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Reference 1: Exhibit 2, Tab 1, Schedule 3, Page 16 of 21

Reference 2: Exhibit 5, Attachment 3, M-factor Revenue Requirement

On page 16 of 21, Alectra Utilities states that "The cumulative 5-year capital revenue requirement associated with the M-factor funding request of $286,036,835 is $27,891,068."

OEB staff is unable to reconcile the M-factor request amount and the associated revenue requirement above. In the M-factor spreadsheet (attachment 3) and other parts of Exhibit 2, Tab 1, Schedule 3, OEB staff notes the total requested M-factor funding to be $264,962,171 and the associated revenue requirement to be $21,845,661.

a) Please reconcile the total amount of Alectra Utilities' M-factor funding request.

b) Please reconcile the total revenue requirement associated with the M-factor funding request.

Response:

a) Alectra Utilities confirms that the cumulative 5-year capital revenue requirement and M-factor funding request is $21,845,661 and $264,962,171, respectively, as provided in Tables 5 and 6 of Exhibit 2, Tab 1, Schedule 3, and in Attachment 3 of the pre-filed evidence. The amounts referenced on Line 18 of Exhibit 2, tab 1, Schedule 3, p. 16 was incorrect.

b) Please see Alectra Utilities' response to part a).

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Reference 1: Exhibit 2, Tab 1, Schedule 3, Table 5

Reference 2: Exhibit 2, Tab 1, Schedule 3, Page 3 of 21

Reference 3: Exhibit 4, Tab 1, Schedule 1, Pages 367-368 of 438

Alectra Utilities provided the following table to show the breakdown of M-factor capital expenditures per the Distribution System Plan (DSP) priority needs:

Table 5 – 2020 - 2024 M-factor Capital Projects by Investment Need ($MM)

DSP Priority Needs	2020-2024 M-Factor Capital Expenditures
Enhancing the resilience of its overhead system to adverse weather events	$62.4
Mitigating the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis	$43.9
Preventing further decline in reliability due to deteriorating underground assets	$35.2
Responding to anticipated needs in areas of new greenfield development and urban redevelopment/intensification	$123.6
Total M-factor Capital Expenditure	**$265.0**

a) Please explain how Alectra Utilities determined the amounts allocated to each DSP priority need.

b) Please explain how "mitigating the need to rebuild or construct new stations" creates a net cost increase to Alectra Utilities ratepayers rather than a cost savings.

c) Please explain what is driving the increase in investment in "environmental protection measures" and explain why that driver was previously unknown to Alectra Utilities (or its predecessor utilities).

d) Please explain how "strategically managing inventory on a consolidated basis" leads to higher inventory costs (i.e. increases rather than reduces inventory).

In reference 2, Alectra Utilities states that it has "… a total of approximately $275MM of unfunded capital expenditures over the five-year DSP period."

e) Given that the M-factor request is for $265 million in funding, please explain how Alectra Utilities arrived at $265 million from $275 million and how Alectra Utilities will deal with the shortfall of approximately $10 million in capital funding.

In reference 3, Alectra Utilities notes that the increases between the five year average net capital expenditure from 2015-2019 and the five year forecast from 2020-2024 are:

- **For system access, $2.1 million ($64.7 million to $66.8 million). Alectra Utilities also describes the "forecast spend per year [as] relatively consistent with the historical average."**
- **For system service, $1.2 million ($36.9 million to $38.1 million).**
- **For system renewal, $25.9 million ($127.8 million to $153.7).**

OEB staff notes that, relatively, the increase in average net capital expenditure spending for system renewal is significantly higher than system access or system service.

OEB staff notes that in Table 5 above, items 1 and 3 would be considered system renewal work totalling $97.6 million, while items 2 and 4 would be considered system access and system service work totalling $167.5 million.

f) Please reconcile the above. Specifically, please explain why Table 5 implies a large amount of incremental spending on system access and system service, which seems to contradict reference 3, which states that system renewal accounts for the bulk of Alectra Utilities' increased capital spending.

Response:

a) Alectra Utilities has provided a further breakdown of the M-factor investments by DSP priority need, in Table 1 below, in order to provide more clarity on the classification of these investments.

Table 1 - 2020-2024 M-factor Capital Projects by Investment need ($MM)

DSP Priority Need	2020-2024 M-Factor Capital Expenditure ($MM)
Enhancing the resilience of its overhead system to adverse weather events	62.4
Mitigating the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis	15.0
Preventing further decline in reliability due to deteriorating underground assets	35.2
Responding to anticipated needs in areas of new greenfield development and urban redevelopment and intensification	112.4
Keeping the business running	32.7
Eliminating Meter Safety Data Risk	7.3
Total M-Factor Capital Expenditure	**265.0**

The updated table introduces two additional DSP needs which include keeping the business running and eliminating Meter Safety Data Risk. As a result, specific projects previously apportioned to other DSP Priority Needs have been classified to the two additional DSP needs for greater clarity.

In developing the DSP, investment solutions required to address the identified needs, exceeded funding provided by base rates. Alectra Utilities considered customer priorities and preferences, balanced with the needs of the distribution system and those of the business, to identify projects that required additional funding.

Alectra Utilities determined the amounts allocated to each DSP priority need as follows:

- To address the need to prevent further decline in reliability due to deteriorating underground assets, Alectra Utilities included unfunded projects for underground cable replacement categorized in System Renewal investments;
- To address the need to enhance the resilience of the overhead system to adverse weather, Alectra Utilities included unfunded rear lot and voltage conversion projects from the Overhead Asset Renewal investment grouping;
- To mitigate the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis, Alectra Utilities included unfunded projects for Supervisory Control and Data Acquisition ("SCADA") system as well as Protection & Communications investments categorized under the Station Renewal investment grouping. Also included in this grouping are unfunded non wires stations alternative projects categorized under the system service investment grouping;
- To respond to anticipated needs in areas of new greenfield development and urban development and intensification, Alectra Utilities included unfunded lines capacity, stations capacity and non-wires alternatives projects categorized in the System Service investment grouping. Also included in this grouping are unfunded Connection and Cost Recovery Agreement ("CCRA") projects as well as a capacity project completed in conjunction with a road widening project from System Access;

- To address the need to keep the business running, Alectra Utilities included unfunded IT, fleet and necessary building projects from the General Plant investment grouping; and
- The eliminating meter safety data risk includes the Residential Icon F meter replacement project from the System Access investment grouping.

b) c) and d) In the development of the 2020-2024 DSP, Alectra Utilities prioritized investments in system renewal, necessary to reverse the negative trend in reliability due to defective equipment and failures due to adverse weather condition. This reflects Alectra Utilities' customer preference to maintain reliability levels, address system resiliency to storms and invest in infrastructure that directly services customers and hence majority of projects that fall under "Mitigating the need to rebuild stations" were identified as incremental projects. Alectra Utilities mitigated, to the extent possible, increases in rates by decreasing investments in station renewal and station expansion through the implementation of monitoring technologies, investing in environmental protection and feeder ties. For example, Alectra Utilities deferred the new Alliston 10 MVA Substation by two years along with deferral of feeder integration, and plans to utilize the existing substations in the area to service the capacity needs of the community.

Alectra Utilities operates 34 power transformers that are in poor condition. Over the 2020-2024 DSP period, Alectra Utilities plans on renewing only two power transformers resulting in cost savings. Please see section 5.4.3 Subsection C.2.4 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 387 of 438). c).

Alectra Utilities has 106 Municipal Stations ("MS") that do not have oil containment systems. When the stations were put in service, befitting of the construction practices of the time, there was no requirement to install oil containment systems. An MS transformer, depending on its power rating, contain approximately 6,000 to 12,000 litres of oil. Without the oil spill containment systems, leaks from the power transformers can result in severe environmental damages not only to the immediate substation site but also adjacent private or public properties. To migrate this risk, Alectra Utilities plans to install Sorbweb oil containment systems. This will enable Alectra Utilities to defer the replacement of these transformers knowing that the failure of these transformers will not cause a major environmental impact.

There are no additional investments in the DSP for the purchase of the spares, however Alectra Utilities has a larger inventory of spare power transformers under the consolidated entity, relative to predecessor utilities. The availability of a larger inventory of transformers enables Alectra Utilities to have in place and to implement if needed, contingency plans that allow for it to continue using transformers that would typically be considered to be beyond the end of their useful life.

For the 2015-2019 period, Alectra Utilities (including its predecessors) invested approximately $44.7MM on projects related to renewing station assets. For the 2020-2024 period, Alectra Utilities plans to invest approximately $28.7MM on investments associated with station renewal, a reduction of $16MM over a five-year period. In conclusion, Alectra Utilities consolidated measures and investment in station monitoring, additional feeder ties, oil containment and managing the available spares on a consolidated basis have led to significant deferred capital in renewing the stations and not building additional stations.

e) Alectra Utilities did not identify the proposed M-factor projects arbitrarily based on the funding level that may be available through the eligible capital calculation. Rather, it aligned the M-factor projects with the work included in the second phase of customer engagement. As described in Exhibit 2, Tab 1, Schedule 3, page 14, "[b]y aligning customer engagement with the proposed capital funding mechanism, any changes to the proposed expenditures in response to customer preferences would be directly captured by the M-factor and, ultimately, reflected in customer bill impacts." Accordingly, the proposed M-factor riders actually reflect slightly less than Alectra Utilities' true capital investment needs during the DSP period. Despite this potential financial impact on the company, Alectra Utilities believes this was a principled approach to identifying M-factor investments for the purposes of calculating the riders.

Alectra Utilities does not know how it will fund the approximately $10MM shortfall between the capital investments set out in the DSP and funded between base rates and the proposed

M-factor riders. The company will assess the capital investment plan based on the OEB's decision in this proceeding and the needs of the distribution system as they exist at that time.

f) As per the tables provided in Exhibit 4, Tab 1 Schedule 1 Pages 367 to 369 the bulk of the increase in spending from 2020 to 2024 is due to system renewal work. In the development of the 2020-2024 DSP, Alectra Utilities prioritized investments in system renewal, necessary to reverse the negative trend in reliability due to defective equipment and failures due to adverse weather condition and to reflect Alectra Utilities' customer preference to maintain reliability levels. Hence a majority of system renewal investments were considered to be funded in rates and significant number of system service projects considered incremental and to be funded through the M-factor. The incremental spending on system access and system service is 119.2MM vs. 101.3MM in the system renewal category.

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Reference: Exhibit 4, Tab 1, Schedule 1, Pages 7-9 of 438

Regarding the priority needs reflected in its DSP, Alectra Utilities states:

> **(iii) Be responsive to anticipated needs in areas of new greenfield development and urban redevelopment intensification.**
>
> **(iv) Take advantage of opportunities to establish additional linkages between legacy systems and balance loads across its entire service area so as to mitigate the need for system expansions.**
>
> **Alectra Utilities plans to make targeted investments in establishing additional connections between adjacent legacy systems to assist it in balancing loads more effectively, thereby enabling it to defer the need for most costly system expansions. For example, Erindale TS capacity relief was proposed by constructing a new station as indicated in the DSP for the Enersource Rate Zone, as filed in Alectra Utilities EDR application on July 07, 2017 (EB-2017-0024). In the Enersource DSP, the construction of a station, Mini-Britannia MS, was proposed. However, as a result of planning capital investments on an integrated and system-wide basis, a more prudent option was identified, linking two of the predecessor Enersource's and Brampton Hydro's distribution systems and will result in capital savings from mitigating the need to build the new MS.**
>
> **(v) Mitigate the need to rebuild or construct new stations by enhancing the use of monitoring technologies, investing in environmental protection measures and strategically managing inventory on a consolidated basis.**

In respect of priority need iii):

a) **Are all capital costs driven by this "priority need" contained within the proposed System Access capital projects?**

   i. **If no, please identify which projects and programs categorized under other capital spending categories are driven by this "priority need".**

In respect of priority need iv):

b) **Please describe Alectra Utilities' process for identifying opportunities to establish additional linkages and to balance loads across its service area.**

   i. **As part of the process described in b), does Alectra Utilities perform a cost comparison between projects that take advantage of linkages versus the projects that would have taken place absent linkages? If yes, please provide the cost comparisons. If no, why not?**

c) Has Alectra Utilities' identified O&M savings from taking advantage of the additional linkages within its service area? If yes, please provide the amount quantified. If no, please explain why no O&M savings were identified.

d) Has Alectra Utilities accounted for the savings identified in parts b) and c) in its incremental capital needs? Please explain why or why not.

In respect of priority need v):

e) Will this "priority need" enable Alectra Utilities to reduce overall stations capital spending?

i. If yes, what is the amount of spending reduced, and has this been reflected in Alectra Utilities' proposed stations capital spending?

ii. If no, why not?

f) Has Alectra Utilities identified OM&A savings resulting from the investments in this priority need?

i. If yes, please provide the amount quantified.

ii. If no, please explain why Alectra Utilities has not identified OM&A savings in light of: additional monitoring, increased environmental protection measures and better inventory management strategies.

Response:

a) The capital cost driven by this priority need are included within the System Service, System Access and General Plant (CCRA payments) category. Table 1, below details the projects, grouping and spending category included under the priority need (iii) *"Be responsive to anticipated needs in areas of new greenfield development and urban redevelopment intensification"*

Table 1 - Projects Listed under the Priority Need (iii)

Project Code	Project Name	Alectra Grouping	Category
100340	Vaughan TS#4 Feeder Integration - Part 3	Capacity (Lines)	System Service
150360	44kV New Feeder Extension Centre View Dr	Capacity (Lines)	System Service

150319	Duke MS New 20 MVA Substation	Capacity (Stations)	System Service
101569	New Alliston 10MVA Substation - Industrial Parkway	Capacity (Stations)	System Service
151124	Goreway TS Expansion (CCRA) - 10 Yr True-Up Payment	CCRA	General Plant
150371	27.6kV Feeder Extension Traders	Capacity (Lines)	System Service
103633	Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	Capacity (Lines)	System Service
100337	Markham TS #4 Feeder Egress Part 3	Capacity (Lines)	System Service
150342	HaLRT_New Stirton Feeder for TPSS#4 and 8852X load shedding	Capacity (Lines)	System Service
150364	Port Credit Village East New Feeders (Marina)	Capacity (Lines)	System Service
150409	42M66/25M7 New Ducts Main St & Queen St	Capacity (Lines)	System Service
100904	Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	Capacity (Lines)	System Service
150343	Bathurst Street Widening	Road Authority	System Access
151125	Connection Cost Recovery Agreement (CCRA) – Midhurst TS – 15th Anniversary True-up	CCRA	General Plant
150680	Alectra Drive at Home	Capacity (Lines)	System Service
100924	Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	Capacity (Lines)	System Service
150693	Blockchain	Capacity (Lines)	System Service
101542	New Barrie 20MVA Substation - Harvie	Capacity (Stations)	System Service
100909	Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills	Capacity (Lines)	System Service
150367	Mini-Orlando MS 27.6kV Land Purchase	Capacity (Stations)	System Service
100632	27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line	Capacity (Lines)	System Service
150368	North Central feeders capacity (Carlton TS to Lakeshore/Lake) relief	Capacity (Lines)	System Service
102128	Aurora MS6 Expansion - (Year 1 of 2) - Design & Order Equipment	Capacity (Lines)	System Service
150370	27.6kV New Feeders Lakeview Development	Capacity (Lines)	System Service
150369	44kV Feeder Extension York/Meadowpine	Capacity (Lines)	System Service
150390	Waterdown 3rd Feeder	Capacity (Lines)	System Service

151117	Vansickle TS True-up Payment	CCRA	General Plant
102547	Two Ccts on Birchmount Rd from ROW to 14th Ave	Capacity (Lines)	System Service
100913	Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50	Capacity (Lines)	System Service
101036	Install a new 4 ccts CNR yard overhead crossing on the south side of Hwy 7	Capacity (Lines)	System Service
101487	Add one Additional 27.6 kV Cct on Major Mack Dr and 9th Line	Capacity (Lines)	System Service
101480	Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	Capacity (Lines)	System Service
150374	13.8kV Feeder Extension 9th Line, Derry to Argentia	Capacity (Lines)	System Service
151233	GUELPH - Campbell TS 36M63 Feeder PHASE 1	Capacity (Lines)	System Service
151234	GUELPH - Campbell TS 36M63 Feeder PHASE 2	Capacity (Lines)	System Service
150716	42M69 Feeder Extension Williams Pkwy - Main St to Kennedy Rd	Capacity (Lines)	System Service
150358	QEW Expansion Dixie West OH Betterment	Capacity (Lines)	System Service
102387	Install 44kV & 13.8kV Bryne Drive	Capacity (Lines)	System Service
150353	Truscott Plaza Voltage Conversion 4.16 - 27.6kV (3 Sections)	Capacity (Lines)	System Service
150401	136M6 Goreway TS Extensions	Capacity (Lines)	System Service
150679	Alectra Drive for the Workplace	Capacity (Lines)	System Service
100919	Install 2nd 27.6 kV Cct on Woodbine Ave from Elgin Mills Rd to 19th Ave	Capacity (Lines)	System Service
151240	GUELPH - Southgate Dr to Maltby Rd O/H Extension	Capacity (Lines)	System Service
151118	Nebo TS 27.6kV True-up Payment	CCRA	General Plant
150361	Airport 88M5 & 88M7 HONI Purchase	Capacity (Lines)	System Service
100159	Hydro One Asset Purchase - Alliston	Capacity (Lines)	System Service
150576	Split the 1/0 loop on Cityview Blvd into two loops	Capacity (Lines)	System Service
151241	GUELPH - Arlen MTS - New Feeder	Capacity (Lines)	System Service
150422	136M9 Feeder Extension Castlemore Rd, Goreway Dr to McVean Dr	Capacity (Lines)	System Service
150410	42M66 OH Feeder Egress Mississauga Rd, Bovaird to CNR	Capacity (Lines)	System Service
150411	42M64 Feeder Extension Mississauga Rd, Williams	Capacity	System

	Pkwy to Queen / Embleton	(Lines)	Service
150694	Cityview microgrid enhancements	Capacity (Lines)	System Service
100340	Vaughan TS#4 Feeder Integration - Part 3	Capacity (Lines)	System Service
150360	44kV New Feeder Extension Centre View Dr	Capacity (Lines)	System Service
150319	Duke MS New 20 MVA Substation	Capacity (Stations)	System Service
101569	New Alliston 10MVA Substation - Industrial Parkway	Capacity (Stations)	System Service
151124	Goreway TS Expansion (CCRA) - 10 Yr True-Up Payment	CCRA	General Plant
150371	27.6kV Feeder Extension Traders	Capacity (Lines)	System Service
103633	Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	Capacity (Lines)	System Service
100337	Markham TS #4 Feeder Egress Part 3	Capacity (Lines)	System Service
150342	HaLRT_New Stirton Feeder for TPSS#4 and 8852X load shedding	Capacity (Lines)	System Service
150364	Port Credit Village East New Feeders (Marina)	Capacity (Lines)	System Service
150409	42M66/25M7 New Ducts Main St & Queen St	Capacity (Lines)	System Service
100904	Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	Capacity (Lines)	System Service
150343	Bathurst Street Widening	Road Authority	System Access
151125	Connection Cost Recovery Agreement (CCRA) – Midhurst TS – 15th Anniversary True-up	CCRA	General Plant
150680	Alectra Drive at Home	Capacity (Lines)	System Service

b) The formation of Alectra Utilities created the opportunity to share infrastructure at specific adjoining areas between Mississauga and Brampton, and between Brampton and Vaughan. If there is a capacity requirement in these areas, and where interconnection is possible, Alectra Utilities' system planners evaluate: the available capacity in both areas; the existing and future load growth; and the technical feasibility of the connection. The system planners then perform an economic evaluation of cost from each of the supply options. A technically feasible solution with the lowest cost is recommended for implementation.

As identified in the question, Erindale TS capacity relief was proposed by constructing a new station as indicated in the DSP for the Enersource Rate Zone, filed in Alectra

Utilities' 2018 EDR Application (EB-2017-0024). In the Enersource RZ DSP, the construction of a station, Mini-Britannia MS, was also proposed. The construction of Mini-Britannia included $5.15MM for a new substation and $2.5MM for feeder egress expansion for a total expansion investment of $7.65MM. Alternatively, Alectra Utilities identified that extension of Feeder 25M9 would provide a more economical solution that avoids $7.21MM in system expansion costs for Alectra Utilities' customers. Over the 2020 to 2022 period, Alectra Utilities plans to increase the interconnections between the legacy Brampton and legacy Mississauga systems to provide capacity, backup and reliability enhancement for Alectra Utilities' customers in Brampton and Mississauga.

A second example includes the installation of a two circuit pole line on Langstaff Rd from Huntington Rd to Highway 50 which was proposed by the legacy PowerStream to remediate the radial supply on Highway 50 between Langstaff Road and Rutherford Road in Vaughan. Alectra Utilities identified opportunities to establish additional linkages on Hwy 50 from Vaughan to Brampton. The project to build two feeder ties on Hwy 50 between Vaughan and Brampton will be completed in 2019 and includes:

- Building one feeder tie between Vaughan and Brampton on Hwy 50 at Langstaff Rd; and
- Building one feeder tie between Vaughan and Brampton on Hwy 50 north of Hwy 407

c) The savings related to capital investments to establish linkages between legacy systems relate to avoided capital investments for system expansion which enables Alectra Utilities to reallocate capital investment funding to urgently needed system renewal investments. There are nominal OM&A related savings (e.g. the business case for the construction of the Mini-Britannia projected an OM&A cost increase of $36k per year for increased inspection, maintenance and property taxes for the new station).

d) Please see Alectra Utilities' response to SEC-1.

e) Please see Alectra Utilities' response to G-Staff-59.

f) Similar to the priority need to establish linkages between systems, the savings driver behind mitigating station renewal and expansion investments are capital and enable Alectra Utilities to reallocate capital investment funds to urgently needed system renewal investments.

G-Staff-4

Reference: Exhibit 5, Attachment 3, M-factor Revenue Requirement

Alectra Utilities provided the following table in the "Summary by RZ" tab within the Attachment 3 excel workbook:

Capex	2020	2021	2022	2023	2024	2020-2024
Horizon	11,863,042	10,953,468	9,264,384	3,521,255	11,814,192	47,416,342
Brampton	9,696,860	2,188,555	6,646,395	3,730,434	3,765,279	26,027,522
PowerStream	23,015,003	16,054,205	15,402,786	32,752,595	23,331,583	110,556,171
Enersource	6,591,094	5,532,703	8,810,404	7,760,537	23,132,111	51,826,849
Guelph	133,500	1,278,753	1,336,164	612,820	745,233	4,106,470
Multiple	1,374,474	7,646,447	10,563,570	3,691,393	1,752,933	25,028,816
	52,673,973	**43,654,130**	**52,023,703**	**52,069,034**	**64,541,330**	**264,962,171**

a) Please provide a breakdown by rate zone of all the individual projects that are to be funded by the M-factor.

b) Please explain how Alectra Utilities determined which projects would be funded through the M-factor and which projects would be funded through Alectra Utilities' base rates.

c) If the M-factor is not approved, please confirm that the projects listed in part a) are the projects that would not proceed absent M-factor funding. Otherwise, absent any M-factor funding, please explain Alectra Utilities' methodology for choosing the projects it would defer.

Response:

a) Tables 1-4 include all capital investments proposed for M-Factor funding provided by rate zone including a set of projects applicable to all rate zones labeled as Multiple.

Table 1 – Proposed M-Factor Funded Capital Investments for Horizon Rate Zone ($MM)

Project	Investment ($MM)
Deerhurst MS Voltage Conversion	$7.8
HaLRT_New Stirton Feeder for TPSS#4 and 8852X load shedding	$4.8
Dewitt MS Voltage Conversion	$4.1
Eastmount MS Voltage Conversion	$3.8
Aberdeen MS Voltage Conversion_2020 to 2022	$3.3
Galbraith MS Voltage Conversion	$3.3

Rear Lot Conversion - Marsdale	$3.1
Elmwood MS Voltage Conversion	$2.8
Rear Lot Conversion - Richlieu Dr and Trelawne Dr	$2.4
North Central feeders capacity (Carlton TS to Lakeshore/Lake) relief	$2.0
Montgomery Dr Voltage Conversion and Rear Lot Relocate_ANC	$1.8
Waterdown 3rd Feeder	$1.7
Vansickle TS True-up Payment	$1.6
Rear Lot Conversion - Strathcona Dr	$0.9
2D7X Pimlico Dr - Voltage Conversion and Rear Lot	$0.6
Nebo TS 27.6kV True-up Payment	$0.5
New WiMAX Communications System - West	$0.5
Facilities Reno John St Roof Deck	$0.4
Fleet_2023_West_Vehicle_Replacement_Bucket Truck_1-354	$0.4
Fleet_2020_West_Vehicle Replacement_Step Vans	$0.4
Fleet_2024_West_Vehicle_Replacement_Pickups	$0.2
SS-2019-Installation of SWI Video security system at 4 MS stations per year	$0.2
Fleet_2020_West_Vehicle Replacement_SUVs_1-268,1-226,1-227	$0.1
Fleet_2023_West_Vehicle_Replacement_Pickups	$0.1
Fleet_2023_West_Vehicle_Replacement_Trailer	$0.1
SS-Driveway Paving- Various Stations -WEST	$0.1
Fleet_2024_West_Vehicle Replacement_Forklift	$0.1
Fleet_2023_West_Vehicle Replacement_ Pole Trailer_1-405	$0.1
Fleet_2022_West_Vehicle_Replacement_Trailers	$0.1
SS-2019-Station LED Lighting Upgrades - West	$0.1
Total Horizon Rate Zone	$47.4

Table 2 – Proposed M-Factor Funded Capital Investments for Brampton Rate Zone ($MM)

Project	Investment ($MM)
Goreway TS Expansion (CCRA) - 10 Yr True-Up Payment	$5.6
MS-12 Hansen Rd 4.16kV Voltage Conversion	$5.5
MS-2 Church St 4.16kV Voltage Conversion	$4.4
42M69 Feeder Extension Williams Pkwy - Main St to Kennedy Rd	$1.1
Cable Injection Project - (F4-G4) - Main - Steeles - Chinguacousy - Queen, Brampton	$1.1
Cable Replacement Project - (F4-G4) - Main - Steeles - Chinguacousy - Queen, Brampton	$1.0
136M6 Goreway TS Extensions	$1.0
Cable Injection Project - (F3-G3-H3) - Phase 2, Brampton	$0.8
Fleet_2024_ Central North Vehicle Replacement_Reel Carriers	$0.7
Facilities_2022_Reno_Sandalwood - CDM Relocation from Jane	$0.6

Cable Injection Project - (G1) - Hwy 410 - Kennedy - Wanless - Main, Brampton	$0.6
Fleet_2024_ Central North Vehicle Replacement_S/Bucket	$0.5
Fleet_2023_ Central North Vehicle Replacement S/Bucket 8910	$0.5
Fleet_2020_ Central North Vehicle Replacement-180 Loader	$0.3
Fleet_2023_ Central North Vehicle Replacement_Stake Trucks	$0.3
New WiMAX Communications System - Central North	$0.3
Fleet_2021_ Central North Vehicle Replacement_ Step Vans 6310	$0.3
Fleet_2020_ Central North Vehicle Replacement-Step Van 8108	$0.2
SS-2019-Station LED Lighting Upgrades -EAST	$0.1
136M9 Feeder Extension Castlemore Rd, Goreway Dr to McVean Dr	$0.1
42M66 OH Feeder Egress Mississauga Rd, Bovaird to CNR	$0.1
SS-2019-Upgrade to Station Facilities (Building / Civil work) MultiYear-EAST	$0.1
Fleet_2023_ Central North Vehicle Replacement_Trailer	$0.1
42M64 Feeder Extension Mississauga Rd, Williams Pkwy to Queen / Embleton	$0.1
JY TS1 Bus & Main Breaker Protections Replacement	$0.1
Fleet_2021_ Central North Vehicle Replacement_Vans	$0.1
SS-2019-Driveway Paving- Various Stations-Program-EAST	$0.1
Fleet_2022_ Central North Vehicle Replacement pick ups	$0.1
Fleet_2023_ Central North Vehicle Replacement pick ups	$0.1
Fleet_2021_ Central North Vehicle Replacement Pick up 9514	$0.1
Fleet_2020_ Central North Vehicle Replacement-Van 5910	$0.1
Total Brampton Rate Zone	$26.0

Table 3 – Proposed M-Factor Funded Capital Investments for PowerStream Rate Zone ($MM)

Project	Investment ($MM)
Vaughan TS#4 Feeder Integration - Part 3	$8.8
Residential Meter "ICON F" Meter Replacement Program - East	$7.3
Install Two 27.6kV Ccts on 16th Ave from Hwy 404 to Woodbine Ave	$5.5
Markham TS #4 Feeder Egress Part 3	$4.9
Residential solar-storage	$4.0
Rear Lot Supply Remediation - Royal Orchard - North	$4.0
Install Double Cct Pole Line on Major Mackenzie - Hwy 27 to Huntington Rd	$3.7
Bathurst Street Widening	$3.4
Connection Cost Recovery Agreement (CCRA) – Midhurst TS – 15th Anniversary True-up	$3.2
Cable Replacement - (V15) - Jardin Dr	$2.9
Cable Replacement - (A02) - Steeplechase Ave	$2.9

Cable Injection Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	$2.8
Install two additional 27.6 kV ccts on Hwy 7 from Jane St to Weston Rd	$2.6
Rear Lot Supply Remediation - East of Queen St. to Eastern Ave./North of Greenway St.	$2.6
Rear Lot Supply Remediation - Main Street / Unionville / Carlton	$2.5
Cable Replacement Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	$2.4
New Barrie 20MVA Substation - Harvie	$2.2
Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills	$2.2
Cable Replacement - (M33) - 16th Avenue and Village Parkway	$2.1
27.6 kV Pole Line on 14th Ave from Hwy 48 to 9th Line	$2.0
Aurora MS6 Expansion - (Year 1 of 2) - Design & Order Equipment	$2.0
New Alliston 10MVA Substation - Industrial Parkway	$1.9
Rear Lot - Gunn/Oakley Park/St.Vincent	$1.8
Rear Lot - East of Queen Street/North of Mill Street	$1.8
Cable Replacement – (Barrie) - Cook St and Steel St	$1.7
Net Zero Energy Emissions	$1.6
Two Ccts on Birchmount Rd from ROW to 14th Ave	$1.6
Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave	$1.5
Cable Injection Project - (V50) - Hwy 7 - Kipling - Steeles - Hwy 27, Vaughan	$1.5
Pole Line Installation Double Cct on Major Mack - Huntington Rd to Hwy 50	$1.4
Install a new 4 ccts CNR yard overhead crossing on the south side of Hwy 7	$1.4
Add one Additional 27.6 kV Cct on Major Mack Dr and 9th Line	$1.3
Build double ccts 27.6kV pole line on 19th Ave between Leslie St and Bayview Ave	$1.3
Cable Injection Project - (V25) - Major Mackenzie - Keele - Rutherford - Jane, Vaughan	$1.3
Cable Injection Project - (V24) - Langstaff - Jane - Rutherford - Keele, Vaughan	$1.3
Install 44kV & 13.8kV Bryne Drive	$1.1
Cable Replacement - (Barrie) - Cundles Rd and Janine St	$1.1
Cable Replacement Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27, Vaughan	$1.0
Cable Replacement Project - (V24) - Langstaff - Jane - Rutherford - Keele, Vaughan	$1.0
Fleet East 2024 Vehicle replacement - Cube Vans	$0.7
Fleet East Unit # 75 83' Double Bucket	$0.7
Cable Injection Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27, Vaughan	$0.7
Fleet East Unit # 125, 83' Double Bucket	$0.7
Install 2nd 27.6 kV Cct on Woodbine Ave from Elgin Mills Rd to 19th Ave	$0.6

Cable Injection Project - (V31) - Langstaff - Weston - Rutherford - Jane, Vaughan	$0.6
Hydro One Asset Purchase - Alliston	$0.5
Redundant Fibre Path to Aurora MS#4 Sub-Station	$0.5
Markham TS#2 Line Protections and HMI Upgrade - KDU-10 Replacement	$0.5
Split the 1/0 loop on Cityview Blvd into two loops	$0.5
Fleet East Unit # 61 Digger truck replacement	$0.4
Vaughan TS#1 Bus Differential & Overcurrent Protections Upgrades	$0.4
Dufferin St S, between MS431 and Albert St S, Alliston	$0.4
Markham TS#1 Bus Differential & Overcurrent Protections Upgrades	$0.4
Markham TS#3 Bus Differential & Overcurrent Protections Upgrades	$0.3
Markham TS#2 Bus Differential & Overcurrent Protections Upgrades	$0.3
Markham TS#1 T1/T2 "B" Overcurrent Protections and HMI Upgrade	$0.3
Vaughan TS#2 Bus Differential and Overcurrent Protections Upgrade	$0.3
Rear Lot Supply Remediation - Blake/Kempenfelt	$0.3
Fleet East 2024 Vehicle replacement - Extened Vans	$0.2
Markham TS#2 T1/T2 "B" Differential Protections Upgrade	$0.2
Vaughan TS#1 T1/T2 "B" Differential Protections Upgrade	$0.2
Markham TS#3 T1/T2 "B" Differential Protections Upgrade	$0.2
Richmond Hill TS#2 Upgrade Bus, Line & Transformer Protections	$0.1
Aurora MS6 (AMS6) Transformer and Bus Protection Upgrade	$0.1
New Three Sector WiMAX Node - MS305	$0.1
Vaughan TS3 - Station Service Transfer Upgrade	$0.1
Cityview microgrid enhancements	$0.1
Vaughan TS#2 T1/T2 "B" Differential Protections Upgrade	$0.1
Fleet East 2024 Vehicle replacement - Work Van	$0.1
Fleet East 2024 Vehicle replacement Pickup truck 2500	$0.1
Total PowerStream Rate Zone	$110.6

Table 4 – Proposed M-Factor Funded Capital Investments for Enersource Rate Zone ($MM)

Project	Investment ($MM)
44kV New Feeder Extension Centre View Dr	$6.5
Duke MS New 20 MVA Substation	$6.2
27.6kV Feeder Extension Traders	$5.5
Port Credit Village East New Feeders (Marina)	$4.4
Left behind - ERZ	$2.7
Clarkson Voltage Conversion 4.16-27.6kV (4 Sections)	$2.7
Windjammer	$2.7

Mini-Orlando MS 27.6kV Land Purchase	$2.2
27.6kV New Feeders Lakeview Development	$1.9
44kV Feeder Extension York/Meadowpine	$1.8
13.8kV Feeder Extension 9th Line, Derry to Argentia	$1.2
Shelter Bay Rd.	$1.1
QEW Expansion Dixie West OH Betterment	$1.1
Truscott Plaza Voltage Conversion 4.16 - 27.6kV (3 Sections)	$1.0
MS Transformer & HV Switchgear Replacement (ACA)Munden MS35 T1 & HV1	$0.9
MS Transformer & HV Switchgear Replacement (ACA) Western MS36 T1 & HV1	$0.8
Fleet_2024_Central South Vehicle Replacement-Step Vans	$0.7
Mason Heights	$0.7
Bough Beeches Blvd.	$0.7
Station Switchgear Replacement (ACA) Bloor MS38 LV1	$0.7
Fleet_2024_Central South Vehicle Replacement- Material Handler	$0.6
Airport 88M5 & 88M7 HONI Purchase	$0.5
Distribution Cable Replacement - Area of Erin Mills pkway. and South Millway	$0.5
Fleet_2024_Central South Vehicle Replacement-209-09 S/bucket	$0.5
Fleet_2023_Central South Vehicle Replacement-236-10 S/bucket	$0.5
Fleet_2021_Central South Vehicle Replacement-210-09 S/bucket	$0.5
New WiMAX Communication Network - Central South	$0.4
Fleet_2024_Central South Vehicle Replacement-Vans	$0.3
King St. Voltage Conversion & Loop (LRT Betterment)	$0.3
Fleet_2022_Central South Vehicle Replacement-Step Vans	$0.2
Fleet_2020_Central South Vehicle Replacement-Step Van	$0.2
Fleet_2022_Central South Vehicle Replacement- Vans	$0.2
Fleet_2024_Central South Vehicle Replacement-Trailers	$0.2
SS-2019-Installation of SWI Video security system at 4 MS stations per year - Annual Program-CENTRAL	$0.2
Fleet_2024_Central South Vehicle Replacement-Pick ups	$0.2
Fleet_2022_Central South Vehicle Replacement-Pick ups	$0.2
SS-2019-Station LED Lighting Upgrades -CENTRAL	$0.1
SS-2019-Driveway Paving- Various Stations-Program-CENTRAL	$0.1
Fleet_2024_Central South Vehicle Replacement-SUV	$0.1
Fleet_2022_Central South Vehicle Replacement- SUV	$0.1
Fleet_2020_Central South_Vehicle Replacement -Vans	$0.1
Fleet_2020_Central South Vehicle Replacement-Pick ups	$0.1
Fleet_2024_Central South Vehicle Replacement-Van	$0.1
Fleet_2021_Central South Vehicle Replacement- Van	$0.1
Fleet_2021_Central South Vehicle Replacement- trailer	$0.0

Fleet_2020_Central South Vehicle Replacement-SUV	$0.0
Fleet_2023_Central South Vehicle Replacement-Bocat	$0.0
Fleet_2023_Central South Vehicle Replacement- Arrowboard	$0.0
Total Enersource Rate Zone	$51.8

Table 5 – Proposed M-Factor Funded Capital Investments for Guelph Rate Zone ($MM)

Project	Investment ($MM)
GUELPH - Campbell TS 36M63 Feeder PHASE 2	$1.2
GUELPH - Campbell TS 36M63 Feeder PHASE 1	$1.2
GUELPH - Rear Lot Conversions	$0.6
GUELPH - Southgate Dr to Maltby Rd O/H Extension	$0.6
GUELPH - Arlen MTS - New Feeder	$0.5
GUELPH - Capacitor Bank Installations	$0.1
Total Guelph Rate Zone	$4.1

Table 6 – Proposed M-Factor Funded Capital Investments for Multiple Rate Zone ($MM)

Project	Investment ($MM)
CC&B upgrade 2021 - 2022	$13.3
Alectra Workforce Management Software	$4.7
Alectra Drive at Home	$2.7
Blockchain	$2.4
Alectra Drive for the Workplace	$0.8
Alectra Single Platform Website ongoing	$0.3
Fieldworker Upgrade 2020	$0.3
Back-end Automation (Orchestration Tool\Setup)	$0.2
IT Innovation (ITx, 2024)	$0.2
Total Multiple Rate Zones	$25.0

b) Please see Alectra Utilities' response to G-Staff 9.

c) Alectra Utilities cannot speculate on potential investment options without the full context of the OEB's decision. As described in Exhibit 1, Tab 3, Schedule 1, pages 4-5, under-investing will result in a growing population of deteriorated assets, declining reliability, and a "snowplow" of capital costs for future customers. It will also lead to more expensive reactive capital investments when asset failures occur.

In the event that Alectra Utilities is denied the M-factor, it will also have to file annual ICM applications during the remainder of the rebasing deferral period.

G-Staff-5

Reference: Exhibit 2, Tab 1, Schedule 3, Page 15 of 21

On page 15 of 21, Alectra Utilities states that:

> **While the M-factor riders are calculated based on the specific investments contemplated by the DSP, they are not tied to those specific investments. Unlike other funding mechanisms during an IRM term, the M-factor provides an envelope of capital funding to fund prudent investments during the 2020-2024 period and is comparable in its approach to Custom IR treatment made in conjunction with a five year DSP.**

a) Please confirm that Alectra Utilities intends to treat M-factor funding as an envelope of funds not tied to any specific investments. In other words, that the M-factor funding will not necessarily be used to fund the projects that make up the capital expenditures shown in Attachment 3, but rather that it will be used as Alectra Utilities sees fit to accommodate the entirety of capital work comprising the DSP.

   i. If yes, please explain how Alectra Utilities will ensure that M-factor revenues collected from one rate zone are not used to fund capital expenditures within other rate zones.

   ii. If no, please explain how Alectra Utilities will maintain rate fairness when M-factor rate riders have been calculated per rate zone, but actual revenues collected in one rate zone might be used to fund capital expenditures in other rate zones.

Response:

Please refer to Alectra Utilities'' response to G-Staff-9.

G-Staff-6

Reference: Exhibit 2, Tab 1, Schedule 3, Table 1

Under the “Flexibility” section in Table 1, Alectra Utilities states that, under the M-factor, “Capital investments are funded on an envelope basis, allowing specific projects to be replaced modified or shifted between years depending on system needs and priorities.”

In the event that Alectra Utilities defers a portion of its capital investments from an earlier year to a later year (in effect underspending M-factor funding for one year and spending it in the next), would Alectra Utilities be over-collecting one year’s worth of depreciation expense and return on capital? Please discuss why or why not. If yes, please discuss if Alectra Utilities intends to refund customers and the mechanism to do so.

Response:

Please refer to Alectra Utilities’ response to G-Staff 9.

G-Staff-7

Reference 1: Exhibit 2, Tab 1, Schedule 3, Pages 18-19 of 21
Reference 2: Exhibit 5, Attachment 3, M-factor Revenue Requirement

Alectra Utilities is requesting OEB approval for its M-factor rate riders as identified in Attachment 3 and reproduced in tables 7-11 in Exhibit 2.

a) Please confirm that Alectra Utilities is seeking OEB approval for all the rate riders covering the DSP period of 2020-2024.

b) Please confirm that Alectra Utilities is proposing for its rate riders to be effective until its next rebasing application.

c) Please confirm that, if approved, the new rate riders will take effect year after year and will be in addition to the rate riders of the previous year (e.g. in 2021, both the 2021 and 2020 rate riders will be in effect).

d) Please explain whether Alectra Utilities intends to make annual updates to its rate riders, if approved, in its future rate applications.

Response:

a) Alectra Utilities is requesting approval for M-factor capital funding and associated 2020 to 2024 M-factor rate riders for each rate zone.

b) Alectra Utilities confirms that consistent with the OEB's ICM methodology, the M-factor rate riders will be in effect until Alectra Utilities' next rebasing Application.

c) Alectra Utilities confirms that the proposed rate riders will take effect year after year and will be in addition to the rate riders of the previous year.

d) Please see Alectra Utilities response to G-Staff-9.

G-Staff-8

Reference 1: Exhibit 5, Attachment 3, M-factor Revenue Requirement
Reference 2: Exhibit 2, Tab 1, Schedule 3, Page 13 of 21

Attachment 3 contains the M-factor threshold calculations per rate zone. OEB staff notes that the distribution revenues used for calculating the growth factor don't match the rate year. The calculation for the PowerStream rate zone is reproduced below as an example:

Price Cap Index	1.20%	*PCI*
Growth Factor Calculation		
2017 Actual Distribution Revenues	$208,214,383	
2013 Board-Approved Distribution Revenues	$203,517,916	
Growth Factor	2.31%	*g* (*Note* 1)
Dead Band	10%	

In the example shown for PowerStream above, OEB staff notes that the $208,214,383 amount appears to be 2018 Actual Distribution Revenues and the $203,517,916 amount appears to be for 2017 Board-Approved Distribution Revenues.

a) **Please confirm the correct distribution revenue years for all rate zones and provide an updated model with the corrections.**

b) **Please provide the calculations Alectra Utilities' used to determine the distribution revenues for each rate zone.**

It appears that the threshold calculations for the PowerStream rate zone are incorrect. The "Threshold CAPEX" in the model does not match the numbers presented on page 13 of 21 of Exhibit 2, Tab 1, Schedule 3. The inconsistent tables are reproduced below:

The model shows:

Threshold CAPEX		
Price Cap IR Year 2018	$	42,668,564
Price Cap IR Year 2019	$	42,869,478
Price Cap IR Year 2020	$	43,074,036
Price Cap IR Year 2021	$	43,282,305
Price Cap IR Year 2022	$	43,494,353
Price Cap IR Year 2023	$	43,710,248
Price Cap IR Year 2024	$	43,930,059

Exhibit 2 shows:

Table 3 – Threshold Capital Expenditure Calculation ($MM)

Description	ERZ	BRZ	GRZ	PRZ	HRZ	ALECTRA
Inflation	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Less: Productivity Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Less: Stretch Factor	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%
Price Cap Index	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
Growth Factor	-0.05%	1.84%	1.60%	2.31%	3.04%	
Rebasing Year	2013	2015	2016	2017	2019	
# Years since rebasing	7	5	4	3	1	
Price Cap Index	1.20%	1.20%	1.20%	1.20%	1.20%	
Growth Factor	-0.05%	1.84%	1.60%	2.31%	3.04%	
Dead Band	10%	10%	10%	10%	10%	
Rate Base	$610.5	$404.6	$151.4	$1,082.8	$555.7	$2,805.0
Depreciation	$28.7	$15.2	$6.3	$52.3	$23.9	$126.4
Threshold Capital Expenditure 2020	$39.1	$30.7	$11.6	$98.5	$50.0	**$230.0**
Threshold Capital Expenditure 2021	$39.2	$31.2	$11.7	$100.0	$51.1	**$233.1**
Threshold Capital Expenditure 2022	$39.3	$31.6	$11.8	$101.5	$52.1	**$236.3**
Threshold Capital Expenditure 2023	$39.4	$32.1	$12.0	$103.0	$53.2	**$239.7**
Threshold Capital Expenditure 2024	$39.4	$32.5	$12.1	$104.7	$54.4	**$243.1**
Threshold Capital Expenditure 2020-2024	**$196.3**	**$158.2**	**$59.2**	**$507.7**	**$260.9**	**$1,182.2**

c) Please reconcile the two tables and provide an updated model.

Response:

a) Alectra Utilities has corrected the distribution revenue years for all rate zones in the updated M-factor Revenue Requirement Model filed as G-Staff-8_Attach 1_M-factor Revenue Requirement.

b) Alectra Utilities relied on Version 4.2 of the OEB's ICM Model to determine the distribution revenues for each rate zone. The OEB's most recent Version 5 ICM Models are filed as Attachments 2 to 6 to this response, and a summary of the 2020-2024 threshold values are provided in Table 1, below.

Table 1 – Summary of Version 5 ICM Model Threshold Values

Description	ERZ[1]	BRZ	GRZ	PRZ	HRZ	ALECTRA
Threshold Capital Expenditure 2020	$39.1	$30.7	$11.6	$98.5	$50.0	$230.0
Threshold Capital Expenditure 2021	$39.1	$31.2	$11.7	$100.0	$51.1	$233.1
Threshold Capital Expenditure 2022	$39.2	$31.6	$11.8	$101.5	$52.1	$236.3
Threshold Capital Expenditure 2023	$39.3	$32.1	$12.0	$103.0	$53.2	$239.6
Threshold Capital Expenditure 2024	$39.4	$32.5	$12.1	$104.7	$54.4	$243.1
Threshold Capital Expenditure 2020-2024	$196.1	$158.2	$59.2	$507.7	$260.9	$1,182.0

c) The threshold calculation summary included in Attachment 3 was incorrect for the PowerStream RZ. The corrected threshold calculation is provided in Attachment 1 and Attachment 4 to this response. However, Alectra Utilities identifies that the threshold provided in Table 3 of Exhibit 2, Tab 1, Schedule 3 is accurate.

[1] ERZ 2020-2024 Threshold total has changed by $177,592.

G-Staff-8

ATTACH 1 – M-factor Revenue Requirement

Back to Index

Allocation of Multiple

Capex	2020	2021	2022	2023	2024	2020-2024		2020	2021	2022	2023	2024	**2020**	**2021**	**2022**	**2023**	**2024**	**2020-2024**
Horizon	11,863,042	10,953,468	9,264,384	3,521,255	11,814,192	47,416,342	19.72%	271,039	1,507,842	2,083,084	727,925	345,670	12,134,082	12,461,310	11,347,468	4,249,180	12,159,862	52,351,902
Brampton	9,696,860	2,188,555	6,646,395	3,730,434	3,765,279	26,027,522	14.36%	197,351	1,097,900	1,516,749	530,021	251,691	9,894,211	3,286,454	8,163,144	4,260,455	4,016,970	29,621,235
PowerStream	23,015,003	16,054,205	15,402,786	32,752,595	23,331,583	110,556,171	38.42%	528,134	2,938,105	4,058,993	1,418,397	673,555	23,543,137	18,992,309	19,461,779	34,170,992	24,005,137	120,173,355
Enersource	6,591,094	5,532,703	8,810,404	7,760,537	23,132,111	51,826,849	22.13%	304,109	1,691,811	2,337,238	816,738	387,844	6,895,203	7,224,515	11,147,642	8,577,274	23,519,955	57,364,589
Guelph	133,500	1,278,753	1,336,164	612,820	745,233	4,106,470	5.37%	73,841	410,789	567,506	198,312	94,173	207,341	1,689,542	1,903,670	811,132	839,406	5,451,091
Multiple	1,374,474	7,646,447	10,563,570	3,691,393	1,752,933	25,028,816												-
	52,673,973	**43,654,130**	**52,023,703**	**52,069,034**	**64,541,330**	**264,962,171**		1,374,474	7,646,447	10,563,570	3,691,393	1,752,933	52,673,973	43,654,130	52,023,703	52,069,034	64,541,330	264,962,171
																		-

CCA	2020	2021	2022	2023	2024	2020-2024		2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2020-2024
Horizon	1,046,319	828,852	765,351	402,824	1,009,546	4,052,891	19.72%	49,569	1,333,489	787,344	168,755	79,553	1,095,888	2,162,341	1,552,694	571,579	1,089,098	6,471,601
Brampton	823,718	264,206	547,026	397,206	684,543	2,716,700	14.36%	36,093	970,949	573,286	122,875	57,925	859,810	1,235,155	1,120,312	520,081	742,468	4,477,827
PowerStream	1,980,392	1,386,281	1,362,730	2,944,754	2,618,112	10,292,270	38.42%	96,589	2,598,370	1,534,178	328,828	155,013	2,076,981	3,984,651	2,896,908	3,273,583	2,773,125	15,005,248
Enersource	614,445	569,138	808,019	679,794	2,365,880	5,037,276	22.13%	55,617	1,496,186	883,406	189,345	89,259	670,062	2,065,324	1,691,425	869,139	2,455,139	7,751,090
Guelph	10,680	102,300	106,893	49,026	59,539	328,438	5.37%	13,504	363,290	214,500	45,975	21,673	24,184	465,590	321,393	95,001	81,212	987,380
Multiple	251,373	6,762,284	3,992,714	855,779	403,422	12,265,572												-
	4,726,926	9,913,062	7,582,733	5,329,383	7,141,042	34,693,146		251,373	6,762,284	3,992,714	855,779	403,422	4,726,926	9,913,062	7,582,733	5,329,383	7,141,042	34,693,146
																		-

Depreciation	2020	2021	2022	2023	2024	2020-2024		2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2020-2024
Horizon	336,465	273,837	244,574	127,160	320,959	1,302,996	19.72%	55,275	173,567	191,396	284,607	73,041	391,740	447,404	435,970	411,768	394,000	2,080,882
Brampton	298,417	98,228	161,680	126,116	168,595	853,036	14.36%	40,247	126,379	139,360	207,230	53,183	338,665	224,608	301,040	333,346	221,778	1,419,436
PowerStream	734,030	587,446	418,395	864,323	735,246	3,339,440	38.42%	107,706	338,205	372,944	554,572	142,324	841,735	925,651	791,340	1,418,894	877,570	4,855,190
Enersource	213,396	172,565	263,792	213,054	757,993	1,620,800	22.13%	62,019	194,744	214,748	319,332	81,953	275,415	367,309	478,540	532,386	839,946	2,493,595
Guelph	3,189	31,730	33,332	15,333	18,636	102,220	5.37%	15,059	47,286	52,143	77,537	19,899	18,248	79,016	85,475	92,870	38,535	314,144
Multiple	280,306	880,181	970,591	1,443,279	370,400	3,944,756												-
	1,865,803	2,043,988	2,092,364	2,789,264	2,371,829	11,163,248		280,306	880,181	970,591	1,443,279	370,400	1,865,803	2,043,988	2,092,364	2,789,264	2,371,829	11,163,248
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Rev Requirement	**4,677,991**	**2,325,042**	**3,921,547**	**5,567,147**	**5,353,935**	**21,845,661**
Return on Rate base - Total	**3,176,272**	**2,569,973**	**3,150,531**	**3,045,566**	**3,887,530**	**15,829,872**
Amortization	**1,865,803**	**2,043,988**	**2,092,364**	**2,789,264**	**2,371,829**	**11,163,248**
Incremental Grossed Up PILs	**(364,084)**	**(2,288,919)**	**(1,321,348)**	**(267,684)**	**(905,424)**	**(5,147,459)**
	4,677,991	**2,325,042**	**3,921,547**	**5,567,147**	**5,353,935**	**21,845,661**
Control Check	-					

BILL IMPACT SUMMARY - CONVENTIONAL

Enersource Rate Class	Unit	kWh	kW	2020 MCM Rate Rider Incl HST	2021 MCM Rate Rider Incl HST	2022 MCM Rate Rider Incl HST	2023 MCM Rate Rider Incl HST	2024 MCM Rate Rider Incl HST	2020-2024 TOTAL	Avg. Annual Rider	Avg. Annual % Increase vs. Total Bill	2019 Total Bill (Approved)
Residential	kWh	750		$ 0.13	$ 0.06	$ 0.17	$ 0.20	$ 0.39	$ 0.95	$ 0.19	0.18%	$ 108.76
General Service < 50 kW	kWh	2,000		$ 0.37	$ 0.17	$ 0.50	$ 0.59	$ 1.15	$ 2.77	$ 0.55	0.19%	$ 294.09
General Service 50 to 499 kW	kW	100,000	230	$ 6.53	$ 3.01	$ 8.83	$ 10.48	$ 20.38	$ 49.23	$ 9.85	0.06%	$ 16,343.79
General Service 500 to 4999 kW	kW	400,000	2,250	$ 40.70	$ 18.74	$ 54.98	$ 65.30	$ 126.93	$ 306.65	$ 61.33	0.08%	$ 75,489.89
Large Use	kW	3,000,000	5,000	$ 163.63	$ 75.35	$ 221.08	$ 262.57	$ 510.39	$ 1,233.03	$ 246.61	0.05%	$ 453,444.03
Unmetered	kWh	300		$ 0.08	$ 0.04	$ 0.11	$ 0.13	$ 0.25	$ 0.60	$ 0.12	0.23%	$ 51.55
Street Lighting	kW	33	0.1	$ 0.02	$ 0.01	$ 0.02	$ 0.02	$ 0.05	$ 0.12	$ 0.02	0.57%	$ 4.07

Brampton Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	2020-2024 Total	Avg. Annual Rider	Avg. Annual % Increase vs. Total Bill	2019 Total Bill (Approved)
Residential	kWh	750		$ 0.32	$ 0.04	$ 0.23	$ 0.20	$ 0.12	$ 0.92	$ 0.18	0.17%	$ 105.95
General Service < 50 kW	kWh	2,000		$ 0.80	$ 0.11	$ 0.56	$ 0.50	$ 0.30	$ 2.26	$ 0.45	0.17%	$ 273.46
General Service 50 to 699 kW	kW	182,500	500	$ 22.58	$ 3.02	$ 15.88	$ 14.16	$ 8.46	$ 64.10	$ 12.82	0.05%	$ 28,468.08
General Service 700 to 4999 kW	kW	627,216	1,432	$ 85.50	$ 11.45	$ 60.12	$ 53.63	$ 32.03	$ 242.74	$ 48.55	0.05%	$ 97,740.35
Large Use	kW	10,220,000	20,000	$ 798.09	$ 106.92	$ 561.20	$ 500.59	$ 299.01	$ 2,265.82	$ 453.16	0.03%	$ 1,518,838.91
Unmetered	kWh	21,296		$ 6.17	$ 0.83	$ 4.34	$ 3.87	$ 2.31	$ 17.53	$ 3.51	0.09%	$ 3,806.85
Street Lighting	kW	2,787,508	7,922.0	$ 1,336.07	$ 178.99	$ 939.50	$ 838.03	$ 500.57	$ 3,793.17	$ 758.63	0.14%	$ 561,277.28
Embedded Distributor	kWh	1,417,701	4,000.0	$ 60.80	$ 8.15	$ 42.75	$ 38.14	$ 22.78	$ 172.61	$ 34.52	0.02%	$ 217,321.03
Distributed Generation	kWh	156		$ 1.52	$ 0.20	$ 1.07	$ 0.95	$ 0.57	$ 4.31	$ 0.86	0.60%	$ 144.11

Horizon Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	2020-2024 Total	Avg. Annual Rider	Avg. Annual % Increase vs. Total Bill	2019 Total Bill (Approved)
Residential	kWh	750		$ 0.23	$ 0.16	$ 0.19	$ 0.15	$ 0.23	$ 0.98	$ 0.20	0.18%	$ 108.72
General Service Less Than 50 Kw	kWh	2,000		$ 0.56	$ 0.39	$ 0.47	$ 0.36	$ 0.56	$ 2.34	$ 0.47	0.17%	$ 278.57
General Service 50 To 4,999 Kw	kW	110,000	250	$ 9.76	$ 6.91	$ 8.16	$ 6.35	$ 9.83	$ 41.01	$ 8.20	0.05%	$ 16,623.28
Large Use	kW	2,555,000	5,000	$ 294.17	$ 208.28	$ 245.81	$ 191.47	$ 296.35	$ 1,236.09	$ 247.22	0.06%	$ 391,833.69
Large Use With Dedicated Assets	kW	10,220,000	20,000	$ 117.40	$ 83.12	$ 98.10	$ 76.41	$ 118.27	$ 493.30	$ 98.66	0.01%	$ 1,444,287.90
Unmetered Scattered Load	kWh	250		$ 0.11	$ 0.08	$ 0.09	$ 0.07	$ 0.11	$ 0.47	$ 0.09	0.24%	$ 38.90
Sentinel Lighting	kW	97,008	216.0	$ 31.26	$ 22.13	$ 26.12	$ 20.35	$ 31.49	$ 131.35	$ 26.27	0.12%	$ 21,677.16
Street Lighting	kW	1,782,038	4,974.0	$ 240.86	$ 170.54	$ 201.26	$ 156.77	$ 242.64	$ 1,012.07	$ 202.41	0.05%	$ 369,947.70

PowerStream Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	2020-2024 Total	Avg. Annual Rider	Avg. Annual % Increase vs. Total Bill	2019 Total Bill (Approved)
Residential	kWh	750		$ 0.32	$ 0.18	$ 0.22	$ 0.49	$ 0.29	$ 1.50	$ 0.30	0.28%	$ 106.91
General Service Less Than 50 Kw	kWh	2,000		$ 0.68	$ 0.38	$ 0.46	$ 1.04	$ 0.62	$ 3.19	$ 0.64	0.23%	$ 274.29
General Service 50 To 4,999 Kw	kW	80,000	250	$ 13.34	$ 7.42	$ 9.05	$ 20.47	$ 12.21	$ 62.50	$ 12.50	0.10%	$ 12,738.87
Large Use	kW	2,800,000	7,350	$ 252.45	$ 140.45	$ 171.34	$ 387.40	$ 231.07	$ 1,182.70	$ 236.54	0.06%	$ 416,389.80
Unmetered Scattered Load	kWh	150	0	$ 0.13	$ 0.07	$ 0.09	$ 0.20	$ 0.12	$ 0.60	$ 0.12	0.41%	$ 29.64
Sentinel Lighting	kW	180	1	$ 0.16	$ 0.09	$ 0.11	$ 0.24	$ 0.14	$ 0.74	$ 0.15	0.41%	$ 35.58
Street Lighting	kW	280	1.0	$ 0.08	$ 0.05	$ 0.06	$ 0.13	$ 0.08	$ 0.39	$ 0.08	0.15%	$ 51.53

Guelph Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	MCM Rate Rider Incl HST	2020-2024 Total	Avg. Annual Rider	Avg. Annual % Increase vs. Total Bill	2019 Total Bill (Approved)
Residential	kWh	750		$ 0.03	$ 0.07	$ 0.15	$ 0.15	$ 0.09	$ 0.49	$ 0.10	0.09%	$ 112.36
General Service Less Than 50 Kw	kWh	2,000		$ 0.05	$ 0.11	$ 0.23	$ 0.24	$ 0.14	$ 0.76	$ 0.15	0.06%	$ 261.15
General Service 50 To 999 Kw	kW	189,800	500	$ 1.85	$ 4.02	$ 8.54	$ 8.89	$ 5.11	$ 28.39	$ 5.68	0.02%	$ 31,096.59
General Service 1,000 To 4,999 Kw	kW	489,100	1,000	$ 4.31	$ 9.35	$ 19.89	$ 20.70	$ 11.89	$ 66.14	$ 13.23	0.02%	$ 79,719.37
Large Use	kW	4,215,750	7,500	$ 25.76	$ 55.93	$ 118.91	$ 123.79	$ 71.12	$ 395.51	$ 79.10	0.01%	$ 632,049.16
Unmetered Scattered Load	kWh	750		$ 0.03	$ 0.06	$ 0.12	$ 0.12	$ 0.07	$ 0.39	$ 0.08	0.04%	$ 189.16
Sentinel Lighting	kW	140	2.0	$ 0.03	$ 0.06	$ 0.13	$ 0.14	$ 0.08	$ 0.44	$ 0.09	0.13%	$ 68.61
Street Lighting	kW	800,000	2,200.0	$ 26.75	$ 58.09	$ 123.49	$ 128.56	$ 73.86	$ 410.76	$ 82.15	0.05%	$ 153,755.46

2020 Rates
M-factor Revenue Requirement_HRZ

Return on Rate Base

Incremental Capital			$	12,134,082
Depreciation Expense			$	391,740
Incremental Capital to be included in Rate Base (avg NBV)			$	11,938,212
Deemed ShortTerm Debt %	4.0%	E	$	477,528
Deemed Long Term Debt %	56.0%	F	$	6,685,399
Short Term Interest	2.82%	I	$	13,466
Long Term Interest	3.74%	J	$	250,034
Return on Rate Base - Interest			$	263,500
Deemed Equity %	40.00%	N	$	4,775,285
Return on Rate Base -Equity	8.98%	O	$	428,821
Return on Rate Base - Total			$	692,321

Amortization Expense

Amortization Expense - Incremental	C	$	391,740

Grossed up PIL's

Regulatory Taxable Income		O	$	428,821
Add Back Amortization Expense		S	$	391,740
Deduct CCA			$	1,095,888
Incremental Taxable Income			-$	275,327
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	72,962
Incremental Grossed Up PIL's			-$	99,268

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	692,321
Amortization Expense - Total		$	391,740
Incremental Grossed Up PIL's	Z	-$	99,268
Incremental Revenue Requirement		$	984,794

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M-factor Revenue Requirement_BRZ

Return on Rate Base				
Incremental Capital			$	9,894,211
Depreciation Expense			$	338,665
Incremental Capital to be included in Rate Base (avg NBV)			$	9,724,878
Deemed ShortTerm Debt %	4.0%	E	$	388,995
Deemed Long Term Debt %	56.0%	F	$	5,445,932
Short Term Interest	2.16%	I	$	8,402
Long Term Interest	6.07%	J	$	330,568
Return on Rate Base - Interest			$	338,970
Deemed Equity %	40.00%	N	$	3,889,951
Return on Rate Base -Equity	9.30%	O	$	361,765
Return on Rate Base - Total			$	700,736

Amortization Expense				
Amortization Expense - Incremental		C	$	338,665

Grossed up PIL's				
Regulatory Taxable Income		O	$	361,765
Add Back Amortization Expense		S	$	338,665
Deduct CCA			$	859,810
Incremental Taxable Income			-$	159,380
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	42,236
Incremental Grossed Up PIL's			-$	57,464

Incremental Revenue Requirement			
Return on Rate Base - Total	Q	$	700,736
Amortization Expense - Total		$	338,665
Incremental Grossed Up PIL's	Z	-$	57,464
Incremental Revenue Requirement		$	981,937

M-factor Revenue Requirement_PRZ

Return on Rate Base				
Incremental Capital			$	23,543,137
Depreciation Expense			$	841,735
Incremental Capital to be included in Rate Base (avg NBV)			$	23,122,269
Deemed ShortTerm Debt %	4.0%	**E**	$	924,891
Deemed Long Term Debt %	56.0%	**F**	$	12,948,471
Short Term Interest	1.76%	**I**	$	16,278
Long Term Interest	3.88%	**J**	$	502,401
Return on Rate Base - Interest			$	518,679
Deemed Equity %	40.00%	**N**	$	9,248,908
Return on Rate Base -Equity	8.78%	**O**	$	812,054
Return on Rate Base - Total			$	1,330,733

Amortization Expense				
Amortization Expense - Incremental		**C**	$	841,735

Grossed up PIL's				
Regulatory Taxable Income		**O**	$	812,054
Add Back Amortization Expense		**S**	$	841,735
Deduct CCA			$	2,076,981
Incremental Taxable Income			-$	423,191
Current Tax Rate	26.5%	**X**		
PIL's Before Gross Up			-$	112,146
Incremental Grossed Up PIL's			-$	152,579

Incremental Revenue Requirement				
Return on Rate Base - Total		**Q**	$	1,330,733
Amortization Expense - Total			$	841,735
Incremental Grossed Up PIL's		**Z**	-$	152,579
Incremental Revenue Requirement			$	2,019,889

M-factor Revenue Requirement_ERZ

Return on Rate Base

Incremental Capital			$	6,895,203
Depreciation Expense			$	275,415
Incremental Capital to be included in Rate Base (avg NBV)			$	6,757,495
Deemed ShortTerm Debt %	4.0%	E	$	270,300
Deemed Long Term Debt %	56.0%	F	$	3,784,197
Short Term Interest	2.08%	I	$	5,622
Long Term Interest	5.09%	J	$	192,616
Return on Rate Base - Interest			$	198,238
Deemed Equity %	40.00%	N	$	2,702,998
Return on Rate Base -Equity	8.93%	O	$	241,378
Return on Rate Base - Total			$	439,616

Amortization Expense

Amortization Expense - Incremental		C	$	275,415

Grossed up PIL's

Regulatory Taxable Income		O	$	241,378
Add Back Amortization Expense		S	$	275,415
Deduct CCA			$	670,062
Incremental Taxable Income			-$	153,270
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	40,616
Incremental Grossed Up PIL's			-$	55,260

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	439,616
Amortization Expense - Total			$	275,415
Incremental Grossed Up PIL's		Z	-$	55,260
Incremental Revenue Requirement			$	659,770

M-factor Revenue Requirement_GRZ

Return on Rate Base				
Incremental Capital			$	207,341
Depreciation Expense			$	18,248
Incremental Capital to be included in Rate Base (avg NBV)			$	198,217
Deemed ShortTerm Debt %	4.0%	E	$	7,929
Deemed Long Term Debt %	56.0%	F	$	111,002
Short Term Interest	1.65%	I	$	131
Long Term Interest	4.91%	J	$	5,450
Return on Rate Base - Interest			$	5,581
Deemed Equity %	40.00%	N	$	79,287
Return on Rate Base -Equity	9.19%	O	$	7,286
Return on Rate Base - Total			$	12,867

Amortization Expense				
Amortization Expense - Incremental		C	$	18,248

Grossed up PIL's				
Regulatory Taxable Income		O	$	7,286
Add Back Amortization Expense		S	$	18,248
Deduct CCA			$	24,184
Incremental Taxable Income			$	1,350
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			$	358
Incremental Grossed Up PIL's			$	487

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	12,867
Amortization Expense - Total			$	18,248
Incremental Grossed Up PIL's		Z	$	487
Incremental Revenue Requirement			$	31,602

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						internal use			
Enersource Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.13	0.12%	$ 108.76	$ 0.12	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.37	0.13%	$ 294.09	$ 0.22	$ 0.0001	5%
General Service 50 to 499 kW	kW	100,000	230	$ 6.53	0.04%	$ 16,343.79	$ 0.39	$ 0.0234	13%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 40.70	0.05%	$ 75,489.89	$ 8.87	$ 0.0121	13%
Large Use	kW	3,000,000	5,000	$ 163.63	0.04%	$ 453,444.03	$ 69.94	$ 0.0150	13%
Unmetered	kWh	300		$ 0.08	0.15%	$ 51.55	$ 0.05	$ 0.0001	13%
Street Lighting	kW	33	0.1	$ 0.02	0.38%	$ 4.07	$ 0.01	$ 0.0586	13%

						internal use			
Brampton Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.32	0.31%	$ 105.95	$ 0.31	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.80	0.29%	$ 273.46	$ 0.32	$ 0.0002	5%
General Service 50 to 699 kW	kW	182,500	500	$ 22.58	0.08%	$ 28,468.08	$ 1.62	$ 0.0367	13%
General Service 700 to 4999 kW	kW	627,216	1,432	$ 85.50	0.09%	$ 97,740.35	$ 14.63	$ 0.0426	13%
Large Use	kW	10,220,000	20,000	$ 798.09	0.05%	$ 1,518,838.91	$ 60.86	$ 0.0323	13%
Unmetered	kWh	21,296		$ 6.17	0.16%	$ 3,806.85	$ 0.01	$ 0.0003	13%
Street Lighting	kW	2,787,508	7,922.0	$ 1,336.07	0.24%	$ 561,277.28	$ 0.03	$ 0.1492	13%
Embedded Distributor	kWh	1,417,701	4,000.0	$ 60.80	0.03%	$ 217,321.03	$ 53.80	$ -	13%
Distributed Generation	kWh	156		$ 1.52	1.05%	$ 144.11	$ 1.34	$ -	13%

						internal use			
Horizon Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.23	0.21%	$ 108.72	$ 0.22	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.56	0.20%	$ 278.57	$ 0.35	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	110,000	250	$ 9.76	0.06%	$ 16,623.28	$ 3.22	$ 0.0217	13%
Large Use	kW	2,555,000	5,000	$ 294.17	0.08%	$ 391,833.69	$ 201.03	$ 0.0119	13%
Large Use With Dedicated Assets	kW	10,220,000	20,000	$ 117.40	0.01%	$ 1,444,287.90	$ 47.66	$ 0.0028	13%
Unmetered Scattered Load	kWh	250		$ 0.11	0.29%	$ 38.90	$ 0.07	$ 0.0001	13%
Sentinel Lighting	kW	97,008	216.0	$ 31.26	0.14%	$ 21,677.16	$ 0.05	$ 0.1279	13%
Street Lighting	kW	1,782,038	4,974.0	$ 240.86	0.07%	$ 369,947.70	$ 0.02	$ 0.0428	13%

						internal use			
PowerStream Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.32	0.30%	$ 106.91	$ 0.27	$ 0.0000	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.68	0.25%	$ 274.29	$ 0.28	$ 0.0002	5%
General Service 50 To 4,999 Kw	kW	80,000	250	$ 13.34	0.10%	$ 12,738.87	$ 1.40	$ 0.0416	13%
Large Use	kW	2,800,000	7,350	$ 252.45	0.06%	$ 416,389.80	$ 60.16	$ 0.0222	13%
Unmetered Scattered Load	kWh	150	0	$ 0.13	0.44%	$ 29.64	$ 0.09	$ 0.0002	13%
Sentinel Lighting	kW	180	1	$ 0.16	0.44%	$ 35.58	$ 0.04	$ 0.0978	13%
Street Lighting	kW	280	1.0	$ 0.08	0.16%	$ 51.53	$ 0.01	$ 0.0626	13%

						internal use			
Guelph Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.03	0.03%	$ 112.36	$ 0.03	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.05	0.02%	$ 261.15	$ 0.02	$ 0.0000	5%
General Service 50 To 999 Kw	kW	189,800	500	$ 1.85	0.01%	$ 31,096.59	$ 0.19	$ 0.0029	13%
General Service 1,000 To 4,999 Kw	kW	489,100	1,000	$ 4.31	0.01%	$ 79,719.37	$ 0.60	$ 0.0032	13%
Large Use	kW	4,215,750	7,500	$ 25.76	0.00%	$ 632,049.16	$ 1.15	$ 0.0029	13%
Unmetered Scattered Load	kWh	750		$ 0.03	0.01%	$ 189.16	$ 0.01	$ 0.0000	13%
Sentinel Lighting	kW	140	2.0	$ 0.03	0.04%	$ 68.61	$ 0.01	$ 0.0088	13%
Street Lighting	kW	800,000	2,200.0	$ 26.75	0.02%	$ 153,755.46	$ 0.00	$ 0.0108	13%

Enersource Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	40.22%	0.00%	0.00%	265,334	0	0	265,334	183,533	1,490,532,667		0.12	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.44%	6.71%	0.00%	49,117	44,280	0	93,397	18,506	685,616,684		0.22	0.0001	0.0000
GENERAL SERVICE 50 TO 499 kW	2.65%	0.00%	20.29%	17,459	0	133,873	151,332	3,735		5,710,412	0.39	0.0000	0.0234
GENERAL SERVICE 500 TO 4,999 kW	7.71%	0.00%	8.38%	50,883	0	55,320	106,203	478	2,037,760,513	4,585,777	8.87	0.0000	0.0121
LARGE USE	1.14%	0.00%	3.98%	7,554	0	26,250	33,804	9	977,049,362	1,753,163	69.94	0.0000	0.0150
UNMETERED SCATTERED LOAD	0.26%	0.14%	0.00%	1,704	949	0	2,653	3,110	11,437,642		0.05	0.0001	0.0000
STREET LIGHTING	0.71%	0.00%	0.36%	4,669	0	2,376	7,046	50,859	13,289,944	40,572	0.01	0.0000	0.0586
Total	**60.13%**	**6.86%**	**33.01%**	**396,721**	**45,229**	**217,820**	**659,770**	**260,230**	**5,215,686,812**	**12,089,924**			
							659,770						

Brampton Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	57.65%	0.00%	0.00%	566,101	0	0	566,101	153,261	1,385,125,813		0.31	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	3.76%	7.61%	0.00%	36,891	74,683	0	111,574	9,462	344,785,907		0.32	0.0002	0.0000
GENERAL SERVICE 50 TO 699 KW	3.15%	0.00%	11.89%	30,951	0	116,744	147,695	1,591	1,131,688,196	3,179,603	1.62	0.0000	0.0367
GENERAL SERVICE 700 TO 4,999 KW	1.88%	0.00%	8.77%	18,430	0	86,123	104,553	105	875,091,030	2,020,563	14.63	0.0000	0.0426
LARGE USE	0.45%	0.00%	2.16%	4,382	0	21,229	25,612	6	350,379,705	657,857	60.86	0.0000	0.0323
UNMETERED SCATTERED LOAD	0.03%	0.15%	0.00%	263	1,513	0	1,776	1,556	5,914,654		0.01	0.0003	0.0000
STREET LIGHTING	0.72%	0.00%	1.50%	7,115	0	14,752	21,867	19,919	34,968,321	98,842	0.03	0.0000	0.1492
EMBEDDED DISTRIBUTOR	0.07%	0.00%	0.00%	646	0	0	646	1	3,402,773		53.80	0.0000	0.0000
DISTRIBUTED GENERATION [DGEN]	0.22%	0.00%	0.00%	2,114	0	0	2,114	131	277,418		1.34	0.0000	0.0000
STANDBY POWER	0.00%	0.00%	0.00%	0	0	0	0	1			0.00	0.0000	0.0000
Total	**67.92%**	**7.76%**	**24.32%**	**666,892**	**76,196**	**238,848**	**981,937**	**186,033**	**4,131,633,817**	**5,956,865**			
							981,937						

PowerStream Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	48.05%	6.02%	0.00%	970,522	121,521	0	1,092,044	334,683	2,783,708,695		0.27	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.52%	9.43%	0.00%	111,466	190,410	0	301,876	32,624	1,049,615,664		0.28	0.0002	0.0000
GENERAL SERVICE 50 TO 4,999 KW	4.32%	0.00%	25.14%	87,256	0	507,719	594,975	5,207	4,679,965,944	12,192,876	1.40	0.0000	0.0416
LARGE USE	0.07%	0.00%	0.11%	1,444	0	2,285	3,729	2	53,218,181	102,871	60.16	0.0000	0.0222
UNMETERED SCATTERED LOAD	0.16%	0.13%	0.00%	3,150	2,670	0	5,820	3,082	13,830,788		0.09	0.0002	0.0000
SENTINEL LIGHTING	0.00%	0.00%	0.00%	86	0	78	164	172	286,385	796	0.04	0.0000	0.0978
STREET LIGHTING	0.64%	0.00%	0.42%	12,881	0	8,401	21,282	91,446	48,883,953	134,152	0.01	0.0000	0.0626
Total	**58.76%**	**15.58%**	**25.67%**	**1,186,805**	**314,601**	**518,483**	**2,019,889**	**467,216**	**8,629,509,610**	**12,430,695**			
							2,019,889						

Guelph Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}		*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	58.40%	0.00%	0.00%	18,457	0	0	18,457	50,914	384,041,745		0.03	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 KW	2.75%	6.61%	0.00%	869	2,088	0	2,957	4,134	142,209,076		0.02	0.0000	0.0000
GENERAL SERVICE 50 TO 999 KW	4.17%	0.00%	10.05%	1,317	0	3,175	4,492	578	402,350,218	1,097,499	0.19	0.0000	0.0029
GENERAL SERVICE 1,000 TO 4,999 KW	0.98%	0.00%	11.54%	310	0	3,646	3,956	43	540,417,878	1,135,425	0.60	0.0000	0.0032
LARGE USE	0.18%	0.00%	3.86%	55	0	1,221	1,276	4	197,428,962	423,180	1.15	0.0000	0.0029
UNMETERED SCATTERED LOAD	0.11%	0.13%	0.00%	34	42	0	77	559	1,810,678		0.01	0.0000	0.0000
SENTINEL LIGHTING	0.01%	0.00%	0.00%	3	0	0	4	35	18,189	51	0.01	0.0000	0.0088
STREET LIGHTING	0.24%	0.00%	0.97%	77	0	306	383	14,152	10,182,750	28,425	0.00	0.0000	0.0108
Total	**66.84%**	**6.74%**	**26.42%**	**21,123**	**2,130**	**8,349**	**31,602**	**70,419**	**1,678,459,496**	**2,684,580**			
							31,602						

Horizon Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.35%	0.00%	0.00%	604,215	0	0	604,215	227,762	1,652,719,193		0.22	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.98%	5.45%	0.00%	78,612	53,651	0	132,263	18,709	594,472,785		0.35	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	9.10%	0.00%	11.14%	89,605	0	109,696	199,301	2,316	1,840,510,488	5,066,406	3.22	0.0000	0.0217
LARGE USE	1.47%	0.00%	0.69%	14,474	0	6,755	21,229	6	242,051,739	569,520	201.03	0.0000	0.0119
LARGE USE WITH DEDICATED ASSETS	0.29%	0.00%	0.61%	2,859	0	6,009	8,868	5	403,775,839	2,136,952	47.66	0.0000	0.0028
UNMETERED SCATTERED LOAD	0.26%	0.12%	0.00%	2,578	1,165	0	3,743	3,006	10,504,342		0.07	0.0001	0.0000
SENTINEL LIGHTING	0.02%	0.00%	0.01%	211	0	132	343	378	363,731	1,030	0.05	0.0000	0.1279
STREET LIGHTING	1.03%	0.00%	0.48%	10,128	0	4,704	14,831	52,273	39,610,413	109,773	0.02	0.0000	0.0428
Total	**81.51%**	**5.57%**	**12.93%**	**802,682**	**54,816**	**127,295**	**984,794**	**304,455**	**4,784,008,529**	**7,883,681**			
							984,794						

2021 Rates
M-factor Revenue Requirement_HRZ

Return on Rate Base

Incremental Capital			$	12,461,310
Depreciation Expense			$	447,404
Incremental Capital to be included in Rate Base (avg NBV)			$	12,237,608
Deemed ShortTerm Debt %	4.0%	E	$	489,504
Deemed Long Term Debt %	56.0%	F	$	6,853,060
Short Term Interest	2.82%	I	$	13,804
Long Term Interest	3.74%	J	$	256,304
Return on Rate Base - Interest			$	270,108
Deemed Equity %	40.00%	N	$	4,895,043
Return on Rate Base -Equity	8.98%	O	$	439,575
Return on Rate Base - Total			$	709,683

Amortization Expense

Amortization Expense - Incremental		C	$	447,404

Grossed up PIL's

Regulatory Taxable Income		O	$	439,575
Add Back Amortization Expense		S	$	447,404
Deduct CCA			$	2,162,341
Incremental Taxable Income			-$	1,275,362
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	337,971
Incremental Grossed Up PIL's			-$	459,824

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	709,683
Amortization Expense - Total		$	447,404
Incremental Grossed Up PIL's	Z	-$	459,824
Incremental Revenue Requirement		$	697,263

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M-factor Revenue Requirement_BRZ

Return on Rate Base				
Incremental Capital			$	3,286,454
Depreciation Expense			$	224,608
Incremental Capital to be included in Rate Base (avg NBV)			$	3,174,151
Deemed ShortTerm Debt %	4.0%	E	$	126,966
Deemed Long Term Debt %	56.0%	F	$	1,777,524
Short Term Interest	2.16%	I	$	2,742
Long Term Interest	6.07%	J	$	107,896
Return on Rate Base - Interest			$	110,638
Deemed Equity %	40.00%	N	$	1,269,660
Return on Rate Base -Equity	9.30%	O	$	118,078
Return on Rate Base - Total			$	228,717

Amortization Expense				
Amortization Expense - Incremental		C	$	224,608

Grossed up PIL's				
Regulatory Taxable Income		O	$	118,078
Add Back Amortization Expense		S	$	224,608
Deduct CCA			$	1,235,155
Incremental Taxable Income			-$	892,469
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	236,504
Incremental Grossed Up PIL's			-$	321,775

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	228,717
Amortization Expense - Total			$	224,608
Incremental Grossed Up PIL's		Z	-$	321,775
Incremental Revenue Requirement			$	131,549

