ONTARIO ENERGY BOARD

STAFF SUBMISSION

2012 ELECTRICITY DISTRIBUTION RATES APPLICATION -

Board Staff Submission

Atikokan Hydro Inc.

EB-2011-0293

May 4, 2012

This is Board staff's submission on Atikokan Hydro Inc.'s ("Atikokan Hydro's") application for rates effective May 1, 2012 (the "Application"). There is an extensive record, comprised of the original Application filed on September 29, 2011 and additional evidence filed on December 14, 2011, as well as two rounds of interrogatories and responses in early 2012. On April 20, 2012, in accordance with Procedural Order No. 2, Atikokan Hydro filed its Argument-in-Chief ("AIC") summarizing its proposal for rebased 2012 rates.

The submission follows the order of exhibits in Atikokan Hydro's Application and as documented in the Board's current *Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011 (the "Filing Requirements"). The order is as follows:

1 Administration
2. Rate Base and Capital Expenditures
3. Operating Revenues and Load Forecast
4. Operating Expenses
5. Cost of Capital
6. Revenue Requirement and Sufficiency/Deficiency
7. Cost Allocation
8. Rate Design
9. Deferral and Variance Accounts
10. Other Matters

Within each section there may be sub-issues on various aspects of Atikokan Hydro's Application and proposals.

Administration

Effective Date for Rates

In its Application, Atikokan Hydro requested an effective date for rates of May 1, 2011. In Procedural Order No. 2, issued March 16, 2012, the Board made Atikokan Hydro's current approved rates interim pending a determination on this proceeding.

While Atikokan Hydro filed its Application at the end of September 2011, there was a delay in the commencement of the proceeding as the Application was incomplete, specifically with respect to the proposed disposition of Accounts 1562 and 1592. Atikokan Hydro filed additional evidence in mid-December, 2011. There was a further time delay as Atikokan Hydro requested, and was granted an extension to respond to the first round of interrogatories. These were necessary to complete and correct the record.

As the financial viability of Atikokan Hydro is one issue in this Application, Board staff takes no issue with the proposed effective date of May 1, 2012 for new rates, despite delays in the process.

Rate Base and Capital Expenditures

In its original Application, Atikokan Hydro proposed a 2012 test year rate base of $2,913,786. Through interrogatories, Atikokan Hydro has revised the rate base to $3,041,625. The increase of $127,838 is a result of the following:

- An increase in the net book value of fixed assets of $34,914 due to restatement of the 2011 bridge year according to MIFRS instead of CGAAP;
- An increase of $6,784 in the working capital allowance, due to recognition of $45,229 of OMERS expenses omitted in the initial Application; and
- Reclassification of certain smart meter-related assets from computer hardware to meters as a result of a review of smart meter costs, increasing the net fixed assets by $86,140.[1]

Board staff takes no issue with Atikokan Hydro's 2012 test year rate base, as revised.

Atikokan Hydro is proposing capital additions of $118,800 in 2012, a 40% decrease from 2008 actual capital additions of $198,112.[2] In 2009 and 2010 Atikokan Hydro had higher capital additions of $323,019 and $476,826, related to one-time additions for a new garage and a double-bucket truck. The 2012 test year forecast is more consistent with 2011 bridge year amounts and with the

[1] Atikokan Hydro, AIC, April 20, 2012, pp. 6-7
[2] Exhibit 2/Tab 1/Schedule 2/page 3/Table 2-8

forecasts for 2013 to 2015, with 2016 showing the next expected spike, again due to a one-time major vehicle acquisition forecasted at that time.[3]

Board staff notes some volatility in capital spending. This is not uncommon for smaller utilities given the “lumpiness” of major capital spending. Board staff observes that the next major bump in capital spending coincides with Atikokan Hydro’s next scheduled rebasing for 2016. Board staff also observes that the major capital spending approved in Atikokan Hydro’s 2008 rates application did not occur in that year due to some delays in the acquisition of the double bucket truck and the completion of the new garage. With respect to the latter, the capital expenditures were reflected in rate base and recovered in rates before these assets actually went into service. Board staff submits that some uncertainty and flexibility with respect to timing of capital additions is to be expected, but the utility should be somewhat cautious about forecasting when such major capital projects will be coming into service and hence recoverable from customers.

Atikokan Hydro has filed its Asset Management Plan (“AMP”) in its Application to support its planned capital expenditures. While an extensive AMP is corroborative support for a capital plan, it is not sufficient in and of itself. A utility must also consider its resources – time, money, and people – and decide what it can and must do, and with what priorities. Board staff submits that Atikokan Hydro’s AMP is generally adequate and supportive of its capital projects and expenditures.

Working Capital Allowance

Atikokan Hydro has used the default 15% formula, whereby the Working Capital Allowance (“WCA”) is calculated as 15% of the sum of the cost of power plus controllable expenses. In response to interrogatories, Atikokan Hydro updated the WCA to reflect the HOEP and RPP commodity rates documented in the Board’s October 17, 2011 *Regulated Price Plan* Report as well as that change in OM&A for OMERS expense increases, as documented above.

[3] Exhibit 2/Tab 1/Schedule 1/page 4/Table 2-3

A lead-lag study would normally be conducted to properly establish the working capital requirements of a utility. However, Board staff recognizes that it would be an onerous and expensive undertaking for a utility the size of Atikokan Hydro.

While Board staff acknowledges that Atikokan Hydro's proposal to use the default 15% factor is consistent with Board policy for 2012 rates, Board staff also notes that Atikokan Hydro does monthly billing for all of its customers.[4] This is in contrast to most distributors who still bill most small consumption customers (i.e. Residential, GS < 50 kW) every two months. As such, the average service lag, one important factor in determining cash working capital requirements, would be expected to be much shorter for Atikokan Hydro than for most utilities. Board staff observes that the 15% is, in all likelihood, overly generous for Atikokan Hydro.

The Board has recently announced that, for 2013 rates, the default WCA factor is being reduced to 13%.[5] Board staff submits that one option would be for the Board to direct Atikokan Hydro to adopt the 13% factor, in recognition in part that its cash working capital requirements should be reduced due to monthly billing.

Operating Revenues and Load Forecast

Load Forecast

Atikokan Hydro used a commonly accepted approach for a regression-based load forecast for demand for all classes, in aggregate. Board staff submits that Atikokan Hydro's approach is appropriate.

Atikokan Hydro has used a linear regression model that has evolved and been accepted by the Board in previous cost of service cases. The general approach is to regress monthly kWhs based on economic activity, days in the month, Heating Degree Days ("HDD"), Cooling Degree Days ("CDD") Spring/Fall binary "flag", CDM and other variables as necessary. This modelling approach attempts

[4] Exhibit 4/Tab 2/Schedule 1/page 5
[5] Board letter of April 12, 2012, http://www.ontarioenergyboard.ca/OEB/_Documents/2013EDR/Letter_WCA_for_2013_Filing_Requirements_20120412.pdf

to estimate the influence of key determinants – such as customer base, economic activity, and seasonal and weather variations on realized demand. The estimated parameters are then used in the model along with forecasted exogenous variables for the test period to estimate a weather-normalized demand.

This aggregate demand is then apportioned within classes based on estimated per customer consumption patterns, and kW demand forecast for demand-billed customer classes are estimated through kW/kWh patterns or trends.

While the aim of this regression-based approach is to produce a suitable forecast and not necessarily to understand the economic relationship of demand on various socioeconomic drivers, the suitability of the model and resulting forecast can be highly affected by the model specification, and the estimated parameters.

Board staff generally takes no issue with Atikokan Hydro's approach, although it observes that, once the demand of the Intermediate customer is removed from the historical data, demand is relatively flat.

In response to a VECC interrogatory[6], Atikokan Hydro filed an alternative regression model excluding the historical demand and consumption of the previous Intermediate customer. This model therefore corresponds with Atikokan Hydro's current customer base. In response to a supplementary interrogatory from Board staff,[7] Atikokan Hydro filed the load forecast resulting from this alternative model.

Atikokan Hydro has used a 2012 test year forecast of 25,592,783 purchased system kWh and 23,593,125 billed kWh, while the alternative model from VECC predicts a purchased system forecast of 25,003,092 kWh and a billed forecast of 23,276,163 kWh, a difference of (1.34%). While Atikokan Hydro is not proposing to change its load forecast, Board staff suggests that the forecast from VECC IR # 8 b) may be more reasonable. The Intermediate customer is gone and there is no evidence of its return or replacement in the foreseeable future. The VECC

[6] Response to VECC IR # 8 b)
[7] Response to Board staff IR # 59

model thus more accurately estimates the load forecast based on the current customer mix. While the lower forecast, which affects the denominators for determining rates, will result in slightly higher rates, using Atikokan Hydro's original higher proposal would mean lower rates but also less revenues if consumption does not turn out as forecasted. Given concerns about the financial viability of the utility, Board staff suggests that the more conservative forecast is less risky. Since volumetric rates comprise only about 20% of distribution revenues, the higher volumetric rate impact on customers would be constrained. Thus, Board staff views the lower forecast from the VECC model as more conservative, in posing a lower risk of over-forecasting and affecting the utility's cash situation, while the lower volumetric allocation would constrain the impacts of slightly higher volumetric rates.

Board staff observes that, while historical CDM was an explanatory variable tried in regression modelling, it was not statistically significant. With respect to its CDM license conditions, Atikokan has included adjustments for 10% (116,000 kWh) of its 1,160,000 kWh licensed CDM target in its 2011 Bridge Year forecast, and 20% (232,000 kWh) in its 2012 Test Year Forecast.[8] Board staff submits that the proposed adjustments are reasonable.

