outages and those on the 44kV system are assumed to be not switchable, however it is likely that some improvement could be made with feeders that are backed up from alternate supplies

Table 4-2 Analysis of historical outages with and without DA

Study Data			
Study Period (Apr 2020->Jan 2022)	33 (months)		
Approx. Customer Count	46,189		
Total Feeder Lockout Events	69		
	As reported	**After DA**	**Improvement w/ DA**
Total Customer Outages	110,155	35,622	- 74,500 Customer Outages
Total Customer Momentary	-	74,533	+ 74,500 Momentary Outages
Total Customer Hours	131,112.89	57,341.34	- 73,700 Customer Hours
Contribution to SAIFI	0.87	0.28	More than ½ outage / cust.
Contribution to MAIFI	-	0.59	Not typically a concern
Contribution to SAIDI	1.03	0.45	More than ½ hour saved /cust.

Note: The similarity between Customer Outages reduced and Customer Hours reduced is a coincidence driven by the fact that the typical target for the duration of an outage (CAIDI) is about 1 hour.

The Whitby Smart Grid project includes an extension of previous DA activities to encompass the entire Whitby rate zone. Previous efforts to modernize the distribution system in the Whitby rate zone, have included the installation of automation-ready distribution switches in 17 locations on 6 feeders generally following the 3.5 devices per feeder concept as proposed in this project. Automation-ready devices are located at:

- Feeder 8F4 – 4 devices
- Feeder 10F1 – 3 devices
- Feeder 10F6 – 3 devices
- Feeder 12F2 – 2 devices
- Feeder 14F2 – 1 device
- Feeder 15F3 – 4 devices

Whitby Rate Zone Specific Application

The distribution system in the Whitby rate zone is denser that the average Ontario LDC. Feeders tend to be shorter and populations more concentrated. The impact of the Whitby specific constraints is that automated devices will be physically closer together however the number of customers per section will be the same. The interconnected nature of the system will mean more tie switches than typical and more opportunities for restoration and load transfers as needed which means the DA system can be expected to make a higher than typical improvement on system operations.

5 Preliminary Feasibility Assessment

This project is designed to integrate with the larger Whitby SmartGrid project and comprises a VVO and an associated CVR scheme along with a DA system which will operated as a first level FLISR scheme. Hardware and services involved in this project include but are not limited to:

- automated switches and reclosers
- voltage regulators and capacitors
- remote voltage sensors
- CFCIs
- radio systems, routers, and landlines, between field devices and data concentrators.
- Field installation of devices on lines and station equipment
- Commission of devices to report back to data concentrators.

Additional components what are required for the operation of the “Grid of the Future” and are components of the Whitby SmartGrid project but external to this report and include:

- station breaker and relay controllers and communicating systems
- communication backbone such as fibre optic cables
- control room software for VVO and DA (assumed to be included in ADMS portion of project)
- commissioning and electrical connectivity of new devices in the control room software.

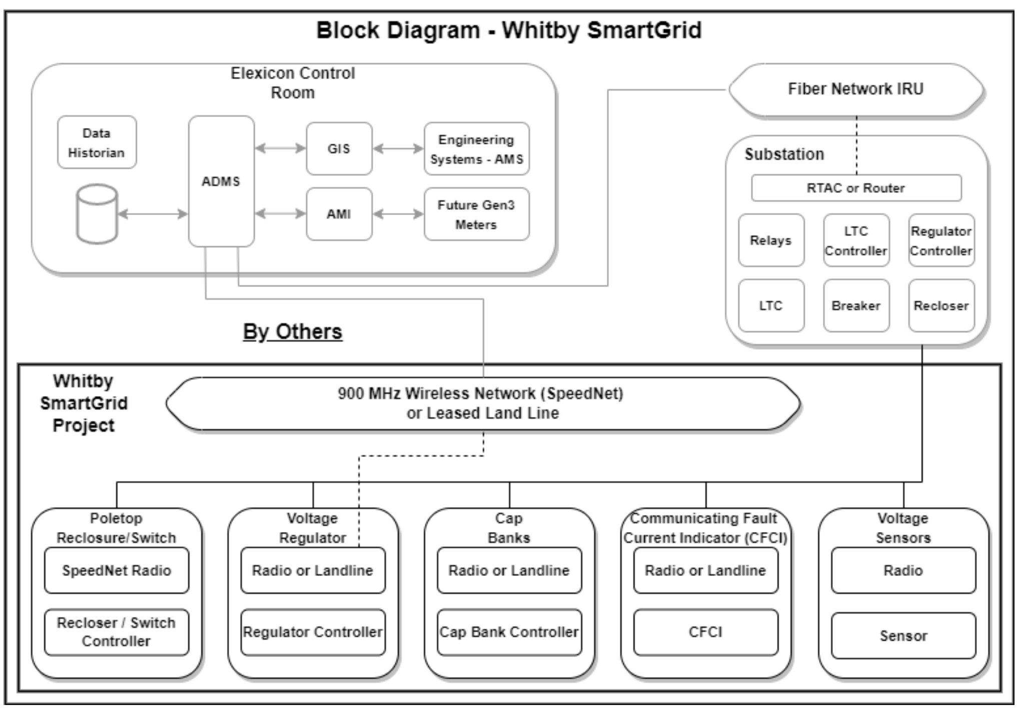


Figure 5-1 – Whitby SmartGrid Preliminary Block Diagram

Typical Feeder Configuration

The design scope of this portion of the Whitby SmartGrid project is consistent with established methodologies for the implementation of VVO and DA. A detailed design on a per feeder and per device basis is required final for implementation measures, however the overall parameters include:

- 3.5 automated switching devices per feeder (plus control of the station breaker/recloser)
- 1 voltage regulator at the start of the feeder load
- 1 capacitor bank near the 66% point on the feeder
- CFCIs as is deemed useful, approximately 1 set per feeder (not shown due to feeder specific nature of application)
- secondary side voltage sensors, approximate 3 per feeder.
- all poles supporting switches, capacitors and regulators need make-ready work
- Station level communications systems exist in each DS/TS/
- field commissioning of all devices

A typical system layout for feeders 9F3 and 11F4 is shown in Figure 5-2 and a typical system layout for feeders 7F3 and 10F4 is shown in Figure 5-3.

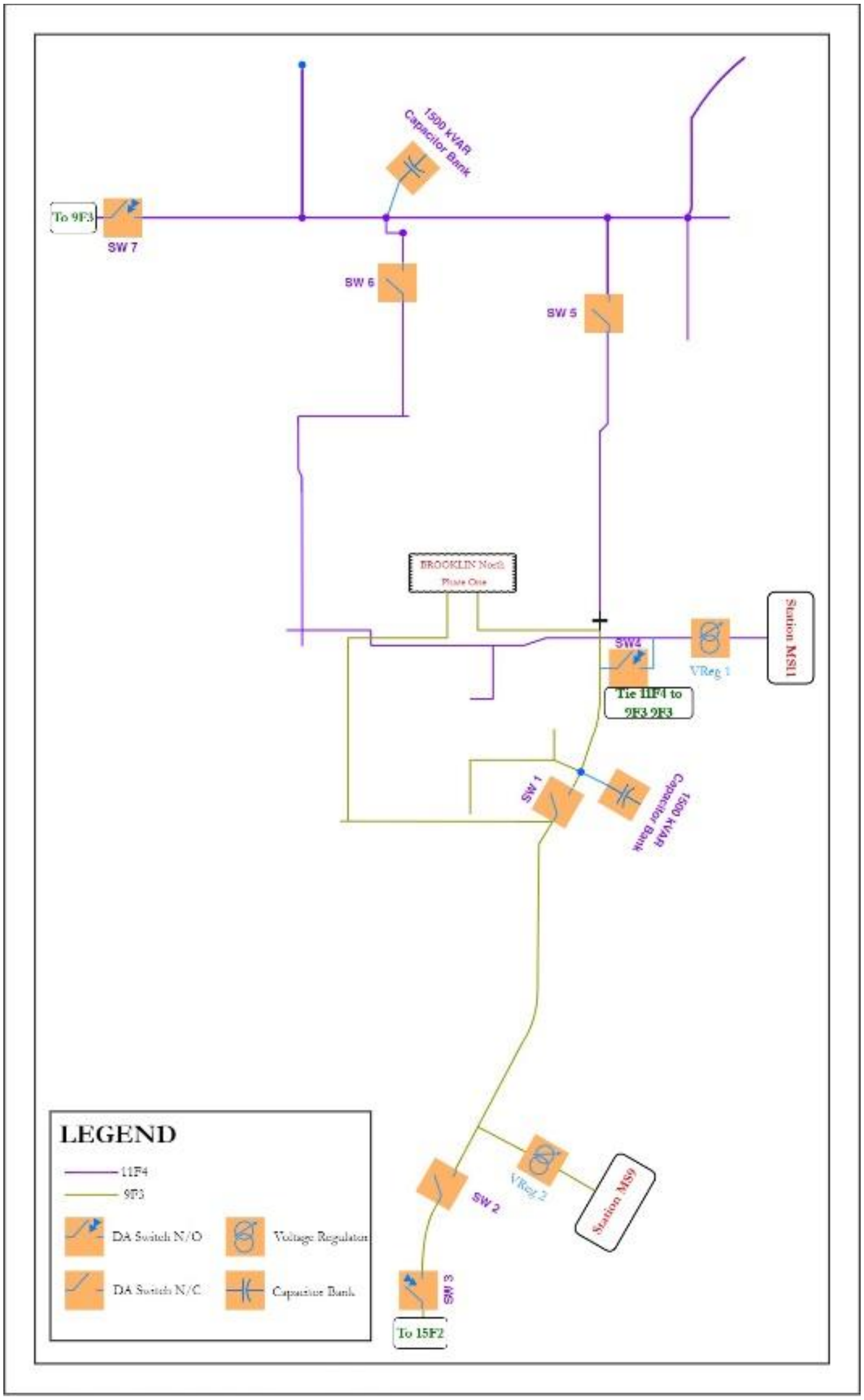


Figure 5-2 – Typical Layout -- 9F3 and 11F4

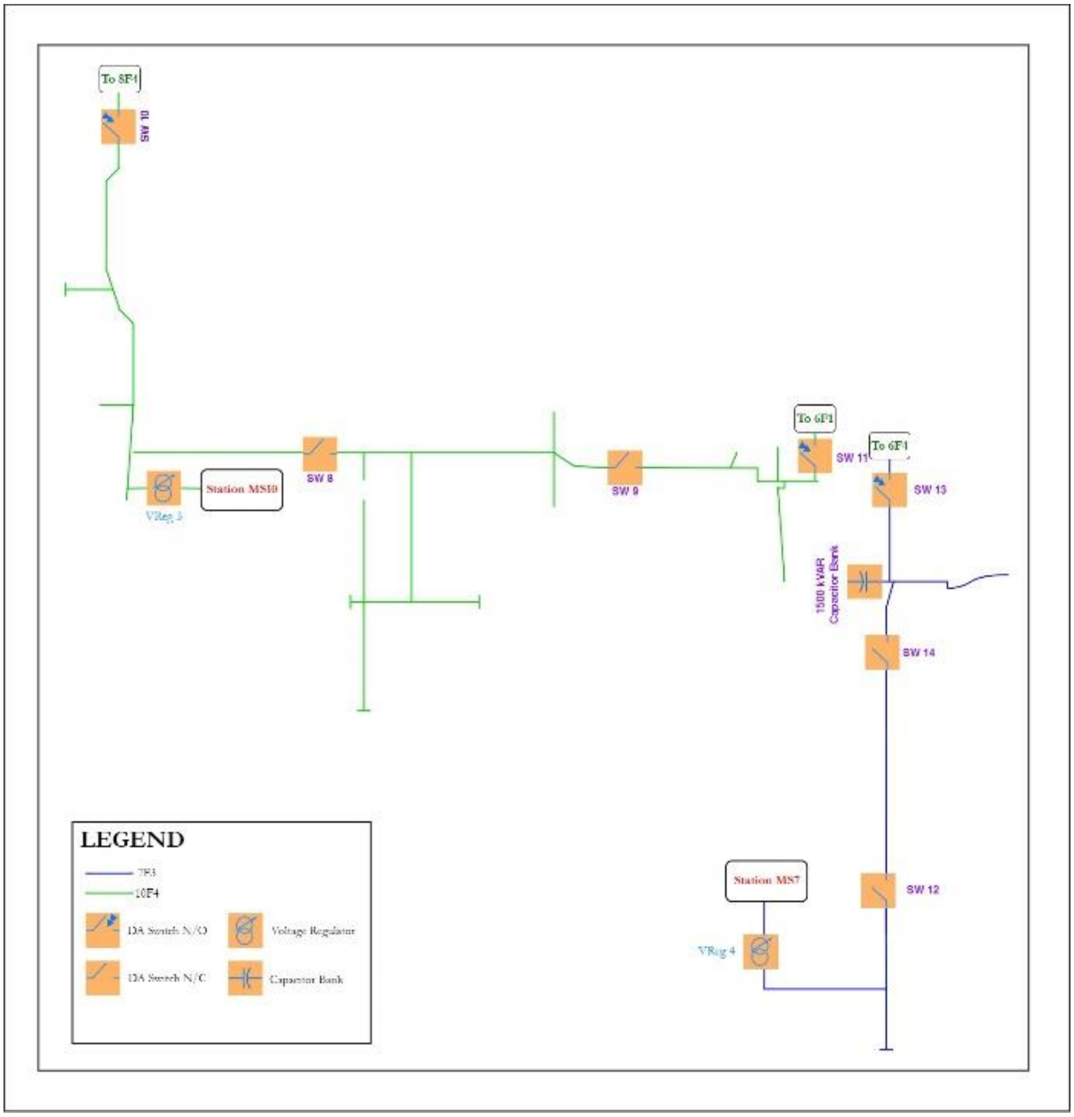


Figure 5-3 – Typical Layout -- 7F3 and 10F4

Project Scope Summary

Table 5-1 summarizes of the estimated quantities for the deployment. All devices are assumed to be pole mounted, however, for underground feeders pad mounted devices would be deployed. Complete design details will be created in the next phase of the engineering.

The project also assumes that the existing stations have breakers/recloser and relays capable of supporting DA and that the communications are sufficient.

Table 5-1 Summary of Assets to be deployed

	Units
Automated Switch	144
Make ready Pole	144
Automation Commissioning	144
Capacitor Bank	46
Make ready Pole	46
Regulator Bank	46
Make ready Pole	46
Line Devices commissioning	92
Communicating Faulted Circuit Indicators	138
Voltages Sensor	138
Radio (SpeedNet) HeadEnd	8
Routers and Leased Line	8
Minor Equip Field Commissioning	292
Project Hard Costs	
Project Management	5%
Engineering	10%
IT Support	2%
Project Total	

Table 5-2 Preliminary Equipment Quantities

Station	Feeder	Voltage (kV)	Ex DA	Estimated DA	Caps	Regulators	Major Equip Field Commissioning	CFCIs	Voltages Sensor	SpeedNet HeadEnd	Routers and Leased Line	Minor Equip Field Commissioning
Totals	46		17	144	46	46	236	138	138	8	8	292
Brooklin	1(Future)	27.6		3.5	1	1	5.5	3	3	1	1	8
	2(Future	27.6		3.5	1	1	5.5	3	3			6
MS5	5F1	13.8		3.5	1	1	5.5	3	3	1	1	8
	5F2	13.8		3.5	1	1	5.5	3	3			6
	5F3	13.8		3.5	1	1	5.5	3	3			6
MS6	6F1	13.8		3.5	1	1	5.5	3	3	1	1	8
	6F2	13.8		3.5	1	1	5.5	3	3			6
	6F3	13.8		3.5	1	1	5.5	3	3			6
	6F4	13.8		3.5	1	1	5.5	3	3			6
MS7	7F1	13.8		3.5	1	1	5.5	3	3	1	1	8
	7F2	13.8		3.5	1	1	5.5	3	3			6
	7F3	13.8		3.5	1	1	5.5	3	3			6
	7F4	13.8		3.5	1	1	5.5	3	3			6
MS8	8F1	13.8		3.5	1	1	5.5	3	3			6
	8F2	13.8		3.5	1	1	5.5	3	3			6
	8F3	13.8		3.5	1	1	5.5	3	3			6
	8F4	13.8	4	-0.5	1	1	1.5	3	3			6
MS9	9F1	13.8		3.5	1	1	5.5	3	3	1	1	8
	9F2	13.8		3.5	1	1	5.5	3	3			6
	9F3	13.8		3.5	1	1	5.5	3	3			6
	9F4	13.8		3.5	1	1	5.5	3	3			6
MS10	10F1	13.8	3	0.5	1	1	2.5	3	3			6
	10F2	13.8		3.5	1	1	5.5	3	3			6
	10F3	13.8		3.5	1	1	5.5	3	3			6
	10F4	13.8		3.5	1	1	5.5	3	3			6
	10F6	13.8	3	0.5	1	1	2.5	3	3			6
MS11	11F1	13.8		3.5	1	1	5.5	3	3	1	1	8
	11F2	13.8		3.5	1	1	5.5	3	3			6
	11F3	13.8		3.5	1	1	5.5	3	3			6
	11F4	13.8		3.5	1	1	5.5	3	3			6
	11F5	13.8		3.5	1	1	5.5	3	3			6
	11F6	13.8		3.5	1	1	5.5	3	3			6
MS12	12F1	13.8		3.5	1	1	5.5	3	3			6
	12F2	13.8	2	1.5	1	1	3.5	3	3			6
MS13	13F1	13.8		3.5	1	1	5.5	3	3	1	1	8
	13F2	13.8		3.5	1	1	5.5	3	3			6
MS14	14F1	13.8		3.5	1	1	5.5	3	3			6
	14F2	13.8	1	2.5	1	1	4.5	3	3			6
	14F3	13.8		3.5	1	1	5.5	3	3			6
MS15	15F1	13.8		3.5	1	1	5.5	3	3			6
	15F2	13.8		3.5	1	1	5.5	3	3			6
	15F3	13.8	4	-0.5	1	1	1.5	3	3			6
MS16	16F1(Future)	13.8		3.5	1	1	5.5	3	3	1	1	8
	16F2(Future)	13.8		3.5	1	1	5.5	3	3			6
	16F3	13.8		3.5	1	1	5.5	3	3			6
	16F4	13.8		3.5	1	1	5.5	3	3			6

Appendix A: VVO Impact -- Preliminary Loss Study

To quantify the loss reduction and energy savings due to the addition of a capacitor, 4 typical feeders are considered for comparison. The terms use below of long, short, lightly, and heavily loaded are not defined but reflect a preference to review a variety of scenarios.

- Short Feeder/Lightly Loaded
- Long Feeder/Lightly Loaded
- Short Feeder/Heavily Loaded
- Long Feeder/Heavily Loaded

A 3-phase capacitor of 1500 kvar, with a nominal voltage of 15 kV is going to be added to the feeders for the comparison assessment of voltage profile from the furthest node of the feeder from station to determine the voltage rise at the furthest node. Then a cost estimate evaluation has been conducted to determine the cost saving due to the loss reduction caused by adding the capacitor. The following approach is used for this purpose:

- The loss reduction is calculated when the loading of the feeder is at 10% (light load), 50% (normal load) and 100% (peak load) of the summer peak.
- The light load is assumed to happen at 30% of the time, the normal load to happen at 60% of the time, and the peak load to happen at 10% of the time.
- Determining the value of loss reduction during 10%, 50%, and 100% loading. The value of loss reduction is determined from the following formula $Loss\ Reduction(kW) = Feeder\ Power_{\ before\ cap}\ (kW) - Feeder\ Power_{after\ cap}\ (kW)$
- Energy saving per year could be calculated from the following formula:

$$Energy\ saving\ \left(\frac{kWH}{year}\right) = \frac{(0.1 \cdot LR_{100\%}) + (0.3 \cdot LR_{10\%}) + (0.6 \cdot LR_{50\%})}{0.1 + 0.3 + 0.6} \times 365 \times 24$$

Which LR demonstrates Loss Reduction.

It should be noted that the capacitors are under control, which means whenever addition of capacitor causes consuming more power than normal, the capacitor will be disconnected from the feeder. This will result in saving more energy at the end of the year.

Note that the voltages at the customer-side should be meeting the limit range defined by CSA 235-83-2015 std, before and after placing the capacitor.

Table 5-3 Voltage limits defined by CSA 235-83-2015 std.

Nominal System Voltages	Voltage Variation Limits Applicable at Utilization Points — Extreme Operating Conditions	Normal Operating Conditions		
Single-Phase				
120/240	104/208	108/216	125/250	127/254
240	208	216	250	254
480	416	432	500	508
600	520	540	625	635
Three-Phase 4-Conductor				
120/208Y	108/187	110/190	125/216	127/220
240/416Y	216/374	220/380	250/432	254/440
277/480Y	240/416	250/432	288/500	293/508
347/600Y	300/520	312/540	360/625	367/635
Three-Phase 3-Conductor				
240	208	216	250	254
480	416	432	500	508
600	520	540	625	635

Short Lightly loaded 7F3:

Feeder F3 located at station MS7 is a comparatively short feeder that is lightly loaded at a summer co-incident peak period. The current values for the R (I_A), W (I_B), and B (I_C) phases of the feeder, during peak load times, have been shown in Table 2.

Table 5-4 Peak load currents of MS7 F3 for different Phases

Phase Color	I_A	I_B	I_C
Current at summer peak (A)	71	79	104

The load flow has been performed for the feeder, before placing the capacitor under the summer peak loading and the voltage profile at the furthest point of the feeder from the station (6600 ft) is depicted in Figure 1.

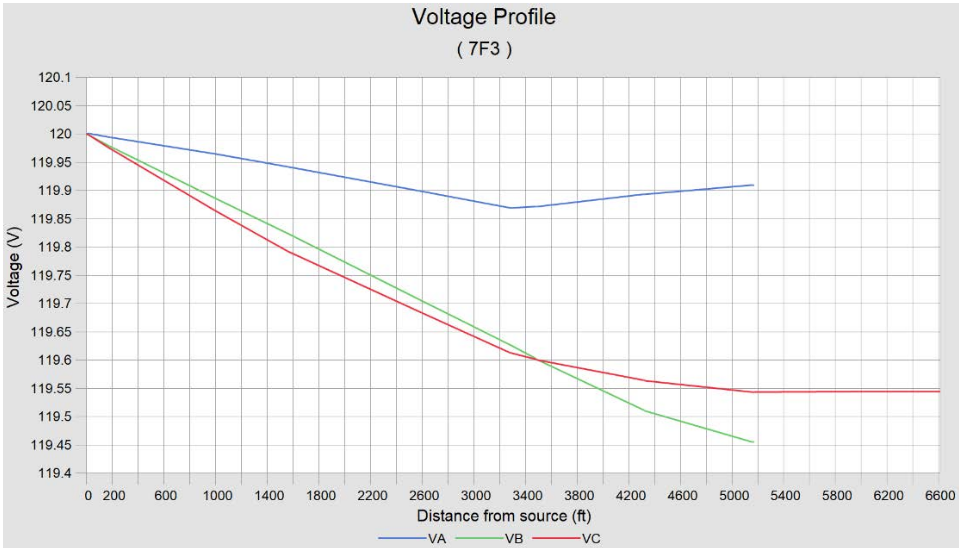


Figure 5-4 Voltage profile for the furthest point of MS7 F3

In the second step, the capacitor placement assessment has been performed to determine an optimal point for the 1500 KVAR capacitor. Node 1258 is determined to be an optional optimal point, for placing the capacitor due to the following reasons:

- Causes higher loss reduction
- Is placed at the 33% end of the feeder
- Is not located underground
- Has three phases available for capacitor placement

Figure 2 depicts the zones the placing the capacitor will cause different ranges of loss reduction by color. In this figure placing the capacitor in the purple zones will result in a loss reduction of greater than 0 and less than 5 kW.

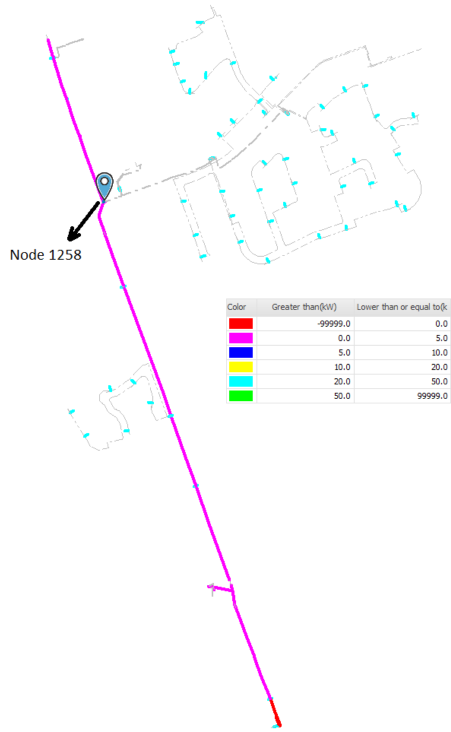


Figure 5-5 Zonal depiction of optimal capacitor placement for feeder MS7 F3

In the third step, the load flow has been performed again when the capacitor is connected to the Node 1258 and the voltage profile of the furthest node from the station (6600 ft) has been shown in Figure 3 when the loading of the feeder is at its 100% of the summer peak load.

Figure 5-6 Voltage profile for the furthest point of MS7 F3

By comparing the voltage profile of the furthest node before and after placing the capacitor, it is concluded that the voltage rise is about 0.1 volt at the customer side which is about 0.08% rise of the nominal voltage.

As the last step, the loss reduction value by adding the 1500 KVAR capacitor is determined with the formula that was mentioned in the first section, and Energy saving in kwh is calculated for a whole year.

- Assuming that the capacitor is under control for connection and whenever the capacitor causes loss increases, it will be disconnected from the feeder.

Table 5-5 Loss reduction and Energy-saving calculation for feeder MS7 F3

MS 7 F3			
Before Placing Capacitor			
Load Factor	0.1	0.5	1
Time of Load Factor	0.3	0.6	0.1
Capacitor Location	-		
Feeder Power (KW)	181	907	1821
After Placing Capacitor			
Capacitor Location	Node 1258		
Feeder Power (KW)	181	906	1821
Loss Reduction & Energy Saving			
Loss reduction (KW)	0	1	0
Energy saving in kwh/year	5256		

Note that this estimate is for the case that the loads connected to the feeder are considered constant resistance loads and by adding the effect of constant power loads the energy-saving in kwh is expected to be lower than the amount calculated here. In other words, 5256 kwh/year is the maximum possible energy saving for feeder MS 7 F3 by placing a 1500 kVAR capacitor at node 1258.

In addition, this feeder will see improvement controllability and cost savings, if the loads were balanced between the phases at close to 85A per phase.

<u>Short Heavily loaded 10F4:</u>

Feeder F4 located at station MS10 is a comparatively short feeder that is heavily loaded at a summer co-incident peak period. The current values for the R (I_A), W (I_B), and B (I_C) phases of the feeder, during peak load times, have been shown in Table 4.

Table 5-6 Peak load currents of MS10 F4 for different Phases

Phase Color	I_A	I_B	I_C
Current at summer peak (A)	247	263	235

The load flow has been performed for the feeder, before placing the capacitor, under the summer peak loading and the voltage profile at the furthest point of the feeder from the station (7100 ft) is depicted in Figure 2.

Figure 5-7 Voltage profile for the furthest point of MS10 F4

In the second step, the capacitor placement assessment has been performed to determine an optimal point for the 1500 KVAR capacitor. As the result of the capacitor placement study, there was no optimal point for the capacitor that causes loss reduction.

Figure 2 depicts the zones where placing the capacitor will cause different ranges of loss reduction by color. In figure 5, placing the capacitor in the red zones will result in a negative loss reduction, which is the entire feeder, and placing the 1500 kVAR at any point will not cause loss reduction.

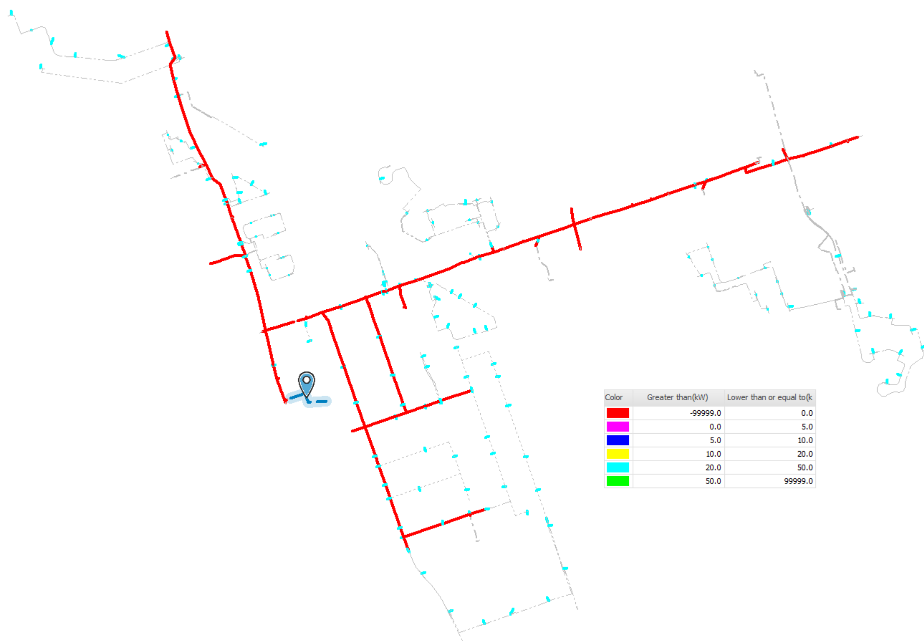


Figure 5-8 Zonal depiction of optimal capacitor placement for feeder MS10 F4

Since the model could not select a point for capacitors to be placed with a positive impact on losses, the third and last steps were not performed, and loss numbers were not generated by the modelling software.

Table 5-7 Loss reduction and Energy-saving calculation for feeder MS10 F4

MS 10 F4			
Before Placing Capacitor			
Load Factor	0.1	0.5	1
Time of Load Factor	0.3	0.6	0.1
Capacitor Location	-		
Feeder Power (KW)	529	2656	5342
After Placing Capacitor			
Capacitor Location	No optimal place found		
Feeder Power (KW)	-	-	-
Loss Reduction & Energy Saving			
Loss reduction (KW)	n/a	n/a	n/a
Energy saving in kwh/year	n/a		

The model did not resolve a loss improvement with a 1500kVAr bank, however with multiple smaller capacitor banks, the loss savings would be typical for other feeders of the same length and load. There is also a small opportunity to balance phases.

Long Lightly loaded 9F3:

Feeder F3 located at station MS9 is a comparatively long feeder that is lightly loaded at a summer co-incident peak period. The current values for the R (I_A), W (I_B), and B (I_C) phases of the feeder, during peak load times, have been shown in Table 6.

Table 5-8 Peak load currents of MS9 F3 for different Phases

Phase Color	I_A	I_B	I_C
Current at summer peak (A)	84	62	105

The load flow has been performed for the feeder, before placing the capacitor, under the summer peak loading and the voltage profile at the furthest point of the feeder from the station (13000 ft) is depicted in Figure 6.