M-factor Revenue Requirement_PRZ

Return on Rate Base

Incremental Capital			$	18,992,309
Depreciation Expense			$	925,651
Incremental Capital to be included in Rate Base (avg NBV)			$	18,529,484
Deemed ShortTerm Debt %	4.0%	E	$	741,179
Deemed Long Term Debt %	56.0%	F	$	10,376,511
Short Term Interest	1.76%	I	$	13,045
Long Term Interest	3.88%	J	$	402,609
Return on Rate Base - Interest			$	415,653
Deemed Equity %	40.00%	N	$	7,411,793
Return on Rate Base -Equity	8.78%	O	$	650,755
Return on Rate Base - Total			$	1,066,409

Amortization Expense

Amortization Expense - Incremental		C	$	925,651

Grossed up PIL's

Regulatory Taxable Income		O	$	650,755
Add Back Amortization Expense		S	$	925,651
Deduct CCA			$	3,984,651
Incremental Taxable Income			-$	2,408,245
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	638,185
Incremental Grossed Up PIL's			-$	868,279

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	1,066,409
Amortization Expense - Total			$	925,651
Incremental Grossed Up PIL's		Z	-$	868,279
Incremental Revenue Requirement			$	1,123,781

M-factor Revenue Requirement_ERZ

Return on Rate Base				
Incremental Capital			$	7,224,515
Depreciation Expense			$	367,309
Incremental Capital to be included in Rate Base (avg NBV)			$	7,040,860
Deemed ShortTerm Debt %	4.0%	E	$	281,634
Deemed Long Term Debt %	56.0%	F	$	3,942,882
Short Term Interest	2.08%	I	$	5,858
Long Term Interest	5.09%	J	$	200,693
Return on Rate Base - Interest			$	206,551
Deemed Equity %	40.00%	N	$	2,816,344
Return on Rate Base -Equity	8.93%	O	$	251,500
Return on Rate Base - Total			$	458,050

Amortization Expense				
Amortization Expense - Incremental		C	$	367,309

Grossed up PIL's				
Regulatory Taxable Income		O	$	251,500
Add Back Amortization Expense		S	$	367,309
Deduct CCA			$	2,065,324
Incremental Taxable Income			-$	1,446,515
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	383,327
Incremental Grossed Up PIL's			-$	521,533

Incremental Revenue Requirement			
Return on Rate Base - Total	Q	$	458,050
Amortization Expense - Total		$	367,309
Incremental Grossed Up PIL's	Z	-$	521,533
Incremental Revenue Requirement		$	303,827

M-factor Revenue Requirement_GRZ

Return on Rate Base				
Incremental Capital			$	1,689,542
Depreciation Expense			$	79,016
Incremental Capital to be included in Rate Base (avg NBV)			$	1,650,034
Deemed ShortTerm Debt %	4.0%	**E**	$	66,001
Deemed Long Term Debt %	56.0%	**F**	$	924,019
Short Term Interest	1.65%	**I**	$	1,089
Long Term Interest	4.91%	**J**	$	45,369
Return on Rate Base - Interest			$	46,458
Deemed Equity %	40.00%	**N**	$	660,014
Return on Rate Base -Equity	9.19%	**O**	$	60,655
Return on Rate Base - Total			$	107,114

Amortization Expense				
Amortization Expense - Incremental		**C**	$	79,016

Grossed up PIL's				
Regulatory Taxable Income		**O**	$	60,655
Add Back Amortization Expense		**S**	$	79,016
Deduct CCA			$	465,590
Incremental Taxable Income			-$	325,918
Current Tax Rate	26.5%	**X**		
PIL's Before Gross Up			-$	86,368
Incremental Grossed Up PIL's			-$	117,508

Incremental Revenue Requirement				
Return on Rate Base - Total		**Q**	$	107,114
Amortization Expense - Total			$	79,016
Incremental Grossed Up PIL's		**Z**	-$	117,508
Incremental Revenue Requirement			$	68,622

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Enersource Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.06	0.05%	$ 108.76	$ 0.06	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.17	0.06%	$ 294.09	$ 0.10	$ 0.0000	5%
General Service 50 to 499 kW	kW	100,000	230	$ 3.01	0.02%	$ 16,343.79	$ 0.18	$ 0.0108	13%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 18.74	0.02%	$ 75,489.89	$ 4.09	$ 0.0056	13%
Large Use	kW	3,000,000	5,000	$ 75.35	0.02%	$ 453,444.03	$ 32.21	$ 0.0069	13%
Unmetered	kWh	300		$ 0.04	0.07%	$ 51.55	$ 0.02	$ 0.0000	13%
Street Lighting	kW	33	0.1	$ 0.01	0.17%	$ 4.07	$ 0.00	$ 0.0270	13%

Brampton Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.04	0.04%	$ 105.95	$ 0.04	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.11	0.04%	$ 273.46	$ 0.04	$ 0.0000	5%
General Service 50 to 699 kW	kW	182,500	500	$ 3.02	0.01%	$ 28,468.08	$ 0.22	$ 0.0049	13%
General Service 700 to 4999 kW	kW	627,216	1,432	$ 11.45	0.01%	$ 97,740.35	$ 1.96	$ 0.0057	13%
Large Use	kW	10,220,000	20,000	$ 106.92	0.01%	$ 1,518,838.91	$ 8.15	$ 0.0043	13%
Unmetered	kWh	21,296		$ 0.83	0.02%	$ 3,806.85	$ 0.00	$ 0.0000	13%
Street Lighting	kW	2,787,508	7,922.0	$ 178.99	0.03%	$ 561,277.28	$ 0.00	$ 0.0200	13%
Embedded Distributor	kWh	1,417,701	4,000.0	$ 8.15	0.00%	$ 217,321.03	$ 7.21	$ -	13%
Distributed Generation	kWh	156		$ 0.20	0.14%	$ 144.11	$ 0.18	$ -	13%

Horizon Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.16	0.15%	$ 108.72	$ 0.16	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.39	0.14%	$ 278.57	$ 0.25	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	110,000	250	$ 6.91	0.04%	$ 16,623.28	$ 2.28	$ 0.0153	13%
Large Use	kW	2,555,000	5,000	$ 208.28	0.05%	$ 391,833.69	$ 142.33	$ 0.0084	13%
Large Use With Dedicated Assets	kW	10,220,000	20,000	$ 83.12	0.01%	$ 1,444,287.90	$ 33.74	$ 0.0020	13%
Unmetered Scattered Load	kWh	250		$ 0.08	0.20%	$ 38.90	$ 0.05	$ 0.0001	13%
Sentinel Lighting	kW	97,008	216.0	$ 22.13	0.10%	$ 21,677.16	$ 0.03	$ 0.0905	13%
Street Lighting	kW	1,782,038	4,974.0	$ 170.54	0.05%	$ 369,947.70	$ 0.01	$ 0.0303	13%

PowerStream Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.18	0.17%	$ 106.91	$ 0.15	$ 0.0000	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.38	0.14%	$ 274.29	$ 0.16	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	80,000	250	$ 7.42	0.06%	$ 12,738.87	$ 0.78	$ 0.0232	13%
Large Use	kW	2,800,000	7,350	$ 140.45	0.03%	$ 416,389.80	$ 33.47	$ 0.0124	13%
Unmetered Scattered Load	kWh	150	0	$ 0.07	0.24%	$ 29.64	$ 0.05	$ 0.0001	13%
Sentinel Lighting	kW	180	1	$ 0.09	0.25%	$ 35.58	$ 0.02	$ 0.0544	13%
Street Lighting	kW	280	1.0	$ 0.05	0.09%	$ 51.53	$ 0.01	$ 0.0348	13%

Guelph Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.07	0.06%	$ 112.36	$ 0.07	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.11	0.04%	$ 261.15	$ 0.04	$ 0.0000	5%
General Service 50 To 999 Kw	kW	189,800	500	$ 4.02	0.01%	$ 31,096.59	$ 0.41	$ 0.0063	13%
General Service 1,000 To 4,999 Kw	kW	489,100	1,000	$ 9.35	0.01%	$ 79,719.37	$ 1.30	$ 0.0070	13%
Large Use	kW	4,215,750	7,500	$ 55.93	0.01%	$ 632,049.16	$ 2.51	$ 0.0063	13%
Unmetered Scattered Load	kWh	750		$ 0.06	0.03%	$ 189.16	$ 0.01	$ 0.0001	13%
Sentinel Lighting	kW	140	2.0	$ 0.06	0.09%	$ 68.61	$ 0.02	$ 0.0191	13%
Street Lighting	kW	800,000	2,200.0	$ 58.09	0.04%	$ 153,755.46	$ 0.00	$ 0.0234	13%

Enersource Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I $_{total}$*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	40.22%	0.00%	0.00%	122,187	0	0	122,187	183,533	1,490,532,667		0.06	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.44%	6.71%	0.00%	22,619	20,391	0	43,010	18,506	685,616,684		0.10	0.0000	0.0000
GENERAL SERVICE 50 TO 499 kW	2.65%	0.00%	20.29%	8,040	0	61,649	69,689	3,735		5,710,412	0.18	0.0000	0.0108
GENERAL SERVICE 500 TO 4,999 kW	7.71%	0.00%	8.38%	23,432	0	25,475	48,907	478	2,037,760,513	4,585,777	4.09	0.0000	0.0056
LARGE USE	1.14%	0.00%	3.98%	3,479	0	12,088	15,567	9	977,049,362	1,753,163	32.21	0.0000	0.0069
UNMETERED SCATTERED LOAD	0.26%	0.14%	0.00%	785	437	0	1,222	3,110	11,437,642		0.02	0.0000	0.0000
STREET LIGHTING	0.71%	0.00%	0.36%	2,150	0	1,094	3,245	50,859	13,289,944	40,572	0.00	0.0000	0.0270
Total	**60.13%**	**6.86%**	**33.01%**	**182,692**	**20,828**	**100,307**	**303,827**	**260,230**	**5,215,686,812**	**12,089,924**			
							303,827						

Brampton Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I $_{total}$*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	57.65%	0.00%	0.00%	75,840	0	0	75,840	153,261	1,385,125,813		0.04	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	3.76%	7.61%	0.00%	4,942	10,005	0	14,948	9,462	344,785,907		0.04	0.0000	0.0000
GENERAL SERVICE 50 TO 699 KW	3.15%	0.00%	11.89%	4,146	0	15,640	19,787	1,591	1,131,688,196	3,179,603	0.22	0.0000	0.0049
GENERAL SERVICE 700 TO 4,999 KW	1.88%	0.00%	8.77%	2,469	0	11,538	14,007	105	875,091,030	2,020,563	1.96	0.0000	0.0057
LARGE USE	0.45%	0.00%	2.16%	587	0	2,844	3,431	6	350,379,705	657,857	8.15	0.0000	0.0043
UNMETERED SCATTERED LOAD	0.03%	0.15%	0.00%	35	203	0	238	1,556	5,914,654		0.00	0.0000	0.0000
STREET LIGHTING	0.72%	0.00%	1.50%	953	0	1,976	2,930	19,919	34,968,321	98,842	0.00	0.0000	0.0200
EMBEDDED DISTRIBUTOR	0.07%	0.00%	0.00%	86	0	0	86	1	3,402,773		7.21	0.0000	0.0000
DISTRIBUTED GENERATION [DGEN]	0.22%	0.00%	0.00%	283	0	0	283	131	277,418		0.18	0.0000	0.0000
STANDBY POWER	0.00%	0.00%	0.00%	0	0	0	0	1			0.00	0.0000	0.0000
Total	**67.92%**	**7.76%**	**24.32%**	**89,343**	**10,208**	**31,998**	**131,549**	**186,033**	**4,131,633,817**	**5,956,865**			
							131,549						

PowerStream Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	48.05%	6.02%	0.00%	539,958	67,609	0	607,567	334,683	2,783,708,695		0.15	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.52%	9.43%	0.00%	62,015	105,936	0	167,951	32,624	1,049,615,664		0.16	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	4.32%	0.00%	25.14%	48,546	0	282,473	331,019	5,207	4,679,965,944	12,192,876	0.78	0.0000	0.0232
LARGE USE	0.07%	0.00%	0.11%	803	0	1,271	2,074	2	53,218,181	102,871	33.47	0.0000	0.0124
UNMETERED SCATTERED LOAD	0.16%	0.13%	0.00%	1,753	1,485	0	3,238	3,082	13,830,788		0.05	0.0001	0.0000
SENTINEL LIGHTING	0.00%	0.00%	0.00%	48	0	43	91	172	286,385	796	0.02	0.0000	0.0544
STREET LIGHTING	0.64%	0.00%	0.42%	7,166	0	4,674	11,841	91,446	48,883,953	134,152	0.01	0.0000	0.0348
Total	**58.76%**	**15.58%**	**25.67%**	**660,289**	**175,031**	**288,462**	**1,123,781**	**467,216**	**8,629,509,610**	**12,430,695**			
							1,123,781						

Guelph Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}		*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	58.40%	0.00%	0.00%	40,078	0	0	40,078	50,914	384,041,745		0.07	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 KW	2.75%	6.61%	0.00%	1,887	4,533	0	6,420	4,134	142,209,076		0.04	0.0000	0.0000
GENERAL SERVICE 50 TO 999 KW	4.17%	0.00%	10.05%	2,860	0	6,894	9,754	578	402,350,218	1,097,499	0.41	0.0000	0.0063
GENERAL SERVICE 1,000 TO 4,999 KW	0.98%	0.00%	11.54%	673	0	7,918	8,591	43	540,417,878	1,135,425	1.30	0.0000	0.0070
LARGE USE	0.18%	0.00%	3.86%	120	0	2,651	2,772	4	197,428,962	423,180	2.51	0.0000	0.0063
UNMETERED SCATTERED LOAD	0.11%	0.13%	0.00%	75	92	0	167	559	1,810,678		0.01	0.0001	0.0000
SENTINEL LIGHTING	0.01%	0.00%	0.00%	7	0	1	8	35	18,189	51	0.02	0.0000	0.0191
STREET LIGHTING	0.24%	0.00%	0.97%	168	0	664	832	14,152	10,182,750	28,425	0.00	0.0000	0.0234
Total	**66.84%**	**6.74%**	**26.42%**	**45,868**	**4,625**	**18,129**	**68,622**	**70,419**	**1,678,459,496**	**2,684,580**			
							68,622						

Horizon Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.35%	0.00%	0.00%	427,802	0	0	427,802	227,762	1,652,719,193		0.16	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.98%	5.45%	0.00%	55,659	37,986	0	93,646	18,709	594,472,785		0.25	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	9.10%	0.00%	11.14%	63,443	0	77,668	141,111	2,316	1,840,510,488	5,066,406	2.28	0.0000	0.0153
LARGE USE	1.47%	0.00%	0.69%	10,248	0	4,783	15,031	6	242,051,739	569,520	142.33	0.0000	0.0084
LARGE USE WITH DEDICATED ASSETS	0.29%	0.00%	0.61%	2,025	0	4,254	6,279	5	403,775,839	2,136,952	33.74	0.0000	0.0020
UNMETERED SCATTERED LOAD	0.26%	0.12%	0.00%	1,825	825	0	2,650	3,006	10,504,342		0.05	0.0001	0.0000
SENTINEL LIGHTING	0.02%	0.00%	0.01%	150	0	93	243	378	363,731	1,030	0.03	0.0000	0.0905
STREET LIGHTING	1.03%	0.00%	0.48%	7,171	0	3,330	10,501	52,273	39,610,413	109,773	0.01	0.0000	0.0303
Total	**81.51%**	**5.57%**	**12.93%**	**568,323**	**38,812**	**90,128**	**697,263**	**304,455**	**4,784,008,529**	**7,883,681**			
							697,263						

2022 Rates
M-factor Revenue Requirement_HRZ

Return on Rate Base

Incremental Capital			$	11,347,468
Depreciation Expense			$	435,970
Incremental Capital to be included in Rate Base (avg NBV)			$	11,129,483
Deemed ShortTerm Debt %	4.0%	E	$	445,179
Deemed Long Term Debt %	56.0%	F	$	6,232,511
Short Term Interest	2.82%	I	$	12,554
Long Term Interest	3.74%	J	$	233,096
Return on Rate Base - Interest			$	245,650
Deemed Equity %	40.00%	N	$	4,451,793
Return on Rate Base -Equity	8.98%	O	$	399,771
Return on Rate Base - Total			$	645,421

Amortization Expense

Amortization Expense - Incremental		C	$	435,970

Grossed up PIL's

Regulatory Taxable Income		O	$	399,771
Add Back Amortization Expense		S	$	435,970
Deduct CCA			$	1,552,694
Incremental Taxable Income			-$	716,954
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	189,993
Incremental Grossed Up PIL's			-$	258,493

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	645,421
Amortization Expense - Total			$	435,970
Incremental Grossed Up PIL's		Z	-$	258,493
Incremental Revenue Requirement			$	822,897

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M-factor Revenue Requirement_BRZ

Return on Rate Base

Incremental Capital			$	8,163,144
Depreciation Expense			$	301,040
Incremental Capital to be included in Rate Base (avg NBV)			$	8,012,624
Deemed ShortTerm Debt %	4.0%	E	$	320,505
Deemed Long Term Debt %	56.0%	F	$	4,487,069
Short Term Interest	2.16%	I	$	6,923
Long Term Interest	6.07%	J	$	272,365
Return on Rate Base - Interest			$	279,288
Deemed Equity %	40.00%	N	$	3,205,049
Return on Rate Base -Equity	9.30%	O	$	298,070
Return on Rate Base - Total			$	577,358

Amortization Expense

Amortization Expense - Incremental		C	$	301,040

Grossed up PIL's

Regulatory Taxable Income		O	$	298,070
Add Back Amortization Expense		S	$	301,040
Deduct CCA			$	1,120,312
Incremental Taxable Income			-$	521,202
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	138,119
Incremental Grossed Up PIL's			-$	187,916

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	577,358
Amortization Expense - Total			$	301,040
Incremental Grossed Up PIL's		Z	-$	187,916
Incremental Revenue Requirement			$	690,481

M-factor Revenue Requirement_PRZ

Return on Rate Base

Incremental Capital			$	19,461,779
Depreciation Expense			$	791,340
Incremental Capital to be included in Rate Base (avg NBV)			$	19,066,110
Deemed ShortTerm Debt %	4.0%	E	$	762,644
Deemed Long Term Debt %	56.0%	F	$	10,677,021
Short Term Interest	1.76%	I	$	13,423
Long Term Interest	3.88%	J	$	414,268
Return on Rate Base - Interest			$	427,691
Deemed Equity %	40.00%	N	$	7,626,444
Return on Rate Base -Equity	8.78%	O	$	669,602
Return on Rate Base - Total			$	1,097,293

Amortization Expense

Amortization Expense - Incremental		C	$	791,340

Grossed up PIL's

Regulatory Taxable Income		O	$	669,602
Add Back Amortization Expense		S	$	791,340
Deduct CCA			$	2,896,908
Incremental Taxable Income			-$	1,435,967
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	380,531
Incremental Grossed Up PIL's			-$	517,730

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	1,097,293
Amortization Expense - Total			$	791,340
Incremental Grossed Up PIL's		Z	-$	517,730
Incremental Revenue Requirement			$	1,370,903

M-factor Revenue Requirement_ERZ

Return on Rate Base				
Incremental Capital			$	11,147,642
Depreciation Expense			$	478,540
Incremental Capital to be included in Rate Base (avg NBV)			$	10,908,372
Deemed ShortTerm Debt %	4.0%	E	$	436,335
Deemed Long Term Debt %	56.0%	F	$	6,108,688
Short Term Interest	2.08%	I	$	9,076
Long Term Interest	5.09%	J	$	310,932
Return on Rate Base - Interest			$	320,008
Deemed Equity %	40.00%	N	$	4,363,349
Return on Rate Base -Equity	8.93%	O	$	389,647
Return on Rate Base - Total			$	709,655

Amortization Expense				
Amortization Expense - Incremental		C	$	478,540

Grossed up PIL's				
Regulatory Taxable Income		O	$	389,647
Add Back Amortization Expense		S	$	478,540
Deduct CCA			$	1,691,425
Incremental Taxable Income			-$	823,238
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	218,158
Incremental Grossed Up PIL's			-$	296,814

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	709,655
Amortization Expense - Total			$	478,540
Incremental Grossed Up PIL's		Z	-$	296,814
Incremental Revenue Requirement			$	891,381

M-factor Revenue Requirement_GRZ

Return on Rate Base				
Incremental Capital			$	1,903,670
Depreciation Expense			$	85,475
Incremental Capital to be included in Rate Base (avg NBV)			$	1,860,932
Deemed ShortTerm Debt %	4.0%	**E**	$	74,437
Deemed Long Term Debt %	56.0%	**F**	$	1,042,122
Short Term Interest	1.65%	**I**	$	1,228
Long Term Interest	4.91%	**J**	$	51,168
Return on Rate Base - Interest			$	52,396
Deemed Equity %	40.00%	**N**	$	744,373
Return on Rate Base -Equity	9.19%	**O**	$	68,408
Return on Rate Base - Total			$	120,804

Amortization Expense				
Amortization Expense - Incremental		**C**	$	85,475

Grossed up PIL's				
Regulatory Taxable Income		**O**	$	68,408
Add Back Amortization Expense		**S**	$	85,475
Deduct CCA			$	321,393
Incremental Taxable Income			-$	167,510
Current Tax Rate	26.5%	**X**		
PIL's Before Gross Up			-$	44,390
Incremental Grossed Up PIL's			-$	60,395

Incremental Revenue Requirement				
Return on Rate Base - Total		**Q**	$	120,804
Amortization Expense - Total			$	85,475
Incremental Grossed Up PIL's		**Z**	-$	60,395
Incremental Revenue Requirement			$	145,884

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						internal use			
Enersource Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.17	0.16%	$ 108.76	$ 0.16	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.50	0.17%	$ 294.09	$ 0.30	$ 0.0001	5%
General Service 50 to 499 kW	kW	100,000	230	$ 8.83	0.05%	$ 16,343.79	$ 0.53	$ 0.0317	13%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 54.98	0.07%	$ 75,489.89	$ 11.98	$ 0.0163	13%
Large Use	kW	3,000,000	5,000	$ 221.08	0.05%	$ 453,444.03	$ 94.50	$ 0.0202	13%
Unmetered	kWh	300		$ 0.11	0.21%	$ 51.55	$ 0.06	$ 0.0001	13%
Street Lighting	kW	33	0.1	$ 0.02	0.51%	$ 4.07	$ 0.01	$ 0.0791	13%

						internal use			
Brampton Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.23	0.21%	$ 105.95	$ 0.22	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.56	0.20%	$ 273.46	$ 0.23	$ 0.0002	5%
General Service 50 to 699 kW	kW	182,500	500	$ 15.88	0.06%	$ 28,468.08	$ 1.14	$ 0.0258	13%
General Service 700 to 4999 kW	kW	627,216	1,432	$ 60.12	0.06%	$ 97,740.35	$ 10.29	$ 0.0300	13%
Large Use	kW	10,220,000	20,000	$ 561.20	0.04%	$ 1,518,838.91	$ 42.80	$ 0.0227	13%
Unmetered	kWh	21,296		$ 4.34	0.11%	$ 3,806.85	$ 0.01	$ 0.0002	13%
Street Lighting	kW	2,787,508	7,922.0	$ 939.50	0.17%	$ 561,277.28	$ 0.02	$ 0.1049	13%
Embedded Distributor	kWh	1,417,701	4,000.0	$ 42.75	0.02%	$ 217,321.03	$ 37.83	$ -	13%
Distributed Generation	kWh	156		$ 1.07	0.74%	$ 144.11	$ 0.95	$ -	13%

						internal use			
Horizon Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.19	0.18%	$ 108.72	$ 0.18	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.47	0.17%	$ 278.57	$ 0.29	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	110,000	250	$ 8.16	0.05%	$ 16,623.28	$ 2.69	$ 0.0181	13%
Large Use	kW	2,555,000	5,000	$ 245.81	0.06%	$ 391,833.69	$ 167.98	$ 0.0099	13%
Large Use With Dedicated Assets	kW	10,220,000	20,000	$ 98.10	0.01%	$ 1,444,287.90	$ 39.82	$ 0.0023	13%
Unmetered Scattered Load	kWh	250		$ 0.09	0.24%	$ 38.90	$ 0.06	$ 0.0001	13%
Sentinel Lighting	kW	97,008	216.0	$ 26.12	0.12%	$ 21,677.16	$ 0.04	$ 0.1068	13%
Street Lighting	kW	1,782,038	4,974.0	$ 201.26	0.05%	$ 369,947.70	$ 0.01	$ 0.0358	13%

						internal use			
PowerStream Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.22	0.20%	$ 106.91	$ 0.18	$ 0.0000	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.46	0.17%	$ 274.29	$ 0.19	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	80,000	250	$ 9.05	0.07%	$ 12,738.87	$ 0.95	$ 0.0283	13%
Large Use	kW	2,800,000	7,350	$ 171.34	0.04%	$ 416,389.80	$ 40.83	$ 0.0151	13%
Unmetered Scattered Load	kWh	150	0	$ 0.09	0.30%	$ 29.64	$ 0.06	$ 0.0001	13%
Sentinel Lighting	kW	180	1	$ 0.11	0.30%	$ 35.58	$ 0.03	$ 0.0664	13%
Street Lighting	kW	280	1.0	$ 0.06	0.11%	$ 51.53	$ 0.01	$ 0.0425	13%

						internal use			
Guelph Rate Class	**Unit**	**kWh**	**kW**	**MCM Rate Rider Incl HST**	**% Increase vs. Total Bill**	**2019 Total Bill (Approved)**	**Fixed Rate Rider**	**Variable Rate Rider**	Taxes
Residential	kWh	750		$ 0.15	0.13%	$ 112.36	$ 0.14	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.23	0.09%	$ 261.15	$ 0.08	$ 0.0001	5%
General Service 50 To 999 Kw	kW	189,800	500	$ 8.54	0.03%	$ 31,096.59	$ 0.88	$ 0.0134	13%
General Service 1,000 To 4,999 Kw	kW	489,100	1,000	$ 19.89	0.02%	$ 79,719.37	$ 2.77	$ 0.0148	13%
Large Use	kW	4,215,750	7,500	$ 118.91	0.02%	$ 632,049.16	$ 5.33	$ 0.0133	13%
Unmetered Scattered Load	kWh	750		$ 0.12	0.06%	$ 189.16	$ 0.02	$ 0.0001	13%
Sentinel Lighting	kW	140	2.0	$ 0.13	0.19%	$ 68.61	$ 0.04	$ 0.0405	13%
Street Lighting	kW	800,000	2,200.0	$ 123.49	0.08%	$ 153,755.46	$ 0.00	$ 0.0497	13%

Enersource Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	40.22%	0.00%	0.00%	358,479	0	0	358,479	183,533	1,490,532,667		0.16	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.44%	6.71%	0.00%	66,360	59,825	0	126,185	18,506	685,616,684		0.30	0.0001	0.0000
GENERAL SERVICE 50 TO 499 kW	2.65%	0.00%	20.29%	23,588	0	180,869	204,457	3,735		5,710,412	0.53	0.0000	0.0317
GENERAL SERVICE 500 TO 4,999 kW	7.71%	0.00%	8.38%	68,746	0	74,740	143,486	478	2,037,760,513	4,585,777	11.98	0.0000	0.0163
LARGE USE	1.14%	0.00%	3.98%	10,206	0	35,466	45,671	9	977,049,362	1,753,163	94.50	0.0000	0.0202
UNMETERED SCATTERED LOAD	0.26%	0.14%	0.00%	2,302	1,282	0	3,584	3,110	11,437,642		0.06	0.0001	0.0000
STREET LIGHTING	0.71%	0.00%	0.36%	6,308	0	3,211	9,519	50,859	13,289,944	40,572	0.01	0.0000	0.0791
Total	**60.13%**	**6.86%**	**33.01%**	**535,989**	**61,107**	**294,285**	**891,381**	**260,230**	**5,215,686,812**	**12,089,924**			
							891,381						

Brampton Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	57.65%	0.00%	0.00%	398,072	0	0	398,072	153,261	1,385,125,813		0.22	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	3.76%	7.61%	0.00%	25,941	52,516	0	78,457	9,462	344,785,907		0.23	0.0002	0.0000
GENERAL SERVICE 50 TO 699 KW	3.15%	0.00%	11.89%	21,764	0	82,093	103,857	1,591	1,131,688,196	3,179,603	1.14	0.0000	0.0258
GENERAL SERVICE 700 TO 4,999 KW	1.88%	0.00%	8.77%	12,959	0	60,560	73,520	105	875,091,030	2,020,563	10.29	0.0000	0.0300
LARGE USE	0.45%	0.00%	2.16%	3,082	0	14,928	18,010	6	350,379,705	657,857	42.80	0.0000	0.0227
UNMETERED SCATTERED LOAD	0.03%	0.15%	0.00%	185	1,064	0	1,249	1,556	5,914,654		0.01	0.0002	0.0000
STREET LIGHTING	0.72%	0.00%	1.50%	5,003	0	10,373	15,377	19,919	34,968,321	98,842	0.02	0.0000	0.1049
EMBEDDED DISTRIBUTOR	0.07%	0.00%	0.00%	454	0	0	454	1	3,402,773		37.83	0.0000	0.0000
DISTRIBUTED GENERATION [DGEN]	0.22%	0.00%	0.00%	1,487	0	0	1,487	131	277,418		0.95	0.0000	0.0000
STANDBY POWER	0.00%	0.00%	0.00%	0	0	0	0	1			0.00	0.0000	0.0000
Total	**67.92%**	**7.76%**	**24.32%**	**468,947**	**53,580**	**167,954**	**690,481**	**186,033**	**4,131,633,817**	**5,956,865**			
							690,481						

PowerStream Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	48.05%	6.02%	0.00%	658,695	82,477	0	741,172	334,683	2,783,708,695		0.18	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.52%	9.43%	0.00%	75,652	129,231	0	204,884	32,624	1,049,615,664		0.19	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	4.32%	0.00%	25.14%	59,221	0	344,590	403,811	5,207	4,679,965,944	12,192,876	0.95	0.0000	0.0283
LARGE USE	0.07%	0.00%	0.11%	980	0	1,551	2,531	2	53,218,181	102,871	40.83	0.0000	0.0151
UNMETERED SCATTERED LOAD	0.16%	0.13%	0.00%	2,138	1,812	0	3,950	3,082	13,830,788		0.06	0.0001	0.0000
SENTINEL LIGHTING	0.00%	0.00%	0.00%	58	0	53	111	172	286,385	796	0.03	0.0000	0.0664
STREET LIGHTING	0.64%	0.00%	0.42%	8,742	0	5,702	14,444	91,446	48,883,953	134,152	0.01	0.0000	0.0425
Total	**58.76%**	**15.58%**	**25.67%**	**805,487**	**213,520**	**351,895**	**1,370,903**	**467,216**	**8,629,509,610**	**12,430,695**			
							1,370,903						

Guelph Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}		*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	58.40%	0.00%	0.00%	85,203	0	0	85,203	50,914	384,041,745		0.14	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 KW	2.75%	6.61%	0.00%	4,011	9,638	0	13,648	4,134	142,209,076		0.08	0.0001	0.0000
GENERAL SERVICE 50 TO 999 KW	4.17%	0.00%	10.05%	6,080	0	14,657	20,737	578	402,350,218	1,097,499	0.88	0.0000	0.0134
GENERAL SERVICE 1,000 TO 4,999 KW	0.98%	0.00%	11.54%	1,431	0	16,833	18,264	43	540,417,878	1,135,425	2.77	0.0000	0.0148
LARGE USE	0.18%	0.00%	3.86%	256	0	5,637	5,892	4	197,428,962	423,180	5.33	0.0000	0.0133
UNMETERED SCATTERED LOAD	0.11%	0.13%	0.00%	159	195	0	354	559	1,810,678		0.02	0.0001	0.0000
SENTINEL LIGHTING	0.01%	0.00%	0.00%	15	0	2	17	35	18,189	51	0.04	0.0000	0.0405
STREET LIGHTING	0.24%	0.00%	0.97%	357	0	1,412	1,769	14,152	10,182,750	28,425	0.00	0.0000	0.0497
Total	**66.84%**	**6.74%**	**26.42%**	**97,511**	**9,833**	**38,540**	**145,884**	**70,419**	**1,678,459,496**	**2,684,580**			
							145,884						

Horizon Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.35%	0.00%	0.00%	504,885	0	0	504,885	227,762	1,652,719,193		0.18	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.98%	5.45%	0.00%	65,688	44,831	0	110,519	18,709	594,472,785		0.29	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	9.10%	0.00%	11.14%	74,875	0	91,662	166,537	2,316	1,840,510,488	5,066,406	2.69	0.0000	0.0181
LARGE USE	1.47%	0.00%	0.69%	12,094	0	5,644	17,739	6	242,051,739	569,520	167.98	0.0000	0.0099
LARGE USE WITH DEDICATED ASSETS	0.29%	0.00%	0.61%	2,389	0	5,021	7,410	5	403,775,839	2,136,952	39.82	0.0000	0.0023
UNMETERED SCATTERED LOAD	0.26%	0.12%	0.00%	2,154	974	0	3,128	3,006	10,504,342		0.06	0.0001	0.0000
SENTINEL LIGHTING	0.02%	0.00%	0.01%	177	0	110	287	378	363,731	1,030	0.04	0.0000	0.1068
STREET LIGHTING	1.03%	0.00%	0.48%	8,463	0	3,930	12,393	52,273	39,610,413	109,773	0.01	0.0000	0.0358
Total	**81.51%**	**5.57%**	**12.93%**	**670,724**	**45,805**	**106,368**	**822,897**	**304,455**	**4,784,008,529**	**7,883,681**			
							822,897						

2023 Rates

M-factor Revenue Requirement_HRZ

Return on Rate Base

Incremental Capital			$	4,249,180
Depreciation Expense			$	411,768
Incremental Capital to be included in Rate Base (avg NBV)			$	4,043,296
Deemed ShortTerm Debt %	4.0%	**E**	$	161,732
Deemed Long Term Debt %	56.0%	**F**	$	2,264,246
Short Term Interest	2.82%	**I**	$	4,561
Long Term Interest	3.74%	**J**	$	84,683
Return on Rate Base - Interest			$	89,244
Deemed Equity %	40.00%	**N**	$	1,617,318
Return on Rate Base -Equity	8.98%	**O**	$	145,235
Return on Rate Base - Total			$	234,479

Amortization Expense

Amortization Expense - Incremental	**C**	$	411,768

Grossed up PIL's

Regulatory Taxable Income		**O**	$	145,235
Add Back Amortization Expense		**S**	$	411,768
Deduct CCA			$	571,579
Incremental Taxable Income			-$	14,576
Current Tax Rate	26.5%	**X**		
PIL's Before Gross Up			-$	3,863
Incremental Grossed Up PIL's			-$	5,255

Incremental Revenue Requirement

Return on Rate Base - Total	**Q**	$	234,479
Amortization Expense - Total		$	411,768
Incremental Grossed Up PIL's	**Z**	-$	5,255
Incremental Revenue Requirement		$	640,991

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M-factor Revenue Requirement_BRZ

Return on Rate Base				
Incremental Capital			$	4,260,455
Depreciation Expense			$	333,346
Incremental Capital to be included in Rate Base (avg NBV)			$	4,093,782
Deemed ShortTerm Debt %	4.0%	E	$	163,751
Deemed Long Term Debt %	56.0%	F	$	2,292,518
Short Term Interest	2.16%	I	$	3,537
Long Term Interest	6.07%	J	$	139,156
Return on Rate Base - Interest			$	142,693
Deemed Equity %	40.00%	N	$	1,637,513
Return on Rate Base -Equity	9.30%	O	$	152,289
Return on Rate Base - Total			$	294,982

Amortization Expense				
Amortization Expense - Incremental		C	$	333,346

Grossed up PIL's				
Regulatory Taxable Income		O	$	152,289
Add Back Amortization Expense		S	$	333,346
Deduct CCA			$	520,081
Incremental Taxable Income			-$	34,447
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	9,128
Incremental Grossed Up PIL's			-$	12,420

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	294,982
Amortization Expense - Total			$	333,346
Incremental Grossed Up PIL's		Z	-$	12,420
Incremental Revenue Requirement			$	615,908

M-factor Revenue Requirement_PRZ

Return on Rate Base

Incremental Capital			$	34,170,992
Depreciation Expense			$	1,418,894
Incremental Capital to be included in Rate Base (avg NBV)			$	33,461,545
Deemed ShortTerm Debt %	4.0%	**E**	$	1,338,462
Deemed Long Term Debt %	56.0%	**F**	$	18,738,465
Short Term Interest	1.76%	**I**	$	23,557
Long Term Interest	3.88%	**J**	$	727,052
Return on Rate Base - Interest			$	750,609
Deemed Equity %	40.00%	**N**	$	13,384,618
Return on Rate Base -Equity	8.78%	**O**	$	1,175,169
Return on Rate Base - Total			$	1,925,779

Amortization Expense

Amortization Expense - Incremental		**C**	$	1,418,894

Grossed up PIL's

Regulatory Taxable Income		**O**	$	1,175,169
Add Back Amortization Expense		**S**	$	1,418,894
Deduct CCA			$	3,273,583
Incremental Taxable Income			-$	679,519
Current Tax Rate	26.5%	**X**		
PIL's Before Gross Up			-$	180,072
Incremental Grossed Up PIL's			-$	244,997

Incremental Revenue Requirement

Return on Rate Base - Total		**Q**	$	1,925,779
Amortization Expense - Total			$	1,418,894
Incremental Grossed Up PIL's		**Z**	-$	244,997
Incremental Revenue Requirement			$	3,099,677

M-factor Revenue Requirement_ERZ

Return on Rate Base				
Incremental Capital			$	8,577,274
Depreciation Expense			$	532,386
Incremental Capital to be included in Rate Base (avg NBV)			$	8,311,082
Deemed ShortTerm Debt %	4.0%	E	$	332,443
Deemed Long Term Debt %	56.0%	F	$	4,654,206
Short Term Interest	2.08%	I	$	6,915
Long Term Interest	5.09%	J	$	236,899
Return on Rate Base - Interest			$	243,814
Deemed Equity %	40.00%	N	$	3,324,433
Return on Rate Base -Equity	8.93%	O	$	296,872
Return on Rate Base - Total			$	540,686

Amortization Expense				
Amortization Expense - Incremental		C	$	532,386

Grossed up PIL's				
Regulatory Taxable Income		O	$	296,872
Add Back Amortization Expense		S	$	532,386
Deduct CCA			$	869,139
Incremental Taxable Income			-$	39,882
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	10,569
Incremental Grossed Up PIL's			-$	14,379

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	540,686
Amortization Expense - Total			$	532,386
Incremental Grossed Up PIL's		Z	-$	14,379
Incremental Revenue Requirement			$	1,058,692

M-factor Revenue Requirement_GRZ

Return on Rate Base				
Incremental Capital			$	811,132
Depreciation Expense			$	92,870
Incremental Capital to be included in Rate Base (avg NBV)			$	764,697
Deemed ShortTerm Debt %	4.0%	E	$	30,588
Deemed Long Term Debt %	56.0%	F	$	428,230
Short Term Interest	1.65%	I	$	505
Long Term Interest	4.91%	J	$	21,026
Return on Rate Base - Interest			$	21,531
Deemed Equity %	40.00%	N	$	305,879
Return on Rate Base -Equity	9.19%	O	$	28,110
Return on Rate Base - Total			$	49,641

Amortization Expense				
Amortization Expense - Incremental		C	$	92,870

Grossed up PIL's				
Regulatory Taxable Income		O	$	28,110
Add Back Amortization Expense		S	$	92,870
Deduct CCA			$	95,001
Incremental Taxable Income			$	25,980
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			$	6,885
Incremental Grossed Up PIL's			$	9,367

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	49,641
Amortization Expense - Total			$	92,870
Incremental Grossed Up PIL's		Z	$	9,367
Incremental Revenue Requirement			$	151,878

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Enersource Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.20	0.19%	$ 108.76	$ 0.19	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.59	0.20%	$ 294.09	$ 0.35	$ 0.0001	5%
General Service 50 to 499 kW	kW	100,000	230	$ 10.48	0.06%	$ 16,343.79	$ 0.63	$ 0.0376	13%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 65.30	0.09%	$ 75,489.89	$ 14.23	$ 0.0194	13%
Large Use	kW	3,000,000	5,000	$ 262.57	0.06%	$ 453,444.03	$ 112.23	$ 0.0240	13%
Unmetered	kWh	300		$ 0.13	0.25%	$ 51.55	$ 0.07	$ 0.0001	13%
Street Lighting	kW	33	0.1	$ 0.02	0.60%	$ 4.07	$ 0.01	$ 0.0940	13%

Brampton Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.20	0.19%	$ 105.95	$ 0.19	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.50	0.18%	$ 273.46	$ 0.20	$ 0.0001	5%
General Service 50 to 699 kW	kW	182,500	500	$ 14.16	0.05%	$ 28,468.08	$ 1.02	$ 0.0230	13%
General Service 700 to 4999 kW	kW	627,216	1,432	$ 53.63	0.05%	$ 97,740.35	$ 9.17	$ 0.0267	13%
Large Use	kW	10,220,000	20,000	$ 500.59	0.03%	$ 1,518,838.91	$ 38.18	$ 0.0202	13%
Unmetered	kWh	21,296		$ 3.87	0.10%	$ 3,806.85	$ 0.01	$ 0.0002	13%
Street Lighting	kW	2,787,508	7,922.0	$ 838.03	0.15%	$ 561,277.28	$ 0.02	$ 0.0936	13%
Embedded Distributor	kWh	1,417,701	4,000.0	$ 38.14	0.02%	$ 217,321.03	$ 33.75	$ -	13%
Distributed Generation	kWh	156		$ 0.95	0.66%	$ 144.11	$ 0.84	$ -	13%

Horizon Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.15	0.14%	$ 108.72	$ 0.14	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.36	0.13%	$ 278.57	$ 0.23	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	110,000	250	$ 6.35	0.04%	$ 16,623.28	$ 2.10	$ 0.0141	13%
Large Use	kW	2,555,000	5,000	$ 191.47	0.05%	$ 391,833.69	$ 130.85	$ 0.0077	13%
Large Use With Dedicated Assets	kW	10,220,000	20,000	$ 76.41	0.01%	$ 1,444,287.90	$ 31.02	$ 0.0018	13%
Unmetered Scattered Load	kWh	250		$ 0.07	0.19%	$ 38.90	$ 0.05	$ 0.0001	13%
Sentinel Lighting	kW	97,008	216.0	$ 20.35	0.09%	$ 21,677.16	$ 0.03	$ 0.0832	13%
Street Lighting	kW	1,782,038	4,974.0	$ 156.77	0.04%	$ 369,947.70	$ 0.01	$ 0.0279	13%

PowerStream Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.49	0.46%	$ 106.91	$ 0.42	$ 0.0001	5%
General Service Less Than 50 Kw	kWh	2,000		$ 1.04	0.38%	$ 274.29	$ 0.44	$ 0.0003	5%
General Service 50 To 4,999 Kw	kW	80,000	250	$ 20.47	0.16%	$ 12,738.87	$ 2.14	$ 0.0639	13%
Large Use	kW	2,800,000	7,350	$ 387.40	0.09%	$ 416,389.80	$ 92.33	$ 0.0341	13%
Unmetered Scattered Load	kWh	150	0	$ 0.20	0.67%	$ 29.64	$ 0.13	$ 0.0003	13%
Sentinel Lighting	kW	180	1	$ 0.24	0.68%	$ 35.58	$ 0.06	$ 0.1500	13%
Street Lighting	kW	280	1.0	$ 0.13	0.25%	$ 51.53	$ 0.02	$ 0.0961	13%

Guelph Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.15	0.14%	$ 112.36	$ 0.15	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.24	0.09%	$ 261.15	$ 0.08	$ 0.0001	5%
General Service 50 To 999 Kw	kW	189,800	500	$ 8.89	0.03%	$ 31,096.59	$ 0.91	$ 0.0139	13%
General Service 1,000 To 4,999 Kw	kW	489,100	1,000	$ 20.70	0.03%	$ 79,719.37	$ 2.89	$ 0.0154	13%
Large Use	kW	4,215,750	7,500	$ 123.79	0.02%	$ 632,049.16	$ 5.55	$ 0.0139	13%
Unmetered Scattered Load	kWh	750		$ 0.12	0.07%	$ 189.16	$ 0.02	$ 0.0001	13%
Sentinel Lighting	kW	140	2.0	$ 0.14	0.20%	$ 68.61	$ 0.04	$ 0.0422	13%
Street Lighting	kW	800,000	2,200.0	$ 128.56	0.08%	$ 153,755.46	$ 0.00	$ 0.0517	13%

Enersource Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I $_{total}$*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	40.22%	0.00%	0.00%	425,765	0	0	425,765	183,533	1,490,532,667		0.19	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.44%	6.71%	0.00%	78,815	71,054	0	149,869	18,506	685,616,684		0.35	0.0001	0.0000
GENERAL SERVICE 50 TO 499 kW	2.65%	0.00%	20.29%	28,016	0	214,818	242,834	3,735		5,710,412	0.63	0.0000	0.0376
GENERAL SERVICE 500 TO 4,999 kW	7.71%	0.00%	8.38%	81,649	0	88,769	170,418	478	2,037,760,513	4,585,777	14.23	0.0000	0.0194
LARGE USE	1.14%	0.00%	3.98%	12,121	0	42,122	54,244	9	977,049,362	1,753,163	112.23	0.0000	0.0240
UNMETERED SCATTERED LOAD	0.26%	0.14%	0.00%	2,734	1,523	0	4,257	3,110	11,437,642		0.07	0.0001	0.0000
STREET LIGHTING	0.71%	0.00%	0.36%	7,493	0	3,813	11,306	50,859	13,289,944	40,572	0.01	0.0000	0.0940
Total	**60.13%**	**6.86%**	**33.01%**	**636,593**	**72,576**	**349,522**	**1,058,692**	**260,230**	**5,215,686,812**	**12,089,924**			
							1,058,692						

Brampton Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	57.65%	0.00%	0.00%	355,080	0	0	355,080	153,261	1,385,125,813		0.19	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	3.76%	7.61%	0.00%	23,140	46,844	0	69,984	9,462	344,785,907		0.20	0.0001	0.0000
GENERAL SERVICE 50 TO 699 KW	3.15%	0.00%	11.89%	19,413	0	73,226	92,640	1,591	1,131,688,196	3,179,603	1.02	0.0000	0.0230
GENERAL SERVICE 700 TO 4,999 KW	1.88%	0.00%	8.77%	11,560	0	54,020	65,579	105	875,091,030	2,020,563	9.17	0.0000	0.0267
LARGE USE	0.45%	0.00%	2.16%	2,749	0	13,316	16,065	6	350,379,705	657,857	38.18	0.0000	0.0202
UNMETERED SCATTERED LOAD	0.03%	0.15%	0.00%	165	949	0	1,114	1,556	5,914,654		0.01	0.0002	0.0000
STREET LIGHTING	0.72%	0.00%	1.50%	4,463	0	9,253	13,716	19,919	34,968,321	98,842	0.02	0.0000	0.0936
EMBEDDED DISTRIBUTOR	0.07%	0.00%	0.00%	405	0	0	405	1	3,402,773		33.75	0.0000	0.0000
DISTRIBUTED GENERATION [DGEN]	0.22%	0.00%	0.00%	1,326	0	0	1,326	131	277,418		0.84	0.0000	0.0000
STANDBY POWER	0.00%	0.00%	0.00%	0	0	0	0	1			0.00	0.0000	0.0000
Total	**67.92%**	**7.76%**	**24.32%**	**418,300**	**47,793**	**149,815**	**615,908**	**186,033**	**4,131,633,817**	**5,956,865**			
							615,908						

PowerStream Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	48.05%	6.02%	0.00%	1,489,342	186,484	0	1,675,826	334,683	2,783,708,695		0.42	0.0001	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.52%	9.43%	0.00%	171,054	292,198	0	463,252	32,624	1,049,615,664		0.44	0.0003	0.0000
GENERAL SERVICE 50 TO 4,999 KW	4.32%	0.00%	25.14%	133,902	0	779,134	913,035	5,207	4,679,965,944	12,192,876	2.14	0.0000	0.0639
LARGE USE	0.07%	0.00%	0.11%	2,216	0	3,506	5,722	2	53,218,181	102,871	92.33	0.0000	0.0341
UNMETERED SCATTERED LOAD	0.16%	0.13%	0.00%	4,834	4,097	0	8,931	3,082	13,830,788		0.13	0.0003	0.0000
SENTINEL LIGHTING	0.00%	0.00%	0.00%	132	0	119	251	172	286,385	796	0.06	0.0000	0.1500
STREET LIGHTING	0.64%	0.00%	0.42%	19,767	0	12,893	32,659	91,446	48,883,953	134,152	0.02	0.0000	0.0961
Total	**58.76%**	**15.58%**	**25.67%**	**1,821,245**	**482,780**	**795,652**	**3,099,677**	**467,216**	**8,629,509,610**	**12,430,695**			
							3,099,677						

Guelph Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}		*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	58.40%	0.00%	0.00%	88,704	0	0	88,704	50,914	384,041,745		0.15	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 KW	2.75%	6.61%	0.00%	4,176	10,034	0	14,209	4,134	142,209,076		0.08	0.0001	0.0000
GENERAL SERVICE 50 TO 999 KW	4.17%	0.00%	10.05%	6,329	0	15,259	21,589	578	402,350,218	1,097,499	0.91	0.0000	0.0139
GENERAL SERVICE 1,000 TO 4,999 KW	0.98%	0.00%	11.54%	1,490	0	17,525	19,014	43	540,417,878	1,135,425	2.89	0.0000	0.0154
LARGE USE	0.18%	0.00%	3.86%	266	0	5,868	6,134	4	197,428,962	423,180	5.55	0.0000	0.0139
UNMETERED SCATTERED LOAD	0.11%	0.13%	0.00%	165	203	0	369	559	1,810,678		0.02	0.0001	0.0000
SENTINEL LIGHTING	0.01%	0.00%	0.00%	16	0	2	18	35	18,189	51	0.04	0.0000	0.0422
STREET LIGHTING	0.24%	0.00%	0.97%	371	0	1,470	1,841	14,152	10,182,750	28,425	0.00	0.0000	0.0517
Total	**66.84%**	**6.74%**	**26.42%**	**101,517**	**10,237**	**40,124**	**151,878**	**70,419**	**1,678,459,496**	**2,684,580**			
							151,878						

Horizon Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.35%	0.00%	0.00%	393,277	0	0	393,277	227,762	1,652,719,193		0.14	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.98%	5.45%	0.00%	51,168	34,921	0	86,088	18,709	594,472,785		0.23	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	9.10%	0.00%	11.14%	58,323	0	71,400	129,723	2,316	1,840,510,488	5,066,406	2.10	0.0000	0.0141
LARGE USE	1.47%	0.00%	0.69%	9,421	0	4,397	13,818	6	242,051,739	569,520	130.85	0.0000	0.0077
LARGE USE WITH DEDICATED ASSETS	0.29%	0.00%	0.61%	1,861	0	3,911	5,772	5	403,775,839	2,136,952	31.02	0.0000	0.0018
UNMETERED SCATTERED LOAD	0.26%	0.12%	0.00%	1,678	759	0	2,436	3,006	10,504,342		0.05	0.0001	0.0000
SENTINEL LIGHTING	0.02%	0.00%	0.01%	138	0	86	223	378	363,731	1,030	0.03	0.0000	0.0832
STREET LIGHTING	1.03%	0.00%	0.48%	6,592	0	3,062	9,654	52,273	39,610,413	109,773	0.01	0.0000	0.0279
Total	**81.51%**	**5.57%**	**12.93%**	**522,457**	**35,679**	**82,855**	**640,991**	**304,455**	**4,784,008,529**	**7,883,681**			
							640,991						

2024 Rates

M-factor Revenue Requirement_HRZ

Return on Rate Base

Incremental Capital			$	12,159,862
Depreciation Expense			$	394,000
Incremental Capital to be included in Rate Base (avg NBV)			$	11,962,862
Deemed ShortTerm Debt %	4.0%	E	$	478,514
Deemed Long Term Debt %	56.0%	F	$	6,699,203
Short Term Interest	2.82%	I	$	13,494
Long Term Interest	3.74%	J	$	250,550
Return on Rate Base - Interest			$	264,044
Deemed Equity %	40.00%	N	$	4,785,145
Return on Rate Base -Equity	8.98%	O	$	429,706
Return on Rate Base - Total			$	693,750

Amortization Expense

Amortization Expense - Incremental		C	$	394,000

Grossed up PIL's

Regulatory Taxable Income		O	$	429,706
Add Back Amortization Expense		S	$	394,000
Deduct CCA			$	1,089,098
Incremental Taxable Income			-$	265,392
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	70,329
Incremental Grossed Up PIL's			-$	95,686

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	693,750
Amortization Expense - Total			$	394,000
Incremental Grossed Up PIL's		Z	-$	95,686
Incremental Revenue Requirement			$	992,065

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M-factor Revenue Requirement_BRZ

Return on Rate Base

Incremental Capital			$	4,016,970
Depreciation Expense			$	221,778
Incremental Capital to be included in Rate Base (avg NBV)			$	3,906,081
Deemed ShortTerm Debt %	4.0%	E	$	156,243
Deemed Long Term Debt %	56.0%	F	$	2,187,406
Short Term Interest	2.16%	I	$	3,375
Long Term Interest	6.07%	J	$	132,776
Return on Rate Base - Interest			$	136,150
Deemed Equity %	40.00%	N	$	1,562,433
Return on Rate Base -Equity	9.30%	O	$	145,306
Return on Rate Base - Total			$	281,457

Amortization Expense

Amortization Expense - Incremental	C	$	221,778

Grossed up PIL's

Regulatory Taxable Income		O	$	145,306
Add Back Amortization Expense		S	$	221,778
Deduct CCA			$	742,468
Incremental Taxable Income			-$	375,384
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	99,477
Incremental Grossed Up PIL's			-$	135,343

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	281,457
Amortization Expense - Total		$	221,778
Incremental Grossed Up PIL's	Z	-$	135,343
Incremental Revenue Requirement		$	367,892

M-factor Revenue Requirement_PRZ

Return on Rate Base

Incremental Capital			$	24,005,137
Depreciation Expense			$	877,570
Incremental Capital to be included in Rate Base (avg NBV)			$	23,566,353
Deemed ShortTerm Debt %	4.0%	E	$	942,654
Deemed Long Term Debt %	56.0%	F	$	13,197,157
Short Term Interest	1.76%	I	$	16,591
Long Term Interest	3.88%	J	$	512,050
Return on Rate Base - Interest			$	528,640
Deemed Equity %	40.00%	N	$	9,426,541
Return on Rate Base -Equity	8.78%	O	$	827,650
Return on Rate Base - Total			$	1,356,291

Amortization Expense

Amortization Expense - Incremental		C	$	877,570

Grossed up PIL's

Regulatory Taxable Income		O	$	827,650
Add Back Amortization Expense		S	$	877,570
Deduct CCA			$	2,773,125
Incremental Taxable Income			-$	1,067,905
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	282,995
Incremental Grossed Up PIL's			-$	385,027

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$	1,356,291
Amortization Expense - Total			$	877,570
Incremental Grossed Up PIL's		Z	-$	385,027
Incremental Revenue Requirement			$	1,848,834

M-factor Revenue Requirement_ERZ

Return on Rate Base				
Incremental Capital			$	23,519,955
Depreciation Expense			$	839,946
Incremental Capital to be included in Rate Base (avg NBV)			$	23,099,982
Deemed ShortTerm Debt %	4.0%	E	$	923,999
Deemed Long Term Debt %	56.0%	F	$	12,935,990
Short Term Interest	2.08%	I	$	19,219
Long Term Interest	5.09%	J	$	658,442
Return on Rate Base - Interest			$	677,661
Deemed Equity %	40.00%	N	$	9,239,993
Return on Rate Base -Equity	8.93%	O	$	825,131
Return on Rate Base - Total			$	1,502,792

Amortization Expense				
Amortization Expense - Incremental		C	$	839,946

Grossed up PIL's				
Regulatory Taxable Income		O	$	825,131
Add Back Amortization Expense		S	$	839,946
Deduct CCA			$	2,455,139
Incremental Taxable Income			-$	790,062
Current Tax Rate	26.5%	X		
PIL's Before Gross Up			-$	209,367
Incremental Grossed Up PIL's			-$	284,852

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$	1,502,792
Amortization Expense - Total			$	839,946
Incremental Grossed Up PIL's		Z	-$	284,852
Incremental Revenue Requirement			$	2,057,886

M-factor Revenue Requirement_GRZ

Return on Rate Base

Incremental Capital			$	839,406
Depreciation Expense			$	38,535
Incremental Capital to be included in Rate Base (avg NBV)			$	820,138
Deemed ShortTerm Debt %	4.0%	**E**	$	32,806
Deemed Long Term Debt %	56.0%	**F**	$	459,277
Short Term Interest	1.65%	**I**	$	541
Long Term Interest	4.91%	**J**	$	22,551
Return on Rate Base - Interest			$	23,092
Deemed Equity %	40.00%	**N**	$	328,055
Return on Rate Base -Equity	9.19%	**O**	$	30,148
Return on Rate Base - Total			$	53,240

Amortization Expense

Amortization Expense - Incremental		**C**	$	38,535

Grossed up PIL's

Regulatory Taxable Income		**O**	$	30,148
Add Back Amortization Expense		**S**	$	38,535
Deduct CCA			$	81,212
Incremental Taxable Income			-$	12,528
Current Tax Rate	26.5%	**X**		
PIL's Before Gross Up			-$	3,320
Incremental Grossed Up PIL's			-$	4,517

Incremental Revenue Requirement

Return on Rate Base - Total		**Q**	$	53,240
Amortization Expense - Total			$	38,535
Incremental Grossed Up PIL's		**Z**	-$	4,517
Incremental Revenue Requirement			$	87,258

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Enersource Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.39	0.36%	$ 108.76	$ 0.38	$ -	5%
General Service < 50 kW	kWh	2,000		$ 1.15	0.39%	$ 294.09	$ 0.69	$ 0.0002	5%
General Service 50 to 499 kW	kW	100,000	230	$ 20.38	0.12%	$ 16,343.79	$ 1.22	$ 0.0731	13%
General Service 500 to 4999 kW	kW	400,000	2,250	$ 126.93	0.17%	$ 75,489.89	$ 27.67	$ 0.0376	13%
Large Use	kW	3,000,000	5,000	$ 510.39	0.11%	$ 453,444.03	$ 218.16	$ 0.0467	13%
Unmetered	kWh	300		$ 0.25	0.48%	$ 51.55	$ 0.14	$ 0.0003	13%
Street Lighting	kW	33	0.1	$ 0.05	1.17%	$ 4.07	$ 0.02	$ 0.1827	13%

Brampton Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.12	0.11%	$ 105.95	$ 0.12	$ -	5%
General Service < 50 kW	kWh	2,000		$ 0.30	0.11%	$ 273.46	$ 0.12	$ 0.0001	5%
General Service 50 to 699 kW	kW	182,500	500	$ 8.46	0.03%	$ 28,468.08	$ 0.61	$ 0.0138	13%
General Service 700 to 4999 kW	kW	627,216	1,432	$ 32.03	0.03%	$ 97,740.35	$ 5.48	$ 0.0160	13%
Large Use	kW	10,220,000	20,000	$ 299.01	0.02%	$ 1,518,838.91	$ 22.80	$ 0.0121	13%
Unmetered	kWh	21,296		$ 2.31	0.06%	$ 3,806.85	$ 0.01	$ 0.0001	13%
Street Lighting	kW	2,787,508	7,922.0	$ 500.57	0.09%	$ 561,277.28	$ 0.01	$ 0.0559	13%
Embedded Distributor	kWh	1,417,701	4,000.0	$ 22.78	0.01%	$ 217,321.03	$ 20.16	$ -	13%
Distributed Generation	kWh	156		$ 0.57	0.40%	$ 144.11	$ 0.50	$ -	13%

Horizon Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.23	0.22%	$ 108.72	$ 0.22	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.56	0.20%	$ 278.57	$ 0.35	$ 0.0001	5%
General Service 50 To 4,999 Kw	kW	110,000	250	$ 9.83	0.06%	$ 16,623.28	$ 3.25	$ 0.0218	13%
Large Use	kW	2,555,000	5,000	$ 296.35	0.08%	$ 391,833.69	$ 202.51	$ 0.0119	13%
Large Use With Dedicated Assets	kW	10,220,000	20,000	$ 118.27	0.01%	$ 1,444,287.90	$ 48.01	$ 0.0028	13%
Unmetered Scattered Load	kWh	250		$ 0.11	0.29%	$ 38.90	$ 0.07	$ 0.0001	13%
Sentinel Lighting	kW	97,008	216.0	$ 31.49	0.15%	$ 21,677.16	$ 0.05	$ 0.1288	13%
Street Lighting	kW	1,782,038	4,974.0	$ 242.64	0.07%	$ 369,947.70	$ 0.02	$ 0.0432	13%

PowerStream Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.29	0.27%	$ 106.91	$ 0.25	$ 0.0000	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.62	0.23%	$ 274.29	$ 0.26	$ 0.0002	5%
General Service 50 To 4,999 Kw	kW	80,000	250	$ 12.21	0.10%	$ 12,738.87	$ 1.28	$ 0.0381	13%
Large Use	kW	2,800,000	7,350	$ 231.07	0.06%	$ 416,389.80	$ 55.07	$ 0.0203	13%
Unmetered Scattered Load	kWh	150	0	$ 0.12	0.40%	$ 29.64	$ 0.08	$ 0.0002	13%
Sentinel Lighting	kW	180	1	$ 0.14	0.40%	$ 35.58	$ 0.04	$ 0.0895	13%
Street Lighting	kW	280	1.0	$ 0.08	0.15%	$ 51.53	$ 0.01	$ 0.0573	13%

Guelph Rate Class	Unit	kWh	kW	MCM Rate Rider Incl HST	% Increase vs. Total Bill	internal use			
						2019 Total Bill (Approved)	Fixed Rate Rider	Variable Rate Rider	Taxes
Residential	kWh	750		$ 0.09	0.08%	$ 112.36	$ 0.08	$ -	5%
General Service Less Than 50 Kw	kWh	2,000		$ 0.14	0.05%	$ 261.15	$ 0.05	$ 0.0000	5%
General Service 50 To 999 Kw	kW	189,800	500	$ 5.11	0.02%	$ 31,096.59	$ 0.52	$ 0.0080	13%
General Service 1,000 To 4,999 Kw	kW	489,100	1,000	$ 11.89	0.01%	$ 79,719.37	$ 1.66	$ 0.0089	13%
Large Use	kW	4,215,750	7,500	$ 71.12	0.01%	$ 632,049.16	$ 3.19	$ 0.0080	13%
Unmetered Scattered Load	kWh	750		$ 0.07	0.04%	$ 189.16	$ 0.01	$ 0.0001	13%
Sentinel Lighting	kW	140	2.0	$ 0.08	0.12%	$ 68.61	$ 0.02	$ 0.0242	13%
Street Lighting	kW	800,000	2,200.0	$ 73.86	0.05%	$ 153,755.46	$ 0.00	$ 0.0297	13%

Enersource Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	40.22%	0.00%	0.00%	827,601	0	0	827,601	183,533	1,490,532,667		0.38	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.44%	6.71%	0.00%	153,201	138,114	0	291,316	18,506	685,616,684		0.69	0.0002	0.0000
GENERAL SERVICE 50 TO 499 kW	2.65%	0.00%	20.29%	54,457	0	417,563	472,020	3,735		5,710,412	1.22	0.0000	0.0731
GENERAL SERVICE 500 TO 4,999 kW	7.71%	0.00%	8.38%	158,710	0	172,549	331,259	478	2,037,760,513	4,585,777	27.67	0.0000	0.0376
LARGE USE	1.14%	0.00%	3.98%	23,561	0	81,878	105,439	9	977,049,362	1,753,163	218.16	0.0000	0.0467
UNMETERED SCATTERED LOAD	0.26%	0.14%	0.00%	5,315	2,960	0	8,274	3,110	11,437,642		0.14	0.0003	0.0000
STREET LIGHTING	0.71%	0.00%	0.36%	14,564	0	7,412	21,977	50,859	13,289,944	40,572	0.02	0.0000	0.1827
Total	**60.13%**	**6.86%**	**33.01%**	**1,237,410**	**141,074**	**679,402**	**2,057,886**	**260,230**	**5,215,686,812**	**12,089,924**			
							2,057,886						

Brampton Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	57.65%	0.00%	0.00%	212,095	0	0	212,095	153,261	1,385,125,813		0.12	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	3.76%	7.61%	0.00%	13,822	27,981	0	41,802	9,462	344,785,907		0.12	0.0001	0.0000
GENERAL SERVICE 50 TO 699 KW	3.15%	0.00%	11.89%	11,596	0	43,739	55,335	1,591	1,131,688,196	3,179,603	0.61	0.0000	0.0138
GENERAL SERVICE 700 TO 4,999 KW	1.88%	0.00%	8.77%	6,905	0	32,267	39,172	105	875,091,030	2,020,563	5.48	0.0000	0.0160
LARGE USE	0.45%	0.00%	2.16%	1,642	0	7,954	9,596	6	350,379,705	657,857	22.80	0.0000	0.0121
UNMETERED SCATTERED LOAD	0.03%	0.15%	0.00%	98	567	0	665	1,556	5,914,654		0.01	0.0001	0.0000
STREET LIGHTING	0.72%	0.00%	1.50%	2,666	0	5,527	8,193	19,919	34,968,321	98,842	0.01	0.0000	0.0559
EMBEDDED DISTRIBUTOR	0.07%	0.00%	0.00%	242	0	0	242	1	3,402,773		20.16	0.0000	0.0000
DISTRIBUTED GENERATION [DGEN]	0.22%	0.00%	0.00%	792	0	0	792	131	277,418		0.50	0.0000	0.0000
STANDBY POWER	0.00%	0.00%	0.00%	0	0	0	0	1			0.00	0.0000	0.0000
Total	**67.92%**	**7.76%**	**24.32%**	**249,857**	**28,548**	**89,487**	**367,892**	**186,033**	**4,131,633,817**	**5,956,865**			
							367,892						

PowerStream Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	48.05%	6.02%	0.00%	888,333	111,230	0	999,563	334,683	2,783,708,695		0.25	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.52%	9.43%	0.00%	102,027	174,285	0	276,311	32,624	1,049,615,664		0.26	0.0002	0.0000
GENERAL SERVICE 50 TO 4,999 KW	4.32%	0.00%	25.14%	79,867	0	464,722	544,589	5,207	4,679,965,944	12,192,876	1.28	0.0000	0.0381
LARGE USE	0.07%	0.00%	0.11%	1,322	0	2,091	3,413	2	53,218,181	102,871	55.07	0.0000	0.0203
UNMETERED SCATTERED LOAD	0.16%	0.13%	0.00%	2,883	2,444	0	5,327	3,082	13,830,788		0.08	0.0002	0.0000
SENTINEL LIGHTING	0.00%	0.00%	0.00%	78	0	71	150	172	286,385	796	0.04	0.0000	0.0895
STREET LIGHTING	0.64%	0.00%	0.42%	11,790	0	7,690	19,480	91,446	48,883,953	134,152	0.01	0.0000	0.0573
Total	**58.76%**	**15.58%**	**25.67%**	**1,086,300**	**287,959**	**474,575**	**1,848,834**	**467,216**	**8,629,509,610**	**12,430,695**			
							1,848,834						

Guelph Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}		*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	58.40%	0.00%	0.00%	50,963	0	0	50,963	50,914	384,041,745		0.08	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 KW	2.75%	6.61%	0.00%	2,399	5,765	0	8,164	4,134	142,209,076		0.05	0.0000	0.0000
GENERAL SERVICE 50 TO 999 KW	4.17%	0.00%	10.05%	3,636	0	8,767	12,403	578	402,350,218	1,097,499	0.52	0.0000	0.0080
GENERAL SERVICE 1,000 TO 4,999 KW	0.98%	0.00%	11.54%	856	0	10,068	10,924	43	540,417,878	1,135,425	1.66	0.0000	0.0089
LARGE USE	0.18%	0.00%	3.86%	153	0	3,371	3,524	4	197,428,962	423,180	3.19	0.0000	0.0080
UNMETERED SCATTERED LOAD	0.11%	0.13%	0.00%	95	117	0	212	559	1,810,678		0.01	0.0001	0.0000
SENTINEL LIGHTING	0.01%	0.00%	0.00%	9	0	1	10	35	18,189	51	0.02	0.0000	0.0242
STREET LIGHTING	0.24%	0.00%	0.97%	213	0	845	1,058	14,152	10,182,750	28,425	0.00	0.0000	0.0297
Total	**66.84%**	**6.74%**	**26.42%**	**58,325**	**5,881**	**23,052**	**87,258**	**70,419**	**1,678,459,496**	**2,684,580**			
							87,258						

Horizon Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	61.35%	0.00%	0.00%	608,677	0	0	608,677	227,762	1,652,719,193		0.22	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	7.98%	5.45%	0.00%	79,192	54,047	0	133,239	18,709	594,472,785		0.35	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	9.10%	0.00%	11.14%	90,267	0	110,506	200,773	2,316	1,840,510,488	5,066,406	3.25	0.0000	0.0218
LARGE USE	1.47%	0.00%	0.69%	14,581	0	6,805	21,386	6	242,051,739	569,520	202.51	0.0000	0.0119
LARGE USE WITH DEDICATED ASSETS	0.29%	0.00%	0.61%	2,881	0	6,053	8,934	5	403,775,839	2,136,952	48.01	0.0000	0.0028
UNMETERED SCATTERED LOAD	0.26%	0.12%	0.00%	2,597	1,174	0	3,771	3,006	10,504,342		0.07	0.0001	0.0000
SENTINEL LIGHTING	0.02%	0.00%	0.01%	213	0	133	346	378	363,731	1,030	0.05	0.0000	0.1288
STREET LIGHTING	1.03%	0.00%	0.48%	10,202	0	4,738	14,941	52,273	39,610,413	109,773	0.02	0.0000	0.0432
Total	**81.51%**	**5.57%**	**12.93%**	**808,609**	**55,221**	**128,235**	**992,065**	**304,455**	**4,784,008,529**	**7,883,681**			
							992,065						

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment,

	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
Enersource Rate Class	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**	**Re-based Billed Customers or Connections**	**Re-based Billed kWh**	**Re-based Billed kW**	**Current Base Service Charge Revenue**	**Current Base Distribution Volumetric Rate kWh Revenue**	**Current Base Distribution Volumetric Rate kW Revenue**	**Total Current Base Revenue**	**Service Charge % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Distribution Volumetric Rate % Total Revenue**	**Total % Revenue**
Total	**A**	**B**	**C**	**D**	**E**	**F**	**G = A * D *12**	**H = B * E**	**I = C * F**	**J = G + H + I**	**L = G / J_{total}**	**M = H / J_{total}**	**N = I / J_{total}**	**O = J / J_{total}**
RESIDENTIAL	24.25	0.0000	0.0000	183,533	1,490,532,667		53,408,103	0	0	53,408,103	40.22%	0.00%	0.00%	40.2%
GENERAL SERVICE LESS THAN 50 kW	44.52	0.0130	0.0000	18,506	685,616,684		9,886,645	8,913,017	0	18,799,662	7.44%	6.71%	0.00%	14.2%
GENERAL SERVICE 50 TO 499 kW	78.41	0.0000	4.7189	3,735	2,051,428,808	5,710,412	3,514,336	0	26,946,863	30,461,199	2.65%	0.00%	20.29%	22.9%
GENERAL SERVICE 500 TO 4,999 kW	1785.59	0.0000	2.4282	478	2,037,760,513	4,585,777	10,242,144	0	11,135,184	21,377,328	7.71%	0.00%	8.38%	16.1%
LARGE USE	14078.67	0.0000	3.0139	9	977,049,362	1,753,163	1,520,496	0	5,283,858	6,804,354	1.14%	0.00%	3.98%	5.1%
UNMETERED SCATTERED LOAD	9.19	0.0167	0.0000	3,110	11,437,642		342,971	191,009	0	533,979	0.26%	0.14%	0.00%	0.4%
STREET LIGHTING	1.54	0.0000	11.7902	50,859	13,289,944	40,572	939,874	0	478,352	1,418,226	0.71%	0.00%	0.36%	1.1%
Total							**79,854,570**	**9,104,026**	**43,844,257**	**132,802,853**				**100.0%**

Brampton Rate Class	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
Total	**A**	**B**	**C**	**D**	**E**	**F**	**G = A * D *12**	**H = B * E**	**I = C * F**	**J = G + H + I**	**$L = G / J_{total}$**	**$M = H / J_{total}$**	**$N = I / J_{total}$**	**$O = J / J_{total}$**
RESIDENTIAL	24.30	0.0000	0.0000	153,261	1,385,125,813		44,690,908	0	0	44,690,908	57.65%	0.00%	0.00%	57.7%
GENERAL SERVICE LESS THAN 50 kW	25.65	0.0171	0.0000	9,462	344,785,907		2,912,404	5,895,839	0	8,808,243	3.76%	7.61%	0.00%	11.4%
GENERAL SERVICE 50 TO 699 KW	127.98	0.0000	2.8986	1,591	1,131,688,196	3,179,603	2,443,394	0	9,216,397	11,659,791	3.15%	0.00%	11.89%	15.0%
GENERAL SERVICE 700 TO 4,999 KW	1154.71	0.0000	3.3649	105	875,091,030	2,020,563	1,454,935	0	6,798,993	8,253,928	1.88%	0.00%	8.77%	10.6%
LARGE USE	4804.99	0.0000	2.5476	6	350,379,705	657,857	345,959	0	1,675,957	2,021,916	0.45%	0.00%	2.16%	2.6%
UNMETERED SCATTERED LOAD	1.11	0.0202	0.0000	1,556	5,914,654		20,726	119,476	0	140,202	0.03%	0.15%	0.00%	0.2%
STREET LIGHTING	2.35	0.0000	11.7823	19,919	34,968,321	98,842	561,716	0	1,164,586	1,726,302	0.72%	0.00%	1.50%	2.2%
EMBEDDED DISTRIBUTOR	4247.63	0.0000	0.0000	1	3,402,773		50,972	0	0	50,972	0.07%	0.00%	0.00%	0.1%
DISTRIBUTED GENERATION [DGEN]	106.17	0.0000	0.0000	131	277,418		166,899	0	0	166,899	0.22%	0.00%	0.00%	0.2%
STANDBY POWER	0.00	0.0000	1.7134	1			0	0	0	0	0.00%	0.00%	0.00%	0.0%
Total							**52,647,912**	**6,015,315**	**18,855,933**	**77,519,160**				**100.0%**

Horizon Rate Class	Current OEB-Approved Base Rates			2019 Board-Approved Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
Total	**A**	**B**	**C**	**D**	**E**	**F**	**G = A * D *12**	**H = B * E**	**I = C * F**	**J = G + H + I**	**$L = G / J_{total}$**	**$M = H / J_{total}$**	**$N = I / J_{total}$**	**$O = J / J_{total}$**
RESIDENTIAL	26.70	0.0000	0.0000	227,762	1,652,719,193		72,974,945	0	0	72,974,945	61.35%	0.00%	0.00%	61.4%
GENERAL SERVICE LESS THAN 50 kW	42.29	0.0109	0.0000	18,709	594,472,785		9,494,443	6,479,753	0	15,974,197	7.98%	5.45%	0.00%	13.4%
GENERAL SERVICE 50 TO 4,999 KW	389.40	0.0000	2.6150	2,316	1,840,510,488	5,066,406	10,822,205	0	13,248,651	24,070,856	9.10%	0.00%	11.14%	20.2%
LARGE USE	24279.27	0.0000	1.4325	6	242,051,739	569,520	1,748,107	0	815,837	2,563,945	1.47%	0.00%	0.69%	2.2%
LARGE USE WITH DEDICATED ASSETS	5755.85	0.0000	0.3396	5	403,775,839	2,136,952	345,351	0	725,709	1,071,060	0.29%	0.00%	0.61%	0.9%
UNMETERED SCATTERED LOAD	8.63	0.0134	0.0000	3,006	10,504,342		311,301	140,758	0	452,060	0.26%	0.12%	0.00%	0.4%
SENTINEL LIGHTING	5.63	0.0000	15.4416	378	363,731	1,030	25,538	0	15,905	41,443	0.02%	0.00%	0.01%	0.0%
STREET LIGHTING	1.95	0.0000	5.1752	52,273	39,610,413	109,773	1,223,188	0	568,097	1,791,285	1.03%	0.00%	0.48%	1.5%
Total							**96,945,079**	**6,620,512**	**15,374,200**	**118,939,790**				**100.0%**

PowerStream Rate Class	Current OEB-Approved Base Rates			2018 Actual Distribution Demand											
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
Total	A	B	C	D	E	F	G = A * D *12	H = B * E	I = C * F	J = G + H + I	L = G / J_{total}	M = H / J_{total}	N = I / J_{total}	O = J / J_{total}
RESIDENTIAL	24.91	0.0045	0.0000	334,683	2,783,708,695		100,043,442	12,526,689	0	112,570,131	48.05%	6.02%	0.00%	54.1%
GENERAL SERVICE LESS THAN 50 kW	29.35	0.0187	0.0000	32,624	1,049,615,664		11,490,173	19,627,813	0	31,117,986	5.52%	9.43%	0.00%	14.9%
GENERAL SERVICE 50 TO 4,999 KW	143.95	0.0000	4.2924	5,207	4,679,965,944	12,192,876	8,994,572	0	52,336,699	61,331,271	4.32%	0.00%	25.14%	29.5%
LARGE USE	6201.88	0.0000	2.2894	2	53,218,181	102,871	148,845	0	235,514	384,359	0.07%	0.00%	0.11%	0.2%
UNMETERED SCATTERED LOAD	8.78	0.0199	0.0000	3,082	13,830,788		324,720	275,233	0	599,952	0.16%	0.13%	0.00%	0.3%
SENTINEL LIGHTING	4.28	0.0000	10.0777	172	286,385	796	8,834	0	8,022	16,856	0.00%	0.00%	0.00%	0.0%
STREET LIGHTING	1.21	0.0000	6.4556	91,446	48,883,953	134,152	1,327,796	0	866,032	2,193,828	0.64%	0.00%	0.42%	1.1%
Total							**122,338,381**	**32,429,735**	**53,446,266**	**208,214,383**				**100.0%**

Guelph Rate Class	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G = A * D *12	H = B * E	I = C * F	J = G + H + I	L = G / J_{total}	M = H / J_{total}	N = I / J_{total}	O = J / J_{total}
RESIDENTIAL	29.22	0.0000	0.0000	50,914	384,041,745		17,852,485	0	0	17,852,485	58.40%	0.00%	0.00%	58.4%
GENERAL SERVICE LESS THAN 50 KW	16.94	0.0142	0.0000	4,134	142,209,076		840,360	2,019,369	0	2,859,728	2.75%	6.61%	0.00%	9.4%
GENERAL SERVICE 50 TO 999 KW	183.66	0.0000	2.7982	578	402,350,218	1,097,499	1,273,866	0	3,071,022	4,344,887	4.17%	0.00%	10.05%	14.2%
GENERAL SERVICE 1,000 TO 4,999 KW	580.97	0.0000	3.1063	43	540,417,878	1,135,425	299,781	0	3,526,971	3,826,751	0.98%	0.00%	11.54%	12.5%
LARGE USE	1116.83	0.0000	2.7908	4	197,428,962	423,180	53,608	0	1,181,011	1,234,619	0.18%	0.00%	3.86%	4.0%
UNMETERED SCATTERED LOAD	4.96	0.0226	0.0000	559	1,810,678		33,272	40,921	0	74,193	0.11%	0.13%	0.00%	0.2%
SENTINEL LIGHTING	7.67	0.0000	8.4893	35	18,189	51	3,221	0	433	3,654	0.01%	0.00%	0.00%	0.0%
STREET LIGHTING	0.44	0.0000	10.4080	14,152	10,182,750	28,425	74,723	0	295,847	370,570	0.24%	0.00%	0.97%	1.2%
Total							**20,431,314**	**2,060,290**	**8,075,283**	**30,566,888**				**100.0%**

Alectra Utilities Corporation
Weighted Average Rates

Back to Index

	HRZ	BRZ	PRZ	ERZ	GRZ	Alectra
OEB-Approved Rate Base ($)[1,2,3,4,5]	555,698	404,619	1,082,805	623,498	151,392	2,818,011
OEB-Approved Rate Base (%)	19.72%	14.36%	38.42%	22.13%	5.37%	100.00%
Cost of Capital Parameters						
Long Term Debt Rate	3.74%	6.07%	3.88%	5.09%	4.91%	
Short Term Debt Rate	2.82%	2.16%	1.76%	2.08%	1.65%	
Return on Equity	8.98%	9.30%	8.78%	8.93%	9.19%	
Weighted Averages based on Approved Rate Base:						
Long Term Debt Rate	0.74%	0.87%	1.49%	1.13%	0.26%	**4.49%**
Short Term Debt Rate	0.56%	0.31%	0.68%	0.46%	0.09%	**2.09%**
Return on Equity	1.77%	1.34%	3.37%	1.98%	0.49%	**8.95%**

Notes:

1. ERZ 2013 COS rate base per EB-2012-0033; 1. In EB-2016-0002, the OEB approved Enersource's proposal to address the expiration of its IFRS adjustment from its 2013 COS
2. BRZ 2015 COS rate base per EB-2014-0083
3. PRZ 2017 COS rate base per EB-2015-0003
4. HRZ CIR Update to 2019 rate base per EB-2018-0016
5. GRZ 2016 COS rate base per EB-2015-0073

	HRZ	BRZ	PRZ	ERZ	GRZ	Alectra
Working Capital Allowance	12.00%	13.00%	7.50%	13.50%	7.50%	
Weighted	2.37%	1.87%	2.88%	2.99%	0.40%	**10.50%**

Capital Module
Applicable to ACM and ICM
Alectra Utilities Corporation - Enersource RZ

No Input Required.

