Application for Service Area Amendment
Redacted

Application & Evidence
EB-2022-0178
Licence: ED-2002-0563
Date Filed: October 17, 2022

1 Table of Contents

2 List of Attachments

1. Map of the Border of the Applicant and Incumbent Services Areas and Existing Facilities
2. Map of the Geographical Features Surrounding the Area
3. The 1997 Letter Between Ontario Hydro and St. Thomas PUC

3 OVERVIEW

Entegrus Powerlines Inc. (“Entegrus”) is making this application (the “Application”) to the Ontario Energy Board (“OEB”) pursuant to Section 74(1) of the Ontario Energy Board Act, 1998 for the purpose of amending the licensed service area of Entegrus as described in Schedule 1 of its Distribution Licence ED-2002-0563 (the “Service Area”) to include the property and industrial customer (the “Customer”) located at 1 Cosma Court, St. Thomas, ON N5R 4J5 (the “Subject Area”). The Subject Area is currently listed as an exclusion in the Entegrus Distribution Licence, although Entegrus acts as the physical distributor for the Customer and the Subject Area is surrounded by the Service Area of Entegrus and falls within the longstanding municipal boundaries of the City of St. Thomas. The Subject Area is currently served by Hydro One Networks Inc. (“Hydro One”). A map of the Subject Area, including the border of the applicant and incumbent services areas and existing facilities, is shown in **Attachment 1.** A map of geographical features surrounding the area is shown in **Attachment 2.**

Hydro One serves the Customer under the terms of a 1997 letter (**Attachment 3**) between Hydro One and Entegrus’ predecessor, St. Thomas Energy (“the 1997 Letter”). Entegrus owns and maintains the feeders that serve the Customer and thereby continues to act as the physical distributor. Under the OEB’s process to eliminate Long Term Load Transfer (“LTLT”) arrangements (EB-2015-0006), the Customer should have been transferred from Hydro One to Entegrus’ predecessor, St. Thomas Energy, in 2017. That did not happen. Hydro One does not agree that the Customer should now be transferred to Entegrus. Instead, Hydro One seeks to rely on the 1997 Letter (which effected the load transfer) to continue to serve the Customer and to purchase the Entegrus feeders that serve the Customer for a fraction of their replacement value. As set out in this Application, the 1997 Letter is inconsistent with the OEB’s current load transfer elimination policy. The Customer should be served by Entegrus. Additionally, it cannot be said that the two dedicated Entegrus feeders that serve the Customer are “surplus to the utility’s needs”. If the Customer and the use of the feeders is transferred to Entegrus, then the utility can use some of the capacity on the feeders to serve growing demand in St. Thomas. This will save ratepayers money, by reducing the need for new infrastructure.

For the reasons set out herein, Entegrus is initiating this Application based on its belief that it is in the public interest to amend Schedule 1 of the Entegrus electricity distribution licence, entitled “The St. Thomas Energy Inc. Rate Zone” (starting on page 16) to remove the exclusion of the Subject Area from the Entegrus Distribution Licence. Consistent with the direction in Section 6.5.3 of the Distribution System Code, approval of this Application would result in the elimination of the current load transfer arrangement related to the Customer. Given the manner in which Schedule 1 of Hydro One’s licence is presented, the latter licence would not need to be amended if this Application is approved.

In considering this Application, Entegrus understands that the OEB will be guided by the principles articulated in the OEB's Filing Requirements for Service Area Amendment (“SAA”) Applications, dated March 12, 2007, and included as Chapter 7 of the Filing Requirements for Transmission and Distribution Applications, together with the OEB's Decision with Reasons in the RP-2003-0044 combined service area amendments proceeding (the “Combined

Proceeding"). Hydro One has indicated that it will contest this Application, and accordingly, the Filing Requirements referenced by Entegrus herein include those for contested SAA applications. Further, as noted above, the Application also references Section 6.5.3 of the Distribution System Code, which established that where load transfers existed, the associated customer would be transferred from the geographic distributor to the physical distributor prior to June 21, 2017. Entegrus / St. Thomas Energy Inc. ("STEI") / the St. Thomas PUC has always been the Customer's physical distributor.

Entegrus notes a key principle of the Combined Proceeding is that economic efficiency and the protection of consumer interests are to be achieved through the rational optimization of existing distribution systems. Entegrus submits that the approval of this unique Application would accomplish just that.

Entegrus wishes to talk to the Customer's management team, to make them aware of this Application, discuss their preferences and answer any questions they may have for Entegrus. In addition, Entegrus wishes to understand any potential issues the Customer may have with public disclosure of the information in the Application. Entegrus has sought consent from Hydro One to discuss this Application with the Customer. Hydro One has formally declined to provide this consent. Accordingly, a letter of support from the Customer will be addressed at a later stage of this application process.

Entegrus has engaged Hydro One in discussions about this Application and the expansion of Entegrus' service territory to service the Subject Area. Hydro One has declined to provide its consent for the Application and as such, this Application is a contested SAA Application.

Entegrus requests that the OEB set a process to allow this Application to be determined as soon as practical within the OEB's timeframes for written hearing processes as set out in the OEB's Performance standards for processing applications (which mostly provide for a 130-day timeframe). The reason for the urgency is that Entegrus has current capacity constraints in its St. Thomas service area, and it is important to have clarity about whether the excess capacity from the breaker positions currently dedicated to the Customer will be available for Entegrus to serve other capacity requirements in St. Thomas. If this will not be the case, then Entegrus needs to pursue alternative solutions (which will take some time).

3.1 Relief Requested

Entegrus requests the following relief:

i. Confirmation that it is appropriate for Entegrus to discuss the Application with the Customer since Hydro One has declined to provide its consent. Entegrus requests that the OEB provide direction on this item before the OEB issues a Notice or publishes the Application (see Section 7.12 below).
ii. A licence amendment pursuant to Section 74(1) of the Ontario Energy Board Act, 1998 for the purpose of amending the licensed service area of Entegrus as described in Schedule 1 of its

Distribution Licence ED-2002-0563. This will result in the termination of the existing load transfer agreement, consistent with the mandatory direction in Section 6.5.3 of the Distribution System Code.

iii. Entegrus further applies to the OEB pursuant to the provisions of the Act and the OEB's Rules of Practice and Procedure for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

Entegrus requests that the OEB dispose of this Application by way of written hearing, unless agreement with Hydro One can be reached regarding this SAA, in which case the Application could be disposed of without a hearing, pursuant to Section 21(4) of the Ontario Energy Board Act, 1998.

This Application is supported by written evidence contained herein and may be amended from time to time as circumstances require.

4 General

4.1 Contact Information

The contact information for all affected parties is listed below.

The Applicant:

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Primary Application Contact:

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Entegrus Powerlines Inc.

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Toronto, Ontario

M5J 2T9

Primary Application Contact:

David Stevens

Aird & Berlis LLP

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Email address: dstevens@airdberlis.com

The Incumbent Distributor:

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Toronto, Ontario

M5G 2P5

Primary Application Contact:

Pasquale Catalano, Senior Regulatory Advisor

Hydro One Networks Inc.

Telephone: 647-616-8310

Email address: Pasquale.Catalano@HydroOne.com

Alternative Distributors:

None

The Customer:

Hydro One has declined to provide consent for Entegrus to contact the Customer, which is necessary to complete this information. Accordingly, Entegrus is unable to provide the Customer contact name and details at this time.

4.2 Applicant Background

On July 21, 2017, Entegrus and STEI submitted a Mergers, Amalgamations, Acquisitions and Divestures ("MAAD") application (EB-2017-0212) to the OEB, seeking approval to amalgamate and continue as Entegrus Powerlines Inc.

At that time, STEI was a local distribution company (former OEB Distributor Licence ED-2003-0563) serving approximately 18,000 customers in the City of St. Thomas, Ontario. Entegrus (OEB Distributor Licence ED-2002-0563) then served approximately 41,000 customers in the Ontario communities of Blenheim, Bothwell, Chatham, Dresden, Dutton, Erieau, Merlin, Mt. Brydges, Newbury, Parkhill, Ridgetown, Strathroy, Thamesville, Tilbury, Wallaceburg, Wheatley, and certain designated land parcels in the Township of Raleigh (adjacent to Chatham), known as the Bloomfield Business Park.

On March 15, 2018, the OEB approved the amalgamation and deferral of rate re-basing for the merged entity until 2026. Thereafter, Entegrus notified the OEB that the transaction was complete, effective April 1, 2018. On April 19, 2018, Entegrus received its amended Licence (ED-2002-0563) and notification from the OEB that St. Thomas Energy Licence ED-2003-0563 was cancelled. Entegrus plans to maintain two separate rate zones (Entegrus - Main and Entegrus - St. Thomas) until such time as rates are re-based.

As of June 2022, Entegrus serves approximately 62,165 metered customers.

