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Ontario

BY E-MAIL

January 31, 2012

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

Dear Ms. Walli:

Re: Board Staff Interrogatories
2012 Electricity Distribution Rates
Atikokan Hydro Inc.
Board File No. EB-2011-0293

In accordance with Procedural Order No. 1, please find attached Board staff interrogatories in the above proceeding with respect to Atikokan Hydro Inc.'s application for electricity rates for 2012. Please forward the following to Atikokan Hydro Inc. and to all other registered parties to this proceeding.

Sincerely,

Original Signed By

Keith C. Ritchie
Project Advisor - Applications

Attachment

Atikokan Hydro Inc.
2012 Cost of Service Rates Application
EB-2011-0293

Board staff Interrogatories

Exhibit 1 – Administration

1. Responses to Letters of Comment

Following publication of the Notice of Application, the Board received no letters of comment. Please confirm whether Atikokan Hydro has received any letters of comment. If so, please confirm whether a reply was sent from the applicant to the author of the letter. If confirmed, please file that reply with the Board. Please ensure that the author's contact information, except for the name, is redacted. In the alternative, please explain why a response was not sent and confirm if the applicant intends to respond.

2. Conditions of Service

a) Please identify any rates and charges that are included in Atikokan Hydro's Conditions of Service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.
b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2009 and the revenue forecasted for the 2010 bridge and 2011 test years.
c) Please explain whether, in Atikokan Hydro's view, these rates and charges should be included on its approved Tariff of Rates and Charges.

Exhibit 2 – Rate Base

3. Ref: Exhibit 2/Tab 2/Schedule 1/page 7/Table 2-14 – 2010 Capital Projects

For 2010 capital additions, under Account 1908, Atikokan Hydro documents $31,180 for "Old Garage Siding & Insulation" and $42,118 for "Old Garage Inside & Lighting".

a) Please confirm that the old garage is still in service for Atikokan Hydro. What is the age of the old garage and its expected remaining life?
b) Please explain the purpose(s) for each of the old garage and the new garage that came into service in 2009.

Green Energy Plan

4. Ref: Exhibit 2/Appendix B – Green Energy Act Plan

On page 11 of its Green Energy Act Plan, Atikokan Hydro states that its system is designed with a basic calculation of 3 kW per residential customer, which makes it physically impossible to install a microFIT of more than 5 or 6 kW for most residential connections.

a) Please provide a further description of the design constraint that creates this capacity limit per residential connection.
b) Are there any similar constraints with respect to the capacity for a microFIT connection for a GS < 50 kW customer?
c) Please explain the reasons for any differences in the capacity constraints for microFIT connections between Residential and GS < 50 kW customers.
d) Please explain what work would be needed to remove the constraints on microFIT connections within Atikokan Hydro's distribution system, and any available estimates of the costs for such work.

Exhibit 3 – Operating Revenues

5. Ref: Exhibit 3/Tab 3/Schedule 3/page 1/Table 3-31 and Appendix 2-C – Other Operating Revenues

For Specific Service Charges, Atikokan Hydro shows $32,896 in revenues in 2009 compared to $5,322 in 2008. In Tables 3-32, 3-33 and 3-34, for 2010 actuals and forecasts for the 2011 bridge and 2012 test years, Atikokan Hydro documents the Specific Service Charge revenues declining to within the range of $6,000 to $7,100. Please provide an explanation for the high level of Specific Service Charge revenues in 2009 relative to prior and subsequent years.

6. Ref: Exhibit 3/Tab 3/Schedule 3 and Appendix 2-C – Other Operating Revenues

The following is a copy of Appendix 2-C as filed by Atikokan Hydro. Board staff has highlighted certain rows to aid in understanding the issue.

Other Operating Revenue

USoA #	USoA Description	Actual 2008	2009	2010	Bridge 2011	Test 2012
4235	**Specific Service Charges**	$ 5,322	$ 32,896	$ 6,745	$ 7,100	$ 7,100
4225	**Late Payment Charges**	$ 5,624	$ 7,043	$ 6,024	$ 6,024	$ 6,024
4080	**SSS Admin Charges**	$ 4,816	$ 7,189	$ 4,788	$ 4,654	$ 4,200
4082	**Retailer Service Revenues**	$ 4,062	$ 3,648	$ 7,234	$ 4,000	$ 4,000
4084	**Retailer Processing Revenues**	$ 6,113	$ 6,324	$ 2,250	$ 1,000	$ 1,000
4210	Elec Prop Rentals	$ 35,045	$ 38,196	$ 34,911	$ 34,911	$ 34,911
4355	Gain Disposal	$ -	$ -	$ -	$ -	$ -
4360	Loss Disposal	-$ 5,526	$ -	$ -	-$ 2,942	$ -
4375	Revenue Non Utility	$ 30,350	$ 171,460	$ 232,108	$ 232,000	$ 232,000
4380	Expense Non Utility	-$ 30,463	-$ 171,460	-$ 232,108	-$ 232,000	-$ 232,000
4390	Misc Income	$ 4,152	$ 1,878	$ 93,568	$ 59,000	$ 59,000
4405	Interest /Dividend	$ 11,341	$ 9,542	$ 14,799	$ 9,000	$ 9,000
Specific Service Charges		$ 5,322	$ 32,896	$ 6,745	$ 7,100	$ 7,100
Late Payment Charges		$ 5,624	$ 7,043	$ 6,024	$ 6,024	$ 6,024
Other Operating Revenues		$ 50,036	$ 55,357	$ 49,183	$ 44,565	$ 44,111
Other Income or Deductions		9,854	11,420	108,367	65,058	68,000
Total		$ 70,836	$ 106,717	$ 170,318	$ 122,747	$ 125,235

[1] List and specify any other interest revenue

Revenues or costs (including interest) associated with deferral and variance accounts should not be included in Other Revenue.

4390	Misc Revenue	Actual 2008	2009	2010	Bridge 2011	Test 2012
	Misc sales	$ 33	$ 1,838			
	Sale of Cunningham power lines	$ 2,279				
	Pst Compensation	$ 40	$ 40	$ 40	$ -	$ -
	Misc services	$ 300		$ 89,845	$ 57,100	$ 57,500
	Payments rec'd on closed accounts	$ 1,500		$ 1,153	$ 400	
	OPA incentives			$ 2,530	$ 1,500	$ 1,500
Total		$ 4,152	$ 1,878	$ 93,568	$ 59,000	$ 59,000

4405 - Interest and Dividend Income	Actual 2008	2009	2010	Bridge 2011	Test 2012
Bank Deposit Interest	$ 5,678	$1,823	$1,388	$1,179	$1,388
Miscellaneous Interest Revenue	$ 5,663	$7,719	$13,411	$7,821	$7,612
Total	$ 11,341	$ 9,542	$ 14,799	$ 9,000	$ 9,000

With respect to Accounts 4375 – Revenue Non-utility and 4380 – Expense Non-utility, please explain:

a) the increase in revenues and expenses from 2009 onwards; and
b) the reason that non-utility expenses fully offset revenues.

7. Ref: Exhibit 3/Tab 3/Schedule 3 and Appendix 2-C – Other Operating Revenues

With respect to Appendix 2-C (as shown in the preceding interrogatory), for Miscellaneous Service Revenues, Atikokan Hydro shows $89,845 in 2010 and forecasts of $57,100 for the 2011 bridge year and $57,500 for the 2012 test year. In E3/T3/S3/page 2/Table 3-32, Atikokan Hydro shows a 2010 actual for Merchandise & Jobbing of $86,125, and explains the increase as recording the amounts as revenues in 2010 rather than as an offset to expenses.

a) Please explain the difference of $86,125 shown in Table 3-32 for 2010 and $89,845 shown in Appendix 2-C.
b) Please describe what work these revenues were for.

c) Please explain why Atikokan Hydro forecasts these Miscellaneous Service revenues to decrease to around $57K in each of 2011 and 2012.
d) What were Atikokan Hydro's unaudited actuals for 2011 for Account 4990?

8. Ref: Exhibit 3/Tab 3/Schedule 1/Table 3-27 – Throughput Revenue

Please provide an update of Table 3-27 including columns for 2011 unaudited actuals and the variance between 2010 actuals and 2011 unaudited actuals.

Load Forecast

9. Ref: Exhibit 3/Tab 2/Schedule 1

In its application, Atikokan Hydro documents the number of customers and connections by class and by year in Table 3-7 of this exhibit.