Final Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1 + g))\right] \times ((1 + g) \times (1 + PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2013**	
Price Cap IR Year in which Application is made		**7**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$132,802,853**	
Revenues Based on 2013 Board-Approved Distribution Demand		**$133,185,702**	
Growth Factor		**-0.06%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	541,300,088	
Add: CWIP Opening	$	4,371,726	
Capital Additions	$	46,257,875	
Capital Disposals	-$	1,026,755	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	4,371,726	
Gross Fixed Assets - Closing	$	586,531,208	
Average Gross Fixed Assets	$	563,915,648	
Accumulated Depreciation - Opening	$	45,750,490	
Depreciation Expense	$	28,721,695	
Disposals	$	-	
Retirements	-$	1,026,755	
Accumulated Depreciation - Closing	$	73,445,430	
Average Accumulated Depreciation	$	59,597,960	
Average Net Fixed Assets	$	504,317,688	
Working Capital Allowance			
Working Capital Allowance Base	$	786,215,891	
Working Capital Allowance Rate		13.5%	
Working Capital Allowance	$	106,139,145	
Rate Base	**$**	**610,456,833**	RB
Depreciation	**$**	**28,721,695**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2014	**134.3%**	
Price Cap IR Year 2015	**134.5%**	
Price Cap IR Year 2016	**134.8%**	
Price Cap IR Year 2017	**135.1%**	
Price Cap IR Year 2018	**135.4%**	
Price Cap IR Year 2019	**135.7%**	
Price Cap IR Year 2020	**136.0%**	
Price Cap IR Year 2021	**136.3%**	$Threshold\ Value \times d$
Price Cap IR Year 2022	**136.6%**	
Price Cap IR Year 2023	**136.9%**	
Price Cap IR Year 2024	**137.2%**	

Threshold CAPEX

Price Cap IR Year 2014	**$**	**38,564,178**
Price Cap IR Year 2015	**$**	**38,643,766**
Price Cap IR Year 2016	**$**	**38,724,263**
Price Cap IR Year 2017	**$**	**38,805,680**
Price Cap IR Year 2018	**$**	**38,888,026**
Price Cap IR Year 2019	**$**	**38,971,312**
Price Cap IR Year 2020	**$**	**39,055,549**
Price Cap IR Year 2021	**$**	**39,140,748**
Price Cap IR Year 2022	**$**	**39,226,919**
Price Cap IR Year 2023	**$**	**39,314,075**
Price Cap IR Year 2024	**$**	**39,402,226**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Alectra Utilities Corporation - PowerStream RZ

No Input Required.

Final Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2017**	
Price Cap IR Year in which Application is made		**3**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$208,214,383**	
Revenues Based on 2017 Board-Approved Distribution Demand		**$203,517,916**	
Growth Factor		**2.31%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	1,183,508,943	
Add: CWIP Opening	$	57,486,862	
Capital Additions	$	114,494,289	
Capital Disposals	-$	2,734,108	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	39,959,632	
Gross Fixed Assets - Closing	$	1,312,796,354	
Average Gross Fixed Assets	$	1,248,152,649	
Accumulated Depreciation - Opening	$	229,378,962	
Depreciation Expense	$	52,272,173	
Disposals	-$	717,703	
Retirements	$	-	
Accumulated Depreciation - Closing	$	280,933,432	
Average Accumulated Depreciation	$	255,156,197	
Average Net Fixed Assets	$	992,996,452	
Working Capital Allowance			
Working Capital Allowance Base	$	1,197,449,515	
Working Capital Allowance Rate		7.5%	
Working Capital Allowance	$	89,808,714	
Rate Base	**$**	**1,082,805,165**	RB
Depreciation	**$**	**52,272,173**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)	
Price Cap IR Year 2018	**183.2%**
Price Cap IR Year 2019	**185.8%**
Price Cap IR Year 2020	**188.5%**
Price Cap IR Year 2021	**191.3%**
Price Cap IR Year 2022	**194.2%**
Price Cap IR Year 2023	**197.1%**
Price Cap IR Year 2024	**200.2%**

$Threshold\ Value \times d$

Threshold CAPEX		
Price Cap IR Year 2018	**$**	**95,780,178**
Price Cap IR Year 2019	**$**	**97,133,532**
Price Cap IR Year 2020	**$**	**98,534,732**
Price Cap IR Year 2021	**$**	**99,985,468**
Price Cap IR Year 2022	**$**	**101,487,493**
Price Cap IR Year 2023	**$**	**103,042,620**
Price Cap IR Year 2024	**$**	**104,652,726**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation - Brampton RZ

No Input Required.

Final Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2015**	
Price Cap IR Year in which Application is made		**5**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$77,519,160**	
Revenues Based on 2015 Board-Approved Distribution		**$73,455,693**	
Growth Factor		**1.84%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	627,821,483	
Add: CWIP Opening	$	-	
Capital Additions	$	32,518,047	
Capital Disposals	-$	2,963,781	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	657,375,749	
Average Gross Fixed Assets	$	642,598,616	
Accumulated Depreciation - Opening	$	295,604,516	
Depreciation Expense	$	15,227,319	
Disposals	-$	2,191,181	
Retirements	$	-	
Accumulated Depreciation - Closing	$	308,640,654	
Average Accumulated Depreciation	$	302,122,585	
Average Net Fixed Assets	$	340,476,031	
Working Capital Allowance			
Working Capital Allowance Base	$	493,403,770	
Working Capital Allowance Rate		13.0%	
Working Capital Allowance	$	64,142,490	
Rate Base	**$**	**404,618,521**	RB
Depreciation	**$**	**15,227,319**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2016		**191.5%**	
Price Cap IR Year 2017		**194.0%**	
Price Cap IR Year 2018		**196.5%**	
Price Cap IR Year 2019		**199.2%**	
Price Cap IR Year 2020		**201.9%**	
Price Cap IR Year 2021		**204.8%**	
Price Cap IR Year 2022		**207.7%**	
Price Cap IR Year 2023		**210.7%**	$Threshold\ Value \times d$
Price Cap IR Year 2024		**213.7%**	
Threshold CAPEX			
Price Cap IR Year 2016	**$**	**29,155,984**	
Price Cap IR Year 2017	**$**	**29,536,360**	
Price Cap IR Year 2018	**$**	**29,928,399**	
Price Cap IR Year 2019	**$**	**30,332,458**	
Price Cap IR Year 2020	**$**	**30,748,905**	
Price Cap IR Year 2021	**$**	**31,178,122**	
Price Cap IR Year 2022	**$**	**31,620,498**	
Price Cap IR Year 2023	**$**	**32,076,438**	
Price Cap IR Year 2024	**$**	**32,546,358**	

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Alectra Utilities Corporation - Enersource Hydro Mississauga Inc.

No Input Required.

Final Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2019**	
Price Cap IR Year in which Application is made		**1**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2019 Board-Approved Distribution Demand		**$118,939,797**	
Revenues Based on 2018 Actual Distribution Demand		**$115,426,603**	
Growth Factor		**3.04%**	$g\ (Note\ 1)$
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	625,029,889	
Add: CWIP Opening	$	3,164,006	
Capital Additions	$	51,272,477	
Capital Disposals	-$	4,597,818	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	3,164,006	
Gross Fixed Assets - Closing	$	671,704,548	
Average Gross Fixed Assets	$	648,367,218	
Accumulated Depreciation - Opening	$	160,425,475	
Depreciation Expense	$	23,877,061	
Disposals	-$	1,426,748	
Retirements	$	-	
Accumulated Depreciation - Closing	$	182,875,788	
Average Accumulated Depreciation	$	171,650,631	
Average Net Fixed Assets	$	476,716,587	
Working Capital Allowance			
Working Capital Allowance Base	$	658,178,026	
Working Capital Allowance Rate		12.0%	
Working Capital Allowance	$	78,981,363	
Rate Base	**$**	**555,697,950**	RB
Depreciation	**$**	**23,877,061**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2020		**209.6%**	
Price Cap IR Year 2021		**213.9%**	
Price Cap IR Year 2022		**218.3%**	
Price Cap IR Year 2023		**223.0%**	
Price Cap IR Year 2024		**227.8%**	
			$Threshold\ Value\ \times d$
Threshold CAPEX			
Price Cap IR Year 2020	**$**	**50,049,666**	
Price Cap IR Year 2021	**$**	**51,067,703**	
Price Cap IR Year 2022	**$**	**52,129,315**	
Price Cap IR Year 2023	**$**	**53,236,365**	
Price Cap IR Year 2024	**$**	**54,390,799**	

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Alectra Utilities Corporation - Enersource Hydro Mississauga Inc.

No Input Required.

Final Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2016**	
Price Cap IR Year in which Application is made		**4**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$30,566,888**	
Revenues Based on 2016 Board-Approved Distribution Demand		**$29,619,525**	
Growth Factor		**1.60%**	$g\ (Note\ 1)$
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	163,625,735	
Add: CWIP Opening	$	-	
Capital Additions	$	11,363,000	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	174,988,735	
Average Gross Fixed Assets	$	169,307,235	
Accumulated Depreciation - Opening	$	32,529,814	
Depreciation Expense	$	6,295,624	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	38,825,438	
Average Accumulated Depreciation	$	35,677,626	
Average Net Fixed Assets	$	133,629,609	
Working Capital Allowance			
Working Capital Allowance Base	$	236,828,275	
Working Capital Allowance Rate		7.5%	
Working Capital Allowance	$	17,762,121	
Rate Base	**$**	**151,391,730**	RB
Depreciation	**$**	**6,295,624**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2017		**177.8%**	
Price Cap IR Year 2018		**179.7%**	
Price Cap IR Year 2019		**181.6%**	
Price Cap IR Year 2020		**183.7%**	
Price Cap IR Year 2021		**185.7%**	
Price Cap IR Year 2022		**187.9%**	
Price Cap IR Year 2023		**190.1%**	
Price Cap IR Year 2024		**192.3%**	$Threshold\ Value\ \times d$
Threshold CAPEX			
Price Cap IR Year 2017	**$**	**11,192,026**	
Price Cap IR Year 2018	**$**	**11,312,283**	
Price Cap IR Year 2019	**$**	**11,435,929**	
Price Cap IR Year 2020	**$**	**11,563,061**	
Price Cap IR Year 2021	**$**	**11,693,775**	
Price Cap IR Year 2022	**$**	**11,828,173**	
Price Cap IR Year 2023	**$**	**11,966,360**	

G-Staff-8

ATTACH 2

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Alectra Utilities Corporation-PowerStream Rate Zone
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2020**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Alectra Utilities Corporation-PowerStream Rate Zone is applying:	**3**
Next OEB Scheduled Rebasing Year	**2027**
Alectra Utilities Corporation-PowerStream Rate Zone is applying for:	**ICM Approval**
Last Rebasing Year:	**2017**
The most recent complete year for which actual billing and load data exists	**2018**
Current IPI	**1.50%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.20%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2018 Actual Distribution Demand}}{\text{Revenues Based on 2017 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **7**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	LARGE USE
5	UNMETERED SCATTERED LOAD
6	SENTINEL LIGHTING
7	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-PowerStream Rate Zone's Revenues Based on 2018 Actual Distribution Demand.
Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2018 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	334,683	2,783,708,695		24.91	0.0045	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	32,624	1,049,615,664		29.35	0.0187	0.0000
GENERAL SERVICE 50 TO 4,999 KW	$/kW	5,207	4,679,965,944	12,192,876	143.95	0.0000	4.2924
LARGE USE	$/kW	2	53,218,181	102,871	6201.88	0.0000	2.2894
UNMETERED SCATTERED LOAD	$/kWh	3,082	13,830,788		8.78	0.0199	0.0000
SENTINEL LIGHTING	$/kWh	172	286,385	796	4.28	0.0000	10.0777
STREET LIGHTING	$/kW	91,446	48,883,953	134,152	1.21	0.0000	6.4556

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

Calculation of pro forma 2017 Revenues. No input required.

Rate Class	2018 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	334,683	2,783,708,695		24.91	0.0045	0.0000	100,043,442	12,526,689	0	112,570,131	88.9%	11.1%	0.0%	54.1%
GENERAL SERVICE LESS THAN 50 kW	32,624	1,049,615,664		29.35	0.0187	0.0000	11,490,173	19,627,813	0	31,117,986	36.9%	63.1%	0.0%	14.9%
GENERAL SERVICE 50 TO 4,999 KW	5,207	4,679,965,944	12,192,876	143.95	0.0000	4.2924	8,994,572	0	52,336,699	61,331,271	14.7%	0.0%	85.3%	29.5%
LARGE USE	2	53,218,181	102,871	6,201.88	0.0000	2.2894	148,845	0	235,514	384,359	38.7%	0.0%	61.3%	0.2%
UNMETERED SCATTERED LOAD	3,082	13,830,788		8.78	0.0199	0.0000	324,720	275,233	0	599,952	54.1%	45.9%	0.0%	0.3%
SENTINEL LIGHTING	172	286,385	796	4.28	0.0000	10.0777	8,834	0	8,022	16,856	52.4%	0.0%	47.6%	0.0%
STREET LIGHTING	91,446	48,883,953	134,152	1.21	0.0000	6.4556	1,327,796	0	866,032	2,193,828	60.5%	0.0%	39.5%	1.1%
Total	**467,216**	**8,629,509,610**	**12,430,695**				**122,338,381**	**32,429,735**	**53,446,266**	**208,214,383**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

Applicants Rate Base		**Last COS Rebasing: 2017**				
Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	1,183,508,943	A			
Add: CWIP Re-based Opening	$	57,486,862	B			
Re-based Capital Additions	$	114,494,289	C			
Re-based Capital Disposals	-$	2,734,108	D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing	-$	39,959,632	F			
Gross Fixed Assets - Re-based Closing	$	1,312,796,354	G			
Average Gross Fixed Assets				$	1,248,152,649	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	229,378,962	I			
Re-based Depreciation Expense	$	52,272,173	J			
Re-based Disposals	-$	717,703	K			
Re-based Retirements	$	-	L			
Accumulated Depreciation - Re-based Closing	$	280,933,432	M			
Average Accumulated Depreciation				$	255,156,197	N = (I + M) / 2
Average Net Fixed Assets				**$**	**992,996,452**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	1,197,449,515	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**89,808,714**	R = P * Q
Rate Base				**$**	**1,082,805,165**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	43,312,207	W = S * T
Deemed Long Term Debt %		56.00%	U	$	606,370,893	X = S * U
Deemed Equity %		40.00%	V	$	433,122,066	Y = S * V
Short Term Interest		1.76%	Z	$	762,295	AC = W * Z
Long Term Interest		3.88%	AA	$	23,542,374	AD = X * AA
Return on Equity		8.78%	AB	$	38,028,117	AE = Y * AB
Return on Rate Base				**$**	**62,332,786**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	96,167,243	AG			
Amortization	$	50,974,104	AH			
Ontario Capital Tax			AI			
Grossed Up Taxes/PILs	$	2,745,639	AJ			
Low Voltage			AK			
Transformer Allowance	$	2,236,782	AL			
			AM			
			AN			
			AO			
				$	**152,123,768**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	3,474,784	AQ			
Late Payment Charges	-$	2,076,532	AR			
Other Distribution Income	-$	2,025,296	AS			
Other Income and Deductions	-$	5,141,699	AT	**-$**	**12,718,312**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**201,738,243**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 4)				$	208,214,383	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-PowerStream Rate Zone's Revenues Based on 2017 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

Rate Class	2017 Board-Approved Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	325,741	2,777,974,550		24.91	0.0045	0.0000	97,370,500	12,500,885	0	109,871,385	47.8%	6.1%	0.0%	54.0%
GENERAL SERVICE LESS THAN 50 kW	32,395	1,041,512,339		29.35	0.0187	0.0000	11,409,519	19,476,281	0	30,885,800	5.6%	9.6%	0.0%	15.2%
GENERAL SERVICE 50 TO 4,999 KW	4,969	4,592,208,771	11,856,847	143.95	0.0000	4.2924	8,583,451	0	50,894,330	59,477,781	4.2%	0.0%	25.0%	29.2%
LARGE USE	2	67,387,072	130,430	6,201.88	0.0000	2.2894	148,845	0	298,606	447,452	0.1%	0.0%	0.1%	0.2%
UNMETERED SCATTERED LOAD	2,945	13,692,255		8.78	0.0199	0.0000	310,285	272,476	0	582,761	0.2%	0.1%	0.0%	0.3%
SENTINEL LIGHTING	195	314,360	859	4.28	0.0000	10.0777	10,015	0	8,657	18,672	0.0%	0.0%	0.0%	0.0%
STREET LIGHTING	88,914	52,642,446	146,080	1.21	0.0000	6.4556	1,291,031	0	943,034	2,234,065	0.6%	0.0%	0.5%	1.1%
Total	**455,161**	**8,545,731,793**	**12,134,216**				**119,123,646**	**32,249,642**	**52,144,627**	**203,517,916**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

Rate Class	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	24.91	0.0045	0	334,683	2,783,708,695	0	100,043,442	12,526,689	0	112,570,131	48.05%	6.02%	0.00%	54.1%
GENERAL SERVICE LESS THAN 50 kW	29.35	0.0187	0	32,624	1,049,615,664	0	11,490,173	19,627,813	0	31,117,986	5.52%	9.43%	0.00%	14.9%
GENERAL SERVICE 50 TO 4,999 KW	143.95	0	4.2924	5,207	4,679,965,944	12,192,876	8,994,572	0	52,336,699	61,331,271	4.32%	0.00%	25.14%	29.5%
LARGE USE	6201.88	0	2.2894	2	53,218,181	102,871	148,845	0	235,514	384,359	0.07%	0.00%	0.11%	0.2%
UNMETERED SCATTERED LOAD	8.78	0.0199	0	3,082	13,830,788	0	324,720	275,233	0	599,952	0.16%	0.13%	0.00%	0.3%
SENTINEL LIGHTING	4.28	0	10.0777	172	286,385	796	8,834	0	8,022	16,856	0.00%	0.00%	0.00%	0.0%
STREET LIGHTING	1.21	0	6.4556	91,446	48,883,953	134,152	1,327,796	0	866,032	2,193,828	0.64%	0.00%	0.42%	1.1%
Total							**122,338,381**	**32,429,735**	**53,446,266**	**208,214,383**				**100.0%**

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-PowerStream Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2017**	
Price Cap IR Year in which Application is made		**3**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$208,214,383**	
Revenues Based on 2017 Board-Approved Distribution Demand		**$203,517,916**	
Growth Factor		**2.31%**	g $(Note\ 1)$
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	1,183,508,943	
Add: CWIP Opening	$	57,486,862	
Capital Additions	$	114,494,289	
Capital Disposals	-$	2,734,108	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	39,959,632	
Gross Fixed Assets - Closing	$	1,312,796,354	
Average Gross Fixed Assets	$	1,248,152,649	
Accumulated Depreciation - Opening	$	229,378,962	
Depreciation Expense	$	52,272,173	
Disposals	-$	717,703	
Retirements	$	-	
Accumulated Depreciation - Closing	$	280,933,432	
Average Accumulated Depreciation	$	255,156,197	
Average Net Fixed Assets	$	992,996,452	
Working Capital Allowance			
Working Capital Allowance Base	$	1,197,449,515	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	89,808,714	
Rate Base	**$**	**1,082,805,165**	RB
Depreciation	**$**	**52,272,173**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2018		**183%**	
Price Cap IR Year 2019		**186%**	
Price Cap IR Year 2020		**189%**	
Price Cap IR Year 2021		**191%**	
Price Cap IR Year 2022		**194%**	
Price Cap IR Year 2023		**197%**	
Price Cap IR Year 2024		**200%**	
Price Cap IR Year 2025		**203%**	
Price Cap IR Year 2026		**207%**	
Price Cap IR Year 2027		**210%**	
Threshold CAPEX			$Threshold\ Value\ \times d$
Price Cap IR Year 2018	**$**	**95,780,178**	
Price Cap IR Year 2019	**$**	**97,133,532**	
Price Cap IR Year 2020	**$**	**98,534,732**	
Price Cap IR Year 2021	**$**	**99,985,468**	
Price Cap IR Year 2022	**$**	**101,487,493**	
Price Cap IR Year 2023	**$**	**103,042,620**	
Price Cap IR Year 2024	**$**	**104,652,726**	
Price Cap IR Year 2025	**$**	**106,319,754**	
Price Cap IR Year 2026	**$**	**108,045,717**	
Price Cap IR Year 2027	**$**	**109,832,699**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

G-Staff-8

ATTACH 3

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Alectra Utilities Corporation-Brampton Rate Zone
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2020**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Alectra Utilities Corporation-Brampton Rate Zone is applying:	**5**
Next OEB Scheduled Rebasing Year	**2027**
Alectra Utilities Corporation-Brampton Rate Zone is applying for:	**ICM Approval**
Last Rebasing Year:	**2015**
The most recent complete year for which actual billing and load data exists	**2018**
Current IPI	**1.50%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.20%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

Revenues Based on 2018 Actual Distribution Demand

Revenues Based on 2015 Board-Approved Distribution Demand

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-Brampton Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **10**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 699 KW
4	GENERAL SERVICE 700 TO 4,999 KW
5	LARGE USE
6	UNMETERED SCATTERED LOAD
7	STREET LIGHTING
8	EMBEDDED DISTRIBUTOR
9	DISTRIBUTED GENERATION [DGEN]
10	STANDBY POWER

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Brampton Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Brampton Rate Zone's Revenues Based on 2018 Actual Distribution Demand.
Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2018 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	153,261	1,385,125,813		24.30	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	9,462	344,785,907		25.65	0.0171	0.0000
GENERAL SERVICE 50 TO 699 KW	$/kW	1,591	1,131,688,196	3,179,603	127.98	0.0000	2.8986
GENERAL SERVICE 700 TO 4,999 KW	$/kW	105	875,091,030	2,020,563	1154.71	0.0000	3.3649
LARGE USE	$/kW	6	350,379,705	657,857	4804.99	0.0000	2.5476
UNMETERED SCATTERED LOAD	$/kWh	1,556	5,914,654		1.11	0.0202	0.0000
STREET LIGHTING	$/kW	19,919	34,968,321	98,842	2.35	0.0000	11.7823
EMBEDDED DISTRIBUTOR	$/kWh	1	3,402,773		4247.63	0.0000	0.0000
DISTRIBUTED GENERATION [DGEN]	$/kWh	131	277,418		106.17	0.0000	0.0000
STANDBY POWER	$/kW	1			0.00	0.0000	1.7134

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Brampton Rate Zone

Calculation of pro forma 2015 Revenues. No input required.

	2018 Actual Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	153,261	1,385,125,813		24.30	0.0000	0.0000	44,690,908	0	0	44,690,908	100.0%	0.0%	0.0%	57.7%
GENERAL SERVICE LESS THAN 50 kW	9,462	344,785,907		25.65	0.0171	0.0000	2,912,404	5,895,839	0	8,808,243	33.1%	66.9%	0.0%	11.4%
GENERAL SERVICE 50 TO 699 KW	1,591	1,131,688,196	3,179,603	127.98	0.0000	2.8986	2,443,394	0	9,216,397	11,659,791	21.0%	0.0%	79.0%	15.0%
GENERAL SERVICE 700 TO 4,999 KW	105	875,091,030	2,020,563	1,154.71	0.0000	3.3649	1,454,935	0	6,798,993	8,253,928	17.6%	0.0%	82.4%	10.6%
LARGE USE	6	350,379,705	657,857	4,804.99	0.0000	2.5476	345,959	0	1,675,957	2,021,916	17.1%	0.0%	82.9%	2.6%
UNMETERED SCATTERED LOAD	1,556	5,914,654		1.11	0.0202	0.0000	20,726	119,476	0	140,202	14.8%	85.2%	0.0%	0.2%
STREET LIGHTING	19,919	34,968,321	98,842	2.35	0.0000	11.7823	561,716	0	1,164,586	1,726,302	32.5%	0.0%	67.5%	2.2%
EMBEDDED DISTRIBUTOR	1	3,402,773		4,247.63	0.0000	0.0000	50,972	0	0	50,972	100.0%	0.0%	0.0%	0.1%
DISTRIBUTED GENERATION [DGEN]	131	277,418		106.17	0.0000	0.0000	166,899	0	0	166,899	100.0%	0.0%	0.0%	0.2%
STANDBY POWER	1			0.00	0.0000	1.7134	0	0	0	0	0.0%	0.0%	0.0%	0.0%
Total	**186,033**	**4,131,633,817**	**5,956,865**				**52,647,912**	**6,015,315**	**18,855,933**	**77,519,160**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Alectra Utilities Corporation-Brampton Rate Zone

Applicants Rate Base

Last COS Rebasing: 2015

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	627,821,483	A			
Add: CWIP Re-based Opening			B			
Re-based Capital Additions	$	32,518,047	C			
Re-based Capital Disposals	-$	2,963,781	D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing			F			
Gross Fixed Assets - Re-based Closing	$	657,375,749	G			
Average Gross Fixed Assets				$	642,598,616	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	295,604,516	I			
Re-based Depreciation Expense	$	15,227,319	J			
Re-based Disposals	-$	2,191,181	K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	308,640,654	M			
Average Accumulated Depreciation				$	302,122,585	N = (I + M) / 2
Average Net Fixed Assets				**$**	**340,476,031**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	493,403,770	P			
Working Capital Allowance Rate		13.0%	Q			
Working Capital Allowance				**$**	**64,142,490**	R = P * Q
Rate Base				**$**	**404,618,521**	S = O + R

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$	16,184,741	W = S * T
Deemed Long Term Debt %	56.00%	U	$	226,586,372	X = S * U
Deemed Equity %	40.00%	V	$	161,847,408	Y = S * V
Short Term Interest	2.16%	Z	$	349,590	AC = W * Z
Long Term Interest	6.07%	AA	$	13,753,793	AD = X * AA
Return on Equity	9.30%	AB	$	15,051,809	AE = Y * AB
Return on Rate Base			**$**	**29,155,192**	AF = AC + AD + AE

Distribution Expenses

OM&A Expenses	$	25,298,362	AG			
Amortization	$	15,794,025	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	1,890,491	AJ			
Low Voltage			AK			
Transformer Allowance	$	1,517,039	AL			
			AM			
			AN			
			AO			
				$	**44,499,917**	AP = SUM (AG : AO)

Revenue Offsets

Specific Service Charges	-$	1,375,119	AQ			
Late Payment Charges	-$	1,354,682	AR			
Other Distribution Income	-$	1,238,963	AS			
Other Income and Deductions	-$	157,825	AT	**-$**	**4,126,589**	AU = SUM (AQ : AT)

Revenue Requirement from Distribution Rates	**$**	**69,528,520**	AV = AF + AP + AU

Rate Classes Revenue

Rate Classes Revenue - Total (Sheet 4)	$	77,519,160	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Brampton Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Brampton Rate Zone's Revenues Based on 2015 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2015 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	140,979	1,308,264,983		24.30	0.0000	0.0000	41,109,476	0	0	41,109,476	56.0%	0.0%	0.0%	56.0%
GENERAL SERVICE LESS THAN 50 kW	8,989	354,668,870		25.65	0.0171	0.0000	2,766,814	6,064,838	0	8,831,652	3.8%	8.3%	0.0%	12.0%
GENERAL SERVICE 50 TO 699 KW	1,491	1,064,497,599	2,979,826	127.98	0.0000	2.8986	2,289,818	0	8,637,324	10,927,142	3.1%	0.0%	11.8%	14.9%
GENERAL SERVICE 700 TO 4,999 KW	115	806,154,180	1,969,146	1,154.71	0.0000	3.3649	1,593,500	0	6,625,979	8,219,479	2.2%	0.0%	9.0%	11.2%
LARGE USE	6	382,619,513	719,987	4,804.99	0.0000	2.5476	345,959	0	1,834,239	2,180,198	0.5%	0.0%	2.5%	3.0%
UNMETERED SCATTERED LOAD	1,562	5,931,733		1.11	0.0202	0.0000	20,806	119,821	0	140,627	0.0%	0.2%	0.0%	0.2%
STREET LIGHTING	22,335	33,306,955	100,672	2.35	0.0000	11.7823	629,847	0	1,186,148	1,815,995	0.9%	0.0%	1.6%	2.5%
EMBEDDED DISTRIBUTOR	1	17,012,414	40,073	4,247.63	0.0000	0.0000	50,972	0	0	50,972	0.1%	0.0%	0.0%	0.1%
DISTRIBUTED GENERATION [DGEN]	68	178,816		106.17	0.0000	0.0000	86,635	0	0	86,635	0.1%	0.0%	0.0%	0.1%
STANDBY POWER	1		54,580	0.00	0.0000	1.7134	0	0	93,517	93,517	0.0%	0.0%	0.1%	0.1%
Total	**175,547**	**3,972,635,063**	**5,864,284**				**48,893,827**	**6,184,659**	**18,377,207**	**73,455,693**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Brampton Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	24.30	0	0	153,261	1,385,125,813	0	44,690,908	0	0	44,690,908	57.65%	0.00%	0.00%	57.7%
GENERAL SERVICE LESS THAN 50 kW	25.65	0.0171	0	9,462	344,785,907	0	2,912,404	5,895,839	0	8,808,243	3.76%	7.61%	0.00%	11.4%
GENERAL SERVICE 50 TO 699 KW	127.98	0	2.8986	1,591	1,131,688,196	3,179,603	2,443,394	0	9,216,397	11,659,791	3.15%	0.00%	11.89%	15.0%
GENERAL SERVICE 700 TO 4,999 KW	1154.71	0	3.3649	105	875,091,030	2,020,563	1,454,935	0	6,798,993	8,253,928	1.88%	0.00%	8.77%	10.6%
LARGE USE	4804.99	0	2.5476	6	350,379,705	657,857	345,959	0	1,675,957	2,021,916	0.45%	0.00%	2.16%	2.6%
UNMETERED SCATTERED LOAD	1.11	0.0202	0	1,556	5,914,654	0	20,726	119,476	0	140,202	0.03%	0.15%	0.00%	0.2%
STREET LIGHTING	2.35	0	11.7823	19,919	34,968,321	98,842	561,716	0	1,164,586	1,726,302	0.72%	0.00%	1.50%	2.2%
EMBEDDED DISTRIBUTOR	4247.63	0	0	1	3,402,773	0	50,972	0	0	50,972	0.07%	0.00%	0.00%	0.1%
DISTRIBUTED GENERATION [DGEN]	106.17	0	0	131	277,418	0	166,899	0	0	166,899	0.22%	0.00%	0.00%	0.2%
STANDBY POWER	0.00	0	1.7134	1	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.0%
Total							**52,647,912**	**6,015,315**	**18,855,933**	**77,519,160**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Brampton Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2015**	
Price Cap IR Year in which Application is made		**5**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$77,519,160**	
Revenues Based on 2015 Board-Approved Distribution Demand		**$73,455,693**	
Growth Factor		**1.84%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	627,821,483	
Add: CWIP Opening	$	-	
Capital Additions	$	32,518,047	
Capital Disposals	-$	2,963,781	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	657,375,749	
Average Gross Fixed Assets	$	642,598,616	
Accumulated Depreciation - Opening	$	295,604,516	
Depreciation Expense	$	15,227,319	
Disposals	-$	2,191,181	
Retirements	$	-	
Accumulated Depreciation - Closing	$	308,640,654	
Average Accumulated Depreciation	$	302,122,585	
Average Net Fixed Assets	$	340,476,031	
Working Capital Allowance			
Working Capital Allowance Base	$	493,403,770	
Working Capital Allowance Rate		13%	
Working Capital Allowance	$	64,142,490	
Rate Base	**$**	**404,618,521**	RB
Depreciation	**$**	**15,227,319**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2016	**191%**
Price Cap IR Year 2017	**194%**
Price Cap IR Year 2018	**197%**
Price Cap IR Year 2019	**199%**
Price Cap IR Year 2020	**202%**
Price Cap IR Year 2021	**205%**
Price Cap IR Year 2022	**208%**
Price Cap IR Year 2023	**211%**
Price Cap IR Year 2024	**214%**
Price Cap IR Year 2025	**217%**

Threshold CAPEX $Threshold\ Value\ \times d$

Price Cap IR Year 2016	**$**	**29,155,984**
Price Cap IR Year 2017	**$**	**29,536,360**
Price Cap IR Year 2018	**$**	**29,928,399**
Price Cap IR Year 2019	**$**	**30,332,458**
Price Cap IR Year 2020	**$**	**30,748,905**
Price Cap IR Year 2021	**$**	**31,178,122**
Price Cap IR Year 2022	**$**	**31,620,498**
Price Cap IR Year 2023	**$**	**32,076,438**
Price Cap IR Year 2024	**$**	**32,546,358**
Price Cap IR Year 2025	**$**	**33,030,685**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

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ATTACH 4

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Alectra Utilities Corporation-Enersource Rate Zone
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2020**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Alectra Utilities Corporation-Enersource Rate Zone is applying:	**7**
Next OEB Scheduled Rebasing Year	**2027**
Alectra Utilities Corporation-Enersource Rate Zone is applying for:	**ICM Approval**
Last Rebasing Year:	**2013**
The most recent complete year for which actual billing and load data exists	**2018**
Current IPI	**1.50%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.20%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2018 Actual Distribution Demand}}{\text{Revenues Based on 2013 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **7**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 499 kW
4	GENERAL SERVICE 500 TO 4,999 kW
5	LARGE USE
6	UNMETERED SCATTERED LOAD
7	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Enersource Rate Zone's Revenues Based on 2018 Actual Distribution Demand.
Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2018 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	183,533	1,490,532,667		24.25	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	18,506	685,616,684		44.52	0.0130	0.0000
GENERAL SERVICE 50 TO 499 kW	$/kW	3,735	2,051,428,808	5,710,412	78.41	0.0000	4.7189
GENERAL SERVICE 500 TO 4,999 kW	$/kW	478	2,037,760,513	4,585,777	1785.59	0.0000	2.4282
LARGE USE	$/kW	9	977,049,362	1,753,163	14078.67	0.0000	3.0139
UNMETERED SCATTERED LOAD	$/kWh	3,110	11,437,642		9.19	0.0167	0.0000
STREET LIGHTING	$/kW	50,859	13,289,944	40,572	1.54	0.0000	11.7902

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

Calculation of pro forma 2013 Revenues. No input required.

Rate Class	2018 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	183,533	1,490,532,667		24.25	0.0000	0.0000	53,408,103	0	0	53,408,103	100.0%	0.0%	0.0%	40.2%
GENERAL SERVICE LESS THAN 50 kW	18,506	685,616,684		44.52	0.0130	0.0000	9,886,645	8,913,017	0	18,799,662	52.6%	47.4%	0.0%	14.2%
GENERAL SERVICE 50 TO 499 kW	3,735	2,051,428,808	5,710,412	78.41	0.0000	4.7189	3,514,336	0	26,946,863	30,461,199	11.5%	0.0%	88.5%	22.9%
GENERAL SERVICE 500 TO 4,999 kW	478	2,037,760,513	4,585,777	1,785.59	0.0000	2.4282	10,242,144	0	11,135,184	21,377,328	47.9%	0.0%	52.1%	16.1%
LARGE USE	9	977,049,362	1,753,163	14,078.67	0.0000	3.0139	1,520,496	0	5,283,858	6,804,354	22.3%	0.0%	77.7%	5.1%
UNMETERED SCATTERED LOAD	3,110	11,437,642		9.19	0.0167	0.0000	342,971	191,009	0	533,979	64.2%	35.8%	0.0%	0.4%
STREET LIGHTING	50,859	13,289,944	40,572	1.54	0.0000	11.7902	939,874	0	478,352	1,418,226	66.3%	0.0%	33.7%	1.1%
Total	**260,230**	**7,267,115,620**	**12,089,924**				**79,854,570**	**9,104,026**	**43,844,257**	**132,802,853**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

Applicants Rate Base

Last COS Rebasing: 2013

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	541,300,088	A			
Add: CWIP Re-based Opening	$	4,371,726	B			
Re-based Capital Additions	$	46,257,875	C			
Re-based Capital Disposals	-$	1,026,755	D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing	-$	4,371,726	F			
Gross Fixed Assets - Re-based Closing	$	586,531,208	G			
Average Gross Fixed Assets				$	563,915,648	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	45,750,490	I			
Re-based Depreciation Expense	$	28,721,695	J			
Re-based Disposals			K			
Re-based Retirements	-$	1,026,755	L			
Accumulated Depreciation - Re-based Closing	$	73,445,430	M			
Average Accumulated Depreciation				$	59,597,960	N = (I + M) / 2
Average Net Fixed Assets				**$**	**504,317,688**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	786,215,891	P			
Working Capital Allowance Rate		13.5%	Q			
Working Capital Allowance				**$**	**106,139,145**	R = P * Q
Rate Base				**$**	**610,456,833**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	24,418,273	W = S * T
Deemed Long Term Debt %		56.00%	U	$	341,855,827	X = S * U
Deemed Equity %		40.00%	V	$	244,182,733	Y = S * V
Short Term Interest		2.08%	Z	$	507,900	AC = W * Z
Long Term Interest		5.09%	AA	$	17,400,462	AD = X * AA
Return on Equity		8.93%	AB	$	21,805,518	AE = Y * AB
Return on Rate Base				**$**	**39,713,880**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	52,564,731	AG			
Amortization	$	25,461,695	AH			
Ontario Capital Tax			AI			
Grossed Up Taxes/PILs	$	3,079,933	AJ			
Low Voltage			AK			
Transformer Allowance	$	2,000,166	AL			
			AM			
			AN			
			AO			
				$	**83,106,525**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	1,236,783	AQ			
Late Payment Charges	-$	1,800,192	AR			
Other Distribution Income	-$	724,731	AS			
Other Income and Deductions	-$	1,068,717	AT	**-$**	**4,830,423**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**117,989,982**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 4)				$	132,802,853	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Enersource Rate Zone's Revenues Based on 2013 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2013 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	176,865	1,423,857,475		24.25	0.0000	0.0000	51,467,715	0	0	51,467,715	38.6%	0.0%	0.0%	38.6%
GENERAL SERVICE LESS THAN 50 kW	17,703	612,188,101		44.52	0.0130	0.0000	9,457,651	7,958,445	0	17,416,096	7.1%	6.0%	0.0%	13.1%
GENERAL SERVICE 50 TO 499 kW	3,950		6,222,022	78.41	0.0000	4.7189	3,716,634	0	29,361,100	33,077,734	2.8%	0.0%	22.0%	24.8%
GENERAL SERVICE 500 TO 4,999 kW	464		5,154,338	1,785.59	0.0000	2.4282	9,942,165	0	12,515,764	22,457,929	7.5%	0.0%	9.4%	16.9%
LARGE USE	9		1,737,267	14,078.67	0.0000	3.0139	1,520,496	0	5,235,949	6,756,445	1.1%	0.0%	3.9%	5.1%
UNMETERED SCATTERED LOAD	2,942	10,383,027		9.19	0.0167	0.0000	324,444	173,397	0	497,840	0.2%	0.1%	0.0%	0.4%
STREET LIGHTING	49,986		49,889	1.54	0.0000	11.7902	923,741	0	588,201	1,511,943	0.7%	0.0%	0.4%	1.1%
Total	**251,919**	**2,046,428,603**	**13,163,516**				**77,352,846**	**8,131,842**	**47,701,013**	**133,185,702**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	24.25	0	0	183,533	1,490,532,667	0	53,408,103	0	0	53,408,103	40.22%	0.00%	0.00%	40.2%
GENERAL SERVICE LESS THAN 50 kW	44.52	0.013	0	18,506	685,616,684	0	9,886,645	8,913,017	0	18,799,662	7.44%	6.71%	0.00%	14.2%
GENERAL SERVICE 50 TO 499 kW	78.41	0	4.7189	3,735	2,051,428,808	5,710,412	3,514,336	0	26,946,863	30,461,199	2.65%	0.00%	20.29%	22.9%
GENERAL SERVICE 500 TO 4,999 kW	1785.59	0	2.4282	478	2,037,760,513	4,585,777	10,242,144	0	11,135,184	21,377,328	7.71%	0.00%	8.38%	16.1%
LARGE USE	14078.67	0	3.0139	9	977,049,362	1,753,163	1,520,496	0	5,283,858	6,804,354	1.14%	0.00%	3.98%	5.1%
UNMETERED SCATTERED LOAD	9.19	0.0167	0	3,110	11,437,642	0	342,971	191,009	0	533,979	0.26%	0.14%	0.00%	0.4%
STREET LIGHTING	1.54	0	11.7902	50,859	13,289,944	40,572	939,874	0	478,352	1,418,226	0.71%	0.00%	0.36%	1.1%
Total							**79,854,570**	**9,104,026**	**43,844,257**	**132,802,853**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Enersource Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2013**	
Price Cap IR Year in which Application is made		**7**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$132,802,853**	
Revenues Based on 2013 Board-Approved Distribution Demand		**$133,185,702**	
Growth Factor		**-0.06%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	541,300,088	
Add: CWIP Opening	$	4,371,726	
Capital Additions	$	46,257,875	
Capital Disposals	-$	1,026,755	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	4,371,726	
Gross Fixed Assets - Closing	$	586,531,208	
Average Gross Fixed Assets	$	563,915,648	
Accumulated Depreciation - Opening	$	45,750,490	
Depreciation Expense	$	28,721,695	
Disposals	$	-	
Retirements	-$	1,026,755	
Accumulated Depreciation - Closing	$	73,445,430	
Average Accumulated Depreciation	$	59,597,960	
Average Net Fixed Assets	$	504,317,688	
Working Capital Allowance			
Working Capital Allowance Base	$	786,215,891	
Working Capital Allowance Rate		14%	
Working Capital Allowance	$	106,139,145	
Rate Base	**$**	**610,456,833**	RB
Depreciation	**$**	**28,721,695**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2014		**134%**	
Price Cap IR Year 2015		**135%**	
Price Cap IR Year 2016		**135%**	
Price Cap IR Year 2017		**135%**	
Price Cap IR Year 2018		**135%**	
Price Cap IR Year 2019		**136%**	
Price Cap IR Year 2020		**136%**	
Price Cap IR Year 2021		**136%**	
Price Cap IR Year 2022		**137%**	
Price Cap IR Year 2023		**137%**	
Threshold CAPEX			$Threshold\ Value\ \times d$
Price Cap IR Year 2014	**$**	**38,564,178**	
Price Cap IR Year 2015	**$**	**38,643,766**	
Price Cap IR Year 2016	**$**	**38,724,263**	
Price Cap IR Year 2017	**$**	**38,805,680**	
Price Cap IR Year 2018	**$**	**38,888,026**	
Price Cap IR Year 2019	**$**	**38,971,312**	
Price Cap IR Year 2020	**$**	**39,055,549**	
Price Cap IR Year 2021	**$**	**39,140,748**	
Price Cap IR Year 2022	**$**	**39,226,919**	
Price Cap IR Year 2023	**$**	**39,314,075**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

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ATTACH 5

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Alectra Utilities Corporation-Guelph Rate Zone
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2020**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Alectra Utilities Corporation-Guelph Rate Zone is applying:	**4**
Next OEB Scheduled Rebasing Year	**2027**
Alectra Utilities Corporation-Guelph Rate Zone is applying for:	**ICM Approval**
Last Rebasing Year:	**2016**
The most recent complete year for which actual billing and load data exists	**2018**
Current IPI	**1.50%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.20%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2018 Actual Distribution Demand}}{\text{Revenues Based on 2016 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-Guelph Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **8**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 999 kW
4	GENERAL SERVICE 1,000 TO 4,999 kW
5	LARGE USE
6	UNMETERED SCATTERED LOAD
7	SENTINEL LIGHTING
8	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Alectra Utilities Corporation-Guelph Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Guelph Rate Zone's Revenues Based on 2018 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

Rate Class	Units	2018 Actual Distribution Demand			Current Approved Distribution Rates		
		Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW
RESIDENTIAL	$/kWh	50,914	384,041,745		29.22	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	4,134	142,209,076		16.94	0.0142	0.0000
GENERAL SERVICE 50 TO 999 kW	$/kW	578	402,350,218	1,097,499	183.66	0.0000	2.7982
GENERAL SERVICE 1,000 TO 4,999 kW	$/kW	43	540,417,878	1,135,425	580.97	0.0000	3.1063
LARGE USE	$/kW	4	197,428,962	423,180	1116.83	0.0000	2.7908
UNMETERED SCATTERED LOAD	$/kWh	559	1,810,678		4.96	0.0226	0.0000
SENTINEL LIGHTING	$/kW	35	18,189	51	7.67	0.0000	8.4893
STREET LIGHTING	$/kW	14,152	10,182,750	28,425	0.44	0.0000	10.4080

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Guelph Rate Zone

Calculation of pro forma 2016 Revenues. No input required.

Rate Class	2018 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	50,914	384,041,745		29.22	0.0000	0.0000	17,852,485	0	0	17,852,485	100.0%	0.0%	0.0%	58.4%
GENERAL SERVICE LESS THAN 50 kW	4,134	142,209,076		16.94	0.0142	0.0000	840,360	2,019,369	0	2,859,728	29.4%	70.6%	0.0%	9.4%
GENERAL SERVICE 50 TO 999 kW	578	402,350,218	1,097,499	183.66	0.0000	2.7982	1,273,866	0	3,071,022	4,344,887	29.3%	0.0%	70.7%	14.2%
GENERAL SERVICE 1,000 TO 4,999 kW	43	540,417,878	1,135,425	580.97	0.0000	3.1063	299,781	0	3,526,971	3,826,751	7.8%	0.0%	92.2%	12.5%
LARGE USE	4	197,428,962	423,180	1,116.83	0.0000	2.7908	53,608	0	1,181,011	1,234,619	4.3%	0.0%	95.7%	4.0%
UNMETERED SCATTERED LOAD	559	1,810,678		4.96	0.0226	0.0000	33,272	40,921	0	74,193	44.8%	55.2%	0.0%	0.2%
SENTINEL LIGHTING	35	18,189	51	7.67	0.0000	8.4893	3,221	0	433	3,654	88.2%	0.0%	11.8%	0.0%
STREET LIGHTING	14,152	10,182,750	28,425	0.44	0.0000	10.4080	74,723	0	295,847	370,570	20.2%	0.0%	79.8%	1.2%
Total	**70,419**	**1,678,459,496**	**2,684,580**				**20,431,314**	**2,060,290**	**8,075,283**	**30,566,888**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-Guelph Rate Zone

Applicants Rate Base

Last COS Rebasing: 2016

Average Net Fixed Assets					
Gross Fixed Assets - Re-based Opening	$ 163,625,735	A			
Add: CWIP Re-based Opening		B			
Re-based Capital Additions	$ 11,363,000	C			
Re-based Capital Disposals		D			
Re-based Capital Retirements		E			
Deduct: CWIP Re-based Closing		F			
Gross Fixed Assets - Re-based Closing	$ 174,988,735	G			
Average Gross Fixed Assets			$	169,307,235	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$ 32,529,814	I			
Re-based Depreciation Expense	$ 6,295,624	J			
Re-based Disposals		K			
Re-based Retirements		L			
Accumulated Depreciation - Re-based Closing	$ 38,825,438	M			
Average Accumulated Depreciation			$	35,677,626	N = (I + M) / 2
Average Net Fixed Assets			**$**	**133,629,609**	O = H - N
Working Capital Allowance					
Working Capital Allowance Base	$ 236,828,275	P			
Working Capital Allowance Rate	7.5%	Q			
Working Capital Allowance			**$**	**17,762,121**	R = P * Q
Rate Base			**$**	**151,391,730**	S = O + R
Return on Rate Base					
Deemed ShortTerm Debt %	4.00%	T	$	6,055,669	W = S * T
Deemed Long Term Debt %	56.00%	U	$	84,779,369	X = S * U
Deemed Equity %	40.00%	V	$	60,556,692	Y = S * V
Short Term Interest	1.65%	Z	$	99,919	AC = W * Z
Long Term Interest	4.91%	AA	$	4,166,751	AD = X * AA
Return on Equity	9.19%	AB	$	5,565,160	AE = Y * AB
Return on Rate Base			**$**	**9,831,829**	AF = AC + AD + AE
Distribution Expenses					
OM&A Expenses	$ 15,137,002	AG			
Amortization	$ 5,745,184	AH			
Ontario Capital Tax	$ 335,074	AI			
Grossed Up Taxes/PILs	$ 692,577	AJ			
Low Voltage	$ 29,301	AK			
Transformer Allowance	$ 64,558	AL			
		AM			
		AN			
		AO			
			$	**22,003,696**	AP = SUM (AG : AO)
Revenue Offsets					
Specific Service Charges	-$ 426,370	AQ			
Late Payment Charges	-$ 120,000	AR			
Other Distribution Income	-$ 710,833	AS			
Other Income and Deductions	-$ 1,049,998	AT	**-$**	**2,307,201**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates			**$**	**29,528,324**	AV = AF + AP + AU
Rate Classes Revenue					
Rate Classes Revenue - Total (Sheet 4)			$	30,566,888	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Guelph Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Guelph Rate Zone's Revenues Based on 2016 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2016 Board-Approved Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	48,758	388,506,233		29.22	0.0000	0.0000	17,096,505	0	0	17,096,505	57.7%	0.0%	0.0%	57.7%
GENERAL SERVICE LESS THAN 50 kW	4,006	144,569,861		16.94	0.0142	0.0000	814,238	2,052,892	0	2,867,130	2.7%	6.9%	0.0%	9.7%
GENERAL SERVICE 50 TO 999 kW	567	390,148,189	1,035,647	183.66	0.0000	2.7982	1,249,623	0	2,897,949	4,147,571	4.2%	0.0%	9.8%	14.0%
GENERAL SERVICE 1,000 TO 4,999 kW	41	544,730,297	1,047,529	580.97	0.0000	3.1063	285,837	0	3,253,941	3,539,778	1.0%	0.0%	11.0%	12.0%
LARGE USE	5	292,417,465	524,780	1,116.83	0.0000	2.7908	60,309	0	1,464,556	1,524,864	0.2%	0.0%	4.9%	5.1%
UNMETERED SCATTERED LOAD	554	1,896,821		4.96	0.0226	0.0000	32,944	42,868	0	75,812	0.1%	0.1%	0.0%	0.3%
SENTINEL LIGHTING	36	20,200	56	7.67	0.0000	8.4893	3,313	0	475	3,788	0.0%	0.0%	0.0%	0.0%
STREET LIGHTING	13,704	10,039,579	28,029	0.44	0.0000	10.4080	72,354	0	291,721	364,076	0.2%	0.0%	1.0%	1.2%
Total	**67,669**	**1,772,328,645**	**2,636,041**				**19,615,124**	**2,095,760**	**7,908,641**	**29,619,525**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Guelph Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	29.22	0	0	50,914	384,041,745	0	17,852,485	0	0	17,852,485	58.40%	0.00%	0.00%	58.4%
GENERAL SERVICE LESS THAN 50 kW	16.94	0.0142	0	4,134	142,209,076	0	840,360	2,019,369	0	2,859,728	2.75%	6.61%	0.00%	9.4%
GENERAL SERVICE 50 TO 999 kW	183.66	0	2.7982	578	402,350,218	1,097,499	1,273,866	0	3,071,022	4,344,887	4.17%	0.00%	10.05%	14.2%
GENERAL SERVICE 1,000 TO 4,999 kW	580.97	0	3.1063	43	540,417,878	1,135,425	299,781	0	3,526,971	3,826,751	0.98%	0.00%	11.54%	12.5%
LARGE USE	1116.83	0	2.7908	4	197,428,962	423,180	53,608	0	1,181,011	1,234,619	0.18%	0.00%	3.86%	4.0%
UNMETERED SCATTERED LOAD	4.96	0.0226	0	559	1,810,678	0	33,272	40,921	0	74,193	0.11%	0.13%	0.00%	0.2%
SENTINEL LIGHTING	7.67	0	8.4893	35	18,189	51	3,221	0	433	3,654	0.01%	0.00%	0.00%	0.0%
STREET LIGHTING	0.44	0	10.408	14,152	10,182,750	28,425	74,723	0	295,847	370,570	0.24%	0.00%	0.97%	1.2%
Total							**20,431,314**	**2,060,290**	**8,075,283**	**30,566,888**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Guelph Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$\textit{Threshold Value}\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g)\times(1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2016**	
Price Cap IR Year in which Application is made		**4**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		$30,566,888	
Revenues Based on 2016 Board-Approved Distribution Demand		$29,619,525	
Growth Factor		**1.60%**	$g\ (Note\ 1)$
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	163,625,735	
Add: CWIP Opening	$	-	
Capital Additions	$	11,363,000	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	174,988,735	
Average Gross Fixed Assets	$	169,307,235	
Accumulated Depreciation - Opening	$	32,529,814	
Depreciation Expense	$	6,295,624	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	38,825,438	
Average Accumulated Depreciation	$	35,677,626	
Average Net Fixed Assets	$	133,629,609	
Working Capital Allowance			
Working Capital Allowance Base	$	236,828,275	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	17,762,121	
Rate Base	**$**	**151,391,730**	RB
Depreciation	**$**	**6,295,624**	d
Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)			
Price Cap IR Year 2017		**178%**	
Price Cap IR Year 2018		**180%**	
Price Cap IR Year 2019		**182%**	
Price Cap IR Year 2020		**184%**	
Price Cap IR Year 2021		**186%**	
Price Cap IR Year 2022		**188%**	
Price Cap IR Year 2023		**190%**	
Price Cap IR Year 2024		**192%**	
Price Cap IR Year 2025		**195%**	
Price Cap IR Year 2026		**197%**	
Threshold CAPEX			$\textit{Threshold Value} \times d$
Price Cap IR Year 2017	**$**	**11,192,026**	
Price Cap IR Year 2018	**$**	**11,312,283**	
Price Cap IR Year 2019	**$**	**11,435,929**	
Price Cap IR Year 2020	**$**	**11,563,061**	
Price Cap IR Year 2021	**$**	**11,693,775**	
Price Cap IR Year 2022	**$**	**11,828,173**	
Price Cap IR Year 2023	**$**	**11,966,360**	
Price Cap IR Year 2024	**$**	**12,108,441**	
Price Cap IR Year 2025	**$**	**12,254,526**	
Price Cap IR Year 2026	**$**	**12,404,729**	

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

G-Staff-8

ATTACH 6

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Alectra Utilities Corporation-Horizon Utilities Rate Zone
Assigned EB Number	
Name of Contact and Title	
Phone Number	
Email Address	
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR**
Rate Year	**2020**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Alectra Utilities Corporation-Horizon Utilities Rate Zone is applying:	**1**
Next OEB Scheduled Rebasing Year	**2027**
Alectra Utilities Corporation-Horizon Utilities Rate Zone is applying for:	**ICM Approval**
Last Rebasing Year:	**2019**
The most recent complete year for which actual billing and load data exists	**2018**
Current IPI	**1.50%**
Strech Factor Assigned to Middle Cohort*	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**1.20%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2019 Board-Approved Distribution Demand}}{\text{Revenues Based on 2018 Actual Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **8**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	LARGE USE
5	LARGE USE WITH DEDICATED ASSETS
6	UNMETERED SCATTERED LOAD
7	SENTINEL LIGHTING
8	STREET LIGHTING

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Horizon Utilities Rate Zone's Revenues Based on 2019 Board-Approved Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

Rate Class	Units	2019 Board-Approved Distribution Demand Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Current Approved Distribution Rates Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW
RESIDENTIAL	$/kWh	227,762	1,652,719,193		26.70	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	18,709	594,472,785		42.29	0.0109	0.0000
GENERAL SERVICE 50 TO 4,999 KW	$/kW	2,316	1,840,510,488	5,066,406	389.40	0.0000	2.6150
LARGE USE	$/kW	6	242,051,739	569,520	24279.37	0.0000	1.4325
LARGE USE WITH DEDICATED ASSETS	$/kW	5	403,775,839	2,136,952	5755.85	0.0000	0.3396
UNMETERED SCATTERED LOAD	$/kWh	3,006	10,504,342		8.63	0.0134	0.0000
SENTINEL LIGHTING	$/kW	378	363,731	1,030	5.63	0.0000	15.4416
STREET LIGHTING	$/kW	52,273	39,610,413	109,773	1.95	0.0000	5.1752

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

Calculation of pro forma 2019 Revenues. No input required.

Rate Class	2019 Board-Approved Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	227,762	1,652,719,193		26.70	0.0000	0.0000	72,974,945	0	0	72,974,945	100.0%	0.0%	0.0%	61.4%
GENERAL SERVICE LESS THAN 50 kW	18,709	594,472,785		42.29	0.0109	0.0000	9,494,443	6,479,753	0	15,974,197	59.4%	40.6%	0.0%	13.4%
GENERAL SERVICE 50 TO 4,999 KW	2,316	1,840,510,488	5,066,406	389.40	0.0000	2.6150	10,822,205	0	13,248,651	24,070,856	45.0%	0.0%	55.0%	20.2%
LARGE USE	6	242,051,739	569,520	24,279.37	0.0000	1.4325	1,748,115	0	815,837	2,563,952	68.2%	0.0%	31.8%	2.2%
LARGE USE WITH DEDICATED ASSETS	5	403,775,839	2,136,952	5,755.85	0.0000	0.3396	345,351	0	725,709	1,071,060	32.2%	0.0%	67.8%	0.9%
UNMETERED SCATTERED LOAD	3,006	10,504,342		8.63	0.0134	0.0000	311,301	140,758	0	452,060	68.9%	31.1%	0.0%	0.4%
SENTINEL LIGHTING	378	363,731	1,030	5.63	0.0000	15.4416	25,538	0	15,905	41,443	61.6%	0.0%	38.4%	0.0%
STREET LIGHTING	52,273	39,610,413	109,773	1.95	0.0000	5.1752	1,223,188	0	568,097	1,791,285	68.3%	0.0%	31.7%	1.5%
Total	**304,455**	**4,784,008,529**	**7,883,681**				**96,945,086**	**6,620,512**	**15,374,200**	**118,939,797**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

Applicants Rate Base

Last COS Rebasing: 2019

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	625,029,889	A			
Add: CWIP Re-based Opening	$	3,164,006	B			
Re-based Capital Additions	$	51,272,477	C			
Re-based Capital Disposals	-$	4,597,818	D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing	-$	3,164,006	F			
Gross Fixed Assets - Re-based Closing	$	671,704,548	G			
Average Gross Fixed Assets				$	648,367,218	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	160,425,475	I			
Re-based Depreciation Expense	$	23,877,061	J			
Re-based Disposals	-$	1,426,748	K			
Re-based Retirements	$	-	L			
Accumulated Depreciation - Re-based Closing	$	182,875,788	M			
Average Accumulated Depreciation				$	171,650,631	N = (I + M) / 2
Average Net Fixed Assets				**$**	**476,716,587**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	658,178,026	P			
Working Capital Allowance Rate		12.0%	Q			
Working Capital Allowance				**$**	**78,981,363**	R = P * Q
Rate Base				**$**	**555,697,950**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	22,227,918	W = S * T
Deemed Long Term Debt %		56.00%	U	$	311,190,852	X = S * U
Deemed Equity %		40.00%	V	$	222,279,180	Y = S * V
Short Term Interest		2.82%	Z	$	626,827	AC = W * Z
Long Term Interest		3.74%	AA	$	11,638,538	AD = X * AA
Return on Equity		8.98%	AB	$	19,960,670	AE = Y * AB
Return on Rate Base				**$**	**32,226,036**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	63,557,394	AG			
Amortization	$	25,278,432	AH			
Ontario Capital Tax			AI			
Grossed Up Taxes/PILs	$	3,145,640	AJ			
Low Voltage			AK			
Transformer Allowance	$	-	AL			
			AM			
			AN			
			AO			
				$	**91,981,466**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	757,312	AQ			
Late Payment Charges	-$	875,000	AR			
Other Distribution Income	$	-	AS			
Other Income and Deductions	-$	4,321,587	AT	**-$**	**5,953,899**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**118,253,603**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 4)				$	118,939,797	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

Input the billing determinants associated with Alectra Utilities Corporation-Horizon Utilities Rate Zone's Revenues Based on 2018 Actual Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

	2018 Actual Distribution Demand			Current Approved Distribution Rates										
Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	226,840	1,658,643,677		26.70	0.0000	0.0000	72,679,536	0	0	72,679,536	63.0%	0.0%	0.0%	63.0%
GENERAL SERVICE LESS THAN 50 kW	18,992	579,935,709		42.29	0.0109	0.0000	9,638,060	6,321,299	0	15,959,359	8.3%	5.5%	0.0%	13.8%
GENERAL SERVICE 50 TO 4,999 KW	2,057		4,745,594	389.40	0.0000	2.6150	9,611,950	0	12,409,730	22,021,679	8.3%	0.0%	10.8%	19.1%
LARGE USE	4		367,306	24,279.37	0.0000	1.4325	1,165,410	0	526,166	1,691,576	1.0%	0.0%	0.5%	1.5%
LARGE USE WITH DEDICATED ASSETS	7		1,995,379	5,755.85	0.0000	0.3396	483,491	0	677,631	1,161,122	0.4%	0.0%	0.6%	1.0%
UNMETERED SCATTERED LOAD	2,970	11,372,501		8.63	0.0134	0.0000	307,573	152,392	0	459,965	0.3%	0.1%	0.0%	0.4%
SENTINEL LIGHTING	338		1,320	5.63	0.0000	15.4416	22,835	0	20,388	43,223	0.0%	0.0%	0.0%	0.0%
STREET LIGHTING	52,548		34,882	1.95	0.0000	5.1752	1,229,623	0	180,520	1,410,143	1.1%	0.0%	0.2%	1.2%
Total	**303,756**	**2,249,951,887**	**7,144,481**				**95,138,479**	**6,473,691**	**13,814,434**	**115,426,603**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

Rate Class	Current OEB-Approved Base Rates			2019 Board-Approved Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	26.70	0	0	227,762	1,652,719,193	0	72,974,945	0	0	72,974,945	61.35%	0.00%	0.00%	61.4%
GENERAL SERVICE LESS THAN 50 kW	42.29	0.0109	0	18,709	594,472,785	0	9,494,443	6,479,753	0	15,974,197	7.98%	5.45%	0.00%	13.4%
GENERAL SERVICE 50 TO 4,999 KW	389.40	0	2.615	2,316	1,840,510,488	5,066,406	10,822,205	0	13,248,651	24,070,856	9.10%	0.00%	11.14%	20.2%
LARGE USE	24279.37	0	1.4325	6	242,051,739	569,520	1,748,115	0	815,837	2,563,952	1.47%	0.00%	0.69%	2.2%
LARGE USE WITH DEDICATED ASSETS	5755.85	0	0.3396	5	403,775,839	2,136,952	345,351	0	725,709	1,071,060	0.29%	0.00%	0.61%	0.9%
UNMETERED SCATTERED LOAD	8.63	0.0134	0	3,006	10,504,342	0	311,301	140,758	0	452,060	0.26%	0.12%	0.00%	0.4%
SENTINEL LIGHTING	5.63	0	15.4416	378	363,731	1,030	25,538	0	15,905	41,443	0.02%	0.00%	0.01%	0.0%
STREET LIGHTING	1.95	0	5.1752	52,273	39,610,413	109,773	1,223,188	0	568,097	1,791,285	1.03%	0.00%	0.48%	1.5%
Total							**96,945,086**	**6,620,512**	**15,374,200**	**118,939,797**				**100.0%**

Capital Module
Applicable to ACM and ICM

Alectra Utilities Corporation-Horizon Utilities Rate Zone

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2019**	
Price Cap IR Year in which Application is made		**1**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2019 Board-Approved Distribution Demand		**$118,939,797**	
Revenues Based on 2018 Actual Distribution Demand		**$115,426,603**	
Growth Factor		**3.04%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	625,029,889	
Add: CWIP Opening	$	3,164,006	
Capital Additions	$	51,272,477	
Capital Disposals	-$	4,597,818	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	3,164,006	
Gross Fixed Assets - Closing	$	671,704,548	
Average Gross Fixed Assets	$	648,367,218	
Accumulated Depreciation - Opening	$	160,425,475	
Depreciation Expense	$	23,877,061	
Disposals	-$	1,426,748	
Retirements	$	-	
Accumulated Depreciation - Closing	$	182,875,788	
Average Accumulated Depreciation	$	171,650,631	
Average Net Fixed Assets	$	476,716,587	
Working Capital Allowance			
Working Capital Allowance Base	$	658,178,026	
Working Capital Allowance Rate		12%	
Working Capital Allowance	$	78,981,363	
Rate Base	**$**	**555,697,950**	RB
Depreciation	**$**	**23,877,061**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2020	**210%**
Price Cap IR Year 2021	**214%**
Price Cap IR Year 2022	**218%**
Price Cap IR Year 2023	**223%**
Price Cap IR Year 2024	**228%**
Price Cap IR Year 2025	**233%**
Price Cap IR Year 2026	**238%**
Price Cap IR Year 2027	**244%**
Price Cap IR Year 2028	**249%**
Price Cap IR Year 2029	**255%**

Threshold CAPEX $Threshold\ Value \times d$

Price Cap IR Year 2020	**$**	**50,049,666**
Price Cap IR Year 2021	**$**	**51,067,703**
Price Cap IR Year 2022	**$**	**52,129,315**
Price Cap IR Year 2023	**$**	**53,236,365**
Price Cap IR Year 2024	**$**	**54,390,799**
Price Cap IR Year 2025	**$**	**55,594,645**
Price Cap IR Year 2026	**$**	**56,850,018**
Price Cap IR Year 2027	**$**	**58,159,123**
Price Cap IR Year 2028	**$**	**59,524,261**
Price Cap IR Year 2029	**$**	**60,947,828**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

G-Staff-9

Reference: Exhibit 2, Tab 1, Schedule 4, Page 2 of 18

Alectra Utilities describes the true-up of the Capital Investment Variance Account (CIVA) as follows:

Subject to the OEB's approval of the M-factor, Alectra Utilities proposes a symmetrical CIVA for the 2020-2024 term of the DSP. Alectra Utilities proposes to track variances between the actual and forecast capital related revenue requirement for the DSP term. The capital related revenue requirement is used to calculate the M-factor for riders applicable in each rate zone.

Consistent with the determination of the maximum M-factor eligible capital at the time of this filing, the CIVA true-up amount must fall within Alectra Utilities' maximum M-factor eligible capital at the time of the true-up based on Alectra Utilities' actual five-year in-service additions. By way of example, Alectra Utilities' total capital envelope, as provided in Table 4, is $0.3B. This is based on total forecasted capital expenditures of $1.5B less the materiality threshold of $1.2B. If actual capital expenditures are $1.3B, then Alectra Utilities' capital envelope is $0.1B (Total capital costs of $1.3B, less the materiality threshold of $1.2B). Therefore, CIVA true-up cannot exceed the capital envelope of $0.1B, determined at the time of the true-up.

a) **Is OEB staff's understanding correct that the CIVA true-up will be calculated as the difference between the actual five-year in-service additions related to M-factor and the forecast M-factor capital related revenue requirement?**

b) **Based on Alectra Utilities' description in the reference above, OEB staff understands that Alectra Utilities proposes that the CIVA true-up amount cannot exceed the difference between the actual capital expenditures at the time of the true-up and the materiality threshold (calculated in Exhibit 2, Tab 1, Schedule 3 for the M-factor) of $1.2 billion. Please confirm if OEB staff's understanding is correct. If yes, please explain the rationale for the proposed calculation for the maximum eligible CIVA true-up amount.**

c) **Please confirm that Alectra Utilities does not intend to track M-factor variances on a project level.**

d) **Based on Alectra Utilities' example above, is OEB staff's understanding correct that the CIVA true-up will be based on actual five-year in-service additions, regardless of whether Alectra Utilities' spending has exceeded the $265 million it has requested through the M-factor?**

i. Please confirm if OEB staff's example is correct: if Alectra Utilities' actual capital expenditure is $1.8 billion, then $1.8 billion less the materiality threshold of $1.2 billion gives Alectra Utilities a maximum capital envelope of $0.6 billion that would be eligible for a true-up.

ii. If the example in i) is correct, please explain why it is appropriate for Alectra Utilities to collect any true-up when the actual M-factor capital spending is in excess of the amount being requested in this application ($265 million).

iii. If Alectra Utilities spends in excess of the amount being requested in this application ($265 million) and requests a subsequent true-up for the excess spending, please explain what evidence Alectra Utilities will provide to the OEB to assess the prudence of the excess spending. Specifically, please explain on what basis the OEB could assess the prudence of Alectra Utilities' excess spending given that there are no set M-factor projects given the proposed "flexible" nature of the M-factor.

Alectra Utilities proposes calculating the annual CIVA amount on a company-wide basis and proposes disposing of the CIVA balance using class specific rate riders that are applied to all rate zones.

e) Please confirm Alectra Utilities is intending to have one set of class specific rate riders applied equally across all rate zones.

i. If yes to e), please explain how this is equitable to all customers given that the original M-factor rate riders are rate zone specific. Furthermore, please explain how Alectra Utilities will prevent subsidization across rate zones if Alectra Utilities does not track variances within rate zones and proposes calculating the CIVA amounts on a company-wide basis.

f) Please explain the apparent disconnect between Alectra Utilities' proposal to dispose of the variance account at the end of the five year term, and Alectra Utilities' proposal to calculate the CIVA amount and dispose of positive and negative balances annually.

Response:

In addition to the specific responses below, Alectra Utilities wishes to provide clarification and responses to a number of related interrogatories regarding the M-factor and the CIVA in a unified manner. The following responds to questions set out in this G-Staff-9, as well as to questions set out in G-Staff-4, G-Staff-5, G-Staff-6 and CCC-22.

M-factor Funding is Limited in Scope

As explained in Exhibit 2, Tab 1, Schedule 3 at p. 3, the purpose of the M-factor is to bridge the gap during Alectra Utilities' rebasing deferral period, between the level of investment funded through base rates and the level of investment that needs to be funded to fully execute its DSP. The utility's base rates will support an average annual capital expenditure of approximately $236MM during the DSP period. However, the DSP contemplates annual capital expenditures of approximately $291MM. Without the M-factor, Alectra Utilities would have $55MM of capital expenditures in each year that are unfunded and which it would not be able to execute. This results in a total of approximately $275MM of unfunded capital expenditures over the five-year DSP period (Exhibit 2, Tab 1, Schedule 3, p. 3). Alectra Utilities would not be able to achieve the outcomes that its customers expect if it does not have the capital funding to fully execute the DSP.

As explained in Exhibit 2, Tab 1, Schedule 3 at pp. 11-13, Alectra Utilities considers the ICM materiality threshold to be an appropriate method for calculating the level of capital funding that it should be expected to absorb within its funding from base rates. Alectra Utilities clarifies that consistent with its request for flexibility to execute the M-factor projects, these projects must fit within the total eligible capital envelope derived from the materiality threshold over the 5 year DSP period. On this basis, the threshold capital expenditure value over the 2020 to 2024 DSP period is $1.182B. Given that the DSP contemplates a total capital investment need of $1.457B over this period, Alectra Utilities' maximum M-factor eligible capital is $274.3MM. Alectra Utilities is proposing to establish riders that reflect total M-factor capital expenditures of $265MM over the five-year period, which is less than the maximum eligible amount. As explained in greater detail below, the $9.3MM difference between this and the $274.3MM maximum M-factor eligible capital amount represents the maximum amount that Alectra Utilities would be able to recover from customers through the Capital Investment Variance Account ("CIVA") true-up at the end of the five-year period, in the event there is a credit balance in the account at that time.

The revenue requirement impact associated with the M-factor capital expenditures of $265MM over five years is proposed to be recovered through M-factor Capital Funding Rate Riders. These riders will be calculated for each rate class within each rate zone, for each of the DSP years, to reflect the particular M-factor Projects that go into service in the corresponding rate zone in the relevant year. These rate riders will remain in place until rebasing and will thereby be cumulative in that, by 2024, customers would be charged the M-factor riders applicable to their rate class/rate zone for each of the five preceding years. In 2024, when all of the M-factor riders would be in effect, Alectra Utilities' total capital revenue requirement associated with the M-factor funding request, reflective of all DSP years, would be $21.8MM. This is shown in Exhibit 2, Tab 1, Schedule 3 at p. 16, with detailed calculations in Exhibit 5, Attachment 3, and as revised for a 'typo' noted in Alectra Utilities' response to G-Staff-1. The resulting M-factor Capital Funding Rate Riders are presented, for each year by rate zone, and for each customer class, on pages 18-19 of Exhibit 2, Tab 1, Schedule 3.

M-factor Funding Amounts Relate to Specific and Identifiable Capital Investments

The proposed M-factor will provide funding for a specific and identifiable set of planned capital investments that are contemplated in the DSP ("M-factor Projects"). M-factor Projects relate to specific rate zones, or in some cases to multiple rate zones. A breakdown of the total planned capital expenditures for M-factor Projects by rate zone and by year is provided in Exhibit 5, Attachment 3, p. 1. A breakdown by rate zone of the individual M-factor Projects is provided in Alectra Utilities' responses to G-Staff-4-1 through G-Staff-4-6. In total, there are 194 individual M-factor Projects that the company proposes for funding through the M-factor.

As is the case for all of its capital investment needs, including those to be funded through base rates and those that are proposed to be funded through the M-factor, Alectra Utilities identified its capital investment requirements through the DSP investment planning process. This process included: multiple rounds of customer engagement; asset condition and needs assessment; identification of options; business case development; risk/value assessment and investment prioritization and optimization using the CopperLeaf C55 software system.

Through this process, Alectra Utilities prioritized all of its identified investment needs so as to develop a portfolio of investments that provides maximum value, while meeting various needs.

This was done by considering factors such as: compliance requirements; safety risks; environmental risks; regulatory risks; reliability impacts; and customer service benefits and costs. Higher value investments are funded through base rates to the extent that such funding is available. Where funding through base rates is not available, investments would be funded through the proposed M-factor. While the investments to be funded through the M-factor would therefore be those considered to be of lower value relative to those that would be funded by base rates, they are of a higher value relative to the numerous other potential investment needs that Alectra Utilities identified but did not ultimately include in its capital investment plan. The M-factor Projects are considered to be important investments that need to be executed during the DSP planning period.

M-factor Riders are Calculated with Reference to Specific and Identifiable Investments

As specified in Exhibit 2, Tab 1, Schedule 3 at p. 16, the proposed M-factor Capital Funding Rate Riders have been calculated based on specific M-factor Projects that are contemplated in the DSP for the corresponding rate zones during particular years. At p. 15 of that Schedule, Alectra Utilities states that, while the M-factor riders are calculated based on specific investments, they "are not tied to those specific investments". This means that the M-factor riders would provide Alectra Utilities with an envelope of capital funding. While the company plans to execute all of the individual M-factor Projects as planned within the DSP period, to effectively implement the DSP, Alectra Utilities requires the ability to accommodate changing circumstances that may require some work to be accelerated and other work to be deferred. For instance, this may result in a particular M-factor Project in one rate zone being deferred to accommodate the acceleration of a different M-factor Project in the same or a different rate zone. As discussed below, such deviations from plan will be tracked in the CIVA over the five-year DSP period to enable any necessary true-ups at the end of this period as between Alectra Utilities and its customers, and as between rate zones.

Amounts will be Recorded in CIVA Annually

As described in Exhibit 2, Tab 1, Schedule 4, Alectra Utilities is proposing to establish a CIVA for the 2020-2024 period to track the difference between capital funding provided through the M-factor and the actual revenue requirement for M-factor Projects placed into service during this period. The CIVA is proposed as a symmetrical account and would include rate zone-specific sub-accounts to enable tracking of investments for each rate zone. While Alectra Utilities would record amounts in the CIVA (including the relevant sub-accounts) on an annual basis, it would not seek to dispose of any amounts recorded in the account until the conclusion of the DSP planning period. As identified above, tracking amounts in the CIVA during the 2020-2024 period will enable any necessary true-ups at the end of this period to ensure fairness as between the company and its customers, and as between rate zones.

Each year during the 2020-2024 period, Alectra Utilities would track the revenue requirement impacts of the individual M-factor Projects that it puts into service in each rate zone and compare these to the revenue requirement impacts that were expected for that rate zone in that year in calculating the M-Factor Capital Funding Rate Riders. Any variances, including those attributable to differences in depreciation expense and return on capital due to the timing of M-factor Projects, would be recorded in the relevant sub-account for that year. Alectra Utilities would also document the reasons for any such variances, which might include that the actual costs of execution are higher or lower than planned, that the scope of an M-factor Project needed to be changed, that a particular M-factor Project is deferred or that a particular M-factor Project is accelerated.

CIVA Will be Trued-Up and Cleared at the End of the 5-Year DSP Planning Period

Through the CIVA true-up process, Alectra Utilities will be able to ensure fairness as between its shareholders and its customers, as well as among customers in its various rate zones. At the end of the five-year DSP period, Alectra Utilities will assess the impacts of the variances that have been recorded in the CIVA in each of the prior five years. The company will identify any revenue requirement impacts resulting from differences between proposed and actual levels of M-factor investments, by rate zone. In doing so, the company will be able to determine whether it may have over-collected or under-recovered, as well as whether customers in any particular rate zone may have overpaid or underpaid, relative to the specific M-factor Projects that were actually put into service and when they were put into service in their rate zone.

If on an overall basis Alectra Utilities has over-collected relative to the M-factor Projects that it has actually put into service, then it would propose to return the difference to customers by calculating negative rate riders for each rate zone that are reflective of the differences between planned and actual investments in each rate zone. For example, if instead of investing $265MM the company only puts $215MM into service and the difference is attributed to $40MM of planned M-factor Projects not being completed in one rate zone and $10MM of planned M-factor Projects not being completed in another rate zone, then the revenue requirement impact of the $40MM would be returned to customers in the first rate zone, the revenue requirement impact of the $10MM would be returned to customers in the second rate zone, and there would be no adjustments for the remaining rate zones.

If on an overall basis Alectra Utilities has under-recovered relative to the M-factor Projects that it has actually put into service, then it would propose to recover the difference from customers by calculating rate riders for each rate zone, similar to the example above, that are reflective of the differences between planned and actual investments in each rate zone. While this aspect is a key element of what makes the proposed CIVA "symmetrical", it is important to note that the CIVA would, in this respect, not be entirely symmetrical. This is because the company's ability to recover additional amounts from customers through the CIVA true-up would be limited to the revenue requirement associated with incremental capital in-service of $9.3MM. This amount represents the difference between the $265MM of proposed M-factor funding and the $274.3MM maximum M-factor eligible capital amount that, as described above, has been calculated based on the ICM materiality threshold. It is important to recognize that an additional $9.3MM of capital in service would have a revenue requirement impact of approximately $0.8MM. As such, the CIVA would be symmetrical for purposes of recording amounts in the account on an annual basis but, overall, it is only symmetrical to the extent of the maximum M-factor eligible capital amount.

It is also important to recognize that, in circumstances where Alectra Utilities has under-recovered relative to the level of investment it actually puts into service and it seeks additional recovery from customers for the revenue requirement impact of up to $9.3MM of additional capital in service by means of the CIVA true-up, the company's ability to recover such additional amounts would be subject to a prudence review by the OEB. Alectra Utilities expects that the evidence it would provide to the OEB to enable such prudence review would include details of the specific drivers of the variances that have contributed to the incremental amount not funded by the M-factor riders. For example, this might include explanations as to why the costs of certain M-factor Projects were higher than forecasted, why the scope of certain M-factor Projects needed to be expanded or why the timing of certain M-factor Projects changed relative to plan and how those timing changes had the effect of increasing the revenue requirement (i.e., by incurring additional depreciation expense or return on capital).

On an overall basis, whether or not Alectra Utilities over- or under-recovers M-factor amounts, the CIVA true-up process will enable the company to ensure fairness as between customers in different rate zones. Specifically, through the tracking of variances in the account, Alectra Utilities will be able to identify any revenue requirement impacts particular to each rate zone. If customers in a particular rate zone have overpaid or underpaid relative to the M-factor related capital actually put into service in their rate zone during the DSP period (which could occur as a result of shifting the timing of specific M-factor Projects, due to the need to expand or reduce the scope of an M-factor Projects, or in the event a planned M-factor Projects is not put into service during the DSP period), then those differences would be addressed through riders that would effectively redistribute amounts as between rate zones to ensure the costs of M-factor Projects are appropriately borne by customers in the rate zones that are benefiting from those investments.

No Approval or Partial Approval of M-factor Funding Will Adversely Impact Reliability

In the event that the OEB does not approve the proposed incremental capital funding through the M-factor, or the OEB only provides approval for a portion of the proposed incremental capital funding through the M-factor, it is generally expected that this would result in a growing population of deteriorated assets, declining reliability and a “snowplow” of capital costs that will need to be borne by future generations of Alectra Utilities’ customers (KP1.1, Slide 24; Exhibit 4, Tab 1, Schedule 1, Section 5.0.1, p. 12). As a further consequence, the company would be expected to incur a greater volume of more expensive reactive capital investment needs due to the need to respond to more frequent asset failures. This more costly approach to system investment would further erode the capital available for planned investments, thereby exacerbating the snowplow effect. The company would need to consider any such decision of the OEB in its full context before it determines which investments, if any, would be able to proceed on a planned basis and which would not.

In response to the specific questions in this G-Staff-9:

a) Confirmed. Please see Alectra Utilities' response, above.

b) Please see Alectra Utilities' response, above.

c) Not confirmed. Alectra Utilities will use all reasonable efforts to track approved M-factor Projects at a project level and by rate zone. Please see Alectra Utilities' response above.

d) Please see Alectra Utilities' response, above.

e) Alectra Utilities' proposed M-factor rate riders included in this Application are based on a proposed list of M-factor Projects that have been identified by rate zone. The rate riders are based on the proposed level of M-factor capital for the respective rate zone. Therefore, Alectra Utilities proposes to true-up the CIVA by rate zone at the end of the DSP term. Please see Alectra Utilities' response, above.

f) Alectra Utilities is not proposing to dispose of the CIVA annually. Please see Alectra Utilities' response, above.