5 Reasons for Amendment

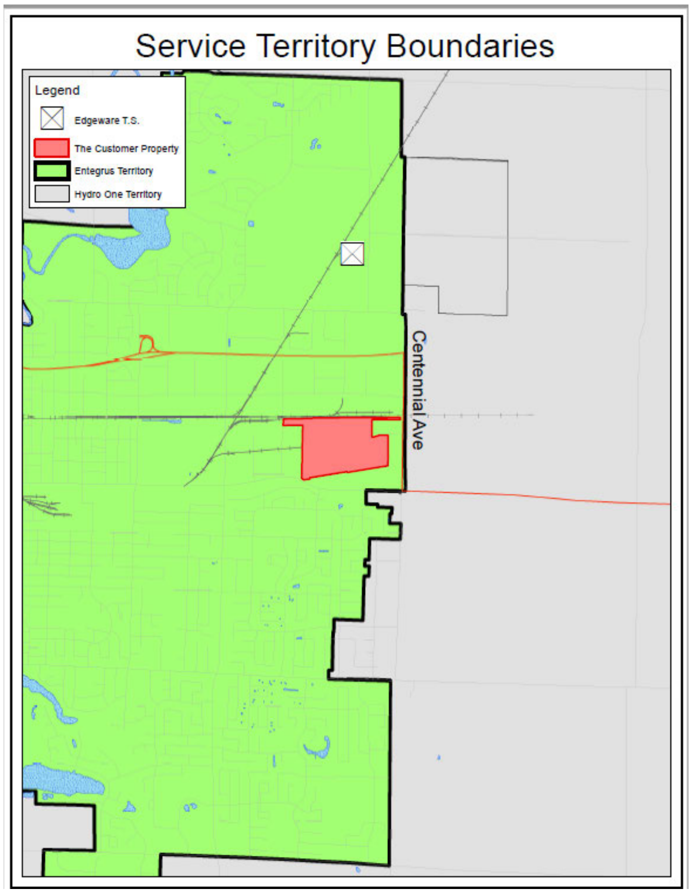
5.1 Subject Area Background

The Customer facilities located within the Subject Area of this Application, at 1 Cosma Court in St. Thomas, were energized in 1998. At that time, the Subject Area was excluded from the service territory of the St. Thomas PUC, the electrical distributor then servicing the surrounding lands (all of which fell within the municipal boundaries of the City of St. Thomas and continue to do so). This arrangement was based on the 1997 Letter between Ontario Hydro and the St. Thomas PUC, regarding the supply of power for the Customer. The 1997 Letter stated that the St. Thomas PUC would build, own and maintain the two dedicated feeders. The 1997 letter also contains an addendum, which is a 1998 letter on the same matter with additional details from Ontario Hydro to the St. Thomas PUC. See Section 5.2 below for additional background on the 1997 Letter.

Thereafter, the Subject Area was an exclusion to the distribution licence of STEI and more recently, an exclusion to the distribution licence of Entegrus. This exclusion from the distribution licence of STEI (and by extension, Entegrus) should have been addressed in the processes that eliminated LTLTs by June 2017 (see Section 5.3 below).

Attachment 2 is a map setting out the Entegrus service territory in the relevant portion of the Entegrus-St. Thomas rate zone. It is reproduced below as Figure 5-1.

FIGURE 5-1: ENTEGRUS SERVICE TERRITORY BOUNDARIES IN ST. THOMAS



As of 2022, the Customer remains a Hydro One customer located within the municipal boundaries of the City of St. Thomas and is served by Entegrus assets. Specifically, the Customer is served by two dedicated 27.6 kV feeders (designated as "M7" and "M8") with an approximate length of 2.5 km each, which were built, owned and maintained by Entegrus and its predecessor organizations, and which connect the Customer to the Hydro One Edgeware TS. As such, the Customer is not directly transmission-connected. Please see **Attachment 1** for a map showing how the Customer is connected within the Entegrus service territory in the STEI rate zone.

The M7 and M8 feeders have an approximate capacity of 14 MW each when fully loaded and an approximate capacity of 28 MW each for emergency loading purposes. In terms of capacity requirements, [redacted]. This understanding is borne out by recent Entegrus metering data.

5.2 The 1997 Letter Between Ontario Hydro and the St. Thomas PUC

Please see **Attachment 3** for a copy of the 1997 Letter between Ontario Hydro and the St. Thomas PUC. Note that the 1997 letter also contains an addendum letter added in 1998 by Ontario Hydro. The 1997 Letter, inclusive of the addendum, is summarized as follows:

- St. Thomas PUC would construct, own and maintain two dedicated 27.6 kV feeders connecting the Customer to the Edgeware TS
- The feeders would be rented to Ontario Hydro from September 1997 through December 2007 for $5,827.93 per month. This rental charge would decrease by $300 per month (to $5,527.93 per month) from December 2007 to December 2017
- Ontario Hydro would have an option to purchase the feeders at book value on January 1, 2018
- Any litigation and/or damage caused by the feeders would be the sole responsibility of St. Thomas PUC

5.3 Entegrus and Hydro One Discussions Regarding the 1997 Letter

In late 2017, Hydro One engaged STEI in discussions to purchase the M7 and M8 feeders, relying on the 1997 Letter between Ontario Hydro and the St. Thomas PUC. Specifically, Hydro One proposed to continue to serve the Customer and purchase the M7 and M8 feeders at their January 1, 2018 book value from Entegrus. STEI expressed its reluctance, due to the strong load growth in St. Thomas. Hydro One later provided a copy of the 1997 Letter to STEI, and it appears that STEI felt that it was compelled to proceed with selling the assets. In doing so, it appears that STEI did not recognize that the purchase option cited by Hydro One had been frustrated by the OEB's December 2015 Distribution System Code amendments (EB-2015-0006), as described below in Section 5.4. Further, apparently STEI did not recognize, nor did Hydro One appear to recognize, the requirement of an OEB Section 86(1)(b) application and OEB approval in order to proceed with any sale of assets from STEI to Hydro One.

Discussions with Hydro One on the matter continued after the amalgamation of STEI and Entegrus (which occurred in April 2018). In 2018, in recognition of Entegrus' upcoming St. Thomas capacity challenges, additional conversations occurred about the concept of Entegrus retaining the M7/M8 feeder poles and then selling the associated conductors and insulators to Hydro One. Hydro One also sought the January 1, 2018, book value of the M7/M8 feeders from Entegrus and discussions occurred about Entegrus billing Hydro One for joint-use charges for 2018, rather than rental fees. This is further described in Section 5.5.1 below.

Thereafter, discussion occurred regarding the January 1, 2018 book value of $116,431 (which excluded the book value of the poles). Entegrus continued to express concern about the requested sale of the M7 and M8 feeders to Hydro One, given the growing Entegrus capacity requirements in St. Thomas. Accordingly, Entegrus enquired as to the opportunity for Entegrus to make use of underutilized feeder capacity. In response, in late 2018, Hydro One confirmed that there was an opportunity for Entegrus to receive approximately 5 MW of restricted feeder capacity from the two dedicated feeders post acquisition by Hydro One. Hydro One further noted that under this scenario, it would levy Low Voltage charges against Entegrus for its utilization of the 5 MW of capacity from the dedicated feeders. This is further described in Section 5.5.2 below.

In 2021, Entegrus management conducted further in-depth analysis of the upcoming St. Thomas capacity challenges. The initial concept to address the St. Thomas capacity challenges is described herein as Scenario 1 (see Section 5.5.1), and involved the sale of the two underutilized dedicated feeders to Hydro One, followed by Entegrus investing approximately $1.7M (including a $1.1M payment to Hydro One) to build a new breaker position and egress at the Edgeware TS. Under this scenario, Entegrus would also incur significant feeder construction costs.

At that time, Entegrus came to the realization that the sale of the assets to Hydro One would require OEB Section 86(1)(b) approval from the OEB. Entegrus recognized that under the circumstances, it could not make such an application because such a sale of assets was contrary to the public interest. Specifically, it would be contrary to regional planning objectives and OEB Act Section (1), regarding the protection of customers in terms of pricing and promoting economic efficiency and cost effectiveness in the transmission and distribution of electricity. Entegrus would not be able to complete the application form in a way that would support approval. Challenges included, but were not limited to, the following application questions:

- Question 2.3: Are the assets surplus to the applicant's needs?
- Question 3.4: Would the proposed transfer impact the distribution rates of the applicant?

Accordingly, since the merger, Entegrus has investigated other solutions to address the St. Thomas loading capacity issue – beyond solely investing in a new breaker position and feeder at the Edgeware TS. The other options, including retaining the underutilized feeders to meet the system needs at a substantially reduced cost, are described as scenarios in Section 5.5.3 and Section 5.5.4 below.

In June 2021, Entegrus released invoices to Hydro One in error that should have been held internally. The first invoice related to the purchase price of the conductor (and not the poles) on the M7 and M8. The second invoice related to charges for Hydro One feeder use in 2018-2020. These invoices would have reflected the sale of assets without OEB approval and Entegrus senior management was not aware that they had been released. Thereafter, in August 2021, after further study of alternatives for the 2021-2025 DSP, Entegrus verbally notified Hydro One that it would not sell the assets and sought an immediate meeting with Hydro One representatives. Hydro One was unable to schedule a meeting until October 2021, prior to which Hydro One paid the invoices (which were cancelled and refunded shortly thereafter by Entegrus).

