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BY EMAIL AND RESS

June 2, 2023

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

Dear Ms. Marconi,

EB-2022-0178 - Entegrus Powerlines Inc. Application for a Service Area Amendment – Hydro One Networks Inc. Interrogatory Questions

In accordance with Procedural Order No. 3, please find attached Hydro One Networks Inc. interrogatory questions to Entegrus Powerlines Inc. in the aforementioned proceeding.

In accordance with previous determinations on the same, Hydro One respectfully request the following information be kept confidential pursuant to Rule 10.01 of the Board's Rules of Practice and Procedure and consistent with the Board's Practice Direction on Confidential Filings revised December 17, 2021:

Information	Specific Page(s) Redacted	Presumptive Confidential Category
Non-public information about a specific customer's load profile	Page 19, Line 4,6,7,15,18,19,31,38,39 Page 20, Line 5,and 40 Page 21, Line 9, 25,26,27	Information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information

A redacted electronic copy of these interrogatory questions has been submitted using the Board's Regulatory Electronic Submission System for public use.

A confidential unredacted version of these interrogatory questions has also been supplied to the OEB in accordance with the OEB's Practice Direction on Confidential Filings.

Sincerely,

Joanne Richardson

ENTEGRUS POWERLINES INC.
Application for Service Area Amendment

Hydro One Networks Inc. Interrogatories
June 2, 2023

HONI-1:

Reference:

1. "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." - Application, p. 3

Interrogatory:

a) Please confirm that the Subject Area was never in the service territory of either Entegrus or the former St. Thomas Energy Inc. ("**STEI**") since the Ontario Energy Board commenced issuing distribution licences i.e., the Subject Area has always been listed as an exclusion in the current Entegrus and STEI Distribution Licence. If not confirmed, please provide a copy of the OEB issued distribution licence that includes the Subject Area in the service area of the Applicant.

HONI-2:

Reference:

1. "Entegrus owns and maintains the feeders that serve the Customer and thereby continues to act as the physical distributor." Application, page 3
2. 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) - Hydro One Intervenor Evidence – Attachment 3 – April 17, 2023

Interrogatory:

a) Please confirm that Entegrus' position of "owning" the Feeders is predicated on the language of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum). If not confirmed, please provide an explanation on what basisEntegrus advances that it owns the Feeders.

b) Please provide a breakdown of the costs that have been incurred by Entegrus, the previous STEI and the former St. Thomas PUC to construct the Feeders. Please provide a breakdown of the costs thats have been incurred by Entegrus, STEI and the former St. Thomas PUC to maintain the Feeders. Please confirm how much of these costs have been recovered to date from current Entegrus ratepayers (or the previous

STEI's and St. Thomas PUC ratepayers). In so doing, please address where these costs can be found in any Entegrus or STEI revenue requirement application.

HONI-3:

Reference:

1. "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." – Application, p. 3

Interrogatory:

a) Please explain in detail what existing utility need the Feeders serve, i.e., are the Feeders currently required to serve Entegrus' existing customers in St. Thomas?

b) With respect to the OEB's Filing Requirements for Electricity Distribution Rate Applictaions, please provide Entegrus' materiality threshold.

HONI-4:

Reference:

1. "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)." – Application p. 4

2. "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)." – Application p. 16

3. Figure 5-2 – Application p. 15

4. 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.--Application p. 14

5. “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.” – Application p. 21

6. “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.” – Application p. 28

7. Figure 5-3 – Application p. 22

8. Attachment 2, Figure B – Entegrus’ Supplementary Evidence

9. Table 6-1: Comparison of Costs (Savings) – Application p. 27

10. “As shown in Attachment 2, in this scenario, Entegrus deploys an intelligent system featuring reclosers on the M7 and M8 feeders, to feed a common line to tie in to the Entegrus system. The reclosers would be configured to dynamically select (with appropriate controls) the lower utilized feeder to supply additional St. Thomas customers.” - Entegrus Supplementary Evidence p.4

11. Figure A - Entegrus Supplementary Evidence, Attachment 2

12. Section 4.3 of Hydro One Intervenor Evidence, p. 24

<u>Interrogatory:</u>

a) Please provide all Entegrus SAIDI and SAIFI data since 2017. Similarly, please provide the SAIDI and SAIFI data for the area limited to the former STEI service territory.

b) Please explain in detail why there is an immediate term (i.e., 2023) need if the St. Thomas system design capacity has been exceeded since about 2018.

