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BY EMAIL and RESS

October 14, 2010

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

Dear Ms. Walli:

Re: EB-2009-0278 – Algoma Power Inc. ("API")

In accordance with Procedural Order No. 3 in the above-referenced matter, we have attached the reply submissions of API.

If you have any questions or concerns, please do not hesitate to contact me.

Sincerely,

Andrew Taylor

cc. intervenors

EB-2009-0278

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Algoma Power Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective July 1, 2010 and January 1, 2011.

REPLY SUBMISSIONS OF

ALGOMA POWER INC.

October 14, 2010

API has prepared the following reply submissions in regard to the three unresolved issues in this proceeding:

> A. Should API's proposal to recover amounts in Account 1572 Extraordinary Event Costs be approved?
> B. What is the appropriate method of calculating the average rate adjustments of other distributors in order to calculate the rate increase for the customers of API, and the remaining amount that is payable under RRRP?
> C. Should API's proposal to establish a new IFRS Deferral Account be approved?

API has addressed each of these issues separately below.

A. Should API's proposal to recover amounts in Account 1572 Extraordinary Event Costs be approved?

Introduction:

API is an electricity distribution company that is solely in the business of owning and operating its electricity distribution system in accordance with Section 71 of the Ontario Energy Board Act (the "OEB Act"). API is the successor of GLPL's distribution business. GLPL operated the distribution system as a division, financially separate from its transmission and generation businesses. Under Section 5(5) of Ontario Regulation 161/99, GLPL was exempt from Section 71 of the OEB Act until December 31, 2008 and, as a result, was permitted to carry on the activities of distribution, transmission, and generation within the same corporation until such date.

In early 2007 in anticipation of the expiry of the Section 71 exemption, a reorganization began in which the transmission assets of GLPL were transferred to GLPT in March 2008. This was approved by a Decision and Order of the Board issued on December 24, 2007 (EB-2007-0647). GLPT became a licensed transmitter (ET-2007-0649) in respect of ownership only. GLPL also remained a licensed transmitter, as the operator of the GLPT transmission system. This completed the first phase of completing the compliance with Section 71. Full compliance with Section 71 occurred when the distribution business was transferred to Great Lakes Power Distribution Inc. ("GLPDI") and the transmission and distribution activity was carried on in two stand alone entities - GLPT and GLPDI, respectively. The cost of transferring the distribution

business from GLPL to GLPDI that API has applied to recover as an extraordinary event cost is $397,667.[1]

The costs in question arose because of the unique circumstance of Section 71 and the expiration of the legislative exemption to it.[2] Unlike nearly all utilities in Ontario, GLPL was corporately organized prior to the existence of Section 71 of the OEB Act. As a result, Section 71 was not an issue of compliance for most utilities since they could organize with it in mind. For GLPL and any successor to it, Section 71 presented a compliance issue. The Section 71 exemption regulation granted time to prepare for compliance, but nevertheless, compliance could not be avoided in the long term. As a result, the unwinding of a long-standing corporation was both a unique and an extraordinary event that was unforeseeable at the time GLPL was created years before market opening. In the event of non-compliance, the ability to operate the distribution business would have been affected and there would have been a possibility of legal consequences against the business. In particular, under the OEB Act, the Board has the power to suspend or revoke a licence and to issue administrative penalties. Moreover, where convicted of an offence, such as for contravening a provision of the OEB Act or a regulation made under the OEB Act, there is a possibility of substantial fines being issued.

Submission:

API submits that recovery is justified because the Extraordinary Event costs meet the Board's criteria of materiality, prudence, inability of management control, and causation. Each of these criteria is addressed below:

i) **Materiality**: Two methodologies for determining materiality were described by Board staff in its October 8, 2010 submission. The two methodologies result in materiality thresholds of approximately $100,000 and $133,000. API submits that the original Electricity Distribution Rate Handbook specifically addresses the materiality criterion for Z factor recovery:

> *Materiality*
> Recovery is reserved for costs which have a significant influence on the operation of the utility. As a guideline, an expense will be considered material if it involves 0.25 per cent of a utility's net assets (i.e., .0025 x net assets). Therefore, materiality will differ depending on the size of the utility.[3]

[1] Undertaking J2.1. We note that at paragraph 2.6 of VECC's submission it incorrectly stated the amount sought is $365,395.
[2] Ontario Regulation 161/99, subsection 5(5).
[3] Electricity Distribution Rate Handbook (November 3, 2000), page 5-6.