At the October 2021 meeting, Entegrus reiterated its intention not to sell the assets. Entegrus explained that the 1997 Letter was frustrated by the OEB's December 2015 Distribution System Code amendments (EB-2015-0006). These amendments established that where LTLTs existed, the customer would be transferred from the geographic distributor to the physical distributor (the "LTLT Elimination Policy"). Specifically, the LTLT Elimination Policy should have resulted in the transfer of the Customer from Hydro One to Entegrus prior to June 21, 2017, since STEI (and by extension Entegrus) has always been the physical distributor for the Customer. In addition, Entegrus noted that an OEB Section 86 (1)(b) approval would otherwise be required for the sale of assets, and that this had not occurred and that, in combination with the OEB's LTLT Elimination Policy, this negated the invoicing sent erroneously by Entegrus to Hydro One. Hydro One responded that it had exercised its right to purchase the two dedicated feeders in December 2017 and noted that Entegrus had agreed to sell the assets and provide sale invoices. Hydro One noted that it did not receive an asset purchase invoice for almost 3.5 years and had followed up on various occasions with Entegrus. Entegrus advised Hydro One that its next steps in the matter would involve the regulator and that proceeding in the manner Hydro One sought was contrary to public interest.

5.4 The 1997 Letter No Longer Applies

Entegrus submits that the 1997 Letter is no longer applicable. In legal terms, the contract has been frustrated and can or should no longer be performed. The 1997 Letter no longer applies because Section 6.5.3 of the Distribution System Code ("DSC") established that where load transfers existed, the associated customer would be transferred from the geographic distributor to the physical distributor prior to June 21, 2017. Accordingly, Hydro One cannot rely on the 1997 Letter as obliging Entegrus to sell the two dedicated feeders to Hydro One. Entegrus submits that the transfer of the Customer to Entegrus, by way of this SAA Application, is the best means to address the unique situation that continues to exist.

In accordance with DSC Section 6.5.3, Hydro One and STEI jointly applied on May 9, 2017 (EB-2017-0192) to the OEB for approval to amend the service areas of both distributors such that all existing load transfer arrangements between the two distributors were eliminated. The EB-2017-0192 decision approved the transfer of one General Service customer and 11 Residential customers from STEI to Hydro One, and three Residential customers from Hydro One to STEI. All the customers transferred from STEI to Hydro One required rate mitigation, while no rate mitigation was required from the customers transferred from Hydro One to STEI. However, due to STEI being the physical distributor of the Customer, the parties should also have applied to the OEB by June 21, 2017, to transfer the Customer from Hydro One to STEI. Apparently, this was not recognized by Hydro One or STEI in 2017.
Of note, Hydro One and Entegrus (pre-merger with STEI) also jointly applied on November 25, 2016 (EB-2016-0337) to eliminate load transfer arrangements. However, in this case, the parties later (after June 21, 2017) recognized that one Residential customer was missed in the process. Accordingly, Entegrus (pre-merger with STEI) supported the transfer of the Residential customer to Hydro One (in the EB-2017-0326 joint application dated October 24, 2017). The EB-2017-0326 decision rendered in November 2017 resulted in the transfer of this Residential customer to Hydro One.

The relief sought in this Application meets the requirements and expectations of the Elimination of Load Transfer Arrangements process as set out in the EB-2015-0006 proceeding. That was true in 2017, when distributors were directed to make Load Transfer Elimination applications, and it remains true now. Additionally, the scenario outlined in this Application meets the requirements and expectations of the OEB in relation to SAAs more generally, as outlined in the RP-2003-0044 Combined Proceeding Decision with Reasons (February 27, 2004), including the fact that the transfer of the Customer and the use of the subject feeders by Entegrus is the most efficient use of existing distribution resources.

In any event, as described in Section 5.5.1 and Section 5.5.2 below, the price at which Hydro One seeks to purchase the M7 and M8 feeders represents a fraction of replacement value. Hydro One then proposes to charge Entegrus for any use of the M7 and M8 feeders at 45 times higher than the monthly amount that Entegrus has historically charged Hydro One on a same capacity basis (see Section 5.5.2). Moreover, for reasons established below, it cannot be said that the two dedicated Entegrus feeder assets (the M7 and M8) are "surplus to the utility's needs". Entegrus is aware that the transfer of the M7 and M8 feeders to Hydro One would require OEB approval under section 86(1)(b) of the Ontario Energy Board Act. Entegrus does not intend to file such an application, as the transfer is not in the public interest.

5.5 Entegrus – St. Thomas Load Growth Background

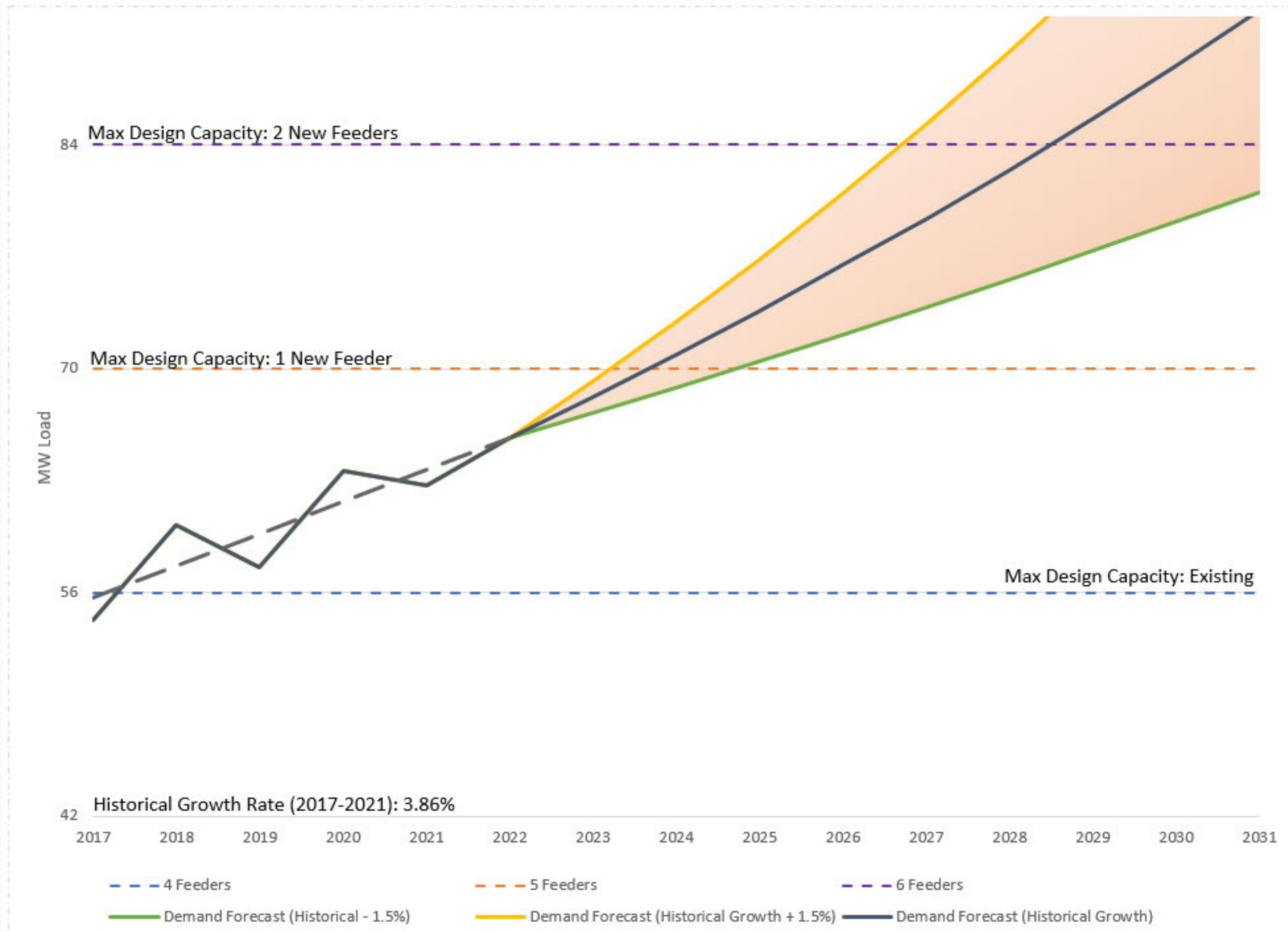
The Entegrus - St. Thomas service territory has long been served by four breakers at Hydro One's Edgeware TS reserved for the exclusive use of Entegrus, and the four associated Entegrus 27.6 kV feeders emanating from Hydro One's Edgeware TS. Since these four feeders are directly connected to the station (and do not tap off Hydro One distribution pole lines), Entegrus is billed directly from the IESO for these assets and does not receive any billings for Low Voltage or other services from Hydro One Distribution.

In addition, the Customer has long been served by two additional, separate breakers (the M7 and M8) at Hydro One's Edgeware TS which appear to be reserved for the exclusive use of the Customer. The Entegrus M7 and M8 feeders provide the distribution connection for the Customer, and accordingly, Entegrus acts as the physical distributor, while Hydro One acts as the geographic distributor for the Customer. Entegrus is not billed for these two additional, separate breakers associated with the Entegrus M7 and M8 feeders.