c) Please provide information regarding the forecast load growth utilized in Figure 5-2. Specifically, please provide information on any real customers (i.e. non-coincident peak load per customer and connecting feeder) that have requested a connection to Entegrus' distribution system that supports the forecast growth, and information on the capital contribution(s) these customers have made towards addressing such capacity needs.

d) Please confirm that the demand forecast provided in Figure 5-2 does not contemplate the Customer's demand and does not accommodate any change in forecast demand for the Customer over the time horizon.

e) Please discuss in detail and elaborate on what Entegrus will do if the transfer of the Feeders, once the Customer's load is accounted for, will not provide Entegrus with 14MW of design capacity. Please outline and discuss what alternatives have been considered and when those alternatives can be implemented.

f) Please clarify if the growth rate sensitivity range is 3.36%/year to 5.36%/year based on the historical growth rate of 3.86% between 2017 and 2021.

g) Please describe and provide any documentation demonstrating what reliability and quality of service impacts will be faced by Entegrus' distribution system and the Customer when one feeder is unavailable and the other feeder would need to run at maximum capacity as described in Reference 5.

h) With respect to Reference 5, please detail the scope, schedule and cost of the additional tie-in to other existing nearby Entegrus assets that would further enhance reliability for both the Customer and other Entegrus customers.

i) With respect to Reference 5 and the evidence that further enhancements to reliability could be experienced, please confirm that the evidence is relative to the currently contemplated Entegrus proposal and not the reliability the Customer currently enjoys with Hydro One. If not confirmed, please detail how the Entegrus proposal will enhance reliability beyond the reliability levels currently enjoyed by the Customer.

j) Please address the inconsistency between Entegrus' evidence at Reference 6 and Entegrus' evidence in Reference 5 that 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.

k) With respect to Reference 4, please provide the longest period that Entegrus has needed to utilize emergency capacity. Please provide details as to when these events occurred and what triggered the event.

l) With respect to Reference 8, please clarify what is meant by *Assets Included in the Application.* Please confirm whether the cost associated with all these *"Assets Included in the Application"* has been included in the cost table provided at Reference 9. If not, please update the Table to reflect this cost.

m) With respect to Reference 8, please clarify what is meant by *New Supply to Entegrus Customers.* Please confirm whether the cost associated with the *"New Supply to Entegrus Customers"* has been included in the cost table provided at Reference 9. If not, please update the Table to reflect this cost. Please also detail the scope and schedule of these new facilities.

n) Please clarify if the intelligent reclosers in Reference 10 are the same as those in Reference 5. If not, please provide the costs for the intelligent reclosers.

o) Please clarify the discrepancy between Reference 5 and Reference 11 as to the number of reclosers required. Please provide the same for Reference 5 and 10.

p) Please clarify if there will be load connected between the 3 reclosers as per Reference 3. Please provide a map of this feeder expansion along with the customer connections, if any.

q) Please provide the costs of this feeder expansion.

r) Please update the costs identified Reference 9 in the column entitled *Entegrus Services the Customer and Accesses Additional Capacity of Table 6-1* of the Entegrus Application to show all forecast costs documented in Reference 12.

s) Please update Reference 9 to include the cost of the additional reclosers, feeder expansion costs, per annum LTLT mitigation costs, and any other costs not currently considered in the initial Application that Entegrus may consider necessary.

HONI-5:

Reference:

1. "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." – Application p. 5

Interrogatory:

a) Please confirm that Entegrus has never filed a compliance complaint with the OEB regarding this alleged outstanding LTLT despite taking over STEI in 2018.

b) Please confirm that this connection has never been settled as an LTLT. If Entegrus takes the position that it has, please provide all documentation that reflects that type of settlement arrangement.

HONI-6:

Reference:

1. "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." – Application p. 10

2. "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." - Application p. 10

Interrogatory:

a) Please confirm that strong load growth or a change in load growth in St. Thomas, is not a term in the agreement which would permit Entegrus, or its predecessors, to resile from the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum). If Entegrus disagrees, please identify the term(s) in the agreement that supports the position that it can.

b) With respect to Reference 2, please confirm that it is equally plausible that STEI and Hydro One did not consider that the 1997 Supply Facilities Agreement (which for greater certainty, includes the May 29, 1998 Addendum) was not frustrated by the OEB's December 2015 Distribution System Code Amendments.

c) Hydro One does not recall that STEI showed any reluctance in respect of the sale of the M7 and M8 feeders once Hydro One agreed that STEI could keep the poles and that Hydro One would enter into a joint use arrangement with STEI for the Feeders. With respect to Reference 1, please provide evidence supporting the supposition that there was reluctance.

