Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2012-0104

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

AND IN THE MATTER OF an application by Algoma Power Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective January 1, 2013.

BEFORE: Marika Hare
Presiding Member

DECISION AND ORDER

Introduction

Algoma Power Inc. ("API"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 22, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that API charges for electricity distribution, to be effective January 1, 2013.

API is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, established a three year plan for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed. In a letter dated October 18, 2012, the Board stated its expectation that the three rate setting methods set out in the *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* would be available for the 2014 rate year.

As part of the plan, API is one of the electricity distributors that will have its rates adjusted for 2013 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications. The applied for rates include the impact of the Rural or Remote Electricity Rate Protection ("RRRP") funding, pursuant to Ontario Regulation 442/01. API also sought approval for smart meter cost recovery.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports provide the relevant guidelines for 2013 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 28, 2012, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

Notice of API's rate application was given through newspaper publication in API's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors could be eligible for cost awards with respect to API's proposed smart meter costs. The Vulnerable Energy Consumers Coalition ("VECC") applied for intervenor status and cost eligibility in this proceeding. The Board hereby grants VECC eligibility for cost awards in regards to API's request for smart meter cost recovery. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

On December 13, 2012 the Board declared API's existing rates interim, effective January 1, 2013, and noted that the order for interim rates should not be construed as predictive, in any way whatsoever, of the final determination of this current application.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Incentive Regulation Mechanism and RRRP;
- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Wholesale Market Service Rate;
- Smart Metering Entity Charge;
- MicroFIT Service Charge;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Smart Meter Cost Recovery; and
- Effective Date of 2013 Rates.

Incentive Regulation Mechanism and RRRP

Algoma's rate application was filed on the basis of the Filing Requirements for 3rd Generation IRM, modified to accommodate the requirements of the Rural or Remote Electricity Rate Protection ("RRRP"). Specifically, the setting of rates for Algoma's Residential R-1 and R-2 classes is subject to the RRRP Regulation, Ontario Regulation 442/01, in particular, section 4 subsections 3.1 and 3.2:

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

In its Decision on API's 2010 and 2011 cost of service application (EB-2009-0278), dated November 11, 2010, the Board approved a methodology to calculate the RRRP adjustment that would be applied to the existing rates to generate the new rates, i.e. the Monthly Service Charge and the Distribution Variable Rate, for the R-1 and R-2 customer classes. The Board indicated that it would communicate the RRRP adjustment, which is based on the average annual change in distribution rates for all rate regulated distributors for the Residential and GS<50 kW customer rate classes. In its application, API used a RRRP Adjustment factor of 2.81% for the R-1 and R-2 rate classes and acknowledged that this factor will be updated in the Draft Rate Order for this proceeding.

Under an IRM regime, absent RRRP, a price cap adjustment index applies to the distributor's existing Board approved rates for all customer rate classes. In this case, the rates applicable to the R-1 and R-2 customer rate classes are to be adjusted by the RRRP adjustment only.

In its EB-2011-0152 Decision for API's 2012 IRM, the Board approved a methodology to calculate the RRRP funding for the R-1 and R-2 rate classes using the difference between:

i. The revenue requirement for the R-1 and R-2 customer rate classes adjusted by the price cap adjustment index; and

ii. The revenues generated by the R-1 and R-2 rate classes using the RRRP Adjustment.

The rates for all other customer rate classes that are not eligible for RRRP would be adjusted by the price cap adjustment index.

Board staff submitted that API had calculated the rate adjustments for its R-1, R-2, Seasonal and Street Lighting rate classes in accordance with the methodology approved in the EB-2011-0152 proceeding, subject to its comments related to Smart Meter Cost Recovery which are addressed later in this Decision.

The Board finds that API has calculated the rate adjustments for the R-1, R-2, Seasonal and Street Lighting rate classes in accordance with the methodology approved in the EB-2011-0152 proceeding.

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the IRM are to be adjusted by a price escalator, less a productivity factor of 0.72% and a stretch factor.

On October 4, 2012, the Board announced a price escalator of 2.2% for those distributors under IRM that have a rate year commencing January 1, 2013.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated November 28, 2012 the Board assigned API to efficiency cohort 3, being the least efficient group, and a resulting cohort specific stretch factor of 0.6%.

On that basis, the resulting price cap index adjustment is 0.88% (i.e. 2.2% - (0.72% + 0.6%)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes.

The price cap index adjustment does not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges shall reflect this RRRP charge.

Wholesale Market Service Rate

The Board's Decision with Reasons and Rate Order (EB-2013-0067) noted above also established that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges shall reflect this WMS rate.

Smart Metering Entity Charge

On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors*. This charge will be in effect from May 1, 2013 to October 31, 2018. The draft Tariff of Rates and Charges flowing from this Decision and Order shall reflect this Smart Metering Entity charge.

MicroFIT Service Charge

On September 20, 2012, the Board issued a letter advising that the default province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator Service Classification was to be updated to $5.40 per month effective with the implementation of electricity distributors' 2013 rates applications. The draft Tariff of Rates and Charges shall reflect the new default microFIT service charge.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the

Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

API's application identified a total tax savings of $42,128 resulting in a shared amount of $21,064 to be refunded to rate payers.

The Board approves the disposition of the shared tax savings of $21,064 over an eight-month period (i.e. May 1, 2013 to December 31, 2013) and the associated rate riders for all customer rate classes.

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2012 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2013. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

On December 20, 2012 the Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2013, as shown in the following table:

2013 Uniform Transmission Rates

Network Service Rate	$3.63 per kW
Connection Service Rates	
Line Connection Service Rate	$0.75 per kW
Transformation Connection Service Rate	$1.85 per kW

The Board finds that these 2013 UTRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

API initially proposed separate threshold calculations for its Group 1 Accounts (excluding 1588 - Global Adjustment sub-account) and Account 1588 – Global Adjustment sub-account. In its EB-2011-0152 Decision, the Board noted that the EDDVAR Report requires that the threshold calculation apply to all Group 1 Account balances. In response to Board staff interrogatory #3, API submitted an updated threshold calculation, and incorporated certain adjustments as a result of Board staff interrogatories #4 and #6, which are discussed below. API's revised 2011 actual year-end total balance for Group 1 Accounts including interest projected to December 31, 2012 is a debit of $228,285. This amount results in a total debit claim of $0.0012 per kWh, which exceeds the preset disposition threshold. API proposed to dispose of this debit amount over a one-year period.

