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November 10, 2017

Ms. Kirsten Walli
Ontario Energy Board
PO Box 2319
27th Floor, 2300 Yonge Street
Toronto, Ontario M4P 1E4

Re: Section 86 MAAD Application of Entegrus Powerlines Inc. and St. Thomas Energy Inc.
Board File No.: EB-2017-0212

Dear Ms. Walli,

Please find enclosed the Entegrus Powerlines Inc. ("EPI") and St. Thomas Energy Inc. ("STEI") responses to Board Staff interrogatories in the above-noted matter.

Pursuant to Procedural Order No. 1, the scheduled response date for the interrogatories is November 22. On November 3, the Applicants wrote to the Board and suggested an expedited interrogatory process (see enclosure). The Applicants are appreciative that Board Staff provided the interrogatories prior to the scheduled November 8 date. Early receipt of Board Staff's interrogatories has, in turn, allowed the Applicants to provide early response, attached.

It is hoped that these schedule savings will allow for submissions to be completed in the coming weeks. The Applicants will make every effort to provide their closing submissions as soon after receipt of Board Staff's submissions as reasonably possible, in the hopes of allowing for a decision to be issued in this matter as soon as possible.

If you have any questions, please do not hesitate to contact us.

Sincerely,

[Original Signed by]	*[Original Signed by]*
______________________________	______________________________
David Ferguson	Rob Kent
VP of Regulatory and Human Resources	Chief Operating Officer
Entegrus Powerlines Inc.	St. Thomas Energy Inc.
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cc: Jim Hogan, President & CEO – Entegrus Powerlines Inc.
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GOWLING WLG

November 3, 2017

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VIA RESS AND COURIER

Ms. Kirsten Walli
ONTARIO ENERGY BOARD
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0212: MAADs Application by St. Thomas Energy Inc. and Entegrus Powerlines Inc.

Procedural Timing

We write as counsel to the applicants herein.

The MAADs application was filed on July 21st. The Notice of Hearing was issued about a month later (August 31st). An intervention period followed, with one request for intervention (by Capredoni Enterprises Ltd.) to which the applicants filed a response on September 10th. Procedural Order No. 1 herein was issued about a month and a half later; on October 25th.

Given the passage of time since the MAADs application was filed, the applicants are now concerned about the commercial and transaction financing impact of a decision date beyond mid-December. Traditionally most non-controversial OEB MAADs applications have taken between 3.5 and 4.5 months from application filing to decision, and the applicants accordingly planned on the basis that the 5 plus month time period between filing and year end would likely be sufficient. The applicants do understand that an appropriate process for consideration and determination of this application is required, that internal Board schedules must also be factored in, and that the intervention request in this instance presented some unique issues.

To attempt to address, to the extent possible, timing issues, the applicants will make every effort to respond to interrogatories received as quickly as possible, and prior to the scheduled response date of November 22nd. To the extent that Board Staff could provide some, even if not all, of its interrogatories in advance of the scheduled November 8th filing date, that could assist the applicants in expediting their responses.

We would also ask that the Board retain for now as much flexibility as it can in respect of further scheduling in this matter, so that if through one or both of the foregoing measures time can be shaved off of the discovery process (without sacrificing the robustness of the discovery), submission dates can be set to be as expeditious as possible.

We would appreciate the Board's co-operation in this respect.

Yours truly,

Ian A. Mondrow

c: D. Ferguson (Entegrus Powerlines Inc.)
R. Kent (St. Thomas Energy Inc.)
J. Fernandes (OEB Staff)

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POWERLINES INC.

St. Thomas energy inc.
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MAAD IR Responses

EB-2017-0212

Filed: November 10, 2017

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LIST OF ATTACHMENTS

A. Table of Specific Charges for EPI & STEI

(provided by Board Staff in reference to IR 1-Staff-18)

1-STAFF-1

Ref: Section 3.1.1.4, p.12

The applicants state that Entegrus Powerlines last rebased its distribution rates effective May 1, 2016 (EB-2015-0061) under the Price Cap Incentive Rate (PCIR) methodology.

a) Please confirm that Entegrus Powerlines 2016 application rebased distribution rates through a cost of service (CoS) approach. In the alternative, please explain.

Response

a) Confirmed.

1-STAFF-2

Ref: Section 3.1.2.4, p.14

The applicants state that St. Thomas Energy last rebased its distribution rates effective January 1, 2015 (EB-2014-0013) under the Price Cap Incentive Rate (PCIR) methodology.

a) Please confirm that St. Thomas Energy Inc.'s 2015 application rebased distribution rates through a cost of service (CoS) approach. In the alternative, please explain.

Response

a) Confirmed.