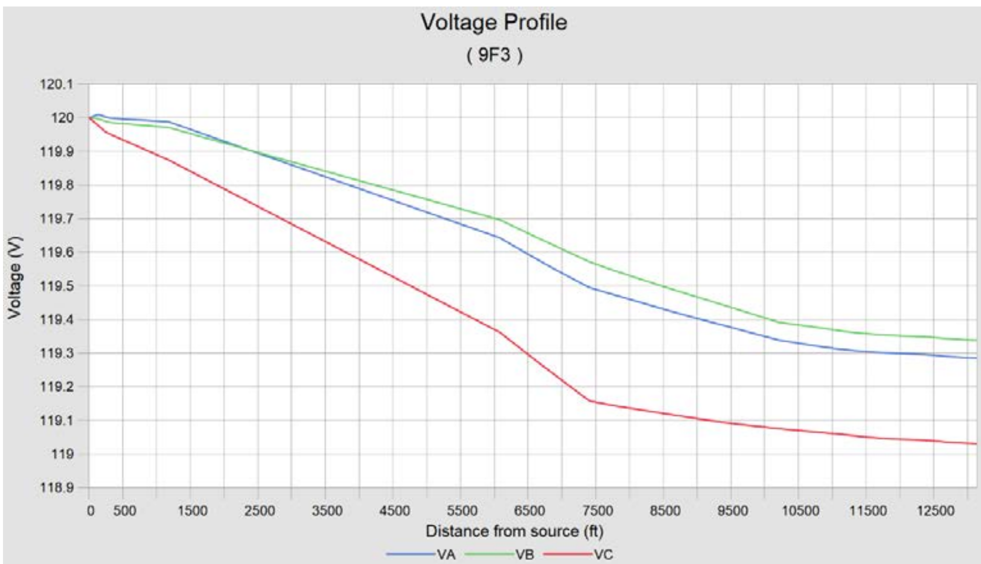


Figure 5-9 Voltage profile for the furthest point of MS9 F3

In the second step, the capacitor placement assessment has been performed to determine an optimal point for the 1500 KVAR capacitor. Node 32811 is determined to be an optional optimal point, for placing the capacitor due to the following reasons:

- Causes higher loss reduction
- Is placed at the 33% end of the feeder
- Is not located underground
- Has three phases available for capacitor placement

Figure 7 depicts the zones where placing the capacitor will cause different ranges of loss reduction by color. In Figure 7 placing the capacitor in the purple zones will result in a loss reduction of greater than 0 and less than 5 kW.

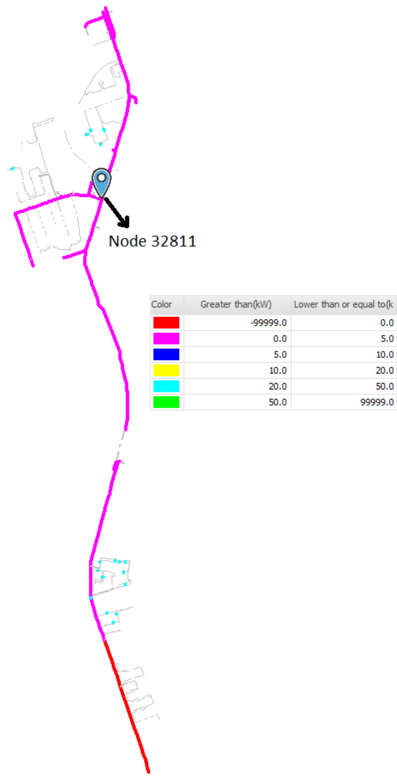


Figure 5-10 Zonal depiction of optimal capacitor placement for feeder MS9 F3

In the third step, the load flow has been performed again when the capacitor is connected to the Node 32811 and the voltage profile of the furthest node from the station (13000 ft) has been shown in Figure 8 when the loading of the feeder is at its 100% of the summer peak load.

Figure 5-11 Voltage profile for the furthest point of MS9 F3

By comparing the voltage profile of the furthest node before and after placing the capacitor, it is concluded that the voltage rise is about 0.15 volt at the customer side which is about 0.13 % rise of the nominal voltage.

As the last step, the loss reduction value by adding the 1500 KVAR capacitor is determined with the formula that was mentioned in the first section, and Energy saving in kwh is calculated for a whole year.

- Assuming that the capacitor is under control for connection and whenever the capacitor causes loss increases, it will be disconnected from the feeder.

Table 5-9 Loss reduction and Energy-saving calculation for feeder MS9 F3

MS 9 F3			
Before Placing Capacitor			
Load Factor	0.1	0.5	1
Time of Load Factor	0.3	0.6	0.1
Capacitor Location	-		
Feeder Power (KW)	178	894	1793
After Placing Capacitor			
Capacitor Location	Node 32811		
Feeder Power (KW)	179	893	1792
Loss Reduction & Energy Saving			
Loss reduction (KW)	-1	1	1
Energy saving in kWh/year	6132		

Note that this estimate is for the case that the loads connected to the feeder are considered constant resistance loads and by adding the effect of constant power loads the energy-saving in kwh is expected to be lower than the amount calculated here. In other words, 6132 kWh/year is the maximum possible energy saving for feeder MS 9 F3 by placing a 1500 kVAR capacitor at node 32811.

There is also a small opportunity for improvement of losses by phase balancing the loads on the feeder.

<u>Long Heavily loaded 11F4:</u>

Feeder F4 located at station MS11 is a comparatively long feeder that is heavily loaded at a summer co-incident peak period. The current values for the R (I_A), W (I_B), and B (I_C) phases of the feeder, during peak load times, have been shown in Table 8.

Table 5-10 Peak load currents of MS11 F4 for different Phases

Phase Color	I_A	I_B	I_C
Current at summer peak (A)	289	335	318

The load flow has been performed for the feeder, before placing the capacitor, under the summer peak loading and the voltage profile at the furthest point of the feeder from the station (45000 ft) is depicted in Figure 9.

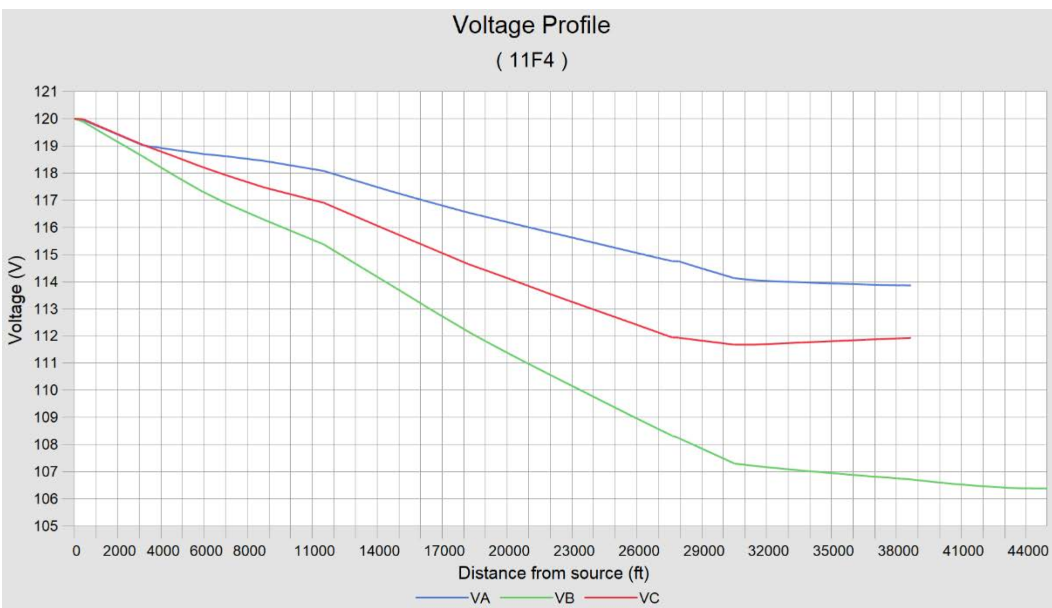


Figure 5-12 Voltage profile for the furthest point of MS11 F4

In the second step, the capacitor placement assessment has been performed to determine an optimal point for the 1500 KVAR capacitor. Node 33377 is determined to be an optional optimal point, for placing the capacitor due to the following reasons:

- Causes higher loss reduction

- Is placed at the 33% end of the feeder
- Is not located underground
- Has three phases available for capacitor placement

Figure 10 depicts the zones where placing the capacitor will cause different ranges of loss reduction by color. In Figure 10 placing the capacitor in the yellow zones will result in a loss reduction of greater than 10 and less than 20 kW.

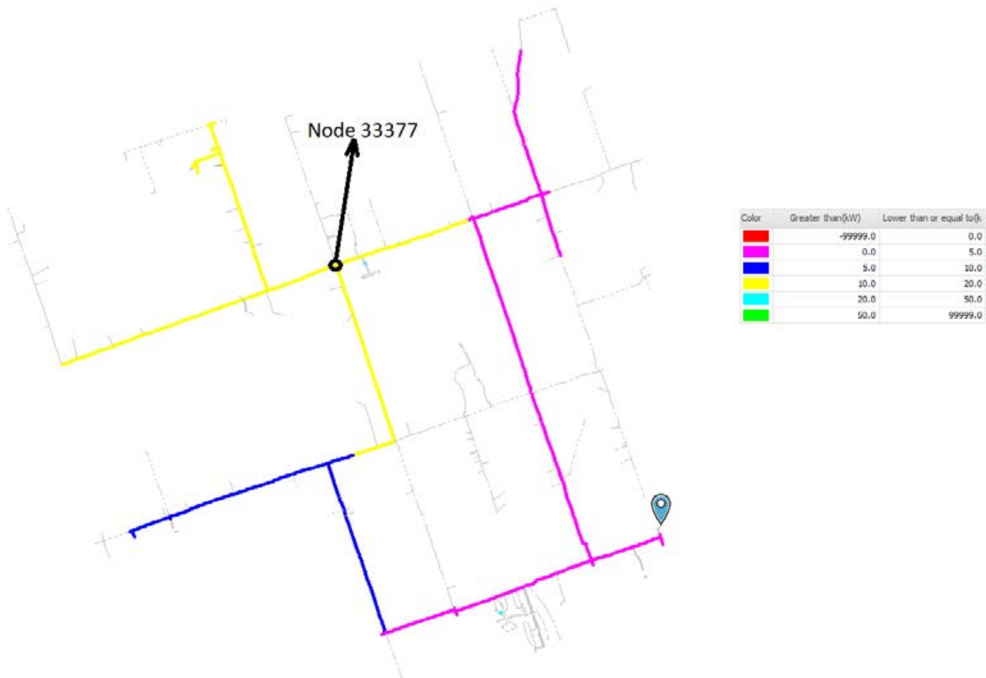


Figure 5-13 Zonal depiction of optimal capacitor placement for feeder MS11 F4

In the third step, the load flow has been performed again when the capacitor is connected to the Node 33377 and the voltage profile of the furthest node from the station (45000 ft) has been shown in Figure 11 when the loading of the feeder is at its 100% of the summer peak load.

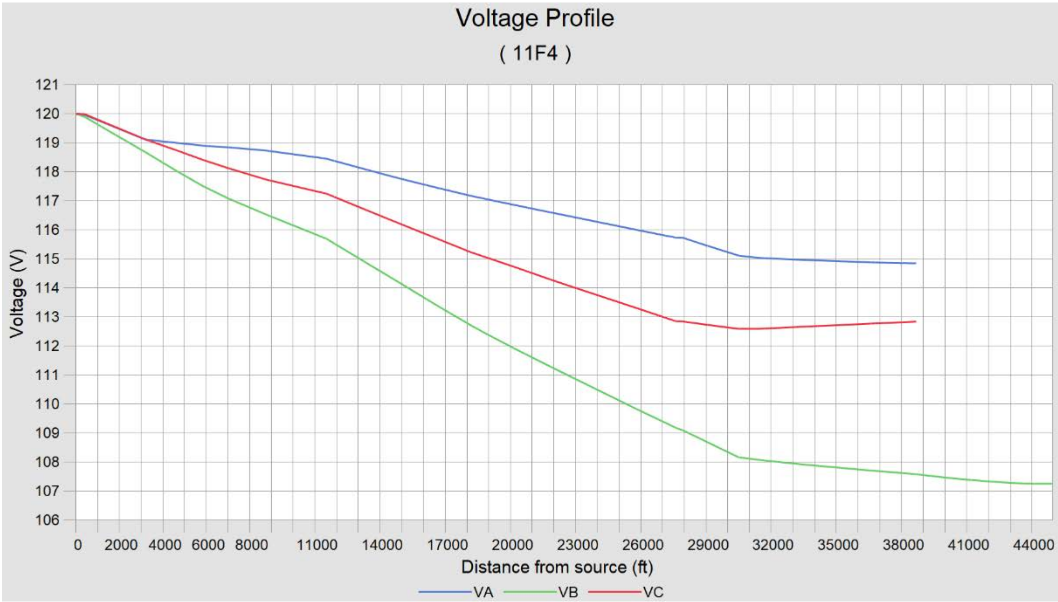


Figure 5-14 Voltage profile for the furthest point of MS11 F4

By comparing the voltage profile of the furthest node before and after placing the capacitor, it is concluded that the voltage rise is about 0.8 volt at the customer side which is about 0.67 % rise of the nominal voltage.

As the last step, the loss reduction value by adding the 1500 KVAR capacitor is determined with the formula that was mentioned in the first section, and Energy saving in kwh is calculated for a whole year.

- Assuming that the capacitor is under control for connection and whenever the capacitor causes loss increases, it will be disconnected from the feeder.

Table 5-11 Loss reduction and Energy-saving calculation for feeder MS11 F4

MS 11 F4			
Before Placing Capacitor			
Load Factor	0.1	0.5	1
Time of Load Factor	0.3	0.6	0.1
Capacitor Location	-		
Feeder Power (KW)	652	3310	6762
After Placing Capacitor			
Capacitor Location	Node 33377		
Feeder Power (KW)	653	3305	6748
Loss Reduction & Energy Saving			
Loss reduction (KW)	-1	5	14
Energy saving in kWh/year	38544		

Note that this estimate is for the case that the loads connected to the feeder are considered constant resistance loads and by adding the effect of constant power loads the energy-saving in kwh is expected to be lower than the amount calculated here. In other words, 38544 kWh/year is the maximum possible energy saving for feeder MS 11 F4 by placing a 1500 kVAR capacitor at node 33377.

There seems to be an opportunity to improve voltage management and loss reduction by balancing the loads on the feeder.

Appendix B -- DA Impact -- Preliminary Study

Table 5-12 and Table 5-13 below illustrate the impact that a DA system would have had on the outages as they occurred in the period of April 2020 to January 2022. The study is based on the following assumptions:

- Full Feeder Lockouts would be sectionalized to 25% permanent and 75% <1min (Outage record designed as F).
- Complex restoration outages, all preliminary stages assumed to be switching.
- Reparations and therefore 100% converted to <1min, final stage assumed to be eligible for improvement (shown as Y)
- Section under repair and therefore 100% permanent fault (Shown as N)
- Station or 44kV level outages, assumed to be not switchable. (Conservative, shown with N)

Table 5-12 – Summary of outage improvement from April 2020 to January 2022 with DA

Study Data			
Study Period (Apr 2020->Jan 2022)	33 (months)		
Approx. Customer Count	46,189		
Total Feeder Lockout Events	69		
	As reported	**After DA**	**Improvement w/ DA**
Total Customer Outages	110,155	35,622	- 74,500 Customer Outages
Total Customer Momentary	-	74,533	+ 74,500 Momentary Outages
Total Customer Hours	131,112.89	57,341.34	- 73,700 Customer Hours
Contribution to SAIFI	0.87	0.28	More than ½ outage / cust.
Contribution to MAIFI	-	0.59	Not typically a concern
Contribution to SAIDI	1.03	0.45	More than ½ hour saved /cust.

Table 5-13 – Analysis of outage improvement from April 2020 to January 2022 with DA

DATE_OUT	DATE_ON	FEEDER	NUM_CUST_OUT	Customer Hours	RESTORATION_TYPE	Eligibility	reported #cust	reported custhours	SAIFI CUST	MAIFI CUST	Effective Cust Hrs
4-9-2020 23:50	4-10-2020 00:54	6F2	1565	1669.3	Partial Restoration	y	1565	1669.3	0	1565	0
4-10-2020 00:54	4-10-2020 02:46	6F2	1051	1961.9	Partial Restoration	y	1051	1961.9	0	1051	0
4-10-2020 02:46	4-10-2020 03:28	6F2	640	448.0	Partial Restoration	y	640	448.0	0	640	0
4-10-2020 03:28	4-10-2020 04:12	6F2	363	266.2	Full Restoration	n	363	266.2	363	0	266.2
4-21-2020 06:23	4-21-2020 07:51	10F3	2449	3591.9	Full Restoration	f	2449	3591.9	612.25	1836.75	897.97
4-21-2020 14:40	4-21-2020 14:44	12F2	2439	162.6	Full Restoration	f	2439	162.6	609.75	1829.25	40.65
4-21-2020 15:21	4-21-2020 16:09	12F2	2439	1951.2	Full Restoration	f	2439	1951.2	609.75	1829.25	487.8
5-1-2020 14:13	5-1-2020 14:22	6F2	34	5.1	Full Restoration	n	34	5.1	34	0	5.1
5-25-2020 13:00	5-25-2020 13:50	14F3	1557	1297.5	Full Restoration	f	1557	1297.5	389.25	1167.75	324.38
6-5-2020 11:19	6-5-2020 12:52	7F4	204	316.2	Partial Restoration	y	204	316.2	0	204	0
6-5-2020 11:19	6-5-2020 11:59	7F4	132	88.0	Partial Restoration	y	132	88.0	0	132	0
6-5-2020 11:19	6-5-2020 13:50	7F4	33	83.1	Full Restoration	n	33	83.1	33	0	83.05
6-10-2020 23:00	6-11-2020 01:19	12F2	2204	5105.9	Partial Restoration	y	2204	5105.9	0	2204	0
6-10-2020 23:00	6-11-2020 03:00	12F2	215	860.0	Full Restoration	n	215	860.0	215	0	860
6-11-2020 13:59	6-11-2020 15:26	6F2	1564	2267.8	Partial Restoration	y	1564	2267.8	0	1564	0
6-11-2020 13:59	6-12-2020 03:21	6F2	1	13.4	Full Restoration	n	1	13.4	1	0	13.37
6-14-2020 02:01	6-14-2020 02:27	7F4	336	145.6	Full Restoration	f	336	145.6	84	252	36.4
6-14-2020 05:46	6-14-2020 08:32	12F2	1647	5050.8	Full Restoration	n	1647	5050.8	1647	0	5050.8
6-14-2020 05:46	6-14-2020 08:02	12F2	557	1262.5	Partial Restoration	y	557	1262.5	0	557	0
6-14-2020 05:46	6-14-2020 08:27	12F2	240	644.0	Partial Restoration	y	240	644.0	0	240	0
6-22-2020 06:35	6-22-2020 07:58	12F2	1887	2610.4	Full Restoration	f	1887	2610.4	471.75	1415.25	652.59
6-27-2020 19:11	6-27-2020 19:53	12F2	1887	1320.9	Partial Restoration	f	1887	1320.9	471.75	1415.25	330.23
7-3-2020 09:45	7-3-2020 09:48	10F2	1678	83.9	Partial Restoration	f	1678	83.9	419.5	1258.5	20.98
7-5-2020 03:59	7-5-2020 04:18	12F2	1887	597.6	Full Restoration	f	1887	597.6	471.75	1415.25	149.39
7-05-2020 04:28	7-05-2020 05:08	12F2	1873	1248.666667	Partial Restoration	f	1873	1248.7	468.25	1404.75	312.17

7-30-2020 23:10	7-31-2020 00:22	8F1	400	480.0	Partial Restoration	f	400	480.0	100	300	120
8-14-2020 16:22	8-14-2020 17:10	7F4	201	160.8	Partial Restoration	y	201	160.8	0	201	0
8-14-2020 17:56	8-14-2020 17:57	7F4	301	5.0	Full Restoration	n	301	5.0	301	0	5.02
9-6-2020 11:00	9-6-2020 11:04	52M6	33	2.2	Partial Restoration	f	33	2.2	8.25	24.75	0.55
9-8-2020 01:49	9-8-2020 04:14	7F4	177	427.8	Partial Restoration	y	177	427.8	0	177	0
9-8-2020 01:49	9-8-2020 05:27	7F4	37	134.4	Partial Restoration	y	37	134.4	0	37	0
9-8-2020 01:49	9-8-2020 06:15	7F4	6	26.6	Partial Restoration	n	6	26.6	6	0	26.6
9-8-2020 09:20	9-8-2020 11:18	10F2	92	180.9	Full Restoration	n	92	180.9	92	0	180.93
9-8-2020 09:20	9-8-2020 11:16	10F2	19	36.7	Partial Restoration	y	19	36.7	0	19	0
9-12-2020 22:00	9-12-2020 22:06	6F2	1592	159.2	Full Restoration	y	1592	159.2	0	1592	0
10-8-2020 08:36	10-8-2020 08:39	12F2	1862	93.1	Full Restoration	y	1862	93.1	0	1862	0
10-16-2020 23:34	10-17-2020 00:09	7F4	293	170.9	Partial Restoration	y	293	170.9	0	293	0
10-16-2020 23:34	10-17-2020 03:00	7F4	35	120.2	Full Restoration	n	35	120.2	35	0	120.17
10-19-2020 12:00	10-19-2020 12:14	11F1	1866	435.4	Full Restoration	f	1866	435.4	466.5	1399.5	108.85
10-22-2020 09:30	10-22-2020 10:05	10F1	124	72.3	Full Restoration	f	124	72.3	31	93	18.08
10-29-2020 15:19	10-29-2020 15:43	12F2	1881	752.4	Full Restoration	f	1881	752.4	470.25	1410.75	188.1
11-2-2020 00:08	11-2-2020 01:08	12F2	1861	1861.0	Full Restoration	f	1861	1861.0	465.25	1395.75	465.25
11-2-2020 02:35	11-2-2020 03:56	12F2	1861	2512.4	Full Restoration	f	1861	2512.4	465.25	1395.75	628.09
11-10-2020 23:44	11-11-2020 01:39	7F1	625	1197.9	Partial Restoration	f	625	1197.9	156.25	468.75	299.48
11-15-2020 15:28	11-16-2020 01:07	10F1	17	164.1	Full Restoration	f	17	164.1	4.25	12.75	41.01
11-15-2020 15:28	11-15-2020 19:14	11F4	1183	4456.0	Partial Restoration	y	1183	4456.0	0	1183	0
11-15-2020 15:28	11-15-2020 18:17	16F3	200	563.3	Partial Restoration	y	200	563.3	0	200	0
11-15-2020 15:28	11-15-2020 19:20	16F3	1856	7176.5	Partial Restoration	y	1856	7176.5	0	1856	0
11-15-2020 15:28	11-16-2020 00:25	16F3	8	71.6	Full Restoration	y	8	71.6	0	8	0
11-15-2020 15:28	11-16-2020 03:32	16F3	10	120.6666667	Full Restoration	y	10	120.7	0	10	0
11-15-2020 15:28	11-15-2020 20:24	40M21	47	231.9	Full Restoration	f	47	231.9	11.75	35.25	57.97
11-15-2020 15:28	11-15-2020 19:00	7F4	329	1162.5	Full Restoration	f	329	1162.5	82.25	246.75	290.62
11-20-2020 10:31	11-20-2020 11:12	52M6	32	21.9	Full Restoration	y	32	21.9	0	32	0
11-20-2020 10:31	11-20-2020 18:33	52M6	1	8.033333333	Full Restoration	n	1	8.0	1	0	8.03

11-20-2020 14:27	11-20-2020 14:54	52M6	32	14.4	Full Restoration	f	32	14.4	8	24	3.6
11-26-2020 23:30	11-27-2020 00:49	7F1	432	568.8	Partial Restoration	y	432	568.8	0	432	0
11-26-2020 23:30	11-27-2020 01:46	7F1	250	566.6666667	Full Restoration	n	250	566.7	250	0	566.67
11-26-2020 23:30	11-27-2020 00:28	7F1	429	414.7	Partial Restoration	y	429	414.7	0	429	0
11-26-2020 23:30	11-27-2020 01:15	7F1	228	399	Partial Restoration	y	228	399.0	0	228	0
12-5-2020 13:55	12-5-2020 14:45	8F3	191	159.2	Partial Restoration	y	191	159.2	0	191	0
4-22-2021 00:55	4-22-2021 01:43	7F1	387	309.6	Partial Restoration	y	387	309.6	0	387	0
4-22-2021 00:55	4-22-2021 02:12	7F1	745	956.1	Full Restoration	n	745	956.1	745	0	956.08
4-22-2021 02:40	4-22-2021 03:25	7F3	100	75.0	Partial Restoration	y	100	75.0	0	100	0
4-22-2021 02:40	4-22-2021 03:50	7F3	449	523.8	Full Restoration	n	449	523.8	449	0	523.83
5-01-2021 18:01	5-01-2021 18:02		16	0.266666667	Full Restoration	n	16	0.3	16	0	0.27
5-01-2021 18:01	5-01-2021 18:02		38	0.633333333	Full Restoration	n	38	0.6	38	0	0.63
5-03-2021 08:54	5-03-2021 09:53	40M21	2455	2414.1	Full Restoration	f	2455	2414.1	613.75	1841.25	603.52
6-27-2021 09:57	6-27-2021 11:57	13F1	772	1544.0	Full Restoration	f	772	1544.0	193	579	386
6-30-2021 08:19	6-30-2021 08:26	11F4	1053	122.9	Full Restoration	f	1053	122.9	263.25	789.75	30.71
7-03-2021 21:05	7-03-2021 22:53	7F4	243	437.4	Partial Restoration	f	243	437.4	60.75	182.25	109.35
7-10-2021 19:09	7-10-2021 23:55	8F1	1537	7326.4	Full Restoration	f	1537	7326.4	384.25	1152.75	1831.59
7-18-2021 09:16	7-18-2021 09:17	10F6	1978	32.96666667	Partial Restoration	f	1978	33.0	494.5	1483.5	8.24
7-24-2021 10:55	7-24-2021 10:58	52M7	6488	324.4	Full Restoration	f	6488	324.4	1622	4866	81.1
7-27-2021 17:09	7-27-2021 17:11	52M7	6488	236.0911111	Full Restoration	f	6488	236.1	1622	4866	59.02
7-28-2021 08:02	7-28-2021 08:05	52M7	6488	324.4	Full Restoration	f	6488	324.4	1622	4866	81.1
7-30-2021 15:51	7-30-2021 15:54	52M1	28	1.4	Full Restoration	f	28	1.4	7	21	0.35
8-04-2021 17:45	8-04-2021 17:46	52M1	28	0.466666667	Full Restoration	f	28	0.5	7	21	0.12
9-08-2021 02:12	9-08-2021 02:14	52M1	17	0.6	Full Restoration	f	17	0.6	4.25	12.75	0.14
9-13-2021 12:00	9-13-2021 13:55	8F4	1476	2829.0	Partial Restoration	y	1476	2829.0	0	1476	0
9-13-2021 12:00	9-13-2021 14:30		1506	3773.785	Partial Restoration	y	1506	3773.8	0	1506	0
9-13-2021 12:00	9-13-2021 15:21		653	2187.55	Full Restoration	y	653	2187.6	0	653	0
9-14-2021 23:58	9-15-2021 00:02	40M28	27	1.8	Full Restoration	n	27	1.8	27	0	1.8
9-14-2021 23:58	9-15-2021 01:30	9F4	1286	1971.866667	Partial Restoration	y	1286	1971.9	0	1286	0

10-8-2021 18:32	10-8-2021 20:03	7F4	224	339.7	Partial Restoration	f	224	339.7	56	168	84.93
10-27-2021 15:51	10-27-2021 15:53	12F2	2463	82.1	Full Restoration	f	2463	82.1	615.75	1847.25	20.53
11-07-2021 09:29	11-07-2021 11:30	7F1	910	1835.2	Full Restoration	n	910	1835.2	910	0	1835.17
11-07-2021 09:29	11-07-2021 11:30		1116	2250.6	Full Restoration	y	1116	2250.6	0	1116	0
11-29-2021 11:17	11-29-2021 11:29	40M26	7910	1582.0	Full Restoration	f	7910	1582.0	1977.5	5932.5	395.5
12-11-2021 15:34	12-11-2021 18:52	14F1	699	2306.7	Full Restoration	y	699	2306.7	0	699	0
12-11-2021 15:34	12-11-2021 18:58		699	2382.4	Full Restoration	n	699	2382.4	699	0	2382.43
12-11-2021 16:32	12-11-2021 20:51	10F1	1614	6967.1	Full Restoration	n	1614	6967.1	1614	0	6967.1
12-11-2021 16:32	12-11-2021 20:51	10f2	528	2279.2	Full Restoration	n	528	2279.2	528	0	2279.2
12-11-2021 16:32	12-11-2021 20:51	10f3	901	3889.3	Full Restoration	n	901	3889.3	901	0	3889.32
12-11-2021 16:32	12-11-2021 20:51	10f4	1240	5352.7	Full Restoration	n	1240	5352.7	1240	0	5352.67
12-11-2021 16:32	12-11-2021 20:51	10f5	1	4.3	Full Restoration	n	1	4.3	1	0	4.32
12-11-2021 16:32	12-11-2021 20:51	10f6	2283	9855.0	Full Restoration	n	2283	9855.0	2283	0	9854.95
12-11-2021 17:27	12-11-2021 18:52	9F1	762	1079.5	Full Restoration	f	762	1079.5	190.5	571.5	269.88
12-11-2021 17:30	12-11-2021 19:00		762	1147.445	Full Restoration	f	762	1147.4	190.5	571.5	286.86
1-24-2022 11:00	1-24-2022 12:20	52M7	1760	2346.7	Full Restoration	n	1760	2346.7	1760	0	2346.67
1-24-2022 11:00	1-24-2022 11:40	52M7	1436	957.3	Full Restoration	n	1436	957.3	1436	0	957.33
1-24-2022 11:00	1-24-2022 12:12	APPLF1	1760	2123.244444	Full Restoration	n	1760	2123.2	1760	0	2123.24
1-24-2022 11:00	1-24-2022 11:40	APPLF1	1436	957.3333333	Partial Restoration	n	1436	957.3	1436	0	957.33

Curriculum Vitae:

Daryn Thompson

METSCO
MAKING IT POSSIBLE

Daryn Thompson

B.A.Sc., P.Eng.

Specialist, Smart Grid Planning

SUMMARY OF QUALIFICATIONS

Daryn Thompson has more than 30 years of experience in consulting and utility engineering with experience in transmission and distribution system planning and design, energy markets, and asset management. Daryn possesses a strong technical background in distribution planning including; long term master plans, asset condition assessments, reliability studies, Smart Grid systems, and standard development. He has written engineering standards and operating and safety procedures for utility power systems. Significant projects have included complete and ongoing development of Distribution System Plans (DSPs) for over a dozen utilities, numerous Asset Condition Assessments, development of the Market Rules and Distribution Standards in Canada and the United States, and preparation of system planning and SmartGrid roadmaps for many utilities.