Board staff noted that the amounts in Account 1588 contained inconsistencies between the amounts proposed to be disposed as of December 31, 2011 and the amounts reported as part of the RRR for the same period. In response to Board staff Interrogatory #6, API responded that the discrepancies netting $553,264 relate to the 2011 fixed price and global adjustment true-up calculations submitted in 2012.

In the updated continuity tables provided in response to interrogatories, API made additional adjustments to the 1588 Power and Global Adjustment sub-accounts, resulting in an additional net credit difference from the RRR balances of ($31,165). API stated that these adjustments relate to “the portion of additional corrections in API’s Motion to Vary the Board’s Decision on API’s 2012 IRM application, that were calculated and remitted to the IESO via former Form 1598 Reporting in Jan 2012”.

In its submission Board staff requested further clarification of the ($31,165) adjustment to Account 1588. In its reply submission, API explained that the ($31,165) related to a combination of the 2009 and 2010 revised fixed price and global adjustment calculations completed and remitted to IESO in January 2012 as part of its Motion to Vary the 2012 IRM Decision. Given that the revised calculations occurred in January 2012 and that the RRR are based on the regulatory balances as of December 31, 2011, this adjustment was reflected in the “Other Adjustments during 2011” column in the continuity schedule.

In its submission, Board staff also noted a discrepancy between the 2008 closing balance in Account 1590 as shown in the continuity tables and as shown in API’s Draft Rate Order in EB-2007-0744. Board staff requested clarification of this discrepancy as well as a transaction in Account 1590 of $87,359 in 2011, subsequent to the approved recovery period.

In its reply submission, API stated that the discrepancy between the 2008 closing balance of Account 1590 as shown in its continuity tables and that shown in its Draft Rate Order in EB-2007-0744 arose due to differences between the forecast balance as shown in EB-2007-0744 and the actual balance. API stated that the actual balance of $899,952 is consistent with the balance contained in the EB-2009-0278 Decision. API also explained that the transaction of $87,359 in this account in 2011 related to customer billing activity in its Seasonal customer class, recorded in 2011 but relating to pre-2011 consumption.

The Board accepts the explanations provided by API as reasonable and will approve, on a final basis, the disposition of a debit balance of $228,285 as of December 31, 2011, including interest as of April 30, 2013 for Group 1 accounts. These balances are to be disposed over an eight-month period from May 1, 2013 to December 31, 2013.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550			
RSVA - Wholesale Market Service Charge	1580	($210,874)	($4,597)	($215,471)
RSVA - Retail Transmission Network Charge	1584	$89,427	$1,767	$91,194
RSVA - Retail Transmission Connection Charge	1586	$1,753	($156)	$1,597
RSVA - Power (excluding Global Adjustment)	1588	($245,642)	$25,638	($220,003)
RSVA - Power – Global Adjustment Sub-Account	1588	$830,898	($55,097)	$775,801
Recovery of Regulatory Asset Balances	1590	($322,541)	$117,707	($204,834)
Disposition and Recovery of Regulatory Balances (2008)	1595			-
Disposition and Recovery of Regulatory Balances (2009)	1595			-
Total Group 1 Excluding Global Adjustment Sub-Account		**($687,876)**	**$140,360**	**($547,516)**
Total Group 1		**$143,022**	**$85,263**	**$228,285**

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates. This entry should be completed on a timely basis to ensure that these adjustments are included in the reporting period ending June 30, 2013 (Quarter 2).

Smart Meter Cost Recovery

The following issues are addressed with respect to smart meter cost recovery as proposed in API's Smart Meter Application:

- Costs incurred with respect to Smart Meter Deployment and Operation;
- Stranded Meter Costs;
- Cost Allocation;
- Cost Recovery;
- Recovery Period; and
- Exemption Requested.

Costs Incurred with Respect to Smart Meter Deployment and Operation

API's Smart Meter Cost Recovery application, EB-2012-0285, was submitted on June 15, 2012. On July 17, 2012, API requested, and the Board approved, that the application be held in abeyance and combined with API's 2013 rate application.

In response to interrogatories from VECC and Board staff, API made certain adjustments to the inputs to its smart meter recovery model. On January 28, 2013, API filed a revised smart meter model incorporating all adjustments requested in interrogatories. The total smart meter costs are as follows:

	As Filed	Revised January 28, 2013
Capital	$4,499,796	$4,458,441
OM&A	$99,868	$99,868
Total	$4,599,664	$4,558,309

These costs are based on audited costs incurred to December 31, 2011, actual 2012 costs and forecast costs for 2013. They also include costs beyond minimum functionality of $131,390 that pertain to MDM/R integration and Time of Use ("TOU") and Operational Data Storage implementation. The total average cost per meter is $394.01.

The revised smart meter costs result in a Net Deferred Revenue Requirement of $1,752,033, being the difference between the Deferred Incremental Revenue

Requirement from 2006 to December 31, 2012 and the smart meter funding adder ("SMFA") revenues collected from 2006 to December 31, 2012. API has also requested recovery of its Smart Meter Incremental Revenue requirement of $635,123 in each of the two years remaining in its IRM plan term, until its next cost of service proceeding scheduled for 2015.

API's evidence described the unique aspects of its service territory, specifically with regard to its expanse of approximately 14,200 square kilometers; its rural and rugged terrain with dense vegetation; and its low customer density of 6.3 customers per kilometer of line, or 0.8 customers per square kilometer. API described its collaboration with the District 9 ("D9") consortium in the Planning and Procurement stages of the Smart Meter Project and its participation with this consortium in the London Hydro RFP process. API collaborated with its affiliates to share IT development costs. API's evidence and interrogatories described operational benefits and efficiencies, among them:

- Elimination of manual meter reading (Meter reading costs occurred in 2012 totaled $416,684 compared to 2011 costs of $457,913);
- Utilization of loading data for system planning purposes;
- Acquisition of data such as outage and voltage alarms to enhance operations functions;
- Automation of billing data collection & processing & centralization of billing functions at CNPI; CNPI & API operate as single entity in interactions with SME & MDM/R; and
- Management of AMI network centralized at CNPI Fort Erie.