G-Staff-10

Reference: Exhibit 2, Tab 1, Schedule 3, Page 3 of 21

On page 3 of 21, Alectra Utilities states: "If Alectra Utilities is unable to execute a capital plan at the level contemplated in the DSP, there will be significant, long-term negative consequences for the utility's distribution system and its customers."

a) Please elaborate what are the "significant, longer-term negative consequences" that would arise in the absence of M-factor funding. In particular, please provide quantifiable reliability impacts and the methodology Alectra Utilities used to arrive at its conclusions.

b) Do the negative consequences affect all of Alectra Utilities' rate zones equally? If not, what are the differences, and what are the reasons for the differences?

Response:

a) The "significant, longer-term negative consequences" are reliability and cost impacts.

The increasing backlog of deteriorating assets results in the replacement of defective equipment on reactive basis, which is more costly. Reactive work also introduces prolonged outages which results in customer dissatisfaction. A recent example is the cable failures in the York Hill/Hilda area. Alectra Utilities deferred the planned renewal project based on limited funding availability. A reactive approach to address this areas resulted in multiple outages to customers as described in Exhibit 4, Tab 1, Schedule 1, Page 3, Lines 8-11.

The DSP sets renewal plans to address deteriorated cable assets through cable replacement and cable rejuvenation (injection). The latter is more cost effective when compared to cable replacement. For cable injection to be effective in renewal, the cable segment has to be injected prior to significant deterioration.

Should Alectra Utilities defer investments due to funding shortages, Alectra Utilities can only renew deteriorated cable through replacements, which is approximately five times more expensive than cable replacement. This is demonstrated in the long-term system renewal needs as provided in Figure 2 on Page 5 of the DSP (Exhibit 1, Tab 3, Schedule 1, Page 5, Figure 2).

b) Since Alectra Utilities' rate zones include different volumes of deteriorated (i.e. very poor and poor condition) assets, the negative consequence of deferring necessary investments will have varying consequences. Furthermore, areas with deteriorated assets within each rate zone will also be negatively impacted at different levels. Alectra Utilities' DSP aims to maintain reliability at historical levels while addressing deteriorated and failing assets in the worst performing areas. Please refer to Alectra Utilities' response to AMPCO-12 where an example of different failure rates of XLPE cables is provided.

G-Staff-11

Reference 1: EB-2016-0025, Applicant's Reply Submissions, October 18, 2016, Page 22
Reference 2: EB-2016-0025, Decision and Order, December 8, 2016, Page 10

In the mergers, acquisitions, amalgamation and divestitures (MAADs) application that formed Alectra Utilities (the MAADs application), the applicant's (Alectra Utilities) final reply submission stated that "The Applicants [Alectra Utilities] have confirmed that [Incremental Capital Module (ICM)] applications during the rebasing deferral period will be made in accordance with the applicable policies of the Board."

The Decision and Order issued on December 8, 2016[1] noted that the applicants (Alectra Utilities) estimated to seek $587.7 million through ICMs over the course of its deferred rebasing period.

a) At the time of the MAADs application, did the applicants (Alectra Utilities) review the OEB's ICM policies on what projects would be eligible for ICM funding?

b) Please explain if the $587.7 million estimate was based on projects that the applicants (Alectra Utilities) determined would be eligible for ICM funding.

c) During the MAADs proceedings, did the applicants (Alectra Utilities) explain the reason for needing $587.7 million in ICM funding? If yes, please provide the reasons.

d) At the time of the MAADs application, were the applicants (Alectra Utilities) aware that ICM funding would not be available for typical annual capital programs?

   i. If yes to d), please explain why Alectra Utilities chose a ten year deferred rebasing period despite the apparent shortfall in funding for its typical annual capital programs.

e) Did the applicants (Alectra Utilities) assess the regulatory risk of the OEB denying any of Alectra Utilities ICM requests?

   i. If yes to e), what plans did the applicants (Alectra Utilities) have to mitigate or deal with the risks.

   ii. If no to e), why not?

[1] Decision and Order, EB-2016-0025, issued December 8, 2016

Response:

a) In Alectra Utilities' Mergers, Acquisitions, Amalgamation and Divestitures ("MAADs") proceeding (EB-2015-0025), in its final reply submission, Alectra Utilities indicated at page 5 *"that it would be able to manage and maintain financial viability as a result of the cash flow support from the synergy/savings of the consolidation; this results in a customer benefit via rates lower than would have been otherwise."* Alectra Utilities identified at that time that, consistent with the MAADs policy, "*While customers <u>do not share directly in the benefits of synergy/savings during the rebasing deferral period</u>, they do benefit from them indirectly, as the ability to retain those synergies/savings permits LDC Co to continue on lower Price-Cap IR/ICM rates for this period*."

At the time of the MAADs Application, the Applicants reviewed EB-2014-0138 – *The Report of the Board: Rate Making Associated with Distributor Consolidation* (the "MAADs Policy"). In the MAADs Policy, the OEB clearly identified the concerns of distributors regarding consolidations; it states that if distributors could "*[include] on-going capital investments into rate base during the deferred rebasing period, they may be more willing to consider consolidation*". Further, in the MAADs Policy, the OEB stated that distributors had identified that *"…few, if any, distributors would be able to operate over a deferred rebasing period without incorporating normal and expected capital expenditures into rate base*."[2]

Of particular significance was the consideration that, in its findings on page 9 of the MAADs Policy, the OEB states that "*The OEB believes that the clarification set out in the September 18th Report establishes that a distributor may now apply for an ICM that includes normal and expected capital investments*."

The Applicants also reviewed EB-2014-0219 - *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module.*

As identified in the Oral Hearing for the MAADs Application, in order to project the volume of ICM during the rebasing deferral period the Applicants considered the capital needs of the predecessor utilities based on past system planning. They undertook an assessment of capital needs going forward, which prompted the intention to use successive ICM funding applications to meet the estimated need.[3]. Neither Alectra Utilities, nor its predecessors, undertook a project-based evaluation for ICM funding comparable to what was provided to

[2] EB_2014-0138, p. 8

[3] EB-2015-0025, Oral Hearing Transcript, vol. 1, p.46; vol. 2, p. 146.

the OEB in Alectra Utilities' previous two ICM applications or in the DSP provided in this application. However, the OEB, in stating in the MAADs Decision and Order that the Applicants were seeking ICM funding over the course of the rebasing deferral period, understood the nature of the evaluation that had been undertaken, to that point.

b) As provided in Alectra Utilities' response to part a), the estimated volume of ICM funding required, \$587.7MM, was based on a mathematical evaluation of capital eligibility at the time of the merger transaction, based on a comparison of the capital program to the capital available in rates, having regard to the ICM methodology as had then been articulated by the Board. The capital program reflected the distribution system and investment plans of the consolidating utilities. The modelling was presented in evidence and was subject to examination during the MAADs proceeding. The M-factor funding sought in this application for five years of the ten year rebasing deferral period seeks recovery for approximately half of this amount.

c) In the MAADs Application proceeding, Alectra Utilities specified that it had ongoing capital funding needs in all of its rate zones and that it anticipated confirming that need annually. On that basis, it would file ICM applications for the rate zones for which such funding was required. Further, as the OEB identified at page 10 of the Decision and Order (EB-2015-0025), Alectra Utilities had revised its projected ICM funding requirements to \$587.7MM as a result of the PowerStream rate application decision (EB-2015-0003). On Day 1 of the MAADs Application Oral Hearing, Alectra Utilities identified that it expected to file a consolidated DSP by 2019, to identify and in support of future ongoing capital needs[4].

d) No. Alectra Utilities relied on the *Report of the Board: Rate-Making Associated with Distributor Consolidation* (the "MAADs Policy") , dated March 26, 2015, and the *Handbook to Electricity Distributor and Transmitter Consolidations* (the "MAADs Handbook"), dated January 19, 2016. The MAADs application was filed on April 15, 2016. As identified in part a) above, the MAADs Policy unambiguously states, on page 9, that "*The OEB believes that the clarification set out in the September 18th Report establishes that <u>a distributor may now apply for an ICM that includes normal and expected capital investments</u>. This clarification of*

[4] EB-2015-0025, Oral Hearing Transcript, vol. 1, p.119

policy should address the need of those distributors who may not consider entering into a MAADs transaction due to concerns over the ability to finance capital investments. The <u>one remaining limitation</u> is that the ability to apply for an ICM continues to be limited to those distributors under the Price Cap IR . . ." Subsequently, in the MAADs Handbook, at page 17, the OEB stated that *"[t]he ICM is now available for any prudent discrete capital project that fits within an incremental capital budget envelope, not just expenditures that were unanticipated or unplanned. To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, <u>thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.</u>*" At the time of the MAADs Application, based on the MAADs Policy and the MAADs Handbook, the Applicants understood that ICM funding would therefore be available to fund "normal and expected capital" and that the MAADs Handbook governed what was acceptable in the context of ICM funding requests during the rebasing deferral period. The OEB's interpretation of this aspect was not known to Alectra Utilities until the OEB's issued its decision with respect to Alectra Utilities' application for ICM funding in EB-2017-0024. Please also see Alectra Utilities' response to Staff-18 a).

e) Consistent with its understanding that all applications to the OEB bear a degree of regulatory risk, Alectra Utilities did consider the regulatory risk of the OEB not approving all of its ICM requests at the time of its MAADs application. However, this consideration of risk was made on the understanding that the Applicants had at the time of the MAADs application based on the MAADs Policy and MAADs Handbook, as identified in response to part c), above. Moreover, Alectra Utilities had clearly articulated in evidence its ongoing capital funding needs through the ten-year rebasing deferral period, that it was relying on incremental capital funding each year of the ten-year period and that the opportunity for ICM recovery was a significant consideration in determining whether to complete the consolidation. The OEB understood this expectation and confirmed in the Decision and Order that Alectra Utilities had identified that it would be making applications for incremental capital funding through the rebasing deferral period. While Alectra Utilities estimated a prospect of risk in filing the ICM applications, it also relied on the OEB policies, as articulated in the MAADs Policy and then reconfirmed in the MAADs Handbook that it could reasonably expect to be able to finance capital investments during the rebasing deferral period without a need to rebase earlier than otherwise anticipated[5]. Inherent in such a statement by the OEB was the implication that funding would not be denied based on a subsequent interpretation of the MAADs Policy and Handbook such that capital funding levels are so low as to require the consideration of a variation to ICM funding through the M-Factor.

[5] MAADs Handbook, p.17

G-Staff-12

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A12, Page 36 of 42
Reference 2: Transcript_Alectra Utilities Presentation_20190807, Page 51

During Alectra Utilities' presentation day on August 7, 2019, in response to a question about the differences between Alectra Utilities current DSP and the DSPs of the predecessor utilities, Mr. Cananzi said:

> **[…] What we've also experienced, though, is accelerating degradation. And to the extent that some of the needs weren't properly addressed within the former years, what we are seeing is obviously a reactive replacement which is costing us significantly more, anywhere from, you know, three to four times more than what you would expend on a planned basis […]**

a) Please explain why the needs as described above were not addressed in past years.

Further regarding the accelerated deterioration of Alectra Utilities' assets, Mr. Cananzi said:

> **In some cases, it's inadequate funding as a result of, you know, the capital envelope that has been approved by the OEB. In other respects, it's also a matter of utilities trying to pace the investment for the benefit of customers and, in some cases, not getting that pacing quite right, so adjustments need to be made.**

b) During the MAADs application, were the applicants (Alectra Utilities) aware of the issues with adequate funding and incorrect pacing as described above?

i. If yes to b), what steps did the applicants (Alectra Utilities) take to mitigate the risks arising from inadequate funding or incorrect pacing?

ii. If yes to b), why did the applicants (Alectra Utilities) select a 10 year deferral period?

iii. If no to b), why were the applicants (Alectra Utilities) not aware?

c) Please provide the annual total amount of forecasted capital expenditures for 2020 to 2024 based on the sum of forecasted capital for each predecessor utility at the time of the MAADs application.

i. Please explain any differences between the amount provided in part c), and the total amount of capital forecasted in the current DSP.

Response:

a) Please see Alectra Utilities' response to G-Staff-14.

b) Please see Alectra Utilities' response to G-Staff-14 and G-Staff-11.

c) Please see Table 1, below for the annual total amount of forecasted capital expenditures for 2020 – 2024 based on the sum of forecasted capital for each predecessor utility at the time of the MAADs application.

Table 1 – Comparison of Capital Expenditure Plans ($MM)

	2020	2021	2022	2023	2024	Total 2020 - 2024
MAADs Application	269.0	299.7	299.9	277.4	271.1	1,417.1
2020-2024 DSP	282.7	280.2	288.3	295.8	309.4	1,456.5
Variance	13.7	(19.5)	(11.6)	18.4	38.4	39.3

i) The variance of $39.3MM is related to the inclusion of Guelph within the Current DSP. The total expenditures for the Guelph operational area over the 5 years is $56.8MM. Without this, the total Current DSP would be lower than the MAADs application by $17.5MM. As identified in Exhibit 2, Tab 1, Schedule 2, p. 10. Alectra Utilities incorporated customer preferences into the DSP by adjusting the pace of investments and deferring certain projects. The overall impact of the adjustment based on customer preferences from the second round of customer engagement on the 2020-2024 Capital Investment Plan, as well as other adjustments, was a net reduction of $17.5MM.

G-Staff-13

Reference: EB-2016-0025, Decision and Order, December 8, 2016, Page 10

The Decision and Order issued on December 8, 2016[1] noted that the applicants (Alectra Utilities) chose a deferred rebasing period of ten years, which the applicants (Alectra Utilities) stated is consistent with the OEB's consolidation policies. The applicants (Alectra Utilities) argued that any deviation from the ten year rebasing deferral period "[…] could fundamentally alter the proposed transaction and the basis on which it has been accepted by the shareholders as providing adequate incentive for entering into the transaction." The Decision and Order further noted that the ICM would be available during the deferred rebasing period, which the applicants (Alectra Utilities) indicated that they intend to use.

Please detail specifically what has changed since the creation of Alectra Utilities that makes the ICM during the ten year rebasing deferral period no longer suitable for Alectra Utilities.

Response:

1 Please see Alectra Utilities' response to G-Staff 16 c) and G-Staff-18 a).

[1] Decision and Order, EB-2016-0025, issued December 8, 2016

G-Staff-14

Reference: KP1.1 – Alectra Utilities August 7, 2019 Presentation Slides, Pages 17-20

Alectra Utilities' identifies declining reliability due to deteriorating underground assets and adverse weather, and significant development and intensification as key focus areas of its DSP.

a) Please explain why none of these risks were identified as part of the due diligence done at the time of the MAADs application.

b) Please explain what steps, if any, the applicants of the MAADs application (now Alectra Utilities) took to mitigate these risks.

Response:

a) The basis for OEB Staff's assumption that the noted risks were not identified as part of the due diligence performed at the time of the MAADs application, as well as the relevance of any due diligence that may or may not have been performed at that time for the present application, are not apparent.

Alectra Utilities has identified the need to: renew its underground assets; enhance the resilience of its overhead system to adverse weather; and support significant development and intensification as urgent system priorities. As identified on Slide 14 of KP1.1, Alectra Utilities has identified two additional priority areas – linking legacy distribution systems and mitigating future expenses by enhancing current station investments. The 2020-2024 Distribution System Plan ("DSP") defines and articulates these needs, as well as Alectra Utilities' investment plans for addressing these needs, having due regard to feedback received on customer priorities and preferences. These focus areas are challenges that, to various extents, were identified in, and which have since evolved from, the DSPs and investment planning efforts of the predecessor utilities.

Those DSPs and investment planning efforts were the basis for identifying the expected capital expenditure needs for the consolidated utility (please see Alectra Utilities' response to Board Staff-11b) and (c)), which informed the financial plans that underpinned Alectra

Utilities' MAADs application (EB-2016-0025). In terms of the evolution of these priority needs since the MAADs application, key factors include the increased need for system access investments and the disapproval of significant portions of prior ICM funding needs.

The primary focus of the due diligence completed at the time of the MAADs application was based on identifying risks and liability that are outside of normal course of matters. Alectra Utilities (and predecessor utilities) considers the deterioration of assets a matter that affects all utilities. Utilities appropriately identify asset renewal needs through ongoing asset management processes and address these needs through capital investments outlined in Distribution System Plans. Asset management and asset lifecycle optimization, especially in the case of emerging asset renewal needs, are well understood and intrinsic to the operation of a distribution system. Alectra Utilities (and predecessor utilities) have identified and prepared plans to address the need to replace and rehabilitate underground assets at an increasing rate corresponding to the rapid expansion which occurred from 1960s to 1990s in the communities serviced by Alectra Utilities. These renewal plans were developed and included in Distribution System Plans previously submitted in past applications at the OEB.

At the time of the MAADs application, Alectra Utilities reasonably expected that system renewal funding necessary to address emerging and incremental needs would be available and supported through the Incremental Capital Module. In fact, the merger was seen as a benefit to the customers as a larger and more diverse utility is better positioned and resourced to address these emerging system renewal needs.

The fact that system renewal needs are increasing and have reached a critical juncture is not a surprise to Alectra Utilities and the electrical industry in North America. Vanry & Associates (Vanry), an independent third party retained to review the DSP observed that *"Alectra, like many utilities in North America, is battling a chronic failure of Underground Residential Distribution ("URD") cable, referred to by Alectra in its DSP documentation as XLPE"*. Alectra Utilities provided Vanry's assurance review report as Appendix G in the DSP (Exhibit 4, Tab 1, Schedule 1, Appendix G). Alectra Utilities has identified that the time to address this issue in a holistic manner is now here. The population of assets in need of renewal is not static, communities and the distribution system that serve them did not expand at a constant rate. Alectra Utilities has experienced that setting rates based on historical spend levels does not appropriately pace and address emerging needs, especially in system renewal. The population of underground assets in need of renewal is growing and should the pace of renewal not match, the reliability of the asset will continue to deteriorate leading to failure and increasing number and duration of outages.

b) As a result of limited funding for needed system renewal and system service, Alectra Utilities prioritized available funding for the most urgent and failing assets. Since the rates of deterioration exceeded the rate of renewal, Alectra Utilities needed to manage the increasing severity of outages due to defective equipment and adverse weather through reactive renewal. The implications of addressing such outages through reactive renewal include increased outage durations and increasing numbers of emergency replacement projects.

Since 2012, each predecessor utility has established plans to gradually and prudently increase system renewal investments to address the emerging issue facings Alectra Utilities. Where possible, Alectra Utilities (and predecessor utilities) allocated available funding to system renewal but increasing need for system access investments, combined with the inability for Alectra Utilities (and predecessor utilities) to attain ICM funding for typical and anticipated capital work have constrained Alectra Utilities to implement the required solutions as planned.

For the DSP planning period 2020-2024, Alectra Utilities has established plans for an increased rate of renewal for those assets that enable the company to meet its system needs and customer priorities. In particular, Alectra Utilities has identified renewing underground assets, enhancing the resilience of its overhead system to adverse weather, supporting significant development and intensification, linking legacy distribution systems and enhancing current station investments as its top priorities. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 1 to Page 58 for an outline of the Alectra Utilities' plans to mitigate the risk of declining reliability due to deteriorating underground assets. See Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 15 to Page 22 for a description of Alectra

Utilities' plans to mitigate the risk of declining reliability, due to adverse weather through system renewal investments of overhead systems. For a description of Alectra Utilities' plans to support development and intensification, please see Exhibit 4, Tab 1, Schedule 1, Appendix A12, Pages 19 to 28 as well as Appendix A13, Pages 14 to 46. Please see Exhibit 4, Tab 1, Schedule 1, Appendix A11 Pages 3 to 5 for an explanation on the use of automation to improve system utilization to deferring large capital investments. For Alectra Utilities' plans to mitigate future expenses by enhancing current station investments, please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A14, Page 4 to Page 16 and Appendix A15, Page 5 and Page 6.

G-Staff-15

Reference: EB-2016-0025, Application, Exhibit B, Tab 6, Schedule 1, Page 1-2 of 4

The MAADs application stated that "The total anticipated savings net of transaction costs over a ten year rebasing deferral period […] total approximately $312 [million] in operating costs and approximately $114 [million] in avoided capital costs, which represent $426 [million] in total cash savings." The following table was provided to show the annual breakdown of net synergies:

Figure 25 – Total Net Synergies

($MMs)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Gross Synergies											
Operating	7.2	20.1	31.7	40.6	42.5	42.5	42.5	42.5	42.5	42.5	354.6
Capital	23.0	22.6	28.8	23.2	30.0	8.0	8.0	8.0	8.0	8.0	167.6
Total Synergies	30.2	42.7	60.5	63.8	72.5	50.5	50.5	50.5	50.5	50.5	522.2
Transition Costs											
Charged to Operating	20.9	11.1	8.2	2.3	0.5	-	-	-	-	-	43.0
Charged to Capital	33.7	15.2	4.4	-	-	-	-	-	-	-	53.3
Total Transition Costs	54.6	26.3	12.6	2.3	0.5	-	-	-	-	-	96.3
Net Synergies											
Operating	(13.7)	9.0	23.5	38.3	42.0	42.5	42.5	42.5	42.5	42.5	311.6
Capital	(10.7)	7.4	24.4	23.2	30.0	8.0	8.0	8.0	8.0	8.0	114.3
Total Net Synergies	(24.4)	16.4	47.9	61.5	72.0	50.5	50.5	50.5	50.5	50.5	425.9

a) Please provide the actual amount of synergies achieved to date by Alectra Utilities.

b) Please explain why Alectra Utilities has not proposed applying the net synergies amounts in excess of transaction costs towards its capital funding gap.

Response:

a) The actual amount of synergies achieved to date and a forecast for the remainder of the rebasing deferral period is provided in Table 1, below. Actual net synergies have been included for 2017, 2018, and year to date June 2019. Forecasted net synergies have been provided for July to December 2019, and for the 2020 to 2026 period.

Table 1 – Total Net Synergies Actual and Forecast

($MMs)	2015-Jan 2017	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Total
Gross Synergies												
Operating	0.0	29.2	36.0	35.8	42.8	43.7	43.2	44.4	44.8	44.8	44.8	409.5
Capital	0.0	21.8	42.2	36.9	15.3	23.0	13.2	7.5	7.5	7.5	7.5	182.6
Total Synergies	**0.0**	**51.0**	**78.3**	**72.7**	**58.1**	**66.7**	**56.4**	**51.9**	**52.3**	**52.3**	**52.3**	**592.0**
Transition Costs												
Charged to Operating	0.0	21.8	3.6	4.3	2.3	0.2	0.3	0.0	0.0	0.0	0.0	32.5
Charged to Capital	0.0	25.1	43.0	36.5	6.6	3.6	0.0	0.0	0.0	0.0	0.0	114.8
Total Transition Costs	**0.0**	**46.9**	**46.5**	**40.8**	**8.9**	**3.8**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**147.2**
Net Synergies												
Operating	0.0	7.3	32.5	31.5	40.5	43.5	42.9	44.4	44.8	44.8	44.8	377.0
Capital	0.0	(3.3)	(0.7)	0.3	8.8	19.4	13.2	7.5	7.5	7.5	7.5	67.8
Total Net Synergies	**0.0**	**4.0**	**31.7**	**31.9**	**49.2**	**62.9**	**56.1**	**51.9**	**52.3**	**52.3**	**52.3**	**444.8**
Transaction Costs	**24.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**24.8**
Synergies, Net of Transaction Costs	**(24.8)**	**4.0**	**31.7**	**31.9**	**49.2**	**62.9**	**56.1**	**51.9**	**52.3**	**52.3**	**52.3**	**420.0**

b) On March 26, 2015, the OEB issued the *Report of the Board - Rate-making Associated with Distributor Consolidation* (the "MAADs Policy"). In the MAADs Policy, the OEB extended the rebasing deferral period from five years to a period up to ten years following the closing of a consolidation transaction. The purpose of the rebasing deferral period is to enable consolidated distributors to fully realize the anticipated efficiency gains from the transaction and retain the achieved savings for a period of time to help offset transaction and transition/integration costs, as well as to encourage distributors to consolidate.[1] Specifically, the OEB stated at p. 5, in regard to the policy of allowing a deferred rebasing period, that "*its purpose…is to allow the net savings of a consolidation to accrue to a distributor's shareholder(s) for an extended period. The OEB recognized that providing a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction is an important factor in a utility's consideration of the merits of a given consolidation initiative.*"

The OEB's MAADs Policy also noted, at p. 5, the suggestion from distributors that *"greater flexibility in terms of the rebasing time frame and the ability to retain any achieved savings for a longer deferral period will provide encouragement to those who may be interested in pursuing consolidation opportunities*."

The MAADs Policy also clarifies, at p. 7-10, that the availability of capital funding is not a function of synergy savings. Under the MAADs Policy, the deferral period and the retention of savings are independent of future capital expenditures funded by the ICM or any capital recovery mechanism like the M-Factor. With or without the ICM, the savings are retained by the utility over the deferral period. The M-Factor is designed to work within the basic paradigm of the ICM, with some deviations to deal with the programmatic nature of the investments contemplated in the DSP and the need for flexibility in order to execute and fund the capital need. On this basis, the MAADs Policy remains intact whereby the merged utility retains the benefit of the synergies for the deferral period and satisfies incremental capital needs through the ICM. This proceeding is about the determination as to whether the M-factor is appropriate and not about the reallocation of the synergies.

[1] MAADs Policy, p. 5-7.

Alectra Utilities also identifies that with respect to Table 1 above, the synergies are largely consistent with expectations provided in the evidence in its MAADs Application (EB-2016-0025) and as understood by the OEB in rendering its MAADs decision, establishing the balance of benefits/ incentives expected to be shared between customers and shareholders.

However, given the "financial pressures" identified in Alectra Utilities' response to SEC-29, despite an expectation of achieving synergies more or less as expected, cashflow and net income during the rebasing deferral period are significantly lower than expected in the merger business case for reasons arising from aspects such as: previous ICM decisions and provincial policy changes regarding Conservation and Demand Management. Consequently, a focus on the merger savings does not lend itself to the full economic picture of the utility; it results in a very narrow overall view.

G-Staff-16

Reference 1: OEB Handbook to Electricity Distributor and Transmitter Consolidations, January 19, 2016, Pages 14-15
Reference 2: OEB Chapter 3 Filing Requirements, Pages 30-31

The OEB's Handbook on MAADs policy dictates that, during the deferred rebasing period:

- **A distributor on Price Cap IR would continue on Price Cap IR.**
- **A distributor on Custom IR would transition to a Price Cap IR once its Custom IR plan expires.**
- **A distributor on Annual IR would continue on Annual IR.**

OEB staff notes that Annual IRs are not relevant to Alectra Utilities as it has no predecessor distributors on Annual IR and, further, that all of its predecessor distributors have now transitioned to Price Cap IR.

The Chapter 3 filing requirements on Price Cap IR applications states that:

> **The IRM application process is intended to be mechanistic in nature. For this reason, the OEB has determined that the IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious.**

The filing requirements further state that "…distributors seeking adjustments that are inconsistent with OEB policy should consider whether one of the other rate-setting options is more appropriate."

a) **Given that Alectra Utilities has filed an incentive rate-setting mechanism (IRM) application on a Price Cap IR plan, please discuss whether the M-factor is consistent with OEB policy. In particular, please explain how the M-factor is mechanistic and is not an "[issue that is] specific to one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious."**

b) **Please discuss whether Alectra Utilities has considered requesting early termination of its deferred rebasing period, as is allowed under MAADs policy, in order to apply for a Custom IR.**

c) **Please discuss if Alectra Utilities has considered proposing capital funding mechanisms other than the M-factor (e.g. use of an Advanced Capital Module (ACM), or multi-year ICM).**

i. **Please provide a list of projects over the DSP period 2020-2024 that Alectra Utilities considers eligible for ACM/ICM treatment.**

d) **What are Alectra Utilities' plans in the event that its M-factor proposal is denied?**

Response:

a) The M-factor is no less mechanistic than the Incremental Capital Module ("ICM"), which is available to all utilities on a Price Cap IR plan. As Alectra Utilities described at the Presentation Day (Tr.1, p. 38), and in its prefiled evidence (Exhibit 2, Tab 1, Schedule 3), the M-factor is calculated using a methodology that is based on and to a significant extent mirrors the ICM. The differences between the two methods relate to the nature of the work in Alectra Utilities' Distribution System Plan ("DSP").

Like the ICM, the M-factor is a method by which the OEB can fund prudent capital expenditures during an IRM period. It is no more complicated than any request for capital funding under ICM during an IRM period. The reference above excerpts a quote from the Filing Requirements. The reference does not include the list of issues that are not appropriate for IRM proceedings. That list includes examples such as loss factor changes and loss of customer load.[1] None of the examples given relate to a utility's prudent capital expenditures, which the OEB has explicitly determined may be addressed during an IRM period, and during a rebasing deferral period.

b) Alectra Utilities believes that early termination of the rebasing deferral period approved by the OEB in EB-2016-0025 ("MAADs Decision") would be inconsistent with that approval. Further, it would be inconsistent with the OEB's policies on distribution consolidations as set out in the *Handbook to Electricity Distributor and Transmitter Consolidations* ("MAADs Handbook").

The MAADs Handbook affirms the OEB's policy of "*providing consolidating distributors with the ability to finance capital investments during the deferral period <u>without being required to rebase earlier than planned</u>*" (MAADs Handbook, p. 17, emphasis added). While Alectra

[1] Incentive Rate Application Filing Requirements, July 12, 2018, Ch. 3, p. 31.

Utilities is proposing a modification to the funding mechanism used to accomplish that goal, the objective of the M-factor and the ICM are the same; to allow the post-merger utility to fund prudent capital investments during the rebasing deferral period, which in turn allows it to recover transaction and integration costs and achieve the operational efficiencies that will ultimately lower rates for customers.

Alectra Utilities' request is consistent with the MAADs Policy; it is simply a variation of the ICM (Exhibit 2, Tab 1, Schedule 3, p. 7).

c) Please see Alectra Utilities' response to SEC-11.

d) Alectra Utilities cannot speculate on potential investment options without the full context of the OEB's decision. As described in Exhibit 1, Tab 3, Schedule 1, pages 4-5, under-investing will result in a growing population of deteriorated assets, declining reliability, and a "snowplow" of capital costs for future customers. It will also lead to more expensive reactive capital investments when asset failures occur.

In the event that Alectra Utilities is denied the M-factor, it will also have to file annual ICM applications during the remainder of the rebasing deferral period.

G-Staff-17

Reference 1: Exhibit 2, Tab 1, Schedule 3, Page 5 of 21
Reference 2: OEB Handbook for Utility Rate Applications, October 13, 2016, Page 27

On page 5 of 21, in describing the impetus for the M-factor, Alectra Utilities states that it "… has capital expenditure needs materially in excess of the level that which is presently funded in existing rates." Additionally, Alectra Utilities notes that the Custom IR option is not available during its deferred rebasing period, but that its "…evolving capital needs are analogous to those distributors whose capital programs have been funded through custom IR frameworks, accepted by the OEB."

The OEB's Handbook for Utility Rate Applications notes that: "The ICM and ACM mechanisms for funding capital for electricity distributors… are not available for utilities setting rates under Custom IR."

a) If M-factor funding is approved, please confirm that Alectra Utilities will not be seeking ICMs during the remainder of this DSP term (2020-2024).

b) If Alectra Utilities does intend to seek ICMs during this DSP term (2020-2024), please explain why this is appropriate given the nature of the M-factor and the similarities with the Custom IR option as described by Alectra Utilities.

c) If yes to a), please explain Alectra Utilities' plans in the event of large unforeseen capital spending needs.

Response:

a) Alectra Utilities confirms that if M-factor funding is approved, Alectra Utilities will not be seeking ICMs during the remainder of this DSP term.

b) Please see response to part a).

c) In order to mitigate risk for customers, and to address uncertainties in its future investment needs, Alectra Utilities is requesting approval to establish the following two capital related variance accounts. First is a symmetric Capital Investment Variance Account ("CIVA") to track the difference between the capital funding provided through M-factor riders and the actual M-factor capital investments during the term of the Distribution System Plan ("DSP"). Customers will be refunded for overall under-investment; any prudent spending above the level funded through M-factor riders will be recovered by Alectra Utilities. The second variance account is the Externally Driven Capital Variance Account ("EDCVA"), which would capture the difference between the revenue requirement in rates associated with externally-driven capital expenditures related to regional transit projects and capital works required by road authorities. Details of both variance accounts are provided in Exhibit 2, Tab 1, Schedule 4.

G-Staff-18

Reference 1: EB-2018-0016, Decision and Order, January 31, 2019 Decision on Alectra Utilities' request for ICM funding.
Reference 2: Exhibit 2, Tab 1, Schedule 3, Page 2 of 21

In the OEB's decision on Alectra Utilities' request for ICM funding for the 2019 rate year, the OEB approved $26.27 million out of the $31.57 million originally proposed by Alectra Utilities.

In the current application, Alectra Utilities states that "The ICM does not provide the flexibility or the longer-term availability of funding needed to execute a DSP."

a) Given that the OEB approved 83% ($26.27 million of $31.57 million) of Alectra Utilities' total ICM request for the 2019 rate year, please explain why Alectra Utilities considers the ICM unable to provide sufficient funding for its capital needs.

b) Please explain why Alectra Utilities incremental capital needs increased by 74% from the $31.57 million requested in 2019 to the approximately $55 million in annual funding requested through the M-factor.

OEB staff notes that in Alectra Utilities' 2019 application EB-2018-0016, Alectra Utilities did not make any requests for capital funding related to underground asset renewal or rear lot conversion work.

c) Please describe how Alectra Utilities prioritized underground asset renewal and rear lot conversion work in the absence of ICM funding.

Response:

a) In order to understand why Alectra Utilities considers the ICM unable to provide sufficient funding for its capital needs, one must first consider the context in which the OEB approved 83% of Alectra Utilities' ICM request for the 2019 rate year. In the OEB's Decision and Order on Alectra Utilities' ICM request for the 2018 rate year (EB-2017-0024), the OEB awarded Alectra Utilities only 51.1% of the capital funding relief that it sought. That Decision and Order was issued on April 5, 2018 (and revised on April 6). As a result of that Decision and Order, which fundamentally changed the Alectra Utilities' understanding of how the OEB would determine the eligibility of investments for ICM funding, Alectra Utilities delayed filing its ICM request for the 2019 rate year to June 7, 2018.

In the ICM Decision for the 2018 rate year, the OEB significantly reduced the ICM recovery to fund important capital investments, not because of any issue with the investments themselves, but because the OEB determined that the ICM required application of an additional test for determining investment eligibility. The additional test had not been part of the OEB's ICM or MAADs policies. Rather, it was based on a prior decision of the OEB on an application by Toronto Hydro, where the OEB assessed each project individually for its significance against Toronto Hydro's total planned capital spending. The OEB applied its judgement to consider whether each capital project proposed for ICM funding was significant relative to Alectra Utilities' total capital budget, not relative to the capital budgets identified for each rate zone. The application of this additional test for ICM eligibility was new and unexpected.

Further, in denying ICM funding for projects in respect of the 2018 rate year the OEB found that Alectra Utilities' projects were not a significant capital cost in comparison to the overall capital budget of Alectra Utilities for 2018. The OEB stated that Alectra Utilities should be able to fund those projects through its normal capital budget during the IRM term[1]. Also, the OEB unexpectedly strayed from its prior finding in the MAADs Policy that "normal and expected" capital investments would be eligible for ICM funding, by finding instead that ICM funding is "not available for typical annual capital programs".[2]

As a result of that Decision in respect of the 2018 rate year, Alectra Utilities revised its 2019 ICM application before filing to reduce its ICM request downward, from $39.2MM to $31.6MM. It is on the basis of that reduced ICM request that Alectra Utilities was awarded 83% of its capital request, but this only represented 67.1% of the incremental capital it actually considered necessary for the 2019 rate year. Therefore, on a cumulative basis over 2018-2019, Alectra Utilities received approval for 62.6% of its required incremental capital.[3] The OEB's determination in the 2018 ICM Decision that ICM funding will not be available for typical annual capital programs (notwithstanding its previously stated policy that normal and

[1] P. 39

[2] P. 41

[3] Presentation Day, Slide 7.

expected capital investments would be eligible) was punitive and is the key reason why Alectra Utilities considers the ICM unable to provide sufficient funding for its capital needs. Further, the annual nature of the ICM does not provide the flexibility that Alectra Utilities requires to efficiently execute its DSP. As an electricity distribution company, the main assets that the company owns and operates are poles, conductors, transformers and stations. As such, the investments that it must make to maintain the safety and reliability of its system and respond to customer priorities are, by their nature, not distinct from other work that it must regularly perform in connection with its system. The 2020-24 DSP identifies and prioritizes the company's investment needs based on considerations including asset condition and customer needs and priorities. Many of those investments involve work that is similar in nature to that which Alectra Utilities performs regularly, as part of its annual capital programs. The exclusion from ICM eligibility for typical annual capital program – or "normal and expected" - investments significantly undermines Alectra Utilities' ability to execute its DSP.

b) and c)

As explained in response to part a) above, based on the OEB's Decision on Alectra Utilities' ICM request for the 2018 rate year, Alectra Utilities did not include capital investments plans related to underground cable and rear lot renewal in the 2019 ICM application. The net impact of not including these necessary capital investments was a reduction of $7.6MM in 2019.

In the absence of available ICM funding for underground renewal, rear lot conversion and specific system expansion investments, Alectra Utilities reduced the pace of underground cable and rear lot renewal from levels proposed in predecessor Distribution System Plans. For 2019, Alectra Utilities deferred two cable renewal projects and two rear lot replacement projects. Where possible, Alectra Utilities deferred System Service investments to accommodate more pressing system renewal investment needs. Alectra Utilities recognizes that deferral of system expansion required to support development, intensification and redevelopment of communities that it serves is a short term strategy that is not sustainable and carries of risk of much higher system expansion implementation costs once communities are build, road are paved and streetscapes completed. Deferral of both system renewal and system service projects has the compounding effect of increasing reactive renewal costs, introducing potential of higher expansion costs and negative impact on system reliability.

In its 2020 EDR Application, Alectra Utilities has filed its first consolidated Distribution System Plan ("DSP"). The DSP identifies the capital funding needs of the utility for the five-year period 2020-2024. Based on an evaluation of the capital funding supported through base rates, Alectra Utilities has identified a capital funding deficit of $55MM, annually, on average.

Alectra Utilities is open to mechanisms for capital funding that will address the funding gap identified in the DSP over the five-year planning period.

The capital investment plan for 2020 to 2024 is the outcome of its extensive business planning efforts, coordinated planning with third parties, multiple rounds of ongoing formal and informal customer engagement, and the implement of Alectra Utilities' robust asset management plan as explained in Exhibit 4, Tab 1, Schedule 1, Page 1 and Page 2.

G-Staff-19

Reference 1: EB-2017-0024, 2018 EDR Application, Attachment 33, July 7, 2017, Pages 26, 33
Reference 2: Exhibit 4, Appendix B, Pages 111-114, 121-123 of 490

OEB staff notes two ICM projects proposed during Alectra Utilities' 2018 rates application, and that were subsequently denied by the OEB, have material business cases submitted in the current application. The budgets proposed for each project are summarized below.

Project Name	Total Budget (ICM)	Total Budget (M-factor)	Variance
Rear Lot Supply Remediation – Royal Orchard (150047)	$4,833,622	$4,009,063	-$824,559
Cable Replacement M49 – Steeles Avenue and Fairway Heights Drive (150141)	$1,749,769	$2,925,454	$1,175,685

a) **Please explain why the Royal Orchard remediation project is now forecasted to cost $824,559 less than what was indicated previously during the 2018 rates application.**

b) **Has Alectra Utilities experienced any further outages in the Royal Orchard area between 2018 and now?**

OEB staff notes that the scope for the M49 cable replacement project is 3.76km in both the 2018 business case and the current business case.

c) **Given that the scope of this cable replacement project remains the same between 2018 and now, please explain why the budget has increased by $1,175,685 ($1,749,769 increased to $2,925,454).**

d) **Has Alectra Utilities experienced any further outages in this area between 2018 and now?**

Response:

a) Project 150047 – Rear Lot Supply Remediation – Royal Orchard addressed the North section of Royal Orchard. Alectra Utilities has reduced the scope of the project and determined that it will address a portion of that project scope under the Royal Orchard South project. Hence, the reduced scope of Project 150047 has resulted in lower project expenditure.

b) Alectra Utilities' customers experienced a total of 18 outages in the Royal Orchard area in 2018 and year-to-date July 2019. Table 1 provides the summary of outages experienced to date since 2018.

Table 1 – Outages in Royal Orchard Area in 2018 and Year-to-Date July 2019

Year	Number of Outages	Customer Interruptions (CI)	Total Interruption Minutes (CMI)	SAIFI (Interruption)	SAIDI (minutes)
2018	12	558	16,485	3.13	92.6
2019*	6	424	12,107	2.38	68.0

*Denotes Year-to-Date July 2019.

c) Project 150141 – Feeder M49 Cable Replacement at Steeles Avenue and Fairway Heights Drive addressed the need to replace the deteriorated and failing cable in the area. Although the overall length of cable in the business case remains the same, as a result of additional site information, the project implementation cost has been revised. Cost increases were due to the need to: obtain additional easements; alter and install the infrastructure at lower depth; and revise the location of transformers. The additional site information was not known at the time of the initial 2018 plan for this project.

d) Alectra Utilities' customers experienced another outage in March 2018, as a result defective equipment stemming from a failed cable segment in the area.

G-Staff-20

Reference 1: EB-2017-0024, 2018 EDR Application, Attachment 33, July 7, 2017, Pages 44-52
Reference 2: Exhibit 4, Appendix B, Pages 45-47 of 490

The business case for Project #100909 – "Rebuild 27.6 kV pole line for 4 Ccts on Warden Ave from Major Mack to Elgin Mills" states that:

> **This project is the third part of a multiple year project of rerouting two feeders 12M10/12M11 to Markham Future Urban Area. The first part is to add two ccts on Warden Ave from Hwy 7 to 16th Ave that has been completed in 2017. The second part is to extend the two ccts on Warden Ave f [sic] from 16th Ave to Major Mack Dr, and the fourth part is to extend 2 ccts on Warden Ave from Elgin Mills to 19th Ave. The total length is 8km from Hwy 7 to 19th Ave. The timing of the fourth part depends on the progress of the FUA development.**

The business case indicates the cost of the project to be $2,180,514.

OEB staff notes that, as part of Alectra Utilities' 2018 rates application, Alectra Utilities submitted the business case (Project #100229) for the first and second parts of this multi-year project because Alectra Utilities was requesting ICM funding for this project. The business case provides the following budget allocation:

Table 13 - Budget Allocation

2017	2018	Total Budget
$1.01MM	$1.30MM	$2.38MM

a) **Please confirm that, despite OEB denial of ICM funding for this project in the 2018 rates application, Alectra Utilities was able to fund and complete the first and second parts of this multi-year project.**

b) **Please explain why the project costs for the third part of the project, the portion included in the current DSP, is almost equal to the budget of the first and second parts combined. In other words, why is the third part almost double the cost of the individual first or second parts?**

c) **What is the progress of the FUA development and has Alectra Utilities experienced growth already in this area of its distribution system?**

Response:

a) Despite not receiving incremental funding, Alectra Utilities was required to proceed with the project of rerouting two feeder 12M10 and 12M11 for the first and second phase in order to meet the development timelines in Markham. The total length of the pole line from Hwy 7 to 19th Avenue is 8 km. Alectra Utilities had paced this project into annual phases considering available resources and funding constraints. Besides the reported developments in Markham's Future Urban Area, Alectra Utilities required to service other developments in the area which needed capacity. In order to meet the development timelines, despite the OEB denial of funding, Alectra Utilities revised the scope and constructed the first and second phase of this project.

b) The scope of the first phase of project to reroute feeders 12M10 and 12M11 was to add two 27.6kV circuits on Warden Avenue from Hwy 7 to 16th Avenue, the length of segment is approximately 2 km. Alectra Utilities revised the scope of the first phase of the project and constructed an additional two circuit pole line on the east side of Warden Avenue instead of rebuilding two circuit pole line on the west side of Warden Avenue into four circuits as initially planned.

The scope of second phase of project to reroute feeders 12M10 and 12M11 was to add two 27.6kV circuits on Warden Avenue from 16th Avenue to Major Mackenzie Drive, the length of segment is approximately 2 km. Alectra Utilities rebuilt the existing two circuit pole line into four circuits. Alectra Utilities took advantage of installing the framing for the second phase during a previous road authority project thereby reducing the scope of work for the second phase of the project.

The third phase of the project to reroute feeders 12M10 and 12M11 is to extend the four circuits on Warden Ave from Major Mackenzie Drive to Elgin Mills Rd, this segment length is also approximately 2 km but is the most challenging to complete. The existing overhead pole line is not designed to convey four circuits and will require to be fully rebuilt. Therefore, the cost of the third phase is higher when compared to the cost of phase one and two of this project.

c) The City of Markham is currently undertaking a comprehensive planning process to guide development of the Future Urban Area lands in north Markham. The Future Urban Area will accommodate neighborhood and employment growth in north Markham. A Conceptual Master Plan is being developed based on several background studies to guide development for the entire area. The Conceptual Master Plan will provide direction for more detailed planning, which will be carried out through Secondary Plans and plans of subdivision.[1]

Alectra Utilities has been in discussions and is informed by developers for the Berczy Glen block bounded by Elgin Mills-Warden Ave-Major Mackenzie Dr and Hydro One Right-of-Way. The construction is expected to start in 2020 and with occupancy scheduled for 2021. The total development is planned for 5,200 low density residential units and four schools.

[1] https://www.markham.ca/wps/portal/home/about/city-hall/city-projects-initiatives/current/north-markham-future-urban-area

G-Staff-21

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Pages 52-53 of 58

On pages 52-53 of 58, Alectra Utilities discusses the replacement strategy for underground civil structures and states that "There is " no historical expenditure for this investment because failures of these assets were previously addressed reactively."

Alectra Utilities further states that:

> **Depending on the vintage of the structure there will be a variety of structural/condition factors… These legacy installations do not meet current design requirements in comparison to modern pre-cast structures which use rebar and have lids rated for vehicular traffic.**

a) Please explain why Alectra Utilities chose to switch from a reactive to proactive replacement strategy.

b) Has Alectra Utilities experienced any failures of its underground civil structures? Please provide all instances of failures.

c) As described above, please explain if any of Alectra Utilities' "legacy installations" fail to meet any technical or safety standards i.e. CSA standards.

d) How does Alectra Utilities identify degraded underground civil structures that are suitable for intervention? Does Alectra Utilities perform routine inspections?

e) In light of the risks that are associated with the failure of these assets as described by Alectra Utilities, please explain why Alectra Utilities did not begin proactive replacement of these assets sooner.

f) Once the DSP period concludes, under Alectra Utilities' proposed levels of capital funding, will Alectra Utilities have fully addressed all degraded assets? If not, what percentage of degraded assets will Alectra Utilities have addressed by the end of the DSP period, and what is Alectra Utilities' plan to deal with the remainder of degraded assets?

Response:

a) Alectra Utilities did not change its approach on civil chambers from reactive to proactive. The "*no historical expenditure for this investment because failures of these assets were previously addressed reactively*" refers to practices and priorities of the predecessor utilities.

In the harmonized asset management practices that Alectra Utilities has developed, it has determined that the renewal strategy would be a planned approach as provided in Exhibit 4, Tab 1, Schedule 1, Page 234.

b) The legacy utility standards for chambers installed in the right-of-way, while appropriate at the time of construction, were not rated for vehicular weight; such is now required based on updated road authority requirements. Alectra Utilities determined that its civil chambers should be renewed to maintain safety standards in public areas.

c) Alectra Utilities is aware that some of its civil chambers do not meet load bearing requirements and require to be renewed.

d) As provided in Exhibit 4, Tab 1, Schedule 1, Page 290, Line 11, civil structures and chambers are inspected on a three year cycle. Through these inspections, Alectra Utilities determines if there are any issues with the chambers and the best case for remediation. Alectra Utilities is guided by and obtains necessary support from civil engineering consultants.

e) Alectra Utilities predecessor, Horizon Utilities, conducted a targeted civil assessment in 2011. PowerStream had started to identify person-holes that required renewal and had commenced the process of determining solutions. The harmonization of asset management practices established the planned strategy of proactive renewal that is uniform across all the operational areas.

f) Alectra Utilities must resolve all of the person-hole issues that it is currently aware of by the end of the DSP planning period. Consistent with best utility practice, Alectra Utilities will continue to inspect all underground structures over a three year inspection cycle. Should Alectra Utilities become aware of new issues from these inspection or otherwise, or as determined by inspection that due to changes the priorities of renewal must be revised, Alectra Utilities will need to revise its plan as outlined in the DSP.

G-Staff-22

Reference: Exhibit 04, Tab 1, Schedule 1, Appendix A02, Page 4 of 33

Loop feed configurations can provide backup supply to customers when equipment fails and can continue to supply customers even while the failed equipment is isolated and repaired or replaced. Alectra Utilities indicates it installs "looped supply" configurations for all new residential subdivisions with fault indicators installed at each transformer, underground switch and riser pole.

a) Does Alectra Utilities currently employ loop feed configurations in the parts of its distribution system currently fed by underground cables?

  i. If yes to a), please explain whether Alectra Utilities has been able to leverage its loop feed configurations to reduce the amount of prolonged and persistent outages.

  ii. **If no to a), please discuss if Alectra Utilities has considered the possibility of converting its underground system to loop feed configurations and changing its replacement strategy for cables to reactive. Particularly, please discuss the possibility of maintaining a reactive replacement strategy while relying on loop feed to reduce outage duration by maintaining supply to customers when equipment fails.**

Response:

a) Alectra Utilities does employ loop feed configurations in the parts of its distribution system currently fed by underground cables

  i) Alectra Utilities has leveraged its loop configurations to reduce the amount of prolonged and persistent outages. This strategy does not work when cables on both segments of the loop are deteriorated and failing. There have been situations such as in the York Hills and Hilda area (and several others) where multiple cable faults has reduced the loop feed advantage. If a second fault occurs prior to repairs of the first cable, then the loop feed could be lost leading to prolonged outages and expensive emergency replacements.

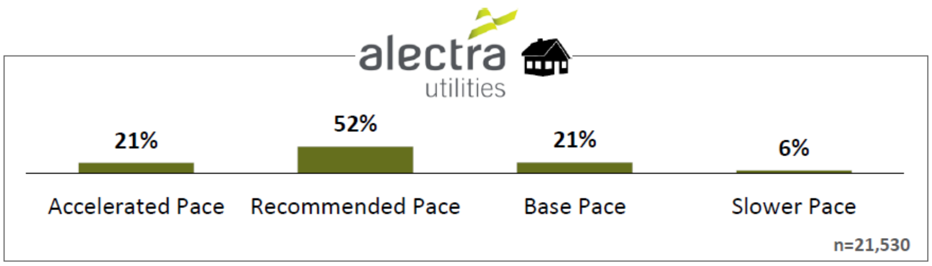
  ii) Not applicable.

G-Staff-23

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 16 of 58
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 41

Alectra Utilities chose the accelerated pace for its cable replacement program citing strong customer preference for underground system renewal: "…73% of residential customers that participated in the second phase of customer engagement indicated support for the recommended or accelerated pace of the renewal."

The following chart and table is a percentage breakdown of customer preferences on the pacing of cable replacement found on page 41 of Appendix C:



Rate Zone Breakdown	ERZ	HRZ	PRZ
Accelerated Pace	21%	26%	17%
Recommended Pace	53%	52%	51%
Base Pace	21%	17%	24%
Slower Pace	6%	6%	7%

Although the aggregate sum of customers preferring the accelerated or recommended pace is 73%, the number of customers preferring the accelerated pace is only 21%. The majority of customers prefer the recommended pace. OEB staff notes that, by Alectra Utilities' methodology, the aggregate sum of recommended pace or base pace is also 73%.

a) **Given that the majority of customers chose the recommended pace, please explain why Alectra Utilities elected to proceed with the accelerated pace.**

b) **Given that 73% of customers also prefer the recommended or base pace, did Alectra Utilities consider proceeding with the base pace? If not, why not, and how is this different from the scenario where Alectra Utilities considered the accelerated pace?**

c) **Please explain why Brampton rate zone customers were not consulted when there are material projects listed in Appendix A10 that pertain to the Brampton Rate Zone (e.g. Project #151286).**

Response:

a) The pacing of system investments was addressed by Mr. Cananzi in his remarks during Alectra Utilities' Presentation Day on August 7, 2019. During his presentation, he stated:

> *"In some cases, it's inadequate funding as a result of, you know, the capital envelope that has been approved by the OEB. In other respects, it's also a matter of utilities trying to pace the investment for the benefit of customers and, in some cases, not getting that pacing quite right, so adjustments need to be made."*

The pacing of system renewal at Alectra Utilities (and predecessors) is falling being the rate of asset deterioration, especially in the underground system, where increases in cable failures are driving a negative trend in reliability. Alectra Utilities must accelerate the cable replacement rate, in order to match the pace of deterioration with the pace of renewal. As provided in Exhibit 4, Tab 1, Schedule 1, page 14, Alectra Utilities has a significant amount of underground cable in Area 2. The amount is much more than in Area 1, that will have to be renewed or rehabilitated through cable injection. Alectra Utilities requires additional funding to increase the rate of renewal to match the current rate of deterioration and address the now very poor condition cable, before the next wave of underground cable reaches end of life. In Appendix G, page 5, Vanry & Associates indicated their support for the position for further increase in expenditure. Specifically Vanry stipulates, "*We are concerned that Alectra may not have allocated sufficient funding required to keep up with the cable failure rates. This leaves Alectra and its customers exposed to risk of entering a vicious cycle…"*

b) No, Alectra Utilities did not consider proceeding with the base pace. Provided in Exhibit 4, Tab 1, and Schedule 1, Appendix 10, page 12 Figure A10-5 and A10-6, both the number and duration impact of cable failures is increasing. It would not be prudent, to further pace out the investments and allow reliability to deteriorate further. This would also put a strain on planned investments as a larger amount of reactive spend would be required.

c) Alectra Utilities' Brampton RZ customers were consulted as part of the Customer Engagement process. The proposed M-factor cable replacement projects were identified in the Horizon Utilities, PowerStream and Enersource RZs only. Therefore, the investments options and bill impacts presented in the Customer Engagement Workbook were customized for customers in the above-mentioned RZs.

G-Staff-24

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Pages 5-6 of 58
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 59

Alectra Utilities describes cable rejuvenation as a "lower-cost solution that can extend the life of cross-linked polyethylene (XLPE) cables by injecting a fluid into the core of a buried XLPE cable." In particular, Alectra Utilities states:

> **Alectra Utilities has been accelerating the underground cable replacement where possible, has introduced cable injection to slow down the rate of deterioration of cables and spent considerable time and effort to understand, document and track cable condition. Despite all of this Alectra Utilities' efforts are being overwhelmed. Reliability is worsening. That is a fact.**

The Asset Condition Assessment (ACA) states that the "Health index of primary XLPE cables is calculated using age."

a) Which specific activities has Alectra Utilities undertaken "to understand, document, and track cable condition"? Please provide the results.

b) Has Alectra Utilities concluded that the only variable input required to determine asset condition for XLPE cable is age?

i. If yes, does that mean the process of understanding, documenting, and tracking cable condition is a desktop exercise?

c) On average, how much cheaper is rejuvenation over replacement per km of cable?

d) To date, how many km of cable has undergone rejuvenation in Alectra Utilities' service territory?

e) How many years does cable rejuvenation add to a cable's life?

f) Given that the health index of XLPE cables is based off age, please explain how the extended life of rejuvenated cables is reflected in the health index.

g) Will renewed cable assets require less maintenance than aged and deteriorating assets?

i. If yes to g), what is the amount of reduction in system operating and maintenance (O&M) spending and is this reflected in Alectra Utilities O&M forecasts?

ii. If no to g), why not?

h) What is the basis for the claim that reliability is worsening? Please provide the evidence for this claim.

i. On what basis was the timeframe for the above data selected?

i) Is the reliability and performance of XLPE cable deviating from the expected reliability and performance that can be inferred from the asset condition assessments undertaken on these assets?

j) Please provide statistics of cable failures for the past 10 years.

Response:

a) Alectra Utilities tracks cable failures as part of its reliability statistics. It investigates cable failure events to understand causes. Alectra Utilities performs cable testing on selected segments and tracks age, cable type (XLPE, Tree Retardant (TR) XLPE, PILC, EPR), construction type (in-duct, direct buried) for each cable segment. Alectra Utilities also tracks cable segments that have been injected and the date of injection (rejuvenation).

b) Age is not the only input in determining the cable condition using the Health Index. As identified in Alectra Utilities' response to part a), Alectra Utilities tracks cable failures as part of its reliability statistics and investigates cable failure events to understand causes. Alectra Utilities performs cable testing on selected segments and tracks age, cable type (XLPE, Tree Retardant ("TR") XLPE, PILC, EPR), construction type (in-duct, direct buried) for each cable segment. Alectra Utilities also tracks cable segments that have been injected and the date of injection (rejuvenation). All of these factors are considered in the Health Index calculation.

c) For a comparable area that requires renewal, cable injection costs are approximately $65,000/km, where cable replacement costs are approximately $350,000/km. Cable injection is 5 times cheaper than cable replacement.

d) As of the end of 2018, 489 km had undergone cable rejuvenation in Alectra Utilities' service territories.

e) Alectra Utilities expects that cable rejuvenation will extend the cable's life for 20 years from the date of injection.

f) As stated in Alectra Utilities' response to part e), cable injection extends the life of the cable by 20 years. The age of the injected (rejuvenated) cable is changed to reflect 20 years of age within the health index process.

g) Alectra Utilities does not expect material O&M savings from cable renewal. Once the injection of all eligible cables is completed, cable testing costs will no longer be required.

h) Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A10, page 12, Figure A10-5 and Figure A10-6. Over the last 5 years (2014-2018), Alectra Utilities has experienced an increasing trend in both the frequency and duration of cable failures. A trend line exists on both figures, and both trend lines over the 5 years is highlighting an increase.

i) The timeframe selected is consistent with the historical requirements of the DSP.

i) Alectra Utilities' reliability performance of XLPE cables is consistent with inferences from the asset condition assessment. Per Exhibit 4, Tab 1, Schedule 1, Page 104, UG Primary XLPE Cables has the highest percentage of Very Poor assets, similarly in Exhibit 4, Tab 1, Schedule 1, Page 121, XLPE cables and accessories account for the greatest impact on customer hours of interruption.

j) Alectra Utilities is unable to provide the last 10 years of cable failures. However, an additional two years (i.e., a total of seven years of cable failure data) is provided in Table G-Staff-24 i).

Table 1 - Quantity of Cable Failures 2012-2018

Cable Type	2012	2013	2014	2015	2016	2017	2018
Cable & Accessories PILC	7	9	16	18	12	11	14
Cable & Accessories XLPE	490	509	410	559	541	477	534
Total	497	518	426	577	553	488	548

G-Staff-25

Reference: Exhibit 4, Tab 1, Schedule 1, Page 3 of 438

Regarding deterioration of underground cables, Alectra Utilities states:

> **A recent specific example underlying these trends is the York Hill/Hilda neighbourhood in Vaughan, which was scheduled for underground cable replacement in 2019 however from June 22 to July 13, 2018, approximately 250 customers starting experiencing an outage approximately once every three days during this period. Cables which Alectra Utilities repaired would fail again within a short duration. Alectra Utilities was ultimately forced to replace the cable in the area on an emergency basis at a higher cost and with greater disruption, causing further impacts to the affected customers.**

a) What were the initial causes of the failures, and were the subsequent causes of failures different from the initial causes?

b) Were the failures in close proximity to one another? Please provide details.

c) Were the cable segments that experienced these failures all of the same age?

d) Did Alectra Utilities do any additional analysis on the retired cable once it had been removed from service? If yes, what were the findings?

e) Did the performance of the cable correspond with the expected performance that Alectra Utilities models in its asset management program?

f) Please quantify the difference in cost of replacing the cable in 2018 rather than the estimated cost of the planned replacement in 2019.

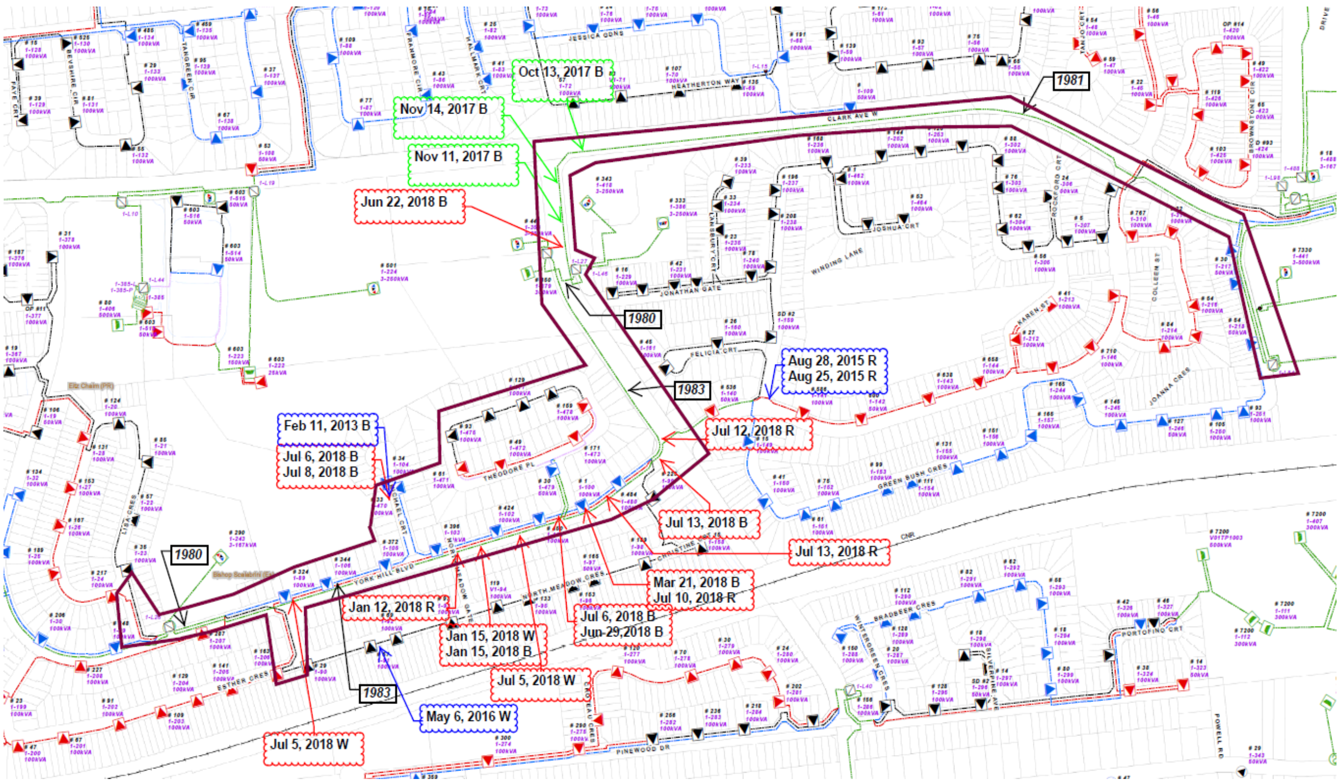
g) Please compare the actual outage duration in 2018 versus the estimated outage duration had the replacement taken place as planned in 2019.

Response:

a) The causes of failure at the York Hill/ Hilda neighbourhood included both cables and splices failures as the initial and subsequent causes.

b) Alectra Utilities has provided Figure 1 below to show where and when the cable and accessory failures occurred.

Figure 1 - Cable and Accessory Failures in the York Hill/Hilda Area



c) The cables were not all the same age, but of similar vintage, installed between 1980 and 1983.

d) Alectra Utilities did not perform additional analysis of the retired cables. The failed cable was consistent with segments previously analyzed by Alectra Utilities (and its predecessors).

e) The cable performance was between the Typical Useful Life ("TUL") and End-of-Useful Life ("EUL") of non-tree retardant direct buried cables.

f) In addition to the $3.8MM in capital investment required for emergency replacement of the cable, the work completed in at York Hill/Hilda in 2018 also required an additional $0.208MM in operating and maintenance cost related to excavation and repair of the deteriorated cable, prior to Alectra Utilities determining that the cable was no longer dependable and required replacement. A significant amount of effort was also required by the customer service and corporate communications group to address the increasing frustration and anger from the customers. In addition, Alectra Utilities had to reallocate capital from other projects in order to accommodate the emergency replacement, causing further disruption and rescheduling of work.

g) The 2018 CMI before Alectra Utilities intervened and replaced the cable was 427,537 minutes of interruption. Should Alectra Utilities not intervened and replaced the cable in the area, Alectra Utilities projects that the outages would have continued and increased in duration for the remainder of 2018. The forecasted reliability improvement in the business case for 2019 was 560,845 CMI, hence Alectra Utilities estimate of reliability improvement of the cable investment project as planned at York Hills and Hilda was very reasonable.

G-Staff-26

Reference 1: Exhibit 4, Tab 1, Schedule 1, Page 3 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Page 5 of 438

In reference 1, regarding underground cable failures, Alectra Utilities states:

> **Figure 5.0 - 2 and Figure 5.0 - 3 illustrate underground systems in neighbourhoods at Rathburn/ Creditview, as well as Bough Beeches/ Claypine which have experienced a high number of recent underground cable failures, which require urgent replacement.**

In reference 2, Alectra Utilities states:

> **While in the York Hill/Hilda example Alectra Utilities was fortunate to be able to work within its capital investment portfolio to substitute and defer other capital work to accommodate this emergency cable replacement, this is not a sustainable solution for Alectra Utilities going forward. Alectra Utilities is facing a large capital asset bubble specifically with underground cables that are now coming due. These cables were installed during a period in time when Alectra Utilities' municipalities experienced significant growth (1960s to 1980s). The required replacement of these underground cables, now 40 to 60 years old, is far and above anything that would have been contemplated in Alectra Utilities' base rates. This issue is further exasperated by an even larger looming demand coming from installed cables between 1980 to 1990 that are starting to reach end of life and it is absolutely imperative that Alectra Utilities secure funding and get under control this renewal investment and address the large inventory of end of life cable that must be replaced now before Alectra Utilities needs to deal with the even larger population of cables installed 30 to 40 years comes due.**

a) **What does Alectra Utilities consider a "high number" of recent underground cable failures? Please quantify the number of failures actually experienced and compare that to the number of failures predicted by Alectra Utilities' asset management plan or ACA process.**

b) **What replacement rate did Alectra Utilities "contemplated in Alectra Utilities' base rates" when the predecessor utilities were merged?**

c) **Was Alectra Utilities aware of the "underground cables that are now coming due" when the predecessor utilities were merged?**

d) **Please confirm that Alectra Utilities uses age to determine asset condition for underground cable, which implies that planned replacement of underground cable can be accurately forecast many years in advance of replacement.**

i. If yes to d), please explain how it is that "[T]he required replacement of these underground cables … is far and above anything that would have been contemplated in Alectra Utilities' base rates".

Response:

a) Alectra Utilities considers anything above the five-year average reliability to be a high number of failures. Further, Alectra Utilities considers the number of failures to correspond to the number of events a customer experiences. As an example, the customers in the Rathburn area (Exhibit 4, Tab 1, Schedule 1, page 3) experienced an average of five failures per year from 2015 to year-to-date 2019. In 2018, the customers in this area experienced eight cable failures. When compared to Alectra Utilities' 5-year average for SAIFI, the customers in the area experienced a number of outages that was 600% higher than average. Alectra Utilities considers this a high number of outages and the resulting poor reliability, unacceptable.

b) Base capital funding for predecessor utilities was set in different years corresponding to legacy plans at that time. Enersource's base capital funding was approved in its 2013 EDR Application, whereas Brampton Hydro's capital funding was approved by the OEB in 2015. Horizon Utilities' capital funding plan was approved for the five year period ending in 2019. The replacement rate of underground assets at the time of the merger was based on established predecessor Distribution System Plans. Please see Alectra Utilities' response to G-Staff-14.

For Brampton Hydro, the predecessor utilities' EDR Application (EB-2014-0083) included a 2015-2019 Distribution System Plan. On page 54 of Appendix E of the DSP, Brampton Hydro planned increasing Feeder and Distribution cable renewal investments, which reflected an increase in investment from $2MM in 2009 to $4.4MM in 2019. Additionally on Exhibit 2, Tab 6, in its DSP Brampton Hydro stated "…cable replacement completed to-date is lagging behind feeder cables' useful life." This supported the need for an increase in system renewal investment in underground cable replacement.

Horizon Utilities' Custom IR Application (EB-2014-0002) included a 2015-2019 Distribution System Plan which, on page 22 (Exhibit 2, Tab 6, Schedule 1, Page 22), included Table 2-

47 that illustrates an increase in cable renewal investment from $2.5MM in 2015 to $10MM by 2019. This was supported by Exhibit 2, Tab 6, Schedule 1, Page 22, Lines 16-23, where 29% of the cable had unacceptable health and need to be addressed.

PowerStream's response to interrogatory BOMA-11 (in EB-2015-0003), provided a five year reliability work plan in (Section III, Tab 4, Schedule 1, BOM-11, Appendix B, Page 38). The work plan indicated plans to increase underground cable renewal from $15.7MM in 2015 to $18.3MM in 2020. This was supported by the results of the ACA as described in EB-2015-0003, Exhibit G, Tab 2, Section 5.4.5 Justifying Capital Expenditures, Page 9 and 10.

For the ERZ, Alectra Utilities' application (EB-2017-0022) indicated an increase in underground asset renewal from $8.4MM in 2012 to $18.5MM in 2022. This was supported by evidence provided in Exhibit 2, Tab 4, Schedule 11, Page 19 Lines 18-19, and Page 20, Lines 1-8, and Exhibit 2, Tab 4, Schedule 11, Page 12, Figure 2, indicating the increasing number of cable failures.

c) Please see response to G-Staff-14.

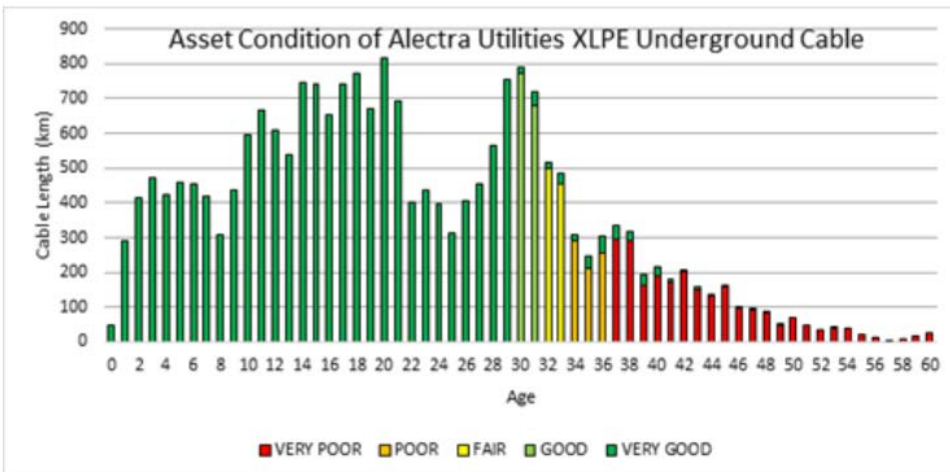
d) Yes, Alectra Utilities applies age, in addition to other asset attributes, to determine cable condition. In addition to age, Alectra Utilities includes cable type (XLPE and its subtypes, PILC, EPR), and construction type (in-duct, direct buried) for each cable segment.
Moreover, Alectra Utilities tracks cable segments that have been injected and date of injection. The above listed inputs are considered, in order to determine cable condition. Planned replacement of underground cable can be forecast in advance, all of which requires appropriate funding. Please see Alectra Utilities' response to G-Staff-14 for an explanation of challenges that have constrained Alectra Utilities' ability to attain appropriate funding necessary to execute required underground system renewal plans.

G-Staff-27

Reference 1: Exhibit 4, Tab 1, Schedule 1, Page 6 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix D, Pages 957 and 992
Reference 3: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 4 of 58

The following figure is taken from reference 1:

Figure 5.0 - 4: Asset Condition of Alectra Utilities XLPE Underground Cable



Alectra Utilities states in reference 2 that the Health Index of primary XLPE cables is calculated using age and provides the following figure showing the XLPE cables age distribution:

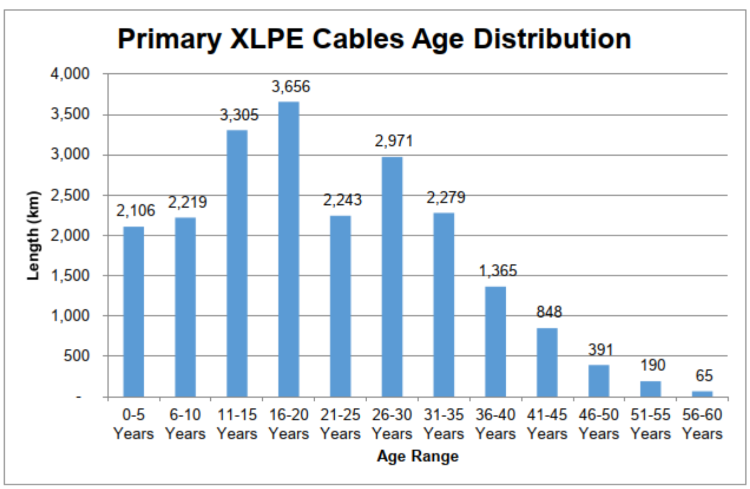


Figure 24 Primary XLPE Cables Age Distribution

In reference 3, Alectra Utilities states:

Alectra Utilities' service area currently contains an extensive population of underground cables totalling approximately 22 million linear meters of cable, which are continuing to degrade. Almost all of these cables are XLPE (either the first generation XLPE cable, or the subsequent tree-resistance XLPE cable).

a) Please confirm that XLPE cables were first used in the late 1960's[1] (i.e., the assets over 50 years of age do not represent XLPE cables).

i. If yes, please explain why Figure 5.0 - 4 contains XLPE cabled labeled as over 50 years of age and provide a revised figure with correct labels.

b) Has Alectra Utilities analyzed the actual lifespan of its underground cable assets vs. expected lifespan?

i. If yes, please provide the results of the analysis.

c) Are underground cables ever treated as run to fail, or are they always replaced at a given age?

d) Does Alectra Utilities replace failed cable segments without replacing adjacent segments? I.e. if one phase of a circuit needs to be replaced on an emergency basis, are all three phases replaced at that time?

Response:

a) Alectra Utilities confirms that cross-linked polyethylene cable, also known as XLPE, was first introduced in late 1960's. Prior to XLPE, Alectra Utilities' predecessor utilities installed Polyethylene (PE) cables which were an early iteration of plastic-insulated cables. Due to similar degradation and replacement requirements, Alectra Utilities considers PE cables the same as XLPE in terms of asset condition assessment and renewal strategy.

b) Alectra Utilities has conducted analysis to better understand the lifespan of its underground cables. Based on this analysis, Alectra Utilities has identified that cables failures of direct buried cables most frequently occur between 33-37 years of age. The study by Alectra Utilities' predecessor, Enersource, is provided as G-Staff-27_Attach 1_Cable Failure Report.

[1] "Long-Life XLPE Insulated Power Cable", N Hampton, 2007 (Retrieved from neetrac.gatech.edu/publications/jicable07_C_5_1_5.pdf)

c) Alectra Utilities does not treat underground cables as a run to fail nor are underground cables replaced at a given age. As outlined in the 2020-2024 DSP (Exhibit 4, Tab 1, Schedule 1, Page 272), Alectra Utilities utilizes multiple factors including condition-based assessment (Health Index), previous outage events and fault rate to identify, prioritize and renew deteriorated underground. Each renewal project includes a business case which is reviewed and optimized through the CopperLeaf C55 system.

d) Under an emergency repair scenario for a three phase circuit, Alectra Utilities only replaces the failed segments.

G-Staff-27

ATTACH 1 – Cable Failure Report

enersource

more than energy™

Cable Failure Report

May 2016

Summary:

This report is a review of an initiatives executed in January of 2014 and completed in March of 2016 to review cable failures on the Enersource distribution system. This report provides some historical context on the significant issue Enersource faces in regards to cable failures as well as the methodology undertaken to study this issue. The analysis focuses on the results from implementing two initiatives in regards to cable failure tracking and trending. Lastly, the recommendations focus on Enersource 'Go Forward' strategy in regards to: Spot Cable Replacements for single cables causing customers significant outages, a Rebuild Planning philosophy rooted in Enersource's overlay methodology and challenges around implementation of Cable Injection.

Background:

Since 2013, Enersource began seeing an increasing trend in customer minutes of interruption related to cable failures. The number of cable failures was also well above 100 failures per year from 2013 to 2015. In comparison to surrounding Utilities, Enersource was not only seeing more cable related failures but a significant contribution to SAIDI from cable failures.

Enersource was experiencing more underground cable failures than any other equipment on their distribution system; with over 100 cables failures year over year, see Table 1 for details.

Table 1: Cable Failures per year 2013-2015

Year	2013	2014	2015
Cable Failures Per Year	133	112	176

Customer minutes due to cable failures accounted for more than 40% of all equipment failures for 2013-2015 see Table 2 for details.

Table 2: Cable Failures in comparison to Defective Equipment

	2013	2014	2015
Defective Equipment	3,763,595	3,808,219	4,459,328
Cable Failure Minutes	1,720,513	1,610,094	2,932,127
Cable Failure as a % of Defective Equipment	46%	42%	66%

In 2013, Enersource's Vice President, Asset Management asked the Asset Planning & Analysis group to investigation this issue and determine if there is a specific project that can be executed to reduce this increase trend.

A project was initiated with Asset Planning & Analysis beginning to review the Geographical Information System (GIS) which also serves as the Asset Repository for information on cables. Unfortunately, installation and cable details were not listed in the GIS, and other than the installation information; no other details could be obtained.

The Asset Condition Assessment (ACA) was reviewed next; this provided some context on the types of cables and estimate install years. Enersource breaks out primary cables into two classes, 1 for Main Feeder Cables and Distribution Cables. Main feeder cables account for all cables larger than and including 250 kcmil, while all Distribution cables are smaller than this size. The ACA also provided context on installation details, all cables before 1989 were considered to be of XLPE construction and direct buried. All cables installed from 1989 to 1993 were considered to be TRXLPE but still direct buried. Lastly all cables newer then 1993 were considered to be TRXLPE installed in duct. A breakdown of the age of the Main Feeder and Distribution cables are provided in Figure 1 and Figure 2.