With Entegrus M7 and M8 feeders currently dedicated to the Customer, as described above, Entegrus serves the public in St. Thomas using the other four 27.6 kV feeders, which have an aggregate design capacity of 56 MW. The recent load growth in St. Thomas has resulted in the need to utilize emergency capacity (i.e. operate the assets at above design capacity at certain points in time) on these four feeders. Emergency capacity is defined as the difference between the maximum rating of the equipment and the design capacity (or operational rating) of the equipment. The difference between design capacity and emergency capacity is typically maintained to ensure that the distribution system can respond to contingency situations, for example when one or more assets are out of service due to maintenance activities or failure, as well as unexpected customer-driven load spikes.

Historically, the former STEI experienced moderate growth. However, since 2017, the St. Thomas growth rate has significantly increased as shown in Figure 5-2 below, driven by strong Residential growth. A key contributor of Residential growth is the proximity of St. Thomas to London, and the increasing emergence of St. Thomas as a bedroom community of London.

FIGURE 5-2: ST. THOMAS LOAD GROWTH AND SYSTEM CAPACITY



Note: The load amounts in Figure 5-2 above exclude the M7/M8 feeder load dedicated to the Customer that is the subject of this Application.

As a result of this strong growth, loading has reached the point where all four feeders available to the general public in St. Thomas are, on average, loaded beyond design capacity during peak periods. Accordingly, Entegrus occasionally experiences periods of time in St. Thomas where no transfer capacity remains in the event of certain single points of failure during peak loading, which can lead to extended outages.

The continued growth in excess of the aggregate 56 MW of design capacity on the four Entegrus St. Thomas general public use feeders can be clearly seen in Figure 5-2 above. This continued growth above design capacity will drive an increasing number of failure points and lack of transfer capacity over time. To address the fact that Entegrus is already running above design capacity of the existing four feeders available to the general public, Entegrus requires the equivalent of a feeder's worth of capacity (i.e. 14 MW) in the immediate term (i.e. 2023). Figure 5-2 also shows that dependent upon the growth scenario, a second additional feeder will be required between 2024-2027.

Entegrus has explored several scenarios to remediate the loading of existing feeders by adding more capacity for St. Thomas general public use in the immediate term, to allow for continued growth in the community. These scenarios are described below (starting in Section 5.5.1) and involve comparison of Edgeware TS breaker position expansion versus increased utilization of the two existing underutilized Entegrus M7/M8 feeders which are dedicated to the Customer.

As noted in Section 5.1, the two existing dedicated Entegrus 27.6 kV feeders have an approximate capacity of 14 MW capacity each when fully loaded and an approximate capacity of 28 MW each for emergency loading purposes. During the process of investigating the sale of the two existing dedicated feeders to Hydro One, Entegrus came to the understanding that [redacted] In the event that Entegrus were to retain and control the feeders, in consultation with the Customer, the underutilized capacity on the M7 and M8 feeders could be used to address the immediate needs in St. Thomas (beyond which the focus would become a second additional feeder between 2024-2027). Conversely, if Entegrus were to sell the feeders to Hydro One, then Entegrus would be required to then meet that capacity by building additional, new capacity (i.e. a new breaker position at Edgeware TS) to serve St. Thomas needs in 2023.

In advance of this Application, Entegrus requested information on the status of the M7 and M8 breakers and if both breakers were currently reserved for the exclusive use of the Customer, or alternatively, whether a portion of the M7 and M8 capacity was reserved or utilized for other purposes. Hydro One declined to provide this information, aside from indicating that 5 MW of capacity from the M8 breaker position was allocated to Entegrus (see Section 5.5.2 for additional detail).

5.5.1 Scenario 1: Sale of the Dedicated Feeders to Hydro One Followed By Entegrus Capacity Expansion at Edgeware TS

The scenario initially considered by Entegrus to expand St. Thomas capacity was the construction of a new 27.6 kV feeder emanating from Edgeware TS with 14 MW of design capacity and an approximate capacity of 28 MW for emergency loading purposes. This scenario was predicated on the position advanced by Hydro One that Entegrus was required to sell its two existing dedicated feeders that could be used to serve both the Customer, and other customers in the Subject Area, to Hydro One. In discussions based on Hydro One's assertion, Hydro One agreed that Entegrus would retain the dedicated feeder poles themselves, while selling the existing conductor on the poles to Hydro One. As contemplated, Entegrus would then charge annual joint use pole rental fees to Hydro One. The retention of the poles and right of way would provide Entegrus the later ability to utilize the same feeder corridor to serve expanding load requirements.

Under this scenario, Entegrus would sell the underutilized feeders to Hydro One at the January 1, 2018, net book value of the feeders of $116,431, which is substantially less than the estimated replacement cost of $3M -$4M for the two feeders (and associated breaker positions). In order to meet its St. Thomas load capacity requirements, Entegrus would then incur estimated aggregate costs of $1.7M for the construction of a single additional Edgeware station bus and breaker position, station egress and metering (as well as significant feeder construction costs). The cost of the additional breaker position would be paid to Hydro One. A breakdown of the bus and breaker position, station egress and metering costs is shown below.

Table 5-1: Breakdown of Costs for the Construction of a New Edgeware TS Station Bus, Breaker Position and Station Egress

Description	**Cost**
Bus and Breaker (Hydro One estimate)	$1,100,000
Station Egress	$450,000
Primary Metering Installation	$90,000
Contingency on Egress & Metering	$60,000
Total	**$1,700,000**

Note: The table above does not include the cost of additional feeder construction.

Entegrus received the Bus and Breaker estimate of $1.1M per Table 5-1 above via an email from Hydro One in September 2019, which indicated that an estimation threshold range of -50% to +100% applies to this figure. The remaining amounts were estimated by Entegrus management based on similar historical project work performed by Entegrus. The contingency applies to only the elements of the project controlled by Entegrus, and thus is exclusive of the Bus and Breaker estimate.

In addition to the estimated construction costs above, Entegrus would also incur feeder construction costs. Since, by way of the new feeder, Entegrus would be directly connected to the Edgeware TS, Entegrus does not believe it would incur any Low Voltage charges under this scenario.

While Entegrus has had discussions with Hydro One about the capacity expansion of Edgeware TS described as Scenario 1 in Section 5.5.1 above, Entegrus believes that this scenario does not best serve the public interest. Simply put, it does not make sense for Entegrus customers to bear $1.7M of cost to Hydro One (plus significant additional feeder construction costs), when there are existing underutilized assets already owned by Entegrus in proximity that could remedy the situation. The optimal utilization of these existing assets is described in Section 5.5.4 below.

In the course of 2021 discussions with Hydro One regarding Scenario 1, Entegrus came to the recognition that the transfer of the M7 and M8 feeders to Hydro One would require OEB approval under section 86(1)(b) of the Ontario Energy Board Act. When this OEB approval requirement was introduced to Hydro One, Hydro One noted that it did not disagree that a utility divesting assets required OEB approval. However, Entegrus does not intend to file a Section 86(1)(b) application, as Entegrus does not believe the transfer of the assets to be in the public interest. Notably, for reasons established below, it cannot be said that the two dedicated Entegrus feeder assets are "surplus to the utility's needs". It is neither rational nor economic for Entegrus customers to bear at least $1.7M of additional costs for one breaker position and egress (plus additional feeder construction costs), when there are existing nearby underutilized assets already owned by Entegrus that could address the current and near-term feeder loading situation.

5.5.2 Scenario 2: Sale of the Dedicated Feeders to Hydro One and Entegrus Receipt of 5 MW of Capacity

A second scenario considered by Entegrus is also predicated on the position advanced by Hydro One, that Entegrus is required to sell the M7 and M8 feeders to Hydro One. Similar to Scenario 1, Hydro One agreed that Entegrus would retain the dedicated feeder poles themselves, while selling the existing conductor on the poles to Hydro One, and then Entegrus would charge annual joint use pole rental fees to Hydro One. However, rather than being followed by Edgeware TS expansion as in Scenario 1, the next step in Scenario 2 would be for Entegrus to obtain an allocation of the underutilized feeder capacity from Hydro One post-sale.

As noted in Section 5.3 above, Entegrus expressed concerns to Hydro One over the course of four years of discussions about the requested sale of the M7 and M8 feeders to Hydro One, given the growing Entegrus capacity requirements in St. Thomas. Accordingly, Entegrus enquired as to the opportunity for Entegrus to make use of underutilized feeder capacity. Hydro One indicated that 5 MW (from the M8 breaker position) was the maximum capacity that could be allocated to Entegrus from the two dedicated feeders. As can be seen in Figure 5-2, this additional 5 MW capacity is insufficient to address the Entegrus supply needs in St. Thomas. And as shown in Table 5-2, this 5 MW of capacity would come at a very high cost to Entegrus customers.