Based on this methodology, API calculated a materiality threshold of approximately $71,000, being .0025 of API's average net assets for 2009.[4] API cannot confirm the $133,000 suggested by Board staff. As such, API submits that the correct materiality threshold in this case is $71,000, which is well below the $397,667 Extraordinary Event cost.

ii) **Prudence**: Subsection 71(1) of the OEB Act provides:

> **71.** (1) Subject to subsection 70 (9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity.

No matter how one interprets subsection 71(1), GLPL's distribution business had be separated from its generation business. The costs that API is seeking to recover primarily pertain to the costs of separating distribution from generation.

This subsection was interpreted by GLPL as requiring the creation of a stand-alone distribution business. API submits that the Board's analysis in this case should not be to retroactively judge whether GLPL was right or wrong in its interpretation of subsection 71(1), long after GLPL reorganized its entire business based on that subsection. Rather, the Board's analysis should be whether GLPL's interpretation was prudent or reasonable at the time it made its decision, based on circumstances it knew or ought to have known. This prudence test is consistent with the Board's practice:[5]

> "The Board agrees that a review of prudence involves the following:
>
> • Decisions made by the utility's management should be generally presumed to be prudent unless challenged on reasonable grounds.
>
> • To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
>
> • Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.

[4] Transcript page 8, lines 21-24.
[5] OEB Decision setting Enbridge Gas Distribution rates for 2002 Fiscal Year, December 13, 2002 (RP-2001-0032), at p.62.

> • Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time."

GLPL's interpretation of subsection 71(1) was not unreasonable, since this subsection deals with restrictions on business activities for both transmitters and distributors, restricting each of them to transmitting "or" distributing electricity. Because the subsection deals with "transmitters or distributors" and the activities of "transmitting or distributing", it is not unreasonable to interpret the subsection such that "transmitting" pertains to "transmitters" and "distributing" pertains to "distributors".

Further, GLPL's interpretation that subsection 71(1) required it to create a stand-alone distribution business has been raised in other proceedings and at no time has the Board questioned GLPL's interpretation. For example, GLPL's understanding was described in GLPL's March 9, 2009 MAAD application to transfer its distribution assets from GLPL to GLPDI:

> "To be compliant with Section 71 of the OEB Act, GLPL must corporately reorganize by establishing a distributor that legally and operationally carries on the business activity of electricity distribution **separate from any other business activity**."[6] [emphasis added]

At no time has the Board questioned this interpretation. As well, the Board had the opportunity to assess the prudence of the reorganization of GLPL into stand-alone businesses on two occasions; first during the MAAD application to create a stand-alone transmission business; and second during the MAAD application to create a stand-alone distribution business. API submits that it would be improper for the Board to challenge the prudence of the reorganization now, after the Board issued final decisions in those proceedings.

For all of these reasons, API submits that GLPL's interpretation of subsection 71(1) was prudent.

iii) **Inability of Management Control**:

It follows that if GLPL's interpretation of subsection 71(1) was prudent, then it was outside management's ability to control the circumstance (ie. management had no choice but to comply with subsection 71(1)). As set out above, under the OEB Act,

[6] At Exhibit A, Tab 1, Schedule 3, Page 7 of 17.

the Board has the power to suspend or revoke a licence and to issue administrative penalties. Moreover, where convicted of an offence, such as for contravening a provision of the OEB Act or a regulation made under the OEB Act, there is a possibility of substantial fines being issued.

iv) **Causation**:

With the exception of a portion of the internal costs associated with creating a stand-alone distribution business, the costs are outside the base upon which rates were derived, and therefore satisfy this criterion. In regard to the $56,440 of internal costs, the following excerpts from the September 29, 2010 transcript are of assistance:

> MR. LAVOIE: This effort -- now, I don't have the split in terms of this, but there was a portion of this cost that certainly was put in by our staff was over and above the time. There was overtime put in to accomplish this task during -- obviously they have regular duties within the department.
>
> And, as well, we utilized some contracted effort in their normal business, engineering business, to accomplish the normal, daily day-to-day tasks while they were working on this particular project.[7]
>
> ---
>
> MR. LAVOIE: At this point, I can say that they're internal costs based on a time-card system that our engineering staff would have charged to the particular project. I know that a number of those hours were overtime, but it would include some regular-time costs. So it is not a purely incremental cost.
>
> MS. HARE: But are those cost not already included in your revenue requirement?
>
> MR. LAVOIE: In the test year, there are engineering costs included in the

[7] Transcript page17, lines 17-26.

revenue requirement. This would have been an accrual of costs from 2009.

MS. HARE: So maybe I am missing something, but I don't understand how those are incremental costs.

MR. LAVOIE: To the extent that there is overtime, that would be an incremental cost.

MS. HARE: But is it overtime?