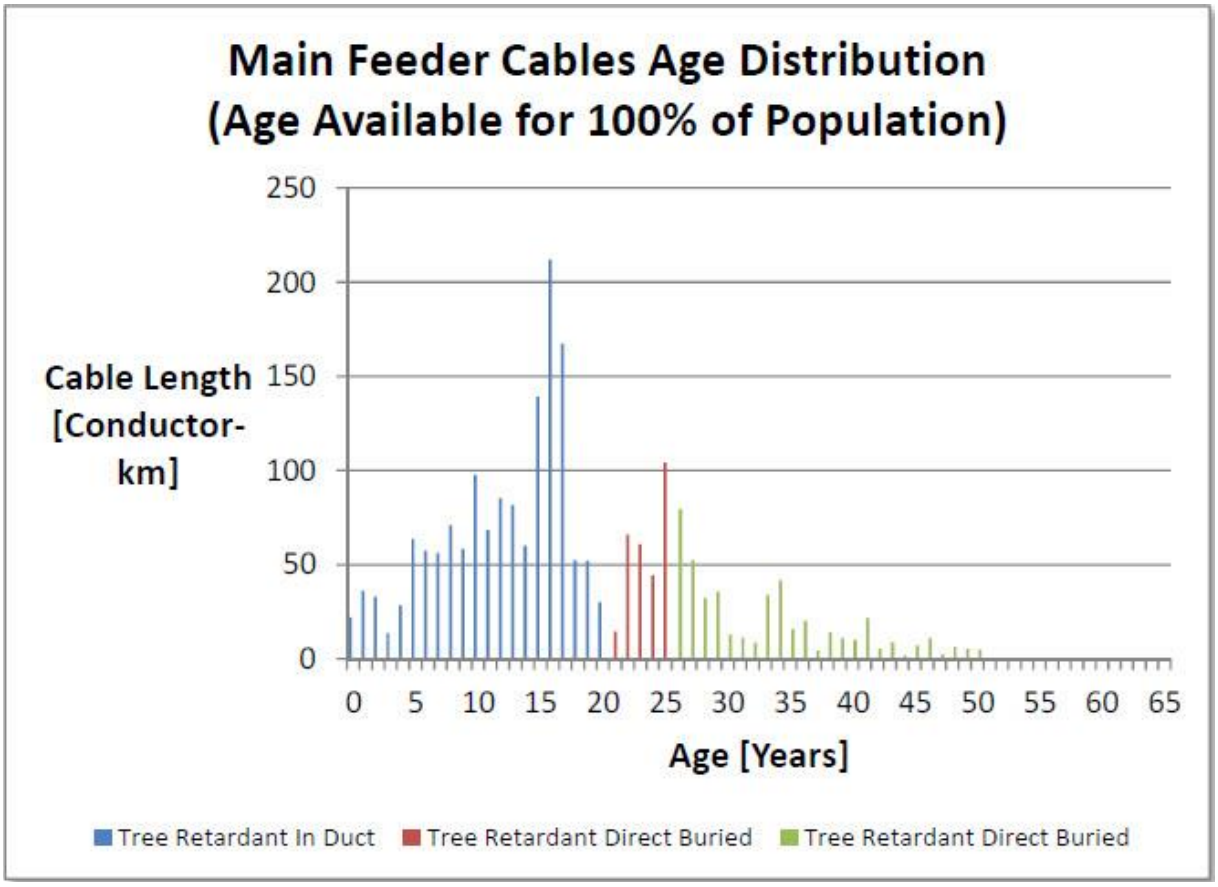


Figure 1: Main Feeder Cables Age Distribution

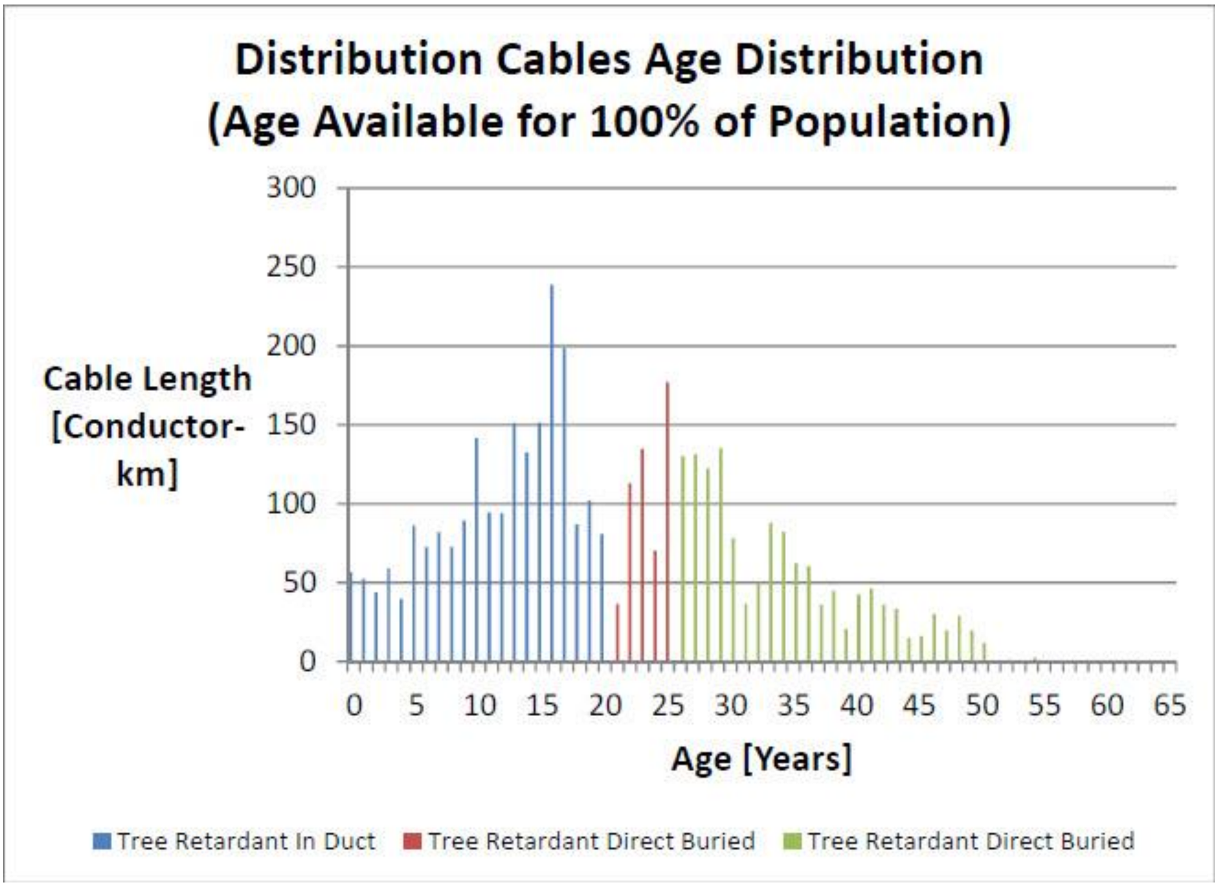


Figure 2: Distribution Cables Age Distribution

Lastly, a review of the outage database was completed and while details in terms of the number of customer effected, outage duration, feeder and location could be provided, very few details relating to cable specifics could be accessed without reviewing each incident individually.

To fill these gaps several initiatives were undertaken to provide staff with the necessary data to generate useful conclusions. In the Methodology section below the details of these initiatives will be discussed.

Methodology:

To resolve some of the data issues Enersource had with respect to cable data two initiatives were undertaken, they consisted of: Outage Location Mapping and Equipment Failure Tracking

Outage Location Mapping

Using the outage management software the locations of the cable faults would be mapped to determine if the outages were location specific to allow for targeted rebuilds.

Equipment Failure Tracking

To determine what kind of cables were failing, and the reason for failure, Enersource crews were asked to bring a small sample of each failed cables into the office, see Figure 3 for details. However, there was difficultly in implementation and only 124 cable failure samples out of 295 cable failures from January 2014 to March 31st, 2016 were collected. This represented 42% of the failed cables during the period.

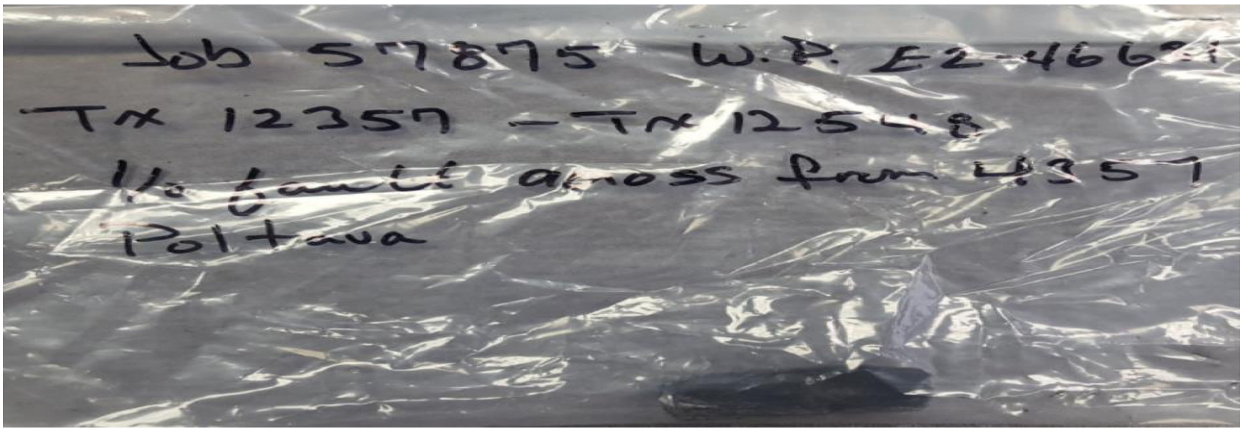


Figure 3: Sample Collected for investigation

Analysis:

Outage Location Mapping

The outage location mapping was very successful, Enersource staff were quickly able to pinpoint subdivisions with significant failures, as well as provide details on emerging areas. Some of this data was reused to develop a tracking sheet of cable segment with multiple cable faults. Based on discussion with field staff and Asset Management it was agreed that based on the data certain cable segments needed to be considered for spot replacement rather than waiting for a complete rebuild. Furthermore, the need to justify a rebuild required more than cable failure data. Using the overlay methodology issues relating to other assets like transformers (leaking, PCB) were included. See Figure 4 for the 2014 Underground Rebuild Overlay Map that includes cable failure locations.

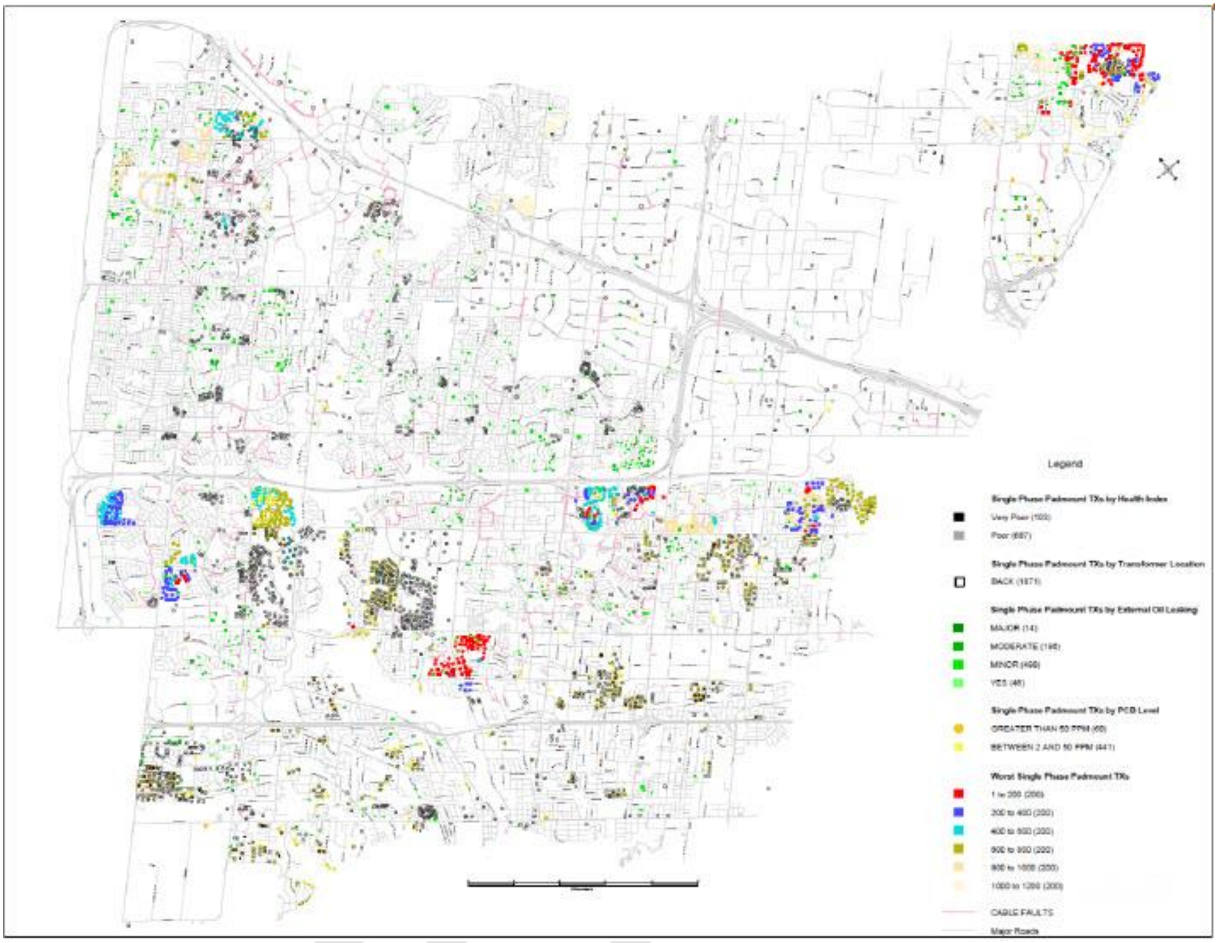


Figure 4: Underground Rebuild Overlay Map

Equipment Failure Tracking

This information proved extremely useful in providing a clear picture of Enersource's assets and issues. The two main points of the analysis and their related issues are outlined below:

Tree Retardant and Non-Tree Retardant XLPE.

Underground medium voltage (5-69 kV) cables and cable accessories have undergone many changes over the last 65 years. Initially, most cables used were of the PILC design (oil-filled, paper-insulated, lead covered). These cables had many good properties, but they were heavy and required especially skilled utility personnel to splice and terminate because of the lead sheath. They were also susceptible to failure due to water ingress. If the lead shield failed moisture could penetrate into the insulation and result in failures. Other polymeric insulations were tried including butyl rubber (very unsuccessful in damp applications), polyethylene (PE), cross-linked polyethylene (XLPE), and various EPRs (rubber). Problems were found because even polymeric insulations were degraded in the presence of moisture and high electric fields.

It was also found that the processing of the polymeric insulations required much more attention than was originally thought. This led to a number of improvements in cable design and manufacture over the year including the use of water tree retardant materials to overcome some of the issues related to consistent moisture. This also meant that older designs of cable were more susceptible to degradation and failure. What the analysis found was the overwhelming majority of cable failures were cables older than 1989. The average age of cables for each year of the study period are provided below:

Annual Average Failed Cable age in 2016	36.1 ≈ 37 years
Annual Average Failed Cable age in 2015	36.2 ≈ 37 years
Annual Average Failed Cable age in 2014	32.7 ≈ 33 years

These cables were non-tree retardant first generation XLPE cables. Furthermore many of these cables were unjacketed, meaning there was no exterior protection for the cables or neutral conductors. Exposed neutral conductors could mean many cables could have suffered some form of neutral corrosion. Figure 5 shows a failed cable with a large void where the cable fault occurred, it is also evident that this cable has no outer jacket, the concentric neutrals are frayed and no longer intact.

Figure 5: Direct buried conductors without a jacket, solid or stranded - 1/0 & main feeder

Styles of Cable

Enersource has referred to types of cable being Non-TRXLPE and TRXLPE construction what was not evident until obtaining failed cable segments is what Enersource refers to as the style of cable. Cables can come in several styles relating to both conductor and neutral construction. Figures 6-9 show various cable types and the failure rates from the analysis.

 **Figure 6: Solid Conductor - 1/0 – AL (62.1% failure rate)**	 **Figure 7: Stranded Conductor - 1/0 and Main feeder – CU (16.9% failure rate)**

Figure 8: Stranded Conductor - 1/0 – AL (1.6% failure rate)

Figure 9: Stranded Conductor - Main feeder – AL (19.4% failure rate)

Enersource Asset Planning & Analysis staff were not aware of the number of styles of cable that had been installed over the years. The use of aluminium cable, especially first generation if not properly installed can easily fail in contrast to copper cable. Cable manufacturers as well as installation practices have made changes to make the use of aluminium cables far more palatable for Utilities. Lastly it was determined that 95.2% of cables that failed are direct buried (not in ducts) and without cable jacket.

Recommendation:

Based on the analysis three recommendations were made: Spot Replacements, Rebuild Planning, and Cable Injection.

Spot Replacements:

Based on the outage mapping information and injection Asset Operations it was decided that cables with three faults are more would be flagged as cables for spot replacement if the majority of cables in the surrounding area were not also seeing faults. These spot replacements would be completed via directional bore to replace only the effected cable. It was agreed that due to the simplicity of the operation the outage map would be continuously updated.

Rebuild Planning:

Plans for underground rebuilds would focus on the use of the overlay methodology. Using the outage map areas with a significant number of cable faults would be grouped as candidate areas. These areas would then be reviewed for any leaking transformers, rusting transformers, transformers with PCB's. ACA results for transformers in very poor and poor condition would also be included. Areas with worsening condition would be prioritized first (i.e. areas with cables and transformers in need of attention would be replaced over areas with only cables). Rebuild areas would also be reviewed by Design technicians with specific planning expertise to determine if the rebuild can be completed more efficiently.

Cable Injection

Enersource faces three major factors that imped the consideration of cable injection, they are the solid core cable construction, cost increases due to the number of splices and corroded neutrals.

Solid core cables cannot be injected because the fluid must be able to flow through the cable strands. As the majority of cables found were solid core they cannot be injected. It should be noted that for cables in the mid 1990s Enersource began using water-blocked (strand filled) cable to prevent water from moving longitudinally along the strands. This also prevents cable injection.

For cables which are not solid core, Time Domain Reflector (TDR) tracing can be used to identify any neutral corrosion on the circuit. If neutral corrosion is identified the cable circuit is not considered to be a good candidate for injection. Since the majority of cables were unjacketed there is a significant likelihood that many of the neutrals will be compromised which would limit the benefits of effectiveness of cable injection.

The cable injection process requires the injection fluid to flow along the entire length of cable from end to end. Where original splices exist, these need to be removed and replaced with splices that allow the fluid to flow. The cables in these areas have seen many outages, meaning that many have more the one splice. There are additional costs and difficulties to accurately locate and replace these splices.

While some cables with only one fault or no faults may see benefit from injection due to the overwhelming issues listed above the existing approach to rebuild an entire area is recommended.

There are significant consequences for cables that suffer neutral corrosion. The loss of the defined, low-impedance path for charging currents may result in currents along “unintended” paths. This could result in step potential, which is a safety concern. While no incidents have occurred yet is not possible to rule out this situation. Step potential occurs when a person’s legs are at two separate points at different voltage levels. If the potential difference between the two points is large enough electricity will flow through a person to reach the lower potential. Figure 10 provides an illustration of step potential this situation can also be referred to as stray voltage.

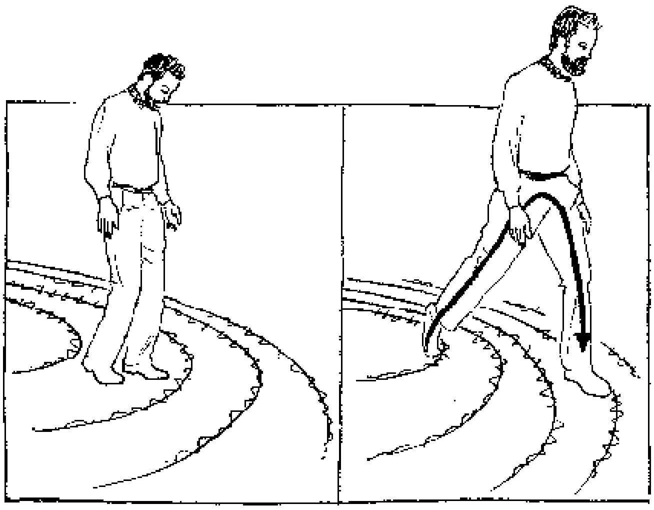


Figure 10: Step Potential

The concentric neutral on a cable is also used to carry any loading imbalance and fault current back to ground. Besides the step potential scenario outlined above if the neutral isn’t effective then protection devices like relays or fuses may not work correctly. Protection systems use a phase to neutral the neutral method where both phase and neutral imbalance is monitored. For example if the neutral current increases while a phase current decreases or drops to 0 that is a clear sign a single phase fault has occurred and the effected phase should be opened to prevent equipment damage. If cables were injected but the neutrals were compromised then the cable could still fail due to a fault protection system not clearing a fault in time.

G-Staff-28

Reference: Exhibit 4, Tab 1, Schedule 1, Pages 27 and 98 of 438

On page 27 of 438, Alectra Utilities states:

> **It is particularly important for Alectra Utilities to focus on its underground systems to address the significant declining reliability customers have experienced as a result of underground cable failures.[8]**
> **…**
> **[8]An average annual 8% increase in outage frequency, as well as the average annual increase in outage duration.**

On page 98 of 438, Alectra Utilities states

> **In order to track performance, relative to the company's Financial AM Strategic Principle of prudently investing in and maintaining assets to provide sustainable value, Alectra Utilities has established two performance measures:**
>
> - **Cost Control – Planned Capital versus Actual Expenditures**
> - **Asset Condition – Health Index of Cable Assets**

a) Is Alectra Utilities asserting that underground cable failures have increased 8% per year?

b) Which specific year over year period (or periods) is being referenced as experiencing "significant declining reliability"?

i. Please provide a breakdown of the number of cable failures in each of the referenced years, as well as the number of customers impacted by each failure and the duration of the resulting outage.

c) Please define "Cable Assets" and provide a list of assets included in this category.

d) What fraction of overall Alectra Utilities asset value does this category comprise?

Response:

a) and b) Table 1, below provides total Cable and Cable Accessory Failures from 2014 to 2018.

Table 1: Cable and Accessory Failures 2014-2018

Metric	2014	2015	2016	2017	2018	Average
Number of XLPE Outages	410	559	541	477	534	504
# of Customer Interruptions	138,717	183,888	177,149	163,118	182,122	168,999
Customer Hours of Interruption Due to XLPE Failures	174,043	209,621	208,444	190,354	227,553	202,003
Change per year for Number of XLPE Outages	N/A	36%	-3%	-12%	12%	8%
Change per year Customer Hours of Interruption Due to XLPE Failures	N/A	20%	-1%	-9%	20%	8%

As provided in Table 1, based on average year over year changes in number of hours of interruption due to XLPE failures and average year over year changes in number of XLPE outages, Alectra Utilities has experienced an annual average increase of 8% in each measure from 2014 to 2018.

The reference to ‘significant declining reliability’ provided by Alectra Utilities in Exhibit 4, Tab 1, Schedule 1 page 27, Line 3 is for the historical period of the DSP, 2014-2018. Table 1 above provides: the number of cable failures in each of the referenced years; the number of customers impacted by each failure; the duration of the resulting outage; and the year over year percentage change for number of outages and hours of interruption.

c) Table 5.2.3-1 the DSP Measures Asset Condition: Health Index (Cable), provided at Exhibit 4, Tab 1, Schedule 1, page 98, defines cable assets as PILC, XLPE (including PE), and EPR cables.

d) Based on the book value of Alectra Utilities’ fixed assets at December 31, 2018, the underground assets comprised 46% of the overall asset value.

G-Staff-29

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 1 and 16 of 58

Alectra Utilities provides the following table showing its historical and forecasted expenditures in its underground asset renewal program:

Table A10 - 1: Underground Asset Renewal Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$44.3	$43.3	$51.8	$43.6	$45.5	$61.1	$74.5	$82.2	$88.5	$95.5
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Safety									
Outcomes:	Improved Reliability, Improved Efficiency and Improved Safety									

For its underground asset renewal program, Alectra Utilities states that it considered three different investment strategies to manage the aging and deteriorating underground cable infrastructure in its service area:

- **Strategy 1: Accelerated pace (Improve cable reliability by 8%)**
- **Strategy 2: Moderate pace (Maintain cable reliability at 2018 level)**
- **Strategy 3: Reduced pace (Allow cable reliability to worsen by 10%)**

a) What is the expected impact on Alectra Utilities' average annual System Average Interruption Durations Index (SAIDI) and System Average Frequency Index (SAIFI) performance if the proposed underground cable projects are completed under each of the three strategies above?

b) Please provide a table similar to Table A10 – 13 showing the cost per unit improvement of SAIDI and SAIFI for each underground facility replacement project and program identified in this filing.

c) How were the claimed reliability outcomes for the different capital investment levels quantitatively derived? Please provide all assumptions and calculations.

Response:

a) Alectra Utilities' calculation was based on the number of cable failure events. The impact was calculated by comparing the total length of cable expected to be replaced under each scenario to the quantity projected to fail based on the survival curve. Please see Alectra Utilities' response to G-Staff-33 for details on the method Alectra Utilities applied to calculate the reliability impacts.

b) Alectra Utilities has reproduced Table A10 – 13, providing the cost per unit SAIDI and SAIFI for each Underground project, as identified in Table 1, below.

Table 1 - SAIDI and SAIFI cost per unit in millions

Project Code	Project Name	SAIDI Impact per $MM	SAIFI Impact per $MM
151091	Switchgear Renewal	0.00092	0.00015
151339	Cable Replacement Project - (BA19) - Letitia - Anne - Edgehill - Ferndale, Barrie	0.00052	0.00026
151325	Cable Replacement Project - (M31) - 14th - Old Kennedy - Steeles - Warden, Markham	0.00088	0.00044
151409	Cable Replacement Project- Central Parkway & Bloor (29), Mississauga	0.00032	0.00017
150263	Cable Replacement Project - East Left Behind Cable	0.00058	0.00029
151420	Cable Replacement Project-Eglinton & Credit Valley (5), Mississauga	0.00109	0.00092
151424	Cable Replacement Project-Miss. Valley & Bloor (15) Mississauga	0.00025	0.00021
151336	Cable Replacement Project - (BA22) - Sunnidale and Anne, Barrie	0.00043	0.00022
151404	Cable Replacement Project- Central Pk E & Miss. Valley (28)	0.00007	0.00004
151407	Cable Replacement Project- Glen Erin & Burnhamthorpe (12), Mississauga	0.00078	0.00041
151426	Cable Replacement Project- Southdown & Lakeshore (35), Mississauga	0.00039	0.00033
151303	Cable Replacement Project - (HAM) - Stone Church - Garth - Lincoln M. Alexander	0.00047	0.00016
151436	Cable Injection-011 - Area 58 & 59-Winston Churchill & The Collegeway, Mississauga	0.00000	0.00000
151402	Cable Replacement Project- Montevideo & Treviso (19a), Mississauga	0.00117	0.00062
150134	Cable Injection Project - (V37) - Langstaff and Weston, Vaughan	0.00415	0.00207
151340	Cable Replacement Project - (V29) - Hwy 7 - Jane - Steeles - Weston, Vaughan	0.00032	0.00016
151362	Cable Injection Project - (M39) -	0.00032	0.00016

	16th - Warden - Hwy 7 - Woodbine, Markham		
151363	Cable Injection Project - (M25) - 14th - McCowan - Steeles - Old Kennedy, Markham	0.00214	0.00107
151299	Cable Replacement Project - (HAM) - Millen - Barton - Fruitland	0.00392	0.00131
151146	Cable Replacement and Transformers Replacement - Project - Folkway, Mississauga	0.00273	0.00068
151066	Cable Replacement Project - Hamilton Mountain URD	0.00399	0.00100
151435	Cable Injection- 010 - Area 56- Derry Rd W & Ninth Line, Mississauga	0.00017	0.00009
151286	Cable Replacement Project - (H2) - Wanless - Heart Lake - Bovaird - Kennedy, Brampton	0.00050	0.00025
151411	Cable Replacement Project- Queensway & Mavis (31), Mississauga	0.00050	0.00026
151301	Cable Replacement Project - (HAM) - Rymal - Mud - Upper Centennial - Upper Red Hill Valley	0.00170	0.00057
151431	Cable Injection- 006- AREA 39- Erin Mills Pkway & Thomas St, Mississauga	0.00015	0.00008
151338	Cable Replacement Project- (BA15) - Burton - Huronia - Little - Bayview, Barrie	0.00032	0.00016
150257	Cable Replacement Project - (V15) - Jardin Dr, Vaughan	0.00049	0.00024
150141	Cable Replacement Project – (M49) - Steeles and Fairway Heights, Markham	0.00014	0.00007
150254	Cable Replacement Project - (A02) - Steeplechase Ave, Aurora	0.00029	0.00014
151418	Cable Replacement Project- Innovator & Courtney Park E (4), Mississauga	0.00153	0.00129
151460	Cable Injection Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	0.00115	0.00058
151367	Cable Injection Project - (M21) - Hwy 7 - Markham - 16th -	0.00066	0.00033

	McCowan, Markham		
151421	Cable Replacement Project- Rathkeale Rd & Edenrose St (6), Mississauga	0.00037	0.00031
151465	Cable Replacement - Mississauga Left Behind Cable	0.00006	0.00003
151141	Cable Replacement and Transformers replacement - Project - Windjammer, Mississauga	0.00242	0.00060
151366	Cable Injection Project - (M19) - Markham - Steeles - McCowan - 14th, Markham	0.00088	0.00044
151335	Cable Replacement Project - (BA14) - Tifffin and Hwy 400, Barrie	0.00031	0.00016
151434	Cable Injection- 009- AREA 54- Highway 401 & Argentia, Mississauga	0.00017	0.00009
151408	Cable Replacement Project- Burnhamthorpe & Miss. Road (13), Mississauga	0.00049	0.00026
151467	Cable Replacement Project - (V17) - Langstaff - Keele - Rutherford - Dufferin, Vaughan	0.00031	0.00016
151416	Cable Replacement Project- Woodchester & Thorn Lodge (34), Mississauga	0.00024	0.00020
150571	Cable Injection Project - (J3-K3-N2-O2), Brampton	0.00217	0.00109
151329	Cable Replacement Project - (V51) - Langstaff - Kipling - Hwy 7 - Hwy 27, Vaughan	0.00030	0.00015
150262	Cable Replacement Project - (M33) - 16th Avenue and Village Parkway, Markham	0.00023	0.00012
151332	Cable Replacement Project - (BA20) - Bayfield and Simcoe, Barrie	0.00033	0.00017
151330	Cable Replacement Project - (A01) - Henderson - Yonge - Bloomington - Bathurst, Aurora	0.00032	0.00016
151333	Cable Replacement Project - (BA9) - Little - Fairview - Harvie - Ferndale, Barrie	0.00032	0.00016
151419	Cable Replacement Project- Thomas St & Hillside (24),	0.00037	0.00031

	Mississauga		
151427	Cable Injection- 001- AREA 11- Truscott & Southdown, Mississauga	0.00041	0.00021
150138	Cable Replacement Project – (BA23-BA24) - Cook St and Steel St, Barrie	0.00016	0.00008
151403	Cable Replacement Project- Montevideo & Battleford (19b), Mississauga	0.00044	0.00023
151413	Cable Replacement Project- Rathburn Rd W & Elora Dr (9), Mississauga	0.00034	0.00018
151176	Cable Replacement Project - MS Argentia distribution feeder(s) upgrade	0.00190	0.00047
151315	Cable Injection Project - (G5) - Steeles - Kennedy - Hwy 407 - Main, Brampton	0.00171	0.00086
151422	Cable Replacement Project-Queen St W & Paisley (30), Mississauga	0.00023	0.00019
151291	Cable Replacement Project - (I4) - Queen - Dixie - Steeles - Hwy 410, Brampton	0.00032	0.00016
151331	Cable Replacement Project - (V41) - Stephanie Blvd, Vaughan	0.00029	0.00015
151328	Cable Replacement Project- (21a) Darcel & Brandon Gate, Mississauga	0.00055	0.00029
150261	Cable Injection Project - (V38) - Rutherford and Weston, Vaughan	0.00133	0.00066
151432	Cable Injection- 007- AREA 43 & 51- Hurontario & Derry Rd W, Mississauga	0.00069	0.00036
151423	Cable Replacement Project-Old Carriage Road (33), Mississauga	0.00015	0.00012
151425	Cable Replacement Project- Rathburn Rd E & Tomken (10), Mississauga	0.00021	0.00018
151292	Cable Replacement Project- (K4) - Queen - Torbram - Steeles - Bramalea	0.00031	0.00015
151429	Cable Injection- 003- AREA36 - Matheson & Kennedy, Mississauga	0.00110	0.00058
151405	Cable Replacement Project- Erin Mills & N.Sheridan (16), Mississauga	0.00027	0.00014
151361	Cable Injection Project - (V26) -	0.00173	0.00087

	Teston - Keele - Major Mackenzie - Jane, Vaughan		
151144	Cable Replacement Project and Transformers Replacement - Rathburn Rd. W, Mississauga	0.01365	0.00341
150025	Cable Injection Project - (V18) - Major Mackenzie and Keele, Vaughan	0.00398	0.00199
150572	Cable Replacement Project - (J4) - Queen - Clark - Bramalea - Kensington - Knightsbridge, Brampton	0.00052	0.00026
151143	Cable Replacement and Transformers Replacement -Project - Shelter Bay Rd. Mississauga	0.00223	0.00056
150255	Cable Replacement Project - (B23) - Cundles Rd and Janine St, Barrie	0.00014	0.00007
151401	Cable Replacement Project- (21b) Sigsbee & Morning Star, Mississauga	0.00084	0.00044
151410	Cable Replacement Project-Roselle & Priority Cres (2), Mississauga	0.00049	0.00026
150026	Cable Injection Project - (M43) - John and Woodbine, Markham	0.00137	0.00069
151337	Cable Replacement Project - (BA18) - Ferndale and Benson, Barrie	0.00031	0.00015
151121	Cable Injection Project - (V43) - Hwy 7 and Pine Valley Dr, Vaughan	0.00133	0.00066

c) Alectra Utilities has provided Table 2, below which provides the calculations and assumptions for the reliability outcomes of each investment. The quantities replaced and injected under column B can be found in Exhibit 4, Tab 1, Schedule 1, Appendix A10, on Pages 17, 19 and 21, in Figure A10-9, Figure A10-11 and Figure A10-13, respectively.

Table 2 - Underground Cable Reliability Outcome Calculation

A	B	C	D	E	F	G
Options	Injected and replaced Cable Quantity (km)	Failures	Remaining Segments (C-B)	Segments per year (D/6)	2018 Year End Projection	Impact on reliability (E-F)/E
Fast Paced	2400	5325	2925	488	524	-7.5%

Proposed Pace	2194	5325	3131	522	524	-0.4%
Reduced Pace	1827	5325	3498	583	524	10.1%

G-Staff-30

Reference: Exhibit 4, Tab 1, Schedule 1, Pages 231-233 of 438

Alectra Utilities describes its asset replacement strategy for primary underground XLPE cables in the following table:

Asset Class	Primary Replacement Strategy	Comments
Underground conductors and accessories - primary Cross-linked polyethylene ("XLPE") cables	Planned	Alectra Utilities implements two types of strategies in managing its XLPE cable population: (i) cables which are beyond end of useful life (i.e. 35 years) will undergo planned replacements; and (ii) cables which are less than 35 years of age will be considered for cable rehabilitation. In the event that a cable fails while in service, Alectra Utilities will repair the cable by splicing out the faulted segment.

a) **Does Alectra Utilities conduct post-removal destructive testing on its retired XLPE cables in order to determine actual condition at the time of retirement?**

   i. **If yes, does Alectra Utilities update the typical useful life (TUL) and end of useful life (EUL) estimates based on the results of these tests?**

   ii. **If no, why not?**

b) **If Alectra Utilities updates its TUL and EUL estimates, will this change the planned pacing of the XLPE replacement program?**

   i. **If no, why not?**

Response:

a) Alectra Utilities does not conduct post-removal destructive testing on retired XLPE cables. Alectra Utilities has conducted a study to better understand the lifespan of its underground cables. The study is provided in response to G-Staff-27 b).

b) Changing the Typical Useful Life (“TUL) and End of Useful Life (“EUL”) will not impact the replacement and pacing of the XLPE underground replacement.

The EUL and TUL are used as a component in the Health Index calculation of the Asset Condition Assessment (“ACA”). The ACA provided guidance based on three strategies - Baseline, Moderate, and Slow (Refer to Exhibit 4, Appendix D, page 61). The pacing of all three strategies is significantly above the recommended pacing plan of 135 km per year on average (Refer to Exhibit 4, Tab 1, Schedule 1, A10, pages 16-18 & 22 of 58).

G-Staff-31

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Pages 24-37 of 58

Alectra Utilities identifies its pad-mounted switchgears as a critical component of its underground distribution system. Alectra Utilities provides the following table to summarize its historical and forecasted spending for switchgear renewal:

Table A10 - 7: Switchgear Summary

	Historical Spending				Bridge	Forecast Spending				
Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CAPEX ($MM)	$3.8	$5.4	$4.0	$2.5	$5.8	$7.4	$7.6	$7.9	$8.1	$8.3
Primary Driver:	Failure Risk									
Secondary Drivers:	Reliability, Functional Obsolescence, Safety and Environmental risks									
Outcomes:	Better Reliability, Expedient Fault Finding and Restoration, Safety and Environmental Risk Mitigation									

a) **Given that Alectra Utilities considers its pad-mounted switchgears to be critical components requiring a steady level of investment, please explain the decreased spending in 2017 and 2018.**

b) **How many legacy switchgear units will be replaced in each year 2020 to 2024?**

c) **How many legacy switchgear units requiring replacement will remain in Alectra Utilities' system after 2024?**

d) **What is the reliability improvement cost-effectiveness of the planned switchgear replacements in comparison with the planned underground cable replacements? Please provide any relevant analysis and calculations.**

Regarding the air-insulated switchgear population, Alectra Utilities states that as the deteriorated assets are replaced, it will "… eventually allow for a reduction in O&M costs with a lower amount of dry ice cleaning."

e) **When does Alectra Utilities expect to see the reduction in O&M and what is the amount expected?**

Response:

a) The relative decrease in Switchgear renewal investments in 2017 and 2018 is a combination of tracking expenditure methodologies at legacy ERP systems and deferral of investments as a result of denied funding that required Alectra Utilities to pace and prioritize investments at different rate and sequence than planned. First, in terms to tracking expenditures, switchgears were replaced in combination with other underground renewal work and therefore combined within the historical underground renewal investments. Second, the decrease in 2018 was related to the ICM decision (EB-2017-0024) in which underground cable rebuilds were not eligible for funding. Alectra Utilities reallocated funding from switchgear to cable projects to manage customer reliability concerns specifically with respect to the Meadowvale Community Centre (effected by Glen Erin and Montevideo and Glen Erin and Battleford underground renewal projects).

b) Alectra Utilities plans to replace distribution switchgear at a rate of 80 units per year over the 2020-2024 time period. In addition, Alectra Utilities plans to implement three units per year as part of the automation strategy. Please refer to Exhibit 4, Tab 1, Schedule 1, A10, page 46 of 58, lines 7-14 for additional details.

c) Through the implementation of the distribution switchgear renewal as planed in the DSP, Alectra Utilities projects to have 91 units would be left in the backlog at the end of 2024. Please refer to Exhibit 4, Tab 1, Schedule 1, A10, page 44 of 58, line 3-4 for additional details.

d) Alectra Utilities Based on renewal plan as proposed in the DSP, Alectra Utilities has determined that each km of cable and padmounted switchgear replaced would prevent a failure and has applied the five year average impact on customer hours of interruption. Based on this methodology, Alectra Utilities derived an overall impact over the DSP period from 2020-2024. Table 1 summarizes this analysis. Based on this analysis, switchgear replacements are slightly more cost effective then cable replacements.

Table 1: Cost Effectiveness Analysis Cable Replacements vs. Switchgear Replacements ($MM)

Cause Code	Customer Hour Interruptions	Expenditure ($MM)	km/units	Total Customer Hours of Interruption Over DSP	Hours of Interruption per dollar spend
Cable & Accessories XLPE	202,003	$332.5	675	136,352,043	0.410
Switchgear	41,099	$39.3	400	16,439,408	0.418

e) Alectra Utilities continues to harmonize inspection practices across its service area. It anticipates that air insulated switchgear maintenance will be harmonized over the planning period of the DSP. In assessing the value of replacing air insulated switchgear, Alectra Utilities has projected that each year all the 80 units replaced are air-insulated, heavily deteriorated and in need of ongoing washing once every two years. Alectra Utilities estimates a reduction of $32,400 per year.

G-Staff-32

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 34 of 58

Figure A10 – 18 forecasts the number of pad-mounted switchgear failures in 2019 to be 230. Please provide the actual number of pad-mounted switchgear unit failures between January 1 and June 30, 2019.

Response:

As illustrated in Figure A10-18, it is important to clarify that Alectra Utilities estimates the number of pad mounted switchgear failures to be 85 per year over the 20 year period, as explained on Page 33 of Appendix A10. From January 1 to June 2019, Alectra Utilities has had 19 Pad-mounted Switchgear outages failures. The lower number of outages due to switchgear failure is a result of Alectra Utilities' practice not to run switchgear to failure, as explained in Section A.2 of 5.3.3 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 241 and Page 242).

G-Staff-33

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 22
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 14

On page 22, Alectra Utilities states that "Within current rates, the reliability of underground cable is expected to further worsen by approximately 4% from current 2018 levels."

On page 14, Alectra Utilities states that:

> **The average number of outages (excluding major event days) has increased by an average of 6% per year from 2014-2018, rising from 1.27 to 1.53 over this period.**
>
> **The average duration of outages (excluding major event days) has increased by an average of 8% per year from 2014-2018, rising from 0.88 hours to 1.14 hours over this period.**

a) Please clarify how the 4% reliability deterioration rate was determined. Please clarify which metric is being quantified.

b) Does this imply that reliability will drop by 4% per year, or by 4% in total through 2027?

c) Given the statement that the number of outages is increasing by 6% and the duration by 8% on page 14, does a 4% decrease in reliability due to underground cables imply that underground cables are deteriorating at a lower rate than aggregate system assets?

d) What steps did Alectra Utilities take to ensure that none of the above questions caused confusion to the survey respondents?

Response:

a) Alectra Utilities identifies that the 4% deterioration of reliability was provided in reference to the worsening of reliability only from cable failures and does not reflect a measure relative to the total system reliability. Further, the specific 4% deterioration of reliability of cables was provided relative to 2018 outages, due to failing underground cables.

Alectra Utilities determined the 4% reliability deterioration based on the amount of underground cable that is required to be renewed relative to the base pacing option.

Considering the current underground cable renewal rate, Alectra Utilities first determined that 2,061 km of underground cable would be renewed over the period of 2019-2024. Based on the 2018 Asset Condition Assessment, Alectra Utilities has identified a total of 5,325 km of cable in need of renewal before 2025. Since the base pace replacement rate is lower than the required renewal rate, Alectra Utilities would not be able to renew all the required cables; this creates a backlog of deteriorated cables in the system. Alectra Utilities projects that the backlog of deteriorated cable would result in 3,264 failures over the 2019-2025 period. Alectra Utilities applied the outage impact of cable failures in 2018 against the 3,264 projected failures of the 2019 to 2025 which results a 4% worsening of reliability.

b) and c) As explained in part a), the 4% reduction in reliability relates to cable failures and not the system reliability measure. The 4% worsening of reliability of underground cables is relative to the 2018 outage rate due to cable failures. If a five-year average rate of reliability of cable failures were applied, the base pace renewal rate would result in a 7.4% worsening of cable reliability, which is proportionate to the overall system’s 8% average annual rate of reliability worsening.

d) Prior to engaging customers to attain investment preferences (i.e., the second phase of customer engagement), Innovative Research Group conducted extensive testing of the material and questions with focus groups as part of the workbook development. The focus groups included randomly recruited residential and small business customers to ensure comprehension and to test for length. Diagnostic questions were included to assess customer experience, clarity and content of the workbook, including all the information related to reliability.

G-Staff-34

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix B, Pages 145-147 of 490

The business case for Project #150263 – “Cable Replacement Project – East Left Behind Cable” states that the proposed annual budget for the project for 2019 and onwards is a continuation of the project at the same budget levels performed in past years 2014-2018.

The business case provides the following table outlining the annual budgets for this project:

	2019	2020	2021	2022	2023	2024
2019-2024 - Optimized for DSP CE v2: $11,758,778	$1,234,223	$1,304,394	$2,703,182	$1,567,248	$3,374,731	$1,575,000
Actuals: $0	$0	$0	$0	$0	$0	$0

a) **Please provide the actual capital expenditures for this project for 2014-2018.**

b) **Please explain why there is a spike in spending in 2021 and 2023 if spending levels are expected to remain level.**

Response:

a) Alectra Utilities has provided the 2014-2018 capital expenditures for the Cable Replacement Project – East Left Behind Cable in Table 1, below. For 2014, the actual spend for left behind cables was $0 as Alectra Utilities’ predecessor PowerStream implemented a course of action to manage these types of situations in 2015.

Table 1 - East Left Behind Cable Capital Expenditures (2014-2018)

Project	2014	2015	2016	2017	2018
East Left Behind Cable	$0	$36,056	$1,293,457	$1,414,263	$2,027,921

b) The increase in 2021 and 2023 is related to the increase in cable injection occurring in the East operational area. As provided in Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 7, Alectra Utilities has criteria for cables which will not be injected. These become ‘left behind’ cable segments. Due to the increase in injection spending provided in Exhibit 4, Tab 1, Schedule 1, Appendix A10, Page 18, Figure A10 – 10, Alectra Utilities forecasts an increase in ‘left behind’ segments which will need to be addressed. The increases in ‘left behind’ spending in 2021 and 2023 are do to an increase in the number of ‘left behind’ segments caused by the increased injection spending. By ensuring that all cable segments including those not suitable for injection i.e. ‘left behind’ segments are replaced, it ensures that a neighbourhood does not have problem segments remaining that would still cause an outage.

G-Staff-35

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix B
Reference 2: EB-2015-0003, PowerStream Inc. IRRs, II-1-Staff-16

Based on the information provided in the business cases in Appendix B, OEB staff has compiled the following table summarizing the recent historical unit costs of cable replacement in each of Alectra Utilities' rate zones:

Rate Zone	**Historical Cable Replacement Unit costs (2016-2018)**
Enersource	$250/m
PowerStream	$389/m
Horizon	$328/m
Brampton	$389/m
Guelph	N/A

a) **Please confirm if the table above is correct and please provide corrections if necessary.**

b) **Please explain why PowerStream, Horizon and Brampton have significantly higher unit costs than Enersource.**

The following table is taken from PowerStream's responses to interrogatories from its 2016 rates application showing PowerStream historical cable replacement unit costs:

Assets		Actual			
		2011	2012	2013	2014
Underground Cable (Injection)	length (m)	9,570	25,100	85,363	106,976
	$	$315,776	$810,310	$4,319,470	$6,006,747
	$/m	$33	$32	$51	$56
Underground Cable (Replacement)	length (m)	10,330	9,060	49,539	54,499
	$	$2,829,932	$1,931,017	$14,722,080	$14,982,276
	$/m	$274	$213	$297	$275

OEB staff calculates the 2011-2014 five-year average unit cost of underground cable replacement to be $265/m and calculates the 2016-2018 historical unit costs of $389/m to be a 47% increase.

c) **Please explain the reason for the large increase in unit costs for the PowerStream rate zone.**

Response:

a) and b)

Alectra Utilities wishes to update the Table as provided in the question with Table 1, below.

Table G-Staff-35-1: Typical Underground Asset Renewal Projects by Rate Zone [IJBD NTD – change project exp. to MM

Rate Zone	Project Number	Project Expenditure ($ MM)	Total Project Meters	Cost/meter ($/m)
BRZ	151288	$0.585	1,674	350
ERZ	151402	$5.183	14,151	366
HRZ	151299	$1.379	4,419	312
PRZ	151329	$2.167	6,192	350
GRZ	151374	$0.617	1,654	373

During the development of the business cases for the capital investment plan that formed Alectra Utilties' 2020-2024 Distribution System Plan, business cases for projects were estimated using legacy estimation processes based on legacy Enterprise Resource Planning ("ERP") systems and reflected the capital project estimation methodology and practice of legacy distributors.

c) The table provided in the preamble to question G-Staff-35 (c) was attained from a response to II-1-Staff-16, in EB-2015-0003. Alectra Utilities wishes to clarify that the dollar values of the investments in this table refer to in-service additions and the corresponding meters values include projects that that were not yet energized (i.e. construction was still in progress). Therefore it understated the rate per meter. Due to the time required to close each project work order and transfer the expenditure in-service, the dollar values did not appropriately align with the meter of cable replaced for that year.

Alectra Utilities wishes to restate Table II-1-Staff-17 from EB-2015-0003 with capital expenditure values for cable replacement so as to provide an accurate indication of per meter expenditure of cable replacement. Please refer to Table 2, which now reflects capital expenditures in alignment with appropriate cable replacement meters, the per unit meter replacement rate produced an average rate of $302 per meter for the period of 2011 to 2014.

Table 2: Cable Replacement Spend ($MM) 2011-2014

Cable Replacement	2011	2012	2013	2014
Spend (dollars)	$3.918	$2.219	$15.417	$15.036
Units (meters)	10,330	9,060	49,539	54,499
Cost/Unit	$379.26	$244.98	$311.21	$275.90

Additionally, Alectra Utilities wishes to identify that in response to II-1-Staff-16 in EB 2015-0003 the per unit replacement forecast in 2015 for 2002 was $511/m-$614/m. Alectra Utilities and its predecessors acknowledged the Board's decision and took corrective action to mitigate the unit cost increases in the cable replacement investments. Alectra Utilities restructured the cable replacement investments from a program basis to a portfolio of projects, where each renewal focus area was structured as a project with distinct scope, budget and schedule. By restructuring the planning and execution of system renewal investments, Alectra Utilities was better able to understand the drivers of unit cost variations and develop projects plans in a manner to deliver better value and mitigate cost increases. For the 2020-2024 system renewal projects, Alectra Utilities' estimate is based on actual historical average cost of $389 per meter, which represents a 31%-56% decrease from the projected units cost proposed in 2015.

G-Staff-36

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix B

OEB staff notes the following cable remediation projects have significantly higher unit costs for cable replacement compared to historical unit costs:

- **Project #150138 (PowerStream) - $712/m vs. $389/m historical.**
- **Project #150141 (PowerStream) - $778/m vs. $389/m historical.**
- **Project #150262 (PowerStream) - $555/m vs. $389/m historical.**
- **Project #150255 (PowerStream) - $760/m vs. $389/m historical.**

a) Please explain the reasons for the higher than average unit costs.

b) Please describe Alectra Utilities' methodology for quantifying the impact on unit costs of the reasons discussed in part a).

Response:

a) An explanation for the higher unit costs is provided for each project, below:

Project 150138 – This project has additional work dealing with seven riser poles, two schools, a townhouse complex with very tight road allowance requiring open trenching and deeper cable depth than typical installs. Several of the civil structures are just lids and not proper foundations. This is also being rectified at the same time and increases the project cost.

Project 150141 – Site conditions resulted in additional easement requirements on private property. Space limitations in the road allowance forced additional open trenching and deeper cable depth. Additionally, civil chambers for transformers had to be relocated as the proposed position was no longer a viable option.

Project 150262 – This project was deferred; the updated estimate includes additional transformers and civil work requirements that were not initially provided for in the original estimate.

Project 150255 – This project's primary driver is cable replacement, with voltage conversion as a secondary driver. This resulted in increased clearances and new switches. This project also involves 14 industrial and commercial customers, which is not typical of most cable projects.

b) When Alectra Utilities completes its detailed design, or updates existing designs, it reviews the assumptions that were made at the time of the initial estimate and updates the costs and material needs. In many of the cases described in part a), the proposed cable route was not a viable option based on other services in the road allowance or insufficient clearances. The redesign is required, and based on the solution, the total cost of the project increases.

G-Staff-37

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix B

OEB staff notes that the business cases for the following projects are missing unit cost information: Project #151146, Project #151176, Project #151144, Project #151465, Project #151143, Project #151066 and Project #151141.

a) For each project listed above, please provide the unit costs for the cable replacement.

b) For the projects that include transformer replacement, please separate the total budget into the budget for cables and the budget for transformers. Also, please provide the unit costs for the transformer replacements.

i. Please explain why budget for transformer replacements is being included in cable renewal projects rather than under transformer renewal programs.

Response:

a) Alectra Utilities would like to clarify that unit cost information is not part of the material business cases. The projects specifically listed in G-Staff-37 are a combination of cable and transformer replacements occurring in the same geographical area and are bundled together under one project. In contrast, projects in other areas may not have transformer replacements selected during the budgeting process and therefore under units the meters can be entered.

For projects with multiple unit types, Alectra Utilities refrains from submitting a unit quantity. The unit cost for cable replacement for each project listed in G-Staff-37 is provided in Table 1.

Table 1: Cable Unit Costs by Project

Project Code	Year	Project Name	Unit Cost ($/m)
151146	2020	Folkway	302.33
151176	2020	MS Argentia	296.67
151144	2020	Rathburn	278.87
151465	2021	Left Behind Cable	251
	2023	Left Behind Cable	275
	2024	Left Behind Cable	300
151143	2020	Shelter Bay	277.85
151066	2020	Hamilton Mountain UDR	368.71*
151141	2020	Windjammer	302.33

*Includes some PILC cable costs

b) The unit cost for Transformer replacement for each project listed in G-Staff-37 is provided in Table 2.

Table 2: Transformer Unit Costs by Project

Project Code	Year	Project Name	Transformers Estimated Budget	Unit Cost ($/transformer)
151146	2020	Folkway	$88,000	$4,000
151176	2020	MS Argentia	$8,000	$4,000
151144	2020	Rathburn	$16,000	$4,000
151465	2021	Left Behind Cable	N/A	N/A
	2023	Left Behind Cable	N/A	N/A
	2024	Left Behind Cable	N/A	N/A
151143	2020	Shelter Bay	$28,000	$4,000
151066	2020	Hamilton Mountain UDR	$20,042	$15,646*
151141	2020	Windjammer	$56,000	$4,000

*includes both three phase (1 units) and single phase transformers (2 units)

G-Staff-38

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix B

OEB staff notes that the business plans for cable replacement projects within the Enersource rate zone include budget for the replacement of assets other than cables. The business cases mention deteriorating assets and transformers that will be replaced as part of the project.

As an example, Project #151409 – "Cable Replacement Project – Central Parkway & Bloor (29), Mississauga" has a total cost of $10.9 million. The business case states that $3.12 million is to be spent on cable replacement, and the remaining $7.78 million is to be spent on deteriorating assets and back-lot transformers in the area.

a) Please explain what deteriorating assets other than cables and transformers will be replaced.

b) Please explain why Alectra Utilities is proposing to replace transformers despite Alectra Utilities' reactive, "run-to-failure" replacement strategy for distribution class pad mount, pole mount and vault mount transformers.

c) Please explain why Alectra Utilities included capital for transformer replacements under the cable remediation category when Alectra Utilities has separate investment categories and funds for transformer replacement and reactive capital (in the event that the transformer fails).

d) Please explain why Alectra Utilities included capital on deteriorating assets other than cables as part of cable remediation projects.

e) Please explain if the deteriorating assets and transformers mentioned above contribute to Alectra Utilities' reliability metrics to the same degree as underground cables (i.e. do those assets cause as many outages as cables)?

f) Please explain why Enersource is the only rate zone with this approach to its business cases.

g) If any investment capital described above has been categorized incorrectly, please provide updated business cases and total forecasted capital expenditures for each affected investment subgroup in Appendix A.

Response:

a) The majority of the $7.78MM is for renewing the underground services to current standard. The investment is required to relocate the rear lot underground service to front lot underground service as rebuilding of underground services in front lot is lower than rebuilding rear lot underground services.

b) Please see Exhibit 4, Tab 1, Schedule 1, Appendix A09 – Transformer Renewal page 1, Lines 3-7 for a list of transformer conditions under which Alectra Utilities replaces transformers proactively. In these situations, it would not be prudent for Alectra Utilities to wait for failure due to the potential risk and reliability avoidance of an impending failure.

c) Alectra Utilities has discrete underground renewal projects, where the main driver and asset replaced are cables. However, referring to Exhibit 4, Tab 1, Schedule 1, Page 229, Lines 15-22. Alectra Utilities describes how it uses an overlay methodology to bundle assets into specific projects. The transformer replacement described in Exhibit 4, Tab 1, Schedule 1, Appendix A09 – Transformer Renewal is specifically for the replacement of individual transformers that cannot be bundled to other projects, and that are stand-alone asset replacements.

d) Please see Alectra Utilities' response to G-Staff-38 c) for an explanation on why Alectra Utilities includes capital on deteriorating assets other than cables as part of underground asset renewal.

e) If Alectra Utilities uses the five-year average number of customer interruptions and customer hours of interruption and divides them by number of events. Cables have a greater impact than transformers, but a lower impact than switchgear and overhead line hardware. This analysis is provided in Table 1.

Table 1: Five Year Average Defective Equipment by Sub Cause

5 Year Average Outage Data Defective Equipment Sub Cause Code					
Cause Code	# of Event	# of Customer Interruptions	Customer Hours of Interruption	Per event # of customer interruptions	Per event Customer Hours of Interruption
Cable & Accessories PILC	14	14,633	23,966	1031	1688
Cable & Accessories XLPE	504	168,999	202,003	335	401
Switches	87	38,916	29,262	446	336
Switchgear	57	51,104	41,099	897	721
OH Line Hardware	157	87,219	85,845	557	548
Transformers	317	20,365	32,666	64	103

It is more prudent for Alectra Utilities to bundle other renewal needs while replacing underground cable. Bundling of required renewal eliminates additional costs related to setup and teardown time to replace the other assets at a later date and incur additional outages for customers. In certain cases, transformers may not be sitting on proper foundations. If the cables are replaced first and the transformer at a later date, additional civil costs will be incurred. These costs relate to rerouting the cables to the new civil transformer base, which did not exist when the cables were replaced.

f) The Enersource rate zone is not the only rate zone with this approach. Replacement of additional assets during cable renewal is project specific. As an example, Project 151066, Cable Replacement Project – Hamilton Mountain URD includes costs for civil work, transformers, and switchgear. All of these assets are part of renewing the underground infrastructure during a rebuild.

g) Alectra Utilities confirms that none of the investments are categorized incorrectly.

G-Staff-39

Reference: Exhibit 4, Tab 1, Schedule 1, Pages 6-7 of 438

Regarding its overhead assets, Alectra Utilities states:

> **… a key focus for investment is on replacing and remediating overhead assets that are deteriorated or otherwise prone to failure from adverse weather conditions. A particular area of focus will be on renewing, through reinforcement or replacement, deteriorated poles that have been assessed as being in Poor or Very Poor condition based on the 2018 Asset Condition Assessment. Reinforced and replacement poles are more resilient to ice and wind loading. Alectra Utilities will specifically target a particular population of wood poles in circumstances where they are carrying four circuits. This is a scenario that has been found to be particularly susceptible to failure during storm and high wind events.**

a) **Please provide a list of multi-pole failure events that have occurred in the service areas of Alectra Utilities or its predecessor utilities over past 5 years, indicating the number of poles that failed in each event and providing the causes of the failures.**

   i. **For wind and/or ice related failures, does Alectra Utilities believe that the wind and ice loads that caused the failures are good proxies for future ice loads and wind loads? Please provide rationale.**

   ii. **Were the failed poles originally designed to meet CSA standards?**

   iii. **Have CSA standards been updated since the poles were initially designed, and would poles conforming to the new standard be able to withstand the types of wind and ice loads that caused the past multi-pole failure events?**

   iv. **If CSA standards are not sufficient, how has Alectra Utilities determined what design standards will be sufficient for its poles?**

b) **Did any of the Alectra Utilities predecessor utilities apply different meteorological loading standards for single circuit vs. multiple circuit overhead line designs?**

   i. **If yes, please provide the different design standards and the rationales for applying them.**

c) **Is Alectra Utilities proposing to adopt new design standards that exceed historical design standards?**

i. **If yes, do the new proposed Alectra Utilities standards exceed typical utility practice in Ontario or for other Canadian jurisdictions?**

ii. **If yes, is Alectra Utilities proposing to upgrade existing facilities to meet the new standards, or will the new standards only be applied to new build or replacement projects driven by asset condition?**

iii. **If yes, what is the per unit cost consequence of applying the new standards? I.e. what is the average incremental capital cost of applying the new standards to poles carrying one, two, three and four circuits?**

iv. **If yes, what is the aggregate cost consequence of applying the new standards? In other words, what is the incremental cost per year of applying the proposed new standards to the planned pole replacements identified in this filing?**

d) Has Alectra Utilities completed a multi-year analysis that shows a correlation between the age of poles and increasing probability of pole failure during adverse weather conditions?

i. **If yes, please provide the analysis.**

e) Has the probability of multiple structure failures been increasing over time in Alectra Utilities' service area over the historical period of 2014-2018?

i. **If yes, please provide quantified evidence demonstrating the relationship between the specific cause and the total number of structure failures in Alectra Utilities' service area over the historical period.**

Response:

a) A list of recorded multi-pole failure events that have occurred in the service area of Alectra Utilities or its predecessor utilities over past 5 years is shown in Table 1, below.

Table 1 - List of Multi-Pole Failure Events

Date	Number of poles	Location	Cause
June 17, 2014	12	Markham	Thunderstorm
January 11, 2017	5	Brampton	High Wind
October 15, 2017	10	Vaughan	High Wind

Further, in the Alectra West service area, Alectra Utilities' predecessor, Horizon Utilities is aware of two multi-pole line failures.

i) Based on Alectra Utilities' experience, high winds greater than 100km/h have been the primary cause of failure. Alectra Utilities believes that the wind and ice loads that caused the failures are good proxies for future ice loads and wind loads.

ii) To the best of Alectra Utilities' knowledge, all the failed poles were built to CSA standards and met design criteria at the time of construction.

iii) CSA standards have been updated since the poles that failed were initially designed. It is expected that poles conforming to the new standards will be able to withstand the types of wind and ice loads that caused the past multi-pole failure events.

iv) As identified in response to part a) iii), Alectra Utilities' poles conform to the new CSA standard. Additionally, Alectra Utilities uses the Spida Calculation program, which is a non-linear analysis program, for pole classing calculations. Alectra Utilities also uses design standards set out in the design standards book which is approved by a standards engineer. In special cases (e.g. extremely long span, at high risk areas such as high populated highway crossing), Alectra Utilities will retain consultants who specialize in these areas to complete the specific design to ensure the new pole line is safe for the public.

b) Alectra Utilities' and its predecessor ensure that pole line designs (single and multi-circuit) comply with CSA standards that already incorporate meteorological loading.

c) i) Alectra Utilities is not currently proposing to adopt new design standards that exceed historical design standards. Alectra Utilities' current design standards were implemented in 2017 to comply with the Canadian Standards Association's ("CSA") C22.3 No. 1-15 Overhead Systems standard. The Electrical Safety Authority ("ESA") mandated that Ontario Utilities comply with the C22.3 No. 1-15 standard in 2017. Alectra Utilities is unaware of design standards used in other Canadian jurisdictions.

ii) No, Alectra is not proposing to upgrade existing facilities to meet the CSA C22.3 No. 1-15 Overhead Systems standard. The standard is applied to new build or renewal projects designed after the standard was implemented by Alectra Utilities.

iii) As Alectra is not currently contemplating changes to its distribution standards and as a result, there is not a cost consequence for any currently proposed changes. The adoption of the CSA C22.3 No. 1-15 Overhead Systems standard in 2017 as mandated by the ESA did have a cost impact. CSA C22.3 No. 1-15 required the use of non-linear analysis for determining the structural load on overhead pole lines. The use of non-linear analysis generally resulted in an increase in pole strength by one class. Alectra Utilities is not able to calculate the exact per unit cost increase as this varies given the pole height, material, and installation techniques but estimates the increase to be approximately 10-15% for the cost of the pole with negligible cost differences for installation, handling costs or cost of other materials involved with installing poles (e.g. insulators, anchors, pole hardware, etc.)

iv) Alectra Utilities has not calculated the aggregated cost consequence of implementing standards compliant with the CSA Standard C22.3 No. 1-15 as compliance was mandated by the Electrical Safety Authority ("ESA"). Calculation of the aggregated cost would require a number of assumptions regarding the number of poles installed, the type (size and material) of the poles being installed, and resulting variability of the costs associated with each of these assumptions.

d) Alectra Utilities' predecessor, PowerStream engaged CIMA+, an independent engineering firm, to produce a report for Hardening the Distribution System against severe storms which is provided as Appendix K of the DSP (Exhibit 4, Tab 1, Schedule 1, Appendix K, Page 21). CIMA identified that weather events that include high wind velocity/wind gusts, expose aged overhead assets and multiple circuit poles as the greatest risk to the distribution system.

e) For the historical period of 2014-2018, Alectra Utilities (and predecessor utilities) has experienced three significant multi-pole line failures as presented in Table 1, above. Based on the outcome of the CIMA report (Appendix K of the DSP), Alectra Utilities believes that the frequency and severity of heaving rain/flooding, high winds and freezing rain will increase. Should Alectra Utilities not implement the renewal investments and match the rate of renewal with the rate of deterioration, the deteriorated poles with reduced strength will not possess the capability to withstand severe weather conditions, which will result in more failures under severe weather conditions.

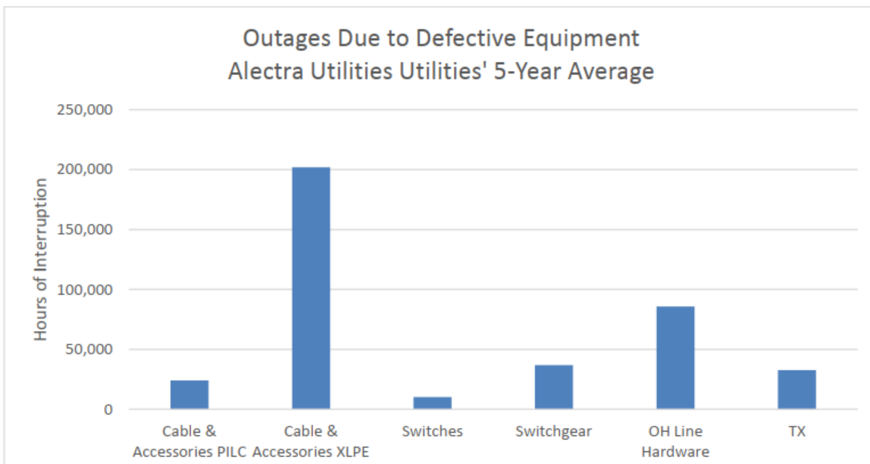
G-Staff-40

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A05, Pages 2-3 of 53

On pages 2-3 of 53, Alectra Utilities states:

> **Deteriorated overhead infrastructure also negatively affects customers' reliability. As shown in Figure A05 - 2, failing overhead distribution hardware is the second largest contributor to equipment related failures. This fact reflects both a large amount of overhead equipment in Alectra Utilities' distribution system, and the condition of those assets. The planned expenditures are necessary to maintain reliability near current levels.**

Figure A05 - 2: Outages Due to Defective Equipment, Alectra Utilities' 5-Year Average (2014-2018)



a) **What specific asset types comprise the class "overhead distribution hardware"?**

b) **Is there a high probability that overhead distribution hardware will spontaneously fail due to deteriorated state, or is failure of deteriorated overhead distribution hardware typically triggered by external factors?**

   i. **If typically triggered by external factors, please list the most common factors.**

c) **Please provide the proportional and absolute 2014-2018 trends for outages caused by overhead distribution hardware failures, i.e. trends should be shown as the percentage of total annual outages and the total number of outages caused by overhead distribution hardware failures.**

d) **Please provide a chart showing the 2014 - 2018 outage hour trends caused by each of the asset categories listed in Figure A05 – 2.**

Response:

a) The asset class “overhead distribution hardware” is a combination of various legacy utility reporting sub cause codes relating to overhead equipment. There is a large amount of variation as each legacy utility has different sub cause codes. Table 1 below provides the mapping of legacy sub cause codes to the ‘OH Line Hardware’ category.

Table 1: Legacy Sub Cause Code for Alectra Overhead Line Hardware

Legacy Utility	Legacy Sub Cause Code	Mapping
PRZ	DE - Line Hardware	OH Line Hardware
PRZ	DE - Arrestor	OH Line Hardware
PRZ	DE - Insulator	OH Line Hardware
HRZ	Broken Cross Arm	OH Line Hardware
HRZ	Broken Insulator	OH Line Hardware
HRZ	Insulink failure/loose	OH Line Hardware
HRZ	Lightning Arrestor failure	OH Line Hardware
HRZ	Primary jumper failure/loose connection	OH Line Hardware
HRZ	O/H Hardware	OH Line Hardware
BRZ	INSULATOR FAILED	OH Line Hardware
BRZ	L/A FAULT	OH Line Hardware
BRZ	O/H TAP FAILURE	OH Line Hardware
BRZ	PRIMARY LEAD	OH Line Hardware
BRZ	X-ARM BROKEN	OH Line Hardware
ERZ	500_CON	OH Line Hardware
ERZ	500_INSU	OH Line Hardware
ERZ	500_LA	OH Line Hardware
ERZ	500_OHH	OH Line Hardware
GRZ	Arrestor	OH Line Hardware
GRZ	Connector	OH Line Hardware
GRZ	Insulator	OH Line Hardware
GRZ	Jumpers	OH Line Hardware
GRZ	Wedge grip	OH Line Hardware

b) Alectra Utilities does not have the data necessary to be able to determine if there is a ‘high probability’ that overhead distribution hardware will spontaneously fail due to a deteriorated state. Alectra Utilities can state that deteriorate overhead equipment does spontaneously fail in the absence of some external factors including ice and contamination.

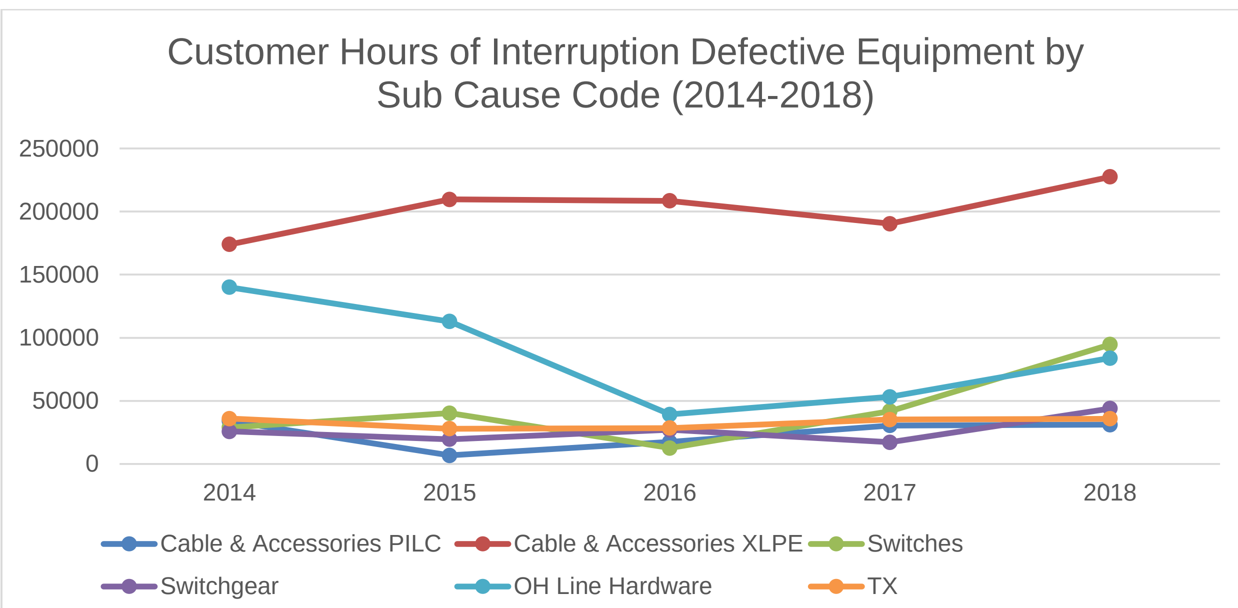
c) Alectra Utilities has provided the proportional and absolute 2014-2018 trends for outages caused by overhead distribution hardware failures in Table 2.

Table 2: Number of Outages Caused by Overhead Line Hardware Failures (2014-2018)

Sustained Outages	2014	2015	2016	2017	2018
OH Hardware Failures	209	170	116	137	151
Alectra Total	5,182	5,468	5,159	5,195	5,364
OH Failures Percentage	4%	3%	2%	3%	3%

d) Please see Figure 1 for the 2014-2018 outage hours caused by each asset category as listed in Figure A05-2.

Figure 1: Customer Hours of Interruption Defective Equipment by Sub Cause Code (2014-2018)



G-Staff-41

Reference:

Please provide the proportional and absolute 2014-2018 trends for outages caused by wood pole and concrete pole failures (i.e. trends should be shown as both the percentage of total annual outages and the total number of outages caused by wood and concrete pole failures).

Response:

Alectra Utilities has provided the proportional and absolute 2014-2018 trends for outages caused by pole failures in Table 1. Please note that only for Brampton Hydro, Guelph Hydro and PowerStream, the record pole failures were identified as a sub cause code under Defective Equipment. Thus, the data below does not include any uncontrollable factors such as Adverse Weather, Adverse Environment, and Foreign Interference. The sub cause code data has no distinction between wood and concrete poles and the distinction between them is not available.

Table 1: 2014-2018 # of Outages Caused by Pole Failures

Sustained Outages	2014	2015	2016	2017	2018
Pole Failures	3	3	4	5	1
Alectra Total	5,182	5,468	5,159	5,195	5,364
OH Failures Percentage	0.06%	0.05%	0.08%	0.10%	0.02%

G-Staff-42

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 19

Regarding planned replacement, Alectra Utilities states:

> **Planned replacement approach applies to critical assets that carry significant risk to the safe and reliable operation of the distribution system and protection of the environment. For example, failure of wood poles carries significant safety risk to the public; therefore, a planned replacement strategy is prudent. In the case of concrete poles, if maintenance is not an option, a planned replacement strategy is applicable.**

a) What is the expected consequence (financial, safety and environmental) for a typical wood pole failure?

b) What is the reasonable worst-case consequence for a typical wood pole failure?

c) What is the consequence that Alectra Utilities uses when calculating the risk for its population of typical wood poles?

d) Please provide evidence (financial, safety, environmental) supporting the selection of this consequence for risk calculation purposes.

Response:

a) The expected consequence of a wood pole failure is the pole falling to the ground with its attached distribution equipment. Such failure can expose the public to safety risks due to the falling objects and exposure to live high-voltage conductors. A falling pole is a reportable incident to Electrical Safety Authority (“ESA”), which can result in an investigation and a potential finding of non-compliance. Alectra Utilities is exposed to financial and legal liabilities resulting from the pole failure should appropriate measures not be taken to remediate hazardous or deteriorated asset conditions.

In instances where the pole is carrying additional equipment such as an overhead transformer, the oil containment can fail leading to an oil leak. Oil spills are reportable and can result in non-compliance in addition to the environmental remediation costs. All of which results in financial and liability implications.

Pole failures result in costly repairs, prolonged outages and complex restoration efforts.

b) A reasonable worst-case scenario is when a pole line experiences pole failure in a high-traffic area – which can result in the failure cascading down a street and exposing the public to a serious safety risk. Alectra Utilities has experienced such events. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 2-6 for more information.

c) Alectra Utilities is guided by Canadian Standards Association ("CSA)" Standard C22.3 No. 1- 10 which states that:

> "When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced."

Based on the condition-based assessment of distribution system poles, pole testing and inspection, as well as past failures, Alectra Utilities is informed that deteriorated poles (poles in Very Poor and Poor condition) and poles susceptible to failure due to adverse weather, pose risks to safety, environment, and compliance.

For safety, the consequence of failure ranges from an injury requiring medical attention to reportable incidents with serious injuries. For environmental risks, the consequence of failure is transformer oil spill with short term (<1 year) clean-up implications. As for compliance risks, non-compliance can result in an administrative order, financial and/or legal penalties ranging from $150k to $500k. The consequences are determined based on CopperLeaf C55 Risk Matrix as provided in Figure 5.4.1-1 in Exhibit 4 Tab 1 Schedule 1 – Section 5.4.1 page 341.

d) As noted in response to part c), Alectra Utilities has identified three areas of risks associated with pole failures according to the CopperLeaf C55 Risk Matrix: safety, compliance, and environmental. All of these risks have financial and/or legal implications.

Safety risks include property damage and physical harm due to the impact of falling objects and exposure to live high-voltage conductors. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 19 of 53, for examples of pole failures resulting in property damage.

A further risk is compliance with external standards and regulations in the event of pole failure, which trigger investigations by ESA that can result in non-compliance and administrative orders.

Furthermore, there is an environmental risk due to oil spills from damaged transformers that can result in additional clean-up costs and non-compliance resulting in financial penalties for environmental violations.

G-Staff-43

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix K, Pages 14-15, 45, 53, 56 and 61

On pages 14-15, the CIMA+ report states:

> **Trees magnify the impact of ice storms. Tree management near distribution lines is an important adaptation action needed to reduce risks of power distribution system outages.**

On page 45, regarding a paper on Best Practice Vegetation Management, CIMA+ states:

> **The report recommends […] using condition based scheduling of vegetation management to optimize the value of funds expended (Reliability Centered Vegetation Management).**

On page 53, regarding PowerStream staff experiences and thoughts on the key issues of the 2013 ice storm, key observation were:

- **Hazard trees/limbs outside the trim zone need to be addressed.**
- **Overhead secondaries are not part of the tree trimming program; this is where a number of the problems were.**
- **Most failures were in heavily treed side streets and rural areas.**

On page 56, regarding reliability good utility practice in vegetation management, the CIMA+ report states, amongst other things:

- **PowerStream has adopted a 3 years tree trimming cycle to standard trim clearances including rear lot easements.**
- **PowerStream has adopted an annual vegetation management focus on worst performing feeders.**

On page 61, the CIMA+ report states:

> **Very little if any PowerStream plant was brought down by ice accumulation that one would expect from an ice storm.**

a) **Please confirm that during an ice storm, trees are a larger factor in causing outages than direct loading on structures.**

b) **Please indicate if Alectra Utilities has plans to implement reliability centered vegetation management programs in lieu of increased capital spending.**

    i. **If yes, please provide the details of the vegetation management program.**

ii. If no vegetation reliability-centered management programs are being proposed in lieu of capital programs, please provide the business case of the decision not to increase the vegetation management program.

c) Please confirm that Alectra Utilities will implement good utility practice in vegetation management, equivalent to that which is described in the CIMA+ report for Powerstream.

d) If not, please describe what vegetation management practice Alectra Utilities will implement in terms of planning, timing and rationale.

Response:

a) During the ice storms, vegetation and trees with heavy accumulation of ice are one of the largest factors in causing outages. Alectra Utilities has experienced failures and outages due to accumulated ice and winds without the presence of trees and vegetation. Further, some overhead assets in a deteriorated condition are unable to maintain the increased loading due to ice. Under these conditions, wires and poles can no longer sustain weight and can cause the structure to collapse.

b) Alectra Utilities' Vegetation Management Program ("VMP") includes Reliability-Centered Maintenance. The VMP is based on proactive vegetation management on defined cycles. Further, Alectra Utilities also performs an annual Worst-Performing Feeder analysis that identifies underperforming areas of the system in terms of reliability and the root causes for underperformance. Where vegetation issues are identified on a feeder as a contributing factor to reliability underperformance, targeted vegetation management activities are performed in order to improve performance.

c) The concept of Good Utility Practice already underpins Alectra Utilities' VMP. While there are some differences in vegetation practices (as a result of specific locational requirements) across Alectra Utilities' service areas, the company continues to harmonize and implement consistent practices. Alectra Utilities' VMP is in alignment and consistent with Alectra Utilities' predecessor, PowerStream VMP in 2013.

d) Please see response to part c).

G-Staff-44

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix K, Page 68

Regarding composite poles, the CIMA+ report states:

> **Compared to wood poles, composite poles are lighter, stronger and have lower conductive properties and are more fire resistant. They are not as vulnerable to rot and insect damage as wood poles are. They also do not lose strength as they age, so require minimal maintenance and inspection needs.**

a) What is the expected useful life of a composite pole?

b) What is the typical driver for replacement of a composite pole, if they do not lose strength as they age?

c) Has Alectra Utilities considered the use of composite poles in its service area? Please explain why or why not.

Response:

a) Alectra Utilities is currently performing a pilot with composite poles, which will further its knowledge of composite poles installation, inspection practices, and deterioration. This information will allow Alectra Utilities to determine the expected useful life of composite poles. At this point, Alectra Utilities has not gathered enough information to estimate the expected useful life. Moreover, Alectra Utilities is not currently deploying composite poles on standard construction.

b) As discussed in response to part a), Alectra Utilities does not have sufficient information to comment on the typical drivers of composite poles replacements.

c) Alectra Utilities continuously examines new solutions and advancements to improve the performance and lifecycle costs of its assets. However, deployment of a new asset class in the distribution system that is critical to the distribution system (i.e., poles) requires extensive research, assessments, and experience before using it as a standard. Alectra Utilities is using the pilot to inform its decision.

G-Staff-45

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix K, Page 75

Regarding suggested practices for design PowerStream should consider adopting, the CIMA+ report lists:

1. **Consider installing periodic ground anchors in the direction of the line in long straight sections to act as dead-end structures (i.e. HQ uses every 10 poles)**
2. **Consider adapting designs to be able to withstand wind gusts of up to 120 km/h in strategic locations (rail and highway crossings, station egress riser poles, 4 circuit poles at corners of major intersections, corner poles, dead end poles, 407 ramp poles, other locations deemed critical by PowerStream) and that require a minimum of guying.**
3. **Consider having poles containing 2 or more primary circuits to be designed to Grade 1 construction standards (Safety factor = 2.0). This is the standard practice in major utilities such as Hydro Quebec, BC Hydro and ATCO.**
4. **Consider using non-wood poles for 3 or more primary circuits based on the advantages previously mentioned and the increased load at risk**
5. **Consider a 70% strength replacement target for Grade 1 construction.**
6. **Consider moving existing flood sensitive equipment above grade in existing stations.**

a) **Have economic optimizations been carried out to determine which of these adaptations provides the greatest performance benefit for the least cost?**

   i. **If yes, please provide the analysis/optimizations that have been carried out.**

b) **Which, if any, of these adaptations are proposed to be implemented in the present DSP? Please provide references to the DSP projects or programs under which the selected adaptations will be implemented.**

Response:

a) Economic optimizations were not carried out to determine which of these adaptations provides the greatest performance benefit for the least cost. CIMA+ presented the six suggested practices as design considerations that could be adopted by PowerStream for overhead construction and for station infrastructure.

Alectra Utilities considered the suggested practices and determined that some of suggested practices would not be practical or affordable.

Suggested Practice 1: Installing periodic ground anchors in the direction of the line in long straight sections to act as dead-end structures, is a theoretical possibility but is not practical in Alectra Utilities' largely urban areas. These anchors, at most locations, do not have adequate space to accommodate additional ground anchors. Placing in line anchoring will be problematic for roadways and driveways that are perpendicular to the lines, and will be in conflict with trees in many locations. Obtaining municipal approval is also problematic given the desire of municipalities to reduce above grade facilities, not increase them.

Suggested Practice 3: Poles with 2 or more primary circuits to be designed to Grade 1 construction standards is approximately 25-30 % higher in cost than Grade 2 construction.

Suggested Practice 5: Consider a 70% strength replacement target for Grade 1 construction: Alectra Utilities currently uses the current CSA guide of 60% strength replacement for all poles. Raising the strength threshold to 70% will lead to a substantially higher number of poles to be replaced under the pole renewal program.

b) Alectra Utilities considered the suggested practices and several have been incorporated in its standards and design methodology:

Suggested Practice 4: Alectra Utilities has a standard for concrete poles and these are being applied in select locations where the overhead consists of 3 or more primary circuits and is to be placed in their ultimate locations.

Suggested Practice 2: As per the requirements of CSA standards, Alectra Utilities has adapted Grade 1 construction for railway crossings, river crossing & highway crossings. In addition, Grade 1 construction is being adapted for poles with longer spans (76m).