1-STAFF-3

Ref: Section 4.1, p.19

It is stated that the merger agreement contemplates the transaction closing effective January 1, 2018, subject to the applicants receiving OEB approval.

a) Please confirm whether this is the date on which the applicants expect to operate as a merged entity under the Entegrus Powerlines electricity distribution licence.

b) Please explain what, if any, implications there are if the OEB decision in this application is not rendered in time to enable the transaction to close effective January 1, 2018.

Response

a) Confirmed.

b) The January 1 closing date was chosen in order to achieve the most efficient and cost-effective transition possible. If the OEB decision in this application is not rendered in time to enable the transaction to close effective January 1, 2018, these efficiencies would not be realized. Further, the January 1 closing date has been externally communicated by the media and stakeholders, and a delay in closing could raise external communications issues. The impacts of a delayed closing include:

   i. The potential for customer and community confusion around the merger date.

   ii. The potential for employee morale and uncertainty concerns. The merger is the culmination of a commercial process that commenced in the summer of 2016. Particularly for STEI employees, the journey has been a long one. The combined resources of the merged entity will assist in balancing work load in STEI and EPI. Both groups of employees are looking forward to working together as one team.

iii. Additional financial compliance work and related costs. A transaction close non-coincident with December 31 year end will result in another deemed year end for tax purposes which will trigger multiple taxation years and associated income tax filings in 2018. The following financial reporting and tax compliance will be required:

- EPI existing – stub period Jan1 – close,
- STEI existing – stub period Jan 1 – close, and
- EPI merged – close – December 31.

This will also require segregation of the budgets into stub period components. In addition, a special purpose financial statement for the period January 1 to December 31 will be required for internal management reporting purposes.

iv. The over collection of CPP and EI premiums from former STEI employees in 2018, as well as over remittance by the Applicants. If there is a 2018 stub period for STEI, former STEI employees would have multiple employers in 2018 and income tax regulations would require separate calculation of annual CPP and EI premium contribution caps, resulting in higher contribution levels for affected employees than would be the case with a January 1, 2018 employment transition date.

v. Increased administrative complexity, including duplicative filings, related to items like OMERS, T4 reconciliations, etc.

vi. Increased reporting complexity for benchmarking (including all scorecard measures).

vii. Added complexity for annual and quarterly RRR reporting between the two companies, creating a lack of comparability between past and future reporting. This will result in additional internal management reporting for the use of the data in future applications. In addition, depending on how the statistics are reported in RRR submissions, it will impact the utilization of these statistics in future applications and tracking requirements.

viii. The potential for added complexity in completing the monthly IESO RPP settlement requirements as well as the subsequent true-up requirements and tracking. This will occur because the IESO will rename the existing STEI portfolio as a subcategory of EPI, subsequent to the close. If the closing date is not a calendar month end, an IESO stub period will therefore occur.

ix. Additional confusion for vendors and a cascading impact to their resourcing commitments to support transition projects, as well as future system enhancements. Currently, many vendors have committed to have key mutual systems harmonized and operational, including a common IT network, by January 1.

1-STAFF-4

Ref: Section 4.2.1, pp.19-20

Section 4.2.1 of the application sets out a list of regulatory approvals requested by the applicants.

a) Please confirm whether the applicants also seek the amendment of Entegrus Powerlines' electricity distribution licence under section 74 of the Act to incorporate St. Thomas Energy's service area.

Response

a) Confirmed.

1-STAFF-5

Ref: Section 5.1.1.1. page 23

a) Please provide the data shown in graphical format in Table 3 in the following tabular format:

Year	Status Quo			Merged	Variance
	EPI	STEI	EPI + STEI	EPI + STEI	
	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(4)-(3)
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					

b) Please confirm that, for the purposes of this analysis, the applicants assumed that:

i. St. Thomas Energy would rebase in 2020 and 2025 under "Status Quo"

ii. Entegrus Powerlines would rebase in 2021 and 2026 under "Status Quo"

iii. The merged entity would rebase only in 2026.

c) Please provide the expected revenue requirement increases for each of the rebasing applications and the high level factors assumed to drive these increases.

d) Please identify the price cap index rate changes assumed for each rate year from 2017 to 2026 as shown in Table 3.