Streetlighting

One aspect of Atikokan Hydro's load forecasting is of some concern to Board staff, for which two interrogatories were posed. Atikokan Hydro has forecasted a marked decrease in the average consumption per streetlight, as shown in the table below:

	Actuals								**Forecast**	
Year	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Average kWh per streetlight	864	842	816	785	819	789	800	779	768	757

Source: Exhibit 3/Tab 2/Schedule 1/page 12/Tables 3-10 and 3-12

[8] Exhibit 3/Tab 2/Schedule 1/page 14

As shown in Table 3-11 of Exhibit 3/Tab 2/Schedule 1, streetlighting shows the highest average annual decrease in consumption per unit, averaging about (1.5%) per annum.

Streetlights are unmetered services. Atikokan Hydro explained its approach for estimating the average consumption in response to Board staff supplementary IR # 63. In response to Board staff IR # 10, Atikokan Hydro indicated that it had no specific initiatives to reduce streetlighting consumption, but then stated that 0.3 kW was due to streetlights being “removed or reduced in size” in Board staff IR #63. Board staff also observes that the number of streetlights has not decreased at all since 2007, with a net increase of 3 streetlights. In the same interrogatory response, Atikokan Hydro states that the 2010 consumption was overstated by 17,845 kWh being based on 383 days rather than 365 days.

Board staff does not understand Atikokan Hydro’s data and explanations concerning the trend for lower consumption per street lighting connection. Insofar as the class allocated revenues will be recovered through the rates based on the fixed/variable split and the load forecast for that class, Board staff views that the resulting rates will be compensatory based on the data, even if somewhat “wrong”. However, Board staff submits that the data is anomalous and the utility needs to better analyse and document its load data at its next cost of service rebasing application.

Board staff takes no issue with the forecasted number of customers and connections for the 2012 test year.

Other Revenues

In its Application, Atikokan Hydro has forecasted Other Operating Revenues as $125,235 for the 2012 test year.[9] In response to various interrogatories, Atikokan Hydro has explained the volatilities and the drivers on year-over-year differences. Board staff submits that the utility has adequately explained apparent discrepancies, which include incorrect accounting of amounts in some

[9] Exhibit 3/Tab 1/Schedule 2/page 2/Table 3-1

years, and takes no issue with Atikokan Hydro's forecast for Other Operating Revenues in this Application.

Operating Expenses

OM&A

Atikokan Hydro forecasted $1,175,151 for Operations, Maintenance and Administration ("OM&A") expenses for the test year. This represents a 45.25% increase over its 2008 Board-approved OM&A of $809,045. Atikokan Hydro's OM&A over time is documented below:

Year	2008 Board approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge year forecast	2011 unaudited Actual (VECC IR # 15)	2012 Test Year forecast	2012 Test Year forecast (revised)
OM&A	$809,045	$845,024	$881,683	$1,000,713	$974,277	$948,775	$1,175,151	$1,220,380

Source: Exhibit 4/Tab 1/Schedule 1/page 1/Table 4.1, VECC IR # 15 and AIC/pages 8-10

Atikokan revised the OM&A amounts during interrogatories. The major difference is an increase in OM&A of $45,229 related to OMERS expense increases. Board staff takes no issue with this adjustment.

Atikokan Hydro explains that the major drivers for increases in OM&A are:

- Change in capitalization policy to be consistent with MIFRS, implemented in 2010;
- Increased expenses due to smart meter and TOU implementation;
- Staffing changes, to hire a lineman apprentice to replace a retiring lineman;
- Regulatory costs, as an increase of $50,000 representing ¼ of expected incremental costs associated with the current Application; and
- General and Administrative Salaries and Management Salaries and Expenses.

Board staff acknowledges that these are generally necessary and reasonable increases. However, there is no real increase in the number of customers served or in energy demand, and the utility lost a major customer in 2008.

Board staff has a number of concerns with this. As documented in Atikokan's response to VECC IR # 18 c), Atikokan Hydro has the highest OM&A per customer in its peer group of small Northern Ontario utilities with low undergrounding, with the exception of Great Lakes Power Limited (now Algoma). Algoma serves primarily a rural service area. Atikokan Hydro, like the other utilities and despite its 22 km of sub-transmission feeder, primarily serves a compact and built-up community.

Thus, Atikokan Hydro is proposing further and material increases to its OM&A, which is already the highest of comparable utilities. In Board staff's view, further increases in OM&A need to be strongly supported by evidence that the utility has pursued appropriately all reasonable economies.

Further, Board staff submits that Atikokan Hydro has over forecasted its OM&A. For example, the 2011 unaudited actuals are about $25K below the 2011 bridge year forecast of $975K.[10] Atikokan Hydro has also used a 2.5% inflation to forecast 2011 and 2012 amounts for certain expenses, such as bad debt. However, even though 2011 unaudited bad debt came in at $3776, below the bridge year forecast of $5311, the test year forecast is $5444.[11]

Board staff also notes that the forecasted regulatory costs for this Application of $200,000 are high for a utility of this size, and submits that there is limited evidence on the record to support the prudence of this level of costs. For example, Atikokan Hydro has not indicated the services provided or what other options were explored or whether a competitive procurement process was used to obtain consulting services.

In addition, Board staff notes that while there are increases due to smart meter implementation, Atikokan Hydro's existing line crew will now be relieved from meter reading and more available for other capital and operations activities. The utility should be able to realize some productivity improvements.

[10] See response to Board staff supplementary IR # 60. Atikokan Hydro has provided explanations for the variances between 2011 Bridge year forecast and 2011 unaudited actuals. Nonetheless, Board staff is concerned about the level of proposed increases for 2012.
[11] See response to Board staff supplemental IR #61

While recognizing the cost pressures faced by the utility, Board staff submits that Atikokan Hydro must also recognize the reality of its situation – it is asking its ratepayers to pay significantly more while there is no growth in customers or demand. Board staff submits that the utility must look further into managing its own costs and looking for ways of meeting existing and new demands with existing resources. To this end, Board staff submits that a significant reduction of the 2012 OM&A is in order, and submits that a reduction to the test year envelope OM&A of about 10% to $1,100,000 is appropriate. Board staff has started from the 2011 unaudited actual of $950,000. To that is added the amounts of $45,000 for OMERS and $50,000 as 25% of the regulatory costs for this Application, plus $30,000 for the additional staffing and an allowance for inflation. Board staff views that smart meter OM&A increases should be offset by line crew, now relieved of most meter reading activities, being able to perform other capital and operations work. Atikokan Hydro's management should also be incented to seek productivity improvements to lower its high OM&A costs per customer.

While the utility will be generally challenged in finding how to better manage its costs, and this could put some financial pressures on the utility to achieve this, Board staff notes that disposing of existing deferral and variance account balances, as addressed later in this document, should start recovery of a significant deferred liability of about $250K and thus maintain adequate cash flow for the utility.

Employee Complement and Compensation

Atikokan Hydro has forecasted a staff complement of 9 for the 2012 test year, representing an increase of 1 new position in 2011 due to increasing regulatory requirements. It is also hiring and training replacements for forthcoming retirements.

While Board staff will not challenge Atikokan Hydro's staff complement as proposed and submits that its succession planning efforts are appropriate, Board staff notes that there is no real increase in demand – while the staff complement is increasing, the number of customers served is hardly changing. The utility needs to become more focussed on dealing with new requirements with its existing complement.

Depreciation

In its Application, Atikokan Hydro states that it has followed the Accounting for Municipal Electric Utilities in Ontario and the *2006 Electricity Distribution Rate Handbook*.[12] It has also adjusted the depreciation rates for various classes of assets in accordance with the change to IFRS. It has estimated a depreciation expense of $168,793 in the updated RRWF filed on April 11, 2011.

Board staff notes that the depreciation expense for the 2012 test year may need to be revised in accordance with any adjustments to rate base and capital expenditures as determined by the Board. Board staff submits that Atikokan Hydro should file sufficient evidence, such as an updated Capital Asset Continuity Schedule to allow for confirmation of any updated depreciation expense to support its draft Rate Order, when filed.

PILs

In its original Application, Atikokan Hydro proposed a grossed-up PILs expense allowance of $17,914. This amount is subject to adjustment for the updated cost of capital, in addition to changes in capital and operating expenses, and possibly other factors, as determined by the Board in its decision. In the updated RRWF filed in response to Board staff supplemental IR # 78, Atikokan Hydro documented an updated grossed-up PILs expense of $14,087.

Board staff takes no issue with the methodology, as amended through discovery, used by Atikokan Hydro to calculate its tax/PILs allowance for 2012, and submits that Atikokan Hydro should use this approach to calculate any updated allowance for taxes/PILs to reflect to the Board's Decision.

Green Energy Act

Atikokan Hydro submitted its Green Energy Act Plan ("GEA Plan") as part of its original Application on September 29, 2010 and proposed no expenditures under

[12] Exhibit 4/Tab 1/Schedule 13

its GEA Plan. The review letter from the OPA on Atikokan Hydro's GEA Plan is submitted as an attachment to the GEA Plan, and expresses no concerns with Atikokan Hydro's GEA Plan.