Analysis indicates that Atikokan Hydro has a ratio of streetlight connections to metered customers of about 1:2.67. The ratio of streetlight connections to residential customers is above 1:2. These ratios would seem high relative to those of other utilities and for the industry as a whole. For example, Kenora Hydro, in its 2010 EDR Cost of Service application, documented approximately 2700 residential customers, 702 GS < 50 kW customers and 75 GS > 50 kW customers versus 550 streetlighting connections.

a) Please explain how Atikokan Hydro has defined and counted its streetlighting connections.
b) What characteristics of Atikokan Hydro's service area or of its distribution network design drive the significantly higher ratio of streetlighting connections to metered customers?
c) Are all streetlights separate connections or are there configurations where streetlights are connected in a daisy chain (i.e., the demarcation point is at a connection to one street light, often with a photovoltaic cell to activate the streetlights based on external light levels, with a number of streetlights connected and controlled from this connection point)?

10. Ref: Exhibit 3/Tab 2/Schedule 1 – Consumption per Customer/Connection

In Tables 3-10 and 3-12, Atikokan Hydro provides the actual and forecasted average consumption (kWh) per customer, by customer class. Atikokan Hydro explains that it calculated the average forecasted consumption by applying the geometric mean for the period 2003 to 2010 to the 2010 data, and this was done

on a class-specific basis. The annual percentage changes in per customer consumption by class is shown in Table 3-11.

Board staff observes that the class-specific annual percentage changes show significant swings. However, the geometric means seem reasonable and may reflect typical energy efficiency and conservation efforts, while variation may largely be driven by weather and economic factors.

However, the geometric mean of a (1.5%) change (reduction) for the Streetlighting class means that the average annual consumption is reduced to 768 kWh for 2011 Bridge year and 757 kWh for the 2012 Test year.

a) Please explain what initiatives have been undertaken in recent years or are proposed for the 2012 Test year that would support the forecasted reductions in the average annual consumption per Streetlight connection.
b) Please update Tables 3-10 and 3-11 showing 2011 actual results.
c) Please explain any material differences between the 2011 Bridge year forecast and the 2011 actual results from part b).

Exhibit 4 – Operating Expenses

11. Ref: Exhibit 3/Tab 3/Schedule 3/Tables 3-33 and 3-34

For Merchandise & Jobbing, Atikokan Hydro documents 2010 actual revenues of $86,125, but forecasts revenues of $55,000 for each of the 2011 Bridge and 2012 Test years.

a) Please provide unaudited actuals for Merchandise & Jobbing revenues for 2011. Please provide a description of the work performed for which these revenues pertain to.
b) Please explain any material difference between the 2011 forecast and the 2011 unaudited actuals.
c) Please provide further explanation of why Atikokan Hydro is forecasting a decline in Merchandise & Jobbing revenues for 2012.

12. Ref: Exhibit 4/Tab 2/Schedule 3/Table 4-21 and Appendix 2-H – Regulatory Costs

Atikokan Hydro has proposed to include $50,000 in operating expenses, calculated as ¼ of $200,000 budgeted for the preparation of this Application. In Appendix 2-H, Atikokan Hydro shows $50,000 as the 2012 portion, fully allocated to external consulting costs. No estimate for intervenors' costs are shown.

Please provide a breakdown, and the basis for the estimate, of regulatory costs budgeted for this Application with respect to:

a) legal costs;
b) consulting costs;
c) intervenor costs; and
d) OEB costs.

13. Ref: Exhibit 4/Tab 2/Schedule 6 – Employee Count and Compensation

In E4/T2/S6 and Table 4-24, Atikokan Hydro provides information on the number of employees and compensation from its last rebasing in 2008. With respect to the 2012 Test year compared to the 2011 Bridge year, Atikokan Hydro states, at pages 5-6:

> Atikokan Hydro's increase in full time employees is dependent on a few factors. Atikokan Hydro may have another retires [sic] in 2012 and will require to hire an apprentice if the employees chooses to retiree [sic]. Atikokan Hydro estimates this to cost an additional $30,000. Furthermore, if the demands of the smart meters continue, another employee will be required on a full time basis. This is expected to be another $30,000 to Atikokan Hydro. (Currently, Atikokan Hydro has one part-time employee; less than three, who is considered to be Full-Time for purposes of this application) These factors have been taken into consideration when forecasting the total 2012 test year employee costs. Further, the April 1, 2012 wage increases were also taken into consideration by taking 2011 wages adding 2.5% as per the collective agreement.

In Table 4-24, there is documented an increase of FTEs of 1 (from 8 to 9) and a change in compensation of $73,876 from 2011 to 2012.

a) Please explain how Atikokan Hydro has estimated an incremental cost of $30,000 for the 2012 test year for the expected retirement.
b) Atikokan Hydro's evidence reads as if this potential retirement could be voluntary or discretionary. Has the retirement occurred or been confirmed?
c) Will Atikokan Hydro find itself in a similar situation regarding succession planning for its workforce in subsequent years (i.e., are retirements likely to continue in 2013, 2014, etc.), or is 2012 a one-time occurrence?
d) Please explain what smart meter-related demands Atikokan Hydro is referring to as justifying a $30,000 increase in compensation and an

increase in work force.

e) Atikokan Hydro has documented an increase in staffing from 7 to 9 employees from 2008 to 2012, and also notes increased costs for outside services. At the same time, Atikokan Hydro documents a decline in the number of customers and in the energy consumption. Please provide further explanation of the increases in the number of employees and compensation and the increase in outside services used, given a reduction in demand.

14. Ref: Exhibit 4/Tab 2/Schedule 7/page 1 – Asset Retirement Obligations

a) Please confirm that Atikokan Hydro has not recognized any asset retirement obligations.

b) Please confirm that Atikokan Hydro will not seek recovery of any asset retirement obligations in the future.

15. Ref: Exhibit 4/Tab 2/Schedule 1 – Efficiencies

On page 4 of E4/T2/S1, Atikokan Hydro states:

> Meter reading is completed using Savage Data for smart meters with the exception of a few customers who have smart meters with demand that have to be read and reset by line crew. The time spent meter reading has significantly been reduced. There is no cost savings to Atikokan Hydro as the meter reading has always been completed by in-house staff; line crew. This however does allot more available to complete other OM&A activities.

a) Please explain Atikokan Hydro's statement that this does not result in cost savings. Does the automation of most of this not mean that staff are available to work on other matters such as maintenance and operations, to improve reliability and safety and to reduce load losses? Would this mean that overtime expenses should be, or have been, reduced as a result?

b) Please explain how this re-deployment of staff for other OM&A expenses has been factored into Atikokan Hydro's 2012 Test year forecast.

16. Ref: Exhibit 4/Tab2/Schedule 6 – Ontario Municipal Employees Retirement System Pension Costs

On page 1 of E4/T2/S6, Atikokan Hydro states that all full-time staff participate in the OMERS pension plan. OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013.

Please state whether or not Atikokan Hydro's proposed pension costs include this increase. If so, please provide the forecasted increase by years and the documentation to support the increases. If not, please state how Atikokan Hydro proposes to deal with this increase.

17. Exhibit 4 – Donations

Please identify whether or not Atikokan Hydro has included any charitable or political donations as part of its forecast OM&A expense for the 2012 Test Year. If yes, please identify the amounts and the account in which the donations are recorded, and whether the amounts are compliant with Section 2.7.2.5 of the *Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011.

PILs

18. Ref: Taxes/PILs Excel Model

a) On Sheet "L. Sch. 7-1 Loss Cfwd Bridge", Atikokan Hydro shows that it is applying the historical loss carry-forward of $4382 to the 2011 Bridge year to reduce taxable income. However, it appears from other sheets, that Atikokan Hydro has a negative net taxable income before taxes. Please confirm and explain that the loss carry-forward is applicable for the 2011 Bridge year.
b) On Sheet "M. Adj. Taxable Income Bridge", there is no entry in cell E8 "Income before taxes/PILs". Please confirm that the 2011 Bridge year amount should be $nil. If not, please correct.
c) If there are adjustments above that would affect the estimated taxes or PILs payable for the 2012 Test year, please revise the Taxes/PILs spreadsheet for the 2012 Test Year.