Hydro One recently indicated that this 5 MW of capacity is allocated to Entegrus. To date, Entegrus has not utilized any of this capacity. Hydro One further indicated that, should Entegrus eventually transfer ownership of the M7/M8 feeders to Hydro One, based on Hydro One's current 2022 rates, to the extent that Entegrus uses this 5 MW in allocated capacity, Entegrus would be subject to Low Voltage ("LV") charges, plus Retail Transmission Service Rates ("RTSRs"). Hydro One notes that the charges are subject to change. The Hydro One LV and RTSRs – plus any additional Hydro One rate riders – would result in this scenario being a very expensive option for Entegrus customers, as shown below in Table 5-2.

TABLE 5-2: PROPOSED MONTHLY HYDRO ONE CHARGES TO ENTEGRUS FOR 5 MW OF M8 FEEDER CAPACITY

Hydro One Charge Type	Rate	kW	Amount
Common ST	1.6208	5,000	$ 8,104
RTSR - Network	4.3473	5,000	$ 21,737
RTSR - Line Connection	0.6788	5,000	$ 3,394
RTSR - Transformation Connection	2.3267	5,000	$ 11,634
Deferred Tax Asset Vol Rider	0.0540	5,000	$ 270
Total Proposed Monthly Hydro One Charges to Entegrus			**$ 45,138**

Note: RTSR charges are applied on loss-adjusted kW, whereas Common ST and Deferred Tax Asset Vol Rider (i.e. rate riders) are applied on non-loss-adjusted kW. For simplicity, the calculations above are shown consistently at 5 MW (5,000 kW).

The Hydro One charges shown above in Table 5-2 are significantly in excess of the monthly charges paid by Hydro One to St. Thomas PUC/STEI/Entegrus; these monthly charges to Hydro One were $5,828 per month for 28 MW of design capacity (on two feeders) for 1997-2007, followed by a reduction to $5,528 per month for the period 2008-

2017. In comparison, when normalizing for equivalent capacity (i.e. 28 MW vs. 5 MW) the equivalent charges which Hydro One proposes to charge Entegrus would be $252,773 (i.e. $45,138 X 28 MW / 5MW) per month. This means that Hydro One proposes to charge Entegrus 45 times more per month than Entegrus has historically charged Hydro One, on an equivalent capacity basis. And future additional Hydro One rate riders could make the proposition even more expensive for Entegrus customers.

Similar to Scenario 1, Entegrus asserts that Scenario 2 clearly does not best serve the public interest. Specifically, selling the M7 and M8 feeders to Hydro One for $116,431, and then receiving back a small portion (5 MW) of underutilized capacity on one feeder for the cost of $45,138 per month (see Table 5-2) – only then to pay $1.7M to Hydro One for a new breaker position, plus incurring significant additional feeder costs – is neither rational nor in the economic best interest of Entegrus customers. Accordingly, similar to Scenario 1 above, Entegrus does not intend to file a Section 86(1)(b) application, as Entegrus does not believe the transfer of the assets to be in the public interest.

5.5.3 Scenario 3: Retention of the Dedicated Feeders by Entegrus and Restricted Allocation of Feeder Capacity to Hydro One to Serve the Customer

A fourth scenario considered by Entegrus is the inverse of Scenario 2, whereby Entegrus would retain the M7 and M8 feeders and provide restricted allocation of feeder capacity to Hydro One, which would continue to serve the Customer. As noted in Section 5.5.2 above, [redacted]. This scenario would provide the opportunity to fully utilize the appropriate available capacity.

Under this scenario, Entegrus would propose the design of a new rate for the Entegrus-St. Thomas rate zone, akin to Hydro One's Low Voltage charge. Further, under this scenario, there would be no sale of assets. Accordingly, a Section 86(1)(b) application would not be a requirement.

This scenario does not address potential sources of confusion and additional co-ordination that would continue to exist between Entegrus and Hydro One (as described in Section 5.5.4), nor does it recognize the LTLT elimination requirement described in Section 5.3. Further, a detailed process to design a new rate would need to be undertaken.

5.5.4 Scenario 4: Service Area Amendment to Optimize Utilization of Existing Entegrus Assets

The fourth and preferred scenario considered by Entegrus to expand St. Thomas capacity is to seek approval of this SAA, in order for Entegrus to assume the relationship with the Customer and work directly with the Customer to optimize the utilization of the existing M7 and M8 feeders, which run from Edgeware TS to the Subject Area.

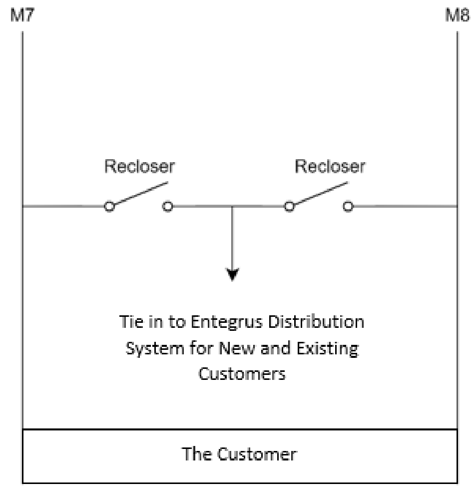
As noted in Section 5.1 above, the M7 and M8 feeders have an approximate capacity of 14 MW each when fully loaded and an approximate capacity of 28 MW each for emergency loading purposes. [redacted]. This understanding is borne out by recent Entegrus metering data.

Approval of this SAA will enable Entegrus to engage in load planning discussions with the Customer and the ability to make arrangements that will ensure the rational and efficient use of existing assets (the M7 and M8 feeders) and avoid the unnecessary and costly construction of new assets while existing assets remain underutilized.

To connect and serve the Customer, Entegrus would install two wholesale meters for a cost of approximately $150,000.

Further, Entegrus would seek to access the pre-constructed, underutilized capacity on the feeders through the construction of a tap point. This point would include two reclosers (costing approximately $50,000 each), one on each feeder, which would be coordinated with the station breakers to allow for diversity of supply to the Entegrus system while protecting the Customer from power disturbances and maintaining reliability. In the event one feeder was unavailable, the other feeder would run a maximum capacity and could pick up the Customer load. A single line diagram of this design is shown below in Figure 5-3. Further, an additional tie-in to other existing nearby Entegrus assets could be made to further enhance reliability for both the Customer and other Entegrus customers.

FIGURE 5-3: SINGLE LINE DIAGRAM OF RECLOSURE INSTALLATION



The utilization of the existing capacity, as shown above, would mitigate the need for the $1.7M of construction costs for an additional Edgeware station bus and breaker position required under Scenario 1 (see Section 5.5.1), plus significant additional feeder construction costs. This also avoids the $45,138 of monthly Hydro One LV, RTSR and rate rider charges that are fundamental to partial capacity utilization (5.0 MW) in Scenario 2 (see Section 5.5.2 and Table 5-2).

The SAA further reduces potential public confusion regarding the servicing of the Subject Area and would reduce an unnecessary layer of co-ordination between Entegrus and Hydro One. Recent examples of potential confusion and additional co-ordination include:

- In February 2022, [redacted]
- In March 2022, while the Edgeware TS was undergoing Protection and Control updates as part of its regular life-cycling, Entegrus requested data pertaining to the Customer such that Entegrus could provide the station settings for the M7 and M8 feeders (within the capabilities defined by Hydro One for the Edgeware TS). Hydro One declined to provide the data and indicated that it would determine the settings

on Entegrus' behalf. Entegrus has declined this request, noting that since it owns the feeders, it should have the ability to design, or at least approve, the station settings.

- In the spring of 2022, [redacted]
- In September 2022, [redacted].

5.5.5 Public Interest Determination

In summary, the SAA proposed in this Application is in the public interest, as defined in the Combined Proceeding, for the following reasons:

- The OEB's LTLT Elimination Policy required that where load transfers existed, the customer would be transferred from the geographic distributor to the physical distributor prior to June 21, 2017. Accordingly, the Customer should have been transferred from Hydro One to STEI (and by extension Entegrus) in 2017, because Entegrus was, and remains, the physical distributor for the Customer. In issuing the LTLT Elimination Policy, the OEB noted the existence of a number of undesirable outcomes associated with load transfer arrangements, which prompted the need for their elimination.
- It is anticipated that the Customer would realize significant distribution rate savings if the SAA were approved, and the Customer was served by Entegrus. Entegrus requested the Customer's current rate class within the Hydro One rate class structure and its bills from January 2021 to current, as well as confirmation of any expected change in the Customer's rate class in the next 5 years. Hydro One has declined to provide this information.

- The proposed SAA is consistent with the objective of a rational and efficient service area alignment based on both economic and engineering efficiency.
- Entegrus serves the area surrounding the Subject Area and accordingly has distribution infrastructure within close proximity, in addition to the M7 and M8 feeders that currently serve the Customer, and can provide the required electrical service with minimal additional investment (see Section 6.3).
- Entegrus' connection proposal for the Subject Area is comparable to Hydro One's in terms of system planning, safety and service reliability, particularly as the same assets (the two M7/M8 feeders) are currently being used to service the Customer. Further, in terms of reliability, the Customer would benefit from the proposed SAA by the removal of an unnecessary layer of coordination between Hydro One and Entegrus, in the event that a reliability event were to occur.
- The proposed SAA will not result in stranded or duplicated assets. Rather, the proposed SAA will mitigate the creation of duplicated assets that would otherwise occur under Scenario 1 (see Section 5.5.1) and Scenario 2 (see Section 5.5.2).
- The proposed SAA would result in the resolution of a longstanding LTLT situation, reduce potential public confusion, remove an unnecessary layer of coordination regarding the distribution relationship, and rationalize the provision of service to the Customer.