MR. LAVOIE: There is some aspect of it that is overtime.

MR. TAYLOR: Sorry, if I could just jump in as well, did you not mention there was backfill time as well?

MR. LAVOIE: That's correct. In the regular operation of engineering services that the department provides to the -- there is some aspect of backfilling that we did require in order to accomplish this particular project. So there is an incremental component that would be related to the backfilling that needs to be accounted for as well.[8]

It is apparent from these exchanges that a portion of the $56,440 of internal costs was not incremental. There is no evidence on the record to break-out the portion non-incremental costs, however there is evidence that there actually were incremental internal costs in the form of overtime and backfill. As such, API submits that a portion of the $56,440 should be characterized as incremental. API submits a reasonable characterization of incremental would be 75% of the $56,440 (approx. $42,000).

Specific Issues Raised:

i. Extraordinary Event Cost vs. Transition Cost

The intervenors have argued that the costs being claimed by API are more appropriately classified as transition costs, rather than extraordinary event costs. API disagrees with this position for a number of reasons:

[8] Transcript pages 45 and 46.

a. Municipal electric utilities ("MEUs") were required to transition to Ontario Business Corporations Act ("OBCA") corporations pursuant to subsection 144(1) of the Electricity Act:

> **144.** (1) After the second anniversary of the day section 142 comes into force, a municipal corporation shall not generate, transmit, distribute or retail electricity, directly or indirectly, except through a corporation incorporated under the *Business Corporations Act* pursuant to section 142.

The basis for the transition costs that MEUs incurred was subsection 144(1) of the Electricity Act. That section, however, did not apply to GLPL, as GLPL was not a MEU. The costs that API is claiming stem from a different piece of legislation altogether – subsection 71(1) of the OEB Act. GLPL was already an OBCA corporation, therefore the costs that are the subject of this proceeding were unrelated to subsection 144(1) of the Electricity Act.

b. MEUs had the benefit of knowing the requirements of subsection 71(1) when they corporatized. Therefore, they could organize themselves in compliance with that subsection from the outset. GLPL had organized itself long before subsection 71(1) of the OEB Act existed. Therefore, the costs that are the subject of this proceeding are compliance costs rather than transition costs.

c. Transition costs pertained to transitioning to the new market structure, as described by the Board in RP-1999-0034:

> "The draft Rate Handbook indicates that the initial rates may, subject to certain criteria such as causality, materiality, management's inability to control and prudence, **include costs associated with the transition to the new market structure**."[9] [emphasis added]

The reorganization of GLPL's business divisions into stand-alone companies was unrelated to the new market structure, as evidenced by the fact that GLPL operated as an integrated utility for years after market opening. It should be noted that GLPL did incur transition costs that pertained to the new market structure (ie. customer information system costs), contrary to the SEC's assertion in paragraph 17 of its October 8, 2010 submission. GLPL recorded those costs in Account 1570, and the Board approved those costs in EB-2007-0744.

d. Extraordinary Event costs are, by their nature, unforeseeable. As mentioned above, the unwinding of a long-standing corporation was both a unique and an extraordinary event that was unforeseeable at the time GLPL was created, years before market opening.

[9] At paragraph 3.3.30.

Therefore, the passage of section 71 was akin to a tornado or ice storm for GLPL when it learned that its existing business organization was not longer acceptable. Although the Section 71 exemption regulation granted GLPL some time to prepare for compliance, compliance could not be avoided in the long-term.

For these reasons, API submits that the costs at issue should not be classified as Transition Costs. However, if the Board decides that they are Transition Costs, API submits that they are eligible for recovery.

Article 480 of the Accounting Procedures Handbook (the "APH") describes the general categories of activities that are eligible for recover as transition costs.[10] Those categories include “regulatory costs (e.g. OEB license fee and proceeding costs)”.[11] According to API's testimony, it estimated that regulatory costs accounted for approximately $280,000. These costs included OEB licensing, regulatory proceeding costs and fees, the omnibus application, as well as other statutory regulatory approvals such as pension filings.[12] API submits that these costs fit within the category of regulatory costs would therefore be eligible (ie. if this were a transition cost, which it is not).

The SEC submitted that a portion of the legal costs that API characterized as regulatory costs are ineligible because they pertain to asset transfer activities. API estimated that approximately $40,000 pertained to asset transfer activities. API submits that the asset transfer activities were part-in-parcel with the subsection 71(1) compliance applications, regulatory requirements for GLPL, and cannot be carved-out separately. MEUs were not required to apply for regulatory approval of their reorganizations, so their asset transfer activities were different from GLPL's. Furthermore, the SEC has submitted that it is unrealistic that a Toronto law firm would charge only $40,000 for such a complex transaction. API submits that the transaction was not complex for a number of reasons: the transfer was not to a third-party (ie. it was an internal reorganization); little due diligence was conducted relative to third-party transactions;[13] no valuations were conducted;[14] and the assets being transferred were unsecured from a debt perspective.[15] For these reasons, the asset transfer was relatively simple and there is no reason to doubt the $40,000 estimate provided by API.