Exhibit 5 – Cost of Capital

19. Ref: Exhibit 5/Tab 1/Appendix A – Long-term Affiliated Debt

Please provide copies of the following documents:

a) Loan with Town of Atikokan, with a December 31, 2010 principal of $1,282,096;
b) Loan with Atikokan Enercom Inc., with a December 31, 2010 principal of $400,000; and
c) Copy of Resolution 389 dated January 21, 2009.

20. Ref: Exhibit 5/Tab 1/Schedule 1/page 2 – Long-term Debt

E5/T1/Appendix A states that three of the debt instruments, including the debt due to Atikokan Enercom Inc. and the two loans due to TD Canada Trust, have variable rates set at "prime +".

a) E5/T1/S1/page 2/line 4 provides a table with the forecasted rates for all instruments. Please provide the estimate of the prime rate used for the forecasts of each of the TD Canada Trust loans and for the Atikokan Enercom Inc. loan. Please provide the date of the prime rate used and the source.
b) How frequently is the applicable rate updated for each loan?
c) If the rates have been updated since the filing of the Application on September 29, 2011, please provide the updated rates and the date of the update.

Exhibit 8 – Rate Design

Transformer Allowance Credit

21. Ref: Exhibit 8/Tab 1/Schedule 4 – Transformer Allowance Credit

In Exhibit 8/Tab 1/Schedule 1, Atikokan Hydro states:

> Currently, Atikokan Hydro provides a Transformer Allowance to those customers that own their transformation facilities. Atikokan Hydro proposes to maintain the current approved transformer ownership allowance of 10% of the distribution volumetric rate for the GS > 50 kW class (i.e. $0.17 per kW). The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

Establishing the Transformer Allowance Credit at 10% of the volumetric rate for the customer class that the customer was in was determined by the Board in its consideration of Atikokan Hydro's application for 2006 rates. In its Decision with respect to with respect to that application, the Board stated:

> The Board finds the current situation of the utility, whereby the transformer allowance credit exceeds the distribution volumetric

charge, is not sustainable. To maintain the financial integrity of Atikokan Hydro while providing some compensation and incentive to customers who have purchased or may be considering purchasing their own transformers, the Board authorizes the transformer ownership credit for Atikokan Hydro to be equal to 10% of the distribution volumetric charge applicable to the customer.

a) Since Atikokan Hydro is proposing an increased volumetric rate for customers in the GS > 50 kW class of $2.1813/kW, why is the Transformer Allowance Credit not proposed to increase to $0.21813/kW?
b) Please recalculate the transformer allowance credit and the adjustment to the GS > 50 kW class assuming that the Transformer Allowance Credit is set equal to 10% of the volumetric rate.
c) With the consolidation of the previous GS 50 to 999 kW and GS 1,000 to 4,999 kW classes approved by the Board in Atikokan Hydro's last Cost of Service rebasing application, the volumetric rate for the GS > 50 kW class is significantly higher than $0.60/kW. Board staff also observes that Sheet O3.1 would support a Transformer Allowance Credit of $0.31/kW. Please provide Atikokan Hydro's views on the appropriateness of adopting a Transformer Allowance Credit of $0.31/kW based on the cost allocation model results and the fact that the class volumetric rate is significantly higher than any TAC.

Loss Factors

22. Ref: Exhibit 8/Tab 1/Schedule 3

In Table 8-9, Atikokan Hydro shows the following distribution system loss factors, by year:

	Historical Years					5-year average
	2006	2007	2008	2009	2010	
Loss Factor in Distributor's System	1.0624	1.0536	1.0949	1.1014	1.0733	1.0730

Board staff observes a significant increase in distribution system losses, calculated on a percentage basis, in 2008. Early in 2008, Atikokan Hydro had a reduction in load due to loss of a major customer, and the utility has noted the decline in customer base and demand in its evidence in Exhibit 3 of the Application.

Atikokan Hydro also documents that another factor contributing to its losses is the presence of 23 km of 44 kV sub-transmission line owned and operated by the utility to deliver electricity from Hydro One's Moose Lake TS to the distribution

network in the Town of Atikokan.

Nonetheless, distribution system losses of the magnitude calculated by Atikokan Hydro are significantly higher than for most utilities, and result in increased costs being borne by Atikokan Hydro's ratepayers.

a) Please explain the drivers of the increased system losses since 2007.
b) Please explain in some detail what efforts Atikokan Hydro has undertaken in recent years, or has planned for the 2012 Test year, for system refurbishment, replacement, or maintenance to address the level of distribution system losses. If Atikokan Hydro is not trying to address this as a capital or operational priority, please explain why.

Proposed Tariff of Rates and Charges

23. Ref: Exhibit 8/Tab 1/Schedule 6 and Exhibit 8/Tab 1/Schedule 7 – Proposed Tariff and Revenue Reconciliation

E8/T1/S6 provides the proposed Tariff of Rates and Charges. E8/T1/S7 provides the reconciliation of the class revenue requirement and the revenues recovered from proposed rates. Table 8-11 replicates Appendix.2_U_Rev_Reconciliation of the Appendices to *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011.

Board staff observes that the revenue reconciliation nets to $nil as Atikokan Hydro has not rounded the proposed monthly service charge and volumetric rates to what it is showing on the proposed Tariff of Rates and Charges. All proposed rates should be rounded to correspond with what the utility will be authorized to charge if the Application is approved as filed.

If, as a result of responses to all other interrogatories, Atikokan Hydro is revising its proposed rates, please provide updates of the proposed Tariff of Rates and Charges and of Table 8-11 and App.2-U_Rev_Reconciliation.

24. Ref: Exhibit 8/Tab 1/Schedule 8 and Exhibit 3/Tab 2/Schedule 1/Table 3-10 – Bill Impacts and Rate Mitigation

In E8/T1/S8, Atikokan Hydro documents the bill impacts resulting if its Application is approved as filed. This includes the proposed rate mitigation of deferring disposition of Groups 1 and 2 Deferral and Variance account balances to 2013 and inclusion of a rate rider of a credit of $0.0034/kWh to reduce the bill impact on a residential customer to under 10%.

From Atikokan Hydro's evidence in Table 3-10 in Exhibit 3, Atikokan Hydro shows a 2012 test year average annual consumption of 6973 kWh. This works

out to an average monthly consumption of 581 kWh, significantly below the commonly accepted "normal" residential monthly consumption of 800 kWh.

What this suggests is that, based on the estimated bill impacts for Residential customers with 500 kWh and 680 kWh consumptions, the overall bill impacts will still exceed 10% for a typical residential customer in Atikokan.

a) Please provide Atikokan Hydro's perspective on what is a "typical" residential bill, and whether the mitigation proposal based on the 800 kWh Residential customer bill impact being limited to 10% will still result in significant bill increases for the majority of customers.
b) Please provide Atikokan Hydro's perspective on whether further mitigation may be warranted to address significant bill impacts over 10% if necessary. If Atikokan Hydro believes that further mitigation efforts may be necessary, please provide Atikokan Hydro's proposal.
c) Please provide evidence on the percentage of customers with typical monthly consumption in the following ranges:
    i. Less than 500 kWh;
    ii. 500 to 600 kWh;
    iii. 600 to 700 kWh;
    iv. 700 to 800 kWh;
    v. 800 to 1000 kWh; and
    vi. Greater than 1000 kWh.

Exhibit 9 – Deferral and Variance Accounts

Deferral and Variance Accounts Other than Accounts 1562, 1555 and 1556

25. Ref: Exhibit 9/Tab 1/Schedule 2/page 1

In its application, Atikokan Hydro states:

> In addition, at the time this application was being prepared Atikokan Hydro's 2010 deferral and variance account balances were under an audit review by Board staff from the Regulatory Audit & Accounting department. The outcome of this audit could impact the 2010 balances which suggest to Atikokan Hydro that seeking disposition of these amounts would not be prudent at this time.

Board staff would like to clarify that the Board's Regulatory Audit and Accounting department has not undertaken an audit review of Atikokan Hydro's 2010 deferral and variance account ("DVA") balances. Board staff understands that Atikokan Hydro has had discussions with Regulatory Audit and Accounting staff in June 2011, where the latter provided some guidance regarding regulatory accounting treatment of deferral and variance accounts. The guidance included references

to Article 490 of the Accounting Procedures Handbook and the accounting procedures for recording the balances in the DVAs. Please confirm that Atikokan Hydro has the same understanding of its discussions and interactions with the Board's Regulatory Audit and Accounting department.