Daryn has completed several Capital Narratives and Business Case documentation as per the Filing Requirements for Electricity Distribution Rate Applications. Daryn has reviewed Capital Plans on behalf of Regulators, and has also authored, co-authored, and supervised the development of Capital Plans for utilities, including: North Bay Hydro, Whitby Hydro, Guelph Hydro, Hydro Ottawa, Entegrus Powerlines Inc., InnPower Corporation, Welland Hydro-Electric System Corp., and Northern Ontario Wires. His work in Distribution Planning also includes 5 and 10 year Master Plans for West Kootenay Power, and GLP and Smart Grid studies and roadmaps for InnPower Corporation, Entegrus Powerlines Inc., Festival Hydro, and CFB Borden. Daryn is currently working with the Ontario Ministry of Energy to provide technical advisory for completed projects under the SmartGrid Fund. Mr. Thompson has completed many benchmarking studies and best-practice development guides for CEATI interest groups, including station Health Index, Costs of Outages, and Safety standards, and more ongoing projects.

Daryn has also been involved in Asset Management, and Asset Condition Assessment since 2006, and in 2008 Daryn conducted an audit of the Asset Condition Assessment methodology for Hydro One's Distribution System. Major asset management projects include the development of Health Index Formulations (HIF) , Asset Condition Assessments (ACA), and audits for customers including Hydro Quebec Substation (HIF, ACA), Hydro One Transmission and Distribution (HIF, ACA, and audit), and Hydro Ottawa (HIF, ACA).

Daryn is an excellent team leader, with experience in project management, quality management, "lean" systems, and field operations and safety.

CAREER HISTORY

Education	University of Toronto, Ontario • B.A.Sc. Electrical Engineering, 1984
Professional Associations	Licensed Professional Engineer, Ontario, Canada
July 2014 to Present	Specialist/Department Leader - METSCO Energy Solutions Inc. Managing projects and leading engineering teams in research and developmental projects in Distribution System Planning, Smart Grid and Asset Management. Projects include:

Regulatory Narratives/BCEs, ACAs, and Capital Plans for several utilities to support Rate Filing Requirements, including:

- Westario Power Inc System Plan, 2021
- EPCOR System Planning Policy Review, 2021
- Elexicon ACA, 2019
- Peterborough Utilities, Distribution System Plan (DSP), 2019
- Algoma Power DSP, 2018
- Burlington Hydro DSP, 2018
- Festival Hydro ACA, 2018
- Kitchener Wilmot Hydro ACA, 2018
- Veridian Connections Inc. DSP, 2018
- Chapleau Public Utilities DSP 2018
- Kingston Utilities Metrics and Benchmarking, 2018
- Essex Powerlines Corporation, Distribution System Plan, 2018
- Northern Ontario Wires, Distribution System Plan, 2016
- Welland Hydro-Electric System Corp., Distribution System Plan, 2016
- InnPower Corporation, Distribution System Plan, 2016
- Ontario Energy Board, DSP Review, 2015
- Entegrus Powerlines Inc., Distribution System Plan, 2014-2015
- Hydro Ottawa, Asset Health Index Validation, 2014-2015
- Guelph Hydro, Distribution System Plan, 2014-2015
- Whitby Hydro, Distribution System Plan and ACA, 2014-2015
- North Bay Hydro, Distribution System Plan and ACA, 2014

Development of Various Guides and Studies for CEATI International including:

- CEATI 50154 – Innovative Techniques to Reduce O&M Costs
- CEATI 50149 – Impact on Worker Safety of DERs
- CEATI 50118 – Health Indices: A Simplified Methodology
- CEATI 30120 – Understanding the Key Factors, Weightings & Prioritization Factors of Health Indices
- CEATI LSMSEA 30110 – Substation Resiliency (ongoing)
- CEATI LCMSEA 30109 – Substation Diagnostics Center and Pilot Project (ongoing)
- CEATI DLAM 50136 – SmartGrid Rollout Plan (ongoing)
- CEATI 3089 – Safety in Substations
- CEATI 3087 – Cost of Outages
- CEATI 3097 – Station Health Index

Smart Grid Roadmap and Implementation

- InnPower Corporation, System Plan, 2015-2016
- Entegrus Powerlines Inc., SmartGrid/System Plan, 2016
- Festival Hydro, Updated Automation Plan, 2014
- Entegrus Powerlines Inc., Feeder Automation Project, 2017
- Medicine Hat, Feeder Automation Project, 2017

Distribution Engineering and Streetlighting

- Sudbury PUC, Kathleen MS, 2018
- HONI One Distribution Strategic Plan, 2017
- Newfoundland Power, Downtown System Plan, 2017
- InnPower, Cedar Point MS Rebuild, 2016
- InnPower, Distribution System Plan, 2016
- City of Markham, Parking Lot Streetlight Conversion
- City of Markham Streetlighting Condition Assessment
- InnPower, Substation Assessment 2016
- InnPower, System Planning Study 2017

SmartGrid Fund Technical Advisor

- Advisor to the Ontario Ministry of Energy for projects completed under the SmartGrid fund.

2009 to 2014 **Director Technical Services, S&C Electric Toronto**

Responsible for PSS group, including Engineering Projects, Automated Systems Projects, Field Services and Training. Major Projects include:

Smart Grid:

- Manitoba Hydro, Waverly West Automation System.
- Kitimat Rio Tinto, Campus Grid and Automation.
- Toronto Hydro – IntelliTeam II Pilot Installation 50 intelligent devices, Studies, Factory Acceptance, Site Coordination, Training (on-going)
- Veridian – IntelliTeam II Pilot Installation 18 intelligent devices, Studies Installation Standards, Installation Supervision, Commissioning, Training
- Brant County, Ontario, -- System Overview Study including reliability and automation.
- Niagara on the Lake – System Automation Implementation.
- Festival Hydro Stratford Ontario, -- System Overview Study including reliability and automation analysis.
- Fortis – IntelliTeam II Installation 30 intelligent devices, Studies Commissioning, Site Acceptance and Service, Training
- ENMAX – IntelliTeam II Installation 25 intelligent devices, Studies Commissioning and Service, Training.

Renewables and Substations:

- Goulais Wind Farm Interconnection --Engineering Design and Procurement
- WEICan Energy Storage Project – EPC
- BC Hydro Energy Storage Project – Commissioning and Service
- Halkirk Windfarm DSTATCOM – EPC
- Multiple Windfarms DSTATCOM – Commissioning and Service, (Ontario Projects, Point Aux Roche, Demoristville. BC Projects, Cape Scott. Quebec Projects, Saint Robert Bellamin, Massif du Sud, Lac Alfred. Alberta, Quality, Blackspring Ridge)
- First Solar – Seven Solar Farm HV Connection and Protection and Control Turnkey. Including Design Procure and installation.
- Gosfield Windfarm – 230 kV Substation, Project Sponsor 200MW connection and collector system, EPC.

2006 to 2009 **Regional Manager Eastern Canada, Hatch T&D(Acres Intl)**

Specialist in management, planning, design, and construction of electrical power systems. Major projects include:

- System Impact Assessments --AEP in Pittsburgh, staff of 2 running SIA studies over a 6 month period on behalf of System Operator
- 240kV Switchyard and Cable Terminations -- Confidential Generation Client, Project Manager
- Static Var Compensator (SVC) Design -- Hydro One 13.8kV Substation, Project Manager
- System Impact Assessments -- Nova Scotia Power.
- Substation Design -- Vale Inco, 69kV Substation, Project Manager

- Connection Impact Assessments -- Hydro One,
- Condition Assessment – NYPA. Assessment of equipment associated with 30 breakers, report on condition and suitability for on-going use.
- Asset Condition Assessment – Hydro One. Condition assessment and health indices for 43 asset classes and Audit Report.
- Asset Condition Assessment – Hydro Quebec. Condition Assessment for 30 stations, including demographics, visual condition data, and health indices for 19 asset classes.
- Distribution System Planning Report – Great Lakes Power. Planning study for distribution system including fuse coordination and reliability recommendations in Northern Ontario.
- System Plan for distribution system extension including capital estimates, system performance and reliability in Caledon, Ontario.
- Feasibility study for distribution system rehabilitation including field survey and assessment of distribution systems including capital investment estimates, load forecasting and system modeling in Vietnam (3 week field data gathering trip to Hanoi Vietnam)
- Design of the electrical overhead distribution system for the Community of Natuashish (Davis Inlet Inuit) comprising sub-transmission, distribution, secondary and street-lighting systems for 200+ homes and community facilities.

2003 to 2005 — Distribution Engineer, Hydro One Lines, Contract

- Distribution Standards – Hydro One Lines. Distribution Engineer, Engineering Lines Dept, including reclosers, fault indicators and complete Underground Standards.

2001 to 2003 — Acres International and Independent Consultant

- New Brunswick Market Rules Review – J.D. Irving. Review and commentary, Proposed Market Rules.
- Contract Management Process Audit, IESO – Mississauga. Risk assessment and report on contract management process.
- Retail metering and billing survey. Circulated survey questionnaire to general managers of municipal utilities, collected data, analyzed responses, sorted and prepared draft and final reports for Market Design Committee.

1999 to 2001 — Build Cycle Manager, IESO, Contract

- Development of Market Rules, co-ordination of rule development and ensure approvals in place for ultimate Minister of Energy Approval (under Bill 35). Specific technical involvement to date include: rules for dispatch of load or generation, dispatch data requirements, contingency trading rules, records, interconnections, etc.

1998 — Distribution Engineer, West Kootenay Power, Contract

- 10 year Master Plan Report for West Kootenay Power. Responsible for base system analysis, options identification, cost of losses evaluation, cost of reliability evaluation, optimal system configuration, economic evaluation of alternatives, project listing and rankings; used Scott and Scott Analysis software to identify voltage drop, and losses, Fuse co-ordination study for West Kootenay Power. Application of fuses, breakers and reclosers.

1989 to 1998

Distribution Engineer, Toronto Hydro (York Hydro)
Responsible for design, project management, planning, records and technical support. Represented York Hydro on all technical committees. Manager of design staff.

- Distribution Standards, Overhead and Underground
- Project management for major projects, including: AM/FM system, Intergraph FRAMME/MicroStation, SCADA system, ABB SPIDER.
- Design and project management of capital projects. Drawing preparation, estimating and material tendering and acquisition, contract tendering/administration and contractor safety.
- Reliability analysis and tracking, incident investigation, annual reliability indices/cost of outages reports.
- Customer Services and Service Entrance design.
- Subdivision planning and design, Major Projects including, Charlton Developments, West Side Mall, and others.
- System planning including, identification of system issues, identification and analysis of planning options, and project funding. York Hydro/North York Hydro/Ontario Hydro Joint Local Integrated Resource Plan (LIRP) for the Downsview area.
- Design and Maintenance of Streetlighting System including and street-lighting studies

1988 to 1989

Project Engineer, Ronald T Gayowsky Ltd.
Design and project management for underground subdivision projects, overhead connections, street-lighting systems and distribution master planning. Hundreds of projects completed in Mississauga, Oakville, Newmarket, Pickering, Ajax, Ancaster, Dundas, Burlington. Major developments include:

- Mississauga Heartland Industrial Commercial area, Erin Mills Developments, Daniels, Hurontario Industrial developments,
- Newmarket, Glenway Golf Course and Subdivision, Daniels,
- Oakville, River Oaks, phase 3-6, Winston Business Park

Selected Technical Publications & Presentations

Health and Risk Index Tool for Stations
CEATI Report No. T133700-3097
(LCMSEA) Ongoing, Completion
November, 2015

Safety in Substations
CEATI Report No. T133700-3089
(LCMSEA) November, 2014

Station Equipment Outage Costs
CEATI Report No. T133700-3087
(LCMSEAIG) September, 2014

Use of Steel Distribution Poles at York Hydro
CEA Electricity 96, Montreal, Quebec, 1996

APPENDIX B-6:

Letters of Support for ICM Application

Town of Whitby
575 Rossland Road East,
Whitby, ON L1N 2M8
905.430.4300
whitby.ca

July 12, 2022

Via Email:

Indrani J. Butany-DeSouza
President and Chief Executive Officer, Elexicon Energy
ibutany@elexiconenergy.com

Re: Confidential Office of the Chief Administrative Officer Report, CAO 21-22
Elexicon Energy – Potential Ontario Energy Board (OEB) Incremental Capital Module (ICM) Applications: Whitby Smart Grid and Sustainable Brooklin

Please be advised that at a meeting held on July 11, 2022, the Council of the Town of Whitby adopted the following as Resolution #186-22:

1. That Council endorse an Incremental Capital Module application to the Ontario Energy Board by Elexicon Energy for the purpose of implementing smart grid technology, including without limitation VoltVar Optimization (VVO), Fault Monitoring and Distribution Automation (FLISR) and an Advanced Distribution Management System (ADMS) in Whitby; and,
2. That Council endorse an Incremental Capital Module application to the Ontario Energy Board by Elexicon Energy for the purpose of funding the extension of the hydro electric grid to north Brooklin in return for the commitment from the North Brooklin landowners to ensure that newly constructed homes serviced by said extension are 'roughed-in' for Distributed Energy Resources and Electric Vehicle (EV) chargers.

Should you require further information, please do not hesitate to contact the undersigned Matthew Gaskell, Chief Administrative Officer at 905.430.4316.

Kevin Narraway
Sr. Manager, Legislative Services/Deputy Clerk

Copy: J. Vellone, Borden Ladner Gervais LLP - jvellone@blg.com
P. Murphy, Chair, Elexicon Energy Board of Directors - paulmarkmurphy@gmail.com
M. Cory, Malone Given Parsons - mcory@mgp.ca

C. Harris, Town Clerk – harrisc@whitby.ca

M. Gaskell, Chief Administrative Officer – gaskellm@whitby.ca
S. Klein, Director of Strategic Initiatives – kleins@whitby.ca
F. Wong, Commissioner of Financial Services/Treasurer – wongf@whitby.ca

Present: Mayor Mitchell (Participating Electronically)
Councillor Drumm (Participating Electronically)
Councillor Leahy (Participating Electronically)
Councillor Lee (Participating Electronically)
Councillor Mulcahy (Participating Electronically)
Councillor Newman
Councillor Roy (Participating Electronically)
Councillor Shahid
Councillor Yamada (Participating Electronically)

Also Present: M. Gaskell, Chief Administrative Officer
F. Wong, Commissioner of Financial Services/Treasurer
S. Klein, Director of Strategic Initiatives
K. Narraway, Manager of Legislative Services/Deputy Clerk
K. Douglas, Legislative Specialist (Recording Secretary)

Regrets: None noted

---

1. Declarations of Pecuniary Interest

1.1 There were no declarations of pecuniary interest.

Moved By Councillor Newman
Seconded By Councillor Drumm

That Council move in-camera in accordance with Procedure By-law # 7462-18, Closed Meeting Policy G 040, and the Municipal Act, 2001, Section 239 (2)(i) a trade secret or scientific, technical, commercial, financial or labour relations information, supplied in confidence to the municipality or local board, which, if disclosed, could reasonably be expected to prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons, or organization.

Carried

2. Closed Session

2.1 Confidential Office of the Chief Administrative Officer Report, CAO 21-22
Re: Elexicon Energy – Potential Ontario Energy Board (OEB) Incremental Capital Module (ICM) Applications

This portion of the meeting was closed to the public. [Refer to the In Camera minutes of the meeting - Town Clerk has control and custody.].

3. Rising and Reporting

3.1 Motion to Rise

Moved By Councillor Drumm
Seconded By Councillor Newman

That Council rise from the closed portion of the meeting.

Carried

3.2 Reporting Out

Mayor Mitchell advised that during the closed portion of the meeting Council discussed commercial and financial information, supplied in confidence to the municipality, which, if disclosed, could reasonably be expected to prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of an organization.

Confidential Office of the Chief Administrative Officer Report, CAO 21-22
Re: Elexicon Energy – Potential Ontario Energy Board (OEB) Incremental Capital Module (ICM) Applications: Whitby Smart Grid and Sustainable Brooklin

Discussion ensued between Members of Council regarding:

- the importance of ensuring a responsible, innovative and robust electrical distribution system to support the needs of the community, including the ability to address future storm events; and,
- the benefits of Whitby Smart Grid and Sustainable Brooklin to community members, including the ability to support green initiatives, new housing development, and the growing number of electric vehicles in Whitby.

Resolution # 186-22

Moved By Councillor Newman
Seconded By Councillor Roy

1. That Council endorse an Incremental Capital Module application to the Ontario Energy Board by Elexicon Energy for the purpose of implementing smart grid technology, including without limitation VoltVar Optimization (VVO), Fault Monitoring and Distribution Automation (FLISR) and an Advanced Distribution Management System (ADMS) in Whitby; and,
2. That Council endorse an Incremental Capital Module application to the Ontario Energy Board by Elexicon Energy for the purpose of funding the extension of the hydro electric grid to north Brooklin in return for the commitment from the North Brooklin landowners to ensure that newly constructed homes serviced by said extension are 'roughed-in' for Distributed Energy Resources and Electric Vehicle (EV) chargers.

Carried

4. Confirmatory By-law

4.1 Confirmatory By-law

Resolution # 187-22

Moved By Councillor Drumm
Seconded By Councillor Newman

That leave be granted to introduce a by-law and to dispense with the reading of the by-law by the Clerk to confirm the proceedings of the Council of the Town of Whitby at its special meeting held on July 11, 2022 and the same be considered read and passed and that the Mayor and the Clerk sign the same and the Seal of the Corporation be thereto affixed.

Carried

5. Adjournment

5.1 Motion to Adjourn

Moved By Councillor Mulcahy
Seconded By Councillor Shahid

That the meeting adjourn.

Carried

The meeting adjourned at 5:42 p.m.

Don Mitchell, Mayor	Kevin Narraway, Deputy Clerk

DURHAM REGION

The Regional Municipality of Durham

Planning and Economic Development Department

Planning Division

605 Rossland Road East
Level 4
PO Box 623
Whitby, ON L1N 6A3
Canada

905-668-7711
1-800-372-1102
Fax: 905-666-6208
Email: planning@durham.ca

durham.ca

Brian Bridgeman, MCIP, RPP
Commissioner of Planning and Economic Development

July 19, 2022

Ontario Energy Board
2300 Yonge Street, 27th floor
P.O. Box 2319
Toronto, ON M4P 1E4

Via Email: Registrar@oeb.ca

Attention: Board Members
Ontario Energy Board (OEB)

Dear Board Members:

RE: Region of Durham on behalf of the Brooklin North Landowners Group (BNLG)
Letter of Support – ICM Application

On behalf of the Brooklin North Landowners Group ("BNLG"), the Region of Durham is providing this letter of support for the joint Incremental Capital Module ("ICM") application submitted to the Ontario Energy Board (OEB) by Elexicon Energy and BNLG. The Region supports the prospect of expanding the hydroelectric system to the North Brooklin Community Area, which will allow for the electrification of a significant number of residential units, retail commercial, employment, and other public uses over the next 20+ years.

Whitby Council passed a resolution on July 11th, 2022 to endorse the ICM application for the purpose of implementing smart grid technology (see attached letter dated July 12th, 2022). This endorsement follows an understanding that BNLG will commit to ensure newly constructed homes will provide 'roughed-in' for Distributed Energy Resources and Electric Vehicle (EV) chargers.

Providing rough-ins for future electric vehicle usage and photovoltaic inputs in North Brooklin is aligned with the objectives Durham Community Energy Plan and low carbon pathway. This will help to reduce fossil fuel consumption and GHG emissions in the community for transportation and help to offset electricity demand attributed to the growth anticipated for Durham Region to 2031, creating more sustainable, adaptable, and resilient communities. The expansion of this electricity system into North Brooklin is the critical path for facilitating development of the community which was enabled by the approval of Regional Official Plan Amendment 128 (ROPA 128) in 2010. The Brooklin Secondary Plan was adopted by the Town of Whitby in October 2017 and subsequently approved by the Region in July 2018. The Brooklin expansion will deliver new housing stock in Durham Region and provide an innovative and robust electrical distribution system capable of supporting a growing community.

Regional staff support the ICM application as it helps to implement the vision for growth in Whitby. It also allows the Region and the Town of Whitby to achieve their population and employment forecasts to the year 2031 as set out in the Durham Regional Official Plan, and enables many Regional objectives related to the development of healthy and complete, sustainable communities. We thank you for your time and consideration in this matter. Please contact me at any time should you have any questions or wish to discuss these matters further.

Sincerely,

Brian Bridgeman

Brian Bridgeman, MCIP RPP
Commissioner of Planning and Economic Development

cc: Matthew Cory, Representative for the Brooklin North Landowners Group (BNLG)
Kevin Narraway, Sr. Manager, Legislative Services/Deputy Clerk, Town of Whitby
Paul Gillespie, Manager, Development Approvals, Works Department, Region of Durham

Encl.

Town of Whitby
575 Rossland Road East,
Whitby, ON L1N 2M8
905.430.4300
whitby.ca

July 12, 2022

Via Email:

Indrani J. Butany-DeSouza
President and Chief Executive Officer, Elexicon Energy
ibutany@elexiconenergy.com

Re: Confidential Office of the Chief Administrative Officer Report, CAO 21-22 Elexicon Energy – Potential Ontario Energy Board (OEB) Incremental Capital Module (ICM) Applications: Whitby Smart Grid and Sustainable Brooklin

Please be advised that at a meeting held on July 11, 2022, the Council of the Town of Whitby adopted the following as Resolution #186-22:

1. That Council endorse an Incremental Capital Module application to the Ontario Energy Board by Elexicon Energy for the purpose of implementing smart grid technology, including without limitation VoltVar Optimization (VVO), Fault Monitoring and Distribution Automation (FLISR) and an Advanced Distribution Management System (ADMS) in Whitby; and,
2. That Council endorse an Incremental Capital Module application to the Ontario Energy Board by Elexicon Energy for the purpose of funding the extension of the hydro electric grid to north Brooklin in return for the commitment from the North Brooklin landowners to ensure that newly constructed homes serviced by said extension are ‘roughed-in’ for Distributed Energy Resources and Electric Vehicle (EV) chargers.

Should you require further information, please do not hesitate to contact the undersigned Matthew Gaskell, Chief Administrative Officer at 905.430.4316.

Kevin Narraway
Sr. Manager, Legislative Services/Deputy Clerk

Copy: J. Vellone, Borden Ladner Gervais LLP - jvellone@blg.com
P. Murphy, Chair, Elexicon Energy Board of Directors - paulmarkmurphy@gmail.com
M. Cory, Malone Given Parsons - mcory@mgp.ca

C. Harris, Town Clerk – harrisc@whitby.ca

M. Gaskell, Chief Administrative Officer – gaskellm@whitby.ca
S. Klein, Director of Strategic Initiatives – kleins@whitby.ca
F. Wong, Commissioner of Financial Services/Treasurer – wongf@whitby.ca

Town of Whitby
575 Rossland Road East
Whitby, ON L1N 2M8
905.430.4300
whitby.ca

July 18, 2022 **Sent via email to:**

Ontario Energy Board
2300 Yonge Street, 27th Floor
P O Box 2319
Toronto ON M4P 1E4

Attn: Board Members, Ontario Energy Board (OEB)

**Re: Town of Whitby on behalf of the Brooklin Landowners Group Inc.
Letter of Support – ICM Application**

On behalf of the North Brooklin Landowner's Group Inc. ("BLGI"), The Town of Whitby is pleased to provide this letter of support for the joint Incremental Capital Module ("ICM") applications to the Ontario Energy Board (OEB) by Elexicon Energy and BLGI.

The ICM application will involve the expansion of the existing hydroelectrical system at Lakeridge and Taunton Roads to Ashburn and Columbus Roads – the front door of North Brooklin. This undertaking will facilitate the development of approximately 14,000 residential units, significant retail, commercial, employment uses and public uses over the next 20+ years and requires sufficient capacity to meet the forecasted electricity needs in order to develop North Brooklin

Not only will this expansion ensure a steady supply of housing in Whitby - which given the current affordability crisis, will increase the number of available units to purchase for homeowners, but it will also support the wider community, Whitby residents, and all customers within the Elexicon distribution grid. This expansion will ensure a responsible, innovative, and robust electrical distribution system capable of supporting the needs of the community.

On July 11th, 2022, Whitby's Council passed a resolution to endorse an ICM application to the OEB by Elexicon Energy for the purpose of implementing smart grid technology (see attached letter dated July 12th, 2022), including without limitation VoltVar Optimization (VVO), Fault Monitoring and Distribution Automation (FLISR) and an Advanced Distribution Management System (ADMS) in Whitby. This endorsement follows an understanding that BLGI will commit to ensure that newly constructed homes serviced by said extension are 'roughed-in' for Distributed Energy Resources and Electric Vehicle (EV) chargers.

Supporting future electric vehicle usage and photovoltaic inputs installed within dwellings in the community are consistent with Whitby's Green Standards and other objectives to achieve a more sustainable, resilient, and adaptable community. As stated in the recently released Draft Whitby Climate Plan, Whitby declared a climate emergency in June 2019, recognizing the need for immediate, transformative action to ensure that the community is prepared for inevitable climate impacts. One such impact was the powerful windstorm, a Derecho that recently impacted our community, causing outages and impacted thousands of people across Ontario.

Our understanding with BLGI will help spearhead climate change by investing in our future and in turn demonstrate future savings and initiatives in the Whitby Smart Grid. This initiative will set a precedent for other communities to take action in approaching development with a smart lens.

We have observed over the years as BLGI has worked to get electricity into the North Brooklin expansion area and are excited at the prospect of expanding access to the electricity grid and creating a resilient Whitby. The extension of the hydro system to a 27.6 kV service to North Brooklin would not only be providing power to the anticipated number of residential units but provide reliable services and capacity to carry forward into the future.

It is estimated the capital contribution by BLGI and Elexicon Energy may be the largest in Ontario history for any residential development and we are delighted to give our full support to the ICM application.

We thank you for your time and consideration in this matter and please contact me at any time should you wish to discuss these matters further.

Sincerely,

Matthew Gaskell
Chief Administrative Officer
Gaskellm@whitby.ca

905-430-4316

cc. Town of Whitby Council
Brooklin Landowner's Group

APPENDIX B-7:

Customer Engagement Report

Customer Engagement Report

Brickworks Communications
Updated February 2021

Table of Contents

Background

Elexicon Energy commissioned Brickworks to oversee an engagement survey of its customers. The purpose of this survey process was to learn more about how Elexicon's investment plans can best reflect the needs and preferences of their customers. The information collected will be used to inform investment decision-making and may also be submitted to the Ontario Energy Board (OEB) as an input into their five-year Distribution System Plan (DSP).

There were two main approaches used in this process, including an open online survey forum which resulted in N=262 completes and a random telephone survey of N=600 customers. Customers were assured that all responses to this survey would be confidential, and only overall or aggregate results would be reported.

Reporting Notes

The survey questions were designed by Elexicon and Brickworks. The role of Oraclepoll Research Ltd was to field the online and telephone surveys and report on the findings.

This report contains an executive summary of the results from both the telephone and online components, as well as the results by question. Findings are presented in the order that they were asked in each survey.

Methodology & Logistics – Online Survey

Survey Method

All surveys were completed online using Computer Assisted Web Interviewing (CAWI). This was a self-selection survey where respondents connected via a hyperlink to the survey site to complete their interview. Elexicon posted the link on their website homepage, and promoted the survey using e-blasts to their customer base.

Study Sample

In total, N=263 customers completed online questionnaires.

Logistics

Surveys were completed online between October 26th and December 13th, 2020.

Confidence

It is not customary to assign online self-selection samples a margin of error. However, a probability sample of N=262 has a margin of error or is considered accurate ± 6.0%, 19/20 times.

Methodology & Logistics – Telephone Survey

Study Sample

Elexicon provided Brickworks with a database of their residential and business customers to be surveyed. A total of N=524 residential customers, N=70 small business customers, and N=6 large businesses were randomly selected from the database and surveyed by telephone, using person-to-person live telephone interviewing.

Respondents were screened to ensure that they were 18 years of age or older, an Elexicon customer, and were one of the persons either at the business or residence that was a decision maker as related to reviewing utility bills and making payments.

Survey Method

The survey was conducted using computer-assisted techniques of telephone interviewing (CATI) and random number selection. A total of 20% of all interviews were monitored, and Oraclepoll management supervised 100%.

Logistics

Telephone interviews were completed between November 20th and December 4th, 2020. Initial calls for the residential component were made between the hours of 5 p.m. and 9 p.m. Subsequent call backs of no-answers and busy numbers were made on a (staggered) daily rotating basis up to 5 times (from 10 a.m. to 9 p.m.) until contact was made. In addition, telephone interview appointments were attempted with those respondents unable to complete the survey at the time of contact. At least one attempt was made to contact respondents on a weekend. Calls to business customers were first made from 8:30 a.m. to 5:30 p.m. during weekdays. There was at least one follow up call after 5:30 p.m. and one on a weekend. In addition, telephone appointments were accepted and made as per the respondent's time preference.

Confidence

The margin of error for the N=600-respondent survey is $\pm$ 4.0%, 19/20 times.

Online Survey Results

Elexicon Energy
Part A: Initial Qualification and Segmentation

Survey participants were shown background information about Elexicon. They were also told that a main objective of the online poll was to learn how Elexicon's investment plans can best reflect the needs and preferences of its customers.

"Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account."

Yes	*N=262*	*100%*

"What is the municipality associated with the Elexicon customer account?"

Whitby	*29%*
Ajax	*23%*
Pickering	*16%*
Belleville	*8%*
Clarington	*7%*
Gravenhurst	*7%*
Port Hope	*4%*
Brock	*3%*
Scugog/Port Perry	*3%*
Uxbridge	*<1%*

The initial set of questions were demographic. First respondents were screened to ensure they were Elexicon customers, then they were probed about where they live, the client segment they belonged to, and if they are responsible for paying the electricity bill.

"To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer."

Residential	*N=262 100%*

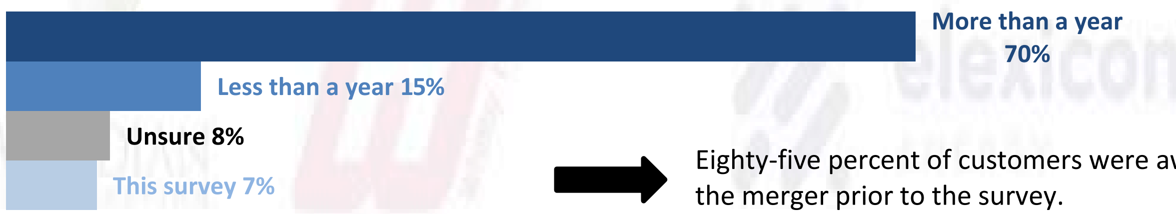
"In your <household/business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?"