5.6 Description of Proposed Service Area

The Subject Area includes the property (and associated Customer) located at 1 Cosma Court, St. Thomas, ON N5R 4J5 (the "Subject Area"). This property is currently listed as an exclusion in the Entegrus Distribution Licence, although the Subject Area is surrounded by the Service Area of Entegrus and falls within the longstanding municipal boundaries of the City of St. Thomas. The Subject Area and associated Customer are currently served by Hydro One.

A map of the Subject Area, including the border of the applicant and incumbent services areas and existing facilities, is shown in **Attachment 1**. A map of geographical features surrounding the area is shown in **Attachment 2**.

5.7 Maps and Diagrams of Proposed Service Area

The following maps, diagrams and pictures are attached:

- **Attachment 1** – Map of the Applicant and Incumbent Service Areas and Existing Facilities
- **Attachment 2** – Map of Geographical Features Surrounding the Area

Collectively, these maps identify the Subject Area, the existing borders of Entegrus and Hydro One, the area around the Subject Area, and the existing infrastructure supplying the Subject Area.

Note that a map of the proposed Entegrus connection is not applicable, since as the physical distributor, Entegrus already connects the Customer to its supply source, the Edgeware TS.

5.8 Description of the Existing Physical Connection

The supply source for the Customer is the Edgeware TS, connected by way of two dedicated 2.5 km 27.6 kV feeders emanating from the Edgeware TS and running to two customer-owned substations adjacent to the Customer facility.

In order to serve the Customer, Entegrus would install two wholesale meters. Further, Entegrus would seek to access the pre-constructed, unutilized capacity on the feeders through the construction of a tap point. This point would include two reclosers, one on each feeder, which would be coordinated with the station breakers to allow for diversity of supply to the Entegrus system while protecting the Customer from power disturbances and maintaining reliability. In the event that one feeder was unavailable, the other feeder would run at maximum capacity and could pick up the Customer load.

5.9 Future Expansions in Adjacent Lands

A map of the Subject Area, including the border of the applicant and incumbent services areas and existing facilities, is shown in **Attachment 1.** A map of geographical features surrounding the area in shown in **Attachment 2.**

As noted in Section 5.5.4 above, [redacted]

6 Efficient Rationalization of the Distribution System

The proposed SAA will result in a rational and efficient service area and optimize the use of existing distribution assets which are currently underutilized.

6.1 Location of the Points of Delivery and Connection

The Customer is served by two dedicated 27.6 kV feeders built, owned and maintained by Entegrus, which connect the Customer to the Hydro One Edgeware TS.

6.2 Proximity to Distribution System

As noted above, the Subject Area is ringed by the Service Area of Entegrus and falls within the longstanding municipal boundaries of the City of St. Thomas.

6.3 Fully Allocated Connection Costs

As noted in Section 5.5.4 above, Entegrus would incur $150,000 in connection costs to install two new wholesale meters. Hydro One would incur costs of $116,431 to purchase the M7 and M8 feeders (which is not reflective of the $3M-$4M replacement cost as discussed in Section 5.5.1). However, connection costs considered alone disregard the benefit to Entegrus ratepayers – and the efficiency benefits for the St. Thomas electricity system in its entirety – of accessing the existing, pre-constructed, unutilized capacity on the feeders through the construction of a tap point.

Please see the comparison of costs versus savings in Table 6-1 below.

TABLE 6-1: COMPARISON OF COSTS (SAVINGS)

Connection Component	**Entegrus Services the Customer and Accesses Additional Capacity ($000's)**	**Hydro One Purchases the Entegrus Feeders and Services the Customer ($000's)**
Wholesale Meters Installation Cost	$ 150	
Reclosures Cost	$ 100	
Hydro One Proposed Cost of Purchasing Both Feeders to Serve Customer (at Replacement Cost) (Note 1)		$3M - $4M
Net (Savings) Costs	**$ 250**	**$3M - $4M**

Note 1: *Hydro One proposes to purchase the Entegrus M7 and M8 express feeders for $116,431. As detailed in Section 5.5.1, Entegrus proposes that the replacement cost of the feeders of $3M-$4M is a more appropriate determinant.*

Entegrus requested confirmation from Hydro One that it has wholesale and customer meters on-site at the Customer premises, along with a description of Hydro One's metering configuration. Hydro One declined to provide this information.

6.4 CAPITAL CONTRIBUTION

There is no capital contribution required from the Customer by Entegrus.

6.5 STRANDED EQUIPMENT COSTS

There will be no stranded equipment due to the proposed SAA. Rather, the Application will result in existing, underutilized assets being used more efficiently.

6.6 INFRASTRUCTURE RELIABILITY

The proposed SAA will not have any adverse effects on reliability in the Subject Area or adjacent areas. Entegrus' connection proposal for the Subject Area is comparable to Hydro One's in terms of system planning, safety and service reliability, particularly as the same assets (the two feeders) are currently being used to service the Customer. In addition, the proposed SAA and Entegrus connection proposal presents the opportunity to tie-in the

M7 and M8 feeders to other existing Entegrus assets nearby, which could further enhance reliability for both the Customer and other Entegrus customers.

Please see additional details, including the tap point and reclosure design, in Section 5.5.4 above.

Further, in terms of reliability, the Customer would benefit from the proposed SAA by the removal of an unnecessary layer of coordination between Hydro One and Entegrus, in the event of an occurrence of a reliability event.

6.7 Cost-Effectiveness of Future Expansions

It is understood that the existing infrastructure more than adequately supplies the Customer, and that significant redundancy (excess capacity) currently exists on the two dedicated feeders serving the Subject Area. Further, the proposed SAA, for the reasons described in Section 5.5.4, provides the ability to avoid, and retain for later, the option of further Edgeware TS expansion (as described as Scenario 1 in Section 5.5.1 and Scenario 2 in Section 5.5.2) as a future expansion opportunity, rather than constraining this expansion option now.

6.8 Cost-Effectiveness of Improvements and Upgrades

No incremental expansion of Entegrus' distribution system will be required, as the two dedicated feeders owned by Entegrus already connect the Customer to the Edgeware TS.

7 Impacts Arising from the Proposed Amendment

7.1 Affected Customers and Land Owners

The Customer within the Subject Area of this Application is an existing Hydro One customer. A letter of support from the Customer located at 1 Cosma Court will be addressed at a later stage of this application process, because Hydro One has not provided consent for Entegrus to talk with the Customer.

7.2 Customer Impacts Within Subject Area

Approval of this SAA will not result in any negative impacts on cost, service quality, and reliability. As more fully described in Section 7.4, it is anticipated that the Customer will enjoy a distribution rate benefit from being served by Entegrus.

7.3 Customer Impacts Outside Subject Area

Approval of this SAA will result in a rational and efficient service area and optimize the use of existing distribution assets which are currently underutilized. Conversely, if Entegrus is required to pay Hydro One for the construction of a new Edgeware TS bus and breaker position to address the capacity requirement, as detailed in Section 5.5.1, the incremental costs will ultimately lead to higher rates for Entegrus customers outside the Subject Area.

7.4 Distributor Impacts

Approval of this SAA will not result in any negative impacts on cost, service quality, or reliability. It is anticipated that the Customer will enjoy a distribution rate benefit from being served by Entegrus. In previous LTLT eliminations, former Hydro One customers enjoyed material distribution rate decreases at the conclusion of their transfer from Hydro One to Entegrus (EB-2016-0037 and EB-2017-0326) and STEI (EB-2017-0192).

Entegrus requested the Customer's current rate class within the Hydro One rate class structure and its bills from January 2021 to current, as well as confirmation if the Customer's rate class is expected to change in the next 5 years. Hydro One has declined to provide this information. This information was requested to confirm that the Customer will enjoy a distribution rate decrease upon transfer to Entegrus, in order to assess rate mitigation requirements under DSC Section 6.4.

7.5 Stranded and Redundant Assets

No assets will be stranded or made redundant as a result of this SAA. Rather, the Application will allow the public to access pre-constructed, unutilized capacity in St. Thomas.

7.6 Transferred Assets

No assets will be transferred as a result of this SAA.

7.7 Transferred Customers

The Customer would be transferred from Hydro One to Entegrus as a result of this SAA.

7.8 Eliminated Load Transfers or Retail Points

The proposed SAA would result in the resolution of a longstanding Long-Term Load transfer situation, reduce potential confusion regarding the distribution relationship, and rationalize the provision of service to the Customer

7.9 New Load Transfers or Retail Points

No new load transfers or retail points of supply will be created by this SAA.

7.10 Written Confirmation of Full Disclosure

Entegrus confirms that this matter has been discussed with Hydro One and that Hydro One has been provided with a copy of this Application. Entegrus also wishes to discuss the Application with the Customer. Please see Section 7.12 below for additional details.