26. Ref: Exhibit 9 and Deferral and Variance Account Continuity Schedule

Has Atikokan Hydro made any adjustments to deferral and variance account balances that were previously approved by the Board, subsequent to the balance sheet date that are proposed to be cleared in the current application? If yes, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

27. Ref: Page 6 of Revised Evidence for Accounts 1592 filed on December 14, 2011, Chapter 2 of Filing Requirements for Transmission and Distribution Applications, issued June 22, 2011

Page 47 of the Chapter 2 of the revised *Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011, states that:

> The Board expects distributors to file for disposition of account 1592 in their cost of service applications.

In this Application, Atikokan Hydro states that:

> Consistent with the rate mitigation plan set out in the Atikokan Hydro's 2012 cost of service rate application, Atikokan Hydro is seeking to defer the disposition of the balance in account 1592 until the 2013 IRM application.

Independent of its proposal, and in the case that the Board does consider disposition of Atikokan Hydro's DVA balances, please complete and file Appendix 2-T from Chapter 2 of the Filing Requirements published June 22, 2011 in support of the request for the disposition of account 1592.

28. Ref: Page 6 of Revised Evidence for Account 1592 filed on December 14, 2011

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization, applicants may benefit from an overall net reduction in costs in the form of Input Tax Credits ("ITCs"). This arises due to cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that have become subject to the HST. These

cost decreases may be partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

During the 2010 IRM application process, the Board directed electricity distributors to record in deferral account 1592 (PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits ("ITCs")), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

In December 2010, as part of its Frequently Asked Questions on the *Accounting Procedures Handbook* for electricity distributors, the Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities.

No additional amounts should be recorded in Account 1592 (PILs and Tax Variances, Sub-account HST/OVAT ITCs) for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement. For the 2012 Test Year, for example, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to December 31, 2011 since the Test Year would include the HST impacts in rates going forward.

a) Please confirm that zero amounts will be recorded in Account 1592, sub-account HST/OVAT ITCs for the 2012 Test Year and going forward. If this is not the case, please explain.
b) Please confirm that only the balance in Account 1592 "Sub-account HST / OVAT ITCs" is being requested for disposition, and not the contra account Account 1592 "HST/OVAT Contra Account", which is used only for RRR reporting purposes. If this is not the case, please explain.

29. Ref: Exhibit 9/Tab 1/Schedule 1/Table 9-1 a Account 1521

According to the Board's letter of April 23, 2010 with respect to the Special Purpose Charge:

> In accordance with section 9 of the SPC Regulation, recovery of your SPC assessment is to be spread over a one-year period, starting from the date on which you begin billing to recover your assessment. The request for disposition of the balance in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charge" should be made after that one-year period has come to an end, and all bills that include amounts on account of that assessment have come due for payment.

In accordance with section 8 of the SPC Regulation, you are required to apply to the Board no later than April 15, 2012 for an order authorizing you to clear any debit or credit balance in "Sub-account 2010 SPC Variance.

a) Please confirm that Atikokan Hydro is requesting disposition of Account 1521 in compliance of the Board's requirement. In the alternative, please explain.
b) Please provide the timing of the completion of the recovery period.
c) Please provide the principal balance in account 1521, "Sub-account 2010 SPC Variance" as of the completion of the recovery period.
d) Please provide the forecasted carrying charges in "Sub-account 2010 SPC Assessment Carrying Charges" as of April 30, 2012.
e) Please provide a copy of the original invoice of the amount Atikokan Hydro has paid with respect to the SPC Assessment.
f) Please confirm Atikokan Hydro's's beginning and ending billing dates to customers for the SPC Assessment.
g) Please complete the following table related to the SPC.

SPC Assessment (Principal balance)	Amount recovered from customers in 2010	Carrying Charges for 2010	December 31, 2010 Year End Principal Balance	December 31, 2010 Year End Carrying Charges Balance	Amount recovered from customers in 2011	Carrying Charges for 2011	Forecasted December 31, 2011 Year End Principal Balance	Forecasted December 31, 2011 Year End Carrying Charges Balance	Carrying Charges for 2012 (Jan 1 to April 30)	Total for Disposition (Principal & Interest)

30. Account 1588 RSVA Power and 1588 RSVA Sub-account Global Adjustment

a) Does Atikokan Hydro pro-rate IESO Charge Type 146 Global Adjustment into the RPP and non-RPP portions? If not, why not? If so, please provide the supporting spreadsheet for the year 2010 showing the pro-ration of the IESO Charge Type 146 Global Adjustment into RPP and non-RPP portions.
b) Is the RPP portion included in the Account 4705 control account and then incorporated into the variance reported in Account 1588 control account? If not, why not? If so, please provide the journal entries for the month of December 2010 to record the RPP portion of global adjustment in Account 4705 control account and incorporate it into the variance reported in Account 1588 control account.
c) Is the non-RPP portion included in Account 4705 sub-account Global Adjustment and then incorporated into the variance reported in Account 1588 sub-account Global Adjustment? If not, why not? If so, please provide journal entries for the month of December 2010 to record the non-RPP portion of global adjustment in Account 4705 sub-

account Global Adjustment and incorporate it into the variance reported in Account 1588 sub-account Global Adjustment.

d) If any of the responses to parts a), b), or c) above indicate that this process is not being followed, please make appropriate adjustments and file the updated evidence. Please provide explanations for any changes made.

31. Ref: Exhibit 9/Tab 1/Schedule 1/Page 3, Accounts 1580, 1584 and 1586, Board Decision EB-2010-0064, Deferral/Variance Account Work Form – Continuity Schedule, Tab 2 , 2012 Continuity Schedule

In this Application, Atikokan Hydro states:

> The variance for these accounts between the RRR 2.1.7 Trial Balance and the Continuity Statement results from the 2009 Deferral and Variance account balances not being moved into sub account 1595 in the RRR 2.1.7 Trial Balance. **However, this movement has been assumed in the Continuity Statements to reflect the Board's decision in EB-2010-0064** for Atikokan Hydro's 2011 rates in regards to 2008 and 2009 Group 1 balances. [emphasis added]

In its Decision EB-2010-0064, the Board stated,

> In EB-2010-0064, Atikokan Hydro proposed the following approach to address the disposition of the 2008 and 2009 Group 1 Deferral and Variance Account balances.
>
> A) For the 2008 Group 1 account balances, the approved 2010 (EB-2009-0212) rate riders would continue until April 30, 2012. These rate riders are expected to refund Atikokan Hydro's customers $120,510 (approved on interim basis in EB-2009-0212) of the $247,027 (revised in EB-2010-0064) owed to them.
>
> B) For the 2009 Group 1 account balances, the $138,360 owed by customers would not be disposed until after April 30, 2012. As of May 1, 2012 the remaining amount of the 2008 balances owed to the customers (i.e. $247,027 minus $120,510 = $126,517) would be used to offset the 2009 balances of $138,360 owed to Atikokan Hydro.
>
> Board staff noted that Atikokan Hydro already has approved rate riders in place to refund $120,510 to customers of the 2008 Group 1 account credit balance of $247,027 by April 30, 2012. This means that Atikokan Hydro will still owe its customers $126,517 related to the 2008 Group 1 accounts once the existing rate riders are discontinued. If the Board approves the

proposed approach and allows Atikokan Hydro to use the additional money owed to ratepayers in the amount of $126,517 (related to the 2008 Deferral and Variance accounts) to offset the 2009 Group 1 account balance of $138,360, the projected amount owed to Atikokan Hydro as of December 31, 2009 is only $11,843 (which would be below the Board's established disposition threshold). Board staff submitted that, from the customer's prospective [sic], this proposal would ensure no rate impacts related to 2008 and 2009 Deferral and Variance account disposition in the 2011 rate year as the current rate riders would continue to be in effect until April 30, 2012 and **no new rate riders would be needed to recover the 2009 Group 1 account balances. Board staff noted that Atikokan Hydro will file a Cost of Service application in 2012 and all Deferral and Variance account balances will be disposed at that time including any residual amounts from prior periods.**

For the reasons set out above, Board staff supported Atikokan Hydro's proposal for Group 1 account disposition. **Board staff submitted that it understands that the difference between the 2008 interim balances versus the 2008 final balances, and the 2009 account balances would be dealt with at the account level.**