I am primarily responsible for paying my household's electricity bill	*N=233*	*89%*
I share the responsibility for paying my household's electricity bill	*N=29*	*11%*

General Questions

Next, online participants were presented with an explanation of the three major cost components of their electricity bill: Generation, Transmission and Distribution – and the portion retained by Elexicon. They were advised that the information collected in the survey related only to their local electricity distributor Elexicon, after which questions were asked.

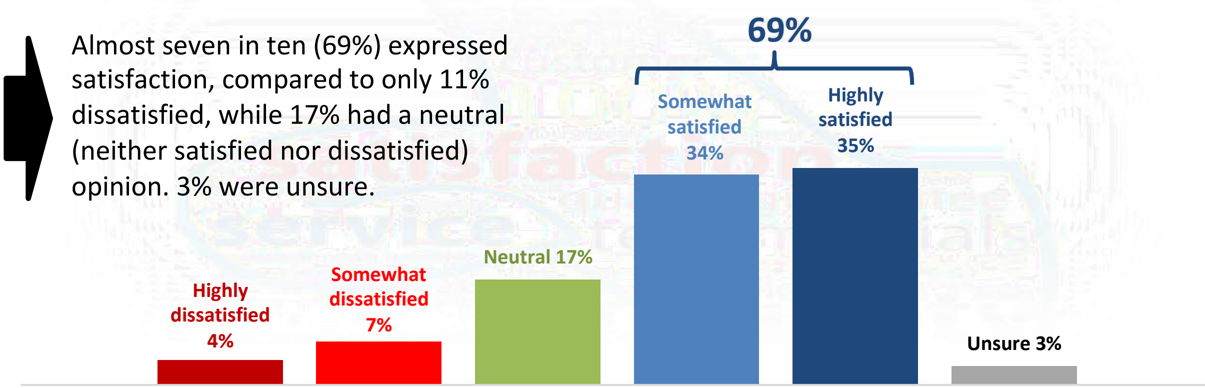
"When did you first become aware of the merger between Whitby Hydro and Veridian to create Elexicon?"



Eighty-five percent of customers were aware of the merger prior to the survey.

"Overall, how satisfied are you with the services Elexicon provides you with?"

Almost seven in ten (69%) expressed satisfaction, compared to only 11% dissatisfied, while 17% had a neutral (neither satisfied nor dissatisfied) opinion. 3% were unsure.



Comments were accepted at the end of the question and results have been sorted into the categories below.

"In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?"

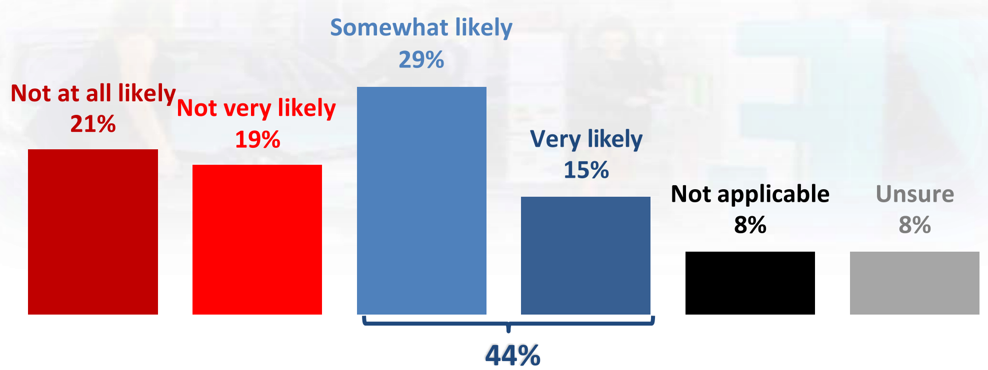
No problems / satisfied	23%	Service has improved	2%
Unsure	21%	Website problems / issues	2%
Reliable / stable service	13%	Simplify billing / payment methods	1%
Poor service / interruptions / outages	11%	Billing problems	1%
Hydro rates are high / expensive	9%	Good customer service	1%
No change	4%	The transition has been seamless	1%
Old / outdated infrastructure	3%	Need alternative energy options	1%
Dislike time of use / simplify / change	2%	Cannot compare due to the monopoly	<1%
No notice for planned outages	2%	Lack of follow up	<1%
No experience / new client / too soon	2%	Give rebates	<1%
Poor costumer service / long waits	2%		

"Please rate your level of agreement with the following statements using a scale from one (strongly disagree) to five (strongly agree)."

	Strongly disagree	Somewhat disagree	Neutral	Somewhat agree	Strongly agree	Unsure	Not applicable
"The amount of my monthly electricity bill is a major expense item for my family and requires me to go without some other important priorities"	25%	20%	27%	**21%**	**7%**	1%	-
"When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved"	**3%**	**9%**	19%	18%	20%	-	31%

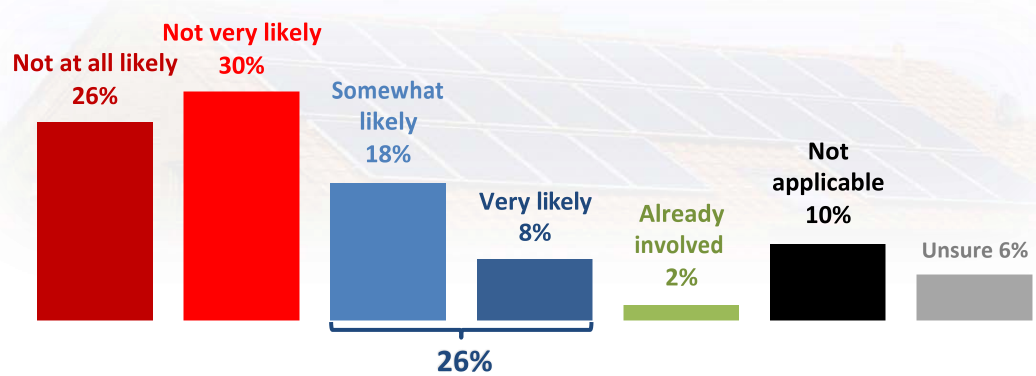
Twenty-eight percent agreed the cost of their bill creates some form of hardship. Total agreement, or being satisfied with how questions or requests were resolved, is 38%, compared to only 12% that disagreed (dissatisfied), while 19% had a neutral opinion. 31% answered not applicable or had no experience.

"If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?"



Interest in EV's is solid at 44%, with 29% somewhat and 15% very likely to consider a purchase.

"How likely are you to become involved in self-generation of electricity at your place of residence over the next five years (for example, by installing solar panels)?"



Slightly more than a quarter or 26% said they are somewhat (18%) or very likely (8%) to become involved in self generation.

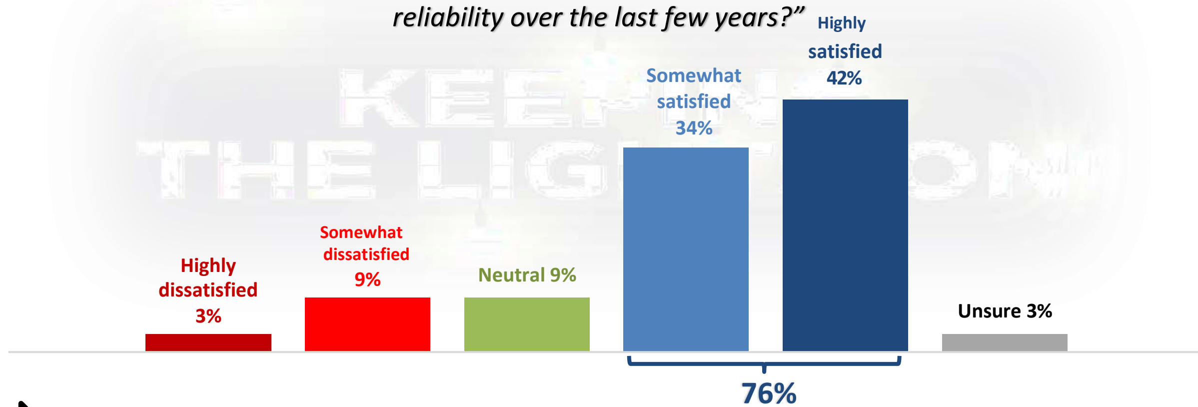
Two questions about outages over the past year were asked, the first about how many times the power has been out, and second related to the length of time the outages lasted.

"In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at your home to the best of your recollection?"	
0	8%
1	14%
2	29%
3	13%
More than 3	24%
Not Sure	11%

"In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average? Please select from the following options based on your best estimate:"	
Under 30 minutes	20%
Under 1 hour	22%
Between 1 and 2 hours	22%
Longer than 2 hours	21%
Not Sure	15%

Customers were then asked about reliability starting with an overall satisfaction question.

"Which of the following options best represents your overall satisfaction with service reliability over the last few years?"



Seventy-six percent are satisfied or very satisfied with service reliability.

"When power outages do occur, which aspect of them has been most inconvenient for you?

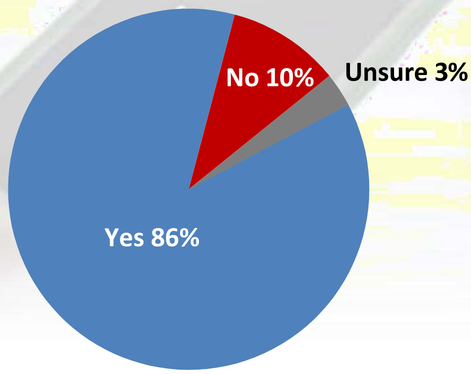
How long the outages have lasted	44%
How often the outages have occurred	20%
Not Sure	16%
Impact it has on my electronics / computers	7%
None / no inconveniences	4%
Getting information from Elexicon / contact with	3%
Both how often & how long	3%
Timing / when they occur	2%
No heat / no cooling / appliances	1%

"When there is a power outage, how do you interact with Elexicon Energy?"

I check the outage map online	37%
I do not take any steps	30%
I phone the outage number posted on the website	19%
I check Twitter	6%
Telephone call	3%
No experience	2%
I use both Twitter and Map	1%
Radio	1%
Unsure	1%

The length of an outage is of most concern to 44%, followed by how often they occur (20%). When asked how they interact with Elexicon during an outage, 37% check the map online and 19% phone the number on the website, while three in ten do not take any actions.

"Please indicate your level of interest in the following: When an outage occurs, are you interested in receiving notifications sent to your phone (via text or voice to landline) about its cause and anticipated restoration time?"



Interest is high at 86% for an outage notification system by text or voice.

"To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?"	
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases.	37%
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the long term.	32%
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term to achieve this.	12%
Not Sure	11%
Maintain reliability & do not raise prices	4%
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially means more and longer outages for myself and others.	3%
Provide better service overall	1%

There is a split of opinion with the two most selected options being spending more on reliability and less on other areas (to avoid some bill increases) as well as maintaining current reliability, even if it increases monthly bills in the long term.

"Elexicon can prevent more outages caused by aging equipment if it proactively replaces more equipment before it fails. Another option is to wait and replace equipment only after it fails, which potentially causes more service interruptions and leads to extra costs such as staff overtime. Which of the following options best describes your views on this trade-off?"	
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable.	81%
Not Sure	10%
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road.	5%
Maintenance on a schedule & no rate increases	4%
Invest in better equipment	1%

A clear majority of 81% feel equipment should be replaced before it fails.

"Elexicon's top spending priority is always to keep its power system and operations safe. With its budget staying nearly flat through 2029, Elexicon will face tough trade-offs when selecting among other investment priorities."

"Please choose two of the following objectives that you think Elexicon should focus its efforts on, in addition to keeping the system safe and accommodating new growth in the coming years."

	First mention	Second mention	Combined
Improving the grid's resilience to major weather events, like storms, etc.	28%	31%	30%
Preparing the grid for new types of uses, like EV's & renewable generation	23%	11%	17%
Investing now in things that will help reduce rate increases after 2029	13%	20%	16%
Minimizing the impact of power outages	7%	19%	13%
Helping customers manage their electricity use	10%	10%	10%
Reducing the environmental impact of Elexicon's operations	12%	5%	8%
Improving power quality	5%	2%	4%
Addressing customer requests faster and more efficiently	2%	1%	2%

➡ While improving the grid's resilience to major events is the number one choice at 30%, results are close for second, with 17% naming preparing the grid for new uses and 16% investing now in things that will help reduce rate increases after 2029.

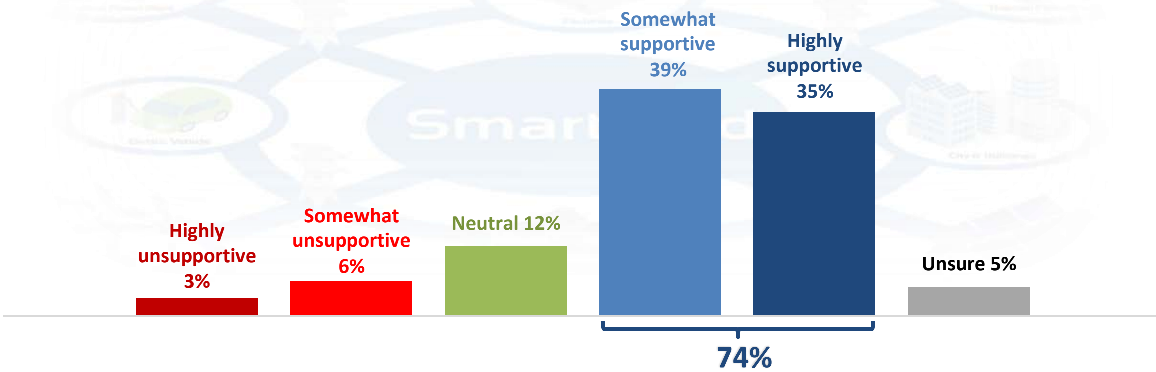
➡ **45% of customers who are dissatisfied with reliability listed minimizing outage impacts in their top two priorities.**

"Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of its power grid.
Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?"

I am satisfied with the planned allocation based on what I know	50%
I would prefer to spend more on the technical upkeep of the power grid & less on the other two	18%
Not Sure	16%
I would prefer to spend more on reliability and less on the other two	8%
I would prefer to spend more on efficiency, health, & safety of operations and less on other two	7%

➡ Half are satisfied with the planned allocation, while 16% were unsure. There are 18% that want more spent on technical upkeep, with the remaining responses divided between more spent-on reliability and more on efficiency, health, and safety of operations.

"Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?"



Support for investing in new technologies is at nearly three-quarters or 74%.

Customers were presented with a description of rear-lot overhead power lines, the challenges they face, and the cost of conversion to underground lines. They were then asked the following two questions.

"To the best of your knowledge, does your place of <<residence>>/<<business>> currently receive power via a rear-lot line?"

"Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?"

Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere. While concentrating the work in a single community for a shorter timeframe is less inconvenient to local residents, it could leave vulnerable rear-lot feeders in other communities unaddressed for longer.	38%
Not Sure	23%
Move lines underground and plan work according to worst performing areas. This spreads the work across Elexicon's service territory over time but may mean that there may be multiple construction-related disruptions.	22%
Maintain the status quo – keep the overhead lines in the rear lots, replacing them as they fail. While budgets can be used elsewhere, it will leave area customers vulnerable to longer than average outages.	17%

Only 17% want to maintain the status quo and 23% were unsure as to a preferred option. There were 38% that want to move the lines underground and work geographically. 22% that also want to move the lines underground, but work on the worst performing areas.

ICM Project #1: New Pickering Area Transformer Station

Next, online participants were provided with background information about three projects that Elexicon plans to seek approval for additional rate increases. They were informed that two projects are driven by population growth, and the third is needed to sustain operations in the Belleville area.

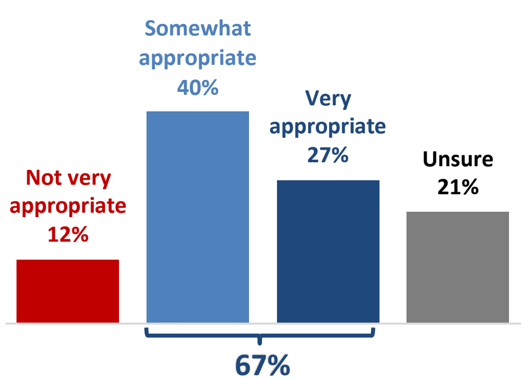
Elexicon will request special rate increases for these projects since it cannot finance them along with its other budgetary priorities. These requests are reviewed by the OEB through a process known as the Incremental Capital Module (ICM).

The first project is a large new Transformer Station in the Pickering area, required to support the residential and commercial growth that is projected to add as many as 32,000 new customers over the next 20 years. Elexicon estimates that to avoid system capacity shortages, the station needs to be in service in 2022.

The project is expected to cost about $40 million, which amounts to an approximate:

- $1.45 - $1.85 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- 2.90 - $3.60 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $280.95 - $343.40 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Transformer Station appropriate?



Two-thirds consider the level of investment appropriate (somewhat & very), only 12% do not feel it appropriate and 21% were undecided.

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	70%
Customers affected should pay	6%
Developers should pay a higher portion	6%
Against the proposed project all together	3%
If it is necessary / if needed / get it done	3%
Better cost-efficient solutions are needed	3%
Do not want to pay for other communities	2%
Do not increase rates	1%
Not enough information	1%
Ensure safely / reliability	1%
More renewable solutions needed	1%
Too costly	1%
Make sure there is a backup plan	<1%
Should focus on conservation	<1%

While most (70%) did not have comments to share, those with opinions tended to cite the belief that customers in the communities affected and developers should pay for costs or a larger portion of the price. Some mentions reflected opposition, others the need to get things done. There were also those that felt other options should be pursued.

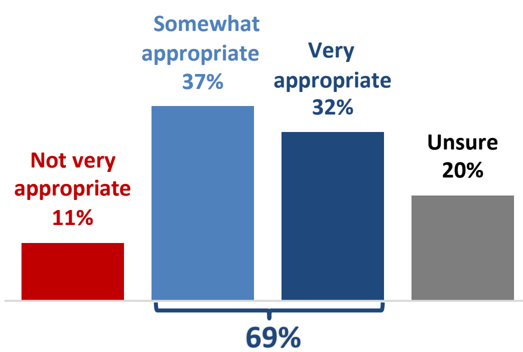
ICM Project #2: Accommodating the Move of the Belleville Operations Centre

The second project for funding is a new Operations Centre in Belleville to accommodate staff and equipment involved in providing customer service and responding to local power outages. The lease on the existing facility is set to expire in 2021 and cannot be renewed. Having considered all feasible options, Elexicon determined that owning a new facility is the most cost-effective option for customers in the long term.

The project is expected to cost about $2.6 million, which amounts to an approximate

- $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian ratezone.
- $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $2.6 million, which amounts to an approximate $18.35 - $23.50 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Operations Centre appropriate?"



Sixty-nine percent consider the level of investment appropriate. This compares to a low 11% that do not, while 21% are unsure.

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	79%
Customers / communities affected should pay	4%
It is a required investment / reasonable / needed	3%
Refurbish an existing building	2%
Should come from reserve funds not customers	2%
Against project all together	2%
Lack of information to make an informed decision	2%
Build it smart / keep future growth in mind	1%
Compare leasing versus new build	1%
Customers should not have to pay	1%
Lease / rent building	1%
Should have been done years ago	1%
Proposed budget seems too low	<1%
Municipality should help finance	<1%
Savings should be passed onto the customer	<1%
Business / developers should pay	<1%
Should be mortgage financed	<1%

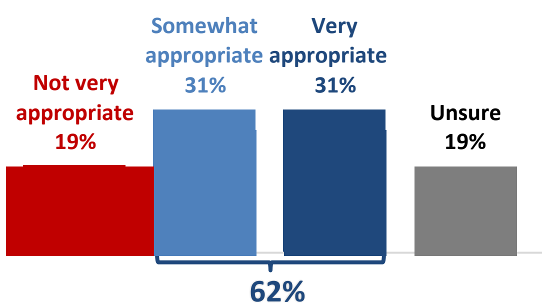
Almost eight in ten had no comment and among those that did, there was a mix of those in support, opposed, or not wanting to pay, and others suggesting alternative solutions for the build and payment.

ICM Project #3: Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit

To enable construction of dedicated Rapid Transit Bus Lanes in the Hwy #2 corridor in Pickering, Elexicon is required to relocate existing underground feeder infrastructure located in the right of way intended for the bus lanes. Elexicon and its customers are responsible for a portion of this cost, estimated to be $2.8 million. While performing this work, Elexicon will have an opportunity to replace or upgrade any equipment, as necessary.

- The project's cost is equivalent to an approximate $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $27.95 - $35.70 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"Do you consider the level of investment proposed for this underground infrastructure project to be very appropriate, somewhat appropriate, or not appropriate? "



Slightly more six in ten said the level of investment is appropriate, less than two in ten not appropriate, and an equal number did not know.

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	74%
Residents / communities affected should pay	6%
Should be a priority	3%
Project should be covered by taxpayers	3%
Project not a priority	3%
Need more information / unclear	2%
Costs should be covered by transit users	2%
Municipality should pay	2%
Should be paid for by investors	1%
Will improve reliability	1%
Poor planning	1%
Project should be completed quickly as possible	1%
Disagree with project	1%
Will raise rates	<1%
Should be Elexicon's responsibility	<1%

Nearly three-quarters had no comments, but most of those that did (14%) referenced the belief that costs should be incurred by users, those affected, by ratepayers, or municipalities.

In the final question about the three ICM projects, respondents were asked which of five options presented would give them the most confidence that Elexicon is acting in their best interest.

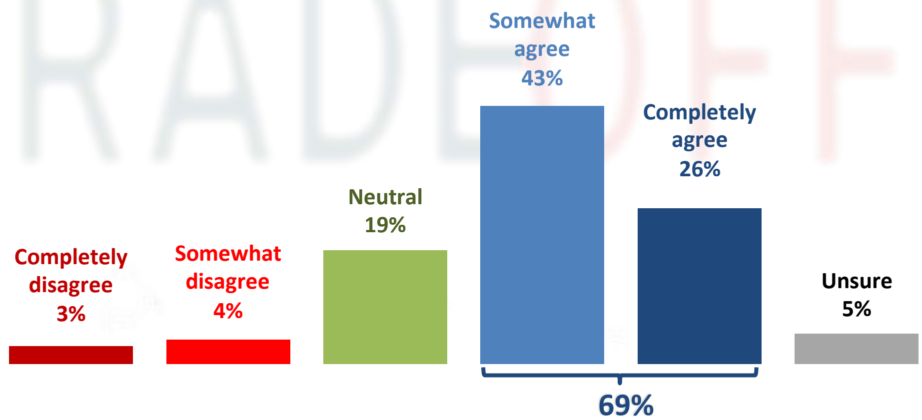
"What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting in the best interest of their customers in mind?"

37%	Why Elexicon could not build these projects without seeking rate increases
15%	Why the chosen design and size are optimal
11%	Why the projects cannot be built for less
5%	Why the projects cannot be reasonably delayed
2%	Why these projects could not be built in other areas
29%	Unsure

Most named was why Elexicon could not build these projects without seeking rate increases, followed by why the chosen designs and sizes are optimal and then why they cannot be built for less. Almost three in ten answered do not know or were unsure.

Elexicon Energy
Part D: Concluding Observations

"As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?"



An almost seven in ten majority somewhat or completely agreed that they have a better appreciation of the planning trade-offs that Elexicon needs to consider when making investment plans. This compares to only 7% that somewhat or completely disagreed, while 19% gave a neutral (neither agree nor disagree) response, and 5% were unsure.

Customers were asked about their preferred method to have Elexicon consult with them on similar topics. Below are the percentage of counts or the responses for each category, revealing that by far, most favour online surveys.

"In the future, what is your preferred method to have Elexicon consult with you about topics similar to what we discussed?"

Online Surveys	93%
Live Online Presentations and Q&A Sessions	13%
In-Person Townhall Meetings	8%
In-Person Focus Groups	5%
Phone Surveys	3%
Mail	1%
Bill inserts	1%
General email	<1%
Newspaper	<1%

"How often should Elexicon engage its customers on matters such as those captured in this survey?"

The percentage of customers that want to be engaged on a yearly basis (once & more than once a year) is 60%, while a third named every 2-3 years. Only 5% stated every five years and 3% were unsure.

"Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?"

Unsure / none	N=218	83%
Lower rates	N=12	5%
Promote Green Energy	N=5	2%
Limit increases to most needed projects	N=2	1%
Removal of overhead wires	N=2	1%
Invest in an outage communication system	N=2	1%
App to monitor usage	N=2	1%
More tools to help manage electricity use	N=2	1%
Keep the utilities public / local	N=2	1%
Amount and length of outages too high	N=1	<1%
Support Electric vehicles	N=1	<1%
Stop all investment in Green Energy	N=1	<1%
Communities should cover costs	N=1	<1%
Support upgrades	N=1	<1%
Create jobs	N=1	<1%
Move to online payments only	N=1	<1%
Improve customer service	N=1	<1%
Would like data from Smart Meter	N=1	<1%
Capital costs should've been pre-planned	N=1	<1%
Upgrades should not impact customers	N=1	<1%
Upgrades too costly	N=1	<1%
Should not pay for new subdivisions	N=1	<1%
Trees are being cut down unnecessarily	N=1	<1%
More outreach needed	N=1	<1%

Telephone Survey Results

Elexicon Energy
Part A: Initial Qualification and Segmentation

Telephone respondents were read background information about Elexicon. They were also told that a main objective of the online poll was to learn how Elexicon's investment plans can best reflect the needs and preferences of its customers.

"Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account."

Yes	*N=600*	*100%*

"What is the municipality associated with the Elexicon customer account?"

Whitby	*29%*
Ajax	*18%*
Pickering	*17%*
Belleville	*10%*
Clarington	*8%*
Gravenhurst	*7%*
Port Hope	*5%*
Brock	*3%*
Scugog	*2%*
Uxbridge	*2%*

The initial questions were demographic. First respondents were screened to ensure they were Elexicon customers, then they were probed about where they live, the client segment they belonged to, and if they are responsible for paying the electricity bill.

"To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer."

Residential	*N=524*	*87%*
Small Business (monthly electricity bill below $2,500)	*N=70*	*12%*
Large Business (monthly electricity bill above $2,500)	*N=6*	*1%*

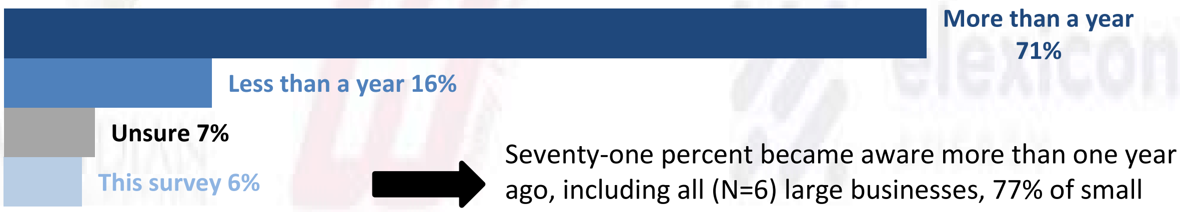
"In your <household / business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?"

I am primarily responsible for paying my household's electricity bill	*N=466*	*78%*
I share the responsibility for paying my household's electricity bill	*N=58*	*10%*
I am the person responsible for managing my organization's electricity bill	*N=42*	*7%*
I am the person overseeing the management of my organization's electricity bill	*N=34*	*6%*

General Questions

Respondents were next read an explanation of the three major cost components of their electricity bill: Generation, Transmission and Distribution – and the portion retained by Elexicon. They were advised that the information collected in the survey related only to their local electricity distributor Elexicon, after which questions were asked.

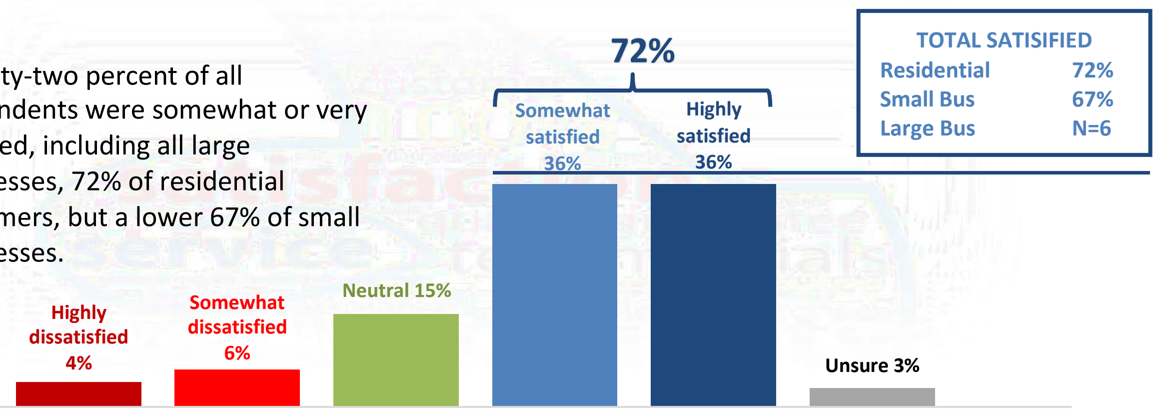
"When did you first become aware of the merger between Whitby Hydro and Veridian to create Elexicon?"



Seventy-one percent became aware more than one year ago, including all (N=6) large businesses, 77% of small businesses, and 70% of residential customers.

"Overall, how satisfied are you with the services Elexicon provides you with?"

Seventy-two percent of all respondents were somewhat or very satisfied, including all large businesses, 72% of residential customers, but a lower 67% of small businesses.



Comments were accepted at the end of the question and results have been coded into the categories below.

"In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?"

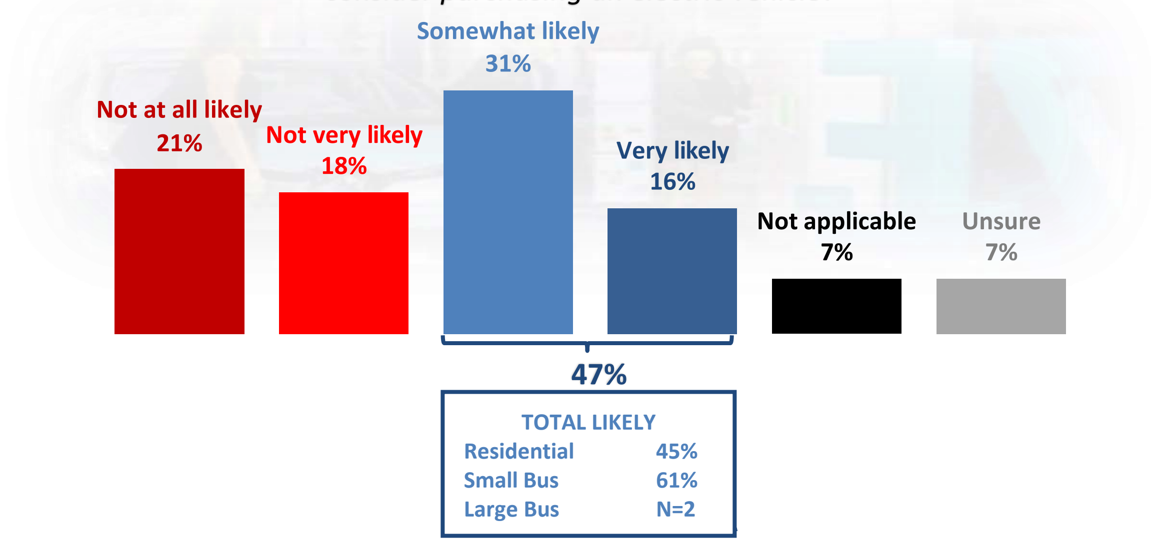
Unsure / none	30%	Good customer service	1%
No problems / satisfied	24%	Poor customer service /long waits	1%
Reliable / stable service	14%	No notice for planned outages	1%
Hydro rates are high / expensive	13%	Simplify billing / payment methods	1%
Poor service / interruptions / outages	10%	Dislike time of use / simplify / change	1%
No experience / new customers	2%	Lack of follow up	1%
Old / outdated Infrastructure	2%	Billing problems	<1%

"Please rate your level of agreement with the following statements using a scale from one (strongly disagree) to five (strongly agree)."