HONI-7:

Reference:

1. "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." - Application p. 10

2. "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)" – Application p. 24.

Interrogatory:

a) Please provide any jurisprudence relied upon to support Entegrus' position that that the commercial agreement, namely, the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) has been frustrated by the issuance of the DSC amendments referenced.

b) Please discuss how the treatment of the Customer in EB-2017-0192 as jointly filed by Hydro One and STEI. and consented to by these parties, can be resiled from if the OEB finds the 1997 Supply Facilities Agreement has not been frustrated.

c) Please confirm that applicability of a s.86 (1)(b) application to sell or lease an asset is the responsibility of the divesting or leasing distributor not the purchaser or lessee of such assets.

d) Please discuss Entegrus' position with regard to any amounts owing to Hydro One and its ratepayers in the case where the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) is not complied with, including Hydro One's right to be made whole in a civil recovery for the payments under the agreement. If it is Entegrus' position that no amounts would be owing to Hydro One, please explain why.

HONI-8:

Reference:

1. "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." - Application p. 11

Interrogatory:

a) Please confirm that the further in-depth analysis referenced in the extract occurred more than three years after Hydro One had exercised the option to purchase these facilities.

HONI-9:

Reference:

1. "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?" - Application p. 11

Interrogatory:

a) Please confirm whether these assets currently reside in Entegrus' rate base.

b) Please confirm and provide documentation demonstrating how Entegrus and its predecessor, St. Thomas Energy Inc. reported the revenue collected from Hydro One under the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) in OEB-approved rates.

HONI-10:

Reference:

1. "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)." - Application p. 12

Interrogatory:

a) Please explain why the first invoice related to the purchase of the facilities was just for the conductor and not the poles. In so doing, please confirm that this is a deviation from the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) and address in the response why Entegrus invoiced just that amount?

b) Please confirm that Hydro One's (and its predecessor, Ontario Hydro's) leasing cost was predicated on the St. Thomas PUC's cost to construct the M7 and M8 which included the poles and conductor in accordance with the terms of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum). If Entegrus disagrees, please explain why and provide the documentation it seeks to rely on to support how the leasing cost was arrived at.

c) Please confirm why the second invoice (related to charges for Hydro One feeder use in 2018-2020) was refunded? Did that invoice also require OEB approval? Please provide a copy of both refunded invoices for the purposes of completing the record.

d) Please provide a copy of the Entegrus 2021-2025 DSP.

HONI-11:

Reference:

1. "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." - Application p. 12-13

Interrogatory:

a) Please confirm that the onus to prove frustration of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) rests with Entegrus.

b) If the contract is not frustrated, please confirm that pursuant to the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) Entegrus is obligated under the terms therein to complete the transfer of ownership as HONI exercised its option to purchase in 2017. If Entegrus disagrees, please explain why and on what grounds it maintains a refusal to transfer ownership.

HONI-12:

Reference:

1. "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... 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."- Application p. 15-16

2. "In many cases, the interests of the individual customer will align with the interests of other customers, and the system as a whole. Each market participant must accept the interdependence which is fundamental to the system. Each participant has a right to expect that others engaged in the same system meet their respective costs, without subsidization or penalty. That is as true for new customers as it is for others." – Para. 230 – OEB Decision with Reasons, RP-2003-0044

Interrogatory:

a) Please clarify/elaborate on how transferring the directly impacted Customer is advantaged by the Entegrus system with respect to reliability and quality of service?

b) Please clarify how the Entegrus proposal is consistent with the OEB statement provided at Reference 2.

c) Please confirm if Entegrus has identified the limitations in Reference 1 when applying for recent SAAs? If not, please elaborate why not?

d) Please clarify/elaborate why Entegrus has pursued new connections in Hydro One service territory despite the capacity constraints and potential reliability concerns outlined in Reference 1?

HONI-13:

Reference:

1. "Entegrus is not billed for these two additional, separate breakers associated with the Entegrus M7 and M8 feeders."- Application p. 14

Interrogatory:

a) Please discuss who Entegrus understands is billed for these separate breakers.