Response

a) Please see the table below for the requested data:

Year	Status Quo			Merged	
	EPI	STEI	EPI + STEI	EPI + STEI	Variance
	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(4)-(3)
2017	$18.2	$7.3	$25.5	$25.5	$0.0
2018	$18.5	$7.4	$25.9	$25.9	$0.0
2019	$18.9	$7.6	$26.5	$26.5	$0.0
2020	$19.2	$7.9	$27.1	$26.9	-$0.2
2021	$20.0	$8.0	$28.0	$27.3	-$0.7
2022	$20.3	$8.2	$28.5	$27.8	-$0.7
2023	$20.7	$8.3	$29.0	$28.3	-$0.7
2024	$21.0	$8.4	$29.4	$28.8	-$0.6
2025	$21.4	$8.8	$30.2	$29.2	-$1.0
2026	$22.2	$8.9	$31.1	$30.0	-$1.1

** The amounts shown in the above table are rounded.*

b)

i. Confirmed.

ii. Confirmed.

iii. Confirmed.

c) An expected rebasing revenue requirement increase assumption of 4.0% was used for the status quo rebasing scenarios, based upon a review of recently approved OEB rate rebasing revenue deficiencies. For the 2026 merged rebasing scenario, an approximate 3.5% rebasing increase assumption was used, which reflects the 4% rebasing increases assumption less the impact of synergies. Rebasing revenue requirement increases are consistent with the experience and expectations of the Applicants regarding the expanding role of LDCs in the implementation of government and regulatory policies such as flexible rate plans, net metering, enabling electric vehicles, etc., and the similar anticipated evolution of the roles and responsibilities of LDCs in the future.

d) The price cap increases assumed under both the status quo and merged scenarios are as follows:

- STEI 2017-2018 = 1.60%;
- STEI 2019-2025 = 1.75%; and
- EPI 2017-2025 = 1.75%.

The inflation portion of the price cap increases are based on the 2017 IRM inflation factor of 1.9% for all years. Under the status quo scenario, the stretch factor portion is based on the current respective stretch factors for STEI (Group 3 = 0.30%) and EPI (Group 2 = 0.15%). Under the merged scenario, the current respective stretch factors are used for 2018. For 2019 and thereafter, a merged stretch factor of 0.15% is assumed. The Applicants note that the legacy EPI and STEI customers will experience the benefit of stable distribution rates (i.e. IRM escalation only) from 2015 and 2016, respectively, until rebasing in 2026.

1-STAFF-6

Ref: Section 5.1.2, pages 25-27

In Tables 5 and 6, the applicants document the expected incremental transition costs and the forecasted savings for each of savings in operating, maintenance and administration (OM&A) and capital.

a) Please confirm whether "capital costs" shown in Table 6 is "capital expenditures" or "capital additions".

b) Please provide the total net benefits forecasted for the total period (2017 to 2026) for the following:

   i. OM&A savings net of transition OM&A

   ii. Capital expenditure savings net of transition capital expenditures

   iii. Revenue requirement savings reflecting i) and ii).

   iv. Please identify this net revenue requirement savings as a percentage of the aggregate revenue requirement estimated for the merged entity as documented in Table 3 and in the data table requested in 1-Staff-5.

c) Please confirm that, unless the earnings sharing mechanism (ESM) is invoked, which will not occur before 2023, the net savings from 2017 to 2025 will accrue solely to merged entity's shareholders.

Response

a) The forecasted capital costs reflected in Table 6 of the Application represent capital additions that will be placed in-service in each of the respective years.

b)

   i. The total OM&A savings net of transition OM&A for the period of 2017 to 2026 is $9,760,255. Please see Attachment M (Line 10) of the Application for the years 2017 to 2026.

ii. The total capital savings net of transition capital for the period of 2017 to 2026 is $1,886,060. Please see Attachment M (Line 11) of the Application for the years 2017 to 2026.

iii. Cumulative revenue requirement savings are approximately $5.0M for the period 2017 to 2026.

iv. The net revenue requirement savings of the aggregate revenue requirement is estimated to be approximately 3.5%, as described as 3%-4% on the top of Page 30 of the Application.

c) As noted in response to 1-Staff-5, part c), the Applicants have assumed, based on both empirical analysis and on expectations of continued evolution of the role of LDCs in implementing government and regulatory policy, rebasing increases of 3.5% to 4%. The avoided rate rebasing increases (i.e. the rate decreases compared to the status quo) resulting from the proposed deferral of rebasing to the 2026 Test Year are set out in the table provided in response to 1-Staff-5, part a). These rate decreases, compared to the status quo, effectively return to ratepayers a portion of the net savings from 2017 to 2025.

1-STAFF-7

Ref: Section 5.1.5, pp.28-29

The application states that staff will have three year employment and locational guarantees, which will ensure continuity of staff knowledge and experience.

a) Please confirm whether the applicants anticipate a reduction in local operations staff after three years.
b) If so, please describe the applicants' plans, identifying the functions and positions that are expected to be eliminated and the expected impact on the operations of the merged entity.
c) Please confirm whether any staffing changes after year 3 is expected to result in changes to the existing operational centres, and if so please provide a description of the anticipated changes.