Suggested Practice 6: Alectra Utilities has plans to move the existing flood sensitive station equipment to above grade at the existing stations included in the DSP.

Alectra Utilities has considered the suggested practices and incorporated them in projects that will be implemented in the DSP. Suggested Practices 4 & 2 are applied on a selective basis where concrete poles will be used for 3 or more primary circuits and Grade 1 construction will be used for crossings and spans which exceed 76m. Refer to the Storm Hardening project in Exhibit 4, Tab1, Schedule 1, Appendix A05 Page 36. Additionally, these will be applied for all projects which involve building new overhead lines or rebuilding overhead lines with additional circuits which are listed under Exhibit 4, Tab1, Schedule 1, Appendix A12, Page 26.

Suggested Practice 6 is reflected in the plans to move the existing flood sensitive station equipment to above grade at some transformer stations, specifically for one station each in Markham, Richmond Hill and Vaughan. Refer to Appendix A08– Substation Renewal.

G-Staff-46

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 49 of 53

Alectra Utilities states that its future voltage conversion expenditures between 2020-2024 total $49.4 million. Further, Alectra Utilities states that, starting in 2020, its voltage conversion spending is expected to remain relatively consistent year-over-year and will continue its level of investment until completion of voltage conversion work.

a) How many remaining kilometers of low voltage lines will exist in Alectra Utilities' service area at the end of 2019, by voltage class?

b) How many kilometers of low voltage lines will be converted in each year from 2020 to 2024, by voltage class?

c) In what year does Alectra Utilities expect to complete its voltage conversion work?

Alectra Utilities notes reliability improvements and efficiencies as outcomes of voltage conversion. In particular for efficiencies, Alectra Utilities states that "Converting to modern voltages will also create efficiencies, since this eliminates the need for having a utility owned substation, hence, avoiding ongoing capital and maintenance costs."

d) What is the impact of voltage conversion on reliability? Please quantify the impact in terms of SAIDI and SAIFI metrics.

e) Has Alectra Utilities quantified the cost savings arising from the efficiencies identified above?

i. If yes to e), please provide the amount of savings in capital and O&M. Also please indicate whether the savings have been reflected in Alectra Utilities' forecasted capital and O&M spending.

ii. If no to e), why has Alectra Utilities not quantified the amount of cost savings?

Response:

a) Alectra Utilities projects to own and operate 1,088 km of low voltage lines in its service areas at the end of 2019. Of that total, Alectra Utilities projects to operate 950 km of 4kV and 138 km of 8kV lines.

b) Alectra Utilities plans to convert a total of 95 km of low voltage lines from 2020 to 2024 which comprises of 57.5 km of 4.16kV and 37.5 km of 8.32 kV lines. Please refer to (Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 38 of 53, line 9) for additional information regarding the areas of conversion. Table 1, below provides the approximate number of km's of low voltage lines that will be converted each year by voltage class. Please note that km of lines converted cannot be correlated to capital spend for that year as the scope of work, complexity and cost of voltage conversion varies from each target area.

Table 1 – Number of Km of Low Voltage Lines Planned to be Converted (2020-2024)

Year	Distance (km)	
	4.16kV	8.32kV
2020	17.5	11.5
2021	8	11.5
2022	8	14.5
2023	5	-
2024	19	-

c) Alectra Utilities has not established a finite timeline to convert all low voltage systems in its service area. Over the period of the DSP, Alectra Utilities plans to covert 95km of 1,088km of low voltage lines which represents 8.7% of the low voltage system.

d) Alectra Utilities has targeted and prioritized voltage conversion in areas where reliability performance is above the system average. Although the customers impacted by the voltage conversion project are expected to experience significant benefits in terms of reliability improvement, the overall System Average Interruption Duration Index is expected to improve by 0.03 hours and the System Average Interruption Frequency Index is projected to improve by 0.02 upon the completion of all the voltage conversion projects presented in the 2020-2024 DSP.

e) Alectra Utilities has estimated both Capital and OM&A avoided costs resulting from voltage conversion projects. In aggregate, for all voltage conversion and in alignment with Alectra Utilities' Value Framework methodology explained in section 5.4.1 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 334), Alectra Utilities projects capital savings of $37.41MM and

OM&A savings of $0.93MM through the completion of all voltage conversion projects over the DSP period 2020-2024. These capital savings result in a reduction to what otherwise would be cost increases in the stations renewal spending for rebuilding of these low voltage stations. Please refer to SEC-1 on further information related to OM&A.

G-Staff-47

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 14 of 53

As part of Overhead Asset Renewal, Alectra Utilities has included investments for the replacement of switches. The following table shows the three pacing options Alectra Utilities considered for its switch renewal.

Table A05 - 12: Overhead switches pacing options

Strategy	Plan period (years)	Switches Remediated Per Year			Total Switch Renewal Plan Cost per year ($MM)
		Total	Through Other Investments	Through Switch Renewal	
Strategy 1: Accelerated pace	5	66	9	57	$3.0
Strategy 2: Moderate pace	7.5	44	9	35	$2.2
Strategy 3: Reduced pace	10	33	9	24	$1.3

a) Please indicate the anticipated annual impact on reliability in terms of SAIDI and SAIFI metrics of each of the three pacing options.

Using the values provided in the table above, OEB staff calculates the following unit costs of switch replacement:

Strategy 1: $3,000,000 / 57 = $52,632 per switch
Strategy 2: $2,200,000 / 35 = $62,857 per switch
Strategy 3: $1,300,000 / 24 = $54,167 per switch

b) Please explain why strategy 2 has a significantly higher unit cost compared to strategies 1 and 3.

Response:

a) The projected annual impact on reliability in terms of SAIDI and SAIFI metrics for each of the three (3) overhead switching renewal pacing strategies is provided in Table 1, below.

Table 1 – Projected Annual SAIDI and SAIFI Impact on Three Pacing Strategies for Overhead Switch Renewal

Strategy	SAIDI (Hours)	SAIFI (Interruptions)
Strategy 1: Accelerated pace	0.041	0.010
Strategy 2: Moderate pace	0.025	0.006
Strategy 3: Reduced pace	0.017	0.004

b) The cost of overhead switch equipment varies by the voltage levels and inclusion of automation of the switch.

For the reduced pace strategy, Alectra Utilities considered a higher number of manual switches to be used as replacements in order to maximize the number of deteriorated and failing overhead switches.

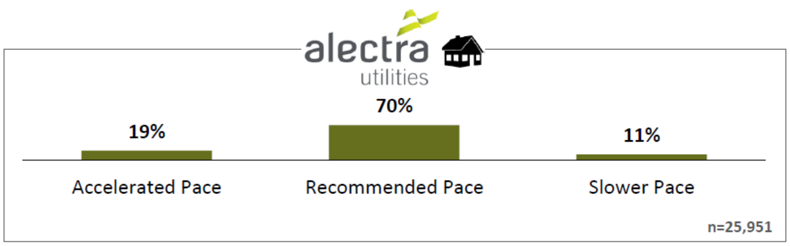
For the moderate pace strategy, Alectra Utilities incorporated more automated switches which increased the per unit cost relative to the reduced pace strategy which considered a higher proportion of manual switches. The inclusion of renewing overhead switches with automated units reflects customer preferences to include system automation improvements during ongoing system renewals.

For the accelerated pace strategy, Alectra Utilities adds onto the moderate pace strategy with more manual switches in order to renew a high number of overhead switches. While the accelerated pace has the benefit of a higher number of overhead switch replacements in order to achieve a higher SAIDI impact at a relatively lower cost increase, the drawback of increased manual units without automation limits the amount of additional reliability benefits from automation.

G-Staff-48

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 43

Alectra Utilities collected the follow customer preferences for overhead system renewal through its customer engagement efforts:



Rate Zone Breakdown	ERZ	BRZ	HRZ	PRZ
Accelerated Pace	19%	23%	21%	14%
Recommended Pace	71%	63%	70%	73%
Slower Pace	10%	14%	9%	13%

Please explain why Guelph rate zone customers were not consulted on overhead system renewals.

Response:

For the Guelph Rate Zone, all the pole replacement capital investments were included in base capital and there is no proposed M-factor bill impact associated with the investment.

G-Staff-49

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix C, Voluntary Online Workbook, Page 24

On page 24 of the voluntary online workbook, Alectra Utilities communicated to customers that the expected outcome of its overhead system renewal is to "Address all of the poor and very poor poles in system by 2024, as well as all the poles prone to catastrophic failures under adverse weather conditions."

a) Did Alectra Utilities provide customers with context to define what is meant by "catastrophic failures under adverse weather conditions"?

b) What evidence was presented to customers explaining the probability of "catastrophic failures"?

c) How does Alectra Utilities determine which poles that are not in poor or very poor condition are "prone to catastrophic failures"?

Response:

a) Alectra Utilities did not specifically define "catastrophic failures under adverse weather conditions" in the Customer Engagement workbook, however, it is generally understood to mean "involving or causing sudden great damage"[1].

b) Alectra Utilities did not provide the probability of catastrophic failures of the poles. However, Alectra Utilities confirms that there have been a few catastrophic failures of these four circuit poles. These poles are on major streets and have the potential to cause significant harm to the public and workers in the event of failure.

c) Alectra Utilities has identified specific wood poles that carry four circuits and do not confirm to the modern construction standards that are prone to catastrophic failures. Please refer to Exhibit 4, Tab1, Schedule 1, Appendix A05 page 16.

[1] Canadian Oxford Dictionary

G-Staff-50

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A07, Pages 3, 13 and 15 of 21

The following tables are taken from Appendix A07:

Table A07 - 1: Investment Subgroup Drivers and Outcomes Summary

	Historical Expenditure				Bridge	ForecasteExpenditure				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPEX ($MM)	$4.0	$4.6	$3.4	$0.0	$5.1	$4.8	$1.2	$1.2	$4.2	$8.5
Primary Driver:	Functional Obsolescence									
Secondary Drivers:	Reliability, Safety									
Outcomes:	Customer Value, Reliability, Safety, Environment, Efficiency									

Table A07 - 4: Average SAIFI/SAIDI Statistics (2015-2017) for Proposed Project Areas

Project		Year	Average SAIDI (min) 2015-2017	Average SAIFI 2015-2017
150399	Rear Lot Conversion - Richlieu Dr and Trelawne Dr	2023-2024	87	40
150044	Rear Lot Supply Remediation - Blake/Kempenfelt	2020	132	0.66
150043	Rear Lot Supply Remediation - East of Queen St. to Eastern Ave./North of Greenway St.	2020	582	1.7
150047	Rear Lot Supply Remediation - Royal Orchard – North	2020-2022	243.60	3.21
150378	Rear Lot - East of Queen Street/North of Mill Street	2023	516	1
150330	Rear Lot Conversion – Marsdale	2023-2027	67.4	19.2
150380	Rear Lot - Gunn/Oakley Park/St.Vincent	2024	780	1
150329	Rear Lot Supply Remediation - Main Street / Unionville / Carlton	2024-2026	100.8	0.50
150397	Rear Lot Conversion - Riverview Blvd and Northcliffe	2024	70.1	16.9
150398	Rear Lot Conversion - Strathcona Dr	2024	21	44
			260	12.82

a) **Per Tables A07 – 1, what is driving the significant inter-annual variability in the rear lot investment subgroup?**

b) **Per Table A07 – 4:**

   i. **What is the expected improvement in Average SAIDI and SAIFI for each of the listed projects?**

   ii. **What is the total capital cost of each of the listed projects?**

iii. Is this the complete list of projects covered under Tables A07 – 1? If no, please provide the complete list.

c) What is the overall expected impact of completing the planned 2020 - 2024 rear lot conversions on Alectra Utilities' overall SAIDI and SAIFI performance?

Response:

a) Alectra Utilities' DSP capital investment plan is based on a bottom up portfolio of capital investment projects optimized through CopperLeaf C55 software to produce maximum value. The decrease in rear lot renewal in 2018 was the result of project deferrals to allow Alectra Utilities to reallocate capital funding to more pressing and urgent investments. The decrease in rear lot conversion investments in 2021 and 2022 is a result of the allocation of capital funding to other investments in those respective years. Please refer to Section 5.4.1 of the DSP for a detailed explanation of Alectra Utilities' capital investment optimization process.

b) (i) Alectra Utilities expects that with the implementation of the rear lot renewal of the projects presented in Table A07-04, the reliability for the customers in the areas will improve to historical system reliability levels (i.e. SAIDI of 0.98 hours and SAIFI of 1.34 interruptions).

(ii) and (iii) Table 1 below, provides a complete list of all rear lot conversion projects included in the DSP and the respective capital cost of each project. Further details are provided in Exhibit 4, Tab 1, Schedule 1, Appendix A07.

Table 1 – Project and CAPEX ($MM)

Project Code	Project Name	CAPEX ($MM)
151085	GUELPH - Rear Lot Conversions	$0.6
150043	Rear Lot Renewal Project - East of Queen St. to Eastern Ave./North of Greenway St.	$2.6
150047	Rear Lot Renewal Project - Royal Orchard - North	$4.0
150378	Rear Lot Renewal Project - East of Queen Street/North of Mill Street	$1.8
150044	Rear Lot Renewal Project - Blake/Kempenfelt	$0.3

150329	Rear Lot Renewal Project - Main Street / Unionville / Carlton	$2.5
150380	Rear Lot Renewal Project - Gunn/Oakley Park/St.Vincent	$1.8
150399	Rear Lot Renewal Project - Richlieu Dr and Trelawne Dr, St.Catharines	$2.4
150398	Rear Lot Renewal Project - Strathcona Dr	$0.9
150330	Rear Lot Renewal Project – Marsdale	$3.1

c) Due to the low number of rear lot projects proposed over the 2020-2024 period, the impact of planned rear lot conversion projects is not expected to have a meaningful impact to the overall system SAIDI or SAIFI metrics at Alectra Utilities. However, with the renewal of the service, the areas where SAIDI and SAIFI are worse than the system average, the reliability for customers in these areas are expected to improve to historical system reliability levels.

G-Staff-51

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A07, Pages 4-5 of 21

Alectra Utilities states that rear lot conversion will limit operational constraints making it easier for its crews to perform maintenance. Furthermore, Alectra Utilities expects the conversion to eliminate tree trimming activities at these locations as a result of the conversion from overhead to underground.

a) Has Alectra Utilities quantified the amount of O&M savings it expects to achieve through its rear lot conversion projects? If yes, how much. If no, why not?

b) Are the efficiencies identified above reflected in Alectra Utilities' forecasted O&M spending?

Response:

a) Alectra Utilities anticipates nominal O&M savings from the rear lot conversion projects. The conversion of rear lots will eliminate the tree trimming activities for these small pockets which will be converted. Alectra Utilities will still be required to complete the inspections of underground assets as per the requirements of the Distribution System Code.

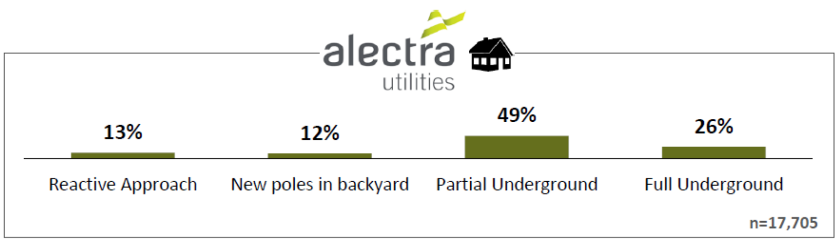
b) The difference between savings from tree trimming activities and inspection of newly installed assets are negligible, and hence not reflected in the forecasted O&M spending.

G-Staff-52

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A07, Page 21 of 21
Reference 2: Exhibit 4, Appendix C, Page 50

Alectra Utilities identifies seven material rear lot conversion projects that it intends to undertake during the DSP period.

Alectra Utilities collected the follow customer preferences for rear lot conversions through its customer engagement efforts:



Rate Zone Breakdown	HRZ	PRZ	GRZ
Reactive Approach	11%	15%	14%
New poles in backyard	11%	13%	9%
Partial Underground	54%	46%	45%
Full Underground	24%	26%	33%

a) **The table above presents the customer preferences taken from a sample of all of Alectra Utilities' customers, not just customers serviced through rear lots. Has Alectra Utilities consulted directly with the customers affected by these projects? If so, what kind of customer engagement efforts has Alectra Utilities undertaken?**

b) **Please explain why Alectra Utilities chose the option of full underground conversion despite a majority of customers choosing the partial underground option.**

Response:

a) Alectra Utilities did attain investment preferences and feedback from customers that are serviced with rear lot distribution. In the second phase of customer engagement, Alectra Utilities consulted with rear lot customers on their preference for design options as well as pacing of conversion and renewal. Please see Figure 1 below, from Appendix C02 Page 53 for the results of customer engagement from customers supplied by rear lot and customers not supplied by rear lot distribution.

Figure 1 – Customer Survey Results (Design) for Rear Lot and Non Rear Lot Customers

Q Converting Rear Lot Service (Design) **by** Service Type

Rate Zone Breakdown	HRZ		PRZ		GRZ	
Service Type	Rear Lot	Not Rear Lot	Rear Lot	Not Rear Lot	Rear Lot	Not Rear Lot
Reactive Approach	11%	11%	13%	15%	19%	14%
New poles in backyard	13%	11%	15%	12%	10%	8%
Partial Underground	49%	55%	44%	47%	38%	45%
Full Underground	27%	23%	28%	26%	34%	34%

b) Where practical and feasible, Alectra Utilities has attempted to implement partial underground conversion. Please refer to appendix A02 - Section 5 where Alectra Utilities has identified the preferred options for rear lot projects. Table 1 provides a list of rear lot conversion projects and the preferred design approach for all projects. The design option chosen for six projects is full underground and for four projects is partial underground.

Table 1 – Preferred Design Approach for all Projects

Project Code	Project Name	Preferred Design Approach
150047	Rear Lot Renewal Project - Royal Orchard – North	Full Underground
150330	Rear Lot Renewal Project – Marsdale	Partial Underground
150043	Rear Lot Supply Remediation - East of Queen St. to Eastern Ave./North of Greenway St.	Full Underground
150329	Rear Lot Renewal Project - Main Street / Unionville / Carlton	Full Underground
150399	Rear Lot Renewal Project - Richlieu Dr and Trelawne Dr,	Partial Underground
150380	Rear Lot Supply Remediation - Gunn/Oakley Park/St.Vincent	Full Underground
150378	Rear Lot Supply Remediation - East of Queen Street/North of Mill Street	Full Underground
150398	Rear lot Renewal Project – Stratcona Dr	Partial Underground

150044	Rear lot Renewal Project- Blake/Kempenfelt	Full Underground
151085	Guelph- Rear lot Conversions	Partial Underground

G-Staff-53

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A18
Reference 2: Exhibit 4, Tab 1, Schedule 1, Page 369 of 438

Alectra Utilities provides the following table outlining its historical and forecast capital spending on Information Technology Systems:

Table A18 - 1: Information Technology Systems Investment Plan, Drivers and Outcomes

	Historical Spending				Bridge	Forecast Spending				
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CAPEX ($MM)	$24.8	$9.2	$5.0	$4.8	$10.2	$15.1	$18.2	$19.8	$12.3	$8.4
Primary Driver:	System Capital and Maintenance Investment Support									
Secondary Drivers:	Functional Obsolescence									
Outcomes:	Efficiency, Customer Value, Reliability, Safety, Cyber Security and Privacy, Coordination and Interoperability, Environment									

On page 369 of 438, Alectra Utilities notes that the increase in forecast spending on Information Technology in comparison to historical expenditures is "…related to the deferral of projects in historical years so such investments could be further evaluated, prioritized and executed by Alectra Utilities as a consolidated entity to maximize efficiency gains and value creation."

a) What studies or analysis did Alectra Utilities perform to re-evaluate its Information Technology Systems investment plan?

b) Please discuss specific efficiency gains and value creation achieved through Alectra Utilities' re-evaluation and re-prioritization.

c) Has Alectra Utilities achieved cost savings through post-consolidation reprioritization compared to pre-consolidation investment plans? If yes, what is the amount of savings? If not, why has Alectra Utilities not been able to achieve cost savings?

On page 6 of Appendix A18, Alectra Utilities indicates that $10.4 million of its IT investments will be used to improve its Customer Care and Billing (CC&B) system in order to comply with regulatory requirements and enhance customer experience.

d) What regulatory requirements are the improvements to CC&B intended to meet?

e) Has Alectra Utilities engaged customer feedback for preferences on capital spending to improve customer experiences with CC&B systems? If yes, what feedback did Alectra Utilities receive? If no, why not?

On page 28 of Appendix A18, Alectra Utilities indicates that $10 million was spent in 2015 on replacing the CC&B system in Alectra Utilities' eastern operating area.

f) Please explain why additional investment is needed in the CC&B system given the 2015 investment and please explain what the differences are between the new proposed system and the 2015 system.

Response:

a) In 2015, once it became probable that an Alectra Utilities merger would proceed, work commenced to evaluate what Alectra Utilities' preferred IT systems, as well as applications and technologies would be, post consolidation. As a result, capital spending on systems, applications and technologies not identified as being part of the future Alectra Utilities preferred IT end-state solution were restricted to only those that were absolutely necessary investments to keep the systems operating; enhancements or upgrades were not approved. By deferring IT investments where possible, Alectra Utilities reduced the risk that near-term spending would be made redundant by the impending consolidation.

Alectra Utilities was formed in 2017. The IT capital expenditure, post-consolidation, was largely focused on migrating the predecessor utilities onto Alectra Utilities' preferred IT end-state solution. These integration-related IT investments (2017 to 2019) were part of the merger transition projects.

The capital investments included in Table A18 from 2020 onwards, relate to post-integration priorities. The majority of the systems have been integrated; all predecessor utilities have migrated onto these systems and are functioning as intended in accordance with the merger business plan. These investments include deferred capital investments relating to enhancements or upgrades that are now being proposed. This is what is meant by deferring these investments until Alectra was consolidated; the investments are now focused on one solution set for Alectra's IT needs, on a more simplified IT architecture.

The analysis and prioritization process that was followed in recommending these projects is similar to the approach used for Alectra Utilities' distribution assets. All projects investments were evaluated and prioritized using the C55 software tool and evaluated along with all other capital investment proposals.

b) The efficiency gains and value creation referred to by Alectra Utilities in its Application was in reference to the fact that deferring capital investments in these IT systems until post-integration (i.e., reducing four systems down to one), would result in improvements to Alectra Utilities' cost structure as a consolidated entity. For example, capital investments required for regulatory changes to billing systems will result in an efficiency gain since only one billing system needs to change as opposed to four billings systems prior to the merger.

c) As identified in the Merger Business Case, filed as part of Alectra Utilities' MAADs Application (EB-2016-0025), Alectra Utilities has achieved synergies due to consolidation of IT systems, applications and technologies (EB-2016-0025, Exhibit B, Tab 5, Schedule 5, page 6). Specifically, by reducing the number of systems and applications that it maintains, Alectra Utilities has been able to reduce its IT operating costs by reducing staff by 20%. As well, prior to the merger, the four predecessor utilities had planned capital investments totaling $89MM for the period 2016 to 2020. The actual and forecast capital expenditure listed in Table A18-1 above, for the period 2016 to 2020, is $44.3MM, reflecting a post-consolidation re-prioritization savings of $44.7MM over the period.

d) Alectra Utilities must maintain the Customer Care and Billing ("CC&B") system, in order to ensure that the utility remains compliant with regulatory requirements. Over the last three years, Alectra Utilities needed to implement regulatory or government changes on an annual basis, including the following:

- 2017
    - The Fair Hydro Plan rebate and Ontario Electricity Support Program
    - Residential Disconnection Moratorium / Disconnection Ban
    - ICI Global Adjustment Expansion
    - Elimination of the Clean Energy Benefit Program
    - Implementation of monthly billing
- 2018
    - ICI rules changes
    - Elimination of the Debt Retirement Charge for all consumers
- 2019

- Energy Retailer Service Charges
- Customer Service Rules
- Rates Mitigation and Bill messaging

While Alectra Utilities cannot predict the specific regulatory and compliance requirements that will be required in future years, the utility forecasts an annual cost of $0.9MM to implement such changes based on historic requirements.

e) Alectra Utilities has not specifically engaged customer feedback for preferences on capital spending to improve customer experiences with CC&B systems. These investments are to automate internal processes related to the billing function which will result in productivity gains, reduced costs and improved service to customers.

f) The investment referenced at page 28 of Appendix A18 was made in 2015 by PowerStream (which is now Alectra Utilities' eastern operating area). This investment updated PowerStream to version 2.3 of Oracle's CC&B platform which supports 350,000 customers.

Post-consolidation, Alectra Utilities' one million customers have now migrated to this common platform. In 2020/2021 work will commence to upgrade CC&B for 2022. The CC&B system will be 7 years old and the upgrade is required: to ensure continued vendor support; update security; and continued use and access of CC&B for maintenance and operability alongside other systems.

Finally, as identified in the related business case, the Oracle License will require renewal, in order to ensure continued use of the application.

G-Staff-54

Reference: Exhibit 4, Tab 1, Schedule 1, Page 168 of 438

On page 168, Alectra Utilities states that it "…executes capital project design and construction through a combination of internal resources and external contractors."

OEB staff notes that Alectra Utilities has included external contractors in most of its investment summary execution plans.

a) Given that Alectra Utilities expects a steady, but significant, increase to its annual capital expenditures, has Alectra Utilities considered hiring additional internal staff instead of leveraging external contractors?

b) Has Alectra Utilities performed any analysis on the cost effectiveness of using external contractors versus hiring additional internal staff? If yes, please provide the analysis. If no, why not?

Response:

a) Alectra Utilities leverages external contractors to complete capital work during peak construction periods, including projects with timelines that overlap with other projects already allocated to internal resources. Alectra Utilities also leverages external contractors to complete work that require a specialized skillset or unique equipment. With a compressed construction season for road widening and other time bound construction, hiring internal resources to a peak level that would accomplish all required work during the peak construction season would not be sustainable nor cost effective during periods of time with lower activity of construction.

b) Alectra Utilities has not completed a cost analysis on hiring additional internal resources. As explained in part a) above, Alectra Utilities utilizes external contractors to complete work during peak construction periods where internal resources are already allocated, as well as for work that requires specialized skillset or unique equipment to complete.

G-Staff-55

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A06, Page 1 of 13
Reference 2: Exhibit 4, Appendix G, Page 31

Alectra Utilities forecasts its reactive capital spending based on historical levels of reactive capital spending. Alectra Utilities forecasts increases in reactive capital spending, despite its proposed increases in system renewal spending, because of the backlog of deteriorated assets and the increasing frequency and intensity of weather events.

a) Please explain why Alectra Utilities expects increases in reactive capital spending if Alectra Utilities' proposed levels of system renewal will maintain or improve asset condition and reliability and if Alectra Utilities is undertaking storm-hardening initiatives.

b) Please discuss the appropriateness of using historical reactive capital spending to forecast future spending in light of the fact that Alectra Utilities has proposed system renewal spending at levels significantly greater than historical levels.

c) Please explain if Alectra Utilities' system renewal programs prioritizes assets that are determined to have a high probability of imminent failure. If so, please explain why reactive spending would not decrease as compared to historical given the increase in system renewal spending that would address equipment prone to failure.

Vanry Associates notes in its DSP Assurance Review Report that:

> **As Alectra Utilities works through the backlog of equipment slated for replacement, we anticipate that the trending increase in reactive spending will slow or possibly reverse, provided that Alectra Utilities invests sufficient resources (financial and human) to ensure that the volume of planned replacements stay ahead of the expected level of deterioration and unplanned failures.**

d) When does Alectra Utilities expect its reactive capital spending to slow and decrease?

Response:

a) Alectra Utilities projects only inflationary increases in reactive capital expenditures over the 2020-2024 period relative to historical actuals. Alectra Utilities DSP is based on the objective to maintain system reliability relative to historical levels. Since reactive expenditures typically occur to address replacement of failed, damaged, and hazardous equipment, in addition to equipment identified for imminent failure, the application of historical reactive expenditures as the basis for future projection is appropriate to match the objective of maintaining reliability levels over the same planning period. Furthermore, the increase in system renewal investments is required to not only address the backlog of deteriorated and failing distribution assets but also to enhance resilience of the overhead system to better sustain adverse weather conditions. Over the planning period of the DSP, Alectra Utilities projects an increasing bubble of deteriorating assets, especially underground cables, which requires Alectra Utilities to increase the pace of renewals to match the pace of deterioration in order to maintain reliability. As Alectra Utilities plans to address the current backlog of deteriorated assets, reactive renewal will continue to be required at historical levels as more assets deteriorate into poor and very poor condition.

b) Alectra Utilities has used historical reactive capital spending to project expenditures based on the rate of deterioration being higher than the rate of renewal. As provided in Exhibit 4, Tab 1, Schedule 1, Page 119, Figure 5.2.3 – 9, customer hours of interruption due to defective equipment is increasing, and the longer an outage takes, the greater the amount of reactive spend required. Vanry supports this decision as provided in Exhibit 4, Tab 1, Schedule 1, Appendix G, Page 31. Vanry states (emphasis added):

> *"As Alectra works through the backlog of equipment slated for replacement, we anticipate that the trending increase in reactive spending will slow or possible reverse, provided that Alectra invests sufficient resources (financial and human) to ensure that the volume of planned replacements stay ahead of the expected level of deterioration and unplanned failures."*

Alectra Utilities has determined that the rate of reactive spending will slow, as the rate of renewal matches the rate of deterioration. Alectra Utilities plans to increase the rate of renewal to match the rate of deterioration but given that a higher number of assets are expected to reach end-of-life in the near term, Alectra Utilities requires reactive renewal expenditures to maintain system reliability levels, and not defer planned renewals to offset unanticipated failures and damage from storms. In the second round of customer engagement, over 80% of residential customers prefer that Alectra Utilities establish an annual allocation for these unplanned repairs and replacement so that there is no need to defer urgent and necessary planned renewal work (Exhibit 4, Tab 1, Schedule 1, Appendix C02, Page 36).

c) Please see Exhibit 4, Tab 1, Schedule 1, Section 5.3.3, Pages 227 to 310 for Alectra Utilities process for system renewal investment optimization. Please also see response to part b), above.

d) Alectra Utilities has determined that the rate of reactive spending will slow once the rate of renewal matches the rate of deterioration and Alectra Utilities is able proactively manage defective equipment, and the condition and resilience of the overhead system matches the requirements needed to withstand the increasing severity of adverse weather conditions. As presented in Figure 5.0 – 8 Long Term System Renewal Trends in the DSP (Exhibit 4, Tab 1, Schedule 1, Page 12), implementation of the proposed capital investments in the DSP will allow Alectra Utilities to match the rate of planned renewal with the rate of asset deterioration in 2027.

G-Staff-56

Reference 1: Exhibit 4, Tab 1, Schedule 1, Page 49 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Pages 51-52 of 438
Reference 3: Exhibit 4, Tab 1, Schedule 1, Page 374 of 438

Alectra Utilities states that it is committed to achieving efficiencies that will drive cost savings in operating, maintenance and administration (OM&A) spending. Alectra Utilities expects that asset lifecycle optimization activities and enhanced asset management planning will result in savings for OM&A.

Alectra Utilities provides the following table showing its historical and forecasted system O&M costs:

Table 5.4.2 - 8: System O&M Costs 2015-2024

in $MM	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Planned	2021 Planned	2022 Planned	2023 Planned	2024 Planned
O&M	$104.4	$108.0	$101.9	$99.2	$102.6	$103.5	$104.9	$106.4	$108.7	$110.9

a) **Please quantify:**

   i. **The amount of OM&A savings by year from synergies achieved through the formation of Alectra Utilities (i.e. efficiencies arising from the merger and consolidation of Alectra Utilities' predecessor utilities).**

   ii. **The amount of OM&A savings by year from the proposed increase in capital spending to be funded by the M-factor.**

b) **Please identify the sources of the savings described in part a).**

c) **Have the savings quantified in part a) been reflected in the O&M forecast above?**

   i. **If yes to c), please explain why significant decreases in O&M have not occurred despite the savings.**

   ii. **If no to c), please update the O&M forecast or explain why these savings have not been included in the O&M forecast?**

d) **Please explain why Alectra Utilities has not proposed to use the OM&A savings from a) ii. above associated with the incremental M-factor capital spending to offset the revenue requirement of the M-factor.**

On pages 51-52 of 438, Alectra Utilities has identified productivity savings in the areas of:

- **Work planning and scheduling ($2 million annually)**

- **Job costing analysis ($1.5 to $3 million annually)**
- **Electronic timesheets and inventory ordering ($1 million annually)**
- **Customer central intake process ($0.75 million)**

e) Have the productivities above been captured in 1) capital project costs and/or 2) forecast O&M costs above, and 3) in response to part a) above?

i. If yes to e), please quantify the amounts and explain why significant decreases in O&M have not occurred despite the savings.

ii. If no to e), why have these savings not been included?

Response:

a) i) Please see response to G-Staff-15 a).

ii) As provided in Exhibit 4, Tab 1, Schedule 1, p. 374, the trade-offs between capital and O&M costs were considered within section 5.3.3.5, Impact of System Renewal on Maintenance, of the DSP. The year over year increases over the planning period are less than 2% reflecting only inflationary impacts. Overall, the expectation is that the capital investment impact on O&M costs will be relatively minimal. Investments in system renewal that are designed to replace functionally obsolete, deteriorated and end-of-life assets may contribute to a gradual and modest reduction in required maintenance.

b) Gross Operating synergies represent payroll and non-payroll cost savings. Payroll savings result from redundant positions largely in administration and back-office functions. Non-payroll savings principally comprise reduction of third-party costs, consolidation of contracts and services, volume discounts, and consolidation of systems.

c) Yes, a portion of the net synergy savings quantified in response to G-Staff-15 a) have been reflected in the System O&M costs. No additional savings from the proposed increase in capital expenditure has been quantified. As provided in response to part a) ii), any additional savings from the capital investment impact on O&M costs will be relatively minimal. The year over year increases over the planning period of less than 2% only reflect inflationary impacts.

d) Please see Alectra Utilities’ response to G-Staff-15 b).

e) Alectra Utilities has not included any future productivity savings in the capital or operating forecasts. Please see Alectra Utilities’ response to G-Staff-15.

G-Staff-57

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A11

Alectra Utilities states that its Supervisory Control and Data Acquisition (SCADA) and Automation investments will allow it to defer near-term capital investments and reduce the amount of work performed by field crews.

a) Please explain what capital investments have been deferred as a result of SCADA and Automation investments and indicate the amount of deferred capital.

b) Does Alectra Utilities expect a decrease in O&M spending as a result of automation reducing the amount of field crew work needed?

i. If yes, please provide the amount and indicate whether this is included in Alectra Utilities' forecasted O&M spending.

ii. If no, please explain why not.

Response:

a) The application of SCADA enabled switching and other automation switching investments enable Alectra Utilities to more effectively provide back-up, improve system utilization through active switching and load balancing, and provide the capability to expeditiously restore the system from outages through remote operations. The implementation of SCADA and automation also provide reliability benefits, as provided in Exhibit 4, Tab 1, Schedule 1, Appendix A11, Page 5, Lines 9-17, where automation is an alternative solution to address worst performing feeders as compared to rebuilding. Distribution Automation allows for a direct impact on SAIDI and sometimes SAIFI that can defer other investments, which ultimately are required, but can be paced as reliability has been improved.

b) Please see Alectra Utilities' response to SEC-1.

G-Staff-58

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A19, Page 6 of 25

On page 6, Alectra Utilities indicates that it has retained Mercury Associates to produce a vehicle utilization study.

a) When does Alectra Utilities expect the vehicle utilization study to be completed?

b) How will Alectra Utilities use the vehicle utilization study to inform its fleet renewal investments?

c) If the conclusion of the vehicle utilization study is to reduce the size of Alectra Utilities' fleet, how will this be accomplished given that Alectra Utilities is already making investments to renew its fleet?

Response:

a) The vehicle utilization study is expected to be completed in Q4 2019.

b) Once the final vehicle utilization study report has been reviewed, Alectra Utilities will develop and implement an action plan, as necessary. The outcome of the study will help to inform Alectra Utilities' vehicle replacement approach, prospectively.

c) Alectra Utilities does believe it can reduce its fleet and this has been considered in this DSP. Alectra Utilities is not proposing to replace vehicles that are disposed of and that are underutilized during this DSP period. Alectra Utilities is proposing to replace only those vehicles that are fully utilized and that will be at or beyond their end of life in each year of the DSP period as stated in Exhibit 4, Tab 1, Schedule 1, Appendix A19 – Fleet Renewal, page 10.

G-Staff-59

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A14, Page 1 of 28

On page 1, Alectra Utilities indicates that its proposed investments in monitoring equipment "… will be able to defer significant capital investments."

Please discuss what significant capital investments Alectra Utilities has been able to defer and how this has been reflected in Alectra Utilities' proposed capital expenditures.

Response:

As provided in Section 5.4.3 Subsection C.2.4 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 387 of 438), Alectra Utilities plans to mitigate the need to rebuild or construct new stations by applying monitoring technologies, investing in environmental protection measures and feeder ties. Over the DSP period, Alectra Utilities expects to be able to defer certain station renewal investments that would otherwise be needed. For the 2015-2019 period, Alectra Utilities (including its predecessors) spent approximately $44.7MM on projects related to renewing station assets. For the 2020-2024 period, Alectra Utilities plans to invest approximately 28.7MM on investments associated with station renewal, a reduction of $16MM over a five year period.

Through the application of monitoring technologies, Alectra Utilities will continuously and remotely monitor critical station assets to mitigate risk and impacts of failure. Monitoring technologies enable real-time observation of combustible gasses in power transformers, oil temperature as well as other key performance telemetry data. Through the continuous monitoring of critical station assets, Alectra Utilities is able to practice Reliability Centered Maintenance ("RCM") on these assets. RCM is a structured process and methodology used to extend asset life through analysis to determine optimal action based on condition and operational criteria.

Secondly, Alectra Utilities plans to implement spill containment solutions to minimize the potential environment impacts of power transformer failure where adequate containment does not currently exist. As of 2018, Alectra Utilities operates 106 municipal substations ("MS") that do not have oil containment systems. Without oil spill containment, leaks from failed power transformers result in severe environmental damages to the area within and outside of the station, impacting public and private neighbouring lands as well as bodies of water.

Alectra Utilities also plans to leverage the larger inventory of spare power transformers under the consolidated entity, relative to predecessor utilities. The availability of larger inventory of transformers enables the company to have in place and to implement if needed, contingency plans that allow for it to continue using transformers that would typically be considered to be beyond the end of their useful life. As identified in the 2018 Asset Condition Assessment (Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 73), Alectra Utilities operates 34 power transformers that are in poor condition. Over the 2020-2024 DSP period, Alectra Utilities plan on renewing only two power transformers.

Together, the investment strategy in monitoring technologies as well as oil containment and ability to leverage its consolidated inventory of spare station equipment will enable Alectra Utilities to defer specific and more costly station renewals.

G-Staff-60

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix B, Pages 121-123 of 490

OEB staff notes that, for the purposes of calculating quantitative customer impacts, Alectra Utilities' methodology uses a generic frequency of failure for all of its business cases, rather than using the actual frequency of failure specific to the project area.

As an example, the business case for Project #150141 – M49 Cable Replacement uses the following methodology for calculating the quantitative customer impacts:

> **Frequency of Failure is: 0.25 failures per 1000 m of cable per year**
> **For 3762 m of cable in the whole area:**
> **Frequency of Failure is: 0.25 x 3762 /1000 = 0.9 failure(s) [annually]**

The business case also states that "There was 1 failure in 2014 (Total of 1 failure from 2012 to 2017)."

a) **Given that the actual annual rate of failure is 0.2 failure(s) (1 failure / 5 years), as opposed to 0.9 failure(s), please explain how Alectra Utilities' methodology above is an appropriate or accurate way of calculating the quantitative customer impacts.**

b) **Does Alectra Utilities use the quantitative customer impacts shown in its business cases as an input to its optimization software for prioritizing its projects?**

c) **Please explain why Alectra Utilities does not use the actual historical number of outages specific to the project area to calculate the quantitative customer impacts.**

Response:

a) In the specific case of Project #150141 – M49 Cable Replacement, although the historical annual rate of failure over the 5-year period (2012-2017) is 0.2, the future annual rate of failure reflects the overall average rate of failure for deteriorated cable in the system. In this case, the estimate of 0.9 failures per year for the neighborhood, serviced by 3,762 meters of cable, is reasonable given that there are several neighborhoods of comparable size in Alectra Utilities' service territory that have experienced several failures in one year. The cable may not fail in a given year but may fail numerous times the following year. In this case (Project #150141), there was 1 failure in 2018, which demonstrates that the estimate of 0.9 failures per year is reasonable.

It should be noted that the estimate of 0.25 failure per 1000m per year does not represent there will always be 0.25 failures every year. Instead, the actual number of failures may be lower or higher in a given year. For example, in another location on Cochrane Drive in Markham, there were three failures between June and August 2019. The total length of cable in this area is 2,500m. The actual failure rate over a 3-month period was: 3 failures/2,500m = 1.2 failures per 1000m, which is greater than the 0.25 failure per 1000m per year.

At a system level, as provided in Exhibit 4, Tab 1, Schedule 1, Page 264, Figure 5.3.3 – 29, the 5-year average number of failures is 504 failures per year. As provided in Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 60, the total length of "very poor" cable is 2,396 kilometers. The 5-year failure rate from 2014-2018 is determined by the ratio of 504 failures per 2,396,000m, which results in 0.2104 failures per 1000m per year. This is consistent with the frequency of failure used by Alectra Utilities of 0.25 failure per 1000m per year.

The estimate of 0.25 failures per 1000m per year (for future years) is reasonable based on the population of cables that are in very poor condition and which have been selected as cable replacement candidates. As a result, the methodology used by Alectra Utilities is an appropriate and accurate way of calculating the quantitative customer impacts.

b) The quantitative customer impacts provided in business cases are used as an input to determining the value of the project that is applied by C55 for optimizing projects.

c) If an area has experienced a high number of failures, the actual historical number of outages specific to the project area is used to predict the number of failures in future years. Where historical data does not provide a reasonable failure rate and the condition of the asset is deteriorated, then the estimated frequency of failure of 0.25 failures per 1000m is used.

G-Staff-61

Reference: Exhibit 4, Tab 1, Schedule 1, Pages 11 and 19 of 438

Alectra Utilities states the following about its DSP:

> **As the 2015 and 2016 capital expenditure decisions were not made by Alectra Utilities but, rather, by separate corporate entities, that historical capital expenditure information does not provide an appropriate basis for comparison or from which reasonable conclusions can be drawn.**

Alectra Utilities further states that "As historical system performance data remains valid when presented on a consolidated basis, this is included in the DSP."

a) If historical system performance data remains valid when presented on a consolidated basis, please explain why consolidated historical capital spending by predecessor utilities does not provide an appropriate basis for evaluating the company's spending plans for the forecast period.

b) Will Alectra Utilities' increased system renewal spending over the forecast period relative to the consolidated historical system renewal spending of the predecessor utilities produce a proportional improvement in reliability performance of the aggregate service area? Please quantify.

Response:

a) Alectra Utilities' predecessor utilities categorized, combined and reported historical capital expenditures in a manner befitting legacy organization structures, accounting systems and practices. In 2017, Alectra Utilities developed a harmonized and uniform capital reporting practice to ensure that all legacy rate zones track and report on capital expenditures in a consistent and uniform manner. For larger investment grouping where re-categorization of historical expenditures were feasible, Alectra Utilities has adjusted historical actual expenditures to permit aggregation of historical expenditures.

In comparison to historical capital expenditure reporting, the predecessor utilities that formed Alectra Utilities reported reliability results consistent with Ontario Energy Board's Reporting and Record Keeping Requirements ("RRR") as provided in Section 2.1.4.2.3. Alectra Utilities (and predecessor utilities) also completed reliability reporting consistent with

Ontario Energy Board's Filing Requirements for Chapter 5 Consolidated Distribution System Plan dated July 12, 2018.

b) As provided in Section C.1.1 and C.1.2 of the DSP (Exhibit 4, Tab 1, Schedule 1, Pages 109 and 111), Alectra Utilities' DSP and the capital investments that underpin that plan, were developed with the objective to maintain reliability levels at historical averages, consistent with the feedback provided to Alectra Utilities from its two rounds of customer engagement. Alectra Utilities does not predict reliability improvements but has developed capital investment solutions to address areas of the system with deteriorated assets which are the most risk to failure and have historically been the largest cause for customer hours of interruption. In addition to addressing deteriorated assets, Alectra Utilities has established plans to renew portions of the overhead system prone to catastrophic failure as a result of adverse weather conditions. The increase in system renewal investments is required for Alectra Utilities to keep pace with the large and increasing volume of end-of-life assets. These renewal investments are urgently required for Alectra Utilities to maintain reliability.

G-Staff-62

Reference: Exhibit 4, Tab 1, Schedule 1, Page 13 of 438

Alectra Utilities states that if it does not receive sufficient funds to implement system renewal as proposed in its DSP, it expects "a projected worsening of reliability by 50% over the next five years, and a further deterioration of 112% over the next ten years, relative to the most recent five-year outage duration average."

a) Please provide the analysis used to derive the forecasted decreases in reliability (i.e. 50% over 5 years and 112% over 10 years).

b) Has Alectra Utilities advised its customers of the anticipated decline in reliability? Please provide details.

Response:

a) The reliability analysis related to the long-term system renewal "snowplow" presented on Page 12 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 12) reflects the reduction of planned system renewal as proposed in the DSP (i.e. DSP-Planned SR) against a partial funding scenario (i.e. Partial Funding- Planned SR), where specific system renewal investment would be deferred beyond the DSP planning period.

Alectra Utilities developed the DSP to maintain historical reliability levels. Please refer to Section 5.2.3 Subsection C1 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 105 to Page 122) for a detailed explanation on the reliability targets and projected outcomes of the DSP.

In the reliability impact analysis, Alectra Uitlities first examined the number of units planned for renewals in the DSP compared to the number of units that would be deferred beyond the DSP planning period, under the partially funded scenario. Table 1 provides an annual listing of assets that would be deferred under the partial funding scenario.

Table 1: Asset Failure Quantities

Year	UG Cable (XLPE) km	Switchgear (All types)	OH Switch (LIS only)	Distribution Transformer (All Types)
2019	0	0	0	0
2020	87	4	12	115
2021	156	4	10	160
2022	183	4	8	195
2023	213	4	5	210
2024	230	4	4	220
2025	279	7	12	0
2026	322	5	17	0
2027	335	3	9	0
2028	314	-3	0	0
2029	102	-8	-11	0
2030	-29	-8	-21	-8
2031	-211	-8	-22	-8
2032	-293	-4	-22	-8
2033	-307	0	-1	42
2034	-311	0	0	-358
2035	-297	0	0	-258
2036	-288	0	0	-258
2037	-254	0	0	-25
2038	-233	0	0	-18

The number of assets initially planned for renewal and deferred under the partial funding scenario was matched with the corresponding reliability data based on historical reliability results from defective equipment outages.

Alectra Utilities utilizes the defective equipment sub-cause data to provide a 5-year average failure impact for a variety of assets. A sample of the sub-cause data can be found in Exhibit 4, Tab 1, Schedule 1, Page 121, Figure 5.2.3-11, and a copy of this data is provided in Table 2.

Table 2 - 5 Year Average Reliability Asset Impact

5 Year Reliability Average Impact					
Asset Type	# of Event	# of Customer Interruptions	Customer Hour Interruptions	Per Event Customer Impact	Per Event Duration Impact (hrs)
Cable & Accessories PILC	14	14633	23,966	1031	1.64
Cable & Accessories XLPE	504	168999	202,003	335	1.20
Switches	87	38,916	29,262	446	0.75
Switchgear	57	51,104	41,099	897	0.80
OH Line Hardware	157	87,219	85,845	557	0.98
TX	317	20,365	32,666	64	1.60

Once the quantities of deferred system renewal assets were matched to historical outage data, Alectra Utilities assessed the change in reliability relative to the 2018 reliability results. The 2018 SADI excluding MEDs were applied and are provided in Exhibit 4, Tab 1, Schedule 1, Page 108, Table 5.2.3-5 and provided in Table G-Staff-62-a3 for reference.

Table G-Staff-62-a1: Alectra Utilities 2018 SAIDI (Table 5.2.3-5 from the DSP)

Metric	2014	2015	2016	2017	2018	Average
SAIDI - Excluding MEDs	0.88	1.05	0.96	0.87	1.14	0.98

The impact of each asset failure was then combined with the quantity of deteriorated assets in need of renewal, but deferred due to partial funding, to determine an impact on SAIDI and SAIFI.

Table 3 - Projected Reliability Impact

Year	SAIDI
2019	**1.14**
2020	**1.19**

Year	SAIDI	
2021	**1.27**	
2022	**1.36**	
2023	**1.47**	5 year
2024	**1.58**	
2025	**1.70**	
2026	**1.83**	
2027	**1.96**	
2028	**2.08**	10 year

The relative impact of worsening reliability was determined by Alectra Utilities by comparing the difference between the projected reliability at year five (i.e. 2023) and year ten (2028) as outlined in Equation G-Staff-62-a and Equation G-Staff-62-b.

Equation G-Staff-62-a – 5 Year Reliability Impact Due to Partial Funding Scenario

$$Five\ Year\ Impact\ on\ SAIDI = \left(\left(\frac{1.47}{0.98}\right) - 1\right) \times 100\%$$

$$Five\ Year\ Impact\ on\ SAIDI = \ 50\%$$

Equation G-Staff-62-a – 10 Year Reliability Impact Due to Partial Funding Scenario

$$10\ Year\ Impact\ on\ SAIDI = \left(\left(\frac{2.08}{0.98}\right) - 1\right) \times 100\%$$

$$Ten\ Year\ Impact\ on\ SAIDI = \ 112\%$$

b) As described in Section 5.2.1 of the DSP (Exhibit 4, Tab 1, Schedule 1), Alectra completed two round of customer engagement in the development of the DSP. In the first round, Alectra Utilities sought to understand customers' needs and priorities, and customers informed Alectra Utilities that despite price concerns, customers are generally willing to consider paying more to maintain a reliable system. Based on these customer needs and priorities, along with other system planning considerations, Alectra Utilities developed a set of potential investments targeted to address the worst performing areas, as a result, reverse the negative trend of worsening reliability. During the presentation of potential investment options as part of the second phase of customer engagement, Alectra Utilities presented customers with the anticipated outcomes for each investment scenario. Alectra Utilities set the majority of underground cable replacements to be funded from base rates to reflect the highest priority of proceeding with the investment and reflecting customer needs and preferences from the first round of engagement. In summary, the proposed set of investments, as presented to customers, reflected the needs and priorities expressed by customers in the first round, that is to maintain reliability even if that requires to increase rates.

G-Staff-63

Reference: Exhibit 4, Tab 1, Schedule 1, Page 16 of 438

Regarding its distribution assets, Alectra Utilities states:

> **Alectra Utilities' assets include… over 38,000 km of distribution line assets. The distribution line assets include approximately 16,400 km of overhead conductors… [and] over 22,000 km of underground primary cables.**

a) Has Alectra Utilities undertaken lifecycle cost/benefit comparisons of overhead versus underground distribution systems, with respect to reliability and life cycle cost per km?

- **i. If yes, how has the analysis informed and impacted Alectra Utilities' planning decisions?**
- **ii. If yes, has Alectra Utilities presented the analysis to its customers?**

b) If no, why not?

c) Has Alectra Utilities investigated replacing any of its underground distribution systems with overhead distribution systems?

- **i. If yes, what were the results?**
- **ii. If no, why not?**

Response:

a) Alectra Utilities has not undertaken lifecycle cost/benefit comparisons of overhead versus underground distribution systems, with respect to reliability and life cycle cost per km.

b) Alectra Utilities was formed in 2017 and the legacy utilities had different data collection practices. Lifecycle costing requires consistent and mature data collection practices in order to provide meaningful analysis. As part of continuous improvement, Alectra Utilities is conducting a discovery process in order to assess the required scope of work enable asset lifecycle costing.

It is important to note that Alectra Utilities might not be able to switch underground infrastructure to overhead regardless of the outcomes of the study for reasons discussed in response to part c), below.

c) Alectra Utilities did not investigate replacing any of its underground distribution system with an overhead distribution system. Legacy utilities have explored this option with many of the local municipalities, but the suggested overhead installations were not approved due to the following reasons:

i. Legacy underground systems exist in urban areas and the residents/business owners/municipalities accept the facilities as installed. Replacing them with an overhead distribution system is not acceptable to the municipalities;

ii. Municipalities require services (e.g. power distribution) to be placed underground in certain locations, and in fact, have local By-laws in place to ensure this provision; and

iii. Replacing the existing underground system with an overhead distribution system can prove technically challenging due to current day clearances and standards being imposed on areas that cannot provide adequate space in the right of way.

G-Staff-64

Reference: Exhibit 4, Tab 1, Schedule 1, Page 23 of 438

Regarding its customer engagement, Alectra Utilities states:

> **The DSP process and the resulting Capital Investment Plan have been informed by a comprehensive customer engagement process to ensure Alectra Utilities' investments are planned to address customer identified needs, priorities, and preferences. As described in more detail further below, Alectra Utilities' Asset Management Process began with an independent assessment of customers' needs and priorities, before specific investments are identified by Alectra Utilities project owners. Once potential investments were identified, Alectra Utilities returned to customers for a second time to assess their preferences between specific investment options and outcomes. In that second phase of customer engagement, the utility's customers identified strong preference for Alectra Utilities to invest in system renewal, specifically the underground asset renewal, transformer replacement, rear lot and voltage conversion.**

a) Were the "specific investment options and outcomes" presented to customers quantitative?

i. If yes, please provide examples and explain how Alectra Utilities analyzed different investment scenarios to determine the quantitative outcomes that were presented to customers.

ii. If no, how were the outcomes developed?

b) What is Alectra Utilities' confidence level that it will achieve the outcomes as presented to customers under each of the different investment scenarios evaluated?

Response:

a) Alectra Utilities presented the quantitative outcomes of the investment scenario to the customers wherever feasible. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix C. Alectra Utilities provides the following examples:

<u>Example 1 - Pacing Investment for Underground Cable</u>

Customers were presented with the reliability impact and km of cables that would be addressed for the various investment options (Slow, Base, Recommended and

Accelerated). Alectra Utilities projected the failure of the cables for each investment level and compared it with the 2018 failures of the cables and presented these for the various scenarios. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 41 of the 2020-2024 DSP Customer Engagement Representative Report.

<u>Example 2 - Monitoring and Control Equipment</u>

Alectra Utilities presented options to customers in terms of pacing of installation of automated switches, which allows the utility to automatically restore the customers and reduce the outage time, thereby improving the reliability for main feeder outages. Alectra Utilities estimated the SAIDI improvements and the number of customers that benefit from the installation of the switches. For example, with the installation of 189 switches, the reliability for 95,000 customers is projected to improve by 17%. Refer to Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 48 of the 2020-2024 DSP Customer Engagement Representative Report.

<u>Example 3 - Rear Lot Conversion</u>

Alectra Utilities presented design options, (Reactive, Like for Like, Partial Underground or Full Underground) as well as options in terms of pacing for the conversion of the rear lots. Alectra Utilities presented quantitative data in terms of restoration times for the customers supplied by rear lot versus customers supplied by front lot. Alectra Utilities offered quantitative data in terms of number of customers which will be remediated under the various investment scenarios. Refer to Exhibit 4, Tab 1, Schedule 1, Appendix C, Pages 52 and 53 of the 2020-2024 DSP Customer Engagement Representative Report.

<u>Example 4 - Voltage Conversion</u>

Alectra Utilities presented quantitative data in terms of number of customers and the number of low voltage stations decommissioned for the different investment levels for voltage conversion. Refer to Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 57 of the 2020-2024 DSP Customer Engagement Representative Report.

b) Alectra Utilities has estimated the quantitative benefits of these investments based on the most up to date information available and is confident that the investments address the priority needs of the distribution system.

G-Staff-65

Reference 1: Exhibit 4, Tab 1, Schedule 1, Page 29 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 10

Regarding its ACA program, Alectra Utilities stated:

> **In order to ensure distribution system needs are considered consistently and objectively, Alectra Utilities undertakes risk management, system capacity and Asset Condition Assessment ("ACA") reviews. Starting in 2017, Alectra Utilities harmonized and consolidated its ACA practices for distribution and station assets.**

Regarding ACA of legacy utilities, Alectra Utilities stated:

> **Legacy utilities that formed Alectra Utilities had different maintenance, inspection and data management practices. The harmonization process adopted asset specific Health Index models that can accommodate the data of legacy utilities.**

a) **Did the adoption of uniform ACA practices lead to a step-change in overall assessed condition of assets in any of the major asset classes relative to the assessed condition of those same assets by the predecessor utilities?**

   i. **If yes, please provide the pre- and post-uniform process adoption results for all asset classes that demonstrate material assessed condition changes.**

   ii. **If no, please explain what has changed to drive the proposed System Renewal capital spending increases.**

b) **Are the Health Index distributions for the different asset classes generally similar across the legacy utilities?**

   i. **If no, please identify which asset classes exhibit significant assessed condition disparity between legacy utilities, and explain the reasons for these disparities.**

c) **Is the input condition data quality for all asset classes similar across all legacy utilities?**

   i. **If no, how did Alectra Utilities adapt its Health Index calculations to account for these data quality differences? Please provide an explanation for each asset class exhibiting input data quality differences between legacy utilities.**

Response:

a) The implementation of a harmonized and uniform Asset Condition Assessment ("ACA") process at Alectra Utilities did not result in any step-change increase in system renewal plans and investments.

A comparison of outcomes from Alectra Utilities' 2018 ACA against predecessor utilities' ACA must take into account the element of time, asset demographics as well as improvements in legacy inspection practices.

First, predecessor utilities conducted ACA studies in different years. Both Brampton and Horizon Utilities completed ACAs in 2013 using data from 2012. Guelph Hydro completed an ACA in 2014 using data from 2013. Enersource completed an ACA in 2015 using data from 2014. ACA provides a condition assessment at a specific point in time. Since completion of the respective ACAs, predecessor utilities and now Alectra Utilities have continued to invest in adding new assets to facilitate expansion for new connections as well as replacements through planned and reactive system renewals.

Alectra Utilities also has diverse asset demographics, which resulted in legacy ACAs that were specifically developed to reflect legacy system needs, standards, operating and maintenance practices. For example, legacy PowerStream owned and operated twelve (12) transformer stations ("TS") where legacy Horizon Utilities and legacy Enersource were supplied by Hydro One Networks Inc. owned and operated Transformers Stations. Hence, the PowerStream Asset Condition Assessment included Transformer Station assets and equipment in the ACA.

Taking the above-mentioned factors in consideration, Alectra Utilities noted moderate changes in asset condition assessment results in two asset categories: stations circuit breakers and distribution switchgear. However, the changes in the asset condition assessment outcomes were not the driving factor that resulted in a decrease (circuit breakers) and increase (distribution switchgear) in system renewal investments.

Relative to legacy ACA results, the percentage of poor and very poor distribution switchgear increased from 9% of the population to 17%. Alectra Utilities recognized that condition evaluation of air insulated switchgear now more appropriately reflect the deterioration of insulating materials that, combined with contamination from dust particles and operation on the 27.6kV system produced conditions that made units more susceptible to flashover. Although the health index distribution of switchgear based on the 2018 Asset Condition Assessment did increase the number of poor and very poor units, Alectra Utilities plans to continue with a similar number of units renewed per year. The increase in system renewal of distribution switchgear, as explained in Appendix A10 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 41) is driven by the best utility practice of replacing 27.6kV air insulated switchgear with solid dielectric units, and in specific locations, solid dielectric units with distribution automation scheme. This practice is consistent with customer preferences to include automation during system renewals. Automation-enabled switchgear introduces several benefits, including the ability to rapidly perform isolation, sectionalizing and restoration during emergencies. The automated units also provide telemetry which enables Alectra Utilities' ability to more readily identify cable faults and provide current readings, which can support the company's ability to restore power, manage load and optimize asset management.

The second change Alectra Utilities recognized in the 2018 ACA results relative to legacy ACA results was an increase in the number of poor and very poor station circuit breakers, which increased from 8% to 32%. Similar to distribution switchgear, Alectra Utilities did not increase the level of system renewal based on the condition assessment of the circuit breakers. As explained in Appendix A08 – Substation Renewal in the DSP, Alectra Utilities has decreased the level of investment in substation renewals relative to historical investment levels. As a consolidated entity, Alectra Utilities has implemented strategic management of emergency spare inventory and monitoring technologies to enable operation of circuit breakers that are obsolete and no longer supported by the manufacturer.

b) The Health Index distributions for different asset classes exhibit some variations between operating areas as would be expected given Alectra Utilities' diverse and extensive service territory, which contains some of the oldest, as well as newest communities in Ontario.

For example, assets in Hamilton, one of the first cities to be electrified in Ontario, contain some of the oldest assets in Alectra Utilities' service territory, when compared to the City of Brampton, which is one of the fastest growing communities in Ontario.

c) Yes, the input condition data quality for all asset classes were similar across Alectra Utilities.

Alectra Utilities retained Kinectrics Inc. ("Kinectrics") to undertake an independent third-party review of Alectra Utilities' Asset Condition Assessment.

Kinectrics is an engineering firm, with asset management expertise, including conducting Asset Condition Assessments. The complete report containing Kinectrics' opinion, entitled "Kinectrics Inc. ACA Assurance Review", is attached in Appendix E in the DSP (Exhibit 4, Tab 1, Schedule 1, Appendix E)

In Kinectrics' opinion, *"The 'inputs' selected for the harmonized model are appropriate indicators of asset degradation, ensuring that Alectra's HI methodology appropriately identifies problematic assets."*

Furthermore, it is Kinectrics' opinion that *"[t]he processes, methodologies, and results are appropriate in serving as the basis for identifying system sustainment needs."*

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Reference 1: Exhibit 4, Tab 1, Schedule 1, Page 29 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix A

Alectra Utilities developed its Asset Management Process after its formation in 2017 by consolidating and harmonizing the asset management processes of its predecessor utilities. OEB staff notes that a common theme within Alectra Utilities' investment summaries is ensuring that new investments meet Alectra Utilities' consolidated safety and equipment standards. For example, on page 4 of Appendix A02, Alectra Utilities states that "The design of customers connections must follow Alectra Utilities' *current standards*" and on page 3 of Appendix A05, Alectra Utilities states that it will "[…] replace deteriorated assets and obsolete infrastructure with infrastructure constructed to *present day standards*." [Emphasis added]

a) Please describe the process Alectra Utilities employed to consolidate the safety standards, equipment standards and engineering practices of its predecessor utilities. In particular, please indicate whether the new standards and practices are in response to regulatory requirements, updated CSA standards or just as part of consolidation efforts.

b) Has Alectra Utilities identified economic efficiencies in using best practices to consolidate the engineering standards and practices of its predecessor utilities?

i. If yes, what efficiencies were identified, and what is the amount of capital and O&M savings from the efficiencies?

ii. If no, please explain why Alectra Utilities was not able to identify any sources of efficiencies.

c) What is the incremental capital and O&M cost/cost savings associated with implementing the new standards as opposed to previous standards?

d) Has Alectra Utilities evaluated the impact on reliability of its new standards?

i. If yes to c), please provide the analysis.

ii. If no to c), why not?

Response:

a) The method used by Alectra Utilities to consolidate the standards and practices of the legacy utilities involved a review of the existing legacy processes by a cross functional team comprised of stakeholders from the various departments and geographic areas impacted by the process. The legacy processes were reviewed to take the experience and learnings from each legacy utility and identify and select the strengths of each process to create a ‘best in practice‘ process for Alectra Utilities. In general, Alectra Utilies’ overall consolidation effort provided the driver of the consolidation of standards and processes. Alectra Utilities placed a priority on standards or processes impacted by a change to regulations or CSA Standards.

There was no need to consolidate the actual safety standards as the safety standards governing electric utilities in Ontario are primarily the Ontario Health and Safety Act & Regulations and the Electrical Utility Safety Rules which applies to all utilities in Ontario. Compliance with these regulations and rules is achieved through the development and implementation of work practices. Although minor variations existed, the work practices from each predecessor utility complied with the Regulations and Rules. Alectra Utilities’ consolidation of these work practices is an ongoing activity with input form the Utility Operations and Health and Safety groups.

Alectra Utilities’ consolidation of the equipment standards is an ongoing effort led by the Standards Department as part of the overall consolidation effort. Working groups were created with representation ensuring that all impacted stakeholders were represented and had visibility and input into the process. Drivers taken into consideration when consolidating the equipment standards included: leveraging best practice from each legacy utility; reliability and operational impacts; cost impacts; long term maintenance requirements; and the ability to leverage Alectra Utilities’ requirement with respect to purchasing volumes. Alectra Utilities’ aim was to ensure that if there were any cost increases resulting from improvement to the specifications, they could be offset through leveraging Alectra Utilities’ purchasing volume.

The consolidation of engineering practices also involved the creation of working groups, led by the Standards Department, with representation ensuring that all impacted Stakeholder groups have visibility and input into the process. Drivers taken into consideration when consolidating the Distribution Construction Standards included: consolidation of materials;

ability to meet the needs of all regions; ability to consolidate construction techniques; and cost impacts.

b) Alectra Utilities' aim is to identify economic efficiencies when consolidating the engineering practices and standards from the predecessor utilities. Areas where economic efficiencies are expected include: reduction of the number of stock codes, thereby allowing a reduction in inventory levels; ability to transfer inventory between regions allowing for a reduction in overall inventory levels; leveraging discounts due to the increases in purchasing volumes; efficiencies gained through implementation of best practices established through leveraging the experience and knowledge of the predecessor utilities; and ability to share people and equipment between regions thereby, improving Alectra Utilities' overall ability to respond to major incidents.

c) Alectra Utilities has not calculated the incremental capital and O&M cost/cost savings associated with implementing the new standards relative to previous standards as the new standards have not yet been fully implemented.

d) Alectra Utilities has not evaluated the impact on reliability of the new standards. Due to the number of variables, and the corresponding assumptions required to estimate the impact, Alectra Utilities is unable to provide an accurate assessment of the impact on reliability.

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Reference: Exhibit 4, Tab 1, Schedule 1, Pages 100 and 170 of 438

Alectra Utilities provides the following table on cost control performance measures:

Table 5.2.3 - 2(A): Finance: Cost Control Custom Performance Measure

Measure Category	2020-2024 Performance Measure	Historical Performance (2018)	Target (2020-2024)
Finance	Cost-Control: Planned Capital (Actual vs. Budget)	84%	100%

On Page 170 of 438, Alectra Utilities states:

> **Where required, projects can be scaled back, cancelled, or otherwise adjusted to reflect the new circumstances and up-to-date information. The utility's senior management reviews program variances on a monthly basis and considers the approval of resource allocation adjustment s may be required.**

a) Please clarify: does Table 5.2.3 – 2(A) imply that for 100% of the budget, Alectra Utilities completes 84% of the planned projects, or that there was an overspend in 2018?

i. If neither, please explain the performance measure.

ii. If overspent, how much did Alectra Utilities overspend?

iii. What steps is Alectra Utilities taking to improve actual project delivery from 84% to 100%?

iv. Are these metrics available for the predecessor utilities? If yes, please provide the metrics for the years 2015 to 2018 with a forecast for 2019.

b) When Alectra Utilities' expenditures reach the budget cap in a calendar year, what happens to the uncompleted projects?

c) Please describe how uncompleted projects are reprioritized against projects in the following year's plans.

d) What activities are undertaken to accommodate these spending changes (e.g. scaling back, cancelling or adjusting projects)?

Response:

a) i)The cost-control measure for Planned Capital is an internal measure developed by Alectra Utilities to measure actual expenditures compared to planned investments for System Renewal and System Service projects, excluding Reactive. In 2018, 84% of the overall budget for Planned Capital in these areas was spent.

ii) Expenditures for Planned Capital were underspent in 2018 because of the ICM decision resulting in the deferral of projects.

iii) Alectra Utilities has developed harmonized policies and practices since its inception in 2017 to improve the execution of the Capital program. Improvements across the organization relating to policies and procedures will contribute to further success of the Capital plan. After the formation of Alectra Utilities in 2017, the Asset Management Process was consolidated and harmonized. The result is a harmonized, uniform and systematic Asset Management Process to collect, assess, evaluate, prioritize and optimize system and operational needs based on current and expected future system operating conditions. On this basis, Alectra Utilities is able to ensure that all system and operational needs are considered and that expenditures are closely monitored.

iv) This is a new metric developed for Alectra Utilities.

b) Throughout the year, Alectra Utilities monitors the spending on each executing project to ensure that this measure is met. The intent is not to spend to a budget cap, rather manage each individual project's spend in order to respect the budget constraint. Alectra Utilities monitors changes in a project's actual spend and evaluates the impact on budget constraints. Alectra Utilities reviews the program in a holistic manner to find opportunities to offset any spending increases with lower expenditures to develop a cost mitigation strategy. Strategies may include improved execution on other projects, scope changes or project deferral or cancellations.

Alectra Utilities has analysis and processes in place to identify, in advance, projects that are at risk of exceeding their budget which allows Management to analyze and determine the best course of action in a proactive manner. In-depth project analysis is performed on a quarterly basis in conjunction with multi-departmental reviews ,to identify projects at risk of exceeding budget.

c) Generally, uncompleted projects will become carry over projects in the following year to be finalized. Cost mitigation strategies discussed in response to part b) allow Alectra Utilities to remain within its budget constraints, including any carry over.

d) Cost mitigation strategies may include improved execution on other projects, scope changes or project deferral or cancellations. Important factors such as customer safety, reliability and environmental impact are taken into consideration when developing a cost mitigation strategy.

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Reference: Exhibit 4, Tab 1, Schedule 1, Page 102 of 438

Alectra Utilities provides the following table on cost control performance measures:

Table 5.2.3 - 3: Finance: Asset Condition Custom Performance Measure

Measure Category	2020-2024 Performance Measure	Historical Performance (2018)	Target (2020-2024)
Finance	% of Cable in Poor and Very Poor (Health Index) Condition	14%	Monitor

a) Please provide a 10 year chart of historical performance.

b) Please explain why Alectra Utilities does not report on asset condition performance for all its major asset classes.

i. In the absence of such measures, how does Alectra Utilities ensure its assets other than underground cables are maintained and kept in good health?

Response:

a) This performance indicator is a new performance measure adopted by Alectra Utilities after the harmonization of its Asset Condition Assessment ("ACA") in 2018. This indicator is informed through the harmonized ACA, therefore, Alectra Utilities does not have historical performance.

b) The underground cable asset has the greatest impact on reliability and Alectra Utilities' capital investment plan, therefore, it is the only major asset where reporting on asset condition performance is completed. Alectra Utilities will be tracking the metric for other major asset classes, however, only underground cables asset condition performance will be reported on regular basis.

To ensure its assets, other than underground cables, are maintained and kept in good working condition, Alectra Utilities plans to conduct annual Asset Condition Assessments to guide the asset management process as described in Section 5.3.1.3 Subsection A.1.3.2 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 152 to Page 153).

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Reference: Exhibit 4, Tab 1, Schedule 1, Pages 107-110 of 438

Alectra Utilities provides the following tables on SAIDI and SAIFI metrics:

Table 5.2.3 - 5: Alectra Utilities' SAIDI, SAIDI Excluding MEDs, LOS Results from 2014 to 2018

Metric (Hours)	2014	2015	2016	2017	2018
SAIDI	1.30	1.42	1.66	1.10	1.87
SAIDI - Excluding MEDs	0.88	1.05	0.96	0.87	1.14
SAIDI - Excluding LOS	1.12	1.35	1.24	1.03	1.66
SAIDI - Excluding MEDs and LOS	0.84	1.00	0.83	0.80	1.04

Table 5.2.3 - 7: Alectra Utilities' SAIFI, SAIFI Excluding MEDs, LOS results from 2014 to 2018

Metric (Number of Outages)	2014	2015	2016	2017	2018
SAIFI	1.51	1.59	1.43	1.34	1.8
SAIFI - Excluding MEDs	1.27	1.41	1.24	1.23	1.53
SAIFI - Excluding LOS	1.40	1.38	1.24	1.22	1.57
SAIFI - Excluding MEDs and LOS	1.21	1.23	1.09	1.11	1.33

Regarding the two tables, Alectra Utilities states:

> **Figure 5.2.3 - 2 and Table 5.2.3 - 5 illustrate an increasing system average interruption duration trend at Alectra Utilities (including its predecessors) since 2014. The five year SAIDI measure indicates a 16% increase on annual average system outage duration that Alectra Utilities customers' service was interrupted. When MEDs are excluded, the 2018 SAIDI measure indicate a 8% increase in annual outage duration since 2014. This trend is not acceptable to Alectra Utilities.**

Additionally:

> **Figure 5.2.3 - 3 and Table 5.2.3 - 7 illustrate a trend of increasing system average interruption frequency at Alectra Utilities (including its predecessors) over the five year period from 2014 to 2018. The five year SAIFI measure indicates a 6% increase on annual average system outage frequency that Alectra Utilities customers' service was interrupted. When MEDs are excluded, the SAIFI measure also indicate a 6% increase in annual outage duration since 2014. This trend is not acceptable to Alectra Utilities.**

a) The 2018 reported SAIFI and SAIDI figures are higher than the previous years shown in the table. If a start date of 2014 and end date of 2017 are used, all reliability trends appear to be improving. In which year did the alleged trends in deteriorating reliability begin?

b) What factors caused the 2017 SAIDI and SAIFI measures to be low, and what factors caused the 2018 SAIFI and SAIDI measures to be high (relative to the 5 year average)?

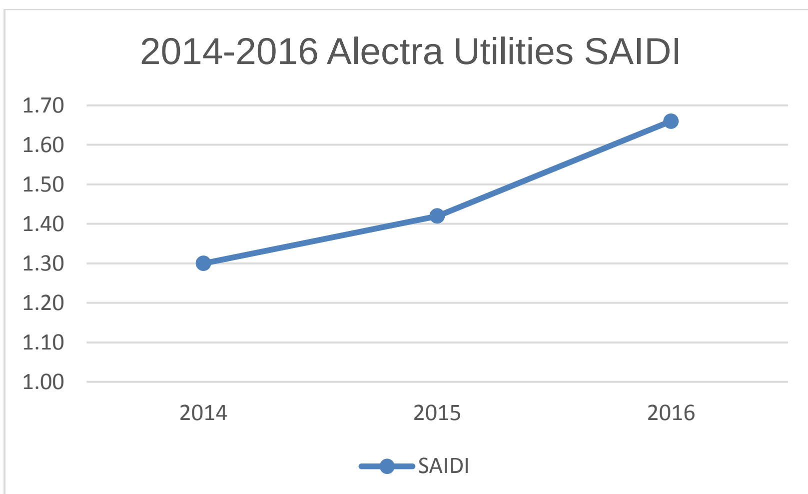
c) How does Alectra Utilities account for the variance in reliability metrics around the multi-year mean and the alleged signaling of an upwards trend?

d) Please provide 10 years of historical SAIFI and SAIDI data for Alectra Utilities and its predecessor utilities.

Response:

a) Alectra Utilities presents Figure 1, below, which provides the SAIDI results from 2014 to 2016. Based on the trends identified over this period, the deteriorating trends in reliability began in 2014 and continued through to 2016. Alectra Utilities' customers experienced better than average SAIDI results in 2017 and substantially worse than average SAIDI result in 2018.

Figure 1 - Alectra Utilities 2014-2016 SAIDI



b) Figure 2, below is a comparison of cause codes for 2017 and 2018 against the five-year average based on the number of customer interruptions (SAIFI).

Figure 3, below, provides a comparison of Customer Hours of Interruption (SAIDI) for 2017 and 2018 against a five year average.

Figure 2 and 3 clearly illustrate that outages as a results of Defective Equipment, Adverse Weather, Tree Contacts, Loss of Supply, as well as Unknown outages are higher in 2018 than 2017, as well as the 5-year reliability average.

Figure 2 -Number of Customer Interruptions 2017 and 2018 versus 5 Year Average

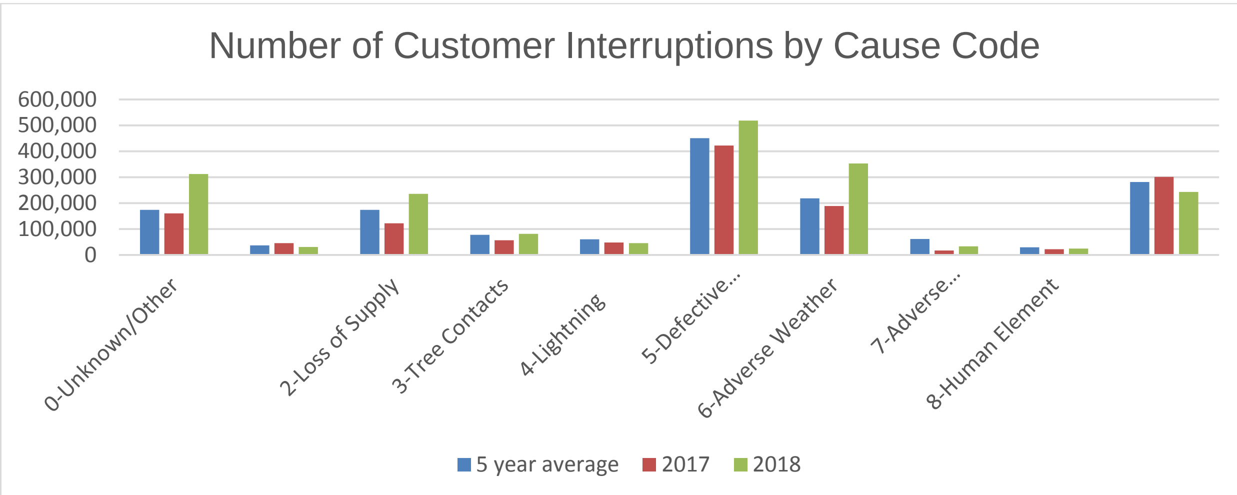
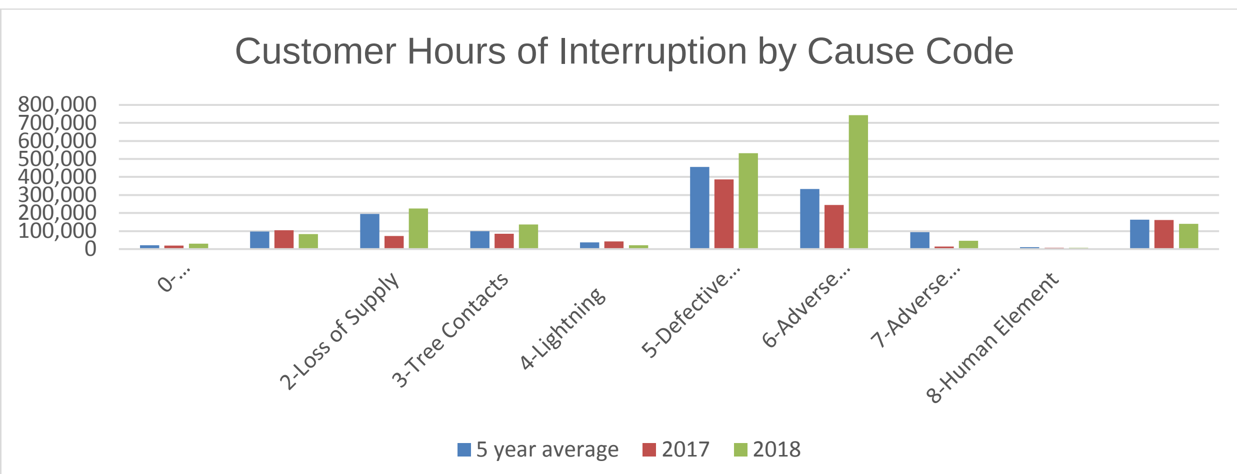


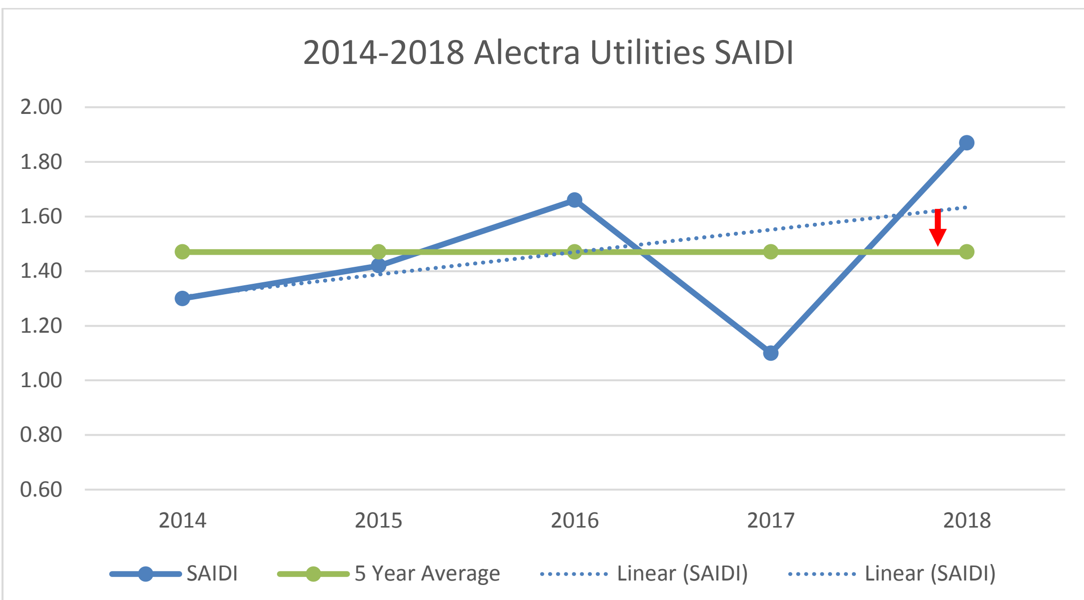
Figure 3 - Customer Hours of Interruption 2017 and 2018 versus 5 Year Average



c) Alectra Utilities reviewed the 5-year mean against the trend line prediction as provided in Figure 4, below. As described in Section 5.2.3, subsections C.1.1 and C.1.2 (Exhibit 4, Tab 1, Schedule 1, Page 107 to Page 111), through the implementation of capital investments proposed in the DSP, Alectra Utilities seeks to maintain reliability levels to historical (i.e. 5-year average) SAIDI and SAIFI levels.