HONI-14:

Reference:

1. "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)"- Application p. 16

2. Hydro One recently indicated that this 5 MW of capacity is allocated to Entegrus. To date, Entegrus has not utilized any of this capacity.-Application p.19

Interrogatory:

a) Please confirm that Entegrus never accepted and/or utilized this available capacity offer from Hydro One and therefore there is no contracted capacity for Entegrus on the M8 breaker position.

b) Please confirm why, to date, Entegrus has not utilized any of the capacity that was offered despite exceeding its system max design capacity since 2018?

c) Please clarify whether the 5MW of design capacity would assist with meeting Entegrus' imminent needs. If the amount is insufficient, please articulate what other investments will be required by Entegrus to address the imminent (2023) needs described in the Application. Please provide any analysis or study Entegrus has taken to address this need aside from what is already in evidence.

HONI-15:

Reference:

1. "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". - Application p. 17

2. Table 5-1 – Application p. 17
3. "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." – Application p. 17

4. "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." – Application p. 18

5. "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." – Application p. 18

Interrogatory:

a) Please confirm that Entegrus and/or STEI and/or St. Thomas PUC received payment for the construction of the Feeders in accordance with the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum).

b) Please confirm that the terms and conditions of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) specify the monthly leasing costs and purchase option cost of the Feeders (including the poles).

c) Please clarify whether Entegrus is of the opinion that all of the other terms and conditions of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum) would have remained unchanged if the purchase option was ultimately to be "replacement cost" rather than "net book value" as currently defined by the 1997 Supply Facilities Agreement.

d) Please clarify that the cost of the additional breaker position and all other costs associated with Edgeware TS in Scenario 1 would be paid to Hydro One Transmission, i.e., the transmitter that owns Edgeware TS, not Hydro One Distribution.

e) Please confirm that Entegrus' ownership position of the Feeders is predicated on the terms and conditions of the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum).

HONI-16:

Reference:

1. "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…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." – Application p. 19

2. Table 5-2 – Application, p.19

3. “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.” – Application, p. 19-20

Interrogatory:

a) Please confirm that the rates documented in Table 5-2 are Entegrus’ understanding of OEB-approved charges for the services being requested by Entegrus of Hydro One Distribution in this scenario.

b) Please confirm, that with respect to the comparison provided at Reference 3, Entegrus has never provided Hydro One with any capacity. In other words, please confirm, Entegrus is not, and has never been, a host distributor to Hydro One on these Feeders.

c) Please clarify the rationale for including the Deferred Tax Asset Vol. Rider in Table 5-2.

HONI-17:

Reference:

1. “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.” - Application p. 22

2. “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.” – Application p. 24

Interrogatory:

a) Please clarify whether “potential public confusion” is limited to the distributors that are parties to this proceeding and the Customer. If not, please provide instances of potential public confusion beyond the aforementioned parties.

b) Please confirm that if Entegrus divested the Feeders in accordance with the 1997 Supply Facilities Agreement (which for greater certainty, includes, the May 29, 1998 Addendum), that would also eliminate the potential public confusion and reduce an unnecessary layer of coordination between Entegrus and Hydro One.

<u>HONI-18:</u>

<u>Reference:</u>

1. "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." – Application p. 28

2. "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." – Application p. 29

3. "Entegrus anticipates that no mitigation is required, as Entegrus believes that the Customer would enjoy a distribution rate benefit if this Application were approved." – Application p. 30

4. "…Entegrus could not confirm which Hydro One rate class the Customer resided in and did not anticipate that the Customer would reside in the Hydro One Sub-Transmission rate class based on Entegrus' understanding that the rate class requires that a customer be connected to Hydro One-owned assets." – Entegrus Letter Regarding Description of Supplementary Evidence – p. 3
5. Hydro One Intervenor Evidence, Section 3.1.1.1 –p.20

<u>Interrogatory:</u>

a) Hydro One understands, based on Reference 4, that Entegrus erred in its understanding of the rate class the Customer qualifies for and Hydro One accepts that Entegrus could not confirm this with the Customer directly given it has no relationship with the Customer to be able to contact them in accordance with the DSC. Accordingly, please update References 1 through 3 of the Entegrus Application to account for the impacts to the Customer and all other Entegrus customers based on the mitigation that is necessary for Entegrus to serve the Customer.

b) With respect to References 1 through 4, please confirm that Entegrus is not licenced by the OEB to *own* these Feeders.