Board staff and VECC observed that API's average costs per meter were higher than the average smart meter costs previously reported by the Board in the following documents:

- Appendix A of the Decision with Reasons of the Combined Smart Meter Proceeding (EB-2007-0063, August 8, 2007) compared data for 9 out of 13 utilities and showed the total cost per meter ranged from $123.59 to $189.96, with Hydro One Networks Inc. ("Hydro One") being the main exception at $479.47, due in part for the need for more communications infrastructure and increased costs to install smart meters for customers over a larger and less dense service area.

- The Board’s Smart Meter Audit Review Report, dated March 31, 2010, indicated a sector average capital cost of $186.76 per meter (based on 3,053,931 meters with a capital cost of $570,339,200 as from January 1, 2006 to September 30, 2009). The corresponding average total cost per meter (capital and OM&A) is $207.37 from the data in that report; and
- The Monitoring Report, Smart Meter Investment – September 2010 (“the Monitoring Report”) issued on March 3, 2011. The Monitoring Report summarized the total smart meter related investments of 78 distributors, as of September 30, 2010, and showed an average cost of $226.92 per smart meter.

Board staff submitted that there are distributors for which the per-meter documented costs are closer to API’s per meter costs. These distributors have characteristics not dissimilar to those of API including distance, low density, topology and vegetation. Board staff noted that API’s average costs, while higher than the averages calculated to date, are lower than the average cost calculated for Hydro One, which experiences similar challenges in implementing smart meters in its territory.

VECC submitted that other utilities in API’s cohort also have average costs per smart meter above the recent sector averages due to their non-contiguous service territories. VECC submitted the following table showing the average smart meter costs of LDCs in API’s cohort, based on 2012 audited costs:

LDC	Average Cost per Meter (Including Costs Beyond Minimum Functionality)	Average Cost per Meter (Excluding Costs Beyond Minimum Functionality)	Reference
API	**$391.97**	**$380.58**	**EB-2012-0104**
Fort Frances	$262.57	$248.16	EB-2012-0327 Board Decision, Page 4
Northern Ontario Wires	$318.05		EB-2012-0353 Board Decision, Page 4
Parry Sound	$286.69	$276.06	EB-2012-0344, EB-2012-0159 Board Decision, Page 12
Sioux Lookout	$338.90		EB-2012-0327 Board staff Submission, Pages 7-8
Atikokan	$420		EB-2012-0327 Board staff Submission, Pages 7-8

VECC noted that next to Atikokan, API's average per meter costs are the highest at $391.97, and are approximately 15.6% greater than the next highest, Sioux Lookout at $338.90.

Board staff submitted that API acted in accordance with the regulations in its processes for the procurement of smart meters and associated equipment and for services to install and operate the smart meters and associated equipment and provided adequate explanation for the challenges within its service territory and the impact on overall costs. As such, Board staff submitted that it considered the documented historical costs and the forecasted costs to be prudent. Board staff took no issue with API's documented costs beyond minimum functionality.

VECC submitted that API's description of its unique circumstances adequately explained its higher smart meter costs. Based on this, coupled with API's documented operational efficiencies, benefits and cost savings resulting from smart meter implementation, VECC took no issue with API's higher costs and submitted that API provided adequate documentation on the prudence of its costs. VECC took no issue with the nature or quantum of API's costs beyond minimum functionality and submitted that recovery of these costs is justified.

Both VECC and Board staff noted that 96% of API's costs are audited and therefore conform with the Board's Guideline G-2011-0001.

In its reply submission, API noted the submissions of Board staff and VECC and stated that it had no further submissions on this matter.

The Board accepts API's explanation of the unique circumstances leading to its higher than average smart meter costs. Having considered these circumstances, as well as API's documented operational efficiencies, benefits and cost savings resulting from smart meter implementation, the Board approves API's smart meter costs as revised.

Stranded Meter Costs

In its original application, API requested to recover $331,640 in stranded meter costs. By letter dated March 12, 2013, API informed the Board that its original request for disposition of the stranded meter amount did not form part of the financial analysis of its

IRM application. API stated that it was not proposing to dispose of its stranded meters in this application, and that it proposed to apply for disposition of its stranded meters in its next cost of service application scheduled for the 2015 rate year.

The Board approves API's proposal.

Cost Allocation

Section 3.5 of the Board's Guideline G-2011-0001 states:

> 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.
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> 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.

API's Smart Meter Costs were allocated by rate class based on actual/forecasted costs incurred. Total Return on Capital (Deemed Interest plus Return on Equity), Amortization and PILS amounts were allocated based on the Smart Meter Costs by class as a proportion of total Smart Meter Costs for all classes. OM&A costs, Smart Meter Funding Adder (SMFA) revenues, and Carrying Charges were allocated based on the number of meters installed by class as a proportion of the total number of meters installed. The Net Deferred Revenue Requirement was then divided by average number of metered customers in 2013, and then also divided by the 48 month recovery period proposed.

The PowerStream methodology approved by the Board regarding the treatment of SMFA revenues is to allocate the SMFA revenues and interest collected from each customer class that receives smart meters, directly to that customer class with a 50:50 allocation of residual SMFA and interest collected from other metered customers (i.e.

GS 50-4999 kW & Large Use) to the customers that received smart meters (typically residential and GS<50 kW classes). In response to VECC IR #8(d) to provide a breakdown of the total SMFA revenue collected by customer class, API indicated that because of the way it posted the revenues it was not possible to break out the amounts collected by rate class.

Through interrogatories, VECC sought separate smart meter models for each customer class in order to recalculate the rate riders using class specific revenue requirements based on available data at the customer class level.