7.11 Consent of Incumbent Distributor

Hydro One is the incumbent distributor for the Customer. Entegrus has engaged Hydro One in discussions about this Application and the expansion of Entegrus' service territory to service the Subject Area. Hydro One has declined to provide its consent for this Application. Accordingly, Entegrus has prepared this Application in accordance with contested SAA Filing Requirements.

7.12 Consent of the Customer

Entegrus wishes to discuss the implications of the Application with the Customer, including answering any questions from the Customer, and discussing its preferences as well as any potential issues with public disclosure of the information in the Application. Entegrus has sought consent from Hydro One to discuss this Application with the Customer. Hydro One has declined to provide consent. Accordingly, a letter of support from the Customer will be addressed at a later stage of this application process.

Entegrus seeks direction from the OEB about contacting the Customer and discussing the Application before the OEB issues a Notice and places the Application on the public record. Entegrus believes that it is efficient to discuss the Application with the Customer, and make any necessary updates to the Application, before the Application is placed on the public record. Hydro One has not provided consent, so Entegrus seeks guidance from the OEB. In any event, Entegrus will provide a copy of the Application to the Customer after the OEB issues a Notice and places the Application on the public record.

7.13 Mitigation Efforts Related to Customer and Asset Transfer

Entegrus anticipates that no mitigation is required, as Entegrus believes that the Customer would enjoy a distribution rate benefit if this Application were approved.

Further, Entegrus ratepayers would benefit – as would the electricity system in its entirety – from the use of existing, pre-constructed, unutilized capacity on the feeders. This would mitigate the costs to Entegrus ratepayers of Scenario 1 and Scenario 2, as described above in Sections 5.5.1 and 5.5.2, respectively.

8 Additional Information Requirements for Contested Applications

8.1 Incumbent Distributor Opportunity to Make an Offer to Connect the Customer

The Customer is currently served by Hydro One.

8.2 Customer Opportunity to Obtain an Offer to Connect from the Applicant

As noted in Section 7.12 above, Entegrus has not yet engaged in discussions with the Customer because Hydro One has declined to provide its consent for Entegrus to do so. As noted under Section 3.1, Entegrus seeks OEB consent to discuss the Application with the Customer, since Hydro One has declined to provide its consent.

8.3 Offer to Connect Documentation

The Customer is currently served by Hydro One. Entegrus has requested a copy of the connection agreement. Hydro One has declined to provide this information.

8.4 Comparison of the Offers to Connect the Customer

As noted above, Hydro One has declined to provide Entegrus with a copy of the connection agreement with the Customer.

8.5 Detailed Comparison of New/Upgraded Infrastructure Necessary for each Distributor to Serve the Customer

The infrastructure necessary for each distributor to serve the customer is already in place. Entegrus proposes certain enhancements to better utilize the M7 and M8 feeders, including additional metering and reclosures. Please see Section 5.5.4 for additional details.

8.6 Reliability of Existing Lines of Each Distributor to Supply the Subject Area

The same infrastructure currently utilized to serve the customer would remain in place, namely the M7 and M8 feeders connecting the Customer to the Edgeware TS. Accordingly, the reliability experienced by the Customer would be comparable from each distributor. Further, in terms of reliability, the Customer would benefit from the proposed SAA by the removal of an unnecessary layer of coordination between Hydro One and Entegrus, in the event that a reliability event was to occur.

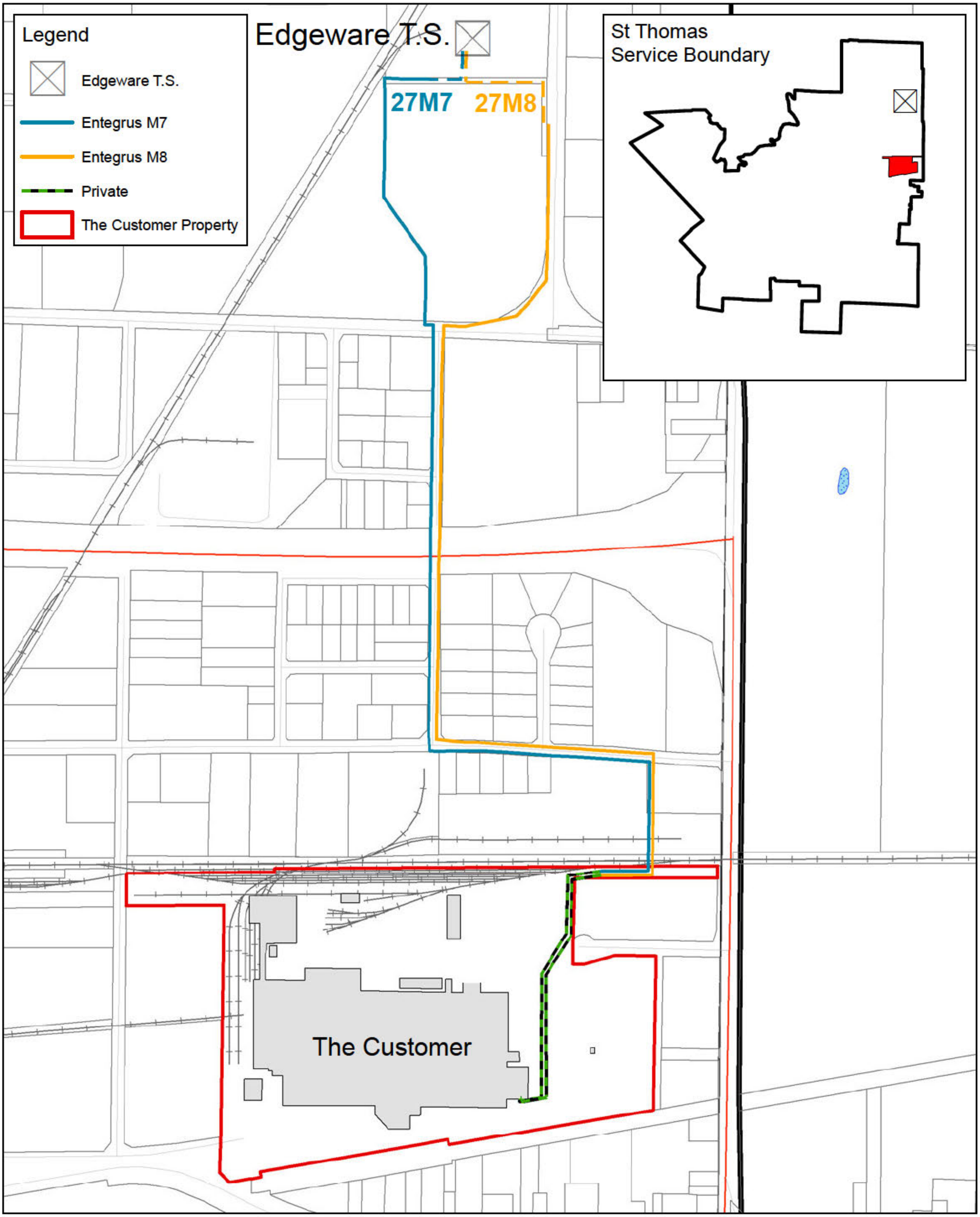
8.7 Quantitative Evidence of Quality and Reliability for Each Distributor for Similar Customers

The same infrastructure currently utilized to serve the customer would remain in place, namely the M7 and M8 feeders connecting the Customer to the Edgeware TS. Accordingly, the reliability experienced by the Customer would be comparable from each distributor due to the way in which the Customer is currently served. In addition, the proposed SAA and Entegrus connection proposal also presents the opportunity to tie-in the M7 and M8 to other existing Entegrus assets nearby, which could further enhance reliability for both the Customer and other Entegrus customers.

ATTACHMENT 1

Map of the Border of the Applicant and Incumbent Services Areas and Existing Facilities