	Strongly disagree	Somewhat disagree	Neutral	Somewhat agree	Strongly agree	Unsure	Not applicable	TOTAL AGREE BY SEGMENT
"The amount of my monthly electricity bill is a major expense item for my family / business and requires me to go without some other important priorities"	20%	24%	22%	**24%**	**9%**	1%	-	*Residential 32% Small Bus 43% Large Bus N=1*
"When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved"	**4%**	**8%**	19%	21%	20%	1%	27%	*Residential 40% Small Bus 45% Large Bus N=5*

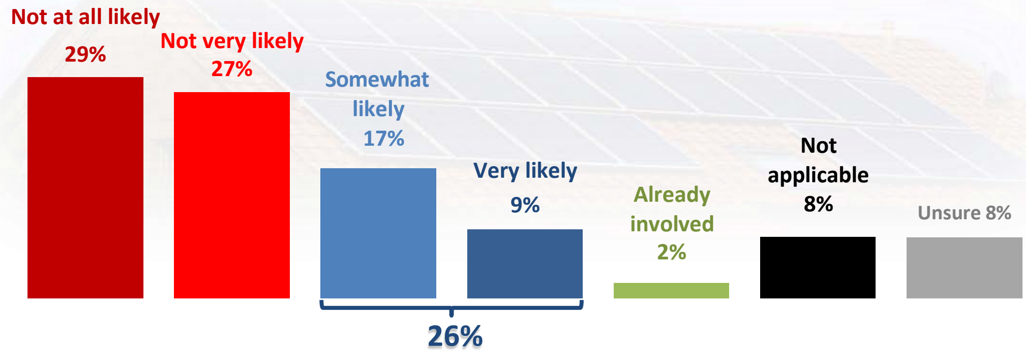
Thirty-three percent of all respondents agreed their monthly bill is a major expense affecting priorities, with small businesses most likely to agree at 43%. More than four in ten or 41% agreed or were satisfied with how their questions were resolved, compared to only 12% that disagreed or were not satisfied – with businesses being more satisfied (total agree).

"If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?"



There is strong overall interest at 47%, with those in the small business cohort showing the strongest interest.

"How likely are you to become involved in self-generation of electricity at your <residence>>/<<business> over the next five years (for example, by installing solar panels)?"



TOTAL LIKELY	
Residential	25%
Small Bus	30%
Large Bus	N=2

Twenty-six percent said they are somewhat (17%) or very likely (9%) to become involved in self generation, with results higher among small businesses.

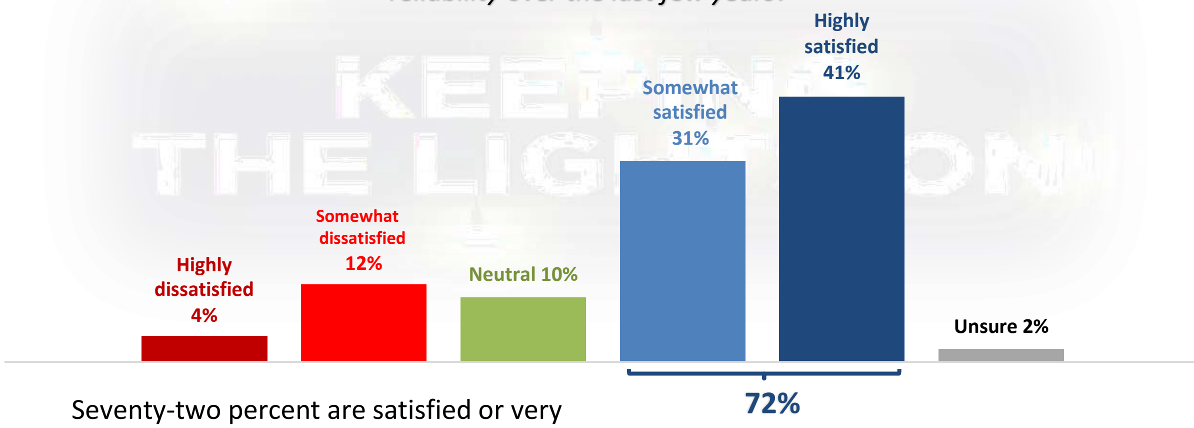
Two questions about outages over the past year were asked, the first about how many times the power has been out, and second related to the length of time they lasted.

"In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at your <home / business> to the best of your recollection?"	
0	7%
1	15%
2	31%
3	14%
More than 3	26%
Not Sure	8%

"In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average? Please select from the following options based on your best estimate:"	
Under 30 minutes	23%
Under 1 hour	21%
Between 1 and 2 hours	21%
Longer than 2 hours	25%
Not Sure	10%

Customers were next probed about reliability, starting with an overall satisfaction question. There were then asked two semi-open follow-ups about what most inconvenienced them during outages and how they interact with Elexicon during these events.

"Which of the following options best represents your overall satisfaction with service reliability over the last few years?"



Seventy-two percent are satisfied or very satisfied with service reliability with residential customers (74%), with 4 of the N=6 large businesses being more satisfied than small businesses (62%).

TOTAL SATISFIED	
Residential	74%
Small Bus	62%
Large Bus	N=4

"When power outages do occur, which aspect of them has been most inconvenient for you?"

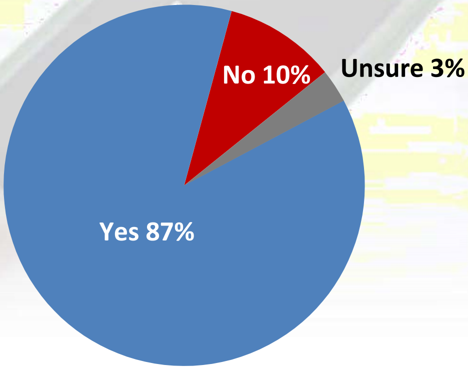
How long the outages have lasted	48%
How often the outages have occurred	19%
Not Sure	15%
Impact it has on my electronics / computers	8%
None / no inconveniences	4%
Both how often & how long	3%
Getting info from Elexicon / contact	2%
Timing / when they occur	1%

"When there is a power outage, how do you interact with Elexicon Energy?"

I check the outage map online	38%
I do not take any steps	29%
I phone the outage number posted on the website	21%
I check Twitter	6%
Telephone call	4%
Unsure	2%
No experience	1%
Radio	<1%

The length of an outage is of most concern to 48%, followed by how often they occur (19%). When then asked how they interact with Elexicon during an outage, 38% check the map online and 21% phone the number on the website, while an additional 4% just said a telephone call.

"Please indicate your level of interest in the following: When an outage occurs, are you interested in receiving notifications sent to your phone (via text or voice to landline) about its cause and anticipated restoration time?"



TOTAL INTEREST	
Residential	86%
Small Bus	94%
Large Bus	N=6

Interest is very high at 87%, and especially among businesses.

"To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?"	
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases	38%
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the long term	37%
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term to achieve this	12%
Not Sure	10%
Maintain reliability and do not raise prices	3%
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially means more and longer outages for myself and others	1%

An almost equal number support spending more on reliability and less on other areas (to avoid some bill increases) and maintaining current reliability, even if it increases monthly bills in the long term.

"Elexicon can prevent more outages caused by aging equipment if it proactively replaces more equipment before it fails. Another option is to wait and replace equipment only after it fails, which potentially causes more service interruptions and leads to extra costs such as staff overtime. Which of the following options best describes your views on this trade-off?"	
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable	85%
Not Sure	7%
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road	5%
Maintenance on a schedule and no rate increases	4%

A very strong majority of 85% feel equipment should be replaced before it fails.

"Elexicon's top spending priority is always to keep its power system and operations safe. With its budget staying nearly flat through 2029, Elexicon will face tough trade-offs when selecting among other investment priorities."

"Please choose two of the following objectives that you think Elexicon should focus its efforts on, in addition to keeping the system safe and accommodating new growth in the coming years."

	First mention	Second mention	Combined
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	32%	30%	31%
Preparing the grid for new types of uses, like electric vehicles and renewable generation	22%	12%	17%
Investing now in things that will help reduce rate increases after 2029	12%	20%	16%
Minimizing the impact of power outages	6%	20%	13%
Helping customers manage their electricity use	11%	9%	10%
Reducing the environmental impact of Elexicon's operations	11%	5%	8%
Improving power quality	4%	3%	4%
Addressing customer requests faster and more efficiently	2%	1%	2%

➡ Improving the grid's resilience to major events is the number one, two, and combined choice. The next highest in terms of combined results is preparing the grid for new uses, followed by investing in things that will help reduce rate increases after 2029.

➡ **45% of customers who are dissatisfied with reliability listed minimizing outage impacts in their top two priorities.**

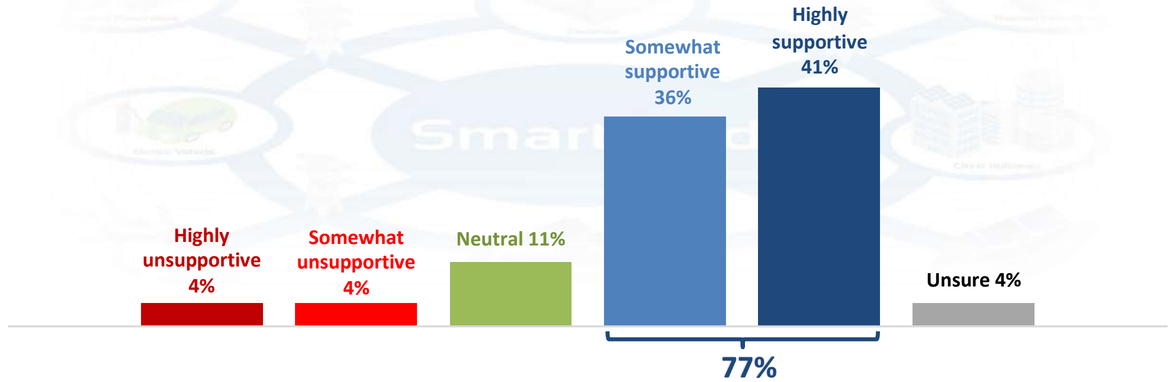
"Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of its power grid."

"Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?"

I am satisfied with the planned allocation based on what I know	53%
I would prefer to spend more on the technical upkeep of the power grid and less on the other two	16%
Not Sure	14%
I would prefer to spend more on reliability and less on the other two	11%
I would prefer to spend more on efficiency, health, and safety of operations and less on the other two	6%

➡ A slim majority or 53% are satisfied with the planned allocation, next followed by those wanting more spent on technical upkeep (16%) and reliability (11%). Only 6% want more spent-on efficiency, health, and safety, while 11% were unsure.

"Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?"



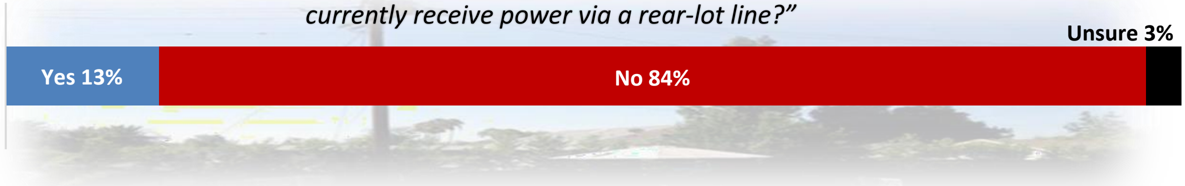
TOTAL SUPPORTIVE

Residential	76%
Small Bus	80%
Large Bus	N=6

➡ Support for investing in new technologies is at a strong 77%.

Customers were read a description of rear-lot overhead power lines, the challenges they face, and the cost of conversion to underground lines. They were then asked the following two questions.

"To the best of your knowledge, does your place of <residence>/<business> currently receive power via a rear-lot line?"



"Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?"

Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere. While concentrating the work in a single community for a shorter timeframe is less inconvenient to local residents, it could leave vulnerable rear-lot feeders in other communities unaddressed for longer.	39%
Move lines underground and plan work according to worst performing areas. This spreads the work across Elexicon's service territory over time but may mean that there may be multiple construction-related disruptions.	24%
Maintain the status quo – keep the overhead lines in the rear lots, replacing them as they fail. While budgets can be used elsewhere, it will leave area customers vulnerable to longer than average outages.	22%
Not Sure	15%

➡ While no option received majority preference, most named was moving lines underground and working geographically, while the other two alternatives received roughly the same percentage of responses.

ICM Project #1: New Pickering Area Transformer Station

Next, online participants were read background information about three projects that Elexicon plans to seek approval for additional rate increases. They were informed that two projects are driven by population growth and the third is needed to sustain operations in the Belleville area.

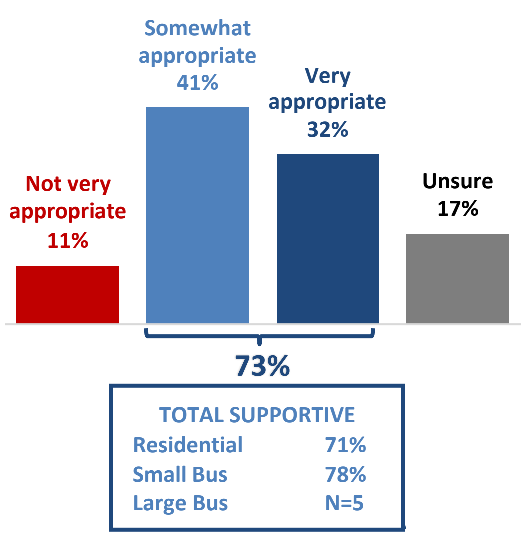
Elexicon will request special rate increases for these projects since it cannot finance them along with its other budgetary priorities. These requests are reviewed by the OEB through a process known as the Incremental Capital Module (ICM).

The first project is a large new Transformer Station in the Pickering area, required to support the residential and commercial growth that is projected to add as many as 32,000 new customers over the next 20 years. Elexicon estimates that to avoid system capacity shortages, the station needs to be in service in 2022.

The project is expected to cost about $40 million, which amounts to an approximate:

- $1.45 - $1.85 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- 2.90 - $3.60 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $280.95 - $343.40 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Transformer Station appropriate?



"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	81%
If it is necessary / if needed / get it done	8%
Developers should pay a higher portion of cost	3%
Customers affected should pay	3%
Against the proposed project all together	1%
Do not increase rates	1%
Better cost-efficient solutions are needed	1%
Do not want to pay for other communities	1%
More renewable energy needed	1%
Should focus on conservation	1%
Apply new rates for new customers	<1%
Too costly	<1%

Seventy-three percent consider the level of investment appropriate (somewhat & very), only 11% do not feel it appropriate, and 17% were undecided. More than 80% had no comments, with those that did being split over support and wanting alternative costing options.

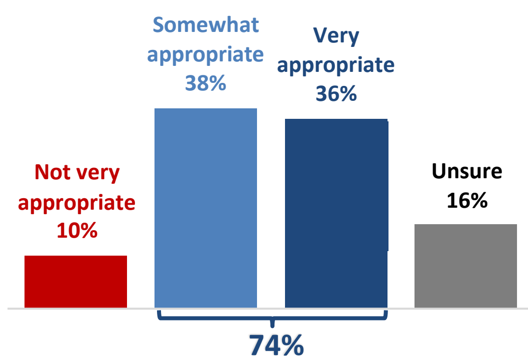
ICM Project #2: Accommodating the Move of the Belleville Operations Centre

The second project for funding is a new Operations Centre in Belleville to accommodate staff and equipment involved in providing customer service and responding to local power outages. The lease on the existing facility is set to expire in 2021 and cannot be renewed. Having considered all feasible options, Elexicon determined that owning a new facility is the most cost-effective option for customers in the long term.

The project is expected to cost about $2.6 million, which amounts to an approximate

- $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- $2.6 million, which amounts to an approximate $18.35 - $23.50 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"To what degree do you consider the level of proposed investments in the Operations Centre appropriate?"



TOTAL SUPPORTIVE	
Residential	72%
Small Bus	87%
Large Bus	N=6

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	88%
It is a required investment / reasonable / needed	4%
Customers / communities affected should pay	3%
Lack of information to make an informed decision	2%
Refurbish an existing building	2%
Customers should not have to pay	1%
Against project all together	1%
Consider lease / renting building	1%
Build it smart / keep future growth in mind	1%
Business / developers should pay	<1%

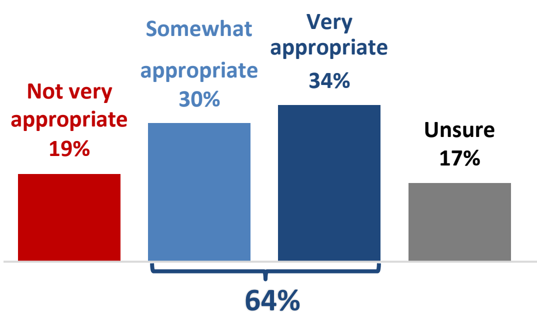
Almost three-quarters consider the level of investment appropriate, with results very strong among businesses. Most had no comments or thoughts to share. Comments were spread among those supporting the project and others opposed to having to pay for it.

ICM Project #3: Underground System Relocation in Pickering to Enable Regional Bus Rapid Transit

To enable construction of dedicated Rapid Transit Bus Lanes in the Hwy #2 corridor in Pickering, Elexicon is required to relocate existing underground feeder infrastructure located in the right of way intended for the bus lanes. Elexicon and its customers are responsible for a portion of this cost, estimated to be $2.8 million. While performing this work, Elexicon will have an opportunity to replace or upgrade any equipment, as necessary.

- The project's cost is equivalent to an approximate $0.10 - $0.15 bill increase per month starting in 2022 for the average **residential customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $0.25 - $0.30 bill increase per month starting in 2022 for the average **small business customer** in the Veridian rate zone.
- The project's cost is equivalent to an approximate $27.95 - $35.70 bill increase per month starting in 2022 for the average **large business customer** in the Veridian rate zone.

"Do you consider the level of investment proposed for this underground infrastructure project to be very appropriate, somewhat appropriate, or not appropriate? "



TOTAL SUPPORTIVE	
Residential	62%
Small Bus	74%
Large Bus	N=6

"Do you have any thoughts you'd like to share with respect to this project?"

Unsure / none	76%
Customers / communities affected should pay	5%
Should be a priority	4%
Project should be covered by taxpayers	3%
Costs should be covered by transit users	2%
Need more information / unclear	2%
Complete as efficiently and quickly as possible	2%
Will improve reliability	1%
Project not a priority	1%
Municipality should pay	1%
Transit is important / needed for growth	1%
Should be paid for by investors	1%
Poor planning	1%
Will raise rates	1%
Disagree with project	1%

Results were lowest for this project with 64% saying the project was somewhat or very appropriate. While some comments expressed support, others reflected the belief that funding or costing should come from others, such as affected users and municipalities.

In the final question about the three ICM projects, respondents were asked which of five options would give them the most confidence that Elexicon is acting in their best interest.

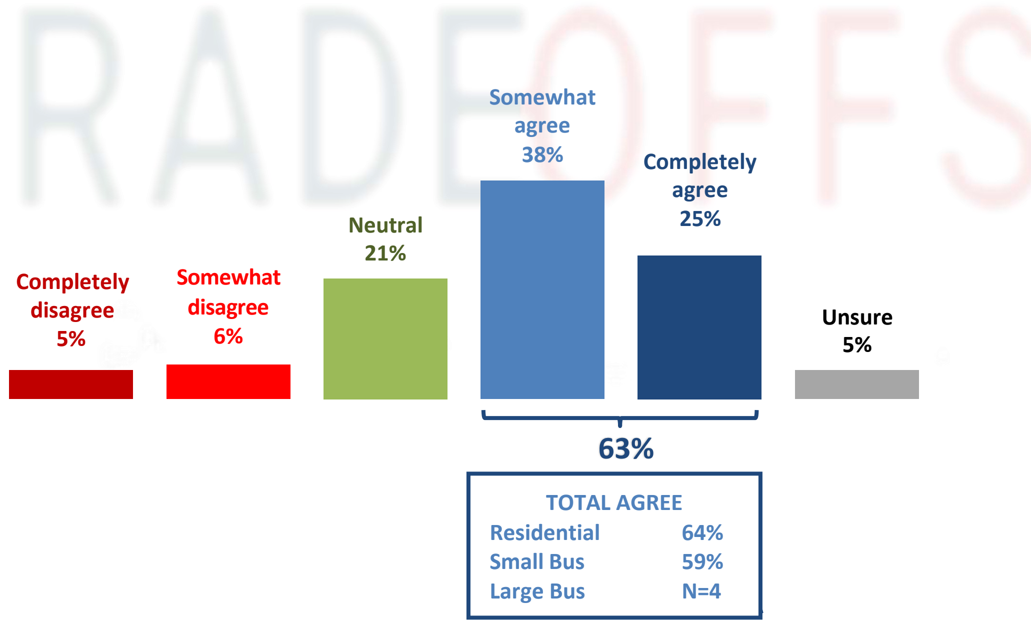
"What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting in the best interest of their customers in mind?"

39%	Why Elexicon could not build these projects without seeking rate increases
16%	Why the chosen design and size are optimal
14%	Why the projects cannot be built for less
6%	Why the projects cannot be reasonably delayed
2%	Why these projects could not be built in other areas
23%	Unsure

Most named was why Elexicon could not build these projects without seeking rate increases, followed by why the chosen designs and sizes are optimal and then why they cannot be built for less. Twenty-three percent answered do not know or were unsure.

Elexicon Energy
Part D: Concluding Observations

"As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?"



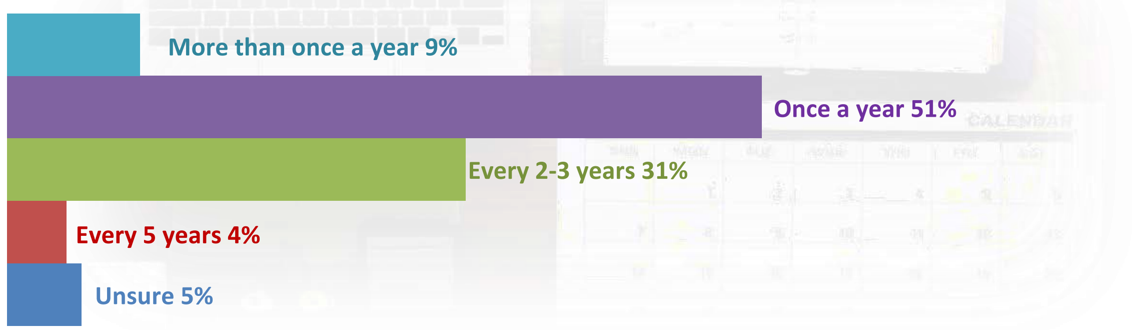
Sixty-three percent somewhat or completely agreed that they have a better appreciation of the planning trade-offs that Elexicon needs to consider when making investment plans. This compares to 11% that somewhat or completely disagreed, while 21% gave a neutral (neither agree nor disagree) response and 5% were unsure.

Customers were asked about their preferred method to have Elexicon consult with them on similar topics. Below are the percentage of counts or the responses for each category.

"In the future, what is your preferred method to have Elexicon consult with you about topics similar to what we discussed?"

Live Online Presentations and Q&A Sessions	33%
Email	22%
Online Surveys	20%
Unsure	15%
Bill inserts	14%
In-Person Townhall Meetings	7%
Phone Surveys	2%
In-Person Focus Groups	2%
Mail	1%
Newspaper	1%

"How often should Elexicon engage its customers on matters such as those captured in this survey?"



Once a year is how often a small majority want to be engaged, followed by 31% that named every 2-3 years, 9% more than once a year, and only 4% every five years.

"Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?"

Unsure / none	N=467	78%
Lower rates	N=51	9%
Limit increases to most needed projects	N=18	3%
Promote Green Energy	N=12	2%
Do most needed first	N=10	2%
Upgrades too costly	N=8	1%
Improve customer service	N=6	1%
More energy savings advice	N=5	1%
More outreach needed	N=5	1%
Amount and length of outages too high	N=3	1%
Communities should cover costs	N=3	1%
Support upgrades	N=3	1%
Upgrades should not impact customers	N=3	1%
Support Electric vehicles	N=2	<1%
Removal of overhead wires	N=2	<1%
The projects should have been planned	N=1	<1%
We should not pay for new developments	N=1	<1%

Online Results by Question

Q1.Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account.		
	N	Percent
Yes	262	100.0

Q01B.What is the municipality associated with the Elexicon customer account?		
	N	Percent
Whitby	75	28.6
Ajax	61	23.3
Pickering	43	16.4
Belleville	19	7.3
Clarington (Bowmanville, Orono, Newcastle)	19	7.3
Gravenhurst	19	7.3
Port Hope	11	4.2
Brock (Beaverton, Cannington, Sunderland)	7	2.7
Port Perry	7	2.7
Uxbridge	1	.4
Total	262	100.0

Q02.To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer.		
	N	Percent
Residential	262	100.0

Q03.In your <household/business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?		
	N	Percent
I am primarily responsible for paying my household's electricity bill	233	88.9
I share the responsibility for paying my household's electricity bill	29	11.1
Total	262	100.0

Q1.When did you first become aware of the merger between Veridian Connections and Whitby Hydro Electric Corporation to form Elexicon?		
	N	Percent
More than a year ago	183	69.8
Less than a year ago	40	15.3
Was not aware until this survey	19	7.3
Not Sure	20	7.6
Total	262	100.0

Q2A.Overall, how satisfied are you with the services Elexicon provides you with?		
	N	Percent
Highly Satisfied	92	35.1
Somewhat Satisfied	90	34.4
Neither Satisfied nor Dissatisfied	45	17.2
Somewhat Dissatisfied	17	6.5
Highly Dissatisfied	10	3.8
Not Sure	8	3.1
Total	262	100.0

Q2B. In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?		
	N	Percent
No problems / satisfied	59	22.5
Unsure	55	21.0
Reliable / stable service	33	12.6
Poor service / interruptions in service	29	11.1
Hydro rates are high / expensive	23	8.8
No change	10	3.8
Old / outdated Infrastructure	7	2.7
Dislike time of use / need to simplify / change	6	2.3
No notice for planned outages	5	1.9
No experience / new customers / too soon to rate	5	1.9
Poor costumer service /long waits	5	1.9
Service has improved	5	1.9
Website problems / issues	4	1.5
Simplify billing / payment methods	3	1.1
Billing problems	3	1.1
Good customer service	3	1.1
The transition has been seamless	2	.8
Need alternative energy options	2	.8
Cannot compare due to the monopoly	1	.4
Lack of follow up	1	.4
Give rebates	1	.4
Total	262	100.0

Q3."The amount of my monthly electricity bill is a major expense item for my family and requires me to go without some other important priorities."			
		N	Percent
	Strongly Disagree	65	24.8
	Somewhat Disagree	52	19.8
	Neither Agree nor Disagree	71	27.1
	Somewhat Agree	54	20.6
	Strongly Agree	18	6.9
	Not Sure	2	.8
	Total	262	100.0

Q4."When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved."			
		N	Percent
	Strongly Agree	51	19.5
	Somewhat Agree	46	17.6
	Neither Agree nor Disagree	50	19.1
	Somewhat Disagree	24	9.2
	Strongly Disagree	9	3.4
	Not Applicable	82	31.3
	Total	262	100.0

Q5.If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?			
		N	Percent
	Very Likely	40	15.3
	Somewhat Likely	75	28.6
	Not Very Likely	49	18.7
	Not Likely at All	56	21.4
	Not Applicable	22	8.4
	Not Sure	20	7.6
	Total	262	100.0

Q6.How likely are you to become involved in self-generation of electricity at your place of residence over the next five years (for example, by installing solar panels)?			
		N	Valid Percent
	I am already involved in self generation	6	2.3
	Very Likely	22	8.4
	Somewhat Likely	46	17.6
	Not Very Likely	78	29.8
	Not Likely at All	67	25.6
	Not Applicable (e.g., housing situation does not permit)	27	10.3
	Not Sure	16	6.1
	Total	262	100.0

Q7. In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at…			
		N	Percent
	0	21	8.0
	1	37	14.1
	2	77	29.4
	3	33	12.6
	More than 3	64	24.4
	Not Sure	30	11.5
	Total	262	100.0

Q8.In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average?	N	Percent
Under 30 minutes	52	19.8
Under 1 hour	58	22.1
Between 1 and 2 hours	57	21.8
Longer than 2 hours	56	21.4
Not Sure	39	14.9
Total	262	100.0

Q9.Which of the following options best represents your overall satisfaction with service reliability over the last few years?	N	Percent
Very Satisfied	111	42.4
Somewhat Satisfied	88	33.6
Neither Satisfied nor Dissatisfied	24	9.2
Somewhat Dissatisfied	23	8.8
Very Dissatisfied	8	3.1
Not Sure	8	3.1
Total	262	100.0

Q10.When power outages do occur, which aspect of them has been most inconvenient for you?	N	Percent
How long the outages have lasted	114	43.5
How often the outages have occurred	52	19.8
Not Sure	42	16.0
Impact it has on my electronics / computers	19	7.3
None / no inconveniences	11	4.2
Getting information from Elexicon / contact with (duration, restoration, etc.)	8	3.1
Both how often & how long	8	3.1
Timing / when they occur	5	1.9
No heat / no cooling / appliances	3	1.1
Total	262	100.0

Q11.When there is a power outage, how do you interact with Elexicon Energy? Select all that apply.	N	Percent
I check the outage map online	98	37.4
I do not take any steps	79	30.2
I phone the outage number posted on the website	51	19.5
I check Twitter	16	6.1
Telephone call	7	2.7
No experience	4	1.5
I use both Twitter and Map	3	1.1
Radio	2	.8
Unsure	2	.8
Total	262	100.0

Q12.Please indicate your level of interest in the following potential service offering: When an outage occurs, are you interested in receiving notifications sent to your phone (via text and/or voice to landline) about its cause and anticipated restoration time?			
		N	Percent
	Yes	226	86.3
	No	27	10.3
	Not Sure	9	3.4
	Total	262	100.0

Q13.To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?			
		N	Percent
	Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases.	97	37.0
	Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the Long term	83	31.7
	Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term	32	12.2
	Not Sure	30	11.5
	Maintain reliability & do not raise prices	11	4.2
	Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially m	7	2.7
	Provide better service overall	2	.8
	Total	262	100.0

Q14 Which of the following options best describes your views on this trade-off?			
		N	Percent
	Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable	212	80.9
	Not Sure	25	9.5
	Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road	13	5.0
	Maintenance on a schedule & no rate increases	10	3.8
	Invest in better equipment	2	.8
	Total	262	100.0

Q15. Please select two potential objectives from the following list that you think Elexicon should focus its efforts on in addition to keeping the system safe and accommodating new growth in the coming years.