Response

a) The Applicants continue to monitor and evaluate the changing environment, growing customer demands and the need for increased industry innovation, as consistent with the 2017 Long Term Energy Plan ("2017 LTEP"). The Applicants do not plan a reduction in local operations staff. The Applicants anticipate that there will be a minimal level of back office administrative support staff attrition after three years.
b) To the extent possible, the Applicants plan to eliminate duplicative back office administrative support positions through normal attrition (a number of employees are approaching retirement). There are no plans to eliminate functions. Rather, some redeployment of existing positions will occur in the process of insourcing STEI billing and certain IT functions. This insourcing is expected to enhance customer service capabilities while reducing overall costs by eliminating the current costs of these outsourced services. This is anticipated to have a positive impact on the merged entity and will allow for knowledge transfer across the organization. Realized staff efficiencies will also assist the Applicants to meet the expectations of the 2017 LTEP, including flexible rate plans, net meter billing, enabling of electric vehicles, etc. with fewer staff compliment increases.
c) There are no plans to change or close any operational centres after year 3.

1-STAFF-8

Ref: Section 5.2.1, pp.29-30

The proposed transaction is expected to result in cost savings in OM&A of approximately $1.2M to $1.4M and reductions in capital costs of approximately $0.2M to $0.3M. Page 30 of the application sets out a number of areas of the distribution business where projected cost savings are expected to be generated as a result of the proposed transaction.

a) Please provide a breakdown of the cost savings by the identified business areas
b) Please confirm whether the projected savings include or exclude the incremental transaction and integration costs identified in the application. If the projected savings do not include the transaction and integration costs, please provide an updated forecast that includes these costs.
c) Please explain what assumptions have been made by the applicants with respect to the expected cost savings.
d) Please identify risks that could negatively impact the projected cost savings, setting out the projected savings if those risks materialize.

Response

a) The OM&A cost savings of $1.2M to $1.4M referenced on Page 30 of the Application refer to anticipated annual impacts once synergies are fully ramped up starting in 2021. The capital cost savings of $0.2M to $0.3M refer to anticipated annual impacts starting in 2018 to 2026.

The breakdown of the estimated OM&A and capital cost savings are as follows:

Line No.	Business Area	Cost Savings by Year ($000's) 2018	2019	2020	2021	2022	2023	2024	2025	2026
1	**OM&A**									
2	Management and consulting fees	$432	$432	$432	$432	$432	$432	$432	$432	$432
3	IT support costs	$0	$0	$150	$300	$300	$300	$300	$300	$300
4	Corporate governance costs	$30	$30	$30	$30	$30	$30	$30	$30	$30
5	Regulatory costs	$55	$55	$120	$207	$207	$207	$207	$207	$207
6	Insurance and employee benefits	$3	$23	$23	$23	$23	$23	$23	$23	$23
7	Staff attrition*	$165	$188	$184	$217	$311	$311	$311	$311	$311
8	Misc.	$58	$122	$95	$68	$82	$87	$97	$107	$117
9	**Total OM&A**	**$743**	**$850**	**$1,034**	**$1,277**	**$1,385**	**$1,390**	**$1,400**	**$1,410**	**$1,420**
10	**Capital**									
11	Fleet purchasing	$200	$200	$200	$200	$200	$200	$200	$200	$200
12	Inventory/stock	$0	$50	$50	$50	$50	$50	$50	$50	$50
13	Deployment efficiency	$29	$52	$91	$89	$86	$80	$80	$80	$80
14	**Total Capital**	**$229**	**$302**	**$341**	**$339**	**$336**	**$330**	**$330**	**$330**	**$330**

* Minimal level of staff attrition has occurred in the latter half of 2017.

b) The projected savings shown above exclude the incremental transaction and integration costs identified in the Application. Please see Attachment M of the Application for the forecast that includes the transaction and integration costs.

c) Please see the table below for the assumptions.

Line No.	Business Area	Assumptions
1	**OM&A**	
2	Management and consulting fees	New EPI has sufficient internal in-house industry expertise to absorb these historic STEI costs.
3	IT support costs	New EPI can absorb STEI outsourced CIS costs subsequent to its contract expiration.
4	Corporate governance costs	Reduction of Board of Director members from EPI/STEI boards.
5	Regulatory costs	Avoided EPI & STEI rebasings (due to rate rebasing deferral) and associated cost amortization.
6	Insurance and employee benefits	Combined purchasing power.
7	Staff Attrition	Some back office administrative support staff attrition is anticipated.
8	Misc.	Elimination of duplicate licences, memberships, audit costs, survey costs, etc.
9	**Total OM&A**	
10	**Capital**	
11	Fleet purchasing	Will share specialized equipment across service centres.
12	Inventory/stock	Will share specialized inventory/stock across service centres.
13	Deployment efficiency	Can more strategically deploy lines construction crews.
14	**Total Capital**	

d) Please see the table below for the risks.

