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BY EMAIL

December 8, 2011

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Algoma Power Inc.
2012 IRM Distribution Rate Application
Board Staff Submission
Board File No. EB-2011-0152

In accordance with the Notice of Application and Hearing, please find attached the Board Staff Submission in the above proceeding. Please forward the following to Algoma Power Inc. and to all other registered parties to this proceeding.

Yours truly,

Original signed by

Richard Battista
Project Advisor, Applications & Regulatory Audit

Encl.

Ontario

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2012 ELECTRICITY DISTRIBUTION RATES

Algoma Power Inc.

EB-2011-0152

December 8, 2011

Board Staff Submission
Algoma Power Inc.
2012 IRM Rate Application
EB-2011-0152

Introduction

Algoma Power Inc. ("Algoma") filed an application with the Ontario Energy Board (the "Board") on September 15, 2011, under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to the distribution rates that Algoma charges for electricity distribution, to be effective January 1, 2012. Algoma subsequently filed an amended application on October 13, 2011.

The purpose of this document is to provide the Board with the submissions of Board staff based on its review of the evidence submitted by Algoma Power.

Board staff makes submissions on the following matters:

- Incentive Regulation Mechanism ("IRM") and Rural and Remote Rate Protection ("RRRP");
- Price Cap Index;
- RRRP Adjustment;
- 2012 Revenue Cost Ratio Model;
- Federal and Provincial Income Taxes;
- Smart Meters;
- Retail Transmission Service Rates ("RTSR") Adjustment;
- Disposition of Deferral and Variance Accounts as per the *Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report");
- Account 1562 – Deferred Payments in Lieu of Taxes;
- Account 1521 – Special Purpose Charge ("SPC"); and
- General Update

INCENTIVE RATE REGULATION MECHANISM AND REMOTE AND RURAL RATE PROTECTION

Background

Board staff notes that Algoma's 2012 IRM application is not a standard IRM application in that the rate making steps and calculations must consider the implications of Rural and Remote Rate Protection ("RRRP") as prescribed by O. Reg. 442/01.

In this regard Algoma indicated that, while it could not categorically confirm that its Application conforms with the Board's Filing Requirements for Incentive Regulation Mechanism Rate Applications ("Filing Requirements") issued June 22, 2011, it has attempted to mimic the 3rd Generation IRM and where possible abide the Filing Requirements.[1]

Compared to a typical IRM application, for those rate classes that are eligible for RRRP, the primary difference in Algoma's case is in the selection of the base to which the price cap index is applied. As proposed by Algoma, it is necessary to apply the price cap index to the underlying pre-RRRP adjusted revenue requirement, and not to the existing Board-approved rates, in order to establish the amount of RRRP applicable for 2012. Also, to reflect proposed changes in Revenue to Cost ratios, Algoma first multiplies the 2011 approved revenue by class, based a 100% Revenue to Cost ratio, by the price cap index, and then applies the Revenue to Cost ratios proposed for 2012 to generate the 2012 base revenue requirement.

Submission

Board staff agrees that a modification to the standard IRM approach is necessary and concurs that the price cap index would be applied to the pre-RRRP adjusted revenue requirement.[2] Board staff notes that Algoma indicated that this approach was agreed to by the intervenors in the stakeholder sessions that took place prior to the filing of the Application.[3]

In this submission Board staff is assuming that Algoma accepts the calculation of the price cap index as described in the Filing Requirements (price cap index = the change

1 Board staff interrogatory No. 1.
2 The specific treatment of Revenue to Cost changes in an RRRP regime is addressed further in this submission.
3 Response to VECC interrogatories No. 4 and 5 and page 9 of the Amended Application dated October 13, 2011.

in annual GDP-IPI less a productivity factor of 0.72 % and less a stretch factor[4]). To ensure that the record is clear on this, Board staff asks that Algoma confirm in its Reply Submission that it accepts this premise.

PRICE CAP INDEX

Background

Pursuant to the Filing Requirements, a distributor's rates will be calculated by multiplying the distributor's existing distribution monthly fixed charge and variable rate by a price cap index. In its Application Algoma noted that the price cap index adjustment is determined as the annual percentage change in the Gross Domestic Product- Implicit Price Index ("GDP-IPI") less the X-factor (0.72% for productivity plus a stretch factor).