	Q15 FIRST CHOICE	N	Percent
	Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	74	28.2
	Preparing the grid for new types of uses, like electric vehicles and renewable generation	61	23.3
	Investing now in things that will help reduce rate increases after 2029	34	13.0
	Reducing the environmental impact of Elexicon's operations	31	11.8
	Helping customers manage their electricity use	25	9.5
	Minimizing the impact of power outages	18	6.9
	Improving power quality	13	5.0
	Addressing customer requests faster and more efficiently	6	2.3
	Total	262	100.0

	Q15 SECOND CHOICE	N	Percent
	Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	82	31.3
	Investing now in things that will help reduce rate increases after 2029	52	19.8
	Minimizing the impact of power outages	51	19.5
	Preparing the grid for new types of uses, like electric vehicles and renewable generation	30	11.5
	Helping customers manage their electricity use	25	9.5
	Reducing the environmental impact of Elexicon's operations	13	5.0
	Improving power quality	6	2.3
	Addressing customer requests faster and more efficiently	3	1.1
	Total	262	100.0

Q16. Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of its power grid. Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?

		N	Percent
	I am satisfied with the planned allocation based on what I know	130	49.6
	I would prefer to spend more on the technical upkeep of the power grid and less on the other two	48	18.3
	Not Sure	43	16.4
	I would prefer to spend more on reliability and less on the other two	22	8.4
	I would prefer to spend more on efficiency, health, and safety of operations and less on the other two	19	7.3
	Total	262	100.0

Q17. Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?

		N	Percent
	Highly Supportive	91	34.7
	Somewhat Supportive	102	38.9
	Neither Supportive nor Unsupportive	32	12.2
	Somewhat Unsupportive	15	5.7
	Highly Unsupportive	9	3.4
	Not Sure	13	5.0
	Total	262	100.0

Q18. To the best of your knowledge, does your place of residence / business currently receive power via a rear-lot line?

		N	Percent
	Yes	29	11.1
	No	192	73.3
	Not Sure	41	15.6
	Total	262	100.0

Q19. Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?	N	Percent
Maintain the status quo – keep all the lines overhead in the rear lots, replacing them as they fail.	45	17.2
Move lines underground and plan work according to worst performing areas.	57	21.8
Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere.	100	38.2
Not Sure	60	22.9
Total	262	100.0

Q20.To what degree do you consider the level of proposed investments in the Transformer Station appropriate?	N	Percent
Very Appropriate	72	27.5
Somewhat Appropriate	105	40.1
Not Very Appropriate	31	11.8
Not Sure / Cannot Rate	54	20.6
Total	262	100.0

Q21.Do you have any thoughts you'd like to share with respect to this project?	N	Percent
Unsure / none	184	70.2
Customers affected should pay	17	6.5
Developers should be covering a higher portion of the cost	15	5.7
Against the proposed project all together	9	3.4
If it is necessary / if needed / get it done	9	3.4
Better cost-efficient solutions are needed	9	3.4
Do not want to pay for other communities	5	1.9
Do not increase rates	3	1.1
Not enough information to make a decision	3	1.1
Safely and reliability	2	.8
More renewable energy sources such as solar or wind	2	.8
Too costly	2	.8
Make sure there is a backup plan	1	.4
Should focus on conservation	1	.4
Total	262	100.0

Q22.To what degree do you consider the level of proposed investments in the Operations Centre appropriate?	N	Percent
Very Appropriate	84	32.1
Somewhat Appropriate	96	36.6
Not Very Appropriate	29	11.1
Not Sure / Cannot Rate	53	20.2
Total	262	100.0

Q23.Do you have any thoughts you'd like to share with respect to this proposed project?	N	Percent
Unsure / none	207	79.0
Customers / communities affected should pay	11	4.2
It is a required investment / reasonable / needed	8	3.1
Refurbish an existing building	6	2.3
Should come from reserve funds not customers	4	1.5
Against project all together	4	1.5
Lack of information to make an informed decision	4	1.5
Build it smart / keep future growth in mind	3	1.1
Compare leasing versus new build	3	1.1
Customers should not have to pay	3	1.1
Lease / rent building	2	.8
Should have been done years ago	2	.8
Proposed budget seems too low	1	.4
Municipality should help finance	1	.4
Savings should be passed onto the customer	1	.4
Business / developers should pay	1	.4
Should be mortgage financed	1	.4
Total	262	100.0

Q24.To what degree do you consider the level of proposed investments in the Underground System Relocation appropriate?	Frequency	Percent
Very Appropriate	81	30.9
Somewhat Appropriate	80	30.5
Not Very Appropriate	51	19.5
Not Sure / Cannot Rate	50	19.1
Total	262	100.0

Q25.Do you have any thoughts you'd like to share with respect to this proposed project?	N	Percent
Unsure / none	194	74.0
Customers / residents / communities affected should pay	16	6.1
Should be a priority	9	3.4
Project should be covered by taxpayers	8	3.1
Project not a priority	7	2.7
Need more information / unclear	5	1.9
Costs should be covered by transit users	5	1.9
Municipality should pay	4	1.5
Should be paid for by investors	3	1.1
Will improve reliability	3	1.1
Poor planning	2	.8
Project should be completed as efficiently and quickly as possible	2	.8
Disagree with project	2	.8
Will raise rates	1	.4
Should be Elexicon's responsibility	1	.4
Total	262	100.0

Q26.What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting with the best interest of their customers in mind?	N	Percent
Why Elexicon could not build these projects without seeking rate increases	98	37.4
Not Sure	76	29.0
Why the chosen design and size are optimal	39	14.9
Why the projects cannot be built for less	30	11.5
Why the projects cannot be reasonably delayed	14	5.3
Why these projects could not be built in other areas	5	1.9
Total	262	100.0

Q27.We're almost done – we have only a few more questions to ask you. As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?	N	Percent
Completely Agree	69	26.3
Somewhat Agree	112	42.7
Neither Agree nor Disagree	50	19.1
Somewhat Disagree	11	4.2
Completely Disagree	7	2.7
Not Sure	13	5.0
Total	262	100.0

Q28. To help Elexicon improve on customer engagement in the future, please identify your preferred ways for being consulted in the future on similar topics.

MULTIPLES RESPONSES ACCEPTED	Responses		Percent of Cases
	N	Percent	
Online Surveys	244	74.8%	93.1%
Phone Surveys	8	2.5%	3.1%
In-Person Focus Groups	13	4.0%	5.0%
In-Person Townhall Meetings	20	6.1%	7.6%
Live Online Presentations and Q&A Sessions	35	10.7%	13.4%
Mail	2	0.6%	0.8%
Newspaper	1	0.3%	0.4%
Bill inserts	2	0.6%	0.8%
General email	1	0.3%	0.4%
Total	326	100.0%	124.4%

Q29.How often should Elexicon engage its customers on matters such as those captured in this survey?	N	Percent
Once a Year	126	48.1
Once Every 2-3 Years	86	32.8
More Than Once a Year	31	11.8
Once Every 5 Years	12	4.6
Not Sure	7	2.7
Total	262	100.0

Q30.Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?	N	Percent
Unsure / none	218	83.2
Lower rates	12	4.6
Promote Green Energy	5	1.9
Limit increases to most needed projects	2	.8
Removal of overhead wires	2	.8
Invest in an outage communication system	2	.8
App to monitor usage	2	.8
More tools to help manage my electricity use	2	.8
Keep the utilities public / local	2	.8
Amount and length of outages too high	1	.4
Support Electric vehicles	1	.4
Stop all investment in Green Energy	1	.4
Communities should cover costs	1	.4
Support upgrades	1	.4
Create jobs	1	.4
Move to online payments only	1	.4
Improve customer service	1	.4
Would like to obtain data from Smart Meter	1	.4
Capital costs should have been pre-planned	1	.4
Upgrades should not impact customers	1	.4
Upgrades too costly	1	.4
The entire ratepayer base should not pay for expansion to new subdivisions.	1	.4
Trees are being trimmed down / cut down unnecessarily	1	.4
More outreach needed	1	.4
Total	262	100.0

Telephone Results by Question

Q1.Firstly, please confirm that you reside in a household or work in an organization associated with an Elexicon customer account.		
	Frequency	Percent
Yes	600	100.0

Q01B.What is the municipality associated with the Elexicon customer account?		
	N	Percent
Whitby	173	28.8
Ajax	107	17.8
Pickering	103	17.2
Belleville	60	10.0
Clarington (Bowmanville, Orono, Newcastle)	45	7.5
Gravenhurst	44	7.3
Port Hope	27	4.5
Brock (Beaverton, Cannington, Sunderland)	17	2.8
Scugog	14	2.3
Uxbridge	10	1.7
Total	600	100.0

Q02.To provide better context for your responses, please confirm whether you are completing this survey as a Residential Customer or a Business Customer.		
	N	Percent
Residential	524	87.3
Small Business (monthly electricity bill below $2,500)	70	11.7
Large Business (monthly electricity bill above $2,500)	6	1.0
Total	600	100.0

Q03.In your <household/business> what is your role with respect to paying for the cost of electricity? Are you primarily responsible, partially responsible, or not responsible for paying the electricity bill?		
	N	Percent
I am primarily responsible for paying my household's electricity bill	466	77.7
I share the responsibility for paying my household's electricity bill	58	9.7
I am the person responsible for managing my organization's electricity bill	42	7.0
I am the person overseeing the management of my organization's electricity bill	34	5.7
Total	600	100.0

Q1.When did you first become aware of the merger between Veridian Connections and Whitby Hydro Electric Corporation to form Elexicon?		
	N	Percent
More than a year ago	426	71.0
Less than a year ago	93	15.5
Was not aware until this survey	36	6.0
Not Sure	45	7.5
Total	600	100.0

Q2A.Overall, how satisfied are you with the services Elexicon provides you with?		
	N	Percent
Highly Satisfied	217	36.2
Somewhat Satisfied	213	35.5
Neither Satisfied nor Dissatisfied	91	15.2
Somewhat Dissatisfied	39	6.5
Highly Dissatisfied	22	3.7
Not Sure	18	3.0
Total	600	100.0

Q2B. In your own words, what are the reasons for your current level of satisfaction or dissatisfaction with Elexicon as expressed in your last response?	N	Percent
Unsure / none	178	29.7
No problems / satisfied	146	24.3
Reliable / stable service	82	13.7
Hydro rates are high / expensive	75	12.5
Poor service / interruptions / outages	61	10.2
No experience / new customers / too soon to rate	12	2.0
Old / outdated Infrastructure	11	1.8
Good customer service	7	1.2
Poor customer service /long wait times	7	1.2
No notice for planned outages	6	1.0
Simplify billing / payment methods	5	.8
Dislike time of use / need to simplify / change	5	.8
Lack of follow up	3	.5
Billing problems	2	.3
Total	600	100.0

Q3.“The amount of my monthly electricity bill is a major expense item for my family and requires me to go without some other important priorities.”	N	Percent
Strongly Disagree	119	19.8
Somewhat Disagree	146	24.3
Neither Agree nor Disagree	135	22.5
Somewhat Agree	143	23.8
Strongly Agree	53	8.8
Not Sure	4	.7
Total	600	100.0

Q4.“When I had specific questions or requests for Elexicon or its predecessors, I was satisfied with how they were resolved.”	N	Percent
Strongly Agree	117	19.5
Somewhat Agree	127	21.2
Neither Agree nor Disagree	112	18.7
Somewhat Disagree	49	8.2
Strongly Disagree	26	4.3
Not Applicable	163	27.2
Unsure	6	1.0
Total	600	100.0

Q5. If you plan to purchase a vehicle in the next five years, how likely are you to consider purchasing an electric vehicle?	N	Percent
Very Likely	94	15.7
Somewhat Likely	189	31.5
Not Very Likely	107	17.8
Not Likely at All	124	20.7
Not Applicable	41	6.8
Not Sure	45	7.5
Total	600	100.0

Q6. How likely are you to become involved in self-generation of electricity at your place of residence over the next five years (for example, by installing solar panels)?	N	Percent
I am already involved in self generation	15	2.5
Very Likely	56	9.3
Somewhat Likely	100	16.7
Not Very Likely	164	27.3
Not Likely at All	171	28.5
Not Applicable (e.g., housing situation does not permit)	47	7.8
Not Sure	47	7.8
Total	600	100.0

Q7. In 2019, an average Elexicon customer experienced 1.28 outages. Thinking back to your experience over the past year, how many times has the power been out at your home to the best of your recollection?	N	Percent
0	42	7.0
1	87	14.5
2	184	30.7
3	83	13.8
More than 3	154	25.7
Not Sure	50	8.3
Total	600	100.0

Q8. In 2019, Elexicon customers experienced power outages lasting an average of 1.63 hours. Thinking back to your experience, please estimate how long your power outages lasted on average?	N	Percent
Under 30 minutes	137	22.8
Under 1 hour	128	21.3
Between 1 and 2 hours	123	20.5
Longer than 2 hours	150	25.0
Not Sure	62	10.3
Total	600	100.0

Q9.Which of the following options best represents your overall satisfaction with service reliability over the last few years?	N	Percent
Very Satisfied	245	40.8
Somewhat Satisfied	188	31.3
Neither Satisfied nor Dissatisfied	61	10.2
Somewhat Dissatisfied	70	11.7
Very Dissatisfied	22	3.7
Not Sure	14	2.3
Total	600	100.0

Q10.When power outages do occur, which aspect of them has been most inconvenient for you?	N	Percent
How long the outages have lasted	289	48.2
How often the outages have occurred	114	19.0
Not Sure	91	15.2
Impact it has on my electronics / computers	46	7.7
None / no inconveniences	24	4.0
Both how often & how long	17	2.8
Getting information from Elexicon / contact with (duration, restoration, etc.)	12	2.0
Timing / when they occur	7	1.2
Total	600	100.0

Q11.When there is a power outage, how do you interact with Elexicon Energy?		
	N	Percent
I check the outage map online	229	38.2
I do not take any steps	171	28.5
I phone the outage number posted on the website	126	21.0
I check Twitter	36	6.0
Telephone call	22	3.7
Unsure	9	1.5
No experience	5	.8
Radio	2	.3
Total	600	100.0

Q12.Please indicate your level of interest in the following potential service offering: When an outage occurs, are you interested in receiving notifications sent to your phone (via text and/or voice to landline) about its cause and anticipated restoration time?		
	N	Percent
Yes	524	87.3
No	58	9.7
Not Sure	18	3.0
Total	600	100.0

Q13.To manage the impact of power outages, Elexicon replaces aging infrastructure, trims trees near powerlines, and invests in equipment that helps restore service faster. Which of the following statements best represents your views on what level of reliability Elexicon should target?		
	N	Percent
Elexicon should spend more on reliability, but less in other areas that also affect customers, if this can help avoid some bill increases	226	37.7
Elexicon should maintain current reliability levels, even if it gradually increases my monthly electricity bill in the long term	219	36.5
Elexicon should invest more to improve reliability, and I would accept a larger increase to my monthly bill in the long term	72	12.0
Not Sure	60	10.0
Maintain reliability & do not raise prices	15	2.5
Elexicon should invest less in outage prevention to reduce the impact of future bill increases, even if it potentially means more and longer outages for myself and others	8	1.3
Total	600	100.0

Q14 Which of the following options best describes your views on this trade-off?		
	N	Percent
Elexicon should replace more equipment before it fails, spending more today to prevent future outages and keep bill increases predictable	507	84.5
Not Sure	41	6.8
Elexicon should wait until more equipment fails, reducing its spending today, even if this causes more future outages and unpredictable bill increases down the road	30	5.0
Maintenance on a schedule & no rate increases	22	3.7
Total	600	100.0

Q15. Please select two potential objectives from the following list that you think Elexicon should focus its efforts on in addition to keeping the system safe and accommodating new growth in the coming years.

Q15. FIRST CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	192	32.0
Preparing the grid for new types of uses, like electric vehicles and renewable generation	133	22.2
Investing now in things that will help reduce rate increases after 2029	73	12.2
Helping customers manage their electricity use	65	10.8
Reducing the environmental impact of Elexicon's operations	63	10.5
Minimizing the impact of power outages	37	6.2
Improving power quality	24	4.0
Addressing customer requests faster and more efficiently	13	2.2
Total	600	100.0

Q15. SECOND CHOICE	N	Percent
Improving the grid's resilience to major weather events, like storms, floods, or freezing rain	182	30.3
Minimizing the impact of power outages	121	20.2
Investing now in things that will help reduce rate increases after 2029	120	20.0
Preparing the grid for new types of uses, like electric vehicles and renewable generation	69	11.5
Helping customers manage their electricity use	51	8.5
Reducing the environmental impact of Elexicon's operations	30	5.0
Improving power quality	20	3.3
Addressing customer requests faster and more efficiently	7	1.2
Total	600	100.0

Q16.Aside from investments to support customer growth, Elexicon currently plans to spend about 73% of its remaining five-year budget on managing reliability, 22% on efficiency, health, and safety of its own operations, and 5% on the technical upkeep of Its power grid. Do you consider this plan satisfactory, or would you prefer to allocate more budget towards one of those three categories above the others?

	N	Percent
I am satisfied with the planned allocation based on what I know	319	53.2
I would prefer to spend more on the technical upkeep of the power grid and less on the other two	95	15.8
Not Sure	84	14.0
I would prefer to spend more on reliability and less on the other two	65	10.8
I would prefer to spend more on efficiency, health, and safety of operations and less on the other two	37	6.2
Total	600	100.0

Q17.Part of Elexicon's future planning involves investing in grid management technologies that will help it manage the impact of more Electric Vehicles, Renewable Generation, and Energy Storage. Like with all budgeting decisions, investing in new technology today requires making trade-offs. How supportive are you of Elexicon's intent to invest in future technologies at this time?

	N	Percent
Highly Supportive	243	40.5
Somewhat Supportive	215	35.8
Neither Supportive nor Unsupportive	66	11.0
Somewhat Unsupportive	25	4.2
Highly Unsupportive	26	4.3
Not Sure	25	4.2
Total	600	100.0

Q18. To the best of your knowledge, does your place of residence / business currently receive power via a rear-lot line?	N	Percent
Yes	79	13.2
No	505	84.2
Not Sure	16	2.7
Total	600	100.0

Q19. Elexicon has several options to consider for how it schedules the rear-lot conversion work. Which of the following options do you see as most preferred?	N	Percent
Maintain the status quo – keep all the lines overhead in the rear lots, replacing them as they fail.	131	21.8
Move lines underground and plan work according to worst performing areas.	144	24.0
Move lines underground and plan work geographically, finishing all work in one area before moving elsewhere.	234	39.0
Not Sure	91	15.2
Total	600	100.0

Q20.To what degree do you consider the level of proposed investments in the Transformer Station appropriate?	N	Percent
Very Appropriate	189	31.5
Somewhat Appropriate	247	41.2
Not Very Appropriate	62	10.3
Not Sure / Cannot Rate	102	17.0
Total	600	100.0

Q21.Do you have any thoughts you'd like to share with respect to this project?	N	Percent
Unsure / none	484	80.7
If it is necessary / if needed / get it done	50	8.3
Developers should be covering a higher portion of the cost	18	3.0
Customers affected should pay	16	2.7
Against the proposed project all together	6	1.0
Do not increase rates	6	1.0
Better cost-efficient solutions are needed	6	1.0
Do not want to pay for other communities	4	.7
More renewable energy sources such as solar or wind	3	.5
Should focus on conservation	3	.5
Apply new rates for new customers	2	.3
Too costly	2	.3
Total	600	100.0

Q22.To what degree do you consider the level of proposed investments in the Operations Centre appropriate?	N	Percent
Somewhat Appropriate	228	38.0
Very Appropriate	215	35.8
Not Very Appropriate	59	9.8
Not Sure / Cannot Rate	98	16.3
Total	600	100.0

Q23.Do you have any thoughts you'd like to share with respect to this proposed project?		
	N	Percent
Unsure / none	525	87.5
It is a required investment / reasonable / needed	21	3.5
Customers / communities affected should pay	17	2.8
Lack of information to make an informed decision	9	1.5
Refurbish an existing building	9	1.5
Customers should not have to pay	6	1.0
Against project all together	4	.7
Lease / rent building	4	.7
Build it smart / keep future growth in mind	3	.5
Business / developers should pay	2	.3
Total	600	100.0

Q24.To what degree do you consider the level of proposed investments in the Underground System Relocation appropriate?		
	N	Percent
Very Appropriate	206	34.3
Somewhat Appropriate	177	29.5
Not Very Appropriate	113	18.8
Not Sure / Cannot Rate	104	17.3
Total	600	100.0

Q25.Do you have any thoughts you'd like to share with respect to this proposed project?		
	N	Percent
Unsure / none	456	76.0
Customers / residents / communities affected should pay	30	5.0
Should be a priority	22	3.7
Project should be covered by taxpayers	15	2.5
Costs should be covered by transit users	14	2.3
Need more information / unclear	10	1.7
Project should be completed as efficiently and quickly as possible	9	1.5
Will improve reliability	8	1.3
Project not a priority	8	1.3
Municipality should pay	7	1.2
Transit is important / needed for growth	6	1.0
Should be paid for by investors	5	.8
Poor planning	4	.7
Will raise rates	3	.5
Disagree with project	3	.5
Total	600	100.0

Q26.What type of information about the three proposed ICM projects would give you the most confidence that Elexicon is acting with the best interest of their customers in mind?		
	N	Percent
Why Elexicon could not build these projects without seeking rate increases	234	39.0
Not Sure	137	22.8
Why the chosen design and size are optimal	94	15.7
Why the projects cannot be built for less	86	14.3
Why the projects cannot be reasonably delayed	36	6.0
Why these projects could not be built in other areas	13	2.2
Total	600	100.0

Q27.We're almost done – we have only a few more questions to ask you. As a result of taking this survey, would you agree that you have a better appreciation of the planning trade-offs that Elexicon must consider when making investment plans?		
	N	Percent
Completely Agree	151	25.2
Somewhat Agree	227	37.8
Neither Agree nor Disagree	129	21.5
Somewhat Disagree	34	5.7
Completely Disagree	28	4.7
Not Sure	31	5.2
Total	600	100.0

Q28. To help Elexicon improve on customer engagement in the future, please identify your preferred ways for being consulted in the future on similar topics.

MULTIPLES RESPONSES ACCEPTED	**Responses**		**Percent of Cases**
	N	Percent	
Online Surveys	121	17.6%	20.2%
Phone Surveys	9	1.3%	1.5%
In-Person Focus Groups	10	1.5%	1.7%
In-Person Townhall Meetings	40	5.8%	6.7%
Live Online Presentations and Q&A Sessions	195	28.3%	32.5%
Mail	7	1.0%	1.2%
Newspaper	5	0.7%	0.8%
Bill inserts	82	11.9%	13.7%
Email	132	19.2%	22.0%
Unsure	87	12.6%	14.5%
Total	688	100.0%	114.7%

Q29.How often should Elexicon engage its customers on matters such as those captured in this survey?		
	N	Percent
Once Every 5 Years	24	4.0
Once Every 2-3 Years	184	30.7
Once a Year	304	50.7
More Than Once a Year	55	9.2
Not Sure	33	5.5
Total	600	100.0

Q30.Do you have any other comments, questions, or suggestions that you would like Elexicon to consider as it develops its capital plans for the coming years?			
		N	Percent
	Unsure / none	467	77.8
	Lower rates	51	8.5
	Limit increases to most needed projects	18	3.0
	Promote Green Energy	12	2.0
	Do most needed first	10	1.7
	Upgrades too costly	8	1.3
	Improve customer service	6	1.0
	Energy savings advice	5	.8
	More outreach needed	5	.8
	Amount and length of outages too high	3	.5
	Communities should cover costs	3	.5
	Support upgrades	3	.5
	Upgrades should not impact customers	3	.5
	Support Electric vehicles	2	.3
	Removal of overhead wires	2	.3
	The projects should have been planned	1	.2
	We should not pay for new developments	1	.2
	Total	600	100.0

APPENDIX C-1:
VERIDIAN RATE ZONE
CURRENT TARIFF SHEET
2022

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

RESIDENTIAL SERVICE CLASSIFICATION

All residential customers with kilowatt-hour meters shall be deemed to have a demand of 50kW or less. This customer classification included single family homes, street townhouses, multiplexes, and block townhouses. This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as Residential, the customer must represent and warrant that the premise is designated as his/her principal residence or, in the case of a rented premise, that the premise is the principal residence of the rental occupant.
A principal residence is defined as meeting the following criteria:
a. The occupant must live in this residence for at least 8 months of the year.
b. The address of this residence must appear on the occupant's electric bill, driver's license, credit card invoice, property tax bill, etc.
c. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.
Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.41
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.76
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0001
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kWh	0.0031
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0083
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

SEASONAL RESIDENTIAL SERVICE CLASSIFICATION

This classification is defined as any residential service not meeting the Residential Service Classification criteria. It includes such dwellings as cottages, chalets, and camps. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	51.90
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	3.22
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kWh	0.0030
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0085
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than 50kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	18.41
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.14
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0185
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0005
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kWh	0.0032
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Retail Transmission Rate - Network Service Rate	$/kWh	0.0074
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50kW but less than 3,000 kW.
Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	117.69
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	7.30
Distribution Volumetric Rate	$/kW	3.6310
Low Voltage Service Rate	$/kW	0.3858
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.1489
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 Applicable only for Non-Wholesale Market Participants - Approved on an Interim Basis	$/kW	(0.3356)
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kW	1.7051

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

		EB-2021-0015
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0817)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2251
Retail Transmission Rate - Network Service Rate	$/kW	3.6527
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4132

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average peak demand used for billing purposes over the past twelve months is equal to or greater than, or forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6,184.42
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	383.39
Distribution Volumetric Rate	$/kW	2.3004
Low Voltage Service Rate	$/kW	0.4346
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.0789
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kW	1.4841
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.1118)

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.1426
Retail Transmission Rate - Network Service Rate	$/kW	4.0244
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6503

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	9,290.25
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	575.93
Distribution Volumetric Rate	$/kW	3.2398
Low Voltage Service Rate	$/kW	0.4157
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.2164
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kW	1.9251
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2008
Retail Transmission Rate - Network Service Rate	$/kW	4.0244
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6503

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

In general, all services will be metered. However, certain types of electrical loads are not practical to meter, or the cost of metering represents an inordinate expense to both the Customer and Elexicon Energy. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. These situations can be managed through a controlled connection and a pre-defined basis for estimating consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.51
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.47
Distribution Volumetric Rate	$/kWh	0.0184
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kWh	0.0033
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kWh	(0.0002)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Retail Transmission Rate - Network Service Rate	$/kWh	0.0074
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

SENTINEL LIGHTING SERVICE CLASSIFICATION

Sentinel lights (dusk-to-dawn) connected to unmetered wires will have a flat rate monthly energy charge added to the regular customer bill. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.94
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.31
Distribution Volumetric Rate	$/kW	14.9572
Low Voltage Service Rate	$/kW	0.2505
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kW	1.1619
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0748)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.9272
Retail Transmission Rate - Network Service Rate	$/kW	2.2784
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5172

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street or roadway lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	0.76
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.05
Distribution Volumetric Rate	$/kW	4.0898
Low Voltage Service Rate	$/kW	0.2618
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until December 31, 2022 Applicable only for Non-RPP Class B Customers - Approved on an Interim Basis	$/kWh	0.0012
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	2.0073
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until December 31, 2022 - Approved on an Interim Basis	$/kW	1.1653
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until December 31, 2022 Applicable only for Class B Customers - Approved on an Interim Basis	$/kW	(0.0753)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2535
Retail Transmission Rate - Network Service Rate	$/kW	2.3989
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5854

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	34.76
Customer substation isolation - after hours	$	905.00

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	107.68
Monthly fixed charge, per retailer	$	43.08
Monthly variable charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.31
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0482
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0146
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0344
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

APPENDIX C-2:

WHITBY RATE ZONE

CURRENT TARIFF SHEET

2022

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to detached, semi-detached or freehold townhouse dwelling units. Energy is supplied to residential customers as single phase, three wire, 60 Hertz, having a normal voltage of 120/240 Volts up to a maximum of 200 Amps per dwelling unit. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.41
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$	(0.06)
Low Voltage Service Rate	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0096
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, shall include small apartment buildings and smaller commercial, industrial, and institutional developments. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.   In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.08
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0208
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kWh	0.0006
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0087
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0068

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW and includes apartment buildings, and commercial, industrial, and institutional developments. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	213.88
Distribution Volumetric Rate	$/kW	4.2717
Low Voltage Service Rate	$/kW	0.3181
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	0.2003
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kW	(0.0131)
Retail Transmission Rate - Network Service Rate	$/kW	3.4495
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5728

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative lighting, bill boards, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	10.40
Distribution Volumetric Rate	$/kWh	0.0332
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0087
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0068

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	6.11
Distribution Volumetric Rate	$/kW	16.4458
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kW	(0.5664)
Retail Transmission Rate - Network Service Rate	$/kW	2.6144
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.0307

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

STREET LIGHTING SERVICE CLASSIFICATION

This classification relates to the supply of power for street lighting installations. Street lighting design and installations shall be in accordance with the requirements of Elexicon Hydro Inc., Town of Whitby specifications and ESA. The Town of Whitby retains ownership of the street lighting system on municipal roadways. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	1.88
Distribution Volumetric Rate	$/kW	7.1956
Low Voltage Service Rate	$/kW	0.2459
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2022) - effective until December 31, 2022	$/kW	8.4586
Rate Rider for Application of Tax Change (2022) - effective until December 31, 2022	$/kW	(0.0869)
Retail Transmission Rate - Network Service Rate	$/kW	2.6016
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9890

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor’s distribution system. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Legal letter charge	$	15.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after regular hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after regular hours	$	415.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	34.76

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0015

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	107.68
Monthly fixed charge, per retailer	$	43.08
Monthly variable charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.31
Notice of switch letter charge, per letter (unless the distributor has opted out of applying for the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0349

APPENDIX D-1:

VERIDIAN RATE ZONE

PROPOSED TARIFF SHEET

2023

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

All residential customers with kilowatt-hour meters shall be deemed to have a demand of 50kW or less. This customer classification included single family homes, street townhouses, multiplexes, and block townhouses. This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as Residential, the customer must represent and warrant that the premise is designated as his/her principal residence or, in the case of a rented premise, that the premise is the principal residence of the rental occupant.
A principal residence is defined as meeting the following criteria:
a. The occupant must live in this residence for at least 8 months of the year.
b. The address of this residence must appear on the occupant's electric bill, driver's license, credit card invoice, property tax bill, etc.
c. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.
Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.26
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.76
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0031
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0095
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0059