Line No.	Business Area	Risks ($000's)	Projected Savings 2026	Savings in Worst Case
1	**OM&A**			
2	Management and consulting fees	New EPI has Insufficient in-house resourcing to absorb STEI costs.	$432	$200
3	IT support costs	New EPI is unable to in-house CIS from STEI vendor by January 2020.	$300	$150
4	Corporate governance costs	Additional board members required.	$30	$10
5	Regulatory costs	Additional unanticipated New EPI application costs materialize.	$207	$100
6	Insurance and employee benefits	Combined purchasing power does not yield expected benefit.	$23	$5
7	Staff Attrition	Anticipated future staff attrition does not occur.	$311	$165
8	Misc.	Various other potential savings do no materialize.	$117	$50
9	**Total OM&A**		**$1,420**	**$680**
10	**Capital**			
11	Fleet purchasing	Specialized equipment required by service centres at the same time, requiring rentals.	$200	$75
12	Inventory/stock	Specialized inventory/stock required by service centres at the same time, requiring higher levels.	$50	$10
13	Deployment efficiency	Labour relations does not allow strategic deployment.	$80	$10
14	**Total Capital**		**$330**	**$95**

1-STAFF-9

Ref: Section 5.2.1, p.30

It is stated that the OM&A and capital savings translate into an approximate decrease of 3- 4% of revenue requirement versus what it otherwise would have been at the end of the proposed deferred rebasing period.

a) Please confirm whether the applicants anticipate ongoing savings beyond the proposed deferred rebasing period and the expected impact on the rates of the merged entity.

Response

a) The OM&A and capital savings which translate into the approximate decrease of 3% - 4% of revenue requirement are inclusive of the stabilized and ongoing synergies as of 2026 that will persist beyond the proposed deferred rebasing period. It is expected that the revenue requirement of the merged entity will be reduced by this amount versus what it otherwise would have been at the time of the 2026 rate rebasing.

1-Staff-10

Ref: Section 5.2.3, pp.31-32

The application states that consideration for the proposed transaction is non-cash, based on an exchange of shares between the parties and that valuation of shares is based on fair market value of the consolidating distributors. It is also stated that the rate base of the consolidated entity will not be set to include any premium attributed to the value of the distributors through the transaction/share allotment and accordingly, there is no impact on ratepayers arising from the valuation.

a) If a premium has been incorporated in the share allotment process, please advise of the premium attributed to the value of the distributors and explain how will this be accounted for in the financial statements of the merged entity.
b) Please confirm what this premium represents as a proportion of the net fixed assets of the merged entity.

Response

a) The estimated merger valuation premium attributed to the distributors is 60% of estimated rate base of the distributors, which is approximately $54M for EPI and approximately $18M for STEI. As the shares being allotted are those of Entegrus Inc. (“EI”), the parent company of the merged distributors, the purchase premium will be recorded by EI and not the merged distributor.
b) The premiums represent approximately 67% of the merged entity’s net fixed assets. The percentage of net fixed assets is higher than the percentage of rate base noted above, as the rate base calculation also includes a working capital allowance.

1-STAFF-11

Ref: Attachment M - Cost Savings and Transitional Costs

Attachment Q - New EPI 2018 Pro-Forma Statements

a) Please confirm that the pro-forma statements reflect the transition costs and savings projected for 2018. If not, please include the transition costs and savings in the proforma.

b) Please explain how the projections in the pro-forma statements are derived.

Response

a) Confirmed.

b) EPI management and STEI management both independently prepared 2018 forecasts on a status quo basis. Subsequently, the forecasts were consolidated and then transition costs and projected synergies for 2018 were factored into the consolidated proforma financial statements.

1-Staff-12

Ref: Section 5.2.2, p. 31

Attachment Q - New EPI 2018 Pro-Forma Statements

On page 31, it is indicated that transition costs will be financed through productivity gains associated with the transaction and that these costs will not be included in the merged entity's revenue requirement and will not be funded by ratepayers. In Attachment Q, the cash flow pro-forma shows long term debt of $2.75M being issued.

a) Please confirm whether the merged entity is issuing debt to finance the transaction costs.
b) If yes, please provide the details and terms of the proposed debt and explain why the applicants consider that the proposed debt should be funded by ratepayers.
c) If not, please explain how the transition costs will be financed and the purpose of the new long-term debt.

Response

a) The merged entity is not issuing debt to finance the transaction costs.
b) Not applicable.
c) The transition costs will be financed through existing working capital until expected productivity gains materialize in 2018. The purpose of the new long-term debt will be to fund normal capital additions.