For customers experiencing poor reliability beyond the system average, Alectra Utilities has established plans to address the deteriorated and failing distribution assets in order to improve reliability to a minimum of overall historical system levels, which reflects the needs, priorities and preferences of customers. As provided in response to part a), Alectra Utilities' customers have been experiencing a negative trend in worsening reliability. Alectra Utilities has assessed the root causes of the negative trend in reliability and has established plans reverse this trend by addressing the leading causes of outages (i.e. defective equipment and adverse weather).

Figure 4 - 2014-2018 Alectra Utilities SAIDI



d) The ten-year historical SAIDI of Alectra Utilities and its predecessors is provided in Table 1, below. The ten-year historical SAIFI of Alectra Utilities and its predecessors is provided in Table 2, below. For years prior to 2014 this data is based on the historical OEB Scorecards of Alectra Utilities' predecessor utilities.

Table 1 - SAIDI Hours for Alectra Utilities and Predecessor Utilities (2009-2018)

SAIDI - Hours										
Territories	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alectra Central South	0.57	0.55	0.72	0.70	5.34	0.67	0.72	0.81	0.71	1.72
Alectra Central North	0.72	0.46	0.68	0.76	10.46	0.57	0.72	0.45	0.48	0.72
Alectra West	0.69	1.15	2.23	1.45	4.97	2.18	1.77	1.64	1.47	2.96
Alectra East	1.59	0.54	1.05	1.16	10.67	1.45	1.99	2.74	1.44	1.95
Alectra South West	0.21	0.33	1.70	1.34	3.37	0.75	0.57	1.08	0.47	0.50
Alectra Utilities						1.30	1.42	1.66	1.10	1.87

Table 2 - SAIFI Hours for Alectra Utilities and Predecessor Utilities (2009-2018)

SAIFI										
Territories	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alectra Central South	0.92	1.10	1.54	1.71	2.72	1.13	1.64	1.13	1.20	1.94
Alectra Central North	1.03	0.76	1.05	1.27	3.64	0.95	1.22	0.72	0.70	0.94
Alectra West	1.12	1.55	1.74	1.95	2.09	1.91	1.92	1.98	1.86	2.85
Alectra East	1.07	0.80	1.00	1.70	2.49	1.71	1.52	1.41	1.35	1.48
Alectra South West	0.50	0.75	1.51	2.50	3.95	1.30	1.53	2.19	1.30	1.20
Alectra Utilities						1.51	1.59	1.43	1.34	1.80

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Reference 1: Exhibit 4, Tab 1, Schedule 1, Pages 119-120 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix C, Page 33

Alectra Utilities provides the following figures on customer hours of interruption due to defective equipment:

Figure 5.2.3 - 9: Customer Hours of Interruption Due to Defective Equipment at Alectra Utilities from 2014 to 2018

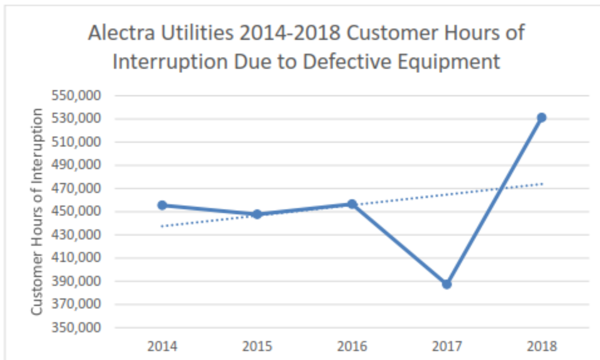
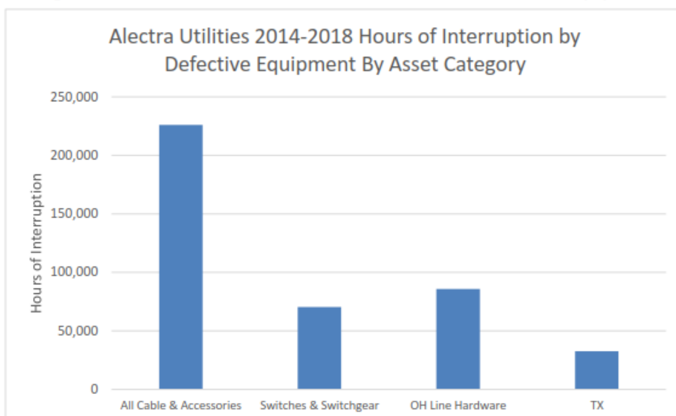


Figure 5.2.3 - 10: Alectra Utilities 2014-2018 Sub-Causes of Defective Equipment



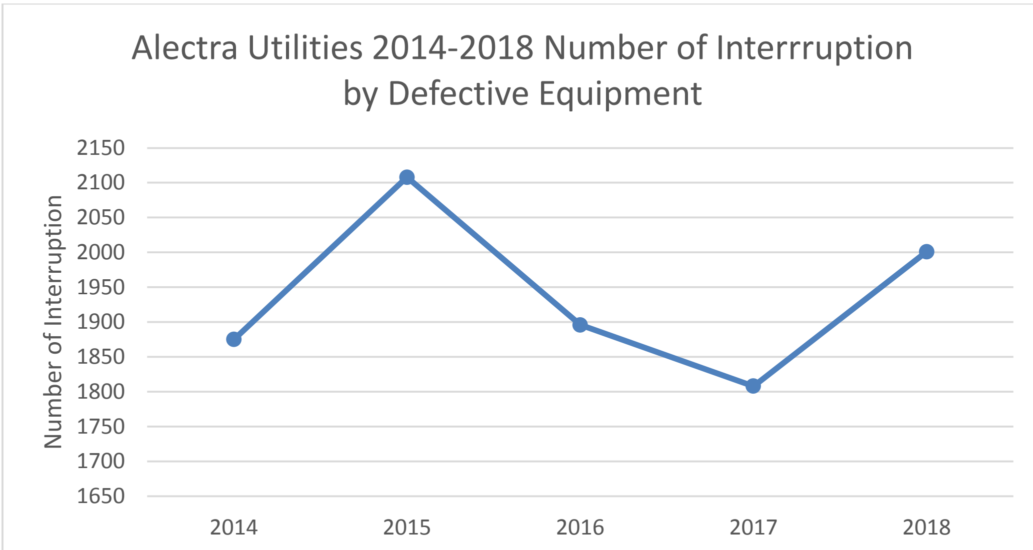
Alectra Utilities further notes in its customer engagement survey that "Defective equipment accounted for 30% of customer hours interruption between 2014-2018."

a) **Please provide a graph of the number of interruptions by defective equipment by year (for the period of 2014-2018).**

b) **Please provide a graph of the number of interruptions by defective equipment by asset category (for the period of 2014-2018).**

a) The number of interruptions by defective equipment by year (for the period of 2014-2018) is provided in Figure 1, below.

Figure 1 - Number of Interruption by Defective Equipment (2014-2018)



b) The number of interruptions by defective equipment by asset category (for the period of 2014-2018) is provided in Figures 2 to 5, below.

Figure 2 - Number of Interruptions by Defective Equipment – All Cable & Cable Accessories

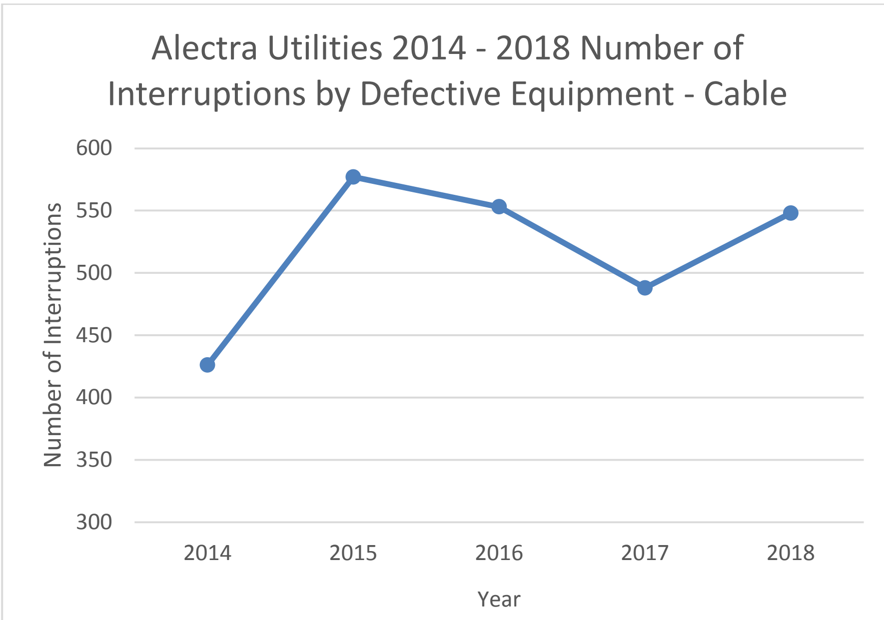


Figure 3 - Number of Interruptions by Defective Equipment -Transformers

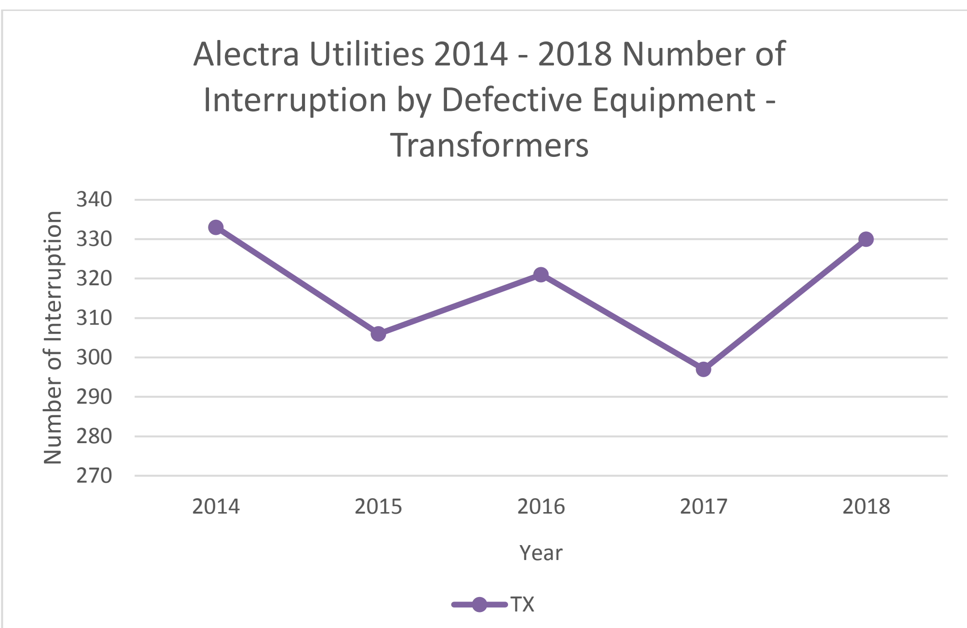


Figure 4 - Number of Interruptions by Defective Equipment – OH Line Hardware

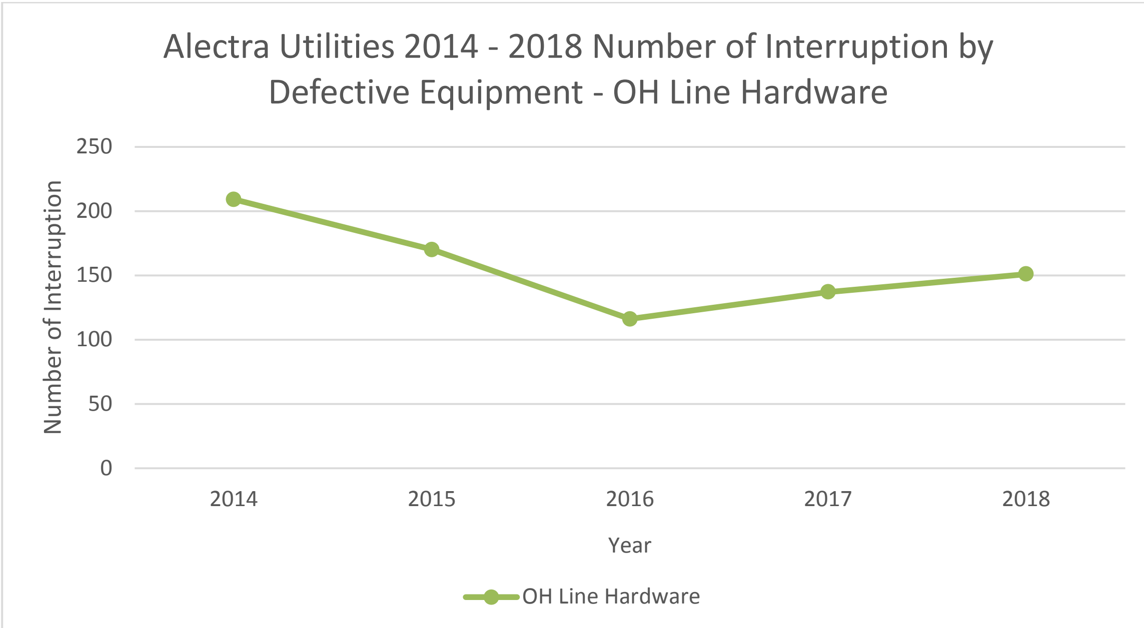
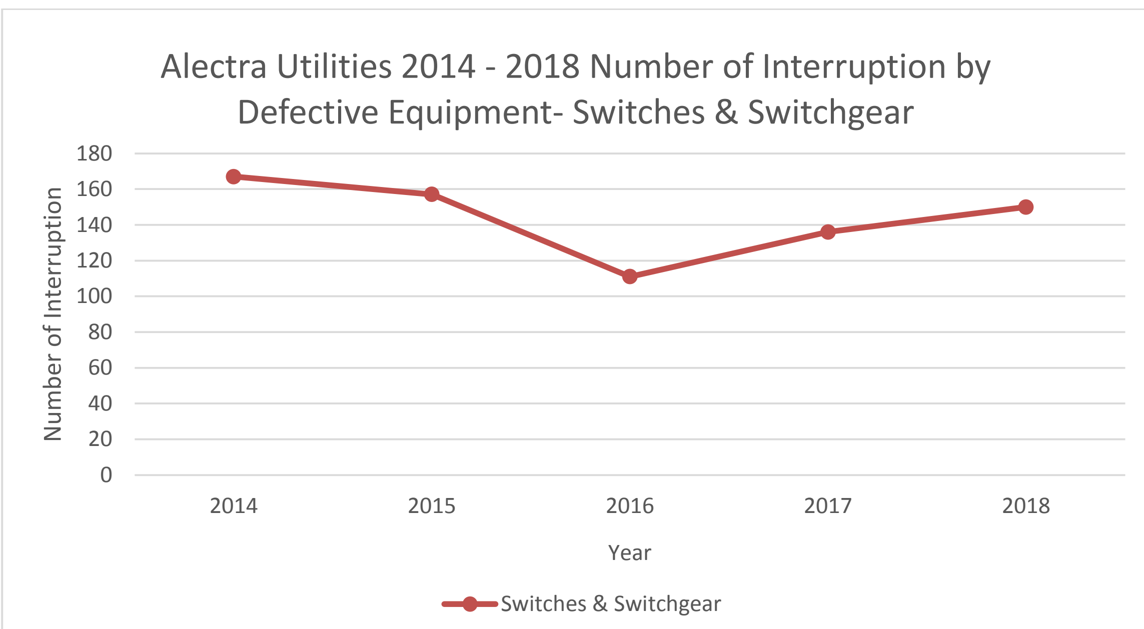


Figure 5 - Number of Interruptions by Defective Equipment – All Cable & Cable Accessories



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Reference: Exhibit 4, Tab 1, Schedule 1, Page 124 of 438

Alectra Utilities provides the following table on unit cost metrics:

Table 5.2.3 - 11: Unit cost Metrics for Performance Measurements

Metric Category	Metric	Measures	
		(2018) 1 Year	2014-2018 (5 Year) Average
Cost	Total Cost per Customer	384	412
	Total Cost per km of Line	19,077	20,215
	Total Cost per MW	74,352	80,809
CAPEX[41]	Total CAPEX per Customer	294	313
	Total CAPEX per km of Line	14,597	15,350
O&M[42]	Total O&M per Customer	90	99
	Total O&M per km of Line	4,480	4,865

a) Please provide this table with separate columns for 2014, 2015, 2016, 2017 and 2018.

b) Please provide a table showing Alectra Utilities' projected unit cost metrics for the budge year and 5 forecast years (2019-2024).

Response:

a) As part of this response, Alectra Utilities has restated Table 5.2.3 – 11: Unit cost Metrics for Performance Measurements, that was filed in Exhibit 4, Tab 1, Schedule 1, Page 124 of 438. The revised table is based on 2018 Electricity Yearbook values, while the original table was prepared based on the preliminary 2018 data.

Table 1 – Unit Cost Metrics for Performance Measurements

Metric Category	Metric	Measures	
		(2018) 1 Year	(2014-2018) 5-Year Average
Cost	Total Cost per Customer	417	419
	Total Cost per km of Line	20,718	20,543
	Total Cost per MW	80,748	82,088
CAPEX	Total CAPEX per Customer	325	319
	Total CAPEX per km of Line	16,182	15,667
O&M	Total O&M per Customer	91	99
	Total O&M per km of Line	4,536	4,876

Table 2 – Unit Cost Metrics for Performance Measurements (2014 – 2018)

Metric Category	Metric	Measures (Actuals, source: Electricity Yearbook) 2014	2015	2016	2017	2018
Cost	Total Cost per Customer	386	477	396	418	417
	Total Cost per km of Line	18,665	23,230	19,362	20,739	20,718
	Total Cost per MW	76,859	92,055	73,974	86,805	80,748
CAPEX	Total CAPEX per Customer	284	374	291	323	325
	Total CAPEX per km of Line	13,739	18,204	14,217	15,990	16,182
O&M	Total O&M per Customer	102	103	105	96	91
	Total O&M per km of Line	4,926	5,026	5,145	4,749	4,536

b) Alectra Utilities' System Peak MW forecast is a non-coincident peak forecast as submitted in Section 5.3.2 Overview of Assets Managed of Alectra Utilities' DSP (Exhibit 04, Tab 01, Schedule 01, page 180 of 438), while system peak MW as presented in the Electricity Yearbook is a coincident peak MW.

Table 3 – Unit Cost Metrics for Performance Measurements (2019 – 2024)

Metric Category	Metric	Measures (Forecast) 2019	2020	2021	2022	2023	2024
Cost	Total Cost per Customer[1]	461	461	437	440	428	438
	Total Cost per km of Line	23,154	23,335	22,306	22,669	22,231	22,969
	Total Cost per MW[2]	86,785	85,957	80,430	80,209	77,616	79,281
CAPEX	Total CAPEX per Customer[3]	365	365	340	344	330	340
	Total CAPEX per km of Line[4]	18,299	18,459	17,386	17,700	17,177	17,837
O&M	Total O&M per Customer	97	96	96	96	97	98
	Total O&M per km of Line	4,854	4,876	4,920	4,969	5,053	5,132

NOTES to the Table:

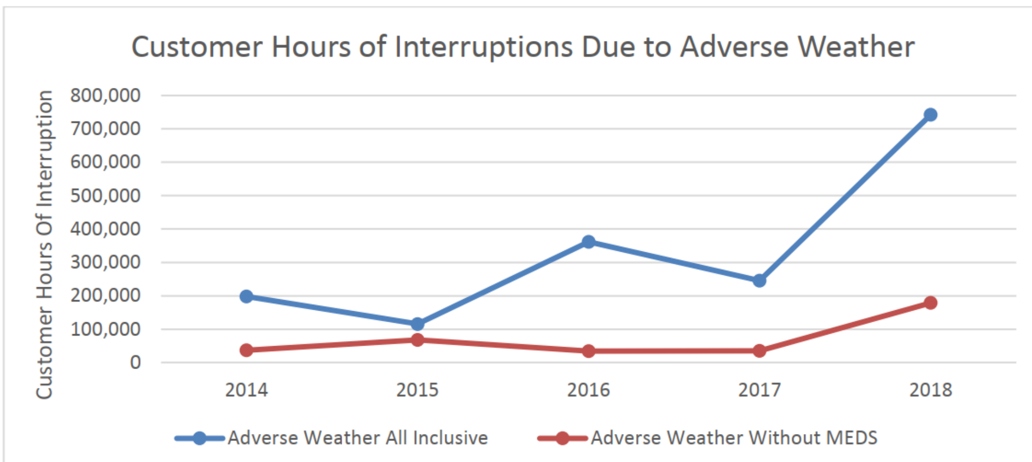
1 - Number of customers based on 2018 OEB Year Book, and application of historical growth rates
2 - Non-coincident peak forecast
3 - CAPEX amounts are Gross Capital Additions including Contributed Capital
4 - Circuit km of Line assumed 0.4% annual growth, as based on a 3-Year (2016-2018) average growth rate

G-Staff-72

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A06, Page 8 of 13
Reference 2: Exhibit 4, Tab 1, Schedule 1, Appendix M

Alectra Utilities provides the following table on customer hours of interruptions due to adverse weather:

Figure A06 - 5: Customer Hours of Interruptions Due to Adverse Weather (2014-2018) with and without MEDs



In Appendix M, Alectra Utilities provides the following tables M01-1, M01-2, M01-3, M01-4, and M01-5 showing total customer hours of interruption for 2018, 2017, 2016, 2015, and 2014 respectively on all Major Event Days.

Table M01 - 1: Summary of Outages on Major Event Days in 2018

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
12-Mar-18	Central-North	2	7,038	13,480
4-Apr-18	Central-South	29	13,408	18,429
14-Apr-18	West	5	15,715	38,487
15-Apr-18	Central-South	23	5,854	10,403
4-May-18	Central-South	69	72,926	132,543
4-May-18	Central-North	20	3,616	9,819
4-May-18	West	59	60,993	218,163
4-May-18	East	57	91,371	315,856
4-May-18	Guelph	20	13,025	11,300
	Total	284	283,946	768,480

Table M01 - 2: Summary of Outages on Major Event Days in 2017

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
11-Jan-17	Central-North	9	3,779	11,795
8-Mar-17	West	44	29,386	59,843
7-Apr-17	East	24	27,857	54,070
15-Oct-17	Central-South	17	12,497	19,575
15-Oct-17	East	17	41,081	90,512
	Total	**111**	**114,600**	**235,795**

Table M01 - 3: Summary of Outages on Major Event Days in 2016

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
24-Mar-16	West	14	12,815	31,711
24-Mar-16	East	23	136,252	592,779
24-Mar-16	Guelph	21	13,274	13,602
25-Mar-16	East	49	28,402	78,891
	Total	**107**	**190,743**	**716,982**

Table M01 - 4: Summary of Outages on Major Event Days in 2015

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
3-Mar-15	Central-North	20	36,852	35,993
3-Mar-15	East	38	78,607	113,906
14-Mar-15	East	34	58,740	174,408
28-Jun-15	West	26	12,549	50,299
	Total	**118**	**186,748**	**374,606**

Table M01 - 5: Summary of Outages on Major Event Days in 2014

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
20-Mar-14	West	7	24,345	121,830
19-Apr-14	West	8	30,212	38,185
1-Jun-14	Central-North	1	21,424	27,354
17-Jun-14	Central-South	12	13,296	15,376
17-Jun-14	East	25	23,200	37,479
22-Jul-14	West	10	13,126	33,274
24-Nov-14	Central-South	32	19,697	14,107
24-Nov-14	East	27	56,485	41,574
27-Nov-14	West	59	37,138	91,258
	Total	**181**	**238,923**	**420,437**

a) Please clarify how Alectra Utilities and its predecessor utilities categorize an outage as due to adverse weather. For example, if a wind storm blows a tree over which in turn falls on transmission lines, is this considered an adverse weather outage or a tree contact? Please provide other examples to illustrate how different outages that occur during adverse weather conditions are categorized.

b) Please provide 10 years of adverse weather outage data for Alectra Utilities and its predecessor utilities.

c) Comparing Figure A06 - 5 to tables M01-1 through to M01-5, there appears to be an inconsistency in the data used to generate this Figure and generate conclusions on trends. Years 2017 and 2018 correspond to the data shown in Tables M01-2 and M01-1 respectively while years 2014-2016 seem to be using only a subset of the data shown in their respective tables. Please clarify.

d) Please provide data for Tables M01-1 through to M01-5 specific to adverse weather outages.

e) For Figure A06 – 5, please provide the prorated results to date for 2019.

Response:

a) If a windstorm blew over a tree onto a distribution line, it would be classified as tree contact. Examples of adverse weather outages are situations where wind knocks over poles as provided in Exhibit 3, Tab 1, Schedule 1, Appendix A05 – Overhead Asset Renewal, Page 19, Figure A05-8 and Figure A05-9. Other examples include strong winds causing deteriorated overhead hardware to come apart causing wire downs. Heavy rain can lead to tracking of equipment, which causes a flashover. Furthermore, Alectra Utilities follows the Ontario Energy Board Electricity Reporting & Record Keeping Requirements for outage classification.

b) Alectra Utilities does not have historical information on outages due to adverse weather prior to 2012. Table 1 provides adverse weather outage data from 2012-2018 for Alectra Utilities and its predecessor utilities. Furthermore, Alectra Utilities follows the IEEE Standard 1366 single day rolling average to calculate the MED threshold.

Table 1- Customer Hours of Interruption Caused by Adverse Weather (2012-2018)

Rate Zone	2012	2013	2014	2015	2016	2017	2018
ERZ	23,131	187,663	27,409	10,052	1,511	21,263	123,219
BRZ	159	1,355,242	1,189	35,612	9,643	2,916	6,089
HRZ	115,501	852,737	110,181	68,776	27,008	79,188	338,252
PRZ	58,204	2,860,667	59,104	1,205	314,158	141,588	271,301
GRZ	63	80,221	2	4	9,705	15	3,291
Alectra	197,057	5,336,529	197,885	115,649	362,026	244,969	742,152

c) Alectra Utilities wishes to clarify that not all MEDs are caused by Adverse Weather, nor are all outages during an MED classified against Adverse Weather. The majority of outages in 2017 and 2018 are adverse weather related and therefore the data may appear to align better than historical years. Therefore, Alectra Utilities confirms that Figure A06 - 5 and Tables M01-1 through to M01-5 are complete. For example on March 24, 2016 Alectra East had an MED for 592,779 customer hours of interruption. Adverse Weather accounts for 40% of this total (239,395), while Loss of Supply accounts for 48% (285,656).

d) Alectra Utilities has provided the total customer hours of interruption for 2018, 2017, 2016, 2015, and 2014 respectively on all Major Event Days specific to adverse weather outages in Table 3 and Table 7.

Table 3 – Summary of Adverse Weather Outages on Major Event Days in 2018

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
12-Mar-18	Central-North	0	0	0
4-Apr-18	Central-South	17	7,540	11,631
14-Apr-18	West	2	97	243
15-Apr-18	Central-South	8	1,118	1,481
4-May-18	Central-South	53	63,475	98,935
4-May-18	Central-North	10	2,819	6,051
4-May-18	West	59	60,993	218,163
4-May-18	East	46	70,733	227,058
4-May-18	Guelph	3	1,568	56
	Total	**198**	**208,343**	**563,619**

Table 4 – Summary of Adverse Weather Outages on Major Event Days in 2017

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
11-Jan-17	Central-North	3	926	2,535.42
8-Mar-17	West	38	28,496	57,382.42
7-Apr-17	East	13	20,202	51,962.85
15-Oct-17	Central-South	9	11,306	18,382.00
15-Oct-17	East	2	38,079	79,210.32
	Total	**65**	**99,009**	**209,473**

Table 5 – Summary of Adverse Weather Outages on Major Event Days in 2016

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
24-Mar-16	West	9	6,595	12,694.40
24-Mar-16	East	15	86,819	239,395.10
24-Mar-16	Guelph	7	3,952	3,512.10
25-Mar-16	East	40	20,738	72,084.76
	Total	**71**	**118,104**	**327,686**

Table 6 – Summary of Adverse Weather Outages on Major Event Days in 2015

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
3-Mar-15	Central-North	17	21,127	35,200.32
3-Mar-15	East	0	0	0
14-Mar-15	East	0	0	0.00
28-Jun-15	West	9	4,212	12,947.83
	Total	**26**	**25,339**	**48,148**

Table 7 – Summary of Adverse Weather Outages on Major Event Days in 2014

Date	Zone	Number of Interruptions	Number of Customer Interruptions	Customer Hours of Interruption
20-Mar-14	West	0	0	0
19-Apr-14	West	0	0	0
1-Jun-14	Central-North	0	0	0
17-Jun-14	Central-South	7	11,083	11,897.15
17-Jun-14	East	7	17,769	26,184.33
22-Jul-14	West	0	0	0
24-Nov-14	Central-South	32	19,697	14,107.07
24-Nov-14	East	14	25,896	18,565.63
27-Nov-14	West	54	34,780	90,069.23
	Total	**114**	**109,225**	**160,823**

e) Alectra Utilities is not able to prorate or forecast the impacts and severity of future adverse weather events. As of July 31, 2019, Alectra Utilities has experienced 127 outages, which results in 87,219 customer interruptions for a combined 74,768 customer hours of interruption due to adverse weather conditions.

G-Staff-73

Reference: Exhibit 4, Tab 1, Schedule 1, Page 235 of 438

Alectra Utilities describes its asset replacement strategy for submersible load break devices switches in the following table:

Asset Class	Primary Replacement Strategy	Comments
Submersible Load Break Devices (“LBD”) Switches	Reactive	Alectra Utilities primarily manages its submersible LBD switches through reactive replacement. However, units that are no longer functioning as intended and no longer receive vendor support (e.g. vac-pac units) will be targeted for planned replacement.

a) **Please provide the Health Index with and without the Condition Flag for Obsolescence.**

b) **If the units are functioning, why not wait for failure before replacing units, because the impact of failure is the same as if they were reactively replaced? What is the business case / rationale for not deriving the maximum service life out of these units?**

Response:

a) Alectra Utilities does not incorporate a condition flag for obsolescence on submersible load break switches.

b) Submersible Load Break Switch (LBDS) enable safe sectionalizing of the distribution system. Failure of an LBDS impacts customer service levels in an unplanned manner requiring a reactive response, often impacting a larger customer base compared to planned replacement. Planned replacement of LBDS facilitates an organized approach to switching the units out of the system and replacing them in a safe manner.

G-Staff-74

Reference: Exhibit 4, Tab 1, Schedule 1, Pages 237-238 of 438

Alectra Utilities states that its Subject Matter Experts (SMEs) evaluate ACA results of its distribution assets to determine investment needs in system renewal. Alectra Utilities further states that SME reviews forms the basis for identifying technical solutions and developing business cases and provides the following table describing the overall process:

Figure 5.3.3 - 5: Distribution Assets Condition Assessment

a) **Do SMEs quantitatively account for consequence of failure when identifying investment needs?**

    i. **If yes, please provide the methodology.**

Response:

a) SMEs quantitatively account for consequence of failure when scoring a project within the Value Framework in Copperleaf C55 as part of the business case submission. Please see Section 5.4.1.2 Subsection A – Value Framework of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 334 to Page 337).

G-Staff-75

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 21

On page 21, Alectra Utilities states:

> **Distribution assets SMEs use quantities of Very Poor and Poor assets as the needs driver for business cases[…]**
> **Station asset investments follow a risk-based approach incorporating a station centric approach to identify specific asset sustainment initiatives. SMEs consider multiple factors along with the HI results for individual components. The sustainment strategies for station assets are guided by risk mitigation and not pacing/timing.**

a) **For distribution assets, please explain if this approach ignores the consequence of failure of the assets being evaluated for replacement. In other words, are all Very Poor condition assets replaced first, even if the consequence of failure is greater for certain Poor (or better condition) condition assets?**

b) **For Station assets, are replacement projects triggered by exceeding specified risk thresholds, regardless of pacing and timing considerations?**

   i. **If no, how are replacement projects triggered?**

c) **How is risk determined for station assets? Is risk different than Health Index results?**

Response:

a) The objective of Alectra Utilities' Asset Condition Assessment is to provide a measure of condition (i.e. Health Index) for each asset considered. The Health Index is one of several elements considered by Alectra Utilities in developing renewal plans. Alectra Utilities has developed asset replacement practices as explained in detail in Section 5.3.3.2 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 231 to Page 279) for each major asset category, including the consequence of failure. For each asset type, Alectra Utilities has designated the primary replacement strategy (i.e. reactive, planned). For example, Alectra Utilities manages the replacement of poles in a planned renewal manner. As outlined in Figure 5.3.3-16 of the DSP, Alectra Utilities priorities pole renewals incorporating information on health index, remaining pole strength, visual inspection results, presence of primary conductors, transformer, switches, number of conductors and other elements such as framing configuration and location in the system. These elements capture the criticality of failure and guide Alectra Utilities in prioritizing renewals within each asset category.

b) For station assets, risk is the primary consideration. Alectra Utilities examines all remediation options (including maintenance and repair) along with renewal of assets as potential solutions to mitigate risks. Risk factors are identified and reviewed with the assistance of Subject Matter Experts (SMEs). The risk probability profile incorporates the pacing and timing of renewal investments. If replacement is the recommended approach, a business case is entered in Copperleaf C55. Pacing and timing of renewal investments are an established part of the portfolio optimization process.

c) Alectra Utilities determines the condition of assets (Health Index) separately from risk assessment. Both measures are completed, but in separate and appropriate steps. Health Indices represent a measure of assets' condition, and is completed using a uniform and consistent process. The risk for station assets is based on specific configurations associated with each given station. These include, but are not limited to:

- Station configuration
- Back-up capability
- Availability of spares
- Magnitude and duration of potential load interruptions
- Safety concerns
- Environmental issues
- Maintenance concerns
- Operational constraints
- Obsolescence

G-Staff-76

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix L, Page 16

Regarding worst performing feeders, Alectra Utilities states:

> **Reliability Value is computed from the Reliability Cost. A 25% premium is added to the Reliability Cost if: a feeder has been identified on the worst performing feeder report in the past 2 years, OR the area been identified by the Key Accounts Manager as an area of concern.**

a) What are the criteria applied by Key Accounts Managers to identify "areas of concern"?

b) Is the 25% reliability cost premium added to all lines within all "areas of concern"? Please explain.

Response:

a) An 'area of concern' applies to a specific neighbourhood or customer where reliability has degraded, and/or customers or political officials have escalated the issue to Alectra Utilities' Key Accounts group, and the Manager, Key Accounts has validated the impact/concern to customers as requiring intervention.

For example, a plastics manufacturer experiencing two momentary interruptions per month for the last two to three months may call the Key Accounts Team. The momentary interruptions may have a significant impact and result in lost production and revenue for the manufacturer. If Alectra Utilities finds that 10-15 poles with porcelain insulators, even after cleaning, are causing the issue, the Key Accounts Manager may request the project be escalated as part of the business case approval process.

Another example would be a residential neighbourhood experiencing a cable fault every other week from June to August. The customers and City Councilor will advise the Key Accounts Team of the concern. If Alectra Utilities determines that a rebuild is required to address the issue, the Key Accounts Team may flag the project as important due to the concerns raised by customers and the municipality.

b) The 25% cost premium is added to the project's value framework, not the actual cost to construct the project. The reliability benefit score carries more weight if the area has higher sensitivity from either significantly poorer reliability or social/political concerns.

G-Staff-77

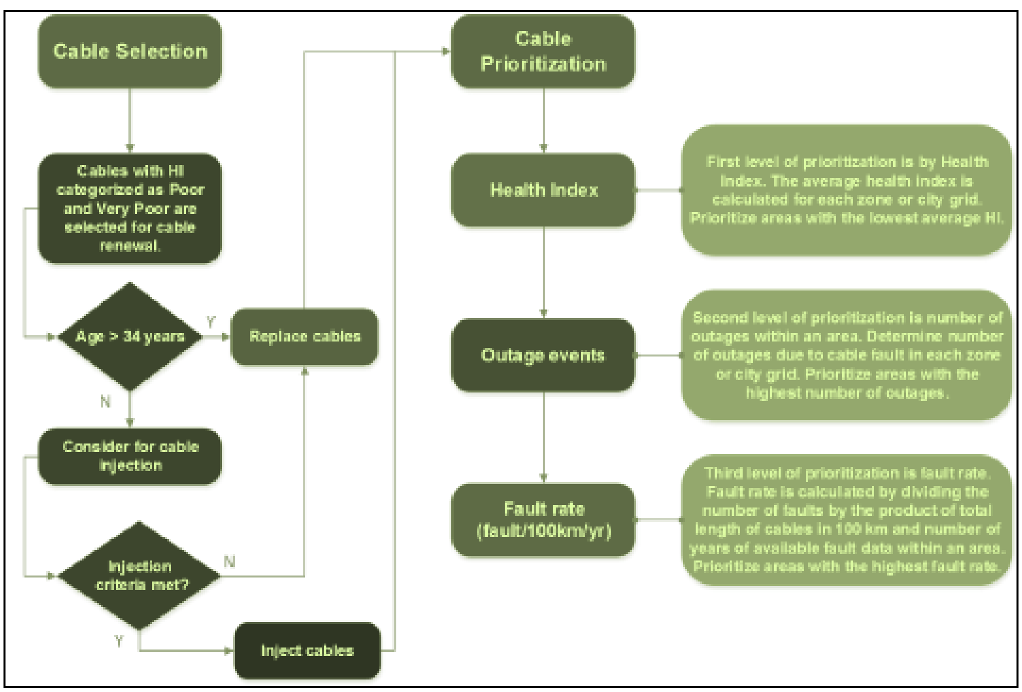
Reference: Exhibit 4, Tab 1, Schedule 1, Pages 247 and 272 of 438

On pages 247 of 438, Alectra Utilities describes its selection and prioritization of pole replacements as follows:

> **Alectra Utilities' selection and prioritization of pole replacement candidates begin with the identification of deteriorated poles (i.e. those in Very Poor or Poor condition, as determined through the ACA). Pole HI is condition based, and computed based on specific forms of degradation identified through inspections and pole testing. Remaining pole strength test results and visual indicators of condition (e.g., rot, decay, splitting, insect infestation, bending, and leaning) factor into the HI models, which provide a means to differentiate asset condition across the entire pole population. Once the utility identifies poles in the Very Poor and Poor condition for further action, it prioritizes poles for replacement or reinforcement starting with poles having the lowest HI scores.**

On page 272 of 438, Alectra Utilities describes its prioritization of its cable renewal process with the following figure:

Figure 5.3.3 - 34: Cable Renewal Prioritization Process



a) **Does Alectra Utilities evaluate Risk (Risk = Probability X Consequence) or Probability of Failure when considering which poles to replace?**

b) Please discuss why is it prudent to use decision parameters related solely to probability of failure (i.e. Health Index, Number of Outage Events, Fault Rate) and not include an evaluation of Risk (Risk = Probability of Failure x Consequence of Failure)?

c) How does Alectra Utilities ensure that it is optimizing risk mitigation if it is using only probability-based parameters to inform decision making?

Response:

a) As described in Exhibit 4, Tab 1, Schedule 1, Page 250, Figure 5.3.3 – 16: Pole Replacement Prioritization Steps and as explained in response to G-Staff-75 a), Alectra Utilities priorities pole renewals incorporating information on pole condition (health index), remaining pole strength, visual inspection results, as well as the presence of primary conductors, transformer, switches, number of conductors and other related elements such as framing configuration and location in the system. These elements capture the criticality of failure and guide Alectra Utilities in prioritizing renewals within each asset category. The assessment of risk (impact, probability) related to the Pole Renewal investment is provided in the business case development in CopperLeaf C55. Please refer to Section 5.4.1.2 Subsection A.2 Value Measures: Risk Mitigation of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 338 to Page 341) for a detailed explanation of the risk analysis completed for each capital investment utilizing a uniform and consistent risk matrix.

b) Capital renewal investments based on condition assessment are prioritized based on renewal strategies as provided in Section 5.3.3.2 of the DSP and evaluated for benefits and risks utilizing Alectra Utilities Value Framework as described Section 5.4.1.2 (Exhibit 4, Tab 1, Schedule 1, Page 338 to Page 341).

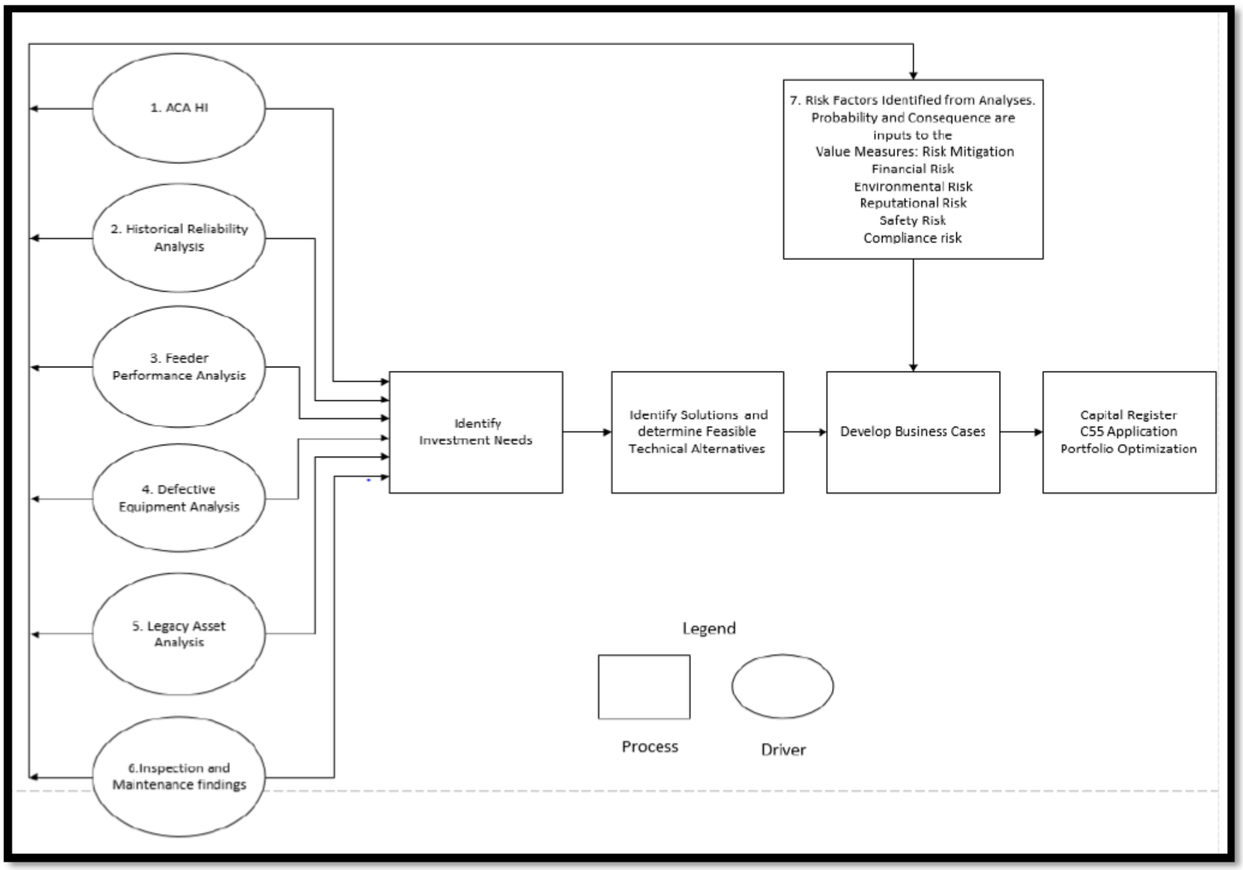
c) System renewal investments are determined using both probability and consequence of impact, as provided in Section 5.4.1.2 Subsection A.2 Value Measures: Risk Mitigation of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 338 to Page 341).

G-Staff-78

Reference: Exhibit 4, Tab 1, Schedule 1, Page 300 of 438

On page 300 of 438, Alectra Utilities provides the following figure describing its Lifecycle Risk Management Process:

Figure 5.3.3 - 41: Asset Lifecycle Risk Management Processes



OEB staff prepared the following table to summarize the primary risk parameters utilized in the 6 analyses shown in the figure above:

Analysis	Primary Risk Parameter
ACA HI	Probability
Historical Reliability	Probability and Consequence
Feeder Performance	Probability and Consequence

Defective Equipment	Probability
Legacy Asset	Consequence
Inspection and Maintenance	Probability

a) Please confirm that the table describes the primary risk parameters utilized in these 6 analyses.

a. If not, please provide an amended table.

b) How does Alectra Utilities ensure that probability of failure is not double counted when evaluating risk using ACA Health Index, Historical Reliability, Feeder Performance, Defective Equipment and Inspect and Maintenance Findings?

c) Why doesn't Alectra Utilities separate Probability of Failure from Consequence of Failure when developing parameters used to calculate risk?

Response:

a) The table provided by OEB Staff does not describe the risk factors utilized by Alectra Utilities. The risk assessment is performed in Copperleaf C55 following a consistent questionnaire. The processes are inputs used to inform the Subject Matter Experts (SMEs) in completing the Value Framework questionnaire. An amended table is provided below. Please also refer to Section 5.4.1 Subsection A.1 in the DSP (Exhibit 4, Tab 1, Schedule 1, Page 336 to Page 337) for a detailed explanation on the application of risk assessment to capital investments.

Table 1 - Value Measures – Risk Mitigation

Value Measure	Risk Parameter
Financial Risk	Probability and Consequence
IT Capacity Risk	Probability and Consequence
Distribution System Capacity Risk	Probability and Consequence
Safety Risk	Probability and Consequence
Compliance Risk	Probability and Consequence
Environmental Risk	Probability and Consequence
Reputational Risk	Probability and Consequence

b) ACA Health Index, Historical Reliability, Feeder Performance, Defective Equipment and Inspection and Maintenance Findings provide indicators of asset condition, degradation and performance trends. These processes are not used directly to calculate risk.

Alectra Utilities evaluates risk (probability and consequence) within the Copperleaf C55 Value Framework when creating business cases for proposed investments. The Value Framework provides a consistent methodology so that all proposed investments are evaluated for risk and benefits consistently, providing an optimized investment portfolio. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix L – Alectra Value Framework Implementation Document for a detailed explanation.

c) Alectra Utilities separates probability of failure and consequence of failure. The questionnaire in the Copperleaf C55 Value Framework separates probability and consequence of failure to assess risk for each business case. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix L – Alectra Value Framework Implementation Document for a detailed explanation.

G-Staff-79

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 16

Alectra Utilities uses condition multipliers as an input to its assets' health index and provides the following examples:

> **Field inspection multiplier is applied to assets that exhibit major degradation or imminent failure as determined by field inspection.**
>
> **Measurement multiplier is applied to assets that exhibit major degradation or imminent failure as determined by a measurement.**
>
> **Safety hazard multiplier is applied to assets that pose a safety hazard or in a condition that is below the acceptable industry safety standards, guidelines and practices.**
>
> **Obsolescence multiplier is applied to assets that are no longer supported by vendors, have limited or no parts availability and/or no longer meet current safety or performance standards. Obsolescence is largely driven by specification changes, compatibility, and/or manufacturer/supplier.**

a) Does the use of Conditions Multiplier imply that the Health Index formula does not accurately reflect Health of the Asset without resorting to an external factor? Please explain.

b) Please explain how a consequence of failure (e.g., Safety Hazard or Obsolescence) is able to impact an asset probability of failure parameter (i.e., Health Index).

c) Please provide examples of Health Index values before and after the listed multipliers are applied.

Response:

a) The Health Index is a composite score of multiple inputs, which include items such as: the presence of corrosion, leaks or contaminants, the condition of insulation, mechanical degradation, damaged components, remaining strength, rot or decay and age. There can be instances where a very important low scoring condition may be masked by other inputs with high scores.

Alectra Utilities retained Kinectrics Inc. to undertake an independent third-party review of Alectra Utilities' Asset Condition Assessment.

Kinectrics is an engineering firm, with asset management expertise including conducting Asset Condition Assessments. The complete document containing Kinectrics' opinion, entitled "Kinectrics Inc. ACA Assurance Review", is attached in Appendix E in the DSP (Exhibit 4, Tab 1, Schedule 1, Appendix E)

Kinectrics' has reported that "[T]he use of such multipliers is good practice" and "Applying a condition multiplier therefore ensures that inputs representing dominant problematic conditions are appropriately captured."

In 2017, Vanry Associates made several recommendations to Alectra Utilities as part of the review of Alectra Utilities' DSP for the Enersource Rate Zone. Alectra Utilities implemented those recommendations to improve its practices. Vanry Associates was retained to review Alectra Utilities' Distribution System Plan (2020-2024) and presented their opinion on condition multiplier (Exhibit 4, Tab 1, Schedule 1, Appendix G, Page 30):

> *"Alectra has incorporated health index multipliers in cases where extreme conditions are expected to have outsized effects on asset health. For example, the distribution line transformer has a field health index multiplier whereby if either of the condition criteria shows "major" degradation, the health index is multiplied by 0.25, which puts the asset in Very Poor condition."*

b) As an example, the obsolescence condition multiplier is applicable to station circuit breakers. Obsolete circuit breakers are no longer supported by the manufacturer, parts are no longer readily available and/or no longer meet safety or performance standards.

Obsolete breakers are difficult to maintain which results in the breakers not getting the timely and required maintenance, thereby increasing the likelihood of failure (i.e. probability). Should a failure occur, parts are scarce, which increases the potential impact upon failure (i.e. consequence). To mitigate the need of renewal, Alectra Utilities has implemented a strategy to leverage a consolidated spare parts inventory and increase the level of monitoring of circuit breakers.

c) Examples of Health Index values before and after the listed multipliers are applied are provided Table 1, below.

Table 1 - Health Index Values with Condition Multipliers

Condition Multiplier	HI Before Multiplier (%)	HI After Multiplier (%)
Field Inspection Multiplier	30.0	7.5
Measurement Multiplier	46.1	11.5
Safety Hazard Multiplier	48.2	12.0
Obsolescence Multiplier	44.0	22.0

G-Staff-80

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Tables 1, 2 and 3

OEB staff created the following table summarizing Alectra Utilities' health index categorizations using Tables 1, 2 and 3 of Appendix D:

Category from Table 1	Range from Table 1	Category from Table 2	Range from Table 2	Category from Table 3	Range from Table 3
Excellent	100%	Excellent	100%	Very Good	HI ≥ 85%
Good	80%	Good	75%	Good	70% ≤ HI < 85%
Fair-Moderate	40-60%	Fair	50%	Fair	50% ≤ HI < 70%
Poor	20%	Poor	25%	Poor	25% ≤ HI < 50%
Very Poor	0%	Very Poor	0%	Very poor	HI < 25%

a) **Please clarify the apparent overlaps/ambiguity in possible categorization based upon Health Index Range classification (e.g., 40% may be categorized as Fair or Poor depending on which asset class is being evaluated).**

b) **How does Alectra Utilities determine Health Indexes in a consistent manner when classification thresholds are, not consistent across asset classes?**

Response:

a) and b) Tables 1 and 2 in Exhibit 4, Tab 1, Schedule 1, Appendix D are Inspection Input Score Tables that are utilized to convert observed inspection criteria into quantitative input values. Once the input values are determined, Alectra Utilities inputs these quantitative inspection values into the Health Index Computation Models to derive the Health Index result output for each asset. Quantitative Inspection Inputs are one of several attributes considered for each asset condition computation model. Alectra Utilities calculates the Health Index in a consistent manner. Each input is scored and weighted according to the Health Index formula of each asset class. All Health Indices across all assets classes are classified according to Table 3 (Exhibit 4, Tab 1, Schedule 1, Appendix D, page 17) in a consistent manner.

G-Staff-81

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Pages 15, 26, 32 and 38

On page 15, Alectra Utilities notes that its asset age scoring formula is calibrated such that the formula yields 1% at the EUL of an asset.

On pages 26, 32 and 38, Alectra Utilities provides EUL data for vault transformers, switchgears and overhead switches. OEB staff has summarized the EUL data below:

- **Vault transformers: EUL at 45 years, currently 568 out of 13,345 (4.3%) remain in-service beyond EUL.**
- **Pad-mounted switchgears: EUL at 35 years, currently 126 out of 3,389 (3.7%) remain in-service beyond EUL.**
- **Overhead switches: EUL at 55 years, currently 140 out of 3,889 (3.6%) remain in-service beyond EUL.**

Although Alectra Utilities stated that EUL is calibrated to indicate the service life at which 1% of assets remain in service. Vault Transformers, Switchgear and Overhead Switches units that are beyond EUL and remain in service represent more than 1% of Alectra Utilities' assets in these categories. Has EUL been mis-calibrated for these asset types? Please explain the apparent mismatch between the stated calibration threshold and actual asset demographics.

Response:

Alectra Utilities did not state that "EUL is calibrated to indicate the service life at which 1% of asset remaining in service" as indicated in the question above. On Page 15 of the 2018 ACA (Exhibit 4, Tab 1, Schedule 1, Appendix D), Alectra Utilities explains that the Gompertz-Makeham Model provides a continuous function based on Typical Useful Life ("TUL") and End of Useful Life ("EUL") values extracted from the OEB's report Asset Depreciation Study for the Ontario Energy Board – Kinectrics Report No: K-418033-RA-001-R000.

Alectra Utilities applied a widely accepted industry practice using TUL and EUL values prepared and accepted by the Ontario Energy Board. To ensure Alectra Utilities' application of industry derived degradation curves was appropriate, the company engaged Kinectrics Inc. to review the 2018 ACA. Kinectrics provided that *"[w]here utility-specific empirically derived asset degradation curves are unavailable, this provides a good representation of service life."*

As explained in the justification for renewal investments for overhead switches in Appendix A05 of the DSP (Exhibit 4, Tab 1, Schedule 1, Appendix A05, Page 23), Alectra Utilities currently has a backlog of deteriorated assets, a portion of which continue to be operated beyond EUL and introduce a heightened risk of failure. The backlog of deteriorated vault-transformers and pad-mounted switchgear has also positioned Alectra Utilities to operate a portion of these assets beyond the EUL and manage the heightened risk failure through reactive renewal at the consequence of worsening reliability.

G-Staff-82

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 31

On page 31, Alectra Utilities describes failures of its switchgear assets as "most often not directly related to the age of the equipment, but are associated instead with outside influences." Alectra Utilities' deemed EUL of pad-mounted switchgears is 45 years of age.

a) Please confirm that age is a not a direct contributing factor in switchgear failures.

b) At EUL, does Alectra Utilities replace assets or does Alectra Utilities continue to let assets operate as long as their condition warrants?

Response:

a) Alectra Utilities considers age to be one of the contributing factors in switchgear failures, in addition to outside influences which include contamination, rusting, rodents and exposure to harsh environmental conditions (moisture, salt, de-icing). Of the input attributes that Alectra Utilities considers in developing a condition assessment of distribution switchgear, age is considered the most minor with a 15% weighting relative to degradation of insulation (43%) and degradation of components (21%). Please refer to Table 7 in Exhibit 4, Tab 1, Schedule 1, Appendix D, page 33 for switchgear attributes considered by Alectra Utilities in developing the condition assessment of switchgear.

b) Alectra Utilities will continue to operate distribution switchgear assets after EUL as long as the condition warrants, does not indicate imminent failure and does not pose any potential harm to worker safety, public safety and the environment.

G-Staff-83

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Pages 27, 33, 48 and 54

Alectra Utilities provides the inputs to the health index of its various asset classes in the ACA. OEB staff has summarized certain asset classes below:

- **Distribution transformers: "Health index of distribution transformers assesses the condition of the transformer according to three components: Corrosion, Oil leak, and Age."**
- **Pad-mounted switchgears: "Health index of pad-mounted switchgears assesses the condition according to five components: corrosion, component failure, insulation, oil leak (for oil types) and age."**
- **Wood Poles: "Health Index of wood poles assesses the condition of the pole according to three components: Pole remaining strength, Overall condition and Age."**
- **Concrete Poles: "Health Index of concrete poles assesses the condition of the pole according to two inputs: Overall condition and Age."**

a) Please explain why age is used as an input factor to calculate a Health Index for a run-to-fail asset.

b) What useful additional Health Index information is obtained or derived by using Age as an input for calculating the Health Index of assets?

c) If there is no other information available for a specific asset, is its Health Index calculated solely using the Age parameter?

d) What percentage of assets are missing non-age data?

Response:

a) Distribution transformers are the only asset in the above list that is a run-to-failure asset.

Alectra Utilities completes an Asset Condition Assessment ("ACA") of all major assets listed in Figure 1 and Figure 2 of the 2018 ACA Report (Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 8 and Page 9). The determination of an assets' Health Index through the ACA process is completed independently of the asset sustainment strategy (i.e. planned replacement, maintenance, continue to monitor or run-to-failure). Please refer to Section 5.3.3.2 of the

DSP (Exhibit 4, Tab 1, Schedule 1, Page 231 to Page 279) for a detailed explanation of the asset replacement strategy used for each major asset class, as well as Section 5.3.3.3 of the DSP (Exhibit 4, Tab 1, Schedule 1, Page 231 to Page 279) for a detailed explanation of the asset refurbishment practices at Alectra Utilities.

b) Age is not a dominant input contributor in determining the Health Index in any of the above-mentioned assets. Health index analysis takes three components into account - direct testing measurements, observed conditions and the age of an asset. Age is used in the health index calculation to smooth the Health Index transition over the years by accounting for the change in overall condition in between the inspection/testing cycles. It is also leveraged as a key indicator of condition in absence of other observational/measurement parameters (e.g. in newly installed assets).

c) If age is the only available input among all parameters, the Health Index is calculated with age only and that is reflected in the Data Availability Index. Alectra Utilities retained Kinectrics Inc. to complete an independent assurance review of the methodologies and assumptions that Alectra Utilities applied in the development of the 2018 ACA. In Kinectrics opinion: *"Where utility-specific empirically derived asset degradation curves are unavailable, this provides a good representation of service life. This model is commonly used by utilities with limited failure statistics."* Further, as provided in response to part b), age is leveraged as a key indicator of condition in absence of other observational/measurement parameters (e.g. in newly installed assets).

d) Please see Table 1, below for the percentage of assets missing non-age data in each of the four noted asset classes.

Table 1 - Percentage of Assets with Missing Non-age Data

Asset Name	% of Assets with Missing Non-age Data
Wood pole	3.5%
Concrete pole	16.7%
Distribution Transformers	5.4%
Pad-mounted Switchgears	5.7%

G-Staff-84

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Pages 28-29, 49 and 55

Alectra Utilities provides the health index distributions of pad-mounted transformers, pole-mounted transfers, vault transformers, wood poles and concrete poles in Figures 11, 12, 13, 21 and 23 of Appendix D respectively.

Please provide a revision of Figures 11, 12, 13, 21 and 23 showing the condition distribution without using Age as a Health Index input.

Response:

The Health Index distributions charts of pad-mounted transformers, pole-mounted transformers, vault transformers, wood poles and concrete poles, without using age as an input, are provided in Figures 1 to 5, below. Alectra Utilities notes, that without age as in input, a significant amount of assets in each class result in an unknown health index calculation.

Figure 1- Pad-mounted Transformers Health Index Distribution without Age Input

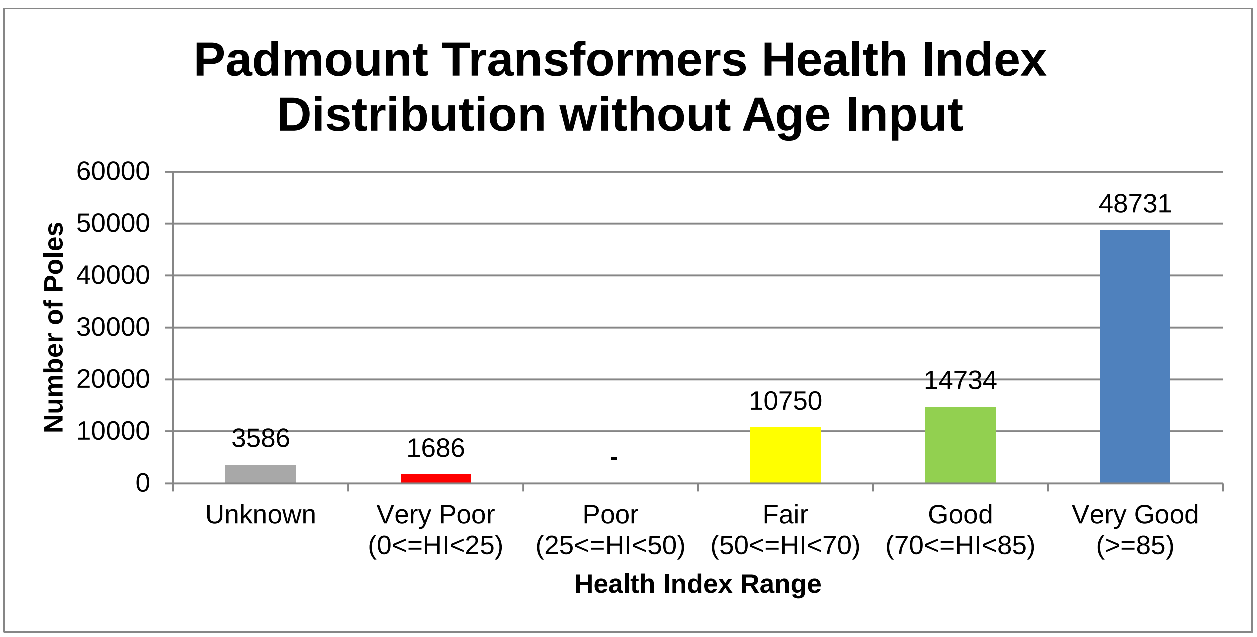


Figure 2- Polemount Transformers Health Index Distribution without Age Input

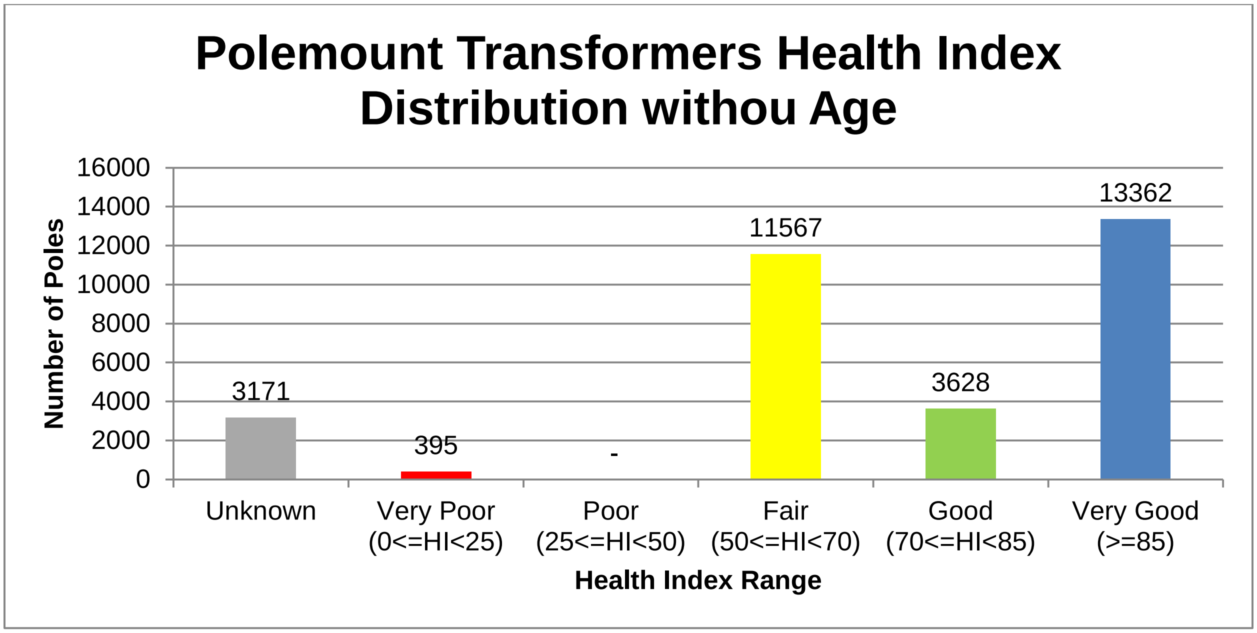


Figure 3 - Vault Transformers Health Index Distribution without Age Input

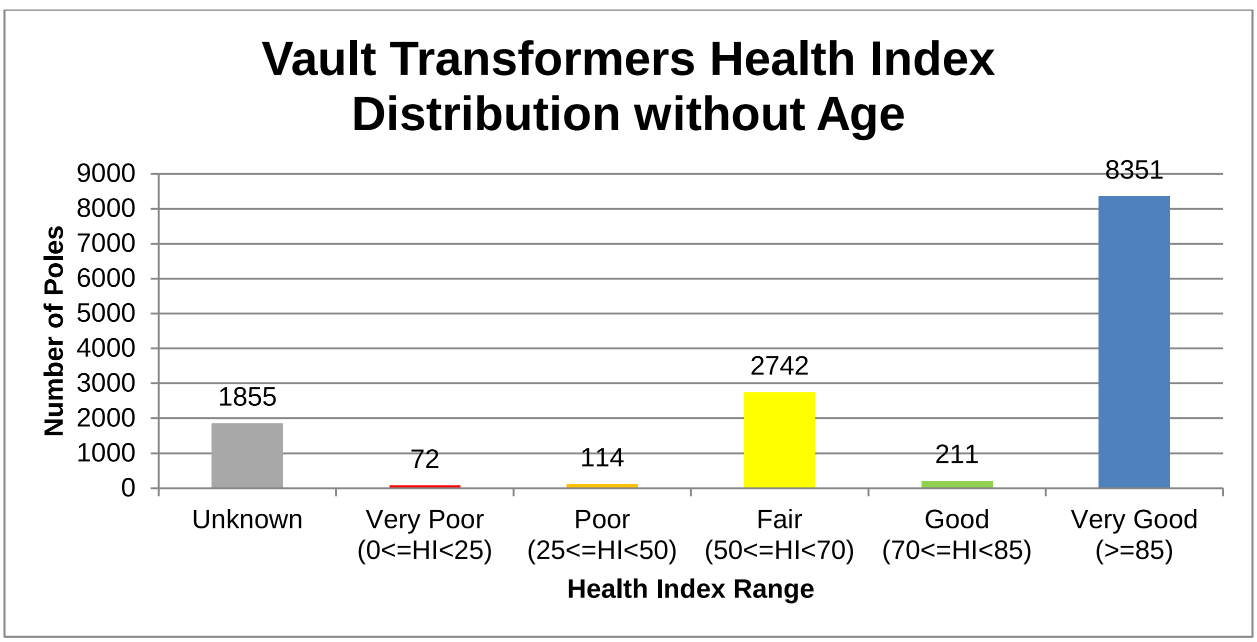


Figure 4 - Wood Poles Health Index Distribution without Age Input

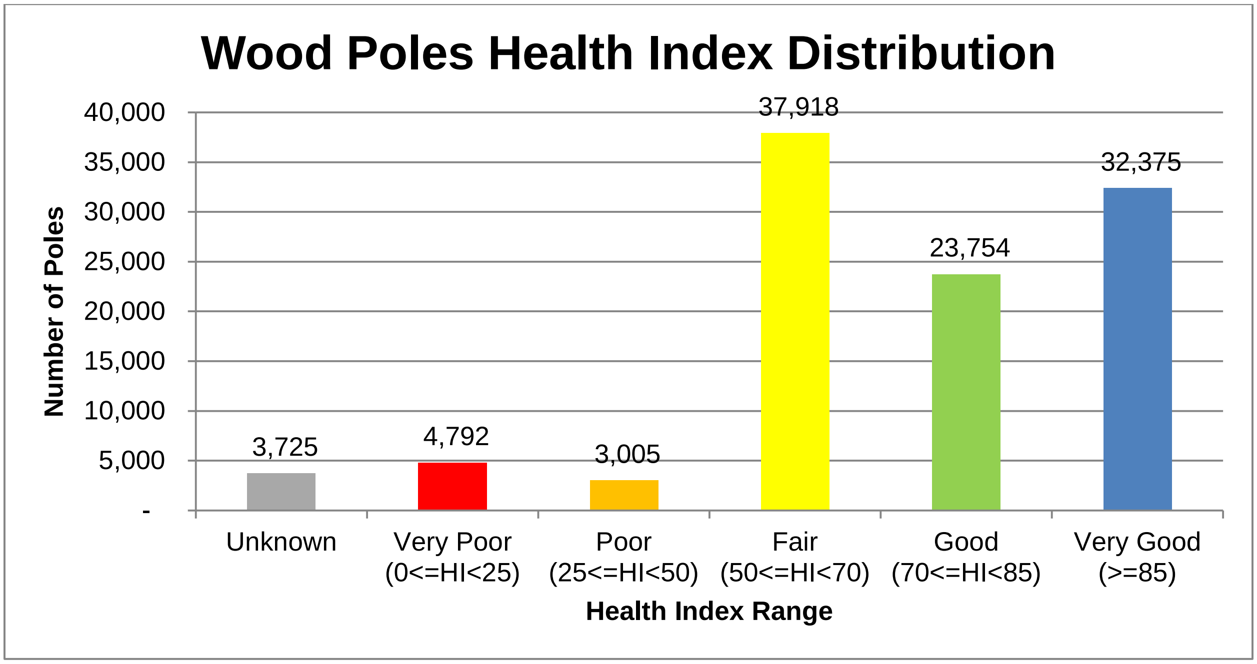
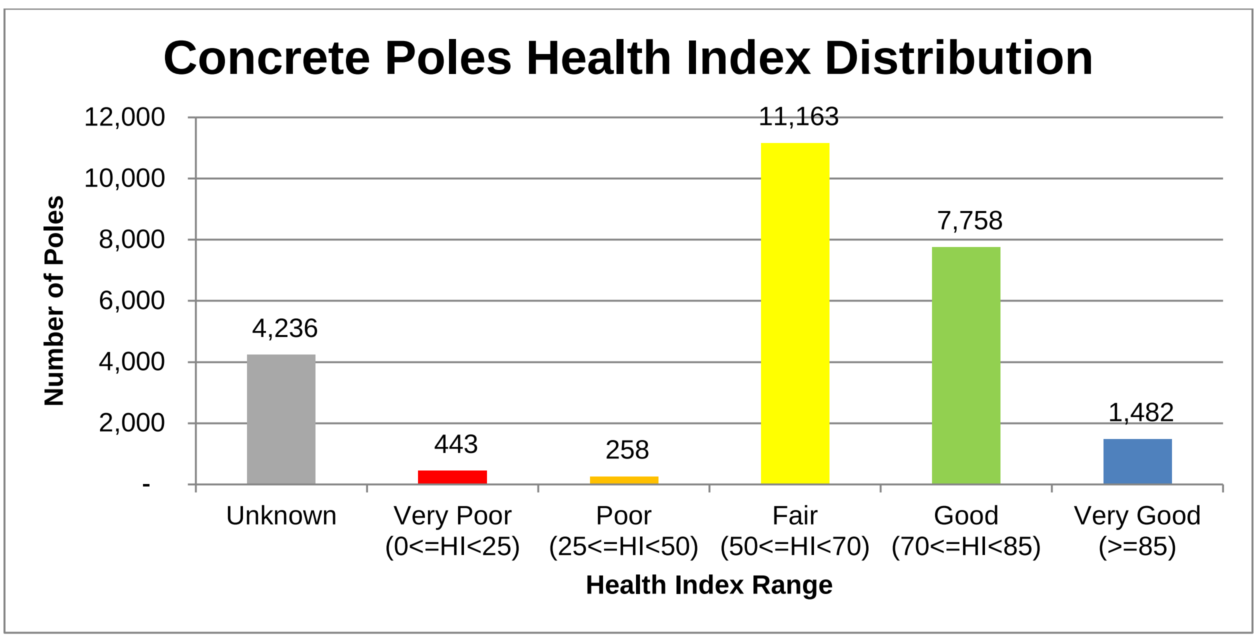


Figure 5 - Concrete Poles Health Index Distribution without Age Input



G-Staff-85

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Pages 53-54

Alectra Utilities considers concrete poles to be EUL at 80 years of age and provides the following graph showing the age distribution of its concrete pole population:

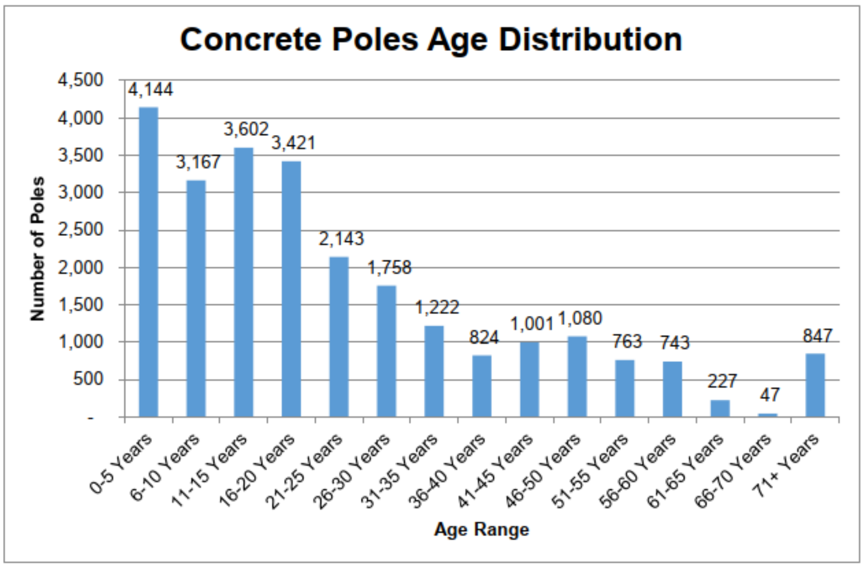


Figure 22 Concrete Poles Age Distribution

When assessing the health index of a concrete pole, Alectra Utilities states that it uses overall condition and age as inputs. Further, Alectra Utilities applies a 25% field inspection multiplier if a concrete pole exhibits major degradation or imminent failure as determined by a field inspection.

a) **Please provide a revised Figure 22 showing the number of poles over 80 years of age.**

b) **Please explain whether a field inspection multiplier is redundant, given that a post-field inspection condition rating should reflect an assessment of major degradation or imminent failure.**

Response:

a) Figure 1, below provides the number of poles over 80 years of age.

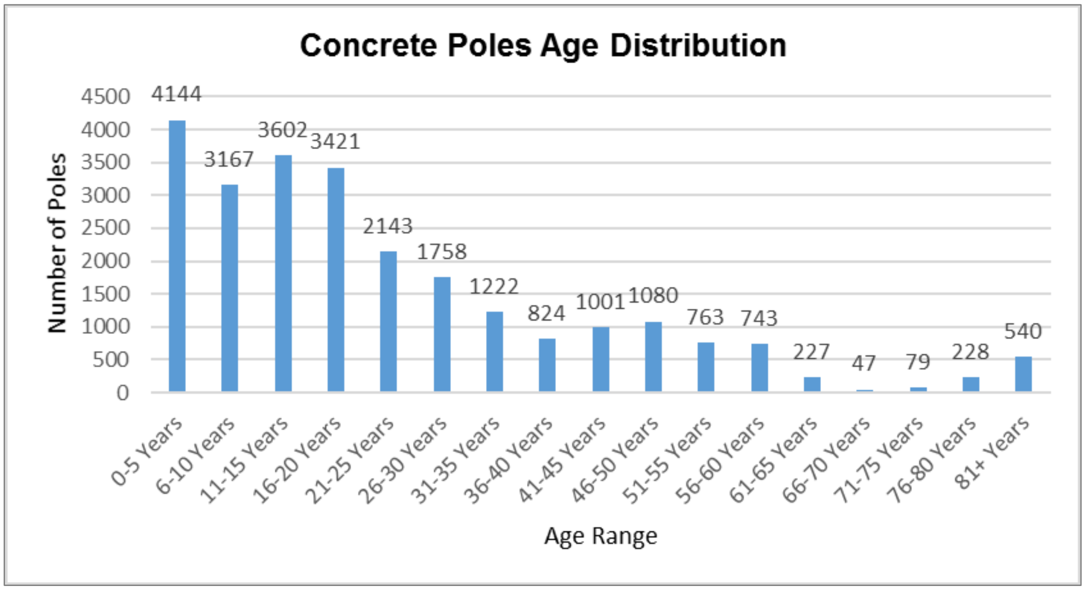


Figure 1 - Revised Concrete Poles Age Distribution

b) The use of the condition multiplier is not redundant. It is triggered when a concrete pole exhibits major degradation or imminent failure through field inspection. The multiplier prioritizes poles that exhibit the mentioned condition factors.

When mounted on concrete poles, distribution equipment (e.g. transformers) utilize the internal rebar of the pole as grounding means. The integrity of the metal rebar is critical for establishing effective grounding. Grounding is crucial for the safety of the public and workers. Major deterioration of the concrete poles can impact the grounding. Therefore, the condition multiplier prioritizes the poles accordingly.

Please refer to G-Staff-79 for a detailed discussion on the use of condition multipliers.

G-Staff-86

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Pages 37-39

Alectra Utilities considers overhead switches to be EUL at 55 years of age. According to Alectra Utilities' overhead switches age distribution, 140 switches would be considered EUL.

Alectra Utilities provides the following figure showing the health index distribution of its overhead switches:

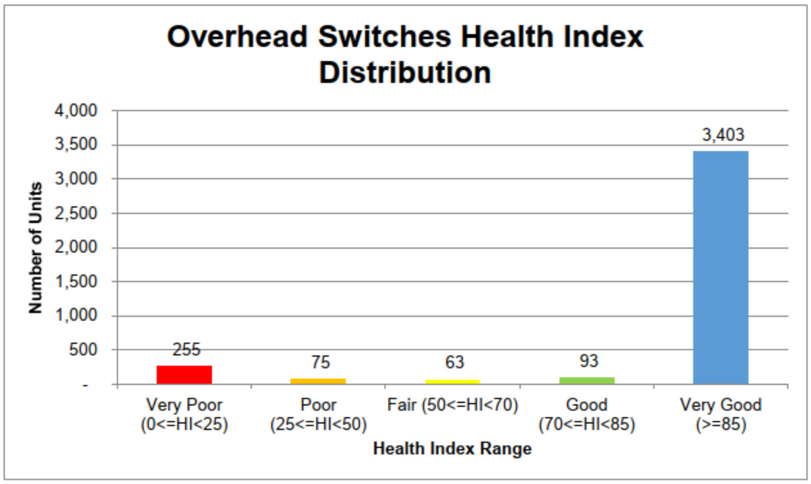


Figure 17 Overhead Switches Health Index Distribution

a) **Given that the Health Index for overhead switches is calculated using only age as an input, and 140 switches are beyond EUL, why have 255 switches been rated as having a Very Poor Health Index?**

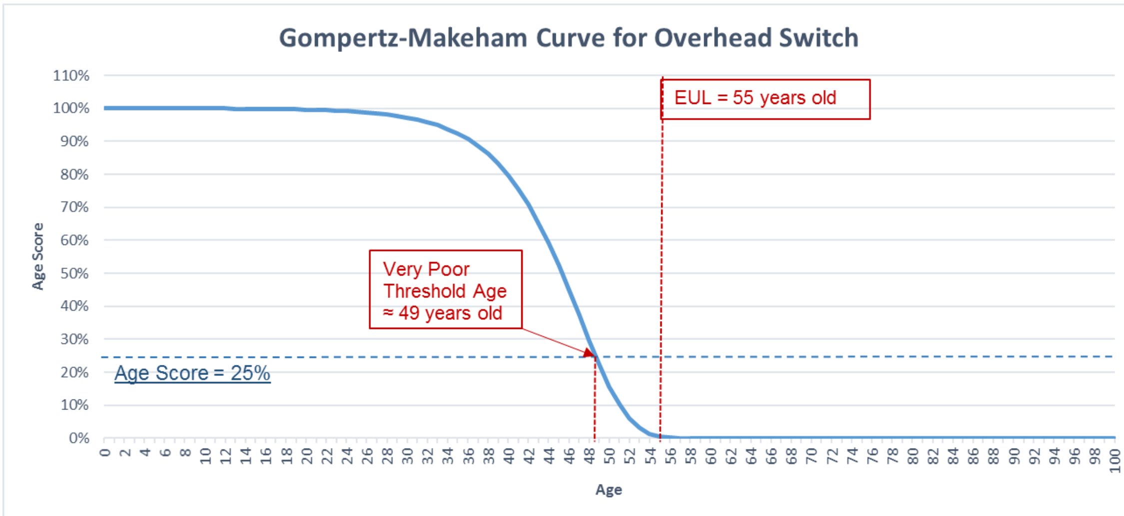
b) **Please show how the Health Index results in Figure 17 were calculated.**

Response:

a) Alectra Utilities categorizes the condition (Health Index) of an overhead switch into one of five bands (Very Good, Good, Fair, Poor, Very Poor), according to the categorization illustrated in Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 17.

The Gompertz-Makeham degradation curve for Overhead Switches, used to determine the Health Index for overhead switches is provided in Figure 1, below. The age demographic for overhead switches, as provided in Appendix D, page 38, displays the number of switches in 5-year increments. When this data is combined with Figure 1, the results are that 255 switches fall beyond the vertical dotted line at 48 years of age, and 140 switches are to the right of the vertical dotted line at 55 years of age.