With respect to the GDP-IPI Algoma acknowledged that for purposes of the filed application it used an estimate of 1.8%, which would be updated with the Board's final number prior to the calculation of the final rates.

With respect to the stretch factor, Algoma proposed a factor of 0.4%, being the mid-point between 0.6% and 0.2%, contending that a stretch factor determined on the basis of comparative operating cost per customer is not valid. This differs from the 0.6% associated with the stretch factor rankings for Algoma that were identified in the Board's latest communication, dated December 1, 2011, for 2012 IRM 3rd Generation applications. Algoma elaborated on the circumstances underlying the Board's decision pertaining to RRRP, in Algoma's cost of service proceeding to set 2007 rates, in order to justify the use of an alternative factor in this proceeding. The question of the specific stretch factor for Algoma is addressed further on in this submission.

Submission

Productivity Factor

Board staff notes that the price cap index calculated by Algoma may contain a calculation or transcription error. The index reflects a productivity factor of 0.60% rather than the prescribed 0.72%.[5] Board staff assumes that Algoma will utilize the prescribed number in its calculations. In the event that Algoma actually intended to use 0.60% as its productivity factor, Board staff asks that Algoma in its reply submission provide the

[4] The question of the specific stretch factor for Algoma is addressed further in this submission.

rationale and derivation of the 0.60% and explain the apparent contradiction with the 0.72% quoted on page 10 of the Application.

Stretch Factor

Board staff submits that for the following reasons, Algoma's calculation of the price cap index must utilize a stretch factor of 0.60% pursuant to the Board's letter to all Licensed Electricity Distributors dated December 1, 2011 referencing "Board Determination of Stretch Factor Rankings for 2012 3rd Generation Incentive Regulation Applications (IRM3)". The stretch factor in this recent communication is unchanged from the one communicated on March 10, 2011 for 2011 applications.

Board staff submits that, firstly, the 2012 IRM proceeding is not the appropriate venue for Algoma to raise issues pertaining to the Board's separate determination as to which stretch factor applies.

Secondly, Board staff questions Algoma's assertion that the reference in the EB-2007-0744 Decision to Algoma's service area as "high cost" and "low revenue" supports the conclusion that a stretch factor based on a comparison of operating costs per customer is not suitable for Algoma. The circumstances giving rise to that characterization of Algoma's service area pertained to the unreasonable rates that would result for the majority of Algoma's if traditional rate-making principles were applied. The Board took notice of the size of the service territory, the large asset base and low customer density as the basis for which RRRP was the non-traditional but appropriate rate-making response in the circumstances.[6] It is not apparent to Board staff that there is a linkage, as claimed by Algoma, between the circumstances which prompted the introduction of RRRP to mitigate what otherwise could be viewed as unreasonable rates and a separate fact-based determination of a particular utility's productivity ranking.

Thirdly, Board staff notes that, during the Board's development, consideration and determination of stretch factors to be utilized in the IR mechanism, Algoma did not take any action to make its views or concerns known to the Board since it did not believe that IRM would apply to it because of the RRRP[7]. Board staff notes that the adoption of O. Reg. 445/07 and the amendment of O. Reg 442/01 were dated August 2, 2007 and July

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[5] Board staff interrogatory response No. 7
6 Response to Board staff interrogatory No. 2
7 ibid

5, 2007 respectively while the Board's *Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, which assigned utilities to one of three groups with stretch factors based on their efficiency as determined through comparative cost analysis, was dated July 18, 2008.

Regardless of the RRRP, if Algoma viewed the stretch factor methodology as inappropriate because of its special circumstances, then the onus was on Algoma (or its predecessor) to make its position and concerns known so that they could be properly considered by the Board. Board staff submits that Algoma's failure to communicate its concerns to the Board, because it did not believe that IRM based rate making would apply to it, is not a justifiable basis for applying a stretch factor different than that communicated by the Board.

RRRP ADJUSTMENT

Background

Sections 3.1 and 3.2 of the O. Reg.442/01 set out how the rates for RRRP eligible customers are to be derived.