1-STAFF-13

Ref: Attachment K - Merger Agreement

Attachment P - 2015, 2016 STEI Financial Statements

The merger agreement references debt restructuring.

a) Please provide a summary of how the existing debt of Entegrus Powerlines and St. Thomas Energy will be restructured post-merger, how the debt restructuring will impact the consolidated entity, and whether or not there will be sufficient financing available for the operations of the consolidated entity.

b) In St. Thomas Energy's 2016 financial statements, note 11 indicates that St. Thomas Energy's debt was subject to certain consolidated financial covenants with its parent company, Ascent Group Inc. The bank acknowledges that certain reporting covenants were not met and the debt is in default.

   i. Please describe the current status of the debt.

   ii. Please explain how the default in debt impacts the consolidated entity, post-merger, including a discussion on impacts to liquidity and financial viability.

Response

a) At the time of merger, the existing STEI bank debt will be replaced with new debt issued by the existing EPI bank. New EPI will maintain a 60/40 debt equity structure, consistent with OEB guidelines and therefore sufficient financing will be available.

b)

   i. The bank default described in the STEI 2016 financial statements was triggered by bank covenants not being met at the STEI parent company group level, Ascent Group Inc. ("AGI"). In accordance with banking arrangements in place at that time, this also resulted in STEI being in default by association. The default was not driven by STEI's own financial position. The matter was resolved in February 2017 when a new financing agreement was established with the bank. AGI and STEI are no longer in default.

ii. The bank has acknowledged that the debt is no longer in default. STEI's own financial position was not a factor in the previous default. The merged entity will maintain a 60/40 debt equity structure, consistent with OEB guidelines, and as such there are no negative impacts to liquidity nor the financial viability of the merged entity.

1-STAFF-14

Ref: Attachment Q - New EPI 2018 Pro-Forma Statements

Attachment O - 2015, 2016 EPI Financial Statements

Attachment P - 2015, 2016 STEI Financial Statements

From 2014 to 2016, Entegrus Powerlines paid dividends ranging from $1.4M and $1.5M and St. Thomas Energy did not pay any dividends. In the 2018 cash flow pro-forma, the merged entity is projecting to pay $2.5M in dividends.

a) Please explain the projected increase in dividends and discuss any implications on financial viability of the merged entity.
b) Please explain how the 2018 projected dividends are expected to be financed.
c) Please confirm whether the boards of directors of the merging utilities were involved in the discussion about dividend payments post-merger and if so, please provide the rationale for planning to make a dividend payment post-merger.
d) Please confirm whether the boards of directors of the merged entity will be required to approve the projected dividend payment? If not, please explain which person(s) or entity/ies will be involved in the decision with respect to proposed dividend payments.
e) Please describe the process whereby the consolidated entity will decide whether to pay dividends in 2018 or thereafter.

Response

a) The projected increase in dividends is reflective of the projected financial results of the combined entity including synergies. The merged entity will maintain a 60/40 debt equity structure, consistent with OEB guidelines, and as such there are no negative impacts to liquidity nor the financial viability of the merged entity.
b) The projected dividends will be funded from earnings from operations.
c) Confirmed. The rationale is explained in part a) of this response.
d) Confirmed.

e) The dividend decision will be made by the Board of Directions of New EPI in the same manner as it has historically been made by EPI, primarily based on an assessment by the Board of Directors, involving the following factors:
   - financial results for the year,
   - the objective of maintaining a 60/40 debt equity structure, consistent with OEB guidelines, and
   - maintaining liquidity and the financial viability of the merged entity.

1-STAFF-15

Ref: Section 6.2, pp. 35-36

It is indicated that starting in year 6, the ratepayer share of earnings would be credited to a newly proposed deferral account.

a) Please confirm whether the applicants are seeking OEB approval for the new proposed deferral account in the current application.
b) If yes, please provide a draft accounting order for the proposed account and explain how the consolidated entity's ROE would be calculated.
c) If not, please advise when the applicants intend to request for approval of this account.

Response

a) No, the Applicants are not seeking approval for the new proposed ESM deferral account in the current application.
b) Not applicable.
c) The Applicants intend to request approval for this account in a later rate application prior to year 6.

1-STAFF-16

Ref: Section 7.4, p. 39

The applicants request to continue to track Account 1508 Other Regulatory Assets, Subaccount OPEB Forecast Cash versus Forecast Accrual Differential Deferral Account with respect to the existing Entegrus Powerline rate zone, pending finalization of the OEB's EB-2015-0440 consultation.

a) The Report of the OEB for EB-2015-0440 has been issued. Please explain whether there are any changes to the applicants' proposal given the final report.
b) Please confirm whether the merged entity plans to consolidate its financial records or keep separate financial records for each rate zone.
c) If it plans to consolidate financial records, please indicate when the consolidation is expected and how it will track the Account 1508 sub-account just for the Entegrus Powerlines rate zone.
d) The applicants request leave to continue to track existing deferral and variance accounts currently approved by the OEB. Please provide a listing of these accounts.
e) With respect to Group 1 variance accounts, it is stated that the accounts for the two rate zones will be combined when the IESO settlement processes for Entegrus Powerlines and St. Thomas Energy can be merged.
    i. Please confirm that the Entegrus Powerlines and St. Thomas Energy account balances will be tracked separately until at least the effective date of the amalgamation (i.e. balances until Jan. 1, 2018 as currently proposed). If not, please explain why not.
    ii. Please explain how the Group 1 variance accounts will be tracked if the settlement process for the two rate zones occur in the middle of the year.