In its response, API indicated that completing separate Smart Meter revenue requirement models by customer class would ultimately result in the same Net Deferred Revenue Requirement by rate class as provided in the original application. This is because the same principles and assumptions that were used would have to be made in the live models to provide the necessary breakdown by rate class. API also noted the residential and GS<50 customers fall under the Residential - R1 service classification. Therefore, those costs are pooled together to calculate one common disposition rider.

Both Board staff and VECC submitted that since the costs are pooled together to reflect the R1 customer class, the calculation of separate smart meter revenue requirements and rate riders for Residential and GS <50kW are not required.

The Board accepts the cost allocation methodology as being reasonable.

Cost Recovery

API proposed to allocate the smart meter costs applicable to its R-1 customer class directly to its R-1 revenue requirement for the purposes of calculating RRRP funding. These costs are related to historical smart meter cost recovery net of Smart Meter Funding Adder revenues received ("the SMDR amounts"), as well as the 2013 incremental revenue requirement associated with smart meter implementation ("the SMIRR amounts"). In other words, API proposed not to fully recover these amounts from its R-1 customers through the SMDR and SMIRR rate riders, which has been the practice of smart meter cost recovery approved by the Board for all other LDCs to date, but to recover the amounts largely from provincial ratepayers.

API stated that the additional revenue requirement arising from smart meter implementation will have two adverse effects on its customers: first, the distribution rates will increase beyond the average of other utilities' increases in the most recent year; and second, the R-1 class will pay for smart meter implementation twice: once through indexation related to other utilities' rates that have increased their distribution rates to recover their own smart meter costs, and again through a separate smart meter rate rider.

Board staff submitted that the calculation of rate adjustments under RRRP, as determined in EB-2009-0278, explicitly excludes the effect of rate riders or rate adders, regardless of whether any of these rate riders or adders were intended to recover revenue requirement items. Board staff's submission noted that while the revenue requirement associated with smart meters may be incorporated into certain distributors ' base rates through cost of service applications, it is Board staff's understanding that most distributors are continuing to recover this revenue requirement through SMIRR rate riders, which will remain in effect through the remainder of each such distributor's IRM term. Further, the impacts of the SMDRs are not reflected in the provincial average. Under these circumstances, the provincial average rate impact is lower than it would have been otherwise (i.e. API's customers would not be paying for the average of most other distributors smart meter costs through their RRRP-adjusted rates).

However, Board staff further submitted that it may be appropriate for the Board to consider socializing a portion of these smart metering costs. Board staff's submission noted that the smart meter program is a mandated provincial initiative, which has resulted in significant costs to API. As noted above, due to the unique circumstances in API's service territory, the costs incurred to implement smart meters are well above the provincial average and would produce significant rate increases for API's customers. Board staff submitted that allowing partial recovery of API's smart meter costs through RRRP funding would allow its customers to benefit from the implementation of this provincial program at comparable costs to those of other provincial ratepayers.

Board staff submitted that, in the event that the Board should approve recovery of the R-1 rate class smart meter amounts through the RRRP mechanism, it would be appropriate to revise the adjustment of the calculation of the RRRP adjustment to incorporate the average for provincial utilities including smart meter cost recovery.

This would ensure that the rates paid by API's customers are more comparable to those of other provincial ratepayers. Board staff submitted that this treatment would also be consistent with the manner in which the costs of other distribution assets and operating expenses are borne by API's R-1 and R-2 rate classes.

VECC did not make a submission on this matter.

In its reply submission, API noted that its proposed treatment of smart meter costs was similar to the manner in which the cost of any Board approved capital addition is recovered from the customers of API. API submitted that the Smart Meter Initiative is essentially a non-discretionary capital addition approved by the Board, which has a marginal impact on API's service revenue requirement. API submitted that its proposal was in keeping with O.Reg. 442/01 which recognizes that API is a high cost LDC for reasons which have been previously recognized. API's submission noted that the higher cost to implement and deliver the smart meter initiative mirrors the recognized higher cost per customer to deliver distribution services, which has been acknowledged through the reliance on the RRRP funding to prevent unsustainable distribution rate increases.

API submitted that Board staff's proposal to modify the RRRP adjustment to incorporate the provincial average would diminish the integrity of the incentive rate making process in place for API. API further submitted that it was not necessary to adjust the calculation, as the current methodology does recognize the contribution to distribution rates of those distributors that have rebased and are now collecting costs attributable to the smart meter initiative in their revenue requirements.

The Board agrees that smart meter implementation is similar to a non-discretionary capital addition approved by the Board. The higher than average costs evident in API's smart meter application are indicative of the higher cost per customer to deliver distribution services, which is addressed through RRRP funding.

The Board finds that it is not appropriate to modify the previously-approved formula for the RRRP adjustment to include smart meter costs with the provincial average, and notes that the provincial average does include some distributors' smart meter costs. The Board has calculated the provincial average increase to be 3.75%, using the methodology as established in EB-2009-0278. The calculations have been attached to this Decision and Order as Appendix A. The Board finds that API is to use this factor in its calculation of the rate adjustments pertaining to the R-1 and R-2 customer rate classes.

The Board approves API's proposal to include smart meter costs applicable to its R-1 customer class in its R-1 revenue requirement for the purposes of calculating RRRP funding.

Recovery Period

In calculating the amount of RRRP funding requested, API adjusted its 2013 revenue requirement to include the total calculated SMDR and SMIRR proposed amounts.

Board staff submitted that this treatment is appropriate for the SMIRR since this is an annual incremental adjustment to the revenue requirement. However, Board staff noted that API proposed to recover its total SMDR amount of approximately $1.7 million through the RRRP from provincial ratepayers in one year, while it had calculated its rate riders for its Seasonal rate class to recover its SMDR over 4 years. Board staff suggested that similar mitigation measures should be considered for provincial ratepayers. Board staff submitted that it would be appropriate for the Board to consider recovery of the portion of the SMDR amount applied to the RRRP over a two-year period until API's next cost of service proceeding.

VECC did not make a submission on this matter.