The Board agrees with Atikokan Hydro and Board staff that the approach proposed by Atikokan Hydro is practical given the distributor's unique situation. The Board is of the view that although the approach is not conventional, it stabilizes rate fluctuations for Atikokan Hydro's customers. The Board will therefore approve Atikokan Hydro's proposed approach. **The Board directs Atikokan Hydro to track the residual balance (i.e. the difference between the 2008 interim balances versus the 2008 final balances, and the 2009 account balances) at the account level such that the future disposition of the residual amounts by account will reflect the allocation methodology prescribed in the EDDVAR Report**, and the disposition of the global adjustment sub-account balance will apply to non-RPP customers only. [Emphasis added]

a) Please explain why Atikokan Hydro would transfer the Group 1 account balances to Account 1595 Disposition and Recovery of Regulatory balance sub-account (2009), given the Board's directions that no new rate riders would be needed to recover the 2009 Group 1 account balances and Atikokan Hydro should track the 2009 account balances at the account level?

b) In Decision EB-2010-0064, the Board directed Atikokan Hydro to track the residual balance (i.e. the difference between the 2008 interim balances versus the 2008 final balances, and the 2009 account balances) at the account level. Please confirm that Atikokan Hydro

has followed the Board direction in this regard? In the alternative, please provide an explanation for deviating from the Board's direction.

c) Please complete the information in the following table per the Board Decision EB-2010-0064.

Account	Residual Balance as of December 31, 2010	Projected Interest for the Residual Balance as of April 30, 2012
1580		
1584		
1586		
1588 excluding global adjustment		
1588 global adjustment		
1590		

d) Please enter the amount shown in the above table in the Continuity Schedule in column BI for the principal amount related to the residual balance as of December 31, 2010 for each account, and in column BN for the projected interest for the residual balance as of April 30, 2012 for each account, per the Board Decision EB-2010-0064.

32. Ref: Exhibit 9/Tab 1/Schedule 1/Page 4, Disposition and Recovery of Regulatory Balances (2009)
Exhibit 9/Tab 1/Schedule 1/Page 6/Table 9-4 2009 Group 1 Deferral and Variance Account Balances EB-2010-0064
Deferral/Variance Account Work Form – Continuity Schedule, Tab 2 , 2012 Continuity Schedule

Please explain why ($139,879) was entered in the continuity schedule cell BE32 as the disposition to Account 1595. If this amount should not be entered in cell BE32, please remove the amount and re-file the DVA Continuity Schedule.

33. Deferral/Variance Account Work Form – Continuity Schedule, Tab 2 , 2012 Continuity Schedule
Board Decision EB-2010-0064
Board Decision EB-2009-0212

Board staff notes that the Board's Decision EB-2010-0064 with respect to Atikokan Hydro's 2011 IRM application stated that no new rate riders would be needed to recover the 2009 Group 1 account balances.

a) Please provide the supporting documents and the Board direction for the amount ($70,428) entered as the "principal disposition during 2011" in cell BP 31 for account 1595.

b) Please provide the supporting documents and the Board direction for the amount $219,265 entered as the "principal disposition during 2010" in cell BE 31 for account 1595.
c) Please identify where Atikokan Hydro has entered the disposition of the balances as of December 31, 2008 plus interest to April 30, 2010, as approved in the Board's decisions EB-2009-0212 and EB-2010-0064.
d) As necessary based on the responses to a), b), and c), please enter the disposition of the balances as of December 31, 2008 plus interest to April 30, 2010 in Column BE of the continuity schedule and re-file the DVA Continuity Schedule.

34. Ref: Exhibit 1/Tab 3/Appendix F/Audited Financial Statements for the year ended December 31, 2010
Exhibit 9/Tab 1/Schedule 1/pages 3-4, Account 1588 RSVA-Power (excluding GA) and Account 1588 RSVA-Power sub-account GA

On pages 3 and 4 of E9/T1/S1, Atikokan Hydro states:

> The variance between RRR 2.1.7 Trial Balance and the Continuity Statement above is ($15,115). Adjustments were made to RPP and non-RPP balances as a result of the OEB 1598 Audit completed in 2010. These net adjustments are included in the Continuity Statements to reflect the 2010 year-end adjustments made to true-up reconciliation for the period of 2005 through the period ending October 2010. The true-up required was to address OEB's concerns:
>
> - *"Our review of the 1598 claims process indicated that Atikokan Hydro Inc. (AHI) used the estimated instead of the actual global adjustment (GA) in the true-up reconciliation for December 2005, November and December 2006, all of 2007, June to December 2008, all of 2009 and from January to May 2010.*
> - *Additionally, we noted that incorrect kWhs were also used for the November and December 2005 true-up reconciliation and*
> - *An incorrect RPP rates for the May and November 2006 true-up reconciliation."* [Emphasis in original]

a) Board staff is unaware of such 2010 audit performed by the Board's Regulatory Audit and Accounting. Please confirm if the audit was conducted by the Board's Regulatory Audit and Accounting staff or by the Ministry of Finance.
b) Atikokan Hydro states that the variance between RRR 2.1.7 Trial Balance and the Continuity Statement above is a credit of $15,115 due to adjustments that were made to RPP and non-RPP balances as a result of the 1598 Audit completed in 2010. Please confirm if the

adjustments were reviewed by Atikokan Hydro's external auditors or in the alternative, please identify the authority that conducted the audit.

c) Please provide a breakdown of Sales of Energy and Energy Cost, as reported in the audited financial statements, by USoA account number for 2010. Please link these numbers to the audited financial statements.

d) Board staff notes that Statements of Operations and Deficit shows a difference between the Sales of Energy and Energy Cost reported numbers. Please explain why Atikokan Hydro is making a profit or loss on the commodity, when the utility and its customers are kept whole?

35. Ref: Exhibit 9/Tab 1/Schedule 1/page 2 - Account 1518 and Account 1548 Retail Service Charges

The difference between revenue collected from retailers for retail settlement activities and the costs incurred to provide the services is recorded in the retail cost variance accounts 1518 and 1548.

a) Please identify the drivers for the balances in each of Accounts 1518 and 1548.

b) Please provide a schedule identifying all revenues and expenses, listed by Uniform System of Account (USoA) number, that are incorporated into the variances recorded in Accounts 1518 and 1548 for 2010, the actual/forecast for 2011 and a forecast for 2012.

c) Please confirm whether or not Atikokan Hydro has followed Article 490, Retail Services and Settlement Variances of the Accounting *Procedures Handbook,* for Accounts 1518 and 1548. In other words, please confirm that the higher of the relevant revenues (i.e. account 4082, Retail Services Revenue and account 4084, STR Revenue) and the incremental expenses in the associated expense accounts (i.e. account 5315, Customer Billing, and possibly 5305, Supervision and 5340, Miscellaneous Customer Accounts Expenses) is reduced (i.e. revenues debited or expenses credited) at the end of each period, with an offsetting entry to the variance account. Please explain if the applicant has not complied with Article 490.

d) Please confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.

36. Ref: Exhibit 9/Tab 1/Schedule 1/page 2, Account 1508 Other Regulatory Assets Cost Assessment and Account 1508 OMERS

In its decision with respect to Atikokan Hydro's 2008 Cost of Service application (EB-2008-0014), the Board directed Atikokan Hydro to include in its rate order a rate rider and supporting rate schedules to clear the balance in account 1508

over a one year period.

Article 220 of Accounting Procedures Handbook, pages 16 and 17, Note A state:

> Effective May 1, 2006, OEB cost assessments were incorporated in the distribution rates of distributors that filed rate applications for the 2006-07 rate year.
>
> Effective May 1, 2006, pension cost contributions to OMERS were incorporated in the distribution rates of distributors that filed rate applications for the 2006-07 rate year.

a) Please explain the nature of the balances recorded in the 1508 sub-account OEB Cost Assessment and sub-account OMERS.
b) Please explain why Atikokan Hydro still has balances in Account 1508 sub- account OEB Cost Assessment and sub-account OMERS when the costs have already been incorporated in the distribution rates effective May 1, 2006.