Response

a) The Applicants have reviewed the Report of the OEB for EB-2015-0440 and understand that no changes to the EPI rate zone's OPEBs accounting are required. Accordingly, no changes to the Application proposal are requested.

b) The Applicants confirm that they plan to consolidate the financial records, with the exception of the deferral and variance accounts noted in part d). The Applicants have the ability to continue to track the deferral and variance accounts by rate zone.

c) The Applicants plan to continue to track the Account 1508 sub-account for OPEBs separately for the EPI rate zone utilizing segregated actuarial reporting and to dispose of sub-account balances to the EPI rate zone accordingly.

d) The Applicants request leave to continue tracking the following Group One and Group Two deferral and variance accounts currently approved by the OEB:

- **Group One:**
  - Account 1550: Low Voltage Variance Account
  - Account 1551: Smart Metering Entity Charge Variance Account
  - Account 1568: LRAM Variance Account
  - Account 1580: RSVA Wholesale Market Service
  - Account 1582: One Time Costs
  - Account 1584: RSVA Network
  - Account 1586: RSVA Connection
  - Account 1588: RSVA Power
  - Account 1589: RSVA Global Adjustment
  - Account 1595: Disposition and Recovery/Refund of Regulatory Balances
- **Group Two:**
  - Account 1508: Other Regulatory Assets, Sub-account OEB Cost Assessment Variance
  - Account 1508: Other Regulatory Assets, Sub-account – OPEB Forecast Cash versus Forecast Accrual Differential Deferral (for original EPI rate zone as approved in EB-2015-0061)
  - Account 1508: Other Regulatory Assets, Sub-account – IFRS Transition Costs
  - Account 1518: RCVA Retail
  - Account 1548: RCVA STR
  - Account 1555: Stranded Meters

- Account 1576: Accounting Changes Under CGAAP

e)

i. Confirmed.

ii. The Applicants plan to work closely with the IESO to ensure the transition to a single settlement process occurs at the end of a calendar year. If this is not possible, the Applicants will track the appropriate variances separately for the portion of the transition year that is settled independently. Thereafter, the Applicants will track the variances on a combined basis for the remainder of the transition year. Upon disposition of these variance accounts, the Applicants will propose three rate riders as follows:

1) Balances related to the original EPI rate zone, applicable for the original EPI rate zone customers.
2) Balances related to St. Thomas rate zone, applicable for customers in the St. Thomas rate zone.
3) Balances related to the combined settlement applicable to all New EPI customers.

1-STAFF-17

Ref: Section 7.5, p. 40

a) Please confirm whether each of the applicants uses different accounting policies and what impact this is expected to have on the proposed consolidation of the two distributors.

b) Please confirm whether either of the applicants intends to make changes, or is required by an accounting standards body to make changes to its accounting policies, as a result of the proposed amalgamation. If so, please describe the impact of any accounting changes and whether they will reduce or increase the earnings of the amalgamated utility.

Response

a) The Applicants use common accounting policies and accordingly, there is no expected impact.

b) No accounting policy changes are anticipated or required.

1-STAFF-18

Ref: Decision and Rate Orders EB-2016-0063 (Entegrus Powerlines) and EB- 2016-0104 (St. Thomas Energy)

OEB staff has reviewed the approved Tariffs of Rates and Charges for the 2017 rate year for each of Entegrus Powerlines and St. Thomas Energy. With respect to Specific Service Charges, OEB staff has prepared the following table that compares the Specific Service Charges for the two applicants.

(Table has been reproduced in Attachment A)

a) Please confirm or correct the above table.
b) Where Entegrus Powerlines and St. Thomas Energy currently both offer the same specific service, the rates are equivalent. However, there are a number of specific service charges that are currently charged by one, but not both, of the applicants. The applicants propose that the merged entity would only rebase for rates for the 2026 rate year.
    i. Please explain how the applicants propose to handle a customer request (or a company-initiated request such as disconnect/reconnect due to nonpayment) for which an approved charge is applicable in one of the legacy service territories but not in the other.
    ii. Please confirm whether the charge would be based on time and materials.
    iii. Please explain how the applicants propose that customers would be informed of any differences.