API replied that Board staff's submission represented a reasonable approach, and that it was in agreement with recovery of the SMDR amount, as well as the SMIRR, through the RRRP over a two-year period until API's next cost of service proceeding for 2015.

The Board approves a two year recovery period for the SMDR and SMIRR amounts as applied to the R-1 rate class for the purposes of calculating the RRRP funding amount.

The Board finds that the SMDR for the Seasonal class will be in effect for 44 months from May 1, 2013 to December 31, 2016. The SMIRR applicable to this class will remain in effect until the effective date of API's next cost of service rate application. As API is scheduled to rebase its rates for the 2015 rate year, the Board notes that the

SMIRR will be in effect from May 1, 2013 until December 31, 2014. At that point, the capital and operating costs will be directly incorporated into API's rate base and revenue requirement.

In granting its approval for the historically incurred costs and the revenue requirement projected for 2013, the Board considers API to have completed its smart meter deployment. Going forward, API is not to record any capital and operating costs for new smart meters and any costs for operations of smart meters in Accounts 1555 and 1556. Instead, the costs shall be recorded in regular capital and operating expense accounts (e.g. Account 1860 for meter capital costs) as is the case with other regular distribution assets and costs.

Exemption Requested

In its original application, API requested an exemption from the requirements of TOU billing for 47 remote customers that are beyond the reach of conventional communications infrastructure.

In a letter dated December 10, 2012, API requested to withdraw this element of its application stating that it will file a separate application requesting an amendment to its distribution license as it relates to its installations.

Effective Date of 2013 Rates

Chapter 3 of the Filing Requirements indicates that distributors that are seeking rate adjustments effective January 1, 2013 were required to file their IRM application by August 3, 2012. API filed its 2013 IRM application on October 22, 2012.

Board staff noted in its submission that API did not provide reasons for its inability to meet the deadline. As a result, notwithstanding the fact that API's existing rates were declared interim as of January 1, 2013, Board staff submitted that the effective date of the rate change should be the 1st of the month following the issuance of the Board's Decision in this proceeding.

In its reply submission, API noted that its application had been complicated by the smart meter cost recovery and rate design component.

The Board finds API's explanation for the late filing to be sufficient and approves January 1, 2013 as the effective date. Given the filing date and the time required to process an application of this nature, the Board has determined that an implementation date of May 1, 2013 is appropriate.

IMPLEMENTATION

The Board finds that API may recover the foregone revenues for the period from January 1, 2013 to April 30, 2013 through rate riders calculated to recover the foregone revenues applicable to each class. The Board has considered the rate impacts and finds the foregone revenues shall be recovered over a 20-month period from May 1, 2013 to December 31, 2014.

For the purposes of calculating the SMDR for the Seasonal rate class, API is directed to accommodate within the SMDR the applicable revenue requirement (SMIRR) amount related to the period from January 1, 2013 to April 30, 2013.

The Board has made findings in this Decision which change the 2013 distribution rates from those proposed by API.

The Board expects API to file a draft Rate Order, including a proposed Tariff of Rates and Charges and all relevant calculations showing the impact of this Decision on API's determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of API's 2013 Rate design model and all supporting IRM models.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. API shall file with the Board, and shall also forward to intervenors, a draft Rate Order that includes revised models in Microsoft Excel format and a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order by April 4, 2013.

2. Board staff and VECC shall file any comments on the draft Rate Order

including the revised models and proposed Tariff of Rates and Charges with the Board and forward to API within 7 days of the date of filing of the draft Rate Order.

3. API shall file with the Board and forward to intervenors responses to any comments on its draft Rate Order including the revised models and proposed Tariff of Rates and Charges within 4 days of the date of receipt of Board staff and intervenor comments.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit its cost claim no later than **7 days** from the date of issuance of the final Rate Order.

2. API shall file with the Board and forward to VECC any objections to the claimed costs within **17 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to API any responses to any objections for cost claims within **24 days** from the date of issuance of the final Rate Order.

4. API shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2012-0104,** be made through the Board's web portal at, www.pes.ontarioenergyboard.ca/eservice/ and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, March 28, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Calculation of Provincial Average Rate Increase