Figure 1 - Gompertz-Makeham Curve for Overhead Switch



b) For overhead switches, age is the sole input parameter to the Health Index calculation. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 15 for a detailed explanation on the methodology Alectra Utilities used to derive the Health Index.

As provided in response to part a), individual Health Index scores are then categorized into one of the five condition bands (Very Good, Good, Fair, Poor, Very Poor) and grouped to produce the results shown in Figure 17.

G-Staff-87

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 78

Alectra Utilities provides the following figure showing the health index distribution of its circuit breaker assets:

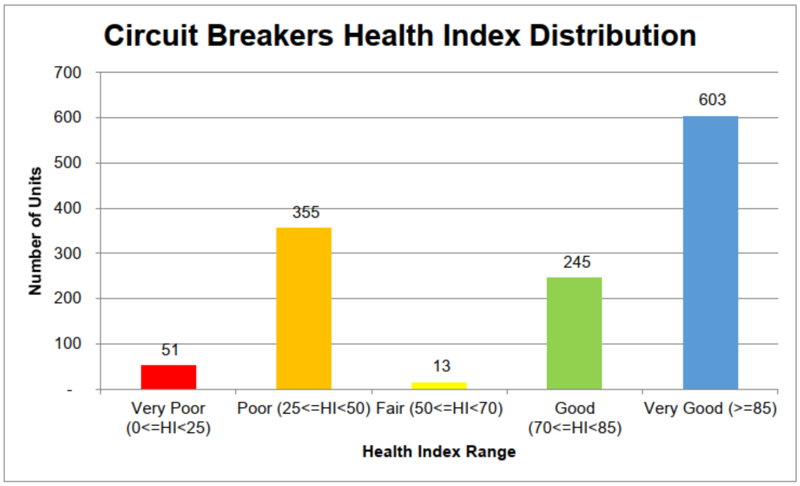


Figure 34 Circuit Breakers Health Index Distribution

a) **What is the primary input driving the Poor Health Index rating for the 355 circuit breakers shown in Figure 34?**

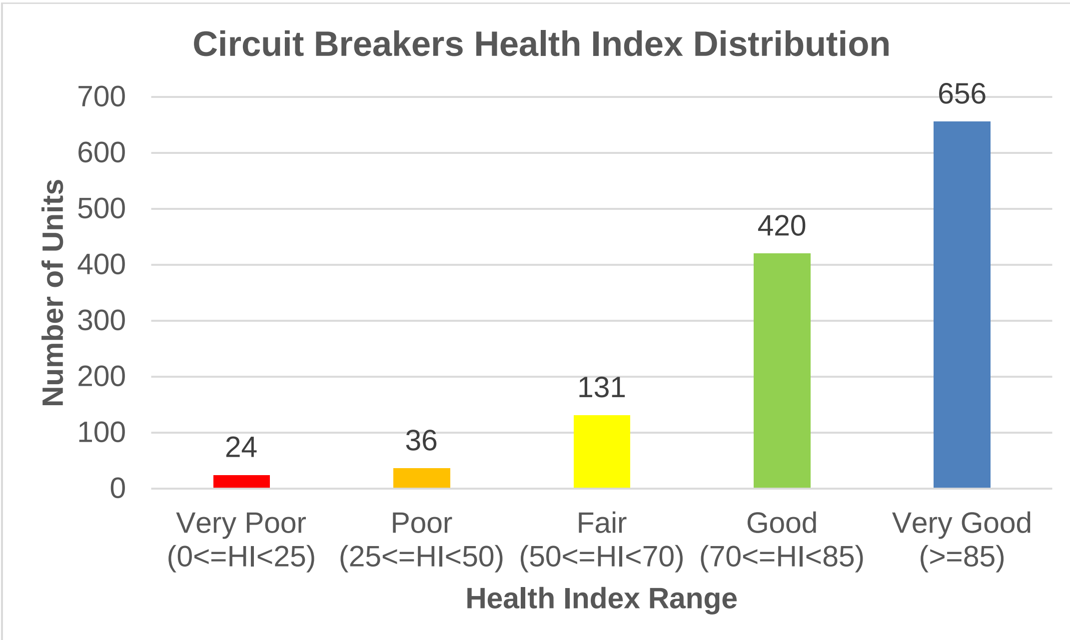
b) **Please provide a revision of Figure 34 without the obsolescence multiplier applied.**

Response:

a) The primary driver of the Poor Health Index rating for the 355 circuit breakers shown in Figure 34 is the obsolescence. Obsolete circuit breakers present a challenge to Alectra Utilities in that the assets are no longer supported by the manufacturer, parts are no longer readily available and/or the assets no longer meet safety or performance standards. Such operational challenges increase maintenance and repairs, and the likelihood of failure. To mitigate the need for renewal, Alectra Utilities has implemented a strategy to leverage a consolidated spare parts inventory and increase the level of monitoring of circuit breakers.

b) The Circuit Breaker Health Index Distribution without the Obsolescence Multiplier is shown in Figure 1, below.

Figure 1 - Circuit Breaker Health Index Distribution without Obsolescence Multiplier



G-Staff-88

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 73

Alectra Utilities' health index distribution for power transformers indicate that 34 power transformers have a "poor" health index rating.

What is the primary parameter driving the poor health index rating for the 34 power transformers shown in the health index distribution?

Response:

The primary parameter driving the poor Health Index rating for the 34 transformers is the oil Dissolved Gases Analysis (DGA), which is a condition-based indicator of the power transformer's insulation.

Alectra Utilities is mitigating the renewal needs of power transformers through a consolidated spare inventory and increased monitoring.

G-Staff-89

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix E, Page 9

Kinetrics Inc. (Kinetrics) gave Alectra Utilities recommendations to improve its ACA methodology and practices as part of its ACA assurance review.

a) Please provide the timing and implementation plan for incorporating Kinectrics' recommendations into Alectra Utilities' harmonized ACA program.

b) Please quantify how implementing the Kinectrics recommendations will impact Alectra Utilities' future capital expenditure plans.

c) Please confirm that:

i. Alectra Utilities does not have asset degradation curves; and

ii. Alectra Utilities' adopted scoring approach is commonly used by utilities with limited failure statistics.

Response:

a) Alectra Utilities has begun to implement the recommendations included in Kinectrics' 2018 Asset Condition Assessment Assurance Review. The recommendations in the Report include: continued improvements in ACA model development; continued investment in collecting more data for each asset category; and leading the development of internal ACA systems and capabilities. Alectra Utilities has implemented plans to develop an Asset Data Register that will enable Alectra Utilities to capture, store and process asset failure information and diagnostics. The implementation of the Asset Data Register commenced in 2019, and will continue in 2020 in coordination with the implementation of Alectra Utilities consolidated Enterprise Resource Planning ("ERP"), Geographic Information System ("GIS") and Outage Management System ("OMS"). The full implementation of the Asset Data Register, will enable Alectra Utilities to gather necessary failure information in order to develop degradation curves for the utility. The Asset Data Register will also provide a centralized repository of data necessary to increase Data Availability Index ("DAI") required for the Asset Condition Assessment process.

b) Alectra Utilities cannot speculate nor quantify the changes, if any, that the continuous improvements which Kinectrics has recommended would impact future Asset Condition

Assessments completed by Alectra Utilities or future capital investment plans. In the 2018 ACA Assurance Review Report Kinectrics has stated, "…Alectra's ACA is aligned with good utility practices. The processes, methodologies, and results are appropriate in serving as the basis of identifying system sustainment needs."

c) i) Alectra Utilities clarifies that it has asset degradation curves that are based on a continuous function rooted in the assumption that asset failures increase with age. In the 2018 ACA Assurance Review, Kinectrics states: *"Where utility-specific empirically derived asset degradation curves are unavailable, this provides a good representation of service life."* Kinectrics continues to state that: *"In the absence of Alectra-specific statistics, use of the OEB TUL and Max UL values is reasonable, given that they are based on surveys of multiple utilities in Ontario, including some of the Alectra legacy utilities."* Alectra Utilities does confirm that at the time of the 2018 ACA development, it did not have Alectra Utility-specific degradation curves as the company formed in 2017 and continues to integrate systems, processes and standards.

ii) Alectra Utilities is in the process of developing a utility specific degradation curve. Further, as identified in response to c) i), Alectra Utilities utilizes an asset degradation curve based on a continuous function given by the Gompertz-Makeham Model, and applied with the Typical Use Life and End of Useful Life from the Ontario Energy Board's "Asset Depreciation Study".

G-Staff-90

Reference: Exhibit 4, Tab 1, Schedule 1, Page 337 of 438

On page 337 of 438, Alectra Utilities describes its reliability benefits as follows:

> **Reliability Benefit computes the cost of an outage to the customer, and is based on variables such as peak load lost, duration of the outage, duration for which redundancy is lost and the *type of the customer* affected. Additional reliability benefits are allocated to projects which affect worst performing feeders. [Emphasis added]**

a) Please discuss the appropriateness of using peak load rather than average load as a measure of consequence.

b) How many hours per year does the typical peak load occur?

c) Given that the probability of failure of an asset is the expected probability of failure, how does Alectra Utilities ensure that using peak load (i.e. maximum rather than average consequence) as a measure of consequence does not overstate risk?

d) Please define the quantitative basis for valuing one customer class more than another.

e) Please provide the Alectra Utilities customer communication that clearly describes Alectra Utilities' approach to valuing one customer class more than another with regards to system reliability.

f) How does Alectra Utilities ensure that cross subsidization of reliability benefits doesn't occur from one customer class to another?

g) Is Alectra Utilities calculating the maximum consequence or the expected consequence (if you use peak load rather than average load you are over stating the consequence)?

h) Please define "duration," i.e. is duration the expected duration or the maximum reasonable duration of the outage?

i) From a risk assessment standpoint, is the outage duration and duration for which redundancy is lost valued the same for the same outage measure?

   i. If yes, why is this prudent from a ratepayer perspective where one risk (i.e. outage duration) negatively impacts the ratepayer (i.e. electricity supply is

lost), and the other (i.e. duration for which redundancy is lost) does not (i.e. has zero consequence).

ii. If no, what is the relative weighting between the two durations, and why was this relative weighting chosen?

Response:

a) Alectra Utilities' distribution assets are most strained during heavy loading which occurs concurrently with peak loading periods. To appropriately capture the reliability benefit, Alectra Utilities evaluates the benefit of reliability at a time when Alectra Utilities' customers are most dependent on the service, which is when the peak demand occurs.

b) As described in Section 5.1.1 Service Area of the DSP (Exhibit 4, Tab 1, Schedule 1), Alectra Utilities service area spans from Penetanguishene to St. Catharines. The distribution system is not continuous and interconnected. Hence, Alectra Utilities does not calculate a system load duration curve of non-coincidental peaks since this information would not provide any operation value upon which decisions could be made. Typically, predecessor utilities experienced system peak duration during 3% of the year. Individual feeder peaks may vary depending on the load factor, the types of customers connected, and any thermal feeder constraints, which means that the feeder is operating closer to peak more often. Feeders with electric heating will peak differently than summer peaking feeders. Similarly, peak demand for commercial/industrial applications will be different for a metal shop than a data centre.

c) Alectra Utilities' Value Framework evaluates the benefit of investments to provide reliability and not the risk. The reliability benefit is one of many benefits used to evaluate the value of projects. As explained in response to part a), the use of peak demand to determine the value of reliability appropriately reflect the benefit of supply when customers are most dependent.

d) Alectra Utilities has leveraged the quantitative analysis to determine the reliability benefit from studies performed by Power System Research Group at the University of Saskatchewan. Alectra Utilities' approach to providing value of reliability between classes is reflected based on customer provided needs and priorities attained from customer engagement. Alectra Utilities work with Innovative Research, described in detail in Section 5.2.1 Subsection C – 2018 Consultations – Needs and Priorities as provided in the DSP (Exhibit 4, Tab 1, Schedule 1, Page 35) identified that the top investment needs for customers include charging reasonable distribution rates followed by ensuring reliable electrical service, with the exception of larger industrial customers that indicated a higher need for ensuring reliability than reasonable distribution rates. Alectra Utilities application of identifying varying value among customer classes is reflective of needs and priorities provide by Alectra Utilities customers to the company.

e) Please see response to part d).

f) Rate allocation is not determined by reliability benefit therefore no cross-subsidization can occur.

g) Alectra Utilities does not calculate the consequence of reliability, rather the Value Framework measure of reliability benefit is calculated using peak demand to appropriately reflect the value of the service at a time when customers most need and demand it.

h) Duration, in this context, is defined as the average time it takes to restore the system after a failure.

i) Outage duration has a higher weighting than the duration for which redundancy is lost. The weighting applied to outage duration for which a redundancy is lost is 5% compared to 100% for outage duration. Alectra Utilities applies this because while loop feeds reduce outage times, if the back up cable fails then the outage time is significantly longer. For example on August 18, 2019, Alectra Utilities had a cable failure event, where an existing cable failed on the other end of the loop, resulting in a 22 hour long outage, for a total customer hours of interruption of 7,450 hours. With an increasing number of deteriorated assets, especially cables, Alectra Utilities application of loss of redundancy is appropriate measure of reliability value.

G-Staff-91

Reference 1: Exhibit 4, Tab 1, Schedule 1, Page 351 of 438
Reference 2: Exhibit 4, Tab 1, Schedule 1, Page 353 of 438

On page 351 of 438, Alectra Utilities describes its Efficiency Frontier tool as follows:

> **Through the Efficiency Frontier tool, fifteen investment portfolio scenarios were developed at incremental investment levels starting at $200M per year up to $550M per year. Portfolio scenarios that resulted in values below the Efficiency Frontier lower boundary were considered sub-optimal because such scenarios did not result in sufficient expected value for the level of investment. Portfolios scenarios that resulted in values above the Efficiency Frontier upper boundary were also considered sub-optimal because such scenarios did not result in sufficient incremental expected value for the incremental level of investment (i.e., demonstrated diminishing returns).**

On page 353 of 438, Alectra Utilities provides the following description of its Maximum Capital Expenditure:

> **As described above, the Efficiency Frontier function in CopperLeaf C55 provided Alectra Utilities with the set of optimal portfolios that offer the highest expected value for a defined level of investment. The outcome of the Efficiency Frontier process guided the Capital Investment Steering Committee through the identification of investment levels that resulted in expected portfolio values above the Efficiency Frontier upper boundary, which established the Maximum Capital Expenditure optimization bounds.**

a) **Please confirm that the Efficiency Frontier tool was used to evaluate entire investment portfolios rather than individual projects.**

   i. **If yes, does this imply that the process allows sub-optimal projects to be included in investment portfolios as long as the aggregate value of the entire portfolio met Alectra Utilities' Efficiency Frontier criteria?**

b) **Please explain the mechanism of the Efficiency Frontier tool and why portfolios above the Efficiency Frontier is also considered sub-optimal.**

c) **For its "investment portfolio optimization," did Alectra Utilities separately develop a total annual capital envelope, against which the project list was prioritized and abridged?**

   i. **If yes, how was the capital envelope size determined?**

Response:

a) The Efficiency Frontier tool evaluated the entire investment portfolio of projects under each constraint level.

   i. This does not imply that sub-optimal projects will be included in the investment portfolio. During the optimization process to develop the optimal portfolios plotted on the efficiency frontier, the system takes into consideration all projects. If a project has a low or negative value score, it will likely be deferred past the planning horizon with the expectation that the value will increase over time.

b) The Efficiency Frontier plots optimized portfolios using the value provided by the portfolio based on the collective benefits, risks and costs of each project, against the investment cost of the total portfolio over the planning period. Each portfolio has been optimized to maximize the value for a defined level of risk within a given annual capital funding constraint and represent the optimal selection of investments and their timing for Alectra Utilities' planning horizon. Suboptimal portfolios were not taken into consideration as each portfolio is optimal to set bounds and represent the efficiency frontier curve.

c) The capital envelope size was determined using the Efficiency Frontier as this determined where the capital investment provided the optimal value to the organization without diminishing returns. The Efficiency frontier is based on several optimized portfolios at different constraints, therefore by selecting the optimal level of investment, the portfolio of projects was established. It was not necessary to then separately prioritize or abridge this project list.

G-Staff-92

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A01

Using Table A01 – 1, OEB staff calculates the total forecast spending for Network Metering from 2020-2024 to be $63.1 million. Using Table A01 – 8, OEB staff calculates the total capital of material investments in Network Metering to be $33.2 million.

Please explain what other expenditures make up the remaining $29.9 million of Network Metering capital.

Response:

Please see Table 1 below for a list of projects which fall below the materiality threshold and comprise the remaining $29.9MM of the Network Metering capital. Alectra Utilities set a materiality threshold of $1MM per year, or $5MM over the five year planning period of the DSP.

Table 1 - Projects below Materiality Threshold

<table>
<tr><th>Project Code</th><th>Project Name</th><th>CAPEX ($MM)</th><th>Description</th></tr>
<tr><td>150659</td><td>Residential Meters - by Metering - Central North</td><td>$4.5</td><td rowspan="6">Investment for installing and replacing (seal expires, failures, etc.) metering equipment</td></tr>
<tr><td>150595</td><td>C & I and Wholesale Metering - East</td><td>$2.8</td></tr>
<tr><td>150651</td><td>C & I Metering - Renewal-Central North</td><td>$2.1</td></tr>
<tr><td>150647</td><td>Transformer Station Metering - Central South</td><td>$0.7</td></tr>
<tr><td>150596</td><td>Meter Renewal - all types but Suite - East</td><td>$0.4</td></tr>
<tr><td>150631</td><td>Transformer Station Metering - Central North</td><td>$0.3</td></tr>
<tr><td>150604</td><td>Smart Meter Network Expansion - East</td><td>$1.3</td><td rowspan="3">Investment for AMI Network expanding, upgrading, or replacing AMI Network equipment which is used to read meters by radio. Also the cost for testing the security integrity of the AMI Network</td></tr>
<tr><td>151221</td><td>AMI Hardware Upgrade - South West</td><td>$0.7</td></tr>
<tr><td>150632</td><td>AMI Gatekeeper Expansion - Central North</td><td>$0.2</td></tr>
</table>

150600	Firmware Upgrades for Smart Meters - East	$0.1	
150601	Advanced Metering Infrastructure (AMI) Security Audit - East	$0.1	
150654	C & I Metering - New Services - Central North	$2.9	Investment for installing and replacing (seal expires, failures, etc.) Suite metering equipment
150649	Suite Metering - Central South	$2.6	
150599	Suite Meter - Reverification - East	$2.6	
101795	Multi-Unit Metering for New Buildings SOUTH - East	$2.5	
150598	Suite Metering - Renewals & Retrofits - East	$1.8	
101924	Multi-Unit Metering for New Buildings NORTH - East	$0.8	
151050	Metering - all types - South West	$2.3	Investment for installing, replacing and enhancing all types of metering equipment (AMI, MIST, and Suite meters; AMI Network; Meter Test Shop equipment)
103637	GS>50 MIST Meter Program Implementation - East	$0.6	Investment for installing MIST meter equipment for GS>50 customers
150650	Replace PCB Risk PT's - Central South	$0.5	Investment for replacing primary metering tanks that contain oil with unacceptable levels of PCB
150602	Smart Meter Test Facility - East	$0.1	Investment for upgrading the Meter Farm at Addiscott, used to test meters, meter firmware, and RNI upgrades prior to putting into production
150597	Lock Box Installs - East	$0.0	The cost for installing lock boxes for access keys at existing buildings

G-Staff-93

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A02

Alectra Utilities provides the historical and forecasted levels of new customer connections in Table A02 – 9.

a) **Is Figure A02 – 11 intended to reflect the data in Table A02 – 9? If yes, please reconcile the table with the graph as they do not appear to match (e.g. 2020 new subdivisions is 8775 according to the table, but the graph shows the data point as being above 10000).**

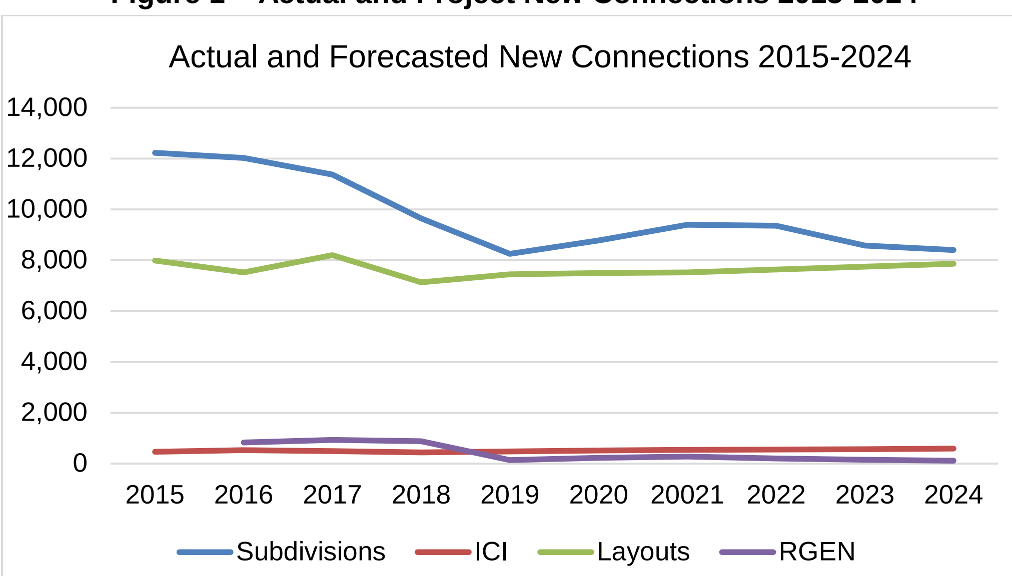
b) **Please explain why the amount of forecast spending in Table A02 – 14 for new subdivisions is increasing every year despite a decreasing number of new subdivision connections as shown in Table A02 – 9.**

c) **Please explain why the forecasted spending in Table A02 – 14 for new layouts has more than doubled compared to historical spending in 2015-2018 despite a relatively level and consistent amount of new layout connections as shown in Table A02 – 9.**

Response:

a) Alectra Utilities has updated the subdivision values in Fig A02-11 and provides it as Figure 1.

Figure 1 – Actual and Project New Connections 2015-2024



b) Alectra Utilities anticipates that future development will incorporate a higher number of high density subdivisions, which are expected to increase the cost of connections. With higher density developments and with the increasing application of multi-use zoning, Alectra Utilities anticipates that availability of space will be an increasing challenge. Further, Alectra Utilities will be required to install necessary electrical infrastructure deeper underground relative to current practices. The cost of connections are a expected to increase to address complexities relating to underground infrastructure congestion, since redevelopment and intensification are more challenging than greenfield expansion.

With an increasing focus on walkable streetscapes and zero-lot line developments, Alectra Utilities continues to be forced to install necessary infrastructure with less space and increased congestion from other utilities seeking room for telecommunication, gas and water infrastructure. Although the number of customer connections are anticipated to slightly decrease relative to historical values, the complexity and costs associated with the higher density and urban connections are projected to increase.

Please refer to Section 4.3 of Appendix A02 for an outline of The Growth Plan for the Greater Golden Horseshoe as it relates to the Alectra Utilities service area. Section 4.3 also provides an explanation of the impacts to Alectra Utilities of future developments required to support greater intensification. Developments include Pier 8 in Hamilton, Lakeview Developments in Mississauga and Langstaff Developments in Markham, all of whom will incorporate high-density construction with a focus on walkable communities.

c) As explained in the Overview section of Appendix A02, layout consists of work required to make the distribution system ready for new residential infill services and to upgrade residential services and small commercial services. Since the formation of Alectra Utilities in 2017, the company has expended significant effort to harmonize practices and develop a uniform manner of collecting, categorizing and reporting on work. The separation of layout customer connections is a new category for several of Alectra Utilities' predecessors, that previously captured such costs in other system access investments. As explained in the footnote on page 19 of the DSP, Alectra Utilities provided information on capital expenditure for historical years based on predecessor utility practices and, where possible, mapped such historical expenditures to current activities. Due to the different practices applied at predecessor utilities to capture, report and track costs associated with layouts, the historical expenditure values related to layouts does not provide an appropriate basis for comparison or from which reasonable conclusion can be drawn.

G-Staff-94

Reference 1: OEB 2017 Yearbook of Electrical Distributors, Page 53
Reference 2: Exhibit 4, Tab 1, Schedule 1, Page 17 of 438

Exhibit 5, Attachment 3, M-factor Revenue Requirement

According to the OEB's 2017 Yearbook of Electrical Distributors, Alectra Utilities served 889,842 residential customers as of December 31, 2017. At the time of filing of the current application, Alectra Utilities notes that it currently serves[1] approximately 950,000 residential customers. OEB staff notes that this is an increase of 6.8% in the number of residential customers served. Using similar calculations, OEB staff calculates an increase of 6.1% for General Service less than 50kW customers, 5.5% for General Service greater than 50kW customers and 10.3% for large use customers.

a) **Please confirm that at the end of this rates application, all of Alectra Utilities' rate zones will have transitioned to fully fixed residential monthly distribution charges.**

b) **Please provide the forecasted percentage of annual growth for the number of customers in each of Alectra Utilities' rate classes for 2020 to 2027.**

c) **Please provide the forecasted percentage of annual growth for the amount of load in each of Alectra Utilities' rate classes for 2020 to 2027.**

d) **Are any increases to Alectra Utilities' revenue through customer and load growth accounted for in the M-factor mechanism? If yes, please explain how it is accounted for. If no, why not?**

In reference 3, Alectra Utilities calculates the growth factor for each of its rate zones using 2017 actual distribution revenues versus the last OEB-approved distribution revenues.

e) **Does Alectra Utilities expect greater annual growth to its revenue from its residential class now that residential rates are fully fixed, compared to if residential rates had not been fully fixed? Please explain why or why not.**

    i. **If yes to e), is the growth factor used in the M-factor threshold calculations still appropriate? Please discuss given that residential rates are now fully fixed, but Alectra Utilities calculated its growth factors using 2017 actual revenues when residential rates were not fully fixed.**

[1] Alectra Utilities' current customer count is taken from the evidence filed in this proceeding as of May 28, 2019

Preamble Clarification:

The OEB has stated above:

> "*According to the OEB's 2017 Yearbook of Electrical Distributors, Alectra Utilities served 889,842 residential customers as of December 31, 2017. At the time of filing of the current application, Alectra Utilities notes that it currently serves approximately 950,000 residential customers. OEB staff notes that this is an increase of 6.8% in the number of residential customers served. Using similar calculations, OEB staff calculates an increase of 6.1% for General Service less than 50kW customers, 5.5% for General Service greater than 50kW customers and 10.3% for large use customers*."

OEB Staff's calculation of the impact is incorrect. OEB Staff excluded Guelph Hydro's customer numbers from the 2017 values to determine total customer count for Alectra Utilities, but included Guelph's customer numbers in the 2018 count, thereby overstating the percentage increase in the number of customers from 2017 to 2018. The increase in residential customers from 2017 to 2018 calculated by OEB Staff is 6.8%; the actual increase, based on 2017 and 2018 Yearbook data for Alectra Utilities and Guelph Hydro is 0.9%.

Please see Table 1, below for the actual percentage change in customer count for Alectra Utilities, inclusive of Guelph Hydro customer numbers.

Table 1 – Preamble Clarification

Class	2017 Year Book Inc. GRZ	2018 Year Book Inc. GRZ	Total % Growth
Residential	940,384	949,231	0.9%
GS>50	83,247	83,718	0.6%
GS<50	13,597	13,794	1.4%
Large Use	33	32	(3.0)%

Response:

a) Alectra Utilities' Enersource, Brampton, Horizon Utilities and Guelph rate zones transitioned to fully fixed residential monthly distribution charges in 2019. The PowerStream RZ will transition to fully fixed residential distribution charges as of January 1, 2020.

b) Alectra Utilities does not have a finalized forecast for 2020-2027. However, the company expects the customer numbers and growth rates to trend close to 1% over the period 2020-2024 for the Residential rate class, close to 0.6% for each of the GS<50kW and GS>50kW rate classes and close to 0.0% for the Large User rate class over this period.

c) Alectra Utilities does not have a finalized forecast for 2020-2027. However, the company expects the growth rates to trend close to 0.5% over the period 2020-2024 for the Residential rate class and close to 0.0% for each of the GS<50kW, GS>50kW and Large User rate classes over this period.

d) Increases to revenue from customer and load growth is accounted for in the M-factor mechanism. The proposed M-Factor mechanism follows the same materiality threshold as the ICM, which includes a growth factor to account for available funding from additional revenue related to load and customer growth. As such, revenue growth is factored into the M-Factor funding request. Per the *Report of the Board - New Policy Options for the Funding of Capital Investments: Supplemental Report* dated January 22, 2016 (EB-2014-0219):

> *"In the OEB's view, a reasonable growth estimate should also be accounted for in the materiality threshold calculation. Capital additions are often, at least in part, to connect and serve new customers. However, new customers and demand also mean new revenues that help to recover the costs to serve the new demand. This is in addition to increased revenue due to the I – X (i.e., price cap index or PCI) price cap adjustment to base rates each year.*
>
> *As originally formulated and implemented in the 3rd Gen IR Supplemental Report, growth is represented by the change in (economic) demand between two time periods. Economic demand is composed of three elements for electricity distribution:*
>
> • *Number of customers*

> • *kilowatt hours (kWh) of electricity consumption*
> • *kilowatts (kW) of energy demand, for demand-billed customers*
>
> *Growth is estimated as the weighted average of the change in each of these demand components between two time periods, where the weights correspond to the revenue weights. For this calculation, prices are held fixed between the two periods, as the impact of changes in prices due to price cap adjustments is captured by the PCI variable in the formula."*

Alectra Utilities further notes that the approach it has taken is conservative. In particular, Alectra Utilities performed the threshold calculation based on historical growth rates, which are higher than forecasted growth rates. If the company used projected growth rates, the threshold would have been lower, with the result being that the capital envelope would have been higher.

e) No, Alectra Utilities does not expect greater revenue due to the transition to fully fixed monthly charges. The transition was mandated by the OEB, under the premise that it would be revenue neutral. In EB-2012- 0410, *Board Policy - A New Distribution Rate Design for Residential Electricity Customers*, issued April 2, 2015 the board indicated:

> *"The OEB has determined that the best approach is the first option: a four-year transition for all distributors. Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue neutral".*

In addition, Alectra Utilities notes that its growth calculation was based on 2019 rates, which were fully fixed for 4 of the 5 rate zones. Therefore, the "greater revenue" that OEB staff is suggesting should be incorporated is already factored into the calculation.

G-Staff-95

Reference: Exhibit 4, Tab 1, Schedule 1, Page 48 of 438

Alectra Utilities notes in its application that “Other important investment drivers include needs for system expansion to prepare for and respond to areas of urban greenfield development and urban redevelopment/intensification.”

a) Are the areas presently experiencing urban development and intensification undergoing greater than historical load growth? Please quantify.

b) Please provide load growth trends for the consolidated service area covering the historical period (starting at 2015) through the next 10 years (i.e. until 2030).

Response:

a) In Appendix A02 Subsection 2.0 of the DSP (Exhibit 4, Table 1, Schedule 1), Alectra Utilities provides details of several known urban developments including the North-Brampton which has received development applications exceeding 5,000 future units. In the York Region, Alectra Utilities provides details of the expected 5,500 new units planned for development through a mixture of new single homes, semis, rows and duplex units, specifically in Aurora, Barrie, Markham and Richmond Hill.

In terms of redevelopment and intensification growth, Appendix A02 provides details related to planned redevelopment of Pier 8 in Hamilton with 1,296 additional residential units, the Square One area in downtown Mississauga as well as the Port Credit and Lakeview developments. Specifically in Vaughan, Appendix A02 provides a summary of development including plans to develop 12,000 residential units in the Vaughan Metropolitan Centre.

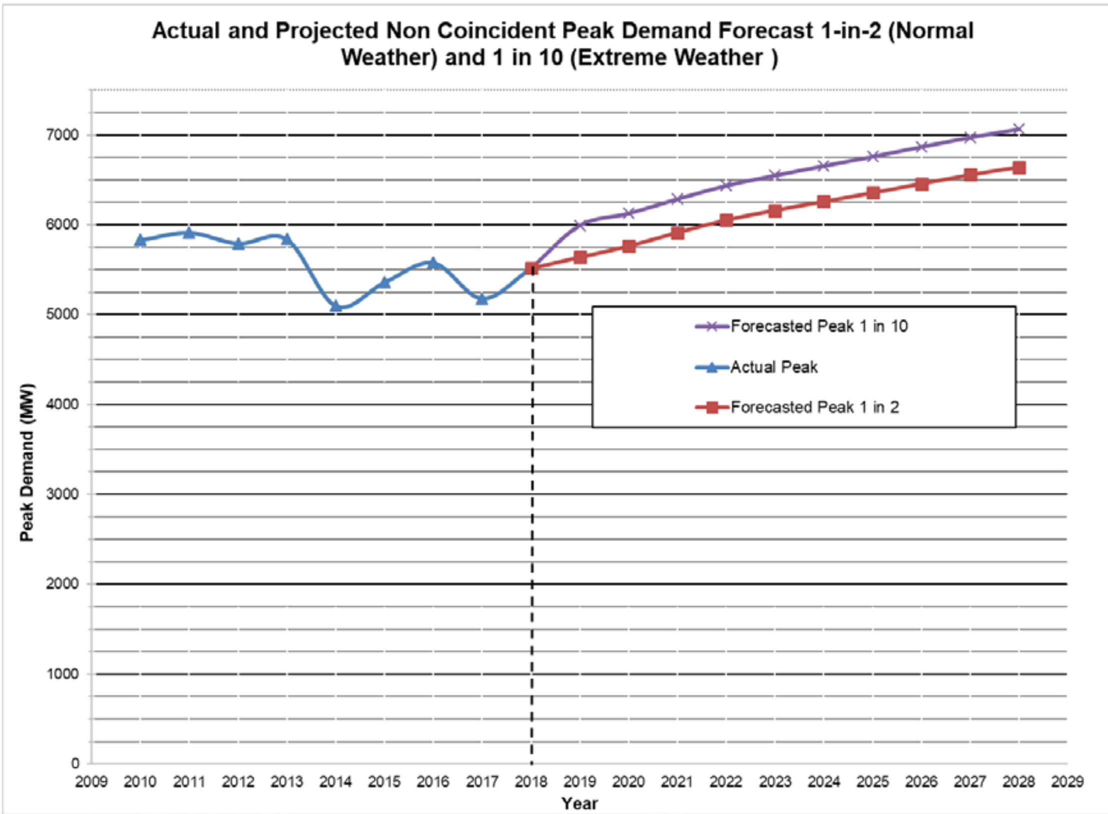
The corresponding system expansion projects for each developing area, including projected demand growth stemming from each development area is provided in the project business case in Appendix B- Material Investment Business Cases. Business Cases for System Service investments related to system expansion provide load demand projections and available capacity presently available.

Over the last ten years, overall consolidated non-coincidental peak demand at Alectra Utilities (and predecessor utilities) has not returned to levels experienced before the 2009 economic recession. Several elements are attributed to the changing use of electricity by Alectra Utilities customers including reduction of industries historically dependent on substantial electrical demand, introduction of conservation and demand side management, improvements in building codes in terms of energy efficiency, behind the meter generation as well changes to housing market conditions based on pricing, mortgage approval practices and regulations.

Although the overall system peak demand remains relatively consistent, there are sections of Alectra Utilities' service territory that are experiencing growth and development and other areas of the system that are experiencing contraction and decline. As described in Section 5.3.2.6, Alectra Utilities attempts to optimize the allocation of capacity to increase system utilization, the company does not have control of where and when development takes form and is unable to relocate capacity from areas of contraction to areas of high growth, especially in green growth development where the system was initially constructed to service rural customers. For additional information related to development and growth in Alectra Utilities' service area, please refer to Section 5.3.2.1 of the DSP where Alectra Utilities provides population and housing growth for each municipality and region.

b) Please refer to Figure 1, below. Alectra Utilities current forecast ends in 2028. The non-coincident peak demand forecast indicates load growth of 1.8 % annually over the next 10 years.

Figure 1 - Actual and Projected Non-Coincidental Peak Demand Forecast (Normal and Extreme Weather)



G-Staff-96

Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A12, Page 36 of 42
Reference 2: Transcript_Alectra Utilities Presentation_20190807, Page 51

Alectra Utilities forecasts $110.2 million in lines capacity investments over 2020-2024. This is an increase of $33.2 million over the historical expenditures between 2015-2018 of $77 million.

During Alectra Utilities' presentation day on August 7, 2019, in response to a question about load growth, Ms. Butany-DeSouza said:

> **[…] And so we are not seeing an overall huge ramp-up in amount of load despite the fact that there may be an increase in numbers of customers or number of connections. And so the M-factor still is consistent with the load experience of Alectra Utilities to date, which is a declining – overall declining load or a minimal or nominal amount of load increase relative to the number of connections and ongoing expansion work that we need to accommodate. […] Load is pretty stable.**

Please explain Alectra Utilities' need for increased capital expenditures in lines capacity investments above historical levels if Alectra Utilities is currently stable or declining levels of load.

Response:

Please see Alectra Utilities' response to G-Staff-95.

G-Staff-97

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A03

In Appendix A03, Alectra Utilities discusses Road Authority projects governed by the Public Service on Highways Act (PSWHA) and Transit projects driven by provincially governed rail transit agencies.

Alectra Utilities proposes the creation of an Externally Driven Capital Variance Account (EDCVA) to track the differences between its revenue requirement in rates and externally-driven capital expenditures.

a) Please explain the need for the EDCVA if the CIVA already captures any differences between the level of actual investment and what is funded through Alectra Utilities' base rates plus M-factor funding.

b) What is Alectra Utilities' proposed effective date for this variance account? Please explain why the proposed effective date is appropriate.

c) Please indicate whether the true-up amounts will be on a per-project basis, or if the true-up will be based on the total account balance.

d) Please explain how Alectra Utilities intends to isolate its revenue requirement in rates for specifically Road Authority and Transit projects.

e) Please explain what steps Alectra Utilities has taken towards mitigating risks associated with third party driven projects (e.g. negotiating agreements with third parties).

Response:

a) The Capital Investment Variance Account ("CIVA") does not capture the difference between the level of actual investment and what is funded through Alectra Utilities' base rates plus M-factor funding. Please see Alectra Utilities' response to G-Staff-9. The CIVA reflects the difference between the forecasted M-factor capital additions and the actual in-service M-factor capital additions for the respective year.

b) The proposed effective date for the variance account is January 1, 2020, the start of the five year Distribution System Plan ("DSP") period.

c) As identified in Exhibit 2, Tab 1, Schedule 4, p.6, Alectra Utilities intends to true-up the EDCVA at the end of the five-year term. In Table 17 of Exhibit 2, and in Exhibit 4, Tab 1, Schedule 1, Appendix A03, Alectra Utilities identified a base level of externally driven capital expenditures over the five year DSP period. Alectra Utilities will track actual externally driven capital expenditures incurred against this baseline, and true-up the cumulative difference at the end of the five-year term.

d) Alectra Utilities has forecast capital expenditures of approximately $20MM per year (net of contributions) for externally driven capital related work. The expenditures were excluded from the list of M-factor capital projects. Therefore, if Alectra Utilities incurs capital in excess of $20MM, Alectra Utilities will calculate the revenue requirement associated with the additional investment.

e) Road Authority investments are entirely driven by the requests from the third parties and, as such, the timing when the project starts and is completed depends on the Road Authority. Alectra Utilities participates during the preliminary stages of project planning with the Road Authority, city planners and civil consultants. Costs associated with the projects are dependent on the size, type and complexity of the individual projects, and divided between the parties as specified in the PSWHA. The allocation of costs is discussed in detail in Exhibit 4, Tab 1, Schedule 1, Appendix A03, pp. 5-6.

The cost sharing for relocating public utilities within a municipal road allowance is determined in accordance with the *Public Service Works on Highways Act* (“PSWHA”). For Road Authority relocation requests, Alectra Utilities follows the PSWHA and associated regulations and collects contributed capital of 50% of the labour and labour-saving devices for Road Authority driven projects. As a result, in the absence of an agreement, the costs of a typical road widening project would be allocated 30-40% to the road authority and 60-70% to Alectra Utilities.

As permitted under the PSWHA, Alectra Utilities and the Road Authority may agree on different apportionment of the cost responsibility for different portions of the relocation project based on the incremental costs of certain requests made by the Road Authority. At the request of the Road Authority, Alectra Utilities may be required for specific portions of the road widening project to relocate some sections underground, install concrete poles with specifications beyond existing standards and relocate assets at different spacing requirements. Alectra Utilities and the Road Authority may agree to reflect these incremental relocation costs by having the Road Authority bear greater portions of those costs. The most efficient way to relocate assets is initially established by Alectra Utilities. If the Road Authority wants to upgrade from the proposed solution to a more expensive approach, they are required to pay for 100% of the difference in cost between Alectra Utilities' initial solution and the Road Authority preferred approach.

G-Staff-98

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A03, Page 17 of 26

Alectra Utilities forecasts $91.3 million in capital expenditures on Road Authority projects over 2020-2024 as shown in the table below:

Table A03 - 5: Material Projects and Initiatives

Project Code	Project Name	CAPEX ($MM)
150645	Road Authority	$91.3
150343	Bathurst Street Widening	$3.4

Please provide a table of all Road Authority projects that have a capital expenditure over $1 million that Alectra Utilities is expecting to undertake between 2020-2024. Please include in the table the forecasted capital expenditures of each individual project.

Response:

Please refer to Table 1, below.

Table 1 – Road Authority Project >$1MM

Project Description	2020 ($MM)	2021 ($MM)	2022 ($MM)	2023 ($MM)	2024 ($MM)
Dixie Rd. - Countryside to Bovaird	1.2				
Williams Pkwy. - Kennedy to North Park	1.7				
Goreway Dr. - Countryside to Castlemore	1.2				
Square One Dr. Extension - Confederation to Rathburn	1.4				
QEW Evans/Cawthra – Phase 1	2.0				
Anne St Bridge	1.1				
Rutherford Rd - Jane to Westburne	2.0				
Keele Street – Steels to Snidercroft Phase 2	1.4				
Mississauga Rd. - Queen to Financial		1.1			
Goreway Dr. - Castlemore to Humberwest		4.0			
Torbram Rd. - Queen to City Limit – Phase 1		1.7			
QEW Evans/Cawthra – Phase 1		2.0			

Duckworth Street (Bell Farm to St.Vincent)		1.4			
Rutherford Rd - Bathurst to Peter Rupert		1.6			
Teston Rd - PVD to Teston		1.4			
Highway 5/6 Interchange (Hamilton)		2.0			
Mayfield Rd. - Hurontario to Heart Lake Rd.			1.1		
Sandalwood Pkwy. -Torbram to Airport			1.6		
Torbram Rd. - Queen to City Limit – Phase 2			1.7		
Mapleview Drive Grade Separation at Yonge to Royal Jubilee			1.7		
Garden City Skyway - Bridge Replacement			3.0		
Mississauga Rd. - Bovaird to Queen				1.5	
Sandalwood Pkwy. - Bramalea to Torbram				1.5	
Torbram Rd. - Bovaird to Queen				1.7	
Sandalwood Pkwy. - Dixie to Bramalea					1.3
Williams Pkwy. - North Park to Torbram					3.5

Some Municipalities, regional authorities and the Ministry of Transportation of Ontario ("MTO") establish their road works program for each year, some of which are annual plans, and some multi-year which are published in advance. Some are not published at all. Despite the existence of long-term plans, the specific projects being conducted each year are subject to change by the Road Authority, making it challenging to accurately forecast the associated capital expenditures. Alectra Utilities constantly attempts to better anticipate these possible requests through participating in meetings with the Cities and Regions and through reviewing site plans and zoning amendments. The expected impact on Alectra Utilities' plant relocation is also based on new, approved work projects from the municipalities, MTO and the regions. The forecast is based on a combination of historical trends and known costs for specific projects identified through coordination with Road Authorities and through a review of published road works plans from the Regions, Municipalities and MTO that are within Alectra Utilities' service territory.

Alectra Utilities has proposed to create an Externally Driven Capital Variance Account ("EDCVA") to mitigate the inherent uncertainty of third-party requirements. Please refer to Exhibit 2, Tab 1, Schedule 4, p. 4 for details on the proposed EDCVA.

G-Staff-99

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A03, Page 6 of 26

On page 6 of 26, Alectra Utilities states:

> **At the request of the Road Authority, Alectra Utilities may be required for specific portions of the road widening project to relocate some sections underground, install concrete poles with specifications beyond existing standards and relocate assets at different spacing requirements. Alectra Utilities and the Road Authority may agree to reflect these incremental relocation costs by having the Road Authority bear greater portions of those costs.**

Alectra Utilities further states:

> **The most efficient way to relocate assets is initially established by Alectra Utilities. If the Road Authority wants to upgrade from the proposed solution to a more expensive approach, they are required to pay for 100% of the difference in cost between Alectra Utilities' initial solution and the Road Authority preferred approach.**

Please explain why only a portion of the incremental costs in the first scenario is allocated to the Road Authority, but 100% of the incremental costs in the second scenario is allocated to the Road Authority. In other words, please explain why Alectra Utilities is expected to pay a portion of the incremental costs in the first scenario when, in both cases, the request for the incremental change is made by the Road Authority.

Response:

Alectra Utilities clarifies that the paragraphs referenced are attempting to convey the same message. Once Alectra Utilities has established the most efficient way to relocate the assets, if the Road Authority requests a change to: the method of installation (underground instead of overhead); the locations of poles; or the materials to be used, those incremental costs are to be borne by the Road Authority.

G-Staff-100

Reference: Exhibit 4, Tab 1, Schedule 1, Page 240 of 438

Regarding distribution transformer replacements, Alectra Utilities states:

> **For larger three phase distribution transformers supplying commercial or industrial customers, the reliability impacts of transformer failures could be significant. These transformers may be replaced as they approach end-of-life or where frequent overloading is identified. In the latter case, the replacement transformer would be sized according to relevant loading requirements. Together, these replacement practices help minimize the impacts of transformer failures on Alectra Utilities' customers.**

a) At what distribution transformer size threshold does Alectra Utilities change from a run to failure strategy to a planned replacement strategy?

b) Please provide the business case that was carried out to determine the size threshold.

Response:

a) For distribution transformers, Alectra Utilities does not use a size threshold to shift between run to failure strategy and planned replacement assets. Ensuring that transformers are operated within the load rating and manufacturer specifications reduces premature degradation of the asset and mitigates the risk of catastrophic failure and potential safety risks.

The referenced paragraph was intended to provide additional clarity about three phase transformers that supply commercial and industrial customers. If these transformers are frequently overloaded, Alectra Utilities right-sizes the transformer by replacing the existing transformer prior to failure. For information on the need for proactive replacement of distributions transformers, please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A09 – Transformer Renewal, Page 8, Lines 20-28.

b) As stated in response to part a), Alectra Utilities does not use a size threshold, and no business case was required.

G-Staff-101

Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A08, Page 18 of 32

On page 18 of 32, Alectra Utilities notes that "42 transformers are currently beyond their typical useful life of 45 years, including 9 units that are expected to exceed their maximum useful life of 60 years within the 2020-2024 period."

a) Please provide the assessed asset condition for all transformers that have been in service for more than 45 years.

b) Does Alectra Utilities often keep assets in service beyond their Maximum Useful Lives?

i. If yes, what does it actually mean when an asset exceeds its "Maximum Useful Life"?

Response:

a) The age and Health Index for the 42 transformers identified as being beyond their Typical Useful Life ("TUL") of 45 years, as of 2018, are shown in Table 1, below. Further, there are factors outside the condition assessment that may influence the timing of a transformer replacement. Please see Alectra Utilities' response to G-Staff-75 c) for additional details.

Table 1 - Health Index for Transformers Exceeding TUL of 45 Years

Station Name	Position	Age in 2018	Health Index
LITTLE MS414	T1	46	90
Amber MS	T1	46	89
WESTERN MS	T1	46	72
Fletcher MS432	T1	47	88
Dewitt MS	T1	47	36
MS8	T1	48	86
MS12	T2	48	94
Spare (Patterson Yard)	Spare	48	88
Amber MS	T2	48	84
Aberdeen MS	T2	49	91
SPARE (AQUITAINE STORAGE_3)	Spare	49	81
MUNDEN MS	T1	49	74
PARK ROYAL MS	T2	50	79
DUCKWORTH MS409	T1	50	89
SUMMERVILLE MS	T1	50	69

ROBIN MS	T1	50	84
ROCKWOOD MS	T1	50	67
SPARE (AQUITAINE STORAGE_1)	Spare	50	78
HENSALL MS	T2	50	71
ROCKWOOD MS	T2	50	70
Kenilworth MS	T2	51	93
Deerhurst MS	T1	52	88
Ottawa MS	T1	52	92
ANNE TEMP MS402	T1	52	83
Ottawa MS	T2	52	92
Highland MS	T1	53	89
Stroud's Lane MS	T1	53	89
Cope MS	T1	54	90
MS2	T1	54	87
Cope MS	T2	54	90
Grantham MS	Spare	54	73
Whitney MS	T2	55	89
Whitney MS	T1	55	89
Spadina MS	T2	55	89
CUNDLES EAST MS407	T1	55	80
King MS	T1	57	78
Dufferin MS431	T1	57	73
Elmwood MS	T3	58	86
York MS	T1	59	85
Wellington MS	T3	59	87
Ottawa MS	T3	60	87
Grantham MS	Spare	60	83

b) As of 2018, there have been no power transformers in Alectra Utilities' service territory exceeding their Maximum Useful Life ("MUL") of 60 years as defined by Kinectrics in their April 28, 2010 Report No. K-418033-RA-001-R000, *Asset Amortization Study for the Ontario Energy Board*. There will, however, be a number of transformers that are expected to exceed their MUL during the 2020-2024 DSP period, as seen in Table 1.

Transformers can still operate past their MUL based on their condition and the risk mitigation plans in place. The risk associated with aging transformers is managed by Alectra Utilities through increased condition monitoring and maintenance activities, where deemed appropriate, and installation of on-line monitoring.

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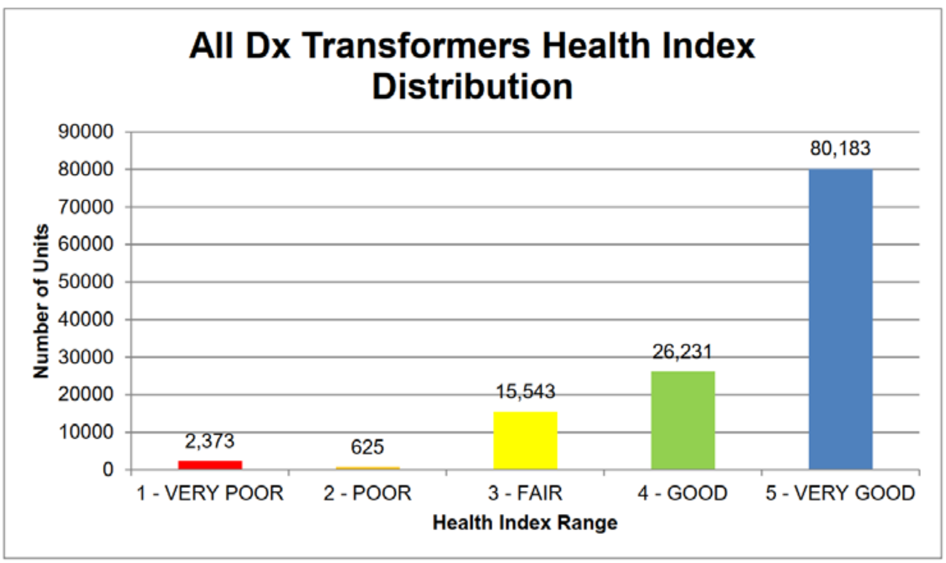
Reference 1: Exhibit 4, Tab 1, Schedule 1, Appendix A09, Page 6 of 15
Reference 2: EB-2017-0024, Exhibit 2, Tab 4, Schedule 11, Page 16 of 49

Alectra Utilities indicates that it expects proactively to replace transformers that are demonstrating possible risks to safety or environment. Further, Alectra Utilities states that it has, and expects to continue to, identify transformers eligible for proactive replacement:

> **During the 2018 transformer inspections, 870 units were found to have moderate to major oil leak or corrosion out of 14,568 units inspected in the East service area. At this rate, Alectra Utilities projects to find more than 2,000 units exhibiting safety and environmental risks, when it completes the three-year inspection cycle. Therefore, Alectra Utilities will target additional 2,000 units for proactive replacement during the five-year DSP period.**

The following table is taken from Appendix A09 and shows the Health Index of distribution transformers:

Figure A09 - 1: Distribution Transformer Condition Demographics



a) **How many poletop transformers does Alectra Utilities plan to replace prior to failure during forecast years 2020 - 2024?**

b) **What is the total cost of these predictive replacements?**

Alectra Utilities received approval to reduce its backlog of leaky transformers in its 2018 and 2019 rate proceedings.[1] In particular, Alectra Utilities noted in its 2018 rate application that:

> **The forecast expenditures associated with the transformer replacement project (i.e. to address units showing signs of leaks) is forecast to cost $8.4MM in each of 2017, 2018 and 2019, $6.4MM in 2020 and $4.3MM in 2021.**

c) Did Alectra Utilities complete the leaky transformer replacements approved in these two proceedings? Please quantify actual results.

d) Are Alectra Utilities' planned spending levels for future leaky transformer replacements over the forecast period consistent with the historical rate of transformer deterioration? In other words, does Alectra Utilities' proposed annual rate of leaky transformer replacements keep pace or exceed the expected occurrence of new transformer leaks? Please quantify and explain.

e) What proportion of Alectra Utilities' average annual poletop unit replacements have historically been undertaken prior to unit failure?

   i. What is that proportion expected to be over the forecast period?

f) Does any evidence of an oil leak have the same impact on the asset condition assessment, regardless of the severity of the leak? Please explain.

g) How many transformers does Alectra Utilities anticipate will fail prior to replacement during the five-year DSP period?

h) Are those replacements accounted for separately from the 2000 units that Alectra Utilities plans to pre-emptively replace over the period?

i) What is the health index distribution of transformers expected to be at the end of the five-year DSP period? Please show in the same format as Figure A09 – 1.

Response:

a) Alectra Utilities plans to replace 21 polemount transformers during forecast years 2020 - 2024. Please refer to Exhibit 4, Tab 1, Schedule 1, Appendix A09, pages 5-9 for a detailed discussion.

[1] EB-2017-0024 and EB-2018-0016

b) The average per-unit cost of a distribution transformer is approximately $0.01MM. The cost of renewal for the number of units mentioned in response to part a) is approximately $0.26MM.

c) In Alectra Utilities' 2018 EDR Application, the OEB approved $8.4MM for the transformer replacement project, which included the replacement of 543 transformers. In 2018, Alectra Utilities completed the replacement of 533 leaking transformers. In Alectra Utilities' 2019 EDR Application, the OEB approved $7.5MM for this project, which included the replacement of 571 transformers. Alectra Utilities is on track to replace these by the end of 2019.

d) Alectra Utilities' predecessor utilities, with the exception of Enersource, did not track replacements costs of transformers that were leaking oil; these costs were bundled with transformers replacement costs. The overall investment in distribution transformers is decreasing as provided in Table A09-4 and sections A09-4.2 and A09-4.3 (Exhibit 4, Tab 1, Schedule 1, Appendix A09, Page 10).

Alectra Utilities analyzed transformer renewal rates relative to the 2018 population. Results are shown in Table 1, below. The analysis includes all the needs listed in A09-Transformer Renewal-Section 3.3 (Exhibit 4, Tab 1, Schedule 1, Appendix A09, Pages 8-9) and is not limited to leaking transformers. It is important to note that the analysis in Table 1 does not account for future growth of the distribution system, which results in an increase of distribution transformers population. In other words, future renewal rates are skewed to higher levels compared to actual.

Table 1 – Distribution Transformer Renewal Rate

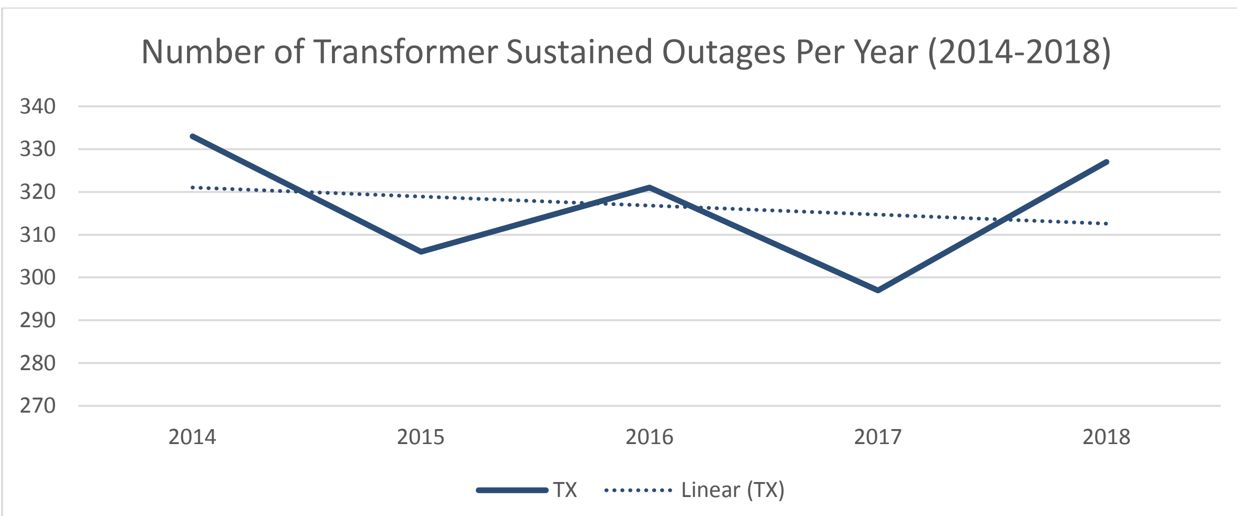
Asset Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Distribution Transformers	0.7%	0.8%	0.8%	0.7%	0.8%	0.4%	0.4%	0.5%	0.5%	0.5%

e) Alectra Utilities does not track poletop unit replacements that have historically been undertaken prior to unit failure. Alectra Utilities will run all its distribution transformers (which includes pole-top transformers) to failure with exceptions noted in Appendix A09 (Exhibit 4, Tab1, Schedule 1, A09).

f) The Asset Condition Assessment ("ACA") takes into account the severity of the leak. Please refer to Health Index Formula for Distribution Transformers in the Asset Condition Assessment (Exhibit 4, Tab 1, Schedule 1, Appendix D, Page 27).

g) Alectra Utilities monitors asset failures through its reliability reporting. Figure 1 below shows the historical number of transformer related outages per year (2014-2018). Historically on average, Alectra Utilities experiences 317 transformer failures based on the reliability statistics shown. Alectra Utilities anticipates that this level of transformer failures will continue (approximately 317 units/year)

Figure 1 - Number of Transformer Sustained Outages Per Year (2014-2018)



h) Yes, the 2000 units that Alectra Utilities plans to replace over the period are accounted for separately. The replacements due to failure prior to renewal are accounted for in the reactive capital budget (Exhibit 4, Tab 1, Schedule 1, Appendix A06).

i) Alectra Utilities' ACA is condition-based and conducted at a given time with available data. The ACA has a heavy emphasis on condition factors. At this point, Alectra Utilities does not have the capability to predict condition factors into the future (i.e. predictive analytics).

Alectra Utilities’ forecast of Long-Term System Renewal Trends is provided at Exhibit 4, Tab 1, Schedule 1, Page 12, Figure 5.0 – 8. Alectra Utilities forecasts that approximately 5,400 distribution transformers will be in Very Poor and Poor condition by the end of the DSP period. This takes into account the replacement quantities proposed in Appendix A09 – Transformer Renewal (Exhibit 4, Tab 1, Schedule 1, Appendix A09).

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Reference: Exhibit 4, Tab 1, Schedule 1, Appendix A09, Page 12 of 15

On page 12 of 15, Alectra Utilities provides the following discussion on the asset condition of its distribution transformers and its transformer renewal plans:

> **Through the annual ACA, Alectra Utilities had identified 2,998 transformers in Very Poor or Poor condition. Based on present day assessment of system-wide renewals, Alectra Utilities' plans to replace 1,148 of the 2,998 transformers through other funded projects, leaving 1,850 transformers to be replaced through the Transformer Renewal portfolio.**
>
> **In addition, Alectra Utilities has identified 900 transformers that are required to be replaced due to functional obsolescence, inadequate redundancy and difficulty of access.**
> **As discussed in Section 3.1, over the next five years, with ongoing inspections, Alectra Utilities expects to find another 2,000 deteriorated and hazardous transformers that will require replacements as well.**
>
> **These quantities form the three investment options shown in Table A09 - 5.**

Table A09 - 5. Pacing Options for Transformer Renewal

Strategy	Plan Period (years)	Total Quantity	Quantity per year	Average Transformer Replacement Plan Cost per year
Strategy 1: Accelerated Pace	5	4,750	**950**	$11.5M
Strategy 2: Moderate Pace	5	2,750	**550**	$6.8M
Strategy 3: Reduced Pace	5	1,850	**370**	$4.5M

a) **Please confirm that the accelerated pace of replacements would involve replacing over 1,750 transformers presently rated as being in Fair or better condition over the forecast period, assuming that all Very Poor and Poor condition transformers are replaced first. (i.e. 4,750 slated for replacement, vs 2,998 identified as "Poor" or "Very Poor" condition)**

   i. **Please explain how that pace would be compatible with a "run to fail" operating policy.**

b) Do all three of the strategies outlined here represent a deviation from a "run to fail" policy?

i. If yes, please provide justification for the policy change.

ii. If no, please explain why not.

Response:

a) The option upon which Board Staff has referenced the question, which is the accelerated option, is an option that is not recommended by Alectra Utilities and hence does not form the capital investment plan in the 2020-2024 Distribution System Plan. As outlined in Appendix A09 pages 12 and 13, Alectra Utilities has recommended and included the moderate pace solution for transformer renewals in the system plans.

b) ii) All three transformer pacing strategies considered in A09 are developed in alignment with Alectra Utilities' lifecycle management strategy for distribution transformers. That strategy is based on a run-to-failure approach, with the exception of situations where a transformer is found to be: a risk to safety; risk to the environment; or no longer suitable for operation due to overloading or configuration.

The transformer renewal moderate pace addresses 2,750 transformers. These transformers are identified as deteriorated (very poor and poor condition). This pace includes transformers that are identified as: obsolete; lacking adequate redundancy; and ones in locations with very challenging access. The moderate pace approach is consistent with the replacement strategy for transformers provided in Section 5.3.3 Subsection A.1 of the DSP (Exhibit 4, Tab 1, Schedule 1, 5.3.3, Page 238). Alectra Utilities' strategy for transformer replacement is based on a run-to-failure approach, except in situations where a transformer is found to be in a deteriorated condition which: poses a risk to public or employee safety; indicates imminent failure; poses a risk of environmental contamination; or the transformer has been identified as overloaded.

Alectra Utilities examined the accelerated pace of transformer renewal and determined that it should not be the recommended option. The accelerated pace scenario considers transformers already identified in poor and very poor condition, as well as, transformers which are currently identified to be in fair or better condition in the 2018 ACA. The subset of transformers in fair or better condition contemplated is projected to be in very poor or poor condition (i.e., deteriorated) over the course of the DSP. This subset will be identified as deteriorated through the ongoing process of inspections and testing during the DSP period.

In all scenarios, including the accelerated pace, Alectra Utilities would continue to apply a run-to-failure approach for transformer renewal consistent with Section 5.3.3 Subsection A.1 of the DSP.

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Reference 1: EB-2015-0003, PowerStream Inc. DSP
Reference 2: EB-2014-0002, Horizon Utilities Corp. DSP
Reference 3: EB-2017-0024, Enersource Hydro Missisauga DSP
Reference 4: EB-2014-0083, Hydro One Brampton Networks Inc. DSP
Reference 5: EB-2015-0073, Guelph Hydro Electric Systems Inc. DSP

OEB staff has prepared actual and forecast capital spending tables by extracting data from the most recent previous DSPs filed by Alectra Utilities' predecessor utilities, as shown below. The tables show capital expenditure data for the years 2012 to 2019 for System Renewal overall, underground cable replacements, wood pole replacements, and reactive & emergency capital programs. In these tables, blue text indicates actual expenditures and red text indicates forecasted or budgeted expenditures at the time of filing of the previous DSPs.

Capital Spending Actual/Forecast ($000,000's)

System Renewal - Overall	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	$16.97	$22.25	$39.19	$42.39	$48.72	$51.50	$52.05	$52.97
Horizon	$14.09	$18.43	$15.37	$18.07	$28.29	$33.17	$33.21	$34.71
Enersource	$16.22	$20.85	$31.24	$37.47	$35.20	$37.40	$40.90	$42.10
Brampton	$8.69	$12.12	$9.07	$8.80	$9.31	$10.33	$10.12	$9.01
Guelph	$2.54	$2.83	$3.73	$3.96	$4.48	$4.61	$4.75	$4.89
System Renewal Total	**$58.52**	**$76.49**	**$98.60**	**$110.69**	**$126.00**	**$137.01**	**$141.03**	**$143.68**

U/G Cable Replacement/Rehab	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	$2.99	$19.56	$20.95	$20.69	$21.60	$22.86	$23.78	$24.67
Horizon	$0.00	$1.57	$0.89	$2.57	$4.93	$8.87	$9.38	$10.27
Enersource						$18.47	$20.77	$21.92
Brampton	$3.50	$4.00	$3.86	$2.66				
Guelph	$2.14	$2.59	$3.17	$3.65	$4.16			
U/G Repl/Rehab Subtotal	**$8.63**	**$27.72**	**$28.87**	**$29.57**	**$30.69**	**$50.20**	**$53.93**	**$56.86**

Wood Pole Replacements	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	$4.11	$5.05	$4.87	$4.65	$4.93	$5.57	$5.87	$6.24
Horizon	$0.93	$0.72	$1.19	$1.23	$1.26	$1.30	$1.33	$1.37
Enersource						$9.00	$10.20	$10.20
Brampton	$1.06	$0.95	$1.20	$1.21				
Guelph	$0.30	$0.09	$0.24	$0.00	$0.00			
Wood Pole Repl. Subtotal	**$6.40**	**$6.81**	**$7.50**	**$7.09**	**$6.19**	**$15.87**	**$17.40**	**$17.81**

Reactive & Emergency Projects	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	$7.92	$8.22	$8.70	$8.42	$8.64	$8.73	$8.89	$8.93
Horizon	$4.03	$6.07	$4.84	$4.78	$4.34	$4.46	$4.54	$4.61
Enersource						$0.33	$0.33	$0.33
Brampton	$1.13	$2.43	$0.79	$0.82				
Guelph								
Reactive & Emerg Proj Subtotal	**$13.08**	**$16.72**	**$14.33**	**$14.02**	**$12.98**	**$13.52**	**$13.75**	**$13.86**

a) **Since the predecessor utilities categorized project and program expenditures differently, it was not possible for OEB staff to homogenously sort and bin the projects and program expenditures. For each table above, please update the annual actual and forecast values for each predecessor utility to reflect the correct values as known at the time of each respective filing.**

b) Please fill in a second set of tables to show the annual actual spending for 2012 to 2018, latest estimated 2019 spending, and forecasted spending for 2020 to 2024 by rate zone for the categories above.

c) Please explain any discontinuities between the historical spending in each of the predecessor utilities and Alectra Utilities' forecast spending for 2020 to 2024 in each of the rate zones per the present DSP plan.

Response:

a) Alectra Utilities has updated the table provided in the question to reflect actual and forecast values for each of Alectra Utilities' predecessor utilities from their last respective rebasing applications.

Table 1 – Actual and Forecast Information based on Legacy DSP ($MM)

Capital Spending Actual / Forecast ($MM)

System Renewal - Overall	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	16.97	22.25	39.19	42.39	48.72	51.50	52.05	52.97
Horizon	14.09	18.43	15.37	18.07	28.29	33.17	33.21	34.71
Enersource	16.22	20.85	31.24	37.47	35.20	37.40	40.90	42.10
Brampton	8.69	12.12	9.07	8.80	9.31	10.33	10.12	9.01
Guelph	2.54	2.83	3.73	3.96	4.48	4.61	4.75	4.89
System Renewal Total	**58.52**	**76.49**	**98.60**	**110.69**	**126.00**	**137.01**	**141.03**	**143.68**

U/G Cable Replacement / Rehab	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	2.99	19.56	20.95	20.69	21.60	22.86	23.78	24.67
Horizon	-	1.57	0.89	2.57	4.93	8.87	9.38	10.27
Enersource	5.10	6.50	16.88	15.75	15.46	18.47	20.77	21.92
Brampton	3.50	4.00	3.86	2.66	4.03	4.00	4.26	4.41
Guelph	2.14	2.59	3.17	3.65	4.16	4.29	4.42	3.40
U/G Repl. / Rehab Subtotal	**13.73**	**34.22**	**45.75**	**45.32**	**50.18**	**58.49**	**62.61**	**64.67**

Wood Pole Replacements	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	4.11	5.05	4.87	4.65	4.93	5.57	5.87	6.24
Horizon	0.93	0.72	1.19	1.23	1.26	1.30	1.33	1.37
Enersource	0.56	0.33	0.47	0.34	0.63	9.00	10.20	10.20
Brampton	1.06	0.95	1.20	1.21	0.46	0.42	0.46	0.49
Guelph	0.30	0.09	0.24	-	-	-	-	-
Wood Pole Replacements Subtotal	**6.96**	**7.14**	**7.97**	**7.43**	**7.28**	**16.29**	**17.86**	**18.30**

Reactive & Emergency Projects	2012	2013	2014	2015	2016	2017	2018	2019
Powerstream	7.92	8.22	8.70	8.42	8.64	8.73	8.89	8.93
Horizon	4.03	6.07	4.84	4.78	4.34	4.46	4.54	4.61
Enersource	0.29	0.30	0.41	0.33	0.31	0.33	0.33	0.33
Brampton	1.13	2.43	0.79	0.82	0.84	0.85	0.92	0.99
Guelph								
Reactive & Emer. Projects Subtotal	**13.37**	**17.02**	**14.74**	**14.35**	**14.13**	**14.37**	**14.68**	**14.86**

b) Table 2, below provides the actual spending for 2012 to 2018, 2019 Q2 forecast, and 2020 – 2024 Plan by rate zone.

Table 2 - Actual spending from 2012 to 2018, 2019 Q2 Forecast, 2020 – 2024 Plan ($MM)

Capital Spending Actual / Forecast ($MM)

System Renewal - Overall	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Plan	2021 Plan	2022 Plan	2023 Plan	2024 Plan
Powerstream	$17.0	$22.3	$39.2	$47.4	$42.2	$39.4	$38.1	$38.2	$52.1	$52.2	$55.6	$61.0	$66.1
Horizon	$14.1	$18.4	$15.4	$17.4	$23.0	$33.3	$31.6	$36.3	$25.7	$27.9	$30.4	$23.4	$33.5
Enersource	$16.2	$20.9	$31.3	$44.7	$40.4	$43.9	$41.6	$32.8	$37.6	$39.8	$42.4	$45.3	$51.8
Barmpton	$8.7	$12.1	$9.1	$9.8	$7.2	$11.9	$13.6	$14.7	$17.4	$15.8	$19.1	$19.8	$19.1
Guelph	$2.5	$2.8	$3.7	$3.3	$6.2	$7.5	$4.8	$5.6	$6.1	$6.3	$6.5	$6.6	$6.8
System Renewal Total	**$58.5**	**$76.5**	**$98.6**	**$122.5**	**$119.0**	**$135.9**	**$129.7**	**$127.6**	**$139.0**	**$142.0**	**$154.0**	**$156.1**	**$177.3**

U/G Cable Replacement / Rehab	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Plan	2021 Plan	2022 Plan	2023 Plan	2024 Plan
Powerstream	$3.0	$19.6	$21.0	$19.3	$14.5	$12.0	$13.5	$11.8	$19.3	$23.0	$26.6	$29.1	$32.3
Horizon	$0.0	$1.6	$0.9	$0.3	$4.7	$7.5	$6.6	$7.8	$6.3	$7.1	$7.4	$7.4	$8.1
Enersource	$5.1	$6.5	$16.9	$15.0	$13.4	$18.7	$16.1	$9.8	$16.8	$24.0	$26.7	$29.3	$30.9
Barmpton	$3.5	$4.0	$3.9	$2.7	$0.6	$4.3	$4.0	$3.8	$4.3	$5.7	$6.3	$7.2	$8.4
Guelph	$2.1	$2.6	$3.2	$1.3	$3.2	$4.0	$0.6	$0.0	$1.3	$1.3	$1.3	$1.3	$1.4
U/G Repl. / Rehab Subtotal	**$13.7**	**$34.2**	**$45.8**	**$38.6**	**$36.4**	**$46.5**	**$40.8**	**$33.2**	**$48.0**	**$61.1**	**$68.3**	**$74.2**	**$81.0**

Wood Pole Replacements	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Plan	2021 Plan	2022 Plan	2023 Plan	2024 Plan
Powerstream	$4.1	$5.1	$4.9	$5.9	$6.2	$4.4	$4.0	$4.6	$4.9	$5.6	$5.9	$6.1	$6.4
Horizon	$0.9	$0.7	$1.2	$1.3	$1.6	$0.8	$1.9	$1.9	$2.3	$2.5	$2.8	$3.1	$3.3
Enersource	$0.6	$0.3	$0.5	$7.3	$9.6	$8.4	$7.7	$6.4	$4.5	$3.9	$3.5	$3.1	$2.7
Barmpton	$1.1	$1.0	$1.2	$0.1	$0.6	$1.3	$0.8	$0.7	$0.9	$2.1	$2.8	$2.9	$3.0
Guelph	$0.3	$0.1	$0.2	$1.5	$2.2	$2.6	$2.7	$1.4	$1.2	$1.2	$1.2	$1.3	$1.3
Wood Pole Replacements Subtotal	**$7.0**	**$7.1**	**$8.0**	**$16.2**	**$20.1**	**$17.6**	**$17.1**	**$15.1**	**$13.8**	**$15.3**	**$16.2**	**$16.6**	**$16.7**

Reactive & Emergency Projects	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Plan	2021 Plan	2022 Plan	2023 Plan	2024 Plan
Powerstream	$7.9	$8.2	$8.7	$11.2	$8.4	$9.4	$11.3	$9.5	$9.4	$9.6	$9.8	$10.0	$10.1
Horizon	$4.0	$6.1	$4.8	$3.4	$3.9	$3.7	$5.4	$3.2	$3.4	$3.5	$3.6	$3.7	$3.8
Enersource	$0.3	$0.3	$0.4	$0.3	$0.3	$0.4	$0.2	$3.2	$3.4	$3.5	$3.6	$3.6	$3.7
Barmpton	$1.1	$2.4	$0.8	$1.6	$1.8	$1.9	$3.2	$1.5	$1.5	$1.6	$1.6	$1.6	$1.7
Guelph	$0.0	$0.0	$0.0	$0.1	$0.2	$0.2	$0.5	$1.1	$1.0	$1.0	$1.0	$1.1	$1.1
Reactive & Emer. Projects Subtotal	**$13.4**	**$17.0**	**$14.7**	**$16.7**	**$14.6**	**$15.6**	**$20.5**	**$18.6**	**$18.8**	**$19.2**	**$19.6**	**$20.0**	**$20.4**

c) Alectra Utilities was formed in 2017. This DSP is Alectra Utilities' first consolidated capital expenditures plan. Projects within each investment category have been grouped based on common drivers and outcomes and the optimization was performed on the portfolio as a whole. Alectra Utilities' predecessor companies categorized project expenditures differently, and therefore, a comparison of historical and forecast expenditures may not be reflective of the trends in the respective rate zones. For example, Alectra Utilities' reporting of reactive spend in a specific category rather than within other areas, which is different from the reporting of reactive spend for Alectra Utilities' predecessors Enersource and Guelph Hydro. The change in Underground Cable Rehabilitation and Pole replacements are discussed further in Exhibit 4, Tab 1, Schedule 1, A10 and A05 respectively.

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Reference: Exhibit 4, Tab 1, Schedule 1, Appendix C, Voluntary Online Workbook, Pages 11-12

On page 11 of the voluntary online customer engagement workbook, Alectra Utilities states:

> **Until rates are rebased in 2027, future rate increases will be limited by an OEB-set Price Cap Formula. Each year Alectra Utilities is permitted to increase rates to reflect inflation minus savings targets established by the OEB […] [T]he distribution charge for the typical bill is estimated to increase by 1.2% on average for the next five years.**

On page 12 of the voluntary online customer engagement workbook, Alectra Utilities states:

> **Planners have indicated the option that in their view provides the best balance between any potential rate increase with the intention to maintain reliability and to fix or avoid pockets of customers that are having significantly below average experiences […] At the end of these questions, you will have an opportunity to review your responses and total rate impact of those choices […] Alectra Utilities may apply for a rate increase under the rules established by the OEB. While the exact amount of any rate increase would consider the views collected in this consultation, the workbook will ask you for your views on a rate increase that will be sufficient to pay for the planners' recommended options.**

a) Please confirm the preamble statement that rate increases are "set" until rebasing in 2027.

  i. If confirmed, please clarify why page 12 implies that different spending programs may result in different rate increases.

b) What steps did Alectra Utilities take to ensure that the above question did not cause confusion with the survey respondents?

Response:

a) All of Alectra Utilities' RZs are on now on Price Cap IR of the purpose of setting electricity distribution rates. Under the Price Cap IR plan, Alectra Utilities is permitted to apply for: a) inflationary increases to rates; and b) incremental capital funding. Alectra Utilities is in a rebasing deferral period, and therefore rates increases are established within the Price Cap IR rate-setting plan until rebasing (i.e., 2027). The workbook clearly identifies and explains both aspects of the rate increases for which Alectra Utilities is permitted to apply. First, the workbook identifies the rate increases defined by the Price Cap IR formula (Exhibit, 4, Tab 1, Schedule 1, Appendix 1.0 Representative Customer Engagement Report p. 30). For the purpose of the workbook, the most recent inflation factor of 1.5%, less Alectra Utilities' stretch factor for all rate zones of 0.3%, was used to forecast a base rate increase of 1.2%. Second, at p. 31 of Appendix 1.0, the workbook identifies that based on the investment options provided, customers can chose to stay within existing rates or indicate a preference for increased investments: *"For each choice, Alectra Utilities has identified an option to **stay within existing rates under the price cap formula**. It has also identified options to increase investments and, in some areas, where practical, options to reduce investments to make room for increased investments in more pressing areas."* Further, the workbook provides the following option for customers: *"At the end of the questions, you will have an opportunity to review your responses and total rate impact of those choices. You will be able to change your responses until you feel you have found the right mix of investments and rate impact, in your view."*

b) As indicated in part a) of the response, the instruction in the workbook clearly identified the two aspects of increases to rates within the Price Cap IR rate-setting plan. Further, nearly all customers (96%) in each rate class and rate zone felt that the purpose of Alectra Utilities' customer consultation were clear. Additionally, 80% of residential customers felt that Alectra Utilities provided "just the right amount" of information in the workbook (see Appendix 1.0, Representative Customer Engagement Report, page 85).

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Reference: Exhibit 4, Tab 1, Schedule 1, Appendix C, Voluntary Online Workbook, Pages 13

The results of the respondent survey on the clarity of Alectra Utilities' customer consultation are 52% reporting feeling "somewhat clear" and 6% reporting feeling "not clear at all."

a) Given that a total of 58% of respondents were not "very clear" on the customer consultation, please explain whether Alectra Utilities views its customer consultation as an accurate representation of customer's desires.

b) How does Alectra Utilities intend to improve upon these results in future customer consultation efforts?

Response:

a) The outcome of high numbers of customers asserting either "very" or "somewhat" is very positive and is confirmation that customers understand the material being presented. In terms of raising levels of reported understanding, layout and content is reviewed to see if the purpose can be communicated with fewer and/or plainer words, as well as working with layout to help key points pop out further.

Looking at those two groups together, nearly all customers (96%) in each rate class and rate zone felt that the purpose of Alectra Utilities' customer consultation was clear. Only a small percentage of customers felt that the purpose was "not clear at all" (see Appendix 1.0, Representative Customer Engagement Report, pages 32, 97, 147, and 195). This question was asked towards the beginning of the Phase 2 engagement, before customers were exposed to the various types of investments, as well the type of specific feedback they would be asked to provide. After answering all the questions in the engagement, customers were asked a series of diagnostic questions to help validate their overall experience in completing the workbook.

In total, 82% of residential customers had at least a "somewhat favourable" impression of the workbook (see Appendix 1.0, Representative Customer Engagement Report, page 84). Additionally, 80% of residential customers felt that Alectra Utilities provided "just the right amount" of information in the workbook (see Appendix 1.0, Representative Customer Engagement Report, page 85).

In addition to this quantitative feedback, Alectra Utilities conducted a series of in-person focus groups amongst residential and small business customers to ensure that the concepts in the workbook were clear and understandable. In those focus groups, it was concluded that customers felt that the overall purpose of the customer engagement was clear. Based on both the qualitative and quantitative customer feedback, Alectra Utilities is confident that the purpose of this customer engagement was clear, and that the feedback gathered is an accurate representation of customers' desires.

b) Each time Alectra Utilities undertakes a new consultation in conjunction with its consultants, Innovative Research Group, they aim to improve the process. In terms of raising levels of reported understanding, working with layout and content is reviewed to see if the purpose can be communicated with fewer and/or plainer words, as well as working with layout to help key points pop out further. During the testing of the workbook, feedback was gathered from those people who did not choose "very", in order to better understand whether that response was due to skepticism, or if they had specific questions about the purpose of the consultation and presentation of the material that could be improved upon for the future.