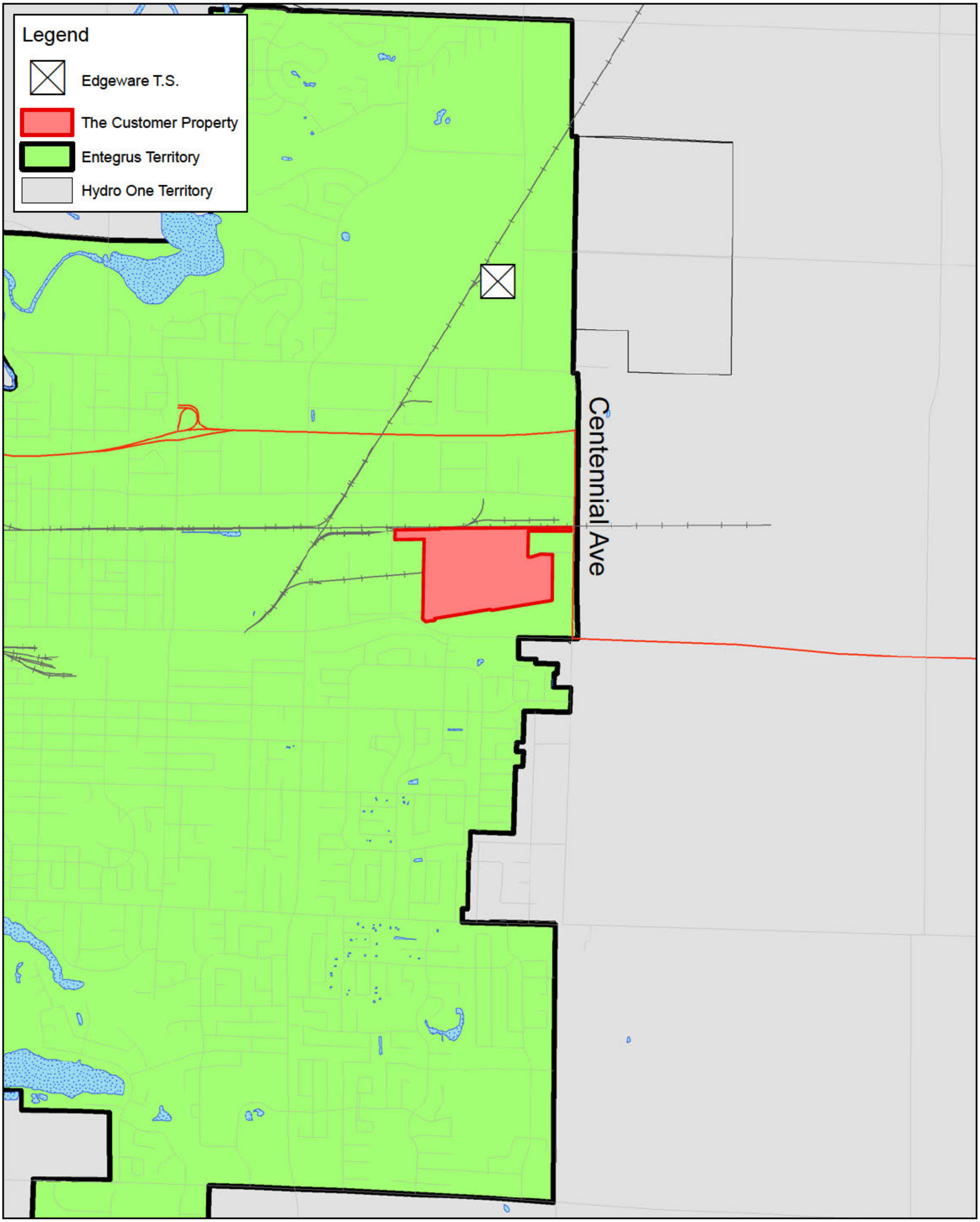
Edgeware T.S. Feed to The Customer



ATTACHMENT 2

Map of the Geographical Features Surrounding the Area

Service Territory Boundaries



ATTACHMENT 3

The 1997 Letter Between Ontario Hydro and St. Thomas PUC

[redacted]

MEMORANDUM

November 10, 1997

File: 510 St. Thomas

[redacted]

See Distribution

[redacted] - ST. THOMAS PUC/ONTARIO HYDRO SUPPLY AGREEMENT

The attached is a copy of the executed agreement between St. Thomas PUC and Ontario Hydro with respect to the 27.6/16 kV supply to the [redacted] plant from Edgeware TS.

A tri-party "Operating & Maintenance Agreement" is being developed to address those issues.

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted] [redacted]

[redacted]

[redacted]855 Pond Mills Road London, Ontario N5Z 4R1
Telephone (519) 649-3713 Fax (519) 649-3720

May 29, 1998

Mr. Denis Iwancewicz
General Manager
Public Utilities Commission of the
City of St. Thomas
135 Edward Street
St. Thomas, Ontario
N5P 3V4

[redacted] FEEDER AGREEMENT - ACTUAL CONSTRUCTION COST

Dear Denis:

In September, 1997 the "Agreement For Supply Facilities [redacted] Two Dedicated 27.6 kV Feeders" was executed by St. Thomas PUC and Ontario Hydro.

Please consider this letter to be an addendum to that Agreement.

One issue addressed within the Agreement was the use of actual versus estimated costs for the calculation of the annual "use of feeders" fee. I would refer you to section 3 of the Agreement.

Now that this work is completed, you have finalized the costs associated with the feeder construction. With the cost of construction increasing from the estimated amount of $661,800 to $739,699.75, the monthly rental and maintenance fee will increase from $$4968.00 to $5827.93. We concur and accept this amount. The 1997 payment will be based on the period from September 14, 1997 (the date the first dedicated feeder went into service) to December 31, 2007 (as per section 3). Please submit an invoice for the 1997 "use of facilities".

We would request that you keep a separate accounting of all maintenance costs associated with these feeders from Edgeware TS to the [redacted] property limit so that the monthly rental and maintenance fee can be adjusted accordingly for the January 1, 2008 to December 31, 2017 period. Refer to section 4 of the Agreement.

Please record all maintenance activity on the [redacted] property separately and advise us accordingly. We would anticipate only a minimal amount of planned routine maintenance with emergency maintenance completed as required. Note that all maintenance on the [redacted] property becomes a [redacted] responsibility January 1, 2008.

Yours truly,

[redacted]

Mark Steeves, P.Eng
Account Executive
Customer Service

cc Bob Coghlan, Southwestern Territory WT1
Mo Nayo, System Development H4 B18

6. Delivery of reliable energy to the Customer is the responsibility of OH. Should the integrity of the Feeders, as extended, from St. Thomas Edgeware TS to the switching facility within [redacted] not meet the performance expectation of OH (not to exceed one outage of more than one minute in a calendar year to the Customer), the PUC will transfer their ownership and maintenance of the Feeders, as extended, and land rights to OH at their book value and all entitlement to monthly rental and maintenance fees will cease. The PUC would not be held responsible for outages caused by a major natural disaster (e.g. tornado and major ice storm). OH will have the sole discretion in determining the timing of this transfer.

7. Any litigation and/or damage claims arising from incidents relating to or caused by the Feeders as extended, or the actions or negligence of the PUC with respect to the operation and maintenance thereof will be the sole responsibility of the PUC and the PUC agrees to indemnify and save harmless OH therefrom.

Accepted By:

Ontario Hydro

[redacted]

Bob Coghlan
Manager - Western District

Date: Sept 19, 1997

St. Thomas PUC

[redacted]

Denis Iwancewicz
President & CEO

Date: Sept 15, 1997

Agreement For Supply Facilities - [redacted]
Two Dedicated 27.6 kV Feeders

This letter sets out the agreement between Ontario Hydro ("OH") and St. Thomas PUC (the "PUC") with respect to the supply of power to the occupants (the "Customer") of the Michigan Blvd. property on which it is proposed a truck frame facility will be built [redacted]

Subject to Ontario Hydro obtaining all requisite internal and governmental or statutory approvals and conditional upon OH reaching a satisfactory power supply agreement with the Customer, the parties agree that OH may supply the Customer with power and the PUC waives any and all rights it may have to supply the Customer, on the following terms and conditions:

1. The PUC will construct and own two dedicated 27.6 kV feeders (the "Feeders") to be in-service on or about September 1, 1997 from the St. Thomas Edgeware TS to the property line at the [redacted] This will include any potheads and underground cable at St. Thomas Edgeware TS and suitable loops for connecting to the portion of the feeders within [redacted] which is being constructed by Ontario Hydro. St. Thomas PUC will maintain the feeders from St. Thomas Edgeware TS to the 27.6 kV switchgear within [redacted] All planned maintenance within the [redacted] will require prior approval by Ontario Hydro. The servicing of any other customers from the Feeders shall be at Ontario Hydro's discretion.

2. The engineering details of the Feeders are subject to Ontario Hydro approval. Any modifications to the Feeders are subject to Ontario Hydro approval.

3. A Four Thousand Nine Hundred and Sixty Eight ($4,968.00) Dollar monthly rental and maintenance fee will be charged by the PUC to OH for the use of the Feeders until December 31, 2007. The PUC will bill OH in the first quarter of each year for the number of months the circuits were used by OH to service the Customer the previous year minus any damages as detailed below. The monthly rental fee will be adjusted by an amount equal to the difference between actual construction costs and the estimated cost amortized over 300 months. The rental and maintenance fee of Four Thousand Nine Hundred and Sixty Eight ($4,968.00) Dollars is based on estimated construction costs of Six Hundred and Sixty One Thousand, and Eight Hundred ($661,800) Dollars and maintenance costs.

4. From January 1, 2008 to December 31, 2017 the PUC will make the Feeders available to OH for supply to the Customer at a monthly rental fee reduced by $300.00 and adjusted by a reasonable amount for actual changes in maintenance costs for the feeders, if appropriate, taking into account that from January 1, 2008 maintenance of the 27.6 kV feeders within [redacted] will be the responsibility of the customer. OH shall have the option to purchase the Feeders from the PUC with appropriate land rights at book value on January 1, 2018.

5. Reliability of service is of paramount importance to the Customer. The PUC agree that any loss of integrity to either of the Feeders or the extensions thereof located on [redacted] will receive immediate attention by the PUC. If the Customer loses supply from the Feeders, as extended, for more than one minute due to their integrity the PUC will pay to OH for each such episode an amount equal to the monthly rental and maintenance fee in effect at the time, which amount is not a penalty but represents a genuine pre-estimate of damages.