The APH also includes regulatory requirements as an eligible transition cost: "Regulatory requirements (e.g. staff contract assistance and systems to accommodate record keeping,

[10] At page 9.
[11] APH Article 480, page 6.
[12] Transcript at page 27, lines 19-24.
[13] Transcript at page 41, lines 24-25.
[14] Transcript at page 41, line 27.
[15] Transcript at page 42, lines 10-12.

monitoring and filing requirements)".[16] According to API's testimony, it estimated that regulatory requirements accounted for approximately $80,000.[17] These activities were described in the hearing as follows:

> MR. LAVOIE: I think the regulatory requirements, there are a number of regulatory requirements that have to -- with respect to the example given, accommodate record keeping and filing requirements. There is a number of record keeping items that I mentioned earlier, obviously land and land rights, the documentation, land agreements, permits, material agreements, preparation of transferring all of that information, legal opinions, in that context.[18]

API submits that these costs fit within the category of regulatory requirements would therefore be eligible (ie. if this were a transition cost, which it is not).

The APH also includes "IMO/IESO requirements (e.g. prudential requirements, registration, communication and market readiness testing)"[19] API expended $3,665 on registration fees that largely[20] pertained to IESO registration. As such, this expense is also eligible.

ii. The GLPT Decision

API understands that the Board's decision in EB-2009-0408 whereby it approved a settlement proposal that allowed GLPT to recover the exact same type of costs being sought by API does not form a legal precedent. However, if the Board believed that the settlement proposal in that case was flawed in that it was based on incorrect interpretation of subsection 71(1) of the OEB Act, it had the option to reject the settlement proposal, just like it did in this proceeding regarding the reclassification of streetlighting customers. The relevant wording from the settlement proposal specifically referred to section 71 of the OEB Act:

> "Account 1572 - Extraordinary Event Costs
>
> As part of acquiring the transmission assets, GLPT incurred costs, which are recorded in Account 1572. These costs arose because of the unique circumstance of Section 71 of the *Ontario Energy Board Act* and the expiration of a legislative exemption to it that had previously been available. GLPT explains in 9-1-6 that the closing balance as at December 31, 2009 which GLPT proposes to disburse, as shown in Table 9-1-6A, is $1,041,454 recoverable by GLPT from ratepayers.

[16] APH Article 480, page 6.
[17] Transcript, page 28, line 23.
[18] Transcript, page 28, lines 13-20.
[19] APH Article 480, page 6.
[20] Transcript, page 18, lines 8-12.

For the purpose of obtaining a complete settlement of all issues but one, the Parties agree that the Board should accept and approve such amounts for disbursal."

Conclusion:

For the reasons set out above, the Extraordinary Event Costs being claimed by API satisfy the four criteria of materiality, prudence, inability of management control, and causation, subject to a minor adjustment for the non-incremental work regarding internal labor. The costs are more appropriately characterized as Extraordinary Event Costs, rather than Transition Costs. In any event, even if the costs were to be characterized as Transition Costs (and they should not), they are eligible for recovery in accordance with Article 480 of the Accounting Procedures Handbook.

B. What is the appropriate method of calculating the average rate adjustments of other distributors in order to calculate the rate increase for the customers of API, and the remaining amount that is payable under RRRP?

API concurs with the conclusion drawn by Board Staff in its submission on the *Report on the Rural and Remote Rate Protection and Adjustment Mechanism* with respect of the class comparator, the unit weighting of each distributor, the inclusion of only fixed and variable charges and the volumetric assumptions.

In respect of the time period over which the average increase (or decrease) is calculated, O. Reg. 442/01 Part (3.2) provides:

> *"…be adjusted in line with the average, as calculated by the Board, of any adjustments to rates approved by the Board for other distributors for the* ***same rate year****."*[21] [emphasis added]

API submits that this section should be interpreted to be the average of the most recent rate year's increase or decrease; not the average of cumulative increases or decreases over a period of time.

[21] Board Staff *Report on the Rural and Remote Rate Protection and Adjustment Mechanism*, page 2

C. Should API's proposal to establish a new IFRS Deferral Account be approved?

API has no further submissions on this issue.

All of which is respectfully submitted. October 14, 2010

Andrew Taylor