Atikokan Hydro notes in its GEA Plan the upstream constraints in the transmission system in northwestern Ontario which would limit connection of additional generation. Within Atikokan Hydro's own distribution system, the utility has noted design constraints that would limit connections of microFIT generation with capacities of 5 to 10 kW; redesign and rebuilding of the distribution network would be required to overcome these constraints.[13] The utility has noted that there is limited uptake of microFIT within its network; there are 8 such connections as of December 31, 2011.[14]

Board staff takes no issue with Atikokan Hydro's proposed GEA Plan, in light of its circumstances and explanations.

Low Income Energy Assistance Program (LEAP)

Atikokan Hydro has proposed that an expense amount for LEAP should be included, equal to $2,000 (the greater of $2,000 or 0.12% of 2012 distribution revenues dependent on the Board's decision), incorporated in the proposed OM&A. Board staff submits that Atikokan Hydro's proposal is compliant with Board policy.

Cost of Capital

In its original Application, Atikokan Hydro used an estimated Cost of Capital of 6.49%, based on a deemed capital structure of 60% debt (56% long-term debt and 4% short-term debt) and 40% equity. It used the then-current ROE of 9.58% and deemed short-term debt rate of 2.08%, which were the Cost of Capital parameters for 2011 applications with May 1, 2011 effective dates as announced in the Board's letter of March 2, 2011. Atikokan Hydro acknowledged that these parameters would be updated with data three months in advance of the proposed effective date of May 1, 2012 for its new rates, in accordance with the methodology documented in the *Report of the Board on Cost of Capital for*

[13] Response to Board staff IR # 4
[14] Response to VECC IR # 8 a)

Ontario's Regulated Utilities, issued December 11, 2009 (the "Cost of Capital Report").

On March 2, 2012, the Board issued a letter documenting updated Cost of Capital parameters for rates effective May 1, 2012. The updated Cost of Capital parameters are:

Cost of Capital Parameter	Rate
Return on Equity	9.12%
Deemed Short-term Debt	2.08%
Deemed Long-Term Debt	4.41%

With its update to Board staff supplemental IR # 78 filed on April 11, 2012, Atikokan Hydro has reflected the updated Cost of Capital parameters in calculating its revenue requirement. With the ROE and short-term debt rates, and a change in the weighted average long-term debt rate addressed below, the weighted average cost of capital becomes 6.09% versus 6.49% as originally applied for.

Board staff offers some further comments on Atikokan Hydro's proposed treatment for the update of its long-term debt in 2012 below. However, Board staff submits that Atikokan Hydro's proposal for its Cost of Capital complies with the Cost of Capital Report and with Board policy and practice.

Long-term debt

Atikokan Hydro notes that it currently has four debt instruments outstanding:[15]

Debt holder	Principal	Rate (%)	Interest
Town of Atikokan Hydro	$1,270,334	5.00%	$63,838
TD Canada Trust	$268,915	4.00%	$11,892
TD Canada Trust	$207,317	4.25%	$9,270
Atikokan Enercom Inc.	$400,000	3.75%	$12,310
Total	$2,146,566.00	4.58%	$97,310

As documented in the Application, all of the notes have variable rates. Two of the debt instruments are affiliated debt – those with the Town of Atikokan and

[15] E5/T1/A1/page 2

with Atikokan Enercom Inc. In accordance with the *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, the utility is required to file copies of the executed agreements for affiliated debt. Atikokan Hydro did not do so in the original Application material, but was requested to do so through interrogatories.[16]

In response to Board staff IR # 19, Atikokan Hydro filed a copy of a letter from the CAO/Treasurer of the Town of Atikokan dated March 24, 2011, documenting the outstanding principal of $1,282,096.59, the rate of 5.0% and the monthly payment including interest of $6300. However, this is not the executed agreement and does not provide sufficient details by which the compliance of the note with guidelines in the Cost of Capital Report could be assessed. Atikokan Hydro provided documentation on the executed loan agreement in Board staff supplemental IR # 65 a). As documented in By-law 14-09[17], the rate established for the loan with the Town of Atikokan is fixed at 5.0%. Board staff submits that this is compliant with the policies in the Cost of Capital Report.

Based on the evidence filed in response to interrogatories, Board staff takes no issue with the proposed debt rates for the other debt instruments that Atikokan Hydro has with Atikokan Enercom and with a third-party bank.

Board staff observes that Atikokan Hydro has adjusted the weighted average long-term debt rate in the RRWF filed in response to Board staff IR # 78 from 4.57% to 4.22%. However, Atikokan Hydro has not documented the reason for this change. Board staff submits that Atikokan Hydro should explain this and shown the calculation in its reply submission.

Cost Allocation

As part of its Application, Atikokan Hydro conducted an updated Cost Allocation study between all customer classes with the following results:[18]

---

[16] Board staff IRs # 19 and 20, and Board staff supplemental IR # 65.
[17] This by-law enacted by the Town of Atikokan, restarted debt payment after a temporary holiday to address cash flow concerns of the utility in the mid-2000s. The by-law is an attachment to Board staff IR # 65 a).
[18] Exhibit 7/Tab 1/Schedule 2/page 3/Table 7-3

Table 7-3 - Revenue to Cost Ratios - 2010 IRM and 2012 Proposed

Customer Class	Low	High	2010 IRM	2012 Cost Allocation	2012 Proposed
Residential	85.0%	115.0%	101.0%	97.6%	98.1%
General Service < 50 kW	80.0%	120.0%	100.0%	134.8%	120.0%
General Service > 50 kW	80.0%	180.0%	80.0%	82.3%	82.3%
Streetlighting	70.0%	120.0%	70.0%	75.0%	98.1%
Sentinel Lighting	70.0%	120.0%	70.0%		
Unmetered Scattered Load	80.0%	120.0%	80.0%		

With one exception, Board staff submits that Atikokan Hydro has correctly adhered to the Board's current policy and practice for cost allocation. The exception is that Atikokan Hydro is not proposing to increase the GS > 50 kW revenue-to-cost ("R/C") ratio more, even though, except for streetlighting, it is the furthest below unity. To offset reducing the R/C ration for the GS < 50 kW class to the upper threshold, Atikokan Hydro is proposing that increases to the R/C ratios be borne by the Residential and Streetlighting classes. As is discussed elsewhere, mitigation of rate impacts, largely on Atikokan Hydro's Residential customers, is an issue in the Application. Increasing the R/C ratio for the GS > 50 kW class could lower the adjustment to the Residential class and help, to some extent, to mitigate rate increases in this class.

Rate Design

Elimination of Unmetered Scattered Load and Sentinel Lighting Customer Classes

In its Application, Atikokan Hydro has proposed the elimination of the Unmetered Scattered Load ("USL") and Sentinel Lighting classes, on the basis that it no longer has any customers in these classes. While the elimination of the Sentinel Lighting class may be more common, the elimination of all USL customers and connections is less common. However, this situation may be possible given the small size of the utility, with less that 1700 metered customers.

Board staff notes that the absence of these classes has been reflected in the load forecast and in the Cost Allocation model filed in this Application. Board staff takes no issue with Atikokan Hydro's proposal to eliminate these two customer classes with no customers. Should Atikokan Hydro serve any new

USL customers in the future, Board staff submits that these customers be included in the GS < 50 kW class, as has been the treatment by other distributors in similar situations.

Fixed/Variable Split

Atikokan Hydro has proposed to retain the existing fixed/variable split for all remaining customer classes, as documented in Table 8-3 of the Application. Board staff observes that Atikokan Hydro's current split is approximately 80% fixed and 20% variable for each class. This split results in higher bills for lower consumption customers but more rate stability for the utility. Board staff takes no issue with Atikokan Hydro's proposal.

Retail Transmission Service Rates

In its Application[19], Atikokan Hydro filed for adjusted Retail Transmission Service Rates ("RTSRs") based on the Board's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Rates*, and based on an analysis of historical trends/patterns for over- or under-collection in the RSVAs and the approved Uniform Transmission Rates effective January 1, 2011, using the Board-issued model. In response to VECC interrogatory # 22, Atikokan Hydro submitted revised proposed RTSRs reflecting the updated Uniform Transmission Rates effective January 1, 2012.

Board staff submits that Atikokan Hydro's proposal complies with Board policy and practice, and takes no issue with the proposed updated RTSRs.

Transformer Ownership Allowance

The Transformer Ownership Allowance ("TOA") credit is paid to those customers within an applicable class that own their own transformation facilities. The estimated credit to be paid is then factored as addition to the revenue requirement to be recovered through distribution rates.

[19] E8/T1/S2/pg. 1/Table 8-8

In its Application, Atikokan Hydro proposed to maintain the current approved TOA credit of 10% of the distribution volumetric rate for the GS > 50 kW class.[20] In fact, Atikokan Hydro documented this as ($0.17)/kW.

In response to Board staff IR # 21, Atikokan Hydro confirmed that the TOA should be updated to correspond with the proposed volumetric rate, and adjusted the proposed TOA to ($0.24)/kW. In response to part c) of that interrogatory response, Atikokan Hydro also indicated that a TOA credit of ($0.31)/kW would be suitable, as corresponding to the theoretical "avoided cost" per kW due to customer-supplied transformation from sheet O3.1 of the cost allocation model.

In response to VECC supplemental IR # 6, Atikokan Hydro clarified that its preferred TOA credit would be ($0.24)/kW. However, in its AIC, Atikokan Hydro reconsidered this and proposed that the TOA credit should be ($0.31/kW). Board staff concurs, as the rate is fixed and not dependent on the volumetric rate of the class, and more closely corresponds to the avoided cost.

Board staff submits that Atikokan Hydro will have to take into account the TOA credit approved by the Board in its decision in the preparation of the proposed rates in the draft Rate Order filing.