Response

a) Confirmed.
b)
    i. New EPI will ensure that it follows the approved tariff sheets when communicating with customers regarding the applicability of charges for each rate zone. EPI has significant experience in maintaining multiple rate zones and communicating different rates and charges to its customers. In addition, the New EPI interactive website will provide

specific rates and charges based on customer postal code. Also, New EPI will provide separate rate brochures for each rate zone.

ii. The Applicants interpret that this question relates to "Switching for company maintenance – charge based on time and materials" from the EPI tariff sheet. The Applicants confirm the charge will follow the tariff sheet description until the time of the next rebasing.

iii. Please see response to i) above.

1-Staff-19

Ref: Decision and Rate Orders EB-2016-0063 (Entegrus Powerlines) and EB-2016-0104 (St. Thomas Energy)

OEB staff has reviewed to current approved Tariffs of Rates and Charges for each of the applicants and observes that there are some differences in the customer rate classes. Specifically, only Entegrus Powerlines has Unmetered Scattered Load, Standby Power and Large Use customer classes.

a) If the application is approved, please explain how the merged entity plans on handling and communicating differences in customer classifications in the legacy service territories until such time as these could be harmonized, potentially at the planned rebasing for 2026.

Response

a) Please see response to 1-Staff-18, question b(i).

1-Staff-20

Ref: Conditions of Service

a) Please identify any material differences in the current Conditions of Service of Entegrus Powerlines and St. Thomas Energy.

b) Please confirm that these current Conditions of Service are available on each of the applicants' websites and available at their business offices for viewing by customers.

c) If there are any material differences, please identify how the merged entity intends to communicate and resolve these in dealing with customers if the application is approved.

Response

a) The Applicants have identified the following material differences between the two Conditions of Service documents:

   i. **Point of Demarcation:** While both documents contain the necessary information defining the customers' point of demarcation for their connection to the distribution system, the STEI document provides more specific detail for unique individual circumstances.

   ii. **Primary and Secondary Voltages:** There are some variations in the levels of primary and secondary voltages offered by EPI and STEI.

   iii. **Maximum Loading:** EPI determines maximum loading based on kVA and STEI determines maximum loading by current limits.

   iv. **Unmetered Loads:** STEI allows only unmetered Streetlight and unmetered Sentinel light loads. EPI has an Unmetered rate class and allows additional options of unmetered loads.

   v. **Voltage Standards:** STEI references the most recently available CSA standards and EPI provides relevant tables within the document.

   vi. **Unauthorized Energy Use:** STEI has a specific section covering this matter and EPI does not.

b) Confirmed.

c) Subsequent to merger approval, a project team will be formed comprised of subject matter experts from each operation centre. The project team will determine the best practices to address the differences noted. Thereafter, New EPI will follow the OEB's Conditions of Service customer engagement process which allows for customer feedback and input prior to implementation of a harmonized Conditions of Service document.

Attachment A

Table of Specific Charges for EPI & STEI

(provided by Board Staff in reference to IR 1-Staff-18)

Specific Service Charge	Current Approved Charge	
	Entegrus Powerlines (EB-2016-0063)	St. Thomas Energy Inc. (EB-2016-0104)
Customer Administration		
Arrears Certificate	$15.00	$15.00
Statement of Account	$15.00	$15.00
Pulling post dated cheques		$15.00
Duplicate invoices for previous billing		$15.00
Request for other billing information		$15.00
Easement letter	$15.00	$15.00
Income tax letter		$15.00
Notification charge		$15.00
Account history		$15.00

Credit reference/credit check (plus credit agency costs if applicable)		$15.00
Returned cheque (plus bank charges)	$15.00	$15.00
Charge to certify cheque		$15.00
Legal letter charge		$15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)		$30.00
Account set up charge/change of occupancy charge	$30.00	
Special meter reads		$30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30.00	$30.00
Non-payment of Account		
Late payment – per month	1.50%	1.50%
Late payment – per annum	19.56%	19.56%
Collection of account charge – no disconnection		$30.00
Collection of account charge – no disconnection – after regular hours		$165.00
Disconnect/reconnect at meter – during regular hours	$65.00	$65.00
Disconnect/reconnect at meter – after regular hours	$185.00	$185.00
Disconnect/reconnect at pole – during regular hours		$185.00
Disconnect/reconnect at pole – after regular hours		$415.00
Install/remove load control device – during regular hours		$65.00
Install/remove load control device – after regular hours		$185.00
Other		
Specific charge for access to power poles – per pole/year (with the exception of wireless attachments)	$22.35	$22.35
Disconnect/reconnect charge at customer's request – at meter during regular hours		$65.00
Temporary service install and remove – overhead – no transformer	$500.00	
Temporary service install and remove – overhead – with transformer	$1,000.00	
Switching for company maintenance – charge based on time and materials	T&M	