37. Ref: Exhibit 1/Tab 3/Appendix F/Audited Financial Statements for the year ended December 31, 2010

Board staff observes the "Going Concern" note from the Audited Financial Statements for the year ended December 31, 2010:

> The continuation of the Corporation is dependent upon the continuing availability of operating and long term financing and achieving a profitable level of operation through the ability to increase rates that are currently regulated by the Minister of Energy and the Ontario Energy Board.

a) Please explain what specific actions Atikokan Hydro has taken or is taking to address the "going concern" issue.
b) Atikokan Hydro is proposing to defer the disposition of a debit balance of $702,336 (RSVA account balance of $50,003 and Non-RSVA account balance of $652,333) representing the 2010 Group 1 and 2 DVA balances in the current rate proceeding. Please assess the impact of this proposed deferment on the utility's going concern with respect to issues such as cash flow, financial ratios, ability to borrow, etc.

Smart Meters

38. Ref: Exhibit 9/Tab 2/Schedule 2 and Excel Smart Meter Model

In its Application, Atikokan Hydro is seeking disposition and recovery of smart meter costs for installed smart meters. Atikokan Hydro is seeking actual and forecasted costs to December 31, 2011 of $507,378 for capital and $149,136 for operating expenses. Atikokan Hydro has provided a Microsoft Excel spreadsheet documenting the derivation of the deferred revenue requirement.

Board staff observes that the filed model does not contain sufficient detail and appears to use a different methodology than that which has been submitted by other utilities in recent applications and which have been approved by the Board. Further, on December 15, 2011, the Board issued *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition,* accessible at http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/OEB_Guideline_G-2011-0001_SmartMeters.pdf . The Board has also issued a Microsoft Excel spreadsheet Smart Meter Model (Version 2.17) to aid utilities in filing for cost recovery. The model can be accessed at http://www.ontarioenergyboard.ca/OEB/_Documents/2012EDR/2012_smart_meter_model.xls

Please re-submit Atikokan Hydro's smart meter model using the Board-issued version 2.17 Microsoft Excel model. When filing, please submit the model as a working Microsoft Excel spreadsheet.

In completing the model, please provide the necessary detail. For example, smart meter costs, computer hardware, computer software, and other equipment and assets should be separately documented. Atikokan Hydro should also distinguish between costs meeting minimum functionality and those exceeding minimum functionality, in accordance with Guideline G-2011-0001.

For the Cost of Capital, for each year, the deemed capitalization and the cost of capital parameters should correspond those approved in the utility's most current Cost of Service rebasing application to that point in time. Similarly, taxes and PILs should reflect what was in effect in each historical year.

To aid in the process, Board staff has populated a draft of the Smart Meter Model Version 2.17 based on staff's interpretation of the data that Atikokan Hydro provided in its model. Atikokan Hydro should use this version and correct or update the data as necessary and in accordance with Guideline G-2011-0001.

39. Ref: Exhibit 9/Tab 2/Schedule 2 and Smart Meter Model

For Smart Meter OM&A expenses, Atikokan Hydro documents $48,942 in 2009, $30.741 in 2010 and $69,453 in 2011.

Please provide further detail with respect to the OM&A expenses for each year, including:

a) a disaggregation of expenses by major categories (e.g. maintenance, operations, licensing, etc.)
b) a detailed description of the nature of the expenses in each category and for each year; and
c) identification of the quantum and nature of OM&A expenses that are "beyond minimum functionality" as defined in Guideline G-2011-0001.

40. Ref: Exhibit 9/Tab 2/Schedule 1 and Exhibit 9/Tab 2/Schedule 2/Table 9-5

In its application, Atikokan Hydro provides the following data on smart meter costs per customer in Table 9-5:

Table 9-5: Smart Meter Capital and Operating Expenses as of December 31, 2011		
Description	**Total Cost**	**Cost per Meter**
Smart Meter and Related Fixed Assets	$507,378	$303
Incremental Operating Expenses	$149,136	$89
Total Cost per Meter		$392

Atikokan Hydro also states that it has not incurred costs for functionality "beyond minimum functionality" per O.Reg. 425/06.

a) Please provide a copy of the letter from the Fairness Commissioner referenced on pages 2-3 of E9/T2/S1.
b) While Atikokan Hydro states that it has not incurred costs for functionality "beyond minimum functionality" in E9/T2/S2, in E9/T2/S1, the utility documents the status of its smart meter program and various activities, including a transition to TOU pricing and consumer education. These latter activities are "beyond minimum functionality" per O.Reg. 425/06 and as accepted by the Board in its Decision with Reasons EB-2007-0063 with respect to the combined smart meter proceeding that reviewed the smart meter costs of distributors then authorized for smart meter activities in the summer of 2007. More recently, Guideline G-2011-0001 confirmed this definition of what constitutes "minimum functionality" and three categories of "beyond minimum functionality". A utility is required to document any costs "beyond minimum functionality" by each of the categories.
    i. Do the costs documented in Table 9-5 include capital or operating costs for TOU implementation, consumer education, or other "beyond minimum functionality" back-office activities as identified in section 3.4 of Guideline G-2011-0001? If so, please identify the

quantum of costs and document them.

ii. Please confirm that smart meter deployment has only involved Residential and GS < 50 kW customers. Smart Meters deployed to other classes (e.g. GS > 50 kW) are "beyond minimum functionality". If there are any smart meters deployed for customers other than Residential and GS < 50 kW, please identify the number of meters deployed and the smart meter costs involved, disaggregated by capital and operating expenses.

c) Atikokan Hydro's documented capital cost of $303 per meter and $392 total cost per meter would appear to be significantly larger than unit costs that the Board has seen in evidence in applications to date. In Appendix A of Decision with Reasons EB-2007-0063, the ranges for the per meter cost (total capital and operating) for the thirteen distributors then authorized for smart meter deployment ranged from $123.59 (Newmarket Hydro) to $189.96 (Middlesex Power) for urban utilities, with only Hydro One Networks showing higher unitized costs at $479.47. Admittedly, costs were based on very limited data at that time. However, in individual applications since then, unitized costs in the range of $120 to about $200 (total capital and operating) have been seen.

i. Atikokan Hydro documents that it was part of a group of utilities (Thunder Bay and the Northwestern group) that cooperated together. Please provide any evidence in Atikokan Hydro's possession with respect to the per meter costs of Thunder Bay Hydro and other Northwestern electricity distributors.

ii. To the extent possible, please document the drivers for any significant differences in the per meter costs between Atikokan Hydro and other members of the Northwestern group.

d) Please provide a variation on Table 9-5 breaking out the capital and operating costs by the categories shown on Sheet 2 of the Smart Meter Model Version 2.17 (e.g. Smart Meter costs, installation costs, etc.)

41. Ref: Exhibit 9/Tab 2/Schedule 1 – TOU Implementation

As Board staff understands Atikokan Hydro's evidence on pages 11 and 12 of E9/T2/S1, Atikokan Hydro expected to implement TOU pricing by October 2011, and thus the utility should have fully implemented smart meter deployment and TOU pricing, with the exception of web presentment. With respect to the latter, Atikokan Hydro documented that the expected capital and operating expenses would work out to about $0.40/month per customer.

a) Please confirm whether Atikokan Hydro has implemented TOU pricing. If so, please indicate the date. In the alternative, please provide an explanation for any delay and a forecast for when Atikokan Hydro

expects to implement TOU pricing.

b) Board staff understands the estimate of ongoing operational expenses for web presentment by Whitecap Canada Inc. as follows:

Description		Annual cost per metered customer for 1673 metered customers	Monthly cost per metered customer
Licensing Costs	$7400 per annum	$4.42	$0.37
Per customer cost			$0.035
Total			$0.40

It appears that the majority of the costs are for the annual licensing fee rather than the cost for the customer data web storage and presentation. Please provide further documentation of the basis for the Whitecap Canada annual licensing fee and the services being received.

42. Ref: Exhibit 9/Tab 2/Schedule 2 – Smart Meter Cost Allocation

In its original application, Atikokan Hydro has proposed a uniform Smart Meter Disposition Rider of $3.54/month for 36 months.

In *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery*, issued October 22, 2008, the Board stated that the applicant should consider "the methodology for allocating the disposition rider to different customer classes." In recent cases, the Board has considered and approved class-specific SMDRs. In its decisions with respect to PowerStream's 2010 and 2011 applications[1] for disposition of smart meter costs, the Board approved approaches that deal with the allocation of costs, adjusted for SMFA revenues, based on principles of cost causality. Whether class-specific SMDRs are warranted is also determined on the basis of data availability and quality, and on materiality.

Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition, issued December 15, 2011, further states:

> The SMFA was calculated and applied as a uniform monthly charge collected from all metered customers. In early decisions, the SMDR and, if applicable, the SMIRR, were calculated similarly on a uniform basis. However, more recently, the issue of differential costs for smart meters by classes of customers has arisen. While the Board notes that utilities have not been specifically directed to record all costs on a class-specific basis, in some cases there may be class specific information available.

[1] Decision and Order (Corrected), [EB-2010-0209], November 19, 2010 and Decision and Order [EB-2011-0128], November 21, 2011

In the Board's decision with respect to PowerStream's 2011 Smart Meter Disposition Application (EB-2011-0128), the Board approved an allocation methodology based on a class-specific revenue requirement, offset by class specific revenues. The Board noted that this approach may not be appropriate or feasible for all distributors as the necessary data may not be readily available [footnote omitted].

The Board views that, where practical and where the data is available, class specific SMDRs should be calculated based on full cost causality. The methodology approved by the Board in EB-2011-0128 should serve as a suitable guide. A uniform SMDR would be suitable only where adequate data is not available.[2]

a) Please provide Atikokan Hydro's views as to whether there are differences in the costs of smart meters deployed between the Residential and GS < 50 kW customer classes.

b) If there are material differences between the costs per meter between the Residential and GS < 50 kW classes, please provide a proposal for allocating the costs between classes based on cost causality and calculating class-specific SMDRs. One potential approach is described below:

(i) Allocate the total revenue requirement for the historical years, as revised per the previous interrogatory, using the following cost allocation methodology:

- Allocate the return (deemed interest plus return on equity) and amortization based on the allocation of Account 1860 in the cost allocation model (CWMC in the cost allocation model filed in this application);
- Allocate the OM&A based on the number of meters installed for each class;
- Allocate PILs based on the revenue requirement allocated to each class before PILs;

(ii) Sum the allocated amounts and calculate the percentages of costs allocated to customer rate classes;
(iii) Subtract the revenues generated from the smart meter funding adder from the overall revenue requirement;
(iv) Allocate the amount calculated in part (iii) by using the allocation factors derived in part (ii);

[2] *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*, December 15, 2011, pp. 19-20.

(v) To calculate the smart meter disposition rider, divide the allocated amount by rate class derived in part (iv) by the number of customers in each class, and then divide by 12; and
(vi) If the proposed disposition period is greater than 1 year, divide the result of part (v) by the proposed number of years.
Please show all calculations.

43. Ref: Exhibit 9/Tab 2/Schedule 1 – Operational Data Store and Operational Efficiencies due to Smart Meter Deployment and Operationalization

On page 9 of E9/T2/S1, Atikokan Hydro identifies as one of the functional requirements of its Operational Data Store "Meter Event Monitoring", which is documented as: "Dashboard visibility to report meter events and indicators such as outages, restorations, tampers, voltage changes, etc., many of which will afford Atikokan Hydro the opportunity to improve the safety and reliability of the distribution system." On the same page, Atikokan Hydro identifies "Outage Reporting", defined as "Real-time outage information to facilitate faster response time, and therefore improved system reliability" as being another feature of the ODS.

What changes has Atikokan Hydro done, or intend to do, to improve its recording, reporting and responding to service interruptions and outages due to the implementation of its ODS?

Stranded Meters

44. Ref: Exhibit 9/Tab 2/Schedule 3 – Stranded Meter Costs

In its application, Atikokan Hydro has noted that it disposed of 1659 conventional meters replaced by smart meters through Greenport Environmental for a fee of $1,122. In Table 9-7, Atikokan Hydro documents a GBV for the removed smart meters of $104,713, accumulated depreciation to December 31, 2011 of a credit of $81,338 and thus a remaining NBV of $23,375. Atikokan Hydro proposes recovery over a 36 month period, amounting to $0.39/month for each of its 1673 metered customers.

a) Please confirm that there were no net proceeds from the salvage of the removed conventional meters.
b) How has Atikokan Hydro factored in the disposal fee of $1,122 into the stranded meter costs to be recovered from customers?

IFRS – Rate Base

45. Ref: Letter of the Board, issued on November 8, 2010 "Transition to IFRS – Amendment to Board Policy"

There are a number of tables in the application that should be confirmed and/or updated to ensure that the evidentiary record on MIFRS and an understanding of its impact on the Board's financial statement are current and complete. The comparison requires that 2011 and 2012 be completed on both a CGAAP and MIFRS basis.

Please file financial information for the 2011 Bridge and 2012 Test years in both CGAAP and MIFRS, as per section 9.1.3 of the letter of the Board issued on November 8, 2010, and update the evidence listed below. Please provide a reconciliation and explanation between CGAAP and MIFRS for both 2011 and 2012.

a) Exhibit 2/Tab 1/Schedule 1/Page 1/Table 2-1 Summary of Rate Base;
b) Exhibit 2/Tab 1/Schedule 1/Page 2/Table 2-2 Summary of Working Capital Calculation;
c) Exhibit 2/Tab 1/Schedule 2/Page 1/Table 2-5 - Rate Base;
d) Exhibit 2/Tab 1/Schedule 2/Page 3/Table 2-8 - Capital Additions;
e) Exhibit 2/Tab 2/Schedule 1/Page 8/Table 2-15 - 2011 Fixed Asset Continuity Schedule;
f) Exhibit 2/Tab 2/Schedule 1/Page 10/Table 2-17 - 2012 Fixed Asset Continuity Schedule;
g) Exhibit 2/Tab 2/Schedule 1/Page 11/Table 2-18. Please also provide the depreciation expense reconciliation between CGAAP and MIFRS for 2011; and
h) Exhibit 2/Tab 3/Schedule 1/Page 2/Table 2-22 – Detailed Working Capital Calculations.

46. Ref: Exhibit 2/Tab 1/Schedule 1/page 2

On page 2 of E2/T1/S1, Atikokan Hydro states:

> In 2010, Atikokan Hydro changed its capitalization policy to no longer capitalize expenses that were not directly related to the installation of capital. This caused an increase in 2010 administration and general expense. However, the revised capitalization policy is aligned with the IFRS standard. As a result, with Atikokan Hydro's movement to IFRS in 2012 there is no impact on 2012 capital additions or OM&A expenses.

The note "New Accounting Pronouncement" on page 11 of Atikokan Hydro's 2010 Audited Financial Statement states:

> The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its consolidated financial statements. At this time, the impact on the Corporation's future financial position and the results of operations is not reasonably determinable or estimable.

a) Has Atikokan Hydro consulted with its external auditors regarding the change in capitalization of overhead within IFRS requirements? If yes, please provide supporting documentation. If not, please identify any plans for so doing in the near future.
b) Please identify all overhead related items (e.g. indirect costs, corporate centre costs) that are impacted. Please identify all items that are ineligible and how much overhead in total has been removed from capitalization for ineligible costs for the 2011 Bridge and 2012 Test years.

47. Ref: Exhibit 2/Tab 1/Schedule 1/page 7 – Capitalization Policy

On Page 7 of E2/T1/S1, Atikokan Hydro states that it "does not have a formal written capitalization policy." Atikokan Hydro further states that it "changed its capitalization practices in 2010 which in turn allowed the capitalization policy to be aligned with IFRS standards for 2012."

a) In the absence of a capitalization policy, what are the changes of Atikokan Hydro's capital practice since its last rebasing application for 2008 rates? Please identify and quantify the changes, and identify the drivers of the changes.
b) Please provide the overall revenue requirement impact of all changes in the capitalization practice for the 2011 Bridge and 2012 Test years.
c) If changes were made for other reasons as well, please provide the overall revenue requirement impacts for the 2011 Bridge and 2012 Test years arising solely from the transition to MIFRS.
d) Please provide the following information in detail for overhead costs on self-constructed assets for the bridge and test years:

Nature of the overhead costs	**Dollar Impact Bridge Year**	**Dollar Impact Test Year**	**Directly attributable? (Y/N)**	**Reasons why the costs are allowed to be capitalized under MIFRS given the more stringent limitations on capitalized overhead**

e) When does Atikokan Hydro plan to develop a formal capitalization policy?

48. Ref: Exhibit 2/Tab 1/Schedule 1/page 7

On page 7 of E2/T1/S1, Atikokan Hydro states that it "does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year."

a) Please confirm whether the borrowing costs are directly attributable to the construction.
b) If the answer to part a) is yes, please explain why the borrowing costs are not capitalized.
c) Please quantify the borrowing costs that are not capitalized on construction.
d) Please confirm if Atikokan Hydro capitalizes the directly attributable borrowing cost for capital projects begun but that do not go into service in the fiscal year.
e) If the answer to part d) is no, please explain and quantify the borrowing costs that are not capitalized.