HONI-19:

Reference:

1. "Hydro One asserts that the facts show that the Customer is not served by an LTLT, and section 6.5.3 of the Distribution System Code ("DSC") does not apply. Hydro One further states that the parties have not treated the arrangement as an LTLT, as evidenced by the fact that it was not included in the 2017 Joint LTLT elimination application from Hydro One and St. Thomas Energy ("STEI"). Load transfers were described in the Combined Proceeding on SAAs. In the Decision in that case, the OEB noted that "Load transfers are arrangements whereby an incumbent distributor permits an adjacent distributor to serve a load located in the incumbent's service territory." That is exactly the case here." – Entegrus Supplementary Evidence p. 8

2. "Because of the LTLT, Entegrus customers are being deprived of a benefit and will have to incur the consequences of additional costs for new capacity to serve St. Thomas. That capacity requirement is imminent, with the recent Volkswagen announcement20. For instance, Entegrus recently received a request from a St. Thomas customer for significant additional capacity. Effectively, the Entegrus assets are providing service for the Customer, yet the LTLT is preventing those assets from being fully utilized for all St. Thomas customers." - Entegrus Supplementary Evidence p. 8

3. "Entegrus is not aware of why the Customer load transfer was not historically billed through STEI, nor why the parties did not include the LTLT in the 2017 Joint LTLT application. There are no management representatives of STEI still working with Entegrus to be able to provide such information. However, that does not change the fact that this is a load transfer, and under section 6.5.3 of the DSC the OEB has directed parties to eliminate load transfers. No requirement is included in the DSC that a load transfer must always be billed by the local distributor on behalf of the physical distributor." - Entegrus Supplementary Evidence p. 9

4. "Hydro One also points to a 2004 decision of OEB Market Operations, which held that the 1997 Letter is a lease agreement that was not impacted by section 26(3) of the Electricity Act. 22 The implication is that it is also unaffected by the LTLT elimination rules. While Entegrus had not been aware of this decision, its position is unchanged. The 1997 Letter is inextricably linked with the load transfer arrangement. As of 2015, distributors are required to eliminate load transfers – this means that the commitments in the 1997 Letter Agreement cannot be completed. The direction to eliminate LTLTs came much later than the 2004 decision cited by Hydro One[23] and does not appear to have been a factor under consideration." - Entegrus Supplementary Evidence pp. 9-10

5. Hydro One Supplementary Evidence, Attachment 1 (July 2000 DSC) and 2 (Notice of Proposed Amendments to the DSC issued February 2015).

6. Retail Settlement Code, section 3.2 – July 1, 2022

<u>Interrogatory:</u>

a) With respect to Reference 2, please confirm where the St. Thomas customer that made a request for significant additional capacity is sited and whether Entegrus is stating that they cannot connect the customer. Please clarify whether Entegrus is outlining that it cannot serve new customer connection requests and whether Entegrus has reached out to Hydro One to determine whether Hydro One could service this other potential connection.

b) With respect to Reference 1 and 2, please elaborate on how the supposed LTLT is preventing those assets from being fully utilized for all St. Thomas customers. In so doing, please clarify Entegrus' position of how asset ownership is prohibiting and/or limiting a customer connection.

c) With respect to Reference 3, the DSC defines geographic distributor as "with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer" . This definition has not materially changed since the release of the initial DSC, provided at Reference 5. Please provide any examples of an LTLT that Entegrus is aware of that a load transfer customer was not billed by a geographic distributor and then settled between distributors.

d) With Respect to Reference 3, please address whether Entegrus has received information whether oral or in writing to explain why the Customer load transfer was not historically billed through STEI from non-management STEI or Entegrus employees and if applicable, to provide same.

e) With respect to Reference 3, please address whether Entegrus has received information whether oral or in writing to explain why the parties did not include the LTLT in the 2017 LTLT application from non-management STEI or Entegrus employees and if applicable, to provide same.

f) With respect to Reference 6 as well as Entegrus' position that this connection is an LTLT, please provide all documentation that supports that this connection has been accounted for as an LTLT in Entegrus' (and the former STEI's) in compliance with the Retail Settlement Code.

g) Based on Reference 5, please clarify whether Entegrus' position remains the same as that documented in Reference 4 with respect to its supposition that the direction to eliminate LTLTs was not a factor in the OEB's 2004 decision regarding this connection because the direction to eliminate LTLTs was provided in 2015.

HONI-20:

Reference:

1. "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." – Application p. 4

2. "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" - Application p.10

Interrogatory:

a) Please clarify Entegrus' position as to why Entegrus has always been the physical distributor when the Feeders were rented to Hydro One with the condition that Hydro One had the option to own the feeders at the end of the term of the lease agreement.

HONI-21:

Reference:

1. "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." - Application p. 13

Interrogatory:

a) Please confirm if Entegrus has made a comparison with Hydro One on the use of these distribution resources? If not, please explain how Entegrus concludes this would be the most efficient use of existing distribution resources.