Board File No: EB-2012-0104

DATED: March 28, 2013

Applicant Name	Class	MFC 2012	VC 2012	MFC 2011	VC 2011	TB 2012	TB 2011	$ Chg	% Chg	Average % Chg
Atikokan Hydro Inc.	Residential	33.99	10.72	30.58	9.68	44.71	40.26	4.45	11.05%	
Atikokan Hydro Inc.	GS < 50	74.07	18.80	70.02	17.80	92.87	87.82	5.05	5.75%	8.40%
Bluewater Power Distribution Corporation	Residential	13.80	15.04	13.68	14.88	28.84	28.56	0.28	0.98%	
Bluewater Power Distribution Corporation	GS < 50	23.71	33.20	24.01	33.80	56.91	57.81	-0.90	-1.56%	-0.29%
Brant County Power Inc.	Residential	11.07	16.64	11.00	18.96	27.71	29.96	-2.25	-7.51%	
Brant County Power Inc.	GS < 50	17.12	35.60	17.00	35.40	52.72	52.40	0.32	0.61%	-3.45%
Brantford Power Inc.	Residential	11.46	11.04	11.36	10.96	22.50	22.32	0.18	0.81%	
Brantford Power Inc.	GS < 50	24.81	13.00	24.59	12.80	37.81	37.39	0.42	1.12%	0.96%
Burlington Hydro Inc.	Residential	12.23	13.28	12.12	13.20	25.51	25.32	0.19	0.75%	
Burlington Hydro Inc.	GS < 50	25.41	27.20	25.19	27.00	52.61	52.19	0.42	0.80%	0.78%
Cambridge and North Dumfries Hydro Inc.	Residential	10.04	12.96	9.95	12.88	23.00	22.83	0.17	0.74%	
Cambridge and North Dumfries Hydro Inc.	GS < 50	11.86	25.20	11.76	25.00	37.06	36.76	0.30	0.82%	0.78%
Canadian Niagara Power Inc. (Average)	Residential	17.30	13.97	17.16	13.89	31.28	31.05	0.22	0.72%	
Canadian Niagara Power Inc. (Average)	GS < 50	24.28	39.80	24.09	39.47	64.08	63.56	0.52	0.82%	0.77%
Centre Wellington Hydro Ltd.	Residential	13.88	10.24	13.79	10.16	24.12	23.95	0.17	0.71%	
Centre Wellington Hydro Ltd.	GS < 50	15.31	32.00	15.21	31.80	47.31	47.01	0.30	0.64%	0.67%
Chapleau Public Utilities Corporation	Residential	20.15	10.80	18.46	8.16	30.95	26.62	4.33	16.27%	
Chapleau Public Utilities Corporation	GS < 50	31.79	34.80	30.00	24.40	66.59	54.40	12.19	22.41%	19.34%
Chatham-Kent Hydro Inc.	Residential	18.30	6.80	18.10	6.72	25.10	24.82	0.28	1.13%	
Chatham-Kent Hydro Inc.	GS < 50	33.59	22.60	33.23	22.40	56.19	55.63	0.56	1.01%	1.07%
COLLUS Power Corporation	Residential	9.00	13.60	8.94	13.52	22.60	22.46	0.14	0.62%	
COLLUS Power Corporation	GS < 50	17.98	22.60	17.86	22.40	40.58	40.26	0.32	0.79%	0.71%
Cooperative Hydro Embrun Inc.	Residential	13.63	10.16	13.51	10.08	23.79	23.59	0.20	0.85%	
Cooperative Hydro Embrun Inc.	GS < 50	20.24	33.40	20.06	33.20	53.64	53.26	0.38	0.71%	0.78%
Enersource Hydro Mississauga Inc.	Residential	11.87	9.52	11.77	9.44	21.39	21.21	0.18	0.85%	
Enersource Hydro Mississauga Inc.	GS < 50	39.93	23.20	39.58	23.00	63.13	62.58	0.55	0.88%	0.86%
ENWIN Utilities Ltd.	Residential	10.77	16.08	10.70	16.00	26.85	26.70	0.15	0.56%	
ENWIN Utilities Ltd.	GS < 50	25.39	32.60	25.22	32.40	57.99	57.62	0.37	0.64%	0.60%
Erie Thames Powerlines Corporation	Residential	15.21	14.24	14.19	10.08	29.45	24.27	5.18	21.34%	
Erie Thames Powerlines Corporation	GS < 50	20.95	27.20	18.94	18.00	48.15	36.94	11.21	30.35%	25.84%
Espanola Regional Hydro Distribution Corporation	Residential	13.59	13.12	9.96	9.60	26.71	19.56	7.15	36.55%	
Espanola Regional Hydro Distribution Corporation	GS < 50	24.36	40.00	17.95	29.40	64.36	47.35	17.01	35.92%	36.24%
Essex Powerlines Corporation	Residential	12.68	11.92	12.57	11.84	24.60	24.41	0.19	0.78%	
Essex Powerlines Corporation	GS < 50	33.19	22.60	25.89	17.60	55.79	43.49	12.30	28.28%	14.53%
Festival Hydro Inc.	Residential	14.92	13.28	14.78	13.12	28.20	27.90	0.30	1.08%	
Festival Hydro Inc.	GS < 50	28.88	29.20	28.87	29.00	58.08	57.87	0.21	0.36%	0.72%
Fort Frances Power Corporation	Residential	11.99	7.04	11.89	6.96	19.03	18.85	0.18	0.95%	
Fort Frances Power Corporation	GS < 50	28.89	13.20	28.64	13.00	42.09	41.64	0.45	1.08%	1.02%
Greater Sudbury Hydro Inc.	Residential	16.14	9.92	16.00	9.84	26.06	25.84	0.22	0.85%	
Greater Sudbury Hydro Inc.	GS < 50	21.55	37.20	21.36	36.80	58.75	58.16	0.59	1.01%	0.93%
Grimsby Power Inc.	Residential	15.11	9.28	15.11	6.88	24.39	21.99	2.40	10.91%	
Grimsby Power Inc.	GS < 50	25.56	25.00	25.56	20.00	50.56	45.56	5.00	10.97%	10.94%
Guelph Hydro Electric Systems Inc.	Residential	13.95	13.60	13.41	13.12	27.55	26.53	1.02	3.84%	
Guelph Hydro Electric Systems Inc.	GS < 50	15.00	25.20	12.26	31.20	40.20	43.46	-3.26	-7.50%	-1.83%
Haldimand County Hydro Inc.	Residential	16.16	23.12	14.10	24.88	39.28	38.98	0.30	0.77%	
Haldimand County Hydro Inc.	GS < 50	28.90	40.80	28.65	40.40	69.70	69.05	0.65	0.94%	0.86%
Halton Hills Hydro Inc.	Residential	12.25	9.20	12.94	9.68	21.45	22.62	-1.17	-5.17%	
Halton Hills Hydro Inc.	GS < 50	26.50	16.60	28.28	17.80	43.10	46.08	-2.98	-6.47%	-5.82%