Loss Factor

In its Application,[21] Atikokan Hydro has proposed updates to its Board-approved loss factors as follows:

[20] The Board approved a TOA credit of 10% of the applicable volumetric rate for the customer class in its decision for Atikokan's 2006 EDR rates application (RP-2005-0020/B-2005-0338) to remedy a historical issue since unbundling where the previous credit of ($0.60)/kW was larger in magnitude than the volumetric rate for one class. With some reclassification and an updated cost allocation study in its 2008 cost of service rates application, the small volumetric rate disappeared but the TOA credit was maintained at 10% of the applicable volumetric rate in a class.
[21] Exhibit 8/Tab 1/Schedule 3

Description	Loss Adjustment Factor
Supply Facility Loss Factor	1.0045
Distribution Loss Factors	
Secondary Metered Customer < 5000 kW	1.0730
Secondary Metered Customer > 5000 kW	1.0623
Primary Metered Customer < 5000 kW	1.0778
Primary Metered Customer > 5000 kW	1.0671

For a Secondary Metered Customer with demand < 5000 kW, the current Board-approved Total Loss Factor is 1.0778.

Board staff considers that Atikokan Hydro's methodology for updating its Loss Factors complies with Board policy and practice, and takes no issue with its proposal on this matter. However, Board staff would offer some comments on Atikokan Hydro's losses.

First, Atikokan Hydro has documented its loss calculations in Table 8-9 of E8/T1/S3. Distribution system losses increased in 2008 and 2009 at 9.49% and 10.14%, respectively. Losses decreased in 2010, with the annual distribution loss of 7.33% being close to the five-year average of 7.30%. In response to Board staff IR # 22, Atikokan Hydro noted that it no longer had the data prior to 2008, and thus was unable to explain the increased losses in 2008 and 2009. It did provide some further explanation of its operating environment that factor into its increased losses. In particular, Atikokan Hydro's distribution system losses are measured from Hydro One Networks Inc's Moose Lake Transformer Station. Electricity flows along 23 km of 44 kV sub-transmission line owned and operated by Atikokan Hydro to the utility's distribution stations. Atikokan Hydro states "[i]f one was to assume a 4.3% loss for an LDC as sparse as Atikokan Hydro, then it would be reasonable to assume 3% for the 44 kV line. The loss attributed to the 44 kV lines is accumulated on the wholesale meters prior to the power reaching any of our customers."[22] However, there is no empirical data supporting this response.

[22] Response to Board staff IR # 22 b).

However, while its circumstances may be a significant factor for the higher losses, this does not obviate the utility's obligation to try to manage its system so as to reasonably reduce losses. Since Atikokan Hydro's distribution losses are above 5%, the utility is expected to address it and to document its efforts when its rates are reviewed through a cost of service application.

Board staff notes Atikokan Hydro's response to an interrogatory:

> Atikokan Hydro expects that time spent previously to read meters will be used to work on capital programs that will support the asset management plan.[23]

In other words, with the implementation of automated reading of smart meters, Atikokan Hydro's line crew should have more time to spend on capital and operations and maintenance on the distribution infrastructure. This would be to ensure the continued reliability and safety of the network, and should, in Board staff's submission, also be directed at cost-effective methods of reducing losses within Atikokan Hydro's distribution system. Board staff recommends that Atikokan Hydro be directed to file a report on capital and operations and maintenance activities undertaken to address line losses and to conduct a review of non-technical losses, and the results of these, in the utility's next cost of service application.

Deferral and Variance Accounts

In its Application, Atikokan Hydro filed the Deferral and Variance Continuity Schedule for the deferral and variance accounts ("DVA") balances as at December 31, 2010. Board staff noted that Atikokan Hydro did not include a credit balance of $7,716 for Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs) as a part of its DVA balances.[24] During the interrogatory process, Atikokan Hydro changed the balances for the DVA to include the omitted balance, and filed revised figures with the Board.

[23] Response to Board staff IR # 15 b)
[24] Response to Board staff interrogatory #69

Board staff has produced table 1 below to show Atikokan Hydro's updated DVA balances. The balances for the smart meter Account 1555 and Account 1556 are excluded from the table, as the issues related to the smart meters are discussed elsewhere in this submission.

Atikokan Hydro's Group 1 and Group 2 DVA Balances

Account Description	Account Number	Principal Amount	Interest Amounts	Total Claim
RSVA – Wholesale Market Service Charges	1580	(36,935)	14,276	(22,659)
RSVA – Retail Transmission Network Charge	1584	8,273	765	9,038
RSVA – Retail Transmission Connection Charge	1586	34,957	13,411	48,368
RSVA – Power (Excl. Global Adjustment)	1588	(5,710)	8,256	2,546
RSVA – Power (Global Adjustment Sub-account)	1588	9,626	59	9,685
Recovery of Regulatory Asset Balances	1590	1,274	(640)	634
Group 1 Total		**11,485**	**36,127**	**47,612**

Account Description	Account Numbers	Principal Amounts	Interest Amounts	Total Claim
Other Regulatory Assets – OEB Cost Assessments	1508	9,061	924	9,985
Other Regulatory Assets – Pension Contribution	1508	137,278	11,776	149,054
Retail Cost Variance Account - Retail	1518	6,879	157	7,036
Retail Cost Variance Account - STR	1548	20,293	601	20,894
Input tax Credit	1592	15,210	221	15,431
Group 2 Total		**188,721**	**13,679**	**202,400**
Special Purpose Charge	1521	1,592	138	1,730[25]
Total of Group 1 and Group 2, including Account 1521		**201,798**	**49,944**	**251,742**

[25] Response to Board staff interrogatory #29

Board staff addresses the following issues:

1. Disposition of Group 1 DVA and Group 2 DVA Balances
2. Disposition of 2008 and 2009 Group 1 DVA Balances
3. Account 1508 OEB cost assessments and OMERS
4. Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs)

1. Disposition of Group 1 DVA and Group 2 DVA Balances

As part of its rate mitigation proposal, Atikokan Hydro requested the Board defer the disposition of the 2010 Group 1 and Group 2 DVA balances until it files its 2013 IRM rate application.[26] The 2010 Group 1 DVA balance is a debit amount of $47,612 and Group 2 DVA balance is a debit amount of $202,400 as at December 31, 2010.

Board staff notes that in the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (EDDVAR), the Board decided that the accounts that would be reviewed in an IRM application will be limited to accounts that do not require a prudence review (i.e. the revised Group 1 Accounts).[27] All account balances would be reviewed at the time of rebasing.

Board staff submits that the Atikokan Hydro's 2013 IRM rate application proceeding would not be an appropriate forum for the Board to review the Group 2 DVA balances, since they require a review for prudence, and may require closer examination that would lengthen the review of the IRM application as a whole.

Board staff submits further that there is a concern with Atikokan Hydro's financial viability if the DVA balances are not disposed in this proceeding since given the not immaterial debit balance.[28] The recovery for the amounts related to Atikokan Hydro's 2010 DVA balances may help enhance Atikokan Hydro's cash flow given the debit balance of the Group 1 and Group 2 accounts.

---

[26] Exhibit 9, Tab 1, Schedule 2, Page 1
[27] *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative*, July 31, 2009, page 11
[28] Exhibit 1, Tab 3, Appendix F, Page 14

2. Disposition of 2008 and 2009 Group 1 DVA Balances

In its Decision EB-2010-0064 regarding Atikokan Hydro's 2011 IRM rates application, the Board accepted Atikokan Hydro's proposal to address the disposition of the 2008 and 2009 Group 1 Deferral and Variance Account balances, stating:

> 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.
>
> 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.[29]

Despite the Board's direction that no new rate riders would be required to recover the 2009 Group 1 account balances and that Atikokan Hydro should track the 2009 account balances at the account level, Atikokan Hydro incorrectly

[29] Decision and Order [EB-2010-0064], March 17, 2011, page 9

transferred the 2009 Group 1 account balances to Account 1595 – Disposition and Recovery of Regulatory balance sub-account.[30]

Through interrogatories, Board staff asked Atikokan Hydro to confirm if it had tracked 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 per the Board Decision EB-2010-0064.[31] Board staff also asked Atikokan Hydro to update its DVA continuity schedule to reflect the Board direction in its EB-2010-0064 Decision.[32] In its response to Board staff interrogatories, Atikokan Hydro stated that it misinterpreted the Board's Decision (EB-2010-0064) regarding the treatment of 2008 and 2009 account balances. Subsequently, the utility updated the continuity schedule on April 11, 2012.

Board staff submits that the revised DVA continuity schedule that was filed on April 11, 2012 correctly reflects the Board Decision EB-2010-0064. Board staff further submits that any variances between the reported RRR and December 31, 2010 DVA balances are immaterial.

3. Account 1508 OEB cost assessments and OMERS

Atikokan Hydro recorded a debit principal balance of $9,985 for the OEB cost assessments in Account 1508 sub-account Other Regulatory Assets Cost Assessment for the period of 2006 to 2009. Atikokan Hydro also recorded a debit principal balance of $149,054 for pension costs contributions to OMERS in Account 1508 sub-account OMERS for the period of 2006 to 2011.[33] The total cost that Atikokan Hydro recorded under sub-accounts of Account 1508 is $159,039. Atikokan Hydro confirmed that the costs for OEB cost assessments and pension costs contributions to OMERS were not included in Atikokan Hydro's 2008 Cost of Service rate application and therefore were not recovered in the 2008 rates.[34]

[30] Atikokan's Deferral and Variance (DVA) continuity schedule, September 30, 2011
[31] Board staff interrogatory #31
[32] Board staff interrogatories #32 and #33
[33] Board staff interrogatories #36 and Deferral and Variance Accounts Continuity Schedule filed on April 10, 2012
[34] Board staff interrogatories #36

In response to interrogatories, Atikokan Hydro has confirmed that it has now included the 2012 OEB Cost Assessment and the OMERS cost in its 2012 operating expenses to be recovered through its 2012 distribution rates.[35]

Article 220 of Accounting Procedures Handbook (APH), pages 16 and 17, Note A states:

> 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.