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SEASONAL RESIDENTIAL SERVICE CLASSIFICATION

This classification is defined as any residential service not meeting the Residential Service Classification criteria. It includes such dwellings as cottages, chalets, and camps. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	53.46
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	3.22
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0030
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0098
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0075

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than 50kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	18.96
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.14
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0191
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2023	$/kWh	0.0021
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0031
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Retail Transmission Rate - Network Service Rate	$/kWh	0.0085
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50kW but less than 3,000 kW.
Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	121.22
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	7.30
Distribution Volumetric Rate	$/kW	3.7399
Low Voltage Service Rate	$/kW	0.3858
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2023	$/kW	0.5814
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023 Applicable only for Non-Wholesale Market Participants	$/kW	0.2237
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.0411
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0521)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2251
Retail Transmission Rate - Network Service Rate	$/kW	4.1910
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5211

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average peak demand used for billing purposes over the past twelve months is equal to or greater than, or forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6,369.95
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	383.39
Distribution Volumetric Rate	$/kW	2.3694
Low Voltage Service Rate	$/kW	0.4346
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2023	$/kW	0.2454
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.4623
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0729)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.1426
Retail Transmission Rate - Network Service Rate	$/kW	4.6175
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.7688

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW. Class A and Class B customers are defined in accordance with O.Reg.429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	9,568.96
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	575.93
Distribution Volumetric Rate	$/kW	3.3370
Low Voltage Service Rate	$/kW	0.4157
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2023	$/kW	0.8717
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.7666
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2008
Retail Transmission Rate - Network Service Rate	$/kW	4.6175
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.7688

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

In general, all services will be metered. However, certain types of electrical loads are not practical to meter, or the cost of metering represents an inordinate expense to both the Customer and Elexicon Energy. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. These situations can be managed through a controlled connection and a pre-defined basis for estimating consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.74
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.47
Distribution Volumetric Rate	$/kWh	0.0190
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0032
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Retail Transmission Rate - Network Service Rate	$/kWh	0.0085
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

Sentinel lights (dusk-to-dawn) connected to unmetered wires will have a flat rate monthly energy charge added to the regular customer bill. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.09
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.31
Distribution Volumetric Rate	$/kW	15.4059
Low Voltage Service Rate	$/kW	0.2505
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.0972
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0506)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.9272
Retail Transmission Rate - Network Service Rate	$/kW	2.6142
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5850

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street or roadway lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	0.78
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.05
Distribution Volumetric Rate	$/kW	4.2125
Low Voltage Service Rate	$/kW	0.2618
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0020)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2023	$/kW	8.4098
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.0925
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0498)
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.2535
Retail Transmission Rate - Network Service Rate	$/kW	2.7524
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6563

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Veridian Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	34.76
Customer substation isolation - after hours	$	905.00

Elexicon Energy Inc.
Veridian Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	110.05
Monthly fixed charge, per retailer	$	44.03
Monthly variable charge, per customer, per retailer	$/cust.	1.09
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.65
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.65)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.55
Processing fee, per request, applied to the requesting party	$	1.09
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.40
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.20

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0482
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0146
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0344
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

APPENDIX D-2:

WHITBY RATE ZONE

PROPOSED TARIFF SHEET

2023

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to detached, semi-detached or freehold townhouse dwelling units. Energy is supplied to residential customers as single phase, three wire, 60 Hertz, having a normal voltage of 120/240 Volts up to a maximum of 200 Amps per dwelling unit. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	34.41
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$	2.85
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Application of Tax Change (2023) - effective until December 31, 2023	$	(0.06)
Low Voltage Service Rate	$/kWh	0.0010
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0024)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0028
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0110
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0077

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW, shall include small apartment buildings and smaller commercial, industrial, and institutional developments. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.92
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$	2.39
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0214
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0024)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2025	$/kWh	0.0007
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0029
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0002)
Rate Rider for Application of Tax Change (2023) - effective until December 31, 2023	$/kWh	(0.0001)
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$/kWh	0.0018
Retail Transmission Rate - Network Service Rate	$/kWh	0.0100
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW and includes apartment buildings, and commercial, industrial, and institutional developments. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	220.30
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$	18.23
Distribution Volumetric Rate	$/kW	4.3999
Low Voltage Service Rate	$/kW	0.3181
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0024)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2025	$/kW	0.2690
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023 Applicable only for Non-Wholesale Market Participants	$/kW	(0.0280)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.3001
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0596)
Rate Rider for Application of Tax Change (2023) - effective until December 31, 2023	$/kW	(0.0133)
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$/kW	0.3640
Retail Transmission Rate - Network Service Rate	$/kW	3.9659
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.7349

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, decorative lighting, bill boards, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	10.71
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$	0.89
Distribution Volumetric Rate	$/kWh	0.0342
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kWh	(0.0002)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.0030
Rate Rider for Application of Tax Change (2023) - effective until December 31, 2023	$/kWh	(0.0002)
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$/kWh	0.0028
Retail Transmission Rate - Network Service Rate	$/kWh	0.0100
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0072

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	6.29
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$	0.52
Distribution Volumetric Rate	$/kW	16.9392
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0563)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	1.1921
Rate Rider for Application of Tax Change (2023) - effective until December 31, 2023	$/kW	(0.1117)
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$/kW	1.4014
Retail Transmission Rate - Network Service Rate	$/kW	3.0057
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1586

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

This classification relates to the supply of power for street lighting installations. Street lighting design and installations shall be in accordance with the requirements of Whitby Hydro, Town of Whitby specifications and ESA. The Town of Whitby retains ownership of the street lighting system on municipal roadways. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per light)	$	1.94
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$	0.16
Distribution Volumetric Rate	$/kW	7.4115
Low Voltage Service Rate	$/kW	0.2459
Rate Rider for Disposition of Global Adjustment Account (2023) - effective until December 31, 2023 Applicable only for Non-RPP Customers	$/kWh	(0.0024)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2023) - effective until December 31, 2025	$/kW	8.8138
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kW	(0.0286)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - effective until December 31, 2023 Applicable only for Class B Customers	$/kW	(0.0521)
Rate Rider for Application of Tax Change (2023) - effective until December 31, 2023	$/kW	(0.0867)
Rate Rider for Recovery of Incremental Capital - effective until effective date of next cost of service based rate order	$/kW	0.6132
Retail Transmission Rate - Network Service Rate	$/kW	2.9911
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.1143

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Elexicon Energy Inc.
Whitby Rate Zone
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2023
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Legal letter charge	$	15.00

Non-Payment of Account

Late payment - per month		
(effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after regular hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after regular hours	$	415.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Temporary service - install & remove - overhead - with transformer	$	1,000.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Specific charge for access to the power poles - $/pole/year		
(with the exception of wireless attachments)	$	34.76

Elexicon Energy Inc.

Whitby Rate Zone

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	110.05
Monthly fixed charge, per retailer	$	44.03
Monthly variable charge, per customer, per retailer	$/cust.	1.09
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.65
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.65)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.55
Processing fee, per request, applied to the requesting party	$	1.09
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.40
Notice of switch letter charge, per letter (unless the distributor has opted out of applying for the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0349

APPENDIX E-1:
VERIDIAN RATE ZONE
BILL IMPACTS

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2023 Filers

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of June 2022 of $0.0967/kWh (IESO's Monthly Market Report for April 2022) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor (eg: 1.0351)**	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0482	1.0482	750			
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0482	1.0482	645			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0482	1.0482	2,000			
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0482	1.0482	432,160	1,480		
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0482	1.0482	1,752,000	4,000		
LARGE USE SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0482	1.0482	4,219,400	6,800		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0482	1.0482	500			1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0482	1.0482	180	1		1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0482	1.0482	424,881	988		10,652
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				
Add additional scenarios if required			1.0482	1.0482				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 0.78	2.6%	$ 0.85	2.3%	$ 2.03	4.2%	$ 1.95	1.6%
SEASONAL RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 1.56	2.8%	$ 1.62	2.6%	$ 2.71	3.8%	$ 2.60	1.9%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 4.95	8.3%	$ 4.95	6.4%	$ 7.68	7.4%	$ 7.37	2.4%
GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 804.80	13.3%	$ (689.26)	-7.6%	$ 267.12	1.5%	$ 301.84	0.4%
GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 1,127.53	6.8%	$ (4,410.47)	-17.0%	$ (1,564.07)	-3.0%	$ (1,767.40)	-0.7%
LARGE USE SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 5,395.71	15.5%	$ 4,317.91	8.5%	$ 9,156.79	9.5%	$ 10,347.17	1.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 0.53	3.0%	$ 0.53	2.4%	$ 1.21	4.2%	$ 1.16	1.5%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 0.60	2.8%	$ 0.56	2.4%	$ 0.96	3.5%	$ 0.92	2.1%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 6,660.59	44.7%	$ 5,254.23	31.4%	$ 5,673.58	27.4%	$ 6,411.15	8.3%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ **28.41**	1	$ 28.41	$ **29.26**	**1**	$ **29.26**	$ 0.85	2.99%	
Distribution Volumetric Rate	$ **-**	750	$ -	$ **-**	**750**	$ **-**	$ -		
Fixed Rate Riders	$ **1.76**	1	$ 1.76	$ **1.76**	**1**	$ **1.76**	$ -	0.00%	
Volumetric Rate Riders	$ **0.0001**	750	$ 0.08	$ **-**	**750**	$ **-**	$ (0.08)	-100.00%	
Sub-Total A (excluding pass through)			**$ 30.25**			**$ 31.02**	**$ 0.78**	**2.56%**	
Line Losses on Cost of Power	$ **0.1034**	36	$ 3.74	$ **0.1034**	**36**	$ **3.74**	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ **0.0031**	750	$ 2.33	$ **0.0031**	**750**	$ **2.33**	$ -	0.00%	
CBR Class B Rate Riders	-$ **0.0002**	750	$ (0.15)	-$ **0.0001**	**750**	$ **(0.08)**	$ 0.08	-50.00%	
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	$ **0.43**	**1**	$ **0.43**	$ -	0.00%	
Additional Fixed Rate Riders	$ **-**	1	$ -	$ **-**	**1**	$ **-**	$ -		
Additional Volumetric Rate Riders	$ **-**	750	$ -	$ **-**	**750**	$ **-**	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 37.34**			**$ 38.19**	**$ 0.85**	**2.28%**	
RTSR - Network	$ **0.0083**	786	$ 6.53	$ **0.0095**	**786**	$ **7.47**	$ 0.94	14.46%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ **0.0056**	786	$ 4.40	$ **0.0059**	**786**	$ **4.64**	$ 0.24	5.36%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 48.27**			**$ 50.30**	**$ 2.03**	**4.20%**	
Wholesale Market Service Charge (WMSC)	$ **0.0034**	786	$ 2.67	$ **0.0034**	**786**	$ **2.67**	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ **0.0005**	786	$ 0.39	$ **0.0005**	**786**	$ **0.39**	$ -	0.00%	
Standard Supply Service Charge	$ **0.25**	1	$ 0.25	$ **0.25**	**1**	$ **0.25**	$ -	0.00%	
TOU - Off Peak	$ **0.0820**	480	$ 39.36	$ **0.0820**	**480**	$ **39.36**	$ -	0.00%	
TOU - Mid Peak	$ **0.1130**	135	$ 15.26	$ **0.1130**	**135**	$ **15.26**	$ -	0.00%	
TOU - On Peak	$ **0.1700**	135	$ 22.95	$ **0.1700**	**135**	$ **22.95**	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 129.15**			**$ 131.18**	**$ 2.03**	**1.57%**	
HST	13%		$ 16.79	13%		$ 17.05	$ 0.26	1.57%	
Ontario Electricity Rebate	17.0%		$ (21.96)	17.0%		$ (22.30)	$ (0.34)		
Total Bill on TOU			**$ 123.98**			**$ 125.93**	**$ 1.95**	**1.57%**	

Customer Class:	SEASONAL RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	645 kWh
Demand	- kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 51.90	1	$ 51.90	$ 53.46	1	$ 53.46	$ 1.56	3.01%
Distribution Volumetric Rate	$ -	645	$ -	$ -	645	$ -	$ -	
Fixed Rate Riders	$ 3.22	1	$ 3.22	$ 3.22	1	$ 3.22	$ -	0.00%
Volumetric Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Sub-Total A (excluding pass through)			**$ 55.12**			**$ 56.68**	**$ 1.56**	**2.83%**
Line Losses on Cost of Power	$ 0.1034	31	$ 3.22	$ 0.1034	31	$ 3.22	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ 0.0030	645	$ 1.94	$ 0.0030	645	$ 1.94	$ -	0.00%
CBR Class B Rate Riders	-$ 0.0002	645	$ (0.13)	-$ 0.0001	645	$ (0.06)	$ 0.06	-50.00%
GA Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Low Voltage Service Charge	$ 0.0013	645	$ 0.84	$ 0.0013	645	$ 0.84	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	645	$ -	$ -	645	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 61.41**			**$ 63.03**	**$ 1.62**	**2.65%**
RTSR - Network	$ 0.0085	676	$ 5.75	$ 0.0098	676	$ 6.63	$ 0.88	15.29%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0072	676	$ 4.87	$ 0.0075	676	$ 5.07	$ 0.20	4.17%
Sub-Total C - Delivery (including Sub-Total B)			**$ 72.02**			**$ 74.73**	**$ 2.71**	**3.76%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	676	$ 2.30	$ 0.0034	676	$ 2.30	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	676	$ 0.34	$ 0.0005	676	$ 0.34	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	413	$ 33.85	$ 0.0820	413	$ 33.85	$ -	0.00%
TOU - Mid Peak	$ 0.1130	116	$ 13.12	$ 0.1130	116	$ 13.12	$ -	0.00%
TOU - On Peak	$ 0.1700	116	$ 19.74	$ 0.1700	116	$ 19.74	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 141.62**			**$ 144.32**	**$ 2.71**	**1.91%**
HST	13%		$ 18.41	13%		$ 18.76	$ 0.35	1.91%
Ontario Electricity Rebate	17.0%		$ (24.07)	17.0%		$ (24.53)	$ (0.46)	
Total Bill on TOU			**$ 135.95**			**$ 138.55**	**$ 2.60**	**1.91%**

In the manager's summary, discuss the reaso

In the manager's summary, discuss the reaso

Customer Class:	**GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 18.41	1	$ 18.41	$ 18.96	1	$ 18.96	$ 0.55	2.99%
Distribution Volumetric Rate	$ 0.0185	2000	$ 37.00	$ 0.0191	2000	$ 38.20	$ 1.20	3.24%
Fixed Rate Riders	$ 1.14	1	$ 1.14	$ 1.14	1	$ 1.14	$ -	0.00%
Volumetric Rate Riders	$ 0.0016	2000	$ 3.20	$ 0.0032	2000	$ 6.40	$ 3.20	100.00%
Sub-Total A (excluding pass through)			**$ 59.75**			**$ 64.70**	**$ 4.95**	**8.28%**
Line Losses on Cost of Power	$ 0.1034	96	$ 9.97	$ 0.1034	96	$ 9.97	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ 0.0032	2,000	$ 6.40	$ 0.0031	2,000	$ 6.20	$ (0.20)	-3.13%
CBR Class B Rate Riders	-$ 0.0002	2,000	$ (0.40)	-$ 0.0001	2,000	$ (0.20)	$ 0.20	-50.00%
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0009	2,000	$ 1.80	$ 0.0009	2,000	$ 1.80	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 77.95**			**$ 82.90**	**$ 4.95**	**6.35%**
RTSR - Network	$ 0.0074	2,096	$ 15.51	$ 0.0085	2,096	$ 17.82	$ 2.31	14.86%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0052	2,096	$ 10.90	$ 0.0054	2,096	$ 11.32	$ 0.42	3.85%
Sub-Total C - Delivery (including Sub-Total B)			**$ 104.36**			**$ 112.04**	**$ 7.68**	**7.35%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,096	$ 7.13	$ 0.0034	2,096	$ 7.13	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,096	$ 1.05	$ 0.0005	2,096	$ 1.05	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	1,280	$ 104.96	$ 0.0820	1,280	$ 104.96	$ -	0.00%
TOU - Mid Peak	$ 0.1130	360	$ 40.68	$ 0.1130	360	$ 40.68	$ -	0.00%
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	360	$ 61.20	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 319.63**			**$ 327.31**	**$ 7.68**	**2.40%**
HST	13%		$ 41.55	13%		$ 42.55	$ 1.00	2.40%
Ontario Electricity Rebate	17.0%		$ (54.34)	17.0%		$ (55.64)	$ (1.30)	
Total Bill on TOU			**$ 306.85**			**$ 314.21**	**$ 7.37**	**2.40%**

In the manager's summary, discuss the reaso

Customer Class:	**GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**432,160** kWh
Demand	**1,480** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 117.69	1	$ 117.69	$ 121.22	1	$ 121.22	$ 3.53	3.00%
Distribution Volumetric Rate	$ 3.6310	1480	$ 5,373.88	$ 3.7399	1480	$ 5,535.05	$ 161.17	3.00%
Fixed Rate Riders	$ 7.30	1	$ 7.30	$ 7.30	1	$ 7.30	$ -	0.00%
Volumetric Rate Riders	$ 0.3740	1480	$ 553.52	$ 0.8065	1480	$ 1,193.62	$ 640.10	115.64%
Sub-Total A (excluding pass through)			**$ 6,052.39**			**$ 6,857.19**	**$ 804.80**	**13.30%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 1.3695	1,480	$ 2,026.86	$ 1.2648	1,480	$ 1,871.90	$ (154.96)	-7.65%
CBR Class B Rate Riders	-$ 0.0817	1,480	$ (120.92)	-$ 0.0521	1,480	$ (77.11)	$ 43.81	-36.23%
GA Rate Riders	$ 0.0012	432,160	$ 518.59	-$ 0.0020	432,160	$ (864.32)	$ (1,382.91)	-266.67%
Low Voltage Service Charge	$ 0.3858	1,480	$ 570.98	$ 0.3858	1,480	$ 570.98	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	1,480	$ -	$ -	1,480	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 9,047.91**			**$ 8,358.65**	**$ (689.26)**	**-7.62%**
RTSR - Network	$ 3.6527	1,480	$ 5,406.00	$ 4.1910	1,480	$ 6,202.68	$ 796.68	14.74%
RTSR - Connection and/or Line and Transformation Connection	$ 2.4132	1,480	$ 3,571.54	$ 2.5211	1,480	$ 3,731.23	$ 159.69	4.47%
Sub-Total C - Delivery (including Sub-Total B)			**$ 18,025.44**			**$ 18,292.56**	**$ 267.12**	**1.48%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	452,990	$ 1,540.17	$ 0.0034	452,990	$ 1,540.17	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	452,990	$ 226.50	$ 0.0005	452,990	$ 226.50	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.0967	452,990	$ 43,804.14	$ 0.0967	452,990	$ 43,804.14	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price			**$ 63,596.50**			**$ 63,863.62**	**$ 267.12**	**0.42%**
HST	13%		$ 8,267.54	13%		$ 8,302.27	$ 34.73	0.42%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 71,864.04**			**$ 72,165.89**	**$ 301.84**	**0.42%**

In the manager's summary, discuss the reaso

In the manager's summary, discuss the reaso

Customer Class:	GENERAL SERVICE 3,000 TO 4,999 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	1,752,000 kWh
Demand	4,000 kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 6,184.42	1	$ 6,184.42	$ 6,369.95	1	$ 6,369.95	$ 185.53	3.00%	
Distribution Volumetric Rate	$ 2.3004	4000	$ 9,201.60	$ 2.3694	4000	$ 9,477.60	$ 276.00	3.00%	
Fixed Rate Riders	$ 383.39	1	$ 383.39	$ 383.39	1	$ 383.39	$ -	0.00%	
Volumetric Rate Riders	$ 0.2215	4000	$ 886.00	$ 0.3880	4000	$ 1,552.00	$ 666.00	75.17%	
Sub-Total A (excluding pass through)			**$ 16,655.41**			**$ 17,782.94**	**$ 1,127.53**	**6.77%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 1.4841	4,000	$ 5,936.40	$ 1.4623	4,000	$ 5,849.20	$ (87.20)	-1.47%	
CBR Class B Rate Riders	-$ 0.1118	4,000	$ (447.20)	-$ 0.0729	4,000	$ (291.60)	$ 155.60	-34.79%	
GA Rate Riders	$ 0.0012	1,752,000	$ 2,102.40	-$ 0.0020	1,752,000	$ (3,504.00)	$ (5,606.40)	-266.67%	
Low Voltage Service Charge	$ 0.4346	4,000	$ 1,738.40	$ 0.4346	4,000	$ 1,738.40	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	4,000	$ -	$ -	4,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 25,985.41**			**$ 21,574.94**	**$ (4,410.47)**	**-16.97%**	
RTSR - Network	$ 4.0244	4,000	$ 16,097.60	$ 4.6175	4,000	$ 18,470.00	$ 2,372.40	14.74%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.6503	4,000	$ 10,601.20	$ 2.7688	4,000	$ 11,075.20	$ 474.00	4.47%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 52,684.21**			**$ 51,120.14**	**$ (1,564.07)**	**-2.97%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,836,446	$ 6,243.92	$ 0.0034	1,836,446	$ 6,243.92	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,836,446	$ 918.22	$ 0.0005	1,836,446	$ 918.22	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0967	1,836,446	$ 177,584.37	$ 0.0967	1,836,446	$ 177,584.37	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 237,430.97**			**$ 235,866.90**	**$ (1,564.07)**	**-0.66%**	
HST	13%		$ 30,866.03	13%		$ 30,662.70	$ (203.33)	-0.66%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 268,296.99**			**$ 266,529.59**	**$ (1,767.40)**	**-0.66%**	

Customer Class:	LARGE USE SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	4,219,400 kWh
Demand	6,800 kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 9,290.25	1	$ 9,290.25	$ 9,568.96	1	$ 9,568.96	$ 278.71	3.00%	
Distribution Volumetric Rate	$ 3.2398	6800	$ 22,030.64	$ 3.3370	6800	$ 22,691.60	$ 660.96	3.00%	
Fixed Rate Riders	$ 575.93	1	$ 575.93	$ 575.93	1	$ 575.93	$ -	0.00%	
Volumetric Rate Riders	$ 0.4172	6800	$ 2,836.96	$ 1.0725	6800	$ 7,293.00	$ 4,456.04	157.07%	
Sub-Total A (excluding pass through)			**$ 34,733.78**			**$ 40,129.49**	**$ 5,395.71**	**15.53%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 1.9251	6,800	$ 13,090.68	$ 1.7666	6,800	$ 12,012.88	$ (1,077.80)	-8.23%	
CBR Class B Rate Riders	$ -	6,800	$ -	$ -	6,800	$ -	$ -		
GA Rate Riders	$ -	4,219,400	$ -	$ -	4,219,400	$ -	$ -		
Low Voltage Service Charge	$ 0.4157	6,800	$ 2,826.76	$ 0.4157	6,800	$ 2,826.76	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	6,800	$ -	$ -	6,800	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 50,651.22**			**$ 54,969.13**	**$ 4,317.91**	**8.52%**	
RTSR - Network	$ 4.0244	6,800	$ 27,365.92	$ 4.6175	6,800	$ 31,399.00	$ 4,033.08	14.74%	In the manager's summary, discuss the reaso
RTSR - Connection and/or Line and Transformation Connection	$ 2.6503	6,800	$ 18,022.04	$ 2.7688	6,800	$ 18,827.84	$ 805.80	4.47%	In the manager's summary, discuss the reaso
Sub-Total C - Delivery (including Sub-Total B)			**$ 96,039.18**			**$ 105,195.97**	**$ 9,156.79**	**9.53%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	4,422,775	$ 15,037.44	$ 0.0034	4,422,775	$ 15,037.44	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	4,422,775	$ 2,211.39	$ 0.0005	4,422,775	$ 2,211.39	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0967	4,422,775	$ 427,682.35	$ 0.0967	4,422,775	$ 427,682.35	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 540,970.60**			**$ 550,127.39**	**$ 9,156.79**	**1.69%**	
HST	13%		$ 70,326.18	13%		$ 71,516.56	$ 1,190.38	1.69%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 611,296.78**			**$ 621,643.95**	**$ 10,347.17**	**1.69%**	

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**500** kWh
Demand	**-** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 7.51	1	$ 7.51	$ 7.74	1	$ 7.74	$ 0.23	3.06%
Distribution Volumetric Rate	$ 0.0184	500	$ 9.20	$ 0.0190	500	$ 9.50	$ 0.30	3.26%
Fixed Rate Riders	$ 0.47	1	$ 0.47	$ 0.47	1	$ 0.47	$ -	0.00%
Volumetric Rate Riders	$ 0.0011	500	$ 0.55	$ 0.0011	500	$ 0.55	$ -	0.00%
Sub-Total A (excluding pass through)			**$ 17.73**			**$ 18.26**	**$ 0.53**	**2.99%**
Line Losses on Cost of Power	$ 0.1034	24	$ 2.49	$ 0.1034	24	$ 2.49	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ 0.0033	500	$ 1.65	$ 0.0032	500	$ 1.60	$ (0.05)	-3.03%
CBR Class B Rate Riders	-$ 0.0002	500	$ (0.10)	-$ 0.0001	500	$ (0.05)	$ 0.05	-50.00%
GA Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	$ 0.0009	500	$ 0.45	$ 0.0009	500	$ 0.45	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 22.22**			**$ 22.75**	**$ 0.53**	**2.38%**
RTSR - Network	$ 0.0074	524	$ 3.88	$ 0.0085	524	$ 4.45	$ 0.58	14.86%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0052	524	$ 2.73	$ 0.0054	524	$ 2.83	$ 0.10	3.85%
Sub-Total C - Delivery (including Sub-Total B)			**$ 28.83**			**$ 30.04**	**$ 1.21**	**4.20%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	524	$ 1.78	$ 0.0034	524	$ 1.78	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	524	$ 0.26	$ 0.0005	524	$ 0.26	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	320	$ 26.24	$ 0.0820	320	$ 26.24	$ -	0.00%
TOU - Mid Peak	$ 0.1130	90	$ 10.17	$ 0.1130	90	$ 10.17	$ -	0.00%
TOU - On Peak	$ 0.1700	90	$ 15.30	$ 0.1700	90	$ 15.30	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 82.83**			**$ 84.04**	**$ 1.21**	**1.46%**
HST	13%		$ 10.77	13%		$ 10.93	$ 0.16	1.46%
Ontario Electricity Rebate	17.0%		$ (14.08)	17.0%		$ (14.29)	$ (0.21)	
Total Bill on TOU			**$ 79.52**			**$ 80.68**	**$ 1.16**	**1.46%**

In the manager's summary, discuss the reaso

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	**180** kWh
Demand	**1** kW
Current Loss Factor	**1.0482**
Proposed/Approved Loss Factor	**1.0482**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 4.94	1	$ 4.94	$ 5.09	1	$ 5.09	$ 0.15	3.04%	
Distribution Volumetric Rate	$ 14.9572	1	$ 14.96	$ 15.4059	1	$ 15.41	$ 0.45	3.00%	
Fixed Rate Riders	$ 0.31	1	$ 0.31	$ 0.31	1	$ 0.31	$ -	0.00%	
Volumetric Rate Riders	$ 0.9272	1	$ 0.93	$ 0.9272	1	$ 0.93	$ -	0.00%	
Sub-Total A (excluding pass through)			**$ 21.13**			**$ 21.73**	**$ 0.60**	**2.83%**	
Line Losses on Cost of Power	$ 0.1034	9	$ 0.90	$ 0.1034	9	$ 0.90	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ 1.1619	1	$ 1.16	$ 1.0972	1	$ 1.10	$ (0.06)	-5.57%	
CBR Class B Rate Riders	-$ 0.0748	1	$ (0.07)	-$ 0.0506	1	$ (0.05)	$ 0.02	-32.35%	
GA Rate Riders	$ -	180	$ -	$ -	180	$ -	$ -		
Low Voltage Service Charge	$ 0.2505	1	$ 0.25	$ 0.2505	1	$ 0.25	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 23.37**			**$ 23.93**	**$ 0.56**	**2.39%**	
RTSR - Network	$ 2.2784	1	$ 2.28	$ 2.6142	1	$ 2.61	$ 0.34	14.74%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 1.5172	1	$ 1.52	$ 1.5850	1	$ 1.59	$ 0.07	4.47%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 27.16**			**$ 28.13**	**$ 0.96**	**3.54%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	189	$ 0.64	$ 0.0034	189	$ 0.64	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	189	$ 0.09	$ 0.0005	189	$ 0.09	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	115	$ 9.45	$ 0.0820	115	$ 9.45	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	32	$ 3.66	$ 0.1130	32	$ 3.66	$ -	0.00%	
TOU - On Peak	$ 0.1700	32	$ 5.51	$ 0.1700	32	$ 5.51	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 46.77**			**$ 47.73**	**$ 0.96**	**2.06%**	
HST	13%		$ 6.08	13%		$ 6.20	$ 0.13	2.06%	
Ontario Electricity Rebate	17.0%		$ (7.95)	17.0%		$ (8.11)	$ (0.16)		
Total Bill on TOU			**$ 44.90**			**$ 45.82**	**$ 0.92**	**2.06%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	424,881 kWh
Demand	988 kW
Current Loss Factor	1.0482
Proposed/Approved Loss Factor	1.0482

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 0.76	10652	$ 8,095.52	$ 0.78	10652	$ 8,308.56	$ 213.04	2.63%	
Distribution Volumetric Rate	$ 4.0898	988.1	$ 4,041.13	$ 4.2125	988.1	$ 4,162.37	$ 121.24	3.00%	
Fixed Rate Riders	$ 0.05	10652	$ 532.60	$ 0.05	10652	$ 532.60	$ -	0.00%	
Volumetric Rate Riders	$ 2.2608	988.1	$ 2,233.90	$ 8.6633	988.1	$ 8,560.21	$ 6,326.31	283.20%	
Sub-Total A (excluding pass through)			**$ 14,903.15**			**$ 21,563.74**	**$ 6,660.59**	**44.69%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ 1.1653	988	$ 1,151.43	$ 1.0925	988	$ 1,079.50	$ (71.93)	-6.25%	
CBR Class B Rate Riders	-$ 0.0753	988	$ (74.40)	-$ 0.0498	988	$ (49.21)	$ 25.20	-33.86%	
GA Rate Riders	$ 0.0012	424,881	$ 509.86	-$ 0.0020	424,881	$ (849.76)	$ (1,359.62)	-266.67%	
Low Voltage Service Charge	$ 0.2618	988	$ 258.68	$ 0.2618	988	$ 258.68	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	10652	$ -	$ -	10652	$ -	$ -		
Additional Fixed Rate Riders	$ -	10652	$ -	$ -	10652	$ -	$ -		
Additional Volumetric Rate Riders	$ -	988	$ -	$ -	988	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 16,748.72**			**$ 22,002.95**	**$ 5,254.23**	**31.37%**	
RTSR - Network	$ 2.3989	988	$ 2,370.35	$ 2.7524	988	$ 2,719.65	$ 349.29	14.74%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 1.5854	988	$ 1,566.53	$ 1.6563	988	$ 1,636.59	$ 70.06	4.47%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,685.61**			**$ 26,359.19**	**$ 5,673.58**	**27.43%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	445,360	$ 1,514.22	$ 0.0034	445,360	$ 1,514.22	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	445,360	$ 222.68	$ 0.0005	445,360	$ 222.68	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	10652	$ 2,663.00	$ 0.25	10652	$ 2,663.00	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0967	445,360	$ 43,066.30	$ 0.0967	445,360	$ 43,066.30	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 68,151.81**			**$ 73,825.40**	**$ 5,673.58**	**8.32%**	
HST	13%		$ 8,859.74	13%		$ 9,597.30	$ 737.57	8.32%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 77,011.55**			**$ 83,422.70**	**$ 6,411.15**	**8.32%**	