49. Ref: Exhibit 2/Tab 2/Schedule 1/Page 10 and Exhibit 2/Appendix A/ page 12 – Useful Life and Depreciation Rate Changes in Conversion to IFRS

On page 10 of E2/T2/S10, Atikokan Hydro states that: "Table 2-18 provides the adjustments made to CGAAP depreciation to reflect modified IFRS under a useful life assumption of 45 years."

On page 12 of E2/Appendix A, Atikokan Hydro states that: "[g]iven the data received from the CGAAP to IFRS conversion exercise, Atikokan Hydro has chosen a useful life of 45 years for distribution equipment and has deemed 10 years remaining on older assets."

a) Please explain how Atikokan Hydro has determined the useful life of 45 years for distribution equipment, and a deemed 10 years remaining on older assets.
b) Please confirm if Atikokan Hydro has used the Kinectrics Report in developing the useful service lives of the assets. If so, please provide a reference to Atikokan Hydro's choice of useful life of 45 years for distribution equipment and deemed 10 years remaining on older assets. Please identify all exceptions from the Typical Useful Lives ("TUL") in the Kinectrics Report and provide detailed justification for

using service lives that are different from the TULs in the Kinectrics Report.

c) Please confirm that significant parts or components of each item of PP&E are being depreciated separately, in accordance with IFRS. If not, please explain.

50. Ref: June 13, 2011 Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment, Appendix A

Pages 31-32 of the above referenced Report of the Board state the following:

> Issue 2: The Board authorizes the creation of a generic IFRS transition PP&E deferral account to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS
>
> Amortization of the adjusting amount, up or down, shall be reflected in any applicable rate application as an adjustment to depreciation expense (the refund or recovery of the amount of the adjustment over time) and the return on rate base calculation on the unamortized balance shall be included in applicable revenue requirement calculations in the same way as for any other component of rate base.

Atikokan Hydro has not provided a calculation or balance in the Board-approved PP&E Deferral Account.

a) Please provide a breakdown of the amount recorded in the PP&E deferral account on the transition date to MIFRS that is effective as of January 1, 2011. Please provide the supporting analysis of the amounts in this account. Please provide an analysis similar to that documented in Appendix A of the March 31, 2011 Staff Discussion Paper – Transition to IFRS (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0408/Discussion_paper_Transition_to_IFRS_20110331.pdf).

b) Please update the evidence to clear the PP&E Deferral Account as an adjustment to depreciation expense in the 2012 Test year and provide an update to the revenue requirement for the 2012 Test year.

51. Ref: EB-2008-0408 Report of the Board -Transition to International Financial Reporting Standards, July 28, 2009

The above referenced Report of the Board states, at page 19:

> **Asset reclassifications from PP&E to intangible assets**
>
> The staff proposal for asset reclassifications read:
>
> > IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. Utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining the revenue requirement. This reclassification is also necessary to preserve continuity of the rate base.
>
> The Board therefore accepts staff's proposal.

Has Atikokan Hydro identified the accounting policy change on asset reclassification from PP&E to intangible assets? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.

IFRS - Operating Costs

52. Ref: Letter of the Board, issued on November 8, 2010, "Transition to IFRS – Amendment to Board Policy"

There are a number of tables in the application that should be confirmed and/or updated to ensure that the evidentiary record on MIFRS and an understanding of its impact is current and complete. The comparison requires that 2011 and 2012 be completed on both a CGAAP and MIFRS basis.

Please file financial information for the bridge year (2011) and test year (2012) in both CGAAP and MIFRS as per section 9.1.3 of the letter of the Board issued on November 8, 2010, for the following tables:

a) Exhibit 4/Tab 1/Schedule 1/Table 4.1 - Summary of OM&A Expenses; and
b) Exhibit 4/Tab 2/Schedule 2/Tables 4-7, 4-8, 4-9 and 4-10 – OM&A Detailed Costs.

Please provide a reconciliation and explanation between CGAAP and MIFRS amounts shown in these tables.

53. Ref: Exhibit 2/Appendix A /Page 4 – One-Time Administrative Costs of Transition of IFRS

On page 4 of E2/Appendix A, Atikokan Hydro states:

> Our accounting system for our major assets will be moving from Canadian Generally Accepted Accounting Practices [CGAAP] to the International Financial Reporting System [IFRS] as of January 1, 2012. Atikokan Hydro has taken the opportunity to do a detailed analysis of its major assets including value, age and amortization policy as part of the conversion from CGAAP to IFRS. The firm of BDO was hired to assist with the conversion process.

a) Please confirm whether Atikokan Hydro has incurred and recorded the One-Time Administrative Costs of Transition of IFRS.
b) If the answer to part a) is yes, please:
   i. Identify which USoA deferral account the One-Time Administrative Costs of Transition of IFRS balance is recorded in.
   ii. Provide the breakdown of the costs recorded in the IFRS deferral account.
   iii. Provide explanations for each category of costs recorded in the IFRS deferral account and indicate how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.
c) If the answer to part a) is no, please explain why there are no costs incurred on the transition of IFRS, and how Atikokan Hydro is satisfied that the financial information provided for 2012 is on a MIFRS basis.

Disposition of Account 1562 – Deferred Taxes/PILs.

54. Ref: PILs Continuity Schedule – PILs Proxy Entitlements

In its PILs 1562 continuity schedule, Atikokan Hydro recorded its entitlement to the 2001 PILs proxy starting on October 1, 2001 and the 2002 PILs proxy on January 1, 2002.

Atikokan Hydro submitted a revised 2002 rate application dated March 28 and April 3, 2002. Due to its amended application for rate adjustment, the effective date of the 2002 rates including the 2001 and 2002 proxies was delayed to May 1, 2002 at the request of Atikokan Hydro.

a) What regulatory reference supports starting the PILs entitlements earlier than May 1, 2002? Please explain.

b) Did Atikokan Hydro consider that its entitlement to the 2001 and 2002 PILs proxy should not begin before May 1, 2002 given the delay caused by filing a revised application?

55. Ref: 2001 to 2005 SIMPIL models – Interest Expense

Interest Portion of True-up

When the actual interest expense, as reflected in the financial statements and tax returns, exceeds the maximum deemed interest amount approved by the Board, the excess amount is subject to a claw-back penalty and is shown in sheet TAXCALC as an extra deduction in the true-up calculations.

For the tax years 2001 to 2005:

a) Did Atikokan Hydro have interest expense related to liabilities other than debt that is disclosed as interest expense in its financial statements?
b) Did Atikokan Hydro net interest income against interest expense in deriving the amount it shows as interest expense in its financial statements and tax returns? If yes, please provide details to what the interest income relates.
c) Did Atikokan Hydro include interest expense on customer security deposits in interest expense for purposes of the interest true-up calculation?
d) Did Atikokan Hydro include interest income on customer security deposits in the disclosed amount of interest expense in its financial statements and tax returns?
e) Did Atikokan Hydro include interest expense on IESO prudentials in interest expense?
f) Did Atikokan Hydro include interest carrying charges on regulatory assets or liabilities in interest expense?
g) Did Atikokan Hydro include the amortization of debt issue costs, debt discounts or debt premiums in interest expense? If the answer is yes, did Atikokan Hydro also include the difference between the accounting and tax amortization amounts in the interest true-up calculations? Please explain.
h) Did Atikokan Hydro deduct capitalized interest in deriving the interest expense disclosed in its financial statements? If the answer is yes, did Atikokan Hydro add back the capitalized interest to the actual interest expense amount for purposes of the interest true-up calculations? Please explain.
i) Please provide Atikokan Hydro's views on which types of interest income and interest expense should be included in the excess interest true-up calculations.

j) Please provide a table for the years 2001 to 2005 that shows all of the components of Atikokan Hydro's interest expense and the amount associated with each type of interest.

56. Ref: 2001 to 2005 Tax Returns – Tax Years – Statute-barred

Please confirm that all tax years from 2001 to 2005 are now statute-barred.

General – Updating of Evidence

57. Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that Atikokan Hydro wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

58. Updated Revenue Requirement

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service and base revenue requirements that Atikokan Hydro wishes to make relative to the original application.