Atikokan Hydro has stated that it had an understanding that it had to cease recording in these accounts once the costs were included in the distribution rates.[36] However, Board staff note that in the Board's Decision EB-2008-0014, the Board approved the disposition of Account 1508 sub-accounts OEB cost assessments and OMERS for the balances as of December 31, 2006, which should include the costs incurred by Atikokan Hydro in 2006.

Board staff submits that the Board may wish to consider the following two options:

Option 1 – Not approve the recovery of prior years' OEB cost assessments and pension costs contributions to OMERS

Reasons that would support denial of past period recoveries are:

a) Atikokan Hydro did not follow the requirements as outlined under the APH to properly and accurately include the costs related to the

[35] *Ibid.*
[36] *Ibid.*

prior years' OEB cost assessments and pension costs contributions to OMERS in its 2008 Cost of Service rate application. As a result, Atikokan Hydro did not recover these costs in the 2008 and subsequent rate years under the IRM regime. Atikokan Hydro had control of its own accounting books as well as its application that it filed with the Board for the 2008 rate year while the ratepayers did not.

b) The amount of $159,039 that Atikokan Hydro is seeking for recovery is related to costs incurred prior to 2011. The costs should have been recovered through rates that were set by the Board effective May 1, 2008. Therefore, these costs are related to the "prior periods" and may be regarded as "out-of-period" expenses from rate-making and regulatory accounting perspectives. The Board is unable to correct the errors made by Atikokan Hydro at this time as the ratepayers should generally have confidence that a final rate is in fact a final rate.

Option 2 – Approve the recovery of prior years' OEB cost assessments and pension costs contributions to OMERS

The Board could consider granting Atikokan Hydro's recovery of the $159,039 from its customers on the following basis:

a) Atikokan Hydro incurred the costs with respect to both OEB cost assessments and pension costs contributions to OMERS and has been tracking these costs since 2006. However, Atikokan Hydro erred in incorrectly following the requirements set out in the APH for recovery of the OEB cost assessments and pension costs contributions to OMERS.

b) There is a concern with Atikokan Hydro's financial viability.[37] The Board's granting of the recovery for the amounts related to the past

[37] Exhibit 1/Tab 3/Appendix F/page 14

OEB cost assessments and pension costs contributions to OMERS may help in this regard.

4. Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs)

Atikokan Hydro states that Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs) has a credit balance of $15,431 as of December 31, 2010 and 50% of this balance which is $7,716 is refundable to the ratepayers.[38]

Board staff takes no issue with the calculation of the Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs) balance. However, Board staff notes that Atikokan Hydro has not included the credit balance of $7,716 in its Deferral and Variance Continuity Schedule under the Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs) and submits that this amount should be included in the 2010 DVA balances as at December 31, 2010 and refunded to the customers.

Disposition of Account 1562 deferred payments in lieu of taxes ("PILs")

The current proceeding is the Board's first prudence review of Atikokan Hydro's evidence related to the disposition of its account 1562 deferred payments in lieu of taxes ("PILs"). The PILs evidence filed by Atikokan Hydro in this proceeding includes tax returns, financial statements, Excel models from prior applications, calculations of amounts recovered from customers, SIMPIL[39] Excel worksheets and continuity schedules that show the principal and interest amounts in the account 1562 deferred PILs balance.

In pre-filed evidence, Atikokan Hydro applied to recover from customers a debit balance of $20,141 consisting of a principal amount of $15,001 plus related carrying charges of $5,140. In response to interrogatories, Atikokan Hydro filed amended evidence that reflects a recovery of $29,597 consisting of a principal amount of $21,696 plus related carrying charges of $7,901.[40]

[38] Response to Board staff interrogatory #69
[39] Spreadsheet implementation model for payments-in-lieu of taxes
[40] Responses to interrogatories, March 2, 2012, PDF pages 119-120

History of the 2001 and 2002 Applications and Process

In its 2001 application, Atikokan Hydro chose to delay implementation of unbundled rates until the date when subsection 26(1) of the *Electricity Act, 1998*, S.O. 1998, c.15, (Schedule A) (market opening) came into force. The Board approved the request. PILs were not included in these unbundled rates:

> By letter dated November 15, 2001, Atikokan Hydro proposed to implement the new unbundled rates on the date that [subsection] 26(1) of the *Electricity Act, 1998,* S.O. 1998, c.15, (Schedule A) comes into force. The Board accepts the Applicant's proposal.[41]

On December 18, 2001 the Premier confirmed that the market would open on May 1, 2002.[42]

On December 21, 2001 the Board issued filing guidelines to all electricity distribution utilities for the March 1, 2002 distribution rate adjustments. Supplemental instructions were issued on January 18, 2002. The Board issued detailed instructions and several filing models created in Excel to make the application process easier for the distributors. The intent was to have the distributors file in January 2002 and the Board's Orders would be issued in February and March for rates effective March 1, 2002:

> The Board will be reviewing a large number of applications within a very short time period. The Board therefore intends to review first those applications that adhere to these filing guidelines. Applications that do not adhere to these guidelines or contain other proposed changes will be reviewed after those applications that have followed the filing guidelines and do not propose other changes.[43]

Atikokan Hydro filed an application, dated January 25, 2002, for an order or orders under section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable unbundled rates including forecast PILs tax expense

---

[41] RP-2000-0261/ EB-2000-0561/ EB-2001-0232, Decision with Reasons and Order, page 3
[42] http://www.ontarioenergyboard.ca/documents/cases/market_readiness/letter_180102.pdf
[43] Filing Guidelines for March 1, 2002 Distribution Rate Adjustments, December 21, 2001

proxies for the distribution of electricity, effective May 1, 2002. Atikokan Hydro filed revised applications dated March 28 and April 3, 2002. The Board issued its decision for this case on April 5, 2002 and approved final unbundled rates including the PILs proxies to be effective May 1, 2002.[44]

Accounting Procedures Handbook (APH) and Frequently Asked Questions (FAQs)

APH Article 220 was revised in December 20, 2001 and provided minimum guidance for the use of account 1562. FAQ April 2003 provided examples of the accounting entries related to account 1562 deferred PILs. The year selected for the example was the twelve month complete year of 2003. FAQ April 2003 did not deal with the complexities associated with periods of less than twelve months. This FAQ guideline was issued more than one year after the Board's decision approving Atikokan Hydro's voluntary request for rates to be effective coincident with market opening on May 1, 2002.

Start date for recording the PILs proxy entitlement and the amount

In its PILs continuity schedule in the current Application, Atikokan Hydro recorded the entitlement to the PILs proxies for the fourth quarter 2001 and the whole year 2002 starting October 1, 2001 and January 1, 2002 respectively. Atikokan Hydro added the two PILs proxy amounts of $7,668 for 2001 and $32,754 for 2002 and pro-rated the total of $40,422 over ten months from March to December 2002. This treatment creates receivables from its ratepayers for the period October 1, 2001 through April 30, 2002 before the effective date of the unbundled rate adjustment on May 1, 2002.

At question is whether the instructions in the APH and FAQs to begin recording the PILs proxy entitlements as at October 1, 2001 and January 1, 2002 should apply to Atikokan Hydro. In its 2001 decision, the Board approved unbundled rates to be effective upon market opening as voluntarily requested by Atikokan Hydro. The decision dated April 5, 2002 for the 2002 unbundled rate adjustment, including PILs proxies, ordered rates to be effective May 1st in accordance with Atikokan Hydro's application.

---

[44] RP-2002-0028/ EB-2002-0037, April 5, 2002, page 5

Board staff asked the following interrogatories concerning Atikokan Hydro's voluntary delay of implementing unbundled rates in Board staff interrogatory # 54:

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?

Atikokan Hydro responded:

> In the Board's Decision RP-2002-0028; EB-2002-0037 for Atikokan Hydro's 2002 rates the Board approved the 2001 deferred Payments in Lieu of Taxes (PILs) of $7,668 and the 2002 Payments in Lieu of Taxes (PILs) of $32,754. However, Atikokan Hydro's rates did not become effective until May 1, 2002 and this was not reflected in the 1562 PILs Continuity Schedule filed originally filed. This oversight has been corrected and the revised 1562 PILs Continuity Schedule is provided below assuming collection of the approved PILs begins May 1, 2002. [45]

Atikokan Hydro thus did not answer the questions originally posed. Supplementary interrogatories[46] were filed by Board staff in order to obtain specific answers to the original questions. Atikokan Hydro replied:

> a) The OEB has set precedent, through the combined proceeding EB-2008-0381, that the entitlement commences with the start of taxation (October 1, 2001) as opposed to the effective date of distribution rates including PILs. Atikokan believes that this precedent should apply equally to all LDCs.
>
> The three combined proceeding applicants (EnWin, Halton Hills and Barrie) started recording entitlements on October 1, 2001 (for 2001 PILS) and

[45] Atikokan Hydro_Cos_BdStf_IRs_20120302.pdf, page 119

[46] Response to Board staff IR # 76

January 1, 2002 (for 2002 PILS). Atikokan could not locate the 2002 rate decisions for these three applicants, which approved PILs in rates, but suspects that rates were effective March 1, 2002 not October 1, 2001 or January 1, 2002. This establishes the principle that entitlement commences with taxation and not with rate approval.

b) Atikokan did not 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.

b2) The 1562 Deferred PILs account was created to keep LDCs "whole", as defined by the rules set out in the combined proceeding. The combined proceeding has confirmed that approved PILs in rates is to be used as the entitlement side of the variance account, the PILs recovered from customers to be the recovery side of the variance account and SIMPILS models to make appropriate adjustments between customers and the LDC. To be consistent with these principles, Atikokan should be entitled to the full amount of PILs previously approved in rates. To approve a 1562 Deferred PILs balance on any other basis would effectively be retroactive rate making (the Board Staff submission would effectively reduce the amount of PILs included in rates that the Board has already approved).