Hearst Power Distribution Company Limited	Residential	9.15	12.72	9.00	12.48	21.87	21.48	0.39	1.82%	
Hearst Power Distribution Company Limited	GS < 50	19.67	13.40	19.50	13.20	33.07	32.70	0.37	1.13%	1.47%
Horizon Utilities Corporation	Residential	14.53	11.44	14.45	11.36	25.97	25.81	0.16	0.62%	
Horizon Utilities Corporation	GS < 50	32.35	16.80	32.16	16.80	49.15	48.96	0.19	0.39%	0.50%
Hydro 2000 Inc.	Residential	12.87	10.32	8.53	4.80	23.19	13.33	9.86	73.97%	
Hydro 2000 Inc.	GS < 50	28.85	25.00	24.61	16.20	53.85	40.81	13.04	31.95%	52.96%
Hydro Hawkesbury Inc.	Residential	5.95	6.40	5.89	6.32	12.35	12.21	0.14	1.15%	
Hydro Hawkesbury Inc.	GS < 50	13.75	11.00	13.60	10.80	24.75	24.40	0.35	1.43%	1.29%
Hydro One Brampton Networks Inc.	Residential	9.83	11.44	9.75	11.36	21.27	21.11	0.16	0.76%	
Hydro One Brampton Networks Inc.	GS < 50	17.75	31.20	17.61	31.00	48.95	48.61	0.34	0.70%	0.73%
Hydro Ottawa Limited	Residential	9.32	18.08	8.54	16.56	27.40	25.10	2.30	9.16%	
Hydro Ottawa Limited	GS < 50	16.11	40.40	14.76	37.00	56.51	51.76	4.75	9.18%	9.17%
Innisfil Hydro Distribution Systems Limited	Residential	19.22	15.04	19.05	14.88	34.26	33.93	0.33	0.97%	
Innisfil Hydro Distribution Systems Limited	GS < 50	28.85	17.20	28.60	17.00	46.05	45.60	0.45	0.99%	0.98%
Kenora Hydro Electric Corporation Ltd.	Residential	18.94	11.04	18.77	10.96	29.98	29.73	0.25	0.84%	
Kenora Hydro Electric Corporation Ltd.	GS < 50	37.18	11.60	36.86	11.40	48.78	48.26	0.52	1.08%	0.96%
Kingston Hydro Corporation	Residential	12.17	11.92	12.06	11.84	24.09	23.90	0.19	0.79%	
Kingston Hydro Corporation	GS < 50	25.05	20.80	24.83	20.60	45.85	45.43	0.42	0.92%	0.86%
Kitchener-Wilmot Hydro Inc.	Residential	9.69	13.76	9.59	13.60	23.45	23.19	0.26	1.12%	
Kitchener-Wilmot Hydro Inc.	GS < 50	25.54	24.60	25.27	24.40	50.14	49.67	0.47	0.95%	1.03%
Lakefront Utilities Inc.	Residential	9.92	11.44	9.29	10.72	21.36	20.01	1.35	6.75%	
Lakefront Utilities Inc.	GS < 50	22.70	16.40	22.20	16.20	39.10	38.40	0.70	1.82%	4.28%
Lakeland Power Distribution Ltd.	Residential	15.35	11.04	15.22	10.96	26.39	26.18	0.21	0.80%	
Lakeland Power Distribution Ltd.	GS < 50	36.65	16.80	36.33	16.60	53.45	52.93	0.52	0.98%	0.89%
London Hydro Inc.	Residential	12.72	11.44	12.61	11.36	24.16	23.97	0.19	0.79%	
London Hydro Inc.	GS < 50	29.58	18.40	29.32	18.20	47.98	47.52	0.46	0.97%	0.88%
Middlesex Power Distribution Corporation (Average)	Residential	12.98	10.24	12.84	10.13	23.22	22.97	0.25	1.07%	
Middlesex Power Distribution Corporation (Average)	GS < 50	22.31	14.47	22.07	14.27	36.78	36.34	0.44	1.21%	1.14%
Midland Power Utility Corporation	Residential	11.78	15.68	11.68	15.52	27.46	27.20	0.26	0.96%	
Midland Power Utility Corporation	GS < 50	14.86	31.00	14.73	30.80	45.86	45.53	0.33	0.72%	0.84%
Milton Hydro Distribution inc.	Residential	14.93	11.12	14.80	11.04	26.05	25.84	0.21	0.81%	
Milton Hydro Distribution inc.	GS < 50	15.89	33.80	15.79	33.60	49.69	49.39	0.30	0.61%	0.71%
Newmarket - Tay Power Distribution Ltd. (Average)	Residential	14.84	11.52	14.71	11.44	26.36	26.15	0.21	0.80%	
Newmarket - Tay Power Distribution Ltd. (Average)	GS < 50	29.54	38.60	29.28	38.20	68.14	67.48	0.66	0.98%	0.89%
Niagara Peninsula Energy Inc. (Average)	Residential	15.76	12.64	15.62	12.56	28.40	28.18	0.22	0.78%	
Niagara Peninsula Energy Inc. (Average)	GS < 50	37.09	27.00	36.77	26.80	64.09	63.57	0.52	0.82%	0.80%
Niagara-on-the-Lake Hydro Inc.	Residential	18.22	10.24	18.06	10.16	28.46	28.22	0.24	0.85%	
Niagara-on-the-Lake Hydro Inc.	GS < 50	45.75	27.40	45.35	27.20	73.15	72.55	0.60	0.83%	0.84%
Norfolk Power Distribution Inc.	Residential	20.77	17.36	20.77	15.20	38.13	35.97	2.16	6.01%	
Norfolk Power Distribution Inc.	GS < 50	49.74	31.00	49.74	27.80	80.74	77.54	3.20	4.13%	5.07%
North Bay Hydro Distribution Limited	Residential	14.34	10.24	14.21	10.16	24.58	24.37	0.21	0.86%	
North Bay Hydro Distribution Limited	GS < 50	21.25	32.80	21.78	33.80	54.05	55.58	-1.53	-2.75%	-0.95%
Northern Ontario Wires Inc.	Residential	17.83	10.80	17.64	10.72	28.63	28.36	0.27	0.95%	
Northern Ontario Wires Inc.	GS < 50	23.90	26.80	23.64	26.60	50.70	50.24	0.46	0.92%	0.93%
Oakville Hydro Electricity Distribution Inc.	Residential	13.05	11.36	13.10	11.44	24.41	24.54	-0.13	-0.53%	
Oakville Hydro Electricity Distribution Inc.	GS < 50	32.09	28.20	32.20	28.20	60.29	60.40	-0.11	-0.18%	-0.36%
Orangeville Hydro Limited	Residential	16.26	11.20	16.14	11.12	27.46	27.26	0.20	0.73%	
Orangeville Hydro Limited	GS < 50	33.11	20.20	32.82	20.00	53.31	52.82	0.49	0.93%	0.83%
Orillia Power Distribution Corporation	Residential	13.61	13.04	13.49	12.96	26.65	26.45	0.20	0.76%	
Orillia Power Distribution Corporation	GS < 50	35.69	31.60	35.38	31.40	67.29	66.78	0.51	0.76%	0.76%
Oshawa PUC Networks Inc.	Residential	8.25	9.36	8.45	9.84	17.61	18.29	-0.68	-3.72%	