> (3.1) For each year, in respect of the rates for a distributor serving consumers described in paragraph 5 of section 2, the Board shall calculate the amount by which the distributor's forecasted revenue requirement for the year, as approved by the Board, exceeds the distributor's forecasted consumer revenues for the year, as approved by the Board. O. Reg. 335/07, s. 1 (2).
>
> (3.2) For the purpose of subsection (3.1), the distributor's forecasted consumer revenues for a year shall be based on the rate classes and on the rates set out for those classes in the most recent rate order made by the Board and shall be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O. Reg. 335/07, s. 1 (2).

In the EB-2010-0297 Decision the Board confirmed the specific methodology that would be followed to calculate the RRRP adjustment, being in effect the equivalent of "… the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year".

For purposes of completing the Application, Algoma utilized a proxy amount of 1.75%, with the full understanding that it would be updated once it received the final number from the Board. By way of letter dated December 7, 2011, the Board indicated that the RRRP adjustment to be utilized in the setting of 2012 rates is 2.81%.

Submission

Board staff assumes that Algoma will reflect a 2.81% RRRP adjustment in its draft Rate Order and requests that Algoma confirm this fact in any reply submission it may file.

2012 REVENUE COST RATIO MODEL

Background

Algoma's proposed rates for 2012 reflect an adjustment to the existing Board-approved Revenue to Cost ratios. Algoma proposes to incrementally move the Residential R-2 and Street lighting ratios to the lower boundary of the range over 4 years, which will also result in an offsetting shift in the Residential R-1 and Seasonal ratios, moving their ratios toward unity. The existing and proposed ratios for 2012 are presented in the table below.

Revenue to Cost Ratios			
	2011 (EB-2009-0278)	Proposed 2012	Range
Residential R-1	114.1%	112.30%	85%-115%
Residential R-2	59.8%	64.85%	80%-180%
Seasonal	115.0%	113.20%	85%-115%
Streetlighting	43.0%	49.75%	70%-120%

Algoma indicated that its proposed changes do not rely on any prior Board decisions that specifically approved or prescribed a phase-in period to adjust Algoma's Revenue to Cost ratios [8] and that it will follow the Board's direction in this proceeding regarding this requested change.[9] In the process of calculating rates for 2012, Algoma implements the Revenue to Cost ratio changes as one of the first steps in the series of calculations to generate rates and the level of RRRP. The calculation starts with the 2011 pre-RRRP base revenue requirement that reflects Revenue to Cost ratio of 100%, to which the price cap index is applied. After the cap index has been applied, the revenue requirement amounts by class are adjusted to reflect the proposed changes in the Revenue to Cost ratios.

8 Response to Board staff interrogatory No. 5b.
9 Response to VECC interrogatory No. 3.

Submission

Board staff submits that the Board should deny the adjustments to the Revenue to Cost ratios proposed by Algoma. The Filing Requirements, at page 24, state that "…changes to revenue-to-cost ratios, other than pursuant to a prior Board decision" are to be excluded from the IRM application process. Algoma has provided little or no evidence to justify why an exception to the Board's requirements is warranted.

In the event that the Board determines that changes to the Revenue to Cost ratios are appropriate in this proceeding, Board staff wishes to note the following. In the methodology proposed by Algoma, changes in the Revenue to Cost ratios that affect the R-1 and R-2 customer classes have an impact on the amount of revenue requirement that will be funded in 2012 by RRRP. This results because the RRRP adjustment (average province-wide change in rates) is applied to the post RRRP rates approved in 2011 while the proposed 2012 revenue requirement for each customer class reflects the changes in Revenue to Cost ratios. All else equal this will impact the level of RRRP funding and, depending on the direction of the Revenue to Cost ratio changes, the customers in the rest of the province will be thereby affected.

Board staff views the purpose of O. Reg. 442/01 as that of ensuring that the changes to the rates for RRRP eligible customers equate to the average province-wide change. In this regard, in and of themselves, changes to Algoma's Revenue to Cost ratios should not affect the level of RRRP funding. On the other-hand, province wide changes, to some extent, reflect the impact of Revenue to Cost ratios changes experienced by the other electricity distributors. On balance, Board staff submits that Algoma's approach is not unreasonable.