Atikokan Hydro's unbundled distribution rates were calculated based on a twelve month rate year. The monthly rates which the Board approved in its Order became effective on May 1, 2002. The annualized dollar amount of PILs tax expense proxies used as an input into the monthly rate calculations is no different than depreciation or any other cost increase included in revenue requirement. For example, the entitlement to the first and second tranches of MARR[47] occurred when Atikokan Hydro's new changed unbundled rates became effective on May 1, 2002.

The three applicants in the combined proceeding did not ask to delay 2001 or 2002 implementation of unbundled rates until market opening. Their specific

[47] First Generation Performance Based Regulation Handbook, Market Adjusted Revenue Requirement, section 5.5.2, page 5-8

regulatory and PILs tax facts were different, and the Board addressed this in its decision:

> The Board cannot adjust the PILs amount included in any final rates – during or after the rate freeze period. The Board is prohibited from changing rates retroactively or retrospectively. No parties disputed this limitation on the Board's jurisdiction.
>
> However, the Board finds that it can review the balances in Account 1562 across the entire time period, including during the Bill 210 period, and dispose of those balances. Some parties have described this as a prudence review. It is not a prudence review in the sense of determining whether expenditures were prudently incurred; rather it is a prudence review in the sense of ensuring the accuracy of the accounts and whether the amounts placed in the accounts were calculated in a manner consistent with the Board's methodology as it was established at the time.
>
> There was no significant disagreement in the submissions on this point either. It is clear from the legislation that the account was permitted to be continued, and reviewing the balance for accuracy and prudence is a necessary part of any disposition determination.[48]

and:

> There may be differences now as to the interpretation of the methodology at various points in time. The EDA and CLD portray the main purpose of the account as being to record the difference between <u>what was included in rates and what was collected from ratepayers through rates</u>. There is some acknowledgement by those parties that the account was also intended for some level of <u>true-up between amounts included in rates and amounts actually payable</u>. To the extent there is some true up component to the account, the resulting balances are not an attempt to change the rates underlying the final rate orders; the balances appropriately reflect the purpose and objective of the account as it was established at the time.

[48] EB-2008-0381, Decision with Reasons, December 18, 2009, page 4

> The parties may well differ in their interpretations of the methodology but the Board will decide those questions on the basis of the facts and the underlying documents. The Board will not enter into an enquiry as to what the methodology should have been but rather, will determine, where necessary, what the methodology was and what the appropriate application of the methodology should have been.[49] [*Emphasis added*]

In Procedural Order No. 8 of the combined proceeding,[50] the Board made the following finding:

> On Issues Day before the Board the CLD, EnWin and SEC made submissions on how the Board should approach its review of the methodology, ratemaking principles and the evidence of the three applicants in this proceeding. The Board finds that its Decision of December 18th, and the discussion contained in the hearing transcript for Issues Day, provide the full extent of the scope of this proceeding that the Board considers appropriate at this time.

In Procedural Order No. 8 of the combined proceeding, the Board included language at the top of the approved final issues list the Board released following Issues Day:

> In the Board's Decision in this proceeding, which was issued December 18, 2009, the Board established certain parameters for this proceeding. Among those parameters, the Board stated: "The Board will not enter into an enquiry as to what the methodology should have been but rather, will determine, where necessary, what the methodology was and what the appropriate application of the methodology should have been." Accordingly, the individual issues below are to be interpreted in a manner that exclusively furthers the Board's determination as set out in the Decision.

[49] EB-2008-0381, Decision with Reasons, December 18, 2009, pages 6-7
[50] EB-2008-0381, Procedural Order No. 8, February 17, 2010, page 3, para. 5

> Further, the issues below only address the issues relevant to the three named applicants; Account 1562 Deferred PILs issues that are relevant to the disposition of the account for other LDCs, but which are not relevant to the three named applicants, are not within the scope of this proceeding.[51] *[Emphasis added.]*

In the transcript of Issues Day before the Board, Presiding Member Ken Quesnelle made the following statements:

> What we don't want to do now, in fairness to the applicants that are before the Board, is slow down these proceedings in testing hypothetical scenarios, in tweaking the existing evidence to a point where it might suit someone else who is outside of this proceeding and to test hypotheticals.[52]
>
> … We have come this far and we want to concentrate on the applicants that are before us and the evidence that is here.[53]
>
> … But we will be resisting the stretching of the current applicants' evidence to consider all permutations of scenarios that could occur.[54]

Atikokan Hydro voluntarily chose to implement unbundled rates including the first and second tranches of MARR, and PILs tax expense, on May 1, 2002. Board staff submits that Atikokan Hydro should pro-rate its PILs tax proxy entitlements in the same time period as it billed its customers for the changed unbundled rates as described in the following section.

The 2001 PILs proxy included in 2002 rates was $7,668. The 2002 PILs proxy was $32,754 and the combined total was $40,422.[55] The period from May 1, 2002 through March 31, 2004 contains 23 billing months. The pro-rated PILs proxy for this 23-month period using the twelve-month total of $40,422 is

[51] EB-2008-0381, Procedural Order No. 8, Final Issues List, February 17, 2010
[52] Decision on Issues List, Transcript, Issues Day, February 9, 2010, Page 32, lines 21-26
[53] *Ibid.*, Page 33, lines 10-12
[54] *Ibid.*, Page 34, lines 10-12
[55] 2002 Application PILs proxy models; and 2002 RAM sheets 6 and 8; filed on December 15, 2011

$77,476. ($40,422/12)*23) During this same period, Atikokan Hydro billed its customers and recovered $75,246 of PILs.[56] Board staff observes, from the Ministry of Finance notices of assessment filed in this proceeding, that Atikokan Hydro did not pay any PILs to the government for the period 2001 through 2006.

Board staff submits that the alternative proffered by staff of calculating the PILs proxy with effect from May 1, 2002 is equitable to the ratepayers and to the shareholder. If Board staff's suggestion is accepted by the Board, the debit principal balance to be recovered from ratepayers would be approximately $8,222. Board staff estimates interest carrying charges to be $2,260 for the period up to April 30, 2012 based on the restated principal amount of $8,222 for a total to be recovered of $10,482.

Board staff submits that this revised debit amount of $10,482 has been calculated in accordance with the regulatory guidance and the decisions issued by the Board in determining the amounts in Account 1562 Deferred PILs.[57]

Board staff requests that Atikokan Hydro file active Excel models with its reply submission to facilitate the final review of its evidence.

Smart Meters

Atikokan Hydro is seeking approval for disposition of its smart meter costs recorded in Accounts 1555 and 1556 in this Application. In fact, Accounts 1555 and 1556 are the only two DVAs for which Atikokan Hydro is seeking disposition of in this Application. Atikokan Hydro is seeking approval to dispose of capital and operating costs related to the deployment of smart meters to all Residential, GS < 50 kW and GS > 50 kW customers.

Atikokan Hydro documented a cost of $392 per installed smart meter as of December 31, 2011. In its Application, Atikokan Hydro sought a Smart Meter

---

[56] Atikokan_PILS_Reconciliation_2001-2012_20111214.XLS
[57] Decisions in Combined Proceeding, EB-2008-0381 – August 12, 2011; June 24, 2011; December 23, 2010; December 18, 2009. Hydro One Brampton, EB-2011-0174, December 22, 2011. Whitby Hydro, EB-2011-0206, December 22, 2011. Staff Discussion Paper, August 20, 2008. Sioux Lookout EB-2011-0102, April 19, 2002, page 12.

Disposition Rider of $3.54 per month, applicable over a period of 36 months from May 1, 2012 to April 30, 2015.