HONI-22:

Reference:

1. "The design intent of being able to supply the Customer [redacted] is supported by the documentation filed by the Customer and the Customer's claims7. As constructed, the feeders feature materials with a safe operating rating [redacted] without equipment degradation, which is significantly higher than Entegrus' initial assessment." - Entegrus Supplementary Evidence p. 2

2. "Hydro One assumes that Entegrus planning capacity is 14 MW. This is too low in terms of how the M7 and M8 feeders were constructed. The use of 14 MW planning capacity in the Application was due to the limited information available to Entegrus at the time the Application was filed and was based on recent feeder construction practice. It is now known that the M7 and M8 feeders built by the St. Thomas PUC in 1997 each have a safe operating rating [redacted], and thus a higher planning capacity than the originally stated 14 MW." -Entegrus Supplementary Evidence p.3

3. "Further, after leaving a 10% contingency [redacted] in the remaining safe operating rating to cover load increases or an abnormally high peak, [redacted] remains, which Entegrus asserts is available capacity for all St. Thomas customers." - Entegrus Supplementary Evidence p.4

4. Table 3-1 - Entegrus Supplementary Evidence p.4

5. Table 3-2 - Entegrus Supplementary Evidence p.5

6. Figure 5-2 – Application p.15

Interrogatory:

a) Please identify the specific statements and documents in evidence that supports the [redacted] capacity of these feeders? Please also confirm this referenced value is what Entegrus assumes is the "safe operating rating" and not the "planning capacity" of the facilities.

b) Please specify what Entegrus supposes the safe operating rating value for the M7 and M8 feeder.

c) Please specify the feeder materials being referenced in the assertion that [redacted] would not cause equipment degradation.

d) Please confirm that Entegrus had built these feeders? If so, why was Entegrus unaware of the feeder ratings in its initial application?

e) Please confirm that Entegrus made the statement that Entegrus' planning capacity was 14MW in the application and therefore not an assumption made by Hydro One.

f) Please clarify/elaborate how the M7 and M8 feeders differ from the other Entegrus' feeders which have a 'planning capacity' of [redacted] and 'safe operating rating' of [redacted]

g) Please confirm reference 6 uses "planning capacity" for the feeders.

h) Conversely, it appears that Reference 3, 4 and 5, utilize the "safe operating rating" of the feeders. Please confirm, and, if so, please clarify why it is appropriate to use "safe operating rating" of the feeders for Reference 3, 4 and 5. Please update Reference 3, 4 and 5 based on the "planning capacity" of the Feeders.

<u>HONI-23</u>

<u>Reference:</u>

1. "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." - Application p.15

2. "For Entegrus, planning capacity represents 50% of the "safe operating rating" of the equipment as defined by the manufacturer. This definition of planning capacity has been adopted widely within the industry as a way to allow operational flexibility and to ensure adequate capacity […] is available in adjacent feeders to quickly restore customers during unplanned outages." - Entegrus Supplementary Evidence p.1

3. "In this scenario, an additional downstream recloser is added (total of four) to allow load to be connected to the M7 and M8 feeders independently. This results in enhanced utilization of existing Entegrus assets for the purposes of Customer supply resiliency by providing two additional alternate supplies (rather than one alternate supply in Attachment 2, Figure A). The updated connection alternative is presented at Attachment 2, Figure B. This allows Entegrus to backfeed the M7 and M8 simultaneously, providing two alternate feeds to the Customer and mitigating a double M7 and M8 failure, which accordingly increases the reliability." - Entegrus Supplementary Evidence p.5

4. "Entegrus can connect between [redacted] to [redacted] (column c and d in Table 3-2) while meeting current customer capacity requirements and remaining within safe operating rating of the feeders." - Entegrus Supplementary Evidence p.5

Interrogatory:

a) Please describe the capability of Entegrus Distribution feeders to take additional new load on the proposed connection to the M7 and/or M8, when, on average, the existing Entegrus Distribution feeders have already exceeded their design capacity of 14MW per feeder.

b) Given current constraints, please elaborate on how the safe operating rating of Entegrus Distribution feeders is maintained under 28MW if connecting an additional [redacted] to [redacted]

HONI-24:

Reference:

1. Attachment 3 – Entegrus Supplementary Evidence

Interrogatory:

a) Please provide a live excel document of this Attachment.

b) Please provide a source (rate order and corresponding page) for all line loss rates utilized in the rate comparison completed.

c) Please describe how and why the loss rates have been applied in the manner proposed in the reference.

[redacted]

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