APPENDIX E-2:

WHITBY RATE ZONE

BILL IMPACTS

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2023 Filers

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of June 2022 of $0.0967/kWh (IESO's Monthly Market Report for April 2022) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor** (eg: 1.0351)	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	RTSR **Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0454	1.0454	750			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0454	1.0454	2,000			
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0454	1.0454	40,000	100		
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0454	1.0454	500			1
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	RPP	1.0454	1.0454	150	1		1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0454	1.0454	283,400	736		12,262
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				
Add additional scenarios if required			1.0454	1.0454				

Table 2

RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**Sub-Total**						**Total**	
		A		**B**		**C**		**Total Bill**	
		$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 3.85	11.5%	$ 5.80	15.2%	$ 7.29	14.2%	$ 7.00	5.5%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 8.23	11.6%	$ 13.63	16.6%	$ 17.18	15.0%	$ 16.50	5.2%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 80.72	12.2%	$ 105.97	15.3%	$ 173.82	13.4%	$ 196.42	3.2%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 3.10	11.5%	$ 4.50	15.2%	$ 5.39	14.3%	$ 5.17	5.9%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kW	$ 3.05	13.9%	$ 4.19	18.4%	$ 4.70	17.2%	$ 4.52	10.8%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 3,569.43	10.3%	$ 2,829.88	8.2%	$ 3,208.77	8.4%	$ 3,625.91	4.5%

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	$ 34.41	1	$ 34.41	$ 1.00	2.99%	
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -		
Fixed Rate Riders	$ (0.06)	1	$ (0.06)	$ 2.79	1	$ 2.79	$ 2.85	-4750.00%	
Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total A (excluding pass through)			**$ 33.35**			**$ 37.20**	**$ 3.85**	**11.54%**	
Line Losses on Cost of Power	$ 0.1034	34	$ 3.52	$ 0.1034	34	$ 3.52	$ -	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	$ 0.43	1	$ 0.43	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 38.05**			**$ 43.85**	**$ 5.80**	**15.24%**	
RTSR - Network	$ 0.0096	784	$ 7.53	$ 0.0110	784	$ 8.62	$ 1.10	14.58%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0072	784	$ 5.65	$ 0.0077	784	$ 6.04	$ 0.39	6.94%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 51.22**			**$ 58.51**	**$ 7.29**	**14.23%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	784	$ 2.67	$ 0.0034	784	$ 2.67	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	784	$ 0.39	$ 0.0005	784	$ 0.39	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	480	$ 39.36	$ 0.0820	480	$ 39.36	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	135	$ 15.26	$ 0.1130	135	$ 15.26	$ -	0.00%	
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	135	$ 22.95	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 132.10**			**$ 139.39**	**$ 7.29**	**5.52%**	
HST	13%		$ 17.17	13%		$ 18.12	$ 0.95	5.52%	
Ontario Electricity Rebate	17.0%		$ (22.46)	17.0%		$ (23.70)	$ (1.24)		
Total Bill on TOU			**$ 126.81**			**$ 133.81**	**$ 7.00**	**5.52%**	

Customer Class:	**GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** 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	$ 28.08	1	$ 28.08	$ 28.92	1	$ 28.92	$ 0.84	2.99%	
Distribution Volumetric Rate	$ 0.0208	2000	$ 41.60	$ 0.0214	2000	$ 42.80	$ 1.20	2.88%	
Fixed Rate Riders	$ -	1	$ -	$ 2.39	1	$ 2.39	$ 2.39		
Volumetric Rate Riders	$ 0.0005	2000	$ 1.00	$ 0.0024	2000	$ 4.80	$ 3.80	380.00%	
Sub-Total A (excluding pass through)			**$ 70.68**			**$ 78.91**	**$ 8.23**	**11.64%**	
Line Losses on Cost of Power	$ 0.1034	91	$ 9.39	$ 0.1034	91	$ 9.39	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	$ 0.0029	2,000	$ 5.80	$ 5.80		
CBR Class B Rate Riders	$ -	2,000	$ -	-$ 0.0002	2,000	$ (0.40)	$ (0.40)		
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ 0.0009	2,000	$ 1.80	$ 0.0009	2,000	$ 1.80	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 82.30**			**$ 95.93**	**$ 13.63**	**16.56%**	
RTSR - Network	$ 0.0087	2,091	$ 18.19	$ 0.0100	2,091	$ 20.91	$ 2.72	14.94%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0068	2,091	$ 14.22	$ 0.0072	2,091	$ 15.05	$ 0.84	5.88%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 114.71**			**$ 131.89**	**$ 17.18**	**14.98%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,091	$ 7.11	$ 0.0034	2,091	$ 7.11	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,091	$ 1.05	$ 0.0005	2,091	$ 1.05	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	1,280	$ 104.96	$ 0.0820	1,280	$ 104.96	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	360	$ 40.68	$ 0.1130	360	$ 40.68	$ -	0.00%	
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	360	$ 61.20	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 329.95**			**$ 347.14**	**$ 17.18**	**5.21%**	
HST	13%		$ 42.89	13%		$ 45.13	$ 2.23	5.21%	
Ontario Electricity Rebate	17.0%		$ (56.09)	17.0%		$ (59.01)	$ (2.92)		
Total Bill on TOU			**$ 316.75**			**$ 333.25**	**$ 16.50**	**5.21%**	

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**40,000** **kWh**
Demand	**100** **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	$ 213.88	1	$ 213.88	$ 220.30	1	$ 220.30	$ 6.42	3.00%	
Distribution Volumetric Rate	$ 4.2717	100	$ 427.17	$ 4.3999	100	$ 439.99	$ 12.82	3.00%	
Fixed Rate Riders	$ -	1	$ -	$ 18.23	1	$ 18.23	$ 18.23		
Volumetric Rate Riders	$ 0.1872	100	$ 18.72	$ 0.6197	100	$ 61.97	$ 43.25	231.04%	
Sub-Total A (excluding pass through)			**$ 659.77**			**$ 740.49**	**$ 80.72**	**12.23%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	100	$ -	$ 1.2721	100	$ 127.21	$ 127.21		
CBR Class B Rate Riders	$ -	100	$ -	-$ 0.0596	100	$ (5.96)	$ (5.96)		
GA Rate Riders	$ -	40,000	$ -	-$ 0.0024	40,000	$ (96.00)	$ (96.00)		
Low Voltage Service Charge	$ 0.3181	100	$ 31.81	$ 0.3181	100	$ 31.81	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	100	$ -	$ -	100	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 691.58**			**$ 797.55**	**$ 105.97**	**15.32%**	
RTSR - Network	$ 3.4495	100	$ 344.95	$ 3.9659	100	$ 396.59	$ 51.64	14.97%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 2.5728	100	$ 257.28	$ 2.7349	100	$ 273.49	$ 16.21	6.30%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,293.81**			**$ 1,467.63**	**$ 173.82**	**13.43%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	41,816	$ 142.17	$ 0.0034	41,816	$ 142.17	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	41,816	$ 20.91	$ 0.0005	41,816	$ 20.91	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0967	41,816	$ 4,043.61	$ 0.0967	41,816	$ 4,043.61	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 5,500.75**			**$ 5,674.57**	**$ 173.82**	**3.16%**	
HST	13%		$ 715.10	13%		$ 737.69	$ 22.60	3.16%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 6,215.85**			**$ 6,412.26**	**$ 196.42**	**3.16%**	

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**500** 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	$ 10.40	1	$ 10.40	$ 10.71	1	$ 10.71	$ 0.31	2.98%
Distribution Volumetric Rate	$ 0.0332	500	$ 16.60	$ 0.0342	500	$ 17.10	$ 0.50	3.01%
Fixed Rate Riders	$ -	1	$ -	$ 0.89	1	$ 0.89	$ 0.89	
Volumetric Rate Riders	-$ 0.0002	500	$ (0.10)	$ 0.0026	500	$ 1.30	$ 1.40	-1400.00%
Sub-Total A (excluding pass through)			**$ 26.90**			**$ 30.00**	**$ 3.10**	**11.52%**
Line Losses on Cost of Power	$ 0.1034	23	$ 2.35	$ 0.1034	23	$ 2.35	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	500	$ -	$ 0.0030	500	$ 1.50	$ 1.50	
CBR Class B Rate Riders	$ -	500	$ -	-$ 0.0002	500	$ (0.10)	$ (0.10)	
GA Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Low Voltage Service Charge	$ 0.0009	500	$ 0.45	$ 0.0009	500	$ 0.45	$ -	0.00%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.70**			**$ 34.20**	**$ 4.50**	**15.15%**
RTSR - Network	$ 0.0087	523	$ 4.55	$ 0.0100	523	$ 5.23	$ 0.68	14.94%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0068	523	$ 3.55	$ 0.0072	523	$ 3.76	$ 0.21	5.88%
Sub-Total C - Delivery (including Sub-Total B)			**$ 37.80**			**$ 43.19**	**$ 5.39**	**14.26%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	523	$ 1.78	$ 0.0034	523	$ 1.78	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	523	$ 0.26	$ 0.0005	523	$ 0.26	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	320	$ 26.24	$ 0.0820	320	$ 26.24	$ -	0.00%
TOU - Mid Peak	$ 0.1130	90	$ 10.17	$ 0.1130	90	$ 10.17	$ -	0.00%
TOU - On Peak	$ 0.1700	90	$ 15.30	$ 0.1700	90	$ 15.30	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 91.80**			**$ 97.19**	**$ 5.39**	**5.87%**
HST	13%		$ 11.93	13%		$ 12.63	$ 0.70	5.87%
Ontario Electricity Rebate	17.0%		$ (15.61)	17.0%		$ (16.52)	$ (0.92)	
Total Bill on TOU			**$ 88.13**			**$ 93.30**	**$ 5.17**	**5.87%**

In the manager's summary, discuss the reaso

In the manager's summary, discuss the reaso

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	150 kWh
Demand	1 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	$ 6.11	1	$ 6.11	$ 6.29	1	$ 6.29	$ 0.18	2.95%	
Distribution Volumetric Rate	$ 16.4458	1	$ 16.45	$ 16.9392	1	$ 16.94	$ 0.49	3.00%	
Fixed Rate Riders	$ -	1	$ -	$ 0.52	1	$ 0.52	$ 0.52		
Volumetric Rate Riders	-$ 0.5664	1	$ (0.57)	$ 1.2897	1	$ 1.29	$ 1.86	-327.70%	
Sub-Total A (excluding pass through)			**$ 21.99**			**$ 25.04**	**$ 3.05**	**13.87%**	
Line Losses on Cost of Power	$ 0.1034	7	$ 0.70	$ 0.1034	7	$ 0.70	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	1	$ -	$ 1.1921	1	$ 1.19	$ 1.19		
CBR Class B Rate Riders	$ -	1	$ -	-$ 0.0563	1	$ (0.06)	$ (0.06)		
GA Rate Riders	$ -	150	$ -	$ -	150	$ -	$ -		
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Volumetric Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 22.69**			**$ 26.88**	**$ 4.19**	**18.44%**	
RTSR - Network	$ 2.6144	1	$ 2.61	$ 3.0057	1	$ 3.01	$ 0.39	14.97%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 2.0307	1	$ 2.03	$ 2.1586	1	$ 2.16	$ 0.13	6.30%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 27.34**			**$ 32.04**	**$ 4.70**	**17.21%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	157	$ 0.53	$ 0.0034	157	$ 0.53	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	157	$ 0.08	$ 0.0005	157	$ 0.08	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0820	96	$ 7.87	$ 0.0820	96	$ 7.87	$ -	0.00%	
TOU - Mid Peak	$ 0.1130	27	$ 3.05	$ 0.1130	27	$ 3.05	$ -	0.00%	
TOU - On Peak	$ 0.1700	27	$ 4.59	$ 0.1700	27	$ 4.59	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 43.71**			**$ 48.42**	**$ 4.70**	**10.76%**	
HST	13%		$ 5.68	13%		$ 6.29	$ 0.61	10.76%	
Ontario Electricity Rebate	17.0%		$ (7.43)	17.0%		$ (8.23)	$ (0.80)		
Total Bill on TOU			**$ 41.96**			**$ 46.48**	**$ 4.52**	**10.76%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**283,400** kWh
Demand	**736** 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	$ 1.88	12262	$ 23,052.56	$ 1.94	12262	$ 23,788.28	$ 735.72	3.19%	
Distribution Volumetric Rate	$ 7.1956	736	$ 5,295.96	$ 7.4115	736	$ 5,454.86	$ 158.90	3.00%	
Fixed Rate Riders	$ -	12262	$ -	$ 0.16	12262	$ 1,961.92	$ 1,961.92		
Volumetric Rate Riders	$ 8.3717	736	$ 6,161.57	$ 9.3403	736	$ 6,874.46	$ 712.89	11.57%	
Sub-Total A (excluding pass through)			**$ 34,510.09**			**$ 38,079.52**	**$ 3,569.43**	**10.34%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	736	$ -	-$ 0.0286	736	$ (21.05)	$ (21.05)		
CBR Class B Rate Riders	$ -	736	$ -	-$ 0.0521	736	$ (38.35)	$ (38.35)		
GA Rate Riders	$ -	283,400	$ -	-$ 0.0024	283,400	$ (680.16)	$ (680.16)		
Low Voltage Service Charge	$ 0.2459	736	$ 180.98	$ 0.2459	736	$ 180.98	$ -	0.00%	
Smart Meter Entity Charge (if applicable)	$ -	12262	$ -	$ -	12262	$ -	$ -		
Additional Fixed Rate Riders	$ -	12262	$ -	$ -	12262	$ -	$ -		
Additional Volumetric Rate Riders	$ -	736	$ -	$ -	736	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 34,691.08**			**$ 37,520.95**	**$ 2,829.88**	**8.16%**	
RTSR - Network	$ 2.6016	736	$ 1,914.78	$ 2.9911	736	$ 2,201.45	$ 286.67	14.97%	*In the manager's summary, discuss the reaso*
RTSR - Connection and/or Line and Transformation Connection	$ 1.9890	736	$ 1,463.90	$ 2.1143	736	$ 1,556.12	$ 92.22	6.30%	*In the manager's summary, discuss the reaso*
Sub-Total C - Delivery (including Sub-Total B)			**$ 38,069.76**			**$ 41,278.53**	**$ 3,208.77**	**8.43%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	296,266	$ 1,007.31	$ 0.0034	296,266	$ 1,007.31	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	296,266	$ 148.13	$ 0.0005	296,266	$ 148.13	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	12262	$ 3,065.50	$ 0.25	12262	$ 3,065.50	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.0967	296,266	$ 28,648.96	$ 0.0967	296,266	$ 28,648.96	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 70,939.65**			**$ 74,148.42**	**$ 3,208.77**	**4.52%**	
HST	13%		$ 9,222.15	13%		$ 9,639.29	$ 417.14	4.52%	
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -			
Total Bill on Average IESO Wholesale Market Price			**$ 80,161.81**			**$ 83,787.72**	**$ 3,625.91**	**4.52%**	

APPENDIX F:

CERTIFICATE OF EVIDENCE

elexicon ENERGY

Certification of Evidence

Attestation

With respect to Elexicon Energy's 2023 IRM Application, I, Cynthia Chan, Chief Financial Officer of Elexicon Energy Inc. hereby certify that the evidence filed is accurate, consistent and complete to the best of my knowledge. Elexicon Energy has processes and internal controls in place for the preparation, review, verification and oversight of account balances being disposed.

With respect to Elexicon Energy's 2023 IRM Application, I, Cynthia Chan, Chief Financial Officer of Elexicon Energy Inc. hereby certify that the application and any evidence filed in support of the application does not include any personal information.

Company Name: **Elexicon Energy Inc.**

Certifier Details:

Name: **Cynthia Chan, CPA, CA**

Position: **Chief Financial Officer**

Signature: ___________

Date: July 27 2022

elexiconenergy.com

Office T (905) 427-9870 T 1 (888) 445-2881 F (905) 619-0210

Customer Care T (905) 420-8440 T 1 (888) 420-0070 F (905) 837-7861

55 Taunton Rd. E.
Ajax, ON L1T 3V3

APPENDIX G:

CHECKLIST

2023 IRM Checklist

Elexicon Energy Inc

EB-2022-0024

Date: July 27 2022

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
3.1.2 Components of the Application Filing		
2	Manager's summary documenting and explaining all rate adjustments requested	Application Introduction and Manager's Summary (3.1)
2	Contact info - primary contact may be a person within the distributor's organization other than the primary license contact	Application pg 10
3	Completed Rate Generator Model and supplementary work forms in Excel format	Excel versions sumbitted
3	Current tariff sheet, PDF	Appendices C-1 & C-2
3	Supporting documentation (e.g. relevant past decisions, RRWF etc.)	Application pg 11
3	Statement as to who will be affected by the application, specific customer groups affected by particular request	Application pg 11
3	Distributor's internet address	Application pg 12
3	Statement confirming accuracy of billing determinants pre-populated in model	Application pg 12
3	Text searchable PDF format for all documents	Confirmed
3	2023 IRM Checklist	Excel version submitted & Appendix G
3	Include a certification by a senior officer that the evidence filed, including the models and appendices, is accurate, consistent and complete to the best of their knowledge, a certification that the distributor has processes and internal controls in place for the preparation, review, verification and oversight of account balances being disposed, as well as a certification regarding personal information	Appendix F
3.1.3 Applications and Electronic Models		
4	Confirm the accuracy of the data. If a distributor has revised any RRR data after it has been incorporated into the model, this change should be disclosed in the application	Application pg 12
4	File the GA Analysis Workform.	Excel version sumbitted
4	A distributor seeking a revenue-to-cost ratio adjustment due to a previous OEB decision must continue to file the OEB's Revenue-to-Cost Ratio Adjustment Workform in addition to the Rate Generator model.	N/A
4	For an Incremental or Advanced Capital Module (ICM/ACM) cost recovery and associated rate rider(s), a distributor must file the Capital Module applicable to ACM and ICM.	Excel versions sumbitted
5	A distributor seeking to dispose of lost revenue amounts from conservation and demand management activities, during an IRM term, must file the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Workform.	Excel version submitted
5	The models and workforms be used by all distributors. If a distributor makes any changes to OEB models or workforms to address its own circumstances, it must justify such changes in the manager's summary.	N/A
3.2.2 Revenue to Cost Ratio Adjustments		
6 - 7	Revenue to Cost Ratio Adjustment Workform, if distributor is seeking revenue to cost ratio adjustments due to previous OEB decision	N/A
3.2.3 Rate Design for Residential Electricity Customers	**Applicable only to distributors that have not completed the residential rate design transition**	
7	A plan to mitigate the impact for the whole residential class or indicate why such a plan is not required, if the total bill impact of the elements proposed in the application is 10% or greater for RPP customers consuming at the 10th percentile	N/A
7	Mitigation plan if total bill increases for any customer class exceed 10%	N/A
.2.4 Electricity Distribution Retail Transmission Service Rates	**No action required at filing - model completed with most recent uniform transmission rates (UTRs) approved by the OEB**	
3.2.5 Review and Disposition of Group 1 DVA Balances		
8	Justification if any account balance in excess of the threshold should not be disposed	N/A
8	Completed Tab 3 - continuity schedule in Rate Generator Model	Confirmed
9	Explanation of variance between amounts proposed for disposition and amounts reported in RRR for each account	Application pg 17 & 18
9	Statement as to whether any adjustments have been made to balances previously approved by the OEB on a final basis; If so, explanations provided for the nature and amounts of the adjustments and supporting documentation under a section titled "Adjustments to Deferral and Variance Accounts"	Application pg 14
10	Rate riders proposed for recovery or refund of balances that are proposed for disposition. The default disposition period is one year. Justification with proper supporting information is required if distributor is proposing an alternative recovery period	N/A
3.2.5.1 Wholesale Market Participants		
10	Separate rate riders established to recover balances in RSVAs from Wholesale Market Participants, who must not be allocated balances related to charges for which WMPs settle directly with the IESO	Applicaton pg 19
3.2.5.3 Commodity Accounts 1588 and 1589		
11	Confirmation of implementation of the OEB's February 21, 2019 guidance effective from January 1, 2019 when requesting final disposition for the first time following implementation of the Accounting Guidance	Application pg 19-28
11	Confirmation that historical balances that have yet to be disposed on a final basis have been considered in the context of the Accounting Guidance, summary provided of the review performed. Distributors must discuss the results of review, whether any systemic issues were noted, and whether any material adjustments to the account balances have been recorded. A summary and description is provided for each adjustment made to the historical balances	Application pg 19-28

2023 IRM Checklist

Elexicon Energy Inc

EB-2022-0024

Date: July 27 2022

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
11 - 12, 4	Populated GA Analysis Workform for each year that has not previously been approved by the OEB for disposition, irrespective of whether seeking disposition of the Account 1589 balance as part of current application. If adjustments were made to an Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed for each year after the distributor last received final disposition for Account 1589	Excel version submitted
3.2.5.4 Capacity Based Recovery (CBR)		
12	Disposition proposed for Account 1580 sub-account CBR Class B in accordance with the OEB's CBR Accounting Guidance. - Embedded distributors who are not charged CBR (therefore no balance in sub-account CBR Class B) must indicate this is the case for them - In the Rate Generator model, distributors must indicate whether they had Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated - For disposition of Account 1580 sub-account CBR Class A, distributors must follow the OEB's CBR accounting guidance, which results in balances disposed outside of a rate proceeding - The Rate Generator model allocates the portion of Account 1580 sub-account CBR Class B to customers who transitioned between Class A and Class B based on consumption	Application pg 33
3.2.5.5 Disposition of Account 1595		
14	Confirmation that residual balances in Account 1595 Sub-accounts for each vintage year have only been disposed once	Application pg 33
14	Detailed explanations provided for any significant residual balances attributable to specific rate riders for each customer rate class, including for example, differences between forecast and actual volumes	Application pg 33
3.2.6 Lost Revenue Adjustment Mechanism Variance Account		
15	The 2021 CDM Guidelines require distributors filing an application for 2023 rates to seek disposition of all outstanding LRAMVA balances related to previously established LRAMVA thresholds	Confirmed
17	Completed latest version of LRAMVA Workform in a working Excel file when making LRAMVA requests for remaining amounts related to CFF activity	See excel file "EE_2023_LRAMVA_ 20220727"
17	Final Verified Annual Reports if LRAMVA balances are being claimed from CDM programs delivered in 2017 or earlier. Participation and Cost reports in Excel format, made available by the IESO, provided to support LRAMVA balances for programs for the period of January 1, 2018 to April 15, 2019. These reports should be filed in Excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017. To support savings claims for projects completed after April 15, 2019, distributors should provide similar supporting evidence	Already filed in support of a previous LRAMVA application
17	File other supporting evidence with an explanation and rationale should be provided to justify the eligibility of any other savings from a program delivered by a distributor through the Local Program Fund that was part of the Interim Framework after April 15, 2019.	N/A
17	Meet the OEB's requirements related to personal information and commercially sensitive information as stated in the Filing Requirements	Confirmed
18	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	Appendix A pg. 2&3 of IndEco report
18	Statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format) and a statement indicating use of most recent input assumptions when calculating lost revenue	Manager Summary pg 35
18	Summary table with principal and carrying charges by rate class and resulting rate riders	Manager Summary Tables 11/12 & 17/18
18	Statement confirming the period of rate recovery	Manager Summary pg 41
18	Statement providing the proposed disposition period; rationale provided for disposing the balance in the LRAMVA if significant rate rider is not generated for one or more customer classes	Appendix A pg. 11 of IndEco report
18	File details related to the approved CDM forecast savings from the distributor's last rebasing application	Manager Summary pg 37-39
18	Rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form)	Appendix A pg. 6-8 of IndEco report & Tabs 3-a and 3-b added to the workform
18	Statement confirming whether additional documentation was provided in support of projects that were not included in distributor's final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable)	Appendix A pg. 7-8 of IndEco report
18	File in support of a previous LRAMVA application, distributors should provide Participation and Cost Reports and detailed project level savings files made available by the IESO and/or other supporting evidence to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available. These reports should be filed in Excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017	Already filed in support of a previous LRAMVA application. Tabs 3-a and 3-b added to the workform

2023 IRM Checklist

Elexicon Energy Inc

EB-2022-0024

Date: July 27 2022

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
18 - 19	For a distributor's streetlighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: Explanation of the methodology to calculate streetlighting savings; Confirmation whether the streetlighting savings were calculated in accordance with OEB-approved load profiles for streetlighting projects; Confirmation whether the streetlighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings. For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information: o Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application o Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans) o Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total) o Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program o A table, in live excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb)	Appendix A pg. 7-8 of IndEco report & Manager Summary pg 40
19	For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information: o The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate o Rationale for net-to-gross assumptions used o Breakdown of billed demand and detailed level calculations in live excel format	N/A
19 - 20	For program savings for projects completed after April 15, 2019, distributors should provide the following: o Related to CFF programs: an explanation must be provided as to how savings have been estimated based on the available data (i.e. IESO's Participation and Cost Reports) and/or rationale to justify the eligibility of the program savings. o Related to programs delivered by the distributor through the Local Program Fund under the Interim CDM Framework: an explanation and rationale should be provided to justify the eligibility of the additional program savings.	Appendix A pg. 5-6 of IndEco report & Manager Summary pg36-37. There were no projects under the Local Program Fund or the Interim Framework to claim.
3.2.6.2 Continuing Use of the LRAMVA for New CDM Activities		
20	Statement whether it is requesting an LRAMVA for one or more of these activities, if this request has not been addressed in a previous application.	N/A
3.2.7 Tax Changes		
21	Tabs 8 and 9 of Rate Generator model are completed, if applicable	Confirmed
21	If a rate rider to the fourth decimal place is not generated for one or more customer classes, the entire sharing tax amount is be transferred to Account 1595 for disposition at a future date	Application pgs 41 & 42
3.2.8. Z-Factor Claims		
21	Eligible Z-factor cost amounts are recorded in Account 1572, Extraordinary Event Costs. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-accounts of this account	N/A
21	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	N/A
3.2.8.1 Z-Factor Filing Guidelines		
22	Evidence that costs incurred meet criteria of causation, materiality and prudence	N/A
22	In addition, the distributor must: - Notify OEB by letter of all Z-Factor events within 6 months of event - Apply to OEB for any cost recovery of amounts in the OEB-approved deferral account claimed under Z-Factor treatment - Demonstrate that distributor could not have been able to plan or budget for the event and harm caused is genuinely incremental - Demonstrate that costs incurred within a 12-month period and are incremental to those already being recovered in rates as part of ongoing business exposure risk - Provide the distributor's achieved regulatory ROE for the most recently completed fiscal year	N/A

2023 IRM Checklist

Elexicon Energy Inc

EB-2022-0024

Date: July 27 2022

Filing Requirement Section/Page Reference	IRM Requirements	Evidence Reference, Notes
3.2.8.2 Recovery of Z-Factor Costs		
22	Description of manner in which distributor intends to allocate incremental costs, including rationale for approach and merits of alternative allocation methods	N/A
22	Specification of whether rate rider(s) will apply on fixed or variable basis, or combination; length of disposition period and rational for proposal	N/A
22	Residential rate rider to be proposed on fixed basis	N/A
22	Detailed calculation of incremental revenue requirement and resulting rate rider(s)	N/A
3.2.9 Off-Ramps		
22 - 23	If a distributor whose earnings are in excess of the dead band nevertheless applies for an increase to its base rates, it needs to substantiate its reasons for doing so	N/A
23	A distributor is expected to file its regulated ROE, as was filed for 2.1.5.6 of the RRR. However, if in the distributor's view this ROE has been affected by out-of-period or other items (for example, revenues or costs that pertain to a prior period but recognized in a subsequent one), it may also file a proposal to normalize its achieved regulated ROE for those impacts, for consideration by the OEB.	N/A
3.3.1 Advanced Capital Module		
4	Capital Module applicable to ACM and ICM, for an incremental or pre-approved Advanced Capital Module (ICM/ACM) cost recovery and associated rate rider(s)	N/A
24	Evidence of passing "Means Test"	N/A
24	Information on relevant project's (or projects') updated cost projections, confirmation that the project(s) are on schedule to be completed as planned and an updated ACM/ICM module in Excel format	N/A
3.3.2 Incremental Capital Module		
25	If proposed recovery differs significantly from pre-approved amount, a detailed explanation is required	N/A
25	If updated cost projects are 30% greater than pre-approved amount, distributor must treat project as new ICM, re-filed business case and other relevant material required	N/A
26	Evidence of passing "Means Test"	App B. Section 3.2.1. pg 30
3.3.2.1 ICM Filing Requirements		
	The following should be provided when filing for incremental capital:	
4	Capital Module applicable to ACM and ICM, for an incremental or pre-approved Advanced Capital Module (ICM/ACM) cost recovery and associated rate rider(s)	ACM/ICM Excel Model
26	An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor	App B. Section 3.1 pg 32-36
27	Justification that the amounts to be incurred will be prudent - amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers	App B. Section 4 pg 38-42
27	Justification that amounts being sought are directly related to the cause, which must be clearly outside of the base upon which current rates were derived	App B. Section 3.2.2 pg 38-39
27	Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth)	App B. Section 3.2.2 pg 38-39
27	Details by project for the proposed capital spending plan for the expected in-service year	App B. Section 2.3 pg. 23-27
27	Description of the proposed capital projects and expected in-service dates	App B. Section 2.3 pg. 23-27
27	Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental capital project	ACM/ICM Excel Model
27	Calculation of each incremental project's revenue requirements that will be offset by revenue generated through other means (e.g. customer contributions in aid of construction)	App B. Section 2.3.1 pg. 23-24
27	Description of the actions the distributor would take in the event that the OEB does not approve the application	App B. Section 4 pg 38-42
27	Calculation of a rate rider to recover the incremental revenue from each applicable customer class. The distributor must identify and provide a rationale for its proposed rider design, whether variable, fixed or a combination of fixed and variable riders. As discussed at section 3.2.3, any new rate rider for the residential class must be applied on a fixed basis	App B. Section 6.3 pg. 52-54
3.3.2.3 ICM Filing Requirements		
28	Calulate the maximum allowable capital amount	App B. Section 3.1.1 pg. 35 & ACM/ICM Excel Model