Board staff noted that Atikokan Hydro used its own model originally. Board staff requested that Atikokan Hydro review its costs and use the Smart Meter Model Version 2.17 issued by the Board along with Guideline G-2011-0001: *Smart Meter Funding and Cost Recovery – Final Disposition,* issued on December 15, 2011. In response to Board staff IR # 38, Atikokan Hydro filed an updated proposal using the Board-issued model. As part of its response, Atikokan Hydro revised its evidence. In particular, capital costs were changed, mostly with reclassification of some costs from computer hardware to meters. More significantly, the deferred OM&A expenses increased from about $150K to $225K. Explanations were provided in responses to Board staff interrogatories.[58]

As a result of Atikokan Hydro's revised smart meter evidence, Board staff has prepared the following table of per meter costs:[59,60]

	2006	2007	2008	2009	2010	2011	2012	Total	
Capital				$ 424,813	$ 56,812	$ 25,073		$ 506,698	
OM&A				$ 61,874	$ 84,080	$ 78,253		$ 224,207	
Number of Smart Meters				1586	65	0	0	1651	
								Total	**Average per meter**
							Total (capex + opex)	$ 730,905	$ 442.70
							Capex only	$ 506,698	$ 306.90

Outside of Hydro One Networks, Atikokan Hydro has the highest per meter cost that the Board and staff have seen to date. The capital cost per meter is higher than seen previously for other utilities. However, smaller utilities may not have the size or density to achieve economies with respect to fixed costs for related infrastructure (communications receivers and transmitters, computer hardware and software) relative to larger urban utilities. Atikokan Hydro is a smaller utility that is remote from neighbouring utilities and usage data is communicated over 200 km to Thunder Bay. While the per meter capital costs are high, Board staff

[58] See responses to Board staff IR # 39 and supplementary IR # 66
[59] Atikokan Hydro has documented that these costs do not include costs "beyond minimum functionality" for TOU implementation, customer education, etc.
[60] See also response to Board staff IR # 40

submits that there is no substantive evidence that these costs are not reasonable in light of its circumstances. As part of the Northwest Group of utilities, Atikokan Hydro complied with O.Reg. 427/06 and the London Hydro process for the procurement and deployment of smart meters.

However, Board staff expresses more concern with the deferred OM&A costs, as these were materially revised through responses to interrogatories. Some of these costs may be related to third party costs for consulting, ODS set-up and operations, communications costs and again, Board staff recognizes that a smaller utility may be faced with some diseconomies due to its size. Nevertheless, Board staff admits that it has not seen historical per meter OM&A costs as high as Atikokan Hydro is reporting. For the three year period covered, this amounts to about $45.27 per year or about $3.75 per month per metered customer of OM&A costs alone.

In studies conducted around 2005, it was estimated that the expected long-run incremental rate increase due to smart meters would be about $3 to $4 per month. This would relate to recovery of both OM&A and capital-related costs for the installation and ongoing operations of smart meters and related communications and computer infrastructure. Atikokan Hydro's OM&A expenses during the deployment stage alone are at the high end of this.

It is primarily as a result of these significant costs that the proposed SMDR is so high, despite the fact that Atikokan Hydro had one of the highest approved Smart Meter Funding Adders in the province, at $3.50 per month per metered customer.

O.Reg. 426/06 provides the authorization and guidance that the Board must consider in deciding whether or not to approve recovery of costs. As smart meters are a relatively new aspect of business, both in Ontario and elsewhere, the Board has largely relied upon cost comparisons. As the number of applications seeking disposition and recovery of smart meter costs increases, the body of knowledge available increases.

The revised OM&A costs, representing a 50% increase over the original proposal, were only filed in responses to interrogatories. These costs are significantly higher than Board staff has seen to date. The response to Board staff IR # 66 documented accounting corrections that Atikokan Hydro discovered in preparing its responses to early interrogatories regarding smart meter costs. However, Board staff submits that there is insufficient support on the record about the nature of the products and services for the requested cost levels. Given the unusually high cost per meter level requested, Board staff suggests that the Board consider a disallowance of 20% of smart meter costs. This would bring the per meter cost to just over $350 – still higher than the Board has seen to date for complete smart meter deployment. This could be accomplished through a reduction in the OM&A costs to avoid a financial impairment to the meter assets recorded by Atikokan.

If the Board approves the revised smart meter costs as proposed by Atikokan Hydro, the Board may wish to consider if a longer recovery period, beyond 36 months, may be necessary, to mitigate rate impacts.

Finally, in its Application, Atikokan Hydro proposed that the SMDR be uniform and be collected from all metered customers. In response to Board staff IR # 42, Atikokan Hydro calculated class-specific SMDRs as summarized in the following table:

Customer Class	**Residential**	**GS < 50 kW**	**GS > 50 kW**	**Average**
SMDR ($/month for 36 months)	3.66	4.17	7.29	3.78

In its AIC, Atikokan Hydro submitted that the class-specific SMDRs as calculated in the response to Board staff IR # 42 would be more appropriate.

Given the cost differentials between customer classes documented in the interrogatory response, Board staff concurs that class-specific SMDRs are appropriate. In many recent cost of service applications for 2012 rates and in stand-alone applications,[61] the Board has upheld that class-specific SMDRs should be used where data of adequate quality is available, on the long-established principle of cost causality.

[61] e.g. Hydro Ottawa Limited's 2012 cost of service application [EB-2011-0054], Lakeland Power Distribution Limited's stand-alone smart meter application [EB-2011-0413]

Stranded Meters

Atikokan Hydro is proposing a Stranded Meter Rate Rider of $0.39 per month, to be effective for a period of three years, to recover the net book value of $23,375 for conventional meters stranded through replacement by smart meters.

Board staff takes no issue with the amount that Atikokan Hydro is proposing to recover. Board staff also takes no issue with Atikokan Hydro's proposal to recover the amount over a period of three years to mitigate the immediate impact on Atikokan Hydro's ratepayers.

In light of Atikokan Hydro's explanations in response to interrogatories about the connection of customers and types of meters, Board staff takes no issue with Atikokan Hydro's proposal for a uniform stranded meter rate rider.

However, it appears in Atikokan Hydro's proposal that the utility is proposing recovery from all of its ratepayers. The Board's policy and practice, as documented in Guideline G-2011-0001, is that the stranded meter rate rider be recovered solely from those classes for which conventional meters became stranded through replacement by smart meters. In the case of Atikokan Hydro, this would be the Residential and GS < 50 kW classes. In Board staff's submission, the stranded meter rate rider should not apply to the GS > 50 kW class. Atikokan Hydro should confirm in its reply submission the calculation of the stranded meter rate rider and the customer classes to which it would apply.

Other Matters

Transition from CGAAP to MIFRS

Board staff addresses the following issues with respect to Atikokan Hydro's transition from CGAAP to MIFRS:

1. Impact of MIFRS on Rate base and Revenue Requirement; and
2. Account 1575 IFRS-GAAP Transitional PP&E Deferral Account

1. Impact of MIFRS on Rate base and Revenue Requirement

The impact of MIFRS on rate base is summarized in the following table which shows the difference in the rate base for 2011 and 2012 between CGAAP and MIFRS.[62] The difference between CGAAP and MIFRS only relates to change in depreciation rates as Atikokan Hydro changed its capitalization policy in 2010.

Description	2011 Bridge Year CGAAP	2011 Bridge Year MIFRS	Variance	2012 Test Year CGAAP	2012 Test Year MIFRS	Variance
Gross Fixed Assets	5,239,138	5,239,138	0	5,750,922	5,750,922	0
Accumulated Depreciation	3,117,804	3,083,802	(34,002)	3,319,549	3,250,890	(68,659)
Net Book Value	2,121,334	2,155,336	34,002	2,431,373	2,500,032	68,659
Average Net Book Value	2,177,045	2,194,046	17,001	2,477,949	2,529,279	51,330
Working Capital	3,172,906	3,172,906	0	3,415,637	3,415,637	0
Working Capital Allowance	475,936	475,936	0	512,346	512,346	0
Rate Base	2,652,981	2,669,982	17,001	2,990,294	3,041,625	51,330

Regarding the MIFRS impact on revenue requirement, Atikokan Hydro indicated that the MIFRS impact on 2012 revenue requirement is an increase of $148,090 due to the increase in OM&A and reduced capital.[63] Atikokan Hydro identified the change in the amortization expenses by using the figures for 2009 and 2010 OM&A increases as an MIFRS impact on the 2012 revenue requirement.[64]

Board staff notes that the 2012 rate base under MIFRS was initially calculated in the application at $2,913,786.[65] During the Board staff interrogatory process, the rate base has increased by $127,838 to $3,041,625 for the following reasons:

(1) An increase of $34,914 in the rate base as a result of a decrease in depreciation expense due to longer useful lives of the capital assets under MIFRS;
(2) An increase of $6,784 through working capital allowance as a result of an $45,229 increase in OM&A resulting from OMERS expenses that were previously being recorded in Account 1508 and now are included in the 2012 operating expenses; and

[62] Response to the Board staff IR #45 c)
[63] Response to the Board staff interrogatory #68
[64] *Ibid.*
[65] Exhibit 2/Tab 1/Schedule 1/page 1/Table 2-1

(3) An increase of $86,140 in the rate base as a result of the corrections made to smart meters.

Board staff is of the view that the increase in OM&A resulting from OMERS expenses explained in (2) above is not as a result of the IFRS conversion. However, Board staff submits that the resulting working capital allowance of $6,784 is a legitimate adjustment to the 2012 rate base.

Board staff notes that Atikokan Hydro changed its capitalization policy in 2010 to no longer capitalize expenses that were not directly related to PP&E. This caused an increase in 2010 administration and general expense. Atikokan Hydro filed a note from its external auditors that indicated that Atikokan Hydro's auditors had reviewed the accounting policy and confirmed that the Atikokan Hydro's policy is in compliance with the IFRS requirements.[66] Therefore, Board staff takes no issue with the adjustments made to update the impact of MIFRS to the rate base and is of the view that working capital would be the same under CGAAP and MIFRS due to the change of capitalization policy that was implemented by Atikokan Hydro in 2010.