FEDERAL AND PROVINCIAL INCOME TAXES

Background

Algoma utilized a combined (Federal/ Provincial) tax rate of 26.25% for 2012 to calculate the 2012 tax savings, amounting to $47,983 to be shared with ratepayers. The 26.25% does not reflect the Ontario Small Business Deduction ("OSBD"). If the OSBD calculation is included, the amount to be shared totals $107,897. [10]

10 Response to Board staff interrogatory No.3.

Algoma explained that it is a wholly-owned subsidiary of FortisOntario Inc. which is a wholly-owned subsidiary of Fortis Inc. Fortis Inc. is considered a public corporation under the Income Tax Act and Algoma is considered a corporation controlled by a public corporation under the Income Tax Act. Since Algoma is not considered a Canadian-controlled private corporation ("CCPC"), as it is owned indirectly by a public corporation, it does not qualify for the OSBD. In addition Algoma stated that even if it were eligible for the OSBD, the surtax regarding OSBD would have fully clawed back the OSBD since Algoma's taxable income is greater than $1.5 million.

Submission

Board staff notes that Algoma's predecessor company, Great Lakes Power Limited ("GLPL"), filed its most recent rates applications on a stand-alone basis for the distribution business, even though GLPL also carried on other activities. While GLPL as a whole was 100% equity financed, the debt and equity of the distribution business was quantified on a stand-alone basis and taxes were calculated on that basis. The Board approved the stand-alone approach as the basis for setting GLPL's rates, including the calculation of taxes.[11] Board staff does not believe that a change in ownership should result in discontinuation of the stand alone principle. Board staff submits that the tax calculation to determine the amount of tax savings to be shared with customers should treat Algoma as if it were a stand-alone distribution company and therefore the amount to be shared should be $107,897. Board staff's understanding is that the threshold test (claw-back) Algoma refers to was eliminated effective July 1, 2010 and Board staff asks Algoma that Algoma confirm this in its reply submission.

SMART METERS

Background

Algoma's current Board-approved rates for the Residential R-1, Residential R-2 and the Seasonal Customer classes include a Smart Meter Funding Adder ("SMFA") of $1.00 per month. Algoma noted that for some other distributors the Board had included a sunset date of April 30, 2012 in the 2011 rate orders. Algoma is proposing to continue its existing SMFA, but with a sunset date of April 30, 2012. In response to Board staff interrogatory No. 4, Algoma indicated that it would file for a final prudence review late in

11 Pg. 38-40 in EB-2007-0744 Decision dated October 30, 2008

the first quarter or early in the second quarter of 2012. Staff notes that Algoma's current tariff includes an SMFA of $1.00 per month per metered customer with no sunset date.

Submission

Board staff agrees with Algoma's request to add an April 30, 2012 sunset date to the SMFA that will continue in the proposed rates for 2012. In addition to aligning the SMFA treatment to that afforded other distributors, it will also encourage Algoma to file for the final disposition of smart meter balances as soon as is practicably possible.[12]

RETAIL TRANSMISSION SERVICE RATES ("RTSR") ADJUSTMENT

Background

Algoma did not utilize the RTSR Workform to calculate its RTSRs for 2012. Instead Algoma is proposing to increase the existing RTSRs by the corresponding % increase in Uniform Transmission Rates ("UTR") between 2010 and 2011. Algoma noted that the existing Board approved RTSRs were based on 2010 and not 2011 UTRs. Algoma explained that to avoid the effect of compounding adjustments based on historical trends in the RTSR and the introduction of future year variances, the only changes that ought to be made are those rate changes arising from changes in the UTR. Algoma proposed to utilize the Board's RTSR Adjustment Workform in a future application when current transmission rates charged by the IESO are aligned with the most recent RTSRs charged by Algoma.[13]

A comparison of the existing, Proposed and Workform-based RTSR are shown in the tables below.

[12] In response to Board staff interrogatory Algoma indicated that it will have audited 2011 smart meter costs midway through the first quarter and that it would file for a final prudence review late in the first quarter or early in the second quarter of 2012.
13 Response to Board staff interrogatory No. 8.

