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BY E-MAIL

November 7, 2017

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Energy Board File Number: EB-2017-0212
Application for approvals to effect the amalgamation of Entegrus Powerlines Inc. and St. Thomas Energy Inc.

In accordance with Procedural Order No. 1, please find attached OEB Staff Interrogatories in the above proceeding. The attached document has been forwarded to the applicants.

Yours truly,

Original Signed By

Judith Fernandes
Project Advisor

Encl.

OEB Staff Interrogatories

Entegrus Powerlines Inc.
St. Thomas Energy Inc.

Application for approvals to effect the amalgamation of Entegrus Powerlines Inc. and St. Thomas Energy Inc.

EB-2017-0212

November 7, 2017

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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

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.

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.

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.

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.

1-Staff-16
Ref: Section 7.4, p. 39

The applicants request to continue to track Account 1508 Other Regulatory Assets, Sub-account 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.

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.

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:

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	

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 non-payment) 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.

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.

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.