Oshawa PUC Networks Inc.	GS < 50	8.16	33.00	8.39	34.40	41.16	42.79	-1.63	-3.81%	-3.76%
Ottawa River Power Corporation	Residential	10.93	11.84	10.95	11.92	22.77	22.87	-0.10	-0.44%	
Ottawa River Power Corporation	GS < 50	22.61	20.80	23.41	16.60	43.41	40.01	3.40	8.50%	4.03%
Parry Sound Power Corporation	Residential	21.67	13.84	21.55	13.76	35.51	35.31	0.20	0.57%	
Parry Sound Power Corporation	GS < 50	32.38	26.60	32.19	26.40	58.98	58.59	0.39	0.67%	0.62%
Peterborough Distribution Incorporated	Residential	11.91	9.28	11.81	9.20	21.19	21.01	0.18	0.86%	
Peterborough Distribution Incorporated	GS < 50	29.90	18.00	29.64	17.80	47.90	47.44	0.46	0.97%	0.91%
PowerStream Inc. (Average)	Residential	13.67	10.88	13.55	10.80	24.55	24.35	0.20	0.80%	
PowerStream Inc. (Average)	GS < 50	22.38	28.00	22.18	27.80	50.38	49.98	0.40	0.79%	0.80%
PUC Distribution Inc.	Residential	8.81	12.16	8.73	12.08	20.97	20.81	0.16	0.77%	
PUC Distribution Inc.	GS < 50	15.00	36.00	14.87	35.60	51.00	50.47	0.53	1.05%	0.91%
Renfrew Hydro Inc.	Residential	13.91	11.52	14.11	11.68	25.43	25.79	-0.36	-1.40%	
Renfrew Hydro Inc.	GS < 50	30.39	26.80	30.07	26.60	57.19	56.67	0.52	0.92%	-0.24%
Rideau St. Lawrence Distribution Inc.	Residential	12.76	11.60	10.28	9.36	24.36	19.64	4.72	24.03%	
Rideau St. Lawrence Distribution Inc.	GS < 50	29.53	18.00	24.34	14.80	47.53	39.14	8.39	21.44%	22.73%
Sioux Lookout Hydro Inc.	Residential	24.26	8.32	24.05	8.24	32.58	32.29	0.29	0.90%	
Sioux Lookout Hydro Inc.	GS < 50	43.11	16.40	42.73	16.20	59.51	58.93	0.58	0.98%	0.94%
St. Thomas Energy Inc.	Residential	11.46	12.72	11.50	12.80	24.18	24.30	-0.12	-0.49%	
St. Thomas Energy Inc.	GS < 50	17.15	29.60	17.00	29.40	46.75	46.40	0.35	0.75%	0.13%
Thunder Bay Hydro Electricity Distribution Inc.	Residential	9.85	9.92	9.88	9.92	19.77	19.80	-0.03	-0.15%	
Thunder Bay Hydro Electricity Distribution Inc.	GS < 50	17.84	26.00	17.89	26.20	43.84	44.09	-0.25	-0.57%	-0.36%
Tillsonburg Hydro Inc.	Residential	9.91	13.52	9.82	13.44	23.43	23.26	0.17	0.73%	
Tillsonburg Hydro Inc.	GS < 50	25.07	30.40	24.85	30.20	55.47	55.05	0.42	0.76%	0.75%
Veridian Connections Inc. (Average)	Residential	10.62	14.04	10.53	13.92	24.66	24.45	0.21	0.88%	
Veridian Connections Inc. (Average)	GS < 50	11.88	33.80	12.28	35.30	45.68	47.58	-1.90	-3.98%	-1.55%
Wasaga Distribution Inc.	Residential	11.15	11.12	11.82	11.76	22.27	23.58	-1.31	-5.56%	
Wasaga Distribution Inc.	GS < 50	13.05	26.40	13.65	27.60	39.45	41.25	-1.80	-4.36%	-4.96%
Waterloo North Hydro Inc.	Residential	14.72	14.88	14.56	14.72	29.60	29.28	0.32	1.09%	
Waterloo North Hydro Inc.	GS < 50	30.96	27.60	30.63	27.40	58.56	58.03	0.53	0.91%	1.00%
Welland Hydro-Electric System Corp.	Residential	14.37	11.52	14.24	11.44	25.89	25.68	0.21	0.82%	
Welland Hydro-Electric System Corp.	GS < 50	24.80	17.40	24.58	17.20	42.20	41.78	0.42	1.01%	0.91%
Wellington North Power Inc.	Residential	18.00	14.40	13.88	11.12	32.40	25.00	7.40	29.60%	
Wellington North Power Inc.	GS < 50	38.21	32.80	27.88	24.00	71.01	51.88	19.13	36.87%	33.24%
West Coast Huron Energy Inc.	Residential	14.20	14.72	14.08	14.56	28.92	28.64	0.28	0.98%	
West Coast Huron Energy Inc.	GS < 50	33.72	23.20	33.43	23.00	56.92	56.43	0.49	0.87%	0.92%
Westario Power Inc.	Residential	11.34	11.36	11.24	11.28	22.70	22.52	0.18	0.80%	
Westario Power Inc.	GS < 50	20.77	18.40	20.59	18.20	39.17	38.79	0.38	0.98%	0.89%
Whitby Hydro Electric Corporation	Residential	17.29	11.36	17.24	11.28	28.65	28.52	0.13	0.46%	
Whitby Hydro Electric Corporation	GS < 50	19.91	39.00	19.80	38.80	58.91	58.60	0.31	0.53%	0.49%
Woodstock Hydro Services Inc.	Residential	12.83	17.60	12.72	17.44	30.43	30.16	0.27	0.90%	
Woodstock Hydro Services Inc.	GS < 50	24.80	28.40	24.58	28.20	53.20	52.78	0.42	0.80%	0.85%

* Rate Order as of December 31, 2012

Average Percent Change	**3.75%**