		Proposed		Per Workform		Existing	
		Network	Connection	Network	Connection	Network	Connection
Residential - R1	kWh	$ 0.0062	$ 0.0049	$ 0.0064	$ 0.0049	$ 0.0057	$ 0.0047
Residential - R2	kW	$ 2.3004	$ 1.7452	$ 2.3808	$ 1.7338	$ 2.1218	$ 1.6634
Residential - R-2 Interval Metered > 1000kW	kW	$ 2.4403	$ 1.9288	$ 2.5256	$ 1.9162	$ 2.2508	$ 1.8384
Seasonal	kWh	$ 0.0062	$ 0.0049	$ 0.0064	$ 0.0049	$ 0.0057	$ 0.0047
Street Lighting	kW	$ 1.7349	$ 1.3491	$ 1.7955	$ 1.3403	$ 1.6002	$ 1.2859

		Proposed % inc./(dec. = -) as compared to			
		Workform		Existing	
		Network	Connection	Network	Connection
Residential - R1	**kWh**	-3.1%	0.0%	8.8%	4.3%
Residential - R2	**kW**	-3.4%	0.7%	8.4%	4.9%
Residential - R-2 Interval Metered > 1000kW	**kW**	-3.4%	0.7%	8.4%	4.9%
Seasonal	**kWh**	-3.1%	0.0%	8.8%	4.3%
Street Lighting	**kW**	-3.4%	0.7%	8.4%	4.9%

Submission:
Board staff asks that Algoma in its submission identify, and if necessary, correct any misstatements in the tables above.

Board staff submits that the purpose of the RTSR Workform is to attempt to align a distributor’s wholesale electricity costs with the charges recovered from customers. The RTSR Workform uses a distributor’s historical wholesale costs and adjusts these costs once the new uniform transmission rates become available. The most recent historical load is used as a proxy for the test year costs.

Board staff questions Algoma’s argument that it is inappropriate to use the RTSR Workform to calculate the 2012 RTSRs because the 2011 UTRs were unavailable when the existing RSTRs were set. The RTSR Workform uses the best information available at the time to set rates going-forward. Board staff believes that it is not meant to offset or true-up for historical variances.

Board staff submits that the 2012 RTSR be set using the RTSR Workform.

DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS AS PER THE ELECTRICITY DISTRIBUTORS' DEFERRAL AND VARIANCE ACCOUNT REVIEW REPORT (THE "EDDVAR REPORT")

Background

Algoma's amended application, dated October 13, 2011, provides for the disposition of its Group 1 deferral and variance accounts. In its amended application Algoma notified the Board that a routine regulatory audit is underway concerning its Group 1 Deferral/Variance Account balances.

On December 7, 2011 Algoma filed revised Principal amounts for the period ended December 31, 2010 that reflect the findings of the completed audit. The findings affected the two accounts as shown in the table below. The debit balance in the Power excluding Global Adjustment account increased by $92,168 and the Power Global Adjustment sub account credit balance increased by $199, 717.

	Group 1 Deferral and Variance Accounts			
		Principal amounts as of Dec. 31, 2010 (as filed)	Audit Findings (Dec. 7, 2011 letter)	Revised Principal amounts as of Dec. 31, 2010
RSVA	**Except Global Power Sub-Account**			
1580	Wholesale Market Service Charge	$ (205,889)	$ -	$ (205,889)
1584	Retail Transmission NetWork Charge	$ (27,302)	$ -	$ (27,302)
1586	Retail Transmission Connection Charge	$ (111,180)	$ -	$ (111,180)
1588	Power excluding Global Adjustment	$ 1,987	$ 92,168	$ 94,155
	TOTAL	**$ (342,384)**	**$ 92,168**	**$ (250,216)**
RSVA	**Global Power Sub Account**			
1588	Global Power Sub account	$ (601,137)	$ (199,717)	$ (800,854)

Algoma filed revised Deferral and Variance Account Continuity Schedules as well as a revised rate rider calculation for the disposition of the RSVA (except Global Power Sub-Account) credit balance as of December 31, 2010, including interest, of $258,055. Board staff notes that the disposition of the Global Power sub account balance awaits the billing capacity to do so, pursuant to the EB-2009-0278 Decision.