As part of the calculation showing the MIFRS impact on the revenue requirement, Atikokan Hydro stated that the amount of $169,035 represents an increase in salaries and expenses as a result of a change by Atikokan Hydro in its capitalization policy in 2009 and 2010.[67] Board staff is of the view that there should not be any impact on OM&A in 2011 and 2012 as a result of the conversion to MIFRS, as Atikokan Hydro had already changed its capitalization practices in 2010 to be aligned with IFRS.[68] Furthermore, Board staff submits that Atikokan Hydro has made an error in calculation of 2012 amortization expenses by using the figures of 2009 and 2010 OM&A increases. Atikokan Hydro should have quantified the MIFRS impact by considering the change in the useful lives of the capital assets as a result of the conversion. As such, Board staff is unclear of the dollar impact on the 2012 revenue requirement for Atikokan

[66] Response to Board staff interrogatory #46
[67] Exhibit 4/Tab 2/Schedule 3/pp. 2-3
[68] Exhibit 2/Tab 1/Schedule 1/page 7

Hydro's conversion from CGAAP to MIFRS due to errors in the utility's calculations.

2. Account 1575 IFRS-GAAP Transitional PP&E Deferral Account

Atikokan Hydro stated that the balance for closing net PP&E between CGAAP and MIFRS is a credit balance of $34,002. Atikokan Hydro proposed to amortize the balance over a four year period.[69] As a result, the annual amortization amount is a credit balance of $8,500 (i.e. $34,002/4). Atikokan Hydro calculated the return on the rate base using the average of the opening and closing balance of the PP&E account in 2012[70] (i.e. ($34,002+$25,501)/2 * 6.49%). Atikokan Hydro updated the return on rate base from 6.49% to 6.09% in its AIC.[71]

Board staff takes no issue on the credit balance of $34,002 as the difference in the closing PP&E deferral account balance between CGAAP and MIFRS and the amortization period of 4 years. However, Board staff notes that the return on rate base of $1,813 was calculated using the average of the opening and closing balance of the PP&E for 2012[72] (i.e. ($34,002+$25,501)/2 * 6.09%). Board staff submits that Atikokan Hydro did not calculate the return on the rate base associated with the deferred balance for difference in closing net PP&E accurately. Instead, Atikokan Hydro should use the PP&E closing balance of $34,002. Board staff submits that Atikokan Hydro should update the calculation for the return on the rate base in the preparation of the draft Rate Order, and should document this in that filing.

Atikokan Hydro should clear the PP&E deferral Account 1575 by taking the following steps:

- A downward adjustment of the depreciation expense should be made to the total depreciation expenses as a part of Atikokan Hydro's 2012 distribution expenses.

[69] Response to Board staff interrogatory #50
[70] Response to the Board staff interrogatory #74
[71] Argument-in-Chief P10
[72] Response to the Board staff interrogatory #74

- The credit amount of the return on the rate base (which should not be recorded in the PP&E deferral account) should be shown as a reduction to the 2012 revenue requirement as a refund to the customers.

Rate Mitigation

In its Application, Atikokan Hydro has proposed to mitigate the impacts to customers by the significant increases that would result from proposed rates. It has proposed to mitigate rate increases to no more than 10% for a typical Residential customer consuming 800kWh per month through the following:

- Deferral of the disposition of all Group 1 and Group 2 DVAs, except for Smart Meter accounts 1555 and 1556, until 2013; and
- Approval for a credit rate rider to reduce the bill impact based on a consumption of 800 kWh in the month to no more than 10% over existing rates. The amount of the credit would be tracked in a DVA for which Atikokan Hydro was seeking approval, with the balance to be disposed of in a subsequent rates application.

In response to Board staff IR # 24, Atikokan Hydro acknowledged that a typical Residential customer in its service territory uses significantly less than 800 kWh. On average, monthly consumption for a residential customer is 581 kWh, and only about 33% of residential customers use at least 800 kWh per customer, as shown by consumption distribution data. Atikokan Hydro hence proposed to adjust the credit rate rider to mitigate rate impacts so that a customer consuming 581 kWh per month would have a total bill increase, after taxes and the Ontario Clean Energy Benefit, of no more than 10%.

<u>Postponement of Group 1 and Group 2 DVA Disposition to 2013</u>

Atikokan Hydro's records, subject to concerns expressed elsewhere about the accuracy of some of the data entries, appear to show that the accounts are in a debit position. Therefore, postponement will reduce the rate increases that customers otherwise would see. However, given the utility's financial picture – persistent losses and the utility's external auditor including a "going concern" note in the 2010 Audited Financial Statements – postponement of disposition does not help the utility's situation.

Second, postponement of the disposition of the DVAs to 2013 would entail consideration of the DVA disposition in an IRM application. For Group 2 accounts, this is contrary to the guidelines in the EDVARR Report.[73] Further, a review for disposition generally entails more analysis and opportunity for discovery. This would complicate the review of the IRM application, which was a large part of the reason that the Board limited DVA dispositions to cost of service applications more amenable to that level of review.

The alternative would be to postpone disposition until Atikokan Hydro's next scheduled cost of service rebasing application, currently scheduled for 2016. Given the length of time, issues of data quality and accuracy and implications on the utility's financial situation, Board staff recommends against that option.

Establishment of the Credit Rate Rider and a DVA to track the foregone revenue

In this Application, Atikokan Hydro has proposed the establishment of a credit rate rider applicable solely to Residential customers. This credit rate rider would have the purpose of mitigating the bill impacts to lower consumption customers to no more than 10% for a "typical" customer. Initially, Atikokan Hydro proposed that this would be based on the industry norm of a "typical" 800 kWh/month Residential customer. However, analysis of the utility's data indicates that the average Residential consumption is about 581 kWh/month. Atikokan Hydro's original proposal would still have meant that most Residential customers would have faced bill impacts exceeding 10%.

In response to Board staff IR # 24 b), Atikokan Hydro amended its proposal so that mitigation would be based on the "typical" (average) 581 kWh/month customer. Atikokan Hydro estimated that the deferred revenue would be about

---

[73] Disposition of Group 1 accounts, dealing with the RSVA balances for Cost of Power and retail transmission rates are regularly disposed of as part of IRM applications. It is the Group 2 accounts, and which are of more importance here because of the debit amount of about $250K; this amount is not immaterial given Atikokan Hydro's size and recovery may help to address the utility's financial condition.

$98,000 for one year. It proposed that the amount be tracked in account 1574 for later disposition.

The proposed credit rate rider has some practical disadvantages in Board staff's view. A deferred amount of about $100K is over 5% of the proposed revenue requirement. Given the concerns about the utility's financial picture, including cash flow, Atikokan Hydro's proposal exacerbates the issue. Further, with the amounts recorded in the DVA, simple interest on the principal will accrue. At a point in time when the account balance is disposed, Atikokan Hydro's Residential ratepayers will pay more. This is just a temporary deferment of the revenue requirement from current ratepayers to some future point.

Board staff observes that the need for the mitigation proposed is largely necessitated by the significant OM&A increases proposed, as well as impacts on the Smart Meter Disposition Rate Rider. Board staff has proposed that Atikokan Hydro's OM&A be significantly reduced. In addition, changes in the revenue-to-cost ratios may also help to address rate impacts on Atikokan Hydro's Residential ratepayers.

In general, Board staff is not in favour of the proposed credit rate rider.

Is Postponement Necessary or In the Public Interest?

One issue addressed in interrogatories concerns the financial viability of the utility[74]. The financial concerns of Atikokan Hydro have been recognized by the Board before, in the 2006 EDR (RP-2005-0020/EB-2005-0335) and 2008 cost of service (EB-2008-0014) applications. The utility's external auditors have documented "going concern" notes in recent audited Financial Statements.

Understanding the utility's financial picture is made difficult by the record keeping. A fair number of interrogatories have been posed by both Board staff and VECC to try to get a complete and accurate picture of Atikokan Hydro's situation. There is a significant amount of amended tables, models and spreadsheets on the record as a result.

---

[74] Responses to Board staff IRs #18, 37 and 64

In Atikokan Hydro's 2008 cost of service application, withdrawal of the disposition of most DVA account balances was approved on the basis of exogenous factors; however, the Board did direct disposition of account 1508 balances. In Atikokan Hydro's 2010 IRM application, the Board approved disposition of Group 1 balances on an interim basis, based on the significant changes in the numbers between original and revised balances.[75] Final approval of the dispositions was approved in Atikokan Hydro's 2011 IRM application, if in what was acknowledged as an "unconventional" but practical approach.[76]

Getting the "right" data has been challenging. However, with corrected data and given the financial picture of the utility, Board staff submits that it is appropriate to begin disposition and recovery of the amounts. Additional time is unlikely to improve the quality of the data. In fact, with the passage of time, it sometimes becomes more difficult to understand historical numbers, as evidenced by the responses to a number of interrogatories, as losses of source data or changes in computer systems make understanding or verifying some numbers challenging or even not possible.

Board staff submits that beginning to recovery the historical debit amounts should also help the cash flow of the utility and alleviate, at least in part, some of the financial concerns. While this will increase the rates faced by ratepayers, Board staff submits that reductions to test year OM&A should offset rate pressures, while forcing the utility to address cost management for what is already a high cost utility. Further, disposition over a longer period (e.g., four years, until Atikokan Hydro is next expected to rebase) should also mitigate rate increases.

For these reasons, Board staff submits that the rate mitigation proposed by Atikokan Hydro should not be approved and alternative approaches be considered..

– All of which is respectfully submitted –

---

[75] Decision and Order [EB-2009-0212], April 12, 2010, page 13
[76] Decision and Order [EB-2010-0064], March 17, 2011, pp. 6-11