Submission

Algoma states that the revised amounts are in accordance with the findings of the regulatory audit and on this basis Board staff accepts them as filed. Board staff has reviewed the associated rate rider calculations, including the charge determinants and term. The charge determinants and term are unchanged as compared to what was previously filed. Board staff submits that the revised rate riders should be accepted by the Board.

Board staff requests that in its reply submission Algoma confirm the approximate date by when its billing system will be able to accommodate the disposition of the Global Power sub account balances.

ACCOUNT 1562 (DEFFERED PAYMENTS IN LIEU OF TAXES)

Background

Algoma's filed D/V Continuity schedule shows no amount recorded for the year ended December 31, 2010 for account 1562 while Algoma's RRR 2.1.7 filing for 2010 shows a credit of $273,002. In response to a Board staff interrogatory as to why Algoma did not provide PILS reconciliations pursuant to Board staff's letter dated September 9, 2011 which provided further guidance to distributors related to clearing account 1562, Algoma responded that it decided to defer the matter since its particular circumstances do not lend itself to a straightforward determination and would likely require additional evidence.[14] Algoma noted that deferral of the matter is consistent with the Board's direction found at page 28 of the EB-2008-0381 Decision and Order where the Board stated:

> If the distributor files evidence in accordance with all the various decisions made in the course of this proceeding, including the use of the updated model referenced above and certifies to that effect, the distributor may expect that the determination of the final account balance will be handled expeditiously and in a largely administrative manner.
>
> Distributors are of course able to file on a basis which differs from that which is contemplated by the decisions in this proceeding. In that event, the application can be expected to take some time to process, and therefore, should not be made as part of an IRM application.

[14] Response to Board staff interrogatory No. 9.

Submission

Board staff agrees with Algoma that its circumstances distinguish it from the findings in the Board's EB-2008-0381 Decision and Order, in that it is an entity controlled by a public corporation that pays federal taxes and not PILS, and given the acquisition of Algoma by Fortis from Great Lakes in 2009. Accordingly, Board staff concurs with Algoma's request to defer the disposition of its PILS account to a future proceeding. Board staff submits that pursuant to the direction provided by the Board to certain other 2012 IRM filers, Algoma should file a stand-alone application to dispose of account 1562 by April 1, 2012.

ACCOUNT 1521 – SPECIAL PURPOSE CHARGE ("SPC")

Background

On April 9, 2010, the Board issued a letter and invoice to all licensed electricity distributors outlining the amount of each distributor's SPC assessment and the associated SPC. On April 23, 2010, the Board issued a letter to all licensed electricity distributors authorizing Account 1521, Special Purpose Charge Assessment Variance Account. Any difference between the amount remitted to the Ministry of Finance for the SPC assessment and the amount recovered from customers was to be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

The Board's letter also indicated, in accordance with section 8 of the SPC Regulation (O. Reg. 66/10), electricity distributors are required to apply to the Board no later than April 15, 2012 for an order authorizing them to clear any debit or credit balance in the "Sub-account 2010 SPC Variance". The Board expected that requests for disposition in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charges" would be addressed as part of the proceedings for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation. In addition, the Board's letter indicated that, in accordance with section 9 of the SPC Regulation, recovery of the SPC assessment is to be spread over a one-year period.

Submission

Algoma indicated that is not filing for the disposition of account 1521 in this proceeding but intends to do so by no later than April 15, 2012. Since Algoma bills its seasonal customers on an annual cycle, not all consumption to June 30, 2011 will have be been recorded.

Board staff notes Algoma's intention to file for disposition of the account balances by April 15, 2011 and has no other concerns at this time.

GENERAL UPDATE

In order to facilitate the issuance of a timely rate order, Algoma should consider filing with its reply submission a scenario whereby its final rates are calculated using the following values:

– The RRRP adjustment of 2.81%
– The % change in the GDP-IPI (Price Escalator) of 1.7%
– The Stretch Factor of 0.6%;
– The Productivity Factor of 0.72%;
– No change to the revenue to cost ratios;
– The revised deferral and variance account balance and proposed disposition period;
– The tax sharing amount of $107,897;and
– Revised retail transmission rates based on the RTSR Workform methodology.

All of which is respectfully submitted